Proceedings World Geothermal Congress 2026
Calgary, Canada, June 8 – 11, 2026

Integrated Geothermal Energy and High-Temperature Electrolysis at Olkaria Domes: A Feasibility Framework for Geothermal Electricity and Green Hydrogen Co-Production in Kenya

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Keywords: Co-production, Olkaria, Green Hydrogen, Solid Oxide Electrolysis (SOEC)

ABSTRACT

Kenya's expanding geothermal capacity and the growing demand for sustainable fertilizers provide a compelling case for integrated green energy systems. This study evaluates the techno-economic feasibility of co-producing electricity and green hydrogen at the Olkaria Domes from geothermal using a hybrid single-flash or binary ORC cycle coupled with high-temperature solid oxide electrolysis (SOEC). Geothermal fluids at 250–300 °C enable cascaded use of heat and power, supporting grid supply while enhancing SOEC efficiency. Using site-specific reservoir parameters and a total installed cost of USD 360 million (2025), the system achieves approximately 73 MWe net power output, with 15 MW allocated to hydrogen production. At 95% capacity factor and 40 kWh/kg-H_2 electrical intensity, SOEC operation yields ~3.12 million kg of hydrogen annually. Applying hydrogen price projections from McKinsey & Company (2023), which decline from USD 6/kg in the early commercial phase toward USD 2/kg by 2050, the project achieves a net present value (NPV) of USD 52.5 million and a payback period of ~9 years. These findings indicate strong commercial potential for geothermal-hydrogen co-production at Olkaria, supporting Kenya's clean-energy strategy and KenGen's industrial development plans.

1 INTRODUCTION

1.1 Background and Study Area

Kenya has the most mature geothermal industry in Africa, with an installed capacity of 940 MWe in 2023 (EPRA, 2024). The Olkaria Domes field, located within the Olkaria geothermal complex in the East African Rift System, is one of the most promising high-enthalpy geothermal prospects (Saitet, 2016). Exposed lithologic units at Olkaria consist mainly of volcanic rocks, including comenditic rhyolites, ashes, pumiceous deposits and trachytes (Omenda, 1998). Geophysical surveys reveal a resistive reservoir zone beneath the Domes field, at depths of ~2.5–4 km, overlain by a conductive cap (Omollo et al., 2022). This suggests a deep heat source, consistent with enthalpies reported in some wells, which reach ~300 °C (Wamalwa, 2017).

1.2 Geologic and Reservoir Characteristics

The Domes field lies in the eastern sector of the Olkaria geothermal area, shown in Figure 1Figure 1Figure 1, associated with Quaternary volcanic centers and an active rift structure. Axelsson et al. (2013) and Rop (2012) describe it as a high-temperature (>250 °C) reservoir, hosted in fractured trachyte and tuff formations, with permeability controlled by faulting and intrusive boundaries (Omenda, 1998). Reservoir simulations (Koech, 2018) indicate significant exploitable potential, though development must be carefully managed to avoid scaling, cooling, and reinjection

constraints. Reported enthalpy values average 1,700–1,900 kJ/kg, with well outputs in the range of 5–8 MWe per well, making it a robust candidate for advanced utilization schemes, including hybrid power and hydrogen co-production.

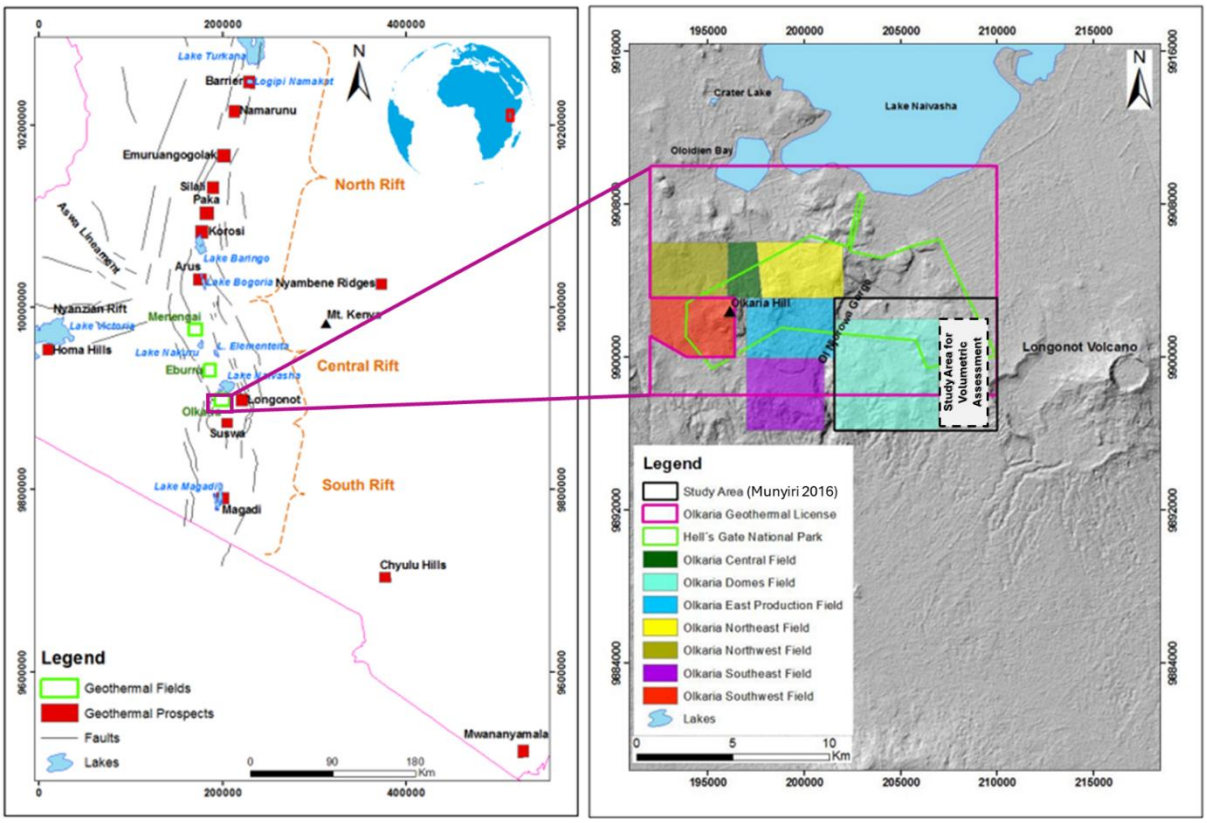


Figure 1: Left: Simplified map of the Kenyan Rift showing locations of geothermal fields and prospects; Right: Detailed map of the Olkaria geothermal field showing the study area (Munyiri, 2016)

1.3 Hydrogen–Electricity Co-Production

In 2023, the global demand for hydrogen reached 97 Mt, primarily driven by its use in petroleum refining, as well as in the production of ammonia and methanol (IEA, 2024). In Kenya, the most strategic application of green hydrogen (GH_2) is fertilizer production, given the country's heavy reliance on imported nitrogen-based fertilizers and the sharp rise in global fertilizer costs due to natural gas price volatility (FAO, 2022). On the other hand, the country frequently experiences power curtailment, particularly from geothermal plants, primarily due to transmission bottlenecks, low off-peak demand (EPRA, 2024), and inadequate grid infrastructure to transmit power from geothermal-rich regions to major demand centres (IEA, 2024).

This persistent curtailment presents a practical opportunity to channel surplus electricity into hydrogen production. An analysis of curtailment data from four geothermal plants in Olkaria from 2020 to 2024 indicates that 2,021,281 MWh of geothermal electricity was curtailed, equivalent to an average of 46 MWe of continuous power, as shown in Table 1. For simplicity, this study adopts the average value to represent a steady surplus capacity that could be utilized for baseload GH_2 production. Approximately 20% of generated geothermal power is allocated to hydrogen electrolysis, while the remainder is dispatched to the grid, optimizing resource use between electricity supply and green fertilizer production.

Table 1: Curtailment figures for geothermal energy, years 2020-2024

Curtailed Geothermal Energy (MWh)					
Month	**2020**	**2021**	**2022**	**2023**	**2024**
January	42,338	24,702	283	-	51,173
February	40.368	14,889	-	19,486	50,849
March	36,164	34,927	3,322	26,385	92,100
April	69,956	41,737	8,365	27,660	68,099
May	91,462	25,872	30,779	18,939	89,717
June	64,658	31,008	34,694	20,830	93,955
July	47,486	32,510	34,759	16,566	58,436
August	34,932	32,856	48,058	20,057	65,496
September	17,430	35,946	38,192	10,397	59,950
October	27,597	12,839	41,003	14,589	39,962
November	46,634	2,646	7,504	43,455	
December	28,573	160	4,725	43,865	
	547,604	**290,013**	**251,689**	**262,233**	**669,740**

2 RESOURCE ASSESSMENT

Resource assessment for the study area (Figure 2) includes volumetric evaluation and re-injection strategy. The volumetric assessment uses the United States Geological Survey (USGS) methodology for estimating geothermal resources and quantifying uncertainties in identified hydrothermal systems (Nathenson and Muffler, 1975). This method applies probability distributions to reservoir parameters to assess uncertainty in stored and recoverable heat. Monte Carlo (MC) simulations generate a probability distribution of recoverable heat, establishing this as standard practice for estimating geothermal systems' power capacity (Garg and Combs, 2015). The re-injection strategy focuses on determining optimal reinjection temperature to mitigate silica scaling, based on Olkaria field samples. These analyses are detailed in Sections 2.1 and 2.2.

2.1 Volumetric Assessment

Reservoir temperatures within the Olkaria geothermal system range between 200 °C and 300 °C (Axelsson et al., 2013). The present study focuses on the eastern sector of the Olkaria IV resource, where a high-temperature zone (>300 °C) exists at approximately 200 m below sea level (bsl), based on the temperature distribution map of Axelsson et al. (2013). The delineated Olkaria Domes peripheral area, covering an estimated 12 km^2, as shown in Figure 2, was selected for volumetric analysis.

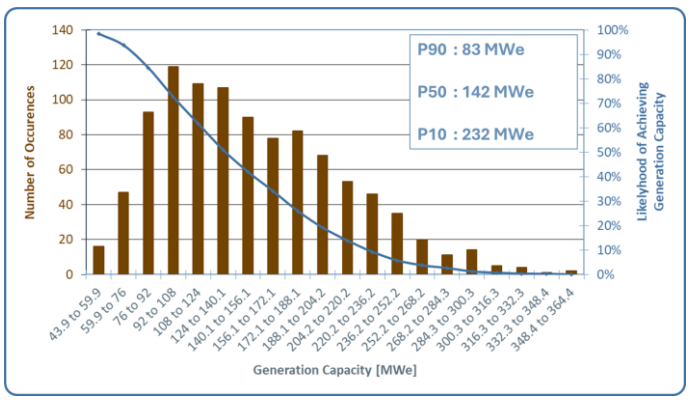


Figure 2: Generation capacity for the project for an estimated 30-year duration based on input parameter in Table 2

As noted in Section 2, the resource potential was evaluated using a Monte Carlo simulation with the input parameters summarized in Table 2. The resulting distribution yields P90 and P50 estimates of 83 MWe and 142 MWe, respectively (Figure 2). These findings align with previous evaluations by Saitet (2016), which reported capacities within the range of 50–150 MWe for the peripheral zones of the Olkaria field. The current P90 and P50 outcomes are therefore considered realistic, whereas the P10 estimate is regarded as optimistic.

Table 2: Input parameters for volumetric assessment

Parameter	Unit	Min.	Most Likely	Max.	Distribution	References
Reservoir Area (A)	km2		12		Fixed	(Mbithi, 2016)
Reservoir Thickness (H)	m	1,000	1,750	2,500	Triangular	(Axelsson et al., 2013)
Reservoir Temperature (T)	°C	200	250	300	Triangular	
Recovery Factor (R)	%	5%	10%	15%	Beta	(After Muffler 1978, in Sarmiento et al., 2018)
Utilization Factor (u)	%	35%	40%	45%	Beta	
Porosity (fi)	%	5%	10%	15%	Beta	
Specific Heat of rock (CR)	kJ/m^3 °C		2,340		Fixed	(Mbithi, 2016)
Average Reservoir depth (D)	m		1,750		Fixed	(Axelsson et al., 2013)
Average Temperature (Ta)	°C		15		Fixed	(After Muffler 1978, in Sarmiento et al., 2018)
Plant Capacity factor (F)	%		95%		Fixed	

2.2 Scaling Risks and Re-injection Strategy

Silica scaling is a common challenge in geothermal systems, affecting surface equipment and reinjection wells (Zarrouk et al., 2014, in Zarrouk and Purnanto, 2015). Silica solubility is controlled by quartz at reservoir conditions and by amorphous silica at the surface (Fournier, 1986; Fournier and Rowe, 1977, in Zarrouk and Purnanto, 2015). Fluids from the Olkaria Domes wells exhibit low calcium and high pH, which minimizes calcite scaling but requires separation above 100 °C to prevent silica precipitation (Karingithi, 2000, in Mbithi, 2016). The silica saturation index (SSI) was computed using WATCH v2.4 (Bjarnason, 2010) and defined as $\log(Q/K)$, where Q is the activity quotient and $K$is the equilibrium constant. Silica precipitation is likely to occur when $\log Q > \log K$.

Two reinjection strategies were assessed: (Scenario 1) brine-only reinjection based on the OW908 chemistry sample and (Scenario 2) mixed brine and condensate, using OW908A and Olkaria Power Plant condensate chemistry data (Kitimo and Opiyo, 2025). According to Barnett (2007), silica saturation index (SSI) thresholds are ≤0.061 for single-flash systems and ≤0.114 for double-flash systems. To prevent silica deposition, simulation results indicate minimum reinjection temperatures of 120 °C for Scenario 1 (Table 3Table 3: Simulated amorphous silica saturation index for Scenario 1 using the WATCH program) and 100 °C for Scenario 2, shown in Table 4. Although lower reinjection temperatures improve binary plant efficiency, they increase the risk of silica deposition.

Table 3: Simulated amorphous silica saturation index for Scenario 1 using the WATCH program

T (°C)	log K	log Q	SSI = log (Q/K)	Remarks
245	-1.670	-2.197	-0.527	Undersaturated
180	-1.872	-2.127	-0.255	Undersaturated
160	-1.946	-2.108	-0.162	Undersaturated
140	-2.028	-2.089	-0.061	Undersaturated
120	**-2.118**	**-2.070**	**0.048**	**Oversaturated**

110	-2.167	-2.061	0.106	Oversaturated
100	-2.218	-2.051	0.167	Oversaturated
80	-2.329	-2.033	0.296	Oversaturated
60	-2.453	-2.014	0.439	Oversaturated

Table 4: WATCH-simulated amorphous silica saturation index, Scenario 2 (GW = geothermal water; CW = condensate water)

Mixing Ratio (GW:CW)	Tmix (°C)	log K	log Q	SSI = log (Q/K)	Remarks
90:10	**~100**	**-2.213**	**-2.105**	**0.108**	**Oversaturated**
80:20	~90	-2.261	-2.156	0.105	Oversaturated

2.3 Resource summary

Based on volumetric assessment and well productivity at Olkaria, a geofluid extraction rate of 1,000 tonnes per hour (tph) is proposed for initial development, corresponding to the P90 resource estimate. Numerical simulations by Koech (2014) comparing deep and shallow reinjection show deeper injection yields lower thermal breakthrough, while a combined strategy sustains steam supply and reservoir pressure. The current design includes two reinjection wells at depths of 1,000 m asl and 2,600 m bsl, with minimum reinjection temperatures determined by the power cycle configuration.

3 FIELD DEVELOPMENT PLAN

The neighbouring Olkaria IV and V fields confirm a high-enthalpy, liquid-dominated system. Monitoring between 2019 and 2023 recorded wellhead pressures of 6.5–9.8 bar(g) and enthalpies of 1,200–2,700 kJ/kg, indicating a stable, mature reservoir. The development plan, described here, proposes twelve production wells, each expected to deliver 7–8 MWe to depths of approximately 3,000 m, for a total geofluid extraction of around 1,000 t/h. Two reinjection wells rated at 100–150 t/h are proposed for brine and condensate disposal, with a third added if monitoring reveals thermal breakthrough. A separator pressure of ~7 bar(g) ought to be maintained to match turbine inlet requirements and limit silica scaling.

4 POWER GENERATION FACILITY

Table 5 provides a summary of the resource assessment conditions, anticipated well productivity, and ambient conditions that would be common to all candidate power cycles. Then, two likely power generation options are presented, illustrating differences in key design criteria, assumed reinjection temperature limitations, and estimated outputs.

Table 5: Summary of resource and plant parameters

Parameter	Units	Common Bases	
Avg. geofluid enthalpy	kJ/kg	1,800	
Non-condensable gas (NCG) content	kg NCG/ kg total flow	0.25%	
Separation pressure	bara	8	
Total geofluid flow	tph	1,000	
Separated steam	tph	526.75	
Separated NCG	tph	2.5	
Separated liquid	tph	471.75	
Cycle type	-	SF-STG	SF-ORC

Cooling system	-	CT	ACC
Gross Output	MW	77	69
Net MW	MW	73	62
Reinjection flow	tph	471 (brine) 146 (cond.)	~1,000
Reinjection temp.	°C	170	100

Two power cycle configurations are considered: a Single Flash Steam Turbine Generator (SF-STG) and a Single Flash Organic Rankine Cycle (SF-ORC). Both are proven technologies suited to high-enthalpy fields. The SF-STG offers large unit capacities and economies of scale, with specific power exceeding 70 kW/tph when using evaporative cooling towers. Cooling towers increase water losses and necessitate the use of separate condensate injection wells. The high flash temperature naturally limits silica scaling and enables potential secondary heat recovery through a bottoming ORC, direct thermal use, or hydrogen electrolysis integration.

Owing to their reliability and familiarity, SF-STG systems are widely applied at Olkaria I, II, IV, and V. SF-ORC plants typically range from 20–60 MW per Unit. Air-cooled systems have higher parasitic loads and larger footprints, but they enable near-total reinjection and NCG recombination, thereby reducing greenhouse gas emissions. Successful applications include Olkaria III and several recent New Zealand projects such as Ngatamariki, Ngāwhā, and Te Huka.

While KenGen may evaluate multiple configurations, each offering different cost–performance trade-offs, assessing their long-term value would require a field-wide sustainability model that accounts for the benefits of enhanced reinjection. For this feasibility study, the SF-STG configuration is adopted as the base case, reflecting its balance of proven performance and compatibility with KenGen's operational experience. The design is flexible, allowing for the future integration of a bottoming ORC or other heat recovery systems.

5 SOEC HYDROGEN PRODUCTION FACILITY

5.1 Production Technology

SOEC technology has advanced rapidly and is now nearing commercial maturity (Hauch et al., 2020). It is selected for this study because of its superior thermodynamic efficiency and unique compatibility with geothermal systems. Based on the SF–STG hybrid configuration described in Section 4, 15 MW of net electrical output is dedicated to solid oxide electrolyzer cell (SOEC) based green hydrogen production. In addition, up to 30 $MW_{(th)}$ of recoverable thermal energy from the separated geothermal brine is available above the reinjection threshold.

Assuming a specific electricity consumption of 40 kWh/kg H_2 (ISPT, 2023), the system is expected to produce approximately 375 kg of hydrogen per hour, or about 3.1 million kilograms annually, at a 95% capacity factor. Hydrogen revenues are derived by applying the projected price trajectory from the Hydrogen Council & McKinsey & Company (2024), which reflects expected market learning and cost reductions over time. In this study, hydrogen is valued at USD 6.0/kg during Years 1–10, USD 4.5/kg during Years 11–20, and USD 2.0/kg during Years 21–30. This production-driven approach ensures that the financial model reflects actual system performance and degradation.

5.2 Green Hydrogen Plant Production Costs

Capital cost of the SOEC facility includes stack, balance of plant (BOP), installation, and project soft costs. For early commercial deployments, costs range between 1,500 – 2,500 USD/kW, varying by location, power source, and project maturity (NREL, 2020; IRENA, 2023) For the Olkaria pilot, this paper uses a baseline of 2,000 USD/kW (installed), including electrolyzer stack, BOP, water treatment, civil works, grid interconnection, and commissioning, some shared with power plant development. Stack replacements, assumed at 25% of initial H_2 CapEx every 10 years, are integrated to capture lifecycle cost effects.

6 FINANCIAL ASSESSMENT

A financial assessment for the proposed GH_2 production facility integrated with the geothermal plant was developed to evaluate project feasibility. CapEx was estimated following the ESMAP (2012) geothermal cost framework, modified to reflect inflation at 40% from 2012 to 2025 using the US Producer Price Index, and updated with recent Olkaria project data, as shown in Table 6. The total installed cost for the project is estimated at USD 376 million (2025). Indicative costs are scaled from specific cost bases using a 73 MW net basis.

Table 6: CapEx summary by phase

No.	Activity	Specific Cost (USD/kW)	Indicative Cost (Million USD 2025)	Basis
1	Preliminary studies	50	3.9	ESMAP (2012)
2	Exploration	80	6.2	ESMAP (2012)
3	Test Drilling and Evaluation	4 % of subtotal	12.5	ESMAP (2012)
4	Feasibility study/planning	100	7.7	ESMAP (2012)
5	Production/Injection drilling	1,200	107.8	Typical Olkaria
6	Gathering System	500	38.5	Typical Olkaria
7	Power Plant	1,600	123.2	Typical Olkaria
8	GH2 Production (15 MW)	2,000	30	IRENA (2023); NREL (2020
9	Interconnection	150	11.6	ESMAP (2012)
	Subtotal		326	
10	Contingency (10%)	10%	34.14	
	Total		360	

6. 1 Project Assumptions

Table 7 summarizes the key financial model assumptions adopted in the analysis.

Table 7: Cost assumptions for the Green Hydrogen Plant

No.	Parameter	Unit	Base Value
1.	Electricity supply cost	USD / MWh	70
2.	O & M	% of CapEx / yr	2
3.	Financing structure	%	30 % Equity, 70 % Debt
4.	Project Tenor	Years	30
5.	Interest Rate	%	8

6.2 Profitability

The project yields an estimated NPV of USD 52.5 million at an 8% discount rate. This positive NPV indicates that the project meets operating and reinvestment obligations while generating returns above the required rate of return. Overall, hydrogen revenues decline in later years, while electricity revenues remain stable, resulting in a balanced and resilient project cash flow, as

shown in Figure 3. Based on the free cash flow (FCF) profile, the project achieves its payback period within approximately 9 years, corresponding to 2035.

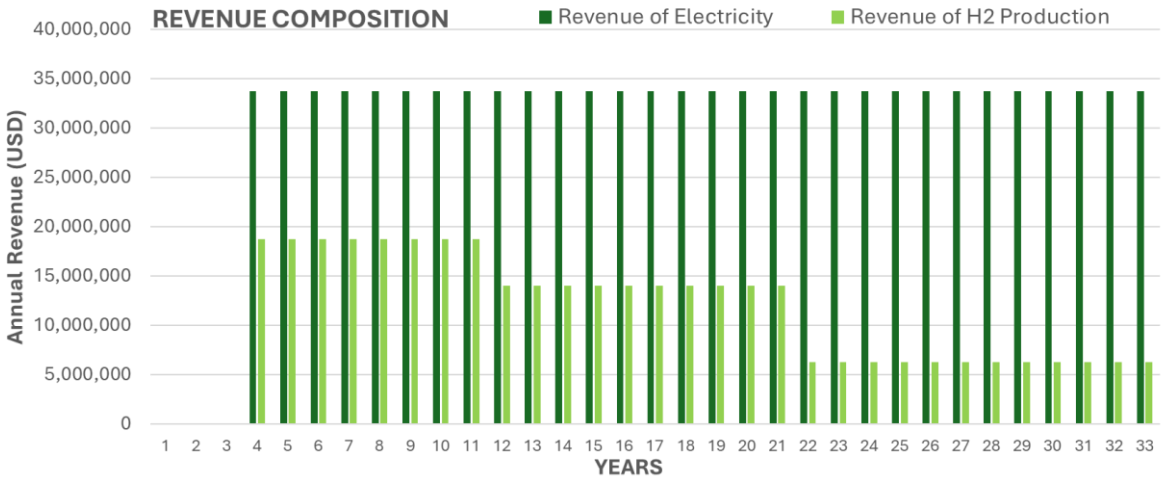


Figure 3: Project revenue composition

7 ENVIRONMENTAL/SOCIAL IMPACTS (PM)

Beyond financial viability, the project offers strong environmental and socio-economic benefits, supporting Kenya's fertilizer self-sufficiency, job creation, and industrial decarbonization. Integration of policy support, concessional financing, and credible offtake structures will be essential to unlock commercial deployment. The Olkaria hybrid system thus represents a model pathway for geothermal-driven green hydrogen development in emerging economies, contributing directly to UN Sustainable Development Goals (SDG) 7 (clean energy), SDG 8 (economic growth), and SDG 13 (climate action).

8 MARKET AND PROJECT EXECUTION

Kenya's National Green Hydrogen Strategy (MoE, 2023) identifies geothermal energy as a cornerstone for low-cost hydrogen production, creating a favorable policy environment for the Olkaria pilot and subsequent expansion phases. Early-stage development will rely on concessional and blended finance instruments to mitigate exploration and technology-integration risks. The recommended implementation pathway follows the ESMAP (2012) geothermal project framework. A mixed partnership model is proposed, involving KenGen (resource and permitting), electrolyzer OEMs/system integrators (technology), anchor off takers (e.g., fertilizer or industrial consumers), and development finance institutions (DFIs) that offer concessional capital and risk guarantees. Structuring Hydrogen Purchase Agreements (HPAs) or Ammonia Offtake Agreements will be critical to ensure price stability and project bankability. The Olkaria project thus serves as a first-of-a-kind demonstrator for geothermal-driven hydrogen in Africa, aligning national priorities with international clean energy goals.

9 CONCLUSIONS

This study demonstrates the financial viability of geothermal–hydrogen co-production at Olkaria. A 73 MWe (net) geothermal hybrid plant, allocating 15 MW to SOEC-based hydrogen production, can sustainably produce 3.12 million kg H_2 annually. With a total installed cost of USD 376 million and an appropriate reinvestment for stack replacement, the system achieves an NPV of USD 52.5 million and a payback period of 9 years. At an average net generation of 58 MW (95% capacity factor), the plant delivers 483 GWh per year for sale at a tariff of 70 USD/MWh. Hydrogen revenues

are expected to decline with maturing markets, yet overall project returns remain positive under realistic price assumptions.

Acknowledgments

This study was supported by a Ph.D. grant from the GRÓ Geothermal Training Programme (GRÓ GTP), with additional research funding from Landsvirkjun Energy Research Fund. The Kenya Electricity Generating Company PLC (KenGen) provided site-specific geothermal data and technical support essential for the analysis.

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