Technical Report

Systems analysis to support increasingly ambitious CO_2 emissions scenarios in the South African electricity system

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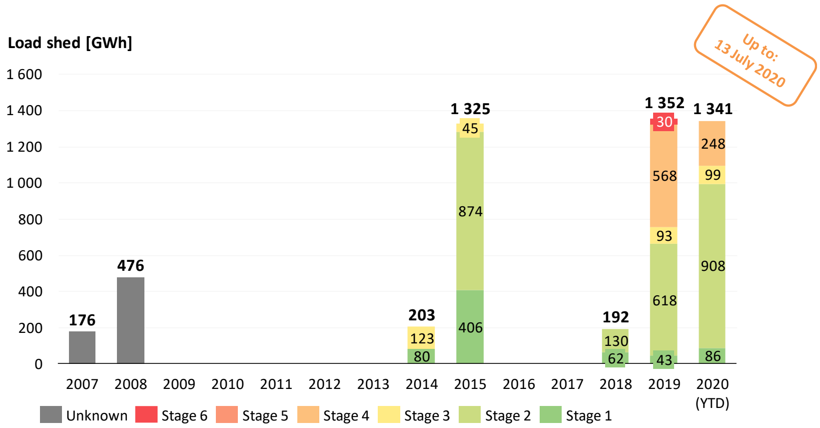
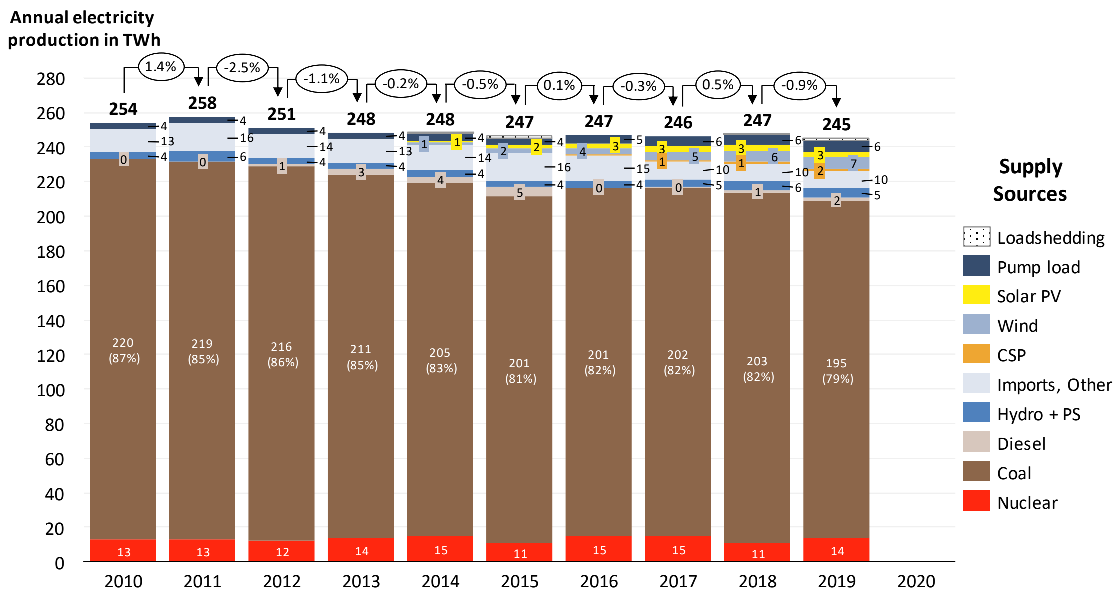
Executive Summary

The South African power system is in a crisis with urgent action required to ensure system adequacy whilst simultaneously ensuring a cleaner and more diversified energy mix



Notes: Load shedding assumed to have taken place for the full hours in which it was implemented. Practically, load shedding (and the Stage) may occassionally change/end during a particular hour; Total GWh calculated assuming Stage 1 = 1 000 MW, Stage 2 = 2 000 MW, Stage 3 = 3 000 MW, Stage 4 = 4 000 MW, Stage 5 = 5 000 MW, Stage 6 = 6 000 MW; Sources: Eskom Twitter account; Eskom se Push (mobile app); Nersa; CSIR analysis

South Africa's electricity demand is currently supplied mostly by coal-fired power stations. A distinctly flat to declining demand has been experienced since at least 2010 with coal-based electricity also playing a reduced role (87% in 2010, 79% in 2019). Following historical periods of supply-demand imbalance over more than 10 years, 2019 and the first half of 2020 saw the most intensive load shedding (controlled rolling demand reduction) with ≈1.3 TWh of load shed in each of these periods. This has been driven by a combination of factors including delayed commissioning and underperformance of new-build coal generation capacity as well as degradation of existing Eskom coal fleet energy availability factor (EAF) declining from ≈94% in 2002 to 67% in 2019.

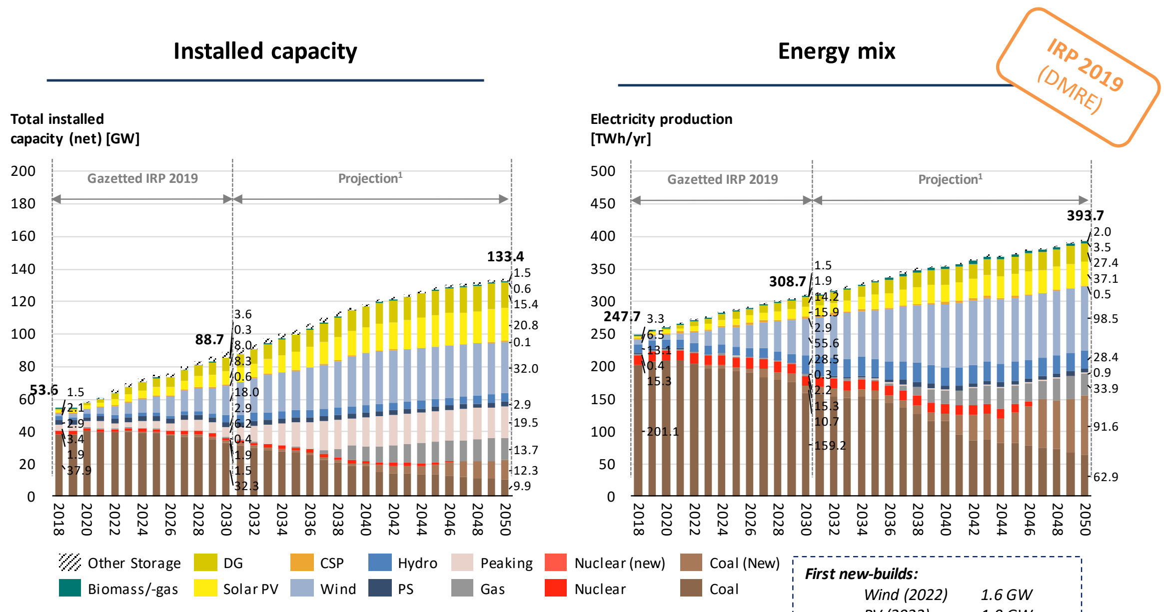


Sources: Eskom; CSIR Energy Centre analysis

Annual electricity production in South Africa (2010 to 2019) revealing flat to declining demand and reduced coal production

The IRP 2019 time horizon is expanded beyond 2030 to 2050 where it is found that a large portion of the existing coal fleet is re-built but a more diversified energy mix is expected

The Integrated Resource Plan (IRP) 2019 represents current policy where first new build capacity (beyond short-term emergency options) occurs in 2022 and consists of 1.6 GW of wind, 1.0 GW of solar PV and 0.5 GW of stationary storage. New coal capacity (0.75 GW) is planned for 2023 (and another 0.75 GW by 2027) as per DMRE policy adjustment process, followed by 1.0 GW of new gas capacity in 2024 (and further gas capacity from 2027 onwards). Imported hydro-based electricity of 2.5 GW from Inga is also included in 2030. After 2030, annual new-build limits on solar PV and wind combined with a non-ambitious CO_2 constraint, results in 12.3 GW of new coal capacity being built by 2050 (driving increased CO_2 emissions). Gas-fired capacity operated as peaking capacity is built pre-2030 (3.9 GW of OCGTs/GEs) whilst considerable mid-merit capacity and further peaking capacity is built thereafter (6.0 GW CCGT/GEs and 21.7 GW OCGT/GEs).



¹ Projection based on optimisation of 2030-2050 energy mix utilising input assumptions from DMRE IRP 2019 (not unconstrained least-cost);
DG = Distributed Generation; PS = Pumped Storage
NOTE: Energy share is a best estimate based on available data.
Sources: IRP 2019. CSIR Energy Centre analysis

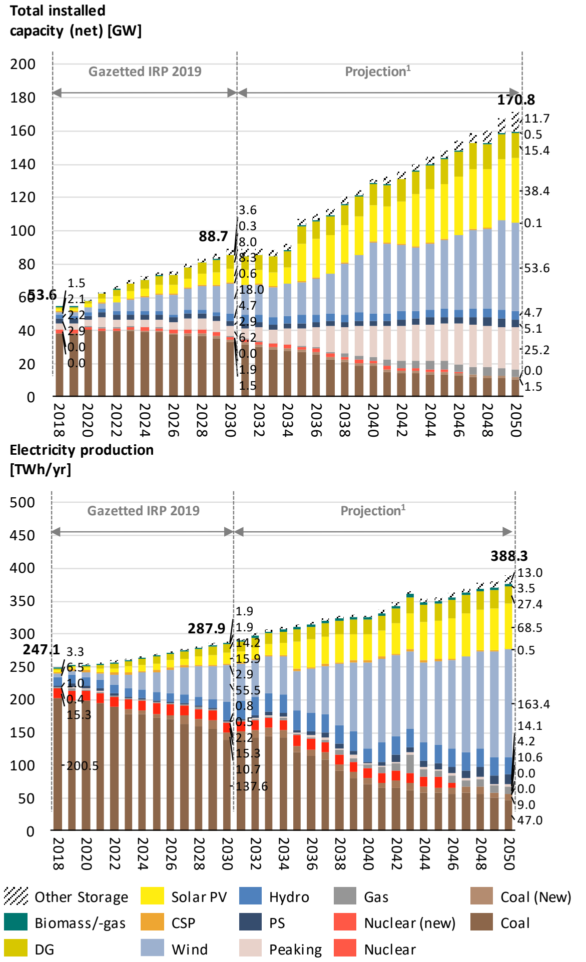
First new-builds:

Wind (2022)	*1.6 GW*
PV (2022)	*1.0 GW*
Storage (2022)	*0.5 GW*
Coal (2023)	*0.75 GW*
Gas (2024)	*1.0 GW*

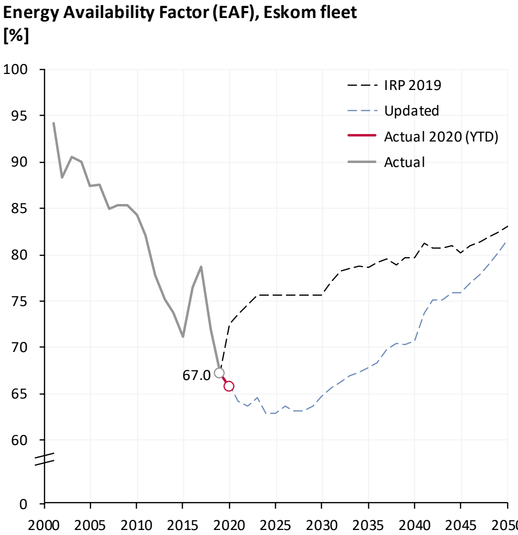
Installed capacity and energy mix for IRP 2019 (extended to 2050 by CSIR) revealing intentions for an increasingly diversified energy mix

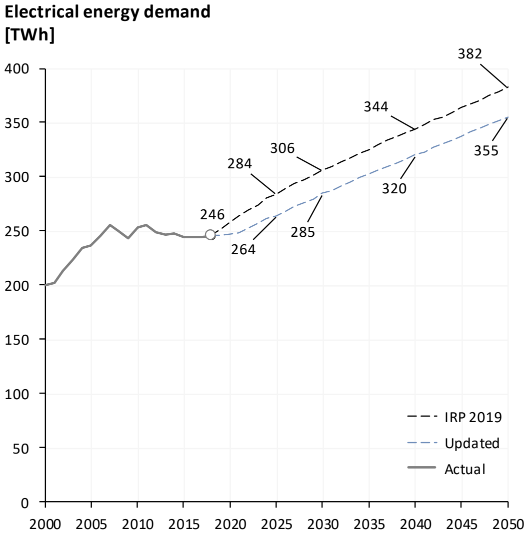
A Reference scenario considers an updated demand forecast and EAF expectation more aligned with the latest information whilst also removing annual new-build constraints

As in the IRP 2019 scenario, new build capacity was forced in as per current policy to 2030 where after the least-cost new build mix consists of solar PV, wind, storage and natural gas-fired capacity, with no further coal capacity being built. Similarly, no new-build nuclear or CSP capacity is built in this scenario. New-build storage capacity is dominated by short duration battery storage and only late in the time horizon is additional pumped storage built. Reductions of CO_2, NOx, SOx and PM emissions are observed as the existing coal fleets decommissions and is mostly replaced by renewable energy. There is also a drastic reduction in CO_2 emissions beyond 2035 as existing coal capacity decommissioning accelerates.



[1] Projection based on optimisation of 2030-2050 energy mix utilising CSIR input assumptions from CSIR;
DG = Distributed Generation; PS = Pumped Storage
Sources: IRP 2019. CSIR Energy Centre analysis

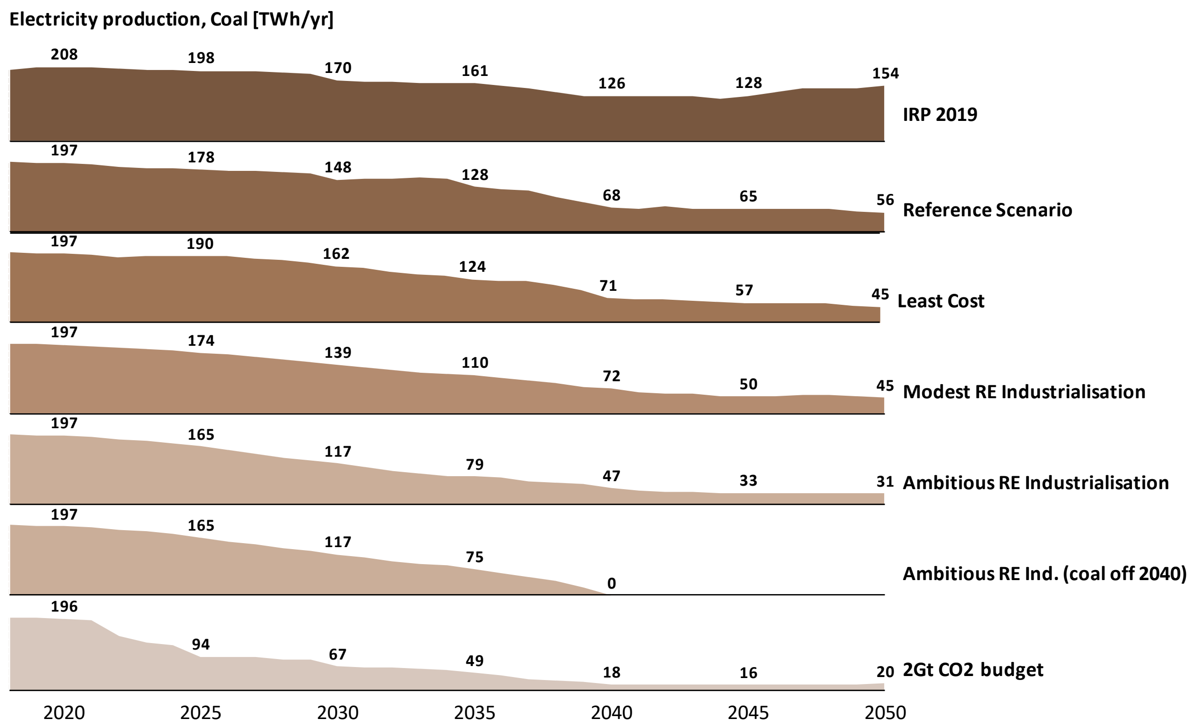




EAF and demand forecast revealing difference between IRP 2019 and Updated assumptions based on more recent information

The South African electrical energy mix is currently 81% coal but is expected to diversify as a least-cost future comprises 55% coal by 2030 and 11% coal by 2050. With lower utilization of remaining coal capacity expected, increased flexibility from this coal fleet is required in a future South African power system

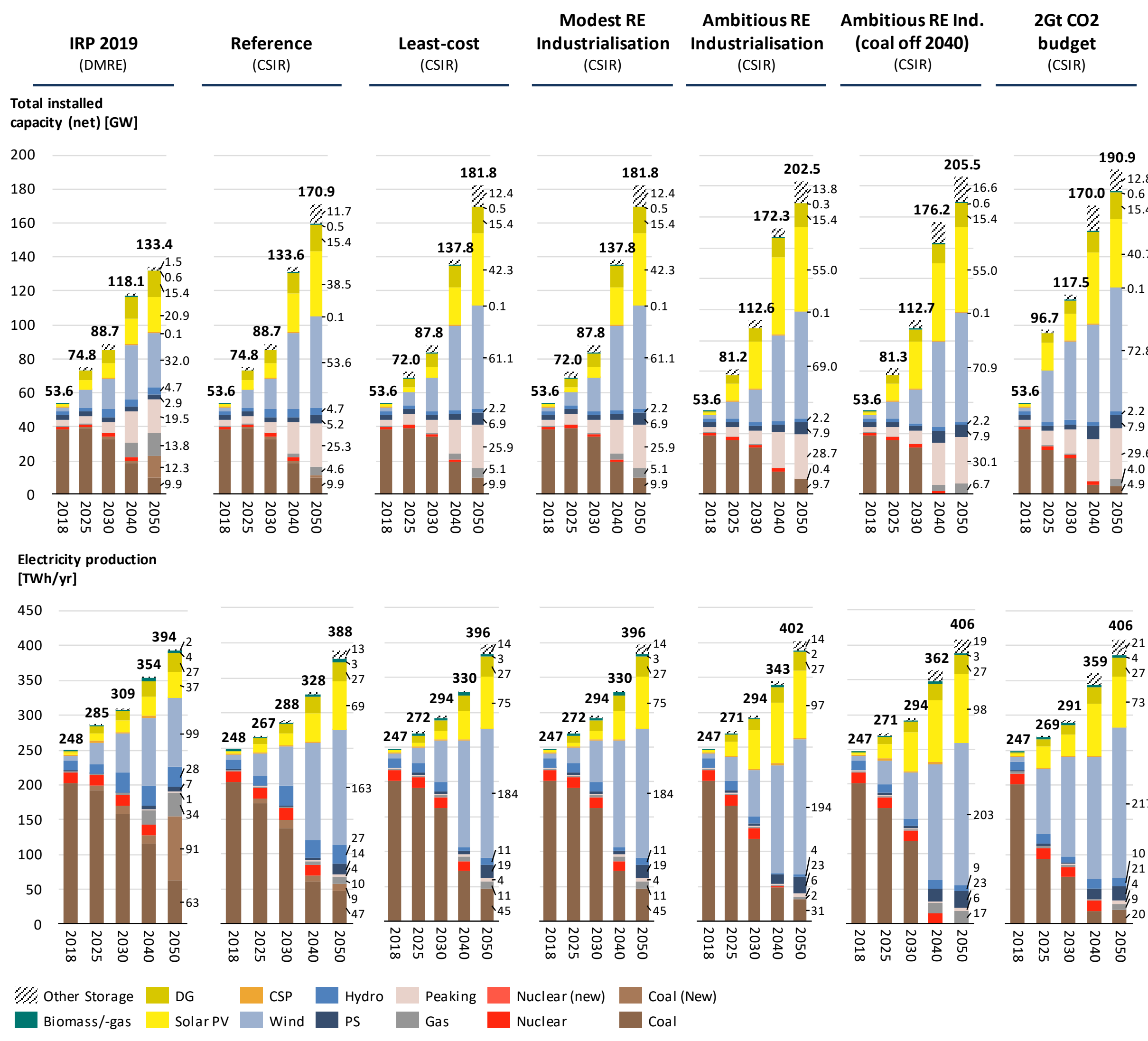
It is least-cost to shift from a coal dominated energy mix to an increasingly diversified energy mix made up of 55% coal by 2030 and 11% coal by 2050. The least-cost new build mix consists of solar PV, wind, storage and natural gas fired capacity supported by an existing fleet of generation capacity including coal, nuclear and imports. Flexibility becomes increasingly important especially in earlier years of the time horizon (pre-2030) as significant levels of coal capacity still exists and should be utilized as much as technically feasible but no more than economically optimal. Existing technical capabilities of the coal fleet is explicitly considered in this study. However, the feasibility as well as cost implications of an increasingly flexibilised coal fleet to operate at low capacity factors will need to be carefully considered as increased variable renewable energy is integrated.



South African electricity production from coal across scenarios where the role of coal reduces (in absolute terms) but remains part of the energy mix in all but one scenario (where coal is forced off by 2040) whilst increased flexibility is expected as capacity factors decline

Regardless of CO_2 ambition, renewable energy is expected to play an increasingly important role whilst other new-build low-carbon energy providers like nuclear, CSP and coal (with CCS) are not part of the least-cost energy mix

Across all scenarios, in order to meet increasingly ambitious power sector CO_2 mitigation in South Africa, wind and solar PV technologies play a dominant role. By 2030, these technologies are expected to comprise 29-64% of the energy mix depending on CO_2 ambition whilst by 2050 the energy mix would be 67-81% solar PV and wind. This means solar PV and wind installed capacity of ≈15-40 GW and ≈20-45 GW by 2030. By 2050, installed capacity of wind and solar PV is expected range from ≈30-75 GW and ≈35-70 GW respectively. Regardless of CO_2 ambition level, no new-build nuclear, coal (with/without CCS) or CSP capacity are part of least-cost optimal energy mixes.

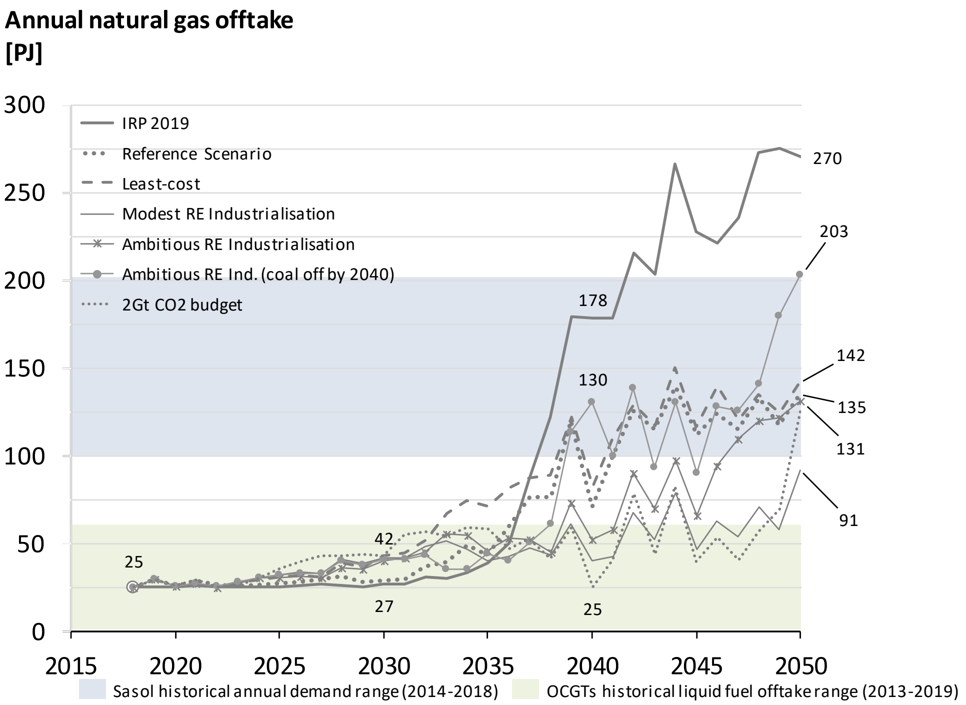


DG = Distributed Generation; PS = Pumped Storage
Sources: CSIR Energy Centre analysis

Installed capacity and production across scenarios revealing how least-cost energy mixes (even with increasing CO_2 ambitions) comprise new-build solar PV, wind, storage and natural gas capacity complemented by existing coal, nuclear, hydro, pumped storage and peaking capacity

Gas-fired generation capacity is considered as a proxy for an increased need for flexible capacity but limited energy provision means limited natural gas offtake

The absolute capacity of flexible natural gas-fired capacity built across scenarios is reduced relative to previous analyses undertaken by CSIR in this domain as increased levels of stationary storage is deployed. The average annual capacity factor of the gas fleet is <30% across all scenarios whilst that of peaking capacity utilizing natural gas is <5%. Thus, demand for new gas capacity is mostly driven by flexible capacity requirements (not energy). Annual natural gas offtake is expected to remain relatively low, increasing from ≈25 PJ to ≈30-40 PJ by 2030 (additional annual natural gas demand of ≈5-15 PJ). Thereafter, increased natural gas offtake of ≈40-90 PJ by 2040 (≈15-65 PJ excluding Sasol) and ≈90-140 PJ by 2050 (≈65-115 PJ excluding Sasol). An exception is when all coal capacity is decommissioned by 2040 forcing an increased annual natural gas offtake of up to ≈130 PJ by 2040 and ≈200 PJ by 2050. Similarly, in the IRP 2019 scenario, projections indicate natural gas annual offtake is expected to rise towards 180 PJ by 2040 (≈165 PJ excluding Sasol) and 270 PJ by 2050 (≈245 PJ excluding Sasol).

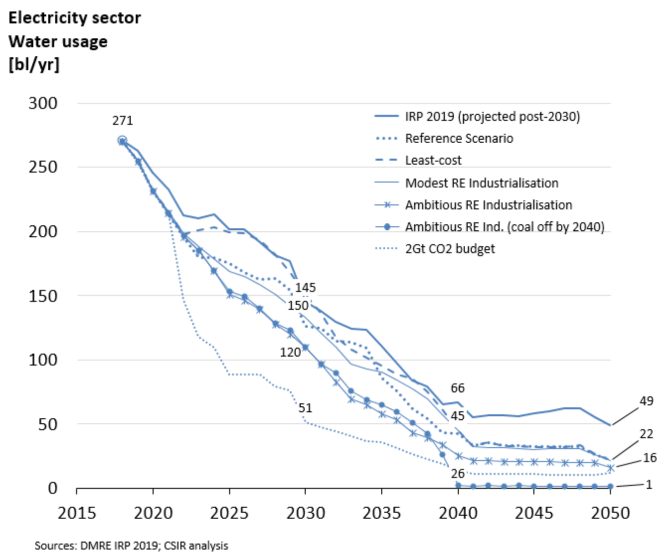


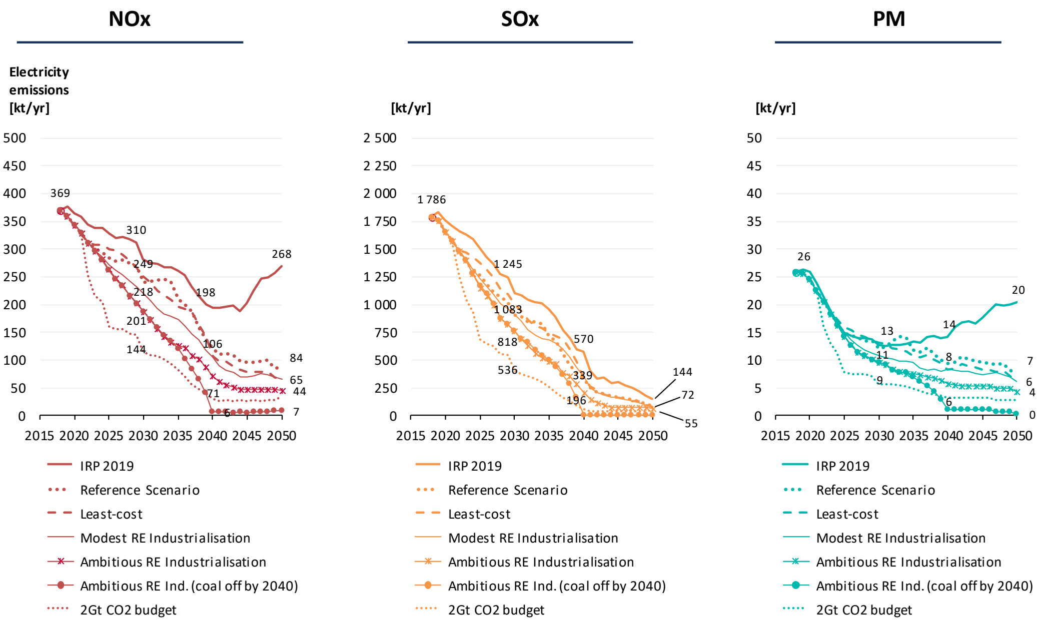
Notes: Natural Gas Price = 150 R/GJ (proxy for "expensive" natural gas); IRP 2019 not directly comparable due to higher demand forecast assumption
Sources: CSIR analysis

Natural gas offtake across scenarios showing relatively low initial natural gas offtake volumes but increasing significantly after 2035 across most scenarios towards the end of the time horizon

Water usage and emissions in the power sector are expected to continually decline with all new technologies deployed exhibiting low water and emissions intensity with resulting localised and national benefits

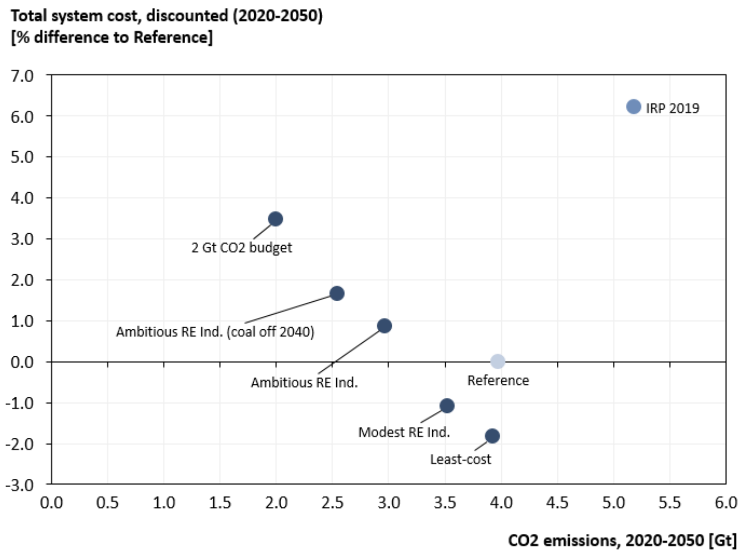
Water usage in the power sector is expected to drop significantly in all scenarios even when new-build coal capacity is built in the IRP 2019. In a scenario where all coal capacity is decommissioned by 2040, water usage becomes negligible from 2040 onwards whilst other scenarios water usage is expected to drop from ≈270 bl/yr in 2018 to ≈120-150 bl/yr by 2030, ≈25-65 bl/yr by 2040 and ≈15-50 bl/yr by 2050. With the exception of the IRP 2019 scenario where further new-build coal is built after 2030, NOx and PM emissions are expected to decline significantly as the existing coal fleet decommissions. SOx emissions decline across all scenarios as a result of any new-build coal being assumed to be fitted with flue-gas desulphurisation (FGD). The result of these findings is reduced localized air pollution and improved air quality for surrounding communities in close proximity to coal generation capacity as NOx and PM emissions are expected to decline.



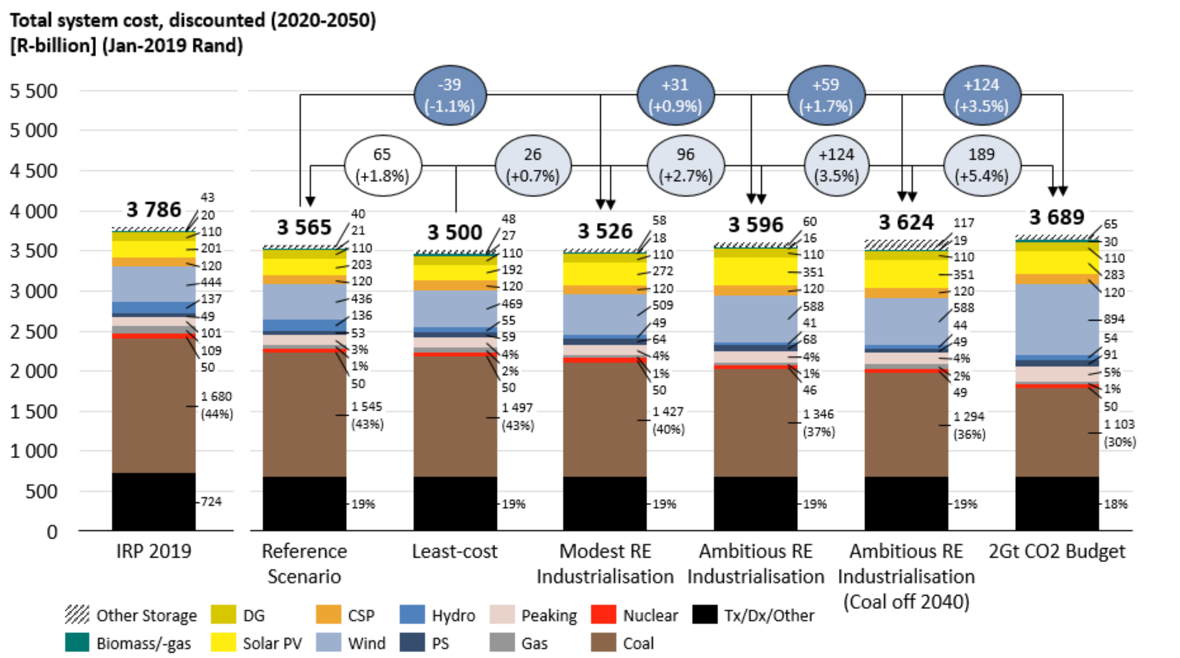


Power sector NOx, SOx and PM trajectories showing notably reduced emissions in most scenarios even as power system size grows

With increasing CO_2 ambition, system costs increase but not as much as initially expected –clearing a path for power sector decarbonization with minimal tradeoffs and substantial power sector benefits



The total discounted system cost for an Ambitious RE Industrialisation with 3.5 Gt of CO_2 emissions (for 2020-2050) is R 31-59-billion more than the Reference whilst a 2.0 Gt CO_2 budget scenario cost R 124-billion more. This represents a less than 4% increase in total system cost for substantial CO_2 mitigation gains of 0.5 Gt and 2.0 Gt of CO_2 respectively. Hence, even when imposing an earlier than optimal and smoothed renewable energy build out program or when an ambitious power sector CO_2 constraint is considered, CO_2 emissions mitigation comes at a relatively small premium. Furthermore, conservative technology costs assumed for renewable energy technologies further strengthens this finding in scenarios with increased levels of CO_2 ambition and resulting renewable energy penetration.

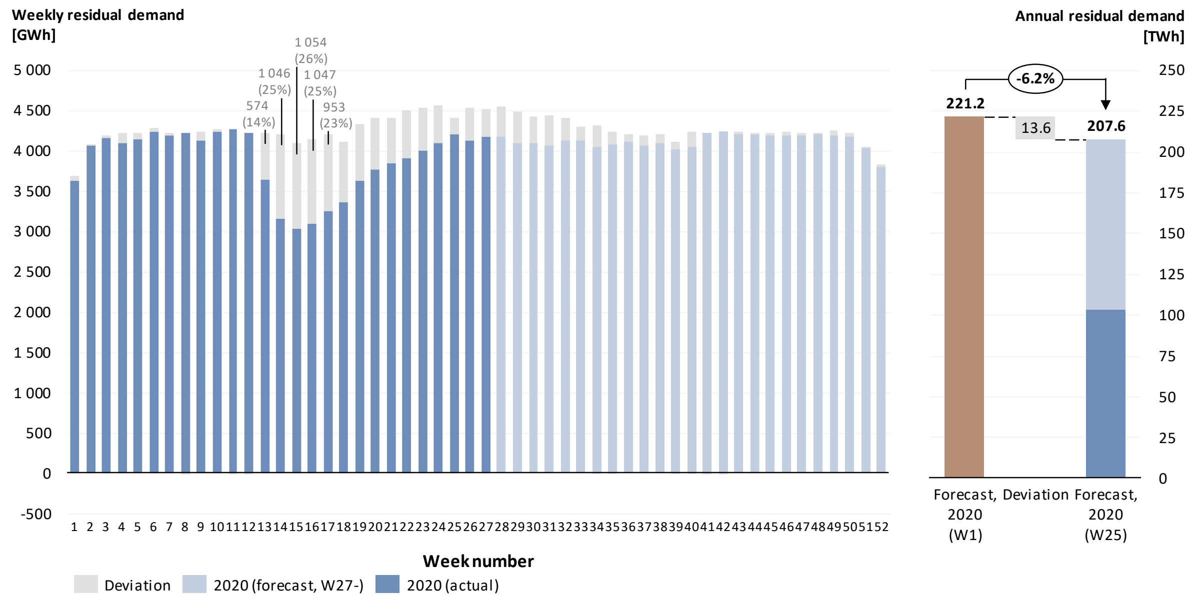


Notes: Transmission (Tx), distribution (Dx), system services (often referred to as ancillary services) and other costs not explicitly included in the PLEXOS. Modelling framework are approximated by a high level assumption of 0.20 R/kWh for all of these cost components consistently across all scenarios. Discount rate = 8.2%
Sources: CSIR Energy Centre analysis

Total system cost (discounted) for 2020-2050 revealing relatively small cost differentials as CO_2 ambition grows relative to Least-cost

The impact of the South African national lockdown to mitigate Covid-19 on the South African electricity sector has been wide-ranging but largely seen as acute reduced demand which quickly returned resulting in the return of load shedding

A novel coronavirus outbreak in Wuhan Province of China occurred in December 2019 called severe acute respiratory syndrome coronavirus 2 (SARS-CoV-2) which causes coronavirus disease 2019 (Covid-19). In response, South Africa enforced a national lockdown with a risk-adjusted strategy from 27 March 2020. One of the impacts of this is substantially reduced electricity demand. During Level 5 (5 weeks), a 23-26% weekly demand reduction occurred whilst energy demand to 7 July 2020 dropped by 10.5 TWh (-16%). For 2020, expectations are for demand to contract by 14 TWh (-6.2%). As the economy began re-opening in Level 3, electrical demand returned near immediately revealing the acute and transient effect of the lockdown on demand. This already manifested in July 2020 as Eskom commenced rotational load shedding.



Sources: Eskom; CSIR Energy Centre analysis

Weekly residual demand for 2020 highlighting the effect of the South African national lockdown (deviations during Level 5 highlighted)