ERC

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COMMENTS

Comments on draft IRP 2018

COMMENTS BY ENERGY RESEARCH CENTRE AT THE UNIVERSITY OF CAPE TOWN

On the draft Integrated Resource Plan (IRP) 2018
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1. Introduction

The Energy Research Centre (ERC) at the University of Cape Town (UCT) welcomes the opportunity to comment on the draft Integrated Resource Plan (IRP), published by the Minister of Energy 27 August 2018, with a request for public comment.(1) The draft IRP has been long awaited, and ERC is please to provide these comments.

2. Return to evidence-based planning

Overall, the ERC reads the draft IRP 2018 as an improvement on the base case published in 2016.(2) Together with the IRP 2010,(3) which remained the official plan, it appeared the political factors were driving electricity planning. We welcome the draft IRP 2018 as a return to evidence-based decision-making. While there are several technical issues which we raise in the following, at the outset we wish to acknowledge that the draft IRP 2018 enables us to engage in the kind of debate that is needed.

3. What is an IRP – and what should it be?

An IRP is an electricity plan. What is to be integrated are electricity demand and supply. The literature suggests that good practice in integrated electricity (and energy) planning is to start from demand.(4-7) ERC takes the view that what people need are services – mobility, warm food, lighting etc. Electricity can provide those services, and this informs demand. A good IRP should therefore come to electricity generating technologies (the supply side) as an output; the IRP is not a supply-side plan. The following sections suggest that, in our reading, the draft IRP 2018 does not address the demand-side adequately.

An IRP is not a result of modeling alone. Various inputs are made into a modeling framework, this generates various scenarios (often base and policy cases). Analysing key factors that make a difference allows more multiple criteria to inform decisions fo a 'balanced' plan. All these results are taken by policy-makers to adjust and for government to adopt a final plan.

The draft IRP, has made significant improvement on the base case published earlier. However, as we will elaborate, there are significant gaps in the IRP – particularly relating to broader trends. Some topics which the IRP should say more include: Just transition; externalities; more on energy storage; demand side management; full consideration of employment in person-years; and others.

4. Demand projections

4.1 Drafters know projections are too high but persist in repeating the mistake

Projections of electricity demand have consistently been higher than actual, in previous IRPs. Figure 3 in the draft IRP 2018 illustrates very clearly that actual electricity sent out was much lower than the 'cone' of projections in the IRP 2010, i.e. even lower than the low projection of electricity demand. Despite this, the drafters of the IRP repeat the error: Figure 7 shows smoothly upward sloping higher, middle and lower projections. It seems likely that, again, even the lower projection will be higher than actual demand.

The lower electricity demand projections are based on somewhat lower GDP as a key driver, but 1.33% GDP growth is higher than currently in a recession.

While it is understood that governments everywhere assume economic growth will pick up, history suggests that no-growth scenario would provide a more realistic envelope – then actual demand might turn out to fall within the 'cone' between lower and higher projections. If that is not palatable to planners, we submit that actual demand should at very least be monitored annually, and the projections adjusted. A complementary option is to subtract distributed energy resources (DER) and demand side management (DSM, see below) from the lower electricity demand projections. That might prove to be closer to actual demand.

Scenarios are a tool to manage uncertainty, and many factors that influence our electricity planning are highly uncertain. It would only make sense to explore a full range of uncertainty. From our own history, with both mothballing and load-shedding, we know that the risk of over- and under-building are both costly to economy and society. ERC recommends adopting a full range of scenarios, and explicitly valuing modular, flexible supply options .

4.2 Implications for utilities and local government

Patterns of electricity demand are changing rapidly globally, not only in SA. Utilities face a 'death spiral', in which greater efficiency, distributed generation and storage lead to reduce energy sales, which increase prices, with lead to more 'grid defections', in which customers choose distributed generation, efficiency and storage.(8) The National Energy Regulator of SA (NERSA) referred to this cycle in engagements with Eskom on 2018/19 tariff increases. The risk is thus understood in SA, but does not seem to be factored in to the draft IRP2018.

Changes in demand patterns also have major implications for municipalities.

Local government accounts for 40% of electricity demand. The SA Local Government Association (SALGA) reports that, since 2007, demand has declined slightly; which is in contrast to projections of smoothly increasing demand in future. (9) This is supported by data on Eskom sales to municipal distributors, the largest customer group by GWh per year. Meanwhile, electricity prices have increased four-fold since 2007, raising concerns about losses,(9) with electricity sales being a key source of revenue. The IRP should take into account global trends, and plan for distributed energy resources and systems.(10)

Electricity service departments (ESDs) need to reinvent themselves, from being on-sellers of a monopoly product with captive markets, to coordinating a complex set of arrangement with prosumers. Managers in ESDs are aware of these challenges, at least in the metros. However, the challenge to the revenue base makes this a political issue.

5. Energy efficiency and demand side management

Modeling interventions in energy efficiency and demand side management (EEDSM) is a distinct matter to demand projections.

While DSM is defined in the glossary, we find no reference in the draft IRP, nor in the CSIR forecasts for electricity demand.[(11)] The draft IRP merely notes that "due to the limited data at present and for the purpose of this IRP Update, these developments were not modelled as standalone scenarios, but considered to be covered in the low-demand scenario" (p21-22).This indicates that there is no explicit modeling of EEDSM interventions.

Good practice in IRP suggests that DSM and EE should be modeled as "decrements", explicitly reducing demand and thereby avoiding the need for increased supply options. DSM and EE have a net present value that is typically positive – while some initial investment may be required, the payback periods are short. Moreover, in the American Council for an Energy Efficient Economy (ACEEE) reported that energy efficiency had been the cheapest energy resource over the preceding decade and suggested planners should regard it as a reliable "first fuel" choice. Among its numerous benefits are reduced need for new generation capacity, increased competitiveness, increased productivity, improved revenue collection and improved system reliability. [(12,13)]

This inadequate treatment of EEDSM is not due to absence of information, but rather this information not being made publicly available. Eskom through its EEDSM programme has compiled a large database. It has contracted teams undertaking measurement and verification (M&V) to determine actual savings, including ERC's M&V team. The National Monitoring & Evaluation Centre (NMEC, see www.nmec.co.za) has a database with real 30-minute data for every EEDSM project funded by Eskom over the past decade. So, verified data of EE and DSM savings has been compiled, by technology and by sector, measuring the potential for EEDSM savings in SA. Yet this data has not been used for planning. ERC recommends that the database should be made available, so the public can be the judge of whether the data is usable. This would provide a sound basis for including modelling of EEDSM in the final IRP.

A recent report by the International Energy Agency (IEA) on energy efficiency included a chapter on South Africa.[(14)] The IEA found that while primary energy demand has increased by nearly 30% since 2000, but in an Efficient World Scenario (EWS) "adopting cost-effective energy efficiency measures could reduce primary energy demand by 4% between now and 2040, and save 566 PJ in additional final energy use" compared to a New Policy Scenario. EWS could save households USD 2 billion a year by 2040 and reduce GHG emissions by 25% compared with current levels.[(14)]

Tapping the potential of EEDSM should be a major priority in the final IRP.

6. Distributed generation and decentralized systems

The IRP does include consideration of embedded generation and fuel switching. However, the IRP does not fully consider a shift to decentralized electricity systems.

The DoE would do well to consider the NPC energy paper[15] – in particular a section on 'modular, robust and sustainable energy investment' - and its implications for revising the draft IRP. This would consider the future of the grid much more fundamentally, including shifts in power both physically (generation much more distributed, with smart grids, etc) and politically (from a few big central producers to many prosumers).

Distributed energy resources (DER) can enable higher penetrations of distributed renewables and reductions in transmission and distribution losses. DER also tend to be more resilient than highly centralized systems, with DER providing demand-side flexibility, grid resiliency to blackouts from extreme contingency events such as natural disasters, solar storms, cyber-attacks, large power plant or transmission line trips, war and other unforeseen events.

The value of generation and energy storage depends, at least in part, on where it is placed in the system. When such facilities are included further downstream, e.g. in municipal distributors, they add value in being able to be dispatched close to customers. The value can 'stack' up, in both technical and financial. If any limits are placed on embedded generation, they might distinguish between private small scale embedded generation (SSEG) and municipal distributors. Where waste heat is used, no limits should be imposed. The Department should finalise policy, rules and regulations for SSEG, including arrangements for wheeling and net metering.

Electrification (rural and urban) using mini-grids can achieve universal access goals while using local renewable resources, strengthening the edge of grid, and providing supply and demand flexibility through smart-grid capabilities and hybrid energy resource combinations.[16]

Having considered the demand-side, our comments now turn to the supply-side options in the draft IRP 2018.

7. Coal

The draft IRP does signal a long-term shift away from coal in the long-term: "The decommissioning of coal plants (total 28GW by 2040 and 35GW by 2050), together with emission constraints imposed, imply that coal will contribute less than 30% of the energy supplied by 2040 and less than 20% by 2050." Diversifying the energy mix has been part of energy policy since 1998,[17] and whether these shift seem unlikely to be fast enough to respond adequately to the challenges of climate change. Furthermore, the draft IRP only recommends a plan up to 2030 (see Time frames below), and in the near-term does propose adding new coal capacity.

South Africa's contribution to climate change mitigation must mean that no new coal capacity should be added in the final IRP.

7.1 Coal IPPs add costs and greenhouse gas emissions

However, the draft IRP includes 1000 MW of coal. Table 7:[1] "Proposed Updated Plan for the Period Ending 2030" in the draft IRP adds 1000 MW of coal in 2023-24; these are presumably coal independent power producers (IPPs).

ERC research has demonstrated that coal IPPs raise energy system costs and increase GHG emissions. The additional discounted system costs to meet the low-PPD trajectory with the coal IPPs is R27.9bn.(18) Even in a base-case scenario for coal (making favourable assumptions), these negative effects of coal IPPs would undo the effects of the carbon tax. If forced in as in the draft IRP, the existing fleet would have to run at lower load factors to allow for the coal IPPs.(18) The comparison of IPPs using coal and those using renewable energy is limited.

7.2 Decommissioning should be endogenous, not an arbitrary 50 years

The draft IRP does foresee decommissioning of coal plant (12 GW by 2030 and reaching a total of 28 GW by 2050), and lower shares of coal in the fuel mix for electricity than in previous plans. However, the basis of decommissioning is an arbitrary 50 year life-span.

In our own on-going research, the ERC's SATIM model[2] endogenously retires power plants based on their relative costs and benefits to the system. However, based on Eskom's announced closures of some of its older stations, we have retired several power plants exogenously, i.e. we have retired them in a given year as an input to the model, since they are already closed or Eskom has announced their closure). This includes units at Grootvlei, Hendrina, and Komati which are already either in cold storage or no longer running as of 2018. This is consistent with earlier work that showed that retiring these stations would be a net saving to the electricity system.(19,20) Doing so avoids underbuilding replacement capacity in the scenarios analysed below. The draft IRP only includes decommissioning from 2021 onwards, see figure 27 (DoE, 2018: 62), which could have the effect of underestimating the need for new capacity, and is not consistent with what is already happening in the electricity sector.

ERC research points to a better approach, in which decommissioning is based on endogenous factors. This means that plant would be retired when they are no longer economic to run; and should also take into account the risks to coal supply by station.

[1] Confusingly, there are two Tables numbered 7 in the draft IRP. In these comments, "Table 7" refers to the recommended plan on p. 41 (not the capacities on p.49, unless specified).

[2] http://www.erc.uct.ac.za/groups/esap/satim

Table 1: Summary of coal supply risk by station

Source: Burton, Caetano & McCall [21]

Power plant	Primary Mine (if relevant)	Contract end	Decommissioning per IRP 2016/ 50 year LOPP *	Cause of supply risk
Arnot	Arnot/Optimum/multiple	2015/ 2023	2029	Eskom refusal to recapitalise/invest at Arnot mine; Corruption; Short-term contracting.
Camden	Usutu/multiple		2023	Insufficient supply from co-located mine.
Grootvlei	Palesa/multiple		2028	Full volumes not secured; Limited supply options; high transport costs.
Hendrina	Optimum		2026	Export risks - fixed price contract; Mine in business rescue; corruption; Under delivery of contractual volumes; Limited alternative supply options (transport infrastructure constraints at the station).
Duvha	Wolvekrans	2034	2034	Export risks – fixed price contract (no margin for mining company on the contract).
Kendal	Khutala	2033	2043	Under delivery of contractual volumes; Contract does not match end of station life; Life of mine is approaching and requires new investment; No agreement or extension to CSA negotiated yet for new open cast; Large shortfall in volumes from early 2020s when mine reaches end of life; Financing, contracting, timing risks of new investment.
Kriel	Kriel	2019	2029	Contract does not match end of station life; Life of mine reached 2019; New capex required or new contract/tender; Mine development risks; Potential higher costs of coal at new mine.
Komati	Koornfontein		2028	Higher cost supply (corruption); Under delivery of contracted volumes; Mine in business rescue.
Kusile	New Largo			Station volumes not secured; Tied mine not yet developed; Transport constraints and costs of imports.
Lethabo	New Vaal	2029	2040	Contract does not match end of station life.
Majuba	multiple		2051	No long-term supply; Rail line construction delays; Multiple contracts including Tegeta (business rescue).
Matla	Matla		2033	Eskom failure to recapitalise the mine; Under delivery of contractual volumes from cost-plus contract; Switch to multiple short-term contracts; Mining right lapses 2025.
Matimba Medupi	Grootegeluk	2038	2041	Supply risks associated with single mine supply to two stations; Export risk: fixed price contract.
Tutuka	New Denmark Multiple top up contracts	2029	2040	Long-term undersupply from cost-plus contract; Multiple short-term contracts; Contract does not match end of station life.

** Note that in 2016, Eskom indicated that it was pursuing a fleet renewal strategy that would extend the lives of power station from 50 to 60 years (according to the then head of Generation, Matshela Koko) (Creamer, 2017).*

Table 1 presents information on some key risks for each of SA's existing coal-fired power stations. As the study notes, "there are different coal supply issues facing different stations. Fundamentally, however, for many stations a stable supply of coal has not been contracted, increasing the risks of supply interruptions and likely raising costs."[21]

Discussion of such evidence should be used to develop a sensible decommissioning schedule.

7.3 Just transition including a managed decline of coal-fired power – overseen by PCCC

While a coal phase out is essential for climate change mitigation, a just transition is required. The IRP should outline a managed decline of coal-fired power, to protect the livelihoods of workers and communities in coal areas.

A Presidential Climate Change Coordinating Commission (PCCCC) has been established in a Framework Agreement emerging from the recent national Jobs Summit. The PCCC is a statutory body that is coordinate and oversee the Just Transition. It will include social partners (which should include civil society) and consider Sector Job Resilient Plans (SJRPs). In ERC comments on carbon tax,[22] we proposed Jobs and Competitiveness Programme, funded by carbon tax revenue – which may be similar to SJRPs though conceived at company level. The opportunities in green jobs, industries, climate resilience that the PCCC will explore are important for a just energy transition and energy democracy.

8. Imported hydro-power

The recommended plan includes 2500 MW of hydro in 2030. The draft IRP motivates this in order to "facilitate the RSA-DRC treaty on the Inga Hydro Power Project in line with South Africa's commitments contained in the NDP to partner with regional neighbours". From ERC's research, we see no analytical basis for including power from Inga. If this is a political decision, then the security of supply from the DR Congo and along all transmission lines to South Africa would also need to be taken into account.

9. Gas

The draft IRP includes a large amount of new capacity from "gas/ diesel": 11,930 MW in total, with 3,830 MW In 2018 (this year – being built where?) and another 8,100 MW added between 2026-29. It is entirely unclear what fuel and technology shares are – how much diesel (to run very expensive OCGT?) and how much gas – in OCGT, CCGT or CC-GE?

It is also unclear whether gas is to come from shale gas fracking or imported as liquefied natural gas (LNG). There are significant differences in price – and ERC research has shown that "there is a clear inflection point at a price between USD 10 and USD 11/Mbtu. This is most visible in the unconstrained cases, in which the function of gas in the energy system changes dramatically below that price, which will be explored in more detail below. The large-scale use of shale gas is related purely to the assumed availability of shale gas at lower prices, since the inflection point is below the minimum price point of LNG, thus different price range assumptions would lead to a different gas mix."[23]

LNG does have the advantage of lower investment. Floating storage regasification units (FSRU) can import LNG without investment in onshore regasification infrastructure.

It is furthermore worth considering contract flexibility in relation to imported LNG. Load factors and flexibility requirements on new gas generation are highly variable (within and year, and as the power system evolves) and will either require fixed long-term contracts (lower gas price), or flexible import contracts (higher unit gas price).

Gas can help balance the intermittency of solar PV and wind (until other storage options such as batteries become more affordable). It is also worth noting that using gas for GTL would be inefficient, compared to using compressed natural gas (CNG) directly in vehicles.

Natural gas has lower greenhouse gas emissions than coal used for electricity- at the point of combustion. However, the risks of fugitive methane – CH_4 physically leaking to the atmosphere – can off-set the emission reductions. This requires careful management and has been explored in relation to shale gas fracking. [24,25]

The estimates of the amount shale gas available in the Karoo have been decreasing. It is now uncertain whether the shale gas in the Karoo, including in two scientific assessments in 2016.[26,27] More recently, a single study undertook actual measurements and found "no desorbed and residual gas, despite high total organic carbon value [and that gas] to be metamorphosed and overmature" [28]. In plain language, the gas may have been 'cooked' and not much may be usable. The study deflates resource estimates to 13 tcf and suggest that, to be economically viable, the resource would be required to be confined to a small, well-delineated 'sweet spot' area [28].

10. Renewable energy is least cost and there is no rationale for annual build limits

Renewable energy is the least-cost technology for electricity generation, both in the medium and long-term. The draft IRP acknowledges this: " The scenario without renewable energy annual build limits provides the least-cost option by 2030" [and]… " The scenario without renewable energy annual build limits provides the least-cost option by 2050"(p.12). However, the draft IRP persists in imposing annual build constraints, without providing any credible rationale.

10.1 Removing build constraints on RE makes no significant difference up to 2030, but constrains the least-cost option after 2030.

The draft IRP states that Imposing annual build limits on RE does not affect cumulative installed capacity and energy mix up to 2030; while for 2030-50, imposing annual build limits on renewable energy will restrict the cumulative renewable installed capacity. If it makes no difference in the short-term (for which the plan is recommended) and constrains the least-cost option – why have build limits?

The draft IRP 2018 has imposed annual build limits on new renewable energy of 1.6 GW for wind and 1 GW for solar PV in most of the scenario analysed, for which no rationale is given. The IRP 1 scenario does not, however, impose such a constraint, and the DoE note that this provides the least-cost option. However, it is clear that there could be limits to a very rapid roll out of renewable energy; this could include technical (grid or EPC capacity), logistical (eg port capacity), institutional (start dates and length of procurement process), legal or financial (prudential) limits if a sudden renewable energy roll out were required

Thus, while there is no rational reason for the annual limits used by the DoE, and these limits in fact raise costs in the electricity sector, we acknowledge that some limit may need to be imposed on the model to approximate the real world constraints facing the sector if it is expected to increase capacity substantially in a single year which would likely be unfeasible to roll out without a pipeline of procurement and plants. It is therefore necessary to constrain the model to more accurately represent the real world barriers to such a large investment in a single year.

In on-going ERC modelling, we do this by considering the last bid round (R4) contracted between 2016 and 2017, during which 620MW came online f wind and between 2015 and 2016 420 MW of solar PV (REDIS). Annual installation limits for PV and wind are set in 2021 to start at the total capacity awarded in round 4 for each technology. Each year thereafter, the annual installation limit increases by the portion of capacity awarded in the final expedited round (590MW for PV and 618MW for wind), until 2030 where the limits are no longer imposed.[18]

Table 2: Annual new build limit on renewable energy 2020-2030 (GW)

Technology	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	1,36	2,04	2,73	3,41	4,09	4,77	5,45	6,13	6,81	7,49	8,17
Solar PV	1,40	2,00	2,59	3,18	3,77	4,36	4,95	5,54	6,13	6,72	7,31

Why do we think these are reasonable? We cross-checked these figures against

- The analysis undertaken by Wright to assess the rate of renewable energy roll outs in other countries and penetration as a portion of peak demand;[29]
- existing research on the availability of grid for, and economics of, solar PV (which has fewer infrastructure constraints such as grid or logistics issues)[30]
- Eskom's Transmission Development Plan from 2018 to 2027, which assumes that after round 4 of the REIPPPP that solar PV will be 3500MW and wind 4400MW for which transmission development is already planned to 2027.[31]

Build limits can be investigated further. However, other methodologies have been recommended and put these in context.

10.2 NREL study examined deployment limits for wind and solar in SA IRP

A study by the US National Renewable Energy Laboratory (NREL) considered build constraints (or 'deployment limits' in a study focused on wind and solar resources for SA's IRP.[32] The NREL audit team outlined three possible considerations: Technology Availability, Grid Flexibility or Dynamic Performance Constraints. [32]

While the draft IRP 2018 does not explicitly state reasons for build limits, it seems to us that technology availability and dynamic performance are less likely, and most likely planners (in DoE and / or Eskom) have raised concerns about grid flexibility.
This is a valid concern, but could be better addressed by careful dispatch modelling and other analysis, than by build constraints. The following paragraph explains the NREL analysis and concludes with the audit team's recommendation:

> *"Grid Flexibility Considerations: System planners may have concerns that a large quantity of wind and solar power generation will lead to insufficient grid flexibility to integrate these variable and uncertain sources of energy without some combination of: significant energy curtailment (leading to harder-to-finance or more expensive renewable IPP contract prices), unreasonably steep ramps for the conventional fleet (leading to reliability issues), and/or more frequent cycling of the conventional fleet (leading to increased maintenance costs). Such concerns might lead to analysts imposing an overall penetration limit (percentage of total generation) for variable renewable resources. Grid flexibility requirements, ramping costs for conventional generators, and the temporal variability of wind and solar power are already somewhat captured within the PLEXOS® LT planning framework. Implementing an improved temporal fidelity for the model will help produce an internally-consistent system with sufficient grid flexibility, mitigating the need to place penetration limits on wind and solar to address flexibility concerns. Expanded, complementary utilization of PLEXOS® ST to simulate hourly dispatch will add confidence to this strategy. We recommend that Eskom pursue this pathway rather than placing limits on wind and solar deployment for flexibility reasons."* [32]

ERC supports this approach. In our own modelling, we also find that significantly higher detail in time and space resolution is needed to accommodate for variations in demand and wind and solar resources (short term forecast errors, extreme weather events, and long term interannual variations), reduced system inertia, rate of change of frequency (ROCOF) and reserve requirements, and resulting transmission/distribution system investment requirements. It would be useful to adopt NREL's recommendation to utilize Plexos modeling. In this process, better understanding of the marginal system value of different energy resource options can be developed. While levelized costs of energy are useful sometimes, the value of resources to the systems at other times requires different metrics.

10.3 Recommends reducing pace and scale of new capacity additions – consistency in procurement is important

The draft IRP recommends that the pace and scale of new capacity developments needed up to 2030 must be curtailed compared with that in the Integrated Resource Plan 2010–2030.   It further suggests that existing Ministerial determinations for bid window 4 (27 singed projects) be reviewed and revised. What is important in this regard is not only scale, but also the timing of procurement. The stop-start approach that we have seen in 2016-17 is detrimental to a rapidly growing industry. Consistency in procurement is important to grow that industry and ensure that localization builds SA companies and employs workers here.

10.4 Draft IRP assumes much lower learning rates than seen in recent past

Technology learning rates assume that, over 35 years, the overnight. Capital costs of PV reduce by 26% and wind by 11% (calculated from Table 1). The CSIR Energy Centre reported that over four years, the costs of solar PV dropped by 83% and wind by 59% (In Nov 2011, solar PV at R3.65 / kWh and wind at R1.51; by Nov 2015, both at R0.62 / kWh). [(20)]

Table 3: Cost reductions for PV, wind and nuclear

Source: own analysis, calculated from draft IRP 2018, and CSIR[(20)]

	R / kW 2015	R kW 2050	Calculated	CSIR – over four years
PV (fixed tilt)	16861	13425	-26%	-83%
PV (tracking)	17861	14221	-26%	-83%
wind	19208	17287	-11%	-59%
nuclear	55260	53768	-3%	

While it is reasonable to expect learning rates to decline over time, this is a function of global cumulative installed capacity. Significantly higher learning rates can be assumed for wind and solar PV.

The IRP 2018 states that it uses overnight capital costs based on the REIPPPP, however, the draft IRP 2018 states that these costs are in January 2017 ZAR, but the numbers in the table are the same as the IRP 2016. It is therefore not clear what currency the figures are in, nor what underlying data they are actually aligned with. The assumptions need to be clearly articulated in the next version of the IRP.

ERC is examining the learning assumptions for solar PV and onshore wind in on-going research. Renewable energy costs in initial analysis are based on the learning curves developed in Ireland & Burton (2018). A comparison of these cost assumptions against the IRP 2018 assumptions can be found in Figure 1.

Figure 1: Solar PV and wind cost and learning assumptions for ERC and IRP 2018 (April 2016 Rand)

Source: ERC modelling (report forthcoming)

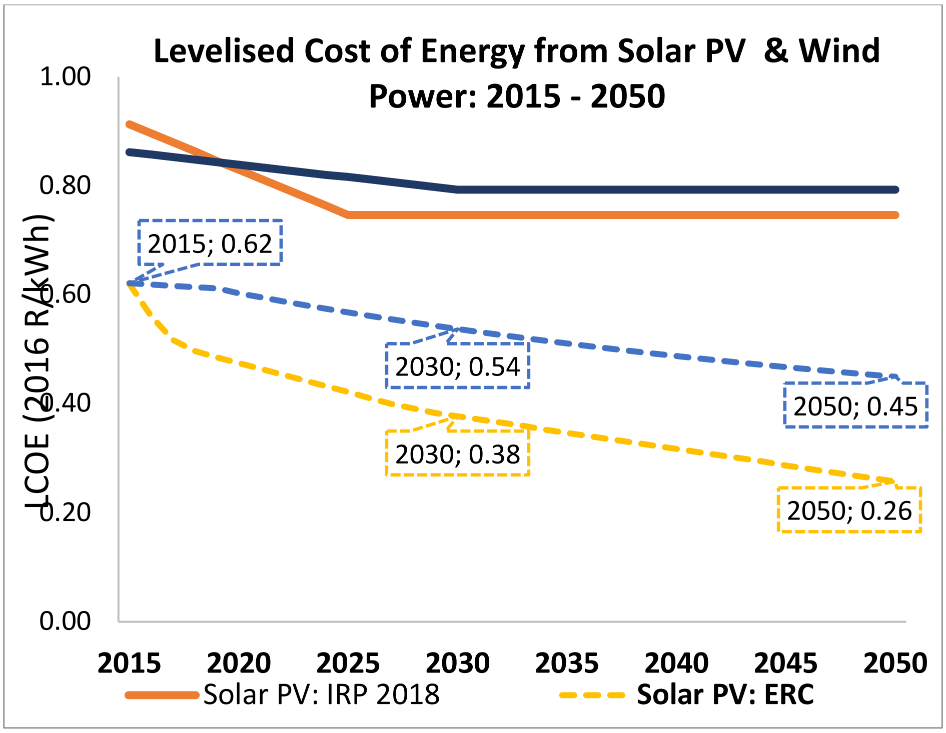


Figure 1. shows the projected levelised cost of solar PV and wind based on the improvements for the respective technology parameters, compared against our reconstruction of the IRP 2018 cost assumptions. It can be seen that levelized costs are significantly below those assumed in the draft IRP 2018.

11. Energy storage

11.1 … is important for future decentralized grids

With electricity systems becoming more decentralized and including higher shares of intermittent resources (renewable energy), storage of electricity (or energy in the form of hydrogen, possibly) becomes important. The draft IRP seems to consider only pumped storage. This is another area in which significant trends globally and in SA seem not be considered.

11.2 Battery storage needs to become more affordable – and factored into IRP

Both stationary storage and batteries in electric vehicles should be included in the IRP. Storage provides benefits (see discussion in section 6 above).

Storage technologies exist, the key issue is affordability. Future scenarios in the IRP should consider declines in the cost of storage, as innovation globally drives down costs. Technologies are being developed not only by Tesla's Elon Musk in California, but also by UWC's Energy Storage Innovation Lab.[3]

Battery storage technology cost and performance parameters are presented in **Error! Reference source not found.** and are based on Lazard (2017), representing utility-scale grid connected lithium-ion batteries. Learning on capital costs are based on the average of the projections made by (BNEF, 2017; IRENA, 2017; CSIRO, 2015; EIA, 2017; Apricum, 2017) as shown in**Error! Reference source not found.**

Table 4: Input assumptions of typical utility scale lithium-ion battery storage project in 2017

Source: assumptions in ERC modelling, see text for details

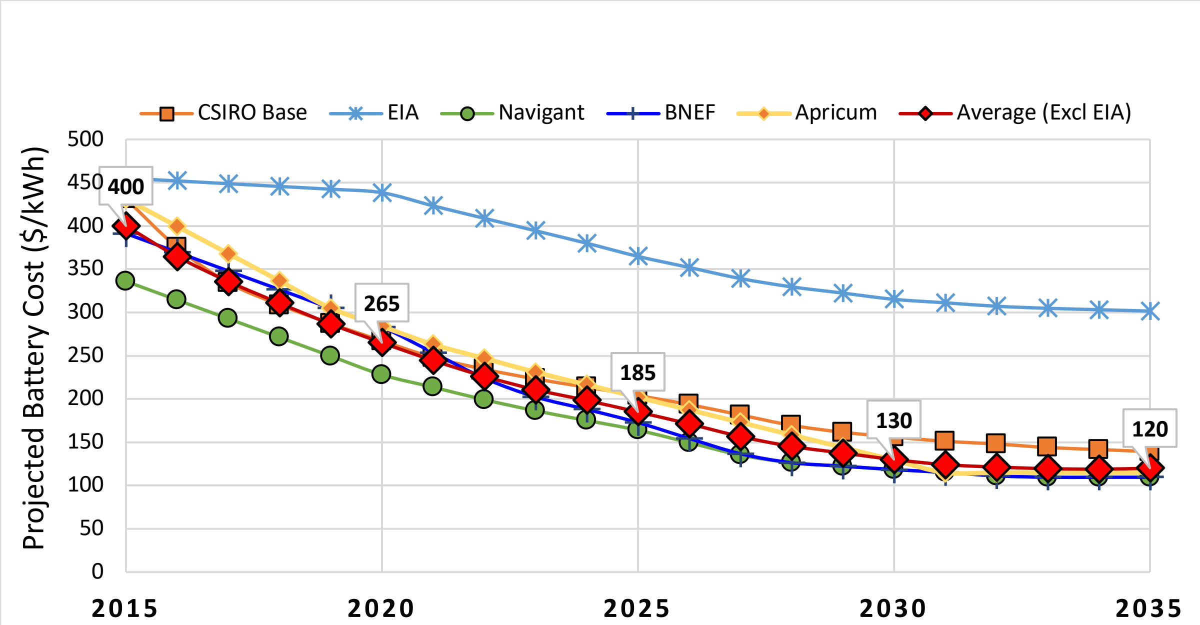
Power Rating (MW)	Storage Duration (Hours)	Usable Energy (MWh)	100% Depth of Discharge Cycles/Day	Project Life (years)	Installed System Capital Cost ($/kWh)	Fixed Maintenance Cost (% of CAPEX/annum)	Efficiency: round trip (%)
100	4	400	1	15	483	0.6 %	89 %

An exchange rate of 13.59 USD:ZAR is used as per the IRP 2018. The proportional learning rates from the industry cost reduction projections are applied to the initial 2017 Lazard parameters to 2030, not the total $/kWh cost shown in . A total installed capital cost reduction of 70% is expected in 2035 from 2015 levels.

Figure 2: Utility scale lithium-ion battery cost projections 2015-2035 (USD/kWh)

Source: assumptions in ERC modelling, see text for details

[3] https://www.uwc.ac.za/Faculties/NS/SAIAMC/Pages/Eskom-Centre-for-Electrochemical-Research-%28ECER%29.aspx



11.3 CSP provides some built-in storage

Concentrating solar power (CSP) remains an important technology, given built-in storage. Relatively little CSP capacity has been added in the REI4P, and none is included in the draft IRP 2018. The potential for CSP for power and heat/cooling needs to be revisited with updated cost and performance data and their future improvement potentials. CSP can allow greater energy mix diversity and flexibility, reduced LNG import requirements and emissions, localisation potential for manufacturing, construction, skills and innovation, potential absorption of retiring coal steam turbine skills.

12. Environmental and social implications

Electricity is relatively clean at the point of use, but its supply can have significant implications on the environment. Emissions from coal-fired power are our largest source of GHG emissions, and local air pollution (with associated health implications) and water are important environmental and social concerns.

12.1 Rapidly reducing GHG emissions from electricity and contributing to the fight against climate change

12.1.1 Carbon budget rather than PPD

The draft IRP takes a carbon budget approach, defining it generally "as a tolerable quantity of GHG emissions that can be emitted in total over a specified time."(1) This is broadly consistent with the definition in the Climate Change Bill, which defines a carbon budget to mean "a greenhouse gas emissions allowance allocated to a person in terms of section 13, over a defined time period".(33) The difference is that the CC Bill allocates to a legal person (a company), while the draft IRP considers a carbon budget for the electricity sector. Both must be remain within or be a share of the national carbon budget, which is the area under the peak, plateau and decline (PPD) trajectory in national climate policy.(34) In our Nationally Determined Contribution (NDC), the "national carbon budget range for the period 2021-2025 is 1.99 -3.01 Gt CO2-eq and for 2026-2030 is in the range of 1.99 to 3.07 Gt CO2- eq".[35]

A carbon budget approach for the electricity sector should be derived from an economy-wide least cost mitigation analysis,[21] and take into consideration the socio-economic implications of allocating carbon space to the electricity sector (where mitigation costs are lowest).

12.1.2 Need 5-year cycles for carbon budgets by least-cost mitigation analysis

The carbon budget approach in the draft IRP to greenhouse gas (GHG) emissions constraints assumes 10 year periods. However, 5-year cycles are preferable because:

- To be consistent with national policies and measures, including company-level carbon budgets[33]
- Cycles in the Paris Agreement, with legal obligations to submit nationally determined contributions (NDCs) every five years under Article 4.9; and five-yearly global stock-take under Article 14;
- A decade is simply too long to make any adjustments, given a very rapidly changing electricity sector

Table 1 shows the simple conversion of 10 year carbon budgets as in the draft IRP to 5 year budgets; the latter could be further smoothed or gradually stepped down.

Table 5: Emission reduction constraints / carbon budgets over 10 years from IRP and halved to 5 year

Source: based on Table 5 in draft IRP (1st and 2nd column) adding 3rd column

	10 years	5 years (calculated – simply halved)
	Mt CO_2-eq	Mt CO_2-eq
2021-2030	2750	1375
2031-2040	1800	900
2041-2050	920	460

The 5-year carbon budgets in can be compared against the PPD trajectory in national policy[34] and national carbon budget in our NDC. Table 6 compares the carbon budgets from the draft IRP (halved, as for Table 5) to carbon budget based on least-cost mitigation analysis. The latter are generated from ERC SATIM model running a Coal Transitions Carbon Cap scenario, which imposes a 9.4Gt cap to entire energy system. [21] The model therefore chooses which sectors reduce energy GHG emissions most cost-effectively

Table 6: Comparing 5-year carbon budgets for electricity, draft IRP compared to least-cost analysis

Source: Col 2 draft IRP (halved for 5 years), column 3 from SATIM Power[21] and 4th and 5ht columns calculated

	5 years (IRP halved)	5 years SATIM power	Difference	Difference (SATIM / IRP)
	Mt CO_2-eq	Mt CO_2-eq	Mt CO_2-eq	%
2021-2025	1375	1131	-244	-18%
2026-2030	1375	1112	-263	-19%
2031-2035	900	521	-379	-42%
2036-2040	900	508	-392	-44%
2041-2045	460	164	-296	-64%
2046-2050	460	187	-273	-59%

It can be seen from Table 6 that that carbon budgets from a SATIM power are significantly lower than those from the draft IRP in absolute units (Mt CO_2-eq). The relative differences tend to get larger over time. The SATIM power carbon budgets for the electricity sector are closer to a zero-emissions electricity sector by 2050 than the draft IRP carbon budgets. DEA would allocate company-level carbon budgets consistent with sectoral shares, and enabling SA to remain within its national carbon budget

International environment is such that more ambitious actions is needed. Countries are expected to show progression in each successive NDC, and to take more stringent domestic mitigation measures.

12.1.3 More rapid decarbonization is possible in electricity and so the share of carbon budget can be expected to decline over time

The assumption of a fixed share is at odds with research for SA and globally, which shows that more rapid decarbonization is both possible and lower cost in the electricity sector than in others. [36-40] The recently published IPCC special report reaffirmed that "1.5°C-consistent pathways include a rapid decline in the carbon intensity of electricity and an increase in electrification of energy end use (high confidence)". [41]

Meanwhile, pursuing more rapid decarbonisation will have economic benefits, given that renewable energy provides more jobs than conventional generating capacity (cite: co-benefits and Bischof-Niemz and Creamer, 2018). Other important socio-economic impacts include lower health burdens on especially poor communities living near coal-fired power stations through improved air and water quality.

Hence ERC recommends that rapid decarbonization in electricity is translated into decreasing shares of 5-yearly national carbon budgets. This is in line with progression in ambition, and in our national context, electricity is an important sector for urgent action – while noting that mitigation is needed in industry and transport sectors too.

12.2 Meeting air quality standards

The draft IRP is not consistent with compliance with the National Environment Management: Air Quality Act (No 39 of 2004)[42] and its minimum emission standards

(MES). The IRP should as a minimum include compliance with NEM:AQA and meet standards. Meeting such standards is important given both the environmental and social (health) impacts of local air pollutants.

The minimum emissions standards (MES) are the legislated maximum emission limit values for all existing and new (as defined) power stations. They are supplemented by an Air Emission License (AEL) issued by the relevant licensing authority, usually a district or metropolitan municipality, to various facilities, which cannot operate without an AEL. Emissions from such facilities must at least meet the MES, unless, as described below, a postponement of compliance has been successfully obtained (which is reflected in the AEL). Stricter emission standards may also be included in AELs.

The purpose of the AEL is to provide permission to emit particular pollutants within limits to a licence-holder. In the case of Eskom, the licences set out these limits in terms of three pollutants: particulate matter (PM), sulphur dioxide (SO2) and oxides of nitrogen oxides (NOx), measured in mg/Nm.

The MES has both “existing plant” and “new plant” standards. The former had to be met by 1 April 2015, and the latter by 1 April 2020 (although termed ‘new plant’ limits, all plants must meet the 2020 limits, unless a postponement has been granted).

Table 7: Compliance timeframes and release rates by pollutant under the Minimum Emission Standards

Source: Eskom’s Background Information Document, August 2018

MES Compliance timeframe	Max Release Rate (mg/Nm^3)		
	PM	**SO_2**	**NO_x**
April 2015	100	3500	1100
April 2020	50	500	750

To meet the MES, Eskom can implement various technologies to limit pollutant emissions. For PM, this includes existing electrostatic precipitators (ESPs), or else Fabric Filter Plants (FFPs), or a high frequency power supply (HFPS) and flue gas conditioning (FGC) (either with sulphur, ammonia or brine injection (Eskom BID, 2018). For NO_x, the implementation of low-NO_x burners is required. Finally for SO_2, flue gas desulphurisation (FGD) technology is required (either wet or dry FGD).

ERC is undertaking further modeling on meeting MES and complying with NEM:AQA.

12.3 Water

12.3.1 Water costs

We use station specific water costs as shown in Table 8.

Table 8: Water tariffs (Rand/cubic meter) per power station for 2018/2019 (2015 ZAR)

Source: Department of Water and Sanitation (DWS)[4]

Power Plant	Total Tariff (cents/m3)	Consumption Tariff	Catchment Management Area Charge	Water Resource Infrastructure Charge
Camden	780	195	2,32	583
Grootvlei	65	62	2,32	0
Komati	525	48	2,32	475
Arnot	50	48	2,32	0
Duvha	270	17	3,57	249
Hendrina	525	48	2,32	475
Kendal	2166	550	2,32	1614
Kriel	833	165	2,32	666
Lethabo	65	62	2,32	0
Majuba	65	62	2,32	0
Matimba	175	171	3,82	0
Matla	329	137	2,32	190
Tutuka	364	116	2,32	246

[4] Department of Water and Sanitation http://www.dwa.gov.za/Projects/WARMS/.

12.3.2 Broader consideration of water-energy-food-land

Water usage for electricity is an important consideration. The draft IRP addressed this issue to some extent in Appendix A. Given that climate change may increase the variability and certainty of water resources, risks to water supply should be taken into account. There is significant work emerging in the academic community about the water-energy-climate-land nexus.[43-47] The complex interactions should be more fully understood, and their implications for future IRPs integrated. The possibility of desalination for industrial, agriculture and commercial water use is a possibility in a water-constrained country.

13. Transparency

Transparency is crucial principle of good governance. ERC publishes its energy model and inputs on our web-site.[5]

The information underpinning the draft IRP is of public interest. The IRP has implications for the prices that households (including poor households) will pay for electricity, for the economy and environment – including GHG emissions, air quality and water, as elaborated in section 12 above.

The models and all assumptions, data and results should be made publicly available, with methodologies well documented so that third parties (including energy researchers like us) can replicate the results. In the draft IRP 2018, many statements are made without clear explanation or information that would enable it to be understood.

We would hope that full information will be made publicly available on the DoE web-site, as a matter of good governance and access to information. It is hoped that it would not become necessary to request information under the Promotion of Access to Information Act (No.2 of 2000). There is indeed precedent, in which the Department in consulting on the IRP 2010, made many input sheets available online. We look forward to the fuller information, and engaging with DoE and other modelers on technical details.

14. Long-term perspectives on short-term decisions

The IRP2010 had a time-frame up to 2030, when published in 2011 it was effectively a 19-year plan. Seven years later, the end-point has not shifted from 2030, so the recommended plan is an 11-year plan.

ERC considers it useful to take long-term perspective on short-term decision, including investment decision. So the 2050 horizon, which is initially considered in the draft IRP, should be considered an important perspective. Some of the trends we have raised in these comments will play out fully over the longer-term. Yet in other senses, 11 years is quite long. For example, we have proposed that carbon budgets be updated every 5 years (not 10 years), given the urgency of climate action. For the IRP, we think that it should be updated every 1 to 2 years. To there would be three time-frames:

[5] http://www.erc.uct.ac.za/groups/esap/satim

- 2050: long-term perspective
- 2030: medium-term plan
- Every 1-2 years, an updated IRP

Such a set of time-frames would be appropriate, for an IRP worthy of the concept ‘integrated’ and fully considering broader trends. We also think that the ‘decision-tree’ approach taken in the 2013 update, which identified key times in the future when decisions would be required, what factors would likely be most influential in those decisions, and keeping the value of options as more information becomes available. The literature suggests that adaptive management is appropriate to managing complex systems, rapid change and high degrees of uncertainty,[48] all of which characterize our electricity system.

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