Assessment of the Need for Proposed Richards Bay Combined Cycle Power Plant

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Executive summary

Assessment of a power system study by Meridian Economics confirms the least-cost path for South Africa involves heavy renewable build out and limited new gas capacity for the next decade.

A recent assessment by Meridian Economics and CSIR of the South African electric power system shows clearly that the least-cost scenario for the grid involves rapidly building large amounts of wind and solar generation in the near term. Gas plants are added to the grid to improve flexibility, but until the mid 2030's the only need is for "peaking" capacity that is used very infrequently (~2% of its availability). Until then, diesel can continue to be used by existing generators to meet reliability needs during limited hours of peak electricity demand. This least-cost pathway avoids building expensive gas infrastructure unless and until the need arises and is economically justified, avoiding locking-in to long-term fuel cost commitments prematurely.

The Meridian study's least-cost pathway also shows battery and pumped hydro storage being built to provide flexibility during hours when there is low renewable generation. Building new coal, nuclear, or hydro is not in line with a least-cost optimization due to high costs. Coal plants are operated at low levels and gradually closed. RMI reviewed the Meridian study and validated its approach, as discussed in this document.

The proposed Richards Bay plant is neither necessary, nor in line with a least-cost pathway.

Applying the Meridian study's analysis to the proposed 3.0 GW combined cycle gas power plant at Richards Bay shows that the plant is neither timely nor economically optimal in the next decade. The study's findings suggest that the plant risks becoming a burden to South African electricity customers, and inconsistent with a least-cost investment plan for the nation. Per the Meridian study, South Africa would be better served by focusing on investment in infrastructure to enable a 21st century electricity system, which Meridian's findings and global trends show to be largely renewable.

We agree with Meridian's conclusion that gas is not needed in South Africa for "mid-merit" generation until the mid 2030s for the following reasons:

1. Meridian's analysis finds no need for new combined cycle gas capacity in the next decade, and no need for 3 GW of such capacity until 2041;
2. Meridian's analysis finds that electricity generation, in terms of kilowatt-hours, should be almost entirely be met by non-gas resources and that meeting peaking generation needs with combined cycle gas capacity in the near-term is not least cost;
3. We caution that these results imply that if the plant were to be built it may create an economic burden for ratepayers.

We recommend postponing any potential investment in Richards Bay, consistent with the findings of Meridian's study.

If the Richards Bay plant is commissioned within the next five years, it would come online as much as a decade prior to the economically optimal addition of any type of new non-peaking gas capacity. This would mean that for a third or more of its operational life, it would represent an uneconomic and unnecessary addition to South Africa's electricity system.

The Meridian study states that the best use of investment is to immediately start to build renewables in areas with existing transmission capacity whilst in parallel building out transmission infrastructure to accommodate additional renewables in future years. This would be consistent with the transition being made by many other historically fossil-heavy grids, and the International Energy Agency (IEA) reports that from 2019–2020 investment in renewables outpaced fossil plants by 250% globally. Based on the study's results, we agree with this recommendation and emphasize that investing in the proposed gas-fired power plant at Richards Bay is more expensive for South African electricity customers and not required for reliable electricity generation.

Introduction

Meridian Economics, a South African advisory group and think tank, in collaboration with the Council for Scientific and Industrial Research (CSIR), published a study and technical report in July 2020, *Systems analysis to support increasingly ambitious CO_2 emissions scenarios in the South African electricity system*. Meridian states that the study was independently conceived and produced by Meridian and CSIR, and was funded by philanthropic sources. The Meridian study evaluates the optimal development of South Africa's electricity system, showing different pathways that both minimize customer costs and meet increasingly ambitious CO_2 emissions reduction scenarios. The Meridian study provides crucial insight into the costs and benefits of various investment strategies that are directly relevant to the proposed gas-fired power plant at Richards Bay.[i]

In this declaration, we review the scope and credibility of the Meridian study's methodology in terms of current best practice, and place its findings in the context of the proposed Richards Bay plant.

This declaration addresses investment in electricity generation plants within the wider context of the grid

The electric power system in the Republic of South Africa (RSA) is a network of resources that provides electricity to consumers and businesses. At a high level, the grid consists of:

1. <u>Generating stations</u> that produce electric power. These can be fossil fuel powered (coal, gas, oil and diesel) or they can be renewable resources such as solar, wind or hydro.
2. <u>Energy storage</u> which stores excess electricity generated and provides power when there is a lack of electricity being generated.
3. <u>Electrical substations</u> that convert electricity into high voltage for long distance transmission or low voltage for distribution to customers.
4. <u>High voltage transmission lines</u> that carry electric power from generating stations over long distances.
5. <u>Lower-voltage distribution lines</u> that deliver electric power at a local level and to individual customers.

Generation capacity is generally defined in terms of power, with units of watts (W), kilowatts (kW or 10^3 W), megawatts (MW or 10^6 W), and gigawatts (GW or 10^9 W). Electricity generated is defined in corresponding units of energy, watt-hours (Wh) through gigawatt-hours (GWh), which are equivalent to producing that amount of power for one hour.

Utilities globally are shifting their approach to grid planning

Descriptors for generation plants are evolving

Generation plants have historically been characterized as “baseload”, “peaking”, and “mid-merit”. We define these terms below, but then explain how they are antiquated, do not address actual electricity system values or services in a modern grid, and do not correspond with economic or reliability considerations.

- **“Baseload” power plants:** Historically, coal and nuclear were seen as essential to supply electricity since there were few alternatives. These plants tend to run at maximum levels, generally only shut down for maintenance and do not change their output quickly. The term “baseload” refers to the minimum level of demand on an electrical grid, and this demand was generally met using coal or nuclear energy, hence these power plants were referred to as “baseload plants”.
- **“Peaking” power plants**: Peaking generators are those that are needed and/or used only during periods of peak demand, when there is much higher demand than usual. For example, peaking plants often run on hot summer afternoons when air conditioning demand is greatest. This type of seasonal peak load has historically been met with gas and hydro plants, which were either more expensive or have less energy availability than coal and nuclear plants. More recently, energy storage technologies including batteries have effectively competed with gas plants to provide peaking power in many global power markets.
- **“Mid-merit” power plants:** To meet fluctuating levels of electricity demand throughout the day and over the course of the year, between the levels at which “baseload” and “peaking” plants tend to operate, utilities have historically used “mid-merit” plants (e.g., gas, diesel or hydro plants) which can easily adjust their output to match changing demand.

Though useful in characterizing the grid operations and planning paradigms for 20th Century electricity systems, these terms are rapidly losing relevance in modern grids where emerging technology, especially variable renewable energy resources (e.g., wind and solar) as well as energy storage, are proving their ability to meet reliability needs at least cost without falling neatly into these historical categories of resources.

Geographically dispersed renewable generation can provide consistent energy production to meet base load requirements and can also be curtailed to meet fluctuating demand levels. Energy storage can also be used to accommodate fluctuating demand and to meet peak loads.

Renewables can increasingly provide services that have historically been met by fossil plants

Many leading global utilities have shifted in their approach to resource planning, and in doing so have found that emerging technologies, and specifically wind, solar, and storage, can provide the same sort of grid services that were provided by “baseload,” “peaking,” and “mid-merit” power plants in the 20th Century:

1. The world’s largest auction for renewables and storage took place in India in 2020 for 1.2 GW of capacity. The requirement was for energy during morning and evening hours which is traditionally met by “mid-merit” generators. Successful bids comprised of renewables, battery storage, and pumped hydro storage. One of the bids by ReNew Power set a world record for the lowest priced renewables plus battery storage capacity, with this and other recent renewable tenders being cheaper than energy from coal in India.[ii]

2. A 350 MW pumped hydro storage plant in Morocco is being constructed and planned to be completed in 2022. It will be coupled with existing wind generation to meet demand during peak hours, otherwise provided by “peaker” plants.[iii]
3. In the Atacama Desert in Chile, the planned Valhalla project planned will use a 600 MW solar PV farm coupled with a 300 MW pumped hydro storage plant to provide continuous power to meet load, avoiding building a “baseload” plant.[iv]
4. In Thailand, the 500 MW Lam Ta Khong pumped hydro storage facility built in 2004 replaced older peaker plants which ran on oil, to provide energy during periods of high demand.[v]
5. In Colorado, USA, the largest utility in the state (Xcel Energy) is retiring two of its largest coal-fired power plants[vi], without direct replacement with new gas-fired power plants. Instead, the utility is replacing these “baseload” plants with a combination of wind, solar, and storage projects, marrying the low-cost energy from wind and solar with flexibility from batteries and the remaining coal and gas fleet to provide both “baseload” and “mid-merit” electricity.
6. In Indiana, USA, one of the state’s largest utilities (NIPSCO), is similarly prioritizing[vii] a transition plan for all of its coal plants, seeking to replace them with very low-cost wind and solar energy, and avoiding any investment in new gas-fired generation. This plan is anticipated to save the utility’s customers USD $4 billion over the lifetime of the renewable projects, relative to continued reliance on coal or investment in new gas-fired power plants.
7. In Oklahoma, USA, a large utility has signed a contract[viii] for a new power plant that includes wind, solar, and storage technologies at a single site, and will provide power to the utility’s customers at a price considerably lower than alternative investment in “peaking” or “mid-merit” gas-fired generation, while maintaining reliability.
8. In North Dakota, USA, a major utility will cease operations of an 1,100 MW coal-fired power plant, replacing its “baseload” power output with electricity from new wind and solar projects[ix], relying on other existing gas plants as well as a new long-duration energy storage project to balance wind and solar variability.
9. In South Australia, Neoen and Tesla have shown with the Hornsdale Power Reserve[x] that large-scale batteries can economically play many of the same roles as “mid-merit” and “peaking” generators, helping to provide critical grid stability services even in times of contingency on the renewables-dominated regional grid.

In general, utilities in leading markets are turning toward modern resource planning approaches that do not rely on legacy generator characterizations to determine investment priorities. For example, even in the United States where natural gas is available at near-record low global prices in 2021, both utilities in traditionally regulated territories[xi] as well as private investors in restructured markets[xii] are using modern planning studies to determine that emerging technologies like wind, solar, and storage can be lower-cost solutions than traditional “baseload” and “mid-merit” power plants – and as a result, the level of planned wind, solar, and storage investment is over ~10x the amount of new gas generation across the country. Globally, the International Energy Agency (IEA) reports that from 2019–2020 investment in renewables outpaced fossil plants by 250%.[xiii]

The study by Meridian Economics credibly assesses grid investment pathways for RSA

The Meridian study is an example of an investment planning or "capacity expansion" model, which seeks to optimize investments over a multi-decade period in generation, storage, and network infrastructure in order to realize least-cost electricity service to customers while maintaining system reliability. The primary focus of the Meridian study is on item (1) of the list on page 2 above – i.e., optimizing investments in different generation resources – but the study also represents the requirements for storage and transmission investments alongside generation investments needed to meet customers' loads.

The study treats electricity generators and grid requirements appropriately

The Meridian study assesses all kinds of power plants and their role in South Africa's least-cost electricity investment plan as part of its analysis, including plants that have historically been characterized as "baseload", "peaking", and "mid-merit." The Meridian study, like most modern electricity planning studies, does not strictly enforce these antiquated categories to define its investment priorities, but rather addresses the problem correctly by modeling solutions that meet specific reliability metrics.

The least-cost pathway found by the study is a mostly renewable grid

Currently, coal is used to produce around 80% of electricity in RSA. 6% is from nuclear, 4% is imported, approximately 1% is from diesel, with the remaining 7% coming from wind, solar and hydro.[1] The study finds that the least-cost optimization chooses a grid mostly comprised of renewables, even though carbon emissions are not constrained in this scenario.

This least-cost option from the Meridian study involves building large amounts of wind and solar, which are over 60% of new capacity built by 2050. There is also an increase in battery and pumped hydro storage to provide flexibility since output from wind and solar is variable, making up 10% of new capacity built. The optimization does not choose new coal, nuclear or hydro due to high costs and there is gradual closure of coal and nuclear plants. Finally, gas plants are added to the grid for flexibility, about 17% of new build capacity, but this happens in the mid 2030s (as discussed in more detail below).

The Meridian study finds that gas is optimally used to provide two services to the grid:

1. Peaking capacity needed for periods of high electricity demand, using open-cycle gas turbine plants which can ramp up and down quickly to follow demand changes.
2. More frequently, but at lower output levels, over a few hours when there is insufficient renewable energy generated. This "mid-merit" application uses combined-cycle gas turbine plants which cannot efficiently ramp as quickly.

Notably, the Meridian study does not find a significant role for gas generation in supplying a significant amount of South Africa's electricity needs on a daily basis. Given the higher operating cost of gas generation compared to renewables, gas only accounts for 4% of total energy produced by 2050. The relevance of these findings to the Richards Bay plant are discussed in more detail later in this document.

[1] An additional 2% is the result of pump load, which is associated with pumped hydro storage losses

The study correctly represents South Africa's planning context and provides useful guidance for near-term investments

The modeling conducted by Meridian Economics shows a least-cost pathway with 90% renewable capacity by 2050. This output is rational and reasonable given new technology costs, technology characteristics, the age of South Africa's coal fleet, and the time scale to make major changes to the grid mix. This pathway aligns with trends seen globally in technology prices and infrastructure investment—for example, 77 countries committed to net zero emissions by 2050 at the 2019 Climate Action Summit[xiv] and a large proportion of these currently have fossil fuel-heavy grids. These countries identified that their optimal electricity system investment pathway would necessarily lead them toward renewables and low-carbon development. Investments in fossil generation plants for electricity have declined globally by approximately 30% since 2010 according to the International Energy Agency[xv], whilst spending on renewables, transmission and distribution has steadily increased.

The model optimizes the generation mix through 2050, and the least-cost option is a grid mainly comprised of renewable resources, with some storage and a very small proportion of gas. In the least cost option, peak load requirements can be met by liquid fuels for the next 10 years. This is in the form of existing diesel generators, which provided 1 TWh[xvi] of electricity (0.8% of total) in 2019 and are expected to provide 1.4 TWh[xvii] in 2030 (0.4% of total). Gas plants are eventually chosen by the model to meet peak demand requirements; however, they are not needed within the next decade since there is adequate existing liquid fuels capacity in the meantime. Waiting to make this decision allows flexibility, avoiding locking-in to long term fuel cost commitments prematurely.

Given the analysis, cost trends, current infrastructure, and planning context, the conclusions from the study suggest directing energy infrastructure investment into rapidly building renewables and transmission, and to delay building significant gas infrastructure only if and when the needs arise, and the costs for potential gas alternatives are better understood. According to a least-cost pathway, with the current low level of renewables and high coal capacity on the grid, there is no need for combined cycle gas capacity, which is used to meet load during hours of insufficient renewable generation. There is also no need for open cycle gas capacity which is used to meet peak demand since there is adequate liquid fuel generation.

The study has a more aggressive renewable strategy than Eskom's 2019 integrated resource plan (IRP), which uses the same modeling software. However, the 2019 IRP "forces in" coal, hydro, and gas using a 'policy adjustment' and does not have up-to-date renewable cost assumptions.

The study adheres to international best practices

The Meridian study uses PLEXOS grid modeling software to optimize grid mixes based on different constraints. This is a standard and well-known tool, which was also used by the RSA government to develop the IRP. The model optimizes for generation plants which are least cost to reliably meet demand, choosing grid expansion power plants under different scenario constraints. Demand is met on a seasonal, daily and hourly basis. This ensures that the final grid mix output will be reliable in different seasons, but also that the generation options chosen provide electricity even during hours of peak load.

The expansion plan was then run in more detail to assess how each power plant behaves. This unit level modeling decides the order of dispatch for each plant and specifies when and for how long each plant is required. This detailed modeling ensures that the grid expansion plan meets specific reliability requirements in the minutes to seconds timeframe. It tests that criteria for reliable grid supply are met, including having enough flexible supply. This level of detail also ensures that generator requirements and capabilities are adhered to.

System services for the grid are omitted from the analysis, which include keeping voltage stable and restarting the grid after a system-wide outage. For the level of detail of the analysis and conclusions made, this is reasonable. Including these services would not impact the outcome, since they need to be addressed regardless of which generation plants are built.

Given this level of detail and the long timeframe of the analysis, the conclusions made for the expansion plans are appropriate. Based on comprehensive analysis sizing specific power plants, recommendations were made about the general pathway for the grid to transition from its current coal-heavy state to incorporate more renewables, and the range of years when it makes sense to build gas.

The study uses valid assumptions for capital and operational costs for the different energy resources included in the analysis. These include Eskom's 2019 IRP, Electric Power Research Institute (EPRI) and National Renewable Energy Laboratory (NREL).[2] The assumptions used for reliability requirements including operating reserves which should be maintained to avoid supply shortcomings correspond to Eskom Ancillary Services Technical Requirements.[3] We also reviewed the following benchmarks to ensure estimates in the Meridian study were reasonable:

1. Cost estimates have been benchmarked with the 2020 Bloomberg New Energy Finance Annual Energy Outlook.[xviii]
2. Solar and wind resource availability taken from CSIR's Wind and Solar PV Resource Aggregation Study for South Africa[xix] have been benchmarked with the 2020 Bloomberg New Energy Finance Annual Energy Outlook and with global reanalysis models and satellite observations.[4]

The study has some limitations, but these do not impact the overall conclusions

The Meridian study's limitations tend to be conservatisms as they pertain to the implied pace of cost-effective decarbonization and the need for new fossil infrastructure. Refining these assumptions and exclusions would likely result in reduced use of fossil-fueled generation in capacity expansion results.

Demand side management measures which reduce the demand for electricity are not included in the study. These include energy efficiency where less energy is used to perform the same task (for example LED lightbulbs) and demand response where utilities pay customers who choose to reduce their electricity usage during periods of peak demand on the grid. These measures would reduce the demand forecasted and improve the economic argument against large fossil infrastructure.

The cost to decommission generation plants at the end of their lifetime is not included in the study. Decommissioning costs for fossil plants are much higher than solar and wind, so including this cost would also improve the economic argument against large new fossil infrastructure.

The electricity demand growth used in the study uses the demand forecast from the Eskom Medium Term System Adequacy Outlook (MTSAO) until 2024 and then the medium growth scenario from the IRP 2019 to project demand up to 2050. This is because the MTSAO has a slower demand forecast which is more realistic for the immediate future given current trends.

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[2] See slide 18 of the Meridian study
[3] See page 31 of the CSIR 2020 Technical report
[4] Modern-Era Retrospective analysis for Research and Applications (MERRA-2) and Surface Solar Radiation Data Set – Heliosat (SARAH) from renewables.ninja website

However, this electricity demand forecast has high growth compared to other countries with similar economies and development paths. Many Organization for Economic Cooperation and Development (OECD) member countries, such as the United States, United Kingdom, and Japan, have effectively decoupled electricity use from gross domestic product (GDP) growth. In the U.S., for example, growth in electricity consumption flattened beginning in the mid-1990s, while GDP growth continued at historical rates. At the same time, electricity planners have tended to overestimate load growth. RMI analysis in the U.S. has shown that for at least the last decade, planners have, on average, over-forecast electricity demand by one percentage point for each year of their forecast. That over-forecast means that results are more than 10 percent too high looking 10 years out, translating to immense spending on unnecessary power plants.[xx] Considering these factors, it is likely that—if anything—Meridian's assumptions overestimate future electricity demand in South Africa, and the associated generation capacity needed.[xxi] [xxii]

Externalities associated with electricity generation are not included in the Meridian study. Environmental pollution, health impacts, waste management and site rehabilitation costs are much higher for fossil generation than renewables. Valuing these impacts and including them in the analysis would improve the economic argument against large fossil infrastructure.

Mid-life generator major maintenance and overhauls for all technologies are omitted, though these are generally higher for coal and gas plants over a fixed period of time than for solar and wind.[xxiii] Including these costs would favor the case for renewables over new fossil plants.

The study assumes that coal plants can ramp down to 35% capacity, which helps accommodate new renewable capacity~~.~~ However, the costs to retrofit the coal plants so they are able to run at this low level relative to current operation have been omitted. The existing coal fleet has aged and has a lower output than planned, with refurbishment costs omitted from the study. The existing Eskom generation plants, which are mostly coal, are expected to be producing energy at 86% of their total capacity but are actually averaging below 70% according to the IRP 2019[xxiv]. The combination of refurbishing coal plants to extend their lifetime and retrofitting to run at a low capacity may be prohibitively high. If it is uneconomic to keep existing coal plants online and ramp down to 35% capacity, further analysis may find that it is lower cost to retire coal and replace it with alternative capacity. However, early retirement of coal is unlikely given the IRP 2019 comments on coal which include: "Eskom's existing generation plant will still dominate the South African electricity installed capacity for the foreseeable future" and "More funding should be targeted at long-term research into clean coal technologies … as these will be essential in ensuring that South Africa continues to exploit its vast, indigenous minerals responsibly and sustainably".

Finally, Meridian's study does not account for the costs of developing and building new gas transport infrastructure. Current gas production and transportation capacity is limited in RSA, and reflecting these costs may reduce the viability of new gas generation that require it.

Building the Richards Bay plant this decade is unneeded and costlier than other options

The Meridian study clearly shows that the proposed 3.0 GW combined cycle gas power plant at Richards Bay is neither timely nor economically optimal. The study's findings suggest that the plant risks becoming a burden to South African electricity customers, and inconsistent with a least-cost investment plan for the nation. Per the Meridian study, South Africa would be better served by focusing on investment in infrastructure to enable a 21st century electricity system (as noted above, Meridian's findings show this to be largely renewable).

This section explains the analysis supporting these implications by placing the Richards Bay plant in context of the scenarios analyzed by the Meridian study. The Meridian study offers two variations of conservative power system scenarios: a business as usual (BAU) reference scenario based on Eskom's 2019 IRP and the policy goals it reflects, and a least-cost scenario which optimizes capacity expansion without policy constraints or environmental goals. We focus on these conservative scenarios as they are reflective of RSA's historical policy and planning environment—however, Meridian's climate-oriented scenarios (which limit CO_2 emissions) also find that a Richards Bay plant is not required until the late 2030s at the earliest.

The proposed Richards Bay gas plant is inconsistent with a least-cost grid investment plan for South Africa

The Meridian study clearly shows that the proposed Richards Bay gas plant is not consistent with any cost-optimized capacity expansion plan for RSA. Most notably, this is true both for the BAU reference scenario and for the least-cost scenario that Meridian models. Fundamentally: (1) the analysis finds no need for new combined cycle gas capacity in the next decade; (2) that electricity generation, in terms of kilowatt-hours, should be almost entirely be met by non-gas resources; and (3) if the plant were to be built it may create an economic burden for ratepayers.

No need for new combined cycle gas capacity until at least 2030. In both Meridian's BAU and least-cost scenarios, two types of gas power generation capacity are included as options: open cycle gas turbines (OCGT) are typically utilized as "peaking" capacity, and combined cycle gas turbines (CCGT) are normally used for mid-merit "energy" applications. In both the BAU and least-cost scenarios, the study finds that the first (and dominant) application of gas capacity is OCGTs for peaking. In contrast, the Richards Bay CCGT plant is proposed to either be a "baseload and mid-merit" system, as specified by the final scoping report, or "must operate as mid-merit" as stated in the final environmental impact assessment report.[xxv] [xxvi] The potential implications of alternatively using this CCGT for primarily peaking capacity are discussed below.

Table 1 shows the study's findings related to OCGT and CCGT capacity expansion in the BAU and least-cost scenarios. The BAU scenario finds a need for slightly more than 3 GW of new OCGT capacity beginning in 2027, but new CCGT capacity is not needed until 2036. For reference, 3 GW of new generation is equivalent to 5% of RSA's currently installed capacity, per Eskom's 2019 IRP. The least-cost scenario finds similar timelines, with new OCGTs needed for peaking capacity in the mid-2020s but new CCGT capacity is not needed until the 2030s.

Notably, existing OCGT and peaking plants in RSA currently utilize liquid fuels (mostly diesel), rather than gas. According to Meridian, the limited new OCGT capacity shown in the next decade may similarly be most cost-effectively run on liquid fuels, rather than requiring new large-scale gas delivery infrastructure.

Table 1: Timeline for gas capacity expansion in Meridian's BAU and least-cost scenarios.

Capacity Type	Year Expansion is First Needed	Amount of Capacity First Needed	Year 3 GW Cumulative New Capacity Needed
BAU Reference Scenario			
OCGT (Peaking)	2024	1.0 GW	2027
CCGT (Energy)	2036	0.2 GW	2041
Total Combined	*2024*	*1.0 GW*	*2027*
Least-Cost Scenario			
OCGT (Peaking)	2023	1.0 GW	2030[5]
CCGT (Energy)	2030	0.3 GW	2041[6]
Total Combined	*2023*	*1.0 GW*	*2030*

If the Richards Bay plant is commissioned within the next five years, it would come online as much as a decade prior to the planned need for any type of new CCGT capacity. This would mean that for a third or more of its operational life, it would represent an uneconomic addition to RSA's electricity system.

Overall, what these results show is that the near-term addition of a single, 3.0 GW CCGT gas plant is inconsistent with optimal power system expansion. CCGT capacity in particular is not recommended until the 2030s. From RMI's experience with utility capacity expansion planning, this is a relatively long time horizon, and it is reasonable that in ten years' time technological developments and system changes will result in a different answer. In the U.S., for example, many utility resource plans in the early 2010s called for significant gas investment—those same utilities' plans have since evolved to call for mostly solar and wind capacity as a result of falling costs and improved integration strategies, leading to the cancelation of numerous gas plants.[xxvii]

Energy needs met by non-gas resources. Meridian's results do not show a significant role for gas resources in meeting RSA's energy needs. In the least-cost scenario, gas and peaking resources (new and existing) are expected to contribute just 1.1% of total electricity generation in 2025. By 2035, this grows to just 2.4%.

Table 2 illustrates the expected contribution of new gas-fired capacity by comparing the capacity utilization of OCGT and CCGT plants over time in Meridian's least-cost scenario. Capacity utilization is a measure of a power plant's actual energy generation compared to its theoretical maximum if the plant ran at constant, full output (i.e., its rated capacity multiplied by the number of hours in a year). Meridian finds that OCGTs are only needed to generate less than 3% of their potential output over the course of a year (the handful of hours where demand spikes or there are other capacity shortages). CCGTs, when they come online, are needed for roughly

[5] New OCGT capacity in this scenario nears 3 GW in 2025, with a total need of 2.8 GW
[6] New CCGT capacity in this scenario nears 3 GW in 2038, with a total need of 2.7 GW

20% of their available output over the course of the year. For international context, these are relatively low capacity utilization rates—in the U.S., CCGTs averaged a 56% capacity utilization over 2018–2020, while OCGTs averaged 11% over the same period.[xxviii]

Table 2: Capacity utilization of new gas-fired generation capacity over time in Meridian's least-cost scenario.

	Capacity Utilization		
Capacity Type	**2025**	**2030**	**2035**
Least-Cost Scenario			
New OCGT (Peaking)	1.9%	2.8%	2.5%
New CCGT (Energy)	N/A	20.5%	22.1%
Total Combined	*1.9%*	*4.0%*	*5.8%*

We believe that this low capacity utilization may be particularly important to consider in light of the limited need for new gas capacity explained above. While CCGTs are typically considered to be low-cost sources of power, this assumption is predicated on relatively high levels of capacity utilization. For instance, the international financial advisory and asset management firm Lazard's benchmark Levelized Cost of Energy analysis assumes new-build CCGTs would have a capacity utilization rate of 50–70% for its comparisons.[xxix] If the need for gas-fired generation in RSA is further limited, this would compromise the economic efficiency of the Richards Bay plant.

In our opinion, accepting that a CCGT with greater annual energy production will not be needed until the 2030s, hypothetical re-imaginations of the Richards Bay plant may similarly not best serve RSA's needs. For example, if the plant were to be redesigned as an OCGT or even just operated as a peaking plant (i.e., at low capacity utilization) in the 2020s, implementing nearly the full amount of new gas capacity in a single plant presents several challenges:

- Risk of change in design assumptions, as small shifts in expected load or the costs of other resource options could easily reduce or delay the need for new gas capacity; this would result in under-utilization of the plant and/or unnecessary additional cost to ratepayers.
- Risk of mis-located capacity, as system balancing and operational needs may not be well met by a single large plant at Richards Bay compared with multiple plants distributed across the country due to transmission constraints and losses (e.g., a balancing issue in the Western Cape might require local flexibility resources rather than peaking capacity across the country).
- Resilience risk, as in the event of a local transmission outage or natural disaster locating the majority of this capacity in one location means all of the capacity could be lost from the grid at once, creating greater operational challenges.

Alternatively, Meridian's study shows that existing peaking plants, alongside investment in up to 3 GW of OCGT capacity over the next decade, can meet RSA's peak demand requirements. Under Meridian's least-cost scenario, these plants can be run on diesel as has been done historically in existing power plants. This would avoid investment in new gas infrastructure until if or when the need arises and the economics are justified.

Potential economic burden for ratepayers. We caution that operating Richards Bay at a low capacity utilization level would mean that the plant sells less electricity than expected, harming customers. Failing to meet the plant's expected capacity utilization, listed as both 20-70% and 48% in the project's final environmental impact assessment, would result in a higher levelized cost of energy from the plant as the plant's costs are recovered over a smaller number of kilowatt-hours. As noted above, running the plant at the bottom half of the proposed range would be unusually low for a CCGT, likely resulting in relatively high per-kilowatt-hour costs.

Given the optimized resource use found in Meridian's study, we can speculate that it is conceivable the Richards Bay plant would either operate at a lower than expected capacity utilization level, or cause other plants to similarly be used less than expected. As noted above, Meridian's least-cost scenario found new and existing gas capacity would optimally provide 1.1% of RSA's electricity generation in 2025. If operated at 48% capacity utilization, Richards Bay alone would provide 4.6% of total generation in 2025. This generation would necessarily displace other sources of power. The fact that the Meridian study's least-cost plan did not prioritize building a more-expensive combined cycle plant like Richards Bay in this decade, and instead prioritized the more cost-effective option of building less-costly OCGT peaking plants to meet near-term capacity needs, supports the argument that early investment in combined cycle capacity is not economic.

There is also a material risk that the plant becomes more expensive to continue operating than new clean energy resources are to build, well before its anticipated end-of-life. The global benchmark costs of new solar, wind, and battery costs have fallen faster than expected for over a decade, and analysis[xxx] in other countries has shown that continued advancement in these technologies – even at a much slower rate of change than experienced since 2010 – will allow combinations of new wind, solar, and storage projects to undercut the operating costs of existing gas-fired generation by the mid-2030s, leading to early retirement for gas capacity and significant financial losses.

With Eskom as owner of the plant, if the plant is approved by regulators it would mean that the plant's costs are borne by ratepayers, along with any potential cost increases as noted above. In light of Eskom's financial challenges, it is possible that the RSA government may be required to provide financial support to Eskom, effectively passing any under-recovered Richards Bay costs on to all RSA taxpayers.

In order to be consistent with the long term least-cost pathway, Meridian's study shows that investment should be targeted toward renewables and transmission expansion in the near term. Given the lower costs of renewables and the availability of transmission capacity in the near term, renewables should first be built in areas where there is existing transmission capacity. These regions include Mpumalanga and Northern Free-State, where there is well developed transmission infrastructure and declining coal and gold mining. This transmission capacity will increase if coal plants are phased down. In parallel, transmission should be expanded to locations with optimal renewable resource, to support further renewable construction. This will enable a rapid build-out of clean energy infrastructure which meets demand at the lowest cost.

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