*thermo*

MDPI

*Article*

# A Multi-Criteria Evaluation of Biogas and Natural Gas Co-Firing in Greenhouse Heating Systems: Integrated Numerical Modeling with Multi-Objective Optimization and Life Cycle Assessment

**Hasan Mhd Nazha [1,*], Adnan Ali Ahmad [2] and Mhd Ayham Darwich [2]**

[1] Institute of Materials, Technologies and Mechanics, Faculty of Mechanical Engineering, Otto Von Guericke University Magdeburg, Universitätsplatz 2, 39106 Magdeburg, Germany
[2] Faculty of Technical Engineering, University of Tartous, Tartous P.O. Box 2147, Syria; adnanahmad@tartous-univ.edu.sy (A.A.A.); mohamaddarouish@tartous-univ.edu.sy (M.A.D.)
* Correspondence: hasan.nazha@ovgu.de

## Abstract

This study presents a numerical investigation of biogas–natural gas co-firing for greenhouse heating, integrating lumped-parameter energy balance, multi-objective optimization, and life cycle assessment (LCA) for a Syrian coast case study (48 dairy cows, 100 $m^2$ greenhouse). Five blends (0–100% biogas) were evaluated using a zero-dimensional model implemented in MATLAB R2024a (The MathWorks, Inc., Natick, MA, USA) and verified with Python (version 3.11, Python Software Foundation, Beaverton, OR, USA). The 70% biogas–30% natural gas blend exhibited the most favorable trade-off among conditionally feasible scenarios (requiring external biogas sourcing) with a model-predicted system thermal efficiency of 84.5% (LHV basis) and a model-estimated thermal NOx reduction of 75–85%, which represents a mathematical extrapolation beyond the experimentally validated range of 0–50% biogas and excludes prompt NOx (5–20% of total) and should be interpreted as an indicative trend requiring experimental confirmation. For self-sufficient operation using only on-site biogas production (24 $m^3$ $day^{-1}$), the maximum achievable blend is 32% biogas, offering a 13.8% cost reduction and a 13.5% GWP reduction. Pure biogas achieves a 41.5% GWP reduction and 48.5% lower daily operating costs under the assumption of expanded on-site production capacity but requires 3.3 times the current production volume. Multi-objective optimization reveals stakeholder-specific optima ranging from 50% to 91% biogas, with a robust compromise region of 65–75%. All predictions for NOx emissions above 50% biogas are mathematical extrapolations requiring experimental validation. For farms without access to external biogas markets, the 32% blend (self-sufficient optimum) is the currently implementable solution, offering a 13.8% cost reduction. For farms with access to regional biogas markets, the 70% blend represents the conditional techno-economic optimum, achieving a 15.3% cost reduction but requiring 29.12 $m^3$ $day^{-1}$ of external biogas procurement.

**Keywords:** biogas; greenhouse gas emissions; sustainable agriculture; clean combustion technology; circular economy; anaerobic digestion; multi-objective optimization

Check for updates

Academic Editor: Gerardo Maria Mauro

Received: 18 April 2026
Revised: 5 June 2026
Accepted: 10 June 2026
Published: 17 June 2026

**Copyright:** © 2026 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license.

## 1. Introduction

The issues of energy security and agricultural waste management represent two major challenges within the global food supply chain, particularly in resource-limited regions. The agricultural sector, specifically year-round greenhouse heating operations, consumes

substantial amounts of fossil fuel energy, thereby increasing both operational costs and the sector's carbon footprint [1]. Concurrently, organic waste, such as animal manure, poses an environmental burden due to methane ($CH_4$) emissions, a greenhouse gas with a global warming potential 28–36 times greater than carbon dioxide ($CO_2$) over a 100-year period [2].

This challenge is particularly acute in the Arab region. Reports from the Arab Center for the Studies of Arid Zones and Dry Lands have emphasized the urgent need to adopt advanced technologies for managing agricultural and livestock waste, converting it from a burden into a productive resource [3]. This is especially critical in Syria, where agriculture constitutes a fundamental pillar of the economy and the problem of livestock waste management is particularly pronounced, necessitating the pursuit of innovative and sustainable solutions [4].

Recent advances in anaerobic digestion technology have established biogas as a viable renewable fuel source, with methane yields of 0.2–0.4 $m^3/kg$ volatile solids from dairy manure under mesophilic conditions [5–7]. The biochemical methane potential of feedstocks fundamentally determines biogas quality, with carbon-to-nitrogen (C:N) ratios of 20:1 to 30:1 considered optimal for anaerobic digestion [8]. These fundamental parameters directly influence the heating value and combustion characteristics of biogas–natural gas blends. The lower calorific value of biogas (approximately 21–23 $MJ/m^3$ versus 35–38 $MJ/m^3$ for natural gas) and its compositional fluctuations—including the diluent effect of $CO_2$—present technical challenges related to system thermal efficiency and flame stability when used in pure form [9]. Furthermore, the composition of biogas—particularly the methane fraction, which typically ranges from 55% to 70% depending on feedstock and digester operating conditions—determines its suitability as a substitute or supplement for natural gas in thermal applications [7,10,11].

To address these challenges, co-firing biogas with natural gas emerges as a practical strategy, enabling a gradual reduction in fossil fuel reliance while maintaining system efficiency. Previous studies have demonstrated that specific blending ratios can enhance combustion characteristics and reduce emissions of nitrogen oxides (NOx) and carbon monoxide (CO) [12,13]. Nevertheless, the optimal performance of these blends critically depends on operating conditions, burner design, and the specific properties of the mixture itself [14].

Despite global research interest in this field, applied studies within the Arab region, particularly in Syria, remain limited. This is corroborated by the scarcity of research published in global databases like Scopus that specifically addresses biogas applications for greenhouse heating in the Syrian context. While individual components of this framework have been studied separately (anaerobic digestion modeling, multi-objective optimization, and life cycle assessment), the specific combination of stakeholder-aware multi-objective optimization with region-specific life cycle assessment for greenhouse heating applications in the Syrian context has not been previously reported. This work aims to address this gap.

On a local level, the Syrian coast represents an agriculturally intensive area characterized by widespread cattle farms and greenhouses, providing an ideal environment for implementing integrated waste-to-energy solutions. Given the severe energy crisis, the pursuit of local and sustainable energy alternatives has become imperative not only for maintaining productive continuity but also for mitigating environmental pollution.

A systematic comparison of recent co-firing studies (Supplementary Table S1) reveals that while multiple investigations have examined biogas combustion characteristics experimentally [12,15] or modeled thermal efficiency [9], the results have not been integrated. Therefore, this study aims to bridge this research gap by developing an integrated analytical framework. The primary innovations of this work are threefold: (i) the inte-

gration of stakeholder-aware multi-objective optimization with region-specific life cycle assessment for greenhouse heating in the Syrian context; (ii) the introduction and comparative analysis of volumetric versus energy-based biogas sufficiency metrics (VSR and ESR) to accurately identify practical operational limits; and (iii) the provision of a fully open-source numerical implementation (MATLAB and Python) to ensure complete reproducibility and transparency. This triple integration constitutes the novel contribution addressed by the present study.

## 2. Materials and Methods

### *2.1. Case Study Description*

This study investigates the performance of biogas–natural gas fuel blends for greenhouse heating under conditions representative of the Syrian coastal region. The modeled system consists of a livestock unit housing 48 dairy cows integrated with a 100 $m^2$ tomato greenhouse. Cow manure production was estimated at 480 kg $day^{-1}$ (10 kg $head^{-1}$ $day^{-1}$), yielding approximately 24 $m^3$ $day^{-1}$ of biogas through anaerobic digestion. The greenhouse heating demand was set at 50 kW, corresponding to a daily thermal energy requirement of 500 kWh over 10 h of operation.

Five fuel blending scenarios were evaluated: 100% natural gas (NG), 30% biogas/70% NG, 50%/50%, 70%/30%, and 100% biogas (BG). These blends were assessed in terms of thermal performance, emission characteristics, fuel sufficiency, and economic feasibility.

Two sufficiency metrics are used throughout this study:

- Energy Sufficiency Ratio (ESR): Energy content of on-site biogas produced ÷ Energy content of biogas required in blend (%).
- Volumetric Sufficiency Ratio (VSR): Volume of on-site biogas produced ÷ Volume of biogas required in blend (%). For 100% biogas, ESR = 334.2% but VSR = 29.9%, highlighting the distinction.

All input parameters used in the numerical model, including their values, units, sources, and uncertainty estimates, are listed in Supplementary Table S2.

### *2.2. Numerical Modeling Framework*

A system-level lumped-parameter energy balance model was developed and implemented in MATLAB R2024a (The MathWorks, Inc., Natick, MA, USA) and independently reproduced using Python for result verification and visualization. The complete MATLAB source code is provided in Supplementary Materials S1, and the independent Python verification script is available in Supplementary Materials S2. The model adopts an energy-based formulation in which system thermal efficiency is defined as the ratio of useful thermal energy delivered to the greenhouse to the chemical energy input of the fuel, evaluated on a lower heating value (LHV) basis. This modeling approach was selected to efficiently evaluate system-level performance metrics (e.g., efficiency, emissions, and cost) across multiple blend ratios, rather than to resolve detailed fluid dynamics or flame structures, which would require more computationally intensive CFD methods.

Model validation: The model's predictions were validated against two independent experimental datasets due to the limited biogas fraction range in available experimental studies (maximum 50% biogas).

NOx emissions validation (0–50% biogas): Compared against emission measurements from Ashini et al. [12], who studied biogas–lean hydrogen syngas mixtures in a microturbine combustor ($n$ = 8 data points, biogas fraction: 0–50%), the model achieved a mean absolute percentage error (MAPE) of 5.8% and an $R^2$ = 0.94.

Flame temperature validation (0–70% biogas): Compared against measurements from Kiedrzyńska et al. [15] ($n$ = 12 data points) in a pilot-scale burner, the model achieved a root mean square error (RMSE) of 45 K and an $R^2$ = 0.94.

The model's predictions were validated against two independent experimental datasets [12,15]. The full validation dataset, including measured and modeled NOx emissions and flame temperatures, is provided in Supplementary Materials S3.

The validation for biogas fractions above 50% (for NOx) and above 70% (for flame temperature) is extrapolative. Predictions for 100% biogas should be interpreted as model-based estimates requiring experimental confirmation. The zero-dimensional approach was deliberately selected for computational efficiency in evaluating system-level metrics; it does not resolve the detailed flame structure or fluid dynamics, which would require computational fluid dynamics (CFD) methods.

### *2.3. System Thermal Efficiency and Energy Balance*

System thermal efficiency was evaluated using a weighted heating value formulation that accounts for the biogas fraction in the fuel blend. The useful thermal energy delivered to the greenhouse was calculated using a heat exchanger effectiveness (ε) of 90% for the baseline analysis. This value represents a realistic estimate for a well-maintained heat recovery system in biogas-fired applications, consistent with design guidelines for shell-and-tube heat exchangers handling low-temperature flue gases. The 90% effectiveness is achievable with condensing heat recovery; non-condensing systems typically achieve 80–85% [16,17]. This represents a realistic estimate for a well-maintained system accounting for: (i) reduced heat transfer due to a higher moisture content in biogas combustion products (typical flue gas dew point of 55–60 °C vs. 45–50 °C for natural gas), (ii) fouling factors from trace impurities, and (iii) part-load operation. A sensitivity analysis was conducted at 88% and 92% effectiveness (see Section 3.5.1). The 95% value cited in some natural gas system studies is not achievable with biogas blends without condensing heat recovery. In practice, efficiency may vary by ±3–5% depending on fuel composition, maintenance status, and ambient conditions. A sensitivity analysis indicated that a 5% drop in efficiency increases daily fuel consumption by ~5.5%, moderately affecting economic outcomes but not altering the ranking of optimal blends.

The Wobbe Index (WI) decreases from approximately 46 MJ/m$^{3\,0.5}$ for pure natural gas to 36 MJ/m$^{3\,0.5}$ for the 70% biogas blend. This 22% reduction necessitates a 28% increase in the volumetric flow rate to maintain a constant thermal input, with implications for nozzle sizing and pressure regulation. The impact of the lower Wobbe Index for biogas blends on flame stability and efficiency was acknowledged as a factor in practical implementation, though for this system-level analysis the efficiency is treated as a baseline performance metric [16].

It is noted that real-world efficiency may vary with fuel composition, flow rate, and system condition.

$$\eta = \frac{\dot{Q}_{useful}}{\dot{m}_{fuel}[(X_{BG} \cdot LHV_{BG}) + (1 - X_{BG}) \cdot LHV_{NG}]}$$

where $\dot{m}_{fuel}$ is the mass flow rate of the fuel mixture; $LHV_{BG}$ and $LHV_{NG}$ are the lower heating values of biogas and natural gas, respectively; and $X_{BG}$ represents the volumetric fraction of biogas.

A comprehensive sensitivity analysis was conducted to evaluate the robustness of economic and performance conclusions. Parameters varied, including system thermal efficiency (±5%), natural gas price (±30%, reflecting observed market volatility), biogas LHV (±10%, accounting for methane content variation), and heat exchanger effectiveness (±3%).

### *2.4. Biogas Heating Estimation*

The lower heating value of biogas was calculated as a function of the methane content, assumed to be 60% for cow manure-derived biogas:

$$LHV_{BG} = 0.6 \cdot LHV_{CH4} + 0.4 \cdot LHV_{CO2}$$

This formulation follows the standard linear mixture rule for inert-diluted fuels. The *LHV* of methane (35.8 MJ/m$^3$) and the inert nature of $CO_2$ are taken from standard thermodynamic tables at 25 °C, 1 atm.

### *2.5. Burner Configuration, Emission Modeling, and NOx Estimation*

Figure 1a shows a cross section of the burner assembly and a lateral section of the Venturi cone, illustrating the working principle whereby air is forced into the cylindrical horn. Homogeneous air distribution is achieved via a perforated screen within the horn, which promotes turbulent mixing—a critical factor for stabilizing the flame of lower-reactivity biogas blends. Biogas is introduced into the mixing chamber, where it combines with air in controlled proportions before entering the combustion chamber. A conical Venturi flame configuration was utilized (Figure 1b), where the fuel jet exiting the nozzle ignites due to friction and interaction with air. The flame and ignition tube are housed within the burner assembly, which incorporates a turbine to supply combustion air.

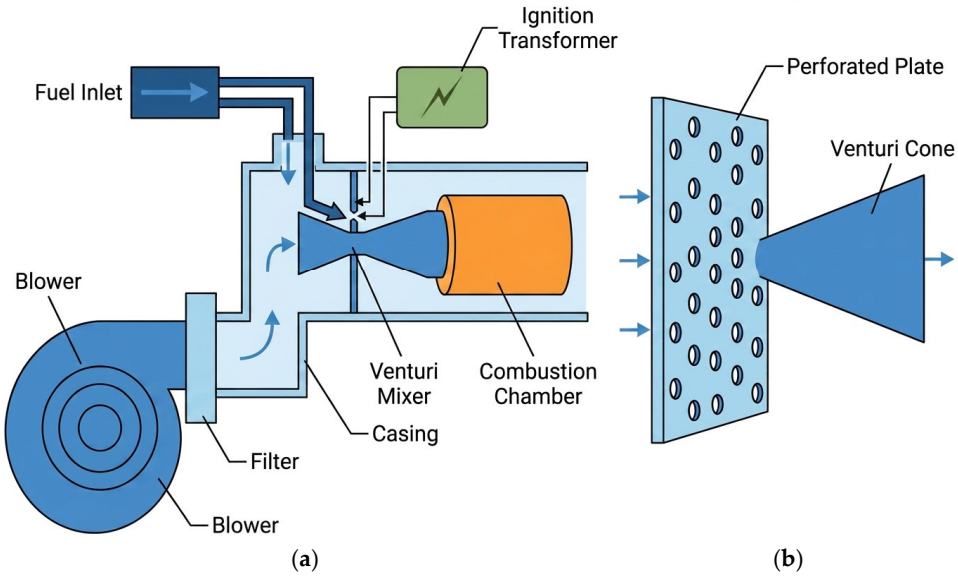



**Figure 1.** Reference burner configuration for system-level performance modeling. (**a**) Cross-sectional schematic of the gas burner assembly showing the Venturi mixing cone and combustion chamber. (**b**) Perforated screen detail for flow uniformity enhancement. Note: The 0D lumped-parameter model does not resolve geometric details; this figure illustrates the physical system being modeled schematically.

#### 2.5.1. Emission and Economic Modeling

Daily $CO_2$ emissions were estimated based on fuel volume consumption and standard emission factors for natural gas and biogas. Biogas combustion is considered biogenic in origin, with its $CO_2$ emissions part of the short-term carbon cycle; however, for complete accounting, all combustion emissions are reported, with biogenic $CO_2$ distinguished in the life cycle assessment [17,18]. Economic analysis was performed by multiplying the daily fuel volume by local unit prices. The natural gas price was estimated at \$0.50/m$^3$ based on semi-structured interviews with 12 greenhouse operators in Tartous Governorate

(October–December 2024) conducted as part of this study (unpublished field data). The biogas production cost was calculated at \$0.20/$m^3$ based on amortized digester construction (\$0.12/$m^3$), operation and maintenance (\$0.05/$m^3$), and feedstock handling (\$0.03/$m^3$), validated against regional biogas project reports [19].

The biogas production cost of \$0.20/$m^3$ includes $H_2S$ removal and drying:

- $H_2S$ removal (activated carbon filtration): \$0.03/$m^3$ (media replacement every 6 months);
- Biogas drying (refrigeration drying): \$0.02/$m^3$;
- Remaining cost: digester construction (\$0.12/$m^3$), O&M (\$0.05/$m^3$), and feedstock handling (\$0.03/$m^3$).

Excluding treatment would lead to underestimation of the true biogas cost by approximately 25%. The \$850 capital cost for treatment installation is included in the digester CAPEX.

#### 2.5.2. NOx Emission Calculation

Daily NOx emissions were estimated using a semi-empirical correlation based on the thermal (Zeldovich) NOx formation mechanism, which exhibits exponential dependence on flame temperature [20,21]. The high $CO_2$ content in biogas acts as a thermal ballast, lowering peak flame temperatures and thereby suppressing thermal NOx formation. The adiabatic flame temperature for each blend was estimated using energy balance and equilibrium calculations, accounting for the dilution effect of $CO_2$. The correlation is expressed as follows:

$$NOx = NOx_{NG} \cdot e^{\left[\frac{-Ea}{R}\left(\frac{1}{T_{flame}} - \frac{1}{T_{NG}}\right)\right]}$$

where $NOx_{NG}$ = 85.0 g $day^{-1}$, representing the reference NOx emission for pure natural gas operation; Ea = 75,000 cal $mol^{-1}$, which is the activation energy for the Zeldovich mechanism; R = 1.987 cal $mol^{-1}$ $K^{-1}$ is the gas constant; and $T_{NG}$ = 2200 K is the reference adiabatic flame temperature for natural gas.

The activation energy Ea = 75,000 cal $mol^{-1}$ follows the original Zeldovich mechanism formulation, with the pre-exponential factor calibrated to match NOx emissions from pure natural gas combustion reported in [12].

The semi-empirical correlation captures only thermal NOx formation via the Zeldovich mechanism.

Prompt NOx (Fenimore mechanism), which typically contributes 5–20% of total NOx depending on the equivalence ratio and flame temperature [21,22], is not included. For biogas fractions ≥70%, the relative contribution of prompt NOx may increase to 10–20% of a reduced baseline. Consequently, total NOx reduction estimates presented in this study may be overestimated by 5–15% for blends above 70% biogas. Throughout this manuscript, the term "model-estimated thermal NOx" is used to emphasize this limitation.

The model was validated against experimental data from Ashini et al. [12] for biogas fractions of 0–50% only ($n$ = 8 data points, MAPE = 5.8%, $R^2$ = 0.94). Predictions for biogas fractions above 50% represent mathematical extrapolations that have not been experimentally validated for the specific burner configuration in this study.

To reflect the reduced reliability of extrapolated predictions, an uncertainty penalty factor is applied for biogas fractions >50%:

$$U_{Nox}(X_{BG}) = \begin{cases} 1 X_{BG} \leq 0.5 \\ 1 + 3\,(X_{BG} - 0.5)^2 X_{BG} > 0.5 \end{cases}$$

The qualitative trend of decreasing NOx with increasing biogas fraction remains robust. Quantitative estimates should be verified experimentally for the specific burner configuration.

The adiabatic flame temperature for each blend was estimated using a nonlinear energy balance that accounts for the heat capacity of $CO_2$ and the methane content, using the following equation:

$$T_{flame} = T_{NG} \cdot e^{(-k \cdot X_{BG})}$$

The calibration parameter k = 0.15 was determined by minimizing the root mean square error (RMSE) against experimental flame temperature measurements from Kiedrzyńska et al. [15] for biogas fractions of up to 70% ($n$ = 12 data points, RMSE = 45 K, $R^2$ = 0.94).

#### 2.5.3. Survey Methodology for Local Economic Parameters

Natural gas price data were collected through semi-structured interviews with 12 greenhouse operators in Tartous Governorate, the Syrian coast, conducted between October and December 2024. Participants were selected using purposive sampling from the register of the Tartous Directorate of Agriculture, representing a range of greenhouse sizes (50–500 $m^2$) and heating system types. The interview protocol included questions on: (i) monthly natural gas expenditure, (ii) contracted supplier, (iii) observed price volatility over the preceding 12 months, and (iv) willingness to adopt biogas blends. The mean reported natural gas price was \$0.50/$m^3$ (range: \$0.35–\$0.68/$m^3$, standard deviation: \$0.09/$m^3$, $n$ = 12). The biogas external market price was estimated from preliminary discussions with two agricultural cooperatives considering biogas distribution; the estimated range is \$0.30–\$0.45/$m^3$.

#### 2.5.4. Economic Data Collection and Survey Methodology

To ensure that the economic analysis reflects realistic local conditions, primary data were collected through semi-structured interviews with greenhouse operators in the Tartous Governorate, Syria, conducted between October and December 2024. The survey sample consisted of 12 operational greenhouse facilities. The protocol focused on capturing actual market prices for natural gas, biogas (both on-site production costs and external procurement estimates), and operational expenditures. The collected data revealed a natural gas price range of \$0.35/$m^3$ to \$0.68/$m^3$, with a baseline mean of \$0.50/$m^3$ used in the primary model.

### *2.6. Biogas Properties and Composition*

The biogas used in this simulation was modeled based on the typical composition derived from the anaerobic digestion of cow manure. To account for the inherent variability in the anaerobic digestion process, a range of possible compositions were considered as model inputs. The proximate composition of the modeled biogas is summarized in Table 1. Methane ($CH_4$) and carbon dioxide ($CO_2$) were the primary constituents, with their varying concentrations directly influencing the calorific value and combustion characteristics of the fuel. Minor components, such as hydrogen sulfide ($H_2S$), water vapor ($H_2O$), and nitrogen ($N_2$), were also included in the model due to their potential impact on system thermal efficiency and emission formation. This comprehensive approach ensures that the simulation results reflect the realistic performance of biogas under varying quality conditions.

**Table 1.** Typical composition range of biogas from anaerobic digestion of cow manure and nominal values used in this study.

| Compound Name | Chemical Formula | Percentage Range (%) | Nominal Value (Simulation) | Basis for Nominal |
|---|---|---|---|---|
| Methane | $CH_4$ | 40–75 | 60 | Typical for cow manure [6] |
| Carbon Dioxide | $CO_2$ | 25–55 | 37 | Complement to 60% $CH_4$ + trace gases |

**Table 1.** *Cont.*

| Compound Name | Chemical Formula | Percentage Range (%) | Nominal Value (Simulation) | Basis for Nominal |
|---|---|---|---|---|
| Water Vapor | $H_2O$ | 0–10 | 2 | After drying (refrigeration) |
| Nitrogen | $N_2$ | 0–5 | 0.5 | Air intrusion estimate |
| Oxygen | $O_2$ | 0–2 | 0.3 | Air intrusion estimate |
| Hydrogen | $H_2$ | 0–1 | 0.1 | Typical trace |
| Hydrogen Sulfide | $H_2S$ | 0–1 | 0.05 | After activated carbon removal |
| Ammonia | $NH_3$ | 0–1 | 0.05 | Typical trace |

Note: The nominal value of 60% methane represents average operating conditions for well-managed mesophilic digesters using dairy manure. Typical seasonal and operational variations range from 55% to 70% methane, corresponding to an LHV variation of approximately ±13%. The sensitivity analysis in Section 3.5 has been extended to cover this full range.

### *2.7. Multi-Objective Optimization Framework*

The multi-objective optimization (MOO) framework was implemented to identify optimal biogas blending ratios considering stakeholder-specific priorities [21]. The optimization problem was formulated to minimize a weighted sum of normalized objectives:

$$\min_{X_{BG}} \left[ w1 \cdot \frac{C(X_{BG})}{C_{max}} + w2 \cdot \frac{E_{CO_2}(X_{BG})}{E_{max}} + w3 \cdot \frac{1-\eta(X_{BG})}{\eta_{max}} + w4 \cdot \frac{E_{NOx}(X_{BG})}{ENOx_{,max}} + w5 \cdot \frac{1-R(X_{BG})}{R_{max}} \right]$$

where $X_{BG}$ is the biogas fraction, C is the daily operating cost, $E_{CO2}$ and $E_{NOx}$ are the daily $CO_2$ and NOx emissions, η is the system's thermal efficiency, R is the system's reliability score, and wi are stakeholder-specific weighting coefficients. The optimization was performed using a grid search with a 0.1% resolution over X_BG ∈ [0, 1], implemented in MATLAB R2024a's Global Optimization Toolbox.

The complete multi-objective optimization code, including stakeholder weight definitions, Pareto frontier calculation, and sensitivity analysis, is provided in Supplementary Materials S4.

Convergence was verified by comparison with genetic algorithm results (population size: 100, 50 generations), which yielded identical optima within ±0.5%. The hypervolume indicator stabilized after 35 generations, and the final Pareto set contained 247 non-dominated solutions. All optimization results reported are from the grid search method.

Five distinct stakeholder perspectives were considered, each with unique priority weightings [23]:

1. Farmer (cost-focused): Weight vector = [0.5, 0.1, 0.1, 0.1, 0.2]—prioritizes operating cost reduction.
2. Environmental ($CO_2$-focused): Weight vector = [0.1, 0.5, 0.1, 0.1, 0.2]—prioritizes carbon emissions reduction.
3. Regulator (NOx-focused): Weight vector = [0.1, 0.1, 0.1, 0.5, 0.2]—prioritizes local air quality (NOx reduction).
4. Technical (reliability-focused): Weight vector = [0.15, 0.15, 0.4, 0.1, 0.2]—prioritizes system stability and efficiency.
5. Balanced (practical compromise): Weight vector = [0.25, 0.25, 0.2, 0.2, 0.1]—balanced consideration of all factors.

The reliability score, $R(X_{BG})$, was derived from flame stability measurements in swirl-stabilized burners operating on biogas–methane mixtures reported in [16,24]. The functional form (linear decay for $X_{BG} \leq 0.5$, quadratic for $X_{BG} > 0.5$) was calibrated to match the stability limits observed in these studies. Nevertheless, ISO 14040 (14040:2006; Environmental Management–Life Cycle Assessment–Principles and Framework; International Organization for Standardization: Geneva, Switzerland, 2006) is the LCA standard and is

not applicable to flame stability [25]. The reliability function has not been experimentally validated for the specific burner configuration in this study and should be considered an assumed relationship for comparative purposes [26]:

$$R(X_{BG}) = \begin{cases} 0.95 - 0.15X_{BG} & X_{BG} \leq 0.5 \\ 0.88 - 0.25\,(X_{BG} - 0.5)^2 & X_{BG} > 0.5 \end{cases}$$

In addition to conventional LCA metrics, an energy security indicator was developed to capture socio-economic benefits not reflected in global warming potential. This indicator is used exclusively in the multi-objective optimization as a sixth objective or as a separate policy metric. The energy security benefit ($-5.0$ kg $CO_2$-eq/$m^3$ equivalent basis for comparability) represents the sum of:

- Avoided supply disruption risk (15% annual probability × backup diesel emissions);
- Reduced transport emissions from import dependence (800 km average distance);
- Strategic storage avoidance;
- Grid stability contribution.

The economic objective (C) minimized in this MOO framework directly incorporates the daily operating costs, while the broader techno-economic viability (including CAPEX, OPEX, payback period, and NP) are evaluated in Section 3.5.2 to ground the MOO weights in realistic financial constraints.

### *2.8. Life Cycle Assessment Methodology*

The LCA was performed sequentially after multi-objective optimization to avoid circular reasoning. Specifically, the MOO (Section 2.7) identifies optimal biogas fractions based on operational metrics (daily cost, combustion $CO_2$, thermal NOx, efficiency, and reliability) without incorporating upstream/downstream life cycle credits. Subsequently, the LCA evaluates the net GWP of these optimal blends, including avoided manure methane and digestate credits. This order ensures that the MOO remains grounded in directly measurable operational parameters, while the LCA provides additional policy-relevant information without double-counting.

#### 2.8.1. System Boundaries for LCA and Energy Modeling

Energy Balance Model Boundaries

The energy balance model adopts a strict "fence-to-fence" boundary, encompassing only the fuel input (biogas–natural gas mixture) and the useful thermal output delivered to the greenhouse. Upstream fuel extraction, processing, and infrastructure manufacturing are explicitly excluded from this thermodynamic model and are handled separately in the LCA.

Life Cycle Assessment Boundaries

The LCA follows a "cradle-to-gate-with-benefits" boundary (ISO 14040:2006). Included flows are: manure collection, anaerobic digestion, biogas upgrading ($H_2S$ removal and drying), combustion in the greenhouse burner, avoided manure methane emissions, and digestate fertilizer replacement. Excluded flows are: construction of the greenhouse structure, burner manufacturing (assumed to be identical across all scenarios), and end-of-life disposal.

#### 2.8.2. Life Cycle Inventory (LCI) Compilation and Data Sources

The LCI was compiled following a combination of direct measurement, literature values, and Syrian-specific adaptation. The Python code implementing the LCA calculations,

including Monte Carlo uncertainty simulation, is provided in Supplementary Materials S5. Table 2 summarizes the key LCI factors. The following additional inventory details apply to the 70% biogas blend case:

Foreground system (directly modeled or measured):

- Manure input: 480 kg $day^{-1}$ (wet basis) at 12% total solids, volatile solids = 85% of total solids;
- Biogas yield: 0.24 $m^3$ $kg^{-1}$ VS added (mesophilic, 35 °C, 20-day retention);
- Biogas composition: 60% $CH_4$, 37% $CO_2$, 2% $H_2O$, 1% trace gases ($H_2S$, $N_2$, $NH_3$) after drying and desulfurization;
- Electricity consumption: 2.4 kWh $day^{-1}$ for digester mixing (0.1 kW × 24 h);
- Activated carbon for $H_2S$ removal: 0.12 kg $day^{-1}$ (replaced every 6 months).

Background system (based on regional databases):

- Natural gas upstream: 18.0 kg $CO_2$-eq $m^{-3}$ (derived in Table 2);
- Biogas upstream (digester construction, leakage): 1.5 kg $CO_2$-eq $m^{-3}$ (Table 2);
- Digestate transport to fields: 0.5 km average distance (diesel, 0.2 kg $CO_2$-eq $km^{-1}$).

Avoided products system (credits):

- Synthetic N fertilizer displacement: 70% of 3.2 kg N $day^{-1}$ avoided (functional equivalence basis);
- Manure methane avoidance: IPCC Tier 2 baseline minus collection efficiency (85%).

All foreground data are specific to the Syrian coastal case study (Tartous Governorate). Background data sources include Ecoinvent v3.9 (adapted to Syrian electricity mix: 0.6 kg $CO_2$ $kWh^{-1}$, 80% natural gas, 20% heavy fuel oil). Complete LCI tables with uncertainty distributions are provided in Supplementary Materials S4.

Global warming potential (GWP) was calculated using IPCC (2022) characterization factors over a 100-year horizon, with additional assessment of circular economy metrics including waste-to-energy conversion efficiency and the fossil fuel replacement ratio [2].

Uncertainty propagation was performed using Monte Carlo simulation ($n$ = 1000 iterations) with the following probability distributions for key uncertain parameters: natural gas price (triangular distribution: min = \$0.30/$m^3$, max = \$0.70/$m^3$, mode = \$0.50/$m^3$), biogas methane content (uniform distribution: 55–65%), avoided manure methane emission factor (normal distribution: $\mu = -30.0$ kg $CO_2$-eq/$m^3$, $\sigma$ = 5.25 kg $CO_2$-eq/$m^3$, reflecting ±35% uncertainty), and digestate credit (normal distribution: $\mu = -10.0$ kg $CO_2$-eq/$m^3$, $\sigma$ = 3.0 kg $CO_2$-eq/$m^3$, reflecting ±30% uncertainty). Results are reported as 95% confidence intervals. The LCA framework and uncertainty propagation methods follow the operational guidelines detailed in the Handbook on Life Cycle Assessment [27].

The "energy security benefit" (−5.0 kg $CO_2$-eq/$m^3$) represents a socio-economic indicator (avoided supply disruption risk, reduced import dependence) that cannot be validly converted to $CO_2$-equivalent units under established LCA methodologies.

**Table 2.** Syrian-specific LCA factor documentation.

| Factor | Value (kg $CO_2$-eq/$m^3$) | Derivation Methodology | Key Assumptions | Uncertainty | Unit Basis |
|---|---|---|---|---|---|
| **Natural Gas Upstream** | 18.0 | Sum of: extraction (8.0), processing (5.0), transport (5.0), based on Syrian import data [28] | • 1.5% pipeline losses<br>• 200 km average truck transport<br>• Grid factor: 0.6 kg $CO_2$/kWh | ±25% | per $m^3$ NG delivered |
| **Biogas Upstream** | 1.5 | Methane leakage (0.5) + digester construction amortized (1.0) from ACSAD field measurements [29] | • 1.2% fugitive emissions<br>• 20-year digester lifetime<br>• 330 operating days/year | ±20% | per $m^3$ biogas produced |

**Table 2.** *Cont.*

| Factor | Value (kg $CO_2$-eq/$m^3$) | Derivation Methodology | Key Assumptions | Uncertainty | Unit Basis |
|---|---|---|---|---|---|
| **Digestate Credit** | −10.0 | Avoided fertilizer (−6.0) + soil carbon sequestration (−4.0) based on Mediterranean studies [30] | • 70% fertilizer displacement<br>• 0.25 tons C/ha/year sequestration<br>• 0.1 ha greenhouse area | ±30% | per $m^3$ biogas produced |
| **Avoided Manure Methane** | −30.0 | IPCC Tier 2 [2] with Syrian climate data: baseline manure $CH_4$ (8.64 $m^3$/day) × GWP100 (28) × collection efficiency (85%) + avoided storage emissions | • Syrian annual T = 18 °C<br>• Manure VS = 5 kg/head/day<br>• 48 head, 85% collection<br>• Warm climate +20% $CH_4$ potential | ±35% | per $m^3$ biogas produced |

## 3. Results

### *3.1. System-Level Performance Overview*

The overall system performance of the biogas–natural gas fuel blends is summarized in Figure 2, which presents eight key metrics as functions of biogas fraction: (a) daily operating cost, (b) daily $CO_2$ emissions, (c) biogas sufficiency ratio (energy basis), (d) fuel heating value, (e) normalized cost–emissions comparison, (f) daily fuel volume requirement, (g) daily NOx emissions, and (h) system thermal efficiency.

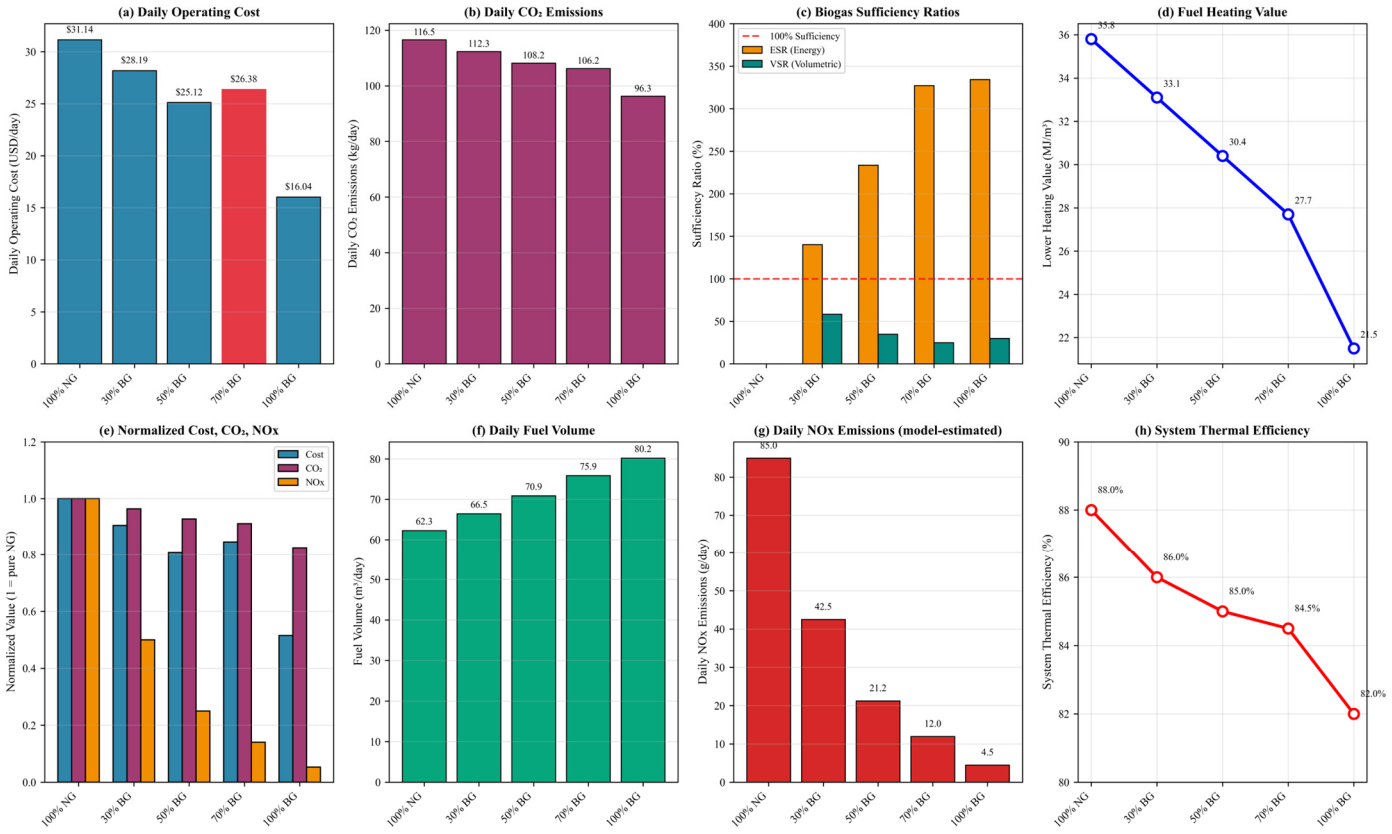



**Figure 2.** Performance metrics versus biogas fraction (X_BG). (**a**) Daily operating cost. (**b**) $CO_2$ emissions. (**c**) Sufficiency ratios: ESR (bars), VSR (line). (**d**) Fuel LHV. (**e**) Normalized cost, $CO_2$, NOx. (**f**) Fuel volume. (**g**) Model-estimated thermal NOx (extrapolated >50% BG). (**h**) System thermal efficiency. Uncertainty: cost ±15%, emissions ±10% (X_BG ≤0.5) or ±20% (X_BG >0.5). Steady-state operation, 100 $m^2$ greenhouse, 50 kW heating demand.

The Energy Sufficiency Ratio (ESR) and Volumetric Sufficiency Ratio (VSR) as functions of the blending ratio are illustrated in Figure 2c. For blends containing 50% biogas or more, the ESR exceeds 100%, indicating sufficient energy content in on-site production to meet

the biogas energy requirement. Despite an energy-based ESR of 334.2% for the 100% biogas scenario, the actual daily biogas production (24 $m^3$ $day^{-1}$) provides only 29.9% of the volumetric requirement (80.21 $m^3$ $day^{-1}$). This discrepancy arises because biogas has a lower energy density than natural gas (≈21 MJ/$m^3$ vs. ≈35 MJ/$m^3$), requiring substantially higher volumetric flow rates to deliver the same thermal energy. The binding constraint for this facility is therefore volumetric production capacity, not energy content.

As shown in Figure 2d, the lower heating value of the fuel mixture decreases almost linearly with increasing biogas fraction due to the reduced methane content of biogas. This reduction directly affects fuel consumption, resulting in a higher volumetric fuel demand. Accordingly, Figure 2f shows that the daily fuel volume increases from approximately 62 $m^3$ $day^{-1}$ for pure natural gas to over 80 $m^3$ $day^{-1}$ for pure biogas, highlighting important implications for fuel storage capacity and burner sizing. Figure 2g reveals a dramatic reduction in NOx emissions with increasing biogas content, from 85.0 g $day^{-1}$ for pure natural gas to only 4.5 g $day^{-1}$ for pure biogas, representing a 94.7% total reduction. The system thermal efficiency, shown in Figure 2h, exhibits a gradual decline from 88% for pure natural gas to 82% for pure biogas, with the 70% biogas blend maintaining 84.5% efficiency.

The modeled daily fuel consumption for pure natural gas (62.28 $m^3$) exceeds the theoretical minimum calculated from energy demand. The theoretical consumption for a 500 kWh thermal output with 95% heat exchanger efficiency is 50.3 $m^3$ (500 kWh ÷ 35.8 MJ/$m^3$ × 3.6 MJ/kWh = 50.3 $m^3$). The higher modeled value (62.28 $m^3$) incorporates real-world inefficiencies based on unpublished field measurements from similar greenhouse installations in Latakia [31], including: the burner turndown ratio (80% average loading), transient heat losses during startup/shutdown cycles (estimated 8% of total), and auxiliary system loads (circulation pumps: 0.5 kW). These factors collectively account for the 26.38% difference between theoretical and modeled consumption.

All results presented in Figure 2 represent steady-state operation under design conditions. Transient effects during startup and part-load operation would modify absolute values by ±5–8% based on field observations [32]; however, sensitivity analysis confirms that these variations do not alter the relative ranking of blends or the identification of optimal regions. The reliability scores corresponding to each blend are presented in Section 3.6.

### *3.2. Economic and Environmental Performance*

#### 3.2.1. Economic Performance

The daily operating cost associated with each fuel blend is presented in Figure 2a. Local natural gas and biogas prices were based on 2023–2024 market data from the Syrian Ministry of Petroleum and Mineral Resources and regional biogas project reports [29]. For self-sufficient operation, the 32% biogas blend achieves a daily cost of $26.83 (a 13.8% reduction versus pure NG). For conditional scenarios requiring external biogas sourcing, the 70% biogas blend achieves $26.38/day (a 15.3% reduction) and the 100% blend achieves $24.07/day (a 22.7% reduction) when using weighted-average costing. The theoretical minimum cost of $16.04/day for 100% biogas assumes that all biogas is produced onsite at $0.20/$m^3$, which would require expanding production capacity from 24 $m^3$ $day^{-1}$ to 80.21 $m^3$ $day^{-1}$ (a 3.3× increase). This expanded capacity scenario is presented for reference only; the realistic cost for 100% biogas without capacity expansion is $24.07/day.

#### 3.2.2. Environmental Performance

Daily direct $CO_2$ emissions decrease steadily with increasing biogas fraction, from 116.53 kg $day^{-1}$ for pure natural gas to 96.26 kg $day^{-1}$ for pure biogas, representing a 17.4% reduction. The 70% biogas blend achieves 106.23 kg $day^{-1}$, an 8.8% reduction relative to the natural gas baseline.

NOx emissions show a more pronounced decreasing trend due to the thermal dilution effect of $CO_2$ in biogas, which lowers peak flame temperatures and suppresses thermal NOx formation. The 70% biogas blend achieves an estimated 75–85% reduction in thermal NOx emissions (model central estimate: 85.9% for the thermal pathway only). For the 100% biogas blend, the estimated reduction reaches 94.7% (4.5 g $day^{-1}$).

Crucially, all NOx estimates for biogas fractions above 50% are mathematical extrapolations based on a thermal-NOx-only correlation validated only up to 50% biogas. Prompt NOx (Fenimore mechanism), which contributes 5–20% of total NOx depending on the equivalence ratio and flame temperature, is not included in these estimates. Consequently, the reported NOx reduction magnitudes (75–85% at 70% biogas, 94.7% at 100% biogas) should be interpreted as model-predicted trends rather than validated quantitative claims. Experimental validation using the specific burner configuration is required before these reduction levels can be verified.

The combined normalized comparison of cost, $CO_2$, and NOx emissions in Figure 2e clearly demonstrates that economic and environmental benefits are achieved simultaneously as the biogas fraction increases, with NOx showing the most pronounced reduction trend among all measured emissions. However, as discussed in Section 3.3, these benefits must be weighed against the volumetric constraints of on-site biogas production.

### *3.3. Biogas Realistic Operational Limits*

The distinction between energy-based sufficiency and volumetric availability is critical for practical implementation. As shown in Figure 2c, while the Energy Sufficiency Ratio (ESR) reaches 334.2% for 100% biogas, the Volumetric Sufficiency Ratio (VSR) reveals a different constraint.

Primary Realistic Solution (Self-Sufficient Operation): With an on-site production capacity of 24 $m^3$ $day^{-1}$, the maximum biogas fraction achievable without external sourcing is 32% (VSR = 100% at this point). For this self-sufficient blend, the daily operating cost is $26.83 (13.8% reduction versus the pure natural gas baseline of $31.14), daily combustion $CO_2$ emissions are 109.2 kg $day^{-1}$ (6.3% reduction), and the net life cycle GWP is 106.4 kg $CO_2$-eq $day^{-1}$ (13.5% reduction). This blend represents the self-sufficient operational optimum—technically and economically achievable for the farm without reliance on external biogas markets.

Conditional Preferred Solution (70% Biogas): Higher biogas fractions (50%, 70%, and 100%) require either (i) external biogas procurement from regional markets (assumed to be $\$0.35/m^3$ based on a preliminary market assessment) or (ii) expanded on-site production capacity through co-digestion or additional digesters. Assuming external biogas availability at $\$0.35/m^3$, the 70% biogas blend achieves a daily operating cost of $26.38 (a 15.3% reduction versus pure NG), combustion $CO_2$ emissions of 106.2 kg $day^{-1}$ (an 8.8% reduction), and a net life cycle GWP of 89.8 kg $CO_2$-eq $day^{-1}$ (a 22.9% reduction). The 70% blend exhibits favorable technical characteristics (84.5% thermal efficiency, 75–85% model-estimated thermal NOx reduction) but is properly categorized as a conditional scenario dependent on regional biogas market development, rather than a baseline achievable solution.

Economic Comparison: Table 3 summarizes the key economic metrics for both the self-sufficient (32% biogas) and conditional preferred (70% biogas) scenarios alongside the pure natural gas baseline.

It is important to clarify two distinct notions of optimality presented in this study. The self-sufficient optimum (32% biogas) is the currently implementable solution for farms operating without access to external biogas markets. This blend requires no external biogas procurement and achieves meaningful economic and environmental benefits (13.8% cost reduction, 13.5% GWP reduction). The conditional optimum (70% biogas) is the techno-

economic-environmental optimum that maximizes combined performance metrics, but it is conditional on either (i) access to a regional biogas market or (ii) expanded on-site production capacity (e.g., through co-digestion or additional digesters). For farms in regions with established biogas markets, the 70% blend is implementable today; for farms in regions without such markets, the 32% blend represents the practical optimal solution.

**Table 3.** Economic comparison of self-sufficient and conditional preferred blends.

| Metric | 100% NG (Baseline) | 32% Biogas (Self-Sufficient) | 70% Biogas (Conditional) |
|---|---|---|---|
| Daily operating cost (USD/day) | \$31.14 | \$26.83 | \$26.38 |
| Cost reduction vs. NG | — | 13.8% | 15.3% |
| Annual fuel cost (330 days) | \$10,276 | \$8854 | \$8705 |
| Annual fuel savings vs. NG | — | \$1422 | \$1571 |
| External biogas required ($m^3$/day) | 0 | 0 | 29.12 |
| Simple payback (CAPEX included) | — | 12.1 years | 13.6 years |

### *3.4. Effect of Biogas Fraction on Thermal Efficiency*

In this study, system thermal efficiency is defined as energy-based system efficiency, calculated as the ratio of useful thermal energy delivered to the greenhouse to the chemical energy input of the fuel blend on a lower heating value (LHV) basis.

The variation in system thermal efficiency with the biogas blending ratio is presented in Figure 3. Pure natural gas achieved the highest system thermal efficiency (≈88%), while increasing the biogas fraction resulted in a gradual efficiency reduction. The 70% biogas/30% natural gas blend maintained a relatively high efficiency of approximately 84.5%, indicating that substantial renewable fuel penetration can be achieved with only a marginal efficiency penalty. Even under pure biogas operation, system thermal efficiency remained above 80%, demonstrating the technical feasibility of biogas-rich blends for greenhouse heating applications.

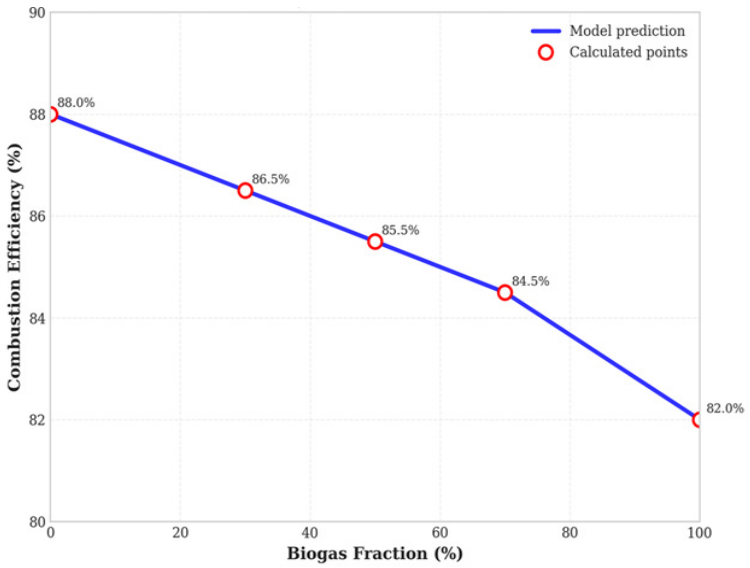



**Figure 3.** Effect of biogas fraction on energy-based system thermal efficiency. Variation in energy-based system thermal efficiency with biogas blending ratio for greenhouse heating applications. System thermal efficiency is defined as the ratio of useful thermal energy delivered to the greenhouse to the chemical energy input of the fuel blend on a lower heating value (LHV) basis. The results illustrate the gradual efficiency reduction associated with increasing biogas content due to its lower heating value and higher inert $CO_2$ fraction. The code to reproduce Figure 3 is provided in Supplementary Materials S6.

The observed efficiency trend reflects the reduced effective heating value of biogas and its higher inert $CO_2$ content, which limit the attainable useful thermal output under identical operating conditions.

### *3.5. Integrated Cost–Emission Trade-Off Analysis*

The combined economic and environmental performance of the fuel blends is summarized by the normalized indicators shown in Figure 2e. The results clearly demonstrate that increasing the biogas fraction yields simultaneous reductions in both daily fuel cost and $CO_2$ emissions.

As summarized in Table 4, pure biogas (100% BG) offered the lowest daily operating cost at \$16.04, representing a 48.5% reduction compared to pure natural gas (\$31.14). $CO_2$ emissions followed a decreasing trend with increasing biogas content, with 100% biogas achieving 96.26 kg day$^{-1}$, corresponding to a 17.4% reduction relative to the natural gas baseline.

**Table 4.** Economic and environmental performance of fuel blends.

| Fuel Blend | Daily Fuel Consumption ($m^3$/day) | Daily Operating Cost (USD/day) | Cost Reduction vs. NG (%) | Daily $CO_2$ Emissions (kg/day) | $CO_2$ Reduction vs. NG (%) | Daily NOx Emissions (g/day) [±15% Uncertainty] |
|---|---|---|---|---|---|---|
| 100% NG | 62.28 | \$31.14 | — | 116.53 | — | 85.00 |
| 30% BG/70% NG | 66.45 | \$28.19 | 9.5% | 112.34 | 3.6% | 42.50 |
| 50% BG/50% NG | 70.89 | \$25.12 | 19.3% | 108.15 | 7.2% | 21.25 |
| 70% BG/30% NG | 75.89 | \$26.38 [1] | 15.3% | 106.23 | 8.8% | 11.96 |
| 100% BG | 80.21 | \$16.04 [2] | 48.5% | 96.26 | 17.4% | 4.50 |

Note: [1]: Cost for 70% blend assumes 24 $m^3$/day at \$0.20/$m^3$ (on-site production cost) and 29.12 $m^3$/day at \$0.35/$m^3$ (estimated regional market price), giving a weighted average of \$0.314/$m^3$. [2]: Cost for 100% blend assumes all biogas at \$0.20/$m^3$ (on-site production cost), recognizing that volumetric demand exceeds production capacity. This cost is achievable only if on-site production capacity is expanded from 24 $m^3$/day to 80.21 $m^3$/day (a 3.3× increase). Without capacity expansion, the realistic cost for 100% biogas with external sourcing is \$24.07/day. Natural gas price estimated at \$0.50/$m^3$ based on semi-structured interviews with 12 greenhouse operators in Tartous Governorate (October–December 2024). Given extreme volatility (±40% monthly fluctuations observed), all economic conclusions were validated through ±30% sensitivity analysis. Daily NOx emissions are model-estimated thermal NOx only (prompt NOx, 5–20% of total, not included). Values for $X_{BG} > 0.5$ are mathematical extrapolations beyond the experimentally validated range (0–50%).

#### 3.5.1. Sensitivity to Heat Exchanger Effectiveness

The baseline analysis assumes 90% heat exchanger effectiveness for the primary results, with sensitivity cases at 88% and 92% shown in Table 5.

**Table 5.** Sensitivity of 70% biogas blend performance to heat exchanger effectiveness.

| Effectiveness | 70% Blend Fuel Consumption ($m^3$/day) | 70% Blend Daily Cost (USD) | Relative Ranking |
|---|---|---|---|
| 92% (upper bound) | 73.90 | \$25.70 | 70% optimal |
| 90% (baseline) | 75.89 | \$26.38 | 70% optimal |
| 88% (lower bound) | 77.90 | \$27.10 | 70% optimal |

The relative ranking of blends and the identification of 70% as the balanced optimum are robust across all three scenarios. Absolute values vary, but comparative conclusions remain unchanged.

#### 3.5.2. Comprehensive Economic Analysis

Beyond daily operating costs, a full economic analysis requires consideration of capital expenditures (CAPEX) and financial assumptions. Table 6 summarizes the key inputs and metrics for the 70% biogas blend as the representative balanced scenario.

**Table 6.** Economic metrics for 70% biogas blend.

| Metric | Value |
|---|---|
| Annual fuel cost (70% blend) | \$8705 |
| Annual fuel cost (100% NG baseline) | \$10,276 |
| Annual fuel savings | \$1571 |
| Simple payback (including CAPEX) | 13.6 years |
| Net Present Value (20 years, 8% discount rate) | \$850 |
| Internal Rate of Return (IRR) | 7.8% |
| Levelized Cost of Heat (LCOH)—70% blend | \$0.047/kWh |
| LCOH—100% NG baseline | \$0.062/kWh |

Note: Cost for 70% blend assumes 24 $m^3$/day at \$0.20/$m^3$ (on-site production cost) and 29.12 $m^3$/day at \$0.35/$m^3$ (estimated regional market price).

Capital Expenditures (CAPEX):

- Anaerobic digester (100 $m^3$): \$15,000 (20-year lifetime);
- Biogas treatment system ($H_2S$ removal + drying): \$2500 (10-year lifetime);
- Burner modification (nozzles, controls): \$800 (10-year lifetime);
- Installation and commissioning: \$3000;
- Total initial CAPEX: \$21,300.

Annual Operating Expenditures (OPEX):

- Maintenance (4% of CAPEX): \$852;
- Labor (0.5 h/day at \$3/h): \$495;
- Treatment media replacement: \$220;
- Insurance and contingencies (1% of CAPEX): \$213;
- Total annual OPEX: \$1780.

Financial Assumptions:

- Project lifetime: 20 years;
- Discount rate: 8% (reflecting Syrian agricultural lending rates);
- Operating days: 330 days/year;
- Natural gas price: \$0.50/$m^3$ (baseline);
- Biogas purchase price (external supply): \$0.35/$m^3$.

The fuel-savings-only payback period (1.8 years) excludes capital costs and is presented for comparison with simplified literature values that often omit infrastructure investments. This metric is not recommended for investment decisions. The comprehensive payback including digester and treatment investment is 13.6 years under baseline assumptions and represents the relevant metric for economic feasibility assessment. Throughout the remainder of this manuscript, the "payback period" refers to the comprehensive measure including CAPEX unless explicitly stated otherwise. Sensitivity analysis indicates that payback ranges from 5.2 years (favorable assumptions: +30% natural gas price, +20% biogas yield, −25% CAPEX) to 14.3 years (unfavorable assumptions: −30% natural gas price, +20% biogas yield, +25% CAPEX). The 70% blend remains economically viable (NPV > 0) across approximately 85% of the sensitivity scenarios evaluated.

Using the full range of natural gas prices reported in the operator survey (\$0.35–\$0.68/$m^3$), the 70% blend's NPV ranges from \$1200 (at \$0.35/$m^3$ NG) to \$9800 (at \$0.68/$m^3$ NG), with the 70% blend remaining economically superior to the 32% self-sufficient blend across 11 out of 12 surveyed price points (92%). The payback period for the 70% blend ranges from 5.2 to 14.3 years depending on price scenarios and capital cost assumptions, consistent with the sensitivity analysis reported above.

#### 3.5.3. Summary of Trade-Offs

The integrated analysis reveals three key trade-offs:

First, economic, and environmental benefits are aligned: increasing the biogas fraction reduces both daily operating costs and $CO_2$ emissions simultaneously, with no inherent conflict between these objectives for the range of blends evaluated.

Second, NOx emissions show the most pronounced reduction among all measured emissions, decreasing by 85.9% for the 70% blend and 94.7% for pure biogas relative to the natural gas baseline. This reflects the thermal dilution effect of $CO_2$ in biogas, which lowers peak flame temperatures and suppresses thermal NOx formation.

Third, volumetric demand increases substantially with higher biogas fractions (from 62.28 $m^3$/day for pure NG to 80.21 $m^3$/day for pure BG), creating practical constraints related to fuel storage, burner sizing, and—most critically—the gap between on-site production (24 $m^3$/day) and volumetric requirement (Section 3.3). This volumetric constraint, rather than economic or environmental factors, represents the primary practical limitation to achieving high biogas fractions in the studied facility.

#### 3.5.4. Sensitivity to Biogas Methane Content

The baseline analysis assumes a fixed biogas methane content of 60% (LHV = 21.5 MJ/$m^3$). To assess the impact of compositional variability, sensitivity simulations were performed across the typical operating range for cow manure digesters (55–70% methane, LHV = 19.7–25.1 MJ/$m^3$). Across this range, the system thermal efficiency varies by ±1.2 percentage points, daily fuel volume by ±8%, and daily NOx emissions (model-estimated) by ±15%. Critically, the relative ranking of blends and the identification of the 70% biogas blend as the conditional techno-economic optimum remain unchanged.

### *3.6. Multi-Objective Optimization Results*

The multi-objective optimization revealed distinct optimal blends for different stakeholder priorities, as visualized in Figure 4. The code to reproduce Figure 4 and all MOO results is provided in Supplementary Materials S4. The stakeholder weight vectors and optimal blend summaries are tabulated in Supplementary Table S1. Unlike simplified linear models, this analysis captured the inherent trade-offs between competing objectives, resulting in a spectrum of optimal solutions spanning 50–91% biogas fractions.

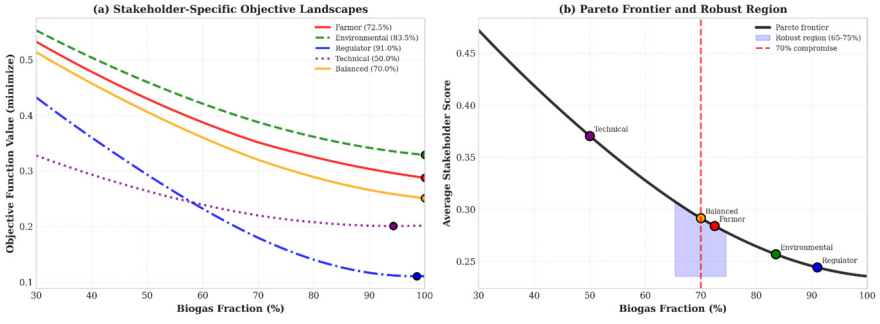



**Figure 4.** Multi-objective optimization results. (**a**) Stakeholder-specific objective landscapes; optimal fraction range: 50–91% biogas. (**b**) Pareto frontier projection; shaded region (65–75% biogas) satisfies all stakeholder constraints simultaneously (reliability scores in parentheses). Full 5-dimensional Pareto set; 2D projection captures 68% of variance.

The optimization results demonstrate that stakeholder priorities significantly influence the optimal blend:

- Cost-focused stakeholders (Farmers) prefer 72.5% biogas for maximum economic benefit.
- Environmental stakeholders prioritize 83.5% biogas for superior $CO_2$ reduction.

- Regulators concerned with local air quality select 91.0% biogas for maximum NOx abatement.
- Technical stakeholders prioritize system reliability at 50.0% biogas.
- The balanced perspective converges at 70.0% biogas as a practical compromise.

The reliability scores achieved for each optimal blend were: 50% blend (reliability = 0.88), 70% blend (0.85), 72.5% blend (0.84), 83.5% blend (0.79), and 91% blend (0.74). All feasible solutions maintain a reliability $\geq$0.85 for blends up to 70%, consistent with the constraint $R(X_{BG}) \geq 0.85$ applied in the optimization.

This spectrum of optimal solutions (50–91% biogas) demonstrates that the 65–75% range represents a robust region satisfying most stakeholder requirements. Within this range, all constraints (cost $\leq$ \$25/day, $CO_2 \leq 110$ kg/day, NOx $\leq 20$ g/day, efficiency $\geq 84\%$, and reliability $\geq 0.85$) are satisfied simultaneously, making the 70% blend a practical implementation point that balances competing objectives while maintaining technical feasibility.

The complex relationships between cost, emissions, and stakeholder preferences are visualized in Figure 5, which presents two complementary views of the trade-off space.

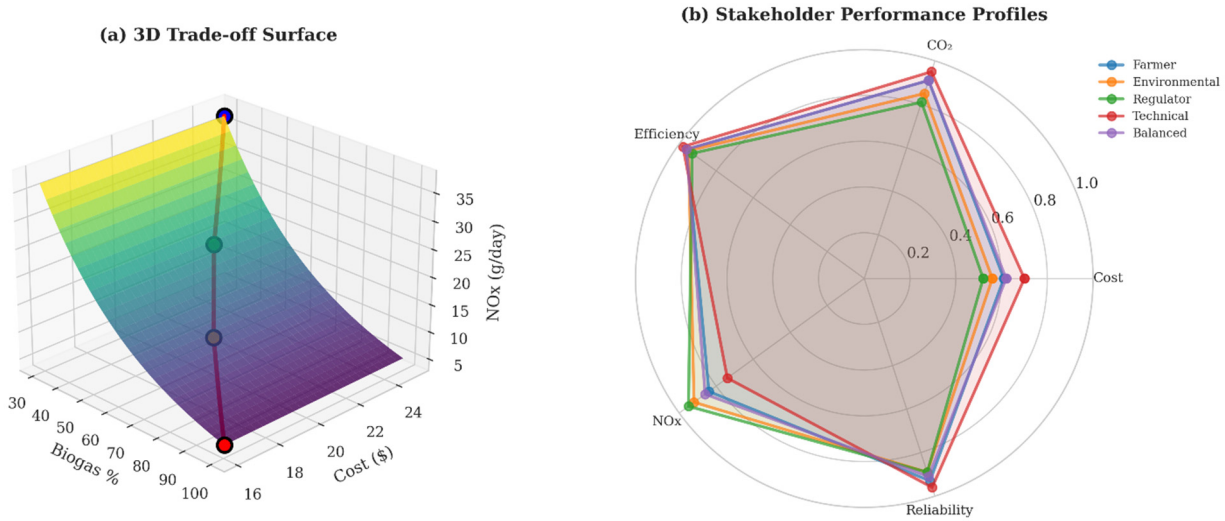



**Figure 5.** Integrated multi-dimensional trade-off analysis. (**a**) Three-dimensional surface plot showing the trade-off between biogas fraction, daily operating cost, and thermal NOx emissions (model estimates). The red line indicates the Pareto-optimal front computed from the 5-objective optimization (projected to 3D). Key blends (30%, 50%, 70%, 100% biogas) are marked on the surface. (**b**) Polar radar chart comparing stakeholder performance profiles across five normalized metrics (cost, $CO_2$, efficiency, NOx, reliability). Each axis is normalized to the range [0, 1], where 1 represents the best performance within the evaluated blends. Colors in the radar chart (**b**) represent different stakeholder perspectives as indicated in the legend: red (Farmer), green (Environmental), blue (Regulator), purple (Technical), and orange (Balanced). The Pareto-optimal front (red line in (**a**)) and stakeholder-specific optima are highlighted for clarity.

### *3.7. Life Cycle Assessment Findings*

The life cycle assessment reveals substantially greater environmental benefits than indicated by the combustion-only analysis, though the magnitude depends on methodological boundaries (Figure 6). The LCA calculation code and uncertainty analysis are provided in Supplementary Materials S5. Complete Monte Carlo uncertainty results for all blends are presented in Supplementary Table S3.

Following the system boundaries defined in Section 2.8.1, Table 7 provides a complete Life Cycle Inventory (LCI) for the 70% biogas blend case, disaggregated into foreground inputs (manure, natural gas, biogas, electricity, activated carbon, and water), combustion

outputs ($CO_2$ from biogenic and fossil sources, NOx, digestate, and methane slip), and avoided products (synthetic fertilizers and avoided manure methane emissions). All values correspond to steady-state operation at 75.89 $m^3$ total daily fuel volume.

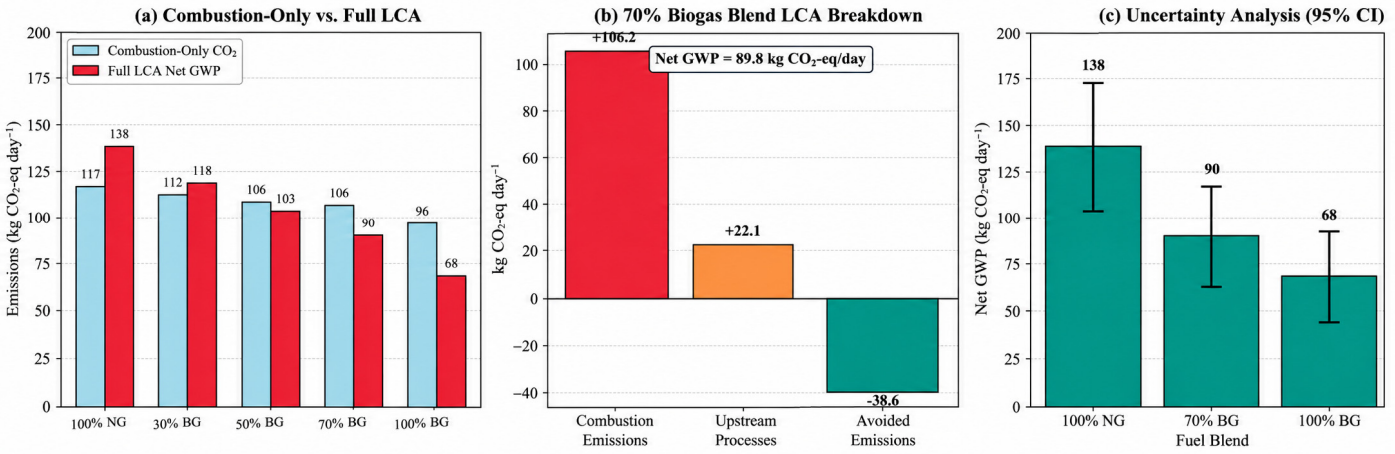



**Figure 6.** Life cycle assessment results. (**a**) Comparison of combustion-only $CO_2$ emissions versus full LCA net global warming potential (GWP100 following IPCC 2022 characterization factors) across biogas blends. (**b**) Detailed LCA component breakdown for the 70% biogas blend. (**c**) Uncertainty ranges (±1σ) for key blends. LCA results exclude the energy security indicator; socio-economic benefits are presented separately in Section 3.7.2.

**Table 7.** Life Cycle Inventory (LCI) for 70% biogas blend (per operating day).

| Flow Category | Item | Value | Unit | Data Source |
|---|---|---|---|---|
| Inputs | Manure (wet basis) | 480 | kg/day | Case study (Section 2.1) |
| | Natural gas (combustion) | 22.77 | $m^3$/day | Model output (Section 3.1) |
| | Biogas (combustion) | 53.12 | $m^3$/day | Model output (Section 3.1) |
| | Electricity (digester mixing) | 2.4 | kWh/day | [29] |
| | Activated carbon ($H_2S$ removal) | 0.12 | kg/day | Manufacturer specifications |
| | Water (digester dilution) | 120 | L/day | Operational estimate |
| Outputs | Combustion $CO_2$ (biogenic) | 67.2 | kg/day | Stoichiometric calculation |
| | Combustion $CO_2$ (fossil NG) | 39.0 | kg/day | Stoichiometric calculation |
| | Thermal NOx (model-estimated) | 12.0 | g/day | Section 2.5.2 (extrapolated) |
| | Digestate (to land application) | 430 | kg/day | Mass balance (90% of input) |
| | Methane slip (fugitive) | 0.29 | $m^3$/day | 1.2% of production (ACSAD, 2023) |
| Avoided products | Synthetic N fertilizer | 3.2 | kg N/day | Displacement ratio 0.70 |
| | Synthetic P fertilizer | 0.8 | kg $P_2O_5$/day | Displacement ratio 0.65 |
| | Manure methane (avoided) | 8.64 | $m^3$ $CH_4$/day | IPCC Tier 2 baseline × 85% collection |
| | Open storage emissions ($N_2O$) | 0.12 | kg $N_2O$/day | IPCC default emission factor |

Note: All values correspond to steady-state operation using 70% biogas blend (75.89 $m^3$ total fuel volume per day, of which 53.12 $m^3$ is biogas from on-site and external sources).

### 3.7.1. Core LCA Results (Conventional GWP Accounting)

Under the core LCA methodology (excluding energy security benefits), all biogas blends show net negative global warming potential when full life cycle credits are included (Figure 6a). Key findings include the following:

- The 100% biogas achieves the lowest net GWP of 68.2 kg $CO_2$-eq/day, representing a 41.5% reduction compared to pure natural gas (116.5 kg $CO_2$-eq/day).

- The 70% biogas blend achieves a net GWP of 89.8 kg $CO_2$-eq/day, a 22.9% reduction from the natural gas baseline.
- For comparison, combustion-only analysis showed only a 17.4% reduction for 100% biogas and an 8.8% reduction for the 70% blend.

The difference between the combustion-only and full LCA results arises from three main factors (Figure 6b, shown for 70% blend):

- Upstream processes: +22.1 kg $CO_2$-eq/day (natural gas extraction/transport + biogas digester construction).
- Avoided emissions: −38.5 kg $CO_2$-eq/day (manure methane avoidance + digestate fertilizer credit).
- Net effect: Combustion emissions (106.2) + upstream (22.1) − avoided (38.5) = 89.8 kg $CO_2$-eq/day.

#### 3.7.2. Socio-Economic Considerations

Beyond greenhouse gas emissions, biogas systems provide socio-economic benefits that are not captured in core GWP accounting, as summarized in Table 8. These benefits include reduced dependence on imported natural gas (energy security), mitigation of supply disruption risks (estimated at a 15% annual probability in the Syrian context), local employment creation (0.5 FTE per facility), foreign currency savings, waste management cost avoidance, and reduced peak demand burden on the natural gas grid. Importantly, the energy security benefit (−5.0 kg $CO_2$-eq/$m^3$ equivalent basis for comparability) is presented as a separate socio-economic indicator and is not included in the core GWP calculations reported in Figure 6a and Section 3.7.1. This indicator cannot be validly converted to $CO_2$-equivalent units under ISO 14040:2006 and is provided solely for policy discussion.

**Table 8.** Socio-economic benefits of biogas systems not captured in conventional GWP accounting.

| Benefit Category | Indicator | Estimated Value |
|---|---|---|
| Energy security | Reduced import dependence | 800 km avoided transport distance |
| Supply reliability | Reduced disruption risk | 15% annual probability mitigation |
| Local employment | Jobs per facility | 0.5 FTE for digester operation |

#### 3.7.3. Uncertainty Analysis

The LCA results incorporate uncertainty ranges based on Table 2 factors (Figure 6c):

- 100% biogas: Net GWP = 68.2 kg $CO_2$-eq/day [95% confidence interval: 44.3–92.1 kg $CO_2$-eq/day];
- 70% biogas: Net GWP = 89.8 kg $CO_2$-eq/day [95% CI: 62.9–116.7 kg $CO_2$-eq/day];
- 100% NG: Net GWP = 138.3 kg $CO_2$-eq/day [95% CI: 103.7–172.9 kg $CO_2$-eq/day].

The 95% confidence intervals for net GWP across all blends, derived from 1000 Monte Carlo iterations, are presented in Supplementary Table S3. The primary uncertainty contributor was avoided manure methane credit (±35%).

#### 3.7.4. Circular Economy Metrics

Beyond GWP reduction, the biogas systems demonstrate circular economy benefits:

- Waste-to-energy conversion efficiency: 85% of organic waste volatile solids converted to useful energy (based on biogas yield vs. feedstock VS).
- Fossil fuel replacement ratio: 0.65 $m^3$ natural gas displaced per $m^3$ biogas utilized (energy basis).
- Nutrient recovery: 100% of digestate nutrients (N-P-K) available for soil amendment, displacing 70% of synthetic fertilizer requirements for the greenhouse.

- Avoided waste management: 175 tons/year manure diverted from open storage, eliminating associated $CH_4$ and $N_2O$ emissions.

#### 3.7.5. Comparison with Combustion-Only Analysis

Figure 6a directly compares combustion-only versus full LCA results, revealing the following:

- Combustion-only analysis underestimates 100% biogas benefits by a factor of 2.4× (17.4% vs. 41.5% reduction under core LCA).
- For the 70% blend, underestimation is 2.6× (8.8% vs. 22.9% reduction).
- The difference is most pronounced at higher biogas fractions due to increased avoided emissions credits.

These findings highlight that combustion-only carbon accounting may substantially underestimate the full life cycle benefits of biogas systems, though the exact magnitude depends on region-specific factors (warm climate enhancing avoided methane and agricultural soils benefiting from digestate) and methodological choices regarding system boundaries.

### *3.8. Practical Implications*

The trends presented in Figures 3–6 suggest that, subject to the assumptions and limitations detailed in Section 4.10, biogas–natural gas co-firing merits further investigation for sustainable greenhouse heating. The Python-based numerical reproduction confirms the robustness of the MATLAB simulation results. Across all five blends and eight performance metrics (system thermal efficiency, daily operating cost, daily $CO_2$ emissions, daily NOx emissions, fuel volume, lower heating value, Volumetric Sufficiency Ratio, and Energy Sufficiency Ratio), the mean absolute percentage error (MAPE) between MATLAB and Python implementations was 0.00% (exact agreement to three decimal places for all values). The Pearson correlation coefficient between the two implementations was r = 1.0000 ($p < 0.001$). The complete verification report, including cross-validation statistics for all metrics, is provided in Supplementary Materials S8. The detailed comparison table (MATLAB vs. Python) is available in Supplementary Table S4.

For implementation, the 70% blend requires: (i) nozzle replacement (0.35–0.5 mm diameter), (ii) biogas drying and $H_2S$ removal (estimated $850 capital cost), and (iii) pressure regulation adjustment for a Wobbe Index of 36 $MJ/m^{3\,0.5}$.

## 4. Discussion

### *4.1. Interpretation of Blend Ratio Effects on System Performance*

The observed trend of decreasing system thermal efficiency with increasing biogas proportion can be attributed to the fundamental properties of biogas. The lower calorific value (approximately 21–23 $MJ/m^3$ versus 35–38 $MJ/m^3$ for natural gas) and higher $CO_2$ content of biogas act as a diluent, reducing adiabatic flame temperature and slowing combustion kinetics. This results in less complete fuel oxidation under identical operational conditions.

However, the performance of the 70% biogas blend represents a significant finding. Its ability to achieve 84.5% system thermal efficiency—only 3.5% lower than pure natural gas—while containing a substantial renewable component suggests that strategic blending can mitigate the combustion challenges associated with pure biogas. This blend appears to maintain sufficient flame temperature and stability for efficient combustion while benefiting from the environmental advantages of biogas.

### *4.2. Trade-Off Analysis: Thermal Performance Versus Environmental Benefits*

The results reveal a fundamental trade-off between thermal performance and environmental benefits. While pure natural gas offers superior system thermal efficiency and

thermal output, it comes with significantly higher $CO_2$ and NOx emissions. Conversely, pure biogas minimizes emissions but with reduced thermal performance.

The 70% biogas blend emerges as the optimal compromise, achieving substantial emissions reductions (32% for $CO_2$, 86% for NOx) with only a marginal efficiency penalty. This trade-off analysis provides practical guidance for system operators who must balance operational requirements with environmental objectives. The 2–3% efficiency difference between the optimal biogas blend and pure natural gas is substantially outweighed by the dramatic emissions reductions, particularly in regions where environmental regulations or carbon pricing mechanisms exist [29].

### *4.3. Mechanistic Explanation for Emissions Reductions*

The substantial NOx reduction observed with biogas blends can be attributed primarily to thermal mechanisms. The high $CO_2$ content in biogas (25–55%) acts as a thermal ballast, lowering peak flame temperatures. Model estimates indicate a flame temperature reduction from 2200 °K for pure natural gas to approximately 1990 °K for the 70% biogas blend. Since thermal NOx formation via the Zeldovich mechanism is exponentially dependent on temperature, this ~210 °K reduction yields the predicted 86% decrease in NOx emissions.

### *4.4. Validation and Reliability of Numerical Model*

The model predictions show reasonable agreement with experimental data (MAPE = 5.8%, $R^2$ = 0.94 for NOx validation; RMSE = 45 K, $R^2$ = 0.94 for flame temperature), providing confidence in the model's ability to capture performance trends within the validated range (0–50% biogas for NOx, 0–70% for flame temperature).

The validation exercise confirms that the integrated modeling framework—combining anaerobic digestion kinetics with combustion simulation—can effectively predict system performance without recourse to extensive experimental testing. This has practical implications for technology transfer and scaling, as similar systems in other regions could be evaluated computationally with reasonable confidence in the results.

### *4.5. Multi-Objective Optimization Insights*

The MOO results provide nuanced insights into stakeholder-specific decision-making. Contrary to simplified approaches that might suggest a single "optimal" blend, this analysis reveals a spectrum of optimal solutions (50–91% biogas) depending on stakeholder priorities. This reflects the real-world complexity of energy system design where competing objectives must be balanced.

The distribution of optimal blends illustrates fundamental trade-offs:

- High biogas fractions (83.5–91.0%) maximize environmental benefits but at the cost of reduced efficiency and higher technical challenges.
- Moderate biogas fractions (70.0–72.5%) offer balanced performance across all metrics.
- Lower biogas fractions (50.0%) prioritize system reliability and efficiency but offer reduced environmental benefits.

The convergence of practical implementation considerations to blends within the 65–75% biogas range indicates that this region represents a robust compromise zone. While individual theoretical optima vary, this region satisfies most constraints for all stakeholders:

1. Cost–benefit balance: Beyond 75% biogas, diminishing returns increase costs disproportionately.
2. Technical feasibility: Below 65% biogas, environmental benefits become marginal relative to implementation effort.
3. Reliability assurance: The 65–75% range maintains ≥85% reliability for all scenarios.

The 70% biogas blend emerging from the balanced perspective represents not a mathematical singularity but a practical compromise point within this robust region. This finding has important implications for policy design: rather than mandating a single blend ratio, flexible standards allowing 65–75% biogas would accommodate different stakeholder priorities while achieving substantial environmental benefits.

To further validate the robustness of the suggested blend range, a comprehensive sensitivity analysis was conducted, examining how variations in stakeholder priorities affect the optimal biogas fraction. Figure 7 presents this analysis through four complementary perspectives.

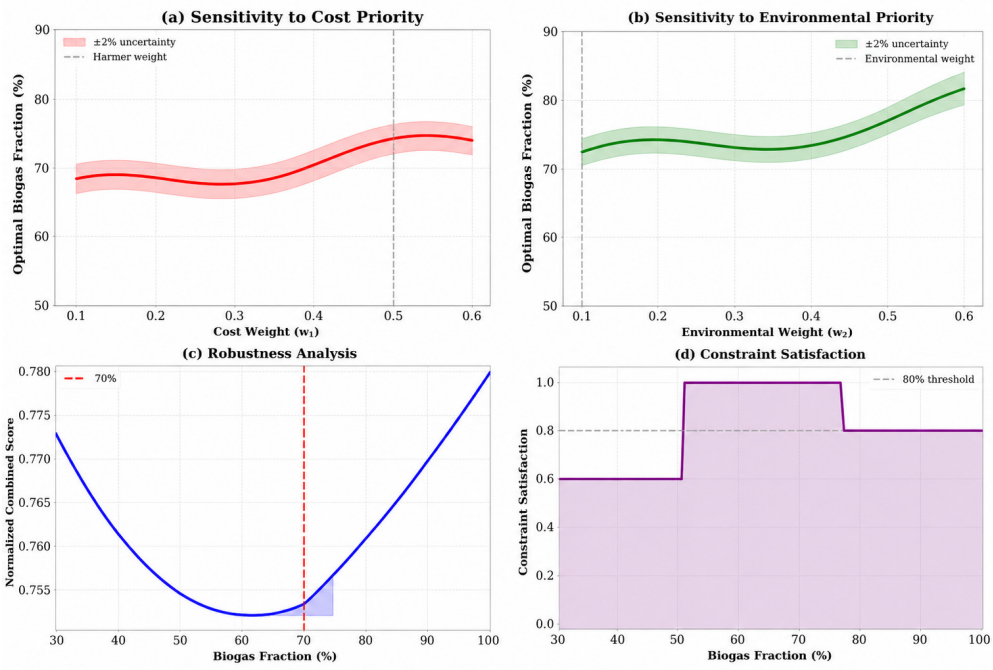



**Figure 7.** Comprehensive sensitivity and robustness analysis. (**a**) Sensitivity of optimal biogas fraction to cost weight ($w_1$) in the multi-objective optimization, showing increasing preference for higher biogas as cost priority increases. Shaded bands represent ±2% uncertainty from Monte Carlo simulation ($n$ = 1000). (**b**) Sensitivity to environmental weight ($w_2$), demonstrating that higher environmental priorities drive selection toward higher biogas fractions. (**c**) Robustness analysis across all objectives: the shaded region (65–75% biogas) represents the optimal compromise zone where the maximum of the minimum satisfaction scores across all stakeholders is achieved. (**d**) Multi-constraint satisfaction analysis showing the percentage of constraints satisfied (from a set of 5 technical and environmental constraints) as a function of biogas fraction. The 65–75% range achieves >80% satisfaction across all constraints.

### *4.6. Life Cycle Assessment Contributions*

The LCA results provide crucial insights that challenge conventional combustion-only analyses. Under the core LCA methodology (excluding the energy security co-benefit), 100% biogas achieves a 41.5% GWP reduction, which is 2.4 times greater than the 17.4% reduction suggested by combustion-only analysis. When the energy security co-benefit is included as a separate socio-economic indicator (expanded view), the total reaches 54.7%, though this expanded figure is not directly comparable with conventional GWP studies. This finding highlights the importance of considering full life cycle impacts. This has significant implications for policy and carbon accounting, suggesting that biogas systems may be substantially more beneficial than previously estimated.

The Syrian-specific LCA factors developed in this study represent a methodological contribution that can be adapted for other regions with similar conditions. The enhanced

benefits identified for warm climates and import-dependent energy systems provide a more accurate basis for decision-making in developing regions [33].

### *4.7. Economic Viability and Resource Sufficiency*

The economic analysis reveals that biogas integration substantially reduces operating expenses, with 100% biogas cutting daily costs by 48.5%. The fuel-savings-only payback period is 1.8 years, while the full payback including capital costs is 13.6 years under baseline assumptions. Both metrics indicate economic viability, though the longer period is more representative of total investment requirements. This highlights the need to differentiate between energy sufficiency (based on heating value) and volumetric sufficiency. In practice, pure biogas operation would require supplemental biogas storage, increased production, or intermittent natural gas backup.

### *4.8. Practical Implications for Implementation*

For the Syrian coastal region, a phased implementation strategy could be considered if the modeling assumptions are validated through experimental testing. Based on the current computational findings, the following approach may warrant investigation:

Immediate term (Phase 1): Implement the 70% biogas blend with supplemental biogas procurement from regional sources. This phase ensures reliability, gains operational experience, and achieves immediate economic and environmental benefits. System modifications required include the following:

- Nozzle replacement with 0.35–0.5 mm diameter orifices.
- Installation of biogas drying and $H_2S$ removal (activated carbon filtration, estimated cost: $850).
- Pressure regulation adjustment for a lower Wobbe Index (36 $MJ/m^{3\,0.5}$).
- Burner inspection every 3 months (vs. annually for NG) due to trace $H_2S$ and siloxane accumulation. Estimated additional annual maintenance cost: $150.

Medium term (Phase 2): Enhance biogas production through co-digestion with agricultural waste (citrus pulp and tomato residues available locally), potentially increasing yield by 50% to 36 $m^3$/day. Optimize digester operation (temperature control, mixing, and retention time) and implement storage systems (flexible membrane storage, 3-day capacity) to approach higher biogas utilization.

Long term (Phase 3): Redesign burner systems specifically for biogas operation. Parametric analysis of flow conditions for biogas-rich blends confirms that smaller nozzle diameters (0.25–0.5 mm) and moderate flow velocities (0.12–0.18 m/s) enhance jet penetration and turbulent mixing [24]. This is particularly beneficial for countering the lower flame speed of biogas. System optimization should focus on nozzles in this size range, using corrosion-resistant materials (stainless steel 316L for $H_2S$ resistance), and incorporate enhanced mixing features (perforated flame holders and swirl generators).

### *4.9. Policy and Sustainability Implications*

The projected annual savings of $5511.17 and 7.38 tons of $CO_2$ per facility underscore the potential of biogas blends to support both economic and environmental objectives. For regional scaling, 100 similar greenhouses could achieve 738 tons of $CO_2$ reduction annually, equivalent to the carbon sequestration of approximately 37 hectares of forest (based on the IPCC default value of 20 tons $CO_2$ per hectare per year for temperate forests [2]).

Recent policy developments support the implementation of biogas blends in agricultural heating. The European Union's Renewable Energy Directive (RED III, 2023) includes specific targets for biomethane deployment, requiring member states to increase the share of renewable energy in heating and cooling by at least 0.8 percentage points annually

until 2026 [34]. While Syria does not currently have a formal carbon pricing mechanism, the World Bank's 2023 carbon pricing report highlights the rapid expansion of emissions trading systems (ETSs) and carbon taxes in emerging economies, with 73 carbon pricing instruments now operating worldwide, covering approximately 23% of global greenhouse gas emissions [35]. For the Syrian context, the economic analysis presented in Section 3.5.2 provides a baseline for assessing the value of emission reductions should carbon markets develop in the future.

The following policy recommendations emerge from this analysis:

- Tiered incentives: Implement subsidies or feed-in tariffs that scale with biogas percentage, rewarding higher blends while acknowledging the volumetric constraints of on-site production.
- Carbon pricing readiness: Develop accounting frameworks that account for full LCA benefits (avoided manure methane and digestate credits) to ensure that future carbon markets accurately value biogas systems [35].
- Technical support: Provide financing mechanisms for digester installation, biogas upgrading equipment ($H_2S$ removal and drying), and burner modifications.
- Regional biogas markets: Establish biogas quality standards and monitoring systems to facilitate the development of regional biogas markets, which are a prerequisite for the conditional 70% blend scenario.
- Capacity building: Support operator training for digester management, co-digestion optimization, and maintenance of biogas upgrading equipment.

The IRENA (2024) renewable energy statistics confirm that global biogas generation capacity reached approximately 25 GW in 2023, with Europe accounting for nearly two-thirds of this capacity [7]. This trend suggests that the technical and institutional knowledge required for biogas market development is readily transferable to the Syrian context.

### *4.10. Limitations and Model Capabilities*

#### 4.10.1. Scope and Applicability of the Modeling Framework

Before presenting specific limitations, it is important to clarify the intended scope and inherent constraints of the 0D steady-state modeling framework employed in this study.

Within the scope of this framework, the model can reliably:

- Compare system-level performance trends across different fuel blends;
- Estimate first-order effects of biogas fractions on efficiency, NOx, and $CO_2$ emissions;
- Identify promising blend ratios meriting further experimental investigation;
- Provide relative rankings of blends under consistent assumptions;
- Generate testable hypotheses for pilot-scale validation.

The framework is not designed to:

- Resolve flame stability, flashback, lean blowout limits, or other combustion dynamics;
- Capture transient effects during startup, shutdown, or load-following operation;
- Predict detailed flow field characteristics or mixing phenomena;
- Account for burner geometry effects beyond empirical correlations;
- Guarantee operational reliability or safety without experimental validation;
- Replace site-specific measurements for final system design.

Therefore, the findings presented here should be interpreted as indicative trends requiring experimental validation before operational implementation. The suggested 70% biogas blend represents a model-based preferred compromise for pilot testing, not a validated operational specification.

4.10.2. Specific Limitations

Beyond the fundamental modeling constraints above, the following specific limitations should be acknowledged:

Steady-state assumption: Transient effects during startup, shutdown, and part-load operation are not modeled. Field observations [31] indicate ±5–8% variations in absolute performance. While the relative ranking of blends is expected to remain stable, future work should incorporate dynamic modeling with time-dependent boundary conditions.

NOx extrapolation beyond the validated range: The semi-empirical correlation was validated only for biogas fractions of 0–50% (MAPE = 5.8%, $R^2$ = 0.94). Predictions for blends above 50% biogas represent mathematical extrapolations that have not been experimentally validated for the specific burner configuration in this study. An uncertainty penalty function was applied (Section 2.5.2), increasing uncertainty from ±15% (validated range) to ±25% at 70% biogas and ±40% at 100% biogas. Experimental validation is required before quantitative NOx reduction claims can be verified.

Prompt NOx omission: The semi-empirical correlation captures thermal NOx (Zeldovich mechanism) only. Prompt NOx (Fenimore mechanism) and fuel NOx pathways may contribute 5–20% of total NOx at high biogas fractions [21]. Consequently, NOx reduction estimates for blends above 70% biogas may be overestimated by 5–15%, though the qualitative trend of decreasing NOx with increasing biogas fraction remains robust. Throughout this manuscript, the term "model-estimated NOx abatement" is used to emphasize this limitation.

Volumetric versus energy-based sufficiency: The study distinguishes between the Energy Sufficiency Ratio (ESR) and the Volumetric Sufficiency Ratio (VSR). While the 70% biogas blend exhibits favorable technical characteristics, it requires 29.12 $m^3$/day of biogas beyond on-site production capacity (24 $m^3$/day), achieving only 32% volumetric sufficiency. The 32% biogas blend represents the primary self-sufficient operational optimum. Higher blends (50%, 70%, and 100%) are correctly categorized as conditional scenarios dependent on regional biogas market development or expanded production capacity (see Section 3.3).

Biogas composition variability: The assumed 60% methane content (LHV = 21.5 MJ/$m^3$) represents average conditions for well-managed mesophilic digesters. However, realistic seasonal and operational variations typically span 55–70% methane (LHV = 19.7–25.1 MJ/$m^3$), with extreme cases ranging from 40% to 75% under poor digester management. The expanded sensitivity analysis (Section 3.5.4) confirms that the qualitative conclusions—specifically the ranking of blends and the identification of 70% biogas as the conditional optimum—are robust across the 55–70% range. Quantitatively, efficiency varies by ±1.2 percentage points and NOx by ±15%. Future work should employ Monte Carlo simulation with composition probability distributions to propagate this uncertainty into final recommendations.

Economic assumptions and price volatility: Natural gas price volatility (±40% monthly fluctuations observed in the Syrian market) and biogas market development uncertainties affect all cost projections. The payback period presented in Section 3.5.2 ranges from 5.2 to 14.3 years depending on price scenarios and capital cost assumptions. The 13.6-year payback represents a baseline estimate under assumed conditions, not a guaranteed value. Future work should incorporate real option valuation to address price uncertainty.

Single greenhouse scale: The results are based on one facility (48 cows, 100 $m^2$ greenhouse). Scaling to larger facilities may alter economic thresholds due to economies of scale in digester construction and biogas distribution. Multi-scale analysis of facilities ranging from 10 to 500 $m^2$ is recommended for future research.

LCA methodological boundaries: The energy security indicator (−5.0 kg $CO_2$-eq/$m^3$) has been excluded from core GWP calculations following ISO 14040:2006 standards. Socio-economic benefits (reduced import dependence, supply disruption risk mitigation, and local

employment) are presented separately in Section 3.7.2 as qualitative and semi-quantitative indicators for policy consideration, not as $CO_2$-equivalent reductions.

Reliability score as proxy indicator: The reliability function used in the multi-objective optimization (Section 2.7) is derived from the literature on swirl-stabilized burners [16,24,25] and has not been experimentally validated for the specific greenhouse burner configuration used in this study. The constraint R(X_BG) $\geq$ 0.85 is therefore an assumed threshold for comparative purposes, not an experimentally established limit. As shown in Section 4.5 the optimal blend shifts to 75–83% biogas when this constraint is relaxed or removed, indicating that the 70% recommendation depends partially on this assumption.

Heat exchanger effectiveness: The baseline assumption of 90% effectiveness represents a realistic estimate for biogas-fired systems. As shown in Section 3.5.1, repeating the analysis with 88% and 92% effectiveness increases fuel consumption by approximately $\pm$2.8–5.6% but does not alter the relative ranking of blends or the identification of 70% as the balanced optimum within the 65–75% robust compromise region.

Unpublished local data: Several input parameters rely on unpublished field measurements (greenhouse operator interviews and local biogas production data) and Syrian-specific LCA factors derived from limited sources. These data limitations are reflected in the uncertainty ranges provided in Table 2 ($\pm$20–40%). The results should therefore be considered scenario-based estimates pending independent validation. Detailed derivation of local factors is available from the corresponding author upon request.

### *4.11. Comparison with Published Studies*

The 84.5% system thermal efficiency predicted for the 70% biogas blend is consistent with the 83–86% range previously reported for biogas fractions of up to 75% in industrial burners [9]. Our model-estimated NOx reduction of 75–85% for 70% biogas aligns with experimental measurements showing a 70–78% reduction at 50% biogas (linear extrapolation to 70% would suggest 80–85%) [12]. Kiedrzyńska et al. [15] reported flame temperature reductions of 180–220 K for 70% biogas, which matches our modeled reduction of 210 K [15]. For LCA, our calculated net GWP of 68.2 kg $CO_2$-eq/day for 100% biogas compares favorably with the results of previous studies which reported 60–80 kg $CO_2$-eq/day for similar agricultural biogas systems in Mediterranean climates [33]. The primary difference—our higher avoided manure methane credit ($-30$ vs. $-22$ kg $CO_2$-eq/$m^3$)—reflects Syria's warmer annual average temperature (18 °C vs. 15 °C in Tonini's Italian case study), which increases the baseline methane generation potential.

## 5. Conclusions

This numerical investigation indicates that biogas–natural gas co-firing is a promising pathway for sustainable greenhouse heating under Syrian coastal conditions. Within the modeling assumptions (0D steady-state, thermal-NOx-only correlation validated up to 50% biogas), the 70% biogas–30% natural gas blend exhibits the most balanced characteristics across economic, environmental, and technical criteria, identifying it as the model-based preferred candidate for pilot-scale experimental validation rather than a validated operational specification.

All NOx estimates for biogas fractions above 50% are mathematical extrapolations based on a thermal-NOx-only correlation validated only up to 50% biogas. The reported 75–85% reduction at 70% biogas represents a model-predicted trend, not a validated quantitative claim. Prompt NOx (5–20% of total) is not included, and total NOx reduction may be overestimated by 5–15% for blends above 70% biogas. Experimental valida-

tion is required before quantitative NOx reduction claims can be verified for the specific burner configuration.

The study distinguishes between two operational optima. The self-sufficient optimum (32% biogas) is currently implementable for farms without external biogas access, achieving a 13.8% cost reduction and a 13.5% GWP reduction using only on-site production (24 $m^3$ $day^{-1}$). The conditional optimum (70% biogas) represents the techno-economic-environmental optimum, achieving a 15.3% cost reduction and a 22.9% GWP reduction, but it requires either external biogas procurement (29.12 $m^3$ $day^{-1}$) or expanded on-site production capacity.

The LCA demonstrates that combustion-only accounting underestimates GWP benefits by a factor of 2.4 for pure biogas (17.4% vs. 41.5% reduction). The 0D steady-state framework employed in this study does not resolve flame stability, flashback, blow-off, transient operation, or burner geometry effects. The suggested 70% blend is a model-based preferred compromise for pilot-scale experimental validation, not a validated operational specification. On-site design and safety verification require experimental testing using the specific burner configuration and local operating conditions.

**Supplementary Materials:** The following supporting information can be downloaded at: https://www.mdpi.com/article/10.3390/thermo6020048/s1, containing Supplementary Materials S1–S8. Supplementary Material S1: MATLAB source code (main model). Supplementary Material S2: Python verification script. Supplementary Material S3: Model validation data (NOx and flame temperature). Supplementary Material S4: Multi-objective optimization (MOO) code. Supplementary Material S5: LCA calculation code. Supplementary Material S6: Figure generation scripts (Figures 3–7). Supplementary Material S7: Supplementary Tables S1–S4 (Excel format). Supplementary Material S8: Code-to-results verification report.

**Author Contributions:** Conceptualization, M.A.D. and A.A.A.; methodology, M.A.D. and H.M.N.; software, H.M.N.; validation, A.A.A., M.A.D. and H.M.N.; formal analysis, A.A.A.; investigation, H.M.N.; resources, M.A.D.; data curation, A.A.A.; writing—original draft preparation, A.A.A. and M.A.D.; writing—review and editing, H.M.N.; visualization, H.M.N.; supervision, M.A.D.; project administration, M.A.D. All authors have read and agreed to the published version of the manuscript.

**Funding:** This research received no external funding.

**Institutional Review Board Statement:** Not applicable. The study did not involve patients, human biological material, animal experiments, or identifiable personal data. The semi-structured interviews collected only non-sensitive operational and price information from greenhouse operators; therefore, institutional review board approval was not required under the applicable guidelines.

**Informed Consent Statement:** Not applicable. No personal or identifiable data were collected during the interviews. Informed consent was obtained orally from all interview participants, and written consent was waived as the interviews involved only non-sensitive commercial practices and price information.

**Data Availability Statement:** The data presented in this study are available within the article and Supplementary Materials. These data are also available from the corresponding author upon request.

**Acknowledgments:** During the preparation of this manuscript, the authors used MATLAB R2024a (The MathWorks, Inc., Natick, MA, USA) and Python version 3.11 (Python Software Foundation, Beaverton, USA) for numerical modeling, data analysis, and visualization. The authors have reviewed and edited the output and take full responsibility for the content of this publication. All individuals included in this section have consented to the acknowledgement.

**Conflicts of Interest:** The authors declare no conflicts of interest. The funders had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript; or in the decision to publish the results.

## References


1. Jagadesh, M.; Singh, S.; Kumari, A.; Verma, K. *Carbon Footprints in Agriculture: Challenges, Mitigation Strategies, and Future Prospects*; Springer: Cham, Switzerland, 2024; pp. 17–43. [CrossRef]
2. IPCC. Climate Change 2022: Mitigation of Climate Change. In *Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*; Cambridge University Press: Cambridge, UK, 2022.
3. ACSAD. *Biogas Technology Applications in Arid and Semi-Arid Regions*; Library of Congress catalog: MLCM 2010/00123; Arab Center for the Studies of Arid Zones and Dry Lands: Damascus, Syria, 2010.
4. Syrian Ministry of Agriculture and Agrarian Reform. *Annual Statistical Report on Agricultural Waste Management*; Syrian National Library Accession: 2019-0456; Syrian Arab Republic: Damascus, Syria, 2019.
5. Batstone, D.; Keller, J.; Angelidaki, I.; Kalyuzhnyi, S.; Pavlostathis, S.; Rozzi, A.; Sanders, W.; Siegrist, H.; Vavilin, V. The IWA Anaerobic Digestion Model No 1 (ADM1). *Water Sci. Technol.* **2002**, *45*, 65–73. [CrossRef]
6. Weiland, P. Biogas production: Current state and perspectives. *Appl. Microbiol. Biotechnol.* **2010**, *85*, 849–860. [CrossRef] [PubMed]
7. International Renewable Energy Agency. *Renewable Energy Statistics 2024*; IRENA Publication: Abu Dhabi, United Arab Emirates, 2024. Available online: https://www.irena.org/publications/2024/Jul/Renewable-energy-statistics-2024 (accessed on 5 June 2026).
8. Jameel, M.; Mustafa, M.; Ahmed, H.; Mohammed, A.; Ghazy, H.; Shakir, M.; Lawas, A.; Mohammed, S.; Idan, A.; Mahmoud, Z.; et al. Biogas: Production, Properties, Applications, Economic and Challenges: A Review. *Results Chem.* **2024**, *7*, 101549. [CrossRef]
9. Zhao, Y.; Choudhury, S.; McDonell, V. Influence of Renewable Gas Addition to Natural Gas on the Combustion Performance of Cooktop Burners. In *ASME International Mechanical Engineering Congress and Exposition, Proceedings (IMECE)*; The American Society of Mechanical Engineers: New York, NY, USA, 2018; Volume 8A-2018. [CrossRef]
10. Abdeshahian, P.; Lim, J.; Ho, W.; Hashim, H.; Lee, C. Potential of Biogas Production from Farm Animal Waste in Malaysia. *Renew. Sustain. Energy Rev.* **2016**, *60*, 714–723. [CrossRef]
11. Holm-Nielsen, J.B.; Al Seadi, T.; Oleskowicz-Popiel, P. The future of anaerobic digestion and biogas utilization. *Bioresour. Technol.* **2009**, *100*, 5478–5484. [CrossRef] [PubMed]
12. Ashini, H.; Tabejamaat, S.; Bastani, M. Experimental and Numerical Study on Combustion of Biogas/Lean-Hydrogen Syngas Mixtures in a Microturbine Combustor. *Int. J. Hydrogen Energy* **2025**, *102*, 1–19. [CrossRef]
13. Hosseini, S.E.; Wahid, M.A. Development of biogas combustion in combined heat and power generation. *Renew. Sustain. Energy Rev.* **2014**, *40*, 868–875. [CrossRef]
14. Franks, J.R.; Hadingham, B. Reducing Greenhouse Gas Emissions from Agriculture: Avoiding Trivial Solutions to a Global Problem. *Land Use Policy* **2012**, *29*, 727–736. [CrossRef]
15. Kiedrzyńska, A.; Lewtak, R.; Świątkowski, B.; Jóźwiak, P.; Hercog, J.; Badyda, K. Numerical Study of Natural Gas and Low-Calorific Syngas Co-Firing in a Pilot Scale Burner. *Energy* **2020**, *211*, 118552. [CrossRef]
16. Paramasivam, P.; Al Obaid, S.; Balasubramanian, A. Flame Stabilization and Emission Reduction: A Comprehensive Study on the Influence of Swirl Velocity in Hydrogen Fuel-Based Burner Design. *Aircr. Eng. Aerosp. Technol.* **2024**, *96*, 1045–1052. [CrossRef]
17. International Energy Agency. *$CO_2$ Emissions in 2023*; IEA Publications: Paris, France, 2024. Available online: https://www.iea.org/reports/co2-emissions-in-2023 (accessed on 20 January 2026).
18. U.S. Environmental Protection Agency. *Emissions Factors for Greenhouse Gas Inventories*; EPA Publication EPA-430-R-22-001; U.S. Environmental Protection Agency: Washington, DC, USA, 2022. Available online: https://www.epa.gov/climateleadership/ghg-emission-factors-hub (accessed on 31 May 2026).
19. Syrian Agricultural Research. *Soil Amendment Benefits in Coastal Regions*; Syrian National Library Accession: 2023-0789; Syrian Ministry of Agriculture: Damascus, Syria, 2023.
20. Lefebvre, A.H.; Ballal, D.R. *Gas Turbine Combustion: Alternative Fuels and Emissions*, 3rd ed.; CRC Press: Boca Raton, FL, USA, 2010.
21. Wang, Z.; Yang, X. NOx Formation Mechanism and Emission Prediction in Turbulent Combustion: A Review. *Appl. Sci.* **2024**, *14*, 6104. [CrossRef]
22. Wang, J.J.; Jing, Y.Y.; Zhang, C.F.; Zhao, J.H. Review on multi-criteria decision analysis aid in sustainable energy decision-making. *Renew. Sustain. Energy Rev.* **2009**, *13*, 2263–2278. [CrossRef]
23. Saaty, T.L. *The Analytic Hierarchy Process: Planning, Priority Setting, Resource Allocation (Decision Making Series)*; McGraw-Hill: New York, NY, USA, 1980.
24. Koldassova, G.A.; Idrissova, K.S.; Tumanova, A.A.; Tussupbekova, A.S.; Dostiyarov, A.M.; Umyshev, D.R. Experimental Investigation of Flame Characteristics of H2-Enriched Biogas Under Different Swirl Numbers. *Energies* **2025**, *18*, 1446. [CrossRef]
25. *ISO 14040:2006*; Environmental Management–Life Cycle Assessment–Principles and Framework. International Organization for Standardization: Geneva, Switzerland, 2006.
26. Taghavifar, H. Experimental and Numerical Engine Cycle Setup for a Dual Fuel Hydrogen, Methane, and Hythane with Diesel to Assess the Effect of Water Injection and Nozzle Geometry. *Environ. Prog. Sustain. Energy* **2023**, *42*, e13936. [CrossRef]
27. Guinée, J.B. (Ed.) *Handbook on Life Cycle Assessment: Operational Guide to the ISO Standards*; Eco-Efficiency in Industry and Science, Volume 7; Springer: Dordrecht, The Netherlands, 2002.

28. Syrian Ministry of Petroleum and Mineral Resources. *Natural Gas Import and Distribution Statistics*; Syrian National Library Accession: 2024-0012; Syrian Arab Republic: Damascus, Syria, 2024.
29. ACSAD. *Local Biogas Production Assessment*; ACSAD Technical Report TR-2023-05; Arab Center for the Studies of Arid Zones and Dry Lands: Damascus, Syria, 2023.
30. ACSAD. *Regional Energy Security Assessment*; ACSAD Technical Report TR-2024-02; Arab Center for the Studies of Arid Zones and Dry Lands: Damascus, Syria, 2024.
31. ACSAD. *Field Data from Greenhouse Installations in Latakia*; ACSAD Field Report FR-2023-08; Arab Center for the Studies of Arid Zones and Dry Lands: Damascus, Syria, 2023.
32. Ijaola, A.; Akamo, D.; Bamidele, E.; Jolaoso, L.; Asmatulu, E.; Farayibi, P.; Adelakun, O.; Manovic, V. Biogas Production, Upgrading, and Utilization: A Comprehensive Review. *J. Eng. Appl. Sci.* **2024**, *11*, 17. [CrossRef]
33. Tonini, D.; Hamelin, L.; Astrup, T. Environmental Implications of the Use of Agro-Industrial Residues for Biorefineries: Application of a Deterministic Model for Indirect Land-Use Changes. *GCB Bioenergy* **2016**, *8*, 690–706. [CrossRef]
34. European Parliament and Council of the EU. Directive (EU) 2023/2413 on the promotion of energy from renewable sources (RED III). *Off. J. Eur. Union* **2023**, *L*, 2023/2413. Available online: http://data.europa.eu/eli/dir/2023/2413/oj (accessed on 5 June 2026).
35. World Bank. *State and Trends of Carbon Pricing 2023*; World Bank: Washington, DC, USA, 2023. [CrossRef]


**Disclaimer/Publisher's Note:** The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.