On the Near Term Carbon Free Hydrogen Export Potential of South Africa

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Abstract- South Africa's abundant solar resource positions it favourably as a renewable hydrogen provider. The country's domestic market for hydrogen is small, with no plans or policies in place to stimulate market expansion. In contrast, Japan is actively pursuing a CO_2 free hydrogen economy, opening export opportunities for several countries. Several existing and emerging hydrogen production technologies were investigated. Solar assisted steam/methane reforming with CO_2 capture is the cheapest option, although current CO_2 capture techniques remove only about 90 % of the CO_2 generated. Using a combination of existing wind, small hydro and solar PV and CSP to power low temperature electrolysis seems like the most economical carbon free solution. Production volumes are limited by the low capacity factor of these renewable energy technologies. Of the emerging technologies, the Cu-Cl cycle shows the most promise, but still requires significant research and development to reach commercial maturity. Furthermore, significant transport and transmission infrastructure investment is required to realize South Africa's full export potential.

Keywords: Hydrogen production, carbon capture, solar energy.

1. Introduction

Population increase and a rise in the standard of living in the developing world have led to a sharp rise in per capita energy consumption in developing countries, putting conventional energy sources under pressure. This comes at a time when global warming, mainly due to the combustion of fossil fuels, is a stark reality. Most countries have signed the Paris agreement, committing to a reduction in their CO_2 emissions through tougher environmental legislation, carbon taxes and the adoption of renewable energy sources. Rapid deployment of renewable energy technologies caused a significant cost reduction for most renewable energy technologies, to the point where they are now competitive with conventional energy technologies.

In South Africa, most electricity is generated from coal, as the country has abundant coal resources, whilst almost all its oil and natural gas are imported. The country is blessed with one of the best solar resources in the world, a fair wind resource but scarcity of water limits its hydro potential. Reference [1] conservatively estimates that South Africa's potential for generating electricity from concentrated solar power is about 550 GW_e. In [1], only sites receiving an annual average DNI of more than 7 kWh/m^2, on land with a slope less than 1 %, that is within 20 km of an existing transmission line and in the least ecologically sensitive areas were considered.

Producer prices for solar PV and wind energy in South Africa has already dropped below that of coal, whilst concentrated solar power is about on par with coal.

Apart from rail transport, the transport sector in South Africa is still reliant on fossil fuels in the form of oil imports, with a smallish portion derived from solid-to-liquid fuel technologies. Hydrogen seems like a good option for greening the transport sector, either through fuel cell technology for road and rail transport, or combusted in a gas turbine for aviation and also for power generation. The high cost of renewable hydrogen compared to fossil fuels, and lack of hydrogen infrastructure are the main barriers that need to be overcome before the country could enter the hydrogen economy. Japan, on the other hand, is moving towards a hydrogen economy, and has the necessary policy framework in place to promote it [2]. Japan's hydrogen import requirement is estimated to exceed 800 000 tons by 2040 [3] at a target price of $ 3/kg H$_2$. Export of hydrogen, especially to Japan, might be the stimulus needed to kick-start wider adoption of hydrogen in South Africa.

South Africa does not have any significant hydrogen infrastructure, and modelling is required to map out future prospects. This paper explores the anticipated production cost and volumes for carbon free hydrogen production in South Africa, and reflects on the country's competitiveness as hydrogen producer to the Japanese market. It ranks various

integration options between existing and emerging hydrogen production and renewable energy technologies based on landing cost at the closest point of export. Results can be used to direct a near term export programme, as well as direct research towards most promising emerging technologies. Other countries may benefit from this research, although their unique mix of resources may lead to a different outcome.

Steam/methane, or more correctly steam/natural gas reforming is the dominant hydrogen production technology in the world today [4, 5]. Reference [6] reviewed steam/methane reforming (SMR) hydrogen production technologies. On the down side, SMR is a significant CO_2 emitter, calling for interventions if it is to meet the Japanese goal of carbon free hydrogen by 2040. Several carbon capture techniques were investigated by [7 – 9], whilst [10, 11] studied the economic impact of SMR with carbon capture and sequestration. Reference [12] compared carbon capture technologies with renewable energy in Germany, [13] addressed carbon capture to promote methane extraction in Turkish coal mines, [14] looked at carbon capture across several industries, whilst [15] investigated the impact of carbon capture in the United States.

Reference [4] gave a comprehensive review on hydrogen production technologies, whilst [16 – 17] focussed more specifically on renewable hydrogen technologies. References [18 – 20] examined the production cost of different hydrogen pathways, whilst [17] looked at its environmental impact as well as cost. Reference [21] is limited to the technological feasibility of solar hydrogen production and [22] focusses on hydrogen production from biomass, rather than fossil fuels. Due to its arid climate, South Africa's biomass resource is fairly insignificant.

Individual technologies are well represented in literature. Of all the technologies, only alkaline water electrolysis is used commercially, but the expectation is that it will be replaced over the next decade by proton exchange membrane electrolysis [23]. References [24 – 26] addressed low temperature electrolysis, [27] turned their focus to solar PV as electricity source for the electrolyser, whilst [28] considers a stand-alone wind farm as electricity source.

References [29 – 31] all studied several high temperature thermo-chemical water splitting technologies. Supercritical Canadian Deuterium-Uranium (CANDU) nuclear reactors deliver an almost constant steam of about 550 °C that corresponds with the maximum temperature required by the Cu-Cl cycle. A significant amount of research on the Cu-Cl came out of the University of Ontario Institute of Technology. References [32, 33] focussed on the Cu-Cl cycle, whilst [34] narrowed it down to a Cu-Cl cycle powered by concentrated solar thermal energy with thermal energy storage.

High temperature steam electrolysis is discussed comprehensively in [35 – 40]. Reference [23] considered both low and high temperature electrolysis to predict future hydrogen cost by electrolysis.

High temperature thermo-chemical water splitting by solid metal oxides has been studied amongst others by [41 – 46].

High temperature electrolysis and several thermo-chemical water splitting technologies are still in the research and development phase. The need for high temperature materials is expected to hamper the development of several high temperature (above 600 °C) technologies.

A rapid move to renewable energy holds risks in terms of the highly intermittent nature of most of these energies, as argued by [47]. Reference [5] pointed out that a 100 % transition to renewable hydrogen is not likely in the next decades; the European Union expects that 30% of hydrogen production by 2050 would still come from coal. They have also shown that renewable hydrogen will not be competitive with SMR for many years to come, but only continuous research and rising fossil fuel feedstock prices will narrow the gap.

Reference [17] carried out a comprehensive review of hydrogen production technologies, and compared them based on cost and environmental impact. They concluded that electrolysis and thermo-chemical water splitting are the two most environmentally benign technologies. SMR is still the cheapest hydrogen production technology by far. Alkaline electrolysis, powered by solar photovoltaic (PV) power is the most mature renewable technology, but also one of the most expensive. However, the price for PV power has dropped from 30 $/kWh [17, 48] to about 0.045 $/kWh today [49]. A similar review, aimed at policy makers, was released by the Royal Society [50].

Liquid organic hydrogen carriers are the preferred mode of transport, due to its low cost compared to compression or liquefaction, high energy density and the fact that existing transport infrastructure for handling of liquid fuels can be used [51, 52].

This paper explores current and emerging carbon free hydrogen production technologies for plant output of an arbitrarily selected 3.6 ton H_2 per hour (about 50 tons per day). This would serve as benchmark against which all other configurations are compared. SMR is not a renewable energy, as natural gas is a finite resource that is rapidly being depleted. Neither is it completely carbon free, as a small percentage of CO_2 will always escape into the atmosphere.

Commercial renewable hydrogen production technologies are limited to alkaline low temperature electrolysis of water. Case studies were conducted for solar PV as well as concentrated solar thermal power with thermal energy storage as electricity source for the electrolysers. We only speculate on a combined solar PV and wind energy scenario, and assume that large scale battery storage is not yet a viable option. Two emerging technologies, namely high temperature steam electrolysis and the Cu-Cl are also considered.

2. Economic parameters

Published capital cost projections for hydrogen technologies [23] and CSP [53] are available for 2020, and for that reason, 2020 was chosen as the base year for this study. Capital cost in the renewable energy sector varies from country to country, and is influenced by the normal market forces of supply and demand, interest rates and technology

improvement [54]. Where capital costs were not available for the base year, published data was adjusted based upon the world-wide inflation rate of 3.05 % [55]. The levelized cost of hydrogen was calculated using South Africa's domestic inflation rate (average of 5.4 % since the introduction of inflation targets in 2010) and the current prime lending (10.25 %) rate [56]. Earlier renewable energy projects were typically financed at significantly higher interest rates by the Industrial Development Corporation. It is assumed that as the technologies matured, risks would reduce to the point that today more favourable interest rates could be negotiated. Furthermore, it is assumed that a 100 % loan is taken out to cover the total capital requirement. The loan term for past renewable energy in South Africa was 20 years, and will be used here as well. Depreciation, decommissioning, site rehabilitation were all excluded from the analysis, and cost of hydrogen is given before tax.

3. Steam/methane reforming with carbon capture

A simplified steam/methane reforming process is illustrated in Fig. 1. Water at 2 MPa is superheated to 560 °C using concentrated solar energy. The steam is mixed with methane feedstock, and enters the reformation reactor. Tail gas, supplemented with methane fuel is burned in the reactor to raise the reactor temperature to 800 – 1 000 °C [57]. Methane feedstock and excess steam react in the presence of a Nickel based catalyst according to the following endothermic reaction [57]

$$CH_4 + 2H_2O \rightarrow CO + H_2O + 3H_2$$
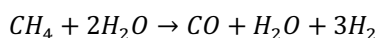
In the gas shift reactor, the temperature is reduced to about 300 °C to favour the gas shift reaction where CO_2 and H_2 is produced according to the following endothermic reaction [57]

$$CO + H_2O \rightarrow CO_2 + H_2$$
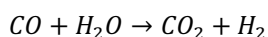
The steam reformation and gas shift reactions are not complete, leaving CO, CO_2 and excess CH_4 in the tail gas. Hydrogen is separated from the tail gases in the pressure swing adsorption (PSA) unit. It is assumed that the hydrogen conversion rate is 89 % [57]. Tail gas is supplemented with methane fuel, and combusted to supply heat for the steam reformation reactor. Flue gas is fed to the CO_2 removal unit, where about 90 % of CO_2 is removed [57], and N_2, H_2O and the remainder of the CO_2 is ejected into the atmosphere.

The hydrogen product is incorporated into a liquid organic hydrogen carrier (LOHC) for transport, whilst the captured CO_2 is compressed before storage. The potential income from O_2 is ignored.
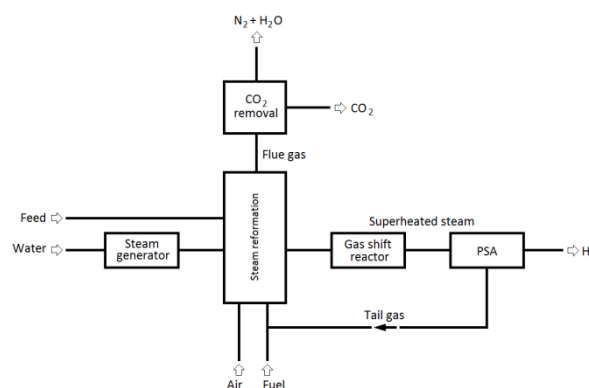

Figure 1. Block diagram of simplified SMR plant with CO_2 capture from the flue gas.

Sites considered in this study are the SASOL solid-to-liquid fuel plants in Sasolburg and Secunda, and the PetroSA gas to liquids plant in Mossel Bay, shown in figure 2. The low direct normal solar irradiation (DNI) at Mossel Bay, and the fact that the natural gas field is nearly depleted, put Mossel Bay at a distinct disadvantage and wasn't considered in the final analysis. Shale gas deposits have been discovered in the Karoo, an arid region in the North-West of South Africa, but no exploration rights were granted yet [58]. This gas source is excluded from the present study.

Sasolburg and Secunda are both situated on the Transvaal Highveld, a highly industrialized region with high levels of air pollution from gases and particulate [59]. Consequently, parabolic troughs are deemed more suitable for solar process heat than central receivers, due to their inherently low attenuation losses. Molten salt is preferred for the heat transfer fluid, due to its high operating temperature compared to thermal oils. Sasolburg and Secunda receive very similar solar radiation; 2.129 MWh/m^2/year for Sasolburg versus 2.171 MWh/m^2/y for Secunda, and the design DNI, taken at the spring equinox is also similar (918 W/m^2 for Sasolburg and 911 W/m^2 for Secunda). Furthermore, the latitudes of the two sites are almost identical, and the parabolic trough plant could essentially be copied from one site to the other. The solar field was designed using the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) for a solar multiple of 3.4 and 14 hours of thermal energy storage, corresponding to the hours of darkness on the winter solstice. It was assumed that the plant operate through hourly successive steady states. The DNI and sun angles were recalculated every hour from www.soda-pro.com. No attempt was made to optimize the parabolic trough plant.

Reference [57] gave a complete cost breakdown for a 9 t/h H$_2$ plant with (their case 3) and without (their base case) CO$_2$ removal. They claim that their cost data is accurate to a range within -15 % to + 35 % of the numbers quoted. Where only total plant cost for a similar plant is known, the capital cost for a 3.6 t/h H$_2$ plant is scaled according to the rule [60]

$$CAPEX_{plant} = CAPEX_{ref} \left(\frac{Actual\ plant\ size}{Reference\ plant\ size} \right)^{0.6}$$
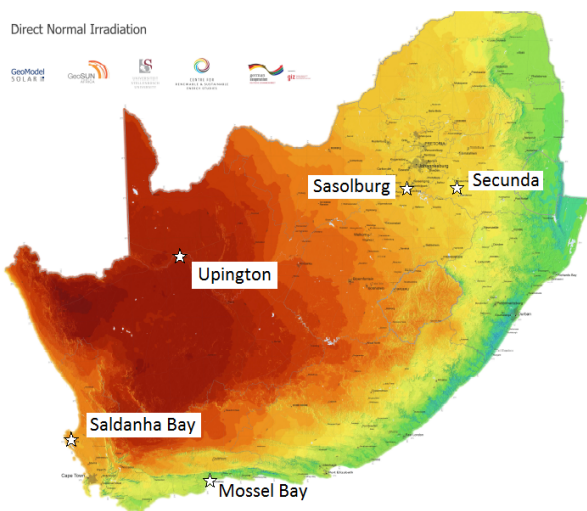
Figure 2. DNI map of South Africa, showing potential sites for SMR plant with CO_2 capture [courtesy of Centre for Renewable & Sustainable Energy, Stellenbosch University].

Table 1. Costing of parabolic trough process heat plant [53].

Item	Unit cost	Units	Size	Units
Land	0.25	$/m^2$	1 000 000	m^2
Site preparation	0.2	$/m^2$	450 000	m^2
Parabolic troughs	190	$/m^2$	300 186	m^2
Heat transfer fluid	50	$/m^2$	300 186	m^2
Thermal energy	25	$/kWh_t$	248 738	kWh_t
Steam generator	100	$/kW_t$	17 767	kW_t
Contingency		10 %	of direct cost	
Indirect cost		24.7 %	+ contingency	
O & M cost	0.02	$/kW_t$	17 767	kW_t

It is assumed that operating cost scales linearly with plant size. Electricity tariffs in South Africa are calculated on time of use, with further adjustments for weekdays and weekends, and winter and summer seasons. It is assumed that electricity is imported from the grid at an annual weighted average energy price of 0.09 $/kWh_e$ and a network charge of 0.05 $/kWh_e$ [61], municipal water at 0.30 $/m^3$ is available as feedstock, and that a carbon tax of 8.50 $/tonCO_2$ is in place. A draft carbon tax bill for South Africa was tabled in 2015, but hasn't been signed into law yet. Reference [57]'s costs are based on the fourth quarter of 2014, and are adjusted for inflation, based on the world-wide average inflation rate, according to

$$Cost_{2020} = Cost_{2014} \times \left(1 + \frac{3.05}{100}\right)^{(2020-2014)}$$

Costing for the parabolic trough solar process heat plant is taken from [53]. Here, their more conservative "trough roadmap" figures, rather than the "Sunshot target" were used. The parabolic trough aperture was determined from SAM, whilst it was assumed that the land that has to be cleared and levelled is 1.4 times the aperture area of the troughs. A typical farm size on the Highveld is 100 – 200 ha.

The Sasolburg plant requires about 3 % more CH_4 (fuel) than the Secunda plant. However, the amount of fuel burnt is small relative to the CH_4 feedstock required, leaving the levelized cost of hydrogen for both plants at 1.72 $/kg H_2. Furthermore, the capital cost of the SMR plant (about $ 330 \times 10^6$) is almost three times higher than that of the solar process heat plant (about $ 122 \times 10^6$). The operating cost of the SMR plant reached almost 40 % of the financing cost (interest and debt repayment). As a result, the levelized cost of hydrogen from a solar assisted SMR plant with CO_2 capture is relatively insensitive to cost variations on the solar side.

There is an existing fuel pipeline between Secunda and Durban (the nearest export harbour to Secunda) that can be used to export hydrogen. It is assumed that the pipeline would be available to transport hydrogen by liquid organic hydrogen carrier (LOHC) to Durban at 0.02 $/ton LOHC per km in 2012 dollars [52]. As hydrogen contributes only 6 % of the mass of the LOHC [62], a round trip from harbour to source back to harbour under full load is assumed. This would add 0.12 $/kg H_2 to the production cost of hydrogen, bringing the hydrogen cost at the point of export to 1.84 $/kg H_2. The cost of hydrogenation and dehydrogenation, as well as shipping LOHC overseas are common to all production methods, and is excluded from this study. Reference [63] estimated that the cumulative cost of hydrogenation, transport over 250 km and dehydrogenation cost for a liquid organic hydrogen carrier would be 2.26 $/kg H_2 based on a production volume of 50 t/day.

4. Renewable energy

4.1 Wind, Hydro and Photovoltaic Power

The total installed capacity of wind and hydropower in South Africa is 1 360 MW for wind [49], and 2 267 MW for hydro, of which 1 580 MW is pumped storage [64]. Wind is highly intermittent, and the maximum hourly output dropped to 6 MW in February 2016. The monthly output was the lowest in May of the same year. Due to South Africa's low annual average rainfall, and the seasonal nature of it, the capacity factor for hydro is about 22 % [64]. The tariff for new build wind power is 0.045 $/kWh_e$ [49], and that for small hydro 0.030 $/kWh_e$ [65]. Although wind and hydro are attractively priced, their intermittent nature and low capacity factor make them ill-suited for hydrogen production in South Africa on their own.

South Africa had 1 474 MW installed solar photovoltaic (PV) power capacity at the end of 2016 at an average capacity factor of 26 % [49]. The tariff for new PV is 0.045 $/kWh_e$ [49]. Given the rapid ramp rates for both alkaline and proton exchange membrane electrolysers, solar PV is considered a viable energy source to drive low temperature electrolysis.

Wind and solar energy is not correlated, hence wind energy might be brought into the mix to increase the electrolyser's capacity factor, as shown in figure 3. May has the lowest monthly electricity generation from wind, and PV output is also low since it is close to winter. The combined monthly average output for wind and PV never dropped below 200 MW_e, sufficient to power a 3.6 t H_2 per hour low temperature alkaline electrolysis plant at the coast. Desalinated seawater is proposed as feedstock for the electrolyser. The combined output may well drop below 200 MW_e on any individual night. Reference [49] only give individual capacity factors for wind and PV (expressed as percentage of installed capacity) in graphical form, making data extraction very difficult. It is assumed without justification that an electrolyser running off wind and PV will have a capacity factor of 80 %.
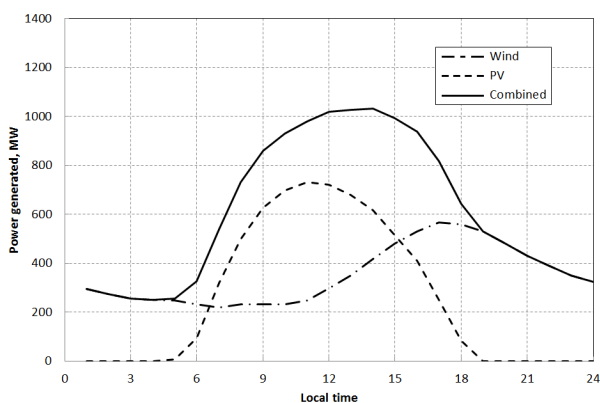

Figure 3(a). Monthly average power production by wind and PV during January 2016 (adapted from [49]).
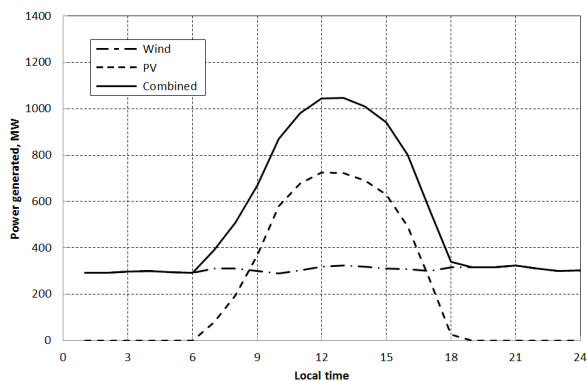

Figure 3(b). Monthly average power production by wind and PV during May 2016 (adapted from [49]).

All independent power producers in South Africa have signed a power purchase agreement with the state owned utility, ESKOM, and are contractually bounded to sell electricity to ESKOM only. The approached followed here is that wind and solar PV is bought in at ESKOM standard tariffs [61], and that a transmission fee of 0.05 $/kWh$_e$ is in place.

A reverse osmosis plant is proposed to desalinate seawater for use in the electrolyser. Capital cost and electricity consumption for the reverse osmosis plant in Table 2 were calculated according to [66]. The base year was not stated, and was taken as the year of publication. Component costs were inflation adjusted to 2020 dollars.

Table 2. Cost items for reverse osmosis plant [66].

Item	Cost
Civil work	15 $/m^2
Reverse osmosis unit	1 207 $/m^3/day
Water treatment plant	55 $/m^3/day
Seawater intake & pumping station	372 $/m^3/day
Contingency	7 % of capital cost
Indirect cost	11 % of installed cost
Operating and maintenance cost	0.56 $/m^3/year
Electricity consumption	4.46 kW$_e$/m^3/day

The cost for the alkaline electrolyser plant was taken from [18]. Based upon a capacity factor of 80 %, this plant should be able to produce hydrogen at 3.13 $/kg H_2.

Table 3. Assumptions for low temperature alkaline water electrolysis plant in 2014 dollars [18].

Item	Cost
Stack	400 $/kW$_e$ (stack is replaced every 10 years)
Balance of plant	570 $/kW$_e$
Contingency	35 % of capital cost
Operating and maintenance cost	5 % of capital cost
Efficiency	65 %
Electricity consumption	62.5 kWh$_e$/kg H_2
Water consumption	11 ℓ /kg H_2
Cost of desalinated sea water	0.965 m^3 (for 40 000 m^3/day RO plant)

4.2 Solar thermal energy

Solar thermal power (CSP) is about three times more expensive than solar PV, with the lowest feed-in tariff, that for Redstone, coming in at 0.14 $/kWh$_e$ [67]. Redstone is designed with 12 hours of thermal energy storage, allowing almost continuous operation through clear nights and days. Low recent bids for CSP [53], and the fact that feed-in tariffs (power purchase agreements) are not directly comparable with levelized cost of electricity warrants a closer look at CSP.

4.2.1 CSP combined with low temperature alkaline electrolysis

Solar thermal power can be used to power a remote electrolysis plant. Since the announcement of a solar park in Upington in the Northern Cape Province [68], Upington has become the default location for CSP studies in South Africa. Upington is selected as the location for the CSP plant, due to its high solar irradiation and high profile in literature. Solar

irradiation data is taken from www.soda-pro.com. A 200 MW$_e$ net dry cooled central receiver plant is envisaged, as this is the electricity required to generate 3.6 t H$_2$ per hour by low temperature alkaline electrolysis, assuming an electricity consumption of 62.5 kWh$_t$/kg H$_2$ [31, 69]. A subcritical steam plant with molten salt as heat transfer fluid is assumed. The tower is 300 m tall, the external cylindrical receiver is 24 m high and 16 m in diameter and the 12.68 m × 9.49 m SENER heliostats, similar to those used at Gemasolar, are arranged in a biomimetic pattern first suggested by [70]. Heat absorbed by the receiver is calculated using SolarPILOT version 1.2.1, whilst convection losses are calculated based upon the wind speed and air temperature at receiver height. A one-seventh power law for wind speed, and the dry adiabatic temperature lapse rate was used to convert wind and temperature measurements at ground level to receiver height. Radiation losses are conservatively based on the maximum salt and ambient air temperature respectively. A solar multiple of 3.4 and 14 hours of thermal energy storage should be sufficient to allow 24/7 operation on clear days and nights through winter and summer.

The life steam temperature and pressure for the Rankine cycle is 540 °C and 16 MPa, turbine and pump isentropic efficiencies are taken as 85 % and 75 % respectively, and the initial temperature difference for the air cooled condenser is 25 °C [71].

Plant component costs are taken as [53]'s more conservative "2020 Sunshot roadmap" figures given in table 3.

Table 4. Cost assumptions for concentrated solar thermal power plant in 2020 dollars [53].

Item	Cost
Heliostats	120 $/m^2
Land preparation	20 $/m^2
Tower and receiver	170 $/kW$_t$
Thermal energy storage	22 $/kWh$_t$
Power block	1 100 $/kW$_e$
Contingency	10 % of capital cost
Indirect cost	24.7 % of installed cost
Operating & maintenance	50 $/kW$_e$ gross/year
Parasitic losses	10 % of generator output

An identical low temperature alkaline water electrolysis plant with accompanying reverse osmosis unit as discussed in section 4.1 is used. A transmission loss of 1 % per 100 km [72] between the in-land CSP plant and the electrolyser on the coast is included.

The plant is capable of producing 21 414 t H$_2$ per annum at a levelized cost of 4.80 $/kg H$_2$.

4.2.2 CSP combined with a Cu-Cl cycle

The Cu-Cl cycle is a hybrid (it requires process heat and an electric input) originally developed to be powered by a supercritical CANDU nuclear reactor. A concentrated solar thermal plant provides both process heat and electricity for a Cu-Cl thermochemical water splitting cycle. The main attraction of the Cu-Cl cycle is its maximum operating temperature of 530 °C, that is close to that of molten salt central receiver plant (565 °C), thus pairing a mature solar technology with an emerging hydrogen technology. The low temperatures required by the Cu-Cl cycle means that ordinary materials can be used for reactors and piping; however, the corrosive nature of some of the intermediary chemicals calls for porcelain lining of equipment in contact with these chemicals that raises the cost of the plant.

Assuming that a Rankine cycle is used to generate electricity from heat, the heat input required by the steam turbine and Cu-Cl cycle is closely balanced [31]. Figure 4 shows how both the Rankine and Cu-Cl cycles are fed from the same hot salt tank, and salt is returned to the cold salt tank. Plant shut-down due to inclement weather can be predicted several hours in advance, based on the thermal energy storage level in the hot salt tank and short term weather forecasts. Thus it is assumed that the Cu-Cl will always be able to shut down in a controlled fashion.

More detail of a simplified five-step Cu-Cl cycle is given in Figure . Heat from the hydrogen and oxygen product streams is used to evaporate feed water. It is assumed that waste heat is recovered between processes [heat recovery heat exchangers are not shown in figure 5]. The Cu-Cl cycle isn't modelled in detail, and the energy and electricity requirements are taken from [73]'s simulation of a 5-step Cu-Cl cycle. Plant cost data comes from [31] and is inflation adjusted to 2020 dollars.
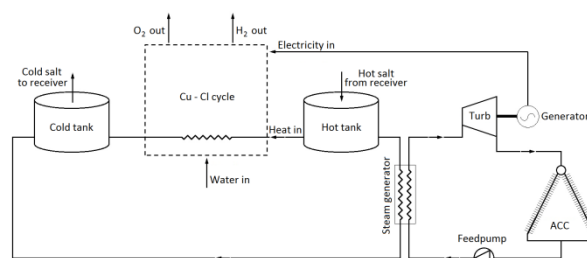
Figure 4. Integrating a Cu-Cl cycle and CSP plant

In this example, it is assumed that the plant is situated at Upington, in the Northern Cape Province. Water feedstock is municipal water from the nearby Orange River, available at a cost of 0.30 $/m^3. Solar plant configuration corresponds broadly to that described in section 4.2.1, except that the total number of heliostats is reduced to lower the heat collected at the receiver to match the Cu-Cl plant's process heat requirements. The steam turbine's gross output is also reduced to 53 MW$_e$, in line with the electricity requirement of the Cu-Cl cycle.

The plant is capable of delivering 26 424 tons of hydrogen a year, at a levelized cost of 3.58 $/kg H$_2$ for a plant life of 20 years. Based upon [1]'s estimates, South Africa's generation capacity exceeds the Japanese hydrogen import demand by 168 times. It is assumed that rail and pipeline infrastructure will not be available for early hydrogen plants in the Northern Cape Province, and hydrogen will be transported

Figure 5. Flow diagram of 5-step Cu-Cl cycle.

Figure 4. Schematic of solarized high temperature steam electrolysis plant with hydrogenation reactor.

by road to the coast. Transport cost in 2020 dollars of hydrogen to the nearest export harbour is taken as 0.109 \$/ton LOHC per km [74]. This translates to a road transport cost of 0.71 \$/kg H_2, assuming that the Saldanha Bay harbour, that is approximate 700 km from Upington, will be used as point of export. Hence, the total cost of hydrogen at the point of export will be about 4.29 \$/kg H_2.

4.2.3   High temperature steam electrolysis

High temperature steam electrolysis, using solid oxide membrane technology, is an emerging technology that has been demonstrated at pilot scale. It has a potentially higher conversion efficiency than low temperature alkaline electrolysis. Since it partially substitutes process heat for work (electricity), its energy cost is also reduced. A comprehensive study by [35] indicated that a plateau in process efficiency is reached at about 700 °C. They singled out the high capital cost and rapid degradation of the stack as the main obstacles that need to be addressed before it would be competitive against low temperature alkaline electrolysis.

A high temperature steam electrolysis plant powered by a combination of wind and PV power is envisaged. High temperature (T > 700 °C) solar heat is supplied by a centrifugal particle receiver, modelled on the DLR's CenTrec receiver [75], with 14 hours thermal energy storage. Particle receivers are capable of higher heat fluxes and temperatures than conventional receivers, however, they are limited to smaller size. The need for solar process heat suggests a location in a high DNI region; Upington was selected as the location for the first demonstration plant. A particle heat exchanger couples the process heat plant to the electrolyser. Waste heat from the LOHC hydrogenation plant and product streams is used to raise the water (feedstock) temperature to boiling point and evaporate it, as shown in figure 6. Solar process heat supplies energy for superheating the steam. Current high temperature steam electrolysis plants are limited to the kW range; it is assumed that multiple units in parallel would be a practical solution to deliver 3.6 tons of hydrogen per hour.

The DNI data for Upington was given in section 4.2.1. Plant cost for high temperature electrolysers, and the stack in particular vary widely between -50 % and + 400 % of the best estimate, whilst the stack has to be replaced every 10 000 hours [23]. The levelized cost of hydrogen is based on [23]'s best estimates. Costs for the solar process heat plant were adopted from [76]. Reference [76] noted that their projections are for a prototype, and that the cost of particle receivers and heat exchangers may come down as the technology matures. An electricity tariff of 0.09 \$/kWh_e, a network charge of 0.05 \$/kWh_e were assumed [61] and the capacity factor for combined PV and wind was taken as 80 %. The capacity factor for the process heat plant is marginally higher. Wind power, generated at various locations, is not expected to correlate with local solar process heat; however, the assumption is made that there would be sufficient solar thermal energy stored to operate the plant whenever wind and PV electricity is available.

Matching two emerging technologies carries a significant risk; here the same financial parameters used elsewhere in this work for more mature technologies were adopted. Resulting levelized cost estimates are expected to be optimistic. Production cost of hydrogen from high temperature steam electrolysis works out at 5.59 \$/kg H_2, or 6.30 \$/kg H_2 delivered at the nearest export harbour. This corresponds to the lower end of the range (6 – 17 \$/kg H_2) suggested by [38].

5   Conclusion

South Africa has sufficient solar resources to supply the domestic and export market with renewable hydrogen. However, given the current state of the art, renewable hydrogen is not price competitive with steam/methane reforming. As first step to enter the export market for carbon lean and/or carbon free hydrogen, solar assisted steam methane reforming with CO_2 capture is proposed.

Low temperature electrolysis is a mature, but relatively expensive technology. Using a combination of wind, solar PV and CSP, and small hydro power from independent power producers will increase the capacity factor of the electrolysis plant. It also allows the electrolyser to be situated at the coast, hence saving on hydrogen transport costs. Desalinating seawater for feedstock would also avoid stressing South Africa's scarce water resources. A high capacity factor would in turn lead to a reduction in production cost. Current South

African legislation dictates that plant operators have to purchase electricity from the state owned utility, ESKOM, at about double the production cost of wind and PV. Adding more electrolysers will drive capacity factors down, as the current total installed generation capacity for wind and PV (about 3 GW_e) is just about sufficient to power a 3.6 ton H_2 per hour electrolyser continuously. A dedicated PV plant would reduce electricity cost, but its low capacity factor will offset the savings on electricity and increase production cost by almost 50 %.

Substituting inland CSP with thermal energy storage for PV as dedicated electricity supply for a low temperature alkaline electrolysis plant at the coast would increase the capacity factor to the point where hydrogen can be produced at a lower unit cost, despite CSP being almost three times more expensive than PV. Line losses are bound to reduce the hydrogen production, as the regions with the highest solar resources are more than 500 km from the nearest export harbour. Furthermore, the Northern Cape Province is sparsely populated resulting in a low grid capacity (about 600 MW_e) that poses a significant hurdle in the large scale roll-out of hydrogen production through this combination.

Of the emerging technologies, the Cu-Cl cycle shows the most promise for large scale hydrogen production. Its temperature requirements are well within the capability of conventional molten salt technology. Its electricity and solar process heat can be supplied by the same CSP plant, negating the need for transmitting electricity over long distances. However, locating the hydrogen plant inland means that it has to rely on a local fresh water supply for feedstock, putting further stress on the country's scarce water resources. The hydrogen product has to be transported to the point of export. A liquid organic hydrogen carrier is proposed due to its low cost and ease of handling over liquid or compressed hydrogen transportation. In this work, road transport was adopted by default, as the current rail network dictates that freight from Upington has to go via De Aar to either Cape Town or Port Elizabeth harbours, almost doubling the distance between Upington and Saldanha Bay. A direct link to the Sishen-Saldanha railway line, that runs about 100 km south of Upington, or if production volumes justify it, a pipeline to Saldanha could decrease transport cost substantially.

High temperature steam electrolysis is the most immature and expensive of the technologies considered. It is probably more suited for small scale production aimed at the domestic market. Its main detractors are the high capital cost of the solid oxide membrane stack, combined with frequent stack replacements.

Both the Cu-Cl cycle and high temperature steam electrolysis still require significant research to mature to the point where it can be commercially exploited. Hydrogen cost at the point of export, based on the current estimates, exceeds the target price of $ 3/kg H_2 set by Japan. However, expected sharp cost reduction with commercialization, as was seen in the PV and CSP markets, may increase the competitiveness of solarized Cu-Cl derived hydrogen in the future.

In order to become a major player in the export market, significant investment in the transport and transmission infrastructure in the Northern Cape Province would be required.

6   Acknowledgement

7   References

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