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Assessing Geothermal Resource Potential in Egypt’s Western Desert Through Integrated Techno-Economic Modeling

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ABSTRACT

Over the past two years, electricity consumption in Egypt has increased from 34.2 GWh to 36.8 GWh, leading to daily power outages of around 3 hours during the summer months. Geothermal energy, a renewable power source stored in subsurface rock and fluids, offers a sustainable solution to Egypt's blackout crisis. This resource has the potential to be a complement to energy sources to address the increased electricity consumption amidst a decline in natural gas production.

Despite Egypt's high potential for groundwater available from different aquifers spread across the country, limited research has been conducted on Egypt's geothermal potential. To investigate this potential, a feasibility study was conducted in a selected field. The study workflow started with collecting available data about the Bahga field in Egypt`s Western Desert, including geographic data like its location and extension, and petrophysical data like hydraulic conductivity, porosity, and depth. Bahga field has been previously explored and drilled with more than 12 wells and has a reservoir temperature of 290°F (143°C), making it a promising site for geothermal resource exploitation.

Using the available data as an input for the Flexible Geothermal Economics Modeling (FGEM) tool, specifically designed for the techno-economic analysis of flexible geothermal power generation, we evaluated the economic feasibility of the Bahga field in Egypt’s Western Desert. The FGEM utilizes a range of surface and subsurface parameters from each aquifer to estimate key economic indicators, such as the Levelized Cost of Electricity (LCOE). In parallel, we developed and applied an in-house resource power potential and techno-economic analysis methodology, which was directly compared against the FGEM outputs to validate and cross-check the results. The in-house workflow incorporated multiple resource power potential estimation techniques, primarily the Volumetric Method and Power Density Method, with the overlap between both approaches used to enhance confidence in the final estimates. Furthermore, a Monte Carlo Simulation (MCS) framework was implemented to generate probabilistic forecasts (P10, P50, P90) for both the geothermal resource potential and the associated economic indicators, ensuring a robust representation of uncertainty.

The comparative analysis of alternative hydrothermal field development scenarios yielded insightful outcomes. The project demonstrates a P50 internal rate of return (IRR) of approximately 24%, with a levelized cost of electricity (LCOE) ranging from 60 to 330 USD/MWh, depending on the selected field development strategy. The results are highly promising and align with Egypt’s Vision 2050, supporting the nation’s transition toward clean, renewable, and reliable energy sources.

1. INTRODUCTION

Energy is the primary driver of human activities and industrial operations. Rapid population growth and expanding economic activities increase energy demand. For instance, between 2000 and 2023, global electricity consumption nearly doubled, rising from 15,276.96 TWh to 29,479.05 TWh (Dora et al., 2025). Currently, global energy production heavily depends on fossil fuels, which are non-renewable resources and a major source of greenhouse gas (GHG) emissions. The continuous emission of GHGs into the atmosphere has led to global warming and a sustained increase in average surface temperatures. These challenges highlight the need for clean and more sustainable energy sources.

Geothermal energy is a low-carbon, renewable resource derived from heat stored in rocks and fluids within the Earth’s crust. Unlike solar and wind energy, it is not weather-dependent, enabling stable and continuous power generation (IRENA, 2017). Geothermal power plants are commonly classified as dry steam, flash steam, and binary systems (El Haj Assad et al., 2017). Dry steam plants use reservoir steam directly to drive turbines, while flash steam plants produce hot water that partially vaporizes upon depressurization to generate steam. Moderate- to low-enthalpy resources, typically at temperatures of 85–150 °C, are utilized in binary plants, where geothermal heat is transferred to a low-boiling-point working fluid that vaporizes and drives the turbine (Gupta & Roy, 2007).

Similar to most countries, Egypt, despite being the largest non-OPEC oil producer and the third-largest natural gas producer in Africa (Hongyun & Radwan, 2021), has experienced an annual rise in energy demand of about 7.6% (Ministry of Electricity and Renewable Energy, 2025), while domestic energy production has not been sufficient to meet this demand. As a result, Egypt has increased oil imports and purchased approximately 13 GWh of electricity to cover this need (Ministry of Electricity and Renewable Energy, 2025), creating a significant economic burden on the national budget.

To reduce reliance on energy imports, Egypt has strong potential to expand its geothermal resources, with the most favorable prospects located in the eastern region (Abdel Zaher et al., 2023). Based on bottom-hole temperature data from 596 deep wells, (Abdel Zaher et al., 2018) developed heat-flow and temperature-gradient maps that identified the Red Sea coast and the Gulf of Suez as the most promising areas for geothermal energy development. These regions are suitable for large-scale geothermal energy deployment. On a smaller scale, it can be applied in remote oil and gas fields that lack reliable electricity, making on-site power generation necessary. The availability of abandoned and dry wells reduces drilling costs, making geothermal systems a technically and economically attractive option for petroleum field operations.

One of the most important aspects of geothermal energy development is project cost. The total cost of a geothermal project includes capital, operational, and development-related expenditures. Capital investment represents a major component of overall project cost and is typically divided into subsurface costs, including geological and geophysical surveys, reservoir characterization, and drilling, and surface costs, which encompass power plant equipment, heat exchangers, turbines, cooling systems, and surface infrastructure (Yehia et al., 2024). Among these, subsurface activities often account for the largest share of total project cost due to drilling depth, technical complexity, and geological uncertainty (Oliver et al., 2024). Consequently, reducing expenditure associated with subsurface activities, particularly exploration and drilling, is essential for lowering the overall levelized cost of electricity (LCOE) of geothermal systems.The development of new, greenfield geothermal resources is often associated with substantial capital investment, long development timelines, and significant subsurface uncertainty. Exploration and drilling activities typically account for 40–60% of total project costs, largely due to the need for deep drilling, limited well success rates, and incomplete characterization of subsurface thermal and hydraulic properties (Sanyal, 2005; Tester et al., 2006; Gasser et al., 2025). Unlike other renewable energy technologies, geothermal projects require major upfront expenditures before resource viability can be confirmed, making financial risk a key barrier to deployment (Carter et al., 2025). These challenges are particularly pronounced in regions where geothermal exploration has not been historically prioritized, underscoring the importance of alternative development pathways that reduce cost and risk while accelerating project timelines.

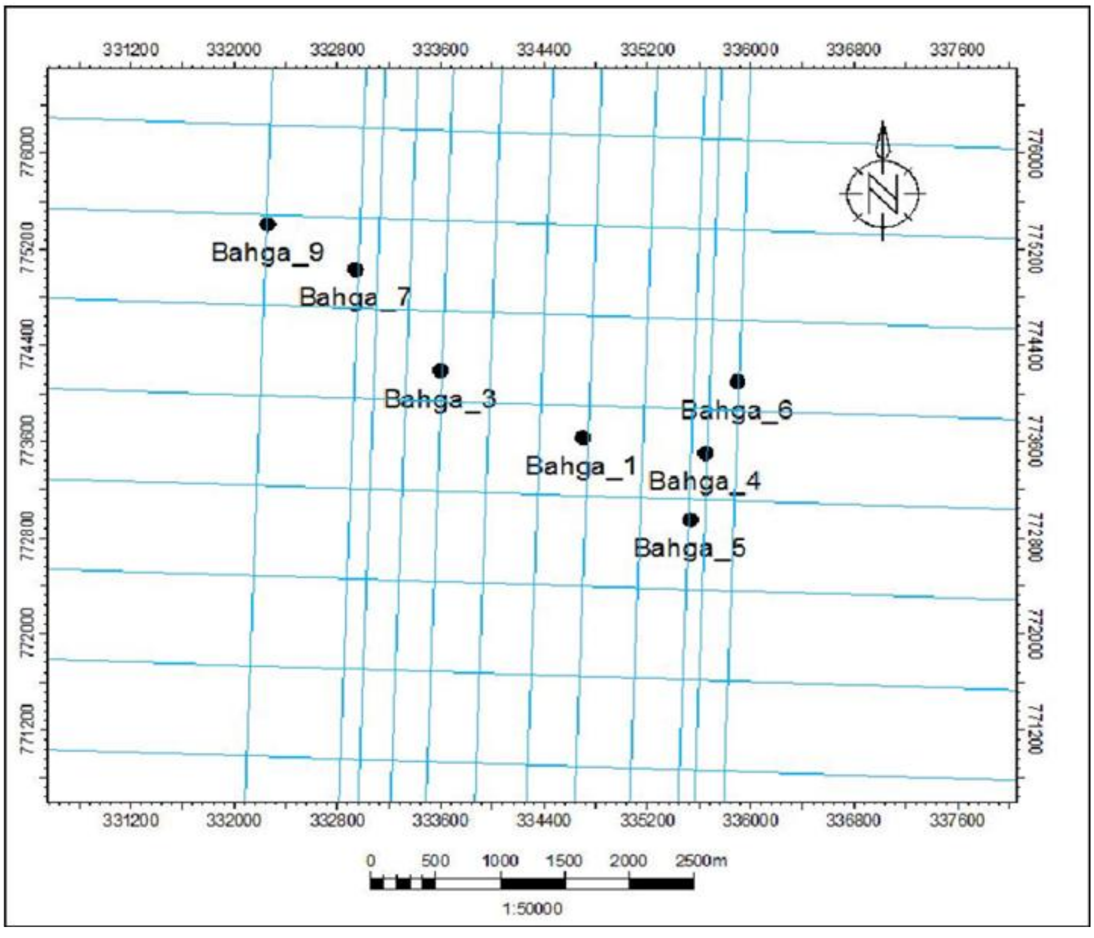

Figure 1: Bahga field well locations. (El-Kadi et al., 2017).

One such pathway is the co-production or repurposing of geothermal energy from existing oil and gas fields (Carter et al., 2025). Mature hydrocarbon reservoirs often possess many of the critical elements required for geothermal exploitation, including drilled wells, established surface infrastructure, and extensive subsurface datasets. Global studies have demonstrated that produced water from oil and gas operations can be used for geothermal power generation or direct-use applications, significantly lowering capital costs by avoiding new drilling and reducing exploration uncertainty (Adams et al., 2014; McKenna et al., 2021; Yehia et al., 2024). This approach has been successfully evaluated in regions such as the United States, Europe, and the Middle East, where declining hydrocarbon production coincides with growing interest in low-carbon energy solutions. As a result, geothermal co-production has emerged as a promising strategy for extending the economic life of oil and gas assets while contributing to energy transition goals.

The Bahga field, located in Egypt's Western Desert within the Abu Gharadig Basin, represents a compelling candidate for geothermal repurposing due to its well-documented geological and petrophysical characteristics (Figure-1). Previous studies have focused on detailed reservoir characterization of the Abu Roash G (AR/G) formation, including stratigraphic interpretation, structural analysis, and petrophysical modeling using well logs and seismic data (El-Kadi et al., 2017; Reda et al., 2024). These studies indicate relatively consistent reservoir thickness, favorable porosity distributions, and sufficient formation permeability to support fluid circulation. Furthermore, the presence of multiple drilled wells and measured bottom-hole temperatures approaching 143 °C provides a strong foundation for evaluating geothermal power generation potential without the need for extensive additional exploration.

Beyond site-specific considerations, recent advances in geothermal techno-economic modeling have emphasized the importance of integrated workflows that combine resource assessment, uncertainty quantification, and economic evaluation. Probabilistic approaches, such as Monte Carlo simulation (MCS), are increasingly used to capture the combined effects of geological uncertainty, operational variability, and cost escalation on project outcomes (Ciriaco et al., 2020; Alarcón, 2023). When coupled with standardized tools like Flexible Geothermal Economics Modeling (FGEM) and flexible in-house models, these workflows enable robust screening of geothermal prospects and support data-driven decision-making. In this context, the present study leverages both established and customized modeling approaches to provide a comprehensive assessment of geothermal feasibility in the Bahga field, bridging the gap between regional resource studies and field-scale economic evaluation.

In this study, we evaluate the feasibility of deploying a geothermal system in the Bahga field, located in Egypt's Western Desert. A hybrid geothermal development approach is assessed through a comprehensive techno-economic analysis of geothermal power generation using available field data. Two modeling frameworks are employed: the (FGEM) tool and an in-house techno-economic model. FGEM is used to evaluate project feasibility and potential power output by integrating a wide range of parameters, including resource characteristics, plant design, operational strategies, and market conditions, thereby providing a holistic assessment of economic viability (Aljubran & Horne, 2024). The in-house model estimates power generation using both power-density and volumetric methods, with the results averaged for subsequent analyses. To account for uncertainties in reservoir and economic parameters, a MCS with 100,000 iterations was also performed.

2. METHODOLOGY

Figure-2 shows the detailed methodology followed in this study. The field selection and data acquisition phase were associated with a preliminary evaluation process. Well logs, production data, reservoir description and surface facilities were assessed. Following the data collection phase, Surfer by Golden Software was utilized to construct a 3D reservoir volume for AR/G formation shown in Figure-3. FGEM and In-House Modelling Tool (IHMT) were used simultaneously to evaluate the feasibility of geothermal power generation from this field. FGEM offers standardized, well-tested technoeconomic analysis and resource assessment. On the other hand, IHMT offers a flexible framework and can be tailored to the specific conditions of the Bahga field. IHMT leverages MCS to simulate 100,000 possible scenarios to create a probabilistic estimate for the power potential of the field and the economics of the project.

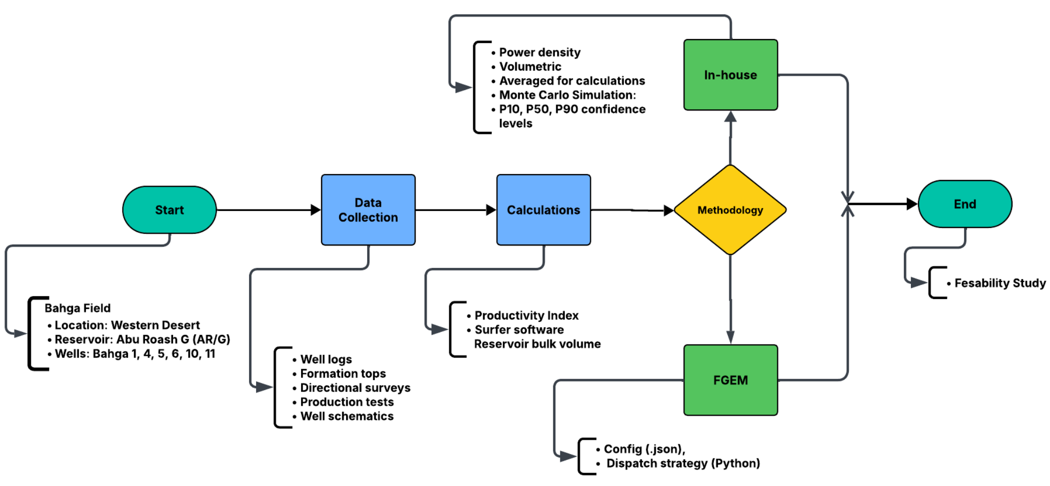

Figure 2: Methodology.

The data used in this study were collected from the Bahga Field, located in the Abu Gharadig Basin in the Western Desert of Egypt. Two reservoirs are present in the field, the AR/G and Bahariya formations; this study focuses on the AR/G reservoir. The analysis is based on six wells (Bahga-1, Bahga-4, Bahga-5, Bahga-6, Bahga-10, and Bahga-11) drilled through AR/G formation (Figure-1) (El-Kadi et al., 2017). The available dataset includes well logs, formation tops, and directional surveys for each well (Reda et al., 2024), in addition to production test data and well schematics. The AR/G reservoir has an average thickness of 30 m, covers an area of 1.38 Km^2, and has a bulk volume of 0.042 km^3, with a reservoir temperature of approximately 290°F. A liner casing with an inner diameter of 6.184in was installed in all wells, with an average well depth of 2,854m.

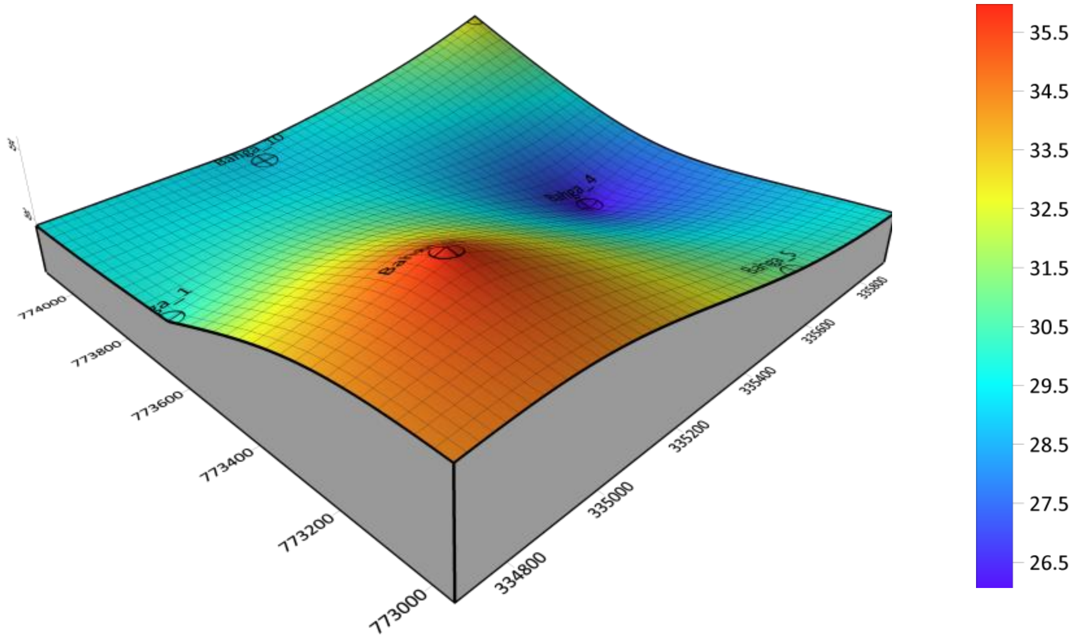

Figure 3: AR/G formation thickness in 3D and well locations. The color legend represents the thickness in meter,

3. MODELLING

3.1 Surfer

To better understand the topology of the AR/G Formation, Surfer software was also utilized to construct a contour map using thickness data obtained from the drilled wells (Figure-4). The resulting map reveals gradual variations in formation thickness, with the highest thickness observed near well Bahga-11 and the minimum thickness near well Bahga-4 (Figure-3).

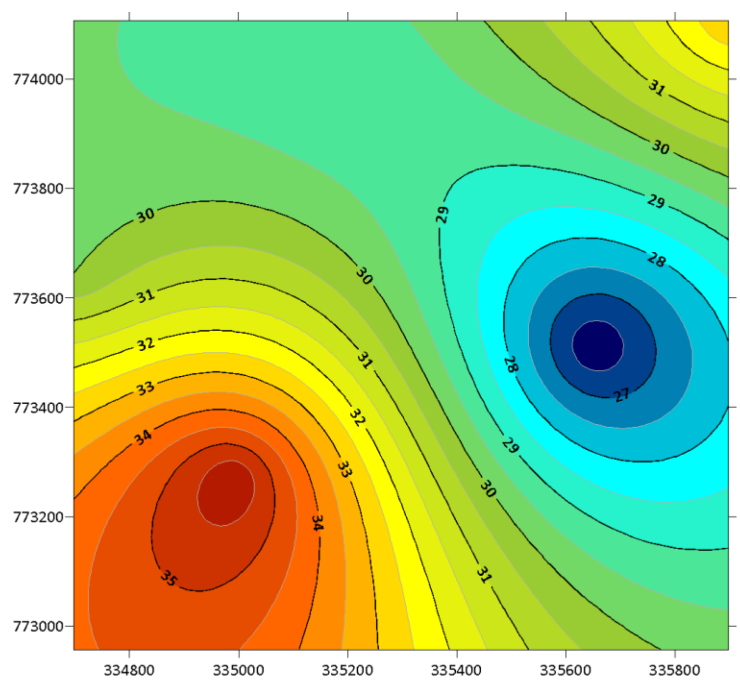

Figure 4. An isopach map for AR/G formation.

3.2 Flexible Geothermal Economics Modeling (FGEM)

In this study, we employ the open-source FGEM tool, which is specifically developed for the techno-economic analysis of flexible geothermal power generation systems. FGEM integrates a comprehensive set of parameters, including resource characteristics, plant design, operational strategies, and market dynamics, to enable a holistic evaluation of the economic viability of geothermal projects. FGEM requires three specifying inputs: configuration (.json format), data (.csv format), and dispatch strategy (Python code). These inputs are then validated and used to initiate the simulation run. Table 1 below shows the major input parameters used in the configuration file of this case study. To quantify the influence of uncertainty and operational variability, a systematic sensitivity analysis was conducted on selected parameters, as presented in Section 4.1, allowing the assessment of their impact on system performance, economic metrics, and overall project viability.

The productivity index (PI) and reservoir bulk volume (Vr) are required input parameters for the model, as summarized in Table 1. The PI is derived from production test data from the Bahga-11 well. The wellhead pressure (WHP) is 35 psi, and the average perforation depth is 2860 m. The flowing bottomhole pressure (Pwf) is estimated to be 1600 psi using the Gilbert correlation, while the measured liquid production rate (Qliquid) is 557.5 bbl/day. Using these values in Equation-1, the productivity index is calculated as 0.22 bbl/day/psi. The oil specific gravity of 0.87 is subsequently applied to convert the PI to SI units, resulting in a value of 0.005 kg/s/bar. At present, the Bahga field contains six producing wells with significantly declined production rates, leading to a very low effective PI. To enable economically viable geothermal operations, field redevelopment is assumed in which three of the existing producers are converted into injectors to enhance reservoir pressure support and circulation efficiency. This configuration is expected to substantially improve well deliverability; therefore, an enhanced PI value of 40 is adopted for the techno-economic analysis to represent the stimulated and reconfigured geothermal system.

$$PI = \frac{Qliquid}{Pr - Pwf} \tag{1}$$

Also, the existing wells in the Bahga field are completed with 3-inch tubing, which imposes significant hydraulic constraints and limits achievable flow rates, thereby adversely impacting project economics. Such a small diameter leads to elevated frictional losses, reduced mass throughput, and lower thermal power recovery. To mitigate this limitation, we evaluate alternative completion strategies, including the use of larger-diameter tubing or production through casing, to enhance well deliverability and improve overall system performance. The impact of tubing diameter on system performance and project economics is quantified through a dedicated sensitivity analysis, with the comparative results for different diameters presented in the Results section 4.1.

The geothermal resource assessment is parameterized using a combination of published literature values and site-specific geological and thermal constraints, which are summarized in Table 1. It summarizes the key input parameters specified in the config.json configuration file for this case study. This file contains the essential information required to define project metadata, economic assumptions, and the characteristics of both upstream components (including the reservoir and wellbore) and downstream components (such as the power plant and energy storage systems). To accurately represent the temporal variability in battery costs, weather conditions, wholesale electricity prices, Renewable Energy Certificate (REC) values, and capacity market dynamics, the model requires user-supplied input files: battery.csv, weather.csv, wholesale.csv, and capacity.csv.

Table 1: Major input parameters used in the config.json file.

Metadata			
Initial Time	2025-01-01		
Economics			
Lifetime	30 years	Grid	130 $/kw
Discount	0.07	ITC	0.3
Inflation	0.02	TES	1434.53 $/m
OPEX escalation	0.0	Batter	Battery.csv
Downstream			
Plant type	Binary	Weather	weather.csv
PPC	7.5 MW	Wholesale	wholesale.csv
CF	0.95	Capacity	capacity.csv
Upstream			
Reservoir	Energy Decline	PRD count	3
T_r (0)	143 C	PRD-INJ ratio	1
P_r (0)	286 bar	Water loss	0%
V_r	0.042 Km^3	Pump efficiency	0.75
T_{surf}	25 C	DSR	0.9
H_{well}	2854 m	PI/II	40 kg/s/bar
D_{prd}	0.157 m	Dinj	0.157 m

Together, these inputs enable FGEM to conduct a comprehensive techno-economic assessment that captures the key factors governing the economic performance and operational flexibility of geothermal power systems.

3.3 In-House Modelling Tool (IHMT)

IHMT allows flexibility in changing field parameters, and it is tailored to each specific field. Unlike FGEM, which is developed based on US field assumptions. The workflow involves MCS with 100,000 iterations conducted to evaluate the economic feasibility of the project. Power production potential and project costs include capital expenditure (CAPEX) and operating expenditure (OPEX) were calculated. Economic performance was assessed using Net Present Value (NPV), Internal Rate of Return (IRR), and cumulative net cash flow with P10, P50, and P90 confidence levels.

To evaluate the power production potential of the Bahga field, two reservoir estimation methods were used: the volumetric method and the power density method. The overlap range between the two methods was adopted to be the estimated power production potential. The volumetric method uses Equation-2 to calculate the megawatts of electric power that can be generated from a geothermal resource (Muffler, 1979). While Equation-3 is used to determine the thermal energy (q) measured in joules (J) (Garg and Combs, 2015; Muffler and Cataldi, 1978).

$$MWe = \frac{q X R_f X \eta_{conv}}{F X L} \tag{2}$$

Where, MWe is the electric power potential expressed in megawatts electric (MWe); q is the total thermal energy available in the reservoir measured in megajoules (MJ); R_f is the recovery factor expressed as a percentage (%); L is the power plant lifespan in seconds; $\eta_{(conv)}$ is the energy conversion efficiency expressed as a percentage (%); F is the load factor expressed as a percentage (%).

$$q = q_r + q_f = Ah\left(T_i - T_f\right)[(1-\varphi)\rho_R c_R + \varphi(X_L \rho_L c_L + X_V \rho_V c_V) \tag{3}$$

Where, A is the areal extent of the reservoir in square meters (m²); H is the reservoir thickness in meters (m); T_i is the initial reservoir temperature in degrees Celsius (°C); T_r is the reference temperature in degrees Celsius (°C); T_f is the final abandonment temperature in degrees Celsius (°C); $\rho_i c_i$ is the volumetric heat capacity of "i" in joules per cubic meter per degree Celsius (J/m³·°C). "i" can be "R" which represent the rock in the reservoir, "L" which represents the liquid in the reservoir or "V" which represents the vapor in the reservoir. X_L is the liquid mass fraction expressed as a percentage (%); X_v is the vapor mass fraction expressed as a percentage (%). X_L and X_v can be calculated using Equation-4 (O'Sullivan and O'Sullivan, 2016). The rock is considered fully saturated where $X_L + X_v = 1$ and their entropies are obtained using the steam tables for two-phase saturated fluid.

$$X_V = \frac{S_{L@Ti} - S_{L@Tr}}{S_{V@Tr} - S_{L@Tr}} \tag{4}$$

Where, $\mathbf{S_L}$ is the entropy of the liquid phase in joules per kelvin (J/K); and $\mathbf{S_v}$ is the entropy of the vapor phase in joules per kelvin (J/K).

Also, the power density method was used, which provides an alternative approach for estimating geothermal power potential on an areal basis (MWe/Km²). Owing to its straightforward formulation and limited number of required assumptions, this method is particularly well suited for early-stage exploration assessments. (Wilmarth and Stimac, 2015) compiled power density estimates for 53 geothermal fields and presented their results as a function of tectonic setting and reservoir temperature (Figure-5).

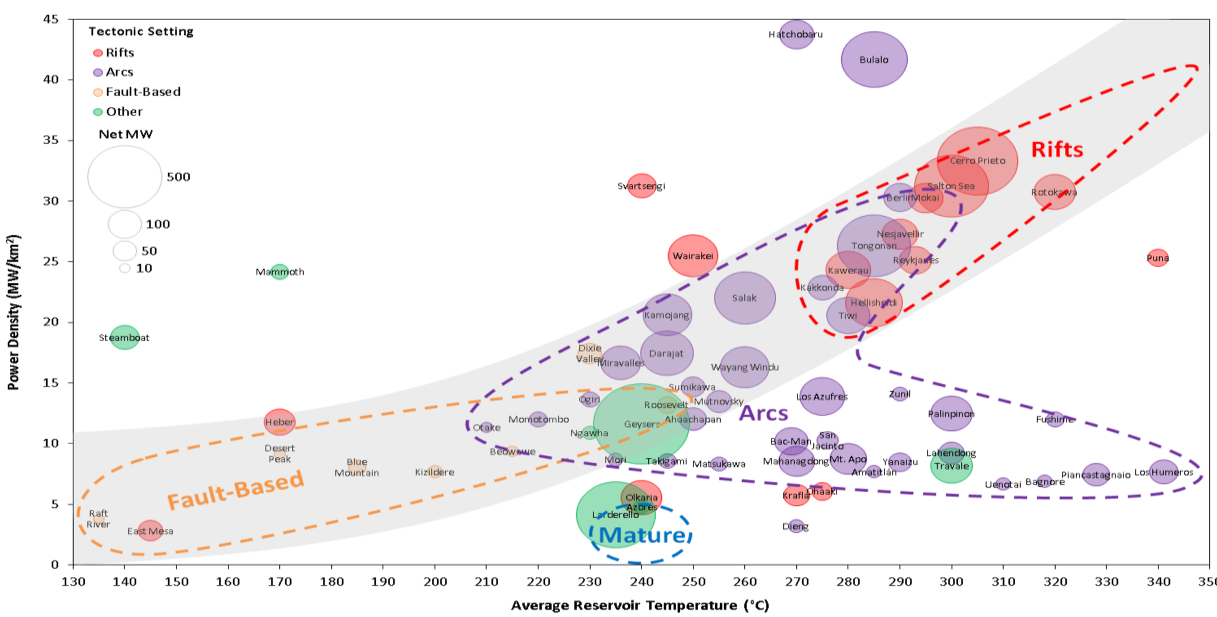

Figure 5: Power density correlation, shows the relationship between tectonic setting, reservoir temperatire and power per area (Wilmarth and Stimac 2015).

The geothermal resource assessment is based on a range of geological, thermal, and economic parameters drawn from published studies and site-specific data. Rock porosity is assumed to be most likely 10%, with a range of 5–15%, consistent with values reported by (Ciriaco et al., 2020). The recovery factor is taken as 15%, bounded between 5% and 20%, following (Garg and Combs, 2015), who also provide the basis for the assumed conversion efficiency of 75% (range 70–80%). The abandonment temperature is set at a most likely value of 80°C, with an upper bound of approximately 85°C. While the reservoir temperature is estimated to be in the range of 120-150°C. Reservoir geometry is constrained by Surfer results, indicating an areal extent of 2.5–3 km^2 (most likely 2.75 km^2) and a thickness ranging from 25 to 35 m. Operational and economic uncertainties are represented through a production decline rate of 0–0.5% (most likely 0.15%) and a cost increase rate of 0–10% (most likely 2%), based on (Alarcón, 2023). Finally, the geothermal power density is assumed to range between 1 and 5 MWe km^{-2}, with a representative value of 3 MWe km^{-2}, in line with regional geothermal analogs reported by (Wilmarth and Stimac, 2015).

The baseline thermal and operational assumptions include a reference temperature of 15 °C, representing ambient surface conditions, as commonly adopted in geothermal assessments (Sanyal et al., 2004, and Williams, 2004). The volumetric heat capacity of the reservoir rock is taken as 2700 kJ m^{-3} $°C^{-1}$, following (Aravena et al., 2016), to account for the thermal storage of the rock matrix. A project lifespan of 30 years is assumed, consistent with long-term geothermal development practices (Ciriaco et al., 2020), and a capacity factor of 95% is adopted to reflect the firm, baseload nature of geothermal power generation (Aravena et al., 2016).

Once the power potential has been determined, the technical evaluation is complete, allowing the economic analysis to begin. The economic evaluation is structured around three principal components: CAPEX, OPEX, and revenue. CAPEX is typically subdivided into development and construction costs. Development costs encompass surface exploration, project management, testing and reservoir management, infrastructure development (e.g., well pads), drilling of production and injection wells, design and engineering activities, land acquisition, permitting, environmental management, and contingency allowances. However, since this is an already developed field, there is no development cost, and the only cost is construction. Construction costs include power plant engineering, procurement, and construction (EPC), as well as insurance, management, and related expenses (Martínez Ruiz et al., 2022; Osorio Luna, 2018). The power plant EPC cost can be estimated using Equation-5 (Martínez Ruiz et al., 2022; Sanyal, 2005).

$$EPC = KW * CC = KW * CPP * e^{-0.0025(MW-5)} \tag{5}$$

Here, CC denotes the capital cost in USD/kW, CPP represents the power plant cost per kilowatt, and W is the gross power output of the plant in megawatts (MW). The value of CPP depends on the power plant configuration and the specific technologies employed, with reported values typically ranging from approximately 1,700 to 2,000 USD/kW (Alarcón, 2023). However, since these equations were not formulated to match Egypt's economy, a conversion factor was needed.

In addition, OPEX accounts for costs such as insurance, easements, concession leases, sales and administrative expenses, environmental mitigation, utilities, auxiliary power consumption, outsourced operations and maintenance, and royalties. The net generation potential is obtained by deducting parasitic loads. The parasitic loads include average powerplant consumption, average rejection pump consumption and any other contingency system consumption. The net potential generation capacity corresponds to 89% of the total potential capacity (Alarcón, 2023).

All development activities are supported by an underlying business plan based on carefully formulated assumptions that are continuously refined as new information becomes available. The project's economic performance is evaluated using metrics such as IRR and NPV. The current viability assessment does not account for potential benefits from tax incentives, carbon offset credits, or debt leverage through project financing. In addition, the project location necessitates relatively high capital and operating expenditures to address geohazard mitigation and costs associated with its remoteness. Finally, the financial analysis assumes a zero-terminal value for the power plant after a 35-year lifespan, despite evidence that many geothermal facilities worldwide continue to operate well beyond their original design life.

4. RESULTS AND DISCUSSIONS

4.1 Flexible Geothermal Economics Modeling (FGEM)

Once the FGEM simulation is completed and the simulated project lifetime ends, operational records are compiled, economic metrics are calculated, and key performance variables are visualized. FGEM reports standard economic indicators such as the LCOE, NPV, and payback period. Among these, LCOE serves as the primary benchmarking metric, as it represents the average cost of electricity generation over the project's lifetime while accounting for capital, operational, and financing costs. As a preliminary analysis, a set of key input parameters specific to the reservoir and operational design was systematically varied to evaluate their influence on project performance. The resulting sensitivity plots and associated analyses are presented below. This sensitivity analysis centers on the LCOE, as it provides a consistent, technology-agnostic measure of economic performance and enables direct comparisons across design scenarios and resource conditions.

The FGEM-based sensitivity analysis demonstrates that project economics are most strongly governed by system scale, well deliverability, and hydraulic efficiency. Installed capacity exhibits a steep inverse relationship with LCOE, with values dropping from over 600 \$/MWh at 1 MW to below 50 \$/MWh at 20 MW, highlighting the importance of operating at sufficient scale to amortize fixed capital costs. Also, for this specific work, a nominal installed capacity of 7.5 MW is adopted as the reference case for the techno-economic evaluation. This capacity is not assumed arbitrarily; rather, it is derived through a sensitivity-based screening that accounts for field-specific properties, particularly reservoir temperature, while using the resulting LCOE as the primary performance metric. By varying plant capacity across a realistic range and evaluating the corresponding LCOE, a 7.5 MW configuration was identified as a representative and economically meaningful scale for the Bahga field under the assumed operating conditions. In addition to the plant capacity, the capacity factor further refines feasibility, with higher utilization directly reducing LCOE by spreading capital costs over greater energy output. Collectively, these results show that geothermal repurposing in the Bahga field is not limited by thermal resources alone but is primarily controlled by well architecture and reservoir productivity. Strategic enhancements in well completion, stimulation, and field configuration are therefore essential to transition the field from marginal performance to a commercially viable geothermal system.

In the wellbore and reservoir portion, the well diameter and productivity index show the most dramatic leverage on economic performance. Small tubing sizes and low PI values produce prohibitively high LCOE, reflecting excessive pressure losses and limited mass throughput. As diameter and PI increase, LCOE rapidly collapses into an economically viable range, confirming that hydraulic constraints dominate system performance in legacy oilfield conversions. This validates the need for larger flow conduits and reservoir reconfiguration through injector–producer schemes.

In addition, the “number of producers vs LCOE” curve shows that system performance is highly sensitive to how the field is configured. Cases with an unfavorable producer–injector balance led to extremely high LCOE, reflecting poor circulation efficiency and inadequate thermal sweep. As the configuration shifts toward fewer producers supported by injectors, LCOE rapidly drops into an economically viable range. This highlights that legacy oilfield layouts cannot be adopted directly for geothermal use and must be re-engineered to support sustainable circulation. The temperature sensitivity shows a strong monotonic decline in LCOE with increasing Tres. Raising the reservoir temperature from ~140 °C to ~225 °C reduces LCOE from ~170 $/MWh to below 60 $/MWh. This confirms that thermal quality is a first-order control on project economics and justifies the use of water geochemistry and thermal indicators for prospect ranking and field screening.

All together, the trends in Figure-6 are used to constrain realistic ranges for productivity, well architecture, field configuration, and thermal conditions based on field data and engineering limits. This enables FGEM to estimate a representative LCOE using site-specific inputs that reflect the true operational potential of the field. Using the field-specific inputs constrained by the sensitivity analysis, the Bahga model was simulated in FGEM, yielding an LCOE of approximately 330 $/MWh. In the context of commercial geothermal systems, this outcome is not economically viable. However, economic performance can be improved by enhancing well deliverability through larger flow conduits or casing flow, reconfiguring the field into an optimized injector–producer network, increasing system scale to amortize fixed costs, and targeting higher-temperature zones. Collectively, these interventions move the system toward the viable operating regime identified by the sensitivity analysis and provide a realistic pathway for transforming a marginal oilfield into a competitive geothermal asset.

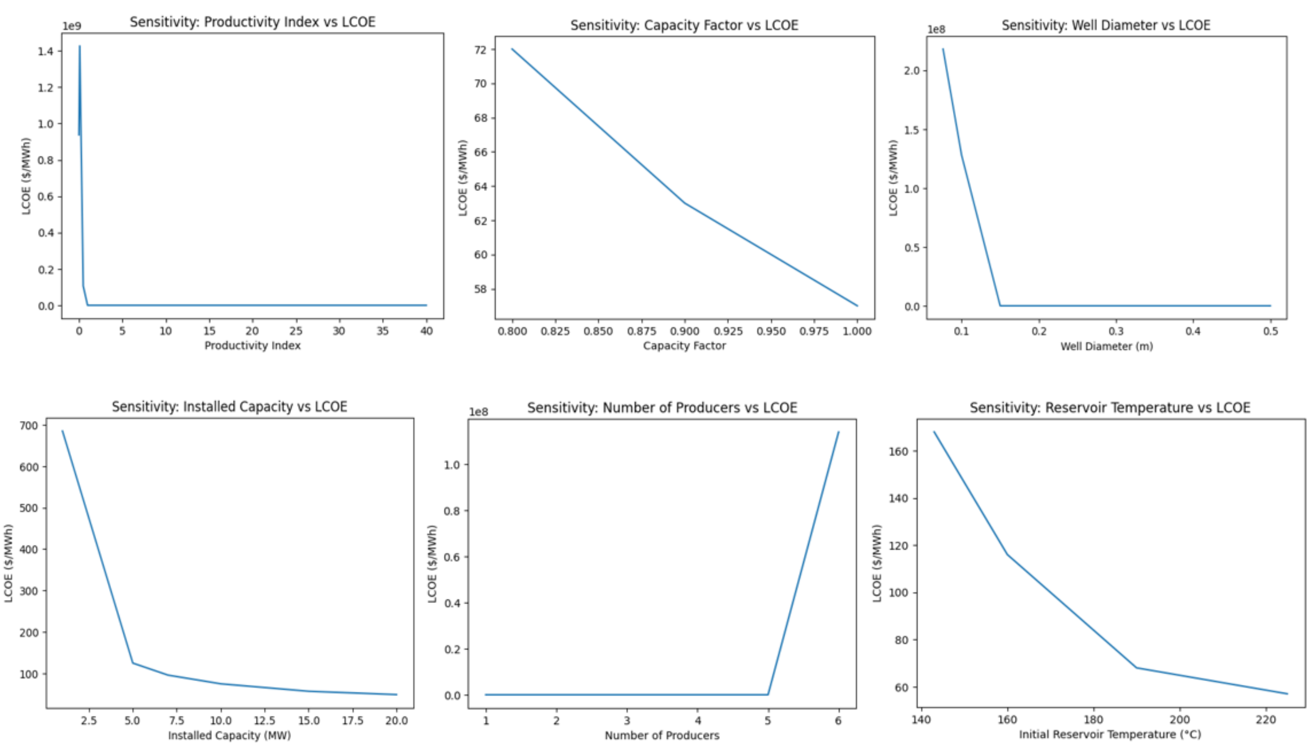

Figure 6: FGEM Sensitivity Analysis a) Productivity Index, b) Capacity Factor, c) Well diameter, d) Installed power plant capacity, e) Number of producers, and f) Initial reservoir temperature

4.2 In-House Modelling Tool (IHMT)

IIHMT provides a probabilistic assessment of both the geothermal power production potential and the associated economic performance of the Bahga field by explicitly accounting for geological, thermal, and economic uncertainties. Unlike the deterministic sensitivity-based approach implemented in FGEM, IHMT leverages MCS with 100,000 realizations to generate statistically robust P10, P50, and P90 estimates, enabling a more comprehensive evaluation of project risk and uncertainty.

Figure-6 presents the histogram of the estimated electrical power production potential for the Bahga field, derived from the overlap between the volumetric and power density methods. The results indicate a median (P50) power capacity of approximately 5 MWe, with a lower-bound estimate (P90) of about 3.4 MWe and an upper-bound estimate (P10) of approximately 6.5 MWe. This distribution reflects uncertainties in reservoir geometry, recovery factor, thermal efficiency, and assumed power density, while still demonstrating consistent and meaningful power generation potential across the majority of realizations. These results are broadly consistent with the FGEM-based analysis in Section 4.1, which identified system scale and thermal quality as primary drivers of economic performance, although IHMT explicitly quantifies the uncertainty envelope rather than relying on deterministic sensitivity trends.

Using the same MCS framework, CAPEX was estimated and normalized by installed power capacity. The resulting CAPEX distribution, shown in Figure-7, indicates a P50 total investment of approximately USD 10 million, corresponding to roughly USD 2 million per MWe. The uncertainty range spans from approximately USD 8.2 million at P10 to USD 11.5 million at P90. These values are notably lower than those typically reported for greenfield geothermal developments, reflecting the advantages of repurposing an existing oil field with established infrastructure, drilled wells, and prior subsurface characterization. While FGEM produced a higher LCOE under conservative assumptions, the IHMT results suggest that when probabilistic resource estimates and field-specific cost structures are considered, the Bahga field exhibits a more favorable economic profile.

The project cash flow behavior further supports the economic viability indicated by the IHMT analysis. Figure-8 illustrates the undiscounted cumulative net cash flow over the project lifetime for multiple realizations. Under the assumed project start date of January 1, 2026, the model predicts a payout period between 2033 and 2035 across most scenarios. This payout window aligns with long-term geothermal development timelines and reflects the capital-intensive nature of early project phases, followed by stable revenue during sustained operations.

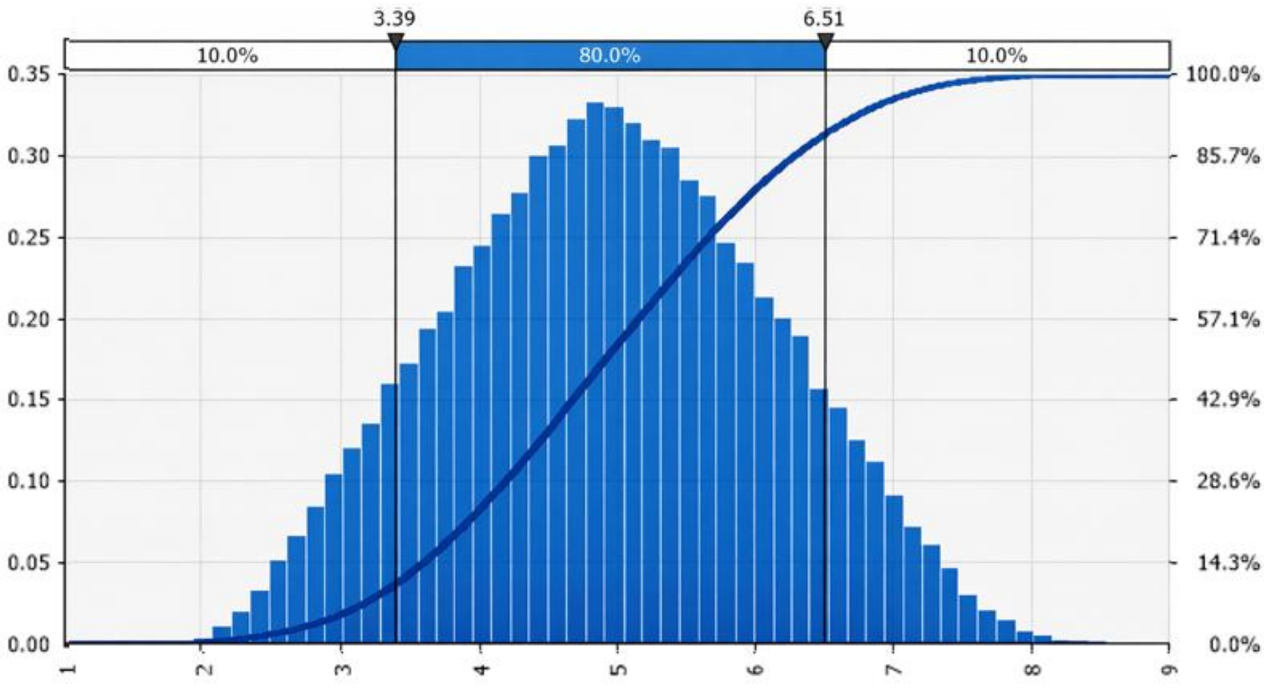

Figure 7: Histogram distribution of power production potential. X-axis is the power potential in MWe.

Economic performance metrics derived from the cash flow analysis indicate strong profitability potential. The IRR distribution shown in Figure-9 demonstrates an 80% probability that the project IRR lies between 19.23% and 27.75%, with a P50 value of 23.81%. These results compare favorably with typical hurdle rates for renewable energy projects and suggest that, under the assumed conditions, the Bahga geothermal project can deliver competitive returns despite moderate reservoir temperatures. In contrast to FGEM, which highlighted the sensitivity of LCOE to well deliverability and system configuration, IHMT emphasizes the aggregate economic outcome once uncertainty and probabilistic resource estimates are incorporated.

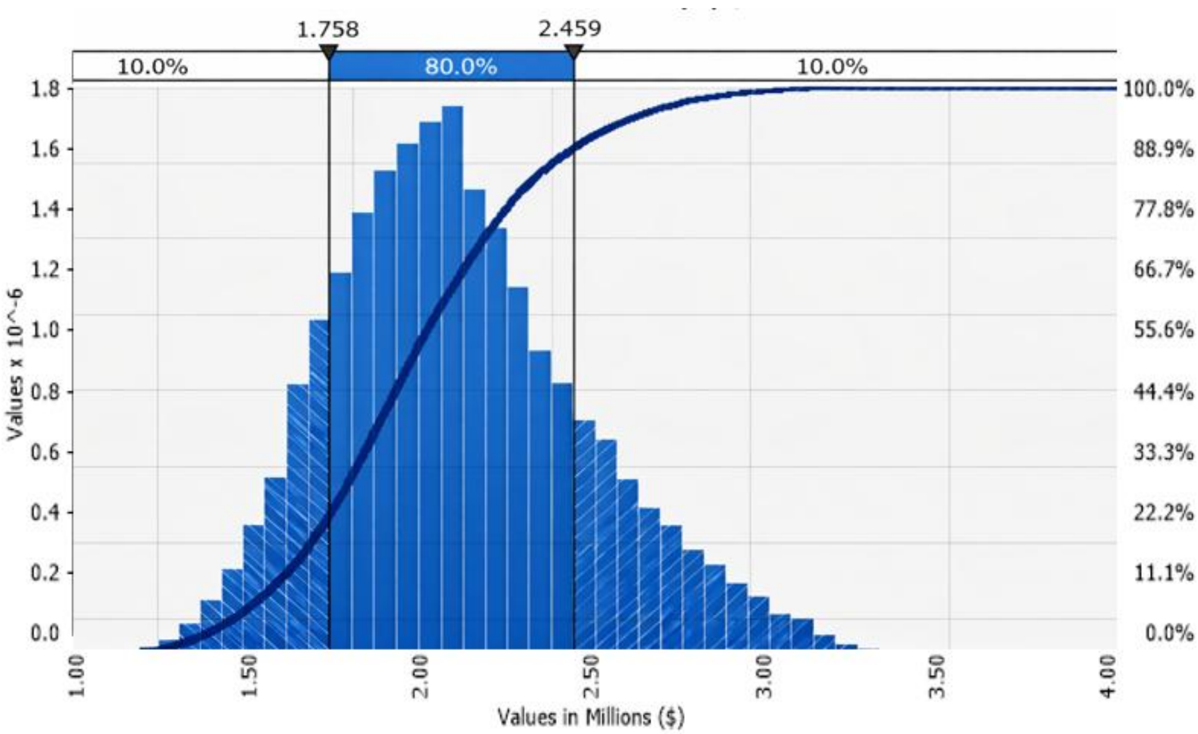

Figure 8: Histogram distibution of CAPEX/MWe.

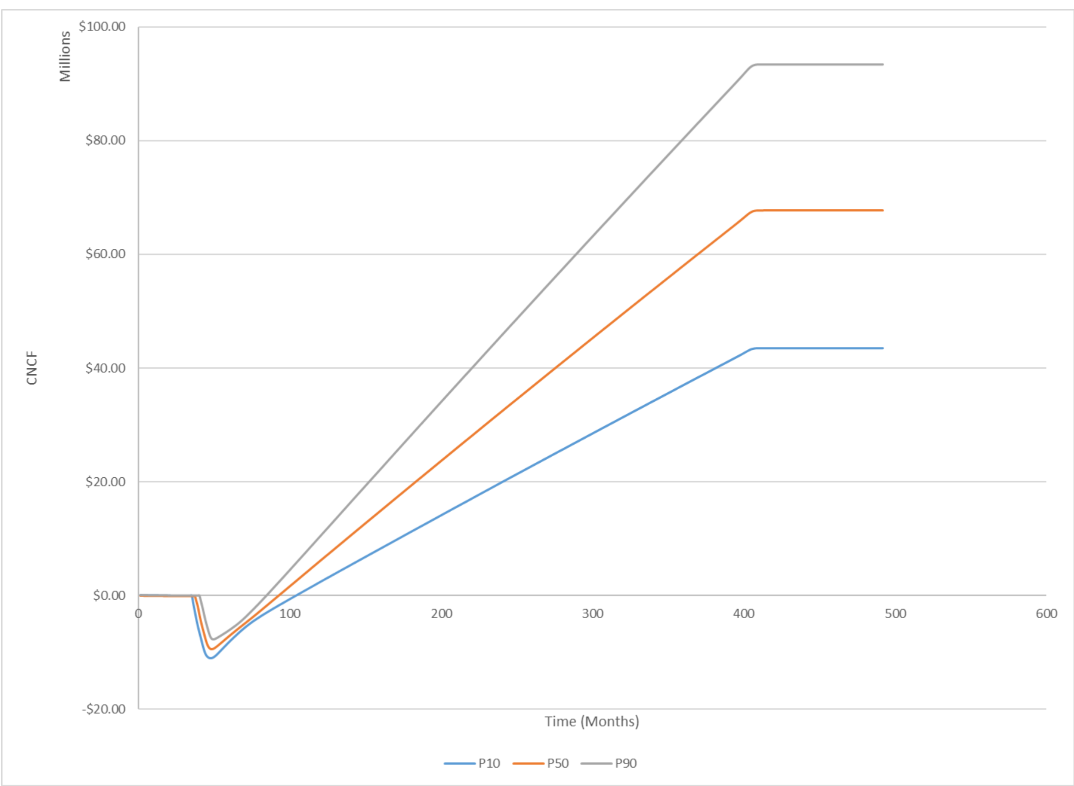

Figure 9: Undiscounted cumulative net cash flow versus time for different scenarios.

Overall, the IHMT results reinforce the conclusion that the Bahga field possesses a technically feasible and economically attractive geothermal resource when evaluated using probabilistic methods. The consistency between the power potential estimates, CAPEX distributions, and economic indicators demonstrates the robustness of the IHMT and its suitability for early-stage geothermal screening in data-limited or repurposed hydrocarbon fields.

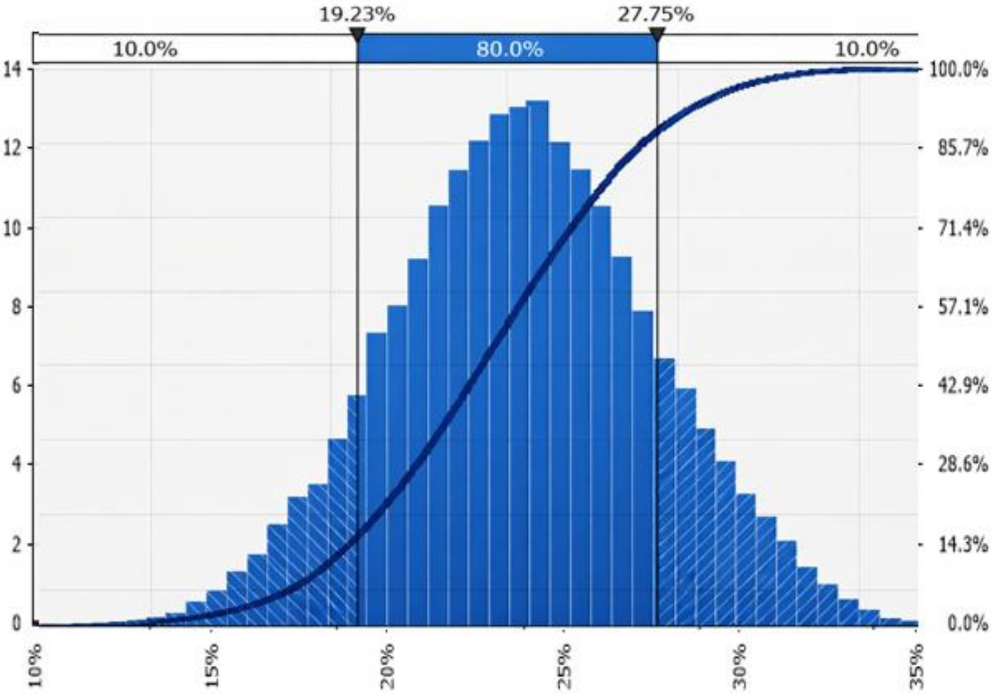

Figure 10: Histogram distibution of IRR.

5. CONCLUSION

This study presents a comprehensive techno-economic evaluation of geothermal power generation potential in the Bahga field, located in Egypt's Western Desert, using an integrated modeling framework that combines the FGEM tool with IHMT. By leveraging existing subsurface data from a mature oil field, this work demonstrates the technical feasibility and economic promise of repurposing legacy hydrocarbon assets for geothermal energy production.

The FGEM-based analysis provided critical insights into the key operational and design parameters governing project viability. Sensitivity analyses revealed that system scale, reservoir temperature, well deliverability, tubing diameter, and field configuration exert first-order control on economic performance, as reflected in the LCOE. Although the baseline FGEM scenario yielded a relatively high LCOE under conservative assumptions, the results clearly identified actionable pathways for economic improvement, including enhanced well completions, optimized injector–producer ratios, and operation at sufficient plant capacity to amortize fixed costs.

Complementing the FGEM analysis, the IHMT framework enabled a probabilistic assessment of geothermal resource potential and project economics by explicitly accounting for uncertainty in geological, thermal, and financial parameters. The Monte Carlo–based results indicate a median power generation potential of approximately 5 MWe, with favorable CAPEX and IRR distributions that compare well with international geothermal benchmarks. The predicted payout period between 2033 and 2035 and a P50 IRR of nearly 24% underscore the project's economic attractiveness under realistic assumptions.

Taken together, the combined FGEM and IHMT analyses provide a balanced and rigorous assessment of both deterministic system sensitivities and probabilistic economic outcomes. The convergence of results from these two independent modeling approaches enhances confidence in the conclusions and highlights the value of integrating standardized economic tools with flexible, field-specific workflows. Importantly, this study illustrates that moderate-temperature geothermal resources, when coupled with existing infrastructure and tailored development strategies, can play a meaningful role in Egypt's future energy mix.

From a broader perspective, the findings of this work support Egypt's Vision 2050 by demonstrating the potential of geothermal energy to contribute to energy security, reduce reliance on fossil fuel imports, and advance national decarbonization goals. The methodology and results presented here are transferable to other mature oil and gas fields in Egypt and to similar geological settings worldwide, offering a scalable pathway to accelerate the deployment of geothermal energy through asset repurposing. Future work should focus on integrating detailed reservoir simulation, wellbore hydraulics, and geomechanical effects to further refine performance predictions and support field-scale development planning.

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