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Analysing the prospects of grid-connected green hydrogen production in predominantly fossil-based countries – A case study of South Africa

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ABSTRACT

Importing substantial amount of green hydrogen from countries like South Africa, which have abundant solar and wind potentials to replace fossil fuels, has attracted interest in developed regions. This study analyses South African strategies for improving and decarbonizing the power sector while also producing hydrogen for export. These strategies include the Integrated Resource Plan, the Transmission Development Plan, Just Energy Transition and Hydrogen Society Roadmap for grid connected hydrogen production in 2030. Results based on an hourly resolution optimisation in Plexos indicate that annual grid-connected hydrogen production of 500 kt can lead to a 20–25% increase in the cost of electricity in scenarios with lower renewable energy penetration due to South African emission constraints by 2030. While the price of electricity is still in acceptable range, and the price of hydrogen can be competitive on the international market (2–3 USD/kgH_2 for production), the emission factor of this hydrogen is higher than the one of grey hydrogen, ranging from 13 to 24 kgCO2/kgh$_2$. When attempting to reach emission factors based on EU directives, the three policy roadmaps become unfeasible and free capacity expansion results in significant sixteen-fold increase of wind and seven-fold increase in solar installations compared to 2023 levels by 2030 in South Africa.

List of abbreviations:

Abbreviation	Meaning	Abbreviation	Meaning
CF	Capacity Factor	LHV	Lower Heating Value
CO2	Carbon Dioxide	LT	Long Term
CO2 cap	Carbon Dioxide Cap	MT	Medium Term
CSP	Concentrated Solar Power	NPV	Net Present Value
EAF	Equivalent Availability Factor	OCGT	Open Cycle Gas Turbine
EPRI	Electric Power Research Institute	PASA	Projected Assessment of System Adequacy
ERA 5	ECMWF Reanalysis 5	PV	Photovoltaic
EU	European Union	R&D	Research and Development
FO&M	Fixed Operation and Maintenance	RED	Renewable Energy Directive
H2	Hydrogen	RES	Renewable Energy Sources
IDC	Interest During Construction	ST	Short Term
IDM	Integrated Demand Management	TDP	Technology Development Plan
IEA	International Energy Agency	TPC	Total Project Cost
IRP	Integrated Resource Plan	UCED	Unit Commitment and Economic Dispatch
JET	Just Energy Transition	VO&M	Variable Operation and Maintenance
JET-IP	Just Energy Transition Investment Plan	vRES	Variable Renewable Energy Sources
LCOE	Levelized Cost of Energy	ZAR	South African Rand (currency)

(continued on next column)

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1. Introduction

To reach the Paris Agreement aims to limit global temperature increase below 2 °C, preferably 1.5 °C [1], the energy sector needs to be transformed completely. Hydrogen, a versatile and clean energy carrier, is expected to play a significant role, as it can be produced in low carbon-based manners, has a wide range of applications, and can be stored for long durations [2]. It is anticipated that hydrogen will fulfil up to 24% of the final energy demand within the European Union (EU) in net zero emission scenarios [3].

However, currently hydrogen production predominantly relies on fossil fuels, contributing significantly to CO_2 emissions [4]. Alternatively, hydrogen can be derived from electrolysis powered by renewable energy sources like wind and solar [5]. While this so-called green hydrogen production is still very small with a production volume of a mere 0.5 million tons in 2020, projections envision a substantial increase to 80 million tons by 2030 [4].

In addition to domestic green hydrogen production, hydrogen is foreseen to be imported from countries with abundant solar and wind resources, such as South Africa and Namibia [6].

Extensive research has been conducted to assess how green hydrogen production can be realised spanning topics such as potentials, costs, and integration into existing power systems. Some studies have focused on the assessment of potentials of green hydrogen in various countries, revealing promising opportunities [2,7–9]. Study by Goudal et al. [10] concludes that it is technically feasible for Pakistan to meet its total hydrogen demand from biomass (including waste). Kakoulaki et al. [11] suggests that the EU and UK have enough wind, solar, and hydro resources to meet current electricity and hydrogen demand. Turkey shows high potential for green hydrogen from solar energy with estimated 427 Mt/year [12]. In Niger, dedicating 5% of land area to solar production could meet hydrogen demand for electricity and transportation by 2040, producing 18 Mt [2]. However, these studies did not consider the impacts of grid integration and associated costs in depth.

Regarding hydrogen production cost, studies indicate currently a cost of approximately $5 per kilogram, notably higher in comparison to its grey and blue hydrogen counterparts, which were priced at $1.2 and $2.4 per kilogram, respectively, in 2019 [5]. These costs depend on the capital investment required for electrolysers, their efficiency, and utilization factors, and the prevailing electricity prices. Expectations are that green hydrogen may be economically viable at a cost as low as $2 per kilogram by 2030 due to declining renewable energy prices and advancing electrolyser performance [5,13]. These costs are based on stand-alone systems [5,13].

Furthermore, research exploring the implications of integrating hydrogen production into the power system reveals mixed outcomes. Positive effects include reduced electricity costs and lower CO_2 emissions [14–16]. Gulvan et al. [14] demonstrates that incorporating green hydrogen (up to 20% of electricity demand) in South America's power system reduces electricity production costs using the LEELO tool. Similarly, utilizing the Plexos simulation tool, another study reveals that green hydrogen (3% of electricity demand) can decrease operational costs by over $6/MWh and lower CO_2 emissions by up to 16% in the 2030 scenario within the U.S. Western Interconnection grid [15]. Also for the U.S., Ricks et al. [17] find that grid-connected electrolysis in 2030 increases emissions unless paired with 100% clean energy on an hourly basis, which effectively reduces emissions at minimal additional cost. Nevertheless, these benefits are counterbalanced by higher hydrogen production costs, partly attributable to underutilized electrolyser capacity and elevated renewable electricity prices [16,18]. Pastore et al. [18] suggests that achieving hydrogen prices below 2.44 euros/kg by 2030 in Italy is unlikely due to high renewable energy prices. Further techno-economic studies are available in the literature review conducted in Ref. [16].

In summary, hydrogen integration into the power system is sensitive to factors, such as power system characteristics, energy source for hydrogen production, hydrogen demand profiles, decarbonisation targets and future technology costs. Decarbonizing fossil-based countries while producing cost-competitive green hydrogen for export presents unaddressed integrated impacts. Therefore, the impact of hydrogen production in a predominantly fossil-based electricity system like in South Africa, remains insufficiently understood. This leads to the following overarching research question: Does the integration of hydrogen production within these systems result in positive impacts by provision of flexibility, thereby reducing unserved energy, emissions, curtailment, and costs? Alternatively, does the additional load required for hydrogen production result in an increase of these factors?

This study seeks to bridge the existing knowledge gap encompassing the impact of hydrogen production within predominantly fossil-based electricity systems, with a particular focus on South Africa as a representative case study.

Around 80% of South Africa's electricity production relies on fossil fuels [19]. Nevertheless, the country has set forth an ambitious strategy for green hydrogen production and renewable energy adaptation by 2030. The Hydrogen Society Roadmap aims to achieve 500 kt of green hydrogen production within the specified timeframe [20]. However, it remains unclear from the study whether this production will be integrated into the grid or operate independently. Currently, Eskom, the primary public utility in South Africa, operates 30 power plants with a total capacity of 46.5 GW, fuelled mainly by coal, and additionally nuclear, hydro/pumped hydro, gas turbines, and wind sources. The Renewable Energy Independent Power Producer Programme (REIPPPP) has resulted in approximately 6 GW of operational renewable energy capacity, primarily from wind and solar PV. Despite these advancements, coal continues to dominate South Africa's generation capacity, accounting for 74% [19].

Several policy roadmaps have been published to increase renewable energy penetration and improve the grid in South Africa until 2030. The Integrated Resource Plan (IRP) by the South African Department of Energy outlines the preferred future generation technologies [19], with increased wind and solar PV capacities and reduced coal capacity. The Transmission Development Plan (TDP) by Eskom focuses mainly on grid infrastructure development [21], while the Just Energy Transition Investment Plan (JET-IP) by the Presidency of South Africa aims for a low-carbon and sustainable energy sector [22].

This study uses these three energy policy roadmaps, along with the South African Hydrogen Society Roadmap, as inputs to analyse the potential impact of grid-connected green hydrogen production on emissions, costs, and system dynamics. This novel approach highlights the integrated challenges and effects of decarbonizing a fossil-based country while pursuing green hydrogen production and export, using a high-resolution temporal feasibility study. Additionally, an analysis based on cost-optimised capacity planning for future technologies up to 2030 is included.

2. Method

To investigate the impact of grid connected hydrogen production, a power system model for South Africa has been developed in the Plexos[1] modelling platform. The analysis includes the three policy scenarios, based on roadmaps introduced earlier, namely the *IRP*, the *TDP* [21] and the *JET-IP* [22]. Additionally, a *Free expansion* scenario has been designed where additional capacity planned after 2023 is freely optimised with cost minimisation. Further analysis has been carried out with *EU H_2 emission standard, High demand, Low demand, Current demand* and *Low gas price* scenarios.

The power system model entails detailed techno-economic properties, hourly resolution, and variable renewable electricity (RE) supply

[1] For more information on the Plexos modelling platform, see energyexemplar.com/Plexos.

patterns based on geographic and temporal sampling, and aggregation for South Africa. The results of the power system model are used to calculate the most important characteristics and outputs within this modelling context, including unserved energy factors, levelized cost of electricity (LCOE), levelized cost of hydrogen (LCOH) and emission factors. Unserved energy is the unmet demand in 2030, summed for each hour when maximum available generation is lower than demand. In the following paragraphs, the power system model, input data, scenario description and post processing methods are explained in more detail.

2.1. Power system modelling

Fig. 1 illustrates the schematics of the South African power system model constructed in Plexos. In the long term (LT) Plexos mode, capacity expansion is optimised by minimizing the net present value (NPV) of the total system including costs for construction, operational, fuel, and the value of lost load [23]. In the short-term (ST) Plexos optimisation, unit commitment and economic dispatch (UCED) costs are minimized on an hourly basis deterministically.

The optimisation process considers the year 2030 with an hourly temporal resolution, considering both existing and planned capacity, exogenously accounting for the power system capacities from the three roadmaps [19]. This approach is important due to the reliance on coal as the primary power source in South Africa, which is expected to continue in 2030. Additionally, nuclear and hydro power are anticipated to be still operational in 2030. Since detailed geographical distribution of new generation capacities are unavailable, a copperplate approach is adopted, assuming that new capacities align with the transmission and distribution capabilities in 2030. Besides the three fixed policy roadmap-based capacity scenarios, a free capacity expansion scenario is explored, where old capacities are exogenously determined and additional capacity endogenously optimised.

To assess the role of hydrogen production in the three roadmaps, a fixed daily hydrogen demand is applied, which must be fulfilled by the end of each day. According to the South African Hydrogen Society Roadmap [20], it is projected that 500 kt of annual hydrogen production will be achieved in 2030, equivalent to 60 PJ/year lower heating value (LHV) of grid-connected electrolyzed hydrogen output, leading to an additional electricity demand of 80 PJ/year.[2] This demand is originally not anticipated in three policy roadmaps (IRP, TDP, JET). This translates to approximately 0.16 PJ_{LHV}/day, with the flexibility of producing optimally at any time of the day. To optimize hydrogen production capacities including electrolysers, fuel cells, and hydrogen storage, the policy roadmap scenarios are also modelled in the LT mode, in addition to the exogenously determined power system capacities. This enables the identification of the most cost-effective pathways for hydrogen production, which is essential for estimating the LCOH. Once all power system and hydrogen production capacities are determined, the power system is modelled in the ST mode for UCED, aiming to assess adequacy and operational costs.

2.2. Input data

For the UCED optimisation, reliable cost assumptions and detailed hourly technical assumptions, including ramp up/down rates, forced outages, start costs and hourly demand and supply portfolios are required.

Where available, data specific to South Africa or Africa has been used (mostly from Electric Power Research Institute EPRI [24]and International Energy Agency (IEA) [25]). Where only EU specific data was available [22], this was modified to the South African context (see assumptions in Table 1) [17,19,20].

The build cost for existing plants such as old coal, nuclear, hydro and gas turbines has been excluded.

Regarding the storage and transport of hydrogen, pressurised tank storage has investment costs of 24,000 ZAR_{2021}/GJ capacity and variable operation cost of 46 ZAR_{2021}/GJ and 7.5 ZAR_{2021}/MJ for short distance transport within South Africa [28,29].

In a post-processing cost analysis, LCOE and LCOH are used as main indicators. LCOE is calculated as the total annualised power system related costs (excluding electrolysers, hydrogen transport and hydrogen storage related costs) divided by served electricity demand. LCOH is calculated as the total cost of electrolysers, input electricity as fuel (based on the LCOE results of the model), hydrogen transport and hydrogen storage related annualised costs divided by total hydrogen production. For both LCOE and LCOH, fixed costs are annualised assuming a discount rate of 8%.

To account for all expenditures in the power sector, costs have been added to the postprocessing results. These costs, such as taxes, levies, and R&D, are exogenous to conventional power system modeling, which typically includes infrastructure investment, operation and maintenance, and fuel costs. However, we add these additional costs post-modeling to provide more realistic and comparable electricity and hydrogen prices. Based on Eskom's multi-year price determination (MYPD4) [30], these costs (see Table 2) help correct the underestimation of electricity prices from the Plexos model. Additionally, the value of lost load is assumed to be 50,000 ZAR/MWh [31].

All existing generation plants that are expected to still be in operation by 2030 [19,24] are included in the model. In cases where additional capacity is expected to be built, but information on expected operating characteristics is lacking, the new capacity is assumed to mirror the characteristics of the most recently constructed generator using the same fuel type. In the *Free expansion* scenario, the addition of these units is optional.

The model includes maximum generation, minimum stable generation, ramp rates, heat rates and starting cost as detailed for the model developed and described in Ref. [11]. Table 3 shows the heat rate of thermal power plant in four load points.

The weighted average outage rates and energy availability factor (EAF) for each technology are based on the assumptions given in the 2019 IRP Addendum [24] (see Table 4) assuming that the current availability factors will be restored to normal levels before 2030 by the corrective measures that are currently being enacted.

The electricity demand data used includes both consumption, and transmission and distribution losses. The hourly demand profile is based on the hourly demand from 2017 [33], because this is the most recent year of data where South African electricity consumption has not been distorted by rotational load shedding. Next, the profile was scaled up to match the projected demand in the low, medium, and high demand scenarios identified in the 2019 IRP [20].

To preserve the relationship between weather-based demand and renewable resource availability patterns, data from 2017 was used. Windspeed and solar irradiation data from the ERA 5 dataset provided by the European Centre for Medium Range Weather Forecasts [34] was used to create composite hourly wind and PV capacity factor curves. The dataset has a 0.25° x 0.25° (longitude x latitude) spatial resolution. Windspeed data was processed using the method outlined in Ref. [35] and solar irradiation data was processed using the PV Watts model in the System Advisor Model [36]. A total of 1800 capacity factor patterns were created for both wind and PV. These patterns were then sorted by annual overall capacity factor. 15 locations between the 80th and 95th percentile, 10 between the 80th and 65th percentile, and 5 between the 65th and 50th percentile were randomly selected and averaged to create one capacity factor curve for solar and one for wind.

Monthly and daily variability of solar and wind portfolios are shown in Fig. 2.

[2] Based on 75% electrolyser efficiency assumed in this study.

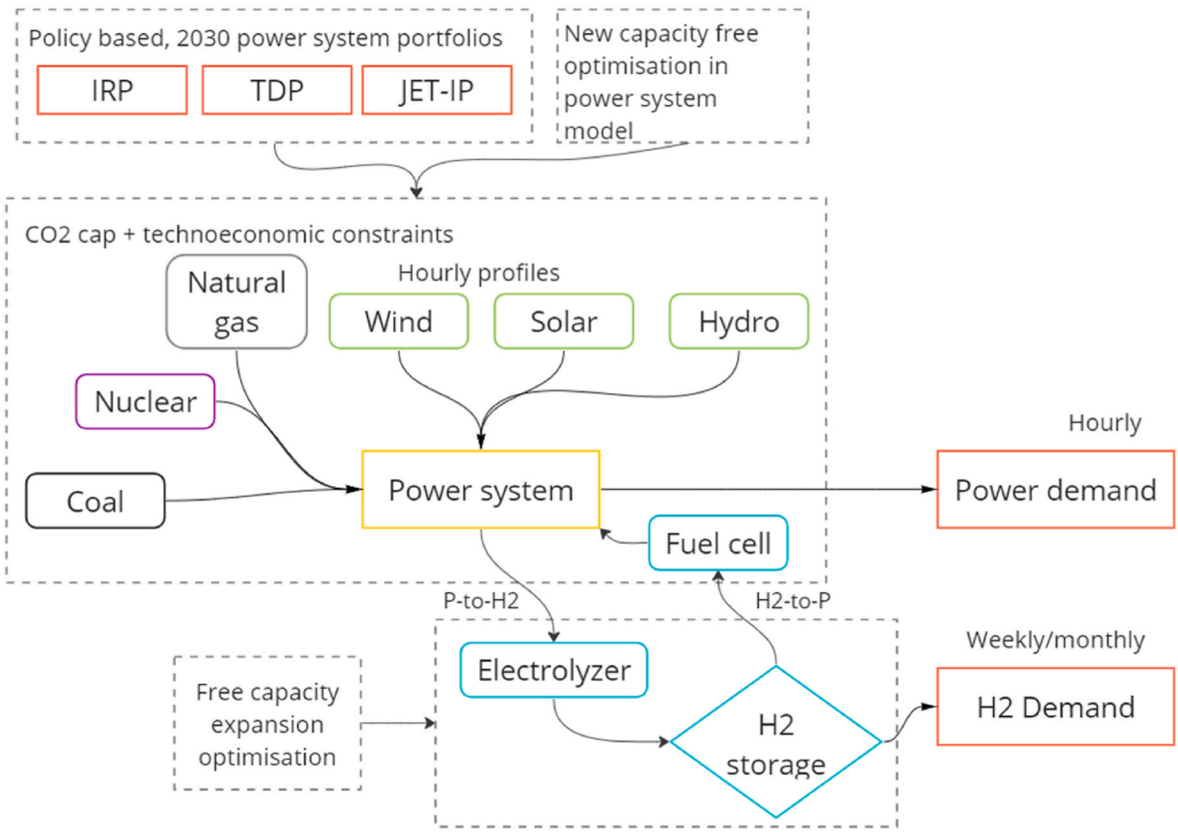

Fig. 1. – Schematic of Plexos model building blocks with orange representing the exogenously determined fixed capacity portfolios based on policy roadmaps and demands (power and hydrogen). The capacities of the hydrogen production related components in light blue are endogenously optimised.

Table 1
– Technoeconomic assumptions for South Africa 2030, expressed in ZAR_{2021} (1 EUR_{2021} = 17.5 ZAR_{2021}).

		TPC + IDC [ZAR_{2021}/kW]	VO&M [ZAR_{2021} MWh]	FO&M [ZAR_{2021}/kW-yr]	Fuel price ZAR_{2021}/GJ	Emission factor [$kgCO_2/GJ_{input}$]	Economic life [yr]	Construction time [yr]	Unit size[g] [MW]
Coal[a]	PC	57,500	78	850	43	101	30	4	750
	IGCC	84,500	85	1606	43	0	30	4	930
Nuclear[a]		–	62		10	0	60	6	167
Gas[a]	OCGT	11,700	3.2	148	241	56	30	2	625
Hydro		62,000[b]		1,230[b]	–	0	60[e]	4[e]	1
Wind[c]	Onshore	21,600	0	86	–	0	20	2	1
PV[c]	C–Si	11,800	0	90	–	0	25	1	1
CSP[a,i]	Parabolic trough	120,900	1	1370	–	0	30	4	100
Battery[f,h]		9300			–		15	1	
Fuel cell[d,h]		10,750	7		–	0	15	1	1
Electrolyzer	PEM[d,h]	9700	9	150	–	0	15	1	1

TPC + IDC: total powerplant costs including interest during construction, VO&M: variable operation and maintenance costs.
FO&M: fixed operation and maintenance costs.
For existing coal, gas, nuclear and hydro generators, no build costs have been included.
All costs are expressed in ZAR2021.
[a] Electric Power Research Institute (EPRI) Power generation technology data for South Africa [24].
[b] IEA Hydropower costs 2030 [26].
[c] JET-IP cost projections to 2030 (high renewable deployment scenario) [22].
[d] IEA Global Hydrogen Analysis costs for 2030 [25].
[e] Zuijlen et al., 2019 [27].
[f] European Commission cost assumptions 2030 [28].
[g] List and unit sizes of existing power plants can be seen in appendix A.
[h] Assumed efficiency of battery: 94%, fuel cell: 75%, and electrolyser: 75% [28], efficiency of thermal generators and RE are further specified below (heat rates and capacity factors).
[I] For CSP, Parabolic trough is assumed with 6 h storage.

Table 2
Additional power generation related expenditure included in total costs after optimisation in ZAR_{2021}.

Category	Billion ZAR_{2021}
International purchase	3.73
Depreciation	72.92
Integrated Demand Management	0.19
Research & development	0.19
Levies and Taxes	8.20
Other expenditure	10.00
Total:	**95.23**

International purchase: acquired energy or services from foreign markets; Depreciation: Gradual decrease in the value of old power plants and infrastructure due to wear and tear, obsolescence, or other factors; Integrated Demand Management (IDM)t: Operation and management cost in monitoring and optimizing customer demand, inventory levels, production, and distribution; Levies and Taxes: Mandatory payments imposed by government; Other expenditure: small and diverse, mainly operational, expenditures. Based on MYPD4 by Eskom [30].

Table 3
– Heat rate curve of coal power plant, open cycle gas turbine (OCGT) and nuclear expressed in 4 load points used in this model (25%, 50%, 75%, 100% capacity) expressed in GJ/MWh. Source of heat rate: EPRI for the 2019 IRP [30].

Load point	Coal	OCGT	Nuclear
25%	12.5	21.0	10.3
50%	10.4	15.0	10.3
75%	9.8	11.2	10.3
100%	9.7	11.5	10.3

Table 4
Average outage percentage by technology type.

Gen Technology	Planned	Unplanned	Total EAF
Coal	7%	21%[a]	72%
Hydro	4%	4%	92%
Storage	4%	4%	92%
Nuclear	10%	5%	85%
Gas	3%	3%	93%
CSP	7%	13%	80%

[a] 50% of unplanned outages in coal plants are assumed to be partial [32].

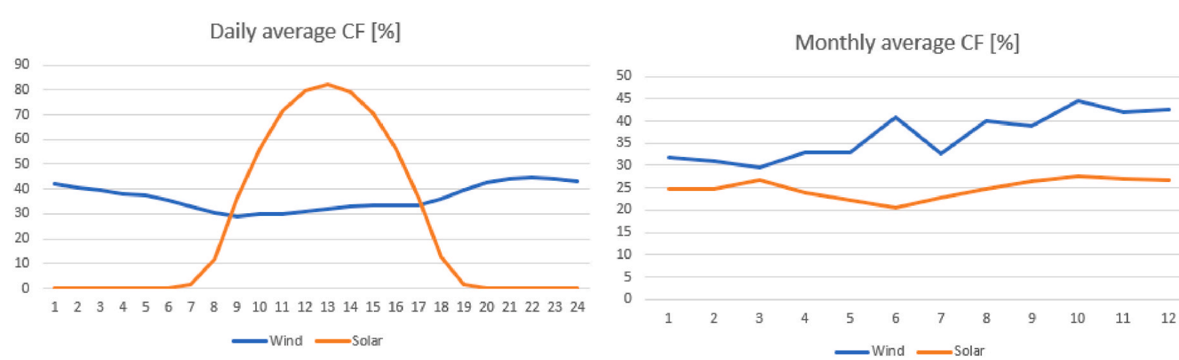

Fig. 2. Daily (left) and monthly (right) average capacity factors (CF) in percentage for the wind and solar generation profiles.

2.3. Scenarios

The study includes four core scenarios that were all investigated with and without hydrogen demand, resulting in eight scenarios. The three policy scenarios are based on the energy strategies for South Africa by 2030: *IRP*, *TDP* and *JET-IP*, and are complemented with a *Free expansion* scenario, where planned constructions from the policy scenarios (after 2024) are replaced with free endogenously optimised capacity expansion. A summary of the scenarios is provided in Table 5.

An emissions cap of 35 % reduction compared to 2019 level is assumed based on the policy target of the South African government [22].

An alternative CO_2 emission cap based on *EU hydrogen standards is also assessed. For this,* the Renewable Energy Directive (RED III) upper limit of renewable hydrogen emissions is used, corresponding to a maximum electricity emission factor ranging from 60 to 90 gCO2/kWh[3] when producing electrolytic hydrogen [37]. Notably, the RED renewable hydrogen directive incorporates a temporal correlation clause, specifying that the emission factor requirement applies solely during hydrogen production hours. However, meeting this emission cap [37] only during hydrogen production periods poses computational challenges. Consequently, the stringent emission range of 90 gCO2/kWh was applied to the overall electricity production to address this complexity.

Additionally, three sensitivity scenarios have been designed. The first one is based on the IRP lower natural gas price projection of 64 ZAR_{2021}/GJ, instead of the base 240 ZAR_{2021}/GJ titled *Low gas price*. The other two scenarios are testing the sensitivity of the results with respect the electricity demand by changing the base demand of 299 TWh/yr_{2030} to 308 TWh/yr_{2030} in the *'High demand'* scenario, and 275 TWh/yr_{2030} in the *Low demand* scenario. Finally, the scenario, *Current demand,* is used to investigate the impact of the electricity demand in 2030 remaining at the 2017 level of 234 TWh/year.

3. Results and discussion

3.1. Generation capacity and production share

The installed generation and electrolyser capacities in the South African electricity system by 2030 under the various roadmaps and their scenarios are shown in Fig. 3. The following can be observed.

- **Large scale wind and solar deployment.** The *Free expansion* scenario without hydrogen demand results in about 39 GW solar capacity and 37 GW wind by 2030, which is a 7-to-8-fold increase compared to 2023 in line with the developments envisioned in the JET-IP scenario. The balance between wind and solar can easily shift, as it is quite sensitive to technoeconomic assumptions. Including hydrogen demand leads to 28% higher solar and 16% lower wind capacity installation, most likely due to increased flexibility via electrolysis and hydrogen to power (H2P) enabling more capacity of highly variable solar production.

[3] 65–90 gCO_2/kWh range depends on the range of fossil fuel comparators of 60 gCO2/MJ to 85 gCO2 in RED-II [48] combined with renewable hydrogen directive stating 70% emission saving requirement of fossil fuel comparators [37].

Table 5
Scenario summary.

	Coal	Nuclear	OCGT	Hydro	CSP	Wind	Solar	Storage	electrolyser	H_2 demand	CO2 cap
	GW									PJ_{LHV}	Mt/yr
IRP	33.3	1.9	6.8	4.6	0.6	17.7	8.3	5	X	X	175
TDP	33.3	1.9	6.8	4.6	0.6	19.5	10.0	2	X	X	175
JET-IP	33.3	1.9	6.8	4.6	0.6	33.7	34.0	5	X	X	175
Free expansion	31.8+	1.9	3.8+	2.1+	Free opt	Free opt	Free opt	Free opt	X	X	175
IRP with H_2 demand	33.3	1.9	6.8	4.6	0.6	17.7	8.3	5	Free opt	60	175
TDP with H_2 demand	33.3	1.9	6.8	4.6	0.6	19.5	10	2	Free opt	60	175
JET-IP with H_2 demand	33.3	1.9	6.8	4.6	0.6	33.7	34.0	5	Free opt	60	175
Free expansion with H_2 demand	31.8+	1.9	3.8+	2.1+	Free opt	Free opt	Free opt	Free opt	Free opt	60	175

OCGT-open cycle gas turbine, CSP – concentrated solar power. All scenarios include fixed nuclear, gas, coal and hydro capacities and hourly demand profile based on IRP in 2017, 2030 strategy, emission constraint of 'Free expansion' is based on JET-IP. '+' means old capacity is fixed and additional capacity expansion is possible. Demand is 298.7 TWh in all scenarios. CSP includes 6-h storage and 'Storage' is a mixture of pumped hydro and chemical battery storage.

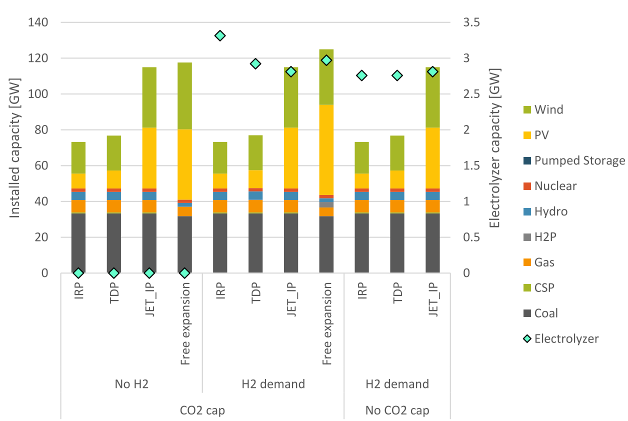

Fig. 3. – Total installed capacities in South Africa 2030.

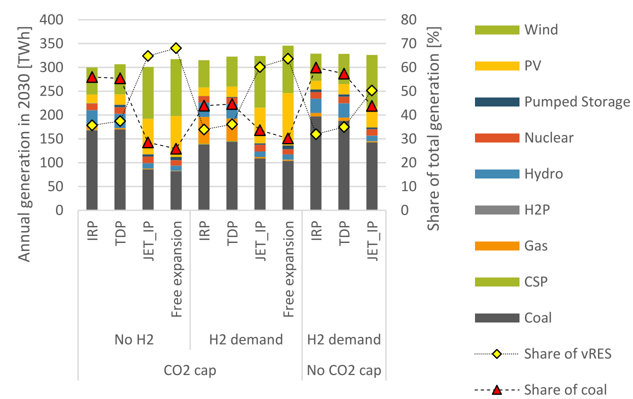

Fig. 4. – Total annual generation and share of chosen technologies in total generation on the secondary axis. vRES: variable renewable energy includes solar, wind and hydro.

- **Electrolyser capacity factor is sensitive to system flexibility.** Electrolyser capacity is similar across scenarios, except for the *IRP* scenario, where it is 18% higher than the average. Consequently, the electrolyser has a lower annual average capacity factor of 76% in *IRP*, compared to around 90% in other scenarios (85% in '*Free expansion*'). This disparity may result from the model's daily hydrogen demand constraint and *IRP*'s limited flexibility due to having the highest share of electricity production from coal.
- **The presence of a CO_2 cap affects electrolyser capacity in *IRP* and *TDP* scenarios.** Without the cap, *IRP* and *TDP* scenarios exceed the 175 MtCO2/yr2030 emission limit by 12% and 7%, respectively, remaining below current emissions of 275 MtCO2/yr_{2019}.

Fig. 4 shows annual power generation by source in South Africa by 2030. Total generation remains relatively stable at 299-330 TWh, but the power mix undergoes significant variation in terms of natural gas, coal, variable renewables (solar and wind), and emission levels, with coal dominating across most policy scenarios.

- **Hydrogen does not increase the share of renewables, but does decrease coal.** When hydrogen (H_2) demand is considered, only the *JET-IP* scenario exhibit 17% increase in solar and wind production combined. Notably, the *Free expansion* scenario experiences only 2% increase in solar and wind generation, while their share out of total generation decreases by 7 % when H_2 demand is added. These shares are lowest in the *IRP* and *TDP* scenarios. When H_2 demand is incorporated, the coal's share decreases in all scenarios with the CO_2 cap, as this cap prevents coal to supply the additional electricity demand for the electrolysers (see Fig. 4).
- **Curtailment effects vary.** In the *IRP* and *TDP* scenarios, wind and solar energy do not require curtailment, even without H_2 demand (see Table 7). In these scenarios, additional electricity required for hydrogen production is provided by natural gas, forcing an important flexibility contribution by gas-fired power plants to become a base load, with 95 % annual average capacity factor. In the *JET-IP* scenario, 14 GWh solar energy had to be curtailed in the absence of H_2 demand, which is utilised when H_2 demand is added, while in the *Free expansion* scenario, curtailment of 47 GWh/yr remains even with added H_2 demand.
- **Hydrogen storage capacity requirements shows an upward trend with the uptake in solar and wind.** The storage capacity varies across different scenarios. The *IRP* scenario has the lowest capacity of 66 TJ, followed by 75 TJ in the *TDP* scenario, 116 TJ in the *Free Expansion* scenario, and 160 TJ in the *JET-IP* scenario. The hydrogen storage capacity can store around 5–14 % of the average solar and wind production per day in the form of hydrogen, and half to all of the hydrogen demand per day.

3.2. Costs and competitiveness with grey hydrogen

The breakdown of total costs and the levelized cost of electricity (LCOE) for all scenarios can be seen in Fig. 5

- **LCOE ranges from 940 ZAR/MWh[4] to 1360 ZAR/MWh across scenarios.** Scenarios excluding hydrogen exhibit comparable total

[4] In July 2024 1 ZAR = 0.054 USD and 0.050 EUR [49].

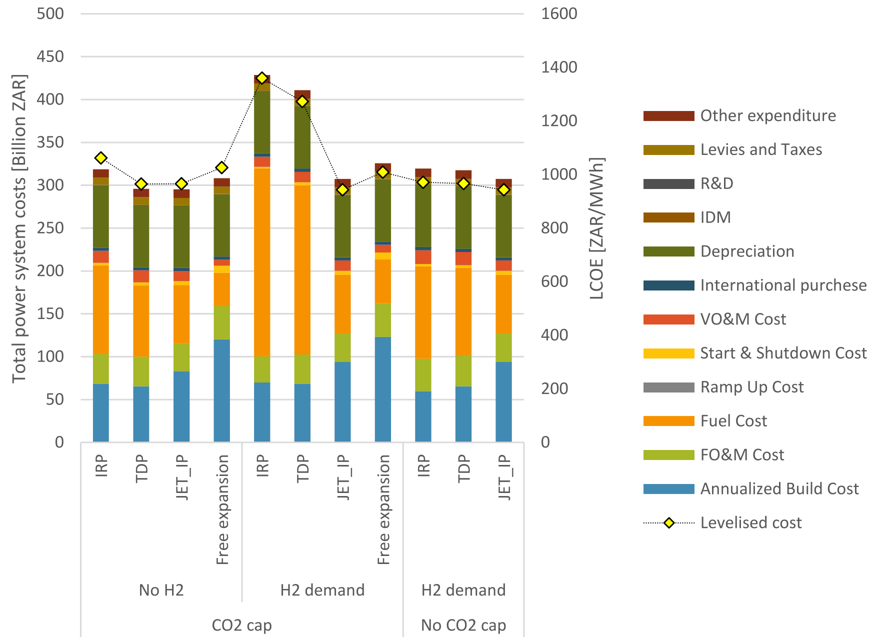

Fig. 5. – Total costs and LCOE in South Africa 2030 (ZAR_{2021}, excludes transmission and unserved energy costs).

costs and LCOE, with *JET-IP* showing higher CAPEX but lower fuel costs. Conversely, the inclusion of H_2 demand impacts LCOE differently, contingent on the level of renewables and curtailed generation, determining their efficiency and cost-effectiveness in meeting the increased generation. In the *IRP* and TDP scenario with lower renewable integration the LCOE increases with, respectively, 28 % and 30 %, when H_2 demand is introduced. In contrast, JET-IP enables a more cost-efficient incorporation of additional flexible demand, given higher VRE shares, leading to a 3% reduction in LCOE.

- **Trade-off between fuel costs and build costs arises as renewable capacity expansion yields fuel savings.** In the *Free expansion* scenarios, introducing H_2 demand results in higher electricity costs due to increased installation of mainly renewable capacity. Furthermore, when the CO_2 cap is excluded, the three policy scenarios exhibit similar total and levelized costs. This suggests that the CO_2 cap plays a significant role in the substantial increase in *IRP* and *TDP* costs when H_2 demand is incorporated.

According to the IRP report, the average costs in 2030 range from 1000 to 1200 ZAR/MWh [24]. In this study, the LCOE for the *IRP* scenario without hydrogen is in the lower end of the range, at 1060 ZAR/MWh.

Table 6
– Hydrogen cost breakdown in selected scenarios for South Africa 2030 with base IRP emission constraints. CAPEX includes electrolyser and storage; FOM, VOM include cost of compression, pressurised storage and water consumption; fuel costs are based on LCOE.

[Billion ZAR]		Annualised CAPEX	FO&M Cost	VO&M Cost	Fuel costs	H2 cost [ZAR/kg]
CO2 cap	IRP	3020	499	201	30,303	68
	TDP	2662	439	201	28,486	63
	JET_IP	2561	423	201	21,012	48
	Free opt.	2605	430	201	27,563	61
No CO2 cap	IRP	2513	415	201	21,636	49
	TDP	2514	415	201	21,547	49
	JET_IP	2561	423	201	21,012	48

Table 6 provides an overview of the total costs associated with hydrogen production.

- **The LCOH ranges from 48 to 68 ZAR/kgH_2, approximately equivalent to 2.6 to 3.7 USD/kgH_2.** In all scenarios, 80–90 % of this LCOH cost consists of the cost for the electricity input into the electrolyser, where cost is based on LCOE results presented in Fig. 5. In the *IRP* scenario with a CO_2 cap, LCOH are the highest due to an oversized electrolyser capacity and also the highest LCOE. Apart from *JET-IP*, the CO_2 cap increases hydrogen costs by around 30%–40%.

Some important indicators of hydrogen implementation on the power system can be seen in Table 7.

- **Grid-connected hydrogen demand reduces curtailment by 3%-5%,** particularly in scenarios with high variable renewable energy source (vRES) penetration. Despite a 6–10 % increase in unserved energy with H_2 demand, unserved energy factors remain low at 0.08–0.10 %, since the increase in unserved energy is proportional to the rise in total electricity demand, keeping the ratio relatively stable. However, none of the scenarios in this modelling context would be considered adequate according the 2013 IRP report in which the criterion for system adequacy was set at a maximum total shortfall of 20 GWh. Still, producing electrolytic hydrogen with only South African emission targets in mind, does not impact the system significantly. In the *JET-IP* scenario, the reduction in curtailment and subsequent lowering of LCOE may even make the slight increase in unserved energy acceptable.

Table 8 demonstrates the potential competitiveness of grid-connected hydrogen production in South Africa on the global market by 2030, where the following can be observed.

- **The hydrogen price range of 48 to 68 ZAR/kgH_2 can be traded on the global market for 2.6–3.7 USD/kgH_2** [38] **and requires an additional costs of 2–3.75 USD/kgH_2 for overseas shipping** [25, 39]. The International Energy Agency expects hydrogen to be competitive globally at around 1.5–2.5 USD/kgH_2 in 2030 [39], and

Table 7
Power system impact indicators for all scenarios with the CO_2 cap.

		Curtailed Solar & Wind	Load	Unserved Energy	Unserved Energy Factor*	Unserved Energy Hours
		GWh	TWh	GWh	%	h
No H2	IRP	0	306	304	0.10	193
	TDP	0	306	276	0.09	135
	JET-IP	14	307	283	0.09	112
	Free Opt.	47	324	256	0.08	134
With H2 demand	IRP	0	324	326	0.10	167
	TDP	0	325	307	0.09	176
	JET-IP	0	331	300	0.09	112
	Free Opt.	48	326	276	0.08	134

* Unserved energy factors are based on short term optimisation results. Note that these are significantly (over 4–10 times) higher than long term capacity expansion unserved energy levels, due to emission cap being the hardest constraint in the model, forcing in more unserved energy, since that is a soft constraint.

Table 8
Levelized cost and emission factor summary. Costs are expressed in 2021 ZAR. Emissions are only CO_2; other greenhouse gas emissions are excluded.

		CO2 emissions	LCOE	LCOH	Electricity emission factor	Hydrogen emission factors
		[MtCO2/yr]	ZAR/MWh	ZAR/kg	kgCO2/kWh	$kgCO_2/kg$
No H_2	IRP	182	1062	–	0.60	–
	TDP	169	965	–	0.56	–
	JET-IP	153	966	–	0.53	–
	Free Opt.	81	1026	–	0.25	–
H_2 demand	IRP	189	1360	68	0.62	24
	TDP	188	1273	63	0.58	23
	JET-IP	172	943	48	0.51	20
	Free Opt.	105	1009	52	0.30	11

when conditions change such as an increased natural gas prices or high carbon prices of 300–400 USD/tCO_2, it may be competitive at 3.5–4.5 USD/kgH_2.

- **The emission factors of this grid connected hydrogen are much higher than grey hydrogen.** A more significant barrier than the levelized cost of hydrogen (LCOH) would be the 30%–250% higher CO_2 emission factors associated with this hydrogen production compared to emissions of 9.4 $kgCO_2$/kg [40] of the conventional and cheaper steam methane reforming route [25]. If emission factors of hydrogen production are restricted internationally or in target countries, they may hinder trade of this type of hydrogen even when it is economically viable.

3.3. Potential for grid connected EU standard green hydrogen

The European Commission Renewable Energy Directive mandates that hydrogen can only be considered renewable if the greenhouse gas emission saving factor is equal to or greater than 70% compared to the fossil fuel alternative including all upstream emissions [41]. This means that emissions of electricity used for hydrogen should not exceed 60–90 gCO_2/kWh [41].

In the scenarios with South African emission target (175 Mt/yr), EU standard green hydrogen production with 90 g/kWh maximum emission factor electricity, takes place in certain hours with high renewable energy share. In the *JET-IP* and *Free expansion* scenarios, 24% and 34% of hydrogen production in 2030 is compliant with the RED-II directive and can, therefore, be considered renewable hydrogen. However, in the IRP and TDP scenarios, none of the produced hydrogen is compliant.

Therefore, an alternative emission constraint has been applied, enforcing an upper emission limit of 90 gCO_2/kWh to investigate trading opportunities with the EU, using base demand for this analysis. Furthermore, we have examined an alternative *Current demand* scenario assuming no increase in electricity demand from 2017, despite capacity expansion plans, potentially using excess capacity for hydrogen production (see Fig. 6) .

Based on the modeling results, the following can be observed.

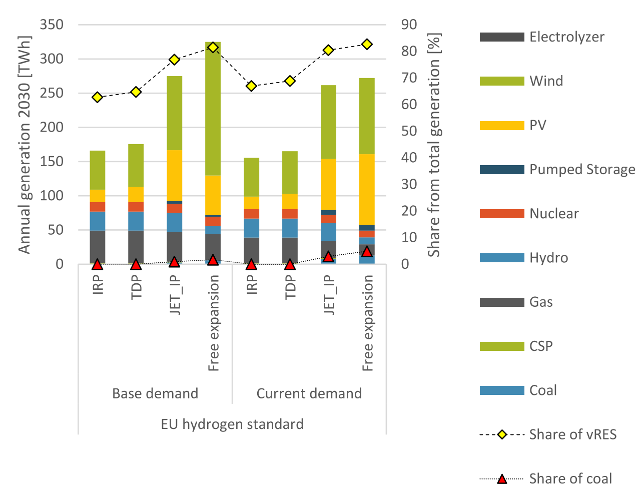

Fig. 6. EU renewable hydrogen standards (90 gCO2/kWh emission constraint) enforced scenario capacity expansion. In addition to the previously used medium demand profile (seen here as base demand), an additional scenario has been explored, where demand does not increase.

- **Although the same coal generation capacities are available, coal generation is near-zero across scenarios.** In the policy scenarios, enforcing European hydrogen standards leads to elimination of coal generation and an increase in renewable generation. The 34 GW of coal capacity will not generate any electricity anymore. Instead, gas fired power plants generate at higher capacity factors. Coal is only used in the *Current demand* scenario (at 2017 levels), in *JET-IP* and free expansion scenarios replacing about 40 % natural gas generation due to lower generation requirements.
- **The total costs of free expansion scenarios significantly rise due to the installation of 56 GW of wind and 43 GW of solar capacity.** Furthermore, fuel costs increase notably as natural gas replaces coal

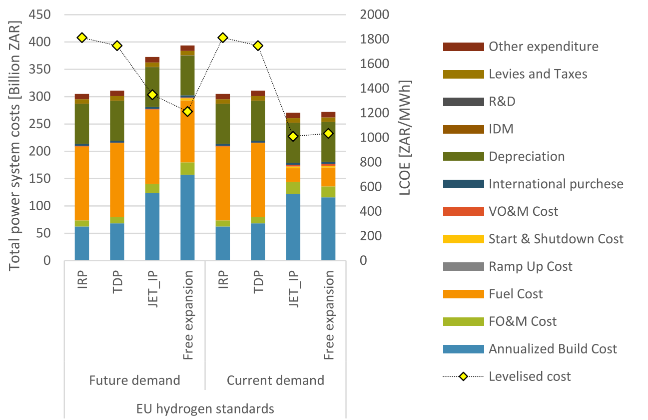

Fig. 7. Total cost and levelized costs of electricity (LCOE) in the 90 gCO2/kWh emission constraint enforced scenario.
Note that due to high levels of unserved energy, the policy scenarios in this context are considered unfeasible.

in future demand scenarios. As LCOEs are determined by dividing total costs by demand minus unserved energy, scenarios with lower production than demand experience a substantial increase in electricity costs.

- **Infeasibility due to large unserved energy factors.** This restricted generation results in significant levels of unserved energy (see Table 9). In the *IRP* and *TDP* scenarios, almost half of annual demand could not be met with 48 % and 45 % unserved energy respectively. It can be concluded that producing grid connected EU standard renewable hydrogen in South Africa is unfeasible in the *IRP* and *TDP* scenarios. Lower levels of unserved energy occur in future demand free expansion and the current demand *JET-IP* and the *Free expansion* scenario, with 7%, 4 % and 3 % respectively. If 3 % unserved energy is considered acceptable, then grid connected EU standard renewable hydrogen can be produced in South Africa in a *Base demand* scenario, with additional 56 GW of wind and 43 GW solar capacities installed by 2030.
- **The only potentially feasible free expansion scenario, with 3 % unserved energy and an assumption of a 2017 demand, LCOH is 52 ZAR/kg$_{H2}$, corresponding to 2.9 USD/kg$_{H2}$ (see Table 10 and Fig. 7).** This could potentially compete on international markets. However, while South African electricity demand has not grown during the 2010s, it is unclear how much of this plateauing effect can be ascribed to supply constraints and how much is due to increased efficiency that arose in response to rising electricity prices. The likelihood of this plateauing effect persisting when electricity supply constraints are removed has not been interrogated here. Additionally, the 3 % unserved energy is unlikely to be considered acceptable in the long term.

A significant trade-off is apparent between producing low carbon, EU standard grid connected renewable hydrogen for international trade and the reliability of the power system for domestic electricity consumption. Based on the modeling reported on above, it can be concluded that producing 500 kt/year grid connected electrolytic hydrogen that complies with the EU standard is highly unlikely in South Africa by 2030. However, about 24%–34% of this demand can be compliant when considering JET-*IP* and *Free expansion* scenarios. Kweinor Tetteh's review [42] of extensive literature concludes that green hydrogen is often deemed crucial for integrating renewable energy into South Africa's predominantly fossil-based power system, aligning with South African policy. However, most technoeconomic and feasibility studies focus on standalone hydrogen production systems, which do not consider renewable energy integration for transitioning away from fossil fuels [43–46]. These studies report higher feasibility and 10%–50% [43,45] lower hydrogen production costs compared to our study. Our research, examines the technoeconomic impact and feasibility of fully integrating hydrogen into the power sector, highlighting a significant gap. We find this integration highly challenging, with notably high emission factors often overlooked [42]. Nonetheless, with accelerated solar and wind adoption, it can still become feasible.

3.4. Sensitivity analysis

In a sensitivity analysis, the impact of a lower and higher electricity demand and a lowered natural gas price was investigated on the generation portfolio. With a low 2017 electricity demand, the renewable installed capacity can supply a larger share of the electricity demand. Natural gas only plays a role in two variants of the IRP and TDP scenarios and increases to 38–51 TWh. In these high demand scenarios natural gas is required to stay below the CO_2 cap, and in the low gas price scenarios it becomes more competitive. The contributions of the generation portfolios in the JET-IP and Free expansion scenarios are less sensitive and only scale up and down proportionally to changes in demand.

In the IRP and TDP policy scenarios, low demand leads to a notable increase in share of coal with 20% and 16% respectively in coal production, predominantly replacing natural gas. Conversely, in the JET-IP scenario, coal generation experiences a decrease of 20% (see Fig. 8).

Fig. 9 shows the change in cost related indicators of sensitivity scenarios, compared to their base case: with hydrogen demand and with CO_2 cap. Lowered demand and gas price runs show a 15%–22% decrease in levelized cost of electricity (LCOE) in all scenarios compared to the base case, except JET-IP. In JET-IP, LCOE increases by 14%–23% in low and high demand scenarios as well, since high demand requires burning of additional fuel, and low demand result in lower capacity factor across generation capacities.

LCOH follows the trends of LCOE, regarding sensitivity to input changes, since 83 %–90 % of the total costs resulting from input electricity price for electrolysis. Therefore, LCOH is sensitive to low demand, especially in case of IRP and TDP. Additionally, Free expansion scenario is sensitive to low gas price, reducing LCOH by about 20 %.

Table 9
Power system performance indicators for the scenarios with H_2 demand and a 90 gCO2/kWh emission constraint.

		Load	Max Unserved Power	Unserved Energy	Unserved Energy Hours	Unserved Energy Factor
		[TWh]	[GW]	[TWh]	[h]	[%]
Base demand	IRP	321	36.0	155	8760	48
	TDP	321	37.6	146	8760	45
	JET_IP	329	33.7	57	5530	17
	Free expansion	329	29.8	22	3232	7
Current demand	IRP	257	26.4	91	8612	35
	TDP	257	25.2	81	8318	32
	JET_IP	268	19.0	12	2585	4
	Free expansion	268	22.3	9	3454	3

Table 10
– EU renewable Hydrogen standard hydrogen production cost breakdown in the 90 gCO2/kWh emission constraint enforced scenario for South Africa 2030. CAPEX includes electrolyser and storage; FOM, VOM includes cost of compression, pressurised storage and water consumption; fuel costs are based on LCOE.

	Million [ZAR]	Annualised CAPEX	FO&M Cost	VO&M Cost	Fuel costs	H_2 cost [ZAR/kg]
Future demand	IRP	2511	414	201	40,397	87
	TDP	2511	414	201	38,971	84
	JET_IP	2511	414	201	30,058	66
	Free opt.	2568	424	201	27,028	60
2017 demand	IRP	2511	414	201	40,397	87
	TDP	2511	414	201	38,971	84
	JET_IP	2521	416	201	22,527	51
	Free opt.	2531	418	201	23,040	52

Note that due to extreme unserved energy, the policy scenarios in this context are considered unfeasible.

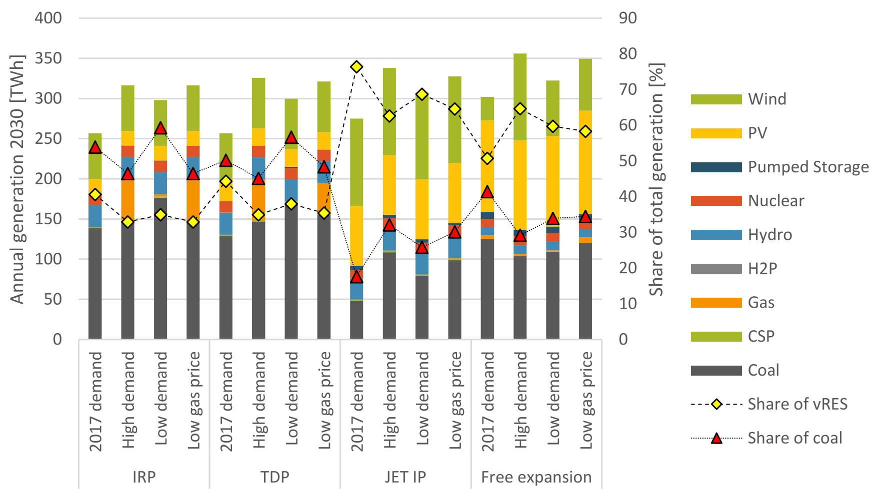

Fig. 8. Generation portfolios of sensitivity runs with high and low electricity demand, and decreased natural gas prices. All scenarios include hydrogen demand and a CO_2 cap of 175 Mt/yr CO_2.

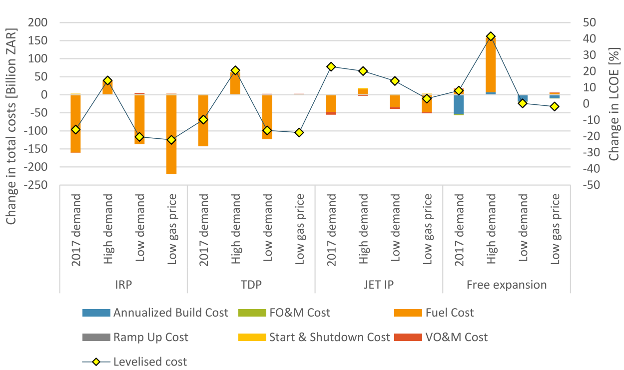

Fig. 9. Differences in total costs and LCOE in the sensitivity runs compared to their base scenarios.

3.5. Limitations

The results of the four 2030 energy scenarios, incorporating grid-connected hydrogen demand in South Africa, should be interpreted while acknowledging the following limitations and uncertainties.

Among the three policy scenarios, only the JET-IP scenario includes hydrogen demand in its power system design, while the IRP and TDP scenarios solely cater to future power demand in South Africa. To address this disparity, all scenarios were compared with and without H_2 demand, revealing up to 20% increase in LCOE and other impacts in the scenarios with H_2 demand.

The Renewable Energy Directive (RED) mandates emission factor compliance only during hydrogen production hours, while in this study annual average factors are used due to computational limitations. Although the limitation is partially mitigated with using upper limit (90 gCO_2/kWh, rather than 60 gCO_2/kWh), it still led to potentially stricter criteria than RED. Applying the constraint only during hydrogen production hours would result in higher average emission factors and increased installed electrolyser capacities, as electrolysers would need to produce the same 500 kt/year hydrogen more intermittently with a lower average capacity factor. Given that electrolyser fixed costs account for 10% of the Levelized Cost of Hydrogen (LCOH), this could significantly raise hydrogen costs while reducing impacts on the power system, costs, and unserved energy. While introducing this additional constraint would increase result accuracy, it not alter the conclusions for the three policy scenarios, although it could make the *Free expansion* scenario more viable. Future research could explore hourly matching in detail, similar to Ricks et al. [17].

The scenarios were modelled with a simplified representation of the power system grid, akin to a copper plate. This design choice was made due to the lack of spatial resolution in the scenarios, particularly regarding the planned locations of future capacities until 2030. This may have affected result accuracy, likely underestimating unserved energy and overestimating solar and wind capacity needs. It is recommended for future research to incorporate transmission and distribution lines into these scenarios.

Technoeconomic assumptions of power generation technologies for 2030 played a pivotal role in this study but are uncertain. As the sensitivity analysis showed, some alternative assumptions had significant impact on the results, thus finding need to be interpreted in the light of the baseline assumptions. The exact capacities and unit commitments depend on these cost assumptions, so their accuracy should be considered accordingly. Nevertheless, the main findings, especially regarding the high emission factors and infeasibilities, will remain unaffected by alternative assumptions.

This study focused on grid-connected hydrogen to understand the interaction between export hydrogen production and the domestic power system. Standalone green hydrogen production systems were not considered, as previous studies have already explored their viability and competitiveness under certain conditions [46,47]. A hybrid approach, optimizing the size of standalone systems with grid connection options, could provide further insights.

4. Conclusion and policy implications

This study investigated the impact of grid-connected hydrogen production on the South African power system in 2030 taking into account its development as outlined in three different policy roadmaps: the Integrated Resource Plan (IRP), Transmission Development Plan (TDP) and Just Energy Transition Investment Plan. The hydrogen demand for 2030 was based on green hydrogen production ambition as published in the South African Hydrogen Society Roadmap. Additionally, this study explores the impact of grid-connected hydrogen in a 2030 power system that is based on cost-optimisation.

The impacts of grid-connected hydrogen production on emission factors, costs, and system adequacy are found to be significant. Results show a considerable trade-off between producing low carbon, EU standard grid-connected renewable hydrogen for international trade versus power system adequacy for domestic electricity consumption. In the three policy scenarios, EU standard renewable hydrogen production was found to be unfeasible. However, in the *Free expansion* scenarios with an additional capacity installation of 56 GW of wind and 43 GW solar, hydrogen with LCOH of 2.9 USD/kg_{H2} and electricity with LCOE of 1034 ZAR/MWh can be produced, both in cost competitive ranges. However, this solar and wind capacity is 45% higher than in the *JET-IP* scenario, approximately 4 times higher than in *IRP* and *TDP* scenarios, and would require a seven-fold increase in solar and a sixteen-fold increase in wind capacities from 2023 levels. The feasibility of realising such an extensive solar and wind capacity installation largely depends on transmission and distribution capacity improvements in the future. Further study into the exact transmission capacities required is essential.

Producing electrolytic hydrogen with South African emission targets in mind for 2030, does not harm the system significantly in terms of system adequacy and levelized cost of electricity. In fact, in the *JET-IP* scenario with high renewables even has a small positive impact on unserved energy factor and curtailment. LCOE increases by 25% and 30% in *IRP* and *TDP* scenarios respectively, when electrolytic hydrogen is produced and CO_2 emissions have to stay under the 2030 emission target of South Africa, but remains in the range of IRP electricity price projections for 2030. Without the emission cap, the LCOE does not increase. However, grid connected hydrogen production, within the South African policy-informed emission constraints, results in high emission factors of 13–24 $kgCO_2$/kg for hydrogen, that is up to 70% higher, than grey hydrogen emission factors. The market for this hydrogen might be non-existent, as grey hydrogen with lower emission factors can be produced at half the price of the hydrogen produced under the assumptions of this study. However, keeping in mind the rapidly and dynamically increasing renewable energy generation in South Africa, grid connected green hydrogen production could be a reality by 2040 or 2050. While the targeted 500 kt H_2 production by 2030 will not be suitable for EU export if grid-produced, initially targeting regions with no strict emission factor standards could act as an important step in the path towards green H_2 production and trading in the upcoming decades.

With increasing interest in importing electrolytic hydrogen from high solar and wind potential Southern countries such as South Africa to Europe or Northern America, the impact on local prices, emissions and system adequacy is a crucial factor. As for international trade, a clear legal definition of green hydrogen is still non-existent in 2023. It is illustrated in this study that hydrogen produced by 34%–50% renewables can still have emission factors higher than those associated with grey hydrogen. This highlights the need for legal definitions around sustainable hydrogen production to be urgently addressed.

CRediT authorship contribution statement

Rebeka Béres: Writing – original draft, Visualization, Methodology, Formal analysis, Data curation, Conceptualization. **Ndamulelo Mararakanye:** Writing – original draft, Resources, Methodology, Conceptualization. **Christina Auret:** Writing – review & editing, Writing – original draft, Methodology, Investigation, Data curation. **Bernard Bekker:** Writing – review & editing, Validation, Supervision, Resources. **Machteld van den Broek:** Writing – review & editing, Validation, Supervision, Resources, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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