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# Techno-Economic Analysis of Green Hydrogen Production Using Geothermal Energy from Barapukuria Coal Mine, Bangladesh

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**ABSTRACT**

Procurement of sustainable and clean energy solutions has become a global requirement, and green hydrogen has emerged as a promising energy carrier. The production of green hydrogen using geothermal energy has gained interest worldwide. One of the major sources of geothermal energy is the active or abandoned mine. In Bangladesh, there are some active and abandoned mines, and Barapukuria coal mine is the most prominent one among them. Adequate thermal energy is exerted from Barapukuria Coal Mine, which makes this mine a potential source for green hydrogen production in Bangladesh. The technology and economy for utilization of a process is a matter of consideration in Bangladesh. This study focuses on the available processes with probable cost to produce hydrogen in Bangladesh from the exerted geothermal heat of Barapukuria Coal Mine. This study assesses the capital investment, operational cost and required hydrogen production cost in the context of Bangladesh's present energy and economic landscape. Given the economic and technological constrains of Bangladesh, it is essential to evaluate the technical and financial feasibility. The study shows that, though drilling depth and thermal energy may be a challenge, the integration of green hydrogen production and geothermal energy from Barapukuria coal mine offers a significant path towards the sustainable energy generation in Bangladesh.

Keywords: Sustainable Energy, Geothermal Energy, Green Hydrogen, Technological Requirement, Economic Landscape



## 1. Introduction

Bangladesh urgently needs to expand and decarbonize its energy system which is essential to support economic growth and meet increasing electricity demand. The annual growth rate of Gross Domestic Product largely depends on the long-term energy security of a country and particularly it is directly related to the energy market of that country [1].
Bangladesh's power sector depends largely on fossil fuels. Recent analyses indicate that fossil-fuel generation accounts for about 90 percent of electricity output, while renewable electricity makes up only a small portion of the mix. This dependence has led to rising $CO_2$ emissions and greater vulnerability to fluctuations in international fuel prices.
Global hydrogen demand has reached more than 97 Mt in 2023 [2]. Green hydrogen production using low-carbon energy like electrolysis from renewable sources or thermochemical processes with low-carbon heat, has become a global interest for its contribution in reducing carbon emissions, storing energy, and helping industries like steel, chemicals and long-haul transport which are hard to decarbonize. For Bangladesh, the production of green hydrogen could fulfill the ongoing demand of energy requirement and help lower the need for imported fuel, as long as the production is cost-competitive. Table 1 shows the power installation capacity of the resources in Bangladesh.
Geothermal heat, which is the internal thermal energy stored on the earth, is recoverable from abandoned and active mine workings and is a promising, low carbon heat source. The Barapukuria coal basin in northwest Bangladesh stands out as a particularly interesting site for geothermal-driven hydrogen in the national context.

**Table 1** Power installation capacity of different resources in Bangladesh [3]

| Fuel/Resource | Installed Capacity | Share |
|---|---|---|
| Coal | 7179 MW | 22.92% |
| Gas | 12384 MW | 39.54% |
| HFO | 5885 MW | 18.79% |
| HSD | 290 MW | 0.93% |
| Imported | 1160 MW | 3.7% |
| Renewable | 1624.89 MW | 5.19% |
| Captive | 2800 MW | 8.94% |
| **Total** | 31323 MW | |

The gross thermal energy potential of Barapukuria coal mine, based on 60º C reservoir temperature, is $6.17286\times10^{17}$ Joules, which translates to a gross power capacity of 56.388 MW [4]. This study analyses the techo-economic feasibility of 10 MW proton exchange membrane (PEM) electrolysis system and its capital and operational cost model, for producing green hydrogen using geothermal energy of Barapukuria coal mine.

## 2. Background Study

Bangladesh's power and energy system has grown quickly but still relies heavily on fossil fuels, especially natural gas, along with a rising share of coal and oil. This dependence is leading to increasing $CO_2$ emissions and vulnerability to international fuel-price fluctuations [5]. To tackle this issue, Bangladesh submitted an updated NDC in 2021. This plan outlines both unconditional and conditional

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emissions-reduction goals for 2030 and lays out longer-term paths for decarbonization [6]. Green hydrogen, which is hydrogen produced with almost no greenhouse gas emissions during its life cycle, is gaining attention as a way to reduce carbon in hard-to-decarbonize sectors. It can also provide large-scale energy storage and supply materials for chemical production. Global studies show that low-emission hydrogen currently makes up a small portion of total hydrogen production. However, decreasing costs for electrolyzers, increased renewable energy installations, and supportive policies are likely to boost its use and lower costs throughout the 2020s and 2030s [2].

Geothermal energy is the heat stored inside the Earth. Heat has been coming from the Earth's core for over 4 billion years. This heat keeps temperatures similar to those on the sun's surface, which is about 5,500°C. The estimated power flow from the Earth's interior, mostly through conduction, is around 42 million MW [7]. The combination of the hydrogen production system with the renewable energy plant has proven to be an effective way to handle the variability and excess energy produced at the plant [8]. Although mine-based heat usually provides lower temperatures than traditional hydrothermal fields, it often takes advantage of existing underground infrastructure and shallow access. Reviews detail several successful mine-water heat recovery projects and highlight important technical factors such as resource temperature, flow rate, water chemistry, design of heat exchangers, and costs of installation and drilling, that affect feasibility and economics [9].

The Gondwana Sandstone Sequence underneath the coal layers in the Barapukuria coal mine exhibits a temperature of 50°C within the depth of 400 m [4]. The coal seams may have an insulating effect that results from elevated temperature in the basement below [10]. As Barapukuria coal mine already has an established underground mine facility, it could reduce the exploration time and cost for geothermal energy to a greater extent, making it an ideal source of geothermal energy for green hydrogen production [4].

## 3. Hydrogen Production Using Geothermal Energy

Table 2 shows the results from earlier investigations which includes key parameters like hydrogen production, simulation method, exergy efficiency, energy efficiency, and main objectives, reflecting either the highest values or the best operating conditions according to other factors like economic viability [11].

**Table 02** Summary of geothermal driven hydrogen production systems

| Reference | Year | Solver/Method | Production | Efficiency | Objective(s) |
|---|---|---|---|---|---|
| Cao et al. [12] | 2020 | EES | 11.42 $g_h$/s & 2050 $kW_e$ | 14.8$\%_{en}$ | Working fluid selection |
| Cao et al. [13] | 2018 | MATLAB | 24.82 $L_h$/s, 7.25 $kg_{ice}$/s & 414.10 $kW_e$ | 20.24$\%_{ex}$ | Ice-making & hydrogen production |
| Ebadollahi et al. [14] | 2019 | EES | 1020 $kW_c$, 334.8 $kW_{heat}$ ,1060 kW & 5.439 $kg_h$/h | 38.33% & 28.91$\%_{ex}$ | Utilizing LNG as a heat sink |
| Ghaebi et al. [15] | 2018 | EES | 1.197 $kg_h$/s | 3.511$\%_{en}$ & 67.58$\%_{ex}$ | Working fluid selection based on the total revenue required method |
| Gholamian et al. [16] | 2018 | EES | 304.2 $kg_h$/day | 55.39$\%_{ex}$ | Incorporating TEG and hydrogen production with geothermal-based ORC |
| Gouareh et al. [17] | 2015 | GIS | 3.4 $Mkg_h$/year | - | Capturing and sequestration of CO2 |
| Han et al. [18] | 2020 | MATLAB | 0.3683 $kg_h$/hr & 125.71 $kW_e$ | 18.9$\%_{en}$ & 57.39$\%_{ex}$ | Zeotropic mixtures |
| Karakilcik et al. [19] | 2019 | EES | 21.1 $kg_h$/h & 3.9 $Mw_e$ | 6.2$\%_{en}$ & 22.4$\%_{ex}$ | Investigation of chlor-alkali cell |
| Karapekmez & Dincer [20] | 2018 | EES | 9.7 $g_h$/s | 27.8$\%_{en}$ & 57.1$\%_{ex}$ | AMIS unit utilization |
| Khanmohammadi et al. [21] | 2020 | - | 37.26 $kW_e$ | - | Contribution of fuel cell & thermoelectric generator |
| Kianfard et al. [22] | 2018 | EES | 15.9 kgh/h & 3804 kW | 23.09 $\%_{ex}$ | Desalination and hydrogen production |
| Li et al. [23] | 2020 | - | 1571.1 $kW_e$ | 4.94$\%_{en}$ & 23.77$\%_{ex}$ | Contribution of fuel cell in the ORFC |
| Ratlamwala & Dincer [24] | 2012 | EES | - | 47.29$\%_{ex}$ | Multi-flash GPPs comparison |
| Seyam et al. [25] | 2020 | Aspen Plus & EES | 335 $ton_h$/day & 130$MW_e$ | 26.74$\%_{en}$ & 85.71$\%_{ex}$ | Investigation of large-scale liquefaction system |
| Yilmaz & Kanoglu [26] | 2014 | - | 0.0340 $kg_h$/s & 3810 $kW_e$ | 6.7$\%_{en}$ 23.8$\%_{ex}$ | Effect of geothermal and electrolysis temperatures |
| Yilmaz [27] | 2017 | Aspen Plus & EES | 0.05269 $kg_h$/s & 7993 $kW_e$ | 8.489$\%_{en}$ & 38.44$\%_{ex}$ | Thermo-economic optimization |
| Yilmaz [28] | 2020 | Aspen Plus & EES | 0.05 $kg_h$/s & 7856 $kW_e$ | 6.5$\%_{en}$ & 32.4$\%_{ex}$ | Hydrogen production and liquefaction |
| Yilmaz et al [29] | 2012 | - | 0.217 $kg_h$/s | - | Hydrogen production and liquefaction |

| Reference | Year | Solver/Method | Production | Efficiency | Objective(s) |
|---|---|---|---|---|---|
| Yilmaz et al [30] | 2019 | MATLAB & EES | 0.05269 $kg_h/s$ & 7978 $kW_e$ | $8.47\%_{en}$ & $38.37\%_{ex}$ | Artificial neural network approach |
| Yilmaz et al [31] | 2015 | Aspen Plus & EES | 0.0253 $kg_h/s$ | $6.7\%_{en}$ & $23.8\%_{ex}$ | Thermodynamic & exergo-economic analyses |
| Yilmaz et al [32] | 2015 | Aspen Plus | 0.0498 $kg_h/s$ | $8.0\%_{en}$ & $45.8\%_{ex}$ | Thermodynamic & exergo-economic analyses |
| Yuksel & Ozturk [33] | 2017 | EES | 0.075 $kg_h/s$ & 8.5 MWe | $47.04\%_{en}$ & $32.15\%_{ex}$ | Energy, exergy & thermo-economic analyses |
| Yuksel et al. [34] | 2018 | EES | 0.0558 $kg_h/s$ & 7937 kWe | $64\%_{ex}$ | Hydrogen production and liquefaction |
| Yuksel et al. [35] | 2018 | EES | 0.06 $kg_h/s$ | $42.59\%_{en}$ & $48.24\%_{ex}$ | Production of power, hydrogen, oxygen, cooling, heat & hot water |
| Yuksel et al. [36] | 2018 | EES | 0.055 $kg_h/s$ | $39.46\%_{en}$ & $44.27\%_{ex}$ | District cooling, domestic hot water & hydrogen production |

## 4. Methodology

### 4.1. Thermal Heat Analysis:

The total thermal energy of the reservoir is determined by factors including its volume, temperature, and heat capacities, the equation is given below [4]:

$$CapQ_R = [(1 - Ø)(\rho_R C_R) + Ø(\rho_F C_F)]A_R D_R(T_R - T_0) \qquad (1)$$

The calculation of gross power capacity ($P$) involves dividing the total electric energy available by the project lifetime. Gross power capacity ($P$) is calculated as follows [4]:

$$P = \frac{\eta(u)}{l}\left[Q(R)r(g) - \frac{Q(R)r(g)T(0)\cdot\{S(R)-S(0)\}}{h(R)-h(0)}\right] \qquad (2)$$

Where, $n(u)$ is the power plant utilization efficiency, $l$ is the power plant lifetime, $r(g)$ is the recovery factor, $T(0)$ is the rejection temperature, $S(R)$ is the specific entropy of geothermal fluid at $T(R)$, $S(0)$ is the specific enthalpy of geothermal fluid at $T(0)$, $h(R)$ is the specific enthalpy of geothermal fluid at $T(R)$, $h(0)$ is the specific enthalpy of geothermal fluid at $T(0)$.

### 4.2. Technical Analysis

10 MW PEM is a commercial-scale choice. At 48 to 55 kWh/kg, it produces about 200 kg/h, which is roughly 1.6 million kg per year at 8,000 hours, and it needs about 10 MW of electric power. The installed CAPEX is around USD 1,000 to 1,500 per kW. The heat from Barapukuria mine, at about 38 to 48 °C/km, is low-enthalpy [4]. Pre-heating the feed from 25 to 80 °C only requires about 0.1 to 0.12 MW, or 80 to 110 kW. Warming it to about 38 to 40 °C takes around 25 to 35 kW, which is about 0.3 to 1.2% of the electrolyser power. So, using direct mine heat only provides small reductions in LCOH unless it is combined with heat pumps or higher-temperature sources [37]. Fig 1 shows the process flow for 10MW PEM integrated with mine-heat (Barapukuria).

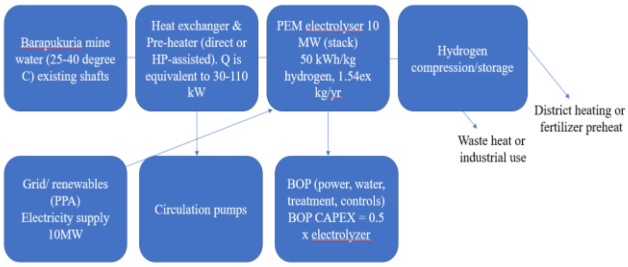


**Fig. 1** 10MW electrolysis integrated with mine heat process

### 4.3. Economic Analysis

#### 4.3.1. Levelized cost of hydrogen (LCOH)

The levelized cost of hydrogen LCOH, given as a cost per energy unit of hydrogen generated (£/MWh $H_2$ HHV) or as a cost per mass unit of produced hydrogen (£/kg), is the discounted lifetime cost of constructing and running a facility of hydrogen production. It includes all pertinent expenses incurred during the lifespan of system, such as CAPEX, OPEX and electricity costs. The LCOH approach is used to assess the economic feasibility of implementing waste heat recovery for powering the hydrogen compression process on the 10 MW PEM electrolysis system. The selected hydrogen compression scenario for the analysis is the 200-bar output pressure, in which the ORC system can completely cover the compression electric requirement [37]. The equations for LCOH estimation are given below [37]:

$$TotalCostsNPV = \sum_{n}^{N} \frac{C_n}{(1+d)^n} \qquad (3)$$

$$HydrogenNPV = \sum_{n}^{N} \frac{Q_n}{(1+d)^n} \qquad (4)$$

$$LCOH = \frac{TotalCostsNPV}{HydrogenNPV} \qquad (5)$$

where N is the system's operating lifetime in years; n is the evaluated year; d is the discount rate; $C_n$ is the cost in period n (including CAPEX, OPEX and electricity costs); and $Q_n$ is the hydrogen production in period n.

The equations for capital expenditure or CAPEX calculation and cost of electricity or $C_{elec}$ consumed for hydrogen pro duction are as follows [37]:

$$CAPEX = C_{inv} + C_{repl,t} \quad (6)$$

$$C_{elec} = Price_{elec} \times E_{inH2} \times h \quad (7)$$

where $Price_{elec}$ is the market price for electricity, $E_{in,H2}$ is total electricity input for hydrogen production, and h is the operating hours which is determined by the load factor of electricity.

## 5. Result and Discussion

Fig 2 shows the values taken for calculation of the economic analysis.

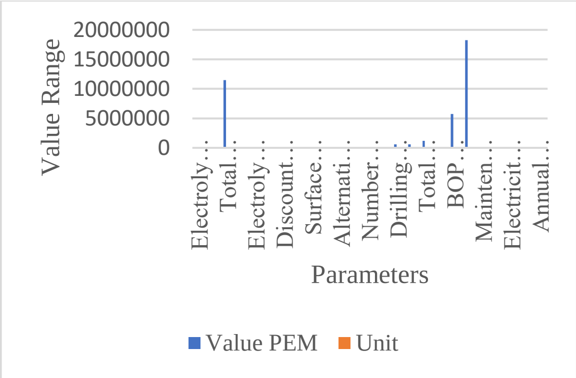


Fig.2: Economic analysis values for calculation

Using an electrolyser efficiency of 65% (HHV basis) the system can produce about 4.8 tonnes of green hydrogen per day at full-load operation (8,000 hours per year). Integrating geothermal heat cuts electricity demand for water preheating by 4 to 6%. This leads to annual savings of around 1.2 GWh in electricity use, which is important for Bangladesh's cost-sensitive power sector. The total installed CAPEX for the 10 MW PEM electrolyser system is estimated at USD 1,150/kW, equivalent to USD 11.5 million. Geothermal integration, requiring drilling to a depth of ~300 m with a gradient of 38 °C/km [10]—is estimated at USD 1.2 million. Annual OPEX, including stack replacement, water treatment, and maintenance, is ~USD 0.25 million/year. Using a 20-year lifetime and a 7% discount rate, the LCOH is USD 4.85/kg at an electricity price of USD 0.08/kWh without geothermal integration. Geothermal heat recovery lowers this to USD 4.62/kg, which is a 4.7% decrease in cost. Although this change is small, it shows that geothermal preheating can improve cost competitiveness. A ±20% variation in electricity price results in an LCOH range of USD 3.90 to 5.70 per kg. This confirms that electricity tariff is the main economic driver. Drilling costs have a minor impact, causing less than a 2% change in LCOH due to the shallow well depths in Barapukuria. Hydrogen selling prices in the regional market must exceed USD 5 per kg to ensure profitability without subsidies.

## 6. Conclusion

The study demonstrates that integrating geothermal heat from the Barapukuria Coal Mine into green hydrogen production can lead to measurable but limited cost reductions in the current Bangladeshi market. Geothermal integration reduces the levelized cost of hydrogen (LCOH) by about 5% due to lower preheating electricity demand. However, the electricity tariff is still the biggest factor in economic viability. Policy measures like feed-in tariffs for renewable electricity, hybrid geothermal–solar–wind systems, and carbon credit incentives connected to Bangladesh's updated NDC targets could enhance feasibility. While Barapukuria's geothermal potential cannot compete with fossil-based hydrogen prices, it marks progress towards energy diversification, decarbonization, and meeting national climate commitments.

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