The long-term viability of coal for power generation in South Africa

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List of Abbreviations

CCGT	Combined cycle gas turbine
CO₂	Carbon Dioxide
COUE	Cost of Unserved Energy
CSP	Concentrated Solar Power
DoE	Department of Energy
EIUG	Energy Intensive User Group
EPRI	Electric Power Research Institute
EWH	Electric water heaters
FFB	Fabric filter bag
IPP	Independent Power Producer
IRP	Integrated Resource Plan
LCOE	Levelized Cost of Electricty
LNB	Low-NOx burner
NERSA	National Energy Regulator of South Africa
NOx	Nitrogen Oxides
OCGT	Open cycle gas turbine
PM	Particulate Matter
PPA	Power Purchase Agreement
PV	Photovoltaic
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
SAV	System Alternative Value
SOx	Sulphur Oxides

1 Background

The CSIR was contracted by IEEFA via ECF to conduct power system analysis on the current and future South African power system.

In this context, analysis was conducted on the "system alternative value" ("SAV") of running particular existing or under construction coal-fired power stations (or set of power stations) in South Africa. In essence the SAV is the absolute value which a particular power stations' optimised energy profile provides to the power system in the long-term. This can also be expressed as an equivalent unitised value (R/MWh). This value to the power system is clearly dependent on the timing of energy provided by the power station, which in turn affects the dispatch of other power generators to meet the residual load. Additionally, the presence of particular types of generators in the power system influences the structure of the corresponding supply mix in the long-term and thus triggers different investment decisions and associated costs.

Once the SAV of running a particular power station (or set of power stations) is determined, it can be compared to the expected fixed and variable operating costs as well as capital costs of that power station (or set of power stations). In order for a new power station (or set of power stations) to be more valuable to the power system than existing and alternative power stations, the total cost of building and operating those power stations (or set of power stations) should be less than the SAV. The SAV thus becomes a ceiling for the cost of any power station (or set of power stations) considered. Similarly, for an existing power station, the cost of operating the power station throughout its lifetime should be less than its SAV to continue providing the most benefit to the power system. If the costs of building and operating a power station are greater than its SAV, then it would be more economical to shut it down (if existing) or not build it (if new) and meet the energy (and capacity) requirements through other supply or demand side options.

2 Methodology and approach

The methodology determines the SAV of a particular power station (or set of power stations) from a systems perspective. The methodology can be applied to any type of electricity generation technology but is specifically applied to a range of coal power stations in South Africa in this analysis.

In order to calculate the SAV, two key cost components resulting from the presence of a particular power station (or set of power stations) are measured; namely:

(i)   the effect on the investment required for additional power generators needed to supply the residual load (when the power station or set of power generators under study are removed); and

(ii)   the effect on the dispatch of existing and possible new power generators to supply the residual load i.e. their fixed and variable operations costs as well as fuel costs.

The steps listed below are followed for each power station (or set of power stations) under study to calculate their respective SAV (also represented graphically in Figure 1):

(i)   A least-cost capacity expansion plan is run to determine a Base Case electricity system over the planning horizon. From this, the total net-present value of all capital, fixed and variable costs for the system is calculated along with the present value of the energy generated from the power station (or set of power stations) under study;

(ii)   Step (i) is repeated with the power station (or set of power stations) under study removed at a particular date. This can take the form of an early retirement of a power station (relative to the expected decommissioning date) or discontinued construction of a committed/new power station. The difference in energy as well as capacity from removal of this power station (or set of power stations) will be replaced by a least-cost optimal supply mix including existing power stations as well as new-build supply options;

(iii) All costs associated with the power station (or set of power stations) under study are entirely removed from the total system cost of both (i) and (ii). This isolates the relative value difference provided by the power station (or set of power stations) and the set of existing and new-build supply options;

(iv)   The absolute difference in total discounted system costs (the value difference) and the energy difference determined previously are then used to determine the equivalent System Alternative Value (SAV).
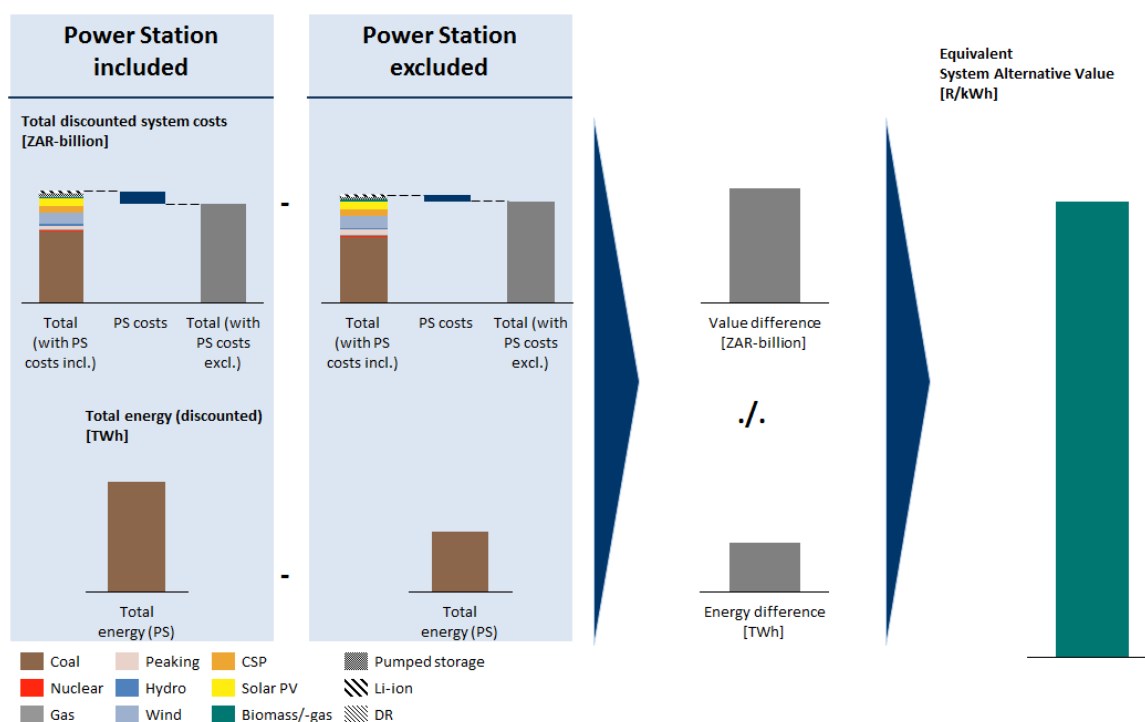
Figure 1. Methodology for calculating the System Alternative Value of a power station

In this study, the methodology is applied to the South African electricity system only. The tool used to implement the methodology is the energy system modelling software package PLEXOS® [1]. The methodology is applied with hourly temporal resolution and a study horizon of 2017-2050. Transmission constraints were excluded from the implementation i.e. only generation costs are modelled. Externalities such as job creation were also excluded from the analysis.

The power stations which were tested in this study are listed in Table 1.

Table 1. List of power stations which System Alternative Value was calculated for

Station name(s)	Case study
Kusile	The last 2 units of Kusile power station which are still under construction.
Arnot	Arnot power station being decommissioned earlier by end financial year (FY) 2020 versus end FY 2029
Camden	Camden power station being decommissioned earlier by end FY 2018 versus end FY 2023
Grootvlei	Grootvlei power station being decommissioned earlier by end FY 2019 versus end FY 2028

Station name(s)	Case study
Hendrina	Hendrina power station being decommissioned earlier by end FY 2018 versus end FY 2026
Komati	Komati power station being decommissioned earlier by end FY 2020 versus end FY 2028
Grootvlei, Hendrina, Komati combined	A combination of early retirement of Grootvlei, Hendrina and Komati as per dates above

3   Data Assumptions

3.1 Economic parameters

The economic input parameters used in this analysis were based on the Draft IRP 2016 [2] and includes a discount rate of 8.2% and a Cost of Unserved Energy (COUE) of 77.30 R/kWh. All costs in this study are in April 2016 Rands.

3.2 Electricity demand forecast

Two electricity demand forecasts were used in this study and are referred to as the "high" and "low" demand forecasts. The high demand forecast was taken from the Draft IRP 2016 Base Case [2] while the low demand forecast from [3] was used which was developed by the Energy Intensive User Group (EIUG). Figure 2 shows the historical electrical demand and forecasted demand from the Draft IRP 2016 ("High") and EIUG ("Low").
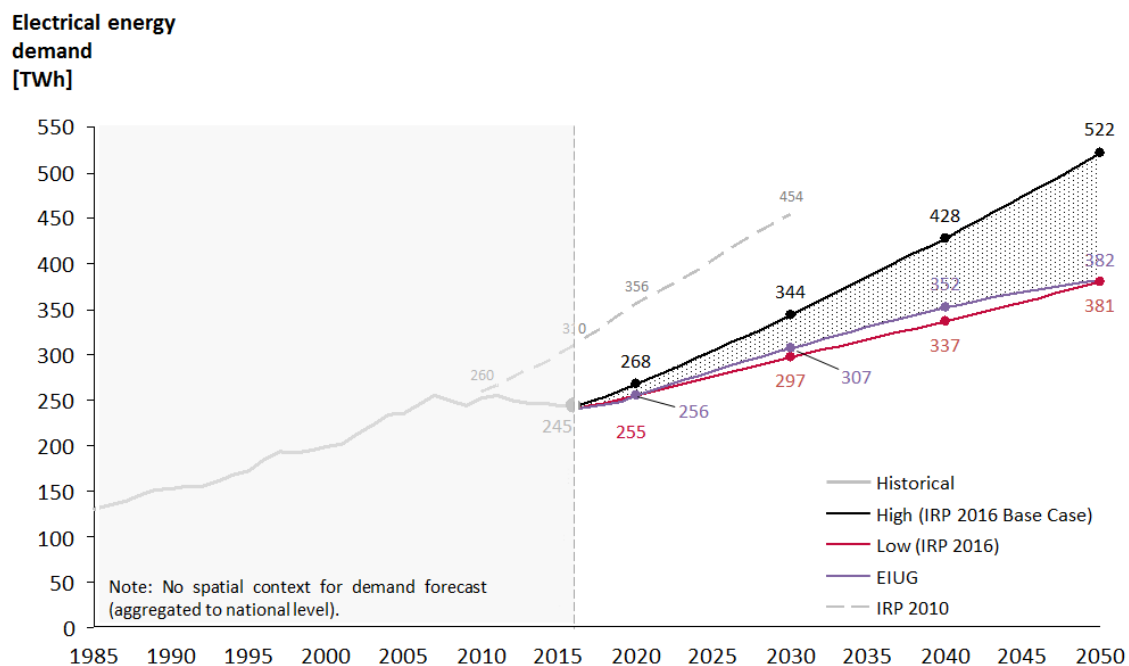
Figure 2. Electrical energy demand forecast from the IRP 2016 (CSIR) and the EIUG

3.3 Existing and committed capacity

The existing and committed utility-scale generation capacity in South Africa was modelled using publically available data. Where available, the technical, cost characteristics and commissioning and decommissioning schedules of the Eskom fleet were obtained from the Eskom website, Eskom integrated reports [4], [5] and the Draft IRP 2016 [2]. This study assumes that all renewable capacity from the REIPPPP Bid Window 1, 2, 3, 3.5 and 4 are committed and excludes Bid Window 4 Additional, Expedited and new-build coal IPPs. The "P80 commissioning dates" from [2] were used for the Eskom committed plant (Medupi, Kusile and Ingula).

The existing generation capacity in South Africa will mostly be decommissioned by 2050 as shown in Figure 3 [3]. Figure 4 shows a more detailed breakdown of how the existing coal fleet in South Africa is planned to decommission. As can be seen, South Africa currently has just less than 50 GW of installed generation capacity. 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, and one unit at Majuba are 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 comes 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.
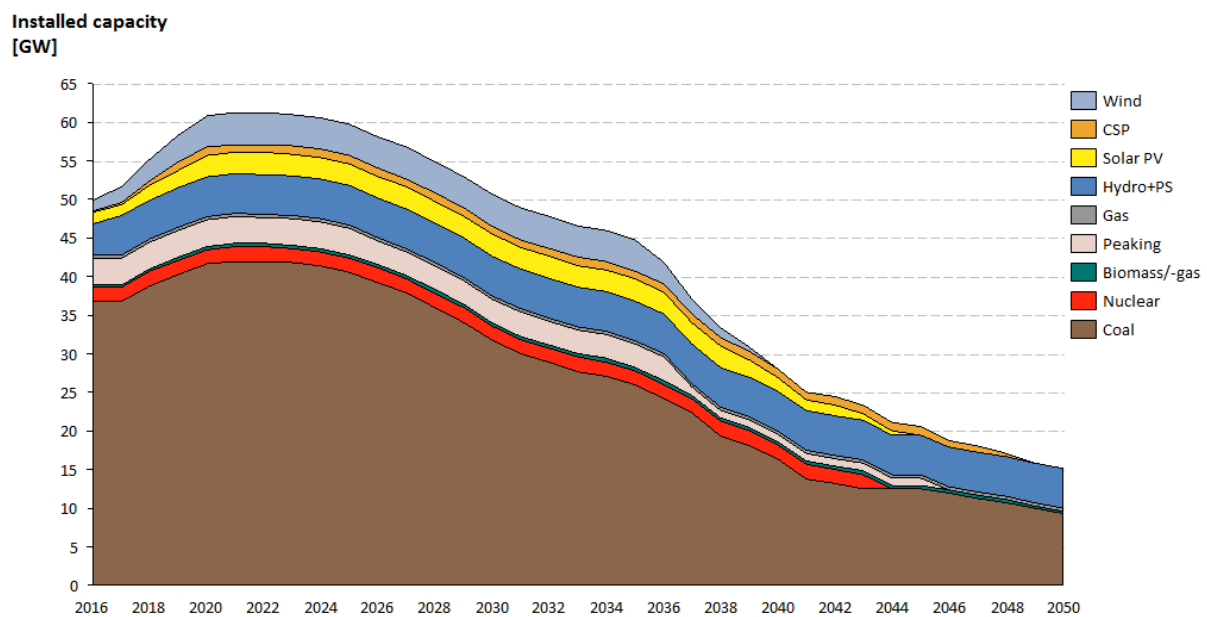
Figure 3. South African generation capacity decommissioning schedule. Source: CSIR
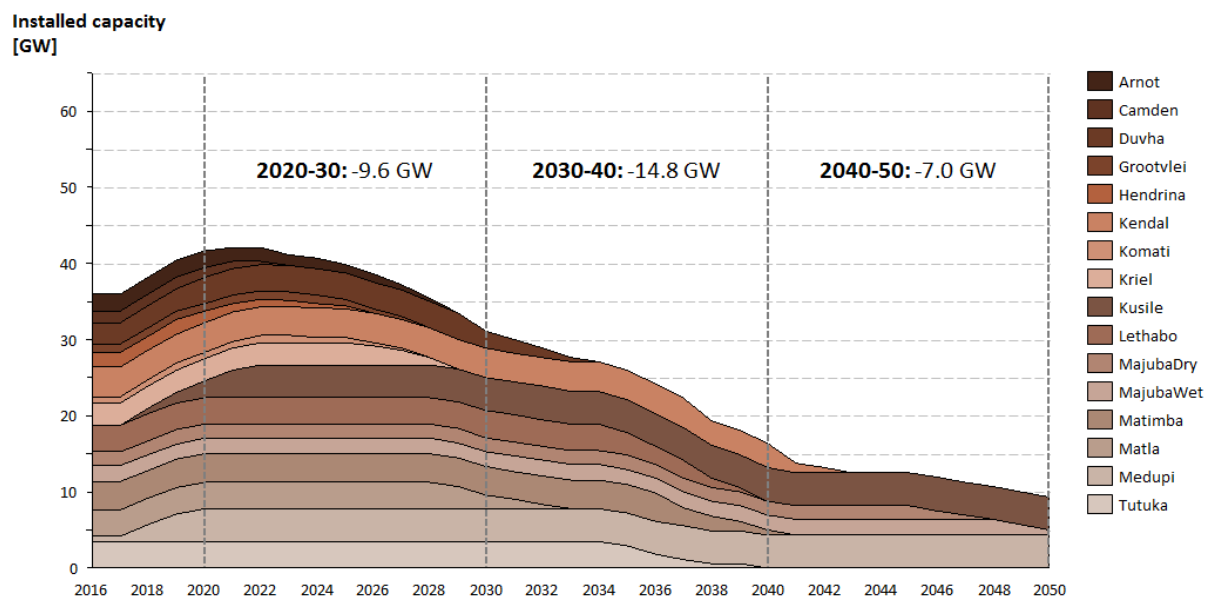
Figure 4. South African coal generation capacity decommissioning schedule. Source: CSIR

The technical characteristics shown in Figure 5 were specified for all generators in the model implementation. The Eskom coal fleet was modelled with the constraint of not being allowed to two-shift (with the exception of Majuba). The Eskom coal fleet therefore cannot be started and shutdown (except during maintenance or unplanned outages). This modelling constraint was added to avoid heavy cycling of the coal fleet which may be technically infeasible in reality.
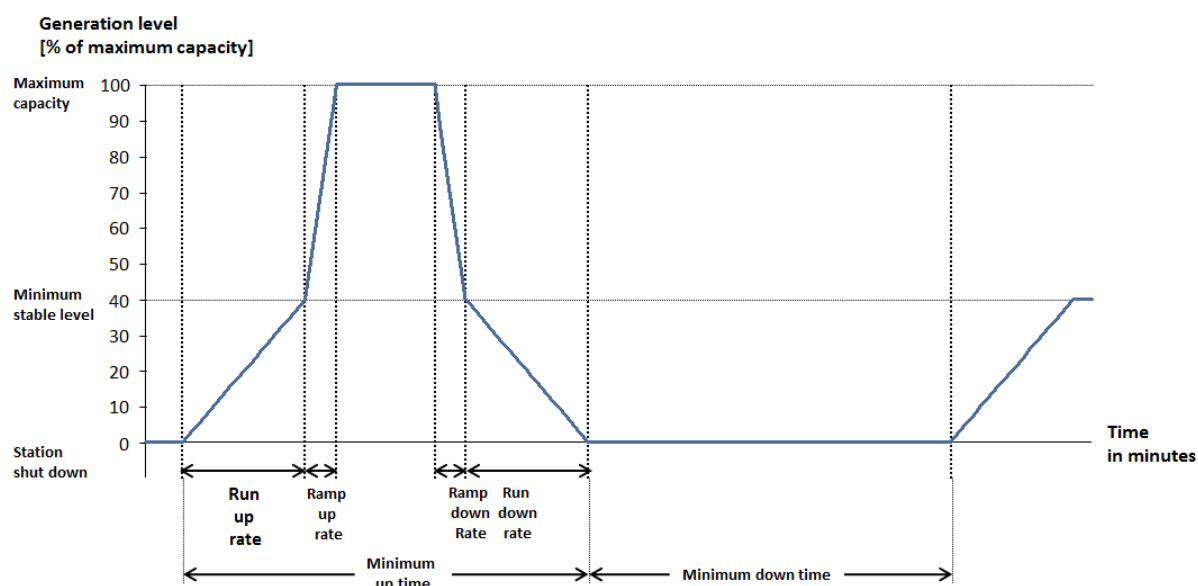
Figure 5. Technical characteristics specified in the model for all generators

3.4 Existing Eskom fleet performance

The existing fleet of power generators in South Africa is predominantly made up of the Eskom coal fleet. As defined in the Draft IRP 2016, the performance of this fleet is as summarised in Figure 6 via the Energy Availability Factor (EAF). This study adopted the Moderate fleet performance profile which has an average fleet availability of 80% from 2020 onwards as used in the Draft IRP 2016 Base Case.
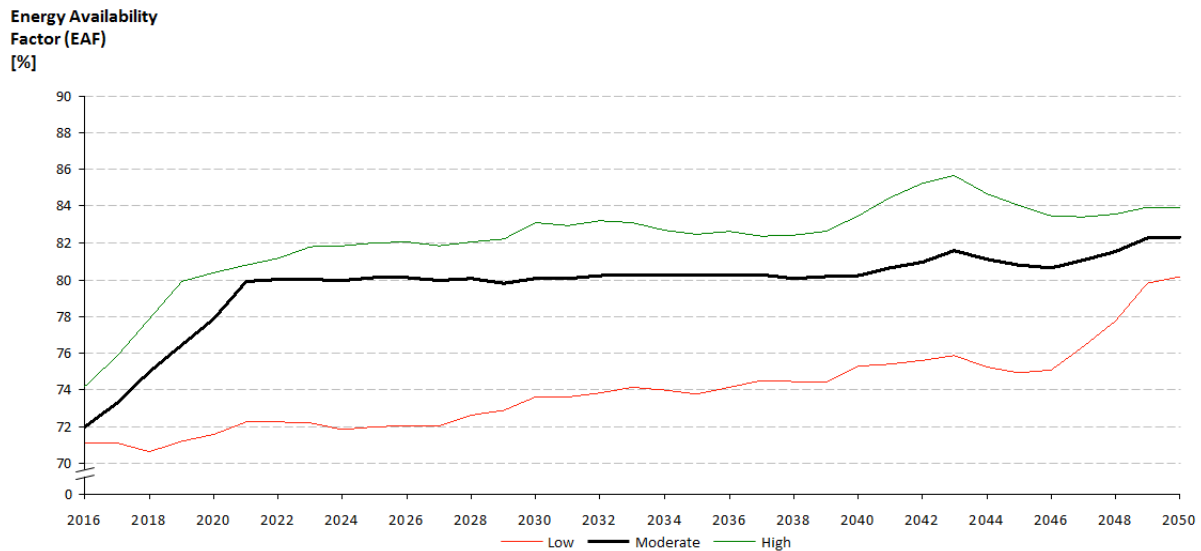
Figure 6. Existing Eskom fleet plant performance. Source: Draft IRP 2016

3.5 Supply technology cost structures

3.5.1 Conventional and renewable technologies

The supply technology cost structures used in this study for conventional and renewable energy technologies are summarized in Table 2 and Table 3 respectively. The costs for conventional technologies are aligned to [2] and [6] and were inflated to April 2016 Rands using Consumer Price Inflation (CPI).

The starting point in 2016 for the costs of wind, solar photovoltaics (PV) and Concentrated Solar Power (CSP) were based on the latest Renewable Independent Power Producer Purchaser Programme (REIPPPP) Bid Window 4 (Expedited) tariffs. CSP was assumed to follow a similar learning curve shape to that of the IRP 2010-2030 [7] until 2030 following which costs remain constant. Learning for wind was based on the latest Bloomberg Energy Outlook report [8], which expects wind costs to decline by ~25% by 2030 and ~50% by 2040 and remain constant thereafter. Similarly, learning for solar PV was also based on [8], whereby solar PV costs decline by ~35% by 2030 and ~70% by 2040 and remain constant thereafter. The wind, solar PV and CSP cost assumptions are shown in figures 7-9.
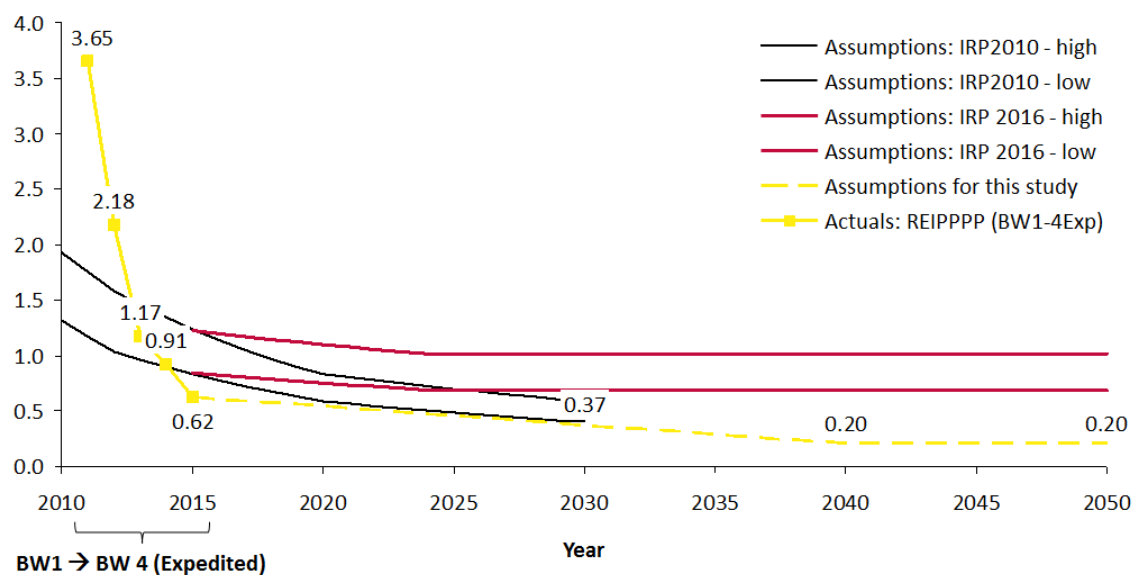
Figure 7. Equivalent cost assumption for solar PV based on cost structure of the technology. Source: CSIR
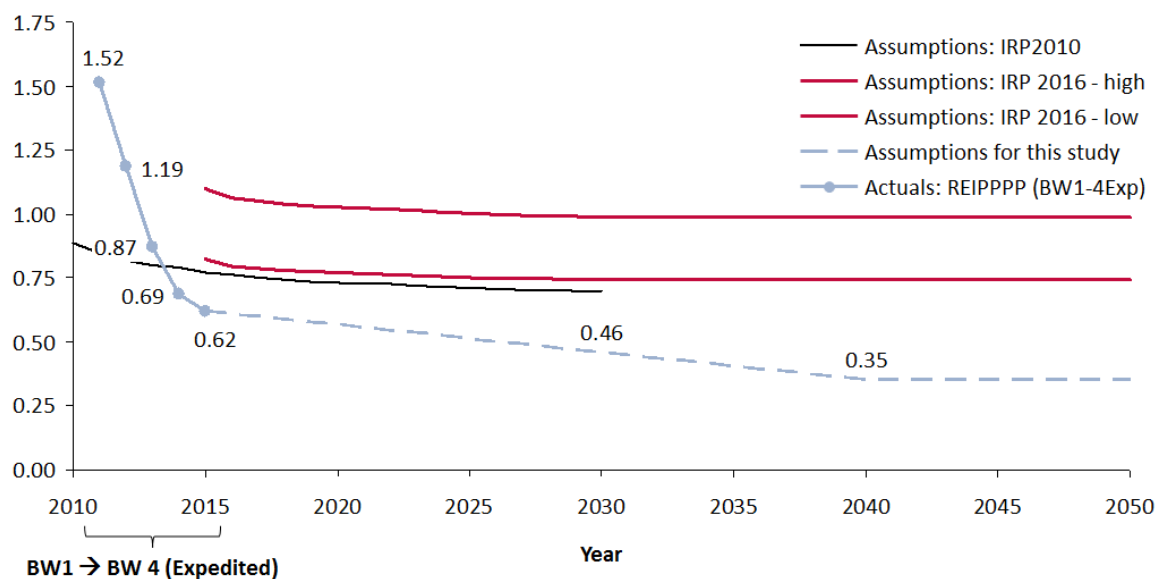
Figure 8. Equivalent cost assumption for wind based on cost structure of the technology. Source: CSIR
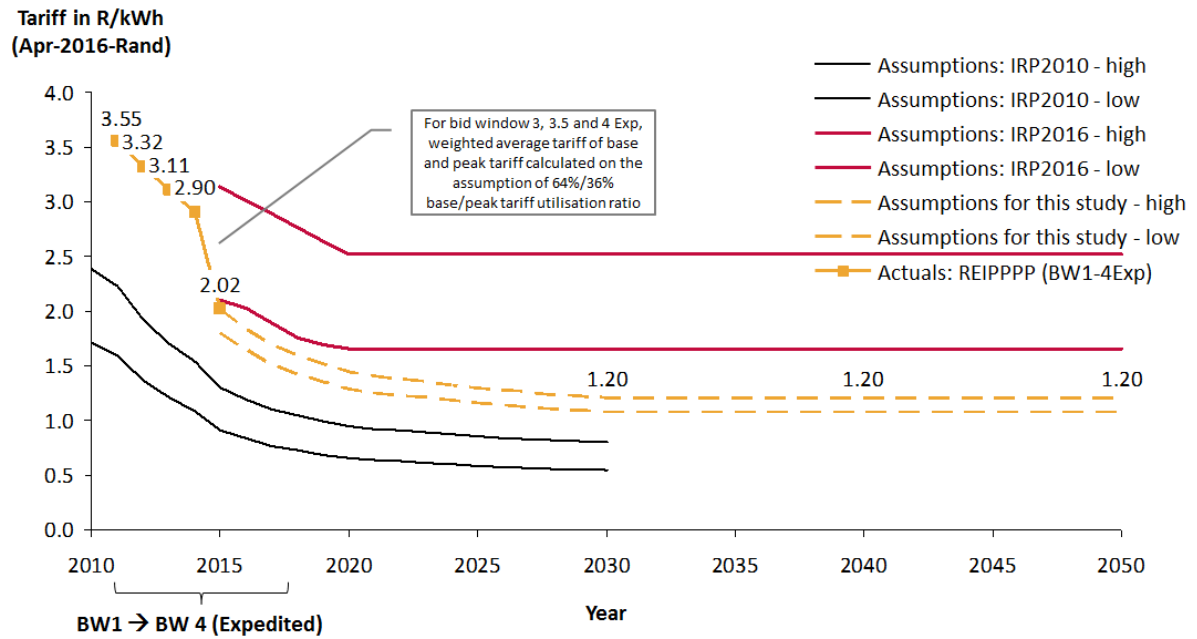
Figure 9. Equivalent cost assumption for CSP based on cost structure of the technology. Source: CSIR

Table 2. Technology cost structures: conventional power plants

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 3. Technology cost structures: renewables

Property			Renewables										
			Wind	Solar PV (fixed)	CPV	CSP (tower, 3h)	CSP (tower, 12h)	Biomass (forestry)	Biomass (MSW)	Landfill Gas	Biogas	Bagasse (Felixton)	Bagasse (gen)
Rated capacity (net)		[MW]	100	10	10	125	125	25	25	5	5	49	53
Overnight cost per capacity	2016	[ZAR/kW]	13 250	9 243	50 375	62 564	93 168	43 893	143 004	31 048	12 751	17 821	34 165
	2030 - 2040		9 780	5 486	50 375	29 013	32 495	43 893	143 004	31 048	12 751	17 821	34 165
	2040 - 2050	[ZAR/kW]	7 480	2 982	50 375	29 013	32 495	43 893	143 004	31 048	12 751	17 821	34 165
Construction time		[a]	4	1	1	4	4	4	4	1	1	2	3
Fuel cost		[ZAR/GJ]	0	0	0	0	0	32	0	0	0	81	81
Heat rate		[GJ/MWh]	0	0	0	0	0	14 243	18 991	12 302	11 999	26 874	19 327
Fixed O&M		[ZAR/kW/a]	606	327	314	941	1 009	1 655	6 470	2 373	1 941	172	390
Variable O&M		[ZAR/MWh]	0	0	0	1	1	66	114	62	52	9	27
Load factor (typical)		[./.]	36%	24%	30%	38%	60%	85%	85%	85%	85%	55%	50%
Economic lifetime		[a]	20	25	25	30	30	30	30	30	30	30	30
Capital phasing		[%/a]											
			5%			10%	10%	10%	10%				
			5%			25%	25%	25%	25%				10%
			10%			45%	45%	45%	45%			33%	30%
			80%	100%	100%	20%	20%	20%	20%	100%	100%	67%	60%

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

3.5.2 Stationary storage technologies

Stationary storage technologies modelled in this work include Lithium-ion batteries (1 hour and 3 hour) and Compressed Air Energy Storage (CAES). The starting cost assumptions in 2016 for these technologies were based on [2] and learning was assumed for Lithium-ion batteries based on [8] and [9] and are summarized in Table 4. Costs for CAES are assumed to remain constant.

Table 4. Cost and input assumptions for stationary storage

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	8 100	9 891	24 492
	2030 - 2040	[ZAR/kW]	22 326	2 293	2 800	24 492
	2040 - 2050	[ZAR/kW]	22 326	1 719	2 100	24 492
	2050	[ZAR/kW]	22 326	1 147	1 400	24 492
Construction time		[a]	8	1	1	4
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.*

3.5.3 Demand shaping – electric water heaters

Demand shaping in the form of residential electric water heaters (EWH) was included in this study and was based on [10]. The input assumptions for the EWHs are summarized in Table 5. The EWH's are assumed to have intraday controllability (can be dispatched as needed on any given day) based on power system needs but must have a net-zero energy balance on a daily basis (no substitution effect).

Table 5. Input assumptions for electric water heaters

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

3.5.4 Demand flexibility – electric vehicles

Similar to the modelling of a demand shaping resource for EWHs, electric vehicles (e-vehicles) were included as a flexible demand side option in the model. The e-vehicle fleet assumptions were adapted from [10] and are summarized in Table 6. The e-vehicle fleet was modelled similarly to the EWH demand shaping resource in that it also has intraday controllability based on power system needs but needs to have a net-zero energy balance on a daily basis.

Table 6. Input assumptions for electric vehicles

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 - 8.2	8.5	12.3	16.2	20.5
EVs adoption	[%]	0 - 0	1.5	8.1	28.5	48.9
Number of EVs	[mln]	0 - 0	0.1	1.0	4.6	10.0
EVs energy requirement	[TWh/a]	-	0.5	3.7	17.1	37.0
EVs energy requirement	[GWh/d]	3.7	3.7	3.7	3.7	3.7
EVs (demand increase)	[MW]	-	100	4 600	44 300	95 800
EVs (demand decrease)	[MW]	-	100	400	2 000	4 200

3.6 Electricity sector emissions and water consumption

Relative power station emission rates for CO_2, SO_x, NO_x, and particulate matter (PM) for all technologies were modelled and aligned with the Draft IRP 2016. Water consumption rates were also modelled for each power station and also aligned with the Draft IRP 2016. The results in this study focus on the resulting electricity sector CO_2 emissions trajectories as the IRP 2016 Moderate Decline CO_2 trajectory constraint was assumed across all scenarios as shown in Figure 10.
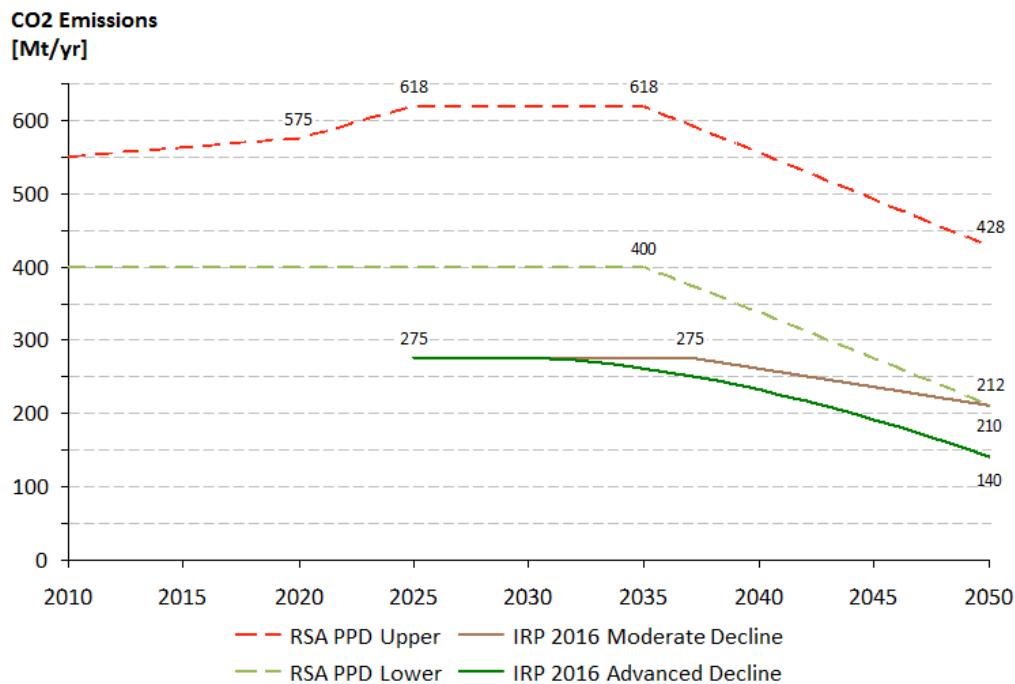

Figure 10. CO₂ electricity sector emissions trajectories for South Africa

3.7 System adequacy

As described in the approach, this study entailed least-cost capacity expansion planning which was solved by the co-optimisation between existing resource utilisation (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. 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). In this work all capacity expansion scenarios were optimized to the same level of system adequacy whereby Unserved Energy is priced very high and thus minimized. Additionally system operational reserve requirements as specified by Eskom up to 2022 and extrapolated forward thereafter had to be met in all scenarios as shown in Figure 11.

			2016-2019	2020-2022	2023-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054
Instantaneous	Summer	Peak	500	500	500	880	880	880	880	880	880
		Off-peak	800	800	800	1 400	1 400	1 400	1 400	1 400	1 400
	Winter	Peak	500	500	500	880	880	880	880	880	880
		Off-peak	800	800	800	1 400	1 400	1 400	1 400	1 400	1 400
Regulating	Summer	Peak	550	550	580	680	800	920	1 040	1 160	1 180
		Off-peak	550	550	580	680	800	920	1 040	1 160	1 180
	Winter	Peak	600	600	640	740	860	990	1 120	1 250	1 280
		Off-peak	600	600	640	740	860	990	1 120	1 250	1 280
Ten-minute	Summer	Peak	920	930	930	1 210	1 450	2 050	2 440	2 700	2 810
		Off-peak	920	930	930	1 210	1 450	2 050	2 440	2 700	2 810
	Winter	Peak	920	930	930	1 210	1 450	2 050	2 440	2 700	2 810
		Off-peak	920	930	930	1 210	1 450	2 050	2 440	2 700	2 810
Operating	Summer	Peak	1 970	1 980	2 010	2 770	3 130	3 850	4 360	4 740	4 870
		Off-peak	2 270	2 280	2 310	3 290	3 650	4 370	4 880	5 260	5 390
	Winter	Peak	2 020	2 030	2 070	2 830	3 190	3 920	4 440	4 830	4 970
		Off-peak	2 320	2 330	2 370	3 350	3 710	4 440	4 960	5 350	5 490
Supplemental Emergency	Summer/ Winter	Peak/ Off-peak	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300	1 300
			300	900	930	1 210	1 450	2 050	2 440	2 700	2 810
Total	Summer/ Winter	Peak/ Off-peak	3 920	4 530	4 600	5 860	6 460	7 790	8 700	9 350	9 600

Figure 11. Assumptions used for system reserve requirements

4 Results

As specified in Section 2, a least cost electricity expansion was conducted in PLEXOS from 2016 to 2050 to meet the low and high forecasted electricity demand scenarios. A Base Case scenario was run to provide a reference case from which all other scenarios are compared. In the Base Case, the Eskom coal-fleet is decommissioned as per their 50 year life or as stated in the Draft IRP 2016. Additionally, all 6 units at Kusile power station are commissioned.

Following this, 7 scenarios were then modelled whereby the power stations being studied were either decommissioned earlier than planned or in the case of Kusile, the last 2 units were not completed. By comparing each scenario to the Base Case, the SAV of the corresponding power stations were calculated. The 7 scenarios are listed below:

- Kusile (2 units);
- Arnot;
- Camden;
- Grootvlei;
- Hendrina;
- Komati; and
- A combination of Grootvlei, Hendrina and Komati.

Results from these scenarios are provided in the sections that follow.

4.1 Base Case

The capacity expansion results of the Base Case are shown in Figure 12 and Figure 13 for the high and low demand forecasts respectively.
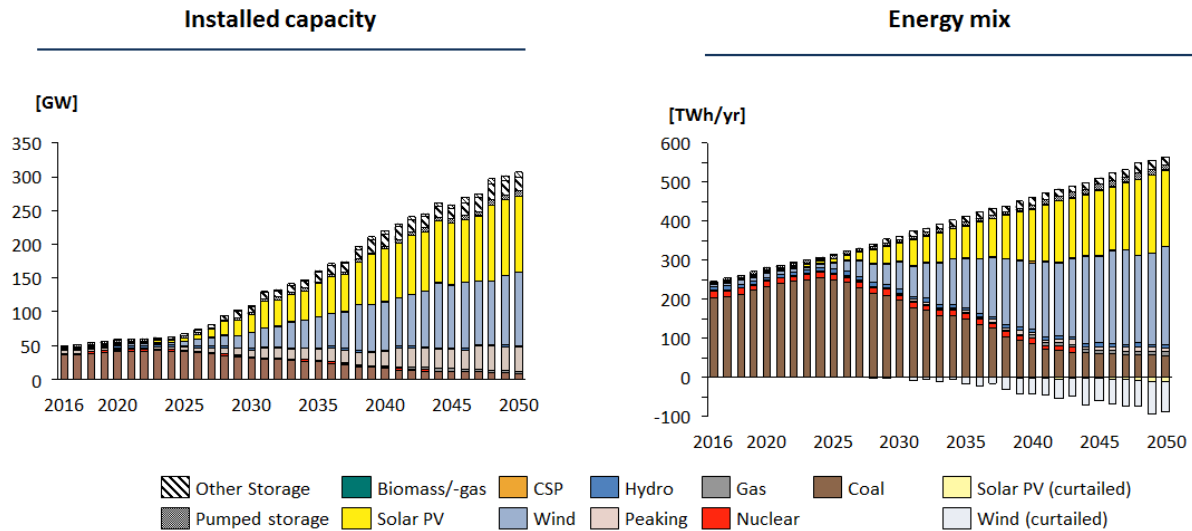

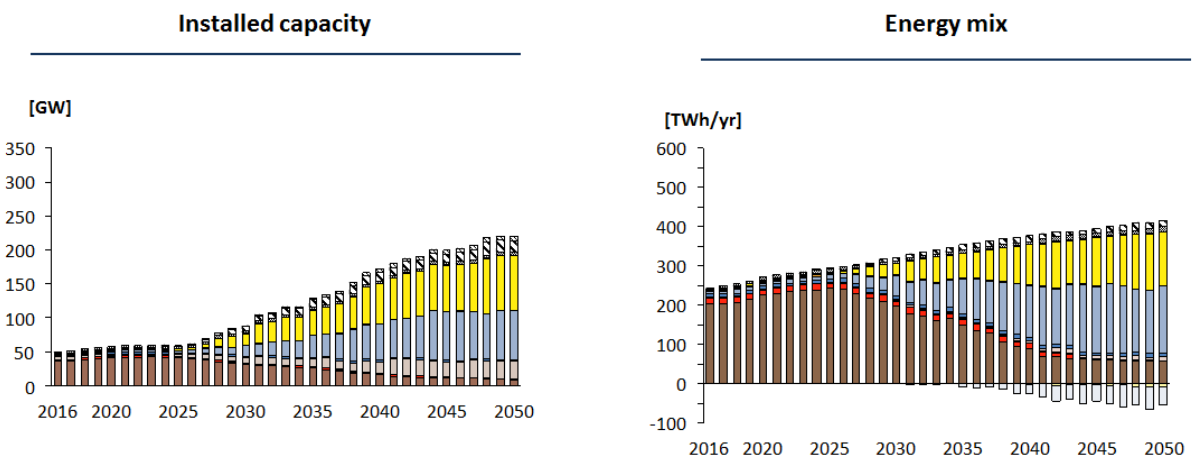**Figure 12. Base Case - High demand: Total annual installed capacity and energy**

Figure 13. Base Case - Low demand: Total annual installed capacity and energy

As can be seen in Figure 12 and Figure 13, for both the high and low demand forecasts new capacity in the form of wind, solar PV and flexible technology options (peaking (OCGTs) and batteries) are deployed up to 2050 with the earliest new build starting around 2023. Mid-merit gas options (CCGTs) are deployed beyond 2040 in the high demand scenario. There is some curtailment of wind and solar PV evident from 2030 - 2035 onwards as the renewable energy share increases. Curtailed energy is costed in the model as a result of the investment in capacity being fully captured in the model (whether the energy is used or not) and thus the decision to build more wind and/or solar PV with some curtailment is made on a

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purely economic basis. The potential additional value of this curtailed energy being used in other applications was not considered in this work.

The annual capacity factors in of the existing coal fleet in the Base Case are shown in Figure 14 and Figure 15 for the high and low demand forecasts respectively. As can be seen, capacity factors remain relatively constant between the two demand forecast scenarios due to the commitment (must-run) constraint of the coal fleet and the dispatch merit order of coal in the South African power system. Majuba was modelled with the ability to cycle freely, resulting in a very low capacity factor in the early years where excess capacity is present. Majuba's load factor increases towards 2030 as the existing coal fleet decommissions but reduces again as the renewable energy share increases into the future.
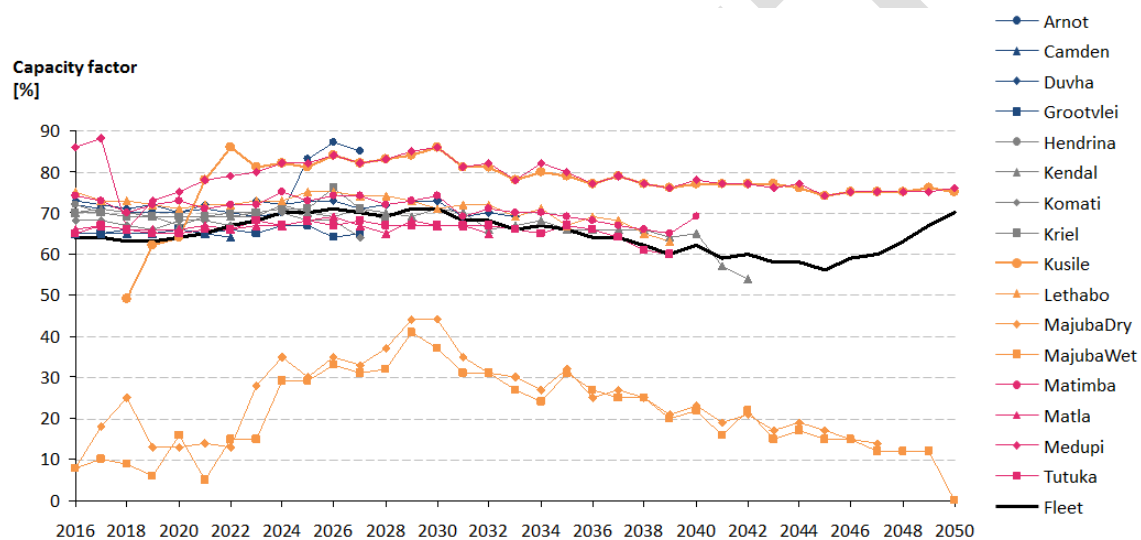

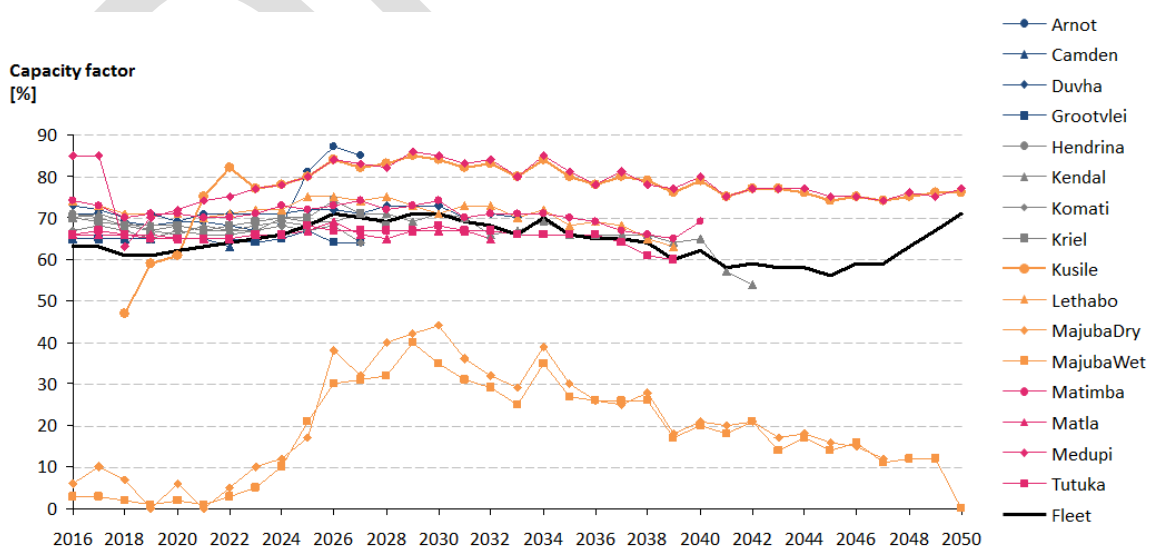**Figure 14. Base Case - High demand: Annual capacity factors of existing coal fleet**

Figure 15. Base Case - Low demand: Annual capacity factors of existing coal fleet

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The annual total system cost and average tariff trajectories for the high and low demand forecasts are shown in Figures 16 – 19. The average tariff is expected to peak in the early 2020s and remain constant for some time following which an absolute reduction is expected as a result of relatively cheap new-build solar PV and wind being deployed into the future.
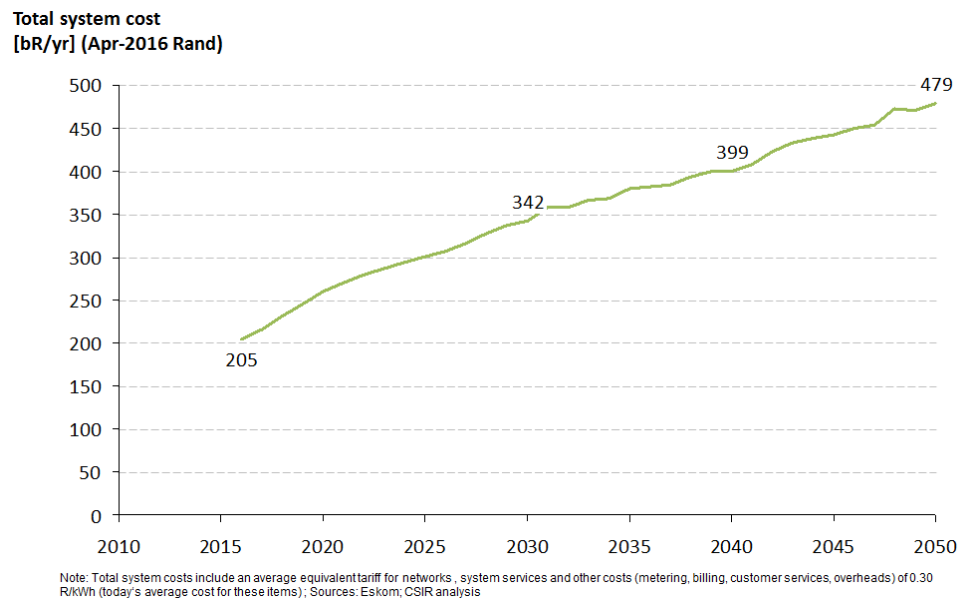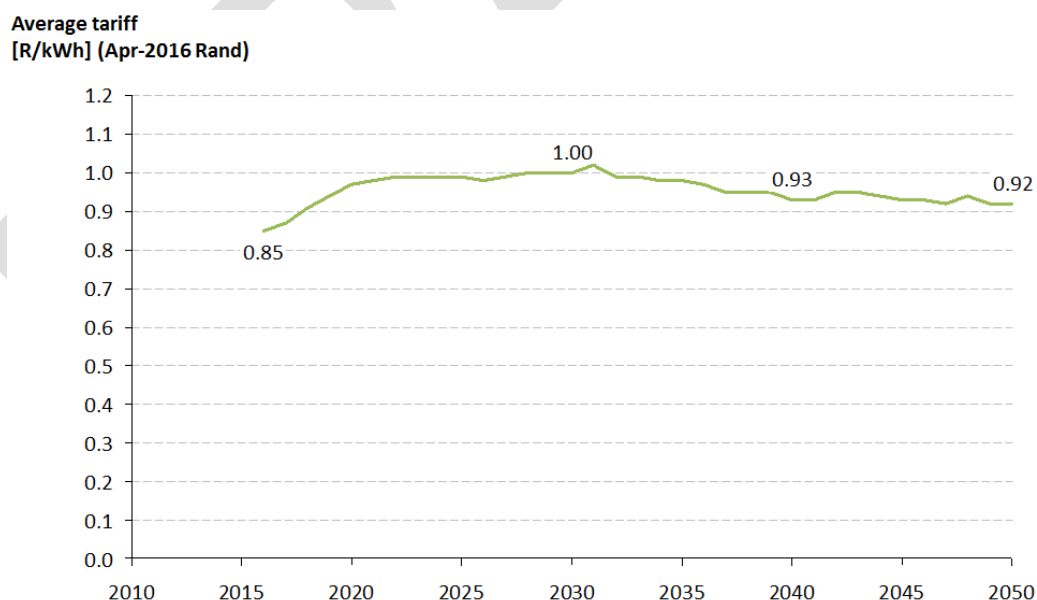
Total system cost [bR/yr] (Apr-2016 Rand)

Note: Total system costs include an average equivalent tariff for networks , system services and other costs (metering, billing, customer services, overheads) of 0.30 R/kWh (today's average cost for these items) ; Sources: Eskom; CSIR analysis

Figure 16. Base Case - High demand: Total system cost

Average tariff [R/kWh] (Apr-2016 Rand)

Figure 17. Base Case - High demand: Average tariff

**Total system cost
[bR/yr] (Apr-2016 Rand)**
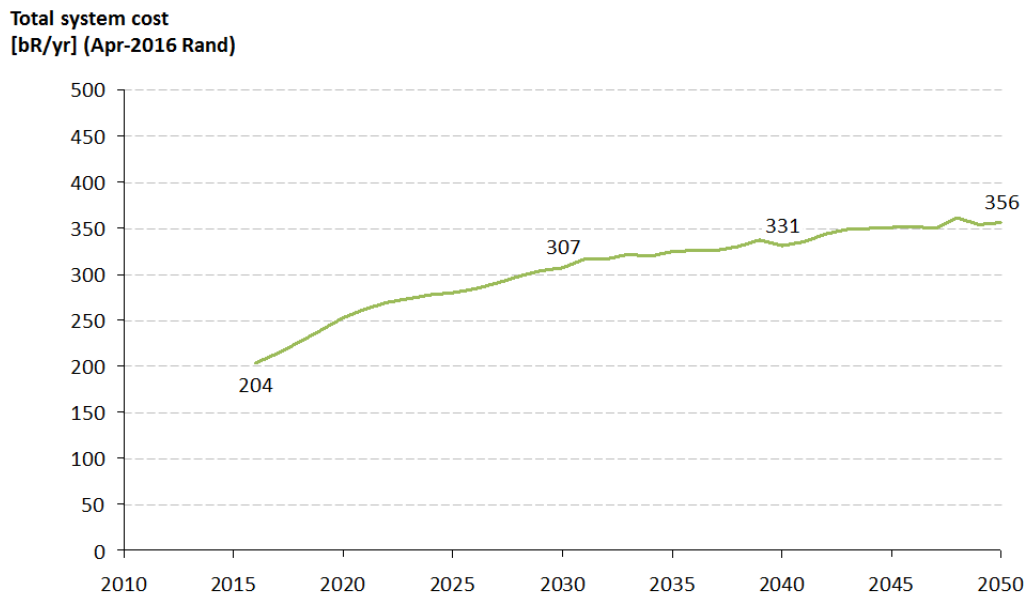
Figure 18. Base Case - Low demand: Total system cost

**Average tariff
[R/kWh] (Apr-2016 Rand)**
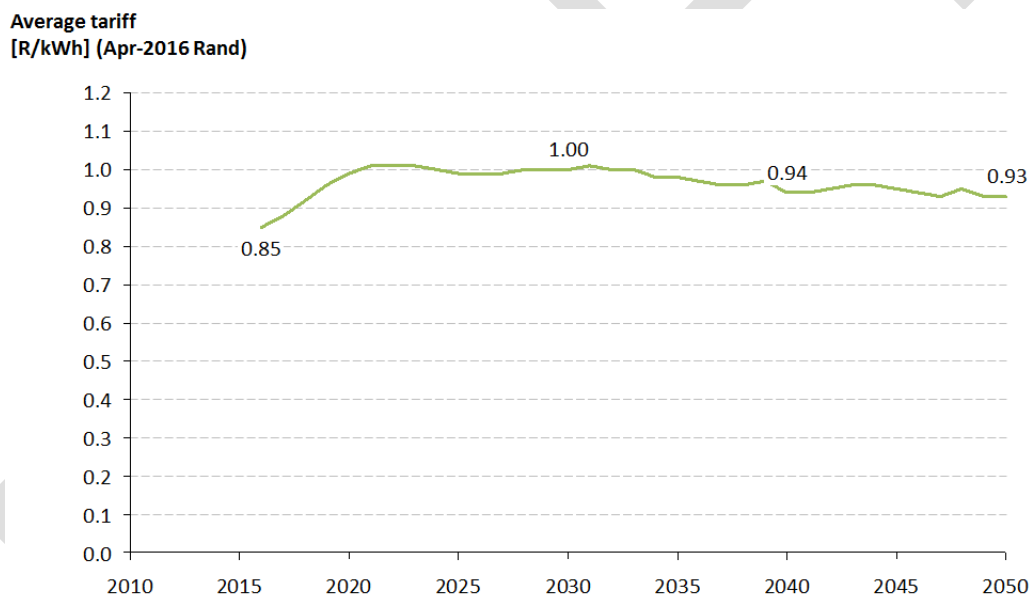

Figure 19. Base Case - Low demand: Average tariff

The resulting annual CO_2 emissions and water usage for the Base Case are shown in Figure 20 and Figure 21 for the high and low demand scenarios respectively. It can be seen for both demand forecasts that annual CO_2 emissions and water usage from the electricity sector decline sharply after 2025 as the coal fleet decommissions and no new coal capacity is built. The PPD (Moderate) CO_2 emissions trajectory is also never binding, i.e. the least cost expansion build consists of zero/low CO_2 emitting technologies. The least-cost build-out results in a CO_2 emissions trajectory below the PPD (Moderate) trajectory for all years into the future.
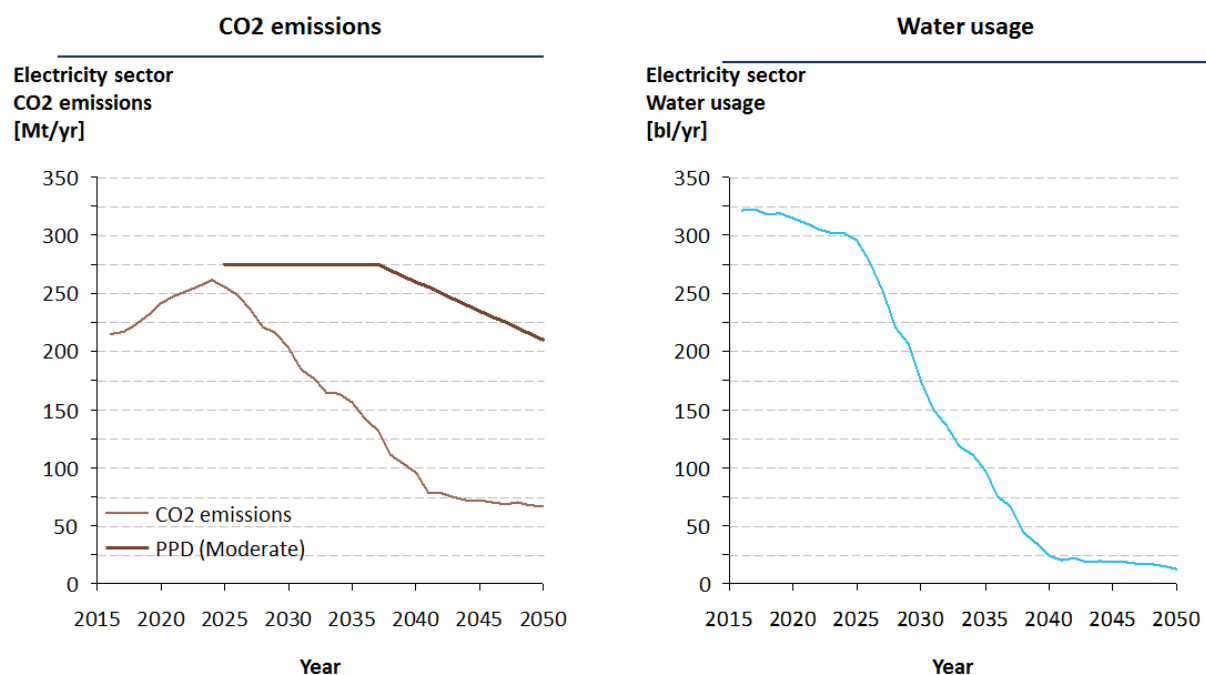
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CO2 emissions

**Electricity sector
CO2 emissions
[Mt/yr]**

Water usage

**Electricity sector
Water usage
[bl/yr]**

Figure 20. Base Case - High demand: Annual CO₂ emissions and water usage

CO2 emissions

**Electricity sector
CO2 emissions
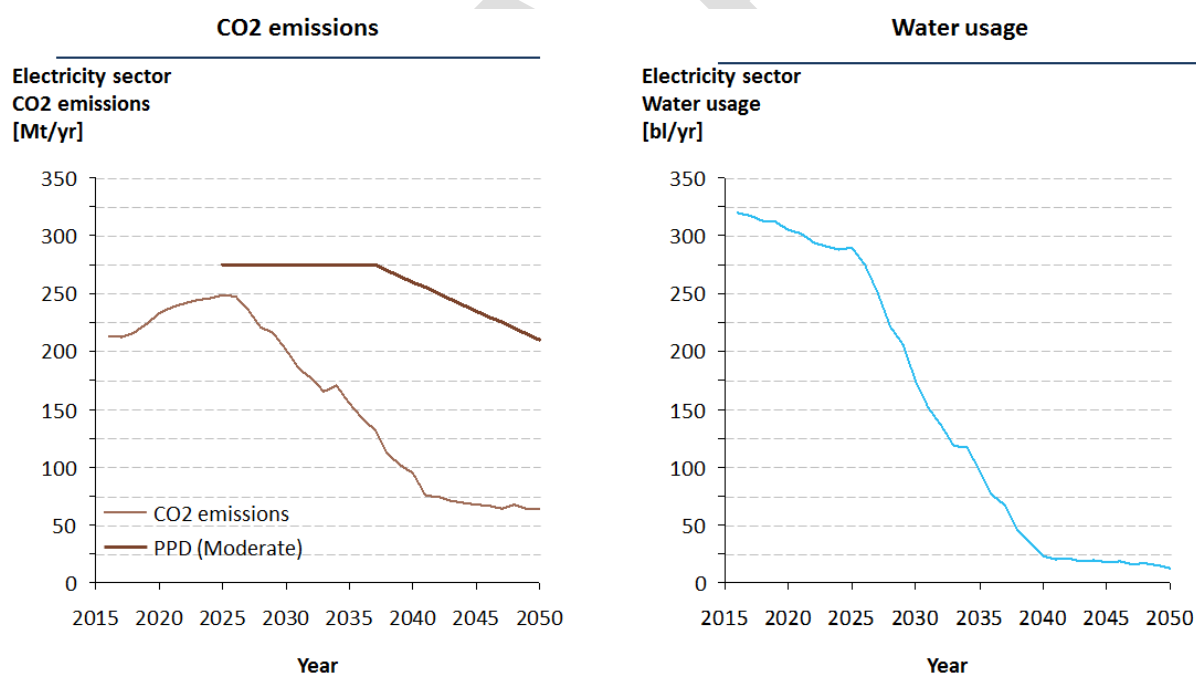[Mt/yr]**

Water usage

**Electricity sector
Water usage
[bl/yr]**

Figure 21. Base Case - Low demand: Annual CO₂ emissions and water usage

4.2 Kusile

In this scenario the last 2 units of Kusile are not built and the least-cost expansion model is re-run. The purpose of this scenario is to identify the SAV of the last two Kusile units. Figure 22 and Figure 23 show the capacity and energy of Kusile with 4 units and 6 units as well as the stations annual capacity factor for the high and low demand forecasts respectively. The average annual energy output of Kusile is similar for both forecasts, indicating that Kusile's output is relatively robust to changes in electricity demand. The average annual energy output with 6 units and 4 units is ~30 TWh/yr and ~20 TWh/yr respectively. The changes in energy output and new capacity built to supply the ~10 TWh//yr energy "gap" from not building the last 2 Kusile units is shown in Figure 24 and Figure 25 for the high and low demand forecast scenarios respectively.
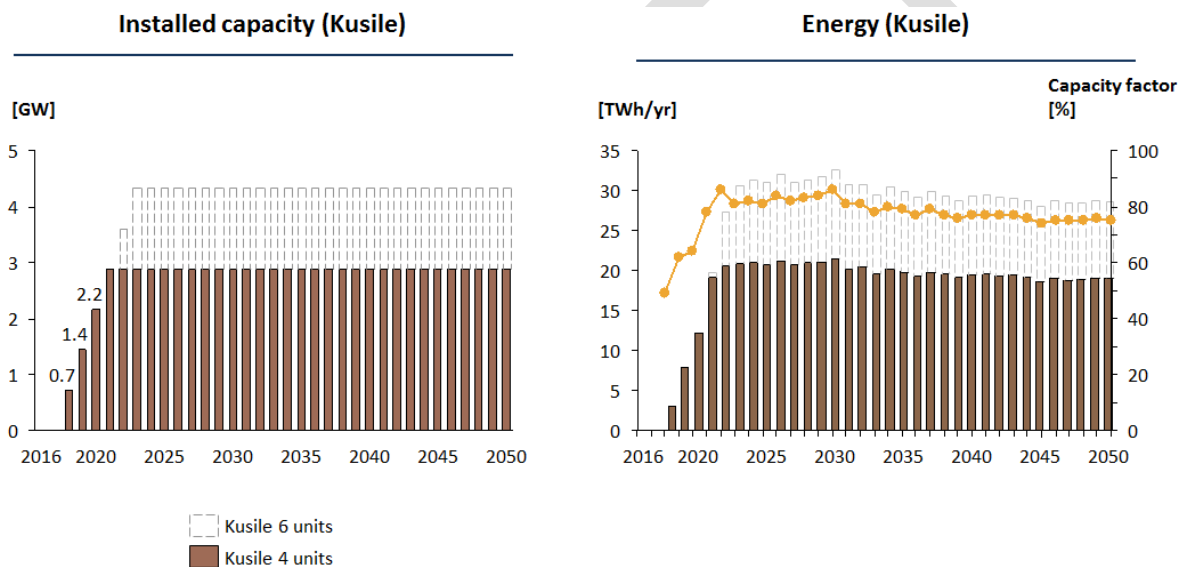
Figure 22. Scenario Kusile - High demand: Installed capacity and energy from Kusile with 4 units vs. 6 units
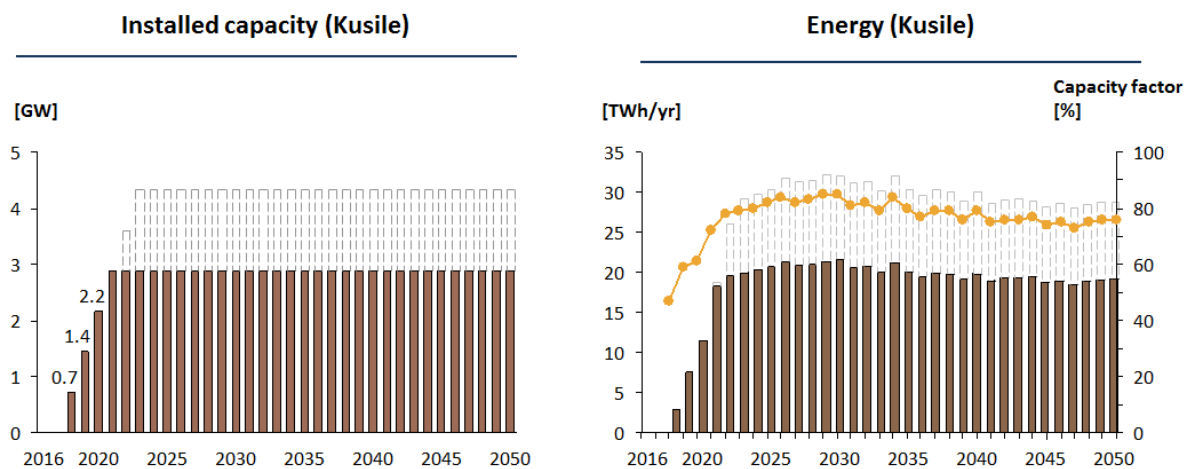

Figure 23. Scenario Kusile – Low demand: Installed capacity and energy from Kusile with 4 units vs. 6 units
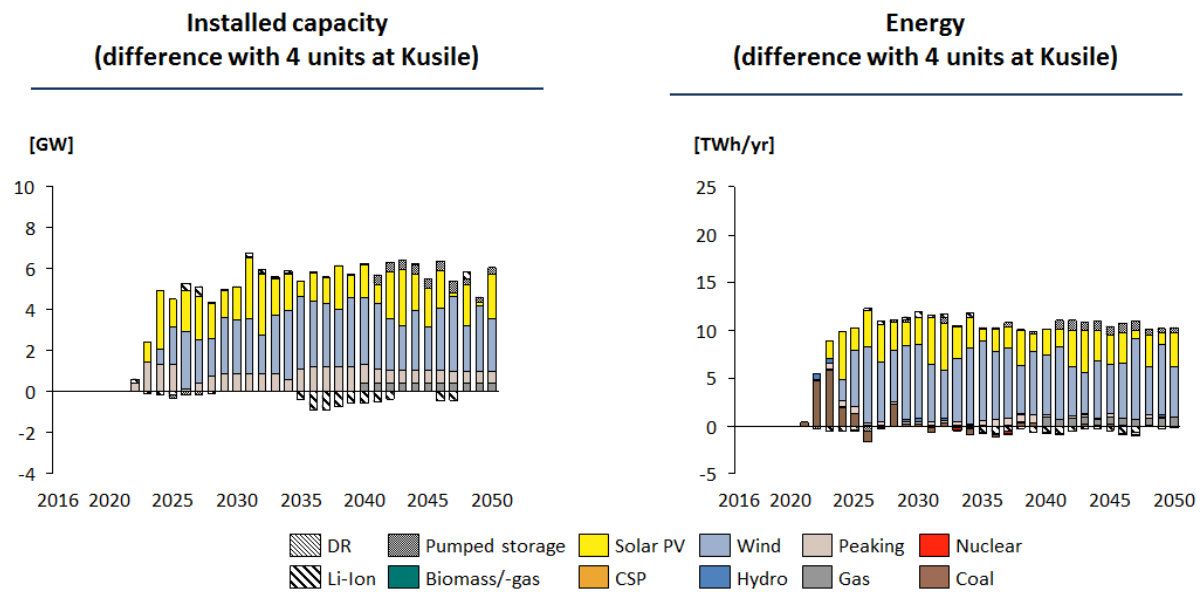
Installed capacity
(difference with 4 units at Kusile)

Energy
(difference with 4 units at Kusile)

Legend: DR, Pumped storage, Solar PV, Wind, Peaking, Nuclear, Li-Ion, Biomass/-gas, CSP, Hydro, Gas, Coal

Figure 24. Scenario Kusile – High demand: Additional capacity and energy required to replace last 2 Kusile units

Installed capacity
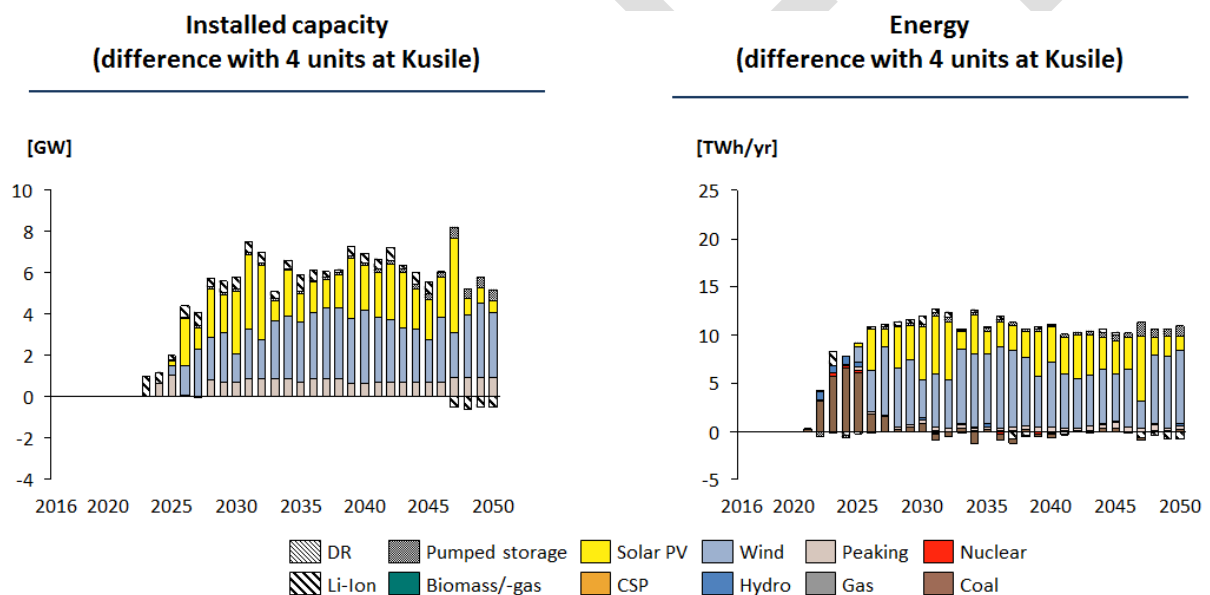**(difference with 4 units at Kusile)**

Energy
(difference with 4 units at Kusile)

Legend: DR, Pumped storage, Solar PV, Wind, Peaking, Nuclear, Li-Ion, Biomass/-gas, CSP, Hydro, Gas, Coal

Figure 25. Scenario Kusile – Low demand: Additional capacity and energy required to replace last 2 Kusile units

The energy from the last 2 Kusile units is primarily replaced by additional energy from the existing coal fleet in the first 4 years, followed by new wind, solar PV, peaking, batteries and gas capacity in the high demand forecast scenario. Similarly in the low demand forecast scenario the initial energy gap is supplied by the existing coal fleet (but for a longer period), followed by the deployment of new wind, solar PV, peaking and battery capacity.

The SAV for the last 2 units of Kusile was found to be between **0.57 - 0.61 R/kWh** for the low and high demand forecast scenarios respectively as shown in Figure 26 and Figure 27.

The total discounted system costs with and without all costs associated with the power station under study (Kusile) are shown for the Base Case (Kusile 6 units) and the scenario with Kusile having only 4 units. The SAV is then the value difference divided by the energy difference.
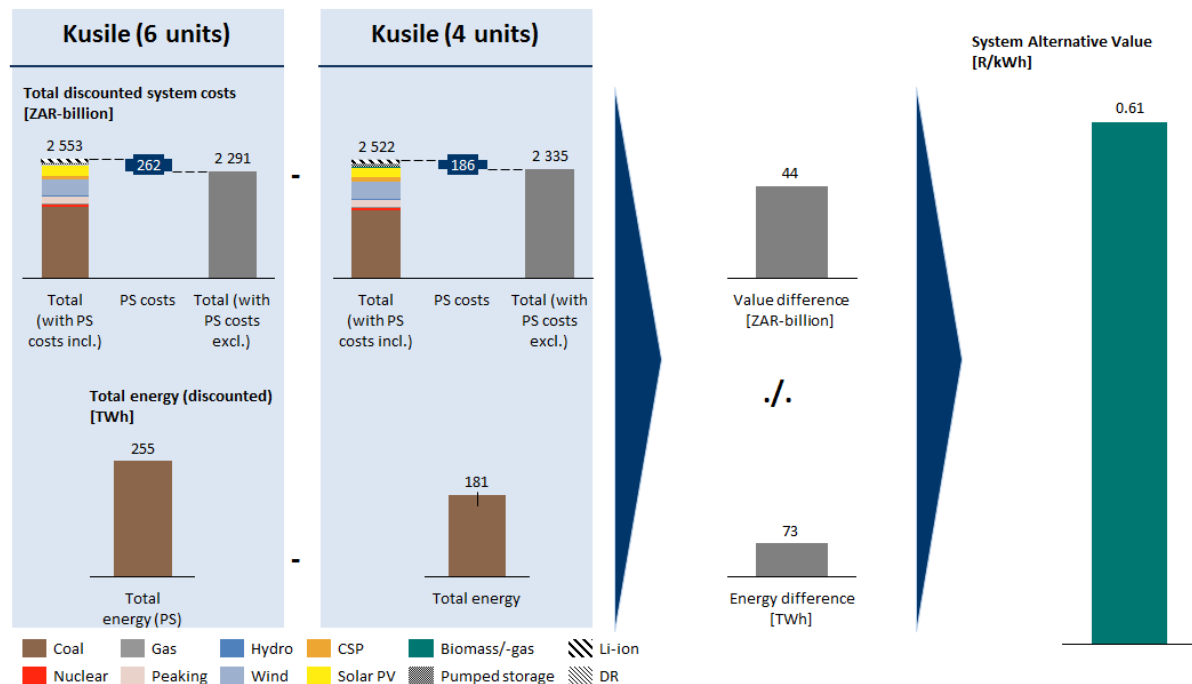

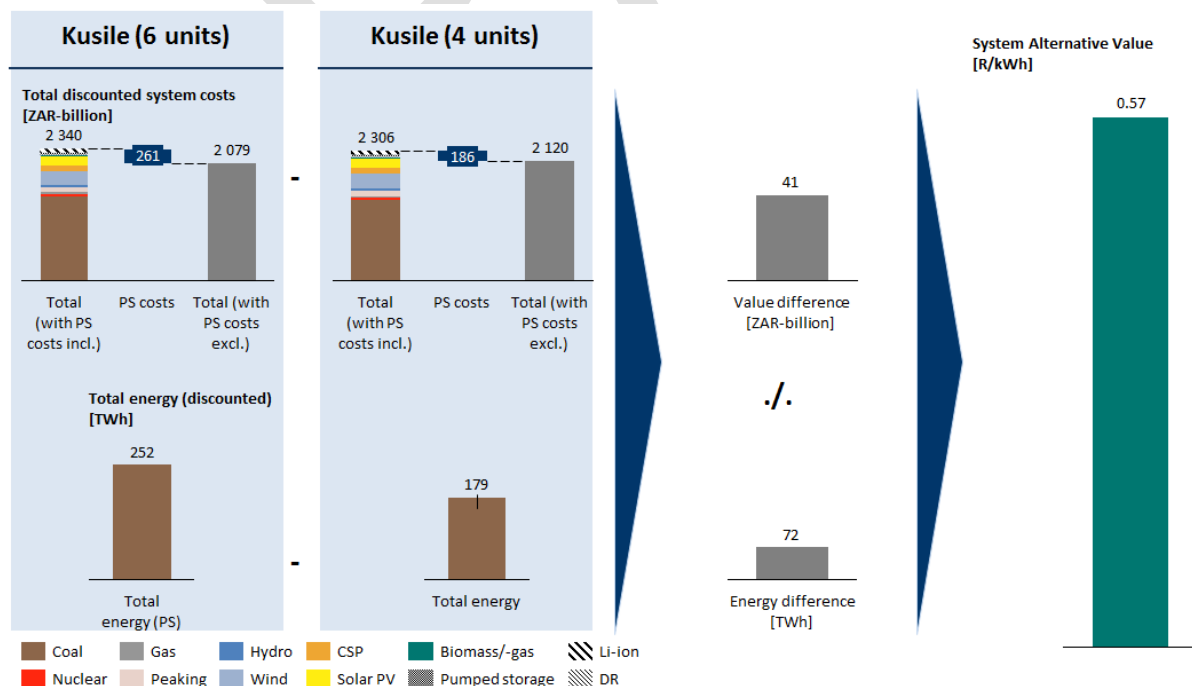**Figure 26. Scenario Kusile - High demand: System Alternative Value for Kusile**

Figure 27. Scenario Kusile - Low demand: System Alternative Value for Kusile

4.3 Arnot

In this scenario Arnot is decommissioned early in FY 2020 instead of the planned decommissioning date in FY 2029. The purpose of this scenario is to calculate the SAV of Arnot providing energy for its full 50 year life as opposed to being decommissioned earlier. Figure 28 and Figure 29 show the capacity and energy of Arnot for the scheduled and early retirement scenarios for the high and low demand forecasts respectively. The changes in energy output and new capacity built to supply the energy gap from retiring Arnot early are shown in Figure 30 and Figure 31 for the high and low demand forecast scenarios respectively.
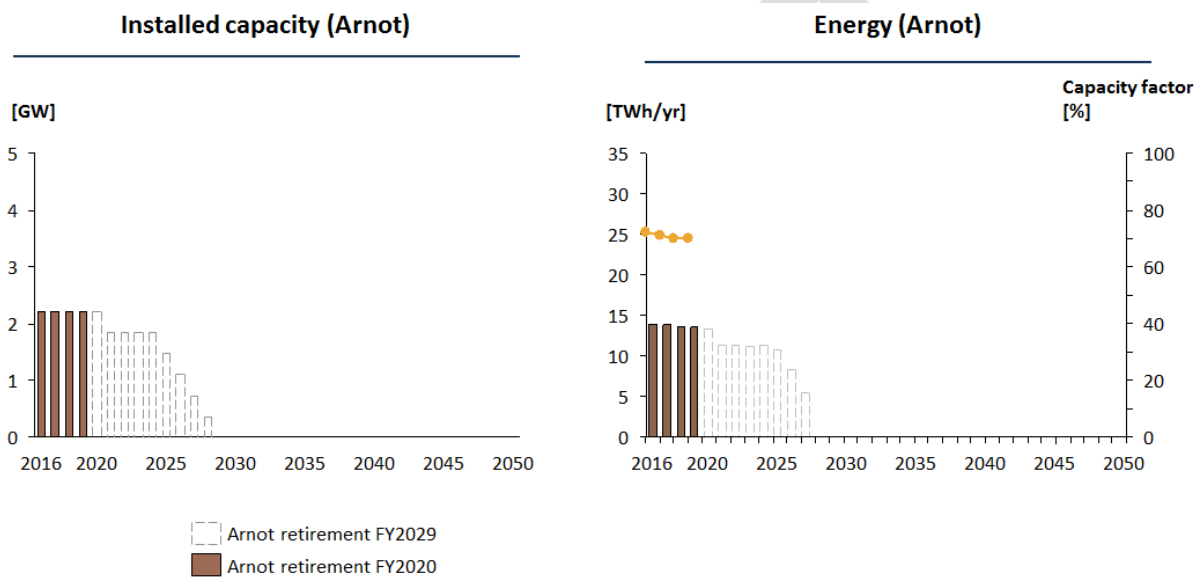
Figure 28. Scenario Arnot - High demand: Installed capacity and energy from Arnot for planned and early retirement
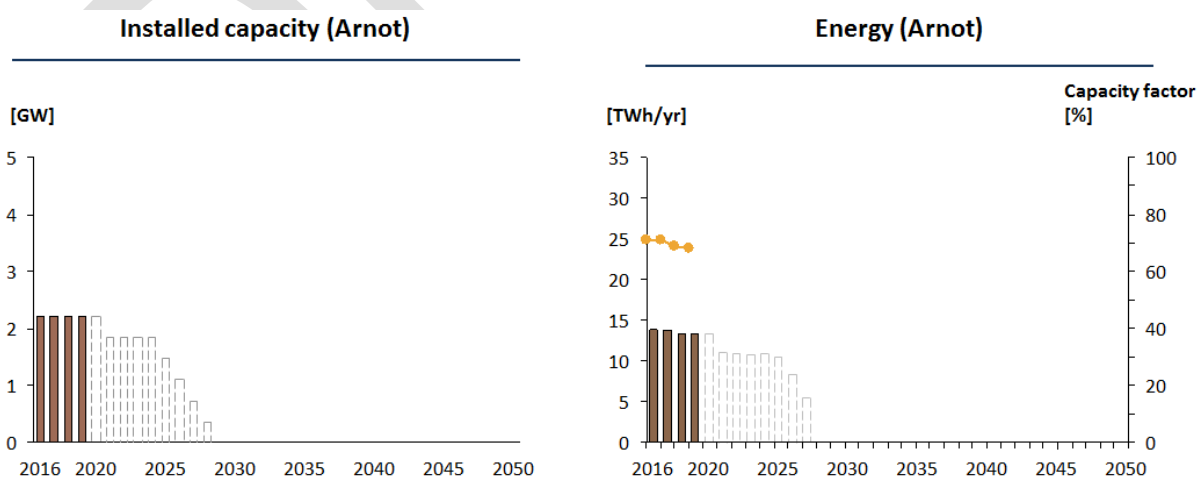
Figure 29. Scenario Arnot - Low demand: Installed capacity and energy from Arnot for planned and early retirement
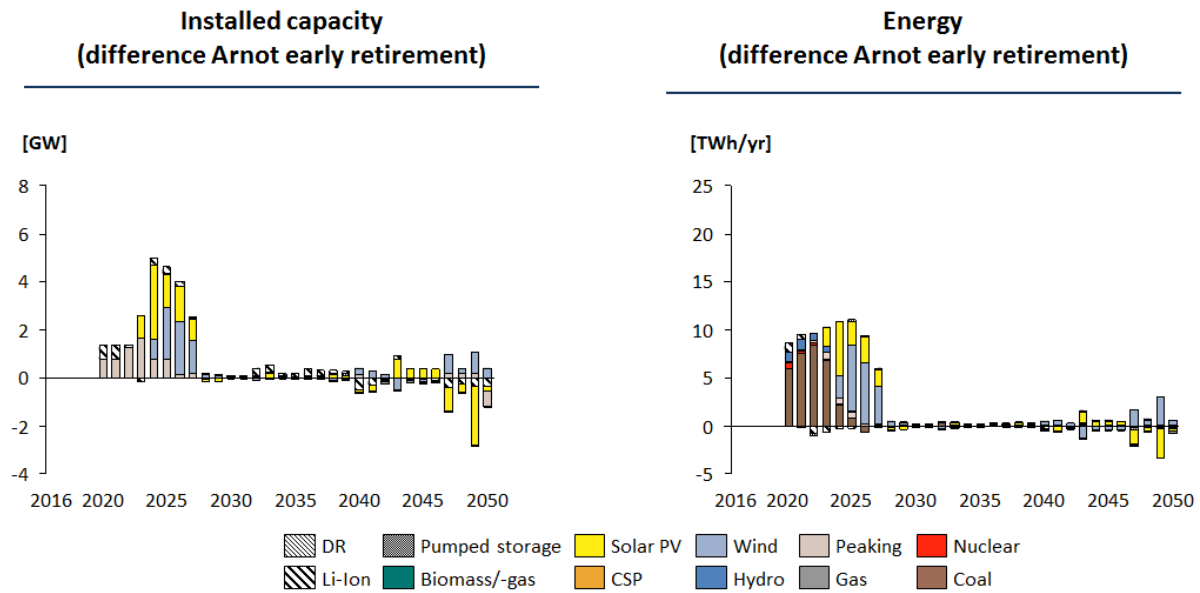
Figure 30. Scenario Arnot – High demand: Additional capacity and energy required to replace Arnot
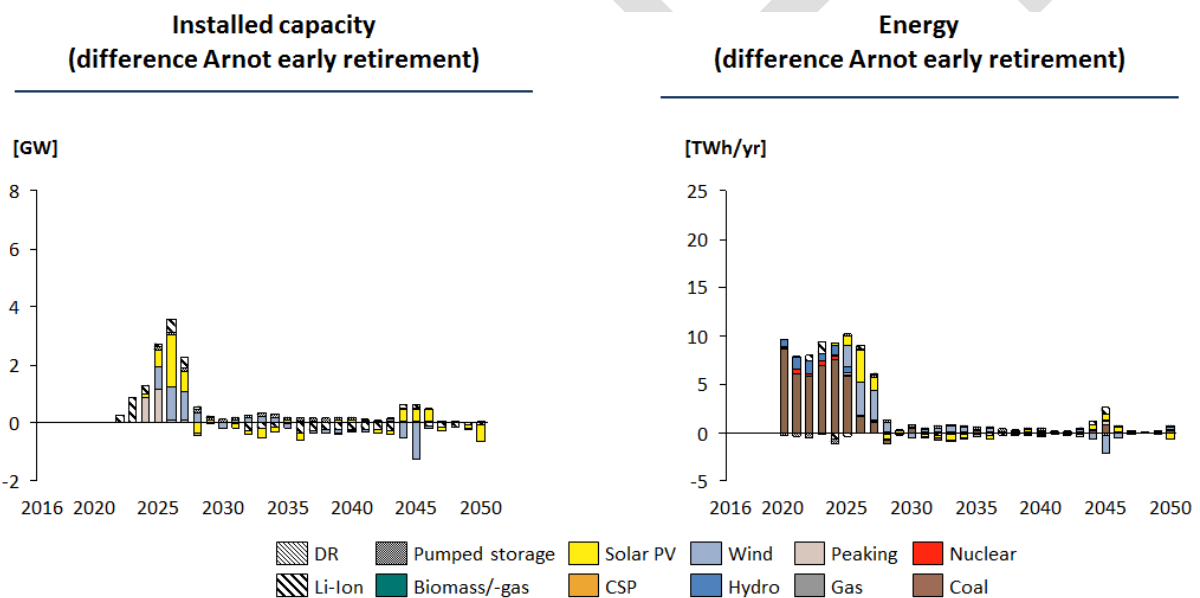

Figure 31. Scenario Arnot – Low demand: Additional capacity and energy required to replace Arnot

The energy gap from the early retirement of Arnot is primarily replaced by additional energy from the existing coal fleet in the first few years. Some additional capacity is also built in the form of OCGTs and batteries for the purpose of providing capacity to the system. From FY 2025 onwards additional wind, solar PV, peaking and battery capacity is built in the high and low demand forecast scenarios.

The SAV for Arnot was found to between **0.34 – 0.50 R/kWh** for the low and high demand forecast scenarios respectively as shown in Figure 32 and Figure 33.
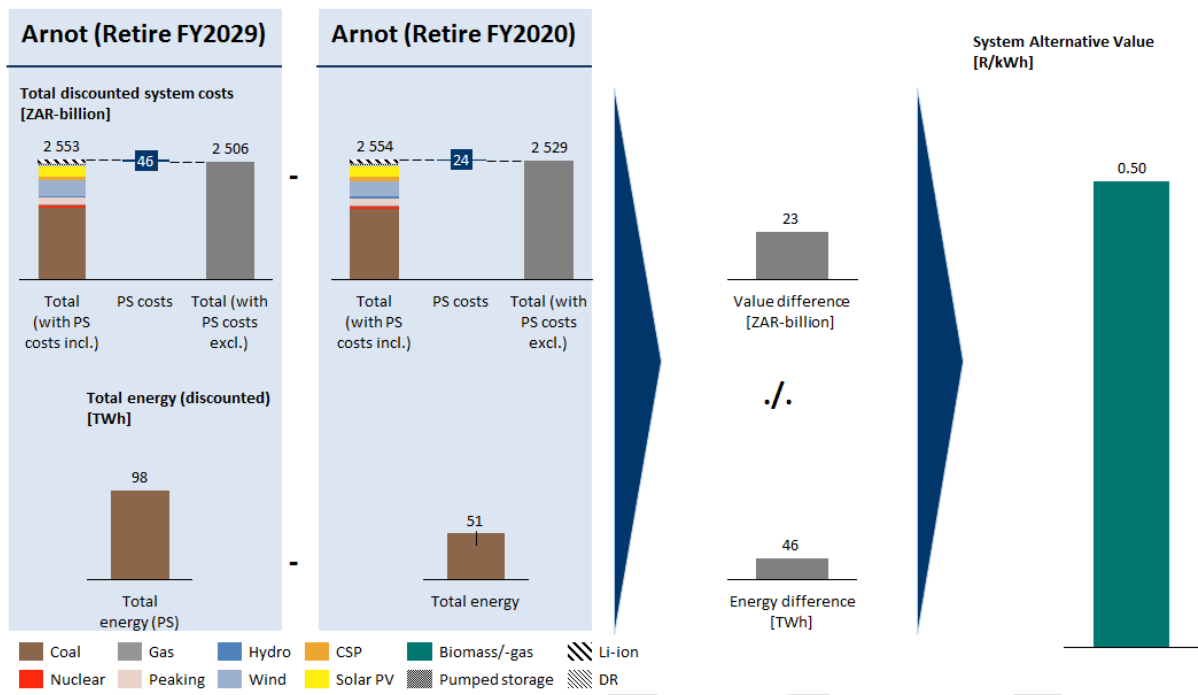
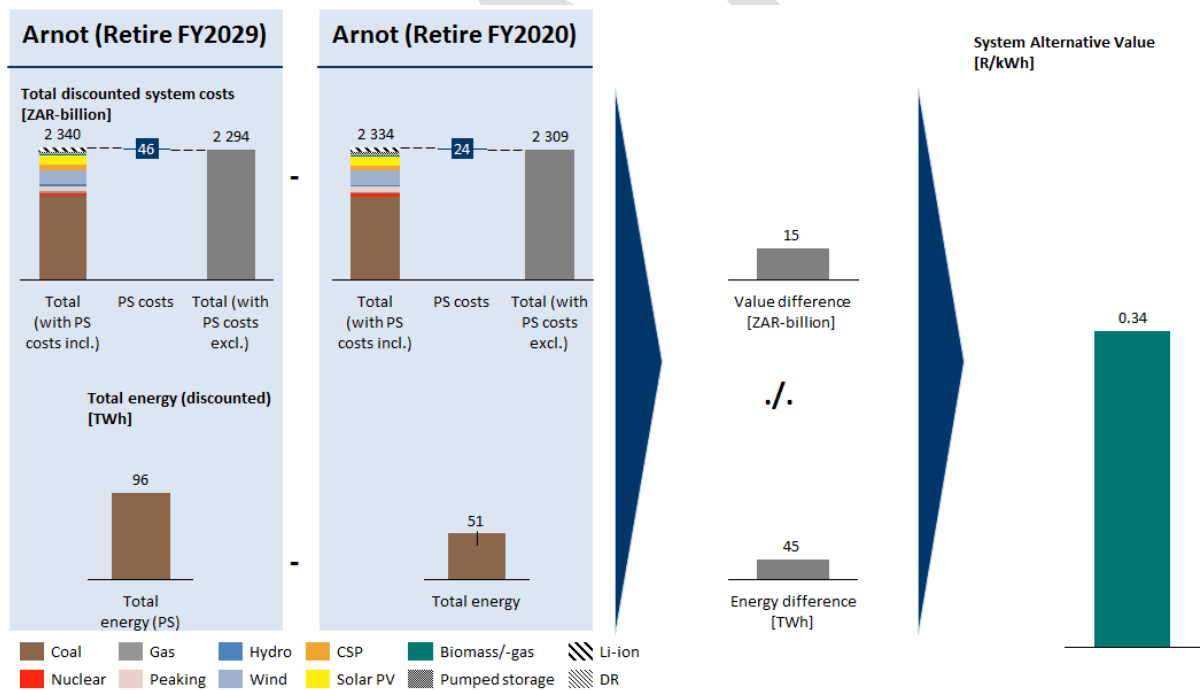**Figure 32. Scenario Arnot - High demand: System Alternative Value for Arnot**

Figure 33. Scenario Arnot - Low demand: System Alternative Value for Arnot

4.4 Camden

In this scenario Camden is decommissioned early in FY 2018 instead of the planned decommissioning date in FY 2023. The purpose of this scenario is to calculate the SAV of Camden providing energy for its planned life as opposed to being decommissioned earlier. The least-cost expansion model was re-run and Figure 34 and Figure 35 show the capacity and energy of Camden for the scheduled and early retirement scenarios for the high and low demand forecasts respectively. The changes in energy output and new capacity built to supply the energy gap from retiring Camden early is shown in Figure 36 and Figure 37 for the high and low demand forecast scenarios respectively.
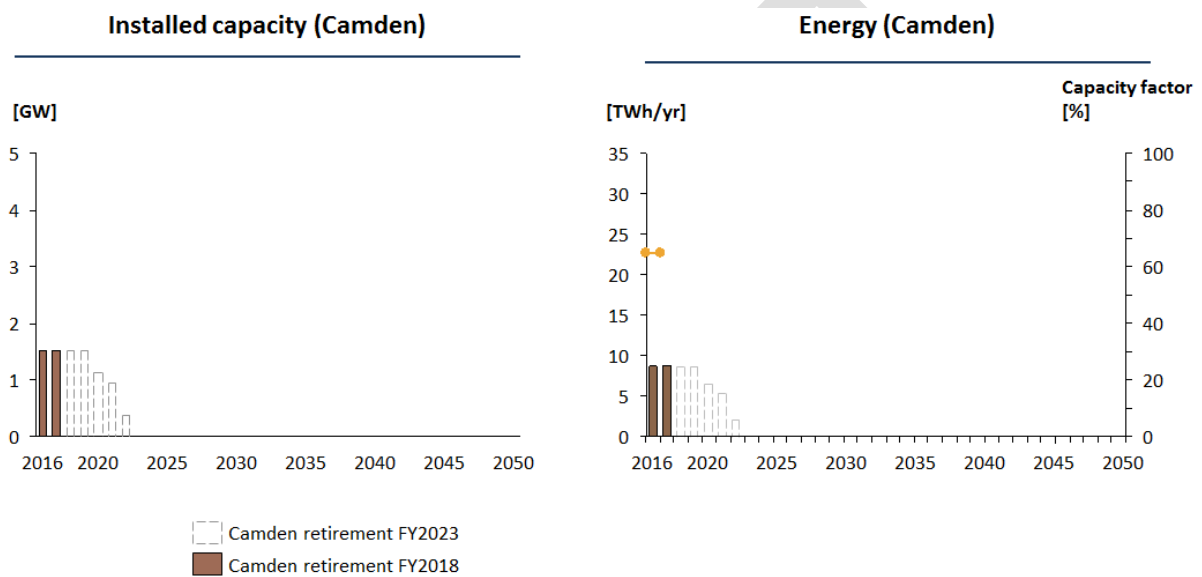
Figure 34. Scenario Camden - High demand: Installed capacity and energy from Camden for planned and early retirement
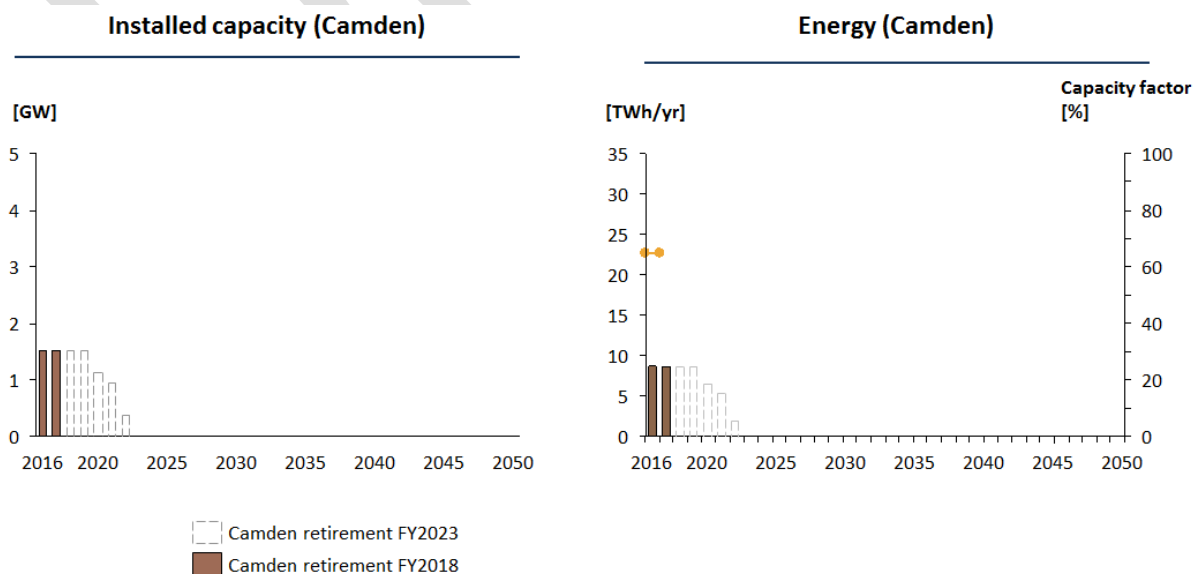
Figure 35. Scenario Camden - Low demand: Installed capacity and energy from Camden for planned and early retirement
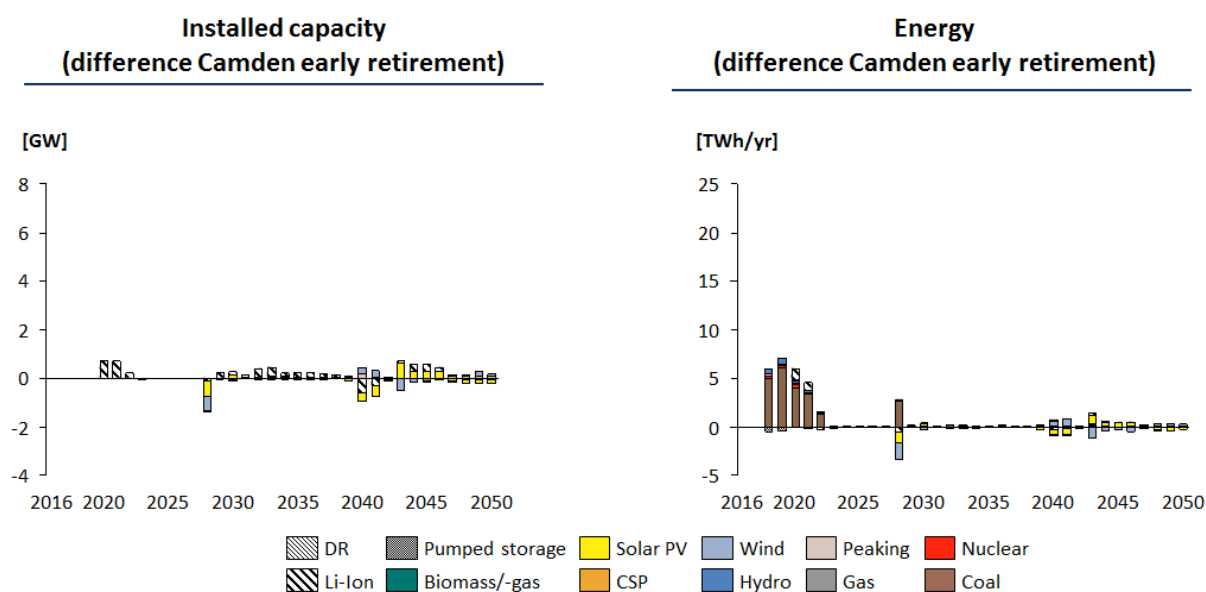

Figure 36. Scenario Camden – High demand: Additional capacity and energy required to replace Camden
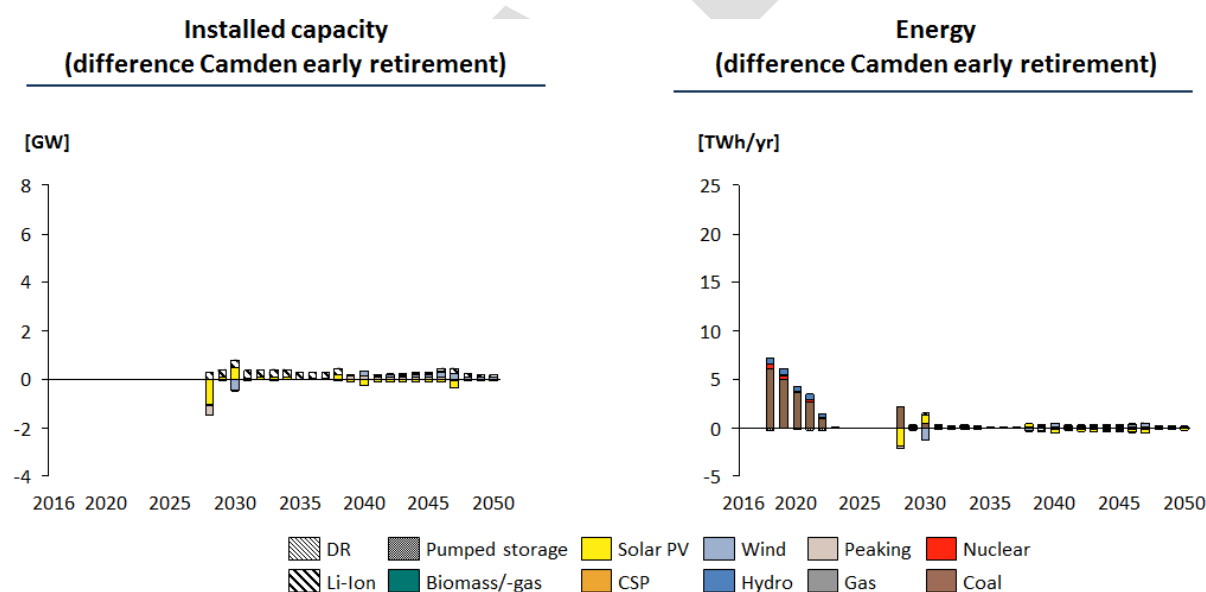

Figure 37. Scenario Camden – Low demand: Additional capacity and energy required to replace Camden

The energy gap from the early retirement of Camden is primarily replaced by additional energy from the existing coal fleet. New capacity is not built before FY 2023 in both the high and low demand forecast scenarios. Small differences in capacity and energy following the decommissioning of the station are a result of conditions inherently changing early on in the time horizon which then perpetuate into the future as a result of the early decommissioning of the station under study.

The SAV for Camden was found to between **0.22 – 0.36 R/kWh** for the low and high demand forecast scenarios respectively as shown in Figure 38 and Figure 39.
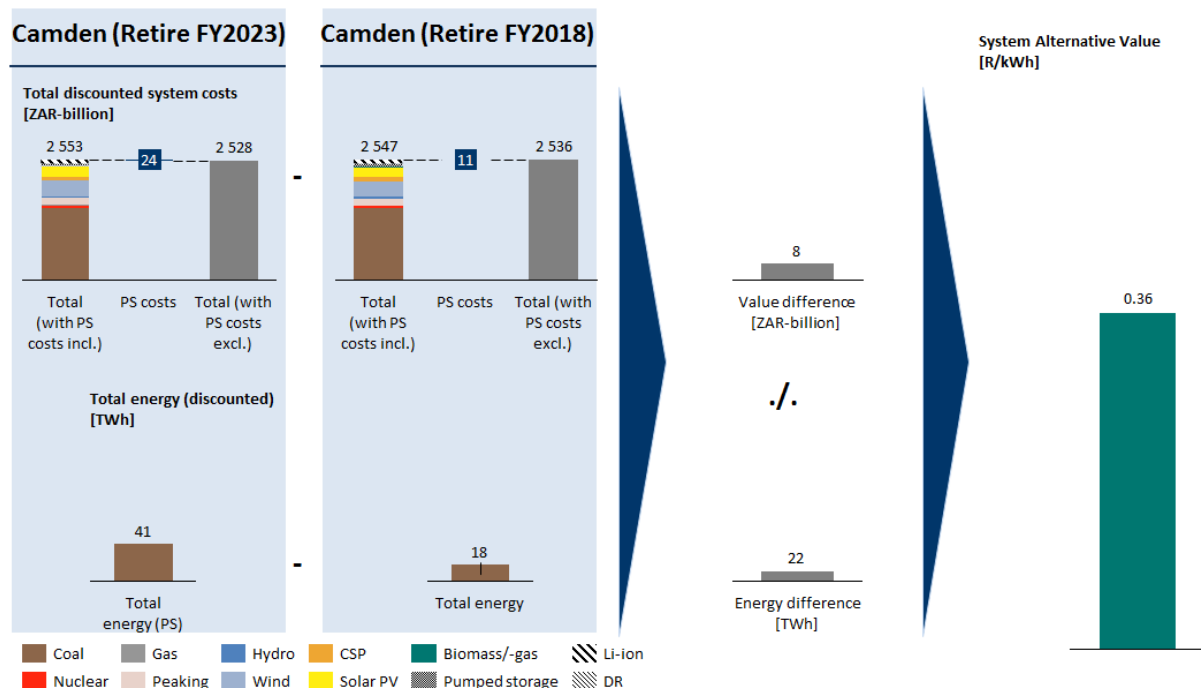

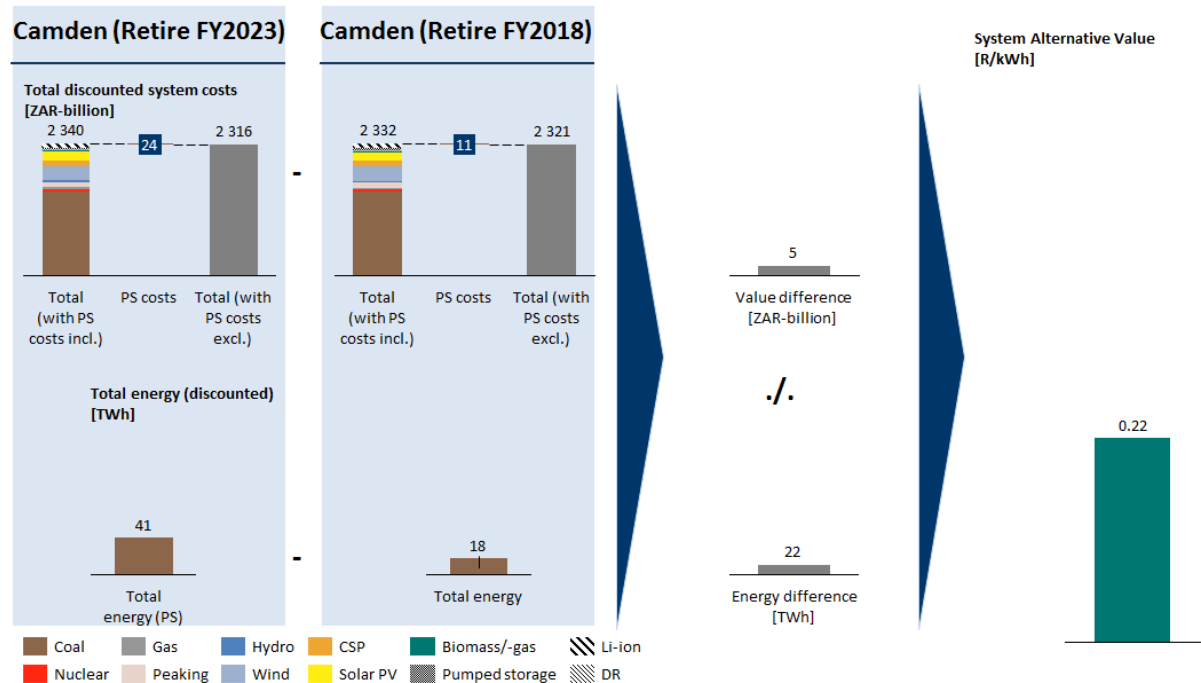**Figure 38. Scenario Camden - High demand: System Alternative Value for Camden**

Figure 39. Scenario Camden - Low demand: System Alternative Value for Camden

4.5 Grootvlei

In this scenario Grootvlei is decommissioned early in FY 2019 instead of the planned decommissioning date in FY 2028. The purpose of this scenario is to calculate the SAV of Grootvlei providing energy for its planned life as opposed to being decommissioned earlier. Figure 40 and Figure 41 show the capacity and energy of Grootvlei for the scheduled and early retirement scenarios for the high and low demand forecasts respectively. The changes in energy output and new capacity built to supply the energy gap from retiring Grootvlei early is shown in Figure 42 and Figure 43 for the high and low demand forecast scenarios respectively.
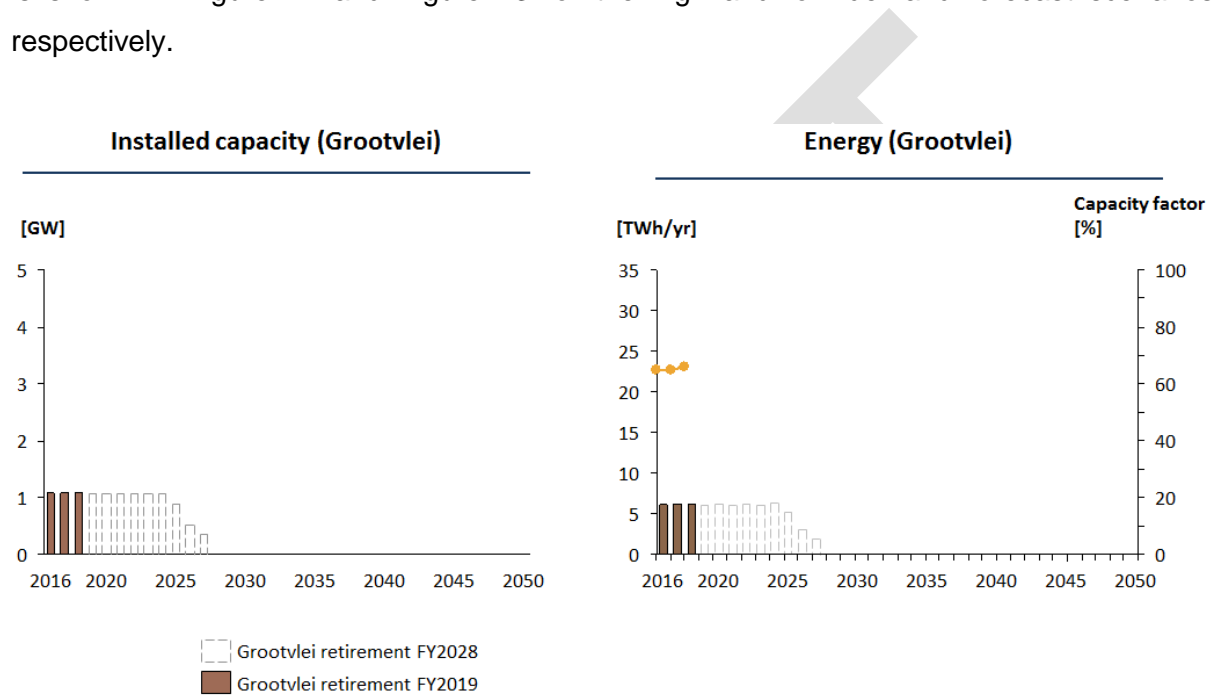

Figure 40. Scenario Grootvlei – High demand: Installed capacity and energy from Grootvlei for planned and early retirement
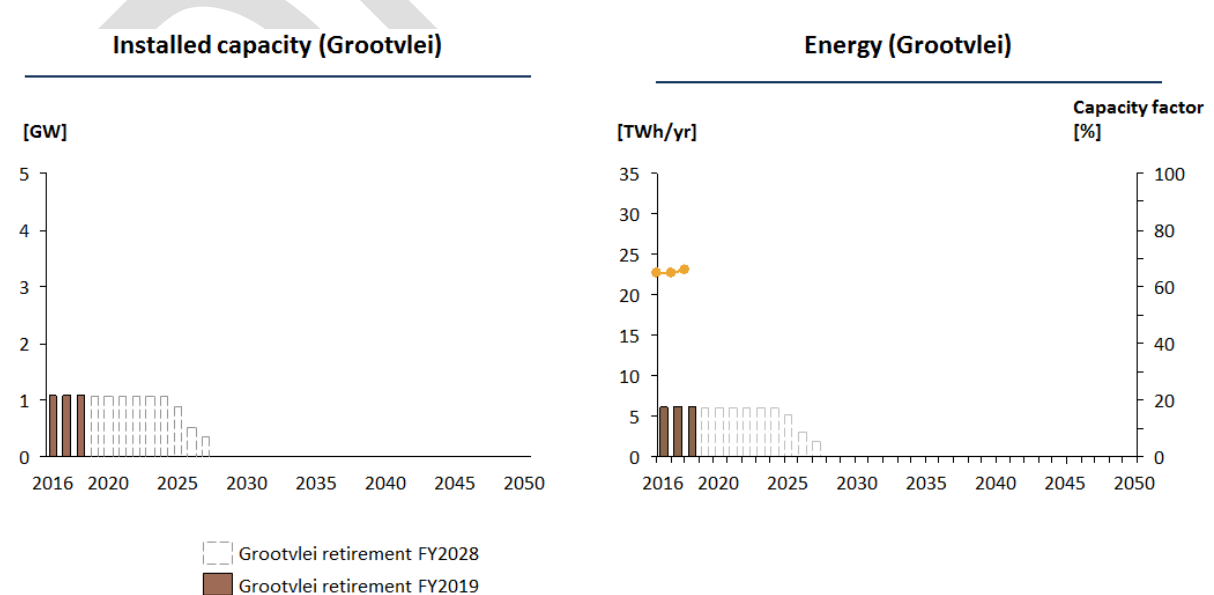

Figure 41. Scenario Grootvlei – Low demand: Installed capacity and energy from Grootvlei for planned and early retirement
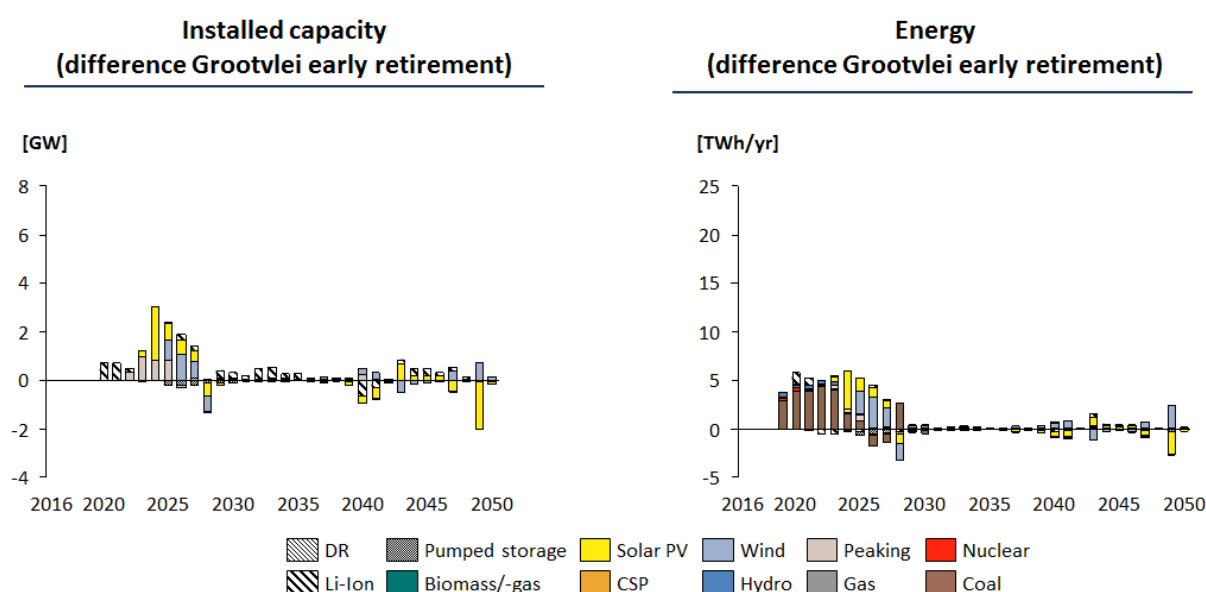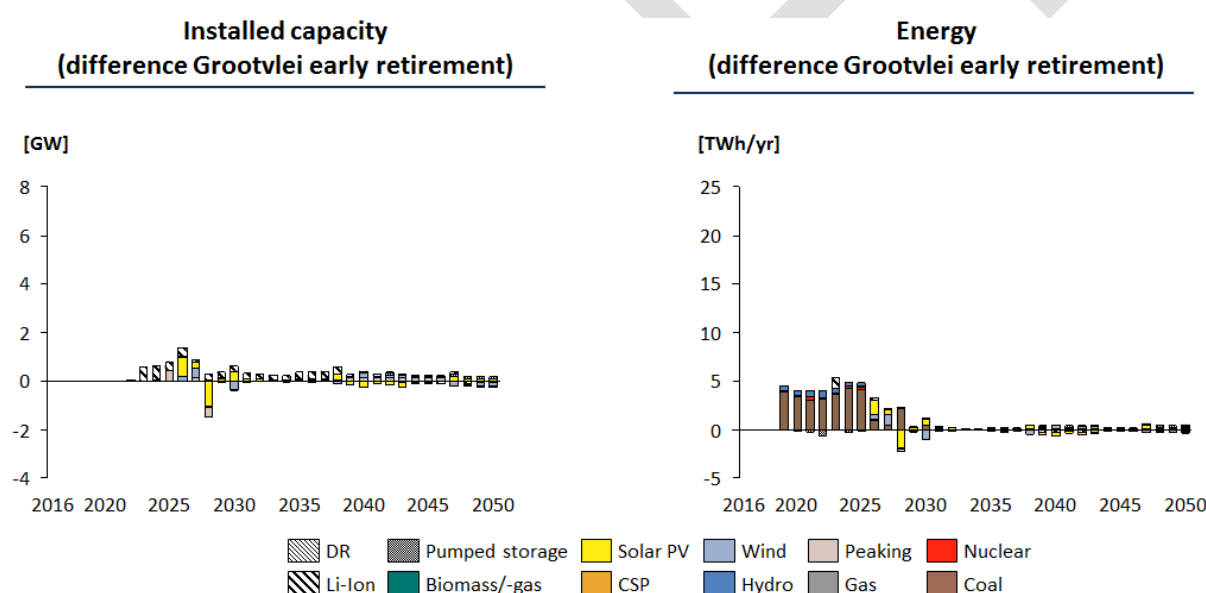
Installed capacity
(difference Grootvlei early retirement)

[GW]

Energy
(difference Grootvlei early retirement)

[TWh/yr]

Legend: DR, Pumped storage, Solar PV, Wind, Peaking, Nuclear, Li-Ion, Biomass/-gas, CSP, Hydro, Gas, Coal

Figure 42. Scenario Grootvlei – High demand: Additional capacity and energy required to replace Grootvlei

Installed capacity
(difference Grootvlei early retirement)

[GW]

Energy
(difference Grootvlei early retirement)

[TWh/yr]

Legend: DR, Pumped storage, Solar PV, Wind, Peaking, Nuclear, Li-Ion, Biomass/-gas, CSP, Hydro, Gas, Coal

Figure 43. Scenario Grootvlei – Low demand: Additional capacity and energy required to replace Grootvlei

The energy gap from the early retirement of Grootvlei is primarily replaced by additional energy from the existing coal fleet, with relatively small capacity additions of wind, solar PV, peaking and batteries for both the high and low demand forecast scenarios.

The SAV for Grootvlei was found to between **0.31 – 0.47 R/kWh** for the low and high demand forecast scenarios respectively as shown in Figure 44 and Figure 45.
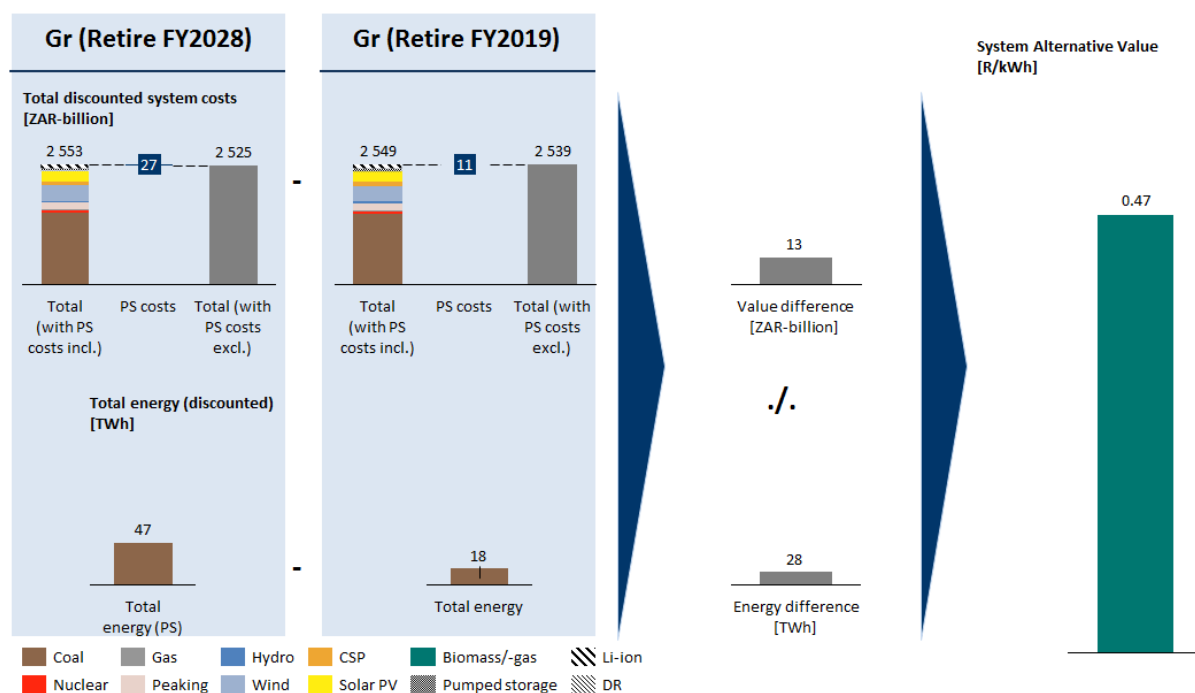
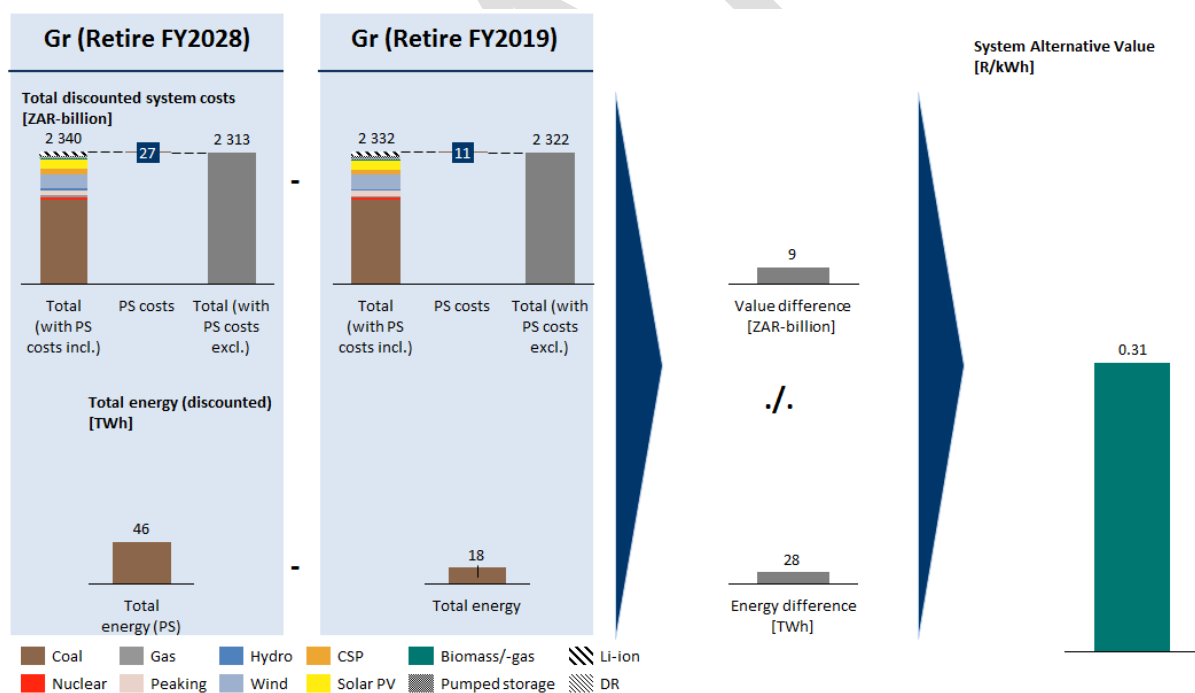**Figure 44. Scenario Grootvlei - High demand: System Alternative Value for Grootvlei**

Figure 45. Scenario Grootvlei - Low demand: System Alternative Value for Grootvlei

4.6 Hendrina

In this scenario Hendrina is decommissioned early in FY 2018 instead of the planned decommissioning date in FY 2026. The purpose of this scenario is to calculate the SAV of Hendrina providing energy for its planned life as opposed to being decommissioned earlier. Figure 46 and Figure 47 show the capacity and energy of Hendrina for the scheduled and early retirement scenarios for the high and low demand forecasts respectively. The changes in energy output and new capacity built to supply the energy gap from retiring Hendrina early is shown in Figure 48 and Figure 49 for the high and low demand forecast scenarios respectively.
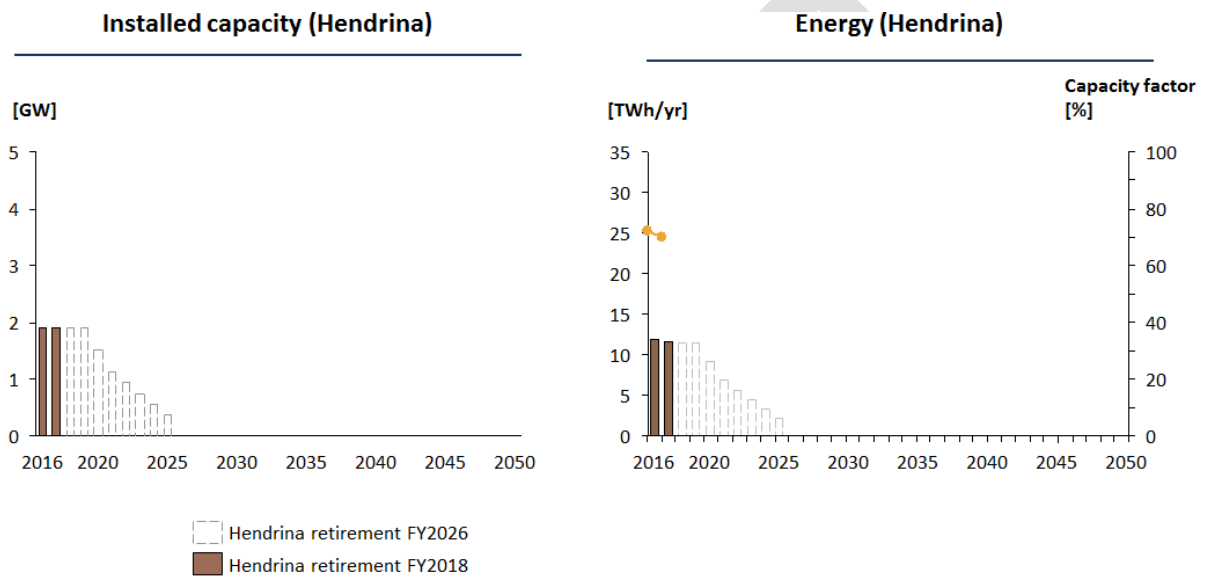
Figure 46. Scenario Hendrina - High demand: Installed capacity and energy from Hendrina for planned and early retirement
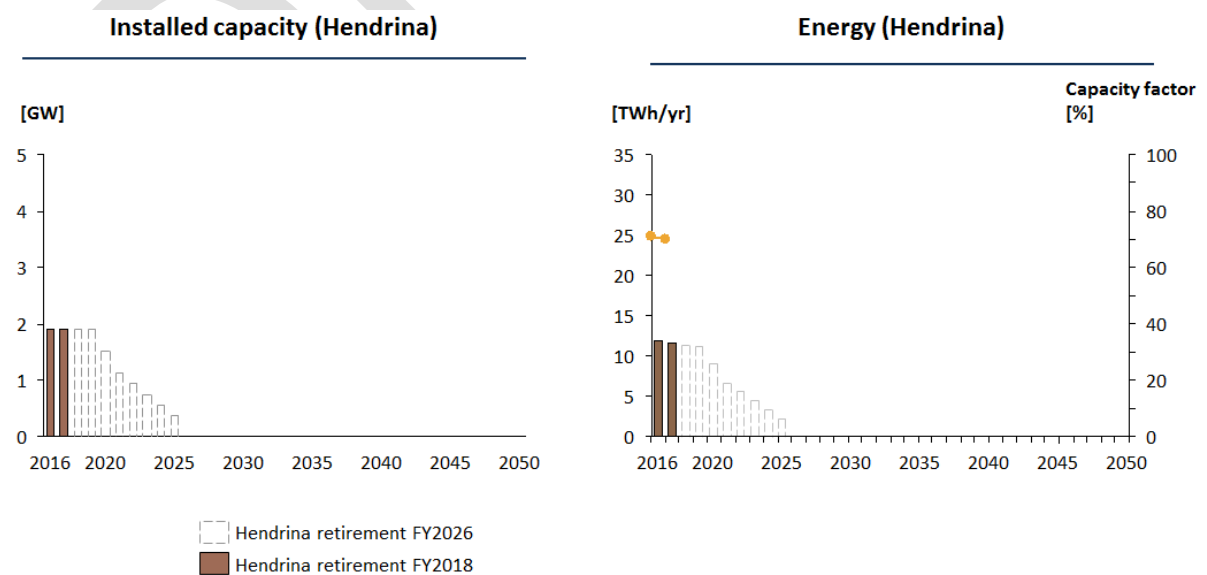

Figure 47. Scenario Hendrina - Low demand: Installed capacity and energy from Hendrina for planned and early retirement
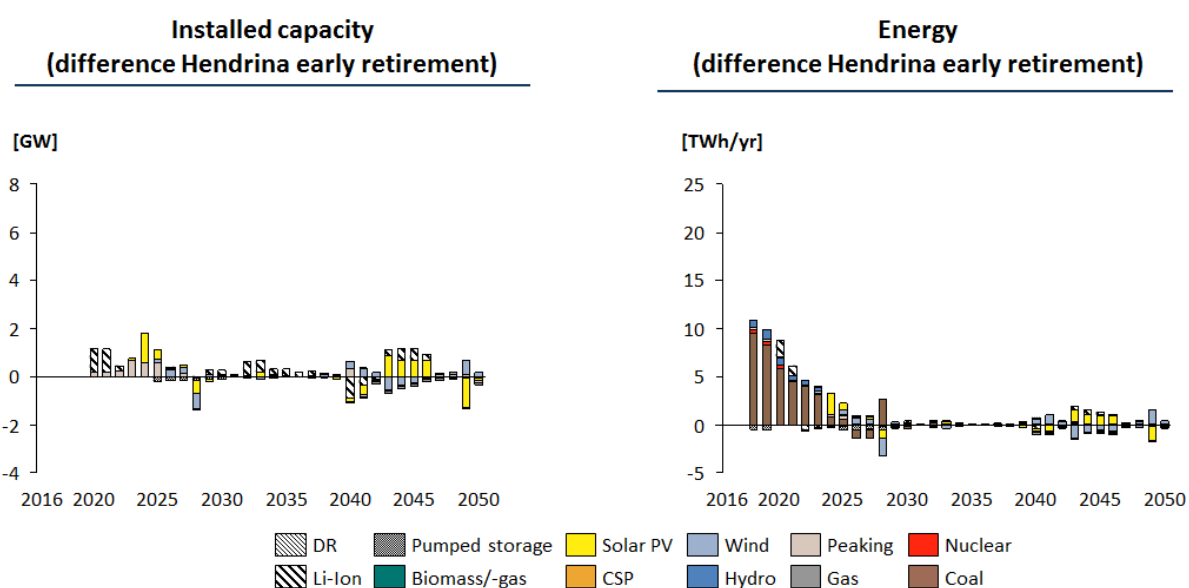
Figure 48. Scenario Hendrina – High demand: Additional capacity and energy required to replace Hendrina
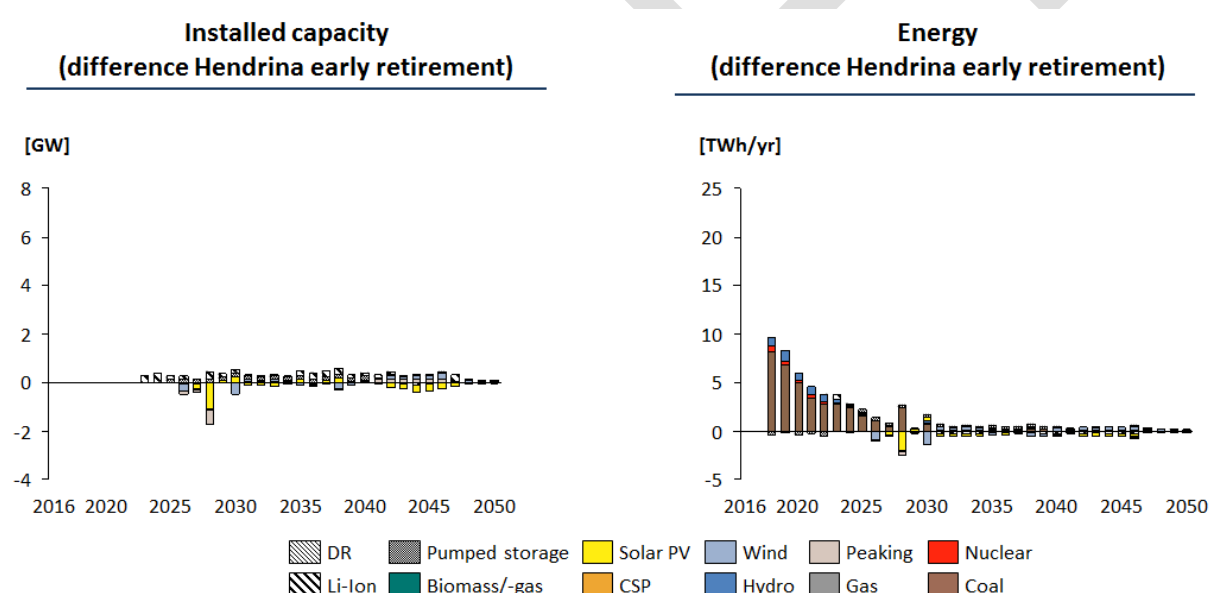

Figure 49. Scenario Hendrina – Low demand: Additional capacity and energy required to replace Hendrina

The energy gap from the early retirement of Hendrina is primarily replaced by additional energy from the existing coal fleet, with relatively small capacity additions of wind, solar PV, peaking and batteries for both the high and low demand forecast scenarios.

The SAV for Hendrina was found to between **0.23 – 0.41 R/kWh** for the low and high demand forecast scenarios respectively as shown in Figure 44 and Figure 45.
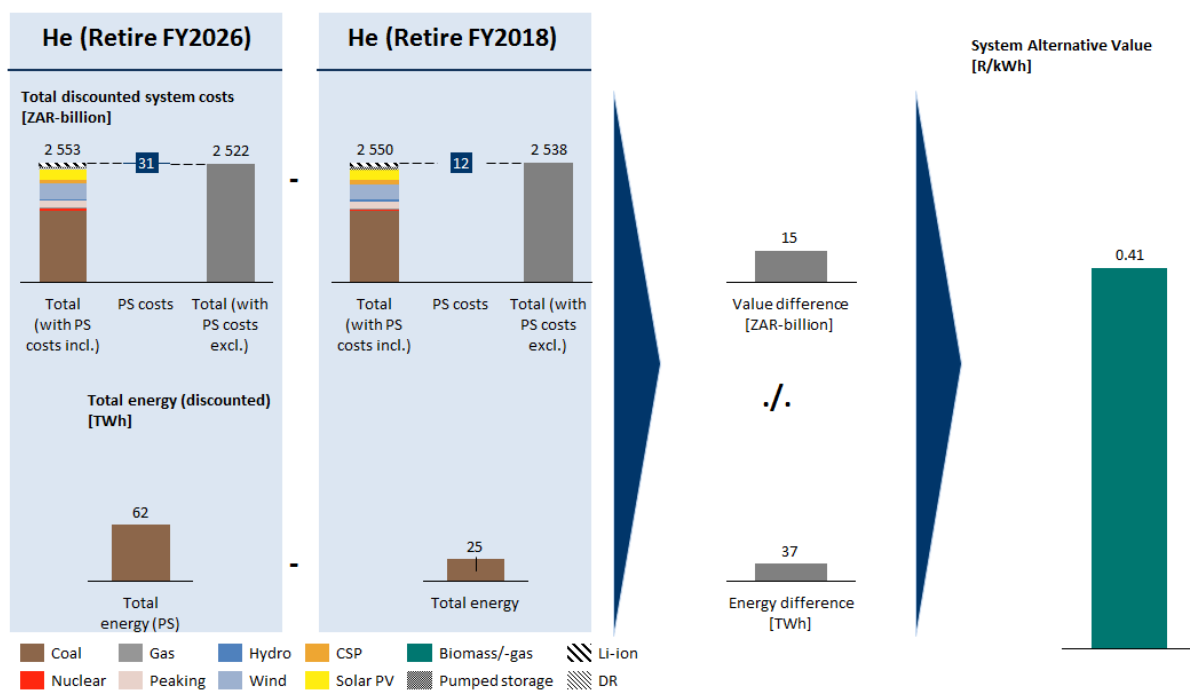
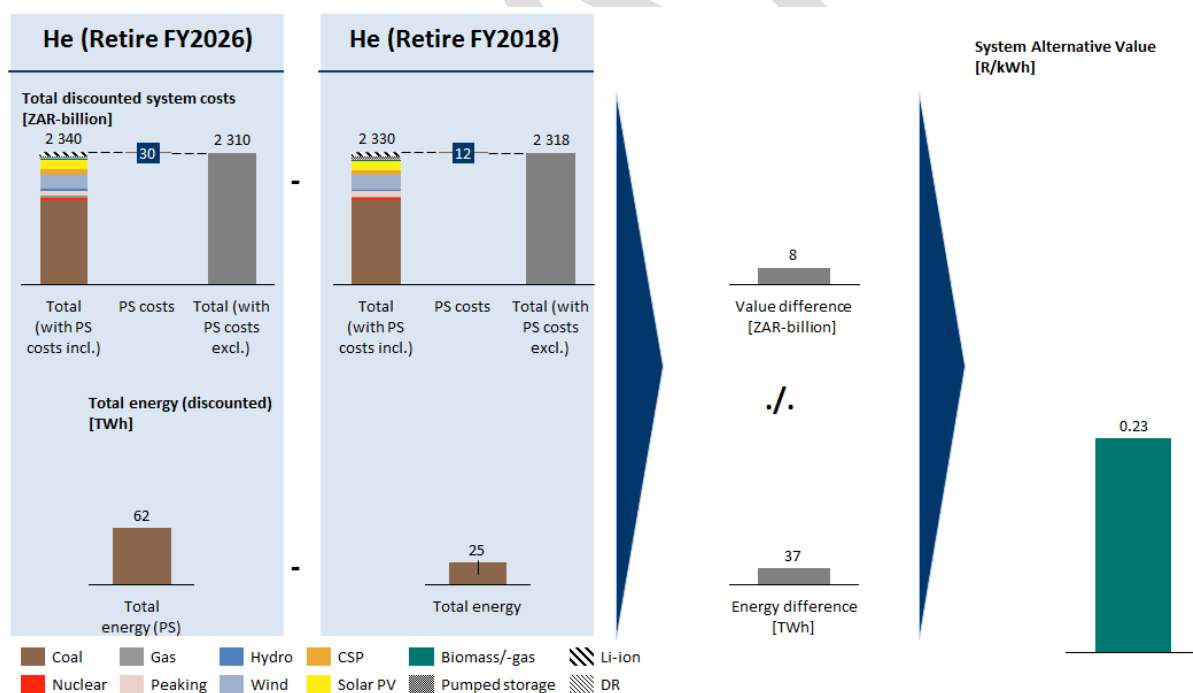**Figure 50. Scenario Hendrina - High demand: System Alternative Value for Hendrina**

Figure 51. Scenario Hendrina - Low demand: System Alternative Value for Hendrina

4.7 Komati

In this scenario Komati is decommissioned early in FY 2020 instead of the planned decommissioning date in FY 2028. The purpose of this scenario is to calculate the SAV of Komati providing energy for its planned life as opposed to being decommissioned earlier. Figure 52 and Figure 53 show the capacity and energy of Komati for the scheduled and early retirement scenarios for the high and low demand forecasts respectively. The changes in energy output and new capacity built to supply the energy gap from retiring Komati early is shown in Figure 54 and Figure 55 for the high and low demand forecast scenarios respectively.
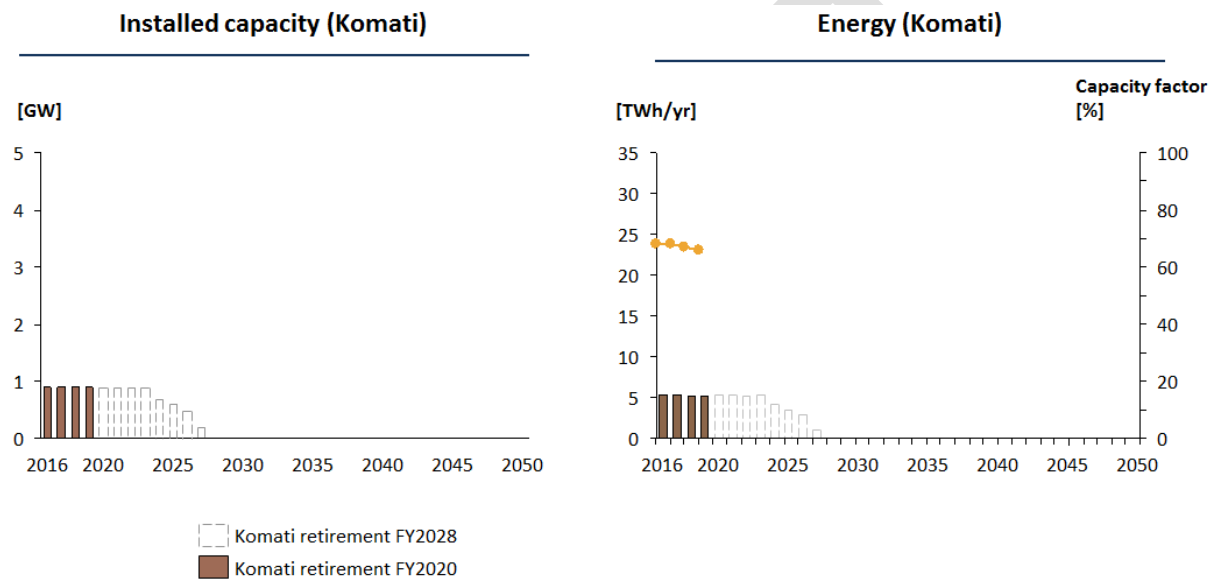

Figure 52. Scenario Komati – High demand: Installed capacity and energy from Komati for planned and early retirement
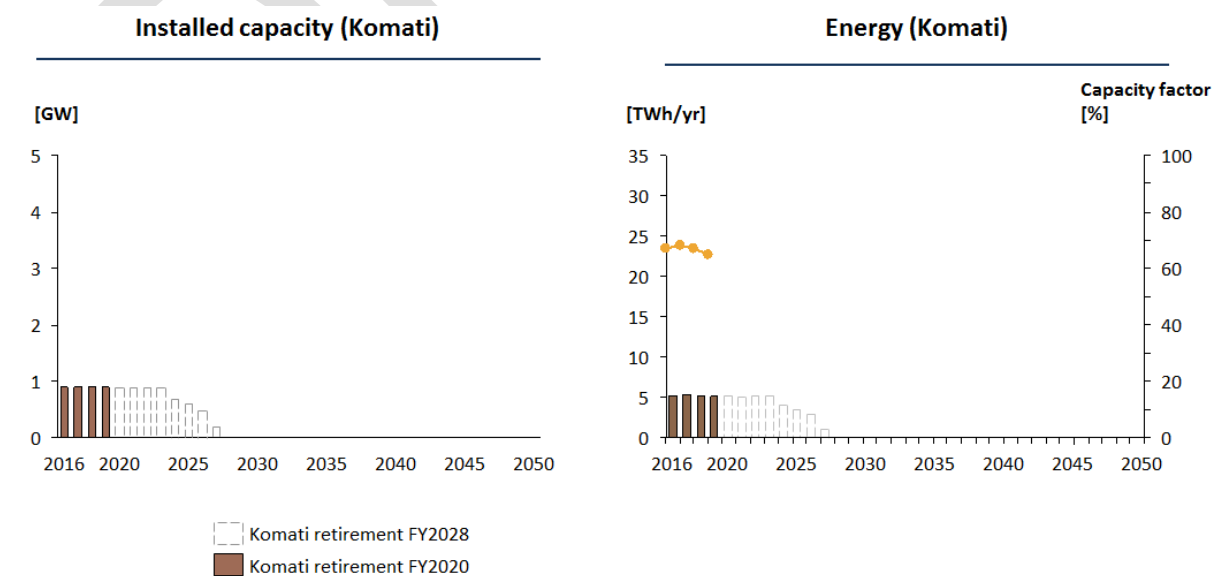

Figure 53. Scenario Komati – Low demand: Installed capacity and energy from Komati for planned and early retirement
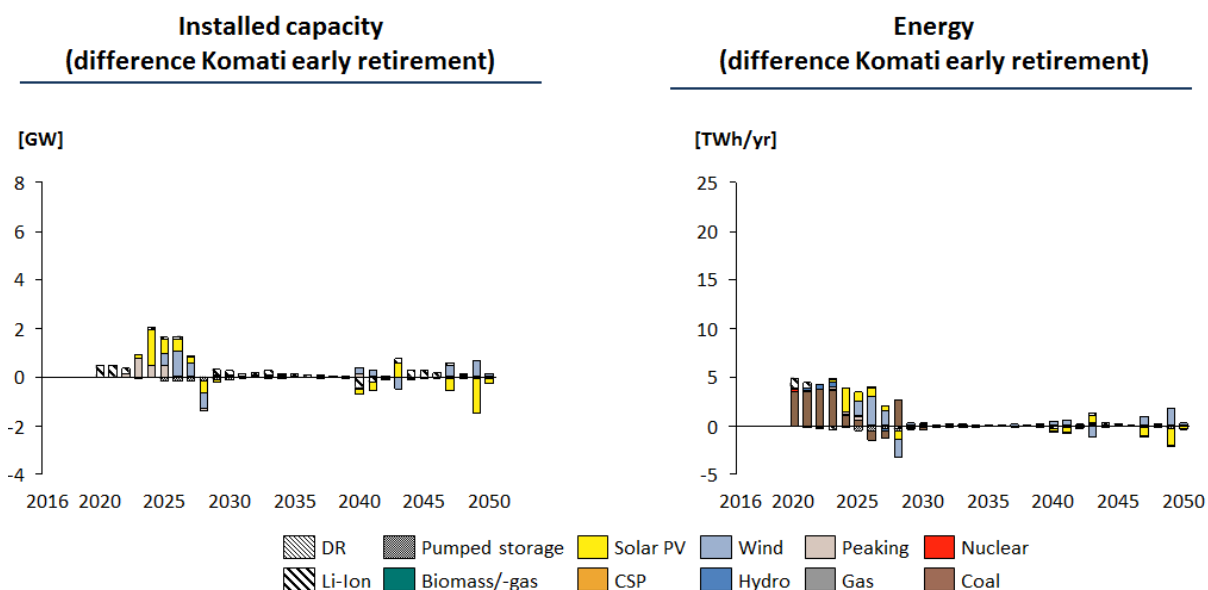
Figure 54. Scenario Komati – High demand: Additional capacity and energy required to replace Komati
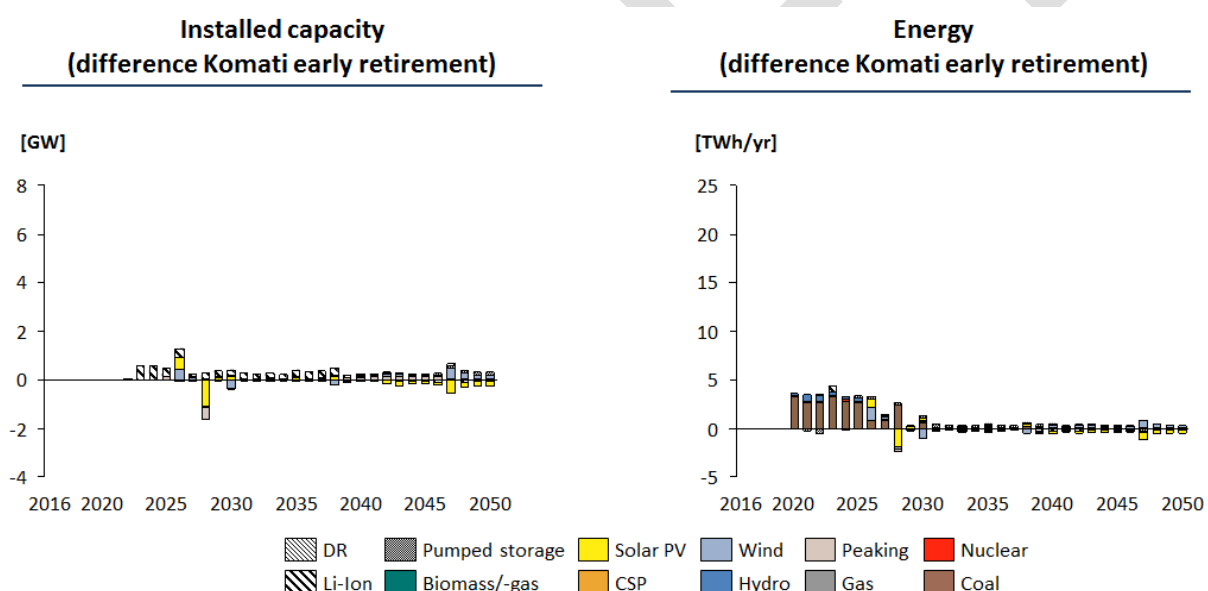

Figure 55. Scenario Komati – Low demand: Additional capacity and energy required to replace Komati

The energy gap from the early retirement of Komati is initially primarily replaced by additional energy from the existing coal fleet, as well as relatively small additional wind, solar PV, peaking and battery capacity in the high and low demand forecast scenarios.

The SAV for Komati was found to between **0.31 – 0.48 R/kWh** for the low and high demand forecast scenarios respectively as shown in Figure 56 and Figure 57.
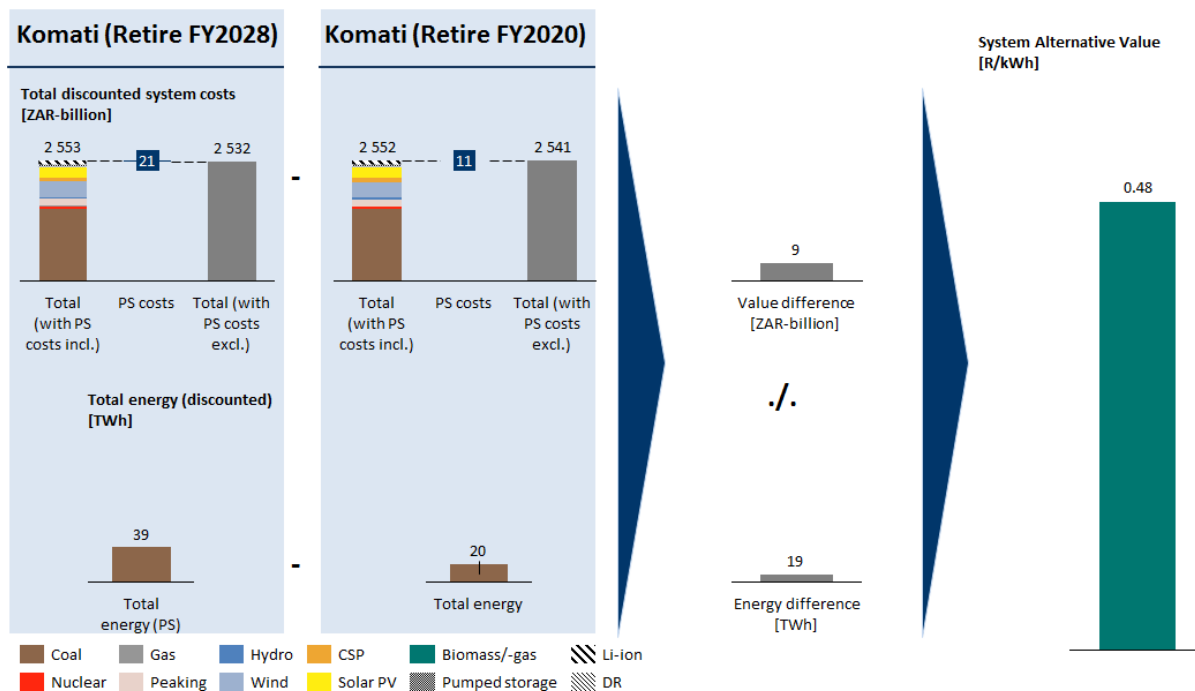
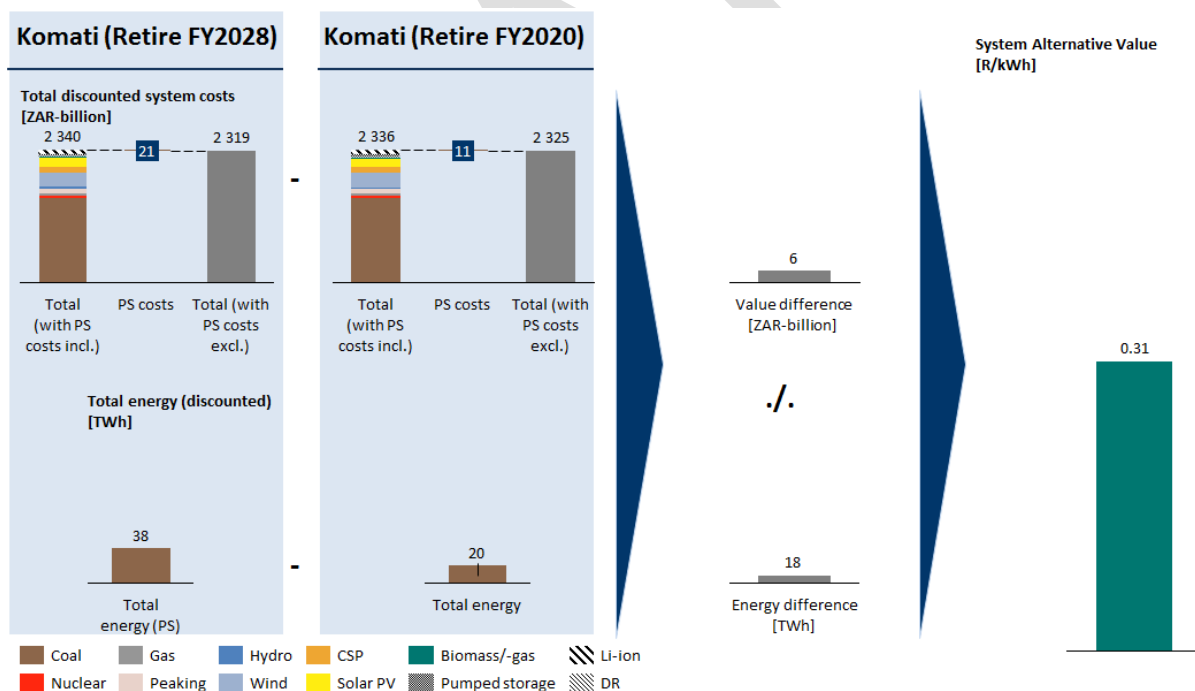**Figure 56. Scenario Komati - High demand: System Alternative Value for Komati**

Figure 57. Scenario Komati - Low demand: System Alternative Value for Komati

4.8 Grootvlei, Hendrina and Komati

In this scenario Grootvlei, Hendrina and Komati (Gr,He,Ko) are decommissioned early as per the dates in section 4.5, 4.6 and 4.7. The purpose of this scenario is to calculate the SAV of the combination of Grootvlei, Hendrina and Komati providing energy for their planned lives as opposed to being decommissioned earlier. Figure 58 and Figure 59 show the capacity and energy of Komati for the scheduled and early retirement scenarios for the high and low demand forecasts respectively. The changes in energy output and new capacity built to supply the energy gap from retiring Komati early is shown in Figure 60 and Figure 61 for the high and low demand forecast scenarios respectively.
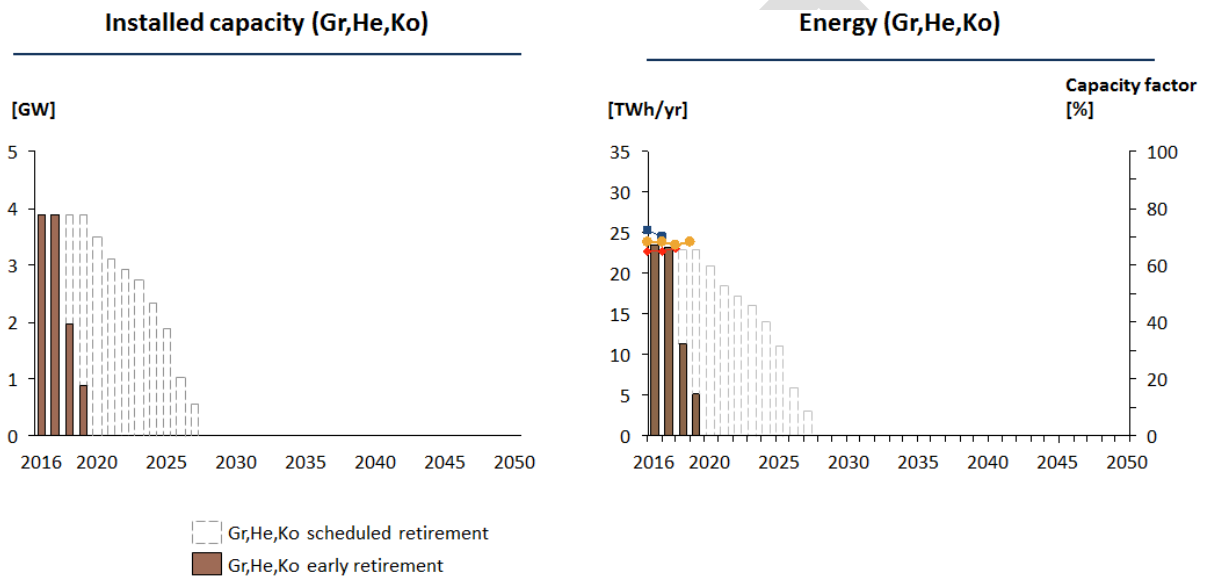

Figure 58. Scenario Gr,He,Ko – High demand: Installed capacity and energy from Grootvlei, Hendrina and Komati for planned and early retirement
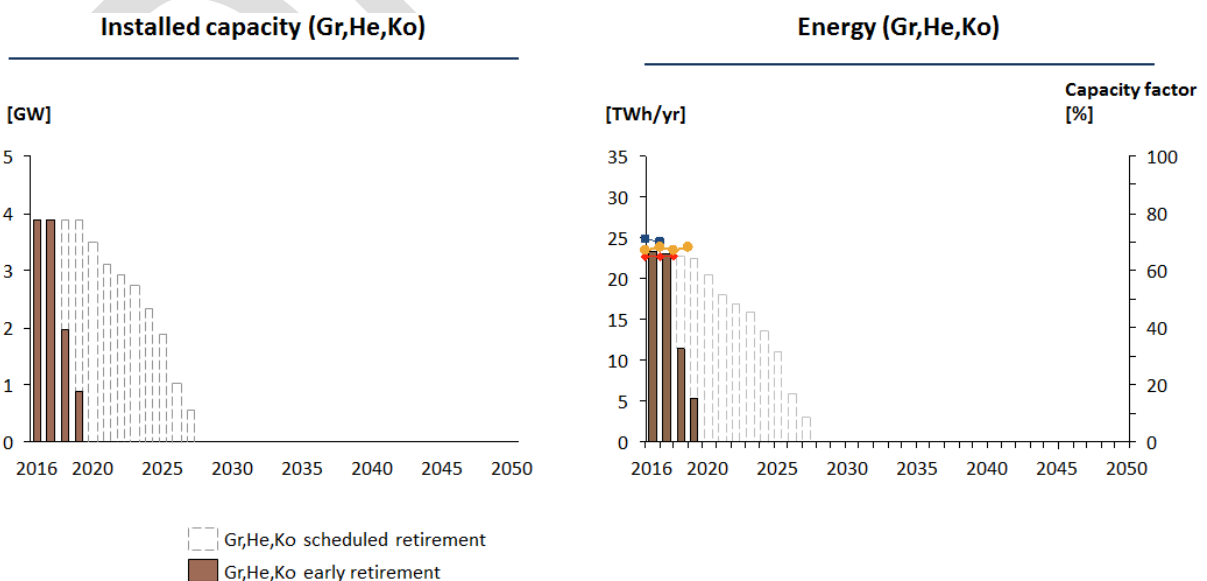

Figure 59. Scenario Gr,He,Ko – Low demand: Installed capacity and energy from Grootvlei, Hendrina and Komati for planned and early retirement
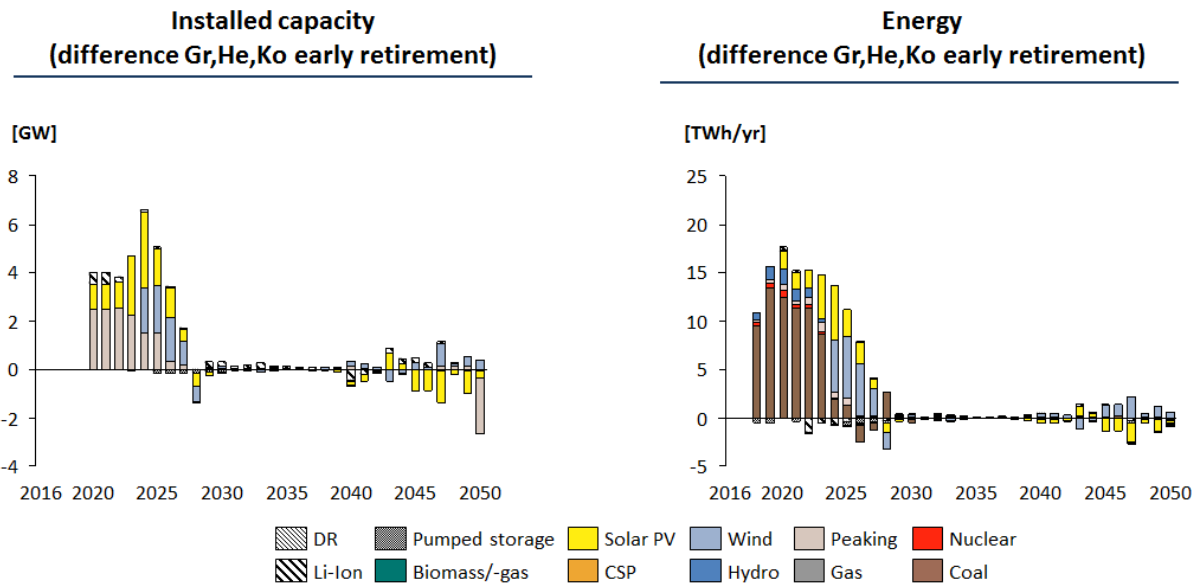
Figure 60. Scenario Gr,He,Ko – High demand: Additional capacity and energy required to replace Grootvlei, Hendrina and Komati
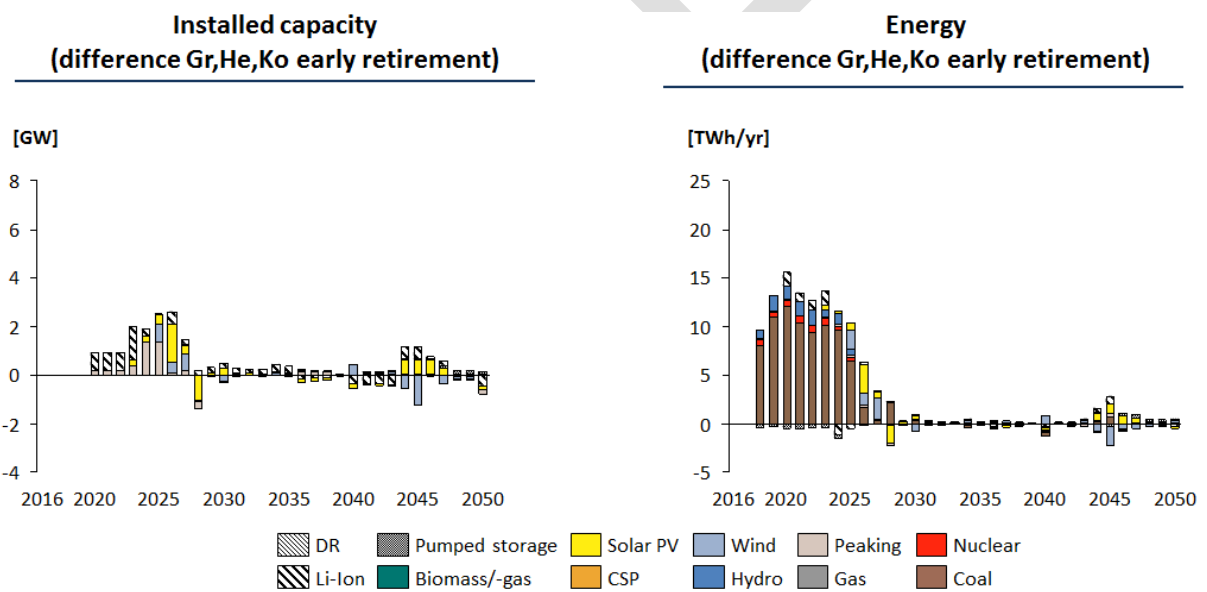

Figure 61. Scenario Gr,He,Ko – Low demand: Additional capacity and energy required to replace Grootvlei, Hendrina and Komati

The energy gap from the early retirement of Grootvlei, Hendrina and Komati is initially primarily replaced by additional energy from the existing coal fleet. Additional peaking, battery and solar PV capacity is also built initially, followed by additional wind capacity from FY 2023, in the high and low demand forecast scenarios.

The SAV for the combined stations was found to between **0.31 – 0.47 R/kWh** for the low and high demand forecast scenarios respectively as shown in Figure 62 and Figure 63.
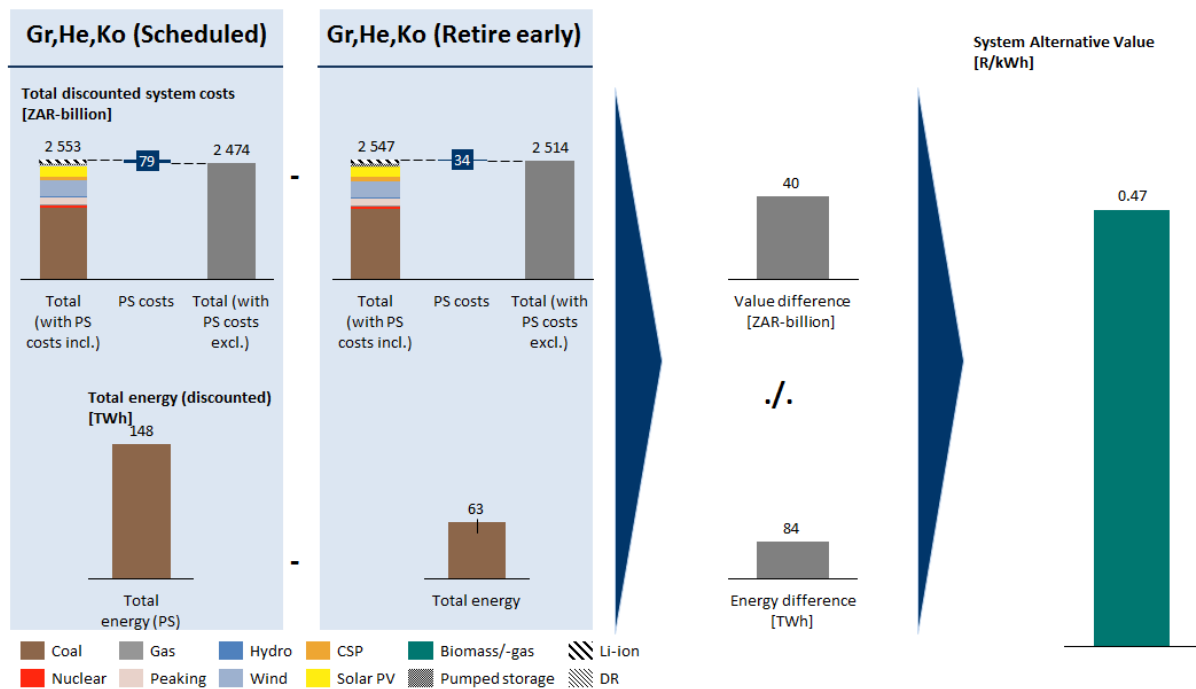
Figure 62. Scenario Gr,He,Ko - High demand: System Alternative Value for combined Grootvlei, Hendrina and Komati
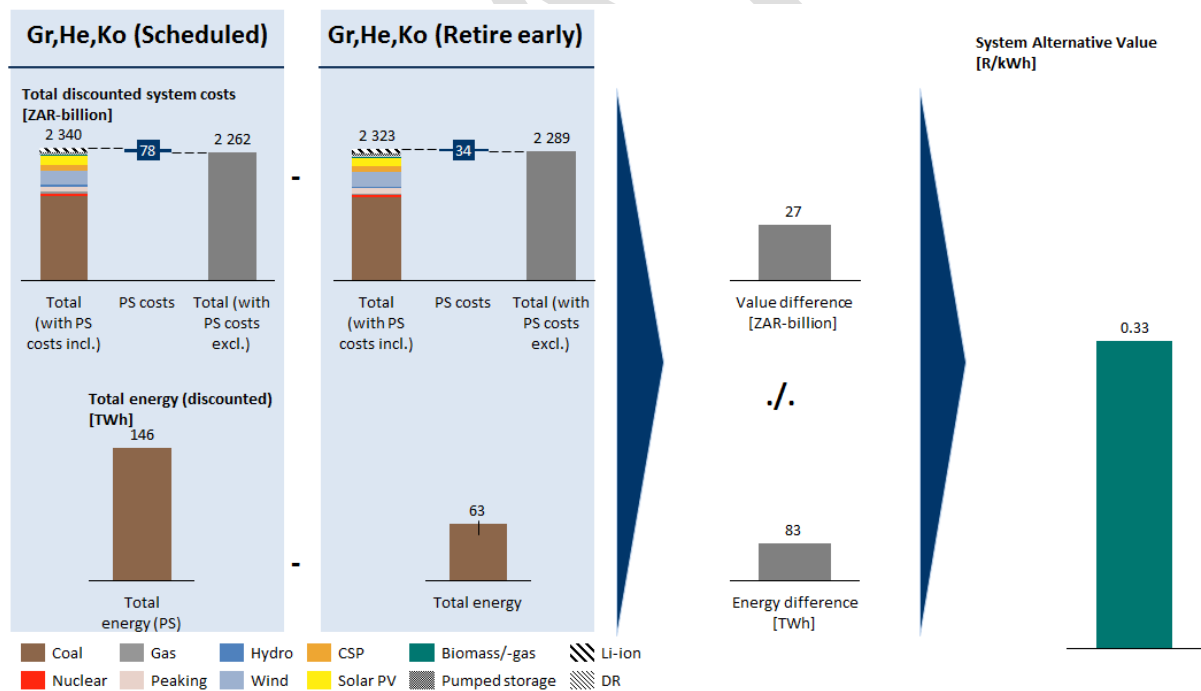

Figure 63. Scenario Gr,He,Ko - Low demand: System Alternative Value for combined Grootvlei, Hendrina and Komati

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4.9 Summary

The SAVs for all scenarios considered are shown in Figure 64 below.
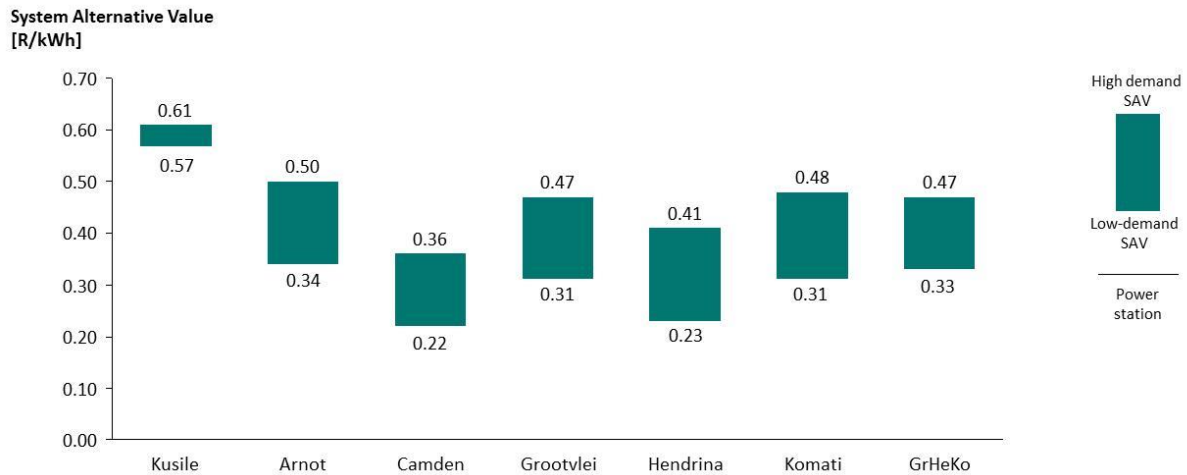

Figure 64. SAV for each power station studied for high and low demand forecasts

As expected, the SAV of a power station is generally higher for higher demand forecasts. Additionally, the SAV of the oldest power stations which do not have many years left and are generating in a period of "over-capacity", would be lower than Kusile which generates throughout the study horizon beyond the period of over capacity.

5 References

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