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Associated Gas Recovery Integrated with Solar Power for Produced Water Treatment: Techno-Economic & Environmental Impact Analyses

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Abstract: Excess associated gas from unconventional wells is typically flared while excess produced water is injected underground. In this work, flare gas recovery is integrated with produced water desalination and a solar pre-heater. The solar module with a beam splitter preheats the produced water. Aspen Plus was used to perform process modeling as well as to estimate capital and operating costs. The Solar-Flare Gas RDcovery-desalination (Solar-FGRD) process can conserve water resources and reduce the brine injection by 77%. The accompanying solar farm results in excess solar electricity for exporting to the grid. The process burner combustion efficiency (CE) is 99.8% with the destruction and removal efficiency (DRE) of 99.99% for methane as opposed to the flare CE of 80-98% (and a methane DRE of 91-98%). The greenhouse gas (GHG) emissions for CO2 and methane in terms of CO2 equivalent (CO2e) can be reduced by 45 % for US North Dakota & Texas flaring and 13% for North Sea flaring by employing the Solar- FGRD process. The comprehensive financial analysis demonstrates the financial-economic feasibility of the investment project with or without tax credits. Best-case and worst-case scenarios provide a realistic range that investors can consider before making investment decisions.

Keywords: economic feasibility; tax credits; produced water; desalination; flare gas recovery; brine disposal; photovoltaic cell; solar thermal collector

1. Introduction

The flaring of associated gas results in wasted energy and raw materials in addition to atmospheric emission of greenhouse gases, which intensifies climate change. Consequently, flare gas recovery (FGR) is a priority for regulatory agencies and the oil & gas (O&G) industry [1–10]. Furthermore, the disposal of untreated produced water, a waste byproduct of natural gas production wells, in evaporation ponds and subsurface injection sites remains under scrutiny due to the shortage of disposal sites and the scarcity of fresh water. The call for produced water treatment for recycling and reuse is getting louder. A cost-effective, integrated solution that promotes the reuse of treated produced water with captured flare gas, not only reduces greenhouse gas emissions and generates a revenue-generating water stream, but also improves a company's Environmental, Social, and Governance (ESG) performance. In previous studies, the FGR-thermal vapor compression (FGR-TVC) processes (Compressor-based or Ejector-based) for produced water desalination were demonstrated to be technically viable [11–16]. In this paper, we performed Aspen Plus process modeling by simplifying the previous flowsheets to maximize potable water recovery and reduce burner flue gas emissions [17]. The rapid advancement of solar energy technology coupled with high solar insolation in the US Southwest makes a compelling argument to utilize solar energy in O&G operations [18–20]. The Solar-Flare Gas Recovery-Desalination (Solar-FGRD) process seeks to reduce operating and utility costs by improving heat integration and decreasing reliance on a power grid to

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operate the desalination plant. The process modeling, economic feasibility, and environmental impact were evaluated and compared to a produced water disposal baseline process, without flare gas recovery (FGR) and without produced water desalination [21–29].

After a well begins to produce oil and gas, flow back water is observed during the first few weeks after which produced water continues to flow throughout the life of the well. The total dissolved solids (TDS) of the produced water varies from 10,000 to 300,000 mg/L. Figure 1 [15] estimates the flow rate of produced water for a well. In this project, 52.2 bbl/hr of produced water was assumed. Figure 2 illustrates the TDS content in typically produced water samples. In this project, 130,000 mg/L was assumed as the average TDS content of produced water. Based on a previous work [11], the TDS composition was assumed to be 28.9 % Na^+, 9.6% Ca^{2+}, and 61.5% Cl^-. The Solar-FGRD process captures this stream and converts 76.8% of the volume to potable water (<500 mg/L), which can be used by municipalities for irrigation, cleaning, household use, and drinking water.

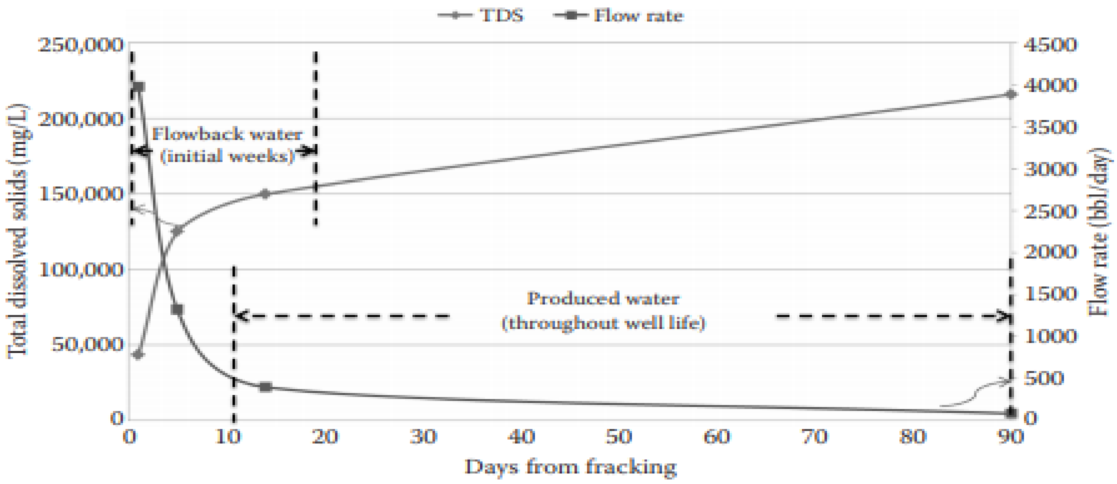

Figure 1. Produced water flow rate throughout well life.

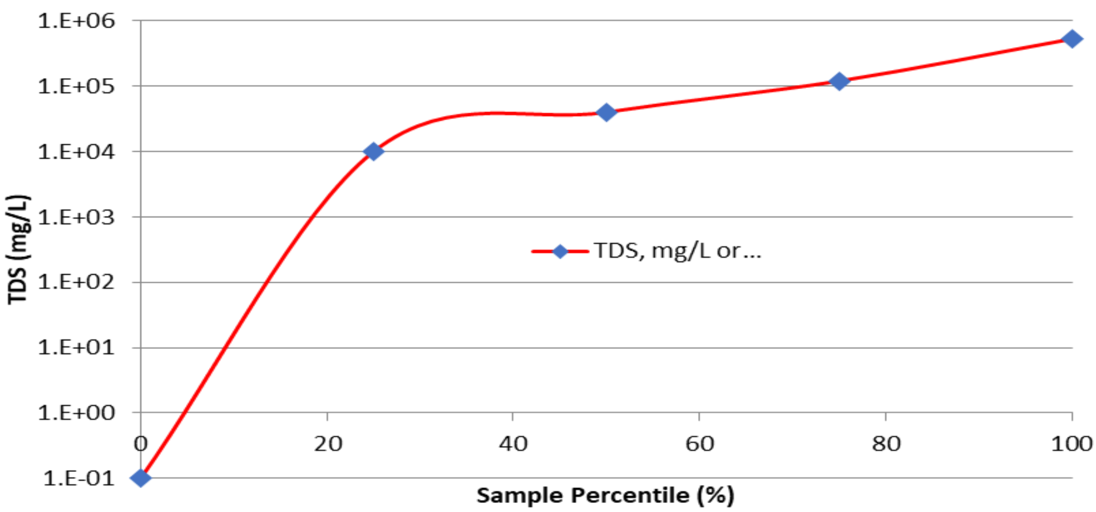

Figure 2. Total Dissolved Solids (TDS, mg/L or ppm) vs. Sample Percentile in typical produced water samples.

The objective of the Solar-FGRD process is to maximize potable water and minimize waste streams including brine and burner flue gas hydrocarbons. In the Chen et al., 2016 work [11], a potable water recovery of 36% (62.9 bbl/hr of potable water) is achieved, with 669.2 bbl/hr of waste streams (113.2 bbl/hr brine and 556 bbl/hr of cooling water). The process intake is 720 bbl/hr. The potable water revenue is $4,628,433/yr and the waste disposal cost is $10,258,836/yr. The Ejector based FGR-TVC (thermal vapor compression) process proposed by Mazumder et al. [13] could save about

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33% capital cost and 16% operating cost per year, compared with the compressor-based FGR-TVC process. The Solar-FGRD process simulation and economic evaluation develops on previous work in the literature [11,13] and integrates advances in solar thermal and photovoltaic technology to optimize produced water desalination coupled with flare gas recovery [18,20]. Unlike the previous works which only dealt with operating costs analysis, comprehensive economic analysis and greenhouse gas (GHG) analysis are carried in this study. Dinani et al. [12] reported an optimization of the natural gas liquid (NGL) product plus the outlet gas (mainly methane) utilization (after FGR) for South Iran oil and gas fields. They concluded the best approach would be 93% of the methane gas going to enhanced oil recovery and 7% used for power generation. However, their paper addresses a different scope of work, and the results cannot be directly compared to this study.

2. Methodology

2.1. Process Description

The Solar-FGRD process as shown in Figure 3 and Table 1 was modeled with Aspen Plus Version 11 [17] and is summarized as follows:

- A feed (INTAKE) of 52 bbl/hr pretreated produced water (metals and sludge removed) at 60 °F & 0 psig containing 131,260 mg/L TDS with 28.9 % Na^+, 9.6% $Ca^{2+,}$ and 61.5% Cl^- is pumped (P1) at 30 psig (via stream INTAKE1) into a cooler (COOLER) which raises the temperature of the feed to 110 °F.
- The stream (PREHEAT) exits COOLER at 110 °F and is further pre-heated through a solar-powered heater (SOLAR) to 145 °F. The solar heat input is 600,000 Btu/hr. The pre-heated stream exits SOLAR as FEED1
- The 52 bbl/hr preheated produced water (FEED1) flows through an evaporator (HX1B) which generates a two-phase stream (FEED) of 59 mol% vapor, at 291 °F. The HX1B exchanger heat input (Q3) is 13,000,000 Btu/hr.
- The FEED stream is heated further via a second evaporator (EVAP) which increases the temperature of FEED from 291 °F to 310 °F and increases the vapor fraction from 59 mol% to 74 mol%. The heated two-phase stream exits EVAP as WATERHOT.
- Then, a separator (SEPARATR) flashes the WATERHOT stream into a 100% vapor stream (POTABLEV). This stream is free of TDS and is considered pure water. The separator also generates a 100% liquid stream BRINEHOT which contains TDS.
- The liquid stream exiting the separator (BRINEHOT) is at 310 °F and contains 503,268 mg/L TDS with 28.9 % Na^+, 9.6% $Ca^{2+,}$ and 61.5% Cl^-. The stream is cooled to 80 °F via COOLER and then the cooled stream (BRINE1) is pumped to storage via pump P3 at 30 psig. The produced water intake is used to cool the hot brine stream. The final waste brine liquid stream BRINE comprises 29.8wt% of the produced water feed. This waste stream will need to be disposed of at a subsurface injection site.
- The pure water vapor stream (POTABLEV) at 310 °F is condensed to 99.91mol% liquid at 212 °F via exchanger HX1A. Q1 represents the 13,000,000 Btu/hr of heat removed. The heat removed from the potable water vapor is used to preheat the produced water feed stream in HX1B. The condensed potable water (POTABLEL) is further cooled to 70 °F via an air-cooler (AIRCOOL), which removes 3,270,934 Btu/hr of heat (Q2). The cooled potable water stream (POTABLE1) is pumped to storage via pump P2 at 30 psig. The final product stream POTABLE is distilled water without TDS for sale and comprises 70.2wt% of the produced water feed.
- The primary heat source for the desalination is stream FUELGAS, which is the recovered gas from the production well at 150 lb/hr, 60 °F, 50 psig, and consists of 65.3 wt% methane, 24.8% ethane, 9.01% propane, 0.575% nitrogen, and 0.226% carbon dioxide. A VALVE is used to drop the pressure to 20 psig. The stream LP-GAS is fed to a burner COMBUST which is modelled as an equilibrium reactor based on Gibbs free energy minimization. The COMBUST combustion reactions and conversions are shown in Figure 4. Excess air (35%) at 60 °F, 5 psig, 3507 lb/hr consisting of 21% oxygen, 78% nitrogen, and 1% argon is fed to the burner via stream AIR.

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- The burner outlet stream HOTGAS is heated to 2904 °F and contains combustion gases. This stream is fed to the evaporator (EVAP) and transfers heat such that the flue gas stream (FLUEGAS) releases into the atmosphere at 320 °F.
- The flue gas waste stream flow is 3657 lb/hr (11.43 wt% carbon dioxide, 8.45 wt% water, 72.22 wt% nitrogen, 6.27 wt% oxygen, 0 wt% carbon monoxide, 0 wt% nitrous oxide, 0 wt% nitrogen dioxide, 0.29 wt% nitric oxide, 0 wt% methane, 0 wt% ethane, and 0 wt% propane).
- The modelled destruction efficiency for the flue gas is ~100% methane, ~100% ethane, and ~100% propane.
- The heat for exchanger SOLAR is provided via solar energy through a solar collector module as shown in Figure 5. The solar heat input is 600,000 Btu/hr. The Solar-FGRD process utilizes a novel solar beam splitter that can split sunlight into photovoltaic (500 < λ <900 nm), infrared (λ >900 nm), and higher-energy (λ<500 nm) spectrums. Figures 6 and 7 illustrate the novel two-stage solar beam splitter technology [18].

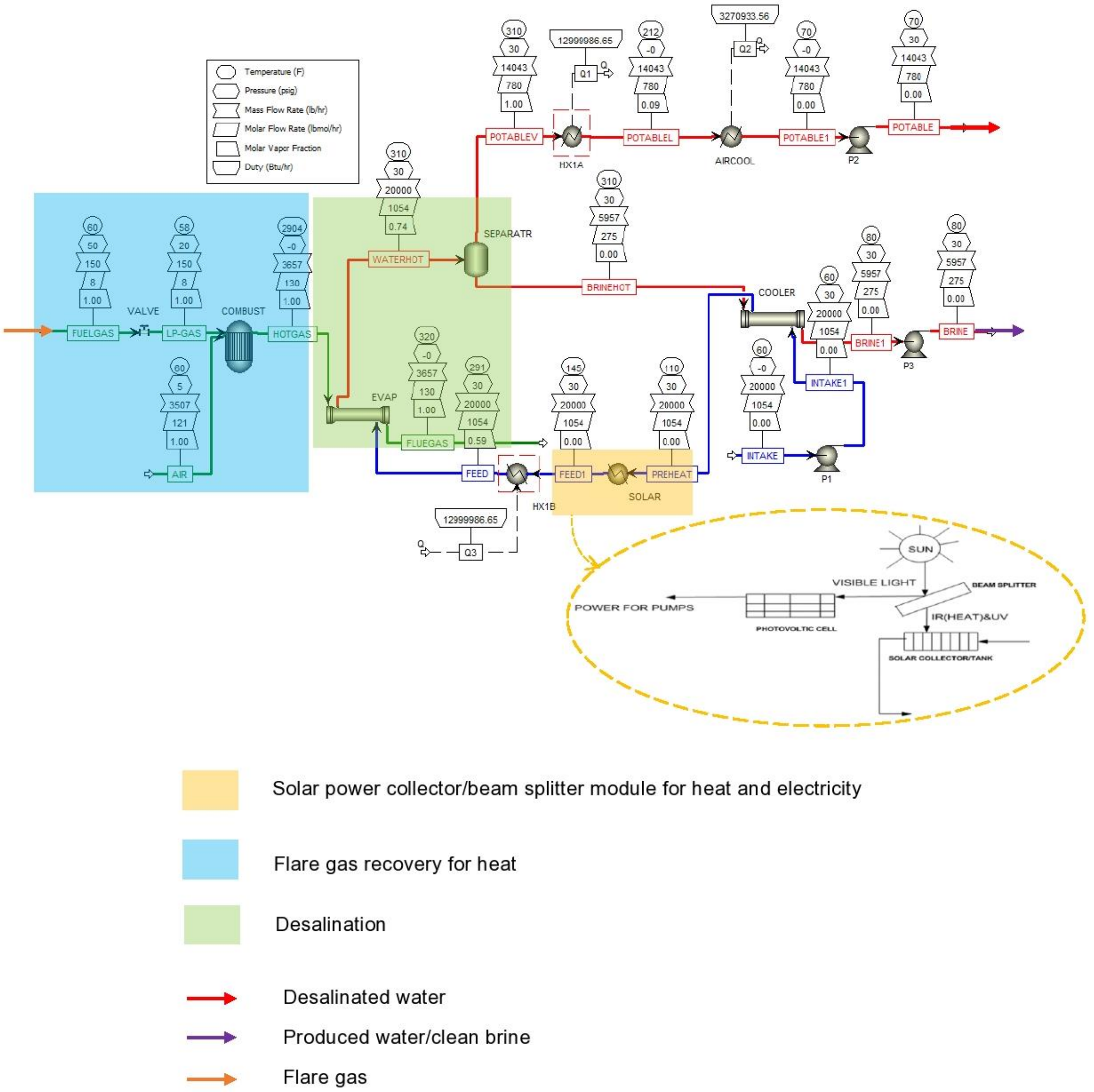

Figure 3. Aspen Plus simulation for the Solar-FGRD process with improved heat integration.

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Table 1. Heat and material balance of the Solar-FGRD process.

Stream	Temperature	Pressure	Enthalpy Flow	Mass Flow	Volume Flow	Mole vapor fraction
	F	psig	Btu/hr	lb/hr	bbl/hr	
AIR	60.0	5	-14804	3507.1	-	1.000
BRINE	80.0	30	-31680818	5956.7	12.5	0.000
BRINE1	80.0	30	-31680818	5956.7	12.5	0.000
BRINEHOT	309.8	30	-30830429	5956.7	13.6	0.000
FEED	291.4	30	-113325111	20000.0	-	0.589
FEED1	144.6	30	-126325087	20000.0	53.2	0.000
FLUEGAS	320.0	0	-3148450	3657.1	-	1.000
FUELGAS	60.0	50	-257062	150.0	-	1.000
HOTGAS	2904.1	0	-271866	3657.1	-	1.000
INTAKE	60.0	0	-127777647	20000.0	52.2	0.000
INTAKE1	60.0	30	-127775476	20000.0	52.2	0.000
LP-GAS	57.7	20	-257062	150.0	-	1.000
POTABLE	70.0	30	-95886918	14043.3	40.1	0.000
POTABLE1	70.0	0	-95888587	14043.3	40.1	0.000
POTABLEL	212.0	0	-92617653	14043.3	6356.8	0.093
POTABLEV	309.8	30	-79617653	14043.3	-	1.000
PREHEAT	109.6	30	-126925087	20000.0	52.7	0.000
WATERHOT	309.8	30	-110448527	20000.0	-	0.739

$$\textit{Burner reaction 1} \qquad CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \qquad (1)$$
$$\textit{Burner reaction 2} \qquad C_2H_6 + 3.5O_2 \rightarrow 3H_2O + 2CO_2 \qquad (2)$$
$$\textit{Burner reaction 3} \qquad C_3H_8 + 5O_2 \rightarrow 4H_2O + 3CO_2 \qquad (3)$$

Figure 4. Combustion reactions in BURNER.

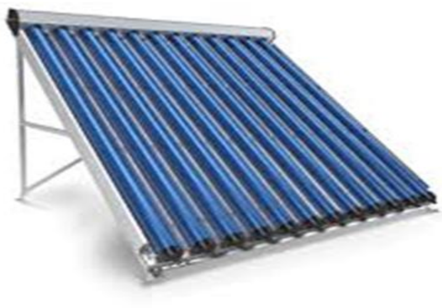

Figure 5. Solar collector module for produced water preheat.

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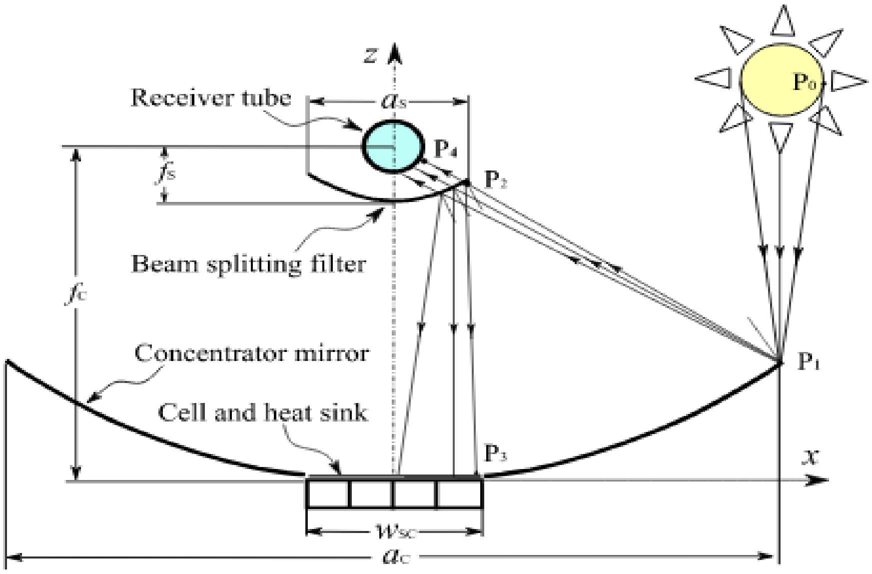

Figure 6. Two-stage parabolic trough concentrating photovoltaic/thermal system with a spectral beam splitter.

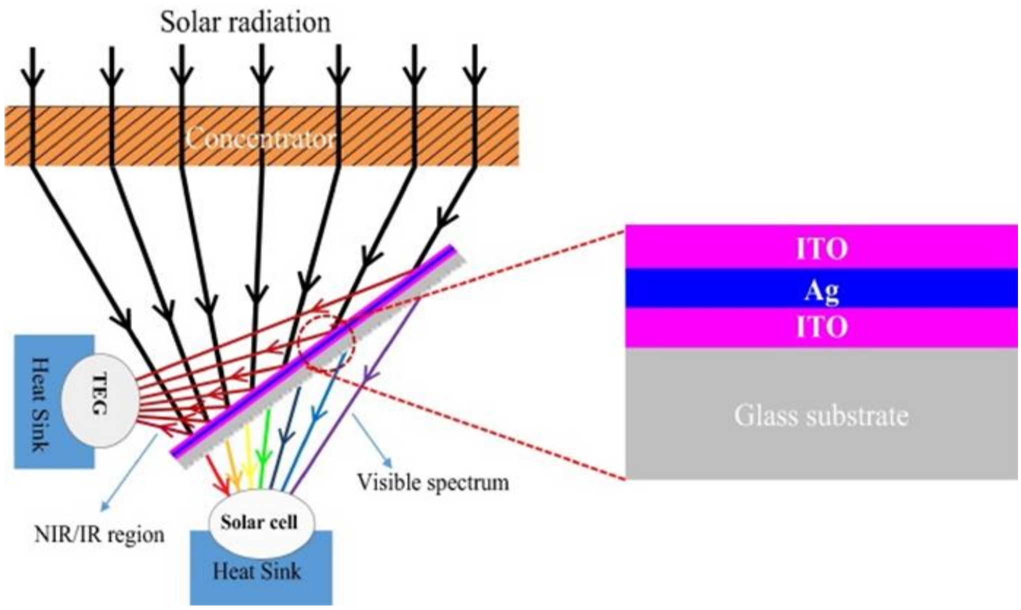

Figure 7. Solar concentrator and beam splitter into electromagnetic spectra.

2.2. Financial and Economic Feasibility Analysis

2.2.1. Aspen Process Economic Analyzer (APEA)

Aspen Process Economic Analyzer (APEA) was used to evaluate total capital cost, total operating cost, total raw material cost, and total product sales [21]. We further investigated several investment evaluation tools: cash flow, net present value (NPV), and payback period (PBP) [22–29].

2.2.2. Cash Flow

Cash flow tables were constructed for a project period of 20 years. Cash flows are determined from design capacity, sales, capital costs, working capital, total operating cost, taxes, & interest payments. These tables also present cumulative cash flow, present value, and present worth factor [23].

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2.2.3. Net Present Value (NPV)

The NPV measures the profitability of a project or investment by assessing the difference between the present value of expected cash inflows and the present value of cash outflows over the investment's time horizon. A positive NPV, as shown in Equation (1), indicates a potentially profitable investment, while a negative NPV suggests that the investment may not be financially viable [24,25,28].

$$\mathbf{NPV} = \sum_{t=0}^{n} \frac{R_t}{(i+1)^t} \quad (1)$$

where R_t = Net cash flow (in–out flows) during a single period t;
i = discount rate;
t = number of time periods.

2.2.4. The Payback Period (PBP)

The PBP method is an important method for capital budgeting or investment decision-making as it gives a more accurate approximation even with the non-uniform future cash flows, which is more likely in the real business world [22,27,29]. PBP is the point in time when the cumulative net cash flow becomes positive:

1. Calculate the cumulative net cash flow for each year. Start from the beginning of the project and sum the net cash flows up to that year.
2. Identify the latest year, denoted as "n", when the cumulative net cash flow becomes positive. This year is when the investment has been fully recovered.
3. To determine the exact point in the latest year n when the remaining original investment is paid back, use the following formula:

Exact Time in Year n = (Original Investment − Cumulative Net Cash Flow at the end of Year n-1)/Net Cash Flow in Year n (2)

3. Results and Discussion

3.1. Solar Heater Integration

To preheat the feed-produced water stream by 35 °F (from 110 °F to 145 °F), the thermal energy required is 175.8 kW. Assuming average solar insolation of 6.37 kWh/m²/day in the US Southwest [19], and solar energy heat recovery of 40%, the total solar collector area required is 1656 m². The Solar-FGRD process requires 20 kW to power the facility and the solar photovoltaic module assumes a 15% efficiency. While the photovoltaic module with beam splitter captures the visible spectrum for power generation, the thermal module captures the rest of the spectrum (~40%) for intake water pre-heating. The photovoltaic module area will match the solar collector area of 1655.9 m². The total excess photovoltaic electricity generated is 0.035 MW, which can be sold to the power grid as a revenue stream. The Solar-FGRD process requires 0.614 acres of the total area to install the plant and associated solar modules. Table 2 summarizes the solar thermal and photovoltaic calculations.

Table 2. Solar thermal and photovoltaic calculations.

Solar Insolation Permian Basin	
Total Solar Insolation (kWh/m²/day)	6.37
Total Solar Insolation (kWh/m²/year)	2,325.05
Solar Collector/Water Heater	
Solar Preheater ΔT (°F)	35
Water Flow Rate (bbl/day)	1254
Solar Preheater Thermal Energy Required (kW)	176

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Solar Preheater Thermal Energy Required (kWh/yr)	1,540,008
Solar Energy Heat Recovery	40%
Thermal Solar Insolation (kWh/m²/yr)	930
Solar Collector Efficiency	40%
Solar Collector Area Required (m²)	1,656
Solar Farm Area	
Gross Area Required (m²)	2484
Gross Area Required (acres)	0.61
Photovoltaic Module	
Electrical Energy Required (kW)	20
Electrical Energy Required AC (kWh/yr)	175,200
Photovoltaic Module Efficiency	15%
Electrical Solar Insolation (kWh/m²/year)	2,325
Photovoltaic Module Area (m²)	1,656
Inverter DC/AC Ratio	1.2
Photovoltaic Electricity Generated DC (kWh/yr)	577,503
Photovoltaic Electricity Generated AC (kWh/yr)	481,253
Excess Photovoltaic Electricity Generated AC (kWh/yr)	306,053
Excess Photovoltaic Electricity Generated AC (MW)	0.03

3.2. Salt Sensitivity Analysis

The base case produced water TDS concentration is 131,260 mg/L, with 28.9 % Na^+, 9.6% Ca^{2+}, and 61.5% Cl^-. The base case TDS concentration results in 76.8% potable water recovery, by volume. The TDS concentration was varied according to Figure 2, which illustrates the typical variance in produced water salinity. Table 3 and Figure 8 below demonstrate the capability of the Solar-FGRD process in handling various TDS concentrations as well as the resulting potable water recovery, which varies between 75.7-77.7%.

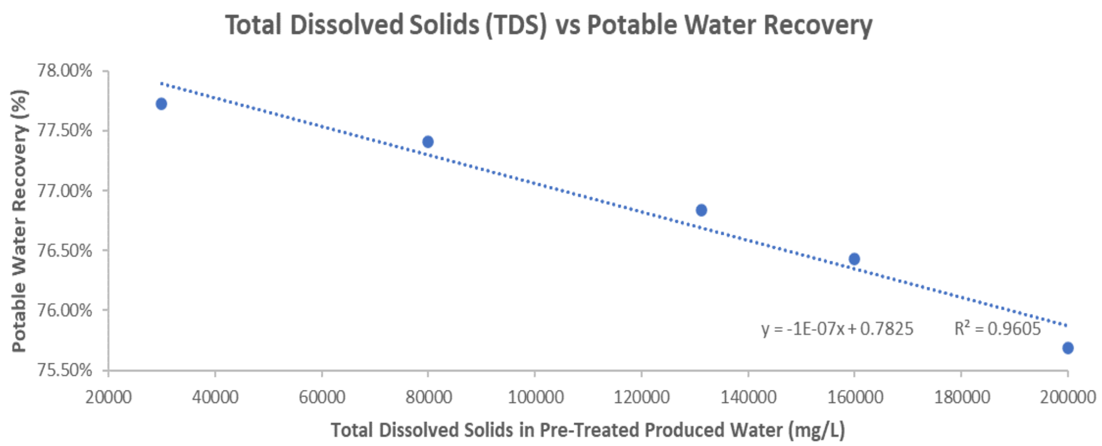

Figure 8. Percentage of potable water recovery via the Solar-FGRD process for various TDS concentrations.

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Table 3. Potable water recovery as a function of produced water TDS concentration.

Produced water feed				Potable water stream			Brine			Potable Water Recovery
density	TDS	mass flow	volume flow	density	mass flow	volume flow	density	mass flow	volume flow	
kg/m³	mg/L	kg/hr	bbl/hr	kg/m³	kg/hr	bbl/hr	kg/m³	kg/hr	bbl/hr	
1021.27	30000	8481.5	52.2374796	998.18	6443.5	40.603	1074.642	2628.4	15.384	77.73%
1056.82	80000	8776.7	52.2374796	998.18	6417.0	40.436	1211.498	2654.8	13.784	77.41%
1092.32	131260	9071.6	52.2374796	998.18	6370.0	40.140	1362.269	2701.9	12.475	76.84%
1111.92	160000	9234.4	52.2374796	998.18	6335.4	39.922	1450.398	2736.4	11.867	76.42%
1138.90	200000	9071.8	52.2374796	998.18	6274.1	39.536	1574.194	2797.8	11.179	75.68%

3.3. Financial and Economic Evaluation

In this section, we demonstrate the financial-economic feasibility of investment providing a comprehensive financial analysis including the best case, base case, and the worst-case scenarios. As shown in Table 4, the base case Solar-FGRD process generates $1,495,168/yr revenue through sales of potable/distilled water and excess solar electricity. Since the 20-year Net Present Value (NPV) is -$1,546,510, a tax credit is required for the base case to deem the project feasible to pursue. The annual cash flow is $42,993. As shown in Table 5, the NPV at year 20 is negative and the payback period for the project exceeds 20 years. Assumptions of the base case financial model include total investment of $5,099,096 (40% equity and 60% loan), 0% down payment on loan, 6% interest rate, $0.1/gal distilled water sales price, $0.06/kWh electricity sales price, and $1.75/bbl brine water disposal cost.

Table 4. The Solar-FGRD process financial model – base case.

Assumptions		
Capital Cost	$5,000,000.00	
Working Capital	$99,095.67	
Total Investment	$5,099,095.67	
Loan	$3,059,457.40	60%
Equity	$2,039,638.27	40%
Annual Interest Rate	6%	
Loan Payback Years	20	
Annual Loan Payment	$263,026.84	
Down payment	0%	
Payments per Year	12	
Operating Cycle	1	months
Revenue		
Produced Water Volume	1254	bbl/day
Distilled Water Recovery	76.84%	
Distilled Water Volume	963.34	bbl/day
Distilled Water Sales Price	$0.10	$/gal
Distilled Water Sales	$1,476,804.94	$/yr
Solar Electricity Generated	306052.5	kWh/yr
Electricity Sales Price	$0.06	$/kWh
Electricity Sales	$18,363.15	$/yr
Total Annual Revenue	$1,495,168.09	
Tax Credits	$0.00	$/yr
Cost		

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Produced Water Volume	1254	bbl/day
Distilled Water Recovery	76.84%	
Brine Water Volume	290.36	bbl/day
Brine Water Disposal Unit Cost	$1.75	$/bbl
Brine Water Disposal Total Cost	$185,465.48	$/yr
Solar Area Required	0.614	acre
Solar Farm Area Lease (1 acre)	500	$/month
Solar Farm Lease Cost	$3,682.57	$/yr
Operating Cost	$1,000,000.00	$/yr
Total Annual Cost	$1,189,148.05	

Table 5. The Solar-FGRD process Cash Flows – base case.

Cash Flows				
Year Count	**Cash Flow**	**Present Value**	**Present Worth Factor**	**Cumulative Cash Flow**
0	($2,039,638.27)	($2,039,638.27)	1	($2,039,638.27)
0	$0.00	$0.00	1	($2,039,638.27)
1	$42,993.20	$40,559.63	0.943396226	($1,996,645.06)
2	$42,993.20	$38,263.80	0.88999644	($1,953,651.86)
3	$42,993.20	$36,097.92	0.839619283	($1,910,658.65)
4	$42,993.20	$34,054.65	0.792093663	($1,867,665.45)
5	$42,993.20	$32,127.02	0.747258173	($1,824,672.24)
6	$42,993.20	$30,308.51	0.70496054	($1,781,679.04)
7	$42,993.20	$28,592.94	0.665057114	($1,738,685.83)
8	$42,993.20	$26,974.47	0.627412371	($1,695,692.63)
9	$42,993.20	$25,447.61	0.591898464	($1,652,699.43)
10	$42,993.20	$24,007.18	0.558394777	($1,609,706.22)
11	$42,993.20	$22,648.28	0.526787525	($1,566,713.02)
12	$42,993.20	$21,366.31	0.496969364	($1,523,719.81)
13	$42,993.20	$20,156.89	0.468839022	($1,480,726.61)
14	$42,993.20	$19,015.94	0.442300964	($1,437,733.40)
15	$42,993.20	$17,939.56	0.417265061	($1,394,740.20)
16	$42,993.20	$16,924.12	0.393646284	($1,351,746.99)
17	$42,993.20	$15,966.15	0.371364419	($1,308,753.79)
18	$42,993.20	$15,062.40	0.350343791	($1,265,760.58)
19	$42,993.20	$14,209.81	0.33051301	($1,222,767.38)
20	$42,993.20	$13,405.48	0.311804727	($1,179,774.17)
	NPV@Yr 20	($1,546,509.60)		
	Payback Period	>20	years	

Depending on project cash flows, revenues, and expenses, tax credits may or may not be needed for project feasibility. Table 6 highlights multiple cases (base case, worst case, and best case) for consideration. A higher potable water recovery percentage leads to greater revenue, in terms of potable water sales, and lower costs, in terms of third-party brine disposal costs. The financial model in Table 4 assumes a sales price of $0.1/gal for distilled water for drinking out of city drinking fountains or bottled consumption. This distilled water sales stream is dependent on demand for an additional volume of water to add to a municipality's current water supply. It is also likely that this

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sales price may be discounted if the water stream is used for general tap use at $0.024/gal (Current Water and Sewer Rates, 2024), such as irrigation or cleaning (worst-case scenario), instead of drinking. For the best-case scenario, the assumption for sales price is $0.2/gal for distilled drinking water. A market analysis of distilled water in Southwestern USA is being conducted to quantify the risk of receiving a discounted sales price for distilled water intended for drinking.

The tax credit is not needed for the best case but has to be provided for the base case and the worst-case scenarios. For the base case, $134,831.75/yr tax credit is provided for the proposed process, that is equivalent to 0.175 cent/kg for water conservation, 0.226 cent/kg for flare gas reduction, or $54.3/m^2/yr. for solar panel installation.

The cash flow and payback period are also determined by the capital cost and annual operating cost, which have currently been estimated in the financial model. The best-case scenario of cash flows and the payback period is demonstrated in Table 7.

Table 6. The Solar-FGRD process Financial Sensitivity Study.

	Base Case	**Worst Case**	**Best Case**
Capital Cost	$5,000,000	$7,000,000	$3,000,000
Annual Interest Rate	6%	7%	5%
Loan/Equity	60%/40%	60%/40%	60%/40%
Annual Loan Payment	$263,026.84	$396,282.33	$147,259.15
Distilled Water Sales Price ($/gal)	$0.10	$0.024	$0.20
Brine Water Disposal Cost ($/bbl)	$1.75	$1.75	$1.75
Without Tax Credit			
Annual Tax Credit	$0.00	$0.00	$0.00
Annual Cash Flow	$42,993.20	($1,212,634.05)	$1,635,565.83
20-Year NPV	($1,546,509.60)	($15,686,300.66)	$19,143,127.17
Pay Back Period	-	-	0.80
With Tax Credits (NPV = 0 for the base case)			
Annual Tax Credit	$134,831.75	$134,831.75	-
Annual Cash Flow	$177,824.96	($1,077,802.30)	-
20-Year NPV	$0.00	-	-
Pay Back Period	11.95	-	-
With Tax Credits (NPV=0 for the worst case)			
Annual Tax Credit	$1,480,675.81	$1,480,675.81	-
Annual Cash Flow	$1,523,669.01	$268,041.76	-
20-Year NPV	$15,436,725.24	$0.00	-
Pay Back Period	1.34	11.25	-

Table 7. The Solar-FGRD process Cash Flows – best case.

	Cash Flows			
Year Count	Cash Flow	Present Value	Present Worth Factor	Cumulative Cash Flow
0	($1,239,638.27)	($1,239,638.27)	1	($1,239,638.27)
0	$0.00	$0.00	1	($1,239,638.27)
1	$1,635,565.83	$1,557,681.75	0.952380952	$395,927.56
2	$1,635,565.83	$1,483,506.42	0.907029478	$2,031,493.40
3	$1,635,565.83	$1,412,863.26	0.863837599	$3,667,059.23
4	$1,635,565.83	$1,345,584.06	0.822702475	$5,302,625.06
5	$1,635,565.83	$1,281,508.63	0.783526166	$6,938,190.90
6	$1,635,565.83	$1,220,484.41	0.746215397	$8,573,756.73
7	$1,635,565.83	$1,162,366.10	0.71068133	$10,209,322.56
8	$1,635,565.83	$1,107,015.33	0.676839362	$11,844,888.39

9	$1,635,565.83	$1,054,300.32	0.644608916	$13,480,454.23
10	$1,635,565.83	$1,004,095.54	0.613913254	$15,116,020.06
11	$1,635,565.83	$956,281.47	0.584679289	$16,751,585.89
12	$1,635,565.83	$910,744.26	0.556837418	$18,387,151.73
13	$1,635,565.83	$867,375.48	0.530321351	$20,022,717.56
14	$1,635,565.83	$826,071.89	0.505067953	$21,658,283.39
15	$1,635,565.83	$786,735.13	0.481017098	$23,293,849.23
16	$1,635,565.83	$749,271.55	0.458111522	$24,929,415.06
17	$1,635,565.83	$713,591.96	0.436296688	$26,564,980.89
18	$1,635,565.83	$679,611.39	0.415520655	$28,200,546.72
19	$1,635,565.83	$647,248.94	0.395733957	$29,836,112.56
20	$1,635,565.83	$616,427.56	0.376889483	$31,471,678.39
	NPV	$19,143,127.17		
	Payback Period	0.80	years	

3.4. Environmental Impacts

The environmental impacts of the Solar-FGRD process are given in terms of greenhouse gases and wastewater streams reduction.

Greenhouse Gases (GHG)

The Solar-FGRD process burner combustion efficiency is 99.8%, in contrast with the typical well-maintained flare combustion efficiency (CE) of 98% (e.g., North Sea) and a CE of 80% observed in the Texas/North Dakota oil & gas fields. [7,8]. CE is defined as the hydrocarbon conversion to CO2:

$$\text{Combustion Efficiency (CE \%)} = \frac{\text{Mass of carbon converted to } CO_2}{\text{Mass of carbon fed as fuel}} \quad (4)$$

Another representation of the flare efficiency is the destruction and removal efficiency (DRE) as defined by each hydrocarbon species flared such as methane and ethane. DRE is referred to a particular parent compound in the fuel. For methane,

$$\text{DRE\% } (CH_4) = \frac{\text{Amount of CH4 fed} - \text{Amount of CH4in flue gas}}{\text{Amount of CH4 fed to the flare}} \quad (5)$$

With the Solar-FGRD's burner design and well-controlled operating temperatures, DRE of 99.99% can be achieved for methane, ethane, and propane. DRE of 98% for hydrocarbons can be realized for the same light hydrocarbons by flares operated under conditions representative of good industrial operating practices [6]. However, the open-air flaring in oil and gas fields is often unassisted and unattended and often results in a lower DRE. For example, the University of Michigan F3UEL project sampled flares in the Permian Basin, the Eagle Ford Shale, and the Bakken Formations from a Scientific Aviation Mooney aircraft, DRE of methane was found to be 91% on average. The contributing factors include inefficient flaring (as low as ~60% DRE caused by windy conditions, insufficient air mixing, or malfunction), or even unlit flares (3-5%) [3–5,7]. Table 8 summarizes the speciated greenhouse gas emissions of these three scenarios: solar-FGRD vs. open-air flaring in North Sea and the US.

The greenhouse gas (GHG) emissions for CO2 and unburnt hydrocarbons in terms of CO2 equivalent (CO2e) are given in Table 9. CO2e changes from 2442 metric ton per year (T/yr., North Dokota & Texas, USA) and 1545 T/yr (North Sea) to 1351 T/yr for the Solar-FGRD process. This represents a 45% and 13% CO2e reduction. Figure 9 shows the methane (line) and CO2e (column) emissions for the above- mentioned three scenarios.

Potable Water Recovery and Brine Reduction

The Solar-FGRD process also recovers 77% of produced water as potable water for sale or reuse, Table 10. Without flare gas recovery, 52.2 bbl/hr of produced water would need to be disposed of underground versus 12.1 bbl/hr with the Solar-FGRD process. In comparison, the prior FGR-TVG and FGR-ETVG processes reduce brine disposal by 36% [11,13].

Table 8. Speciated GHG emissions: Solar-FGRD vs. flaring scenarios.

		Produced Water to Potable			Gas Flaring (North Sea)			Gas Flaring (N. Dakota & Texas)				
	IN	OUT	DRE	CO2e	OUT	DRE	CO2e	OUT	DRE	CO2e	100-Y GWP	
	lb/hr	lb/hr		lb/hr	lb/hr		lb/hr	lb/hr		lb/hr		
Methane	98.9	0.01	0.9999	0.3	1.5	0.99	41.5	8.9	0.91	249.1	28.0	
Ethane	37.2	0.00	0.9999	0.0	0.8	0.98	8.0	3.3	0.91	34.1	10.2	
Propane	13.6	0.00	0.9999	0.0	0.4	0.97	3.9	1.2	0.91	11.6	9.5	
Carbon Dioxide	0.3	339.55	-	339.6	332.2		332.2	273.6		273.6	1.0	
Carbon Monoxide	0.0	0.50	-		1.7		3.3	23.0		46.0	2.0	
Nitrous Oxide	0.0	0.00	-		0.0			0.0				
Nitric Oxide	0.0	10.61	-		10.6			10.6				
Nitrogen Dioxide	0.0	0.00	-		0.0			0.0				
Total	150.0			339.9			388.8			614.5		
CE		0.998			0.976			0.804				

Table 9. Comparison of methane, carbon dioxide, and CO2 equivalent for the Solar-FGRD, North Sea flaring, and US flaring.

	Solar-FGRD	Flaring (North Sea)	Flaring (Texas & N. Dakota)
Methane (T/yr)	0.04	5.89	35.35
CO2 (T/yr)	1349.21	1319.81	1087.28
CO2e (T/yr)	1350.52	1545.05	2441.88
Potential % Reduction		13	45

* Flaring data from Texas and North Dokata Fields is used as the baseline.

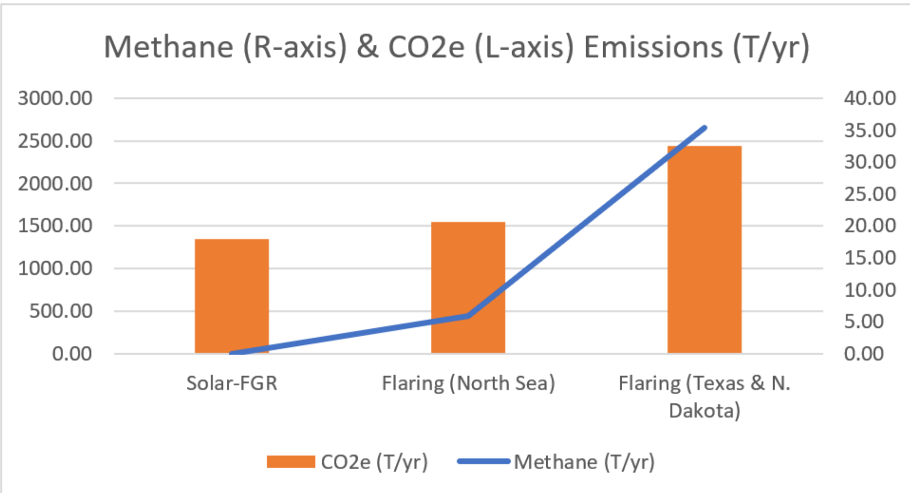

Figure 9. Comparison of methane and GHG (CO2e) emissions.

Table 10. Water recovery and brine reduction from the Solar-FGRD process.

	IN	OUT	Water Recovery/Brine Reduction
	bbl/hr	bbl/hr	
Brine/produced water	52.2	12.1	76.8%
Potable Water	0	40.1	76.8%

4. Conclusions

The Solar-Flare Gas Recovery-Desalination (Solar-FGRD) Process can desalinate pre-treated produced water with TDS between 30,000 – 200,000 mg/L. The process can achieve 76-78% potable water recovery with 0 mg/L TDS, which is a revenue-generating distilled water product for drinking as well as irrigation, cleaning, & household use. As such, it reduces brine disposal volume by 77%, from 52.2 bbl/hr to 12.1 bbl/hr, compared to Chen et al. & Mazumder et al.'s previous works (36%).

The photovoltaic module recovers ~100% of solar insolation with 15% photovoltaic efficiency for electricity generation and 40% recovered as thermal energy to pre-heat the produced water feed by 35 °F. The process eliminates reliance on the power grid for plant operations by generating excess solar power for sale which serves as a revenue stream.

The process burner combustion efficiency (CE) is 99.8%, in contrast with the well-maintained flare CE of 98% and some observed flare CE of 80%. In terms of the destruction and removal efficiency (DRE), the FGR burner has 99.99% DRE for light hydrocarbons such as methane whereas in flaring it can vary from 98±1% for well-maintained flares to ~91% for poorly maintained flares. The greenhouse gas (GHG) emissions for CO2 and unburnt hydrocarbons (i.e., methane) in terms of CO2 equivalent (CO2e) changes from 2442 metric ton per year (T/yr., North Dokota & Texas) or 1545 T/yr (North Sea) to 1351 T/yr for the Solar-FGRD process. This represents a 45% and 13% CO2e reduction.

The comprehensive base case financial analysis demonstrates the financial-economic feasibility of the investment project. Best-case and worst-case scenarios provide a realistic range that investors can consider before making investment decisions. The cash flow and payback period are also determined by the capital cost and annual operating cost. Depending on project cash flows, revenues, and expenses, tax credits may or may not be needed for project feasibility. The tax credit is not needed for the best case, which has a payback period of 0.8 year. Tax credit must be provided for the base case and the worst-case scenarios. For the base case, $134,831.75/yr tax credit is required at the minimum for the proposed process with a payback period of 11.95 year.

Supplementary Materials:

Author Contributions: D.C.: Conceptualization, Funding acquisition, Methodology, Project administration, Supervision, Writing—review and editing. F.A.: Investigation, Methodology, Software, Validation, Visualization, Writing—Original draft. G.S.: Funding acquisition, Methodology, Writing—review and editing. All authors have read and agreed to the published version of the manuscript.

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