COMMENTS & RESPONSES ON THE DRAFT INTEGRATED RESOURCE PLAN

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mineral resources
& energy

Department:
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ABSTRACT

The Draft Integrated Resource Plan 2023 was gazetted by the Department of Mineral Resources & Energy (DMRE) for public comments on 04 January 2024. The comments submission period closed on 23 March 2024. A total of 4338 comments were received out of which 136 comments were substantive. This document summarizes the comments on the Draft IRP 2023 made under emerging themes and provides a response by the DMRE.

Contents

1. PROCESS, REPORTING & IMPLEMENTATION

COMMENT	RESPONSE
PUBLIC PARTICIPATION	
1.1 No adequate public participation in the development of IRP. The right to meaningful and fully informed participation was not taken into consideration. The process has had many issues, from it not being accessible to communities and youth due to the digital divide - with many of the public engagements happening online. It has not authentically engaged all people (including the youth) in meaningful and fully informed ways - as is our right. **Recommendations:** • Media platforms such as billboards, local radio stations and the television be used to advertise the IRP. • There should be civil education when it comes to the IRP to help the bridge the gap between decision makers, policy makers and the grassroots communities and capacity building so that the grassroots communities can be involved in the IRP commenting process. • The public participation process must recommence once the updated policy adjusted revision is released.	The comment is noted.
TRANSPARENCY	
1.2 Inadequate transparency and information provided, particularly in respect of economic assumptions, socio-economic policy/ boundary constraints, technology costs, fuel costs, life-extension costs, technology rollout constraints, costs of externalities, assumed ramp rates for dispatchable plants such as coal and nuclear, operating regime for BESS, and scenario boundary conditions used in the modelling process. This will enable third-party verification and replication of results obtained in future IRP iterations. **Recommendations:** • More details can be provided in terms of the IRP methodology and cost assumptions in the next iteration of the IRP.	The comment is noted.
1.3 The IRP lacks transparency in terms of how decisions were taken in the document, and how the data used for projections was implemented. **Recommendations:** • To ensure credibility, decisions must be documented and be transparent, objective and evidence based.	

COMMENT	RESPONSE
REPORT	
1.4 Recommendations: • Document the breakdown of assumptions, methodology, and resulting calculations to improve public understanding of the analysis. For instance, an entire assumption section clearly listing and justifying the assumptions would be worthwhile in understanding the technical and strategic logic in this document especially considering the modelling. So, what technologies have been considered in the modelling? These should be listed and clearly defined as the technologies selected with reason. Referencing the EPRI report is insufficient and leaves the reader to investigate why these were selected over others. • Draw a concise table showing the differences between the assumptions made in this document that were updated or adapted from the one provided in the IRP2019 document. This will help the reader and lay out clearly the main updates made in this document.	The recommendation is noted and will be considered for the final IRP report and future iterations.
1.5 Skills planning in the IRP is a critical component for the successful implementation of South Africa's energy strategy. The lack of skilled personnel could exacerbate the supply-demand deficit and prolong load shedding, undermining energy security. Focusing on skills development can drive job creation and support economic growth, aligning with South Africa's broader development goals. **Recommendations:** • The IRP should explicitly address the need for skills development to ensure that the country has the workforce necessary to achieve its energy and climate objectives. Incorporating skills projection into IRP planning and implementation is essential for ensuring that organizations have the right talent in place to achieve their objectives. By proactively identifying and addressing skill requirements, DMRE will enhance its capacity to deliver IPP projects on time and with the desired quality.	The comment is noted.
FREQUENCY OF REVIEWS	
1.6 Frequency of 2-3 years for the review of the IRP is recommended. The reviews should not be complete overhauls of the IRP. Instead, they should clearly show how the plan is updated based on the latest information. It should reflect changes in the following information: • Changes in energy regulations • Project completions and closures • Evolving energy sources and technologies (e.g., renewables, battery storage) • Fluctuations in costs and prices (e.g., interest rates, fuel costs) • Climate change initiatives (e.g., carbon tax)	The comment is noted.

COMMENT	RESPONSE
1.7 Every 4-5 years, informed by the Integrated Energy Plan (IEP), Annual or bi-annual reviews can cause delays and hinder progress.	Ideally, the development and review of IRP (and other sector plans) should be informed by IEP to ensure consistency in planning assumptions, methodology and review processes. Secondly, government policies, especially those that directs roll out for major infrastructure and capital investment programmes, should not be revised too frequent to allow for sufficient capital programme execution timeframe. Government policies should be afforded sufficient time for execution. This approach enhances policy certainty which is critical to attract large capital investment. The longer time horizon stretch will also provide sufficient time to assess the impact of implementation of the plans recommended programmes.
IMPLEMENTATION	
1.8 Recommendations: To form a monitoring and evaluation working group where civil society is present to monitor the progress of the plan. There is no fairness into the energy resources access for all divisions in the populations because of the focus on the private sector procurement (Independent Power Producers). There should be more public procurement where there is a suggestion for the socially owned renewable energy sources as it is the clean and affordable energy.	

2. ALIGNMENT WITH OVERALL NATIONAL POLICY & OTHER SECTOR RELATED INITIATIVES

COMMENT	RESPONSE
SOUTH AFRICAN RENEWABLE ENERGY MASTERPLAN (SAREM)	
2.1 The IRP2023 must provide consistent and strong market signals to support the developmental policies like SAREM. The current plan's reduction in new renewable energy capacity by 2030 risks undermining market confidence and industrial policy objectives.	The renewable energy targets are set by the IRP and SAREM is based on the outcomes of the IRP 2019, as it was agreed that this IRP 2019 will be used as the base. There might a misinterpretation of what Horizon 1 in the draft 2023 IRP report means. The DMRE wishes to clarify that this Horizon is supposed to read as an additional "top up" to what is contained in the approved IRP 2019. Also, SAREM takes into consideration that since the amendment of Schedule 2 of the ERA, other spheres of government including national departments and the private sector are planning to procure renewables independently (i.e. outside of the DMRE led procurement process).
JUST ENERGY TRANSITION FRAMEWORK	
2.2 The Just Energy Transition Framework is a critical component of South Africa's energy strategy, focusing on the shift to cleaner and more competitive generation technologies. The Just Energy Transition Framework is expected to work in conjunction with other policies and plans, such as the South African Renewable Energy Master Plan and the Just Energy Transition Investment Plan, to achieve a just and sustainable energy transition. The Just Energy Transition Framework aims to restore security of supply, which is a critical aspect of a just energy transition. • The IRP's approach to security of supply is questioned, as it seems to imply an immediate elimination of unserved energy without a clear long-term strategy. • The IRP contradicts the decarbonizing objectives of the Just Energy Transition Framework, which states that there is "need to shift to cleaner and more competitive generation technologies" and it does not fully incorporate the recommendations from the South African Presidential Climate Commission on energy pathways. • The Eskom 2035 strategy plans to run coal plants beyond their design lives and previous shutdown dates does not align with the JET IP and funding plans. **Recommendations:** • The IRP to align with the objectives laid out within the Just Energy Transition Framework to ensure a coherent energy strategy that supports the transition to a low-carbon economy.	While renewable energy sources like solar and wind are valuable components of South Africa's energy mix, a balanced and diversified approach is crucial for a sustainable energy transition. The Integrated Resource Plan (IRP) should serve as the overarching strategic document, considering a comprehensive range of energy sources to ensure energy security and affordability. The Just Energy Transition Investment Plan (JETIP) is an important initiative, but it's primarily focused on specific funding priorities and may not fully capture the broader energy landscape and long-term needs of the country. It's essential to strike a balance between short-term funding opportunities and long-term strategic planning. The IRP should remain the guiding framework for South Africa's energy future. To this effect, South Africa should still be realistic enough to appreciate its developmental realities are reflected by the current analysis in the IRP. The climate decisions provide for consideration of responsible consumption of transitional fuels blended with cleaner fuels as part of energy transition.

COMMENT	RESPONSE
GREEN HYDROGEN COMMERCIALIZATION STRATEGY (GHCS)	
2.3 The Green Hydrogen Commercialization Strategy (GHCS) is a key component of South Africa's energy strategy, focusing on the development and integration of green hydrogen into the country's energy mix. It aligns with the broader goals of the Just Energy Transition Framework and is expected to contribute to the country's energy security, economic growth, and environmental sustainability. The GHCS emphasizes the integration of its objectives into the Integrated Resource Plan (IRP), highlighting green hydrogen's pivotal role in South Africa's energy security and transition towards sustainability.	The catalytic technologies (PEM) for onsite developed are still at early stages and are not commercially viable for grid tied scenarios (for inclusion in the IRP). However, the periodic review of the IRP provides for the inclusion of new technologies as they become viable for both energy storage and grid tied generation. The Demand Projection Model in Support Of IRP Update 2023 has projected some power demands for hydrogen in particular for mobility. However, as the technology matures the periodic updates will include additional power demands for hydrogen. IRP is concerned with balancing electricity supply and demand in a manner that ensures continued energy security for South Africa. More specifically security of electrical energy supply. Part of green hydrogen production value chain (i.e. Solar and Wind) are built independently on the Integrated Power Plan (IPP).
INTEGRATED ENERGY PLAN, GAS UTILIZATION MASTER PLAN, UPSTREAM PETROLEUM BILL & TRANSMISSION DEVELOPMENT PLAN	
2.4 The development of the Integrated Resource Plan (IRP) for electricity should have been preceded by the creation of a comprehensive Integrated Energy Plan (IEP) for the entire energy sector. The IEP sets the overarching framework, while the IRP is a more specific plan focusing on electricity. The IRP should align with the IEP to avoid contradictions. The draft IRP 2023 lacks a finalized IEP and Gas Master Plan (GMP) for proper context. The GMP is expected to define gas supply preferences and should be coherent with the IEP. The IEP aims to guide energy infrastructure investments, policy development, and technology selection for a "just energy transition." It considers all energy sectors, while the IRP focuses solely on electricity. The IRP should take its cues from the Integrated Energy Plan objectives and Climate Change Bill sector emissions allocations, once published. Hence its release prior to the release of an IEP or sector emissions targets may be seen as premature.	The comment is noted however, Draft IEP was developed by the Department in the past, however this work was never concluded as more focus was required to address the electricity supply challenges at that time. Ideally the development of Integrated Energy Plan (IEP) as an overarching policy document should precede the development of sector plans (IRP & Gas Master Plan (GMP)). However, given the current challenges in the electricity sector and the natural gas sector, the Department has decided to intervene at sector level to address these challenges.

COMMENT	RESPONSE
INTEGRATED ENERGY PLAN, GAS UTILIZATION MASTER PLAN, UPSTREAM PETROLEUM BILL & TRANSMISSION DEVELOPMENT PLAN (CONTINUED)	
Recommendations: • Halt the IRP process to start afresh once an IEP has been finalized. • Explicit reference in the IPR 23 should be made to the Gas Masterplan and the draft Upstream Petroleum Resource Development (UPRD). Without these references the IRP23 will fail to fulfil its goal of bringing energy to the people.	A process to develop the IEP is currently underway within Government. However, the Department is of a view that sector plans development/review should not be delayed as there is urgent to address challenges within the respective sectors. Work is currently underway to align the IRP 2024 and GMP 2024.
2.5 The IRP2023 mentions Eskom's TDP 2023 - 2032 as a factor considered during its development. However, Eskom predicts that about 53 GW of additional generation capacity, mainly from solar and wind power, is required by 2032. The IRP only provides for an additional 29 GW of generation capacity by 2030. This significant discrepancy should, at the very least, warrant a clear and thorough explanation in the IRP2023.As Eskom uses the IRP as an input for its TDP, the current version of the IRP will likely result in significant changes to the planning outlined in the TDP. This is likely to reduce investment and expansion of the transmission network in the Northern, Western, and Eastern Cape. Such an outcome would directly contradict Intervention 4 under the Horizon One analysis.	The IRP model will now consider generation and transmission to ensure alignment.
ELECTRICITY REGULATION AMENDMENT BILL	
2.6 The IRP2023 identifies existing and anticipated electricity supply industry changes but is silent on the impacts of these market liberalization policies, indicating a need for the final draft to show anticipated developments in the evolution of the electricity market.	The comment is noted.
2.7 South Africa is moving towards a wholesale electricity market, and the IRP will need to function as a framework for investment into transmission and distribution systems, end-use efficiency options, and the mix of wholesale power that best results in stated IRP objectives.	The comment is noted. The revised section 34 of the ERA provides for powers of the Minister to make determinations that cover new generation capacity as well as electricity infrastructure (transmission). The comments anticipates that the IRP should make pronouncements on transmission and distribution capacity needs and allocations. The Minister would then be enabled to issues determinations for such infrastructure needs.
2.8 In a competitive market, each market operator, including Eskom, would have its own non-integrated plan, indicating a move away from centralized planning towards decentralized market operations.	The comment is noted. The revised ERA provides for a single market operator (Eskom based) and not multiple market operators.
STRATEGIC INTEGRATED PROJECTS	
2.9 Eskom's Strategic Integrated Projects (SIPs) are a set of initiatives aimed at addressing the country's energy challenges and ensuring a sustainable energy future. The Just Energy Transition Program 1 looks at building up to 5GW which has been gazetted by the Minister of Public Works. **Recommendations:** • Consider including all Eskom SIP projects1 in the IRP and highlight as important levers for minimising unserved energy.	

COMMENT	RESPONSE
MUNICIPAL PLANS	
2.10 Municipalities should play a crucial role in South Africa's Integrated Resource Plan (IRP) due to their high energy consumption and vulnerability to climate change. Many cities have already formulated their own climate and energy plans, and these should be incorporated into the IRP 2023.	
VGBE REPORT	
2.11 The VGBe report, which was completed and submitted to the Treasury in September 2023, is an independent technical review that diagnoses the challenges facing Eskom's power stations and provides recommendations on actions to be taken. It should carry significant weight in the context of energy planning and policy making. **Recommendations:** • The findings and recommendations of the VGBe report should have been included in the IRP document to ensure that the energy planning process is informed by the latest technical analysis.	The comment is noted.
NATIONAL ENERGY CRISIS COMMITTEE	
2.12 The National Energy Crisis Committee (NECOMM) is a body established by President Ramaphosa to address the energy crisis in South Africa. NECOMM's stated priorities include making it easier for the private sector to invest in new energy sources and to fast-track new generation capacity from wind, solar, gas and battery storage. It is evident that a combination of the South African Renewable Energy Master Plan, the renewable energy programme and the Just Energy Transition Investment Plan work optimally to enable localisation of elements in the renewable energy value chain over the long term, while the focus on clean coal technologies risks distracting away from it. **Recommendations:** • IRP should align with NECOMM's approach to ensure that the energy planning process is responsive to the immediate needs of addressing the energy crisis.	See comment under section 2.2 above.
PRESIDENTIAL CLIMATE COMMISSION	
2.13 The PCC has conducted research and modelling for power provision to the grid, including variable renewable energy (VRE), and recommends a rapid and large-scale build of 50 to 60 GW of VRE by 2030, supported by co-located storage and peaking support. The IRP in comparison provides only up to ~20GW of VRE. **Recommendations:** • The IRP should align with the PCC's recommendations and other third-party research to ensure that it reflects the most credible and up-to-date information.	The IRP is highest electricity supply government policy. It seeks to balance electricity supply and demand in a manner that takes into account electricity supply security and the ability of System Operations to operate the system in a reliable manner. Other plans are focused on how to increase volumes of electricity generation from a particular source, without any analysis on implications on the existing electricity supply system. Therefore, these plans cannot be relied upon to direct the development/review of IRP. Placing reliance on these plans will result in a compromised electricity supply system which could result in prolonged periods of supply-demand mismatch and thus load shedding.

COMMENT	RESPONSE
PRESIDENTIAL CLIMATE COMMISSION (CONTINUED)	
• The apparent misalignment between the DMRE and the PCC, alongside minimal input from labor and civil society in recent energy transition planning, highlights the need for more inclusive discussions and social dialogue on the energy transition. • The IRP should develop scenarios with ambitious greenhouse gas reduction targets in line with the net-zero emissions target by 2050 and the 1.5-degree target, which is informed by the PCC's modelling.	
NATIONALLY DETERMINED CONTRIBUTIONS	
2.14 The Draft IRP neither adequately explains how the choices for energy pathways impact greenhouse gas emissions, nor does it fully address the net-zero NDC target by 2050. Additionally, it does not fully acknowledge the importance of sector emission targets and the need for a just clean energy transition.	There were discussions held with DFFE on this and perhaps further engagements are needed with the DFFE in this regard.
2.15 The implications of the Draft IRP 2023 on South Africa's National Determined Contributions (NDCs) and its commitment to reduce greenhouse gas emissions are significant. It is concerning that there seems to be a misalignment of the Draft IRP 2023 with the NDC targets, particularly in relation to carbon emissions. South Africa has to adhere to its initial commitments made in the Paris Accord and to transition from fossil fuels to renewables in a manner that aligns with the concept of a just transition.	There will be a need for DMRE and DFFE to have a discussion on this since the country is expected to develop a revised NDC following the decion of COP 28. It would seem that the DFFE has begun with the revision of the NDC. Once again, while alignment is necessary, there should also be respect for different sector mandates and planning processes.
2.16 Whilst the Draft IRP 2023 indicates a decline in carbon emissions from 2025, it is concerning that this decline may not be in alignment with the country's NDC targets, and maybe a departure from the commitments made in the Paris Agreement.	The comment above applies.
MINIMUM EMISSION STANDARDS	
2.17 South Africa can address the challenges related to Minimum Emission Standards (MES) compliance, energy security, and the transition to renewable energy sources through a multifaceted approach. Firstly, the country should prioritize the development of a diversified energy mix that includes renewable energy resources, nuclear energy, and gas. This approach aligns with international trends and developments and ensures compliance with emission reduction plans while providing security of supply.	The statement is supported.
GENERAL	
2.18 Conduct further analysis considering the following: • The work of the National Planning Commission (NPC) • South Africa's Just Energy Transition Plan (JETP) • South Africa's Just Energy Transition Investment Plan (JETIP) • South Africa's JET IP Implementation Plan • The National Infrastructure Plan (NIP 2050) • South African Renewable Energy Masterplan (SAREM) • The work of the National Energy Crisis Committee (NECOM) • The 2023 Eskom Medium Term System Adequacy Outlook (MTSAO) • The Eskom Transmission Development Plan TDP 2023 • The work of the PCC	As indicated above, while it is worth looking at the body of work listed, the development of the IRP and a policy instrument should not be compromised in the name of taking cue from implementation instruments that are based on aspirations and international compliance but inimical to socio economic imperatives of the country.

3. SOUTH AFRICA'S PROGRESS ON CLIMATE CHANGE COMMITMENTS

	COMMENT	RESPONSE
3.1	South Africa is struggling to meet international demands while addressing local socio-economic needs. The country's contribution to global CO_2 emissions is relatively small, and therefore South Africa should not be expected to achieve net-zero targets on par with more established nations. The Paris Agreement is non-legally binding and scepticism about the commitment of developed countries to provide financial support is expressed. A balance must be struck between climate commitments and practical, cost-effective energy solutions, otherwise there are potential adverse effects on economic growth, employment, and energy security.	The comment is in the main consistent with the principles that South Africa and other developing nations are advancing by calling for the recognition that we are developing form different starting points, and as such, the developing nations need to be given space to determine their needs and how to develop their economies and of course provided that they are supported financially by developed nations.
3.2	It is important to have a comprehensive energy mix, encompassing nuclear, gas, clean coal, and renewables, to ensure energy security and support economic growth. There is a need for more effective policy alignment with electricity planning, and a focus on the need for clear milestones, contingency plans, and coordinated efforts among government, the private sector, and civilians to achieve the set climate targets. There is a requirement for an alignment of the country's energy plan with its climate mitigation ambitions, with an emphasis on the need for decarbonization and a transition to cleaner energy sources.	The development of the IRP has taken into consideration all these elements and therefore this comment is welcomed.
3.3	Concerns are raised about the draft IRP 2023 not aligning with South Africa's climate mitigation ambitions, scaling back on renewable energy, and proposing significant contributions from gas-fired power generation, which may hinder the country's ability to meet international climate commitments. This prioritization of gas and coal also undermines the sustainability of South Africa's energy pathway.	Paris agreement recognises the role of transitional fuels and therefore in line with technological neutrality South Africa should embrace in its planning the role that the widest variety of sustainable and transitional fuels, energy sources and technologies, including, but not limited to, fossil fuels with abatement and removal technologies and offset mechanisms, biofuels, natural gas and LPG, hydrogen and its derivatives, including ammonia, nuclear power, and renewables, can play a role in facilitating the energy transitions while ensuring energy security. Therefore the notion that the IRP is not aligned with climate ambitions cannot be correct as the role of renewables is balanced by those of other technologies in accordance with our needs and capabilities give the resources that are at the country's disposal.
3.4	Climate change has severe impact of on human existence, with specific reference to its uneven distribution across gender, race, and class lines. The importance of aligning the IRP with South Africa's obligations under the Paris Agreement and the just energy transition and highlight the need for greater consideration of how energy choices impact greenhouse gas emissions. Non-compliance with minimum emissions standards, the health impacts of poor air quality, and the need for Eskom's coal-fired power stations to meet mandatory emission standards is concerning. The incorporation of new energies such as biomass and biogas to support decarbonization initiatives in the industrial sector.	This comment repeats what has been state above, and as such it has been responded to. On the issue of noncompliance of Eskom stations with emissions standards, I think this issue has been ventilated in accordance with balancing the energy system and responding to climate commitments and accordingly, the Ministry of DFFE takes responsibility in this regard.

4. HOW CAN SOUTH AFRICA BALANCE OBJECTIVES ON REDUCING CARBON EMISSIONS WHILST ENSURING ENERGY SECURITY?

COMMENT		RESPONSE
4.1	South Africa should pursue a diversified energy mix that includes BESS with renewable energy resources (10-20%), nuclear energy (60-80%), and gas (not diesel). This approach aligns with international trends and developments and ensures compliance with emission reduction plans while providing security of supply.	The comment on the energy mix that is based on the realities of what is at the country's disposal and how that will alleviate the socio economic conditions of the population through access to affordable, reliable and secured supply of energy should be supported.
4.2	South Africa needs to continue developing renewable energy resources beyond wind and solar PV, including other renewable energy options to maintain grid flexibility. Public education is essential to promote the understanding that cleaner energy does not necessarily mean less use, but smarter use.	Public engagement should not only be limited to the promotion of awareness and understanding of the clean energy techs, but also to source the inputs and views of the communities in terms of their views on the kind of transition, but also the support the communities need such as financial models for the development of the SMMEs etc.
4.3	The country should invest in energy storage technologies, such as pumped storage power stations, to store surplus energy produced by renewable sources for dispatch during peak times. This will enhance energy security and grid stability.	Noted and supported.
4.4	South Africa should prioritize the optimal use of indigenous gas resources and support the expansion of renewable energy technologies, such as wind, solar, and hydro. The country can also explore the implementation of climate projects, including technology-based and nature-based solutions, to reduce greenhouse gas emissions while minimizing costs.	No further inputs from our side.
4.5	Utilizing nuclear energy can help in reducing carbon emissions and ensuring energy security. It can provide stable baseload power and contribute a significant portion of the country's energy needs. CO_2 is 0,04% of the earths atmospheric gas; of this 0.04% of CO_2 South Africa is responsible for 1.2% of this; therefore as a country we are irrelevant and our contribution is insignificant. In comparison to India and China coal build rate, South Africa's coal emissions are even more insignificant.	Noted.
4.6	Prioritizing energy efficiency as the "first fuel" in all industries can help minimize energy demand before considering supply, thereby reaching energy security while reducing carbon emissions.	The comment is noted and supported. The country has made significant strides in energy efficiency, but further investment and support are crucial to maximize its potential.
4.7	Forming public-private partnerships can expedite the development of renewable energy projects, such as solar and wind, and expand the transmission network to accommodate more renewable energy into the grid.	The focus should not only be on the development of RE projects, but it is critical that attention is paid to the creation of manufacturing companies that will ensure creation of jobs but also the security of energy system through localization of the technology.
4.8	Implementing climate projects, including technology-based and nature-based solutions, can effectively reduce greenhouse gas emissions while minimizing costs. South Africa can also engage in carbon credit trading with other African countries to reduce its net emissions.	The comments is noted. The DMRE and DFFE are currently working on various planning elements, including the development of Article 6 framework (which aims at recording, approving and monitoring carbon markets projects and credits) in preparation of the implementation of Article 6 as a response mechanism to energy transition.
4.9	Investing in research and development can promote innovative ways of harnessing energy with minimal carbon emissions.	Comment noted and supported.

COMMENT	RESPONSE
4.10 Various independent models have suggested that a least-cost mix for electricity generation in South Africa consists mainly of renewables, with a small portion of gas (around 5% of a year's electricity would be supplied by gas). Such gas fuel could be provided in the form of green hydrogen, which could be produced in large quantities if there is enough renewable generation. Hence a least-cost mix could also have net-zero emissions. In finding the least cost mix, the models either require that there be no load-shedding at all, or highly penalise any loadshedding with a high cost of unserved energy, so any last-cost mix outputted by these models should provide security of supply up until the assumed electricity demand projection. However, there are risks that can negatively impact security of supply, such as inability to obtain import fuel if there is a global supply shock, or failure of single large generators. This risk is also mitigated by relying more on renewables which does not have fuel requirements and which are spatially spread out with less concentration risk, and ensuring a large installation of renewables to ensure the reliance of gas as a % of annual generation capacity is low (for example below 10% of demand expected to be supplied by MWhs of gas generation). To further ensure energy security, it would be prudent to plan for a high economic growth scenario, i.e. to install more than the expected average growth would demand, to have some buffer to absorb lower generation due to problems such as the lower than expected EAFs of our current coal fleet. Also it would be good to plan for the low end of wind and solar years, such as assuming a 33% capacity factor for wind and 25%for solar. Finally, security of supply will depend on ancillary services managing the frequency control and inertia needs on the grid correctly. Such needs were traditionally supplied by rotating mass generators including coal, but new technology such as synthetic inertia, fast frequency response and the installation of flywheels can supply that need in a cost-effective way in a renewables-led mix. Chapter 13 of the EPRI report gives details on techniques of integrating nonthermal renewables into the grid in a way that can ensure security of supply. South Africa should consider the social aspect in addition to climate, affordability, and security nexus when planning for energy security and emission reduction, ensuring that the Just Energy Transition is a lived experience and takes into account the needs of local communities.	The comment is noted.

5. METHODOLOGY, COSTS & MODELLING ASSUMPTIONS

COMMENT	RESPONSE
METHODOLOGY IN GENERAL	
5.1 The methodology applied to develop the plan is highly questionable. It does not provide for a least cost unconstrained case from which policy adjusted measures could be applied. This is in contrast to previous plans which were premised on such a basis. The assertion that post 2030 that this is the case is not supported by the outcomes.	The Draft IRP 2023 in principle did not impose generation constraints. However, due to limited transmission capacity in the Cape areas as experienced by REIPPPP Bid Window 5, new generation capacity was limited until transmission development occurs as per Transmission Development Plan. The optimization model was free to choose generation capacity anywhere else in country, but it didn't.
5.2 The methodology applied is inconsistent with international norms and best practice.	Noted.
5.3 The current methodology is sound, but the studies in terms of details should follow what was done in the draft IRP 2016.	Noted.
5.4 IRP2023 is much better than IRP2019	Noted.
MODELLING TOOL	
5.5 Needs to be complemented by other optimization tools.	Plexos simulation platform is a widely used tool by system operators, regulators, and utilities globally. In addition to Plexos, other tools such as DigSilent for system operability studies, and Power System Simulation for Engineers (PSSE) for grid expansion.
5.6 The current basis of producing the IRP (Plexos) is insufficient. **Recommendations:** The basis that should be used is Levelized Avoided Cost of Electricity (LACE). LACE represents a power plant's value to the grid. "A generator's avoided cost reflects the costs that would be incurred to provide the electricity displaced by a new generation project as an estimate of the revenue available to the plant. Strangely or significantly none of the scenario planners within the IRP 2019 consider LACE at all, it is not even mentioned, there was a reference in the Tucson State IRP but not in South Africa's. Even ERCOT (The load shedding regulator in the US state of Texas) uses LACE in conjunction with LCOE and Net value (Profitability metric) when energy planning.	Levelised Avoided Cost of Electricity is embedded within Plexos.
5.7 Assumptions: • Capacity factors of coal-fired power plants used in the modelling: the actual energy availability may be lower than nominal capacity.	The energy availability factor of each generator is modelled and its energy production will always be lower than nominal capacity.
5.8 Recommendation: It is advocated for that a review of the IRP development process to shift away from a result-driven approach, i.e. industry feedback on the results of the IRP modelling process, to a standardised, repeatable modelling process or methodology approach. I.e. Industry stakeholders, and technical experts assist the DMRE to develop a modelling methodology aligned to international best practices that is transparent with clearly defined input parameters and scenario assumptions. Energy security, Total practical system least cost (defined externalities included) and Network Stability would be key considerations and objective functions for the reformed IRP methodology. In the absence of a fully reformed IRP methodology, industry comments and inputs be put on a "live" working model to reduce the time taken between industry feedback and IRP model updates.	Noted.

COMMENT	RESPONSE
MODELLING CONFIGURATION	
5.9 Something is very wrong with the modelling process, and how it is done. For example, Monte Carlo Simulation and its use does not validate these IRP models, rather is an added layer of irrelevant complexity not adding value.	Expansion modelling in nature is crude because of long study horizons and the level of detail. Therefore it is necessary to take the results of the expansion and subject them to economic dispatch which takes into account stochasticity of parameters such as outages, variable generation resources, as well as demand.
5.10 The IRP addresses different pathways but does not conclude on the best/recommended pathway. At some point, a specific pathway should be adopted or else all of these simply remain pathways/scenarios without any implementation. One would assume given the state of the economy and Eskom's debt that a "least cost pathway" is the preferred option.	The pathways in Horizon 2 were exploratory in nature and were not intended to inform policy direction. Although the IRP optimizes for cost, it takes into account the reliability and operability of the power system.
5.11 The draft IRP's cost assumptions and modelling scenarios do not reflect real-world dynamics where renewable energy is increasingly becoming the cheapest form of energy. It places artificial constraints on models, leading to conclusions that support continued reliance on fossil fuels. For instance, rooftop solar PV is not included in the modelling which has huge implications on new capacity.	Regarding constraints in the Draft IRP refer to 5.1 Rooftop Solar PV was considered with assumptions adopted from the latest GreenCape report, a reputable source.
5.12 There is no systematic evaluation of scenario performance against the planning objectives of security of supply, cost and environment. The following issues are among those present: • Lack of optimisation: While the inclusion of a long-term planning horizon to 2050 is useful, the Horizon 1 analysis only considers capacity currently in development, with no power system optimisation conducted to determine potential additional new capacity that may end loadshedding sooner. • Use of predetermined technologies: The Horizon 2 analysis presents five pathways for the power sector, each of which represents a different combination of technology options. Since these technology combinations are determined prior to optimisation, they are necessarily sub-optimal, presenting a false choice of options from a limited set of seemingly arbitrary and unrealistic technology combinations. • Inexplicable new-build limits: Excessively stringent (and undisclosed) annual build limits are applied to solar (capped at 900 MW) and wind (capped at 1720 MW) in the Horizon 2 analysis, significantly.	• Optimization: Horizon 1 first considered capacity under development/construction/committed and then optimized to close the remaining shortfall. • Pre-determined technologies: The reference case pathway considered "…an array of generation expansion options from which to select an optimum plan up to 2050". • New build limits: Refer to 5.1 and 5.11. • Gas load factors: The optimization is given a basket of generation options from which to select. The type and load factors are an outcome.

COMMENT	RESPONSE
MODELLING CONFIGURATION (CONTINUED)	
• The IRP should not limit itself to gas in mid merit "a priori" but consider all load factors, including baseload. Only the analysis of each project should determine whether they are beneficial for the South African power mix. More specifically, excluding gas in baseload as a starting point is likely to exclude the consideration of attractive power supply options. Moreover, limiting the load factor of gas projects could jeopardize the gas supply. It is understood that power generation will be the anchor to enable gas supply. In order to enable this, it is necessary to take into consideration the constraints of gas supply, which reflect in a load factor that needs to be sufficient. As the IRP is a reference for procurement programs, such as the ones done by the IPP Office, it is essential that the IRP doesn't restrict the ability of the IPP Office to develop procurement programs that have a large range of options, and actually allow gas supply to develop.	
CONSIDERATIONS	
5.13 There is limited consideration for energy equity. The plan does not adequately address issues of energy equity, potentially exacerbating disparities in energy access and affordability among different regions and socioeconomic group. **Recommendations:** • It is recommended that consideration be given to energy equity to mitigate energy access and affordability barriers. This could be in the form of a preferred price path trajectory.	The price path trajectory will be provided in the final report.
5.14 It is of importance to consider the implications of tightening climate regulation, carbon taxes, and mechanisms such as the EU Carbon Border Adjustment Mechanism (CBAM) on goods produced in South Africa.	The total system costs do consider the carbon tax.
5.15 The is a need for the IRP to consider the implications of future stranded assets and nuclear decommissioning costs, as well as the financial implications of moving away from fossil fuels.	Noted, it will be incorporated into the final Socio-Economic Impact Assessment System (SEIAS) report which will be made available on the departmental website after the final IRP is approved.
COSTS	
5.16 Cost Comparisons of the Pathways: There is no explanation of what Cost Of Unserved Electricity (COUE) multiplier is used, in R/kWh. The Eskom COUE methodology, moreover, is based on the assumption that economic activity simply stops when the power is switched off, and therefore, the full cost of losing this economic activity is attributed to every unserved kWh of electrical energy, namely about R30/kWh direct and about R100/kWh indirect COUE. **Recommendations:** It would further be useful to separate out overnight construction costs, construction financing costs, and operations costs, including fuel, fixed costs, etc., as is usually done in calculating Levelized Unit Electricity Costs (LUEC). The estimated COUE should be presented separately, and the methodology explained.	Cost of Unserved Energy: This is calculated by NERSA and the methodology is available on the NERSA website. Overnight construction costs, construction financing costs, and operations costs, including fuel, fixed costs, etc, are separated as provided in the EPRI report.

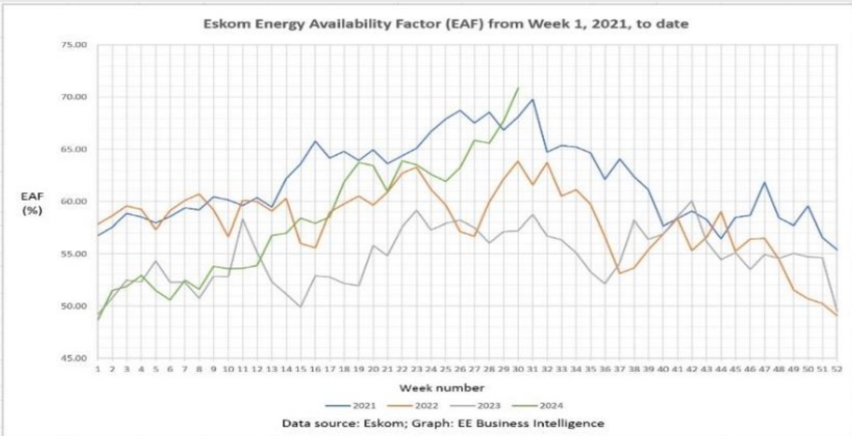
COMMENT	RESPONSE
COSTS (CONTINUED)	
5.17 The technology costs used for solar PV, wind, and battery energy storage (BES) are unrealistically high without reference to the REIPPP bid windows in South Africa, and the ongoing cost reduction learning curves for these technologies.	The IPP Office have calculated costs based on the latest bid windows and have provided them to the department for the final IRP.
DEMAND FORECAST	
5.18 The draft IRP 2023's demand forecasts, underestimates of the impact of load shedding and the growth of private electricity generation and is therefore unrealistic.	
• Load shedding has led to a decrease in overall demand. This is because consumers reduce their electricity usage during these periods or resort to alternative energy sources.	• Demand is calibrated to 2017 – pre-load shedding era. Demand is projected from 2024, assuming load shedding fades. The economic impact of load shedding is accounted for in GDP projections for 2023, 2024.
• The COVID-19 pandemic has had a notable impact on electricity demand, it's likely that changes in work patterns, business operations, and consumer behaviour during the pandemic have influenced electricity usage.	• This is possibly true, but post-covid data is clouded by load-shedding. A fresh post-covid/load shedding will be done once 2024 data becomes available.
• The economic recovery from COVID-19 would have been quicker if not for the challenges posed by load shedding. The current economic climate, characterized by uncertainty and slow growth, has also led to a lower-than-projected demand. The high growth scenario used in the IRP 2023 is questioned, with comparisons to other growth projections indicating a potential overestimation.	• That is captured in the near term GDP projections.
- It is higher than the IDC's January 2024 economic projections for 2023 and 2024, but comparable over the 2025 – 2028 period. After 2028, the model assumes an acceleration in economic growth with a long-term average rate of 3.8%, and this is significantly higher than the economic growth achieved over the past 10 years to 2023 of an average of around 1% per annum.	- This is now addressed by using 3 different growth projections to cover for the uncertainty in growth.
- The model used in the IRP 2023assumes GDP will climb to 3.2% in 2030, 3.8% in 2040, 3.8% in 2050. This is unrealistically high given that currently GDP growth contracted to South African real gross domestic product (GDP) contracted by 0,2% in the third quarter (July–September) of 2023.1stands at 0.9%, and Treasury is optimistically predicting 1.6% for 2024 and 2025. Investec for example estimates that GDP might reach 2% by 2027. The IRP arguably assumes demand that might well be too high for realistic planning.	
Recommendations:	
• Demand modelling should be revisited to include grid and non-grid demand, with a focus on self-generated energy and its impact on overall demand.	• Demand model used by IRP excludes self-generated energy as it is included in the supply model.
• Review the economic growth assumptions to ensure they are realistic and aligned with other projections.	• Addressed in new projections.

COMMENT	RESPONSE
DEMAND FORECAST (CONTINUED)	
• The draft IRP currently relies on a single electricity demand profile that does not accommodate economic growth before 2030. An incorporation of multiple demand profiles to model the impact of economic growth, an uptake in energy efficiency projects, and the adoption of new energy vehicles is proposed. This approach would enhance the credibility of the IRP and provide a robust foundation for future modelling and optimization. • Take into account the energy demand required to achieve the expected GDP targets in terms of National Development Plan.	• Addressed in new projections. • This is hopefully catered for by the high growth scenario.
5.19 The recommended sustainable growth rate is 3.8% per year, which is considered the maximum achievable level. • This target is significantly lower than previous goals - ASGISA target: 6.5% per year - NDP target: 5.5% per year • Even achieving 3.8% growth is difficult due to the current state of the economy. • A growth rate of 5% could unlock South Africa's economic potential due to its resource wealth. This would attract more domestic and foreign investment.However,achieving a higher growth rate requires strong political will, economic reforms, and social commitment. • The 3.8% growth target translates to an electricity demand increase of approximately 3.0% per year. Increased electricity generation capacity (due to 3% annual growth) could lead to: - Higher GDP growth - More jobs - Lower unemployment - Improved living standards • This growth scenario assumes policies are implemented to stimulate growth in industries and mining. **Recommendations:** 5% demand growth a year to cope with an economy growing fast enough to reduce unemployment significantly.	• We currently find it hard to come up with plausible drivers of a growth beyond the level in the new hight growth scenario. • ASGISA and NDP targets are aspirational and were also developed nearly a decade ago. Underlying domestic and international economic conditions have changed since then. • National Treasury research (2019) shows that unlocking several key constraints facing the economy would only increase real GDP growth by between 2-3 percentage points above potential growth over the next 10 years. SARB potential growth estimate stands at 2.5%. • Given current growth trends and short- to medium-term projections from the National Treasury and IMF, along with Treasury expectations of what is possible over the next 10 years, achieving 5% per annum growth over the 2024-2050 period would require growth of around 8% between 2040 and 2050 – this is unrealistic.
5.20 Demand forecast recommended scenarios: • Scenario 1: Doubling Energy Efficiency: This scenario explores the impact of significantly amplifying energy efficiency efforts, potentially leading to a substantial decrease in demand. • Scenario 2: Industrial Electrification: This scenario investigates the consequences of transitioning industrial processes from traditional fuels to electricity, potentially causing a significant rise in demand. • Scenario 3: Transportation Electrification: This scenario analyzes the influence of widespread EV adoption on electricity demand, potentially leading to a considerable increase.	• There is work underway to better understand the energy efficiency scenario (LBNL-DMRE). For now, hopefully the low growth scenario caters for this one. • There is some degree of electrification taking place in the scenarios (low grade heat using heat pumps), however to electrify beyond low grade heat would require very high CO_2 prices or ambitious climate goals currently not modelled in scenarios presented here. • Transport electrification is included in all scenarios.

COMMENT	RESPONSE
DEMAND FORECAST (CONTINUED)	
• Scenario 4: Demand Response for Residential Water Heating: This scenario examines the potential of implementing demand response programs specifically for residential water heating, potentially enabling strategic load management during peak periods.	• There is some work underway (UCT-SANEDI) to better understand this, and it is not currently captured in detail. We do assume roughly a third of all geysers are replaced by either heat-pumps/SWH by 2050.
5.21 Electric Vehicles: • The transition to electric vehicles (EVs) will place additional strain on the grid. The demand projections need to account for the increased electricity demand from the electrification of the transport sector. The e-mobility projections in the demand forecast appear to be quite conservative. • The forecast is realistic until 2030, however 50TWh of electrified transport is ambitious, the entire transport sector is estimated to consume 800PJ, this forecast implies that 22.5% of the entire transport fleet is electrified in the next 27 years. This forecast is closely aligned with plans to decarbonise the transport sectors globally, it is doubtful that it would be achievable in South Africa by 2050.	• This is taken into account. We now have two scenarios for electrification of vehicles a moderate and pessimistic one.
5.22 Energy Efficiency and Private Generation: • As businesses and households adopt more efficient energy practices or generate their own electricity, the overall demand on the national grid decreases. The demand-side management and energy efficiency measures should be considered alongside private electricity generation. Both effectively lower the strain on the national grid and should be treated similarly in the planning process. • Adaptation includes minimizing energy demand through passive means and designs, which should be incorporated into the forecast.	• There is further work to better understand EE potential. Private generation is taken into account in the supply model.
Recommendations: • Incorporate energy efficiency measures into the IRP, as it is a critical component of the energy plan. • Account for adaptation measures by incorporating carbon reduction targets in the forecast.	• Current projections assume we meet the upper range of 2030 NDC target. • Future work could include more ambitious climate goals, such as NZ.
5.23 Green Hydrogen Initiatives: • The demand for electricity required for green hydrogen production is not fully accounted for in the current demand projections. **Recommendations:** The green hydrogen initiatives, which are part of South Africa's energy plans, will require additional electricity and should be included in demand forecasts to ensure a comprehensive understanding of future energy requirements.	• The demand for hydrogen mainly from industry is quantified but currently not included in the total demand. The reason for this is there is a lot of uncertainty about the diurnal/seasonal profile of electrolysers, as it would be a flexible load. It would be better modelled in the supply model.
5.24 Had South Africa followed the actual load growth from 1982-2007 (25 years) of 3.4% pa the country would now have an annual peak of over 65GW. This is aligned with the actual experience of other non-OECD countries.	
Recommendation: • To build to create the "excess capacity" to encourage long term industrial expansion.	• Current thinking is that demand should drive supply rather than over supply driving demand.

6. ENERGY **AVAILABILITY FACTOR**

	COMMENT	RESPONSE
6.1	The Draft IRP states that "performance for the 2023 financial year has plummeted to 54.72%, this is the plant performance level that was assumed in this review which is a conservative approach". Experts have explained that Department modellers have used an annual average coal EAF as basis for the modelling, but that the Eskom fleet EAF is much lower than the total fleet EAF due to high availability of other plants.	The sections of the draft IRP dealing with this are section 3.1 and 4.2. Both in their headings explicitly state that they relate to Eskom plant i.e., "3.1 Eskom Plant Performance" and "4.2 Eskom Plant EAF". The EAF history as well as projections supplied by Eskom in terms of this relate exclusively to the Eskom Generation fleet. Eskom's Generation fleet includes coal, nuclear and peaking plant. Based on the above it is not clear how experts would infer that the performance is limited to coal or includes non-Eskom generation.
6.2	The assumptions in the Integrated Resource Plan (IRP) 2023 regarding the improvement of EAF are unrealistic. There is a need for realistic EAF projections (per power station and the uncertainty range), a detailed analysis of efforts to improve the coal fleet's performance and claims of substantial EAF improvement should be backed up with evidence-based analysis.	Section 4.2 of the IRP presents two EAF trajectories i.e., Low EAF and High EAF. As per Figure 3 the Low EAF was adopted for IRP 2023 planning purposes. The trend for the low EAF shows a trend where the EAF continues to decrease until 2025 where it reaches a low of 50%. As such the base assumption for the IRP is a decrease in EAF performance as opposed to and improvement. The high EAF performance was based on Eskom planning assumptions made during the Eskom FY23 corporate planning process. The process was based on a bottom-up approach that attempted to provide realistic and achievable performance improvements. After this, several major issues were experienced in Eskom Generation that triggered revisions to the recovery plan, most notably the collapse of the ducting to the stacks and stack internals at Kusile affecting three of its units. The plan was subsequently updated, and it is this updated plan that is commonly referred to as the Generation Recovery Plan. This plan factored in the issues experienced and as a result has a lower initial trajectory that factors in the time to deal these. Current performance of the Eskom fleet has shown that there has been an improvement in EAF with ~55% achieved in FY24. This trend of increasing performance has been noted and is one of the key reasons the country has not experienced loadshedding for more than 140 days. This has also culminated in Eskom for the first time in 3,5 years exceeding a weekly EAF of 70% as acknowledge by amongst other independent analysts like EE Business Intelligence on the 3 Aug 2024 and highlighted in the graphs below.



COMMENT	RESPONSE
6.3 Eskom's Generation Recovery Plan is crucial to improving EAF, however the following should be considered: • The need for a separate project management unit from Eskom's Operational Divisions to focus on the execution of the Generation Recovery Plan (GRP), with a period of two to three years to complete the GRP. • The inclusion of the costs and details of efforts to improve the coal fleet's performance. • Addressing of systemic constraints within Eskom, such as procurement processes and scoping of technical projects, to improve plant performance. • Moving away from a fixation on the EAF, as it may lead to poorer plant performance. • The plant performance figures will have to be monitored closely for divergence from the plan during implementation. During the determination phases, the Minister, assisted by NERSA, can make an assessment of its impact on the implementation of the plan. It may result in either moving new capacity forward or backward, depending on the direction the trend takes. • Stemming wide-scale corruption and criminal activity, as part of South Africa's broader plan to achieve energy security.	Generation has set-up a Recovery Office to expedite the implementation of critical actions to drive the turnaround in Generations performance. The Generation Recovery Plan was approved by Eskom Board in March 2023. The recovery plan had a large focus on ancillary plant performance, improved risk management, spares availability, quality of outage execution and skills. The implementation of the plan has greatly assisted with the recovery in performance. The recovery office will continue to operate for the next few years or until sufficient sustainability of performance is embedded in the generation fleet. The recovery plan addresses operational recovery, the implementation of more efficient and sustainable business processes and external enablers. Through the assistance of the National Energy Crisis Committee (NECOM) and business, Eskom has also been able to unlock some critical constraints in legislation as well as support in various other areas including safety and security. In term of new capacity, recent history and experience with bringing new capacity projects online has shown that whether it is from either an Eskom point of view or private sector, these have been plagued by delays. Examples of this include Eskom's new build programme, the RMIPPP and the NECOM land lease initiatives. All these projects were specifically aimed at addressing capacity shortages and were to be done on expedited timelines but failed to achieve them. This clearly indicates the complexity of bring new capacity online and as such illustrate that moving capacity forward especially within the short to medium task is not a trivial task and has a high probability of not materialising. Eskom agree with DOEEs stance on retaining dispatchable coal capacity until it can be shown that there are alternatives within the system that are able to provide the grid stability services this type of capacity introduces.
6.4 Eskom's coal fleet is ageing faster than the designed life-of-plant due to delayed refurbishments, poor plant quality control, and inadequate maintenance. • Strategic and systematic investment in improving the EAF of key mid-life and newer stations is likely to be a more effective and economic option than attempting to life-extend old, smaller stations. • The position taken to halt the shortening of the lifespan of coal power stations is correct. Globally there is a trend whether you go to the USA, Germany or Russia, the life spans of coal power fleets are continuously extended on the basis of the economic needs of the economy and to ensure reliability of supply to their communities. While it is true that the average age of a coal power plants is 50 years, the United States has demonstrated that some coal plants can run up to 80 years economically with refurbishments. However, Eskom struggles with a key precondition that need to be in place for effective outage planning for refurbishments, modernization, and maintenance – timely and efficient procurement planning and processes based on a realistic understanding of the current local and global market for key services and components. Additionally, the	Five independent reviews (including National Treasury's VGBE assessment) by external specialist teams, have been conducted since 2019, to understand and identify the challenges behind the declining plant performance. The findings included specific technical actions related to each station, as well as overarching, cross cutting (central led) actions. Findings were categorised as follows: People, Leadership and Human Performance, Plant Performance and Supporting Processes. The actions related to specific stations are tracked through SAP QIM (Quality Issue Management) system, and the overarching actions are being driven centrally through the Recovery Office, making use of the Project Management Office (PMO) function and Recovery App that was developed. the findings of the reports, Actions, workplans and approach was shared with multiple executive committees and approved. Quarterly feedback is given to a newly established board committee, the Board Operational Performance Committee (BOPC). Eskom's position on power station lifetime, life extension (LIFEX) and continued ops is as given below: **Context on mid-life refurbishment and LIFEX** • Coal power stations have traditionally been built with an assumed design of 30 years. - Experience has shown that with some reinvestment at the end of the 30 years depending on the plant health and condition, that a 50-year life can be achieved with high certainty.

COMMENT	RESPONSE
Eskom corporate strategy, which was revised in February 2024 indicated that Camden, Grootvlei and Hendrina are to continue operations up to 2030. Furthermore, the strategy indicated that the intention of continued operations is not to replace any alternative generating options but rather to bridge the gap while other options are being pursued. This decision is not a long term or blanket commitment, and the commercial and technical viability should continually be monitored.	- This reinvestment after the 30 years is often referred to as a mid-life refurbishment. - Therefore, Eskom has adopted a plant life of 50 years as a planning parameter for coal stations. • LIFEX refers to a decision to operate the plant past the planned 50 years and therefore increase the planning life of the stations, which requires extensive Life determination studies on major components and systems as well as specific interventions not executed during the mid-life refurbishment of the station. - Decision criteria for life extension will also include the future operating requirements, compliance to the latest safety, health, and environmental requirements, the need for the capacity and the economic feasibility of extension as an alternative to the new (greenfield) power generation options/technologies. - LIFEX should not be confused with mid-life refurbishments which are also interventions but only designed to ensure efficient and effective operations up to the current planning life. - For some coal stations, it may not be economically feasible to implement LIFEX. • On the other hand, continued operations requires the implementation of inspections, repairs, and upgrades only to the extent required to allow the units to operate beyond the planned shutdown dates in the 2035 shutdown plan which may or may not result in operations for longer than 50 years. It should be noted that the continued operations of stations and Eskom's coal fleet in general is based on the principles of balancing not only commercial and technical viability but rather addressing the Energy Trilemma and JET objectives of the country at large.

7. ENERGY **TECHNOLOGIES**

SOLAR PV

<table>
<tr><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td colspan="2">SOLAR PHOTOVOLTAIC (PV)</td></tr>
<tr><td>7.1 The cost-effectiveness of Solar PV as the cheapest source of electricity needs to be recognized, making it an important energy source. Regarding solar PV costs the following needs to be done:
• The Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) has successfully procured renewable energy at prices far lower than the EPRI report. The costs used in the Integrated Resource Plan (IRP) are too high for Solar PV when compared to the latest bid rounds and international benchmarks.
• The Solar PV costs need to reflect the local context as experienced through public bid windows and private sector CAPEX data submitted to NERSA.
• It is noted that Solar PV costs must be based on the latest projects that have achieved financial close, as well as realistic projections for South Africa.
• The Lazard low bound case is between the EPRI amount and the REIPPPP actual bids received and may be realistic as a current cost of Solar PV and Wind in South Africa. Some REIPPPP bids have failed to reach financial close, which could indicate the chosen bids did not plan properly and offered prices too low to be realistic. It may be worthwhile calculating the median bid for use in planning the future energy mix.
• Solar PV costs should take learning curves into account, and technology cost decreases should be incorporated into the assumptions.</td><td>• Local context prices: The 2024 revision of the EPRI report will include costs of the latest REIPPPP.
• Median bid costs: The 2024 revision of the EPRI will incorporate the low and high bound of the latest REIPPPP bid window costs. The suggestion of taking the median is noted.
• Learning curves: Noted.</td></tr>
<tr><td>7.2 Whilst solar PV is considered as the cheapest source of energy, there are also high costs associated with it based on the following points:
• Solar PV’s unsuitability for base load and intermittent energy input makes it costly to convert the electricity into reliable, dispatchable energy, requiring additional infrastructure and controls.
• Solar PV costs should factor in the logistics involved in moving the equipment from source to the chosen sites, as failure to consider such expenses can ultimately lead to increased energy prices for consumers. In Europe, for example, initially predicted establishment costs have been surpassed due to the failure to consider such expenses, which ultimately have to be passed on to consumers, making the price of energy more expensive.
• The capacity factor of Solar PV is around 26% which does not make it efficient to meet a growing demand for industries and growing population.</td><td>Noted.</td></tr>
</table>

COMMENT		RESPONSE
SOLAR PHOTOVOLTAIC (PV) (CONTINUED)		
•	Small Scale Embedded Generation (SSEG) poses challenges for consumers due to the additional costs incurred for self-generation of electricity. The high costs of food and other products/services are attributed to manufacturers generating electricity and passing the extra costs to consumers, which is seen as detrimental to South Africa. Moreover, the reduction in renewable procurement in the 2023 plan, particularly for solar PV and wind, is expected to lead to increased costs and grid electricity supply instability, further exacerbating challenges for consumers.	
•	The rise of renewable energy sources like solar has a few advantages: it can be generated locally (distributed generation), creates new industries, and reduces the need for expensive grid expansion. However, this trend of switching to renewables could hurt Eskom, the South African power utility. As more people use renewables, Eskom will have fewer reliable customers and its income will shrink. This could lead to even higher electricity prices, more illegal connections, and difficulty for low-income households to afford electricity.	
Recommendations:		
•	There are opportunities to build capacity within South Africa, particularly in the manufacturing of structural components of solar PV systems. By ensuring a stable supply chain within the country, the likelihood of cost disruptions, such as those experienced during the pandemic, can be reduced. China produces solar PV cheaper than any other major country competitor, and given South Africa's economic partnership with China, there are opportunities to build capacity within the country. Therefore, the recommendation is to focus on building local manufacturing capacity within South Africa to reduce the high costs of solar PV.	
•	The IRP should strive to generate electricity from different sources, all feeding to the grid, to increase the supply and ensure availability of cheaper state generated electricity.	
7.3	The combination of Solar PV with energy storage to provide reliable and dispatchable electricity should not be overlooked. It is also advocated that there be policy adjustments and the integration of smart grids to maximize the potential of this technology combination.	Both Solar PV and energy storage is one of the options in the IRP and its viability is evaluated against other options. The 2024 revision of the EPRI report has made provision for the combination of solar PV and energy storage which will be used in the final IRP.
•	The costs of converting intermittent and unreliable electricity from PV panels into reliable and dispatchable electricity include additional expenses such as back-up generators, spinning reserve, extra controls, extra transmission, storage, and compensation for loss of electrical inertia.	
•	Solar PV combined with energy storage can save energy and improve the economy, making it a viable option for the environment.	
•	The integration of smart grids with Solar PV and energy storage technologies to match demand with supply and stabilize the grid.	
•	The preference for concentrated solar power (CSP) with storage over PV + batteries, is outdated as PV is now much cheaper. It is suggested that the focus should be on locating storage on the grid at the system level, which is more efficient.	

COMMENT	RESPONSE
SOLAR PHOTOVOLTAIC (PV) (CONTINUED)	
7.4 There are issues around mining of raw material for solar panels, inverters, and batteries where there is serious environmental degradation during the process. Hence, it is important to admit that renewables are not necessarily clean and renewable. Renewable energy is also not labour-intensive, and it cannot create much needed employment in the value chain due to the fact that even the equipment is imported from outside the continent. Once these plants are up and running there is very little work for unskilled and even for semi-skilled workers.	The objectives of the South African Renewable Energy Masterplan is to create a manufacturing industry for renewable energy equipment for job creation.

CONCENTRATED SOLAR POWER

COMMENT	RESPONSE
CONCENTRATED SOLAR POWER	
7.5 CSP technology is not used around the world anymore due to its high cost compared to PV solar combined with Battery Energy Storage Systems (BESS). The cost of CSP technology is considered far too optimistic in the Integrated Resource Plan (IRP) and should not have been considered at all. **Recommendations:** • Solar PV combined with Battery Energy Storage Systems (BESS) to be used as a cheaper alternative to CSP technology.	All technologies are made available for the model to choose, the outcomes will therefore be determined by the optimization model. The costs used will be from the 2024 revision of the EPRI report which includes all technologies including CSP, and there is consideration for learning up to 2040.
7.6 CSP technology is deemed expensive during development and may require longer wheeling, making it non-affordable for end-users.	
7.7 The technology and current market prices of CSP appear to have stabilized, but it is still considered extremely expensive.	

WIND

COMMENT	RESPONSE
WIND	
7.8 South Africa has substantial offshore wind resources. Offshore wind has higher costs but provider better availability than onshore wind. The IRP deals with wind but does not specifically provide for offshore wind.	The latest revision of the EPRI report has made provision for off shore wind costs and characteristics, however off shore wind profiles are not yet available. While SA potentially has good offshore wind potential of average wind speeds of 7m/s or more. However there are challenges of the depth of coast line as well as environmental constraints such as Marine Protected Areas, Critical Biodiversity Areas, Marine Important Bird Areas and Shipping Lanes.
7.9 The regions suitable for wind power in South Africa are few and mostly remote and coastal, leading to technical energy losses during transmission and making the technology inefficient.	The IRP takes into account transmission network and inherent losses are considered.

COMMENT	RESPONSE
WIND	
7.10 There is variability in the annual capacity factors for wind, with lower capacity factors leading to increased costs and potential reliance on more expensive energy sources or even load shedding.	Noted.
7.11 The costs used in the Integrated Resource Plan (IRP) for wind power are too high compared to the latest bid rounds and international benchmarks.	Refer to response in 7.1 bullet 1.

HYDRO-ELECTRIC POWER

COMMENT	RESPONSE
HYDRO	
7.12 Importing from countries like the Democratic Republic of Congo (DRC) is risky due to political instability and delays in projects like Grand Inga. Mozambique's existing Cahora Bassa dam is threatened by recent insurgencies. Additionally importing hydro power comes with challenges such as: • Building of new transmission lines for imports which is expensive and time-consuming. There's also a lack of transparency on costs and timelines for these projects. • Displacement of communities and harming of ecosystems to build these large dams.	There is no updated data on the Grand Inga project, however data for Mozambique has been received and will be considered.
7.13 Domestic hydropower can be considered but has limitations such as: • Variable rainfall - South Africa's inconsistent rainfall patterns make large hydropower projects unreliable for electricity generation. • Environmental and Social Concerns - Even small domestic hydro projects can have negative environmental and social impacts.	An engagement with the Department of Water and Sanitation led to the conclusion that the project status of hydropower projects in the pipeline at the time they were not advanced enough for consideration.
7.14 Recommendations: • Focus on Renewables: Solar and wind power offer a more viable short-term solution for South Africa. They have a faster implementation timeline, less reliance on unpredictable factors, and potentially lower environmental impact. • Pumped Storage is Essential: Pumped storage hydropower acts as a battery, storing excess energy from renewables like solar and wind for use during peak demand periods. This is crucial for a renewable-based energy grid as it provides services such as inertia, frequency control, voltage regulation, and black start capability.. • Small Scale Hydro with Caution: Smaller run-of-river hydropower projects could be explored, but their environmental and social impacts need careful evaluation, with a focus on benefiting rural communities. • The treaty signed between SA and DRC in 2013 was due to expire in October 2023. An extension of the treaty would provide a more efficient route to resuscitating the viability of the Grand Inga project	• Focus on RE: The model is given an array of generation expansion options from which to select an optimum. • Pumped storage essential: Pumped storage was considered with capability of providing ancillary services in the optimization model based on sites where feasibility studies were conducted such as Tubatse and Steelpoort. • Small scale hydro: Refer to 7.13

STORAGE

COMMENT	RESPONSE
BATTERY ENERGY STORAGE SYSTEMS	
7.15 Costs: • BESS technology learning rates may not achieve cost reductions similar to those seen with solar PV and wind due to potential raw material and manufacturing constraints. • Cost estimates for BESS used in the Draft IRP are inaccurate, as learning rates have not been applied. • Batteries used for grid electricity storage, as seen in South Australia, have demonstrated staggering costs in the past. Additionally, they have short life span, huge decommissioning costs and require a lot of land space. **Recommendations:** • Base BESS costs on recent projects which have reached financial close and realistic projections for South Africa. • The ERPI report, which predicts significantly lower capital costs for batteries by 2030, and these lower estimates must be used for future energy system planning. Also consider LAZARD low BESS scenario which will be more realistic. • The impact of BESS on tariffs should be considered.	The IRP process makes available technologies for the model to choose. The 2024 revision of the EPRI report provides three sensitivities on battery storage costs up to 2040, the base of which is the South African IPPPP costs.
7.16 Energy mix: • BESS is not a primary energy source but a method to store energy from other sources, and therefore shouldn't be considered in the energy mix. • Inclusion of storage in the energy mix is important, particularly as coal is phased out. When coupled with inverters, it is good for grid stability and creating artificial inertia. A large and growing storage roll-out to meet Net Zero scenarios will be required. • The draft IRP's increased capacity allocation for battery storage is noted but there is lack of incentives for BESS localization. **Recommendations:** • A battery must be charged using different forms of energy production, such as wind, solar, or fossil fuels. When resources like wind or solar are used to charge batteries (or to pump water uphill), the capacity being utilized to charge the battery cannot simultaneously be sent into the grid. For instance, if a system is generating 100MW and 50MW is allocated to charge a battery, only the remaining 50MW will be available to be transmitted into the grid. To prevent accounting for the same electricity generation twice, it is necessary to either subtract an amount equivalent to the storage capacity from other sources of power generation or to classify storage separately and not as a form of "generation" itself.	• Refer to 7.15 • Inertia: Operation of battery storage and the nuances is the responsibility of the system operator and becomes an input into the IRP. • Double accounting: This is inherent to the model and is verified.
7.17 Risks: Susceptible to explosions and runaway fires.	Noted.

COMMENT	RESPONSE
COMPRESSED ENERGY AIR STORAGE	
7.18 With a considerable number of coal power plants to be decommissioned, leading to a significant reduction in grid inertia, compressed air will not only provide ancillary services for grid support but also have the potential to create employment opportunities through local manufacturing and maintenance.	CAES was one of the technologies considered in the IRP, however due to cost it was not feasible.
7.19 This technology combined with wind energy can potentially provide cheaper energy storage.	Noted.
PUMPED STORAGE	
7.20 Potential: • Pumped storage hydroelectricity stands as the sole established large-scale technology capable of storing substantial amounts of energy over extended periods. These facilities function akin to immense water-based energy reserves, utilizing surplus grid power to push water to a higher reservoir for storage until needed. It's recommended to investigate alternatives beyond Tubatse, such as small-scale pumped storage solutions. In contrast to Battery Storage, pumped storage entails no chemical byproducts, boasts a longer operational life, and poses lower supply chain vulnerabilities concerning critical minerals like Lithium and Cobalt. • South Africa's pumped storage potential should be taken seriously. The country can easily advance 5GW of pumped storage which can be brought online within 10 years or less and not only is this cost effective but it will help in integrating renewables en masse.	To the knowledge of the DMRE, Tubatse and Steelpoort are the only sites where feasibility studies were done, and welcomes alternative feasibility studies for submission.
7.21 Concerns: • Insufficient sites and water • Long project lead times	Noted.
HYDROGEN STORAGE	
7.22 In the larger scope of energy storage, it is important to also acknowledge and consider hydrogen storage as a distinct form of energy storage.	The 2024 revision of the EPRI report has made provision for hydrogen storage costs and therefore it will be considered for the final IRP. However, EPRI notes that, significant amount of cost uncertainty exists for "power-to-hydrogen-to-power" energy storage. According to the latest Lazard report – Levelized Cost of Hydrogen Analysis ver 2.0. Green hydrogen is not yet broadly cost competitive as compared to the conventional fuels. Applications which require minimal additional steps (e.g., conversion, storage, transportation, etc.) to reach the end user will achieve cost competitiveness sooner than those that do not.

GAS

COMMENT	RESPONSE
FOSSIL FUEL GAS	
7.23 Costs: • Distinction should be made between natural gas (indigenous) and LNG/CNG which requires additional processing and transportation costs • While acknowledging the potential short-term benefits of gas in stabilizing the grid and reducing loadshedding, the IRP 2023's reliance on gas is misguided. South Africa's gas infrastructure and exploration are not sufficiently developed, making gas imports an expensive option. • LCOE (R/kWh): 2 – 3 • Capital Costs (R/kW): 15 000 - 26 000 • O&M Costs (R/kW/year): 100 – 500 • Gas peaking $115 – $221/kWh • Natural gas prices are susceptible to large swings, as evidenced by the extreme price increase in Europe during August 2022. The IRP's assumption of a stable $15/GJ price might be overly optimistic. **Recommendations:** • Dependence on imported gas makes South Africa vulnerable to supply disruptions or price hikes caused by global market factors. Considering scenarios with higher gas fuel costs is recommended.	The price per GJ of gas is a landed price at usable form. A sensitivity on the gas price will be done for the final IRP.
7.24 Gas infrastructure: • Developing a gas industry would require substantial investment in infrastructure, including pipelines, processing facilities, and power plants. This could lead to increased costs in the short term but could also create economic opportunities in the construction and engineering sectors. • South Africa lacks sufficient infrastructure to import LNG and has limited domestic gas supplies. Delays in building LNG import terminals could worsen load shedding in the short term. • Gas-to-Power projects appear to be premised on the supply of natural gas, either from Liquefied Natural Gas facilities onshore or offshore from moored regasification vessels. It appears that electricity generation from LPG, more specifically propane, has not been considered at all. This is alarming when there already exists significant capacity for import at Richards Bay and when the lead time for the implementation of such LPG to electricity projects is significantly shorter than for natural gas projects – LPG Gas-to-Power facilities have a lead time of some 18 months and at Richards Bay it is reported that transmission capacity is available. • Gas to power project in the inland would serve to act as a a catalyst for infrastructure development around the existing ROMPO pipeline, which currently transports gas from depleting Pande and Temane fields in Mozambique, into the inland of South Africa.	The final IRP will leverage on the work done in the Gas Masterplan.

COMMENT	RESPONSE
FOSSIL FUEL GAS (CONTINUED)	
Recommendations: • The practicalities of implementing gas-to-power projects, including the need for extensive infrastructure development, the risks of price volatility, and the environmental impact of gas extraction, calls for a more detailed analysis of the costs associated with different types of gas supply and the implications for the country's balance of payments.	
7.25 Economic impacts: • The development of a gas industry could create significant employment opportunities, both directly in the gas sector and indirectly in related industries. Estimates suggest that a single domestic gas project could create up to 70,000 jobs during the mature phase of production. • A domestic gas project could have an annual turnover of R15 billion, with a total upstream and downstream economic impact of R50 billion per annum. The value added to the economy could be as much as R26 billion per annum. • Gas can provide a more stable and flexible energy supply compared to intermittent renewable sources like solar and wind. This can help reduce loadshedding and improve the reliability of the energy supply, which is crucial for economic growth. • The availability of gas can support the development of gas-based industries, potentially making South Africa a hub for energy and resource development in the region.	Noted.
7.26 Negative economic impacts: • Importing gas would have implications for the country's trade balance, as payments would be made in US dollars. This could put pressure on the South African rand and increase the cost of electricity. • Focus on gas could lead to stranded assets by 2050, as the world moves towards net-zero emissions.	Noted.
7.27 While gas is a cleaner alternative to coal, as it emits about half as much CO_2 as coal, methane leaks from the production, transportation, and use of natural gas can have a significant impact on climate change. It is therefore not a long-term solution due to its status as a fossil fuel and the associated emissions. These will be the environmental impacts of gas: • Gas-fired power plants emit nitrogen oxides (NOx), volatile organic compounds, and hazardous air pollutants like formaldehyde. These emissions can contribute to smog and have adverse health effects. • Gas extraction, especially from shale or coal beds, can lead to water pollution and land degradation. Fracking, a method used to extract shale gas, requires large amounts of water and can contaminate groundwater if not properly managed.	The IRP considers emissions for electricity generation only. Emissions at the gas field will be accounted for in the gas sector, similar to other mining activities.

COMMENT	RESPONSE
FOSSIL FUEL GAS (CONTINUED)	
• Offshore gas exploration and extraction can negatively impact marine ecosystems and the livelihoods of coastal communities that rely on fishing and tourism. **Recommendations:** • They advocate for a greater emphasis on renewable energy sources and energy storage solutions, which are either already cost-competitive or expected to be in the near future.	
7.28 Gas options: • Distinction should be made between natural gas (indigenous) and LNG/CNG which requires additional processing and transportation costs. • Ethane and methane can effectively complement baseload generation. • LPG power plants offer a compelling solution for decentralized energy generation in South Africa. - Unlike traditional power plants tethered to the grid, LPG plants can be situated directly where energy is needed. This eliminates energy loss during transmission over long distances, ensuring all generated power is consumed efficiently. - South Africa already boasts a well-established LPG infrastructure, including import terminals in Richards Bay and Saldanha Bay, a robust distribution network (road and rail), and on-site storage capabilities. This minimizes the need for additional logistical investments. - LPG offers exceptional fuel efficiency: a 1MW engine running for just 5 hours per day utilizes only 1 metric ton (MT) of LPG. - A single 25MT ISO container, filled with 21MT of LPG, can provide fuel for 21 days of operation. Unlike gasoline or diesel, LPG has no time limitations for storage, allowing for flexible fuel management. - Existing bulk transportation via tankers, already utilized by various South African industries for heating and other applications, can be directly adapted to deliver fuel to power generation sites. This leverages the existing robust LPG supply and logistics network, avoiding the need for costly new infrastructure development. - South Africa's LPG industry is well-developed and subject to strict regulations, ensuring safety and reliability.	The gas technologies in the 2024 revision of the EPRI report, LAZARD, consider LNG as a fuel and not LPG.

COMMENT	RESPONSE
FOSSIL FUEL GAS (CONTINUED)	
7.29 While Fluidized Bed and Flue Gas Desulphurisation technologies might seem attractive for reducing emissions from South African coal plants, they come with drawbacks like high cost and limited effectiveness. Hydrogen Industrial, a coal additive, is a potential solution. This additive is claimed to: • Reduce coal usage by 50% • Cut CO_2, SO2, and NOx emissions by 50% • Purify half of the exhaust gases without needing filters • Help earn carbon credits and lower carbon tax burdens • Maintain reliable baseload power with reduced coal consumption By achieving these, Hydrogen Industrial could offer a path towards cleaner coal power generation while ensuring energy security and mitigating the economic and health impacts of shutting down coal plants altogether.	
GREEN HYDROGEN	
7.30 Cost: • Capital Equipment for development of green hydrogen gas is so expensive and this makes green hydrogen so expensive too, although costs could be set to drop overtime as technology development surpasses demand. • PEM \$4.77 - \$7.37 & alkaline \$3.79 - \$5.78	The current capital costs (PEM) for development of green Hydrogen is quite high and this is one of the major hinderance for production of green H2. According to IEA report, Hydrogen from renewable electricity is only cost effective if low-cost, surplus electricity is used. Grid electricity at future retail prices (2050) of USD 115 (United States) to USD 137 (EU 4) per MWh is assumed to be cost-prohibitive, even if T&D costs are zero.
7.31 Green Hydrogen as LNG replacement: It has to be noted that new CCGT technology is compatible with adding Hydrogen feedstock to natural gas. Therefore investing in CCGT is an easy way to develop an outlet for South Africa's future hydrogen economy in the power sector. Green hydrogen could displace LNG for CCGTs in future, resulting in net zero emissions. At high levels of variable renewable energy (VRE) in the generation mix, there may be a lot of electrity that is curtailed, it may be worth considering how much of that could be used to produce green hydrogen as an extra benefit to the economy, or which extra electricity above the demand projection could be sold to offset some generation costs.	The economic viability of Green H2 as a replacement for LNG is dependent on CO_2 costs. For example even under optimistic assumptions with regard to the techno-economic parameters of the electrolyser, electrolytic hydrogen remains considerably more expensive than hydrogen from natural gas reforming, unless very low-cost renewable electricity is available and carbon or natural gas prices are high. The periodic review of the IRP provides for the inclusion of new technologies as they become viable for both energy storage and grid tied generation.
7.32 Clarifying that green hydrogen is not included in the modelling for this plan is essential. It is suggested that Green Hydrogen be included especially since there may be projects that would utilise grid capacity and that could likely provide excess power for other offtakers. Given the magnitude of the projects it would be prudent to include analysis on the impact of green hydrogen in the IRP2023.	**The Demand Projection Model in Support** Of IRP Update 2023 has projected some power demands for hydrogen in particular for mobility. However, the Green hydrogen is not yet broadly cost competitive as compared to the conventional fuels. In particular the use case of energy storage from green hydrogen makes the economics unviable.

COMMENT	RESPONSE
GREEN HYDROGEN (CONTINUED)	
7.33 In the interest of meeting our climate change commitments, we would have expected green hydrogen to have been the subject of serious scrutiny at the very least. If Namibia can embark on the construction of a large-scale green hydrogen industry with its Hyphen project, there is no reason why South Africa should be incapable of doing likewise. Concentrating on natural gas and 'clean' coal, as the IRP 2023 does, clearly betrays the political agenda underlying the proposals.	A cost competitive analysis of current costs for RE is critical in order to assess the economic viability of green hydrogen production in South Africa. The periodic review of the IRP provides for the inclusion of new technologies as they become viable for both energy storage and grid tied generation. There are several country specific strategic technology risks that must be traded-off before being considered which include the technology maturity, the economics of the technology, the pipeline infrastructure required, the ports infrastructure and others.
7.34 South Africa can potentially be a global leader in green hydrogen production and export, leveraging its abundant renewable energy resources to drive economic growth, decarbonization, and industrial development. • Competitive Advantage - Unparalleled solar and wind resources, particularly in the Northern, Western, and Eastern Cape provinces, provide a cost-effective foundation for green hydrogen production. - Situated at the crossroads of major shipping routes, South Africa offers optimal export opportunities for green hydrogen derivatives. - Leveraging existing gas infrastructure can accelerate the transition to green hydrogen, reducing capital expenditure. - A strong industrial foundation provides a solid platform for developing the green hydrogen value chain. • Key Focus Areas - Identify and prioritize hard-to-abate sectors such as heavy haul, maritime, aviation, and industrial heating for green hydrogen applications. - Develop a robust hydrogen fueling infrastructure to support the adoption of hydrogen-powered vehicles. - Target key export markets with growing demand for clean energy solutions. - Build strategic partnerships with international investors and off-takers. - Invest in grid expansion and strengthening, particularly in the Western Cape, to accommodate increased renewable energy generation and hydrogen production. - Develop world-class hydrogen production, storage, and transportation infrastructure. - Foster innovation in green hydrogen technologies, including electrolysis, storage, and applications. - Collaborate with academia and industry to develop local expertise. - Create a supportive policy environment that incentivizes green hydrogen production and investment. - Establish clear regulations for safety, environmental standards, and grid integration.	According to IEA report, Hydrogen from renewable electricity is only cost effective if low-cost, surplus electricity is used. Grid electricity at future retail prices (2050) of USD 115 (United States) to USD 137 (EU 4) per MWh is assumed to be cost-prohibitive, even if T&D costs are zero. A cost competitive analysis of current costs for RE is critical in order to assess the economic viability of green hydrogen production in South Africa. The periodic review of the IRP provides for the inclusion of new technologies as they become viable for both energy storage and grid tied generation.

COMMENT	RESPONSE
GREEN HYDROGEN (CONTINUED)	
7.35 Draft IRP promotes Green Hydrogen but ignores its downsides: • It highlights South Africa's potential for green hydrogen (renewable resources, Fischer-Tropsch) but doesn't mention the high energy inefficiency or current black/grey hydrogen production (from fossil fuels). Draft IRP overlooks Green hydrogen 's impact on the energy sector: • The plan doesn't consider how Green hydrogen might affect South Africa's energy landscape, particularly in the long term (2031-2050). Green hydrogen production may benefit the electricity grid: • While Green hydrogen facilities generate power for themselves, they could also produce surplus green electricity for the national grid. This suggests the Draft IRP should consider Green hydrogen 's potential electricity contribution. **Recommendation:** • Develop a broader Integrated Energy Plan (IEP).The lack of an IEP that considers all energy sources holistically is a major flaw in the Draft IRP.	As per Lazard, Green hydrogen is not yet broadly cost competitive as compared to the conventional fuels. Applications which require minimal additional steps (e.g., conversion, storage, transportation, etc.) to reach the end user will achieve cost competitiveness sooner than those that do not. The IRP studies and policies are to be reviewed periodically and as technologies mature (or not) these technology performance, economic costs will determine whether Green Hydrogen will be incorporated into future IRP policy. The production of green hydrogen is still in its infancy and therefore is not cost competitive at this stage, further applications such as storage further makes the technology costly. This will be considered as the technology matures.
7.36 There is also a need for the IRP to make a determination of at least a 100 MW new build capacity for Green Hydrogen production and electricity production using Hydrogen Fuel Cells. This will stimulate the hydrogen sector and the 100 MW system can be used to produce electricity during peak periods, with hydrogen production taking place during low-demand periods using solar and wind energy that would otherwise be curtailed.	The catalytic technologies (PEM) are still not commercially viable for grid tied scenarios (for inclusion in the IRP). However, the periodic review of the IRP provides for the inclusion of new technologies as they become viable for both energy storage and grid tied generation.
HYDROGEN INDUSTRIAL	
7.37 Another option for Cleaner Coal Technologies could be Hydrogen Industrial, a coal additive. **Hydrogen Industrial offers significant advantages:** • Reduced Coal Consumption: By 50% • Lower Emissions: By 50% • Exhaust Gas Purification: By 50% (without requiring filters) • Ash Reduction: By 50% • Elimination of Boiler Furnace Clogging **Potential Benefits of Hydrogen Industrial:** • Cost-Effectiveness: Hydrogen Industrial could be the least expensive option compared to other clean coal technologies. • Improved Security of Supply: By reducing reliance on coal, Hydrogen Industrial could enhance energy security. Guaranteed Adequacy: Delays in new energy development due to legal challenges pose a risk to energy adequacy. Hydrogen Industrial could be a "game-changer" by enabling emission reductions without waiting for new power plants.	The comment is rather vague. The assumption is that the suggestion is co-firing a coal fired power station with hydrogen. Whilst this may be theoretically possible, this will require significant changes to the boiler and other modifications to the plant. We are not aware of any large scale pilots or commercial operation of such a technology/plant.

THERMAL TECHNOLOGIES

COMMENT	RESPONSE
NUCLEAR	
7.38 Nuclear not supported: • New nuclear energy generation is opposed because of the radiation it produces and its waste is non-bio gradable. Renewable energy is much safer because it does not produce greenhouse gas emissions as much as the coal and nuclear. Renewable energy must be highly considered to decrease the impacts of climate change. IRP iphinde ikhulume nge Nuclear energy njenge energy ehlanzekile kodwa sibesazi ukuthi sixakwe yiyo inkunkuma ye Nuclear esingazi ngishonamanje ukuthi sizo gcina senzenjani ngayo sogcina siyiyisekuphi. • Young people raise the concern that it is not safe - this noted in recently unredacted safety case, where 14 safety concerns were identified and listed about the current power station. • While nuclear energy production may not release greenhouse gases, nuclear power is by no means a 'clean' source of energy, requiring the mining and enrichment of uranium, which is an environmentally degrading process that can leave radioactive residues and pollute water systems.	According to a holistic studies, such as the United Nationals Lifecycle Assessments, Nuclear power is the lowest emitter of greenhouse gas emissions and produces less than half the emissions of wind and solar plants. Ref. United Nations Economic Commission For Europe, Life Cycle Assessment of Electricity Generation Options, 2021 It is important to note that South Africa's Radioactive Waste Management Policy and Strategy of 2005, provides for the manner in which nuclear waste should be managed. The National Radioactive Waste Management Act, 53 of 2008 established the Institute that is managing Radioactive waste on behalf of the country, so we have a fully fledged waste management framework that is functional. • All energy sources produce waste, and nuclear waste degrades on its own over time, without any biological intervention. Other wastes such as toxic materials used in solar panels and wind turbines are non-biodegradable and do not decay but present an indefinite danger to life and ecosystems. One has to look at the picture holistically, as done by the United Nations Economic Commission for Europe's 2021 report which shows the overall impact of the energy source throughout life (including waste management) Here it can be seen that nuclear has the second lowest lifecycle impact and fairs much better than renewable sources such as wind and solr. It is only beaten by a small hydro plant. • South Africa is not a newcomer country when it comes to nuclear Energy programme. The country has safely operated the Koeberg Nuclear Power Station for more than 40 years without any major accidents. Similarly the SAFARI 1 Research Reactor. The National Nuclear Regulator Act, Act 47 of 1999 establishes the Nuclear Safety Authority that is responsible to exercise oversight on the safety operatiopns of nuclear installations, work that they have been executing with distinction over the years. • The graph above covers the life cycle CO_2 emissions from mining, enrichment to waste management, the emissions are found to be the lowest and better than solar power by a factor of 3.
7.39 Nuclear power offers the significant advantage of clean energy generation, producing no CO_2 emissions and contributing to a stable, safe and baseload supply. South Africa should focus on this technology for building a reliable, safe and clean energy future. The country would benefit from both large and small units (PWRs & SMRs) spread across the country as a coal replacement over the long term. However, careful planning is necessary to address the following concerns and risks related to nuclear energy: • High initial investments • The time-consuming licensing process • Management of waste such as spent fuel rods • Decommissioning • The severity of potential nuclear accidents	It is agreed that nuclear provide a safe and clean baseload solution to South Africa's energy needs. In order to address the High Initial Investments, the Department in 2020 issued the non-binding RFI to test the market appetite in this regard in order to investigate market appetite for viable financial and funding models that could be considered for the investment decision making of nuclear technology in South Africa. This took into account the pace, scale, value for money, affordability, ease of deliverability and other benefits for the country. Proposals from a number of Vendor Companies indicated there was an interest in investing in the programme. • Pursuant to the RFI Exercise, a Multi- Attribute Analysis of technology choices was done to include licensability and risks associated with licensing approaches will be considered.

COMMENT	RESPONSE
NUCLEAR (CONTINUED)	
Recommendations: • The remote and isolated siting of any future nuclear plants is crucial for mitigating these risks. • Building trust through strong relationships between regulatory authorities, government, and the private sector, as well as investing in advanced reactor research, to improve public acceptance. • The IRP to reflect the low LCOE of nuclear power due to the 60 year life span and its high load factor as advantages of this technology. • International experience shows that South Africa could and should have new nuclear power generation within six years. The Nuclear Energy Corporation (NECSA) seems ideally positioned to be tasked with responsibility for government-owned SMRs. It is, after all, as is clear from its founding documents, an 'energy' corporation.	• South Africa has a full policy and strategy on management of waste hich is followed to the latter. • Decommissioning is embedded in license holders strategies as part of a license condition imposed by the National Nuclear Regulator. • Safety Assessment Reports are submitted to the regulator for the entire value chain of the programme, from siting to commissioning and waste management. Until a record of decision is provided the Nuclear Programme will not go ahead. Recommendations: These are noted and will further be guided by costs policy decisions based on compliance with the relevant laws.
7.40 Koeberg Nuclear Power Station's: • Council for Scientific and Industrial Research (the CSIR) found that, after extensive modelling of the electricity system, Koeberg was not necessary for stabilising the grid. Nuclear energy is therefore not a cost effective or 'clean' long-term energy source and therefore the operational extension of Koeberg Nuclear Power Station is not supported. • Unless the Koeberg Nuclear plant operation lifespan is extended there is a need for an additional plant. • South Africa's Koeberg Nuclear Power Station, owned by Eskom, boasts an impressive capacity factor and is considered one of the most efficiently run facilities globally. The country can further strengthen its nuclear position with domestic uranium mines and readily available reserves in neighbouring Zimbabwe. Beyond resource security, South Africa has fostered international collaborations to explore further development of the technology. • South Africa is one of the most diligent countries in as far as operational risk is concerned. Since its commissioning in 1984, Koeberg has never had any life and/or environmentally threatening incident/s. Even after the Fukushima disaster, Koeberg underwent rigorous stress testing done in collaboration with the International Atomic Energy Agency and was found to be seismically robust and well designed.	The decision to have Koeberg Nuclear Power Station's life extension was done through the IRP 2019. The National Nuclear Regulator is the entity responsible to ensure this happens safely and will thus grant such approvals and not CSIR, the latter is a research and development entity. Both the Long Term Operation of Koberg Nuclear Power Plant and introduction of new Nuclear Power Plants are a policy of Government. Comment is about Koberg's capacity factor is noted, this is one attribute that gives Nuclear Power Plants an advantage over other technologies. This factor can go up to 90% for the Nuclear Power Plants. It is the intention of Government to take advantage of the entire fuel cycle value chain including mining of uranium, enrichment and fuel fabrication. This principle is embedded in the Nuclear Energy Policy of 2008. Comment about safe operation of Koeberg Nuclear Power Plant is noted and agreed to.

COMMENT	RESPONSE
NUCLEAR (CONTINUED)	
7.41 Small Modular Reactors: • Research on small modular reactors (SMRs) has found them to be more expensive and create far fewer jobs than renewables. They can be built quicker than large nuclear reactors but will still take longer than renewables. They are also more complex than renewables and designs often cannot be replicated due to different conditions at different sites. SMRs still produce radioactive waste that, as of yet, cannot be adequately managed in South Africa. • The view in the nuclear industry is that SMRs will inevitably cost more than large plants, per MWh delivered. The NuScale plant's projected electricity price was at US$89 per MWh. This is not to say that SMRs will not have their place in the global power mix. Markets off the current grid, such as large mining operations in remote areas, come to mind. Or wealthier countries with weak grid infrastructure, such as Nigeria. Generally, the SMR companies are not targeting countries with well-developed grids (such as South Africa), if these countries will naturally prefer larger plants. • Small modular reactors (SMRs) could be a viable alternative, offering advantages such as not requiring a water source for cooling (but rather using air cooling for the turbine exhaust steam) and being deployable in various locations. Our Mines and Intensive Energy Users can also enjoy the benefits of nuclear energy and distributed SMRs. Nuclear energy is the only technology that meets all the Energy Trilemma criteria. However, there is lack of commercial SMR operations worldwide and generally potential risks associated with new technologies do exist. • SMRs stand to replace coal power with limited investment in long distance power transmission network. • SMRs must be brought forward into Horizon 1 following the recent Mining Indaba where the commercial HTMR-100 producing 35MW was unveiled, positioning South Africa as a global leader in SMR development. **Recommendations:** • Allowing the private sector to undertake the development and operation of SMRs, South Africa can diversify its energy portfolio while mitigating risks associated with centralized control and management. • SMRs used to repurpose our coal power stations is a reliable medium to long-term solution for load-shedding.	**Small Modular Reactor:** • The large impetus of private investors investing in SMRs is contrary to the research being touted. Investors would not risk their money on expensive energy sources in a competitive electricity market such as the USA, Europe and Asia. • The jobs to be created in SMRs are expected to exceed those of traditional large scale reactors as they would need more personnel per unit power than a large reactor. • Small Modular Reactors provide reliable baseload supply and have capacity factors of 85-95%. They can be built in modular forms thus reducing the construction time to about 5 years. SMRs have high intensity of jobs per Mega-Watt energy produced with short footprints as opposed to Renewables energies, in particular Solar and Wind technologies. • Although the renewable technology share has grown over the years, the technology remains intermittent depending on the weather (i.e. the sun, wind, rain, and cloud cover). Renewable capacity factors range from 15%-40%. The lower the capacity factor, the more likely the energy resource is susceptible to drops in performance and potential disruptions. • The costs derived from the Department's RFI process proved to be very competitive, with most costs falling below the most quoted figure of $5000/kWh. All technologies will eventually require additional grid for power evacuation, the good thing about SMRs is that they provide the necessary inertia to the grid for balancing and can also load follow to provide peaking power in support of Renewables. • It is indeed true that some SMR technologies such as gas cooled High Temperature Reactors can be deployed anywhere else including inland especially in water scarce countries like South Africa. The SMRs are ideal for High Energy Intensive users and these can take advantage of SMR technology to amongst other things sink the shaft in mines, provide process heat for heavy industry and desalinate sea water to produce fresh water. Most of these SMRs will be commercialised come 2030. • Indeed, it has been found in other countries like Poland that are looking to re-power their coal fleet that costs can be reduced by about 40%. Therefore, re-powering of most of power stations in Mpumalanga that are earmarked to be decommissioned can be done with SMR technology. • SMR technology choices will be made in due course leading up to the RFP process. A position Paper is being drafted to this effect. Recommendation: This is noted and agreed, however solid decisions as to private sector participation still have to be made.

COMMENT	RESPONSE
NUCLEAR (CONTINUED)	
7.42 Economic considerations cannot be ignored when it comes to the high investment costs of nuclear energy, and that it also provides low cost energy in the long run. Some economic risks include: • Potential overruns. • Nuclear annualized costs have a sensitivity to interest rates, and risk free real rates in South Africa are much higher now than they were , at 5%+CPI for long term risk free RSA inflation linked bonds currently, compared to 2%+CPI in Jan 2017. • The challenges of financing large-scale nuclear plants. • In government-funded nuclear projects, government usually takes all the risk of paying and not getting the generation expected, as opposed to privately funded generation where the equity is provided by private capital which bears the risk. Such private projects do not get paid if they don't generate, putting less risk on the fiscus. As a case in point, take the UAE's Barakah nuclear power plant with generation capacity of 5400MW. In 2017 it was considered "on schedule and on budget" up until the very year it was expected to be completed, 2017 (https://www.news24.com/fin24/anthonie-cilliers-cost-of-nuclear-vs-other-energy-sources-20170921). Fast forward to 2020 and it turns out even that project, under the leadership of an experienced nuclear generation country, South Korea, subsequently experienced significant delays and some calculate as much as a 50% cost overrun to 2020: "The initial projected cost for the plant was $20bn. But thanks to delays, that figure had ballooned to more than $24bn by 2016. Some estimates put the total cost of the Barakah build at around $28bn to $30bn" (https://www.aljazeera.com/economy/2020/7/15/nuclear-gulf-experts-sound-the-alarm-over-uae-nuclear-reactors). So, it may be prudent to assume a 50% buffer on such big projects. If $30bn was the capital cost for construction, that works out to $5,555/kWe. **Other cases:** • Vogtle in Georgia, United States, which achieved COD in July 2023 "seven years behind schedule and more than double the projected cost" and has an LCOE of approximately USD180/MWh. • The latest nuclear power plant in the UK, Hinkley Point, eventually cost almost twice as much as was initially projected with an LCOE of approximately £128/MWh.	Economic and financial considerations underpin the feasibility and business case for nuclear power plants. The DMRE has done extensive financial modelling on nuclear power plants from the 9.6GWe and is in the process of updating such for the 2.5GWe case. These financial models and their outputs will be scrutinised by National Treasury, external consultants, investors, NERSA and banks to ensure that the project results in an affordable tariff. Every point mentioned here will be taken into account, including other points where nuclear power was build cheaper and on schedule, especially in Asia.

COMMENT	RESPONSE
NUCLEAR (CONTINUED)	
7.43 Nuclear costs: • Based on current actual contracts internationally, the use of the following costs is recommended - $6,000/kWe for the first unit - $4,800/kWe for unit 2 - $3,600/kWe for unit 3 - $3,000/kWe for subsequent units. This is based on contract experience on international sales such as the 4 unit Barakah plant in UAE being built by South Korea. • New build $141 – $221/kWh • The Ingerop study commissioned by the DMRE for the 2019 IRP had nuclear build costs at around 5000$/kWe, which would translate to over R100,000/kWe in today's money which is more realistic.	Learning rates were studied extensively by our consultants based on real market data. These will be taken into account in the IRP and financial modelling.
COAL	
7.44 Coal currently makes up 86% of South Africa's total generation capacity. This shows an over reliance on coal which: • Contributes significantly to greenhouse gas emissions and air pollution, which is a major concern for environmental degradation and climate change. • Contradictory to global trends of moving away from fossil fuels • Is not sustainable in the long run due to its status as a finite fossil fuel resource. • Has negative environmental health impacts such as concerns about the physical hardship, medical costs, and premature deaths due to particulate matter emissions.	CO_2 emissions related to coal for energy generation accounts for approximately half of South Africa's annual CO_2 emissions. It is possible to reduce these emissions through the implementation of technologies such as Carbon Capture, Utilisation, and Storage. These technologies are shown to be highly positive for the reduction of CO_2 emissions and for South Africa's CO_2 reduction targets. This is evident with the Council for Geoscience's Carbon Capture, Utilisation and Storage programme, and the implementation of CO_2 capture at the Kelvin power plant. These programmes highlight that CO_2 emissions linked to coal can be mitigated. This includes a mitigation of associated environmental impacts. These mitigation technologies should be implemented as part of South Africa's Just Transition framework. This will allow South Africa to enable alternative energy sources, while maintaining South Africa's energy security.
7.45 Coal should be seen as a strategic resource for energy security and therefore economic activity, with the country having over 200 years of coal reserves. • Coal is crucial for economic development, particularly for impoverished communities, due to its role in industrialization and job creation. • There is therefore a need for technological interventions to decarbonize energy generation, such as carbon capture and storage (CCS), to support the continued use of coal in a more sustainable manner. • clean coal technologies are associated with high costs and technological limitations, and may not be economical feasible nor viable for widespread deployment in South Africa.	Coal forms one of South Africa's largest raw mineral producers and one of the largest employers in South Africa. This accounts significantly toward South Africa's socioeconomic growth and development. It is possible to limit the negative effects of coal through the adoption and implementation of technologies such as Carbon Capture, Utilisation and Storage. Moreover, there are alternative uses of coal. This includes the extraction of key materials needed for the energy transition. Financially, a blended solution of these technologies can make coal economically favourable, especially relative to carbon reduction incentives. South Africa should therefore implement these new mitigation technologies and enable maximum benefit of coal as a natural resource, while minimising any associated negative environmental impacts.

COMMENT	RESPONSE
COAL (CONTINUED)	
7.46 Carbon Capture and Storage: • Coal with Carbon Capture and Storage (CCS) technology should be included in future energy plans for South Africa. Here are the key points: - While coal use is expected to decline, stricter emission targets may necessitate its continued use in the future. Including CCS assumptions in the IRP would allow for a more complete picture. - CCS plant assumptions exist in the EPRI report, with considerations for future cost reductions. - The current IRP lacks a dedicated CCS coal column and doesn't specify assumptions used for different generation types in each scenario. - The final IRP should clearly list assumptions for each generation type (including heat rates, capacity factors, installed capacity, electricity output, and water use) across different scenarios. - While CCS coal is more expensive than nuclear, both offer reliable, weather-independent baseload power. However, both share risks like decommissioning costs, project delays, and financial sensitivities. - Similar to nuclear, while the model may not select new CCS coal as part of the least-cost solution in 2050. However, existing coal plants (Kusile and Medupi) could potentially be retrofitted with CCS for a lower cost compared to building new ones.	Coal will form part of South Africa's Just Transition. This will enable energy security while alternative energy sources are implemented. During this transitionary period, coal usage should be used in combination with CO_2 mitigation technologies such as Carbon Capture, Utilisation and Storage. Moreover, the implementation of these mitigation technologies shall be developed proximal to existing coal utilisation regions. The proximity to existing infrastructure and industry will support cost effectiveness. Furthermore, the reduction of CO_2 emissions should be considered relative to carbon reduction incentives and carbon market trading. The proposed carbon mitigation technologies may form a significant economic and financial driver. This includes the utilisation of captured CO_2 within the framework of industries that require carbon, this includes the production of the fertilisers.
The use of clean coal technology (carbon capture and storage) in South Africa's future energy plans (IRP) is argued against and should be abandoned as an unrealistic solution for several reasons: • Studies show that capturing carbon is expensive and complex, with limited success globally. • South Africa's geology is not ideal for storing captured carbon, requiring extensive and expensive infrastructure. • Existing CCS projects rely heavily on subsidies and don't actually reduce emissions since captured carbon is used for oil extraction. • Leakage from storage sites could negate any environmental benefits of capturing carbon. • The IRP downplays the significant water consumption required by CCS technology. • Reliance on future subsidies (like climate finance) to develop this unproven technology is an unrealistic expectation. • The environmental impact of coal mining itself is not addressed in the IRP. • CCS is a distraction used to justify continued coal dependence and that South Africa should focus on proven renewable energy sources to reduce emissions.	Research undertaken by the Council for Geoscience has shown that South Africa does indeed have potentially significant geological storage potential for anthropogenic CO_2. This significantly changes the perspective and economic viability of implementing technologies such as Carbon Capture, Utilisation and Storage. Furthermore, this research suggests that the water requirement can be offset through the utilisation of waste water supply. This presents an opportunity for the rehabilitation of waste water, which presents a huge burden on the state, while meeting CO_2 reduction targets. Furthermore, the geological investigations suggest that potential leakages can be mitigated.

COMMENT	RESPONSE
COAL (CONTINUED)	
7.47 Other Methods of Clean Coal Need to be Explored: South Africa has abundant coal reserves, and which are available locally. It would be extremely unfortunate to leave coal as a stranded asset and rather apply a form of "domestic substitution" by replacing domestic coal with imported solar panels, wind turbines or even gas. In this regard it must be remembered that the whole of the African continent only puts out less than three percent of world CO_2 emissions, while China alone is currently constructing coal-fired power plants with a capacity exceedingly even the maximum theoretical capacity of the entire Eskom fleet. It is thus in the country's interests to explore the options for flue gas beneficiation contemplated in the Hydrogen Valley concept document or even the addition of ammonia to coal fired power plants contemplated by Japan in an effort to retain its coal generating capacity beyond 2050.	The comment is noted. Also see responses to comments 7.41; 7.42 & 7.43 above.
7.48 Delayed decommissioning: Delaying the shutdown of old coal-fired power is opposed based on the following: • It's unclear if this delay is factored into the modelling used for future scenarios. • Delaying shutdowns would worsen climate change and harm public health due to continued coal emissions. • The actual power generation capacity of these old plants is overestimated. • Coal plants are not ideal for quickly adjusting energy output to meet short-term spikes in demand. • Delaying shutdowns without adding pollution controls would lead to a rise in carbon emissions.	Noted.
Recommendations on delayed decommissioning: • Include a detailed plan in the IRP for the phase-out of coal power in a socially responsible manner, which includes addressing the needs of communities dependent on coal mining and power generation. • Delay the decommissioning of older coal-fired power plants as a way to maintain dispatchable capacity and energy security, reducing the risk of load shedding and unserved energy, and to avoid an economic hit, but this is seen as overlooking the impact on meeting the country's minimum emissions standards. • The delayed decommissioning process must comply with environmental regulations, which may require the installation of pollution abatement measures such as flue-gas desulphurization (FGD) to mitigate SO2 emissions. • The plan to delay coal plant shutdowns needs to align with air quality policy, with consideration for conversion to gas as an alternative for some older stations. • Explore converting older coal plants to natural gas instead of simply shutting them down, especially if they are located near gas infrastructure.	• Coal Phase out: The DFFE's report of the National Environmental Consultative and Advisory Forum pertaining to the Appeals relating to Eskom's Power Stations is looking to address the socio-economic aspect of power generation from coal and the IRP will take guidance from it. • The 2024 revision of the EPRI report provides a roadmap of life extension of some coal power plants in South Africa based on international experience.
7.49 Costs: • Price: 85c/kWh • New build cost: \$68 – \$166/kWh	

8. HORIZON 1

SOLAR PV

COMMENT	RESPONSE
SCENARIO 1: FIRM INITIATIVES	
8.1 This will probably be very costly due to high unserved energy and high utilisation of the peaking plants. This would make the price of electricity more unstable.	The purpose of this scenario was to assess the worst case should only the priority projects from Business materialise and no other new capacity materialises while the Eskom EAF doesn't recover. Scenario 3, the "Firm Initiatives & All Initiatives' considered the other business initiatives up to 2030. The results take into account the production profiles of Solar PV. Similarly, production from coal is based on this availability.
8.2 The rationale behind including this scenario in the model is unclear. Given the realities of new generation capacity development between 2024 and 2030, it appears highly unrealistic.	
8.3 The "Business" contribution of 2,842MW from solar is misleading because it is not fully available during peak demand periods. Therefore, coal generation remains a necessary part of the energy mix.	
SCENARIO 2: REFERENCE	
8.4 Peaking power stations shouldn't be utilised at those high levels.	This utilization is indicative of a highly inadequate system.
8.5 This initiative is supported because it appears to be a readily achievable solution for restoring system adequacy. However, the performance of these plants should be viewed with cautious optimism.	Noted.
8.6 The current reference case has a major drawback: it automatically includes natural gas by default. While gas-fired Open Cycle Gas Turbines (OCGTs) and Combined Cycle Gas Turbines (CCGTs) might be a reasonable temporary solution, this approach unfairly excludes other potential short- to medium-term energy sources. Furthermore, relying on gas turbines for baseload power generation makes neither technological nor financial sense. South Africa's dwindling gas reserves and vulnerability to future supply disruptions pose significant risks to this strategy.	In the medium term the number of available new options are limited. The risks associated with gas availability and price volatility is one of the reasons why Horizon 2 explored pathways with limited gas.
8.7 The modelling of Scenario 2 as the "Reference Case" raises concerns. It appears unrealistic in terms of new generation capacity for the 2024-2030 period. • Missing SSEG Capacity: - Scenario 2 omits the expected 900 MW per year of Small-Scale Embedded Generation (SSEG) totalling 6,300 MW (7 years x 900 MW) by 2030, as shown in Table 2 but not in Figure 9. - This omission is unclear, especially considering the potential for SSEG to exceed the scenario's assumed annual rollout of 900 MW. As previously mentioned, South Africa installed 2,000 MW of rooftop solar PV in 2023 alone. • Underestimated Wind Capacity: - Scenario 2 fails to account for the additional 3,470 MW of wind capacity in the Western and Eastern Cape enabled by Eskom's GCCA 2025 curtailment addendum, approved by NERSA. Including the missing 14,000 MW of SSEG (adjusted to a more realistic 7 x 2,000 MW) and the additional 3,470 MW of wind capacity would create a more credible "Reference Case" scenario for Scenario 2.	• SSEG capacity: The assumptions of 900MW per year for SSEG were included, although the reporting is misleading. This was acknowledged and depicted during the public workshops. • Wind capacity: At the time the Draft IRP23 was published, the GCCA 2025 addendum was not yet published.

COMMENT	RESPONSE
SCENARIO 3: FIRM INITIATIVES AND ALL INITIATIVES	
8.8 There are two main risks associated with this scenario: • overreliance on business. • potential issues with Transmission.	• This scenario was to assess the impact on the power system should all the business initiatives materialise. • Current developments in transmission were taken into account reflecting capacity constraints in the Cape areas.
SCENARIO 4: FIRM INITIATIVES & GAS	
8.9 The price of gas will still cause electricity price stability. It would be better to start up the Pebble Bed Modular Reactor (PBMR) project to take over the gas role.	The revised 2024 EPRI report has not found any PBMR projects at commercial stage which can be used for cost and characteristics of this technology.
8.10 This intervention is fully supported as gas technologies are an enabler to the energy transition.	Noted.
The Firm Initiatives & Gas Scenario includes gas power, but the source of this gas is unclear. While South Africa has potential gas reserves, the current plan's heavy reliance on uncertain gas supplies might not be feasible. Concerns regarding gas are as follows: • Sasol, a supplier, is reducing gas supplies from Mozambique due to declining reserves. This gas isn't even currently used for electricity generation. • The IRP mentions gas as early as 2025 (with some capacity already procured) and Eskom gas by 2028, but it doesn't specify where this gas will come from or who will supply it. • While potential gas reserves exist (e.g., TotalEnergy's discovery), relying on unproven fields with uncertain deliverability is risky. It's also unclear how much of these potential finds would actually be available to South Africa. • The country lacks a proven history of being a reliable and consistent gas supplier. **Recommendations:** • The Department of Mineral Resources and Energy (DMRE) report should clearly detail South Africa's gas situation: current production, granted production licenses (location, target market), exploration activities, and resource estimates (proven vs. potential). • Continue exploration and plans to monetize discovered gas resources.	This scenario leverages on the IPP Office procurement process and the Gas Masterplan.
8.11 The recent inland gas discovery by Kinetiko could be a source for repurposed power stations, potentially offering affordable, reliable, and lower-emission energy.	The Eskom strategy is considering repurposing options for coal power stations as they age and retire. The IRP will consider Eskom's plans to repurposing plans should they submit them.

COMMENT	RESPONSE
SCENARIO 4: FIRM INITIATIVES & GAS (CONTINUED)	
8.12 It is noted that the gas-to-power capacity of 6220 MW listed for Scenario 5 includes DMRE gas, Eskom Richards Bay gas, and RMIPPP dispatchable gas (which includes about 1200 MW from three Karpowership IPP projects). As the Karpowership projects no longer have any reserved grid access and are off the table at least for the time being, they should not be included in this analysis. **Recommendation:** • It is suggested that this scenario both adjusted suitably as indicated above, and then should be used to determine what the minimum gas-to-power capacity and the associated load factor would be necessary in order to eliminate unserved energy and load-shedding.	The final IRP will be based on the latest developments and assumptions.
SCENARIO 5: FIRM INITIATIVES & RECOVERY	
8.13 This scenario appears to be the most favourable, but it hinges on a series of optimistic assumptions. It may be overly optimistic to expect everything to proceed flawlessly. • Statistically there is no reason to believe the current trend in EAF will improve. It is however the most important initiative to maintain grid stability, reduce and nearly eliminate load-shedding as the coal fleet retirements reduce synchronous inertia. • This scenario has no gas generation which could compensate for the loss of the inertia in the coal fleet unless there are fast frequency response initiatives not revealed in IRP2023. **Recommendation:** In the short term, to improve the EAF for Eskom power plants: • Allow Original Equipment Manufacturers (OEMs) to operate all Kusile and Medupi generation units. • Implement the concession model at power station level • Eskom EAF and Erratic performance (unit trips) recovery need to be the focus of the Gx utility, even from a Shareholder Compact point of view.	The Draft IRP23 considered the statistical trendline of EAF as the reference case. Scenario 5 was to study the colossal effect of any improvement of the EAF on the power system. Interventions were then proposed to support the Eskom Generation Recovery plan.
8.14 Benefits of pursuing this scenario are: • No new capital-intensive greenfield projects/programmes have to be embarked upon. • Eskom does not have to enter into unfavourable long-term PPAs, increasing its contingent liabilities and weakening its balance sheet. Government doesn't have to provide sovereign guarantees for these contracts, which should be good news for National Treasury and South Africans in general. • There is no need to spend R500 billion on building 14,000 km of transmission lines that will be utilised only 25% of the time anyway because of the low load factors of solar and wind plants. • Government / Eskom assets, the +/- 15GW of UCLF that is lying idle, will be utilised and sweated.	Noted.

COMMENT	RESPONSE
SCENARIO 5: FIRM INITIATIVES & RECOVERY (CONTINUED)	
8.15 The critically constrained power system significantly limits Eskom's ability to conduct essential maintenance. While increased maintenance is a proven strategy to improve the Energy Availability Factor (EAF), its implementation faces challenges due to the tight supply situation.	Noted.
8.16 Eskom turnaround is crucial, and this view aligns with the NECOM Energy Action Plan, prioritizing fixing Eskom. **Recommendation:** • The turnaround should focus on - improved management, operations, and maintenance - capital investment in refurbishing and renewing power plants. • Improve coal plant lifespan: While designed for 60 years with mid-life upgrades at 30, proper management and maintenance are key to reliable performance, not just age (examples: Germany, Japan, India). • Concessioning power stations is a potential solution as the National Treasury Report and VGBE consortium recommend significant investment in extending the lifespan of existing plants due to the financial losses from load shedding. • The existing fleet should be optimally used within technical and economic constraints.	Life span extension: Pathway 4, the Delayed Shutdown pathway, sought to assess the impact of refurbishing and renewing power plants that are currently around mid-life on new generation and transmission developments.

9. HORIZON 1: INTERVENTIONS & OBSERVATIONS

<table>
<tr><th>COMMENT</th><th>RESPONSE</th></tr>
<tr><td colspan="2">INTERVENTIONS</td></tr>
<tr><td>9.1 Intervention 1 – Eskom fleet EAF improvement:
Drastic improvement Eskom’s EAF is essential for enhancing energy security and reducing load-shedding in South Africa.
Recommendations:
• Eskom’s EAF should be aligned with international experience for units of similar age, which is around 70% or more.
• Invest in the midlife renewal of coal-fired power plants to extend their operational life, ensuring they comply with environmental standards and contribute to a stable energy base load.
• Incentives should be put in place at the plant level to improve EAF, and possibly through privatization.
• The improved EAF scenario eclipses all scenarios in effectiveness and therefore the cost implications of improving EAF should be considered.
• Improvement of Eskom’s EAF through the Generation Recovery Plan should only be considered an input for scenario analysis rather than a separate intervention.</td><td>Refer to response 8.13.</td></tr>
<tr><td>9.2 Intervention 2 – Deployment of dispatchable generation options:
• The role of gas should be seen as a transition fuel, coupled with Variable Renewable Energy (VRE) to provide flexibility, and not to replace procurement from wind and solar.
• Accelerating gas-to-power generation to address unserved energy does not necessarily follow from the analysis done for Horizon One and requires further justification.
Recommendations:
• Provide a definition of “dispatchable capacity” in the IRP, as it could include most dispatchable generation already accounted for, such as coal and gas.</td><td>• The comment is noted. Dispatchable capacity means a power plant that can be turned on and off at the request of the system operator as and when required by the system operator. (The Scheduling and Dispatch Rules Draft Rev 7.15T – April 2015 5)</td></tr>
<tr><td>9.3 Intervention 3 – Delayed shutdown of coal fired power plants:
• The proposal to delay shutting down coal-fired power plants to retain dispatchable capacity where it is technically and commercially feasible is supported.
• The delayed shutdown of coal-fired power plants could hinder progress towards aligning with sustainable development goals and transitioning to cleaner energy sources by 2030.
• The proposal to delay the shutdown of coal power plants lacks a clear rationale and connection to the preceding analysis or the energy plan in Table 2. The social and environmental costs of delaying the planned shutdowns appear not to have been considered in the analysis of Horizon One. While there is mention of managing the risks of non-compliance with minimum emission standards, this aspect is not sufficiently explored.</td><td>• Alignment with SDGs: Eskom will add a pipeline of solar PV, battery, and nuclear projects.
• Rationale for delayed shutdown as an intervention: Refers to plants shutting down by 2030 and should not be confused with the delayed shutdown pathway which refers to coal plants currently in mid-life. This intervention was based on observations of an inadequate system due to a low EAF and lack of readily available new capacity.</td></tr>
</table>

COMMENT	RESPONSE
INTERVENTIONS (CONTINUED)	
Recommendations: • Even if there is an improvement in the EAF, some coal units should be maintained for strategic purposes rather than completely shut down. • Some of the identified coal units must be in reserve as a security buffer, with a 3-to-6-month Ready To Supply (RTS) period. • In the motivation for the delay in shutting down coal-fired power plants, provide detail on which power plants' lifespans will be extended or duration of extension. • Include in the modelling the financial costs associated with the life span extension of coal-fired power plants. • Conduct a risk assessment to understand the implications of the reliance on coal-fired power plants, including political, economic, or energy supply-related costs.	• Social and environmental costs of delaying shutdown: All costs of fossil fuels incur a levy of environmental and carbon tax. • MES compliance: At the time of publication, Eskom's appeal with the Minister of DFFE was still pending, as a result no analysis was carried out in this aspect. • Recommendations: Noted.
9.4 Intervention 4 – Support Transmission Development Plan implementation: • Reliance on private sector initiatives requires grid development, which is a significant consideration for the success of Horizon 1 interventions. • Supporting the development of the transmission grid could be effectively achieved by providing a strong market signal for the integration of generation projects in grid-constrained areas. **Recommendations:** • Explicitly factor in grid infrastructure developments in planning scenarios, as this will drive the quantum, speed, and location of new energy generation coming online. • Account for Eskom unbundling and ERA amendments, which could result in changes that impact transmission grid development.	All scenarios in Horizon 1 factored in the availability of the grid and its development as per the Transmission Development Plan (2022-2032) and the Grid Connection Capacity Assessment 2023 and the recommendations are noted.
9.5 Intervention 5 – Manage risks: **MES** Compliance with MES will decrease the nominal capacity and Energy Availability Factor (EAF) during retrofitting because MES equipment installations are large capital projects that require the plant to be offline for installation, which will further decrease the EAF. **Recommendations:** • The use of Hydrogen Industrial as a coal additive could assist coal-fired power plants to achieve a fifty percent emission reduction and thus comply with MES. • An economic evaluation of options to determine the least costly way to meet security of supply while considering MES compliance is suggested. • MES compliance needs to be discussed for each of the scenarios in the IRP. • Coal units should be maintained for strategic purposes and not completely shut down, considering MES compliance. • Policy and regulation may need to be revised to support compliance with MES.	It is very common misunderstanding to join Carbon Emissions (Net zero ambitions) and MES compliance. From the bullets it seems that the author made this error. MES compliance at a high level is based on meeting limits set for three types of emissions: 1. Particulate Matter (PM), 2. Nitrogen Oxide (NOx) 3. Sulphur Dioxide (SOx). The retrofits required for PM and NOx emissions have been factored into Eskom's plans already and will not impact the EAF further. The technology currently used to reduce SOx emissions is the installation of Flue Gas desulphurisation (FGD) technology. This requires major modification to the generating unit, specifically to the boiler plant and its auxiliaries. This involves modification to the boiler draught plant including fans, ducting and flue gas stack. This work can only be executed while the unit is off load on a planned outage of 4-to-6-month duration. Significant auxiliary plant in addition to the unitised FGD needs to be constructed and tied into the generating unit during planned outages.

COMMENT	RESPONSE
INTERVENTIONS (CONTINUED)	
	Given the above in Eskom's plans to date propose that only Medupi will be retrofitted with this technology. The requirements to do the FGD retrofit at Medupi have been considered in the current plans and will not have an impact on EAF.The MES limits applicable to Eskom plants were subject to legal processes and appeals. The latest decision/directive issued by the Minister of DFFE on 22 May 2024 in terms of MES has provided a decision that plants operating up to 2030 are granted suspension to operate at existing plant limits (as reflected in the MES). Eskom is directed by the Minister to submit exemption applications for plants operating beyond 2030 and stipulates the following: "Eskom, however, remains responsible to evaluate and decide on the best cost-effective way to ensure they come into compliance with the new plant MES for SOx". Based on this decision Eskom is in the process of evaluating the options available and will complete the exemption application by the end of this calendar year. The impact on EAF can only be determined once the preferred option has been determined and approved by the DFFE. Hydrogen co-firing in boilers to reduce emissions, at a conceptual level, is technically possible. However currently this option has an extremely poor roundtrip energy efficiency balance for boiler combustion in a "power to power (PtP)" application, along with very exorbitant costs. Higher efficiency power generation machines such at gas turbines and fuel cells are being considered for initial niche PtP applications. High cost clean/green hydrogen also has a higher "system value" for other more efficient end uses (within the hard to abate sectors) in the "power to X (chemicals, fuels, etc)" value chains. Its overall emerging and developing value chain technology status from production to end use render this a possible long-term option. Globally, broadscale hydrogen boiler cofiring is unlikely before 2035, for PtP applications, except in very niche cases and will depend on greatly reduced hydrogen fuel costs. This option is nevertheless being tracked and constantly assessed until further proven and adopted globally, for overall viability with respect to corresponding MES, Just Energy Transition (JET), and other benefits within the Eskom context. For bullet 2 and 3 see IRP Section 1.2 "The main purpose of the IRP is to ensure security of supply necessary by balancing supply with demand, while considering the environment and total cost" Since it is a recommendation it is seemingly suggesting the current process for the IRP does not achieve the main purpose. DOEE need to comment on this. Bullet 4 The MES decision by the minister has put clear limits on this i.e., Arnot, Camden, Grootvlei, Hendrina and Kriel will need to cease operating as Coal Fired Power plants by the 31 March 2030. Eskom's current stance is to align with the decision and these plants will be removed from operation by 31 March 2030.

COMMENT	RESPONSE
GENERAL	
9.6 Energy Efficiency: The absence of Energy Efficiency (EE) as an intervention for Horizon 1 is a missed opportunity for South Africa to address its energy crisis while achieving environmental gains. • EE is a cost-effective resource compared to building new power plants. Improving energy efficiency offers substantial savings. Energy reductions of about 10-20% can be achieved for various customers. • DSM/IDM programs run by NERSA and Eskom between 2004 and 2018 demonstrate the effectiveness of EE in reducing demand. • Current EE efforts fall short because existing EE programs haven't been fully institutionalized. • Significant benefits from EE include: - Reduced electricity demand - Lower consumer bills - Decreased greenhouse gas emissions - Job creation - A fairer energy system	A concerted effort has been made to include EEDSM for the final draft of the IRP. It is true that EEDSM could be more economic and have shorter lead times compared to generation options.
9.7 These interventions rely on unavailable gas and transmission expansion, and therefore the premise for these interventions for Horizon 1 is unrealistic.	Noted.
9.8 A crucial output missing from this draft is a clear picture of how electricity prices might change under each scenario. This information is especially important for stakeholders and the public. It is understood that the projected prices might not directly reflect the final decisions made by NERSA (National Energy Regulator of South Africa) on electricity prices. However, these projections would still be very valuable. They would show how different choices (scenarios) could affect electricity prices in the coming years. **Recommendations:** To achieve true transparency and social justice, the Draft IRP 2023 (or an appendix) should include clear and easy-to-understand graphs. These graphs should show the projected electricity price paths for each scenario, from 2024 to 2050. Without this information, it's difficult to ensure that the planning process considers fairness and the needs of ordinary citizens.	Noted.
9.9 Procurement concerns: • The IRP 2023 fails to mention the role of municipal procurement within the plan. The Electricity Regulation Act amendment allows municipalities to "procure or buy own generation capacity." However, the IRP 2023 does not seem to consider this new provision and its potential impact on the overall generation mix. • The IRP 2023's Horizon 1 results lack clarity regarding private sector generation capacity additions. This includes both the total amount of additional capacity (MW) and the timeframe for these additions.	• Municipal procurement: The capacity in the IRP is not spoken for and is therefore carried out through Ministerial Determination which municipalities can apply for as per Amendment of Electricity Regulations on New Generation Capacity, 2020. • Clarity on private sector initiatives: Business initiatives as per Schedule 2 we accounted for in 3 Horizon 1 scenarios: Firm initiatives (2824 MW), Reference case (5304MW), and the Firm Initiatives + All Initiatives (10 436 MW).
9.10 The renewable energy capacity allocated in the IRP 2023 falls short of the 2,600 MW per year required to meet the industrialization objectives outlined in the South African Renewable Energy Masterplan (SAREM). This raises concerns about achieving the country's renewable energy goals.	The renewable energy targets are set by the IRP and SAREM is based on the outcomes of the IRP 2019.

HORIZON 2

COMMENT	RESPONSE
PATHWAY 1: REFERENCE CASE	
10.1 It's important to remember that the pathway achieves minimal cost because the model can freely choose any combination of technologies. However, accurate cost assumptions for each technology type remain crucial.	The 2024 revision of the EPRI report will include costs of the latest REIPPPP.
10.2 The Reference Case gives rise to large contribution by solar and wind, seems to be the most balanced and therefore robust. The balancing of the system will be done by a large amount of gas at 33 399MW. This large amount of gas ensures the system adequacy. It is noted that the model is not restrictive, therefore as much of what is needed can be built as necessary. **Recommendations:** • In this reference case, gas should not be limited to mid merit, as it has more potential that should be investigated on a project-by-project basis. • Pathway 1's assumptions should address the concrete reality of including system costs. These costs include grid expansion and associated infrastructure to integrate solar PV and wind, estimated at R400 billion for the additional 14,000 km of transmission lines.	• Mid merit gas: Utilization of gas is an outcome of the model. • System costs: These will be included in the final IRP.
10.3 Risks: • The recommended volumes of gas may not necessarily be feasible in real terms, and therefore remains precarious until long-term gas supplies are secured. • The early shutdown of coal-fired baseload plants hinges on the successful development of upcoming upstream gas projects, which introduces an element of risk.	Noted.
PATHWAY 2: RENEWABLE ENERGY	
10.4 A Renewable-Energy-only approach will not be able to supply the national, industrial energy requirements of South Africa, against the backdrop of loadshedding, South Africa's planned economic growth trajectory and the increased industrialisation ambitions. • Power systems solely reliant on intermittent renewable energy (RE) and storage have yet to be fully implemented and demonstrated (excluding countries with significant hydropower resources). This lack of experience alone could pose challenges regarding system instability during the initial deployment years. • Specifically, a system with heavy reliance on wind and solar could face limitations due to factors like system inertia, intermittency, and non-dispatchability, potentially leading to instability. Further investigation into the modelling assumptions and how Gas-to-Power integration addresses these limitations is recommended.	Noted.

COMMENT	RESPONSE
PATHWAY 2: RENEWABLE ENERGY (CONTINUED)	
10.5 When calculating the least-cost pathway, the IRP factors in the cost of unserved energy (load shedding) alongside technology costs. Their modelling shows very high levels of unserved energy in the 'renewable energy pathway,' leading them to conclude it's the most expensive option. However, other modelling exercises suggest it's the least-cost path to a reliable system.	Noted.
10.6 This pathway output rightly highlights the unreasonableness of assuming no new gas generation. **Recommendation:** • Instead of presenting scenarios with loadshedding, perhaps a more realistic approach would be to set the cost of unserved energy high enough to incentivize complete avoidance of load-shedding (ideally below 0.05% of annual demand). With this revised cost assumption, the scenario should be re-modelled to ensure it meets adequacy criteria.	Noted.
10.7 Rolling out new renewable generation capacity is faster than building new coal or gas plants and offers much more desirable route to energy security.	Noted.
10.8 Pathway 2 for "Renewable Energy" presents a puzzling outcome, favouring large-scale concentrated solar power (CSP) deployment of 34.5 GW by 2050 over the seemingly more cost-effective combination of solar PV 18 GW) and battery energy storage systems (BESS). This figure for CSP is roughly five times greater than the current global installed capacity. This is likely due to a combination of factors: • New build limitations applied to solar PV, restricting annual growth to 900 MW. • Imposing no constraints on concentrated solar power (CSP). • High-cost assumptions for both solar PV and BESS new build. • The absence of learning curve reductions factored into the cost calculations for these technologies. This inconsistency in applying build limitations raises concerns about the rationale behind these choices.	• New build limitations: Refer to Response 5.11 • There was no basis for imposing constraints on CSP. • Costs: The 2024 revision of the EPRI report has been updated with the latest Bid window costs • Learning curve reductions: Noted.
PATHWAY 3: RENEWABLE ENERGY & NUCLEAR	
10.9 Pathway 3 emerges as the optimal choice in Horizon 2, relying on nuclear as the baseload. • This pathway is fully supported due to its minimal carbon emissions and substantial baseload power provided by nuclear plants. Nuclear power significantly aids in emissions reduction while enhancing electricity security as a reliable power source. Moreover, this pathway ensures compliance with minimum emissions standards.	Noted.

COMMENT	RESPONSE
PATHWAY 3: RENEWABLE ENERGY & NUCLEAR (CONTINUED)	
• More nuclear power capacity should be included as this would be a better solution to South Africa's energy crisis than the other pathways. A larger nuclear build would not only meet the country's energy demands more effectively but also compensate for the planned closure of coal-fired plants after 2030. • One of the challenges surrounding nuclear deployment would be public acceptance. Some members of the public perceive nuclear energy as unsafe. Additionally, due to its high capital costs, nuclear deployment may not be economically favourable or extensive enough to fully compensate for the coal capacity that would be decommissioned after 2030. • While initial investment costs may appear high, nuclear power offers long-term cost advantages with stable electricity tariffs. Koeberg exemplifies this, having provided reliable and affordable power for over 40 years. • The nuclear industry creates a significant number of high-quality, well-paying jobs. • Nuclear technology has a successful track record globally, with countries like France, the UAE, China, Russia, Japan, and (partially) Germany utilizing it in their energy mixes.	
10.10 Combining renewable energy (RE) and nuclear power in the same scenario can be a complex issue. While there may be potential benefits, there are also technical and economic considerations that need to be carefully evaluated. • Nuclear excels at providing low-cost, baseload power due to its high upfront capital costs and minimal fuel expenses. However, its efficiency suffers significantly when production needs to be ramped down (throttled) to compensate for increased solar and wind generation during peak sun and wind hours. • This throttling reduces a nuclear plant's overall annual output without a proportional decrease in fuel costs, ultimately driving up the cost per kilowatt-hour (kWh) of nuclear power. This characteristic makes nuclear less suitable for directly balancing the intermittency of wind and solar, as frequent ramping up and down becomes unprofitable. Consequently, using nuclear might involve under-building capacity to meet minimum daytime demand. This strategy would require additional sources to compensate for the higher demand periods.	The costs and performance characteristics of each technology is modelled appropriately and the system selects appropriate technologies to meet demand while minimizing system cost.

COMMENT	RESPONSE
PATHWAY 3: RENEWABLE ENERGY & NUCLEAR (CONTINUED)	
10.11 Natural gas seems perfect to complement nuclear power's reliable baseload generation due to its flexible output. However, gas is expensive and pollutes the environment. Ideally, a large portion of solar and wind power would be added for their low cost and minimal emissions. Unfortunately, solar and wind are intermittent, meaning they can't always be relied upon. • On days with no wind or sun, a combination of nuclear, solar, and wind will inevitably lead to power shortages and blackouts. Pumped storage and batteries can help by storing excess solar energy during the day to compensate for low wind in the evening. However, these storage solutions are limited, and extended periods of bad weather can deplete them. **Recommendations:** • The obvious solution during such times is to rely on gas turbines for extended periods. Therefore, the optimal mix should include nuclear, renewables, storage, and gas. However, if this scenario limits gas power usage too much, it becomes both expensive and fails to provide the necessary energy security.	Noted.
10.12 Pathway 3's objective of "exploring the impact on security of supply" presents a potential issue within a capacity expansion model. Security of supply is inherently tied to user-defined energy modelling adequacy specifications. Ideally, a well-designed IRP study should ensure all pathways achieve the same level of security of supply.	Noted.
10.13 If a specific pathway results in inadequate security of supply, it suggests a potential flaw in the modelling approach. This could be caused by: • Impossible boundary constraints: Insufficient new build capacity might have been allowed in the model. • Incomplete modelling: Production cost modelling might not have been run after the capacity optimization. • Inappropriate reliability criteria: The criteria used to assess reliability might not be suitable.	A production cost model is always run iteratively with a capacity optimization model to meet defined reliability criteria. However, based on the type of technology options made available, some criteria may never be met. This is typically the case where the capacity value reduces as more capacity is added.
10.14 This pathway's reliance on nuclear power generation might be inflated due to the limited availability of alternative dispatchable sources (reliable power on demand). Notably, nuclear capacity only appears in this pathway, not others, likely due to imposed restrictions on other technologies. Therefore, this pathway shouldn't be used to solely justify the need for nuclear power. It highlights that nuclear might only become necessary in scenarios with limitations placed on potentially more cost-effective options. Including nuclear power in this instance would require explicit policy decisions. These decisions would need clear justifications regarding the amount of nuclear capacity needed and its economic viability compared to other options.	Noted, this pathway was developed to assess the risk where gas is limited as South Africa doesn't currently have proven gas resources.

COMMENT	RESPONSE
PATHWAY 4: DELAYED SHUTDOWN	
10.15 Life extension of 10 years for plants due for shutdown after 2035(Lethabo, Matimba, Kendal, Majuba, Kusile, Medupi). Presumably, this assumes enhanced EAF as unserved energy is eliminated. The record to date hardly inspires confidence. The IRP does not say what replaces retiring coal plants. Carbon emissions are high. We may assume that MES remains suspended.	• EAF: The assumption is that performance remains high due to refurbishment and renewal in addition to other new capacity. • MES: Refer to Response 9.3.
10.16 A data-driven review of the shutdown plan and implementation of this pathway is supported, considering economic, security, and social impacts. The decision to delay coal plant decommissioning should be based on engineering, technical, and practical reasons, not ideology. Upgrading existing plants to cleaner fuels might be an option, but cost-effectiveness needs careful analysis. • Eskom's original shutdown dates considered a larger planned new build program (Coal-3, Coal-4, Nuclear-1) that may not be happening now. • Shutting down plants before design life could be economically and security-wise risky for South Africa. • Decommissioning could lead to job losses across the energy sector, impacting the already high unemployment rate (41.1%), especially among black South Africans (unemployment rate 36.8%). • Delaying shutdown (Pathway Four) could be best for maintaining energy security during the transition to renewables. • Some BRICS partners have more relaxed net-zero targets, suggesting South Africa shouldn't rush its own. **Recommendations:** • Find a way to remain compliant with minimum emission standards with delayed decommissioning. • More studies are needed to support claims of extending plant life beyond technical limits while improving performance. • Conduct a comparison of the cost breakdown of extending plant life (including pollution abatement equipment) vs the cost of unserved energy and include the results in the IRP. • Consider refurbishing coal plants to gas (e.g., Komati), however an evaluation of the cost-effectiveness is required. • Learning from past decommissioning mistakes (e.g., Komati) is crucial.	• Noted. • MES: Refer to Response 9.3. • Studies: The assumption is that extensive refurbishment and renewal is undertaken to maintain current performance.

COMMENT	RESPONSE
PATHWAY 4: DELAYED SHUTDOWN (CONTINUED)	
10.17 The delayed decommissioning plan has flaws due to unrealistic EAF assumptions which may result in risks to electricity supply, sustainability, and stakeholder support. • The proposal for delayed decommissioning assumes an improved EAF (Electricity Availability Factor) for the aging coal fleet. This is unlikely due to their exceeding design life and potential performance issues. • There's a high risk of supply disruptions if the assumed EAF improvement doesn't happen or is significantly delayed. • This pathway contradicts existing policy commitments due to its unrealistic EAF assumptions. • The pathway fails to address net-zero emissions by 2050 and could hinder progress toward sustainability goals. • Ignoring EAF issues could exacerbate environmental problems from continued reliance on coal. • Without a clear plan to address EAF, consistent electricity supply remains at risk despite delayed shutdowns, impacting industry, commerce, and healthcare. • The unresolved EAF issue could lead to lack of support from stakeholders who prioritize long-term sustainability and reliable energy. • Increasing EAF (70%) and delaying coal decommissioning are incompatible. Delaying decommissioning means an older fleet with more breakdowns, lowering EAF. New gas, nuclear, and renewable builds offer a better chance of increasing EAF due to managing brand-new assets.	The delayed shutdown pathway is not a reference and is meant to be exploratory in nature. It refers to coal plants currently in their mid-life.
10.18 Coal Plant Repurposing Replacing aging coal plants with CCGT (Combined Cycle Gas Turbine) technology might be more cost-effective than extending their life with rising maintenance costs.Instead of decommissioning, consider upgrading coal plants to use alternative baseload fuels. • Biomass derived from waste could be a potential alternative fuel, depending on existing technology and costs. **Benefits of Repurposing:** • Maintains grid connection. • Saves existing site permits. • Utilizes existing utility infrastructure. • Retains experienced staff. • Leverages written-off capital investment.	The current location of Mpumalanga does not have readily available fuel other than coal. Gas finds in that area are at early stages of development.

COMMENT	RESPONSE
PATHWAY 4: DELAYED SHUTDOWN (CONTINUED)	
10.19 The pathway delaying coal plant decommissioning is not supported due to its negative consequences on health, the environment, and alignment with climate goals. • Delaying decommissioning past 2035 would likely cause significantly more than the projected 79,500 air pollution-related deaths by 2025. • Exemptions from emission standards to delay shutdowns prioritize energy security over public health and environmental rights. • No clear information exists on costs of extending plant life, refurbishment, or ensuring compliance with emission standards. • There's no data on technical, environmental, or economic feasibility of life extension compared to new generation sources. Financing such extensions might also be difficult. • Delays would violate South Africa's emissions commitments and net-zero ambitions. • Emission abatement technology cannot be readily installed with current coal plants. • A ten-year delay prioritizes political expediency over worker and resident health. • The entire delay period would have unacceptable carbon emission impacts.	Noted.
PATHWAY 5: RENEWABLE ENERGY & COAL	
10.20 Renewables backed up by storage can replace fossil fuelled plants as they are retired.	Noted.
10.21 Solar and wind should be avoided. The coal stations should run as long as possible.	
10.22 Waste of time - clean coal does not exist. Either use coal, or don't.	
10.23 This scenario is said to be marginally adequate, however for a scenario to be credible it has to meet the adequacy criteria.	
10.24 Another option for Cleaner Coal Technologies could be Hydrogen Industrial, a coal additive. **Hydrogen Industrial offers significant advantages:** • Reduced Coal Consumption: By 50% • Lower Emissions: By 50% • Exhaust Gas Purification: By 50% (without requiring filters) • Ash Reduction: By 50% • Elimination of Boiler Furnace Clogging **Potential Benefits of Hydrogen Industrial:** • Cost-Effectiveness: Hydrogen Industrial could be the least expensive option compared to other clean coal technologies. • Improved Security of Supply: By reducing reliance on coal, Hydrogen Industrial could enhance energy security. • Guaranteed Adequacy: Delays in new energy development due to legal challenges pose a risk to energy adequacy. Hydrogen Industrial could be a "game-changer" by enabling emission reductions without waiting for new power plants.	Noted. Information about this technology is not available as an abatement for emissions.

COMMENT	RESPONSE
PATHWAY 5: RENEWABLE ENERGY & COAL (CONTINUED)	
10.25 Pathway Five is criticized for its reliance on unproven and expensive CCUS technology while neglecting more cost-effective clean energy alternatives. • CCUS (Carbon Capture, Utilization, and Storage) technology is the main weakness of this pathway. Its economic viability compared to other options remains unproven. • This pathway prioritizes saving jobs in the coal sector over transitioning to cleaner energy sources, potentially worsening the financial situation of Eskom. • The pathway advocates for a significant life extension (over 25 years) for existing coal plants to justify past investments. • Supports investment in research for clean coal technologies to utilize South Africa's vast coal reserves. • The inclusion of CCUS technology in this pathway significantly increases capital expenditure compared to new coal builds.	Noted.
10.26 The basis for this pathway is unclear. While it seems to consider all technologies like the Reference Pathway, the generation mix differs due to the inclusion of new coal. • Any clean coal technology would likely be more expensive than regular coal, suggesting it's being forced into the mix and might not be cost-effective compared to alternatives. • The technical and economic feasibility of clean coal technologies in South Africa remains uncertain, and the IRP 2023 lacks evidence of its cost-effectiveness. • No information on clean coal or CCUS costs is provided by the DMRE, hindering stakeholder assessment of this pathway's economic viability. • The pathway proposes 6,000 MW of new coal capacity with CCUS replacing nuclear from scenario 3. However, it doesn't explain how Eskom will replace the planned 15,000 MW of decommissioned coal plants. • It also fails to mention any additional technologies needed to support the extra generation capacity from CCUS or address Eskom's reported reserve challenges.	The pathways in Horizon 2 were exploratory in nature and were not intended to inform policy direction. Although the IRP optimizes for cost, it takes into account the reliability and operability of the power system.
10.27 Clean coal technology has environmental limitations of coal and potential shortcomings. • Traditional coal power's significant contribution to greenhouse gases and air pollution remains a major environmental concern. • Even with advancements in "clean coal" technology, the inherent carbon intensity of coal combustion casts doubt on its long-term viability. • Clean coal technology might offer some improvements, but it's likely insufficient to meet stricter emission standards for sustainable energy production.	The emission rates for the technology were considered and the impact was reflected in the reported CO_2 system emissions.

COMMENT	RESPONSE
PATHWAY 5: RENEWABLE ENERGY & COAL (CONTINUED)	
• The assumptions behind deploying clean coal technologies (FBC - Fluidized Bed Combustion, PF with CCUS - Pulverized Coal with Carbon Capture, Utilization, and Storage) need clarification. • The feasibility of deploying these technologies within the proposed timeframes (7-16 years) is questionable. Delays could eliminate Pathway Five as a viable option. • Transparency is needed regarding clean coal technology parameters for each power station, allowing public scrutiny and independent analysis.	
GUIDING PRINCIPLES INFORMING THE PATHWAYS	
10.28 The guiding principles used to develop the pathways exhibited a bias towards variable renewable energy.	The guiding principles used to develop the pathways emanate from identifying the risks in the reference case such as gas, as well as considering all resources that South Africa is endowed with.
10.29 Overall good guiding principles (except for clean coal).	
10.30 The guiding principles used to develop the pathways appear unrealistic, potentially forced by the limitations of the modelling methods or tools employed.	
10.31 The underlying principles guiding the pathways are deemed incorrect and lack proper consideration of key factors like emissions reduction, security of supply, and cost-effectiveness. Predetermining technology mixes before optimization limits the exploration of all possible combinations and results in suboptimal solutions. • This approach restricts the choice of technologies to a pre-selected set, potentially excluding better options. • The technology cost assumptions used in Horizon 2 are considered inaccurate, leading to misleading conclusions about South Africa's energy options. **Recommendations:** • The IRP should replace predetermined pathways with a technology-agnostic approach. This would allow all potential technologies to be considered and optimized based on specific needs. • The IRP should establish an unconstrained, least-cost reference case as a starting point for further analysis. • Exploring sensitivities like technology costs, fuel prices, and emission limits based on the reference case would provide a more comprehensive understanding of potential outcomes. Any deviations from the least-cost reference case should be clearly explained with the rationale behind them.	The reference case is a least cost optimization taking into account transmission constraints as per TDP. All technology options are made available. Other pathways are of an exploratory in nature. Sensitivity will be done.

COMMENT	RESPONSE
GUIDING PRINCIPLES INFORMING THE PATHWAYS (CONTINUED)	
10.32 Overall, the general technology choices in Horizon 2 are supported but a more nuanced approach is required which considers the need for a costing review, the re-inclusion of socio-economic criteria, and a transparent multi-criteria analysis to determine the optimal volume of each technology within the IRP. **Recommendations:** • The costing assumptions used in determining the technology mix need to be reviewed. • Return to the socio-economic assessment criteria used in the 2019 IRP to evaluate different technologies. This implies a broader analysis that considers factors beyond just cost. • The current IRP lacks a clear explanation of the multi-criteria approach used to analyse different technology scenarios. The 2019 IRP explicitly considered factors like cost, social benefits, and environmental impact. The inclusion of this multi-faceted approach in the current IRP is important.	
10.33 The purpose of the pathways in the IRP is understood to explore various realistic scenarios (pathways) to understand the effects of uncertainties and constraints in the real world. Therefore, each pathway should represent a rational response to different situations that could realistically occur, such as changes in technology or fuel costs. • The alternative pathways in Horizon 2 are criticized for using a predetermined technology mix with unrealistic constraints. **E.g.1:** Power System Transition Scenarios - These completely exclude fossil fuels, leading to higher costs. This is seen as an unrealistic policy scenario that shouldn't be forced into the analysis. **E.g. 2:** Delayed Decommissioning Scenarios-These include excessive amounts of coal power beyond what's economically optimal. This suggests forcing a specific outcome rather than exploring realistic possibilities. **Recommendations:** • If a pathway is constructed solely to illustrate a specific point, it should be explicitly stated in the IRP to avoid confusion.	• Uncertainties in technologies: Sensitivities will be assessed in the final IRP. • Predetermined technology mix: Refer to 10.30, the messaging regarding the exploratory nature of Horizon 2 was stated in the draft report but this can be made more explicit.
10.34 The IRP should move beyond a "least-cost" approach and prioritize "value for money" as recommended by the Zondo Commission. This suggests a broader consideration of long-term benefits beyond just initial costs. The IRP should disclose the total system cost for each pathway, including: • Impact on electricity tariffs • Costs of additional transmission lines • Costs of distribution network upgrades • Potential premium for choosing a more expensive but potentially more beneficial pathway (e.g., faster decarbonization)	• Price paths for all scenarios will be conducted for the final IRP. • Costs for transmission and distribution upgrade will be considered only as far as they may impact integration of generation.

COMMENT	RESPONSE
GUIDING PRINCIPLES INFORMING THE PATHWAYS (CONTINUED)	
Recommendations: • Provide transparent cost information; by doing so, the IRP can empower the public, government, and investors to make informed decisions. This includes: • Understanding the "decarbonization premium": the additional cost associated with transitioning to cleaner energy sources. • Weighing the social costs of carbon emissions against the potential economic benefits.	
10.35 The IRP's approach to scenario design in Horizon 2 is criticized for its focus on pre-determined technology mixes and the inclusion of unfeasible scenarios leading to confusing and suboptimal outcomes. • The IRP prioritizes pre-selected technology mixes (e.g., renewable energy) instead of defining desired outcomes (e.g., emission reduction) and letting the model identify the best solutions. This flaw is absent only in the Reference scenario, which focuses solely on least-cost solutions. • Prescribing technology combinations leads to suboptimal outcomes. For example, the Renewable Energy scenario achieves only slightly lower CO_2 emissions than the Nuclear and Renewable Energy scenario by 2050. • Despite being cheaper than nuclear, the Renewable Energy scenario has a much higher construction cost (R1,970bn) compared to the Nuclear and Renewable Energy scenario (R751bn). • The Renewable Energy scenario includes 35 GW of concentrated solar power (CSP) which is not needed in the Nuclear and Renewable scenario. This suggests CSP might be compensating for the intermittency of solar and wind in the Renewable Energy scenario, further highlighting the benefit of nuclear power as a stable baseload source. **Recommendations:** • The IRP should prioritize defining desired outcomes and let the model identify optimal technology mixes. • Unrealistic scenarios should be removed from the IRP to improve clarity and focus on feasible options.	Pre-selected technology mix: Refer to 10.31
ENERGY MIX	
10.36 Renewable energy should be the anchor source of energy for South Africa's power sector. Changing baseline assumptions on baseload from coal and nuclear towards renewable energy sources and dispatchable batteries. Recognizing and streamlining rooftop solar penetration in South Africa's energy mix.	Noted.

COMMENT	RESPONSE
ENERGY MIX (CONTINUED)	
10.37 To ensure reliable and sufficient energy supply (adequacy and security), each scenario in the IRP should be evaluated based on its ability to meet these criteria. The optimal energy mix for each scenario should be a result of the model's calculations, not predetermined before analysis. This allows for a more data-driven and adaptable approach.	• Adequacy criteria: All scenarios are evaluated to meet the same adequacy criteria. • Predetermined technology mix: Refer to 10.31.
10.38 All pathways should include nuclear energy thanks to it's low carbon and high reliability credentials. Nuclear should be prioritised.	Noted.
10.39 There needs to be clarity around any 'policy adjustments' incorporated into any scenarios. The updated IRP should clearly outline any deviations from a least cost modelling approach.	The draft IRP, though considers policy imperatives, it does not impose policy adjustments.
10.40 The energy mix of each pathway should be clear in terms of technologies that are forced-in and technology that are constrained.	The draft report states the assumptions of each scenario, including any technologies that are forced in. However, this can be more explicit.
10.41 Prescribing technology combinations upfront, rather than desired outcomes, appears to have led to suboptimal results. For instance, the Renewable Energy scenario seems designed to prioritize aggressive CO_2 reduction over other, potentially greener options. However, Figure 21 (right panel) reveals minimal CO_2 emission differences between the Renewable Energy and Nuclear & Renewable scenarios by 2050. From a CO_2 reduction standpoint, replacing nuclear with solar and wind offers negligible benefit. One might expect significant cost savings from this substitution, given the lower cost of solar and wind compared to nuclear. However, Figure 22 shows a contrasting picture. The Renewable Energy scenario boasts a construction cost of R 1,970 billion, a staggering 2.6 times higher than the R 751 billion of the Nuclear & Renewable scenario. Figure 19 sheds some light on this discrepancy. The Renewable Energy scenario requires building 35 GW of concentrated solar power (CSP), which is absent in the Nuclear & Renewable scenario. Nuclear power likely contributes to the lower construction cost of the latter scenario by reducing intermittency in the system. This decreased intermittency lessens the need for CSP's storage capabilities, potentially explaining the cost advantage of the Nuclear & Renewable pathway.	• Predetermined technology mix: Refer to 10.31 • Emission reduction: Noted.

11. PROPOSED SCENARIOS **AND PATHWAYS**

COMMENT	RESPONSE
PATHWAY 1: REFERENCE CASE	
11.1 Conduct a single, long-term scenario for South Africa's energy future, potentially spanning from the present day to 2050 or even 2100. It must be a phased approach focused on reliability, efficiency, and a gradual transition towards cleaner energy sources. **Phase 1: Coal Plant Optimization (Immediate - Ongoing):** • Prioritize maximizing the reliability and efficiency of existing coal-fired power plants. • Implement a long-term retirement plan for these plants, ensuring a smooth transition away from coal. **Phase 2: Natural Gas and Battery Storage Integration (Immediate - Ongoing):** • Strategically introduce natural gas power plants and Battery Energy Storage Systems (BESS) into the grid. • Align this integration with ongoing transmission line network expansion plans. • Phase this implementation over the next 30-40 years. **Phase 3: Nuclear Power Expansion (Immediate - Ongoing):** • Commence large-scale construction of proven nuclear power plants without delay. • Remain open to incorporating smaller, next-generation nuclear units as their technologies mature. This simplified plan offers potential advantages such as: • Improved Reliability: Focusing on existing coal plant optimization can enhance near-term energy security. • Phased Transition: The gradual introduction of cleaner technologies allows for a smoother and more manageable energy shift. • Flexibility: Integrating gas and battery storage provides a degree of flexibility to accommodate future energy needs. • Nuclear Baseload: Large-scale nuclear deployment offers a reliable and low-carbon baseload power source.	• Long-term planning is uncertain in nature and requires that sensitivities are assessed that may potentially impact the power system. • Phase Approach: Noted.
11.2 Proposed combinations: • Utility-Scale (PV + Storage) • Utility-Scale (Wind + Storage) • Utility-Scale (Standalone) • Utility-Scale (Gas +P V + Storage) • Utility-Scale (Gas+ Wind + Storage) • Utility-Scale (green hydrogen + PV + Storage) • Utility-Scale (green hydrogen + Wind + Storage) Perhaps a higher demand scenario could be considered, although the current assumption is perhaps high enough. Higher fuel cost scenarios are valuable to input as we have seen high volatility in gas prices in recent years.	• Scenario development: Noted, reporting has to be optimized to minimize confusion. • Sensitivities: A cone of demand trajectories as well fuel cost will be assessed for the final IRP

COMMENT	RESPONSE
PATHWAY 1: REFERENCE CASE (CONTINUED)	
11.3 Climate change mitigation scenarios/pathways: • Net-zero • Carbon budget	Noted.
11.4 Proposed pathway: Nuclear and Clean Coal, supported by Gas To Power and Pumped Hydro for peaking power.	Noted.
11.5 Consider adding another scenario where the EAF continues on it trajectory and continues to decline by 2-4 percentage points per year, as it has for the last 12 years, despite many previous interventions. Failing to even consider a scenario where EAF continues its current trend is not responsible, especially if coal plant decommissioning is delayed further.	A cone of EAF trajectories will be cosnidered for the final IRP.
11.6 Considering early retirement of coal plants by repurposing them to gas plants, and thereby improving EAF. **Benefits:** • Reduces air pollution risks. • Lowers greenhouse gas emissions to combat climate change. • Creates opportunities for new energy sources.	Noted.
11.7 Scenario options: • A scenario incorporating solar power, wind power, hydropower and stating the additional costs required to upgrade the transmission and distribution system, as well as the cost of baseload backup. • A scenario involving nuclear power and upgrading the transmission infrastructure, with total system cost calculated. • A scenario focusing on traditional fossil fuels, notably a commitment to coal and liquefied natural gas (LNG). IRP2023 should also consider various hybrid scenarios combining elements from the above options.	• Scenario development: balance of the number of scenarios is necessary to avoid confusion. • Costs for transmission and distribution upgrade will be considered only as far as they may impact integration of generation.

12. SCENARIOS & PATHWAYS IN RELATION TO DISTRIBUTION & TRANSMISSION GRID CONSTRAINTS

COMMENT	RESPONSE
PATHWAY 1: REFERENCE CASE	
12.1 The integration of renewable energy sources into the transmission and distribution grid in South Africa presents several risks and challenges: • The existing grid capacity is insufficient to accommodate the rapid expansion of renewable energy sources, particularly in regions with high renewable energy potential like the Northern, Western, and Eastern Cape. The Draft IRP2023 indicates that approximately 14,000 km of new transmission lines are required by 2032, which is a significant challenge given the historical pace of construction (4,000 km in 9 years). • The cost of expanding the grid to accommodate renewables is estimated to be around R390 billion. This substantial investment requirement poses a challenge, especially if the costs are to be distributed across all customers, potentially impacting the affordability of electricity. • The alignment between the IRP and the TDP is critical but appears to be inadequately considered. The TDP is essential for ensuring that transmission connection capacity is available for generation expansion, but the IRP's reliance on the TDP for guidance indicates a reactive rather than proactive approach to grid planning. • The IRP's development process is criticized for focusing too much on short-term solutions over long-term sustainability. Additionally, the document does not adequately address the detailed planning required for grid expansion and upgrades, which is crucial for effectively integrating new power sources, particularly renewables. • The integration of renewables requires significant enhancements to the transmission grid to handle distributed energy resources, manage load balancing, and ensure efficient energy transportation. The Draft IRP2023 is seen as lacking in detailed planning for these technical requirements. • Decentralized generation and microgrids could reduce the need for extensive grid expansion. However, this approach is not adequately considered in the IRP, which may lead to missed opportunities for more localized and efficient energy solutions. • The stability of the grid is a critical concern, especially in the context of integrating intermittent renewable energy sources. The IRP does not fully address the measures needed to ensure grid stability, which is essential for reliable electricity supply. • The IRP overlooks significant challenges related to weak municipal licensees and pervasive losses in municipal infrastructure. Strengthening regulatory oversight and ensuring compliance with licensing conditions are necessary to address these issues. • The theft of cables and destruction of pylons are major issues that could hinder the development and maintenance of transmission grids. Mitigating these risks requires additional measures and considerations in the planning process. • The current planning process for new power plants does not adequately consider grid constraints, leading to potentially higher costs for upgrading the transmission grid to meet generation capacity expansions.	• Grid development costs: The cost of generation integration will be included in the total system costs. • TDP: Network plans and generation expansion plans feed off each other in an iterative manner. • IRP Process: The approach to evaluate Horizons 1 was as a result of acknowledging the supply constraints in the short- to medium-term and developing mechanisms to resolve them while Horizon 2 developed pathways for the long-term. • Integration of renewables: The final IRP will address grid development requirements and operability of the power system. • Localized generation: The IRP develops an energy mix and the decision of how to deploy these is a procurement process. • Municipal infrastructure: the Electricity Regulation Act, 2006 mandates NERSA as the enforcer of regulations and is empowered to ensure that licensees comply with licence conditions. • Infrastructure theft: The Electricity Regulation Amendment Bill, 2023 (B23B-2023) makes provision for the criminalization of damage and theft to electricity infrastructure. Mitigation measures include fines between R1 million to R5 million, jail time ranging from 5 years to 10 years, or both. This is applicable to both the offender and recipient of stolen infrastructure.

COMMENT	RESPONSE
PATHWAY 1: REFERENCE CASE (CONTINUED)	
12.2 To immediately build out the transmission and distribution grid to accommodate renewable energy sources, several strategic approaches are suggested: • Encourage private sector participation in the development of transmission infrastructure. This can include the involvement of private electricity companies in supplying power to municipalities and industries, fostering competition that is advantageous to the economy. • Consider the development of municipal grids and microgrids, which can reduce the reliance on extensive country-wide grid expansion. These smaller-scale grids can be powered by renewable energy sources and serve rural communities effectively. • Utilize proven technologies for harnessing energy from various sources, such as methane from landfills, biogas from wastewater treatment facilities, and energy from bagasse and mines. These can contribute to local generation capacity and reduce the need for grid expansion. • Implement a coordinated generation-transmission planning method. This involves closely aligning the development of new renewable energy projects with the expansion and upgrading of the transmission grid to ensure efficient integration. • Prioritize the expansion of the distribution grid network to enable approved renewable energy projects to come online quickly. This involves channeling funds towards grid expansion rather than deconstructing power stations. • Focus on regions with the best renewable energy resources, such as the Western and Eastern Cape. These areas require dedicated grid development to harness their potential effectively. • Develop renewable energy projects in areas that do not require extensive transmission infrastructure, thereby reducing the overall grid expansion requirements. • Ensure that policies such as the IRP, TDP, and market reform policies are aligned to generate investor confidence and facilitate necessary investments in generation, transmission, and distribution. • Develop a robust regulatory framework that allows for the efficient integration of renewables into the grid, including the establishment of an independent procurement office for transmission infrastructure. • Explore various funding options, including public-private partnerships, to finance the required grid infrastructure projects. • Utilize off-balance sheet financing models, such as Independent Transmission Projects (ITPs), which have been successful in other emerging markets. Engage with local communities to address land acquisition, compensation, and other stakeholder concerns that can delay project implementation.	Noted.

13. CLARITY SEEKING QUESTIONS

COMMENT	RESPONSE
MODEL RELATED QUESTIONS	
13.1 Please advise whether other uncertainties like feedstock availability and price fluctuations are included in the stochastic model. Kindly further clarify as to what degree is the level of certainty in a forecast model valued and factored into security of supply of the various scenarios.	A stochastic production cost model is run iteratively with a capacity optimization model. Price fluctuations, e.g. gas are only considered in the optimization.
13.2 The Plexos modelling tool can "produce deterministic economic dispatch or be setup to incorporate stochasticity of parameters that consider variability." Can DMRE kindly include a list of all the assumptions and values for the parameters? In addition, an equation showing how these parameters are prioritized and balanced would further clarify the methodology used.	Key parameters that are subjected to stochasticity are demand forecast, plant outages, production profiles of intermittent generation resources.
13.3 Can DMRE kindly disclose and provide the following: • Financial input assumption used in the analysis as many are missing (e.g. WACC, discount rate, debt structure). • Supply outputs such as historical data on annual energy and capacity amounts for generation along with the capacity factor by generator type. • Detail on how much of each resource is modelled. Capacity expansion module: • The assumptions and equations. This can help inform which restrictions are applied and prioritized in the module (e.g. LCOE, construction times) • The characteristics of the power plants modelled (procurement plans, calendar, costs, efficiencies, capacities, LCOE, lifetime, etc).	• Economic parameters will be provided in the final report. Debt structure details are of procurement in nature and will not be provided. • Statistics South Africa reports on electricity consumed in South Africa on a quarterly basis. Refer to their Report P4141. The Eskom portal reports on generation, including the REIPPPP contracts. • Assumptions: The EPRI report outlines cost and performance characteristics of each technology.
13.4 Was an energy production cost model or capacity expansion model, or both, used for Horizon 2?	Refer to 13.1
COST RELATED QUESTIONS	
13.5 What value did the draft IRP use to estimate the cost of unserved energy (aka loss of load)? And what are the source assumptions for this estimate?	Cost of Unserved Energy: This is calculated by NERSA and the methodology is available on the NERSA website.
13.6 Can DMRE kindly include more detail in the demand forecast analysis on the marginal operation cost assumptions and the cost of non-supplied energy?	The question is unclear as the cost of unserved energy is not included in the demand forecast.
13.7 The approach to resolving the challenges with Minimum Emission Standard (MES) for coal fired power stations is unclear. What measures are required to bring the coal plants into compliance with the minimum emissions standards and has the cost of this been factored into the scenario analysis? Can these cost estimates also be included in the IRP 2023 update?	Refer to 9.3

COMMENT	RESPONSE
TECHNOLOGY RELATED QUESTIONS	
13.8 Was the Tubatse pumped storage program considered as an option for the analysis for new build? Feedback as to whether this station was included, and the reasons if not included, needs to be provided.	Tubatse I one of the sites considered for pumped storage in the country as feasibility analysis has been done.
13.9 Could the DMRE clarify if it considered CCUS in its modelling outcomes. If not, why not?	CCS is considered.
TECHNOLOGY RELATED QUESTIONS	
13.10 What are the arguments for not using diesel-fired peaking generation compared to lower capacity factor gas fired generation? These arguments should be narrated in the IRP document. If there are no compelling reasons, then this must be explored, and results included in the IRP.	Diesel is more expensive to operate than gas.
13.11 What capacity factor assumptions are used for Solar PV? What capacity factor assumptions are used for wind?	The capacity factors for wind and solar are not an input to the model. Generation profiles are inputs and distributed across many locations in the country.
SCENARIOS & OUTPUT RELATED QUESTIONS	
13.12 In the "delayed shutdown" scenario (delaying the shutdown of 5 key power stations), which five stations (and their units) are extended and by how long?	The scenario is exploratory in nature as there are no decisions made by Eskom to extend the life of coal stations.
13.13 The Horizon 1 five scenarios range from very high levels of unserved energy (up to 50 000 MWh by 2030, Scenario 1) to immediate restoration of supply security (Scenario 5). All the 6 scenarios are difficult to comprehend, and they do not appear to consider the previous sections of the IRP. Does Horizon 1 work towards an end of load shedding? Or is this totally dependent on Eskom and its performance?	The scenario which considers improvement in Eskom EAF demonstrated the great impact in eliminating unserved energy while others did not completely achieve this. This led to a proposed intervention to support the Eskom Generation Recovery Plan.
13.13 Using "MW" for BESS is confusing – does this mean 10 000 MW of inverter capacity or 10 000 MWh of battery capacity?	BESS in the draft IRP is with 4 hour storage capacity.
13.14 It is unclear what 'Distributed Generation Capacity for own use' means and where the allocation of 900MW has been derived from. Kindly clarify.	Refer to 5.11
13.15 Can clarity be provided on how likely battery storage equivalent to 4283 MW is by 2030 given the enormous high costs?	Some of the capacity is already committed (commercial and at procurement stage) while the remainder is a result of optimization based on system requirements.
13.16 Has the private sector been allocated any provision?	The business initiatives considered are a direct submission from private entities and were simply subjected to a criteria based on the status of project development stages to determine whether they should be committed or studied as a sensitivity as shown in Figure 9.
13.17 The rationale behind the fixed annual addition of 900 MW for "Distributed Generation" is also unclear and requires further explanation.	Refer to 5.11

COMMENT	RESPONSE
POLICY RELATED QUESTIONS	
13.18 Is there an intention to have a policy adjusted IRP pursuant to comments?	
13.19 Is Horizon 1 a policy-based IRP and the Horizon 2 a least-cost model?	Horizon 1 is an analysis of the adequacy of the power system based on imminent developments in the medium-term and proposes additional interventions to support and ensure security of supply. Horizon 2 is a capacity expansion that seeks to evaluate the impact of various pathways in the long-term, including the least-cost plan.
COMMENT	**RESPONSE**
POLICY RELATED QUESTIONS (CONTINUED)	
13.20 Could a waiver of the MES be granted for a certain period to prevent the shutting down of coal plants? However, a blanket exemption cannot be granted to coal plants – there should be a requirement that all efforts have been expended in getting new RE generation capacity online first then exemptions granted.	Refer to 9.3
13.21 Can new and existing RE plants be used to 'off-set' the emissions from coal plants?	The carbon emissions are reported as an outcome of the model.
13.22 The DMRE is requested to indicate the role of the IRP in a liberalized market, suggesting that the IRP may need to shift from a blueprint energy generation plan to one that provides a benchmark guiding regulation of the private power market.	The IRP will always be used as an instrument for policy guidance, even in a liberalized market environment.
GENERAL QUESTIONS	
13.23 What is an acceptable ROCOF, and how will ROCOF be measured? Say for coal?	ROCOF studies are conducted as part of the operability analysis of a plan.