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Techno-Economic Performance of Eavor-Loop 2.0

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ABSTRACT

This project evaluated techno-economic performance for a sample Eavor-Loop 2.0 design for electricity production and direct-use heating. The Eavor-Loop 2.0 design investigated is a 7.5-km deep closed-loop geothermal system consisting of 12 laterals for a total of more than 90 km of downhole well and lateral length. Both a high geothermal gradient scenario of 60°C/km and a low geothermal gradient scenario of 30°C/km were considered. With pure water injected at 60°C and 80 kg/s, reservoir simulations with the Slender-Body Theory simulator indicate average production temperatures over a 30-year lifetime of ~125°C and ~210°C for the low and high geothermal gradient scenario, respectively. These correspond to heat production of ~22 MW_{th} and ~51 MW_{th}, respectively. Using IPSEpro simulations, we find average power production of ~2.2 MW_e and ~8.6 MW_e, respectively, for a subcritical organic Rankine cycle power plant with air-cooled condensers. Cost estimates indicate the overall capital and levelized costs are dominated by the lateral drilling cost. Obtaining a levelized cost of electricity below \$70/MWh requires a geothermal gradient of 60°C/km, a discount rate below 9%, and lateral drilling cost below \$400/m. A well cost model indicates that ~\$400/m for the Eavor-Loop 2.0 design investigated can be obtained for a drilling rate of penetration about 40 ft/hr (with bit life of 50 hours), and omitting casing and cement. Traditional (geothermal) well drilling has achieved these drilling rate conditions, including the Utah FORGE project where the rate of penetration has exceeded 50 ft/hr in granite. However, it is unclear if these conditions are still valid for drilling the Eavor-Loop 2.0 laterals (i.e., ~82 km of laterals at 4 to 7.5-km vertical depth with rock temperatures up to 460°C), as such downhole completion has never been developed before. Competitive levelized cost of heat values (\$1.2-\$8.2/GJ) are calculated, even for the low geothermal gradient scenario (30°C/km) and lateral drilling cost of \$600/m.

1. INTRODUCTION

Advanced geothermal systems (AGS), also called closed-loop geothermal systems, are geothermal systems in which a heat transfer fluid—e.g., water or CO_2—circulates in a closed-loop configuration (i.e., without penetrating the reservoir) to extract heat from the subsurface and bring to the surface. Proponents of AGS highlight its ability to develop geothermal anywhere, without the need for in-situ fluids or reservoir permeability. Challenges of AGS include a potentially complex subsurface completion, and typically low thermal output and rapid initial temperature decline due to a combination of low rock thermal conductivity and limited area for heat transfer between the fluid and the rock. Simulations indicate that multi-MW_e systems require developing AGS in very high reservoir temperatures (several 100s of °C) and/or several dozen of kilometers of subsurface heat exchanger length (Beckers et al., 2022).

Various AGS designs have been proposed over the last several decades, including co-axial heat exchangers ("pipe-in-pipe" configurations in which the fluid is injected either in the center pipe or annulus) and U-loop type configurations (in which the fluid is injected in one well and flows through multiple laterals before being produced from a second well). Several AGS studies were recently reviewed by Beckers et al. (2022). For example, Morita and Tago (1995) and Morita et al. (2005) studied co-axial AGS configurations and estimated heat production on the order of 1 MW_{th} for a 2-km deep system with bottom-hole temperature of ~300°C. Riahi et al. (2017) estimated heat production on the order of 3 MW_{th} for a 2-km deep co-axial AGS with 1.1-km horizontal extension and bottom-hole temperature of 240°C. Oldenburg et al. (2016) and Riahi et al. (2017) estimated several MW_{th} of heat production for a 2.5-km deep U-loop design with a single 1.1-km long horizontal lateral and bottom-hole temperature of ~250°C. Beckers et al. (2022) performed a techno-economic analysis of both co-axial and U-loop scenarios under different operating conditions, and found relatively high levelized cost of energy, particularly for electricity generation, unless significant reductions can be obtained in drilling costs. However, their focus was on direct-use heat instead of electricity as the end use, and only relatively small systems were considered. A handful of AGS demonstration projects have also been undertaken. GreenFire Energy successfully demonstrated their co-axial downhole heat exchanger technology at Coso in California (Higgins et al., 2019), with results indicating potential electricity generation up to 1.2 MW_e using supercritical CO_2 as circulating fluid. Eavor Technologies ("Eavor") successfully tested a 2.4-km deep U-loop configuration with two horizontal laterals of 1.7-km length each, in Alberta, Canada (Vany and Toews, 2020). With bottom-hole temperature of 78°C, the thermal output was on the order of 800 kW_{th}. Measurements at this test site, referred to as Eavor-Lite, were used in our study to validate our reservoir model.

Eavor recently designed a commercial-scale system of their AGS technology, referred to as Eavor-Loop 2.0, consisting of 12 laterals up to 7.5-km deep. Eavor contracted the National Renewable Energy Laboratory (NREL) to conduct an independent techno-economic analysis of their system, the results of which are presented in this paper. The methodology of our study, including an overview of the software we used, is provided in Section 2. Our reservoir simulation results for the Eavor-Loop 2.0, assuming a low geothermal gradient (30°C/km) and high geothermal gradient (60°C/km), are presented in Section 3. This section also provides results of our validation study with measurements from the Eavor-Lite demonstration site. The heat production with the Eavor-Loop 2.0 is investigated both for direct-use heating as well as electricity generation using an organic Rankine cycle (ORC) power plant. Surface plant simulation results are provided in Section 4. Results for capital, operations & maintenance (O&M), and levelized cost of electricity and heat (LCOE and LCOH) of the Eavor-Loop 2.0 are presented in Section 5. Finally, conclusions are provided in Section 6.

2. METHODOLOGY

We investigated the techno-economic performance of the Eavor-Loop 2.0 using reservoir and surface plant simulations, combined with capital and O&M cost estimates and overall LCOE and LCOH calculations. Production temperature, production pressure, and thermal output over a 30-year lifetime are estimated using reservoir simulations with the Slender-Body Theory (SBT) tool (Beckers et al., 2015). The SBT tool was developed by Beckers et al. (2015) and recently upgraded (Beckers et al., 2022). Validation studies of the SBT tool were conducted by Beckers et al. (2015; 2022) by comparing with results using the Ramey (1962) analytical model and COMSOL (2019) numerical simulator. Additional validation was performed as part of this study by comparing with Eavor-Lite measurements. Power plant models were developed in IPSEpro (SimTech, 2021) to estimate heat-to-power conversion using air-cooled and water-cooled subcritical and supercritical ORC cycles. System capital and O&M costs were assessed using cost correlations published in the literature. A drilling cost model was developed to generate a range of drilling costs (in \$/m) for drilling of the laterals. Overall cost-competitiveness of the Eavor-Loop 2.0 was assessed by calculating the LCOE and LCOH for a 30-year lifetime and discount rates in the range of 5% to 9%.

3. RESERVOIR MODELING

3.1 Eavor-Lite Validation

Measurements at the Eavor-Lite demonstration site from December 2019 (start-up) through April 2021 were used to validate the SBT reservoir simulator. The Eavor-Lite is a 2.4-km deep AGS with two horizontal laterals of about 1.7 km length each (Figure 1). Rock density and specific heat capacity are 2,663 kg/m^3 and 1,112 J/kg-K, respectively. Rock thermal conductivity is 2.25 W/m-K around the injection and production well and 4.64 W/m-K around the two horizonal laterals. The geothermal gradient is approximately linear with surface temperature of 3°C and bottom-hole temperature of 78°C. Water is injected with a total flow rate of about 6 kg/s (Figure 2) and injection temperature fluctuating around 24°C (Figure 3). At a few instances (around October 1, 2020, and January 1, 2021), the flow rate was zero. Simulated production temperatures with the SBT model are in good agreement with Eavor measurements (Figure 4). Measured and simulated injection and production pressures are plotted in Figure 5. From April 2020 until October 2020, Eavor staff made some minor changes to the working fluid chemistry, which had a large impact on outlet pressure but minor impact on outlet temperature. Our modeling studies assume pure water for the entire operating period. The SBT model requires a constant injection pressure, which was set to 150 kPa. The simulated production pressure is in approximate agreement with the measured production pressure, confirming the strong thermosiphon effect observed (i.e., production pressure is about 250 kPa above injection pressure).

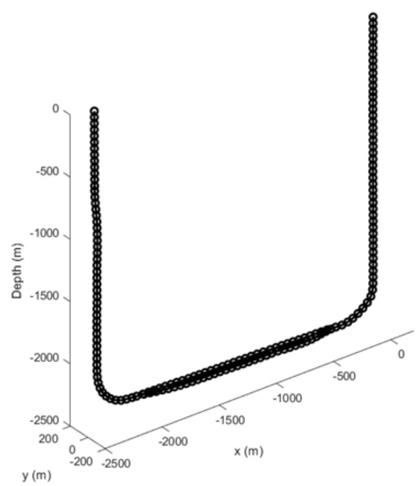

Figure 1: Eavor-Lite is a 2.4-km deep U-loop type AGS with two 1.7-km long horizontal laterals. Circles represent nodes in the SBT simulator.

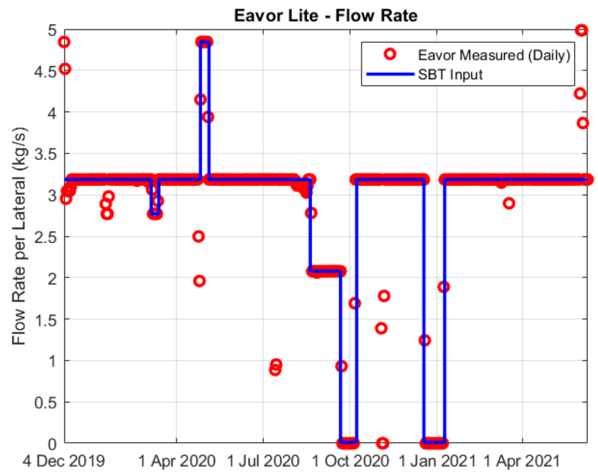

Figure 2: Measured Eavor-Lite flow rate (red circles) processed for input in SBT simulator (blue line). Average total flow rate was approximately 6.2 kg/s.

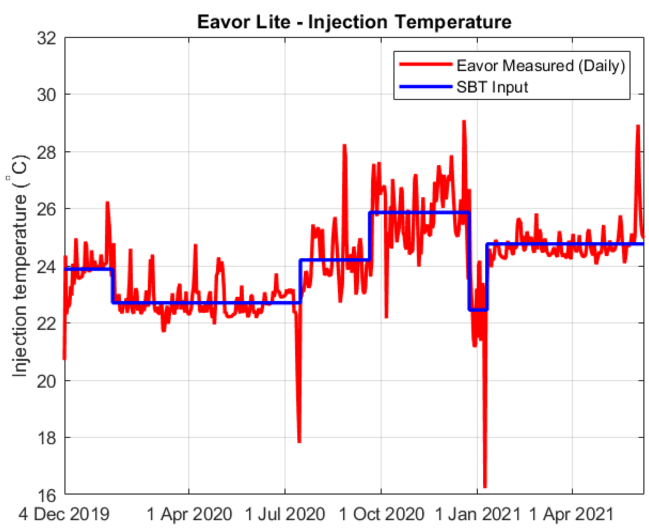

Figure 3: Measured Eavor-Lite injection temperature (red) processed for input in SBT simulator (blue). Average injection temperature was about 24°C.

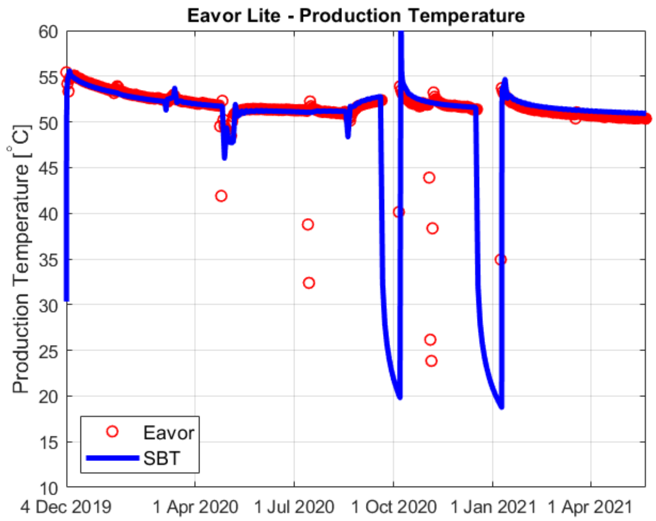

Figure 4: Eavor-Lite production temperature. Red circles are measurements by Eavor. Blue is simulated production temperature with SBT simulator.

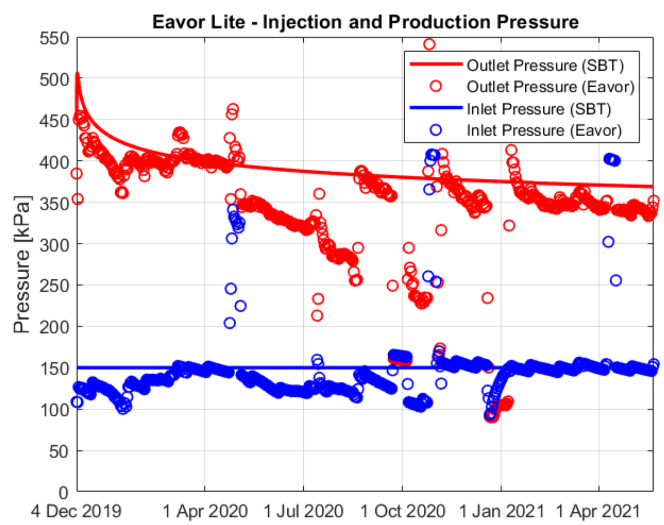

Figure 5: Eavor-Lite injection pressure (blue) and production pressure (red). Circles represent measurements by Eavor, and solid line is input and output for SBT simulator. The SBT simulator requires a constant injection pressure (solid blue line).

3.2 Eavor-Loop 2.0 Reservoir Simulations

The SBT simulator was applied to a sample Eavor-Loop 2.0 design consisting of 12-lateral U-loop type passes with total depth of about 7.5 km (Figure 6). The spacing between the laterals is about 75 m. The length of each lateral is about 6.5 km. Pure water is injected at 80 kg/s and 60°C. The rock thermal conductivity is set to 2.5 W/m-K, the rock density is 2,663 W/m-K, and the rock specific heat capacity is 1,112 J/kg-K. The well and lateral diameter is 0.216 m. Two scenarios are considered: a high geothermal gradient scenario (60°C/km) and a low geothermal gradient scenario (30°C/km). The surface temperature is set to 10°C. The bottom-hole temperature (at 7.5-km depth) for the high geothermal gradient scenario is 460°C, and for the low geothermal gradient scenario is 235°C. The production temperature over a 30-year lifetime as calculated with the SBT simulator is plotted in Figure 7. Simulations were performed with and without thermal interference between the laterals, indicating a spacing of 75 m is sufficient to limit thermal interference. The high geothermal gradient case has an average production temperature of about 210°C, while the low geothermal gradient case has an average production temperature of about 125°C. The corresponding heat production (in MW_{th}) for each scenario is plotted in Figure 8. Simulation results for difference between production and injection pressure are shown in Figure 9. In both scenarios, a positive thermosiphon is calculated.

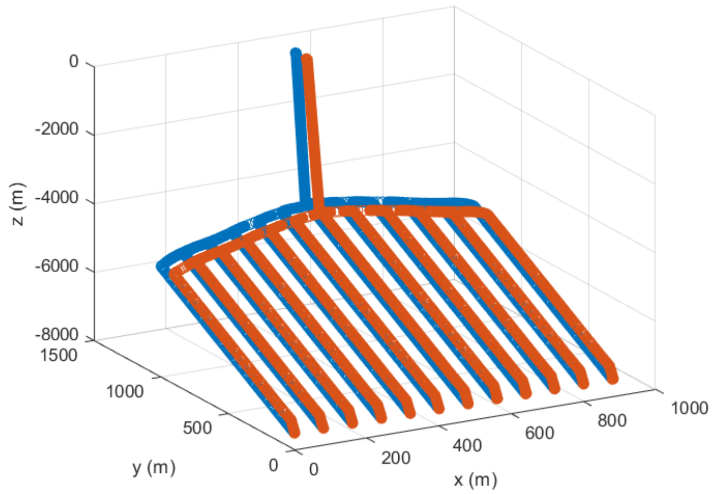

Figure 6: Eavor-Loop 2.0 has 12 laterals with total depth of approximately 7 km. Blue represents the injection side; red represents the production side. Spacing between laterals is approximately 75 m. Figure is not to scale.

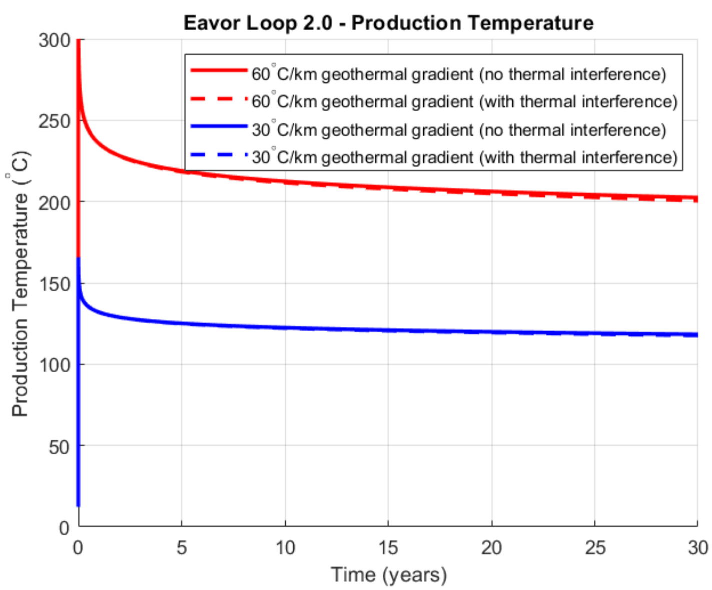

Figure 7: SBT simulation results for production temperature with Eavor-Loop 2.0 with low geothermal gradient (30°C/km) and high geothermal gradient (60°C/km). Results are shown with and without considering thermal interference between the laterals.

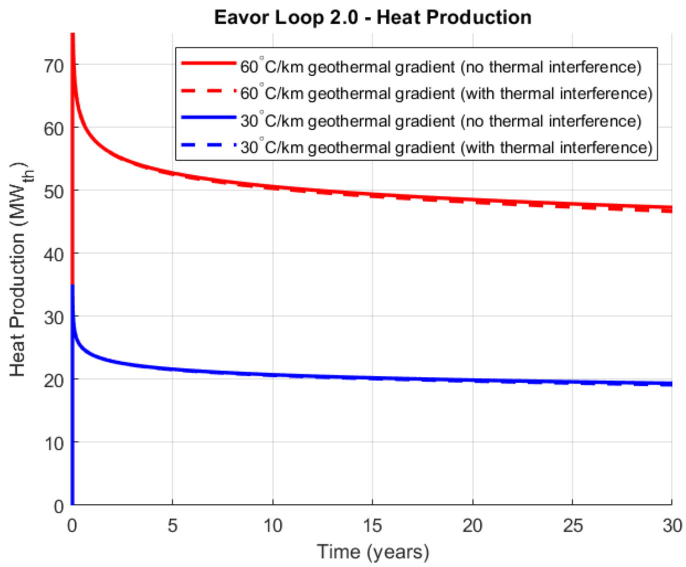

Figure 8: SBT simulation results for heat production with Eavor-Loop 2.0 with low geothermal gradient (30°C/km) and high geothermal gradient (60°C/km). Results are shown with and without considering thermal interference between the laterals.

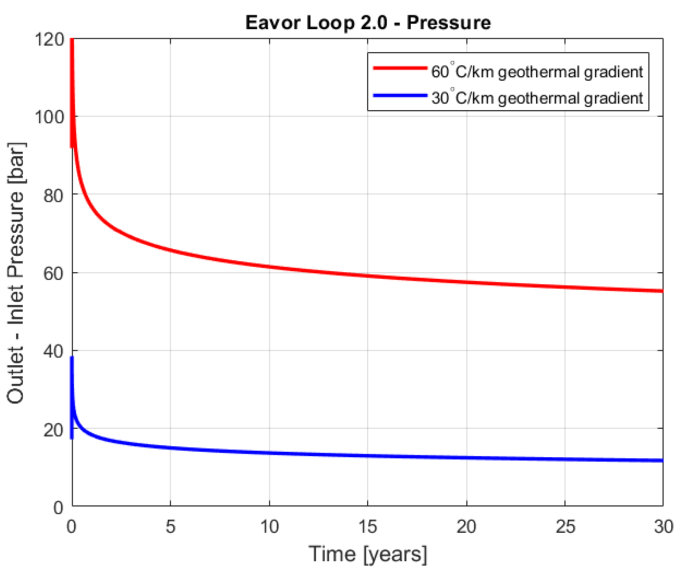

Figure 9: SBT simulation results for the difference in pressure between outlet and inlet with Eavor-Loop 2.0 for the low geothermal gradient (30°C/km) and high geothermal gradient (60°C/km) scenario. A constant inlet pressure of 100 bar was assumed. Results show a positive thermosiphon effect in both scenarios indicating no pumping power is required.

4. SURFACE PLANT MODELING

Heat production achieved with the Eavor-Loop 2.0 system (see Section 3) is investigated for electricity generation using an ORC power plant. Power plant models were developed in IPSEpro (SimTech, 2021) to estimate heat-to-power conversion using air-cooled condensers (ACC) and water-cooled condensers (WCC) in subcritical and supercritical cycles with and without heat recuperators. Various working fluids within the ORC power plant were considered to maximize net efficiency for the low geothermal gradient (30°C/km) and high geothermal gradient (60°C/km) scenarios. A constant geothermal production temperature was assumed at 125°C and 210°C, respectively.

Results for eight cases are provided in Table 1. The low geothermal gradient scenario has net efficiencies ranging from ~10% to ~13% with net power ranging from ~2 MW_e to ~3 MW_e. The best performing working fluid was propane. The high geothermal gradient scenario has net efficiencies ranging from ~17% to ~19% with net power ranging from ~8.6 MW_e to ~9.7 MW_e. The best performing working fluid was butane for a subcritical cycle and isobutane for a supercritical cycle. An example IPSEpro simulation is shown in Figure 10. This case represents a subcritical ORC with ACC for the high geothermal gradient scenario, with butane as working fluid. The corresponding temperature-entropy diagram is visualized in Figure 11. Additional IPSEpro input assumptions and pinch point delta temperatures for this case are provided in Appendix A.

Table 1: IPSEpro simulation results for air- and water-cooled ORC cycles for the low and high geothermal gradient scenario.

Case	Conditions	Geofluid Temperature (°C)	Recuperator	Working Fluid	Net Efficiency (%)	Net Power (MW_e)
ORC with ACC	Subcritical	125	No	Propane	10.3	2.2
ORC with WCC	Subcritical	125	No	Propane	11.3	2.5
ORC with ACC	Supercritical	125	No	Propane	11.7	2.6
ORC with WCC	Supercritical	125	No	Propane	12.6	2.8
ORC with ACC	Subcritical	210	Yes	Butane	16.8	8.6
ORC with WCC	Subcritical	210	Yes	Butane	17.8	9.1
ORC with ACC	Supercritical	210	Yes	Isobutane	18.0	9.2
ORC with WCC	Supercritical	210	Yes	Isobutane	18.9	9.7

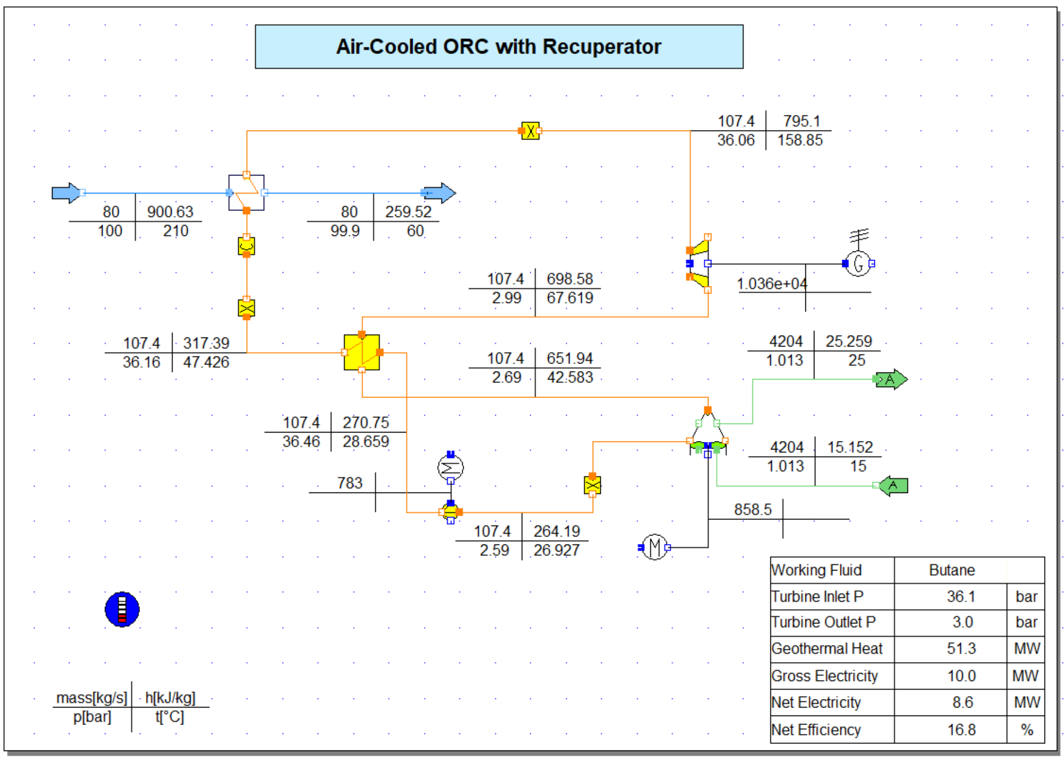

Figure 10: IPSEpro model for a subcritical ORC with air-cooled condenser and heat recuperator.

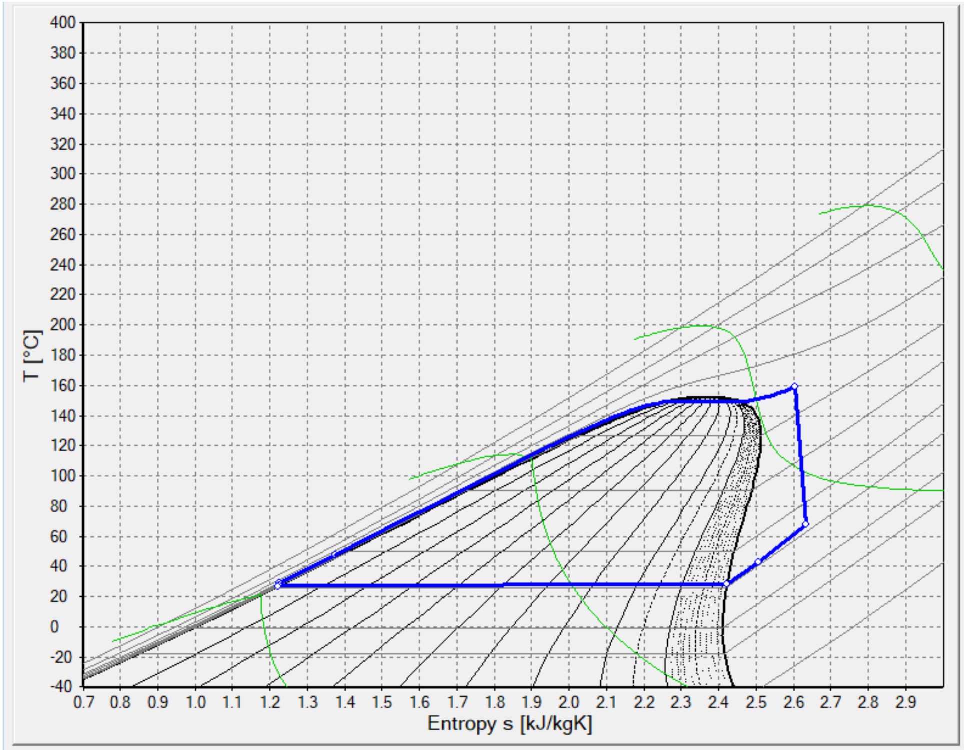

Figure 11: IPSEpro temperature vs. entropy diagram for subcritical ORC with air-cooled condenser and heat recuperator. Butane is the working fluid.

5. TECHNO-ECONOMIC EVALUATION

5.1 Capital and O&M Cost Estimates

Overnight capital costs are estimated for the Eavor-Loop 2.0 for electricity generation and direct-use heating. Drilling and completion of the wells and laterals represents the major cost item. The Eavor-Loop 2.0 consists of 2 vertical wells of about 4.2 km depth each and 12 laterals with total length of about 82 km (see Figure 6). The *GeoVision* drilling cost curves are applied to estimate drilling costs for the vertical wells (Lowry et al., 2017). Based on recent drilling activities at FORGE (e.g., Winkler and Swearingen, 2021), the two vertical wells may be drilled at a drill rate of about 50 ft/hr, suggesting the *GeoVision* baseline drilling curves may be too conservative. Hence, here we assume each well can be drilled at $5M, corresponding to about a 40% reduction in drilling costs from the baseline, comparable to the Intermediate I drilling cost curve for vertical wells with small diameter (Lowry et al., 2017).

No drilling cost correlations or published cost data are available for drilling the laterals given the new nature of this technology. The laterals are envisioned to be completed without casing or cement as demonstrated in the Eavor-Lite project, resulting likely in a significant cost reduction from traditional well drilling as casing and cement can represent over 50% of total well cost (Lowry et al., 2017). Here, we develop a simple cost model to estimate open-hole lateral drilling costs as a function of drill rate and bit life. We consider similar assumptions as in the *GeoVision* Study (Lowry et al., 2017), presented in Table 1. The main difference with traditional geothermal well drilling is that casing and cement are not included. Also, we assume that the laterals do not require any other completion after being drilled.

Table 1: Lateral drilling cost assumptions

Fixed costs	Mobilization / de-mobilization	$250,000 (total)
	Site preparation	$250,000
	Pre-spud engineering	$10,000
	Wellhead equipment	$80,000
Tripping	In and out of hole	1000 ft/hr
	Handling time	6 hrs
Mud costs	Initial volume	$10,000
	Make-up volume	$4,000/day

BHA cost	Bit cost	\$3,800 × (diameter in inch) – \$21,800
	Bit diameter	8.5”
	Bottom-hole assembly	50% of bit cost
Directional drilling	Specialized labor	\$75/hr
	Motor and steering tools	\$500/hr
Drilling costs	Rate of penetration (ROP)	25 – 50 – 75 ft/hr
	Rig rental rate	\$40,000/day
	Bit life	50 – 100 – 150 hr
Trouble time	Contingency	5%
Casing	Omitted	
Cement	Omitted	

For the assumptions listed in Table 1, the resulting lateral drilling cost for drilling 12 laterals with total length of 82.4 km (with the depth of the laterals from ~4 km to ~7.5 km), as a function of rate of penetration (ROP) and bit life is provided in Table 2. For example, for the scenario with ROP of 25 ft/hr and bit life of 50 hr, the total lateral drilling costs is \$49.9M, corresponding to \$606/m. The total rig rental time for this scenario is ~895 days when drilling with one rig. When drilling with two rigs simultaneously, the total drilling time would be about half. For a bit life of 50 hr, a lateral drilling cost of \$400/m is calculated for an ROP of 38 ft/hr. Drilling ~82 km of open-hole laterals at 4 to 7.5 km vertical depth with rock temperatures in the range of ~250°C to ~460°C (high geothermal gradient scenario) has never been done before. Hence, the assumptions listed in Table 1, derived from a well cost model for traditional geothermal wells, are potentially no longer applicable. Therefore, the drilling cost results should not be interpreted as predictions but rather as estimated costs if lateral drilling can be performed under the conditions listed in Table 1. Also, the relation between \$/m and ROP and bit life as presented in Table 2 applies specifically to the Eavor-Loop 2.0 design studied, for which the fixed costs become negligible given the long lateral length and total drill time. For laterals with length of only a few kilometers, higher ROP and longer bit life are required to obtain the same \$/m drilling cost. The lateral drilling cost results presented in Table 2 assume a range of drilling parameters as listed in Table 1. Additional sensitivity is performed regarding the tripping speed and rig rental rate. These results are presented in Table 3, indicating significant sensitivity to these two parameters.

Table 2: Calculated lateral drilling cost for Eavor-Loop 2.0 (82.4 km total lateral length) using assumptions listed in Table 1.

	Bit life = 50 hr	**Bit life = 100 hr**	**Bit life = 150 hr**
ROP = 25 ft/hr	\$606/m	\$472/m	\$427/m
ROP = 50 ft/hr	\$306/m	\$239/m	\$217/m
ROP = 75 ft/hr	\$206/m	\$161/m	\$147/m

Table 3: Calculated lateral drilling cost for Eavor-Loop 2.0 (82.4 km total lateral length) using assumptions listed in Table 1.

	-50%	**Base Case**	**+50%**
Tripping speed	\$403/m (500 ft/hr)	\$306/m (1,000 ft/hr)	\$274/m (1,500 ft/hr)
Rig rental rate	\$198/m (\$20,000/day)	\$306/m (\$40,000/day)	\$414/m (\$60,000/day)

The capital cost for an ORC plant is estimated in the range of \$2,000/kW$_e$ to \$3,000/kW$_e$ with \$2,500/kW$_e$ as baseline, based on the ORC cost correlations in GETEM (Mines, 2016) and GEOPHIRES (Beckers and McCabe, 2019), and ORC cost numbers estimated by Bianchi et al. (2019) and Ergun et al. (2017). This translates into a baseline ORC plant cost of \$21.5M for the high geothermal gradient scenario (assuming 8.6 MW$_e$ output) and \$5.5M for the low geothermal gradient scenario (with 2.2 MW$_e$ output). For direct-use heating, we consider a single plate-and-frame heat exchanger as main surface equipment. Heat exchanger size is estimated using the standard $Q = UA\Delta T_{LMTD}$ equation with a heat transfer coefficient U of 2,000 W/m^2-K (Peters et al., 2003) and ΔT_{LMTD} in the range of 5 to 10°C. The required heat exchanger area A (m^2) is 2,500 – 5,000 m^2 for the high geothermal gradient scenario (with $Q = \sim 51$ MW$_{th}$) and 1,250 – 2,500 m^2 for the low geothermal gradient scenario (with $Q = \sim 22$ MW$_{th}$). Based on cost correlations for plate-and-frame heat exchangers by Peters (2003), brought from 2002 to today’s dollars using the Bureau of Labor Statistics producer price index for power boiler and heat exchanger manufacturing (BLS, 2022), the heat exchanger cost is estimated at \$350k–\$450k for the high geothermal gradient scenario and \$220k–\$350k for the low geothermal gradient scenario. Using “Lang Factors” to account for other project cost components such as instrumentation, electrical work, engineering, and supervision, etc. (Peters, 2003), the total direct-use surface plant cost is estimated at \$1.75M for the high geothermal gradient scenario and \$1.25M for the low geothermal gradient scenario.

The O&M cost for the ORC power plant is estimated at 1.5% of the plant capital cost (Shenjun et al., 2011; Casartelli et al., 2015; Fiaschi et al., 2017). For the direct-use plant, given its more simple technology, the plant O&M cost is estimated at 1% of the plant capital cost. No pumping power is required for circulating the fluid downhole due to the positive thermosiphon effect. Given the closed-loop nature and use of pure water as heat transfer fluid, no O&M cost for surface piping and heat exchanger cleaning, and scaling mitigation are considered. Also, we assume that no rework on the wells and laterals is required throughout the lifetime. Further, no exploration costs, royalties, or leasing costs are considered.

5.2 Levelized Cost of Energy Estimates

LCOE and LCOH values are estimated for the Eavor-Loop 2.0 considering the thermal and electricity output calculated in Sections 3 and 4, and the capital and O&M cost estimates presented in Section 5.1. For electricity generation as the end use, we assume for the high geothermal gradient scenario that the average net output is 8.6 MW_e (see Section 4) and availability is 95%, corresponding to ~72 GWh of electricity production per year. For the low geothermal gradient scenario, we assume a net power output of 2.2 MW_e (see Section 4) and availability of 95%, resulting in ~18 GWh of electricity per year. For direct-use heating, for the high geothermal gradient scenario, we consider an average thermal output of 51 MW_{th}, combined with 95% availability, resulting in ~424 GWh of heat per year. For the low geothermal gradient scenario, the annual heat production is ~183 GWh per year.

Levelized costs are calculated with a standard discounting levelized cost model as implemented in GEOPHIRES 2.0 (Beckers and McCabe, 2019). We consider a discount rate in the range of 5% to 9%. Given the large uncertainty in lateral drilling costs (see Section 5.1), we considered a range for lateral drilling costs of $200/m to $600/m. The calculated LCOE values are presented in Table 4; the calculated LCOH values are presented in Table 5.

Table 4: Eavor-Loop 2.0 LCOE estimates (in $/MWh) for high and low geothermal gradient scenario.

High Geothermal Gradient Scenario (60°C/km)			
	Discount Rate = 9%	**Discount Rate = 7%**	**Discount Rate = 5%**
Lateral Drilling Cost = $600/m	LCOE = $105/MWh	LCOE = $90/MWh	LCOE = $75/MWh
Lateral Drilling Cost = $400/m	LCOE = $85/MWh	LCOE = $72/MWh	LCOE = $60/MWh
Lateral Drilling Cost = $200/m	LCOE = $64/MWh	LCOE = $55/MWh	LCOE = $46/MWh
Low Geothermal Gradient Scenario (30°C/km)			
	Discount Rate = 9%	**Discount Rate = 7%**	**Discount Rate = 5%**
Lateral Drilling Cost = $600/m	LCOE = $321/MWh	LCOE = $272/MWh	LCOE = $224/MWh
Lateral Drilling Cost = $400/m	LCOE = $241/MWh	LCOE = $204/MWh	LCOE = $168/MWh
Lateral Drilling Cost = $200/m	LCOE = $160/MWh	LCOE = $136/MWh	LCOE = $113/MWh

Table 5: Eavor-Loop 2.0 LCOH estimates for high and low geothermal gradient scenario. LCOH values are provided in $/GJ, which is approximately equal to $/MMBtu.

High Geothermal Gradient Scenario (60°C/km)			
	Discount Rate = 9%	**Discount Rate = 7%**	**Discount Rate = 5%**
Lateral Drilling Cost = $600/m	LCOH = $3.6/GJ	LCOH = $3.0/GJ	LCOH = $2.5/GJ
Lateral Drilling Cost = $400/m	LCOH = $2.6/GJ	LCOH = $2.2/GJ	LCOH = $1.8/GJ
Lateral Drilling Cost = $200/m	LCOH = $1.7/GJ	LCOH = $1.4/GJ	LCOH = $1.2/GJ
Low Geothermal Gradient Scenario (30°C/km)			
	Discount Rate = 9%	**Discount Rate = 7%**	**Discount Rate = 5%**
Lateral Drilling Cost = $600/m	LCOH = $8.2/GJ	LCOH = $7.0/GJ	LCOH = $5.7/GJ
Lateral Drilling Cost = $400/m	LCOH = $6.0/GJ	LCOH = $5.1/GJ	LCOH = $4.2/GJ
Lateral Drilling Cost = $200/m	LCOH = $3.8/GJ	LCOH = $3.2/GJ	LCOH = $2.6/GJ

LCOE values less than $70/MWh are calculated for the Eavor-Loop 2.0 in case the laterals can be drilled below $400/m and the geothermal gradient is relatively high (~60°C/km). As presented in Section 5.1, a low lateral drilling cost requires high ROP values and long bit life. A geothermal gradient of 60°C/km is not typically found in the eastern United States but occurs at "hot spots" in the western United States. While the LCOE values calculated are higher than those for wind and solar, the electricity generated with the Eavor-Loop 2.0 is available 24/7 and not subject to variability, which can ultimately reduce the average end-use price in a fully decarbonized electricity system (Sepulveda et al., 2018).

Competitive LCOH values are found with the Eavor-Loop 2.0, even for the low geothermal gradient of 30°C/km, lateral drilling cost of $600/m and discount rate of 9%. This requires that the underlying assumptions are met, including system availability of 95% over a 30-year lifetime, O&M cost of 1% of surface plant capital cost, all heat between the production temperature and the injection temperature is utilized by the end-use application, and a single heat exchanger with no energy losses as surface equipment. We only considered a single flow rate and injection temperature in our analysis. These parameters can be adjusted to obtain production temperatures that match the surface application, and higher flowrates (with correspondingly higher thermal outputs and lower levelized costs) are likely achievable due to the excess thermosiphon pressure generated. This level of optimization was outside the scope of this project.

Tables 4 and 5 indicate the levelized cost values are strongly dependent on lateral drilling cost, discount rate, and geothermal gradient. Additional sensitivity analysis is performed to investigate dependence of the LCOE of the high geothermal gradient scenario on ORC capital cost, O&M cost, vertical well drilling cost, and ORC plant electricity output (Table 6). All cases in Table 6 assume a lateral drilling cost of $400/m and discount rate of 7%. The calculations reveal that the LCOE is moderately sensitive to the ORC capital cost, and only to a small degree sensitive to the vertical well drilling cost and O&M cost. The LCOE is strongly dependent on the ORC power output, e.g., a 5% increase in electricity production would result in a ~5% decrease in LCOE. We selected the lower-end value of 8.6 MW_e for baseline ORC power output (see Table 1) as subcritical ORC plants are more common and to avoid water consumption for operating water-cooled condensers.

Table 6: Eavor-Loop 2.0 LCOE (in $/MWh) for high geothermal gradient scenario (60°C/km) for various ORC capital cost, ORC power output, ORC O&M cost and vertical well drilling cost. For all cases, the lateral drilling cost is $400/m and the discount rate is 7%.

	-50%	Base Case	+50%
ORC Capital Cost	$61/MWh ($1,250/kW)	$72/MWh ($2,500/kW)	$84/MWh ($3,750/kW)
Vertical Well Drilling Cost	$67/MWh ($2.5M/well)	$72/MWh ($5M/well)	$78/MWh ($7.5M/well)
O&M Cost	$70/MWh ($160k/yr)	$72/MWh ($320k/yr)	$75/MWh ($480k/yr)
	-5%	**Base Case**	**+5%**
ORC Electricity Output	$75/MWh (8.2 MWe)	$72/MWh (8.6 MWe)	$70/MWh (9.0 MWe)

6. CONCLUSIONS

In this paper, we present the results of a techno-economic assessment NREL conducted during the fall of 2021 of a sample Eavor-Loop 2.0 design for direct-use heating and electricity production. The Eavor-Loop 2.0 design studied is a U-loop type 7.5-km deep closed-loop geothermal system consisting of 1 injection well, 1 production well, and 12 lateral passes. The injection and production well are vertical and each about 4 km deep. The laterals are each about 6.5 km long, spaced ~75 m apart, and occur from ~4 km to ~7.5-km depth. We considered pure water as heat transfer fluid, injected at 60°C and 80 kg/s over a 30-year lifetime. We considered a low geothermal gradient (30°C/km) and high geothermal gradient (60°C/km), with bottom-hole temperature of 235°C and 460°C, respectively.

Reservoir simulations with the SBT simulator for heat conduction only in the reservoir indicate long-term average production temperatures of about 210°C for the high geothermal gradient scenario and about 125°C for the low geothermal gradient scenario. This corresponds to average heat production of ~50 MW_{th} and ~22 MW_{th}, respectively. Due to a positive thermosiphon effect, no pumping power is required for circulating the water, and ~50 to ~100 bar of excess thermosiphon pressure is generated for the high geothermal gradient scenario. Using IPSEpro simulations for an ORC power plant with air-cooled condensers, we find a net power output of about 8.6 MW_e for the high geothermal gradient scenario and about 2.2 MW_e for the low geothermal gradient scenario.

Cost assessment of the Eavor-Loop 2.0 design suggests that the overall capital costs are dominated by the lateral drilling cost. A simplified well cost model suggests lateral drilling cost for the Eavor-Loop 2.0 design are in the range of ~$200 to ~$600/m for an ROP in the range of 25 to 75 ft/hr, bit life in the range of 50 to 150 hours, and omitting casing and cement. Published cost correlations are applied for an ORC power plant for electricity generation and a plate-and-frame heat exchanger for direct-use heating. O&M costs are set to 1.5% of the ORC plant for electricity generation and 1% of the surface plant for direct-use heating. Using a standard discounting levelized cost model with discount rate in the range of 5% to 9% and lateral drilling cost in the range of $200/m to $600/m, we find LCOE values in the range of $46/MWh to $105/MWh for the high geothermal gradient scenario and $113/MWh to $321/MWh for the low geothermal gradient scenario. The LCOH values are $1.2/GJ to $3.6/GJ for the high geothermal gradient scenario and $2.6/GJ to $8.2/GJ for the low geothermal gradient scenario.

The levelized cost results indicate that LCOE values under $70/MWh can be obtained with the Eavor-Loop 2.0 if the laterals can be drilled under $400/m, the local geothermal gradient is relatively high at 60°C/km, and the discount rate is under 9%. For the Eavor-Loop 2.0 design studied, a lateral drilling cost of ~$400/m would require an ROP of ~40 ft/hr, a bit life of 50 hours, and omitting casing and cement. Traditional (geothermal) well drilling has achieved this ROP, including recent wells drilled in granite at the Utah FORGE site. However, the Eavor-Loop 2.0 requires drilling of ~82 km of open-hole laterals at 4 to 7.5 km vertical depth in rocks with temperatures up to 465°C. Such downhole completion has never been developed before. Hence, it is unclear if traditional geothermal well drilling conditions are still valid. In comparison with electricity generation, competitive LCOH values are calculated even for the lower geothermal gradient scenario of 30°C/km, and higher lateral drilling costs of $600/m. These LCOH values assume a 95% system availability over its 30-year lifetime, and a single heat exchanger as surface equipment. Both the electricity and direct-use heat scenario assume that once the subsurface system is installed, no maintenance is required over its lifetime (e.g., rework of a lateral).

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APPENDIX A. IPSEPRO INPUT ASSUMPTIONS AND PINCH POINT TEMPERATURES FOR HIGH-TEMPERATURE SUBCRITICAL ORC WITH ACC

Table A1: IPSEpro Input Assumptions

Surface Plant Input Parameter	Parameter Value
Turbine Inlet Pressure	36 bar
Turbine Inlet Temperature	159°C
Turbine Isentropic Efficiency	90%
Turbine Mechanical Efficiency	100%
Generator Electrical Efficiency	98%
Generator Mechanical Efficiency	98%
Turbine Outlet Pressure	3 bar
Recuperator Thermal Duty	5,007 kW
ACC Fan/Air Flow Ratio	0.12 kW / kg/s air
Pump Isentropic Efficiency	90%
Pump Mechanical Efficiency	90%
Pump Motor Electrical Efficiency	98%
Pump Motor Mechanical Efficiency	98%
Geothermal Fluid Inlet Pressure	100 bar
Geothermal Fluid Outlet Temperature	60°C

Table A2: Pinch Point delta Temperatures

Surface Plant Heat Exchangers	Pinch Point delta Temperature
Recuperator	13.9°C
Air Cooled Condenser	3.3°C
Primary Heat Exchanger	5.8°C