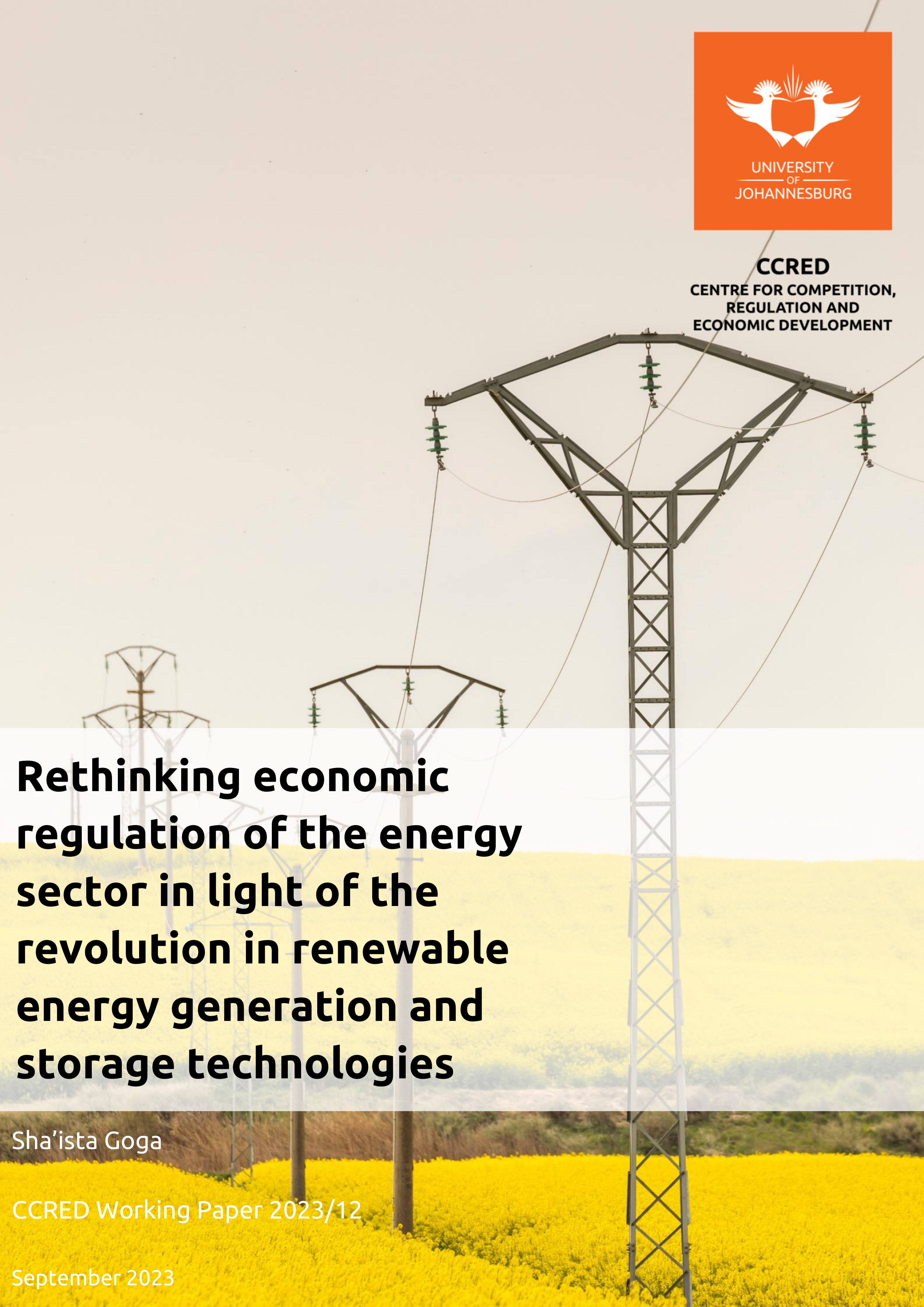

UNIVERSITY OF JOHANNESBURG

CCRED
CENTRE FOR COMPETITION, REGULATION AND ECONOMIC DEVELOPMENT

Rethinking economic regulation of the energy sector in light of the revolution in renewable energy generation and storage technologies

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CCRED Working Paper 2023/12

September 2023

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1. Introduction

The energy sector in South Africa is in a state of transition as a result of two main disruptions. Firstly, South Africa is embarking on a **suite of reforms** related to the unbundling of Eskom, to separate generation from transmission and incorporate elements of competition in the value chain. This is similar to some of the transitions that have occurred in other economies previously. Secondly, given the increased **international focus on decarbonisation** of the economy and a heightened impetus towards using renewables as a result the United Nations Framework Convention on Climate Change (UNFCCC) in terms of the Paris Agreement there is also a transition to a greener energy landscape.[1] This brings in different technologies and a different market structure. These changes mean that the focus and requirements of regulation are changing and that the regulatory framework in South Africa, a large part of which had been developed primarily to deal with monopoly industries requires significant rethinking.

A large part of this involves the role of renewable energy and green energy alternatives including green hydrogen. This is particularly in the context of availability of funding to assist in a just transition. Renewables hold strong promise in South Africa given the abundance of resources for solar and wind power though this requires changes to the way that energy is stored and transported given the interruptability of supply. One of the ways in which this can occur is using renewable energy for the production and use of green hydrogen as a substitute for particular fossil fuels. Green hydrogen is currently expensive to manufacture and has large sunk costs requiring large amounts of investment. Incentivising this investment requires a measure of certainty over projected prices and volumes over time as well as the availability of inputs and the potential for interconnection where necessary. As a result, the development of the industry will to a large extent be affected by the incentives and barriers created through the regulatory framework. In South Africa economic regulation in energy influences prices, entry, quality and other aspects of firm behaviour.

An economic regulator typically aims to intervene to remedy the potential for abuse given the market structure, particularly where scale or scope economies or limited resources means that the market has a likelihood of a monopoly or dominant firm (Viscusi, 2005). This may be through intervention in setting prices. This occurs in instances where the market structure is such that prices set by a company would not be reflective of competitive prices, so a price at which (i) customers are not exploited, (ii) at which ongoing investment is feasible and rewarded at an appropriate level and (iii) at which innovation and efficiency are incentivised (Decker, 2015). The regulator may also set rules over competition, for example, by regulating interconnection or access to ensure that there is sufficient scope for entry and competition along the value chain where market power at one level may distort outcomes in another level. A core challenge of regulation is therefore to ensure that a balance is struck between affordability (interests of consumers), stability (ensuring sustainability through an adequate return on investment and sufficient revenue to cover costs) and incentives for innovation and efficiency (absent competition). As such, the twin shifts in the energy landscape in South Africa requires a shift in regulatory thinking. This includes considering the types of market reforms that have occurred in other economies previously and to also consider the thinking that is not occurring in these economies as they also adjust to

[1] UNFCCC, accessed on 28 October 2022, available at https://unfccc.int/node/61201

decarbonisation goals (see, for example, Joskow 2019 and 2021). This includes consideration of what requires to be covered by regulation, and what the focus of the regulator should be in different parts of the value chain. For example, in a context of a vertically integrated state-owned enterprise there may be more of a focus on price setting to constrain exploitative pricing which may be the result of an exertion of power. In contrast in an environment where the introduction of competition is occurring there may be more of a focus on the regulator's role in facilitating third party access to essential facilities (Decker, 2015)

A further challenge from a policy perspective is balancing the need for appropriate regulation in a market (including ensuring that potential competition is not stifled) with the support that may be required and given by a government for a new or strategic industry. Given the imperative to move the economy to using cleaner forms of energy, considering the aims and objectives of regulation in the context of renewables and green hydrogen becomes an important part of strategic planning for a green hydrogen economy. In particular, there is the need to consider the following:

1. The impact of the existing regulatory framework in energy (including electricity, gas and petroleum pipelines and storage) on **investment incentives.** This includes a macro consideration of whether the energy framework is suitable for green hydrogen. In addition, we need to assess the specifics, for example:
    a. the **pricing of inputs and infrastructure** required for green hydrogen.
    b. any **barriers to investment and expansion** in terms of the regulatory framework.
2. The appropriateness of regulation in terms **of accommodating entry and protecting competition**, for example, access to infrastructure.

In this paper we critically assess the current energy regulatory framework in South Africa (particularly for electricity, natural gas and fuel pipelines and storage) and consider how it intersects with green hydrogen production and value chains, and whether it is fit for the purpose. We further consider challenges in the regulatory landscape and the implications this may have for green hydrogen investment. This paper should be read with a second paper in which Goga, Hawthorne and Roberts discuss potential regulatory structures and solutions.[2]

The paper is structured as follows.

- Firstly, we describe the green hydrogen value chain and the various use cases that may be relevant to South Africa.
- Secondly, we consider how the current regulatory framework is structured and how it impacts on the hydrogen value chain overall. This includes considering the existing regulatory frameworks for electricity, natural gas and petroleum products (including their licensing and compliance frameworks) in more detail and discussing areas that intersect with green hydrogen.
- Thirdly, we draw together key themes and conclude.

[2] Goga, Hawthorne, Roberts (2023) Energy Regulation for Green Hydrogen: Weighing-up alternatives.

2. Context

Renewable energy is typically defined as energy that is derived from natural sources (for example, wind, solar, hydro and tidal power) which are replenished at a higher rate than they are used.[3] This is often in contrast to non-renewable sources such as fossil fuels (such as coal, oil and gas) that produce energy when burned but cannot be replenished in short space of time and nuclear energy (which although a cleaner source than fossil fuels uses non-renewable fuel to produce. Fossil fuels have contributed to CO_2 emissions which has in turn contributed to climate change. Renewable energy is increasingly of importance to energy policy as the clean energy it provides is seen as an important lever to tackling climate change. For example, the EU Directive (EU) 2018/2001 notes that increasing renewable energy is important to reducing greenhouse emissions in line with the Paris agreement on Climate with a 2021 European Council decision made to reduce emissions by 55% by 2030 (relative to 1990).[45] South Africa's NDP 2030 notes the need to reduce the carbon intensity of the economy with the goal of "reducing carbon emissions per unit of power by one-third".[6] Renewables are likely to be a key tool.

However, one of the key challenges with renewables is that generation is often intermittent and variable as it is dependent on the factors such as wind and sunshine that are not continuous. Furthermore, there may be a mismatch between peak generation times and peak usage times. As such, mechanisms for storing clean energy for use in later periods or making available alternative generation capacity is important. One way of capturing and transporting clean energy is through using renewable energy during its peak times to make hydrogen which can be used for a variety of uses allowing power use to be deferred.

Uses of hydrogen include the following: transportation fuel (including aviation, road and shipping); heating fuel (using fuel cell technology); to generate electricity and for industrial uses (for example, to be used as a replacement for gases or liquids currently used as a feedstock or fuel). There are additional uses within the South African context for Sasol using the Fischer Tropsch process which uses hydrogen and CO_2 to make hydrocarbon chains to create synthetic fuels such as diesel, petrol, jet fuel and propane and which is currently used by Sasol. Given this technology it is possible to use green hydrogen as an input together with CO_2 to make greener fuels.[7] Furthermore, hydrogen can be combined with other molecules to create compounds for plastics and chemicals. Hydrogen can be stored across seasons and depending on its form can be transported through pipelines, overland and on freight ships. It therefore can be used across time and geography. As such, it has various potential use

[3] United Nations, What is Renewable Energy?, accessed on 28 October 2022, available at https://www.un.org/en/climatechange/what-is-renewable-energy

[4] European Council (2020), European Council meeting (10 and 11 December 2020), EUCO 22/20, Brussels.

[5] European Union, Directive (EU) 2018/2001 of 11 December 2018 on the promotion of the use of energy from renewable resources.

[6] National Development Plan 2030, Executive Summary, p24

[7] https://www.sasol.com/media-centre/media-releases/sasol-explore-potential-cleaner-aviation-fuels-world-class-partners and https://www.sasol.com/media-centre/media-releases/sasol-arcelormittal-south-africa-partner-decarbonise-and-reindustrialise-vaal-saldanha-through

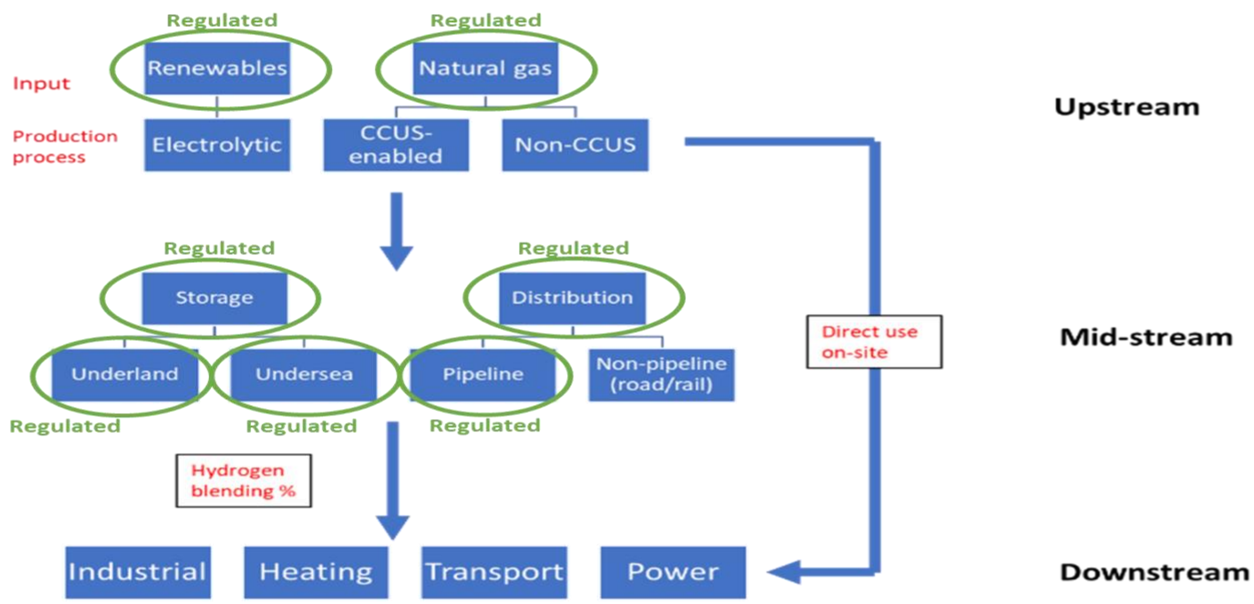
cases. Various countries are focusing more on green hydrogen as part of their decarboniosation strategy . The EU for example, has released a Hydrogen Strategy.[8]

Hydrogen can be produced using different methods (Velazquez and Dodds 2020). The three most common categories are "grey" hydrogen, the method currently used, which is generated from natural gas and emits CO_2, Blue hydrogen which is the same production method but captures the CO_2 so that it is not released into the atmosphere and Green which is created by electrolysing water into hydrogen and oxygen using electricity (from renewable energy sources) and is therefore clean (Velazquez and Dodds, 2020). This paper is focused on the third category as this is clean and therefore relevant to climate change goals.

The green hydrogen value is summarised in Table 1 below with the components that are regulated in South Africa in the current framework highlighted. As can be seen from the value chain there are a range of areas in which the hydrogen value chain intersects with existing energy systems. As a result, it also intersects with different types of existing regulations. This includes the following:

- Regulation of **renewable electricity** as a key input to green hydrogen
- Regulation of **natural gas as an alternative input** to hydrogen
- Regulation of **storage and distribution** of hydrogen and the extent to which it intersects with storage and distribution of natural gas and of fuels, particularly if existing infrastructure is used or repurposed

Figure 1: Hydrogen value chain

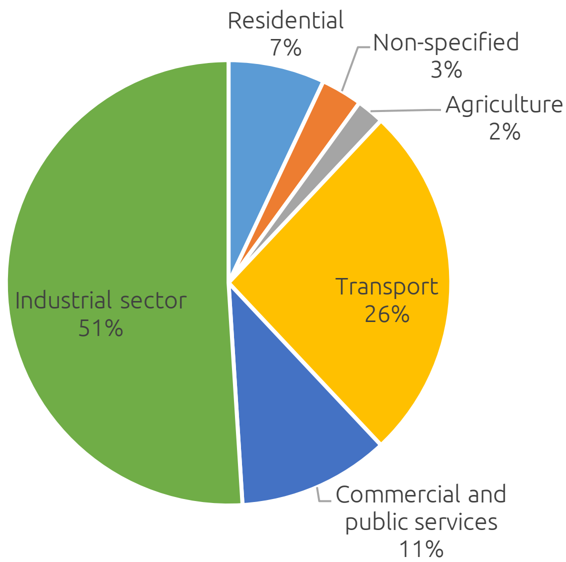


Source: Adapted from HM Government (2021), 'UK Hydrogen Strategy', August with authors own additions to reflect the South African regulatory context

[8] European Commission, A hydrogen strategy for a climate-neutral Europe, Brussels, 8 July 2020, available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020DC0301

In South Africa the current energy landscape is heavily dependent on fossil fuels. The 2018 Energy Balances shows that 65% of energy is derived from coal, 18% from crude oil and the remaining 3% from gas. Over half of the energy needs comes from industry with transport utilising a high share of energy. Given the high dependence on fossil fuels South Africa's industrial future depends strongly on getting the transition to a greener economy correctly planned and incentivised.

Figure 2: Energy demand by sector 2019



Source: DMRE South African Energy Sector Report 2021

Statistics on energy usage published by the DMRE have some discrepancies to other sources (Crompton and Masika 2021). However, coal and gas together with electricity make up a significant proportion of energy demand. Given the high reliance of industry on fossil fuels the greatest scope for changing emissions is through a shift to cleaner energy in the industrial sector, and potentially in the transport sector. While some of this may be directly form a shift to renewable electricity, green hydrogen is likely to be part of this.

Within a South African context while green hydrogen is still at a very early stage, the Hydrogen Society Roadmap published by the Department of Science and Technology notes the following aims for the green hydrogen industry: [9]

- Decarbonisation of **heavy-duty transport**;
- Decarbonisation of **energy-intensive industry** (cement, steel, mining, refineries);
- Enhanced and **green power sector** (main and micro-grids);
- Centre of Excellence in Manufacturing for **hydrogen products** and **fuel cell components**;
- Creating an **export market** for South African green hydrogen; and

[9] Department of Science and Technology, Hydrogen Society Roadmap for South Africa 2021, available at https://www.dst.gov.za/images/South_African_Hydrogen_Society_RoadmapV1.pdf

- Increase the role of hydrogen (grey, blue, turquoise[10] and green) in the South African **energy system** in line with the move towards a net-zero economy.

Specific initiatives noted in the Hydrogen Roadmap include the following:[11]

1. Platinum Valley Initiative (South African Hydrogen Valley) focused on hubs. Johannesburg will focus on changes in industrial use from grey hydrogen to green, and potentially for power in buildings and public transport. Durban and Richards Bay hubs will support the movement of current heavy duty diesel trucks to fuel cells trucks and use green hydrogen as fuel for port activities. Mogalakwena/Limpopo will utilise hydrogen as fuel for the mining sector.
2. The CoalCO2-X Project aims to combine pollutants from coal fired boilers such as CO_2 with green hydrogen to create value added products such as green ammonia, fertiliser etc.
3. Boegoebaai Special Economic Zone (SEZ) in the Northern Cape which has established a hydrogen production plant and will construct green hydrogen and green ammonia sites with a 30GW solar and wind farm.
4. The Sustainable Aviation Fuels (SAF) project is looking at means of commercially manufacturing aviation fuels.

Some of related commercial projects that have been announced at the time of writing include the development of green hydrogen for export in Saldhana, and the use of green hydrogen together with carbon captured from steel manufacturer ArcelorMittal South Africa to replace natural gas in the development of chemicals by Sasol in the Vaal area.[12] The DTIC has also released a Green Hydrogen Commercialisation Strategy[13]

However, it can be noted that while many of these projects align with the commercial imperatives and technologies of existing market participants, it would be short-sighted for the policy and regulatory framework to develop in a way that does not consider new entrants and investors. This is particularly since this is a relatively new area and likely to experience dynamic changes (including in costs) and since the renewable resources are non-rivalrous and are therefore not dependant on rights to the same extent that previous fossil fuel industries were.

A move to use of green hydrogen requires a reconsideration of energy related infrastructure and also the underlying regulatory frameworks and whether they are fit for purpose. Furthermore, we need to consider whether an integrated regulatory regime is more appropriate.

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[10] Turquoise hydrogen is made using a process called methane pyrolysis to produce hydrogen and solid carbon.
[11] Department of Science and Technology, Hydrogen Society Roadmap for South Africa 2021, available at https://www.dst.gov.za/images/South_African_Hydrogen_Society_RoadmapV1.pdf
[12] Sasol Media Release, Sasol, ArcelorMittal South Africa partner to decarbonise and reindustrialise Vaal, Saldanha through green hydrogen, 18 October 2022, available at https://www.sasol.com/media-centre/media-releases/sasol-arcelormittal-south-africa-partner-decarbonise-and-reindustrialise-vaal-saldanha-through
[13] DTIC (2022), Green Hydrogen Commercialisation Strategy for South Africa, 30 November 2022, available at www.thedtic.gov.za/wp-content/uploads/Full-Report-Green-Hydrogen-Commercialisation-Strategy.pdf

This includes the following:

1. Considering the role of electricity regulation and its impact on renewables as a key input into green hydrogen.
2. Consideration for using hydrogen in the distribution system. Regulatory frameworks are developed for the storage, transmission and distribution of fuels or natural gas. Considering where hydrogen fits within this framework is important.
3. Consideration of the way in which pricing of fuel alternatives such as natural gas or diesel are regulated and what this means for the pricing of green hydrogen.

We now turn to this.

3. Regulation in South Africa

In the South African context energy regulation has been focused on three sectors, electricity, piped gas and petroleum pipelines. These are industries characterised by high levels of vertical integration and historic (and current) state support. This will be discussed in greater detail when we look at each sector.

The economic regulatory framework in the energy sector in South Africa is fragmented. It is governed by two sector-specific bodies, the Department of Mineral Resources and Energy (DMRE) and an economic regulator the National Energy Regulator of South Africa, which was established in terms of the National Energy Regulator Act of 2004. Without a sectoral focus, there is also the Competition Commission of South Africa (CCSA) which focuses on competition. Given the high levels of energy insecurity in South Africa, which is hampering investment and overall growth, questions can be asked as to whether the regulatory framework at present has achieved its goals or whether it is holding back much needed planning and development. The differing regulatory roles and responsibilities are discussed in Appendix A. In this section, however, we consider the interaction between the key regulated sectors and green hydrogen in more detail.

3.1. Regulation of electricity

Electricity is a key input into green hydrogen and regulation thereof has an impact on the incentive structure and ease of entry for green hydrogen investments. There are various components of the regulatory framework that impacts on incentives to invest in green hydrogen.

1. Firstly, where electricity is generated and converted onsite there are questions over the licensing and registration required to allow a company to generate that electricity.
2. Secondly, the prices set for electricity as an input, and where sales of that electricity is an alternate use (rather than as an input into hydrogen) is of importance to determining the feasibility of green hydrogen investment.
3. Thirdly, in instances in which electricity is purchased and requires wheeling from a different location, the pricing and incentives will be significantly impacted by the regulatory framework chosen for wheeling.
4. Fourthly, since adequate transmission infrastructure is required, the incentive to invest in transmission grids will also be affected by the regulatory framework and the extent to which externalities are priced in.

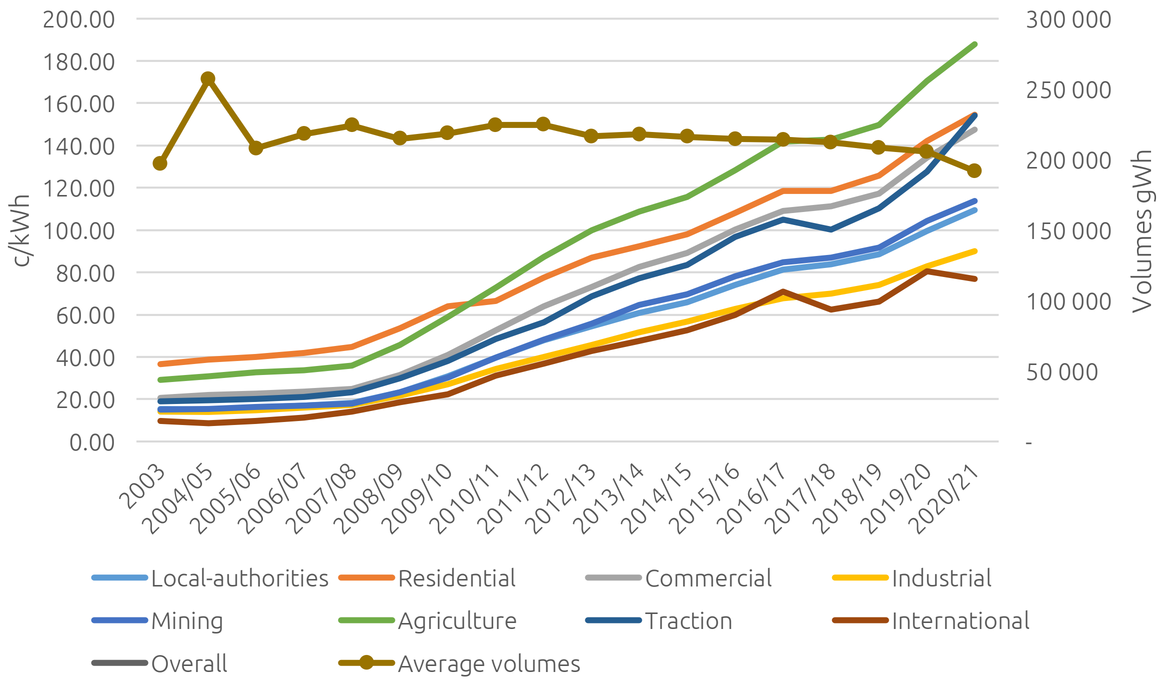
3.1.1. Context- Challenges in the provision of electricity in South Africa

At present the electricity sector in South Africa is in a state of crisis with inadequate electricity supply leading to loadshedding or rolling blackouts. This is largely a result of aging coal plants that require maintenance, a delay in investment in new capacity as well as high levels of inefficiency and corruption over time at Eskom, the state-owned electricity enterprise.

Eskom is the key provider of electricity and is present in generation, transmission, and distribution where it has until recently had a monopoly. While historically Eskom had an oversupply of cheap electricity, which allowed several energy intensive industries to benefit from low-cost structure, over the past two decades South Africa has morphed to being to being a country faced with an electricity shortage and spiralling prices. **Electricity prices have increased substantially over time, rising** by 497% between 2003 and 2020/21, from 16 cents to R1,05 per kilowatt hour, on average (see prices per customer group in **Error! Reference source not found.**). In parallel, electricity volumes have decreased marginally over the same period, from 196,980GWh in 2003 to 191,852GWh in 2020/21. This is due to a mixture of reasons including economic conditions, supply constraints, improved energy efficiency and increases in self-supply of electricity.

The increasing costs combined with the unreliability of supply has meant that household and **industry have experienced cost shocks combined with interruption in operations**. This has made a move to renewable alternatives more attractive, particularly as changes in technology have brought some costs as low as 37c/kwh.

Figure 3: Eskom average tariffs and volumes (cents/kWh) 2003 – 2021



Source: Eskom, 'Tariff history', available at: https://www.eskom.co.za/distribution/tariffs-and-charges/tariff-history/)

From a regulatory perspective there have been several challenges in terms of electricity supply over time:

1. There has been **inadequate introduction of new generation** to match the supply to demand. This is for various reasons including the following:
1.1. A fragmented policy and regulatory framework with two Ministries (DMRE and DPE) responsible for different aspects of electricity.
1.2. Delays in licensing and contracting with IPPs.
1.3. Licensing limitations and delays for self-supply and supply to others.
1.4. Inadequate investment in transmission infrastructure to facilitate the movement of energy from the areas of renewable supply to areas of demand.
2. There have been **issues in terms of reforms aimed at introducing competition into the value chain**.
2.1. Market based reforms to introduce competition as envisioned by initial legislation **have not been implemented.**
2.2. Renewable providers have been required to sell to Eskom. At **times Eskom has obstructed these sales** leading to a lack of progress and uncertainty for investors in renewables.
3. There have been **challenges in pricing electricity regulation** with prices often being contested and the processes taking a long time to resolve through legal processes, with the outcome often occurring after the time period for which the price was applicable.

3.1.1.1.Inadequate generation as a result of the policy and regulatory framework

The delay in the planning for new energy: The electricity plan for the country is published by the DMRE in the form of Integrated Resource Plan. The 2011 IRP was published with the expectation that it would be updated every two years. However, after various versions were created and not adopted (2013, 2016, 2017) only one draft, published in 2018 and finalised in 2019 was adopted. By the time that it was adopted some of the elements were already being criticised as being outdated.[14] As such, there has been a failure in planning for electricity supply by the DMRE which has resulted in insufficient capacity.

Delays in the licensing and contracting with IPPs. While renewables have been very slowly introduced to the energy mix there have been significant challenges with this (Montmasson-Clair and das Nair, 2017). The IRP 2019 for example maintains build limits on renewables.[15] Renewables have been introduced from various providers through the Renewable Energy Independent Power Producer (REIPP) programme which is currently entering its sixth bid window.[16] However, based on laws at the time, this capacity had to be purchased directly by Eskom (who also competed with the renewable providers for generation). While the programme had a successful start, there have been significant delays and challenges over time. For example, between 2015 and 2018 the CEO of Eskom refused to sign any agreements to purchase power from IPPs (Bid Window 4) on the basis that Eskom did not negotiate the prices. Furthermore, many renewable bids have failed to reach financial close for various reasons. For example, Bid Window 5 was launched in April 2021 with preferred

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14 https://www.dailymaverick.co.za/article/2019-01-17-paralysis-over-south-africas-irp-for-electricity-presents-massive-economic-risk/ and https://researchspace.csir.co.za/dspace/bitstream/handle/10204/11200/22850_GWDMS%20279138%20CSIR-IRP2019.pdf?sequence=1&isAllowed=y
15 Department of Mineral Resources and Energy (2019), Integrated Resource Plan 2019, p46
16 See https://www.ipp-renewables.co.za/

bidders selected by October 2021. However, most have not reached the project close at the time of writing in early 2023 with concerns raised that rises in input costs have in the interim may make project close infeasible for many.[17]

Self-generation as an alternative for industry has been restricted. Historically self-generation has been restricted as a result of an onerous licensing framework. NERSA has historically been responsible for the licensing of generation with The Electricity Regulation Act requiring that they decide an application within 120 days. NERSA typically required an extensive range of information in their license application. They evaluate generation based on a range of factors including environmental and land use, technical, financial, economic and regulatory analysis. The type of information required included detailed information on shareholdings, financial models and information, benefits to the community, shareholdings and more.[18] There are also certain public processes that needed to be followed. For example, the applicant also needs to advertise their application in local newspapers, and NERSA checks for objections, advertises and holds public hearings. The benefit of some of these processes (such as requirements for newspaper advertisements) seems questionable Furthermore, NERSA requires evidence of an Eskom grid-tie in. This process which is a separate process with Eskom can take up to 7 months. One of the key changes to policy in recent years has been the raising of the licensing threshold for generation from 1MW to 100MW in 2019.[19] By 2021 however, there were only 27 authorised though it was estimated that there were thousands of installations that existed but were technically illegal.[20] This differential suggests inefficiencies in the system.

Even with changes from licensing to **registration, there are still onerous requirements**. In September 2022 a removal of that threshold has been proposed, which would now allow the private sector to engage in generation *without a licence being required*. The DMRE has proposed exemptions from licensing[21] for generation for standby/backup electricity for the duration of an electricity supply interruption, the operation of any generation that does not have a point of connection and the operation of a facility up to 100MW. It has proposed registration, but not licensing for various categories including generation for customers, but with no wheeling of electricity; as well as for generation which requires wheeling in specific circumstances (namely, where the generator has a connection agreement with the holder of the transmission or distribution licence (ie. Eskom) and where the generation facility has a connection point but does not export or import electricity onto the transmission or distribution power system). However, it can be noted that to our knowledge registration still follows a very onerous process that is close to licensing in terms of complexity and time requirements. The current registration form requires registration certificates, technical feasibility studies and models, environmental authorisations and financial details including

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17 https://www.news24.com/fin24/economy/sas-renewable-energy-programme-in-trouble-many-projects-no-longer-financially-viable-20220720

18 NERSA, Licensing process and requirements https://www.ee.co.za/wp-content/uploads/2021/07/Nersa-generation-licence-process-and-requirements.pdf

19 Government Gazette, Amendment of government notice: Licensing Exemption and registration notice, 12 August 2021

20 https://www.esi-africa.com/features-analysis/raising-gen-licence-threshold-to-100mw-necessary-but-insufficient/

21 Department of Mineral Resources and Energy (2022), Licensing Exemption and Registration notice for public comment, Electricity Regulation Act 4 of 2006, Government Gazette no 46850 of 2 September 2022,

rate of return, debt equity ratios, post-tax IRRs etc.[22] It still requires an analyst to analyse the application, draft a Reasons for Decision which includes assessing the financials such as investment cost, technical parameters, power purchase agreements, economic analysis and tariff analysis. It also gets considered by the Electricity Subcommittee for approval within 60 working days with registration certificate provided within a further 20 working days.[23] While information on returns and pricing may be useful to analysis of tariffs, and shareholding structures may assist it is unclear why this level of detailed information, analysis and approval processes is required for processing a registration where a decision on licensing is not required.

Inadequate transmission grid expansion. Another concern in the electricity sector has been the inadequate investment in the transmission grid. At present, the bulk of the generating capacity is based near the coal fields in Mpumalanga. New capacity from solar and wind would come from other areas such as the Northern, Eastern and Western Cape. However, there has been insufficient investment in grid capacity from these areas over time.[24] As a result there is the potential for investment in renewables in these areas to be constrained. While Eskom has developed a Transmission Development Plan[25] funding this adequately within the context of Eskom's financial difficulties may prove challenging.

3.1.1.2. Difficulties in introducing market reforms and competition

While **competition was meant to be introduced as part of energy reforms, this process has been stalled** and not successfully implemented. The White Paper on Energy of 1998 envisioned a range of reforms to the electricity supply industry. This included the unbundling of Eskom into generation and transmission through creation of an independent system and market operator which would manage transmission including for independent generators, and the creation of regional energy distributors. This unbundling falls under the remit of the Department of Public Enterprises. However, there has been a lack of progress on this over the last decade and this has not occurred. Operation Vulindlela is only now targeting some of these reforms. The decision not to develop regional energy distributors has meant that pricing policies developed with the idea of regional distributors now have to apply for far smaller, more poorly capacitated municipal distributors with multiple resultant challenges to recent tariff approvals in courts.

3.1.1.3. Uncertainty in regulatory decisions

In addition, there have historically been several **challenges in relation to decisions made in the regulation of electricity prices**. Prices are typically set based on a methodology published by NERSA, typically in the form of a multiyear pricing determination. Eskom applies for a tariff on the basis of the methodology, and NERSA approves or does not approve the tariff. Municipalities purchase from Eskom and develop their own tariffs for customers that they distribute to. This also gets approved by NERSA. The challenge for

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[22] Registration Application Form in terms of Schedule 2 of the Electricity Regulation Act, 2006 (Act No: 4 of 2006), available at https://www.sseg.org.za/wp-content/uploads/2021/03/Registration-Application-Form-For-SSEG-NERSA.pdf

[23] Registration Procedure in terms of Schedule 2 of the Electricity Regulation Act, 2006 (Act No. 4 of 2006)

[24] https://www.engineeringnews.co.za/article/south-africas-transmission-infrastructure-must-urgently-be-strengthened-extended-2022-11-10/rep_id:4136

[25] https://www.eskom.co.za/wp-content/uploads/2021/08/TDP-Report-2019-2029_Final.pdf

Eskom, the municipalities and the regulator in recent years has **been balancing cost reflectivity of tariffs with affordability for consumers** within the context of questions over efficiency and prudency at Eskom and the various municipalities. As a result, in recent decades the electricity tariff has been strongly contested and there have been a range of legal cases brought forward relating to tariffs (as well as other components of decisions). This has had several implications:

1. There are often **delays in resolving regulatory disputes**, with many court challenges only resolved after the period for which the price was set has elapsed. For example, in Borbet case[26], the March 2016 RCA decision which related to costs in 2013/14 was set aside by the High Court. NERSA appealed to the SCA and the appeal was upheld. The plaintiffs took it to the Constitutional Court, where they were not given leave to appeal. However, this was only finalised in August 2017. The allowable revenue calculated in terms of the MYPD 4 in October 2019 was also set aside in the High Court and eventually settled in July 2020.[27] This has meant that there has been a delay of at least a year over some decisions which has increased uncertainty over electricity tariffs, and a lack of certainty over the regulatory framework.
2. There have also been **various challenges to pricing methodology.** This includes challenges with the methodology used such as the treatment of depreciation and questions over the validity benchmarking used at municipal level in terms of the pricing methodology used by NERSA for municipal tariffs as well as assumptions used. A recent case focused on the fact that the NERSA decisions do not reflect the cost of supply as required by legislation, largely as NERSA has not enforced this and used a simplified benchmarking methodology instead.[28]

There are two sets of reforms that are likely to impact on the use of electricity in green hydrogen. Firstly, there is the **lifting of licensing requirements** for own generation. Secondly, there are reforms related to **structural separation of transmission from Eskom** which may allow for wheeling over the grid in cases in which a hydrogen producer may want to procure energy from a private party. Third There are also other pricing issues such as **subsidies**.

3.1.2. Role of the regulatory framework on green hydrogen going forward

Going forward, proposed changes in the regulatory framework are likely to have an effect on green hydrogen incentives. Key to this is the impact of the structural separation of Eskom.

While an unbundling of Eskom into transmission and generation was mooted as early as the 1998 White Paper, this has not occurred. However, in October 2019 the Department of Public Enterprises (DPE) announced the structural separation of Eskom's Transmission operations through the establishment of a Transmission Entity that will *"develop a competitive market and encourage use of diverse sources of energy"*. Eskom has begun a functional separation and has transferred its transmission division to a wholly-owned subsidiary the National Transmission Company South Africa (NTCSA).[29] In the Roadmap for

[26] NERSA v Borbet SA (Pty) Ltd [2017] ZASCA 87 (1288/2016 & 1309/2016) (6 June 2017)
[27] Eskom Holdings SOC Limited v National Energy Regulator of South Africa and Others (74870/2019) [2020] ZAGPJHC 168 (28 July 2020)
[28] Nelson Mandela Bay Business Chamber and Others v National Energy Regulator of South Africa and Others (63393/2021)[2022]
[29] Eskom (2022), Q and A Further to Eskom's Global Investor Presentation dated 18 February 2022, available at https://www.eskom.co.za/wp-content/uploads/2022/03/PublicQA_March2022.pdf

Eskom in a Reformed Supply Industry the DPE notes that a Transmission System Market Operator would play a role in connecting generation (through Eskom, IPPs and others) with distribution (including Eskom, Municipalities, SAPP and Large power users). The Roadmap notes that it would need to provide access to the grid on a non-discriminatory basis.

3.1.2.1. The procurement by the transmission entity may lead to challenges if incentives are not correct

The Roadmap also notes that procuring new energy will remain with the Department of Mineral Resources and Energy, while the buyer function will rest in the transmission entity stating:

> "*During the transitional separation process, this function of procuring new energy will remain within the Department of Mineral Resources and Energy. The Buyer function will remain with Transmission entity. The TE will buy energy from generators as procured by the Minister of Mineral Resource and Energy*"

While the Roadmap envisioned a legal separation by 2021, this separation has not yet occurred. However, even when it does this structure could potentially lead to a mismatch in the type of investment commissioned and prices at which they are commissioned. Absent the correct incentive structure for the transmission entity in terms of there being a complete unbundling from Eskom and incentives focused on purchasing low-cost energy from the most suitable provider this could lead to the same situation in which REIPPP providers found themselves in in 2015-2018 where Eskom refuses to purchase energy from them. Procurement requiring Ministerial approval can also be problematic given the likely delays this may entail (this is discussed in more detail in the companion paper).

The Electricity Regulation Act, no 4 of 2006, and the Electricity Pricing Policy are currently being amended to allow for markets and greater participation by the private sector. There are various ways in which the pricing structure could impact on incentives for green hydrogen depending on how it is structured.

3.1.2.2. Low tariffs arising from the wholesale market may benefit green hydrogen

The current draft of the ERA provides for a competitive multi-market structure for electricity, including a day-ahead market for electricity.[30] This permits hourly pricing of electricity, which at certain times of the day and in certain seasons in South Africa are likely to be very low (including in the middle of the night and in the middle of summer). **Green hydrogen producers might benefit from the introduction of low tariffs that may arise from the multi-market structure** if production processes are sufficiently flexible to take advantage of these very low day-ahead prices. In fact, green hydrogen may be an important sink for excess variable renewable energy that would otherwise be curtailed (wasted). This is known as 'flexible sector coupling' (Zerrahn, Schill and Kemfert, 2018).

3.1.2.3. Generation capacity charges may increase input costs where standby capacity is not required, and may present an opportunity for green hydrogen

At the time of writing (February 2022) Eskom submitted a proposal for changing their retail tariffs. This includes the introduction of generation capacity charges and a distribution fixed-

[30] See Electricity Regulation Amendment Bill, available at: https://www.gov.za/sites/default/files/gcis_document/202203/45898gon1746.pdf

charge network to increase the fixed component.[31] While this is currently for retail, it is likely that similar structures will be used for wholesale. Eskom has also suggested a generation capacity charge. This will be applicable to all loads and would entail a charge for the cost of back-up capacity. They argue that a fixed capacity charge would cover the costs of having standby capacity in the context of contracting with dispatchable IPPs which would require backup.

Given the type of renewable energy systems used for green hydrogen would not necessarily require backup from the national grid **this may lead to prices for capacity that are too high and artificially inflate the costs**. It is important in this regard that a clear delineation is made between companies with interruptible and non-interruptible supply. **Where electricity is being used to generate hydrogen when renewables peak and not used elsewhere, standby capacity is not required and therefore standby charges should not be implemented** for the purpose of companies that manufacture green hydrogen solely using renewable resources, to avoid skewing investment incentives (Zerrahn, Schill and Kemfert, 2018).

At the same time, green hydrogen may be an important alternative to natural gas a source of electricity generation, particularly for capacity purposes (i.e. as a back-up to variable renewable energy supply). A green hydrogen electricity plant is being built in Namibia, for example.[32] The Integrated Resource Plan (IRP) for South Africa, for instance, proposes 1000MW of gas to power generation in 2023, and 2000MW in 2027.[33] Rather than developing new natural gas infrastructure or converting existing diesel-powered combined cycle gas turbines (CCGT) to natural gas, the feasibility of using green hydrogen instead might be considered. Linked to this is the fact that green hydrogen may become a viable alternative to battery storage, particularly for ancillary services used in the electricity grid.[34]

3.1.2.4. Incentivising transmission infrastructure

There are large externalities to the economy as a result of enhanced use of renewables. This needs to be facilitated though by sufficient grid capacity to allow it to be optimally harnessed. This will be facilitated by investments in grid infrastructure. At present it is not clear that there is sufficient funding for grid infrastructure and that the externalities of renewables on the economy are being considered. As such, it is necessary to consider how best to facilitate investment in the grid by private parties who may benefit from some of these externalities as well as by the state in pursuit of industrial policy objectives.

3.1.2.5. Wheeling charges

Another question relates to network wheeling. Wheeling may be relevant for green hydrogen in instances in which the hydrogen is produced in a different location from the

[31] NERSA (2022), Consultation Paper on Eskom Retail Tariff Restructuring Plan, available at https://www.nersa.org.za/wp-content/uploads/2022/09/Consultation-Paper-on-Eskom-Retail-Tariff-Restructuring-Plan.pdf
https://www.eskom.co.za/distribution/wp-content/uploads/2022/08/RTP-2023-detailed-presentation-version-2.pdf
[32] See: https://www.reuters.com/business/energy/africas-first-hydrogen-power-plant-seen-producing-electricity-2024-2022-09-12/
[33] See: https://www.energy.gov.za/IRP/2019/IRP-2019.pdf
[34] See: https://cordis.europa.eu/article/id/413231-green-hydrogen-promises-more-renewable-integration-with-more-stable-grids

generation as is likely to be the case if renewables are based in areas conducive while green hydrogen production requires access to water.

The revised Electricity Pricing Policy (still at a comment stage) notes that "*Network (transmission and distribution) owners have an obligation to allow customers access to and use of their networks to wheel power irrespective of the supplier of the power, provided that the customers are not in arrears in paying all the relevant charges……. The full cost to operate the networks should be reflected in the various connection and use of system charges. In other words, no additional charges are needed to facilitate the wheeling of electricity between two parties, unless such wheeling would result in incremental costs*."

The cost of wheeling and the ability to be able to use the Eskom grid to wheel energy will be an important consideration in developing green hydrogen in instances in which the renewables are located away from the hydrogen plant). At present any strategy that requires wheeling would require registration with NERSA. Furthermore, any costs or charges if developed would affect incentives. Given the role of the transmission infrastructure and the natural monopoly characteristics, ensuring the charges required for wheeling are limited to incremental costs would be important from a competition standpoint to prevent exclusion of competitors from the network and to prevent exploitative pricing that ultimately impacts on the green hydrogen industry.

Going forward the potential for green hydrogen will also intersect with the regulation of electricity insofar as the price of electricity sold forms an alternative to the use of electricity for the development of green hydrogen. As the current framework is still in a state of development both in terms of the licensing and registration framework as well as from a pricing perspective (given the unbundling in particular), there is still substantial uncertainty as to how it will impact on green hydrogen.

3.1.2.6. Subsidies

There are various subsidies built into electricity tariffs in South Africa that might undermine the business case for green hydrogen if this is produced using renewables connected to the national electricity grid. These subsidies are in addition to the free basic electricity that is paid for directly by government through explicit budget allocations.[35] For instance, there are a range of Eskom tariff categories that receive subsidies from other users, including the Landrate, Ruraflex, Nightsave Rural, and Homelight tariffs.[36] While these subsidies are no doubt needed for socio-economic reasons, there is a question as to whether they should be paid directly by tax-funded government allocations (in the same way that free basic electricity is) rather than by users, since this undermines the business case for various applications, including green hydrogen. For instance, Eskom customers on the Megaflex, Miniflex, 'Urban small' and '-large' tariff structures pay R0.1163 – 0.1173 / kWH (excluding VAT) for the electrification and rural network subsidy charge.[37] These subsidies may undermine the business case for green hydrogen.

[35] See 'free basic services' in the explanatory memorandum to the national budget, available at: http://www.treasury.gov.za/documents/national%20budget/2022/review/Annexure%20W1.pdf

[36] See: https://www.eskom.co.za/distribution/wp-content/uploads/2022/08/RTP-2023-detailed-presentation-version-2.pdf

[37] See: https://www.eskom.co.za/distribution/wp-content/uploads/2022/05/4756-ESKOM-Tariff-Booklet-2022-Final-Rev.pdf

3.2. Green hydrogen and regulation of gas

In South Africa gas is regulated by the Gas Act, 48 of 2001. However, at present the Act defines gas as follows:

> *"all hydrocarbon gases transported by pipeline, including natural gas, artificial gas, hydrogen rich gas, methane rich gas, synthetic gas, coal bed methane gas, liquefied natural gas, compressed natural gas, re-gasified liquefied natural gas, liquefied petroleum gas or any combination thereof."*

Hydrogen itself is not therefore captured under the Gas Act, though natural gas enriched by hydrogen would be. Despite this the Gas Act still plays a role in determining the growth of green hydrogen in South Africa. Grey hydrogen is currently produced in South Africa using natural gas. As such there is an interplay between the natural gas and hydrogen frameworks. Firstly, NERSA licenses participants in the gas industry. Secondly, the piped gas regulatory framework (under the Gas Act, 48 of 2001) currently regulates the price of natural gas, as well as transmission and distribution tariffs and trading margins. The gas price level will have an impact on the adoption of green hydrogen as an alternative.

In South Africa, natural gas has historically been supplied by Sasol Gas which sources its natural gas from the Pande and Temane fields in Mozambique and imports the gas via the high-pressure ROMPCO pipeline. However, while the demand for gas energy is growing, particularly in the context of poor electricity supply, this has not been matched by adequate supply. This is largely due to dwindling gas resources in the Pande and Temane fields in Mozambique and the absence of existing natural gas sources in South Africa. This means that there is an expected decline in supply from 2024. As such, within South Africa, there has been a continued deficit of gas with demand exceeding supply for the past seven years. While there are potential alternative natural gas sources[38], this has not yielded a clear solution to the problem. This is largely due to a lack of engagement with the issue by the DMRE. A Gas Masterplan was delayed and when eventually published in 2021 contained little specific detail. This has created massive uncertainty for gas companies and users as little investment is being made absent policy direction.

Historically Sasol Gas was vertically integrated across transmission and distribution (and was a monopoly provider) and benefitted from state support (Mondliwa and Roberts, 2019). Pricing structures agreed upon were based on the price of alternative energy sources available to customers. This has subsequently changed. At present NERSA approves a maximum price methodology and tariffs for natural gas. There are two key tariffs used for gas pricing. Firstly, there is a formula for maximum prices that uses a weighted average of prices in international hubs, namely the Dutch TTF, Britain's NBP and United States Henry Hub. For example, the war in Ukraine has led to large increases in the prices to gas users despite there being no change in costs to Sasol, resulting in windfall profits. As an alternative there is a pass-through methodology which is used by third-party traders of and importers of LNG which determines prices based on acquisition, trading, regasification and transport costs and an appropriate benchmarked margin. As such, going forward there are

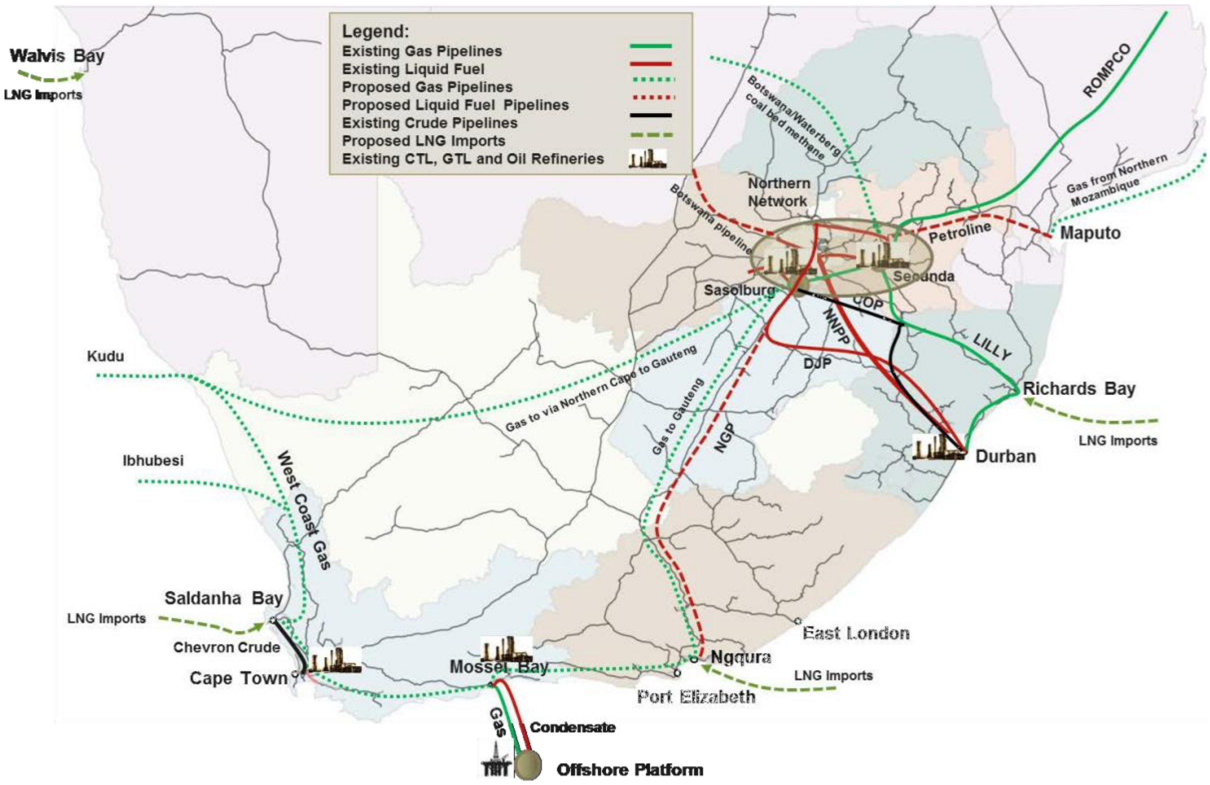
[38] https://www.nersa.org.za/wp-content/uploads/bsk-pdf-manager/2021/05/NERSAs-Determination-of-the-adequacy-of-competition-in-the-piped-gas-industry-2018-19.pdf

repercussions for **the pricing of green hydrogen as an alternative to natural gas.** If the price of natural gas is far higher as a result of prices in global markets, this makes green hydrogen a more cost-effective alternative in certain instances (noting that there are conversion costs). This is important in a context in which there is a supply issue for natural gas.

In certain instances, hydrogen can also be mixed in with natural gas using existing pipelines and for certain current functions.

At present natural gas in South Africa is transmitted through various pipelines. This includes ROMPCO which brings gas from Mozambique to Secunda, a line between Secunda and Sasolburg and the Lilly pipeline which takes gas from Sasolburg to KZN through Richards Bay to Durban. ROMPCO was historically a partnership between Sasol and the government of Mozambique and as such had interests aligned to Sasol. However, Sasol has now divested 30% of its stake. Lilly is owned by Transnet which is a state-owned enterprise.

Figure 4: Pipelines in South Africa



Source: Transnet

There are various smaller players in the industry that largely depend on Sasol supply as well as one company Tetra 4 that produces compressed natural gas. However, competition is fairly limited.[39]

NERSA licences pipelines, provides methodologies for tariffs and pricing, and approves pipeline tariffs. Going forward, if some of the natural gas infrastructure was repurposed for

[39] NERSA (2019), Reasons for the decision on the 2018/19 determination of inadequate competition in the piped gas industry in terms of Section 21(1)(p) of the Gas Act

hydrogen, or if a mix of hydrogen and natural gas was allowed there are several regulatory issues that may arise.

Firstly, there are questions over **access to the infrastructure for new entrants** given that there are existing volumes utilising the pipelines and in instances in which incumbent owners of the infrastructure also produce hydrogen (as may be a possibility with Sasol Gas, for example).

Secondly, there are questions over **the pricing of new transmission infrastructure**. An interesting issue will be how pricing of new infrastructure will compare to existing pipelines. If older pipelines are already paid for while new ones have large construction costs, pricing them individually may result in high prices for the users of new pipeline infrastructure. In this case allowing pipeline companies such as ROMPCO or Transnet to pool their costs may allow for lower costs overall (particularly if incumbent companies already have volumes on existing pipelines). Alternatively, there may be challenges if pooling is allowed and entirely new companies enter in the provision of infrastructure as this cross-subsidisation could make new entry infeasible. As such, the use of existing pipelines for hydrogen is likely to raise various challenges from both an entry and a pricing perspective. Some of these principles have been considered in similar circumstances in piped gas.

In parallel to the case with electricity, there have been **several contested matters with respect to the pricing of gas and the pipeline tariffs** such as the approval of the application by Sasol for a Maximum price for gas in March 2013 which was set aside by the Constitutional Court in 2018 (though the period of the price decision lapsed in 2017), and a decision related to pipelines for ROMPCO in which a decision made in 2013 was set aside in 2016 by the Constitutional Court.[40] As such, ensuring that the regulatory framework does not tie hydrogen providers in long-running disputes will be important.

3.3. Green hydrogen and fuel and petroleum

The Petroleum Pipelines Act, no 60 of 2003, regulates petroleum pipelines, storage, and distribution. This is defined as

> *"any liquid petroleum, fuel and any lubricant, whether used or unused, and includes any other substance which will be used for a purpose for which petroleum fuel or any lubricant may be used."*

As such, it is likely that the Act covers liquid hydrogen. As noted previously the Act covers loading and storage facilities as well as transmission through pipelines. At present, petroleum pipelines, loading and storage facilities are regulated by NERSA. This includes pipelines that are for own use by companies (for example, pipelines that would run between a storage facility owned by a company and its own refinery as well as common carrier pipelines (for example, Transnet pipelines). Storage facilities (which refers to bulk storage facilities excluding those at premises where petroleum products are manufactured, storage for own final use, for retailing products to the public and used to transport by road, rail, sea and air) are regulated.

[40] National Energy Regulator of South Africa and Another v PG Group (Pty) Limited and Others 2019 ZACC 28

As of September 2022, NERSA had 183 licensees with a total capacity of 15,704,648m^2 ranging from a single tank of 52m^2 to facilities with multiple tanks over 100 000m^2.[41] **Regardless of size, these all require licences** that need to be approved in NERSA processes as well as individually calculated tariffs. These are currently determined using a full rate of return methodology using trended original cost asset valuation which requires assessments of the regulatory asset base, depreciation, WACC and an assessment of whether expenses are prudent. This requires the applicant to provide very detailed financial models and cost projections. While there was a move towards simplifying tariff determination with a lighter methodology (version 3) which used indexed original cost and certain standardised assumptions as well as a simpler formula. However, this was withdrawn due to various unintended consequences, including the fact that the tariffs applied for increased under the methodology relative to previous tariffs.[42] After the reversion to the previous methodology a new methodology was developed in 2020. However, this still requires the provision of detailed information. It also requires an extensive regulatory process to be followed including public hearings.

Though NERSA determines the pipeline and storage tariffs and infrastructure licensing it is important to note that NERSA does not determine the prices of petroleum products, which are calculated by the Central Energy Fund on behalf of the DMRE. These prices are based on international spot prices as well as various local levies and taxes. It also includes a storage margin which generally differs from that used by NERSA. It also does not determine licensing of retail and wholesale of petroleum products.

There are therefore various ways in which the shift to green hydrogen intersects with the regulatory framework for fuel.

1. Firstly, there is the impact of the **pricing of fuel developed using green hydrogen** as an input. If fuel is developed using green hydrogen as an input it may be costlier than fossil fuels but may sell at a premium as a result of its lower carbon footprint. As such fuel sold using green hydrogen inputs may require a different pricing methodology and structure as compared to imported petroleum.
2. Secondly, there is the impact of **the conversion of storage facilities or pipelines** from petroleum to hydrogen and how that would impact on pricing and tariff structures for those facilities. This is likely to raise similar issues to that discussed in the section on gas, namely how incremental investments in infrastructure will be considered and how this will impact on entrants at infrastructure level and downstream entrants who require access to facilities.
3. Thirdly, there are issues related to the **licensing of storage facilities and pipelines** and the extent to which obtaining a license regardless of the size of the storage facility could be a regulatory barrier to industry. This is particularly if it inhibits the uptake of hydrogen at lower levels of the value chain.

[41] NERSA Petroleum Storage Facility Database September 2022, available at https://www.nersa.org.za/wp-content/uploads/bsk-pdf-manager/2022/09/3Petroleum_st_db_2022-23_Q2-1.pdf

[42] National Energy Regulator of South Africa , Reasons for decision on the review of the tariff methodology for the approval of the tariffs for petroleum storage and loading facilities. 25 March 2020

4. Fourthly, also related to licensing there are issues related to **the roles of the DMRE and NERSA** and the extent to which there is overlap which creates challenges for applicants who need to go through to separate regulatory processes with different regulators.

4. Conclusion

Given the role that the regulatory regime is likely to have on facilitating investment in green hydrogen, and the challenges that have been experienced in terms of the policy and regulatory framework in recent years it is essential that it is carefully reconsidered. Across the different regulatory systems there are a few cross-cutting themes that emerge.

Licensing: The licensing framework in fuels can be burdensome and not necessarily accommodating of new entrants and dynamic investments in capacity. This is because even smaller storage facilities or pipelines for own use often require licensing or registration which in turn requires large amounts of information, including often detailed financial and engineering information. It is not clear that in many instances this is necessary from the perspective of economic regulation in instances in which there is no clear market power or ability to exert it. The processes are also time consuming, can take months or even years and this could potentially slow down investment. In the case of green hydrogen, it is likely that multiple licenses would be required. Firstly, registration for generation of electricity would be necessary (and in some instances a full licence may be required). Secondly, storage or transmission of pure hydrogen may be required. The regulatory framework for this has not been developed. However, use of existing infrastructure will require the conversion of existing fuel or gas infrastructure. This will require license amendments. Going forward **the licensing and registration framework should be streamlined to reduce unnecessary red tape and the commensurate delays**.

Pricing: The price of electricity as an input or alternative use for renewable energy (as opposed to green hydrogen production), the cost of wheeling it (and the potentially higher prices could be exclusionary) as well as the price of natural gas as an alternative is likely to be subject to contestation and this would possibly lead to uncertainty regarding the financial incentives. **It is important that flexibility be possible in the pricing framework, such that the business case for green hydrogen producers is not undermined** in the **cross-subsidy** framework for electricity, for example, or in being **forced to pay electricity capacity charges** where loads on the system are fully interruptible. This is because the possibilities for very low prices available at certain times of the day through proposed electricity markets may well help support the introduction of green hydrogen. A second issue is the regulation of hydrogen itself. If hydrogen prices are fully regulated in a similar framework to that used for gas or electricity at present this may lead to time delays and contestation related to it. As such, the **challenges associated with such a pricing framework needs to be considered**. Thirdly, where petroleum products are manufactured using green hydrogen, **price setting based on oil imports is also likely to lead to prices that may not be suited to the costs of green fuels** made using green hydrogen, which may be costly but would have the benefit of being cleaner. As such a different framework may be necessary. Fourth, there may be opportunities for green hydrogen as a source of energy during periods of high market prices for electricity, such as in winter or in peak hours, and as a source of back-up capacity (for which prices are currently being introduced) and ancillary services (for which a price already exists) to keep the electricity grid stable. This means that any new pricing framework for electricity capacity and ancillary services will have an impact on the business case for green hydrogen.

Access and entry: There may be challenges related to entry and access to infrastructure, particularly in instances where it is held by incumbents that are invested in both manufacture and produce products including or competing with hydrogen. While there is some consideration for competition in the gas and petroleum pipelines Act, it is unclear how hydrogen will fit into the regulatory framework.

Incentivising investment: The externalities of enhanced energy supply through green hydrogen may not be fully captured in the incentives of the provider. There is likely additional gain to the economy beyond profitability to the provider. As such means of incentivising the complementary investments required such as investments in the transmission grid infrastructure, and regulating it so that such investment is incentivised will become important.

Going forward it is important to consider how the regulatory framework can be amended to incorporate and incentivise green hydrogen in a manner that minimises distortions. In addition, it would be useful to consider the existing regulatory framework and where adjustments or rethinking of the framework will assist in preparing the sector for a significantly different scenario, where aside from price and investment intangible factors such as the impact on climate change are also incorporated into decision-making. Absent the development of a good regulatory framework potential outcomes include insufficient investment in green hydrogen which would squander South Africa's natural advantages, or alternately investment that is focused on minimising regulatory requirements and interactions, which is likely to result in hydrogen being produced for export or own use which would limit the overall spillovers on industry and the South African economy.

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Appendix A: Regulatory roles and responsibilities

At present, the roles of different regulators are fairly fragmented. The DMRE is responsible for the policy direction of the industry and shaping the supply side upstream. This includes, but is not limited to the following:

1. *Electricity supply:* In electricity, for example, the Minister has an important role in determining generation capacity, including whether generation capacity is needed, the types of energy sources required, and who can purchase the energy sold. It further has powers incidental to those purposes such as managing procurement, permits etc.[43] They also bear responsibility for universal access. This includes the development of the Integrated Energy Plan and the Integrated Resource Plan (IRP) which is a plan for electricity capacity. It also includes for example, IPP procurement.
2. *Upstream exploration and supply for petroleum and gas:* This is governed by the Mineral and Petroleum Resources Development Act (28/2002). The Petroleum Agency of South Africa promotes gas exploration and regulates permits and rights related to this.
3. *Petroleum licensing and price control:* The DMRE is responsible for licensing of petroleum retail and wholesale (though not infrastructure) and for setting the price of petroleum products through the Central Energy Fund.

NERSAs functions include setting and approving tariffs and prices, licensing, compliance monitoring and enforcement, and dispute resolution for electricity, gas and petroleum pipelines.[44]

The responsibilities of NERSA per product are highlighted in the table below.

Table 1 : Responsibilities of NERSA per product

	Electricity	Piped Gas	Petroleum Pipelines
Licensing	Operation of generation transmission and distribution of electricity	Construction of gas transmission, storage, distribution, liquification and regassification	Construction of petroleum pipelines, loading and storage facilities
	Import and export of electricity	Conversion of gas transmission, storage, distribution, liquification and regassification	Conversion of petroleum pipelines, loading and storage facilities
	Trading of electricity	Operation of gas transmission, storage, distribution, liquification and regassification	Operation of petroleum pipelines, loading and storage facilities
		Gas trading	
Price regulation	Regulates all prices and tariffs	Regulates upstream and downstream prices and tariffs (including gas, pipelines and trading)	Sets or approves downstream prices and tariffs (pipelines, loading and storage) but not fuel itself

[43] S46 of the Electricity Regulation Act
[44] NERSA Annual Report 2020-2021

Information gathering	Yes	Yes	Yes
Make relevant rules	Yes	Yes	Yes
Monitoring	Yes	Yes	Yes
Compliance	Yes	Yes	Yes
Mediation	"May" rather than "must"		
Investigation	"May" rather than "must"	Yes	Yes
Competition		Promotes competition	Promotes competition
		Monitors non-discrimination	Monitors non-discrimination and access
Promote optimal use of resources		Yes	Yes

The regulatory framework itself is split into three key bodies of legislation with different acts regulating electricity, gas and petroleum. From the economic regulatory perspective, the key acts are the Electricity Regulation Act, no 4 of 2006, the Gas Act, 48 of 2001 and Petroleum Pipelines Act, no 60 of 2003. In addition, there is the Petroleum Products Act, 120 of 1977 which regulates petroleum products. The various Acts carry through the theme of balancing the different objectives of regulation listing a range of objectives which differs slightly across each sector.

In addition, there are various other institutions involved in determining energy policy:

- Central Energy Fund (which owns PetroSA and the Strategic Fuel Fund) which fall under the DMRE
- The Department of Public Enterprises which is the line department for the state-owned enterprise Eskom.
- Operation Vulindlela- a set of reforms spearheaded by the Presidency and National Treasury that includes a focus on electricity.

Operation Vulindlela:

Operation Vulindlela is a set of structural reforms spearheaded by the Presidency and National Treasury. One of the five key objectives is the stabilisation of the supply of electricity. The eight reforms that relate to electricity including raising the licensing threshold for embedded generation, emergency procurement of 2 000 MW, procuring new generation capacity in terms of the IRP 2019, enabling municipalities to procure power from independent power producers, restructuring Eskom, increasing the Energy Availability Factor (EAF) to 70% and addressing inefficiencies in municipal electricity distribution.[45]

As can be seen from the discussion above the roles and responsibilities of the DMRE and **NERSA are fragmented.** This has had very real consequences for the development of the energy sector. For example, while the DMRE has developed certain policies (such as the proposed movement from municipal to regional distributors), **a lack of progress at departmental level has created consequences for the regulator** who has had to regulate on the basis of policy developed for a different market structure. In the example of regional distributors this has resulted in court challenges due to an electricity pricing policy that envisions better capacitated distributors than exists in practice and requires cost-based pricing, which has not been practically possible.

The **regulatory structure also differs depending on the product** in question. For example, in piped gas, NERSA is involved in licensing, compliance and pricing of the gas molecule, as well as setting and approval of tariffs for transmission and distribution. In contrast, in the liquid fuel sector the DMRE is responsible for licensing and price setting of fuel, while NERSA is responsible for the licensing and approval of tariffs for infrastructure petroleum pipelines, storage and loading. In petroleum, different licences are required from DMRE as well as NERSA, given one regulates retail and wholesale, and the other regulates infrastructure including loading and storage facilities. As such, there is a fragmentation in regulatory responsibility and some overlap.

There are also **differences in the extent to which competition and entry is emphasised** across sectors. In the electricity sector the Act does not specify a mandate for NERSA in ensuring that there is competition and access (which is likely a legacy of having a single monopoly provider). In contrast, this is a stronger consideration in gas regulation which also has a dominant supplier Sasol, and petroleum. For gas, NERSA has undertaken studies into adequacy of competition and there has been a focus on regulating for competition. However, the efficacy of this has been debatable has been given the industry context and in particular, the limitation in supply and historical circumstances which has led to a near-monopoly incumbent and very limited forms of competition (at trading level) on the margin.

In petroleum pipelines and storage facilities, NERSA focuses less on promoting competition and more on regulating tariffs and the like. While there are hundreds of storage facilities in South Africa, and therefore likely competition in at least some geographic areas, each storage facility has a specific tariff set which may in some instances may be inefficient and impede dynamic competition. However, in respect of pipelines, NERSA failed to licence an independent pipeline in 2007 that might have competed with Transnet's facilities.[46] Transnet remains a monopoly pipeline provider for key supply routes.

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[45] National Treasury and Presidency (2022), Operation Vulindlela Summary Booklet, available at http://www.treasury.gov.za/Operation%20Vulindlela%20Summary%20Booklet%20March%202021.pdf

[46] See: https://www.engineeringnews.co.za/article/nersa-defends-decision-not-to-award-ipayipi-licence-2009-03-16