CONNECTIVE CITIES



ANALYSIS

Green Hydrogen Feasibility Assessment

WATERBERG REGION, SOUTH AFRICA

3 expansion phases

30 MV solar expansion

approx. 1,400 t hydrogen per year

Commissioned by

Federal Ministry for Economic Cooperation and Development

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Deutscher Städtetag · Deutscher Landkreistag · DStGB Deutscher Städte- und Gemeindebund · VKU Verband kommunaler Unternehmen e.V. · giz Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH · Engagement Global with its SKEW Servicestelle Kommunen in der Einen Welt

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Document type	Short hydrogen feasibility assessment
Region	Waterberg District Municipality, Limpopo Province, South Africa
Anchor use case	Stationary green hydrogen energy supply at an operating solar and mining site
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Disclaimer. *This document is a scoping-level assessment, not a bankable feasibility study. It works with transparent assumptions, open formulas and value ranges rather than fixed quotations. Where a figure is an assumption, the text says so. Cost figures at this early project stage carry an accuracy band of about minus 30 to plus 50 percent, in line with the international cost-estimate classification for concept and feasibility studies (AACE class 4 and 5) [20]. Final values require a subsequent preliminary-engineering and site-data phase. The assessment reflects information available up to early July 2026.*

How to read the sources. *Key figures carry a numbered reference. Marks such as [M1] point to the presentations and official documents that were provided to the mission team during the field week in June 2026. These are the most current data available for the region and are listed in the first part of the reference chapter. Marks such as [1] point to independent external sources, most of them with a direct internet link, listed in the second part of the reference chapter. Findings from the field week itself, for example* from the site visit and from conversations, are described as such in the text and are not dressed up as documents.

Abbreviations

Abbreviation	Meaning
AC / DC	Alternating current / direct current (grid-side versus panel-side solar capacity)
BESS	Battery energy storage system
CAPEX	Capital expenditure, the one-off investment cost
DSTI	Department of Science, Technology and Innovation (South African ministry)
EPC	Engineering, procurement and construction
FLH	Full-load hours, a normalised measure of annual plant utilisation (annual energy divided by rated power)
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit, the German development agency
HAZOP	Hazard and operability study, a structured process safety risk assessment method
IDC	Industrial Development Corporation, a South African state development finance institution
JET	Just Energy Transition, South Africa's national programme for a socially fair move away from coal
LCOE	Levelised cost of electricity, the average cost of one kilowatt hour over the plant lifetime
LCOH	Levelised cost of hydrogen, the average cost of one kilogram of hydrogen over the plant lifetime
MCWAP	Mokolo Crocodile River Water Augmentation Project, a regional water supply pipeline project
OPEX	Operating expenditure, the recurring annual cost
PEM	Proton exchange membrane, a common low-temperature electrolyser and fuel cell technology
PGM	Platinum group metals
PV	Photovoltaics, solar power from panels
SALGA	South African Local Government Association
SEC	Specific energy consumption of the electrolyser (kilowatt hours per kilogram of hydrogen)
TVET	Technical and Vocational Education and Training (the public college system)
WDI	Waterberg Development Initiative, a private-sector regional coordination platform

Executive Summary

The Waterberg District is one of South Africa's most important mining regions. Mining contributes about 53.5 per cent of the district economy [19]. The region also sits close to a unique strategic asset: the Bushveld Complex holds around 80 per cent of the world's reserves of platinum group metals [1], and platinum group metals are the catalyst material inside electrolysers and fuel cells. Local mining is a core industry, but also known as an energy-intensive one. This makes it a good target for a renewable energy approach, which might, if successful, significantly contribute to climate protection while reducing dependency on fossil fuels.

Despite significant efforts towards renewable energy, and partly green hydrogen, that the Waterberg district has made in the past, the study shows that in the medium term the region will not be able to produce economically green hydrogen to export. The Waterberg's realistic strength lies elsewhere. The strategic objective for Waterberg is to become a green hydrogen application hub that supports local industry in using sustainable energy resources.

As a first dedicated activity towards this objective, the study recommends an anchor demonstration project for stationary green hydrogen energy supply. Chapter 4 further describes this anchor as a concrete worked example at the Lephalale solar site of Cennergi, the energy subsidiary of the mining company Exxaro, next to the Grootegeluk coal mine. The example is calculated step by step in three expansion phases, from a small pilot that uses solar peaks which today cannot be absorbed (Phase 1), up to a dedicated 30-megawatt solar expansion that would produce roughly 1,400 tonnes of hydrogen per year (Phase 3).

Phase 1 already stands on its own as a low-risk starting investment. It uses solar energy that is otherwise lost today and needs no new power generation, so its economics do not depend on the assumptions discussed below. Phases 2 and 3 build on this foundation to reach genuine fuel-scale volumes. At Lephalale the solar resource is excellent, but the wind resource is weak, so a hydrogen plant runs only about 2,560 to 2,640 fullload hours per year on solar power alone. Under these conditions, the levelised cost of hydrogen (LCOH) today is about USD 6.4–6.6 per kilogram with Western-made electrolysers and about USD 5.6–5.8 per kilogram with Chinese equipment landed and installed in South Africa. These two paths differ only in where the electrolyser is manufactured and how it reaches South Africa; the site, the solar plant, and all operating assumptions are identical either way.

The decisive comparison is not hydrogen against cheap grid power but hydrogen against expensive diesel. Diesel-generated electricity at a mine costs about USD 0.34–0.46 per kilowatt-hour for fuel alone at July 2026 prices, depending on whether the mining fuel rebate applies [14]. A solar plant combined with hydrogen storage would deliver around-the-clock electricity at a blended cost of roughly USD 0.16 per kilowatt-hour, because 70 per cent of the energy comes directly from very cheap solar power. For mining trucks, one kilogram of hydrogen replaces about 4.2 litres of diesel, so hydrogen becomes competitive as a truck fuel at about USD 5.5–6.5 per kilogram.

Beyond the direct cost comparison, locally produced green hydrogen carries a strategic value that a pure price comparison understates. It decouples the mine's energy supply from oil-price swings and global market disruptions. It also supports the region's own stated goal of building up renewable energy capacity and reducing CO2 emissions. These benefits apply even where the immediate cost advantage over diesel is small or absent.

The report follows that logic: Chapters 2 and 3 explain why the region's role is to become a green hydrogen industrial application area for the mining industry rather than an export producer; Chapter 4 shows how a first project could work in practice, calculated step by step at one real site; and Chapters 5 and 6 set out what has to happen next.

What sounds easy in theory requires a long process to implement in practice. A joint masterplan process is therefore needed as a core mechanism to engage all key actors and ensure there is a shared interest in following the proposed path. Smaller projects related to innovation, business, or skills development are beneficial as accompanying measures.

1. Introduction and Context

1.1 Mission background

This assessment is a deliverable of the GIZ Connective Cities "Green Hydrogen Africa" Expert Mission. H2KNOW participated as hydrogen expert during the field mission to the Waterberg from 8 to 12 June 2026. The programme combined policy sessions, a technical site visit at Lephalale, a strategy workshop and the presentation of findings to the municipality.

1.2 Objective and scope

The objective is a short hydrogen feasibility assessment with five elements: a site assessment, a prioritised use case, an initial system concept, a budgetary estimate of investment and operating costs including the levelized cost of hydrogen, and a roadmap for the next planning phases. As a scoping study delivered within a deliberately limited budget, it works at the level of system logic and order-of-magnitude figures. Verified facts, planning-stage figures and assumptions are labelled as what they are, and the data gaps that the next phase must close are listed explicitly.

1.3 Methodology applied

The assessment follows a demand-first method in five steps. First, understand who needs energy or hydrogen in the region, for what purpose and in what volume. Second, check the physical basis, meaning solar and other energy resources, water, land, grid and logistics. Third, choose the use case where hydrogen competes against the most expensive alternative, because that is where it can win first. Fourth, size a system for that use case and calculate its costs with open formulas. Fifth, define next steps to allow the region to move further.

The demand picture in this assessment is built from the documented site visit, the stakeholder presentations and the closing strategy workshop. A structured demand survey across the district's operations is a task of the next phase.

The field week of 8th to 12th June 2026 is the primary evidence base for Chapters 2, 3 and 5, so it is set out here in full.

- **8th June, Johannesburg — opening policy session.** Hosted at the offices of the South African Local Government Association (SALGA), with presentations on the role of municipalities in the Just Energy Transition [M1], on the national policy and regulatory framework for hydrogen [M3], and on hydrogen innovation and the Platinum Valley Corridor [M4]. A green ammonia project in the Northern Cape was presented as a comparator [M8]. Participants included the Waterberg District,
  Lephalale Local Municipality and international delegations; SALGA issued minutes of the session [M2].

- **9th June, Lephalale — site visit and technical discussions.** Eskom's Matimba coal-fired power station was visited on site. The Lephalale Solar Project operated by Cennergi, next to Exxaro's Grootegeluk coal mine, was covered through a presentation and through discussions with the operators, not through a plant visit. The topics were plant and grid data, water sources, and the possible expansion of the solar plant. The plant figures used in Chapter 4 are taken from published company data, not from measurements made during the mission.

- **10th June — Eskom presentation to the municipality.** Introduction of the planned solar and battery cluster on Eskom land near Medupi and Matimba, at planning stage [M5].

- **11th June, Mogalakwena — institutional visit.** Waterberg TVET College, including its engineering skills training centre. The discussion covered the existing solar and wind curricula, the conditions under which a new course can be offered, and the college's own capacity to teach hydrogen (Chapter 5).

- **12th June, Mookgopong — closing strategy workshop.** The Waterberg Development Initiative presented its regional coordination model [M7]. The workshop closed by agreeing several action points, of which to initiation of a common regional hydrogen masterplan process for the district, a stakeholder mapping as well as the idea of smaller accompanying measures related to innovation and entrepreneurship have relevance to this study

Beyond the field mission, the assessment draws on the documents listed in Section 7.A and on published company and public-sector data, referenced individually in the text.

2. Site Assessment of the Waterberg Region

Waterberg is South Africa's premier mining district. Platinum group metals, coal and iron ore underpin a regional economy in which mining contributes about 53.5 percent of the district's economic output (2023 figure published by the Waterberg District Municipality) [19]. Nationally, however, the designated green hydrogen production zone is the Northern Cape. That province offers the country's best combined solar and wind resource, carries the national target of 10 gigawatts of electrolysis by 2030 set out in the Hydrogen Society Roadmap [2][M9], and has the coastal export ports. The national skills programme of the Just Energy Transition is setting up Skills Development Zones, hubs linking training to jobs in renewable energy, green hydrogen and new energy vehicles, in Mpumalanga, the Eastern Cape and the Northern Cape [27]. Limpopo is not among them.

The mission mapped a clear and complementary set of actors. The table lists them with their potential role for a future hydrogen economy in the district.

Table 1: Stakeholders and their role in a Waterberg hydrogen economy

Stakeholder	Role in a Waterberg hydrogen economy
Waterberg Development Initiative (WDI)	Privately driven regional coordination platform. Aligns actors and takes over a certain kind of coordination role. Its own stated gap, according to WDI representatives during the mission week, is deep technical hydrogen expertise that might be needed in the future.
Eskom and its renewables unit	Grid operator, landowner and planned solar developer at Lephalale. Its current planning covers solar and batteries but not yet green hydrogen. [M5]
Exxaro / Cennergi	Owner of the Grootegeluk mine and operator of the Lephalale solar plant, the natural host for the anchor project of Chapter 4. [6]
Waterberg TVET College	Public vocational college, willing to teach hydrogen but without hydrogen teaching capacity yet. The college can add a course once industry demand is demonstrated, so real projects have to come first (Chapter 5).
SALGA and the municipalities	Municipal governance, SALGA coordinates the municipal pillar of the Just Energy Transition and promotes the principle that benefits must reach communities within a 50 kilometre radius of projects. [M1]
DSTI and IDC	National policy and finance. The science ministry runs the national hydrogen research programme and the Platinum Valley Corridor. The IDC leads the green hydrogen pillar of the Just Energy Transition and manages dedicated funds. [M1][M4]

The Waterberg Development Initiative deserves emphasis. Its operating model (align, package, mobilise, measure) and its central message, that technology is rarely the constraint but coordination usually is, position it as the natural partner for converting opportunities into financeable initiatives [M7]. The Initiative coordinates, but it does not itself hold technical hydrogen depth, feasibility calculation or curriculum content.

Those missing pieces are exactly what external technical partners can contribute within the masterplan process proposed in Chapter 6.

2.1 Energy landscape: what operates, what is planned

Lephalale, in the western Waterberg, hosts the largest power cluster in South Africa. It is important to keep three categories apart: coal plants that operate today, one solar plant that operates today, and further solar capacity that exists only as planning.

Operating coal. Eskom's Matimba station (3,990 megawatts, six units) and the neighbouring Medupi station (4,764 megawatts net) together provide close to 8,750 megawatts of installed coal capacity [5]. Medupi's unit 4, which was lost to a hydrogen explosion of its conventional generator cooling system in 2021, returned to service in July 2025. These two stations anchor the Just Energy Transition in the district. For a hydrogen project they matter for a practical reason: they bring grid connections, water infrastructure and a skilled workforce to the immediate area.



Figure 1: Matimba power station near Lephalale. Photo: JMK, Wikimedia Commons, licence CC BY-SA 3.0.



Figure 2: Medupi power station, the newer of the two Lephalale coal stations. Photo: Caracal Rooikat, Wikimedia Commons, licence CC BY-SA 4.0.

Operating solar. The verified renewable anchor in the district is the Lephalale Solar Project, developed and operated by Cennergi, the energy subsidiary of Exxaro. The plant was commissioned in December 2025 and has 68 megawatts of grid-side capacity from 77.4 megawatt-peak of panels (about 129,000 modules on 236 hectares). It generates about 176 gigawatt hours per year under a 25-year power purchase agreement and supplies the neighbouring Grootegeluk coal mine directly, behind the mine's own meter, covering roughly 30 percent of the mine's electricity demand [6][24][28]. Up to 20 megawatts of surplus can be fed into the Eskom grid when the mine does not need it. This offset arrangement is contractually committed to Eskom (a delivery commitment when surplus occurs, not a guaranteed long-term supply contract). The plant has no night storage, so the mine runs on Eskom grid power at night. This supply comes predominantly from the coalfired Matimba and Medupi stations described above, so the mine's electricity is not fully green today. Exxaro's own decarbonisation roadmap already treats this as a priority. The Lephalale Solar Project itself is named as the first step in the company's scope 2 (purchased electricity) decarbonisation plan, expected to cut scope 2 emissions by about 25 percent, with further wheeled solar and wind capacity planned through 2028 [34]. A stationary hydrogen-plus-storage system would extend exactly this logic into the hours the solar plant cannot yet cover. A further expansion of about 30 megawatts is considered possible on land next to the plant. This operating plant is the factual basis for the worked example in Chapter 4.

Planned solar. Beyond these operating assets, an Eskom planning presentation shown to the mission (10 June 2026) describes a large solar and battery cluster on Eskom land near Medupi and Matimba. In total about 1.0 gigawatts of grid-side (AC) capacity from up to roughly 2.05 gigawatt-peak (DC) of solar panels in several phases, plus large battery storage, with a first phase of about 300 megawatts targeting commissioning around 2029 [M5]. These figures are a planning stage and have no independent public confirmation yet. This assessment therefore does not base any cost calculation on them. But the plans should not be dismissed either. They were presented officially to the municipality, and if even the first phase is built, it multiplies the solar energy available at Lephalale and therefore the potential scale of hydrogen production there. If built, the Eskom expansion is the main growth option beyond the worked example of Chapter 4 (Figure 3). One point is worth noting about this planning. The pre-feasibility work around the Eskom sites considers solar power and battery storage, but does not yet consider green hydrogen [M5]. Hydrogen is therefore not competing with an existing plan in the district. It is not yet part of one.

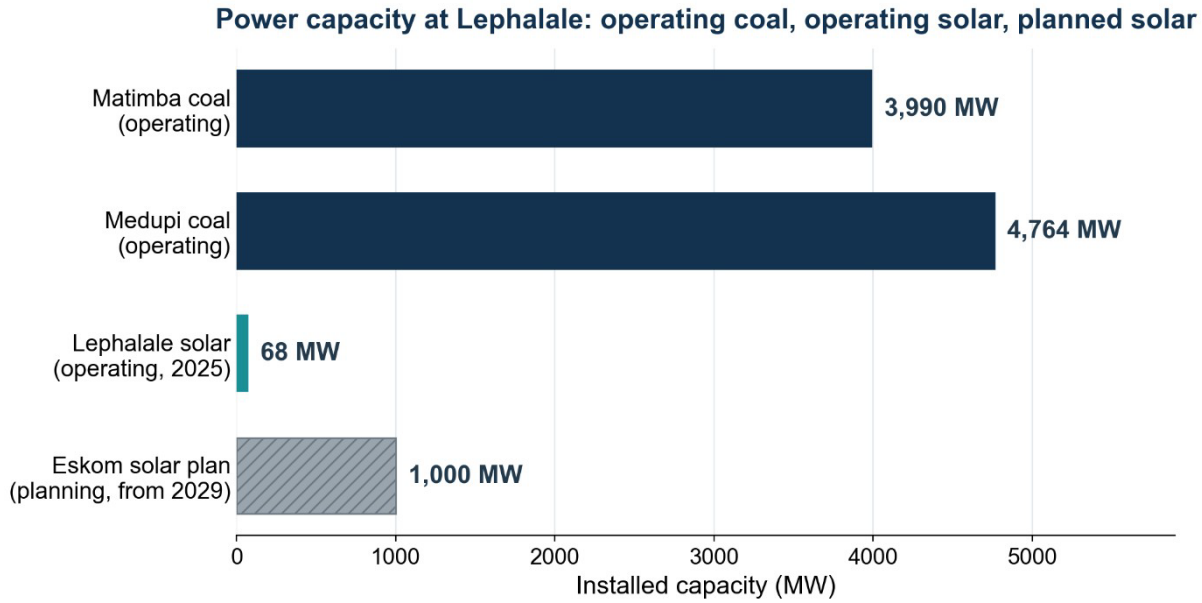


Figure 3: Installed and planned power capacity at Lephalale: a large operating coal cluster, one operating solar plant, and a large planned solar expansion. Sources: Eskom station data [5], Exxaro results [6], Eskom planning deck [M5].

2.2 Renewable resource: strong sun, weak wind

The most important physical fact for hydrogen economics in the Waterberg is the imbalance of its renewable resource (Figure 4). The solar resource is excellent. The specific yield at Lephalale is about 1,790 kilowatt hours per year for each kilowatt-peak of installed panels, which is one of the best values in the world and only slightly below the Northern Cape [9]. The wind resource, in contrast, is weak. The Limpopo interior is a recognised low-wind region with measured capacity factors far below the coastal Cape provinces, and there is no utility-scale wind farm anywhere in Limpopo [10]. The wind measurements underlying reference [10] were taken at Polokwane, about 150 kilometres from Lephalale, and are used here as the closest available regional proxy, since no wind measurement masts exist yet for the higher plateau sites at Lephalale itself, so any hybrid solar-plus-wind concept would currently rest on unmeasured assumptions. This assessment therefore treats the Waterberg as a solar-only location.

The consequence is central to everything that follows. A solar-only electrolyser reaches only about 2,300 to 2,700 equivalent full-load hours per year. An equivalent full-load hour is a simple normalisation. It divides annual energy by rated power. If

an electrolyser processes 15.8 gigawatt hours in a year and has 6 megawatts of rated power, it has run the equivalent of 2,640 hours at full load, even though in reality it ran many more hours at partial load, following the sun. The concept matters because the investment cost of the electrolyser is spread over these hours. At a strong solar-**plus**-wind site the same machine would reach 4,000 hours or more and each kilogram of hydrogen would carry less investment cost [23]. This is the single biggest structural cost disadvantage of Waterberg as a production location, and it is treated as such throughout Chapter 4.

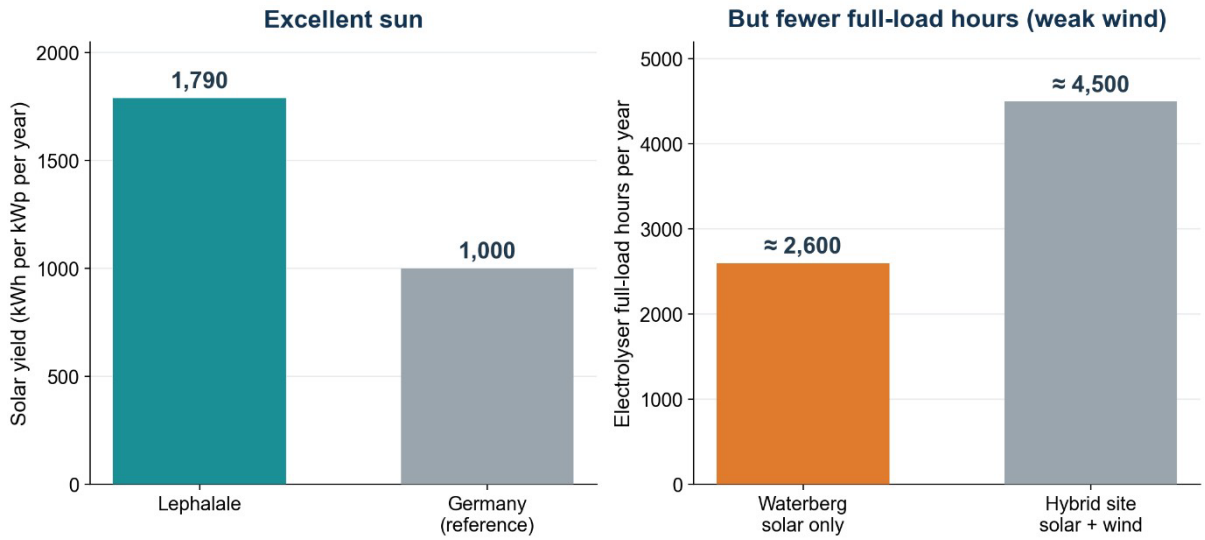


Figure 4: Strong sun, weak wind: the Waterberg resource in comparison. Sources: Global Solar Atlas [9], Shambira and Mukumba 2026 [10] (Polokwane wind data, used as regional proxy).

2.3 Water: availability, and a circular answer

Electrolysis splits water into hydrogen and oxygen. It consumes about 10 to 11 litres of purified water per kilogram of hydrogen, and producing that purified water requires roughly 20 to 30 litres of raw water per kilogram once treatment losses are included [17]. For the worked example of Chapter 4 this means concretely, the small pilot phase needs about 2,400 cubic metres of raw water per year, and the full 30 megawatt expansion about 35,000 cubic metres per year. For comparison, 35,000 cubic metres is the annual water use of roughly 120 average South African households (based on the national average of 237 litres per person per day [35] and an average household size of 3.34 persons [36]). It is a small volume by industrial standards, but the Waterberg is water-scarce, so even small new demands need a secured source.

A common assumption is that the regional water question is about to be solved by the MCWAP Phase 2A pipeline, which will bring an additional 75 million cubic metres per year into the area. The construction contract for that pipeline was only signed in July 2025, commissioning is expected around 2029, and its water is largely reserved for Eskom, Exxaro and the growing Lephalale population [8]. New hydrogen demand therefore cannot rely on that pipeline before roughly the end of the decade.

The realistic near-term answer is to treat mine water instead of withdrawing fresh water, and the industrial configuration at Lephalale makes this unusually attractive (Figure 5). Mines produce acidic contaminated water, called acid mine drainage, which they are legally obliged to manage in any case. Coal power stations produce alkaline fly ash as a bulk waste product. South African research has shown that this alkaline ash can neutralise acidic mine water and remove most dissolved metals [29]. This could replace the most chemicalintensive first treatment stage. It is a promising approach identified by the assessment team rather than an established industrial-scale process at Lephalale. Its applicability and scalability should be verified with materials or process engineering specialists in the next project phase. After that, standard membrane treatment (reverse osmosis) brings the water to potable quality, a step that has run at industrial scale in a South African coal region since 2007 at the eMalahleni water reclamation plant using limestone neutralisation [16]. A final polishing stage then reaches the purity needed for electrolysis. The result could be a triple win: a power-station disposal problem, a mine's environmental liability and the hydrogen water question would be addressed together, without taking fresh water from farms or communities. The honest caveats are that water quality and volumes at the specific site still need to be measured, and that the disposal of the concentrated brine from treatment remains a cost item. The Lephalale solar plant already uses borehole water for panel cleaning and a pipeline from the mine for mine water is already planned, so the basic infrastructure logic exists.

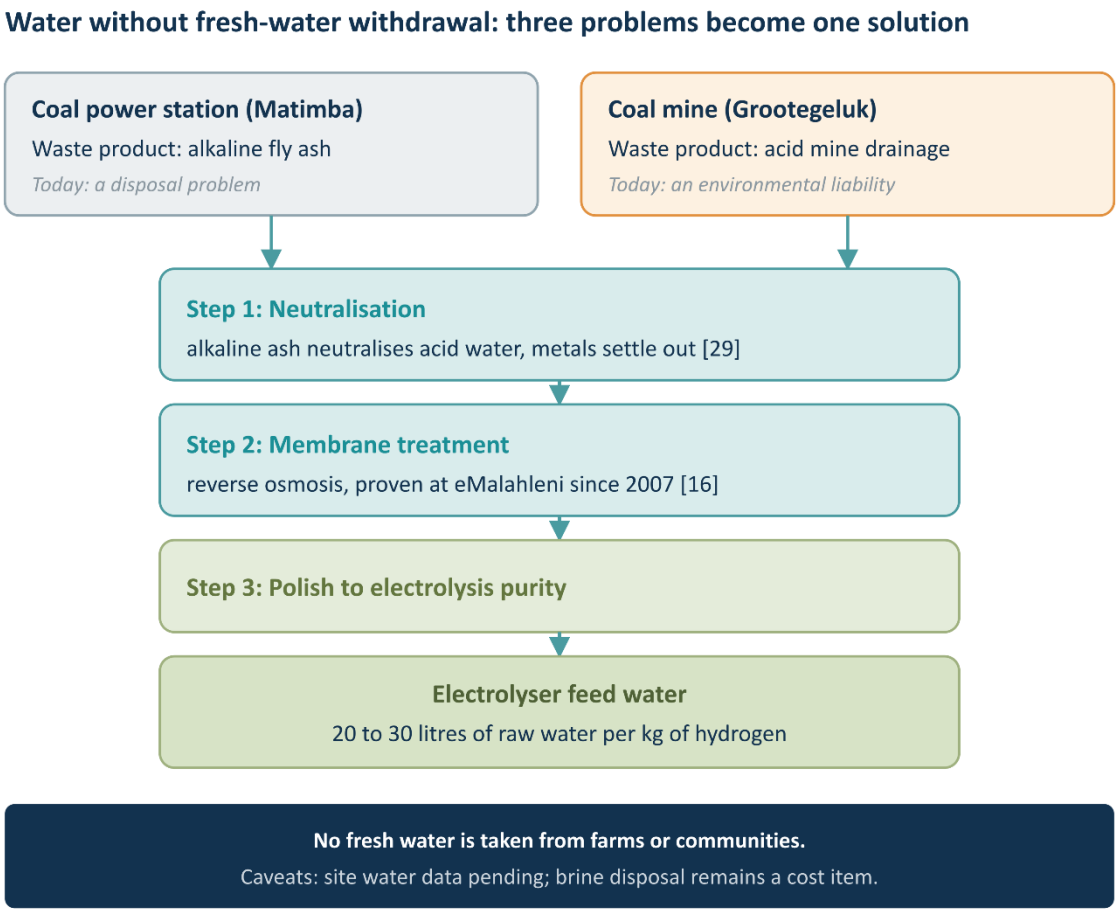


Figure 5: Water without fresh-water withdrawal: fly ash neutralises acid mine drainage, treated water feeds the electrolyser. Sources: fly ash neutralisation research [29], eMalahleni precedent [16], water figures [17].

2.4 Infrastructure and logistics

The Eskom stations give Lephalale a strong grid backbone. 132 kilovolt and 33 kilovolt connections are available at the solar site itself. Road access is good and the Waterberg rail line connects the coal cluster to the national network. There is no hydrogen pipeline anywhere in the region, so any near-term hydrogen distribution beyond the production site would use tube trailers, which are truck trailers carrying pressurised gas cylinders. The strongest siting argument remains re-use. A hydrogen project placed at an existing Eskom or Exxaro site inherits grid connection, water infrastructure, secured land and a workforce, all of which are otherwise expensive and slow to obtain.

2.5 Policy frame

South Africa's hydrogen policy rests on three documents that build on each other. The Hydrogen Society Roadmap of 2022 sets the national targets: 500,000 tons of green hydrogen per year and 10 gigawatts of electrolysis in the Northern Cape by 2030 [2][M9]. The Green Hydrogen Commercialisation Strategy of 2023 defines how to get there, and two of its elements matter directly for the Waterberg. These are support for localisation, meaning domestic manufacturing of electrolysers, fuel cells and their components, and securing finance through grants, concessional loans and price-support contracts [3][M3]. The "Platinum Valley Corridor," also known as "Hydrogen Valley," forms the geographic framework of the strategy [M4]. It is an official government initiative with Strategic Integrated Project status since December 2022 [4][M3]. It runs about 835 kilometres from Mokopane in Limpopo through Johannesburg to Durban and is meant to string hydrogen projects along the platinum belt. The corridor is still at proof-of-concept stage. Mokopane, its northern end point, lies in the Waterberg district, which is why the corridor is the region's strongest policy hook.

The Just Energy Transition Programme is the institutional umbrella above all of this. In plain terms, it is South Africa's internationally funded programme for moving away from coal in a socially fair way. International partners pledged 8.5 billion US dollars at its start, and its investment plan channels money into the electricity sector, electric vehicles, skills development and green hydrogen [M9]. The green hydrogen pillar is led by the Industrial Development Corporation, and the municipal pillar is coordinated by SALGA [M1]. For local projects the programme brings two practical things: access to concessional finance through the IDC and the Development Bank of Southern Africa, and a political requirement that projects create measurable local benefit, commonly framed as benefits within a 50 kilometre radius.

On the European side, the European Union committed 5.4 billion US dollars to South Africa at the March 2025 summit under

its Global Gateway programme, with a clean-energy emphasis [15]. Specifically for green hydrogen, two grants totalling 36.5 million US dollars (628 million rand) were announced in September 2024: a 490 million rand grant channelled through the Industrial Development Corporation to develop the hydrogen value chain, and a 138 million rand grant through the French development agency AFD to the logistics utility Transnet for hydrogen studies and pilots in ports and rail [15].

One item that circulates in regional discussions is deliberately not used in this assessment. This is a standalone 'Limpopo Green Hydrogen Strategy' document. No published document of that title could be found. The practical recommendation is that the province and the district should create, or formally publish if a draft already exists, exactly such a strategy, ideally as part of the regional masterplan work described in Chapter 6, so that future projects can refer to an agreed provincial framework.

2.6 Conclusion

The Waterberg's comparative advantage lies in the mixture of having certain capabilities to produce green hydrogen and a significant and expensive energy demand. The mining sector, world-wide, is under pressure to become more sustainable and more green. If Waterberg district positions itself as a application hub for green hydrogen in the mining sector, it plays to its real strengths.

The mining industry might have a capability and interest to invest in sustainable energy use, incl. green hydrogen. The region can offer a proper infrastructure. Based on such a public-private partnership the region can become a pilot region for green hydrogen application in the mining sector. This positioning is summarised in Figure 6 and was reinforced repeatedly during the field week.

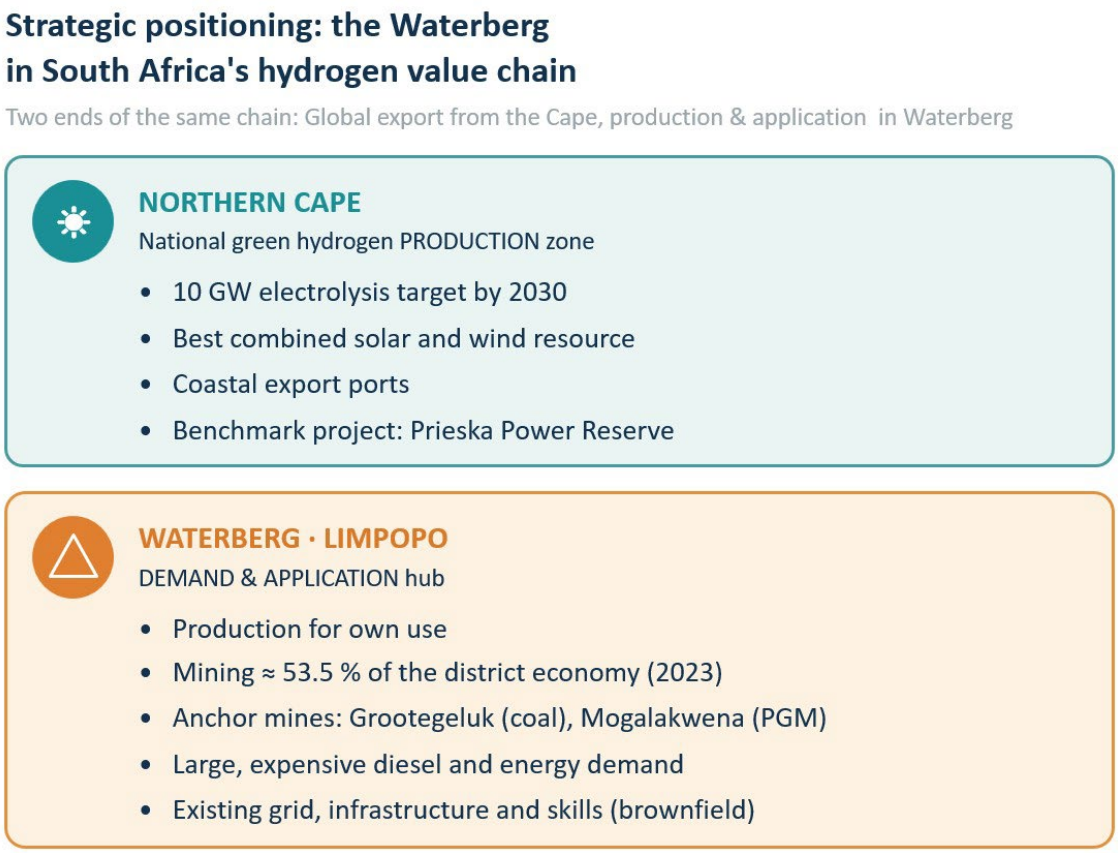


Figure 6: Strategic positioning of the Waterberg in South Africa's hydrogen value chain

3. Demand and Value-Chain Positioning

This chapter deals with the question where the Waterberg can position itself in the green hydrogen value chain. The chain has the following stages: producing, transporting, applying or exporting green hydrogen. Each stage is assessed for the Waterberg below.

3.1 Stationary energy

The green hydrogen application stage is where the Waterberg can start now, and stationary energy supply is the entry point because it competes against the most expensive incumbent. Diesel-generated electricity costs about 0.34 to 0.46 US dollars per kilowatt hour at July 2026 prices, several times the cost of grid or solar power (own calculation from diesel price and generator fuel consumption, formula F7, shown in full in Annex B.3) [14][26]. Wherever a mine or community load runs on diesel generators, or needs guaranteed power through grid outages, a solar-plus-hydrogen system can already compete today (Chapter 4). This stage also includes grid stabilisation. The coal-dominated regional grid faces growing balancing needs as more solar is added, and a hydrogen plant can absorb solar peaks that would otherwise be lost and return the energy in the evening and at night. That interplay between solar overproduction, electrolysis and re-electrification is exactly what the worked example in Chapter 4 quantifies.

3.2 Hydrogen mobility: strategically important, not the first step

Mining vehicles are the region's largest diesel consumers. A single ultra-class haul truck of the 300 tonne class burns on the order of 140 litres of diesel per hour and around 0.9 million litres per year in typical operation [30]. Replacing that diesel is strategically attractive for the mines, both for cost stability and for their decarbonisation targets.



Figure 7: An ultra-class diesel haul truck of the type used in open-pit mines, one such truck burns roughly 0.9 million litres of diesel per year. Photo: Geomartin, Wikimedia Commons, licence CC BY-SA 4.0.

The region has already seen the flagship attempt. In May 2022, Anglo American unveiled the nuGen truck at the Mogalakwena platinum mine. It was a 290 tonne haul truck converted to a 2 megawatt hybrid drive of fuel cells and batteries, refuelled from an on-site electrolyser. The truck worked. The programme still collapsed. Anglo American stopped funding its technology partner First Mode in late 2024 during a company-wide capital review, First Mode filed for insolvency in December 2024, its assets were bought by the engine maker Cummins in February 2025, and the mine itself was spun off into the new company Valterra Platinum in May 2025, which has not continued the programme [7].

The lesson is about sequence, not about the technology. A hydrogen truck fleet only makes economic sense once a cheap, reliable hydrogen supply exists at the mine, and the truck programme was carrying the full cost of building that supply chain by itself. The right order is the reverse. First build hydrogen production sized for a stationary use that pays for itself, then extend it to vehicles once the supply is proven and its cost is known. Chapter 4 follows this order and calculates the

truck fuel case as an outcome of the stationary anchor. With hydrogen from the third expansion phase, one kilogram of hydrogen replaces about 4.2 litres of diesel, and the break-even hydrogen price against rebated mining diesel is about 5.47 US dollars per kilogram. Hydrogen truck conversions themselves also still carry significant vehicle-side cost, so the fuel price is a necessary condition, not the whole story. Mobility therefore sits in the middle of the roadmap, with a clear trigger, not at its start. It is worth noting that Grootegeluk is already being used as a test site for new drivetrain technology. Exxaro confirmed Grootegeluk in 2026 as the site for trials of a hybrid mining truck of another manufacturer, with the actual test operation planned to begin by October 2027 [25].

3.3 Regional supply rather than export

A recurring question during the mission was whether the region should produce hydrogen for export to Europe or Asia. The honest answer is no, not from the Waterberg. Export projects live on the lowest possible production cost and on port access, and both belong to the Northern Cape. What the Waterberg can do well is produce for itself. Hydrogen made from local solar surpluses can be used locally in mines, vehicles and backup power, replacing fuels that are far more expensive than any world-market hydrogen price. The worked example in Chapter 4 is deliberately built around this regional self-supply logic, and the value it creates stays in the district, which is also what the Just Energy Transition's local-benefit principle asks for [M1].

3.4 Green ammonia and fertiliser: a later option, limited by water

Ammonia is the feedstock of nitrogen fertiliser. Making it from green hydrogen is a natural further processing idea for an agricultural province. The demand logic is real. Sub-Saharan Africa imports most of its fertiliser, and transport can be a large share of the delivered price. Two facts push this option into the medium term. First, ammonia production is extremely water-hungry in hydrogen terms. Each tonne of ammonia contains the hydrogen of about 178 kilograms of electrolysis output (based on the stoichiometry of ammonia synthesis) [13], so a small fertiliser plant would multiply the water demand of everything discussed in this report. Second, ammonia is stored and shipped as a liquid, which requires either cooling it to minus 33 degrees Celsius, its boiling point at normal pressure, or keeping it under about 10 bar of pressure. Both add plant complexity and energy demand. In a water-scarce region with an existing agriculture-versus-industry water tension, this option should wait until a dedicated non-fresh water source (Section 2.3) is proven at scale. It is therefore listed in the roadmap as a medium-term option, conditional on water, not as part of the anchor.

3.5 The frame: hydrogen as a regional development engine

Everything above connects to the theme that ran through the whole mission. Hydrogen should not remain an industrial initiative. It must become a regional development engine [M7]. Use cases must be justified by local benefit, local jobs and local value creation, not by technology enthusiasm. That is not only good politics. It is also good project design, because community-supported projects are the ones that survive changes of ownership and management, as the nuGen story shows. The worked example in the next chapter was chosen by exactly this standard. It uses an existing local asset, it serves a local energy need, its savings stay with a local operation, and its skills demand feeds the local college.

4. Worked Example: Hydrogen at the Lephalale Solar and Mining Site

Chapters 2 and 3 concluded that the Waterberg's realistic entry point is stationary hydrogen supply at an existing industrial site with its own renewable generation, not export production and not an early move into vehicles. This chapter tests that conclusion against real numbers. This chapter is the core of the assessment. It develops one concrete, staged project at one real site, and it reports the outcome of every calculation step from energy demand to investment cost, operating cost, hydrogen cost and the comparison against diesel. The calculation itself is set out in full in Annex B. All formulas are collected in Annex A and are referenced in the text as F1 to F8. Wherever a number is an assumption rather than a verified fact, it is labelled with an assumption number (A1 to A9) and listed again in Annex B.4, because verifying these assumptions is precisely the task of the next project phase.

4.1 Why this site

The Lephalale Solar Project of Cennergi, next to the Grootegeluk coal mine, is the natural host for the region's first hydrogen project for four reasons. First, it is real. 68 megawatts of solar capacity have operated there since December 2025, so the electricity source needs no new permitting or construction for the first phases [6][24]. Second, it has an anchor customer on site. The mine consumes large amounts of electricity around the clock and operates a large diesel vehicle fleet, so both possible hydrogen uses (electricity backup and vehicle fuel) sit within one fence. Third, the infrastructure exists. This includes 132 and 33 kilovolt grid connections, road and rail access, land for expansion, and mine water infrastructure. Fourth, the owners are already investing in exactly this direction. The solar plant itself was built to cut the mine's energy cost and emissions, an expansion of about 30 megawatts is considered possible, and the mine has been confirmed as the site for upcoming trials of a new hybrid truck drivetrain, due to begin by 2027 [25].

Calculation logic at a glance

The whole example runs on eight formulas. They are listed here in short form so that the chapter can be read without turning to the annex. Six input values feed them: E is the annual electricity used for electrolysis, P the rated power of the electrolyser, SEC its specific consumption, C the installed investment cost per kilowatt, m the annual maintenance share and p the electricity price. Every other symbol is a result, and it is named in the row of the formula that produces it. Annex A gives each formula in full, with the derivation and a worked example.

Table 2: Calculation basics at a glance

	What it gives	Short form
F1	Hydrogen output per year (M)	`M = E ÷ SEC  (SEC = 55 kWh/kg)`
F2	Equivalent full-load hours (FLH)	`FLH = E ÷ P`
F3	Raw water demand (W)	`W = M × 25 L ÷ 1,000`
F4	Annuity factor (a) that turns the investment into an annual payment	`a = i(1+i)ⁿ ÷ ((1+i)ⁿ − 1) = 0.102  (i = 8 %, n = 20 years)`
F5	Annual operating cost (OPEX)	`OPEX = C × P × m + E × p + water treatment`
F6	Levelized cost of hydrogen (LCOH)	`LCOH = C(a + m) ÷ (FLH ÷ SEC) + SEC × p + water`
F7	Diesel that one kilogram of hydrogen replaces	`1 kg ≈ 4.2 L diesel; break-even = 4.2 × diesel price`
	What it gives	**Short form**
F8	Blended cost of the delivered electricity (LCOE), where s is the direct-solar share, c_PV the solar cost and c_H2 the hydrogen-path cost	`LCOE = s × c_PV + (1 − s) × c_H2  (s ≈ 0.7)`

4.2 Facts and assumptions

The calculation uses the following inputs. The first block is verified. The second block consists of assumptions that are reasonable at scoping level but must be replaced with measured data in the next phase.

Verified inputs.

Table 3: Verified inputs used in the Lephalale worked example

Input	Value	Source
Solar plant grid-side capacity	68 MW (77.4 MWp panel-side, ≈ 129,000 modules)	[6][24][31]
Solar generation	≈ 176 GWh per year	
Share of mine demand covered by the solar plant	≈ 30 %	[6]
		[6]
Grid feed-in arrangement	up to 20 MW surplus to the Eskom grid, contractually committed	Site presentation, June 2026
Expansion potential	≈ 30 MW on adjacent land	Site presentation, June 2026
Specific solar yield at Lephalale	≈ 55 kWh per kg of hydrogen≈ 1,790 kWh per kWp per year	[9]
Electrolyser energy demand	(system level)	[11]
Electrolyser investment cost, Western make, installed (1 MW reference price)	≈ 2,000–2,600 USD per kW	[12]
Electrolyser investment cost, Chinese make, landed and installed outside China (1 MW reference price)	≈ 1,500–2,400 USD per kW	[12]
Diesel wholesale price, July 2026	24.78 R/L (≈ 1.52 $/L), June: 27.93 R/L	[14]
Diesel refund for mining (tax rebate)	3.82 R/L, 100 % of eligible litres, net diesel ≈ 20.96 R/L (≈ 1.29 $/L)	[32]
		[17]
Raw water demand of electrolysis	≈ 20–30 L per kg of hydrogen	

Assumptions (to be verified in the next phase).

Table 4: Assumptions used in the Lephalale worked example, to be verified in the next phase

#	Assumption	Value used	Basis
A1	Mine electricity demand, derived from "solar covers ≈ 30 %"	≈ 587 GWh per year (≈ 67 MW average load)	derived from [6][28]
A2	Share of annual solar energy exported to the Eskom grid today	≈ 10 % (≈ 17.6 GWh per year)	scoping assumption
A3	Share of annual solar energy in peaks that neither the mine nor the 20 MW export can absorb	≈ 3 % (≈ 5.3 GWh per year)	scoping assumption
A4	Value of solar electricity redirected from export to electrolysis	≈ 22.8 $ per MWh, dedicated new solar ≈ 31.9 $ per MWh	own estimate, informed by IEA global solar-PV price ranges [12]
A5	Diesel consumption of one ultra-class haul truck	≈ 0.9 million litres per year	Caterpillar 793F fleet telematics data [30]
A6	Cost–capacity scaling exponent for compression and dispensing equipment, applied to a documented 5 MW reference calculation	n ≈ 0.60 (compression), n ≈ 0.95 (dispensing, near–linear)	H2KNOW internal costing guide [33], compression exponent consistent with published hydrogen supply-chain cost-scaling studies
A7	Share of today's exported solar energy that can realistically be redirected to electrolysis in Phase 2	≈ 60 %	scoping assumption, not yet confirmed with Eskom
A8	Cost-scaling of electrolyser investment with plant size (stack cost linear, balance-ofplant cost scaling with capacity)	Stack share s ≈ 0.45, scaling exponent n ≈ 0.675 (range 0.60–0.75), reference size 1 MW	[37][38], reference size not independently confirmed for the specific cost figures in [12] (see Annex B.4)
A9	Capital recovery assumptions used for the annuity factor (interest rate and plant lifetime, see F4)	Interest rate i = 8%, plant lifetime n = 20 years ⟶ annuity factor a = 0.102	scoping assumption, not a site-specific financing quote, to be confirmed with real project financing terms in the next phase

4.3 The mine's load and the solar surplus

The mine runs essentially around the clock. Crushing, conveying and processing create a high, fairly flat base load, with moderate daytime peaks from shift patterns and pumping. Against this stands the solar plant, which produces a bell-shaped curve during daylight only. Figure 8 shows the resulting representative day in two variants. On a normal operating day, the mine absorbs almost all solar output directly. On a reducedload day, for example during maintenance or low production, solar output exceeds mine demand around midday. Up to 20 megawatts of the surplus goes to the Eskom grid, and whatever exceeds mine demand plus the export limit is lost, because the plant must curtail it. These lost peaks, and the exported energy, are the cheap energy sources that a hydrogen plant can harvest.

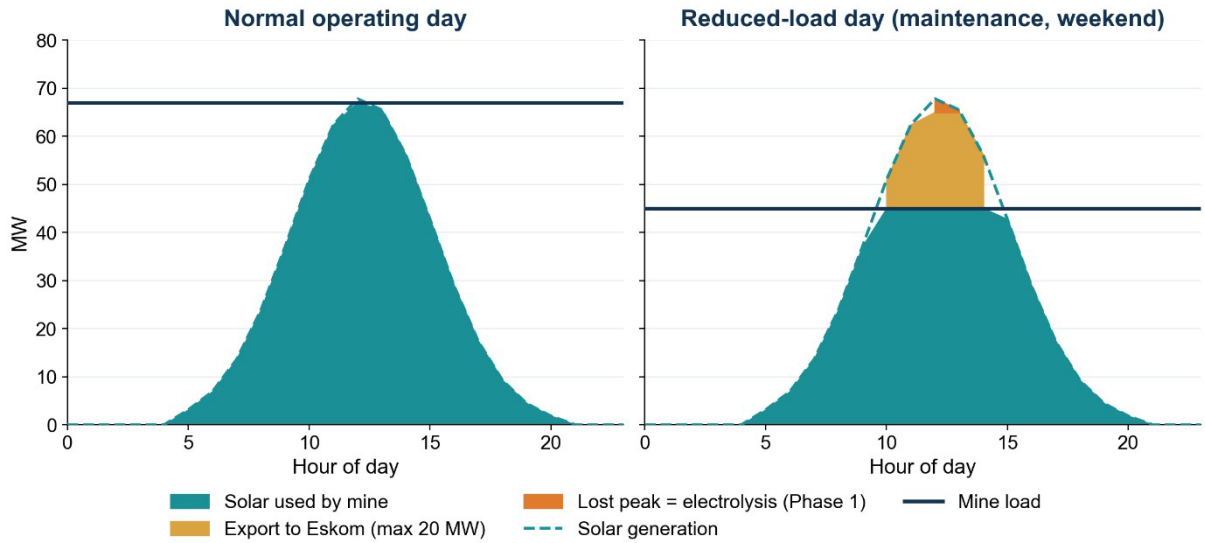


Figure 8: Representative day at the site: mine load, solar generation, the 20 MW export band and the surplus peaks that electrolysis can use. Illustrative profiles based on the verified annual quantities and assumptions A1 to A3.

4.4 Three expansion phases

The project grows in three phases, each of which works on its own and prepares the next. The phase energies follow directly from the inputs above. Each electrolyser is sized by applying formula F2 in reverse, calculating size as annual energy divided by the target full-load hours, with a target of about 2,600 equivalent full-load hours per year (Section 2.2, Annex A): about 5.3 GWh ÷ 2,600 h ≈ 2 MW (Phase 1), 15.8 GWh ÷ 2,600 h ≈ 6 MW (Phase 2), 76.7 GWh ÷ 2,560 h ≈ 30 MW (Phase 3). This is why the electrolyser grows in proportion to the energy each phase has available.

Phase 1: use the lost peaks. A small electrolyser of about 2 megawatts converts the solar peaks that today cannot be used at all (assumption A3, about 5.3 gigawatt hours per year). This electricity is effectively free, because it would otherwise be curtailed. The purpose of this phase is to build and learn. It creates the region's first operating hydrogen plant, the first trained operators, and real cost data, at the smallest sensible scale.

Phase 2: redirect the export. The up to 20 megawatts that today flow into the Eskom grid become the second energy source (assumption A2). This phase needs a commercial agreement, because Eskom currently has a contractual claim on this energy. The negotiation position is that the offset was designed as a valve for surplus, not as a firm supply commitment. Assuming about 60 percent of today's export energy can be redirected, the electrolyser grows to about 6 megawatts and processes about 15.8 gigawatt hours per year. The 60 percent figure is a scoping-level assumption, not a negotiated or measured value (assumption A7). The remaining 40 percent is assumed to stay with Eskom to preserve a stable base offtake and negotiating relationship, but the actually achievable share should be tested directly with Eskom in the next phase.

Phase 3: build dedicated solar for hydrogen. The step from Phase 2 to Phase 3 is deliberately large. This is not a gap in the model. Phases 1 and 2 use energy that already exists today (curtailed peaks and exported surplus), so they carry very low technical and commercial risk. Phase 3 is different, it requires a genuinely new investment decision, a dedicated solar expansion, rather than a further increment of the same kind. A smaller intermediate step was not modelled separately, because once new solar capacity has to be built, the same commercial and permitting process applies regardless of size, so this assessment treats Phase 3 as the next real decision point rather than a continuous scale-up. The roughly 30 megawatt expansion option next to the existing plant (about 34 megawatt-peak of panels) is built specifically for hydrogen production, adding about 61 gigawatt hours per year. The electrolyser grows to about 30 megawatts. The exact full load hour target implies about 29.5 megawatts, rounded here to a tidy 30 megawatts, which is why the equivalent full load hours in the table below come out slightly under 2,600 at about 2,560 instead of slightly over as in Phases 1 and 2. From here on, hydrogen is available in quantities that matter for vehicles, about 1,400 tonnes per year. If the Eskom solar plans at Medupi and

Matimba materialise (Section 2.1), the same logic scales further. That is the growth option beyond this example.

The quantities per phase follow from formula F1 (hydrogen output = energy divided by 55 kilowatt hours per kilogram) and F2 (full-load hours = energy divided by electrolyser size):

Table 5: Energy, hydrogen output and other quantities per phase

	Phase 1	Phase 2	Phase 3
Energy for electrolysis	5.3 GWh/a	15.8 GWh/a	76.7 GWh/a
Electrolyser size	2 MW	6 MW	30 MW
Equivalent full-load hours	≈ 2,640 h	≈ 2,640 h	≈ 2,560 h
Hydrogen output (F1)	≈ 96 t/a	≈ 288 t/a	≈ 1,395 t/a
Raw water demand (F3)	≈ 2,400 m^3/a	≈ 7,200 m^3/a	≈ 35,000 m^3/a
Enough fuel for haul trucks (F7)	≈ 0.5	≈ 1.4	≈ 6.6
Or night-time power via fuel cell (F8)	≈ 0.4 MW	≈ 1.3 MW	≈ 6.4 MW

4.5 The system

The plant itself is a standard modular configuration used worldwide for this purpose: solar power feeds an electrolyser, the electrolyser splits treated mine water into hydrogen and oxygen, the hydrogen is compressed into pressurised storage, and from storage it flows either to a fuel cell that generates electricity at night and during outages, or to a dispenser that refuels vehicles (Figure 9). A battery belongs in the design as well, and the division of labour between battery and hydrogen deserves a plain explanation, because it decides how the system is sized.

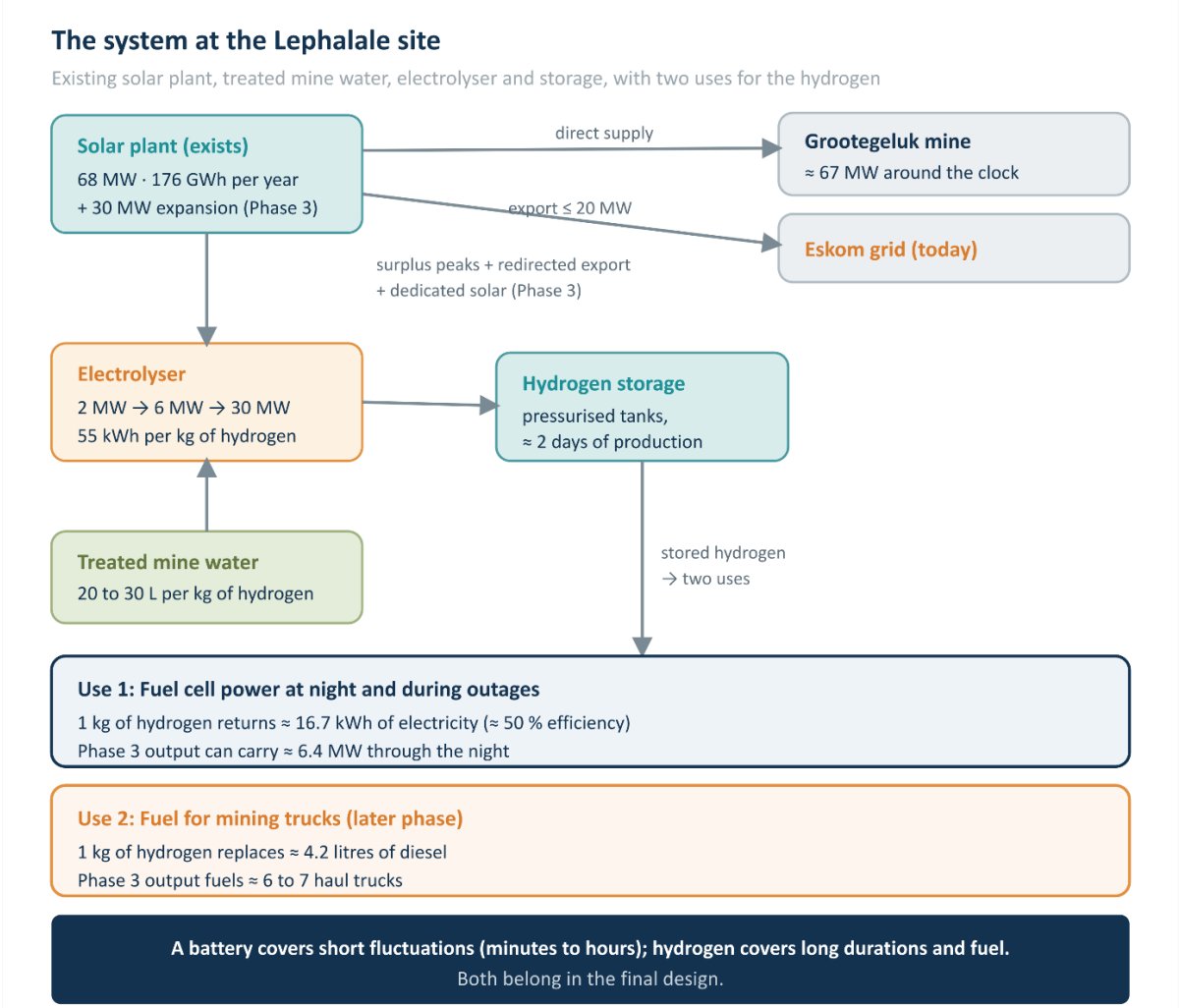


Figure 9: The system at the Lephalale site: existing solar plant, treated mine water, electrolyser, storage, and the two uses of the hydrogen (night-time power and vehicle fuel).

Batteries store electricity directly and return about 90 percent of it, but their cost grows in proportion to every stored kilowatt hour, so they are the right tool for minutes to hours. Hydrogen works differently [22]. Converting electricity to hydrogen and back loses about two thirds of the energy (the electrolyser converts at about 68 percent, compression takes several percent more, and the fuel cell converts back at about 50 percent, which multiplies to roughly 35 percent round trip). In exchange, storing more hydrogen only needs a bigger tank, which is cheap compared to battery cells, and the stored energy keeps indefinitely. Hydrogen is therefore the right tool for long durations (nights, cloudy days, seasonal reserves) and for fuel, while the battery covers short fluctuations. Published cost analyses put the crossover at roughly half a day of storage duration. Below that, batteries are cheaper, above it, hydrogen wins [22]. In this project the strongest argument for hydrogen over a pure battery solution is a different one anyway. Only hydrogen can also refuel trucks. The battery-only alternative is quantified in Annex B.3.

4.6 Results at a glance

Annex B sets out the full calculation step by step, together with Tables 6 to 9. It covers the seven investment blocks, the operating cost build-up, the resulting hydrogen cost, and the four comparisons against the alternatives. This section only reports what that calculation shows and what it means for the decision.

Hydrogen costs about 5.3 to 5.8 US dollars per kilogram with Chinese equipment, landed and installed, and about 6.3 to 6.6 with Western equipment. The supplier choice therefore matters more than the size of the plant, because Phase 1 runs on solar peaks that are free today while Phase 3 has to pay for a dedicated solar extension. Figure 10 shows each case as one bar, split into what pays for the investment, the electricity and the water, against the price band at which hydrogen breaks even with diesel as a truck fuel.

Cost of hydrogen:

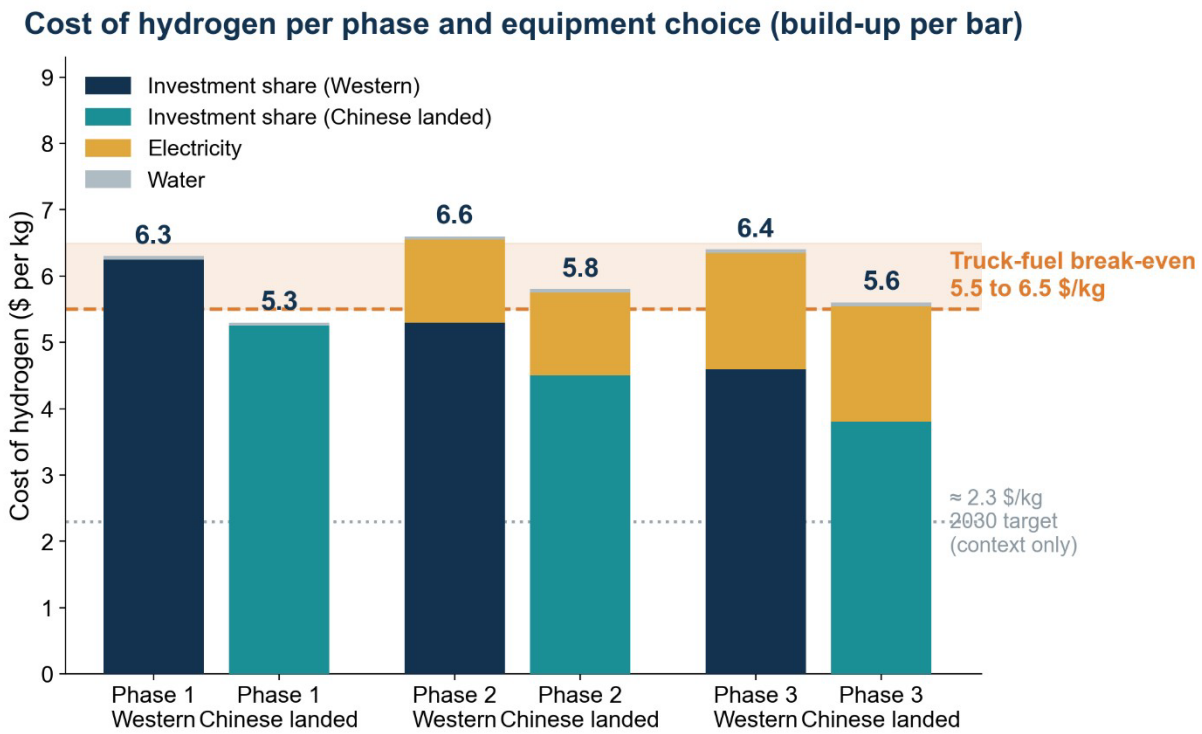


Figure 10: The cost of hydrogen per phase and equipment choice, with the cost build-up (investment share, electricity, water) shown per bar. The 2030 industry aspiration is shown only as context.

The decisive comparison is against diesel, not against the grid:

Solar carries about 70 percent of the delivered energy directly and hydrogen only the night and outage hours, so the site supplies round-the-clock power at about 0.16 US dollars per kilowatt hour, against 0.34 to 0.46 for a diesel generator. This is the core economic finding of the example: as a complete supply, solar plus hydrogen clearly beats diesel generation, even though hydrogen on its own, kilogram for kilogram, is not yet a cheap fuel. Figure 11 puts these price levels side by side, with the Eskom tariff shown for reference.

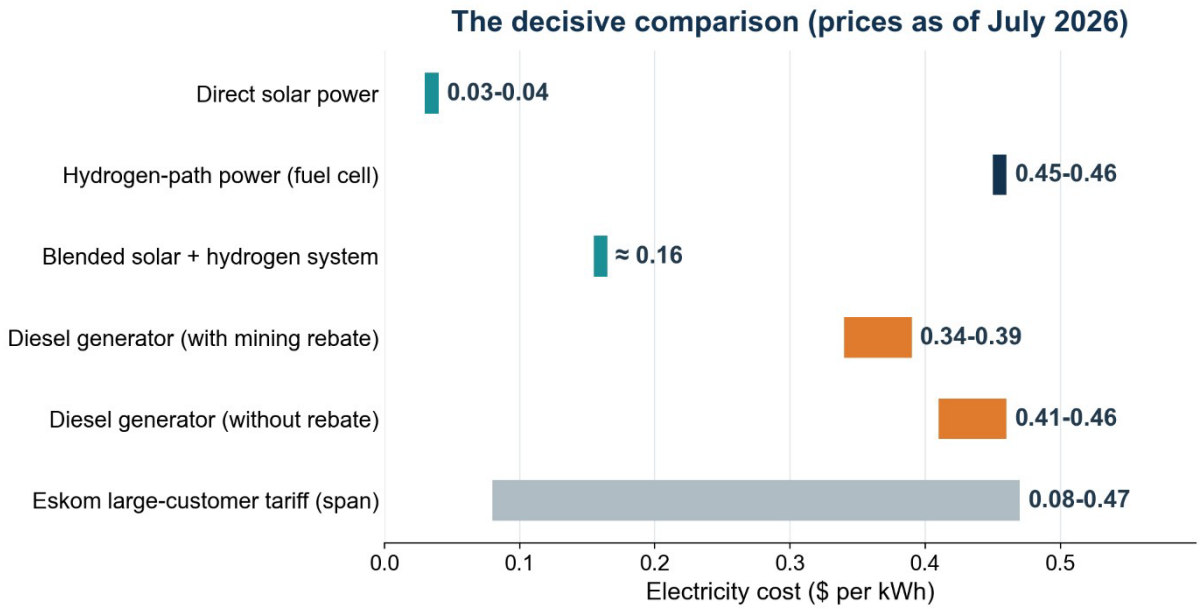
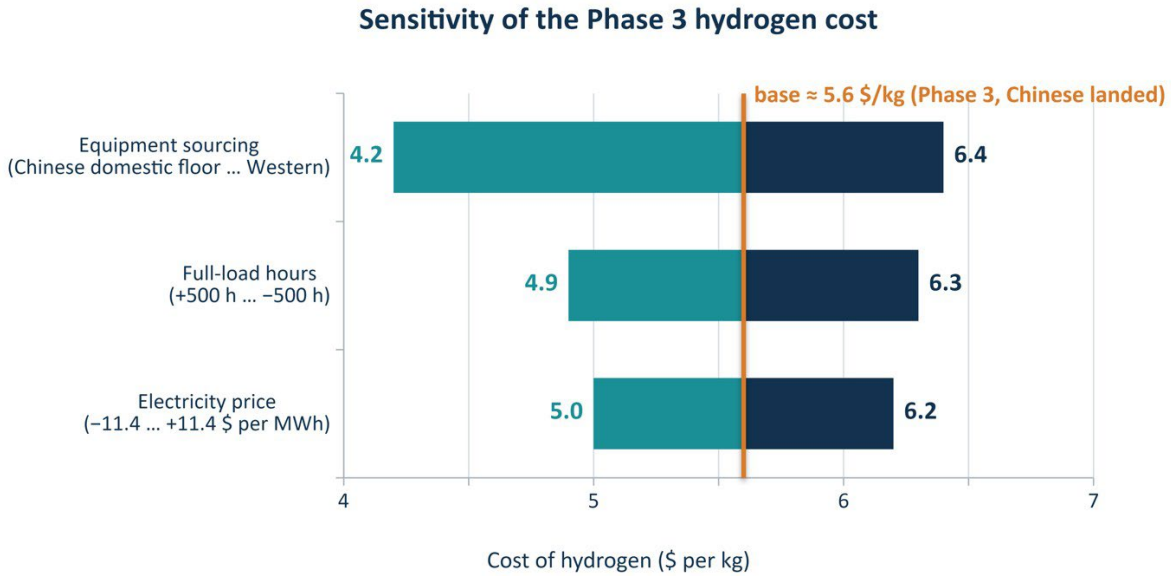


Figure 11: The decisive comparison: blended solar-plus-hydrogen electricity (≈ 0.16 $/kWh) against diesel-generator electricity (0.34–0.46 $/kWh) and the Eskom tariff band (0.08–0.47 $/kWh depending on season and hour). Prices as of July 2026 [14][21].

What moves the result:

Three levers move the result: the equipment sourcing by about 0.8 to 1.0 US dollars per kilogram, the utilisation of the electrolyser, and the electricity price. The largest uncertainty is not a price at all but the assumption about how electrolyser cost scales with plant size, which this report carries as open rather than verified. Figure 12 shows how far each lever moves the Phase 3 cost away from its base case of about 5.6 US dollars per kilogram.



Not shown: the electrolyser scaling assumption is the largest single uncertainty (see Annex B.4).

Figure 12: Sensitivity of the Phase 3 hydrogen cost to the three main levers, calculated from the formulas in Annex A.

These results rest on the assumptions A1 to A9. Annex B.4 lists them, together with the data that would have to be measured in order to replace them.

4.7 What this example is, and what it is not

This worked example shows that a staged, realistically sized hydrogen project at an existing site can be built responsibly. Its first phase rests on measured data, while its later phases rest on clearly labelled, individually flagged assumptions rather than on hidden or unstated ones. The first phase already makes economic sense as a learning investment, while the later phases approach genuine fuel economics if those assumptions hold. The largest single assumption behind that later-phase picture is the electrolyser cost-scaling with plant size described in Annex B.1 and Annex B.4, which this report treats as an open, labelled uncertainty rather than a verified fact. This is a scoping calculation on verified plant data and labelled assumptions, not an engineering design, a quotation or a bankable study. The named companies have not been asked to endorse this example, which draws on their published figures and the mission's discussions with the operators as its factual basis. Any actual project would of course be shaped and decided by them. The value of the example is that it gives the region a concrete, calculable starting point instead of an abstract potential.

4.8 Safety concept for the next phase

Hydrogen is a well-understood industrial gas with established international and South African safety codes, and it has been produced, stored and used safely in South African industry for decades, for example in refining and the chemicals sector. It is nonetheless a flammable gas with a wide explosive range, and safety needs to be designed into the system from the outset rather than added afterwards. This assessment does not include a safety design, because that work depends on a site layout, equipment selection and vendor that are not yet fixed. It belongs in the early stage of a preliminary-engineering phase. Three items should be carried into that phase as fixed requirements:

- a formal hazard identification and risk assessment (for example a site-specific risk assessment combined with HAZOP or an equivalent methodology) covering production, storage, compression and dispensing, in line with relevant South African and international standards for hydrogen installations
- explosion-protected equipment and area classification around the electrolyser, storage and dispensing areas, with appropriate separation from the mine's other operations
- an emergency response plan coordinated with the mine's existing safety organisation

None of these are unusual requirements for an industrial gas installation, and none change the economics calculated in this chapter. They are listed here so that a credible next-phase budget and schedule includes them explicitly.

5. Skills Development

The proposed example in Chapter 4 demands people who can build, operate and certify a hydrogen installation. They are missing at present, and building this capacity can start before any capital is committed. That is why the skills track is the first, not the second, part of the entry strategy.

5.1 The skills bottleneck

The mission's visit to the Waterberg TVET College made the skills situation concrete. The college is a public vocational institution with four campuses, including an engineering skills centre, and it already teaches solar and wind curricula. It wants to teach hydrogen, but it faces a double blockage. First, no acute hydrogen demand exists yet. Companies in the region have not yet asked for hydrogen-trained staff, and the college's rules require proven industry demand before a course can be offered. Second, the college itself does not yet hold the hydrogen knowledge needed to teach and certify credibly. No course without demand, no demand without visible projects, no projects without skilled people. This is a classic cold-start problem.

5.2 Two kinds of education, one cycle

The way out is to distinguish two kinds of education that are often mixed up. The college system educates the next generation through multi-year vocational and engineering programmes that produce new technicians and engineers, with formal accreditation that in South Africa takes considerable time. Company training does something different. It takes the workforce and the decision makers that a region already has and qualifies them for hydrogen in weeks, not years. A region that wants to move quickly needs the second kind first, because it creates the demand and the projects that the first kind then feeds.

The two options can be connected into one cycle. Short, practical training for companies and municipal decision makers can be an option to increase awareness and provide fundamental knowledge. A higher awareness and a better understanding of fundamentals can create projects, such as the worked example of Chapter 4. Projects create real demand for hydrogen-skilled workers, and that demand is exactly what might be needed in the future. A college that produces hydrogen-qualified graduates makes the region attractive for future applicants. Run through once, this cycle makes the region self-sufficient in hydrogen skills. The practical sequence is therefore: begin with decision-maker workshops and short courses now, then deep hydrogen courses for engineers and afterwards practical trainings for technical staff. After that the knowledge has become established in the region and train-the-trainer support for the college can be started, through which a formal accreditation proceed can be established.

A first workshop for decision makers would typically cover in one to two days:

- what hydrogen is and is not (properties, safety basics, the difference between grey and green hydrogen)
- where it makes economic sense today, using the regional numbers of this report
- how a project is structured, financed and permitted
- what each participant's organisation would concretely need to do next

The purpose is not technical depth but decision ability. After the workshop, a mine manager, a municipal planner or a business owner can judge where hydrogen belongs in their own planning, and the region gains the informed sponsors that every later step needs.

6. Next Steps

The study identified how the region can position itself in the green hydrogen context and where concrete measures can start. However, there is still no common understanding among the local key actors, but rather different ideas that vary significantly.

Thus, as a key next step it is recommended to initiate a common regional hydrogen masterplan for the district, together with a stakeholder mapping and smaller accompanying measures. This would allow the district to turn ideas into a politically adopted, investment-ready Green Hydrogen Masterplan within approximately six months. The masterplan covers the whole Waterberg District, with Lephalale as its technical focus, since the worked example of Chapter 4 provides the concrete starting point.

No single actor can build a local green hydrogen economy on its own, so the decisive success factor for the masterplan is not a technical or financial variable but whether the district succeeds in establishing a functioning **public–private dialogue (PPD)**. This PPD brings public and private partners together regularly, in a structured and transparent format, with each accepting and delivering on a defined role. The masterplan process should install such a dialogue from the outset — a standing platform convened by the Waterberg District Municipality, with a clear mandate, an agreed meeting cycle, a joint work programme and shared monitoring.

- **Municipalities (the Waterberg District Municipality, Lephalale and Mogalakwena Local Municipalities):** convene and chair the dialogue, integrate green hydrogen into their Integrated Development Plans, Local Economic Development strategies and spatial plans, make land, bulk services and predictable local procedures available, and account transparently for the revenue and services generated.
- **Mining operations:** bring the demand side — energy and diesel-consumption data, application sites and an off-take perspective — align their decarbonisation targets with the district process, and open procurement so that investment translates into local value chains.
- **Private developers, investors and technology partners:** commit capital, technology and delivery capacity against the conditions the public side guarantees, and build local supplier and service capability.
- **Waterberg TVET College, organised labour and business chambers:** develop and certify the skills the value chain requires (Chapter 5) and ensure the transition creates decent local employment.
- **Communities and traditional authorities:** participate as co-owners with transparent benefit-sharing, rather than as parties that are merely consulted.
- **GIZ Connective Cities and international partners:** facilitate and moderate the dialogue, provide technical input and peer learning, and help mobilise follow-up financing.

Such a dialogue only works if it is binding. Commitments should be recorded, assigned to a named institution with a date, and reviewed at every meeting against a joint monitoring and risk register covering access to demand data, regulatory movement, financing gaps, municipal capacity and community expectations. Where a partner cannot deliver, this should surface early enough for the others to adjust rather than for the process to stall. Organised in this way, the dialogue itself becomes the district's central asset: it turns a single anchor project into a conducive local green hydrogen economic ecosystem in which suppliers, service providers, skills institutions and communities all hold a stake.

6.1 Conclusion

The realistic role of the Waterberg in South Africa's hydrogen economy is that of a demand and application hub, not that of an export production region, which is where the Northern Cape has the mandate and the ports. The most concrete way to begin is Phase 1 of the worked example: a small electrolyser running on solar peaks that are lost today, needing no new power infrastructure and justifiable on its own as a low-risk learning investment. Alongside it, the skills track can start immediately and at little cost, and it is where the region can gain its first real foothold. The overall recommendation is therefore a conditional go: begin these two tracks now, take the anchor project into a preliminary-engineering and site-data phase, and treat hydrogen mobility and green ammonia as medium-term options with clear cost triggers.

7. References

7.A Documents provided to the mission

These are the presentations and official documents provided to the mission team during and around the field week of 8 to 12 June 2026. They are held in the project folder.

Ref	Source (issuer · title · date)
[M1]	SALGA · "Green Hydrogen Linkage with the JET Municipal Council", mission deck, 8 Jun 2026 (18 slides)
[M2]	SALGA · Minutes, Hydrogen Economy SA Mission, Day 1, 8 Jun 2026 (7 pp.)
[M3]	GIZ H2.SA · "Strategy, Policy & Regulatory Framework" (Workstream I), mission deck, Jun 2026 (16 slides)
[M4]	DSTI (M. Mlilo) · "Green Hydrogen Innovation for R&D Commercialisation", mission deck, 8 Jun 2026 (26 slides)
[M5]	Eskom · "Lephalale Solar PV & BESS Project", municipality introduction, 10 Jun 2026 (12 slides), planning stage
[M6]	Eskom RT&D (M. Verby) — "Clean Coal and Hydrogen Master Class", 18 May 2026 (20 slides)
[M7]	Waterberg Development Initiative (A. van Zyl) · "Enabling Regional Collaboration", mission presentation, 12 Jun 2026
[M8]	Prieska Power Reserve (CENEC / Mahlako / IDC) · green ammonia project deck, 8 Jun 2026 (11 slides), Northern Cape comparator
[M9]	DNA Economics for SANEDI / GIZ · "Green Hydrogen Research Review", 29 Nov 2023
[M10]	GIZ / Raventech · "Hydrogen Research Activities in South Africa", Feb 2017
[M11]	SAIMM · 2nd Southern African Hydrogen & Fuel Cell Conference, Proceedings, 7–8 Apr 2025
[M12]	Hydrogen Expert Mission · Closing strategy workshop, agreed action points, 12 Jun 2026

7.B External sources

Ref	Source
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Annex A. Formulas

The formulas use the following symbols:

E = annual electrical energy for electrolysis (kilowatt hours per year),

P = electrolyser rated power (kilowatts),

SEC = specific energy consumption of the electrolyser (55 kilowatt hours per kilogram), C = installed investment cost (US dollars per kilowatt), m = annual maintenance share (approx. 5% 5% of electrolyser + storage + compression + dispensing CAPEX, according to [11], p = electricity price (US dollars per kilowatt hour).

F1: Hydrogen output. Annual hydrogen mass in kilograms: $M = E \div SEC$.

> Example (Phase 2): 15,800,000 kWh ÷ 55 kWh/kg ≈ 288,000 kg ≈ 288 t.

F2: Equivalent full-load hours. $FLH = E \div P$.

> Example (Phase 2): 15,800,000 kWh ÷ 6,000 kW ≈ 2,640 h.

F3: Raw water demand. Cubic metres per year: $W = M \times w \div 1{,}000$, with $w \approx 25$ litres of raw water per kilogram (range 20 to 30).

> Example (Phase 3): 1,395,000 kg × 25 L ≈ 35,000 m^3.

F4: Annuity factor. $a = i \times (1+i)^n \div ((1+i)^n - 1)$ with assumed interest rate i = 8 % and assumed lifetime $n = 20$ years gives $a = 0.102$. The investment C is thereby converted into an equal annual payment.

F5: Annual operating cost. $OPEX = C \times P \times m + E \times p + W \times$ water treatment cost per m^3.

F6: Levelised cost of hydrogen. $LCOH = C \times (a + m) \div (FLH \div SEC) + SEC \times p +$ water cost per kilogram. The term $FLH \div SEC$ is the annual hydrogen output per kilowatt of electrolyser.

F7: Diesel equivalence. One kilogram of hydrogen carries 33.3 kilowatt hours (lower heating value). With a fuel cell drivetrain efficiency of about 47.5 % and a diesel engine efficiency of about 37.5 % (diesel: 9.96 kilowatt hours per litre), the replaced diesel volume is $(33.3 \times 0.475) \div (9.96 \times 0.375) \approx \mathbf{4.2}$ litres per kilogram. Break-even hydrogen price = 4.2 × diesel price per litre. Diesel-generator electricity cost = specific consumption (0.27 to 0.30 litres per kilowatt hour [26]) × diesel price per litre.

F8: Blended system electricity cost. $LCOE = s \times c_PV + (1 - s) \times c_H2$, where s is the direct-solar share of delivered energy (≈ 0.7), c_PV the direct solar cost (≈ 0.034 US dollars per kilowatt hour) and c_H2 the hydrogen-path cost, itself $LCOH \div (33.3 \times$ fuel cell efficiency 0.50) + fuel cell capital charge (≈ 0.11).

> Example: 0.7 × 0.034 + 0.3 × 0.46 ≈ 0.16 US dollars per kilowatt hour.

Annex B. Detailed cost tables

This annex carries the full calculation behind Annex B.1: how the investment per phase is built up, how operating cost and the levelized cost of hydrogen follow from it, how hydrogen compares against the four alternatives, and which assumptions move the result. It is the material a reviewer needs in order to reproduce or challenge the figures.

B.1 Investment cost (CAPEX)

The investment per phase is built from seven blocks. These are the electrolyser (size times specific cost, formula F4), the hydrogen storage (sized for about two days of production), compression to storage and dispensing pressure (to approximately 300 bar for storage, with further compression to 700 bar at the point of vehicle dispensing), the dispensing/trailer interface, the fuel cell, the water treatment plant, and, in Phase 3 only, the new solar plant itself. The electrolyser cost is stated in the two verified categories from Section 4.2. The often-quoted much lower Chinese figures of 600 to 1,200 US dollars per kilowatt apply to plants built inside China and are not achievable landed and installed in South Africa, although they indicate where prices may move as local assembly develops [12].

Table 6: Estimated CAPEX values for the three phases

CAPEX block (million USD)	Phase 1 (2 MW)	Phase 2 (6 MW)	Phase 3 (30 MW)
Electrolyser, Western / Chinese landed	3.6 / 2.9	9.1 / 7.5	37.9 / 31.3
Hydrogen storage (≈ 530/1580/7640 kg)	0.46	1.48	6.95
Compression, to storage/dispensing pressure [33][A6]	0.46	0.91	2.39
Dispensing / trailer interface [33][A6]	0.17	0.50	2.38
Fuel cell (1 / 4 / 10 MW)	2.74	8.21	22.80
Water treatment (mine water to electrolysis grade)	2.85	2.85	2.85
New solar plant (34 MWp, Phase 3 only)	—	—	≈ 21.32
Total (rounded)	**≈ 10.3 / 9.6**	**≈ 23 / 21.5**	**≈ 96.60 / 90.00**

All figures carry the scoping accuracy band of minus 30 to plus 50 percent [20]. The fuel cell is deliberately sized above the average night output (for example 10 megawatts in Phase 3 against an average night demand of about 6.4 megawatts), because it must also carry the higher evening and outage peaks. Storage and dispensing scale close to linearly with capacity, because these components are modular and added in parallel units. The electrolyser and compression both follow a sub-linear cost–capacity relationship instead. This applies to

the electrolyser as described below, and to compression under the same cost–capacity logic already introduced as assumption A6 (Section 4.2). Real vendor quotations are one of the first tasks of the next phase.

Electrolyser cost-scaling with plant size. The electrolyser line is scaled with plant size using a standard cost– capacity approach for process equipment. The stack portion of the cost (assumed 45 percent at the 1 megawatt reference size [38]) scales linearly with capacity, while the balance-of-plant portion (55 percent) scales with an exponent of 0.675 (midpoint of the range 0.60–0.75 [37][38], assumption A8, Section 4.2). This reduces the effective cost per kilowatt from the 1 megawatt reference price [12] as plant size increases: for Western equipment, from 2,000 USD/kW at 1 megawatt to about 1,778 USD/kW at Phase 1 (2 megawatts), 1,514 USD/kW at Phase 2 (6 megawatts), and 1,264 USD/kW at Phase 3 (30 megawatts). Chinese-landed equipment scales the same way, from 1,650 to about 1,467, 1,249 and 1,043 USD/kW. The reference plant size underlying [12] is not independently confirmed (see Annex B.4), so this scaling is itself an assumption, not a verified correction. Real vendor quotations remain the first task of the next phase.

1 megawatt reference values for the remaining components. For consistency with the electrolyser figures above, which use a 1 megawatt reference price as their starting point, the same reference size is used here for the other scaled cost items. Hydrogen storage would be about 0.23 million US dollars at 1 megawatt, following the same physical sizing logic as the other phases (about two days of output at the corresponding full-load hours) rather than a cost-scaling curve. Compression would be about 0.31 million US dollars and dispensing about 0.09 million US dollars, both extrapolating the same cited cost–capacity scaling already used for Phases 1–3 (assumption A6) down to 1 megawatt. Fuel cell, water treatment and the new solar plant do not have an established capacity-scaling basis, so no 1 megawatt figure is given for these.

Scope of the electrolyser cost, and why compression and dispensing are added separately. The IEA's own definition of the [12] cost range covers the electrolyser system, electric equipment, gas treatment and engineering, procurement and construction (EPC) together. In other words, the fully installed electrolyser system, not the bare stack alone. Safety and control systems and the piping that connects the electrolyser's own internal components are therefore treated as already included in the electrolyser line above and are not added again. What that definition does not cover is compression to the higher pressure needed for storage and for vehicle or trailer dispensing, and the dispensing interface itself. These two items are added here as separate lines, scaled from a documented 5 megawatt reference calculation using standard cost–capacity scaling [33][A6]. This addition should be confirmed against real vendor quotations in the next project phase, in particular whether the IEA's "gas treatment" category already covers part of the compression duty assumed here.

B.2 Operating cost (OPEX) and the cost of hydrogen (LCOH)

OPEX and LCOH deliberately exclude accounting depreciation, because depreciation schedules are company- and tax-jurisdiction-specific and cannot be prescribed for the client. Instead, LCOH recovers the electrolyser investment through a standard annuity factor (see below), a finance-neutral method that does not depend on any company's own depreciation policy. The annual operating cost OPEX, as shown in the following table, consists of three cost elements (formula F5):

- maintenance, spares, staffing and insurance (about 5 percent per year for PEM [11]),
- electricity (the phases differ here: the Phase 1 peaks are free, the redirected export in Phase 2 is valued at about 22.8 US dollars per megawatt hour, and the dedicated solar of Phase 3 costs about 31.9 US dollars per megawatt hour),
- and water treatment.

Table 7: Estimated OPEX values for the different Phases

OPEX (million US$ per year)	Phase 1	Phase 2	Phase 3
Maintenance, spares, staffing and insurance (5 % of electrolyser + storage + compression + dispensing CAPEX) [11][33]	≈ 0.20-0.23	≈ 0.52-0.60	≈ 2.15-2.48
Electricity	≈ 0	≈ 0.36	≈ 2.45
Water	< 0.01	≈ 0.01	≈ 0.06
Total	**≈ 0.21-0.24**	**≈ 0.89-0.97**	**≈ 4.7-5.0**

The 5 percent maintenance figure is a fixed-cost proxy that already includes an allowance for staffing, but not a detailed personnel plan. A realistic minimum crew is indicatively on the order of 3, 4 and 6 full-time equivalents for Phases 1, 2 and 3

respectively. This has not been costed against local South African wage levels, which is a task for the next phase and could materially reduce the OPEX figures above once real numbers are available.

The levelized cost of hydrogen LCOH relate the operational costs to the hydrogen output in kilogram, according to formula F6 (Annex A) and considers:

- capital recovery on the electrolyser investment with a specific annuity factor (0.102, derived in F4 from an assumed 8% interest rate over the plant's 20-year lifetime)
- maintenance on the wider production system (electrolyser, storage, compression and dispensing together)
- Energy and water costs

Applying formula F6 to Phase 3 with Western equipment gives a total of about 6.4 US dollars per kilogram. The same calculation for all phases and equipment choices leads to following values, given in Table 8.

Table 8: Estimated LCOH values for the three phases and different equipment sources

LCOH ($/kg)	Phase 1	Phase 2	Phase 3
Western equipment	≈ 6.3	≈ 6.6	≈ 6.4
Chinese equipment, landed and installed	≈ 5.3	≈ 5.8	≈ 5.6
Chinese domestic price level (indicative floor)	≈ 3.3	≈ 4.1	≈ 4.2

The Western rows use a 1 megawatt reference price of 2,000 US dollars per kilowatt, scaled down by phase as described in Annex B.1. The Chinese landed rows use about 1,650 US dollars per kilowatt at the same reference size, toward the lower part of the verified 1,500 to 2,400 US dollar range. The indicative floor uses about 950 US dollars per kilowatt, scaled the same way.

First, the ranking of phases is consistent across all equipment and pricing paths. Phase 1 is always cheapest, because it draws on solar energy that would otherwise be curtailed and needs no new generation capacity. Phase 3 is consistently the second-cheapest, undercutting Phase 2, because its larger scale brings the per kilowatt electrolyser cost down enough to offset the cost of the dedicated new solar capacity it requires. Only at Chinese domestic price levels are Phase 2 and Phase 3 close enough to be considered essentially tied. Second, the equipment sourcing decision still moves the cost substantially by roughly 0.8 to 1.0 US dollars per kilogram depending on the phase. This remains the single most important procurement decision of the project.

For comparison, the roughly 2.3 US dollars per kilogram often quoted in industry discussions is a target for 2030 at ideal high-wind sites. South Africa's own national target is about 1.60 US dollars per kilogram by 2030 at the Northern Cape scale [18]. Neither describes what a real plant in the Waterberg can deliver today, and this report deliberately does not use such figures.

B.3 What the hydrogen is worth: four comparisons

Comparison 1: against diesel generators (backup and night power). Electricity from a diesel generator costs, at July 2026 prices, about 0.34 to 0.39 US dollars per kilowatt hour with the mining tax rebate and about 0.41 to 0.46 without it, for fuel alone (formula F7 applied to 0.27 to 0.30 litres per kilowatt hour) [14][26]. Electricity from stored hydrogen through the fuel cell costs about 0.45 to 0.46 US dollars per kilowatt hour at Phase 2 and 3 hydrogen prices (the hydrogen price divided by the 16.7 kilowatt hours that one kilogram yields through a 50 percent efficient fuel cell, plus about 0.11 US dollars for the fuel cell itself). Hydrogen backup power alone is therefore currently only slightly more expensive than diesel backup even at today's unusually low diesel price, and already cheaper than diesel without the mining rebate once diesel returns towards its May 2026 level (the wholesale price swung from over 31 rand per litre in May to under 25 in July, a 20 percent move in two months [14]). But backup power is not the full picture, which is what the blended system cost shows.

Table 9: Build-up of the blended solar-plus-hydrogen electricity cost

Component of the blended cost	Value	Where it comes from
Direct solar share of delivered energy	≈ 70 % at ≈ 0.034 $/kWh	solar plant cost level
Hydrogen share of delivered energy	≈ 30 %	night and backup hours
Hydrogen input cost	≈ 5.6-5.8 $/kg	Annex B.2, Phases 2 and 3
Fuel cell conversion	16.7 kWh per kg (≈ 50 % efficiency)	formula F8
Fuel cost of hydrogen power	≈ 0.34-0.35 $/kWh	hydrogen cost ÷ 16.7
Fuel cell capital charge	≈ 0.11 $/kWh	formula F8
Hydrogen-path power, total	≈ 0.45-0.46 $/kWh	sum of the two lines above
Blended system cost	**≈ 0.16 $/kWh**	$0.7 \times 0.034 + 0.3 \times 0.46$

The blended cost remains roughly half, or less, of diesel-generator electricity. This is the core economic finding: as a complete round-the-clock supply, solar plus hydrogen beats diesel generation clearly, even though hydrogen alone, kilogram for kilogram, is not yet a cheap fuel.

Comparison 2: against grid electricity. For a grid-connected site, the honest benchmark is Eskom's large customer tariff. At the relevant voltage level it currently ranges from about 0.08 US dollars per kilowatt hour at night in the low season to about 0.47 US dollars per kilowatt hour in winter peak hours, before network and legacy charges, and regulated increases continue (8.76 percent approved for 2026/27) [21]. Average grid power is therefore still cheaper than the blended solar-plus-hydrogen cost. The hydrogen system does not primarily compete with the average grid price. It competes with the expensive hours (winter evening peaks), with diesel during outages, and with the cost of not producing when the grid fails. For an off-grid or unreliable-grid site, the comparison tilts fully to hydrogen. For a well-connected site, the system earns its keep as peak-hour and resilience supply. Both situations exist in the district.

Comparison 3: against a pure battery solution. For bridging a single night, a battery system is today the cheaper storage. Battery storage costs have fallen sharply and published levelized storage costs for utility scale batteries are around 0.10 to 0.25 US dollars per kilowatt hour delivered [22]. Put into the project's own numbers, carrying the Phase 3 night share of about 6.4 megawatts for twelve hours requires about 77 megawatt hours of storage. As a battery, at current installed costs of roughly 200 to 330 US dollars per kilowatt hour [22], that is an investment of about 17.1 to 28.5 million (the 200 to 330 US dollar range is itself sourced from Lazard's utility-scale reference systems, which span 60 to 1,000 megawatt-hours. The 77 megawatt-hour requirement here falls within that range, so no separate scale adjustment is needed) US dollars, in the same range as the hydrogen storage and fuel cell blocks of Annex B.1. The difference is not the first night but everything beyond it. A second cloudy day doubles the battery investment, while the hydrogen system only needs a larger tank, and a battery cannot refuel a truck. The hydrogen path therefore earns its place for the longer durations (strings of cloudy days, seasonal patterns, multi-day mine outages) and for the fuel product. The recommended design is not hydrogen instead of batteries but a battery for the short cycles plus hydrogen for long duration and fuel, sized in the next phase against the measured load profile.

Comparison 4: as truck fuel. One kilogram of hydrogen (at 700 bar, the standard vehicle dispensing pressure) carries 33.3 kilowatt hours. A fuel cell drivetrain uses it about 25 percent more efficiently than a diesel engine uses diesel, so one kilogram replaces about 4.2 litres of diesel (formula F7). At the July 2026 net mining diesel price of about 1.29 US dollars per litre, the break-even hydrogen price is about 5.47 US dollars per kilogram. Without the rebate it is about 6.4 US dollars per kilogram. Phase 3 hydrogen at Chinese-landed equipment cost (about 5.6 US dollars per kilogram) now sits within this band, above the rebated break-even price but below the unrebated one. The indicative Chinese-domestic floor (about 4.2) sits clearly below it, beating even the rebated diesel price. In plain terms, hydrogen as truck fuel is close to economic today with landed Chinese equipment once the diesel rebate is set aside. It would already be economic at the Chinese domestic price level. One truck consumes about 212 tonnes of hydrogen per year (assumption A5), so the Phase 3 output could fuel about six to seven trucks, a realistic first conversion tranche for a mine fleet. The vehicle conversion cost itself is not included here and belongs in the mobility study of the roadmap.

B.4 Sensitivity: what moves the result

The sensitivities follow directly from the calculations above; Figure 12 in Section 4.6 shows them. Ranked by impact on the hydrogen cost of Phase 3:

1. **Equipment sourcing.** Western versus Chinese-landed moves the result by about 0.8 to 1.0 US dollars per kilogram depending on the phase. Reaching Chinese domestic price levels (for example through partial local assembly) would move it by about 2.2 to 3.0 US dollars per kilogram. These figures already include the effect

of electrolyser cost-scaling with plant size (Annex B.1). The scaling itself depends on equipment origin and phase size, so the sourcing decision and the scale effect are not independent. The gap between Western and Chinese pricing narrows somewhat at larger plant sizes, which is why the Phase 3 gap (0.8) is smaller than the Phase 1 gap (1.0).

2. **The electrolyser scaling assumption itself.** The cost-scaling applied throughout the calculation (Annex B.1) assumes the [12] reference price applies at 1 megawatt. If the true reference size is larger, the calculated cost reduction for Phases 2 and 3 would be smaller than shown here. This is plausible, since the underlying IEA survey covers real 2024 projects that are, on average, larger than 1 megawatt, and Phase 3's current advantage over Phase 2 could narrow or disappear (Annex B.1, Annex B.2). This is the single largest source of uncertainty in the scaled figures.
3. **Full-load hours.** Every additional 500 full-load hours (for example through modest grid supplementation at night tariffs or oversizing the solar field relative to the electrolyser) reduces the investment share by about 0.74 US dollars per kilogram.
4. **Electricity price.** Every 11.4 US dollars per megawatt hour moves the hydrogen cost by 0.63 US dollars per kilogram (55 kilowatt hours times 0.011 US dollars). This is why the free Phase 1 peaks and the cheap redirected export matter so much.
5. **Diesel price** (affects the comparison, not the cost). The 20 percent diesel price swing observed between May and July 2026 moves the truck-fuel break-even by about 1.14 US dollars per kilogram in either direction and moves the diesel-generator benchmark by about 0.08 US dollars per kilowatt hour.

The assumptions A1 to A9 are the data gaps of this example: the mine's real load profile and demand (A1), the real share of solar energy exported today and the share currently lost as unused peaks (A2 and A3), the achievable commercial value of redirected and dedicated solar electricity (A4), the fleet's real fuel consumption (A5), the cost–capacity scaling of compression and dispensing equipment (A6), the realistic redirection share for Phase 2 (A7), and the reference plant size and stack-share used to scale the electrolyser cost (A8), and the interest rate and plant lifetime used to derive the capital recovery (annuity) factor (A9). A further gap not yet covered by a lettered assumption is minimum staffing per phase, indicatively on the order of 3, 4 and 6 full-time equivalents for Phases 1, 2 and 3 respectively, not yet costed against local South African wage levels. This could materially change the OPEX figures in Annex B.2 once real numbers are available. All of them are measurable at moderate cost and measuring them is the core of the proposed next phase.

Annex C. Data request for the next phase

The following information should be requested from the site partners at the start of the preliminary engineering phase: twelve months of metered mine load data (15-minute resolution); solar plant generation and export logs; the contractual terms of the 20 megawatt export arrangement; mine water analyses (volume, acidity, metals) and current treatment costs; land availability and grid connection details for the 30 megawatt expansion; the mine's diesel purchase volumes and fleet duty cycles; and the mine's electricity tariff structure. In parallel, budget quotations should be requested from at least two Western and two Chinese electrolyser suppliers (landed and installed in South Africa), one hydrogen storage and dispensing supplier, and one fuel cell supplier.

IMPRINT

Published by
Connective Cities
International Community of Practice for
Sustainable Municipal Development
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www.connective-cities.net/en/

Connective Cities is a joint venture between
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The German Association of Towns and Municipalities
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Engagement Global gGmbH and its
Service Agency Communities in One World
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Text layout
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Editorial revision
Paulina Koschmieder

Picture credits
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Basic design and layout
blickpunkt x – Büro für Kommunikation und Design

November 2026

Commissioned by
German Federal Ministry for Economic Cooperation and Development
(BMZ)

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Since 2013, Connective Cities has been promoting the worldwide exchange of municipal expertise. Within the framework of structured learning processes, the platform disseminates proven-practice solutions for sustainable municipal development and supports peer learning between German and international municipal experts, as well as the joint development of project ideas.

Connective Cities is commissioned by the German Federal Ministry for Economic Cooperation and Development (BMZ). It is a cooperation between the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH, Engagement Global with its Service Agency Communities in One World (SKEW) and the Association of German Cities (DST), the German Association of Towns and Municipalities (DStGB), the German County Association (DLT) and the Association of Municipal Enterprises (VKU).

Further information can be found here:
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