ARLINGTON RE-GEN

Arlington County Water Pollution Control Plant

Biogas Utilization

Executive Summary

Updated November 2022

Contents

Figures

Tables

Introduction

Arlington County (County) is implementing new biosolids management facilities at the Arlington County Water Pollution Control Plant (Plant). Arlington Re-Gen (Program) is part of the Arlington County Water Pollution Control Bureau's commitment to protecting public health and the environment, while recovering valuable resources with innovative processes that will also reduce our carbon footprint. This comprehensive biosolids program, adopted by the County Board in 2018, includes a new thermal hydrolysis process followed by anaerobic digestion as the main treatment processes. Thermal hydrolysis treats the biosolids under high pressures and temperature to break down the solids and remove pathogens. To achieve these high pressures and temperatures, steam boilers are required. Anaerobic digestion uses microbes to digest the solids in the absence of oxygen, which stabilizes and reduces the quantity of the biosolids, while also reducing odors of the finished product. These upgrades will produce a high quality marketable biosolids product.

Biogas, comprised of approximately 60% methane and 40% carbon dioxide, is also a product of the digestion process. Beneficial use of the biogas can have a significant impact on the County's sustainability goals, as it is estimated to have an energy content of 120 billion British thermal units (Btu) per year and the capability to reduce greenhouse gas emissions by up to 3,500 metric tons per year.

The objective of this gas utilization evaluation is to look at all feasible alternatives for the beneficial use of the biogas to assist in meeting Arlington County's sustainability goals while also reliably meeting the Plant's heating (steam generation) and electrical needs. Monetary, non-monetary, and sustainability evaluations were completed to determine the recommended alternative for the County.

Overall Biogas Recommendations

Based on the analyses presented below, the Arlington County Water Pollution Control Bureau recommends proceeding with the production of renewable natural gas (RNG) as the selected biogas utilization approach. The basis for this recommendation is as follows:

- The RNG alternatives have the lowest net present value (i.e., lowest total cost to the County over the life of the equipment) for the baseline conditions using conservative capital and operating costs.
- Injecting RNG into the local utility pipeline scored the highest in the County's non-financial scoring. In particular, the County found that the RNG alternatives would be less complex to maintain and would result in fewer localized impacts

such as noise and emissions than the combined heat and power (CHP) alternatives.

- A sensitivity analysis concluded that when considering multiple variables, including RIN market volatility and changes in electrical rates, injecting RNG into the local utility pipeline had a very high likelihood of being more financially advantageous than generating electricity through CHP.
- The County has the ability to retain greenhouse credits if the biogas is used within Arlington County for transportation purposes.
- Benefits of on-site CHP are limited because the CHP size would not be sufficient to power the entire Plant, which is already protected with two independent power feeds and backup generators. In addition, the use of CHP onsite will generate new, localized air emissions.

Biogas Utilization Alternatives

The range of feasible alternatives includes using the biogas for one or a combination of the following:

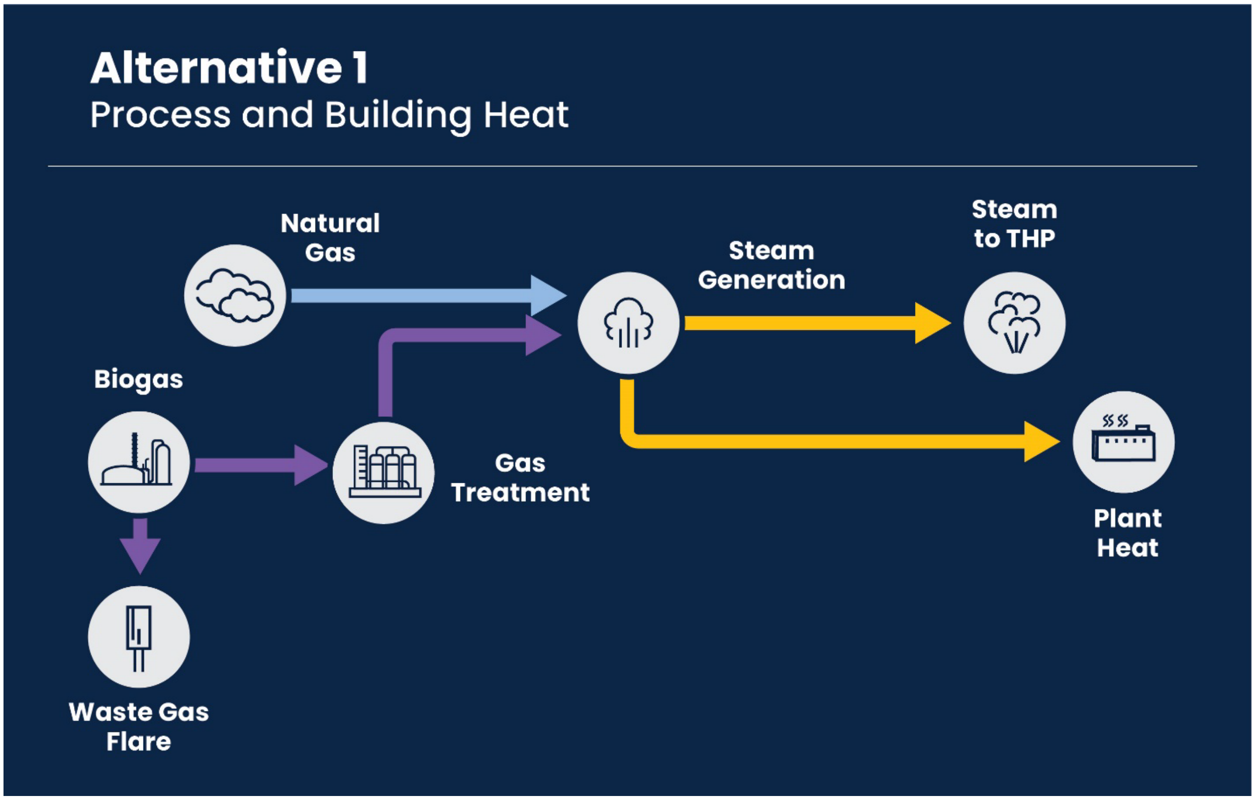
- On-site use for process and building heating
- Production of electrical power and recovery of waste heat (CHP)
- Production of RNG for use offsite through pipeline injection or as CNG for direct use as vehicle fuel.

From these potential biogas uses the following alternatives and sub-alternatives were identified for the evaluation. An energy balance was used to develop preliminary sizing of the equipment and summarize any energy production and heat recovered as well as the energy purchase requirements and biogas flared.

Alternative 1 – Process and Building Heating

In this alternative, shown schematically in Figure 1, the biogas produced during digestion would be used to fuel steam boilers to satisfy the process and building heating requirements. However, the steam demand for the Thermal Hydrolysis Process (THP) would use only about 30 percent of the biogas produced, leaving 70 percent as excess, which would be flared. **Because this alternative does not fully utilize the biogas, it is not a viable biogas utilization option, but it is included in the analysis as the minimum required to meet process needs.**

Figure 1. Alternative 1 – Process and Building Heat

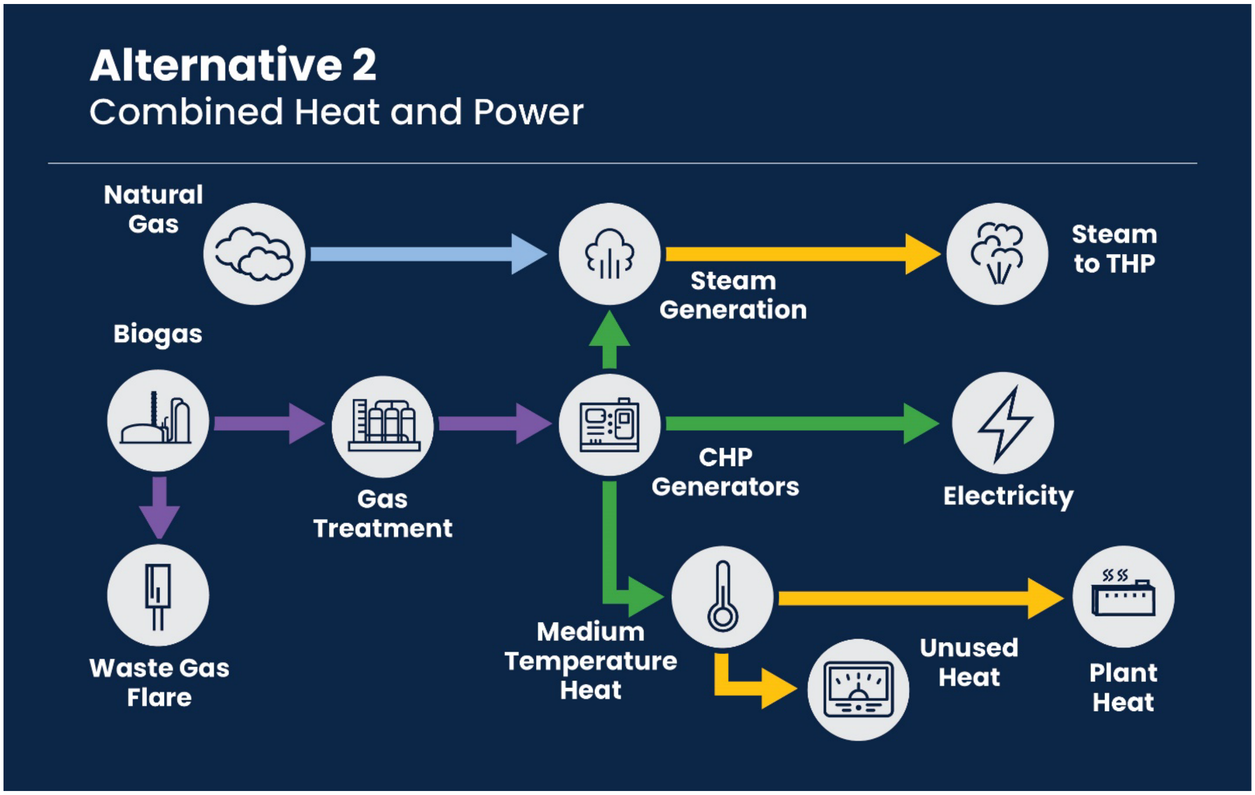


Alternative 2 – CHP

In this alternative, shown schematically in Figure 2, the biogas would be used as fuel for engines to produce electrical power. Recovered heat from the engines would be used for production of steam for process needs and building heat. Multiple types of power generation equipment are available, each with its own electrical and heat transfer efficiencies, so this alternative was divided into the following two sub-alternatives:

- **Alternative 2A – CHP with Engines:** Internal-combustion engines would produce more power at the site but would recover less heat. As supplemental heat would be required to meet process needs, some of the biogas would be bypassed around the engines to fire directly in the boiler and provide the steam for THP.
- **Alternative 2B – CHP with Gas Turbine:** A gas turbine engine would produce less power but would recover more steam. The heat recovered would satisfy process needs.

Figure 2. Alternative 2 – Combined Heat and Power

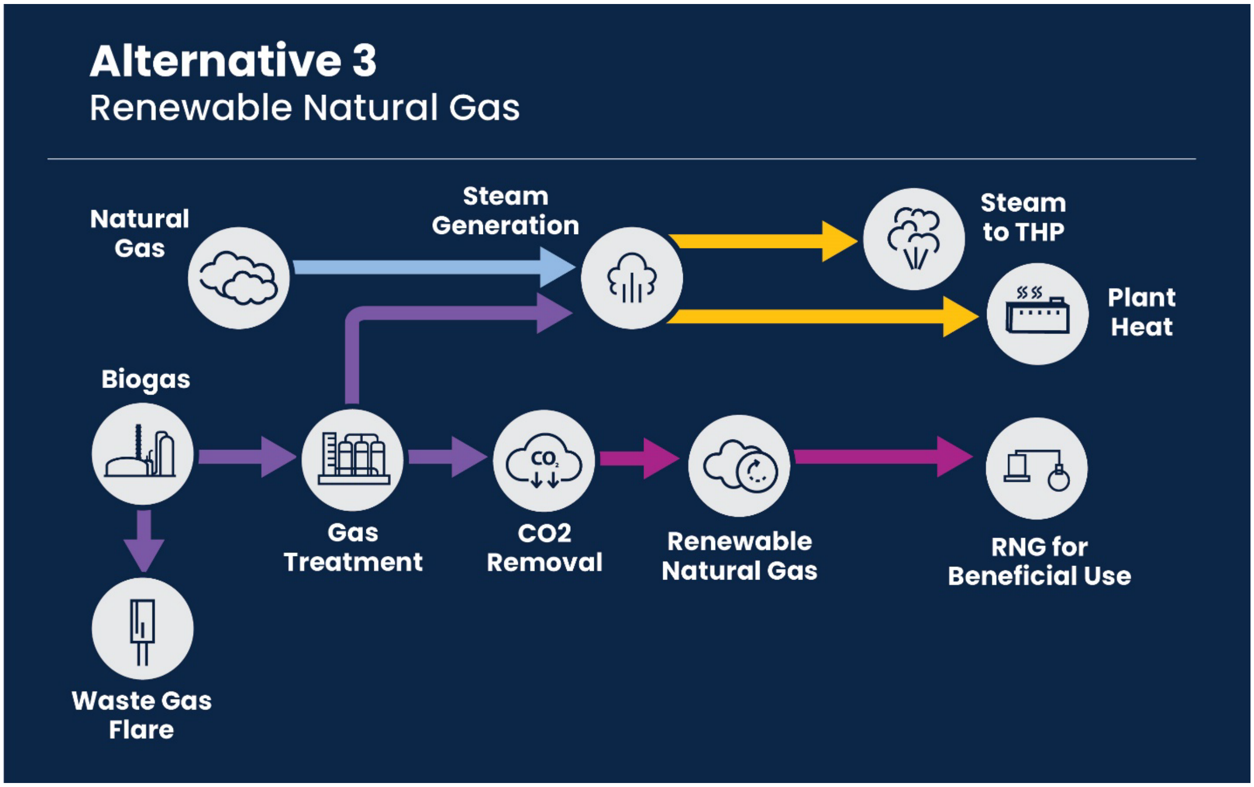


Alternative 3 – RNG

In this alternative, shown schematically in Figure 3, all of the biogas would be conditioned to RNG quality for use off site. The facility heating requirements would be met using steam boilers fueled by natural gas or from biogas onsite. There are two potential points of entry into the natural gas system so this alternative was divided into the following two sub-alternatives:

- **Alternative 3A – RNG Injected into the Natural Gas Pipeline:** In this alternative, all of the RNG would be injected into the local natural gas pipeline for off-site use as vehicle fuel.
- **Alternative 3B – RNG Used as Compressed Natural Gas (CNG):** In this alternative, the RNG would be sent to local CNG stations for use directly at those stations. This alternative is similar to Alternative 3A, but instead of injecting the RNG into the natural gas pipeline, it would be used across the road to fuel CNG buses operated by Arlington Transit and the Washington Metropolitan Area Transit Authority.

Figure 3. Alternative 3 – Renewable Natural Gas

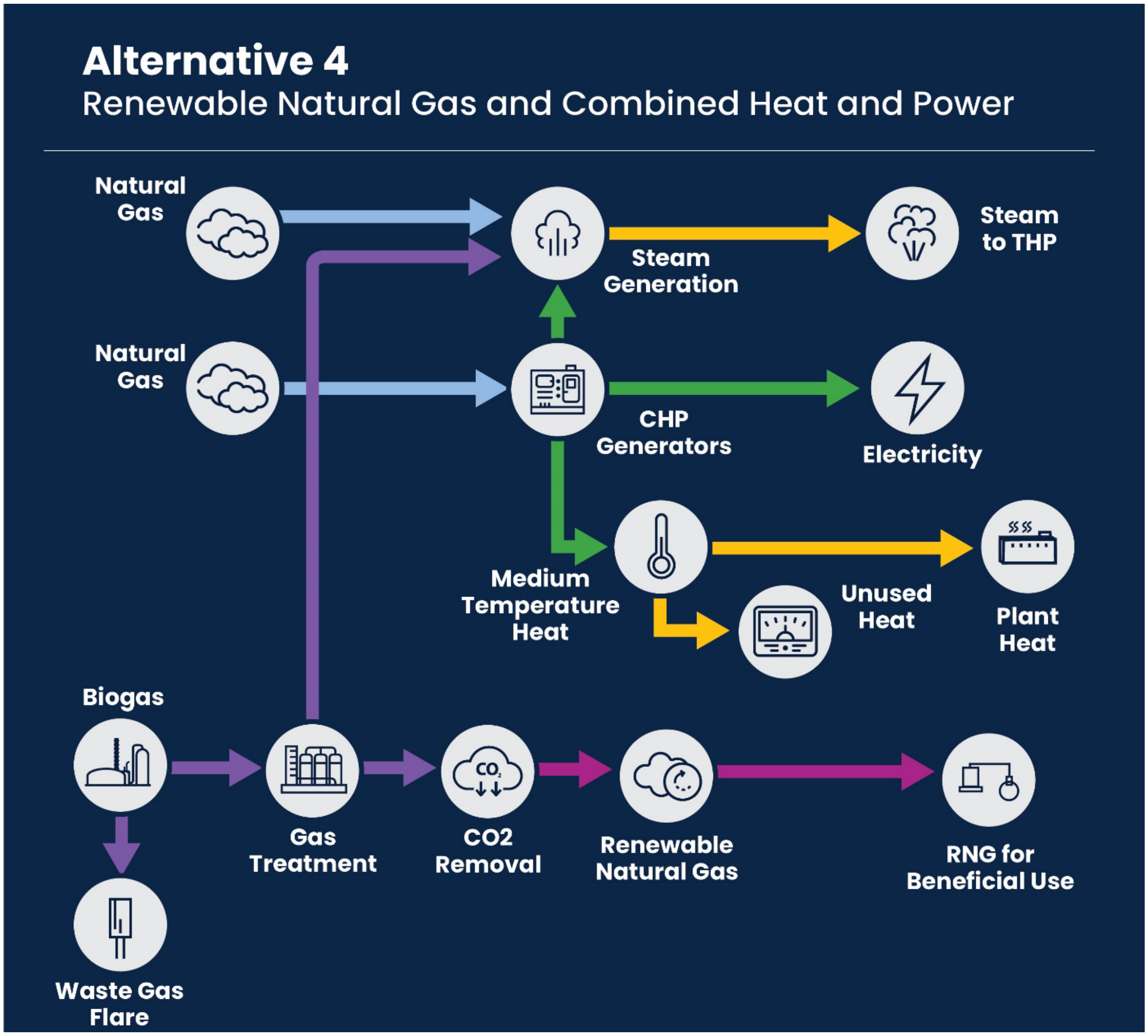


Alternative 4 – RNG and CHP

This alternative, shown schematically in Figure 4, would combine using the biogas to produce RNG as described above with using CHP fueled by natural gas for electricity and heat production. Similar to the CHP Alternative, there are two different engine options, so this alternative was divided into the following two sub-alternatives:

- **Alternative 4A – RNG and CHP with Engines:** Larger internal-combustion engines would be provided to produce all of the supplemental heat required to provide the steam for THP.
- **Alternative 4B – RNG and CHP with Gas Turbine**: Smaller gas turbine engines would produce less power but would recover more steam. The heat recovered would satisfy process needs.

Figure 4. Alternative 4 – Renewable Natural Gas and Combined Heat and Power



Alternatives Evaluations

The alternatives described above were developed and sized using the projected biogas production (approximately 120 billion Btu/year) and steam demands (approximately 35 billion Btu/year) and then evaluated using the following methods:

- **Financial analysis:** A present value of each alternative was developed from conceptual capital costs, operations and maintenance costs, energy production offsets, and RNG revenue.
- **Non-financial analysis:** A non-financial analysis was used to reflect such criteria in the overall alternatives analysis. Examples of non-financial criteria include noise production, facility aesthetics, and Plant safety.
- **Sustainability criteria:** The environmental and sustainability benefits (carbon emissions reductions) were monetized using an industry standard approach.
- **Sensitivity analysis:** To reflect future market and pricing unknowns and risks, multiple approaches were used to illustrate the sensitivity of the major assumptions.

The financial analysis considered the change in solids production and costs of electricity, natural gas, and equipment operations and maintenance over time to develop a net present value for each alternative. Based on discussions with the County, a 25-year planning period following construction was selected. With construction anticipated to finish in 2027, the planning period for this study runs from 2027 to 2052. The target year of 2052 was selected for when the design flows and loads are anticipated to be reached, resulting in a design solids production loading of approximately 40 tons per day. To illustrate the energy balance and economic analysis results presented in the subsequent sections, an evaluation year of 2037 was selected as it is close to the midpoint of the planning period and falls on one of the 5-year increments developed.

Financial Analysis

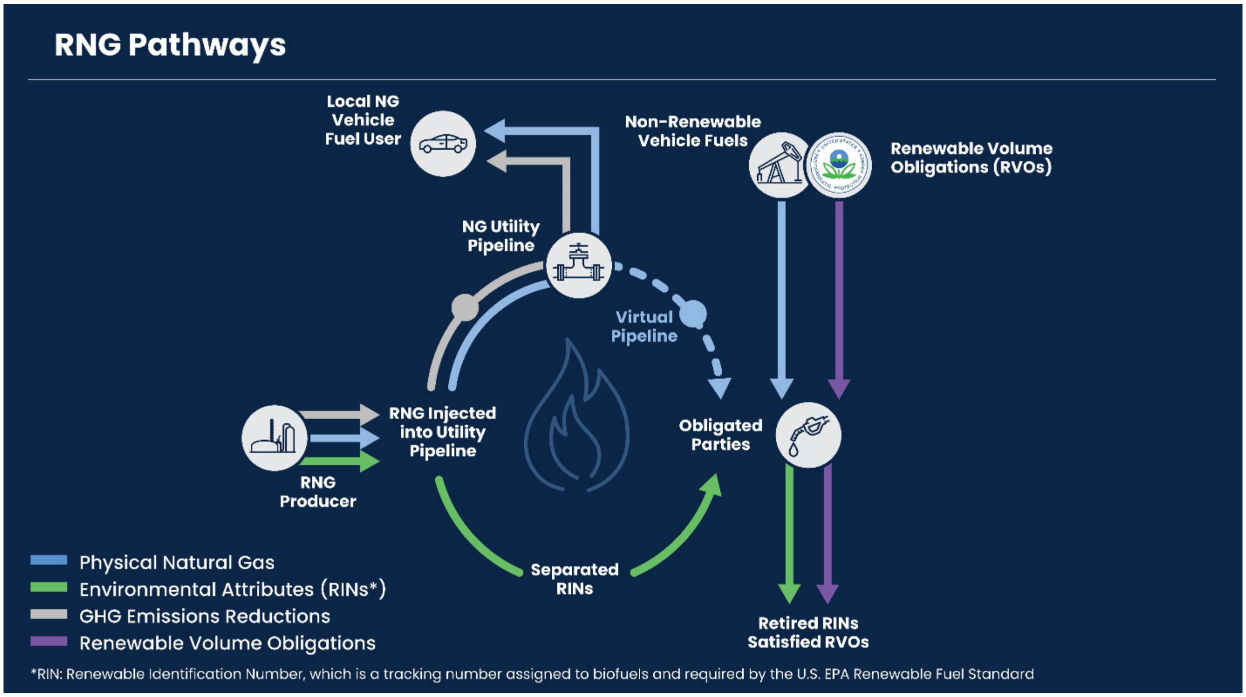
For each alternative, conceptual capital costs of the process heating, CHP, and biogas conditioning systems were developed. In addition, annual operations and maintenance costs and potential energy savings or revenues were summarized and totaled for each year of the 25-year planning period. The present value of each alternative was then developed.

For the alternatives that include CHP, it is likely that the County could either sell Renewable Energy Credits (RECs) for the electricity produced or defer purchase of RECs for other County needs. The County currently purchases RECs at a cost of $4,500/kWh and it is assumed that all CHP alternatives would be able to sell RECs for all of the electricity produced at that value.

For the alternatives that include the off-site sale of RNG, the RNG revenues were developed from the commodity value of natural gas and the historical and anticipated values of the environmental attributes of the RNG in the U.S. Environmental Protection Agency (EPA) Renewable Fuel Standard (RFS). This program is specifically for renewable fuels for transportation programs. Therefore, the fuel must ultimately be used as a transportation fuel for the renewable attribute to be recognized. In addition to the EPA's RFS, similar state programs exist such as the California Low Carbon Fuel Standard (LCFS). These state programs could be pursued by Arlington County but are not currently included in the financial metrics.

The production and sale of RNG and environmental attributes like Renewable Identification Numbers (RINs) through the RFS occurs via two pathways: the physical pathway for the commodity value and the contractual pathway for the attributes. The physical pathway is the sale of the RNG by the producer to an end user of the actual gas via the natural gas grid. The gas can be sold either to the current gas supplier or to another party directly. The contractual pathway for the environmental attributes (RINs) is separate and handled by a third party that verifies that the RNG produced complies with the RFS and markets the attributes to Obligated Parties (any refiner or importer of gasoline or diesel fuel in the United States). Note that these two pathways are independent of carbon credit programs. The County will be able to take credit for the reduction of greenhouse gases (GHGs) in its internal accounting independently of the sale of RINs as long as the gas is used within Arlington County. The valuation of RINs and GHG credits are treated separately in this report. The various physical, contractual, and greenhouse gas pathways are shown schematically on Figure 5.

Figure 5. RNG Pathways



In the RFS, RINs include a "D code" that identifies the type of biofuel based on the feedstock used. Each D code has a different market value in the RFS program. RNG generated from wastewater biosolids qualifies as a D3 RIN (cellulosic biofuel), which have historically traded at the highest value. Historical RIN values are provided in Figure 6. The base RIN value used in the financial analysis was $1.15/RIN or $15 per 1 million British thermal units (MMBtu). This value is also represented on Figure 6. The October 2021 D3 RIN value was approximately $38/MMBtu[1]. The value of the RNG environmental attributes greatly impacts the results of the financial analysis, which is why a sensitivity analysis was performed to further characterize the financial risks associated with RNG. The results of the sensitivity analysis are summarized later in this section.

[1] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information#regulatory-categories

Figure 6. Historical RIN Pricing

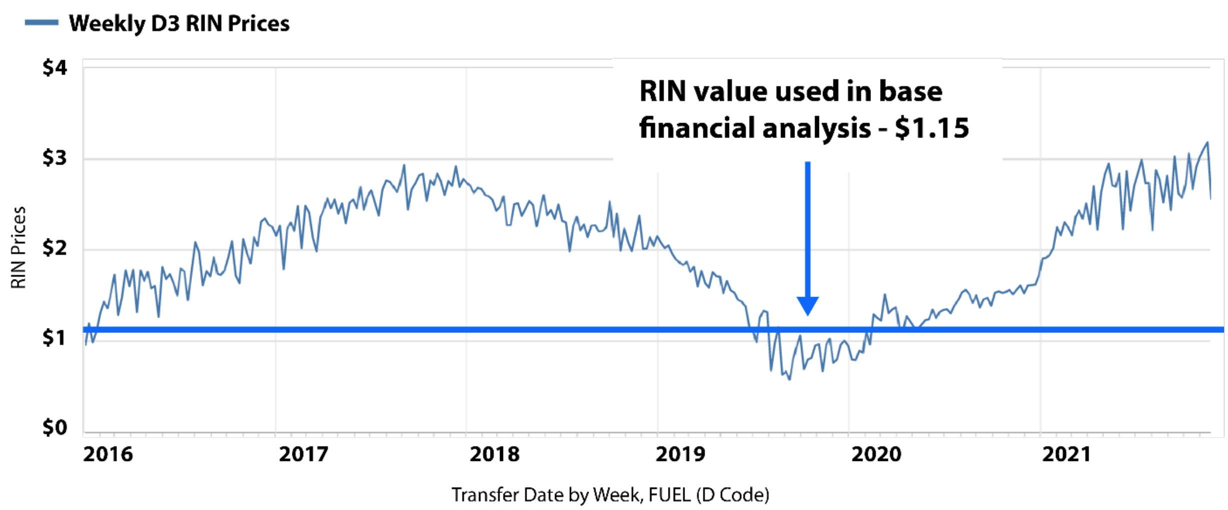
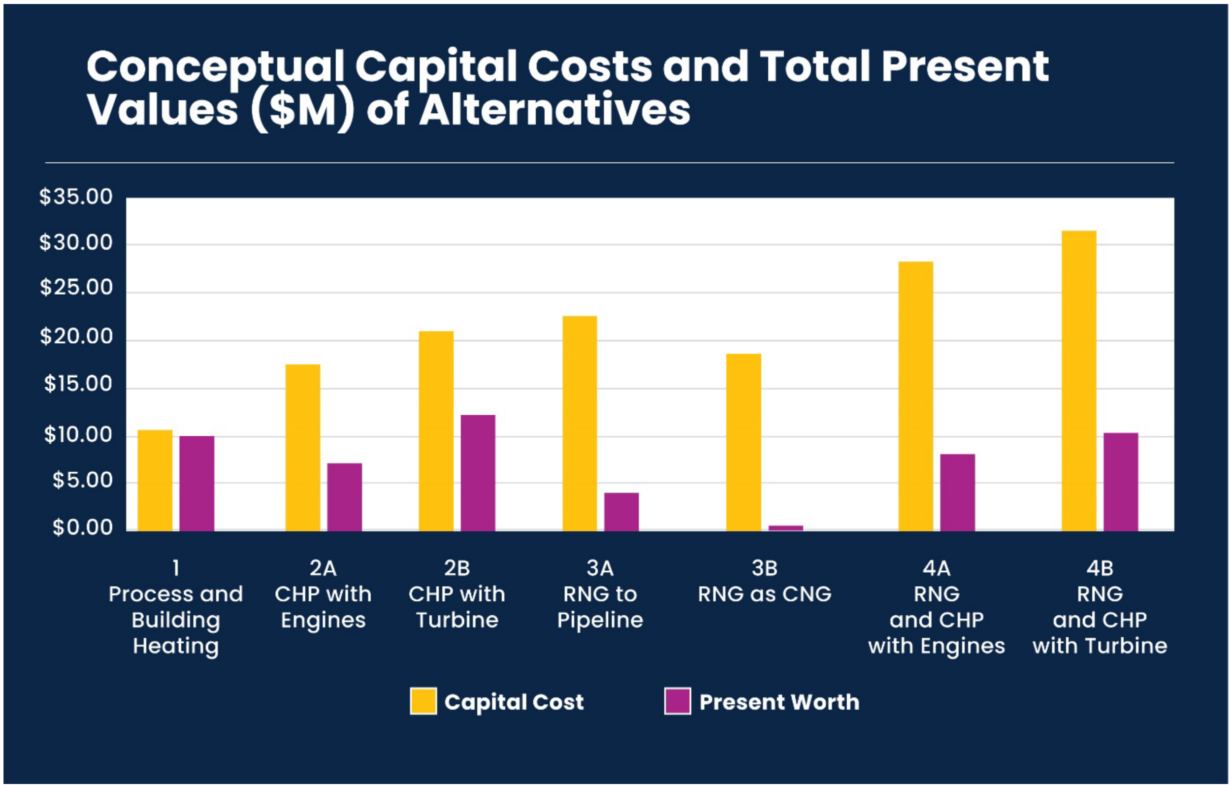


Figure 7 shows the conceptual capital costs and total present value for all alternatives. In this analysis, the cost of electricity was assumed to be $0.078 per kilowatt-hour (kWh) as this is the current average rate paid by Arlington County and energy prices are projected to remain stable.

The base cost analysis indicates that although the RNG alternatives (Alternatives 3A and 3B) do not have the lowest capital cost, they do have the lowest cost when taking into account the entire life cycle of the gas handling equipment to develop a total present-value cost, primarily because the value of the RINs offsets the initial capital investment. In comparison, the RNG and CHP alternatives (Alternatives 4A and 4B) would entail larger capital costs and comparable present-value costs to CHP alternatives (Alternatives 2A and 2B).

Figure 7. Conceptual Capital Costs and Total Present Values ($M) of Alternatives



The initial present-value analysis supported eliminating Alternatives 4A and 4B (RNG and CHP alternatives) from further consideration because of high capital costs, high overall complexity, significant use of natural gas to run the engines, and comparable present financial values to Alternatives 2A and 2B (CHP alternatives). The remaining alternatives were further analyzed for risk and non-financial factors, sustainability, and sensitivity to changing market conditions.

Non-Financial Analysis

Non-financial criteria were developed and weighted using input from County stakeholders. A description of the non-financial criteria and the weights established by the County for those criteria are presented in

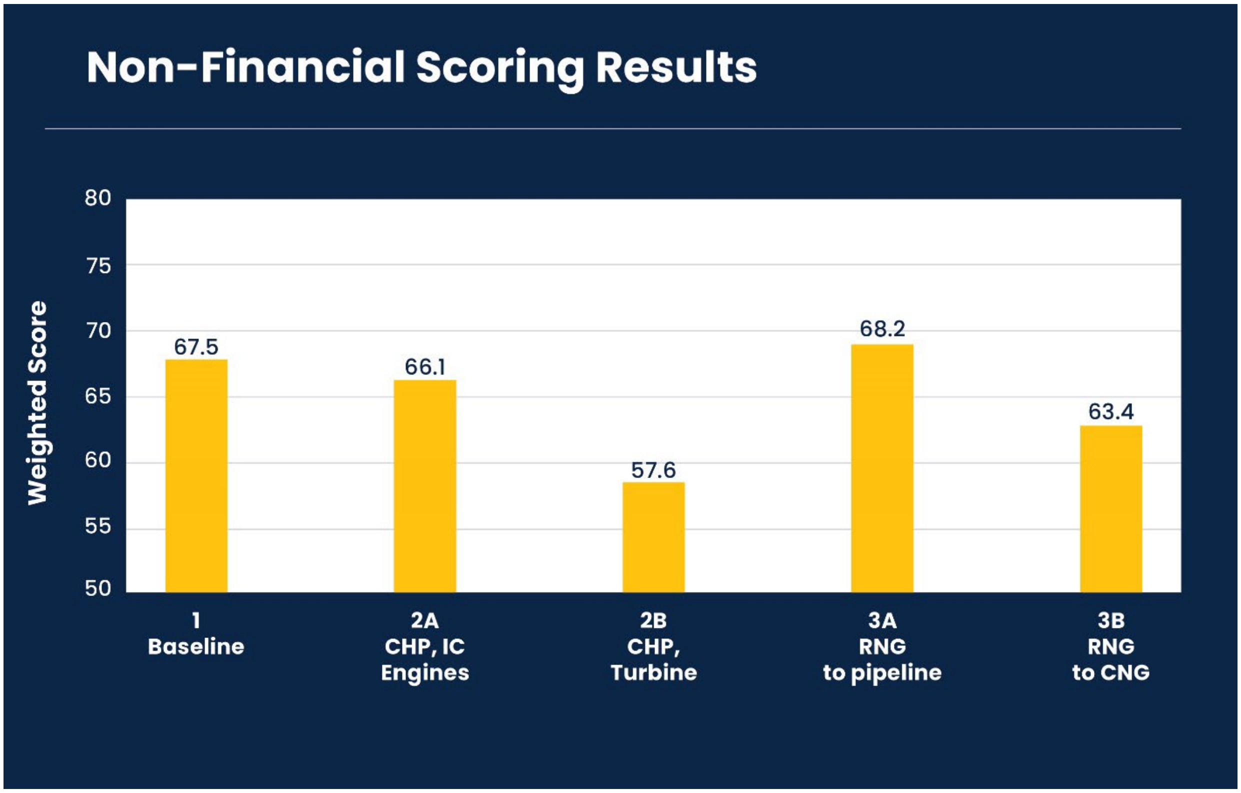
Table 1.

Table 1. Non-Financial Criteria

Criterion	Description	Weight
Localized emissions	Produces emissions at Plant site that may negatively impact air permitting requirements, cause neighborhood issues, or result in poor air quality in immediate area	8.0%
Noise	Generates excess noise that may impact neighbors or result in costly noise reduction measures	8.4%
Visual aesthetics	Is acceptable to the neighbors and general Arlington County community from a visual aesthetics standpoint	4.1%
Footprint	Sufficient space for operations and maintenance; does not take land space from current needs or potential future add-ons	6.9%
Potential for flaring	Provides multiple outlets for use of biogas or redundancy options to minimize the amount of biogas sent to the waste flare	8.4%
Operational complexity	Complexity of equipment and facilities in operation	11.8%
Maintenance complexity and reliability	Reliability of equipment and facilities, ongoing maintenance requirements, annual downtime for maintenance, and number of components that could fail, resulting in failure of system	11.8%
Safety	Risks for operation of system, including leaks, pressures, number of components, etc.	22.5%
Resilience	Provides for additional resilience benefits for the Plant and solids handling systems	8.8%
Future opportunities	Maintains flexibility for modifying approach should market conditions change	9.3%

The remaining alternatives (excluding Alternatives 4A/4B – RNG and CHP) were then scored based on this criteria to develop a non-financial score. With this methodology higher scores are better. Figure 8 presents the average scores for each alternative carried forward. Alternative 3A (RNG into pipeline) had the highest average non-financial score at 68.2, followed by Alternative 1 (Process and Building Heat) at 67.5. As stated previously, Alternative 1 is not a viable biogas utilization option, but it is included in the analysis as the minimum required to meet process needs. Alternative 1 scored well in the non-financial analysis as it is generally less complex than the other alternatives. Alternative 2B (CHP with Turbines) had the lowest non-financial score of 57.6.

Figure 8. Non-Financial Scoring Results



The main differentiators between the RNG alternatives (Alternatives 3A/3B) and CHP alternatives (Alternatives 2A/2B) were that the RNG alternatives had:

- Lower localized emissions
- Reduced noise
- More outlets for beneficial use of the biogas and ability to reduce flaring
- Lower maintenance complexity and reliability
- Ease of adaptability to other gas utilization alternatives in the future

Sustainability Criteria

Table 2 presents net change in GHG (namely carbon dioxide [CO_2]) emissions for each of the sources of energy for 2037. The net GHG change presented in Table 2 is solely for the gas utilization equipment, not the entire biosolids upgrade program. Alternatives 2A and 2B (CHP alternatives) result in emissions reductions from the offset of purchased power, while Alternatives 3A and 3B (RNG alternatives) result in emissions reductions because of the reduction in use of petroleum-based natural gas. Overall, Alternatives 2A (CHP with Engines) and 3A/B (RNG =alternatives) have greater GHG reductions than Alternative 1 (Process and Building Heating) and Alternative 2B (CHP with Turbines).

GHG reductions for Alternatives 2A and 2B (CHP alternatives) are based on the current Dominion Energy CO_2 emission profile, which includes a combination of fossil-fuel and renewable energy sources. Electricity for Arlington County operations is projected to be 100 percent renewable by 2025 through separate power purchase agreements, in which case the GHG reduction for net electricity production would be zero. However, the generation of renewable power at the Plant may allow for currently forecasted renewable sources to be used elsewhere and the financial analysis assumes that the County would be able to sell RECs for these alternatives.

Table 2. Total Change in Net CO_2 Emissions (Metric Tons) in Year 2037

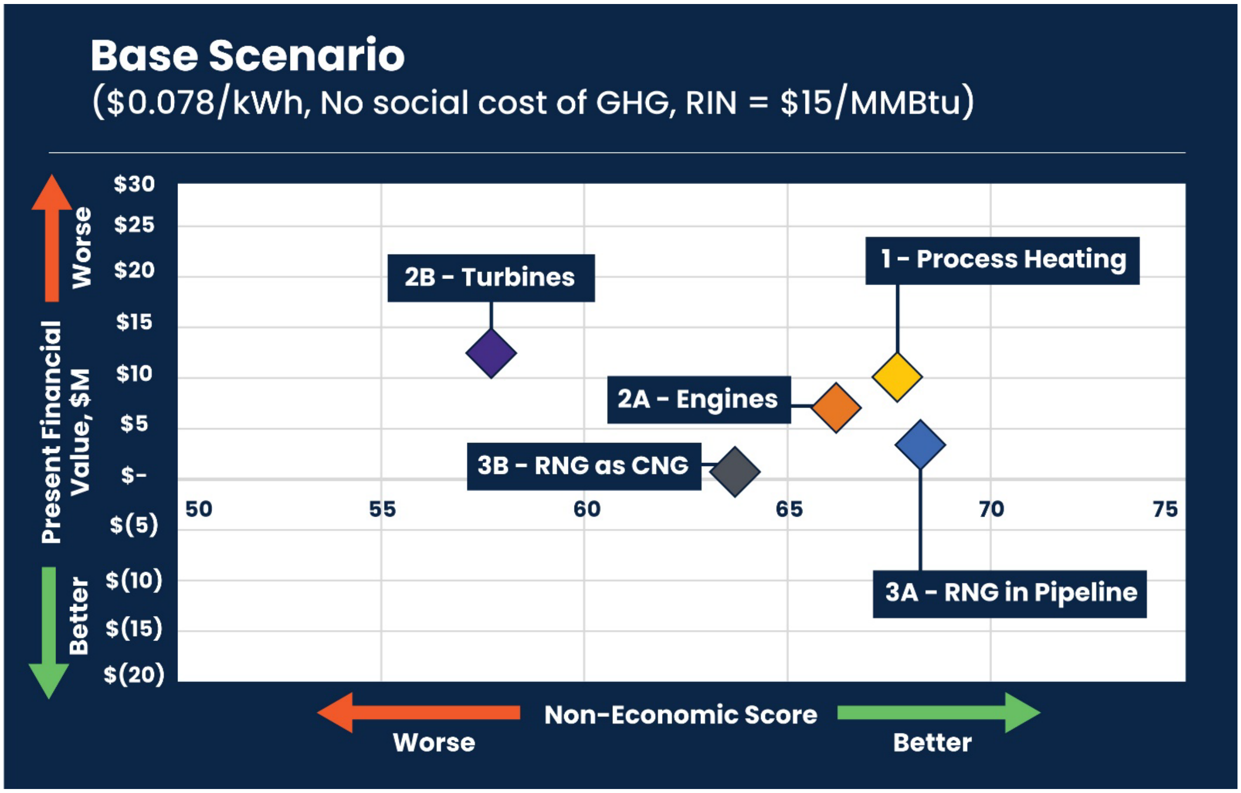
Alternative	Net Electricity Use of Biogas Utilization	Biogas Production (Offsets Natural Gas Purchases)	Natural Gas Purchased	Total Change in Emissions
1: Process and Building Heat	80	-40	0	40
2A: CHP with Engines	-3,330	-40	0	-3,370
2B: CHP with Turbines	-2,310	-40	0	-2,350
3A: RNG to Pipeline	770	-6,240	1,970	-3,500
3B: RNG Used as CNG	770	-6,240	1,970	-3,500

Note: Negative values are emissions reductions and positive values are emissions increases.

Composite Results

Figure 9 presents a composite result of the financial and non-financial scores using the base financial conditions (namely current electrical price of $0.078/kWh and average RIN market value of $15/MMBtu). The non-financial score is presented on the x-axis, the present financial value is presented on the y-axis, and the size of the bubble represents the conceptual capital cost. For this base condition, without considering the social cost of GHG, Alternative 3A (RNG to Pipeline) had the highest non-financial score and the second-lowest present financial value.

Figure 9. Base Scenario ($0.078/kWh, No social cost of GHG, RIN = $15/MMBtu)



Several alternative scenarios were run to test the sensitivity to key parameters.

Figure 10 provides the same analysis including the social cost of GHG and the average RIN value for the past six years of $23.35/MMBtu. This RIN value furthers the financial advantage of the RNG alternatives.

Figure 10. Average RIN Scenario ($0.078/kWh, Includes social cost of GHG, RIN = $23.35/MMBtu)

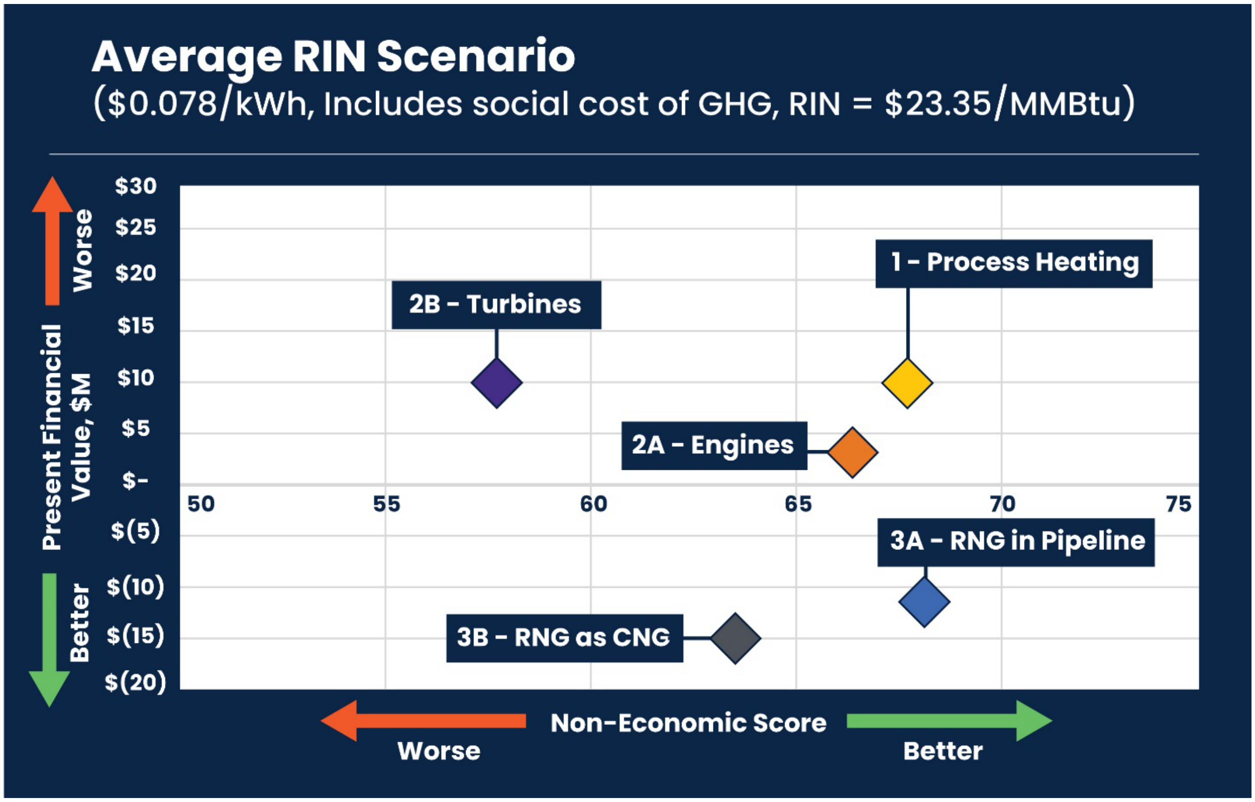


Figure 11 provides the same analysis including the social cost of GHG and the lowest weekly RIN value over the last six years of $6.38/MMBtu. In this scenario, Alternative 2A (CHP with Engines) becomes more financially advantageous.

Figure 11. Lowest RIN Scenario ($0.078/kWh, Includes social cost of GHG, RIN = $6.38/MMBtu)

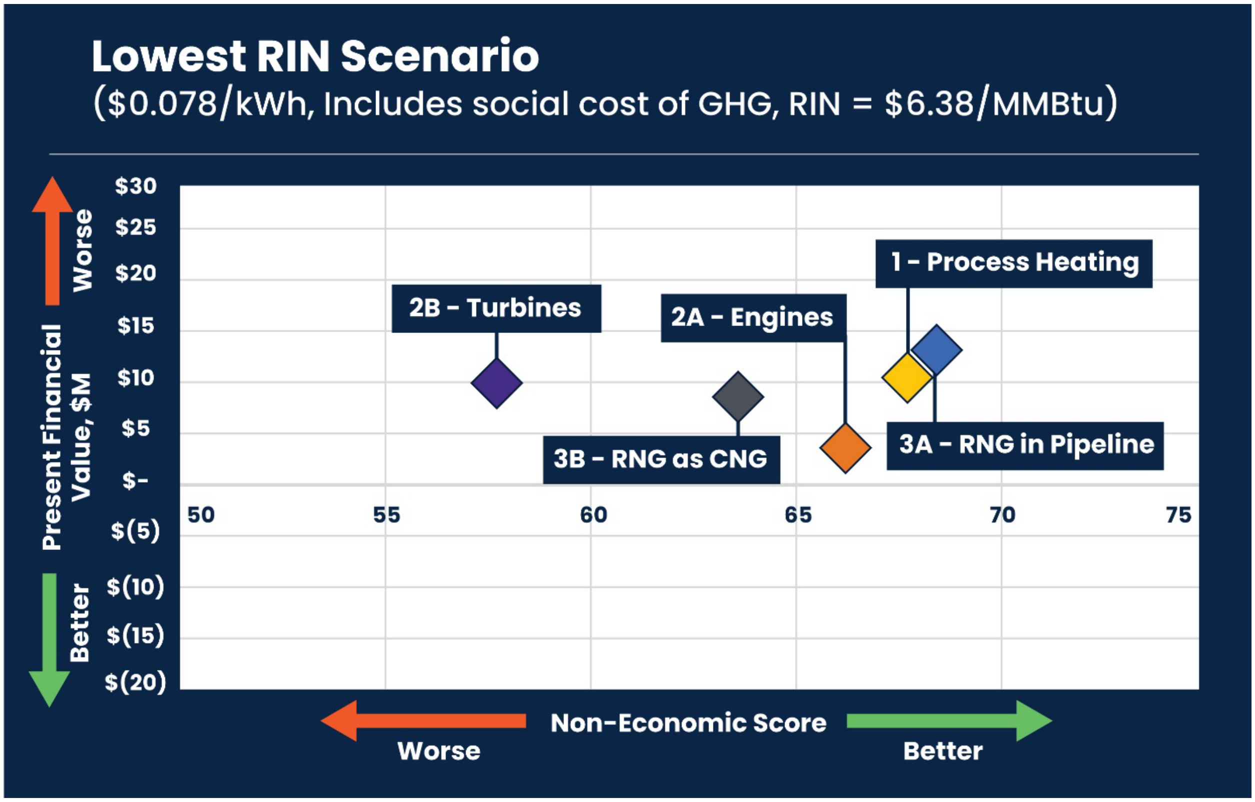
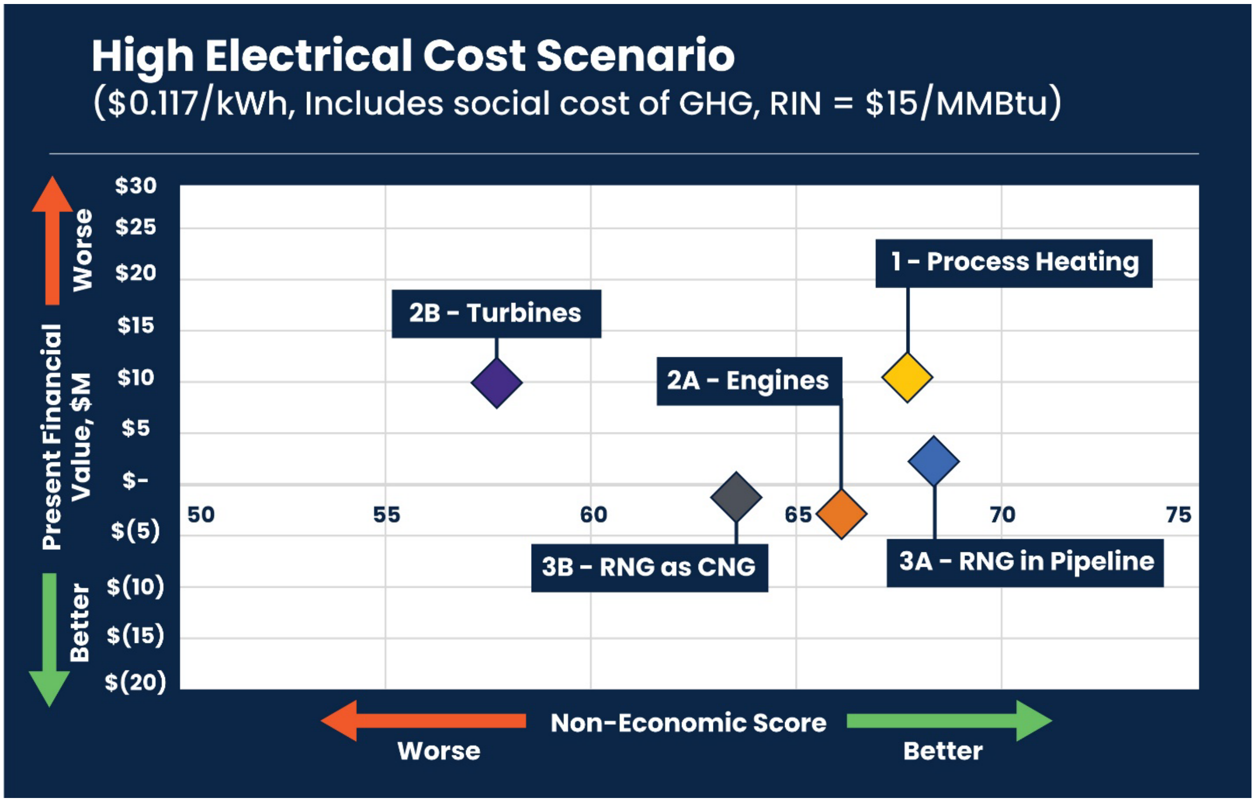


Figure 12 provides the analysis including the social cost of GHG and higher electricity cost of $0.117/kWh. In this scenario, the CHP alternatives become more financially favorable than the RNG alternatives.

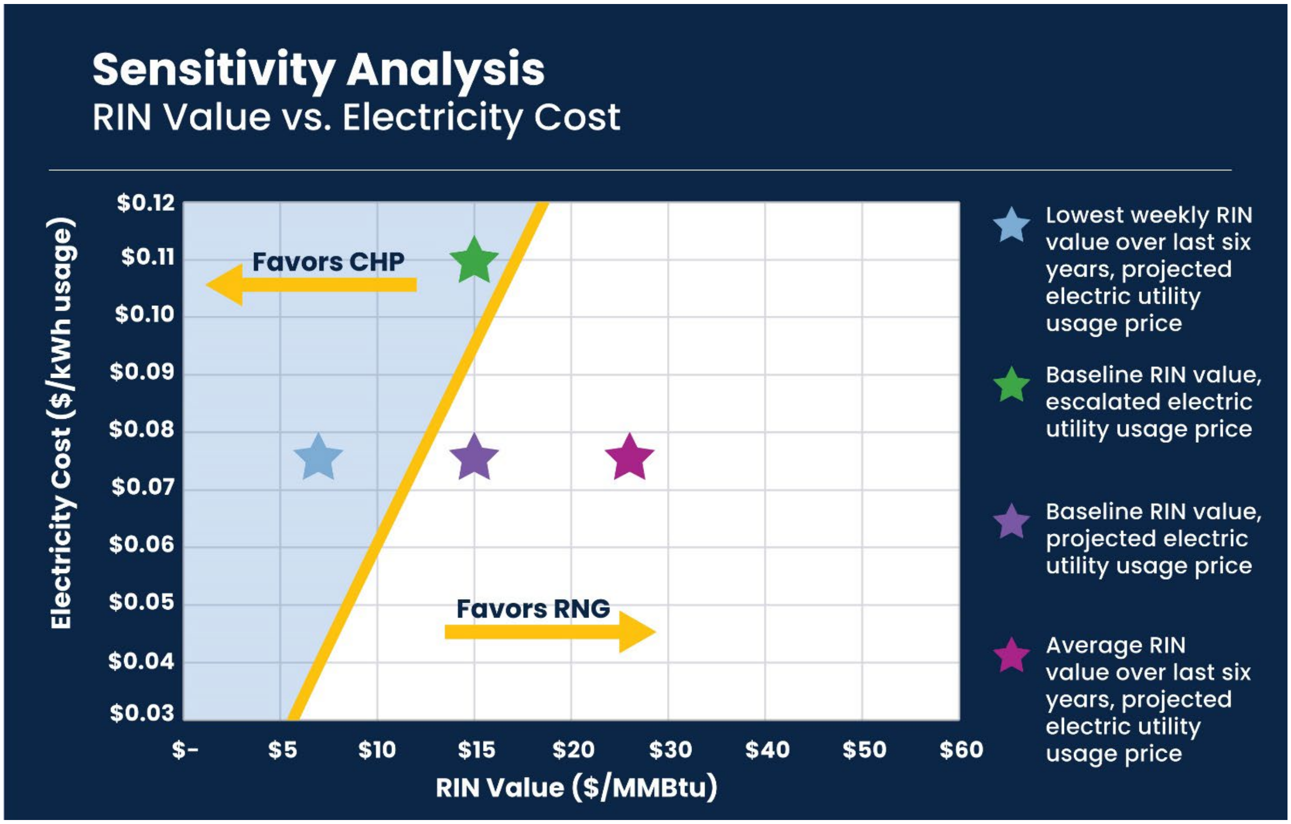
Figure 12. High Electrical Cost Scenario ($0.117/kWh, Includes social cost of GHG, RIN = $15/MMBtu)



Sensitivity Analysis

The financial analysis makes it clear that the main drivers in the comparison are the cost of electricity and the value of the RIN market. A break-even analysis was completed to identify the point at which Alternative 2A (CHP with Engines) is financially equal to Alternative 3A (RNG into Pipeline). This break-even analysis is shown on Figure 13, with the scenarios completed above identified.

Figure 13. Sensitivity Analysis of RIN Value vs. Electricity Cost



Additional detailed computer simulations were completed and these simulations confirmed the very high likelihood (greater than 90%) that the RNG alternatives will be more financially advantageous to Arlington County than the CHP alternatives.

Biogas Utilization Conclusion

Based on the analyses presented, the Arlington County Water Pollution Control Bureau recommends proceeding with Alternative 3 (RNG) as the selected biogas utilization approach. The basis for this recommendation is as follows:

- Alternative 3 (RNG) has the lowest net present value (i.e., lowest total cost to the County over the life of the equipment) for the baseline conditions using conservative capital and operating costs.
- Alternative 3A (RNG into Pipeline) scored the highest in the County's non-financial scoring. In particular, the County found that the RNG alternatives would be less complex to maintain and would result in fewer localized impacts such as noise and emissions than the CHP alternatives.
- A sensitivity analysis concluded that when considering multiple variables, including RIN volatility and changes in electrical rates, Alternative 3A (RNG into Pipeline) had a very high likelihood of being more financially advantageous than Alternative 2A.
- The County has the ability to retain GHG credits if the biogas is used within Arlington County for transportation purposes.
- Benefits of on-site CHP are limited because the CHP size would not be sufficient to power the entire Plant, which is already protected with two independent power feeds and backup generators. In addition, the use of CHP onsite will generate new, localized air emissions.

The County's current preference is for Alternative 3A (RNG into Pipeline) over Alternative 3B (RNG as CNG) due to the uncertain future of Arlington Transit and Washington Metropolitan Area Transit Authority fueling stations and the lack of a match between fueling times and gas production times (resulting in the need for additional storage). However, the final decision to inject RNG into the natural gas utility pipeline or to use CNG will be made in the future as more discussions with the stakeholders are conducted.

ARLINGTON RE-GEN

Biogas Utilization Final Report

HDR

November 18, 2022

Contents

Figures

Tables

Appendices

Abbreviations

°F	degree(s) Fahrenheit
AD	anaerobic digestion
ART	Arlington Transit
Btu	British thermal unit(s)
CDF	cumulative density function
CF	cubic foot/feet
CH_4	methane
CHP	combined heat and power
CI	carbon intensity
CIP	Capital Improvement Program
CNG	compressed natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
County	Arlington County
d	day(s)
Dominion	Dominion Energy
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EQ	Exceptional Quality
Facilities	solids handling processes
FOG	fats, oils, and greases
gCO_2e	gram(s) carbon dioxide equivalent
GHG	greenhouse gas
H_2S	hydrogen sulfide
HDR	HDR Engineering, Inc.
hp	horsepower
hr	hour(s)
HRSG	heat recovery steam generator
IC	internal combustion
IWG	Interagency Working Group
kg	kilogram(s)
kW	kilowatt(s)
kWh	kilowatt-hour(s)
lb	pound(s)
lbm	pound(s) mass
LCFS	Low Carbon Fuel Standard
LHV	low heating value
MAD	mesophilic anaerobic digestion
MBH	1,000 British thermal units per hour

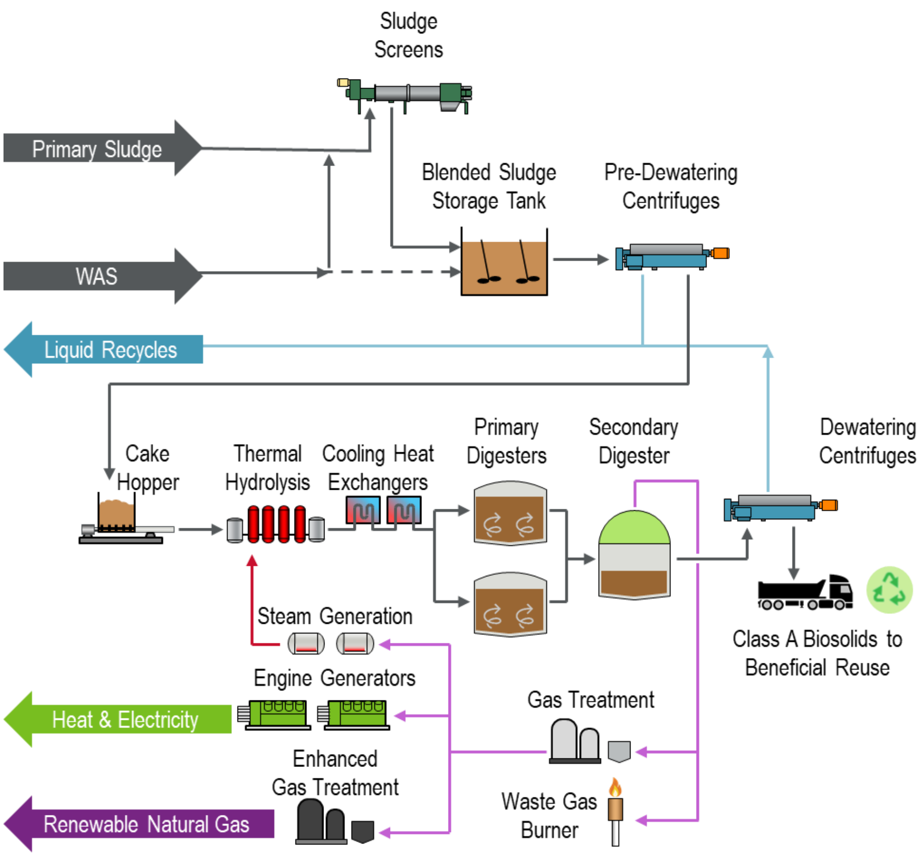
MBtu	1,000 British thermal units
MMBtu	1 million British thermal units
mgd	million gallons per day
MJ	megajoule(s)
MMscf	million standard cubic feet
MT	metric ton(s)
MW	megawatt(s)
MWh	megawatt-hour(s)
N/A	not applicable
N_2	nitrogen
NG	natural gas
O_2	oxygen
O&M	operations and maintenance
O&P	overhead and profit
PDF	probability density function
Plan	Arlington County Water Pollution Control Plant Solids Master Plan
ppm	part(s) per million
Program	Arlington County Water Pollution Control Plant Re-Gen/Biosolids Program
psig	pound(s) per square inch gauge
QA	quality assurance
REC	Renewable Energy Credit
RFP	request for proposals
RFS	Renewable Fuels Standard
RIN	Renewable Identification Number
RNG	renewable natural gas
RTO	regenerative thermal oxidizer
RVO	Renewable Volume Obligation
S	sulfur
scf	standard cubic foot/feet
scfm	standard cubic foot/feet per minute
SF	square foot/feet
THP	thermal hydrolysis process
TM	technical memorandum
VOC	volatile organic compound
WMATA	Washington Metro Area Transit Authority
WPCB	Water Pollution Control Bureau
WPCP	Water Pollution Control Plant
yr	year(s)

1 Introduction and Goals

1.1 Introduction

Arlington County (County) is implementing new biosolids management facilities at the Arlington County Water Pollution Control Plant (WPCP). The Arlington County WPCP Re-Gen/Biosolids Program (Program) is a comprehensive program that will include the engineering, design, construction, maintenance, startup, and operation necessary to add sustainable equipment and systems to effectively recover the County's renewable resources, produce a Class A biosolids product, and most efficiently utilize the biogas. The new solids handling processes (Facilities) will entail upgrades or replacement of nearly all existing solids handling processes. A thermal hydrolysis process (THP) followed by anaerobic digestion (AD) form the backbone of the new treatment train. The THP process uses temperature and pressure to breakdown the solids and remove pathogens, while the AD process stabilizes the solids and generates a methane (CH_4) rich biogas. The solids end product is a marketable Class A biosolids product. The overall process flow diagram for the Facilities is shown in Figure 1.

Figure 1: New Solids Handling Processes Flow Diagram



1.2 Program Mission Statement

A mission statement can be a valuable tool to help set the tone for a program during internal meetings and workshops. The Program's mission statement is as follows:

Upgrade resource recovery facilities to produce Class A biosolids and renewable energy, maximizing sustainability and community acceptance. Collaborate with team members to select and implement processes that are safe, reliable, and financially responsible throughout planning, design, construction, operations and maintenance.

1.3 Program Goals

Building on the mission statement and related drivers for the Program, below are the Program goals developed by the County:

1. **Produce a Class A Exceptional Quality (EQ) end product:** high-quality, low-odor product suitable for beneficial use and reduced risk of regulatory impact for land application
2. **Recover biogas for beneficial use:** recovering and beneficially using renewable resources to help achieve County-wide sustainability goals
3. **Provide ease of maintenance and repairs:** easy to work with equipment, updated technology with high efficiency and long-term ability to find replacement parts
4. **Keep safety in mind:** throughout process, design, construction, and ongoing operations
5. **Apply proper process selection and configuration:** appropriate choice of processes, well-designed and coordinated across the entire system, reliable with adequate redundancy
6. **Implement an open, transparent, and collaborative process between all team members**
7. **Achieve and maintain community acceptance:** maintain "good neighbor" status, including construction, and produce an outcome that is an asset to the community
8. **Implement cost-effective solutions:** make the most out of the investment
9. **Develop operator-friendly solutions:** comprehensive training on reliable and accessible equipment with clear operations and maintenance (O&M) and troubleshooting guidance
10. **Design for long-term reliability:** eliminate nuisance-causing, aging equipment and processes
11. **Actively engage staff throughout process:** during design, construction, startup, and training

12. **Ensure that staff are well prepared to operate and maintain the new processes:** via comprehensive training, ample transition time, and appropriate staffing levels for new systems

This Biogas Utilization Report is intended to provide more clarity on achieving Goal 2 (recover biogas for beneficial use). The following chapters summarize biogas production and energy needs at the WPCP, and evaluate several alternatives based on financial, non-financial, and sustainability criteria to recommend a biogas utilization approach that is consistent with the remaining Program goals listed above.

2 Background

2.1 Previous Reports

Several previously completed Arlington County planning reports and documents serve as a foundation for the Program evaluations:

- Arlington County Community Energy Plan (2019)
- Arlington County WPCP Foul Air Study (2017)
- Arlington County Sanitary Sewer Study (2020)
- Arlington County WPCP Condition Assessment (2019)
- Arlington County WPCP Solids Master Plan (2018)

The most relevant previous report for the biogas utilization analysis is the Arlington County WPCP Solids Master Plan (Plan) authored by CDM Smith. Additional descriptions of the Plan goals and recommendations are provided in the next sections.

2.1.1 Arlington County WPCP Solids Master Plan

The Plan, dated March 2018, evaluated several solids handling alternatives and developed a recommendation that addressed several needs of the WPCP. The overall goals of the Plan are listed below:

- Replace failing and end-of-life equipment
- Mitigate the risk of potential future regulatory changes to the current practice of recycling Class B biosolids through application to agricultural land
- Provide a solution that reduces the energy and greenhouse gas (GHG) footprint of the WPCP
- Achieve additional County-wide sustainability goals
- Develop a solids management strategy that offers long-term reliability
- Establish an implementation plan compatible with County Capital Improvement Program (CIP) funding

The alternatives evaluated in the Plan to achieve these goals included continuing lime stabilization, mesophilic anaerobic digestion (MAD), THP followed by MAD, and MAD followed by heat drying. The evaluation took into consideration 19 criteria, including the energy balance of each alternative. The energy balances are presented in Figures 10-10a, 10-10b, and 10-10c of the Plan.

The recommended alternative from the Plan was THP followed by MAD and a key aspect of the selection of this alternative was the energy value of the biogas produced. Section 12.4 of the Plan discusses the potential for future biogas utilization alternatives, but no formal recommended biogas use was made. Text from Section 12.4 of the Plan is shown below.

> ## 12.4 Biogas Utilization
> In addition to the equipment and processes described, the County will continue to evaluate opportunities for biogas utilization. Opportunities identified include utilization of the biogas on-site through a combined heat and power system or cleaning and exporting the gas as a biomethane.
>
> A combined heat and power system would include a combustion engine generator that produces electrical power for use on-site or potential metering the electrical utility. A heat recovery system for the engines and exhaust would allow heat to be captured for potential uses in building or process heating (e.g., steam generation). A biogas cleaning system is recommended for the system. The cleaning system would remove contaminants in the biogas such as hydrogen sulfide, siloxanes, and moisture that could impact engine wear and performance.
>
> The opportunity to purify and export biogas as a biomethane may also be considered. Biomethane production involves increasing the energy content of the gas as well as removing contaminants including carbon dioxide, hydrogen sulfide, and moisture. Multiple technologies exist for producing biomethane. Opportunities to inject the biomethane into the natural gas distribution system or pipeline can be explored. The County may also consider a partnership with the Arlington Rapid Transit's CNG (compressed natural gas) fueling station located adjacent to the WPCP.
>
> As the County moves ahead with implementation of thermal hydrolysis and anaerobic digestion, biogas utilization opportunities can be explored.

This Biogas Utilization Report does not seek to revisit the previous Arlington County Board-adopted decision to proceed with THP followed by MAD, but rather to evaluate the biogas utilization alternatives to meet the biogas utilization goal of recovering and beneficially using renewable resources to help achieve County-wide sustainability goals.

2.1.2 Planning Period

The planning period is important for this study as the financial analysis needs to consider the change in solids production and costs of electricity, natural gas (NG), and equipment O&M over time to develop a net present value for each alternative. Based on discussions with the County, a 25-year planning period following construction was selected. With construction anticipated to finish in 2027, the planning period for this study runs from 2027 to 2052. The target year of 2052 was selected for when the design flows and loads are anticipated to be reached, resulting in a design solids production loading of approximately 40 tons per day. Based on the current solids production of 30.7 tons per day, it is anticipated that the solids production will increase linearly by approximately 0.37 ton per year, or roughly 1.0 percent per year based on anticipated population growth. To illustrate the energy balance and economic analysis results presented in the subsequent chapters, an evaluation year of 2037 was selected as it is close to the midpoint of the planning period and falls on one of the 5-year increments developed.

2.2 Process Requirements

The energy required to achieve the WPCP process requirements was calculated to develop the overall energy balance of the WPCP and determine the best use of the biogas. The sections below summarize the solids production, heating requirements, and biogas production throughout the planning period.

2.2.1 Solids Production

Current and future solids production were determined as part of the review of historical WPCP data and the resulting mass balance as presented in Technical Memorandum (TM) No. 1, *Solids Production and Design Criteria*. The three sizing scenarios are based on loadings in 2020 at 23.0 million gallons per day (mgd), a year 2052 design condition at 30.8 mgd, and ultimate capacity at 40.0 mgd. Solids production and corresponding energy needs and biogas production are assumed to increase at a linear rate between now and the design year. Table 1, Table 2, and Table 3 below present the biosolids total solids; volatile solids; and primary scum and fats, oils, and greases (FOG) volatile solids loadings, respectively, over the planning period in 5-year increments.

Table 1: Biosolids Total Solids Loading to Pre-dewatering, dry lb/d

Parameter	2027	2032	2037	2042	2047	Design 2052
Average	65,872	69,122	72,371	75,621	78,870	82,120
30-day max	86,190	90,442	94,694	98,946	103,197	107,449
14-day max	93,892	98,524	103,156	107,788	112,419	117,051
7-day max	99,391	104,294	109,197	114,099	119,002	123,905
3-day max	109,423	114,821	120,219	125,616	131,014	136,412

Table 2: Biosolids Volatile Solids Loads to Pre-dewatering, dry lb/d

Parameter	2027	2032	2037	2042	2047	Design 2052
Average	50,865	53,374	55,883	58,392	60,901	63,410
30-day max	66,085	69,170	72,400	75,780	79,317	83,020
14-day max	71,980	75,341	78,858	82,539	86,393	90,426
7-day max	76,190	79,747	83,470	87,367	91,446	95,715
3-day max	83,904	87,821	91,921	96,213	100,705	105,406

Table 3: Primary Scum and FOG Volatile Solids Loads to Digestion, dry lb/d

Parameter	2027	2032	2037	2042	2047	Design 2052
Average	4,625	4,854	5,082	5,310	5,538	5,766
30-day max	6,244	6,552	6,860	7,168	7,476	7,784
14-day max	6,752	7,086	7,419	7,752	8,085	8,418
7-day max	7,123	7,474	7,825	8,177	8,528	8,879
3-day max	7,955	8,348	8,740	9,132	9,525	9,917

2.2.2 Biogas Production

Future biogas production is based on the same assumptions as presented in TM No. 1, which included 95 percent solids capture in the pre-dewatering system, 60 percent volatile solids reduction for primary and secondary biosolids, and 90 percent volatile solids reduction of primary scum and FOG. The assumed biogas yield is 17 standard cubic feet (scf) of biogas produced per pound (lb) of volatile solids destroyed.

Table 4 below presents the biogas production values for the planning period in 5-year increments. The average values for each year are used for the financial analysis in Chapter 4.

Table 4: Biogas Production, scfm

Parameter	2027	2032	2037	2042	2047	Design 2052
Average	388	408	428	445	466	486
30-day max	511	536	562	587	612	637
14-day max	556	584	611	639	666	693
7-day max	589	618	647	676	705	734
3-day max	649	681	713	745	777	809

The above biogas production values were used with an energy content of 580 British thermal units (Btu)/scf (low heating value [LHV]) to develop the biogas energy production in thousands of British thermal units (MBtu) per hour (MBH) in Table 5 below. LHV is the energy produced from combustion excluding the latent heat of vaporization. The efficiencies of combustion equipment such as boilers and engines are stated based on the LHV of the fuel inputs.

Table 5: Biogas Production, MBH

Parameter	2027	2032	Used 2037	2042	2047	Design 2052
Average	13,500	14,200	14,900	15,500	16,200	16,900
30-day	17,800	18,700	19,500	20,400	21,300	22,200
14-day	19,400	20,300	21,300	22,200	23,200	24,100
7-day	20,500	21,500	22,500	23,500	24,500	25,500
3-day	22,600	23,700	24,800	25,900	27,100	28,200

2.2.3 Steam Demand

The THP system consumes 1.0 ton of steam for each ton of solids processed. In the 2037 evaluation year that equals an annual average steam demand of 3,020 pounds per hour (lb/hr) or 3,490 MBH. That is an average steam demand, but the batch nature of THP requires higher peak flows of steam reaching more than 10,000 lb/hr. The average demand was used for the financial analysis, whereas the peak demand of 10,000 lb/hr was used for sizing steam boilers. Table 6 below presents the steam required for the planning period in 5-year increments.

Table 6: Steam Required, lb/hr

Parameter	2027	2032	Used 2037	2042	2047	Design 2052
Average	2,740	2,880	3,020	3,150	3,290	3,420
30-day	3,590	3,770	3,950	4,120	4,300	4,480
14-day	3,910	4,110	4,300	4,490	4,680	4,880
7-day	4,140	4,350	4,550	4,750	4,960	5,160
3-day	4,560	4,780	5,010	5,230	5,460	5,680

Table 7 presents the steam requirements above as energy required in MBH.

Table 7: Steam Required, MBH

Parameter	2027	2032	Used 2037	2042	2047	Design 2052
Average	3,170	3,330	3,490	3,640	3,810	3,960
30-day	4,150	4,360	4,570	4,770	4,980	5,180
14-day	4,520	4,760	4,980	5,190	5,410	5,650
7-day	4,790	5,030	5,260	5,500	5,740	5,970
3-day	5,280	5,530	5,800	6,050	6,320	6,570

2.3 Other Energy Requirements

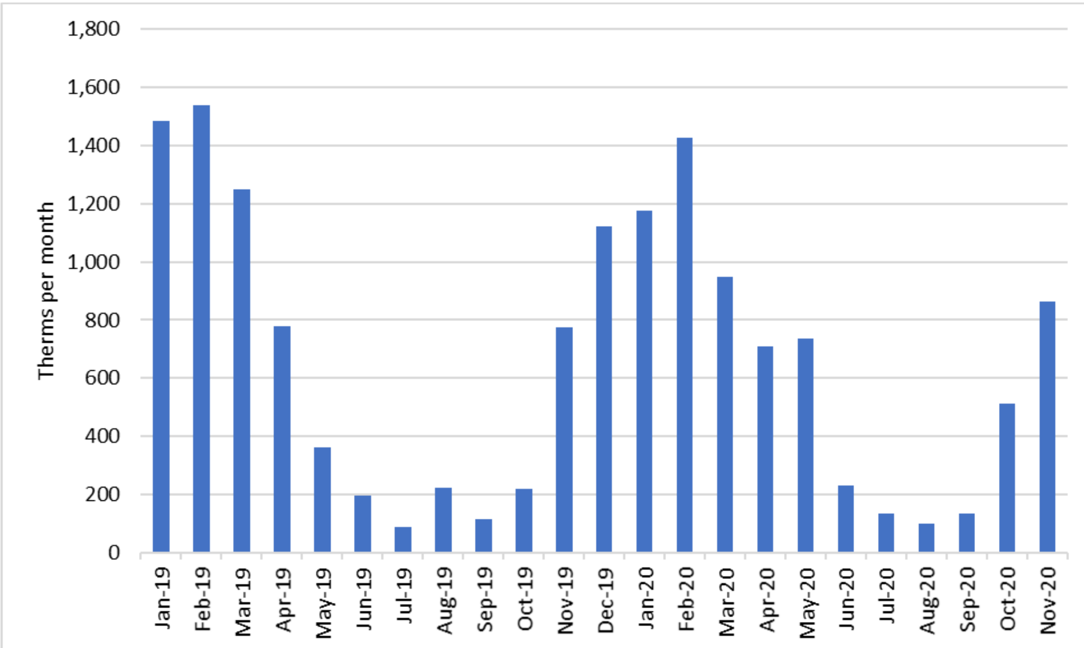
In addition to process heating requirements described above, the Arlington WPCP has other energy requirements, including providing heat for buildings and overall WPCP electrical demands. These energy requirements are summarized in the sections below.

2.3.1 Building Heating

Current building heating requirements were based on existing NG bills for the period between January 2019 and November 2020.

Figure 2 shows the monthly NG usage. Based on these data the average annual NG usage is 7,800 therms per year (780 million British thermal units per year [MMBtu/yr]) or 89 MBH and a heating load of 71 MBH at 80 percent efficiency. Building heating needs will likely change over time and will be refined as the building modifications are refined throughout the Program. For now, building heating needs are assumed to be constant through the duration of the planning period.

Figure 2: Monthly Natural Gas Usage



2.3.2 WPCP Electrical Usage

Similar to natural gas, current and future WPCP electrical requirements were based on existing power bills for the period between January 2019 and November 2020.

Figure 3 shows the monthly power usage in kilowatt-hours (kWh) per month. Based on these data the average annual power usage is approximately 29,624,000 kWh/yr, or a 3.38-megawatt (MW) average load. Assuming a similar usage increase as the flows and loads, the future electrical usage can be developed and is shown in Table 8.

Figure 3: Monthly Electrical Usage

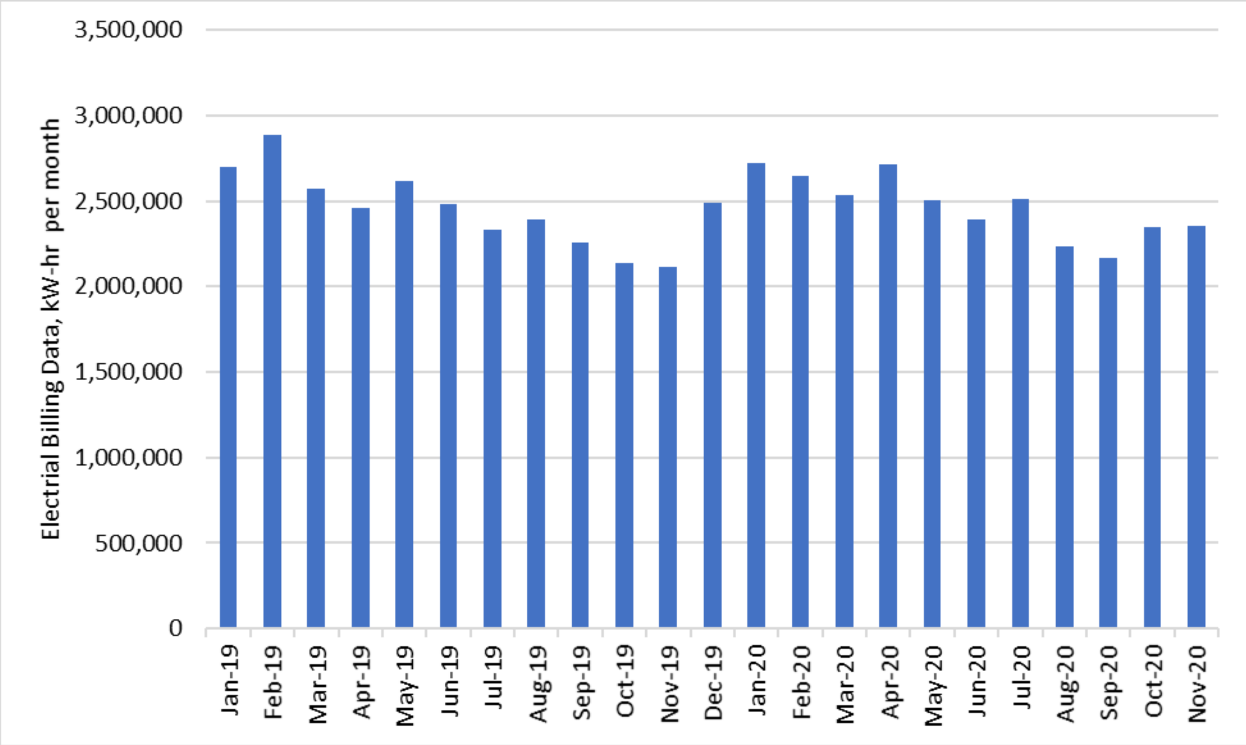


Table 8: Facility's Electrical Usage Forecast

Parameter	Actual 2020	2022	2027	2032	Used 2037	2042	2047	Design 2052
kWh/yr	29,624,000	30,252,000	31,822,000	33,391,000	34,961,000	36,531,000	38,101,000	39,670,400
MBH	11,500	11,800	12,400	13,000	13,600	14,200	14,800	15,500
MW	3.38	3.45	3.63	3.81	3.99	4.17	4.35	4.53

2.4 Renewable Natural Gas Market Summary and Potential Values

Biogas produced from anaerobic digestion has historically been used on site at wastewater facilities to provide fuel for process and building heating or by generating electricity and recovering waste heat for process and building heating. Over the last decade, the option of conditioning the biogas to NG quality and using the renewable natural gas (RNG) off site as vehicle fuel has become a viable third potential use of the biogas. The major drivers of this biogas utilization option are federal programs, like the U.S. Environmental Protection Agency (EPA) Renewable Fuels Standard (RFS), and state incentive programs, like the California Low Carbon Fuel Standard (LCFS), that encourage the use of renewable fuels to lower the use of petroleum products. Summaries of the EPA RFS and California LCFS are provided below.

2.4.1 EPA Renewable Fuels Standard

The United States Congress created the RFS through the Energy Policy Act of 2005 and revised the program with the Energy Independence and Security Act in 2007. The RFS is a renewable-fuels program within the Clean Air Act that mandates that large fossil-fuel producers and blenders (Obligated Parties) must include within their fuel mix a growing portion of renewable fuels. The quotas required of the Obligated Parties are referred to as Renewable Volume Obligations (RVOs) and are established and tracked by EPA through the use of renewable credits, also known as Renewable Identification Numbers (RINs). The original program was designed to increase the RVOs until 2022 and then level off beyond that point unless Congress issued another amendment. EPA can lower or raise the RVOs up to the maximum RVO quota set for 2022 but Congressional action would be required to eliminate the RFS program. The RFS program has pressure against it from the oil and gas industry, but also has strong support from the corn ethanol industry, which represents half of the RIN market.

As part of EPA's RFS, RVOs are developed by categorized RIN types based on their environmental benefit and the production pathway. These categories, D3 through D7, encompass lower-value biofuels like corn-based ethanol (D6) up to high-value biofuels like cellulosic biodiesel or ethanol (D3). Refer to Figure 4 for classifications of the RIN types.

The biogas produced from the digestion of municipal biosolids is considered D3 cellulosic and has the highest market value. However, any biogas produced by the co-digestion of municipal solids with hauled-in or high-strength wastes will be considered D5 advanced, unless each individual feedstock has a 75 percent or higher cellulosic content. Hauled-in wastes are defined as any wastes brought to the WPCP by truck, not the sewer, and these wastes are typically not considered cellulosic as they are not woody or starchy by nature. The exception to this requirement is hauled-in septage, which is still considered cellulosic. At this point the County does not intend to receive any wastes by truck.

Figure 4: EPA RFS Nested RIN Categories and Volumes

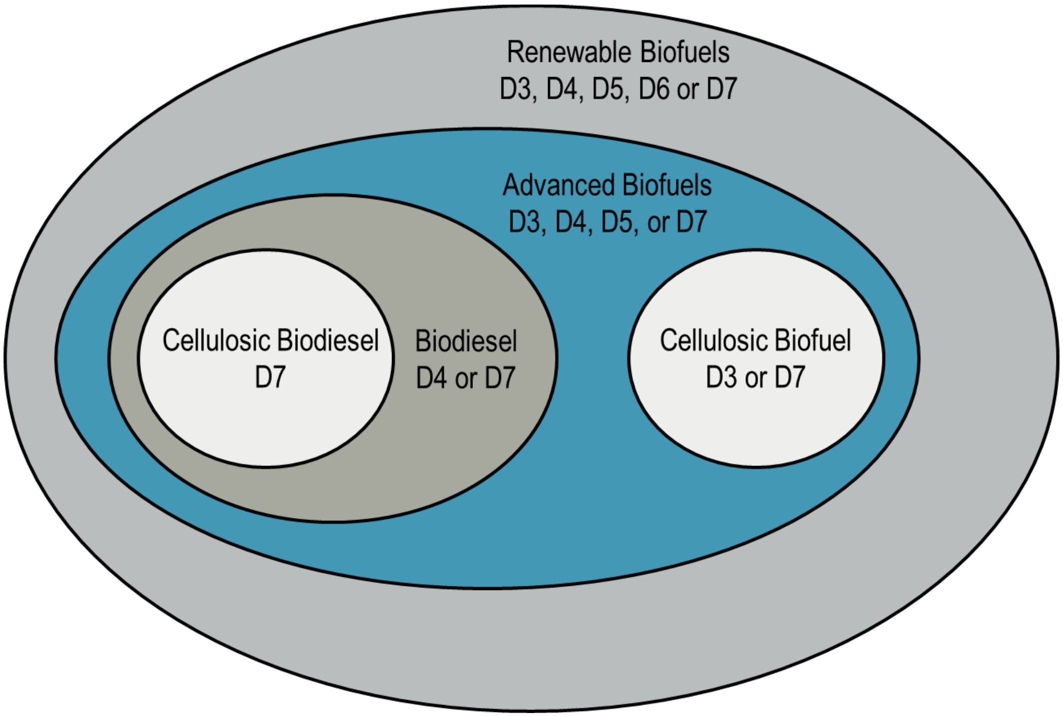
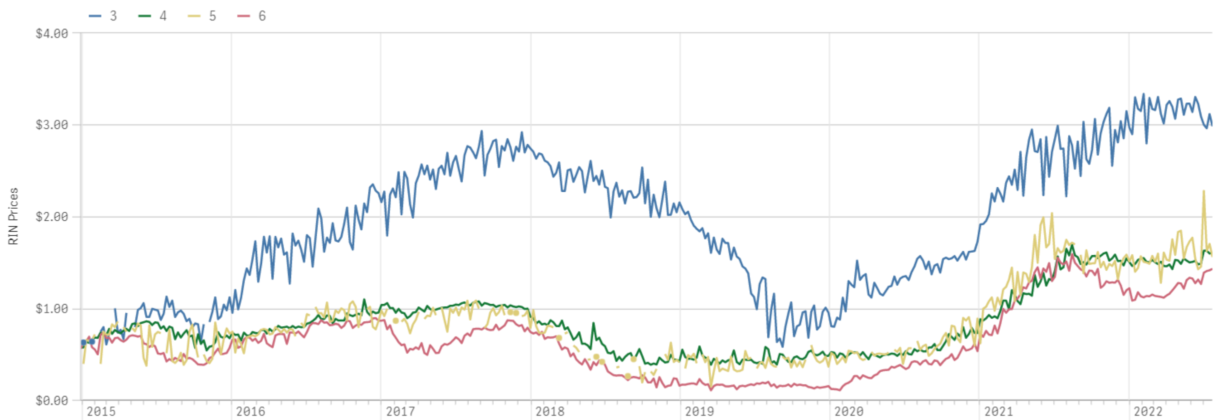


Figure 5 presents the historical RIN values as reported by EPA from 2015 through June 2022 (https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information). Note, there are 13 RINs per 1 MMBtu, so a RIN price of $1.00 equates to $13/MMBtu.

Figure 5: EPA RFS RIN Historical RIN Values



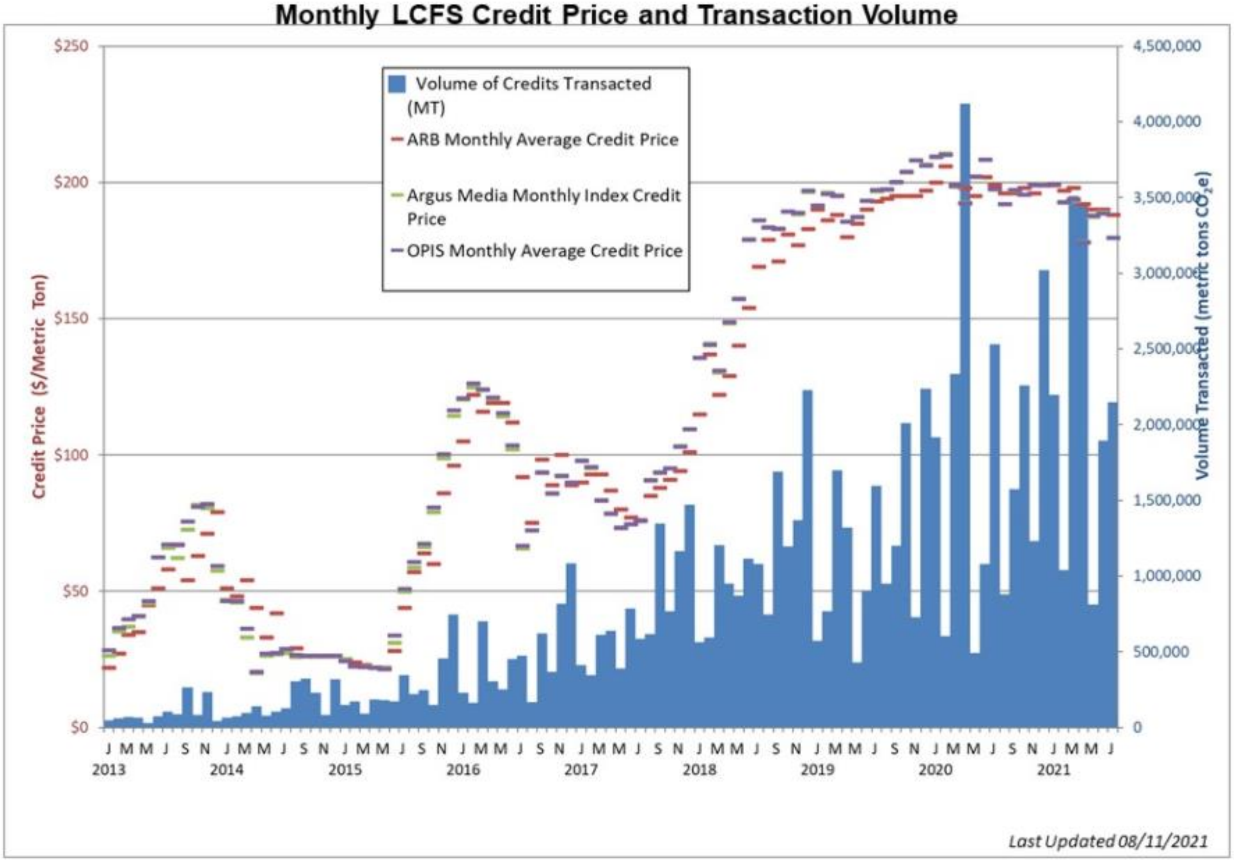
As shown in Figure 5, all RIN market values peaked in late 2017 and continued to fall through 2019 with a market rebound occurring in 2020 through 2022. The drop in market values in 2018 and 2019 was due to two major short-term factors:

- **Small refinery exemptions:** EPA administration at the time was allowing this hardship exemption to be used by large blenders, reducing their obligation for RINs.
- **Carry-over bank:** The program allows Obligated Parties to carry more than 20 percent of their obligation to the next year. In 2018 and 2019 Obligated Parties were using this carry-over allowance, but they are not allowed to do that year over year, so demand for all RINs returned in 2020.

2.4.2 Low Carbon Fuel Standard

In addition to RINs, carbon offset credits are available through California's LCFS program. The LCFS has become a healthy market with more transactions and higher values throughout the last 8 years (see Figure 6) and the program is currently slated to run through 2032. It could be renewed to extend past that date. LCFS credits can be obtained in addition to RIN credits as long as the renewable fuel is contracted for sale to an Obligated Party with end use in California. The value of RNG in the LCFS market is dependent on the carbon intensity (CI) score of the RNG produced as determined by the LCFS program requirements. The CI score takes into account the net carbon reductions achieved by producing the RNG including the energy required for processing and transporting the RNG to the end use. Typical wastewater treatment CI scores are in the range of 20 to 40 grams carbon dioxide equivalent per megajoule (gCO_2e/MJ). The current credit price of $180 per metric ton (MT) is equivalent to $12.30/MMBtu at an average CI score of 30 gCO_2e/MJ. This value can be added to the values of the RINs from the RFS. Arlington County would be eligible to participate in the LCFS program. However, it is a highly competitive program. It is attractive to producers of biogas generated from animal manure, as that biogas has a lower CI score.

Figure 6: California LCFS Market History

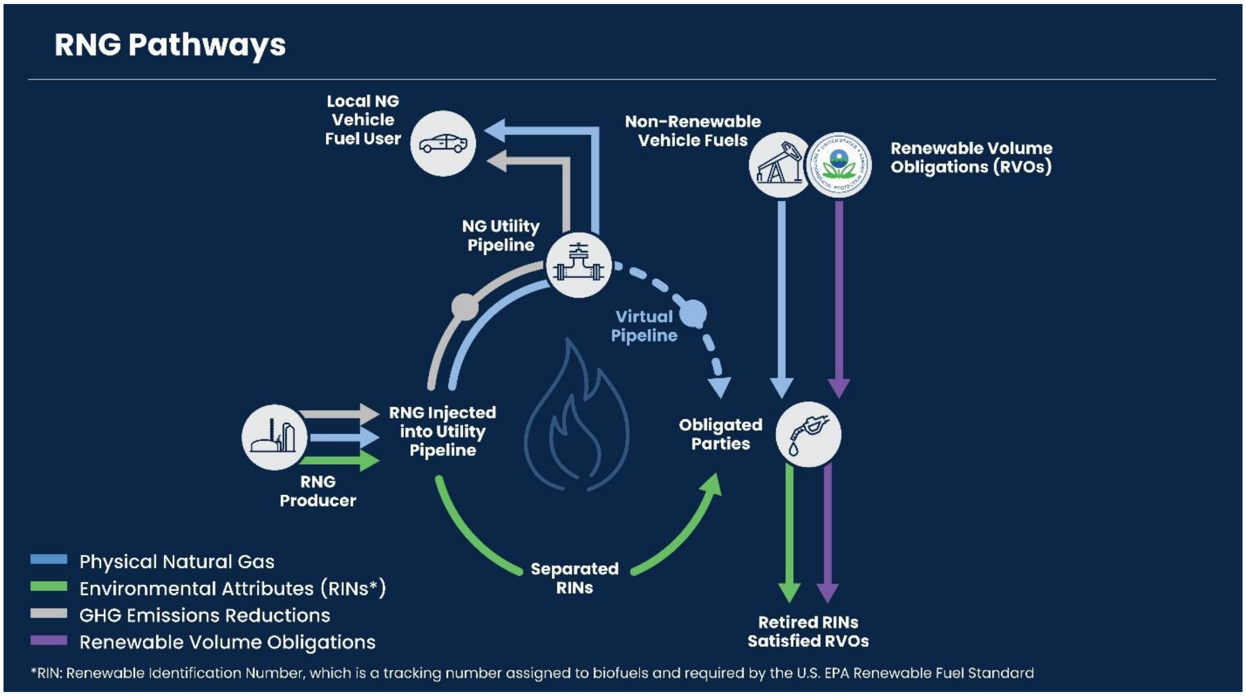


2.4.3 Pathways and Requirements

Both the RFS and LCFS are specifically for renewable fuels for transportation programs. Therefore, the fuel must ultimately be used as a transportation fuel for the renewable attribute to be recognized. A renewable-fuel producer is not required to explicitly find a transportation end user of the fuel it produces; however, at some point along the fuel supply pathway, it must be capable of being used as a transportation fuel so that an Obligated Party can claim the RIN and/or the LCFS credit and meet its obligation with EPA or California.

The production and sale of RNG and environmental attributes, like RINs through the RFS, occurs in two pathways: the physical pathway and the pathway for the separated environmental attributes. The physical pathway is the sale of the RNG by the producer to an end user of the actual gas via the NG Utility. The gas can be sold to the current gas supplier or to another party directly. The pathway for the separated environmental attributes (RINs) is handled by a third party that verifies that the RNG produced complies with the RFS and markets the attributes to Obligated Parties to satisfy their Renewable Volume Obligations (RVOs) in the RFS. Figure 7 illustrates the two pathways of RNG and RIN/LCFS sales. Note that the molecules of natural gas do not actually have to be used as vehicle fuel, but the physical pathway from the point of injection to the vehicle fueling point needs to be verified by a third-party RIN developer or broker.

Figure 7: Physical and Contractual Pathways for RNG



These two pathways are independent of GHG emissions reductions and local greenhouse gas accounting. The County will be able to take credit for the reduction of GHGs in its internal accounting, independently of the sale of RINs, as long as the gas is used for transportation purposes in Arlington County. The valuations of RINs and carbon credits are treated separately in this report.

2.4.4 RNG Value Considerations

The value of RNG should take the following factors into account:

1. The value of the RNG as natural gas based on the NG commodity market
2. The value of environmental attributes obtained through the RFS (D3 or D5)
3. The value of environmental attributes obtained through the LCFS (CI score)
4. The cost of compliance with the RFS and LCFS
5. The cost of marketing the environmental attributes to Obligated Parties

Items 1 through 3 should be considered as ranges (low, average, high) to account for the variability in future market values. The biogas revenues at the WPCP need to be designated as either D3 (highest market value) or D5 categories. The biogas produced in the anaerobic digesters handling municipal biosolids will produce D3 RNG, but biogas produced from the co-digestion of FOG or other high-strength waste will be D5. Discussions are occurring currently at EPA regarding how to account for the RIN designation of biogas produced at wastewater plants where FOG and high-strength wastes are also digested. For facilities that wish to receive and digest these organics, the recommended approach is that they be sent to one specific D5 digester with the remaining digesters designated as D3 to maintain the high-value biogas designation. Biogas metering is needed on all digesters to quantify the D3 and D5 RNG quantities separately to meet the RFS program requirements. There is the potential that EPA may allow a blended D3/D5 approach in the future where the biogas production from biosolids is designated D3 with the additional biogas produced from hauled-in wastes designated D5, even if these materials are digested together in the same digester. However, there is currently no indication of if, or when, EPA might consider these changes. The current Program does not include facilities to receive and process high-strength wastes in the new digesters, but provisions will be included to add such a facility in the future if it is deemed appropriate by the County.

Items 4 and 5 are included to reflect the cost of bringing the gas to market within the environmental attribute programs. The RFS is highly regulated, so market RIN values are typically reduced by 15 percent and the LCFS values by 15 to 30 percent to account for the third-party cost of compliance and marketing the environmental attributes to Obligated Parties. The third parties are either gas marketing companies or the Obligated Parties themselves and are typically selected by the RNG producer through a request for proposals (RFP) process. The resulting contractual arrangement specifies that the County's share be based on either a fixed price or percentage of total revenue and the term of the agreement. The third party will qualify the RINs with EPA, qualify with California for LCFS credits, develop quality assurance (QA) programs for certification, and administer the program. The County is then paid by the third party for both the NG commodity value and the associated environmental attributes on a monthly or quarterly basis.

Table 9 comparatively presents the range of RNG market values of the RFS program. Cellulosic RINs (D3) have the highest value and have been valued from a minimum of \$0.50/RIN to a maximum of \$3.26/RIN between January 2016 and July 2021 with an average value of \$1.96/RIN over that time frame. The ranges shown in Table 9 are based on a tighter range of values because the markets for RNG are anticipated to become more mature and less variable than they have been over the last 5 years. The statistical distribution of historical RIN prices is discussed below in Section 5.4. The net

D3 RIN values are calculated by converting the $/RIN to $/MMBtu by multiplying by 13 RIN/MMBtu (LHV) and 85 percent to account for the cost of marketing the RINs and regulatory compliance. The RFS value is combined with the commodity price of natural gas, which is currently approximately $2.70/MMBtu (LHV). If the renewable fuels are sold into the California fuels market, LCFS is also available and is worth approximately $12.30/MMBtu (based on CI of 30 gCO_2e/MJ and $180/MT).

Table 9: RINs and Carbon Market Comparative Values: March 29, 2021

RIN and Carbon Market	County Share of Environmental Attributes	Conservative	Moderate	Aggressive
Commodity price of RNG ($/MMBtu)	100%	$2.70	$2.70	$2.70
D3 market value ($/RIN)		$0.55	$1.25	$2.25
D3 market value ($/MMBtu)		$7.15	$16.25	$33.75
Net D3 RIN ($/MMBtu)	85%	$6.10	$13.80	$24.90
Total for D3 + commodity ($/MMBtu)		$8.80	$16.50	$27.60
Net LCFS ($/MMBtu)	70%	$0.00	$4.00	$10.00
Total for D3 + commodity + LCFS ($/MMBtu)		$8.80	$20.50	$37.60

A RIN value of $15/MMBtu has been used in this Biogas Utilization Report for the base financial analyses. This is reflective of a conservative value for RINs only and does not include any potential value from the LCFS. Sensitivity analyses are also included to address potential volatility of the RIN market, and these are described in Section 5.4.

2.4.5 Anticipated RNG Specifications

There are two major ways to use RNG produced at the Arlington WPCP as vehicle fuel, and each method has different RNG quality requirements. The most common method is to inject the RNG into an NG utility pipeline. This allows the environmental attributes of the RNG, the RINs and LCFS credits, to be sold to Obligated Parties across the country, providing the largest market of potential buyers. NG utilities have stringent specifications and monitoring requirements for the RNG injected into their pipelines—with the largest market comes the highest RNG standards. A less common method is to use the RNG in a dedicated fleet fueling station. If an RNG producer is located near, or has access to, a fleet of CNG vehicles, the RNG could be directly used to fuel that fleet without having to be injected into the NG pipeline. This method is less common because of challenges related to matching supply and demand and making sure that all the RNG produced will be used. The benefit of this option is that fleet fueling typically has lower standards for RNG quality as the only limit is what is needed by the vehicles, not other uses on a pipeline. The Arlington WPCP is located across the street from two transit bus facilities, Arlington Transit (ART) and Washington Metro Area Transit Authority (WMATA), and these fleets currently have the fueling needs necessary to use all the RNG produced. The Arlington County Transit Bureau is currently completing a study for the County bus fleets, including electrification and resiliency alternatives. Supply of RNG to these facilities may be limited or eliminated in the future based on the pace of bus electrification.

2.4.5.1 Pipeline Injection

The American Biogas Council has developed a recommended RNG-quality specification for pipeline injection, which is presented in Table 10 below.

Table 10: Anticipated RNG Pipeline Specification

Parameter Maximum (unless noted otherwise)	Unit	Acceptable Limit	Typical Raw Biogas
Minimum high heating value	Btu/scf	960	580–680
H_2S	ppm	0.0057	300–1,000
Total sulfur	ppm	0.458	300–1,200
CO_2	Percentage by volume	2.0%	32%–42%
O_2	Percentage by volume	0.4%	<1.0%
Total inerts	Percentage by volume	5.0%	33%–45%
Water	lb/MMscf	7.0	~2,000
Siloxanes	ppm	1.0	5–20
Dust, gum, bacteria, and pathogens	Filter microns	Commercially free	N/A
Minimum and maximum limits of acceptable temperature range	°F	50–120	90–110

2.4.5.2 Compressed Natural Gas Bus Fleet Fueling

Preliminary discussions have been conducted with ART to use the RNG produced as fuel for compressed natural gas (CNG) buses within its system. Table 11 below provides a summary of the major parameters for RNG used for bus fueling at the ART facility. The complete anticipated fuel specification for the ART bus facility is included in Appendix A . These limits are less restrictive than the pipeline specification described above. The minimum LHV of 16,100 Btu per pound mass (lbm) is roughly equivalent to an RNG product gas with 89 percent methane, 10 percent carbon dioxide (CO_2), and less than 1 percent oxygen (O_2) and nitrogen (N_2).

Table 11: Anticipated CNG Bus Gas Specification

Parameter Maximum (unless noted otherwise)	Unit	Requirements
Minimum CH_4 number[a]	MN	65/75
Minimum LHV	Btu/lbm	16,100
Hydrogen	ppm	300
H_2S	ppm	6
Sulfur (S)	ppm	10
Siloxanes	ppm	3
CO_2	Percentage by volume	3.0%
N_2	Percentage by volume	4.0%

a. Methane number is the calculated knock resistance of a fuel used by engine manufacturers to ensure that the fuel does not combust automatically on temperature and pressure.

3 Alternatives Development

3.1 Biogas Utilization Alternatives

There are several options for the beneficial use of the biogas produced in anaerobic digestion, each with its own advantages and disadvantages including biogas conditioning requirements, capital cost, O&M requirements, financial benefits, sustainability impacts, and GHG emissions.

The objective of this analysis is to look at all feasible alternatives for the beneficial use of the biogas while reliably meeting the WPCP's heating and electrical needs and then perform monetary, non-monetary, and sustainability evaluations to determine the recommended alternative for the County.

The range of feasible alternatives includes using the biogas for one or a combination of the following:

- On-site use for process and building heating
- Producing electrical power and recovering wasted heat (combined heat and power [CHP])
- Production of RNG for use off site through pipeline injection or as CNG for direct use as vehicle fuel.

From these potential biogas uses the following four major alternatives were developed:

- **Alternative 1:** process and building heating
- **Alternative 2:** CHP
- **Alternative 3:** RNG
- **Alternative 4:** RNG and CHP

For each of the alternatives, Sankey diagrams (depiction of energy balance) were developed to help illustrate the sources and flows of energy purchased and produced. These diagrams show the process and building heating requirements, electrical power requirements and production, equipment efficiencies, NG purchase, and biogas flaring for each alternative. Note the following regarding the Sankey diagrams:

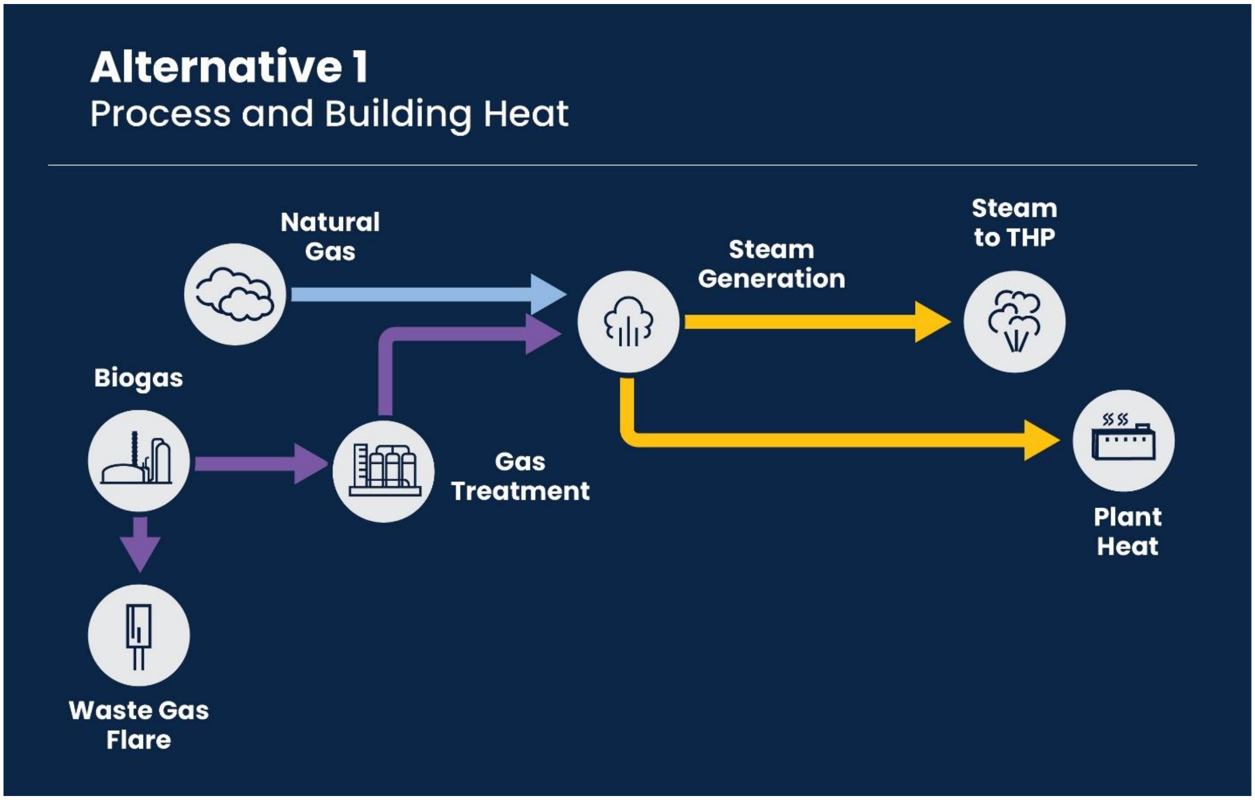
- The diagrams are based on anticipated 2037 operating conditions.
- The diagrams represent the annual average total energy flow, not capacity or peak conditions.
- The units of the diagrams are represented in MBH.

It is assumed that all methane generated at the WPCP is combusted, whether through beneficial use on site, beneficial use off site, or combusted through a flare. A description of each of the alternatives and the corresponding Sankey diagrams are provided in the following sections.

3.1.1 Alternative 1: Process and Building Heating

The simplest and least expensive way to beneficially use the biogas produced in the digesters would be to fuel the boilers that produce steam for the THP system, as shown schematically in Figure 8. The THP steam demand would consume only about 30 percent of the biogas produced, leaving 70 percent as excess, which would be flared in a waste gas flare. Note, all alternatives would require a waste gas flare for flaring during equipment maintenance or downtime. However, Alternative 1 is the only option where biogas would constantly be flared.

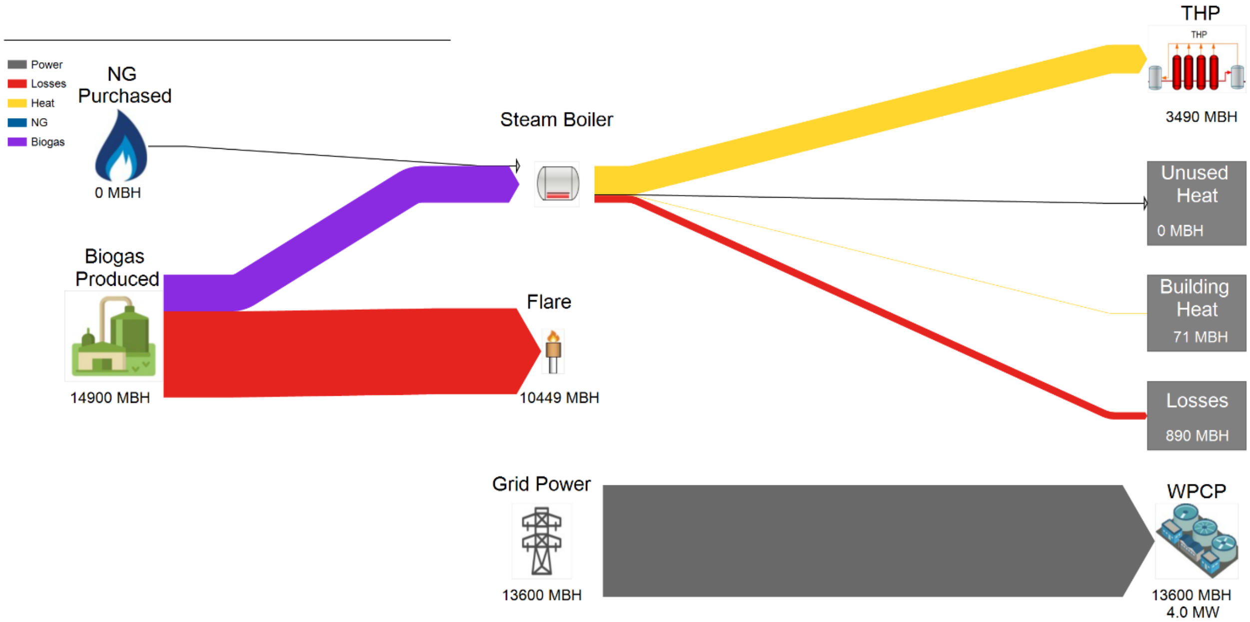
Figure 8: Alternative 1: Process and Building Heating



Alternative 1 was developed for comparison against the alternatives that target higher beneficial use of biogas. **Because this alternative does not fully utilize the biogas, it is not a viable biogas utilization option, but it is included in the analysis as the minimum required to meet the process needs.**

For the 2037 condition, the anticipated biogas production is 14,900 MBH and the THP steam requirement is 3,020 lb/hr or 3,490 MBH with 200 pounds per square inch gauge (psig) steam. In addition, the building heating requirement is 71 MBH, which results in a total heating requirement of 3,560 MBH. The assumed boiler heating efficiency for all alternatives is 80 percent, so 4,450 MBH of biogas is needed to produce the steam needed for THP and building heating demands. This leaves 10,450 MBH of biogas production that must be flared. These values are illustrated graphically in the Sankey diagram for Alternative 1, shown in Figure 9.

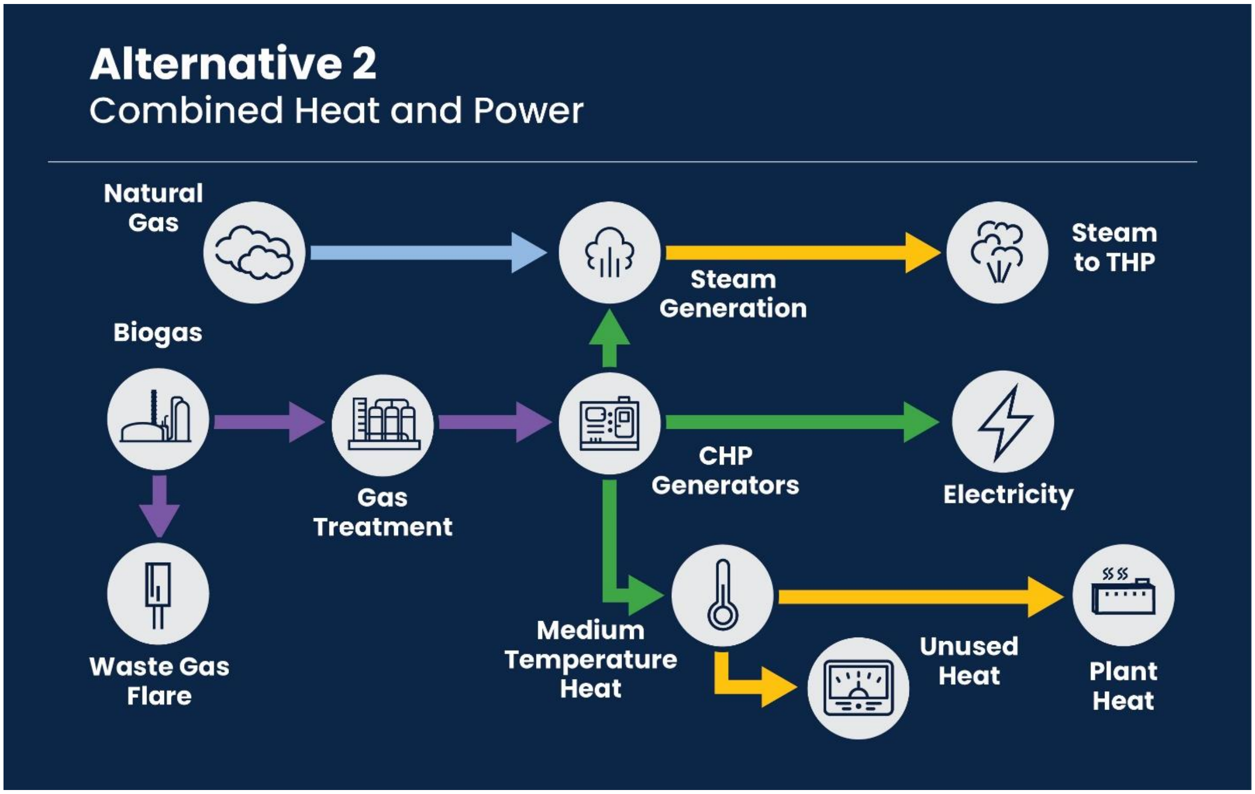
Figure 9: Alternative 1: Process and Building Heating



3.1.2 Alternative 2: Combined Heat and Power

CHP includes any options that use a fuel to produce electrical power and recover the wasted heat from the electrical generating equipment for beneficial use. The goal of the CHP options, shown schematically in Figure 10, is to balance the power produced and heat recovered from the biogas with the heating needs of the WPCP. As discussed previously, the primary heating need for the Facilities is steam production for the THP process.

Figure 10: Alternative 2: Combined Heat and Power



CHP is a popular option for wastewater facilities because it is more efficient than heat production only and more of the biogas can be used while still meeting the heat requirements of the WPCP. There are three major types of CHP combustion equipment for electrical production: internal-combustion (IC) engines, microturbines, and gas turbines. Microturbines were discussed as part of the initial workshops, but a preliminary analysis showed that the electrical and heat recovery efficiencies are similar to internal-combustion engines but at an increased capital and O&M cost. Therefore, microturbines are not presented specifically in the subsequent analysis, but would be considered like the engine options. The sections below describe the engine and gas turbine CHP sub-alternatives in more detail.

3.1.2.1 Alternative 2A: Internal-Combustion Engines

Internal-combustion engines have been standard combustion equipment used in wastewater CHP systems. These engines have a fuel train that blends a stoichiometric ratio of biogas and air prior to entering the cylinders for combustion. Older styles of engines were derived from large marine or locomotive diesels, converted to use spark ignition. These were inefficient, large, and slow, capable of burning raw biogas. However, modern engines need to meet tighter emissions standards, which has resulted in more efficient, smaller engines requiring a higher quality of biogas for fuel with strict standards for hydrogen sulfide (H_2S), moisture, and siloxane content. The electrical efficiency used for this analysis is 35 percent based on the LHV of methane. New engines may have up to 39 percent electrical efficiency, but an engine's efficiency typically drops as it ages. Figure 11 shows a typical engine installation for a CHP system at a wastewater treatment facility.

Figure 11: Typical Engine Installation

Heat recovered from internal-combustion engines comes from two sources, the exhaust and the engine cooling system. The heat from the exhaust is considered high-value heat (greater than 500 degrees Fahrenheit [°F]) and can be used for steam generation in a composite boiler. The engine cooling system recovers a low-value heat (less than 500°F) that cannot be used for steam generation, but it can produce hot water for other uses at the WPCP, such as building heat. The high- and low-value heat recovery efficiencies for the engines are 18 and 24 percent, respectively, for a total maximum CHP efficiency of 77 percent.

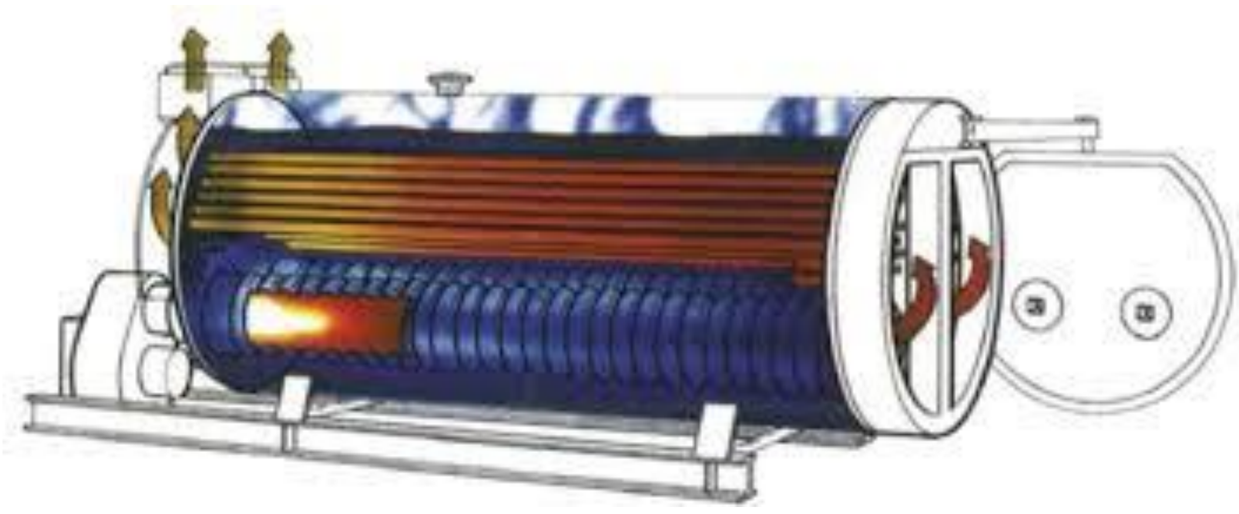
The same 2037 condition was used with a biogas production of 14,900 MBH, 3,490 MBH of steam, and 71 MBH of building heating. If all the biogas was used in the engines 5,215 MBH or 1.53 MW of electricity would be produced, 2,682 MBH of high-value heat would be recovered as steam, and 3,576 MBH of low-value heat would be recovered as hot water. Therefore, the anticipated steam production does not meet the heating values needed by the THP and supplemental heating is required either through the use of purchased natural gas or diverting some of the biogas from the engine directly to a boiler.

Another factor that should be considered in this analysis is the uptime of engines. For the engine alternative, the uptime was assumed to be 90 percent for each engine and a total 95 percent system uptime based on providing two engines sized to provide 70 percent of the needed capacity. This means that for 10 percent of the time during a typical year, one of the engines is offline and only 70 percent of the biogas can be used in the engine for power production. During these periods the excess biogas would be used in a boiler or flared if necessary. When the downtime is taken into consideration 522 MBH of biogas is flared.

3.1.2.2 Composite Boiler

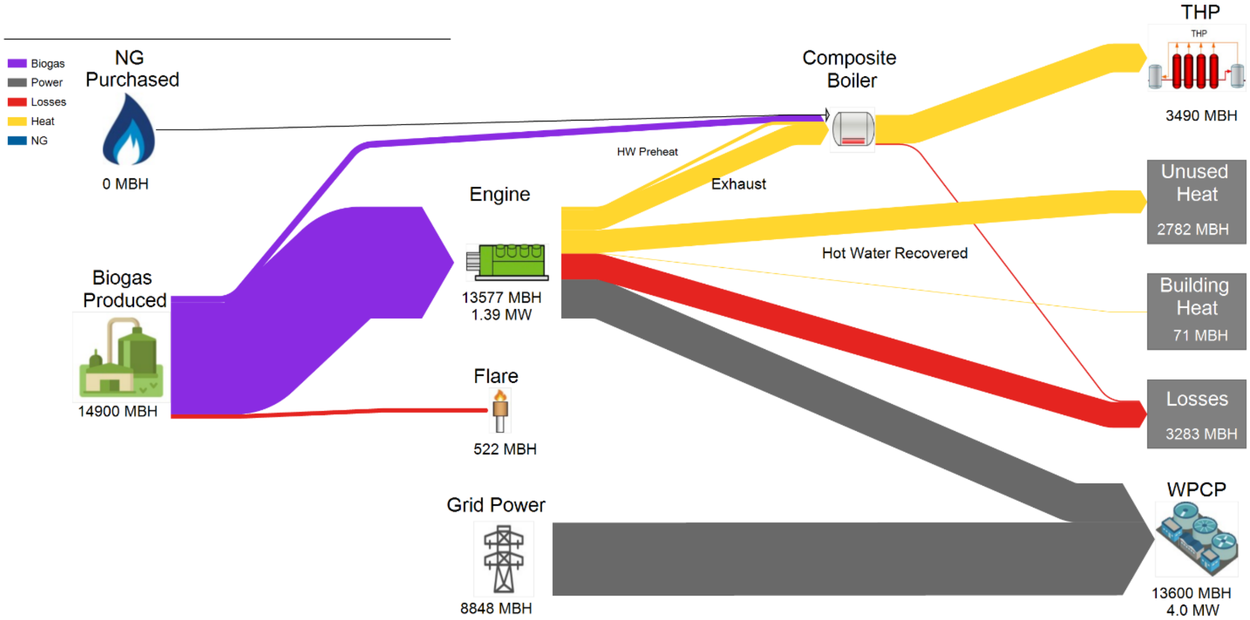
To address the lack of high-value heat recovered, maximize the use of biogas, and minimize flaring, a composite boiler would be used to recover heat from the exhaust and also provide supplemental heating. A composite boiler is a fire tube–style boiler that can recover the heat from the exhaust, but also has a direct-fired burner that can be fueled with biogas or natural gas as shown in Figure 12. To provide the supplemental heating for steam production when both engines are operating, a small percentage of biogas would be sent directly to the burner. Also, when one engine is down for maintenance, additional biogas would be sent to the burner to meet the heat demand and minimize flaring.

Figure 12: Composite Boiler Configuration



The energy balance is presented graphically in Figure 13. This balance takes into consideration the efficiencies of the engine and heat recovery, uptime for the engines, and supplemental heating needed for the steam demand.

Figure 13: Alternative 2A: CHP with Engines



Note: The unused heat is low-value hot water that can be recovered from the engine. If it is not used, the heat produced will be wasted through a radiator.

3.1.2.3 Alternative 2B: Gas Turbines

Gas turbines are the standard combustion equipment in the power generation industry. These turbines combust compressed air-fuel mixtures to produce hot gases that rotate a high-speed turbine to produce power and waste heat. The turbines operate at much higher pressures and speeds than internal-combustion engines and are more similar to a jet engine than a diesel engine. A gas turbine is shown in Figure 14. Gas turbines are often used in high-capacity electrical production applications, but there are suppliers that provide smaller sizes for wastewater treatment plants. Gas turbines are electrically less efficient than engines at only 25 percent electrical efficiency but produce a greater amount of high-value heat at approximately 50 percent efficiency. This heat can be recovered to produce steam for additional electrical production (combined-cycle generator) or process heating.

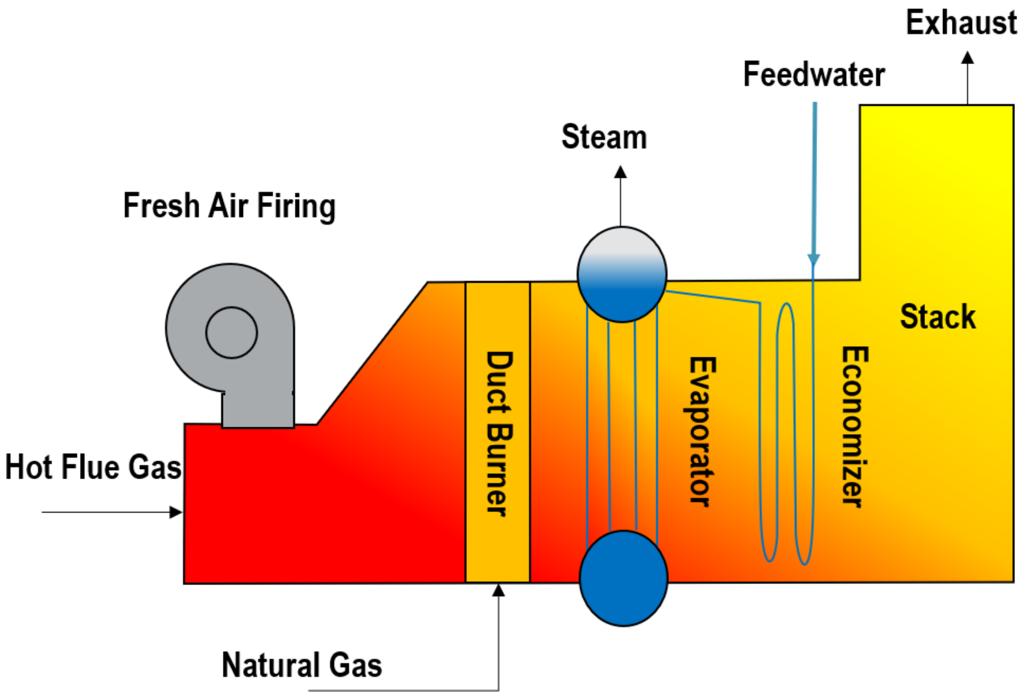
Figure 14: Example Gas Turbine

For the same evaluation condition, if all the biogas was used in the turbine, 3,725 MBH or 1.1 MW of electricity would be produced, and 7,450 MBH of high-value heat would be available, which would meet the steam demand. However, because of their cost, gas turbine systems are usually sized with one turbine sized for the desired capacity. This reduced redundancy is reflected in an assumed uptime of 90 percent. This means that during a typical year 90 percent of the biogas would be directed to the turbine and during the remaining time the biogas would need to go to a boiler or the flare. This reduces the electrical output of the turbine to an annual average production of 0.98 MW.

3.1.2.4 Heat Recovery Steam Generator

Similar to composite boilers, gas turbine systems are often installed with heat recovery steam generators (HRSGs) on the exhaust to recover heat and produce steam. HRSGs are water tube boilers that, like composite boilers, can include a duct burner to supplement heating requirements or bypass the turbine during downtime, as shown in Figure 15.

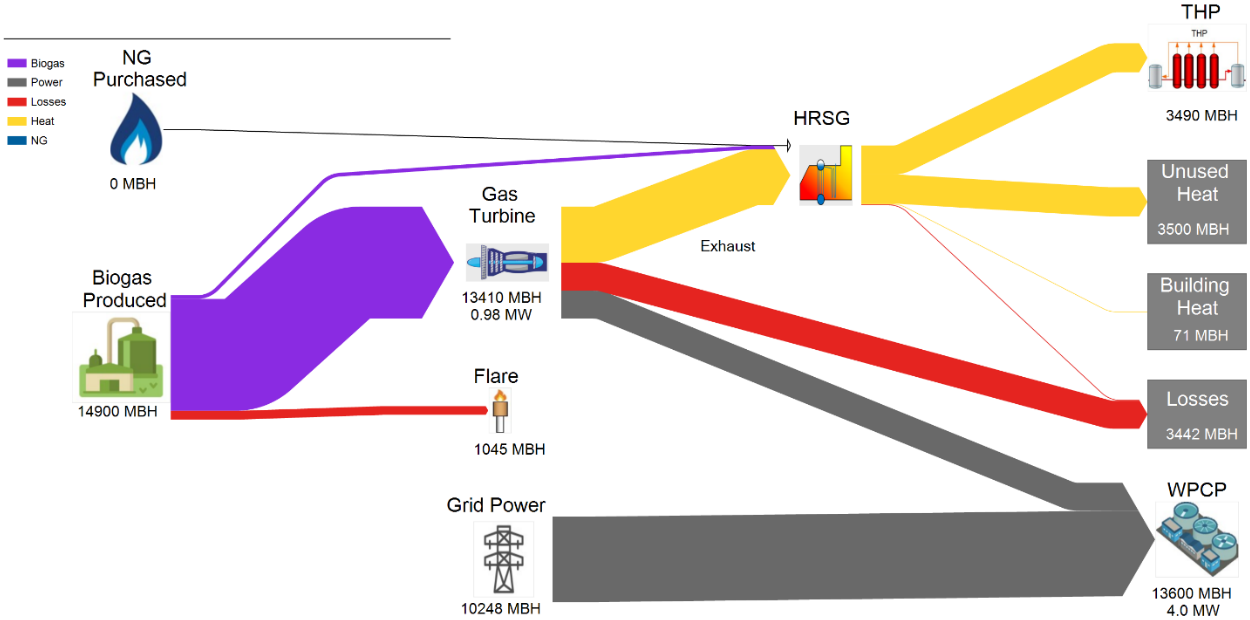
Figure 15: Heat Recovery Steam Generator



To minimize biogas flaring, it was assumed that during gas turbine downtimes, the biogas would be directed to the HRSG to maintain steam production. A summary of the energy balance for the gas turbine option is presented in Figure 16. The gas turbine option produces less electrical power than the engine option, but sufficient high-value heat for steam production without any biogas bypass when the turbine is operating. The biogas bypass shown is only for when the turbine is down for maintenance. However, the significant amount of high-value heat is not entirely used by the THP system, and 2,427 MBH is left unused.

When the downtime is taken into consideration 1,045 MBH of biogas is flared.

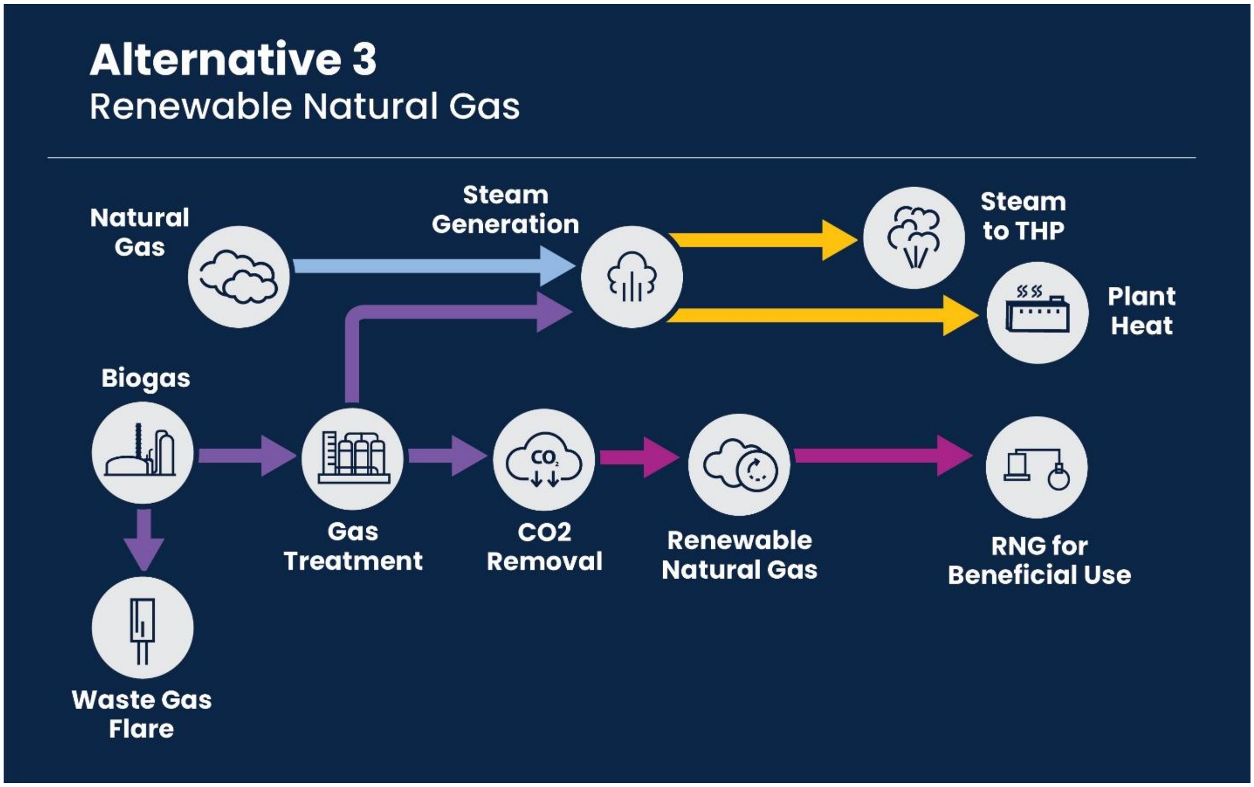
Figure 16: Alternative 2B: CHP with Gas Turbine



3.1.3 Alternative 3: Renewable Natural Gas

For Alternative 3, shown schematically on Figure 17, all the biogas produced would be conditioned to RNG quality for use off site. The production of RNG from biogas requires treatment of the biogas to remove contaminants such as hydrogen sulfide, moisture, siloxanes, volatile organic compounds (VOCs), and carbon dioxide. A discussion on the technologies available to accomplish this treatment is presented in Appendix D . For this alternative, it was assumed that all of the biogas would be conditioned and used off site and natural gas would be purchased and used in boilers to meet the process and building heating needs in order to maximize the amount of RINs.

Figure 17: Alternative 3: Renewable Natural Gas



The energy balance for Alternative 3 does not distinguish between injecting the RNG into the NG utility pipeline or piping the RNG directly to bus fleet fueling. However, these two options will have different costs, risks, and potential future revenues. Therefore, Alternative 3 will have two sub-alternatives. Alternative 3A represents injecting the RNG into the NG utility pipeline and Alternative 3B represents piping the RNG directly for bus fleet fueling.

The removal of contaminants from the raw biogas, regardless of the technology used, results in some loss of methane to the waste biogas stream, or tail gas. The disposal of the tail gas is site-specific and dependent on air quality regulations and sustainability goals as it contains a small amount of methane as well as some hydrogen sulfide and other contaminants. For this evaluation it was assumed that the tail gas was combusted in a regenerative thermal oxidizer (RTO) designed to oxidize low-Btu gas streams, effectively converting methane to carbon dioxide and other contaminants to oxidized states. The overall methane capture is technology-dependent but is generally in the range of 95 to 98 percent. For this evaluation a methane capture rate of 95 percent was used and the 5 percent leaving in the tail gas is oxidized and shown as directed to the RTO.

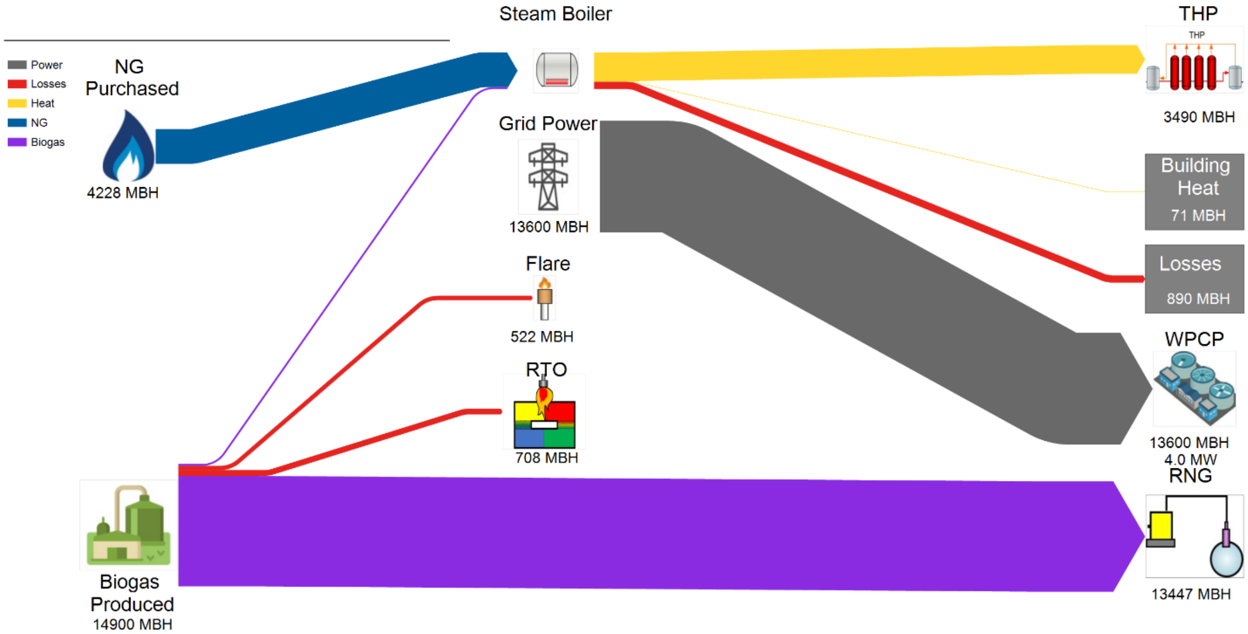
Similar to the CHP alternatives, the RNG conditioning equipment will have downtime for maintenance. During these periods it was assumed that the biogas would be diverted directly to the boilers to minimize flaring. The uptime for the RNG options was assumed to be 95 percent.

For the 2037 evaluation condition, 14,900 MBH of biogas is produced. The biogas conditioning system has a 95 percent uptime and 5 percent downtime. Accounting for the 95 percent methane capture in the conditioning equipment, this results in 708 MBH ending up in the tail gas and combusted in the RTO. During the 5 percent downtime, approximately 30 percent of the biogas or 223 MBH can be diverted and used in the boiler. The remaining 70 percent would go to the flare. On an annual basis, this results in an average 522 MBH flared because of downtime. The total amount not beneficially used is 1,230 MBH.

During RNG production, natural gas is used in the boiler for process and building heating. This heating requires 3,561 MBH of heat production or 4,451 MBH of natural gas. When the 5 percent downtime biogas diversion is subtracted from this amount, an annual amount of 4,228 MBH of natural gas to be purchased results. Figure 18 illustrates the energy balance for the RNG and boiler alternatives.

Note, it is possible to use RNG in the boiler for process and building heating such that no NG purchase is required. However, in this case more biogas would be used on site and less RNG would be sent to others as a replacement for fossil fuel–based natural gas. The production of RNG does not change the quantity or type of uses for natural gas. Because there are economic benefits to sending RNG off site, the analysis presented below assumes that all biogas is being upgraded to RNG. If this alternative is chosen, the system would be piped to use either natural gas or biogas in the boiler.

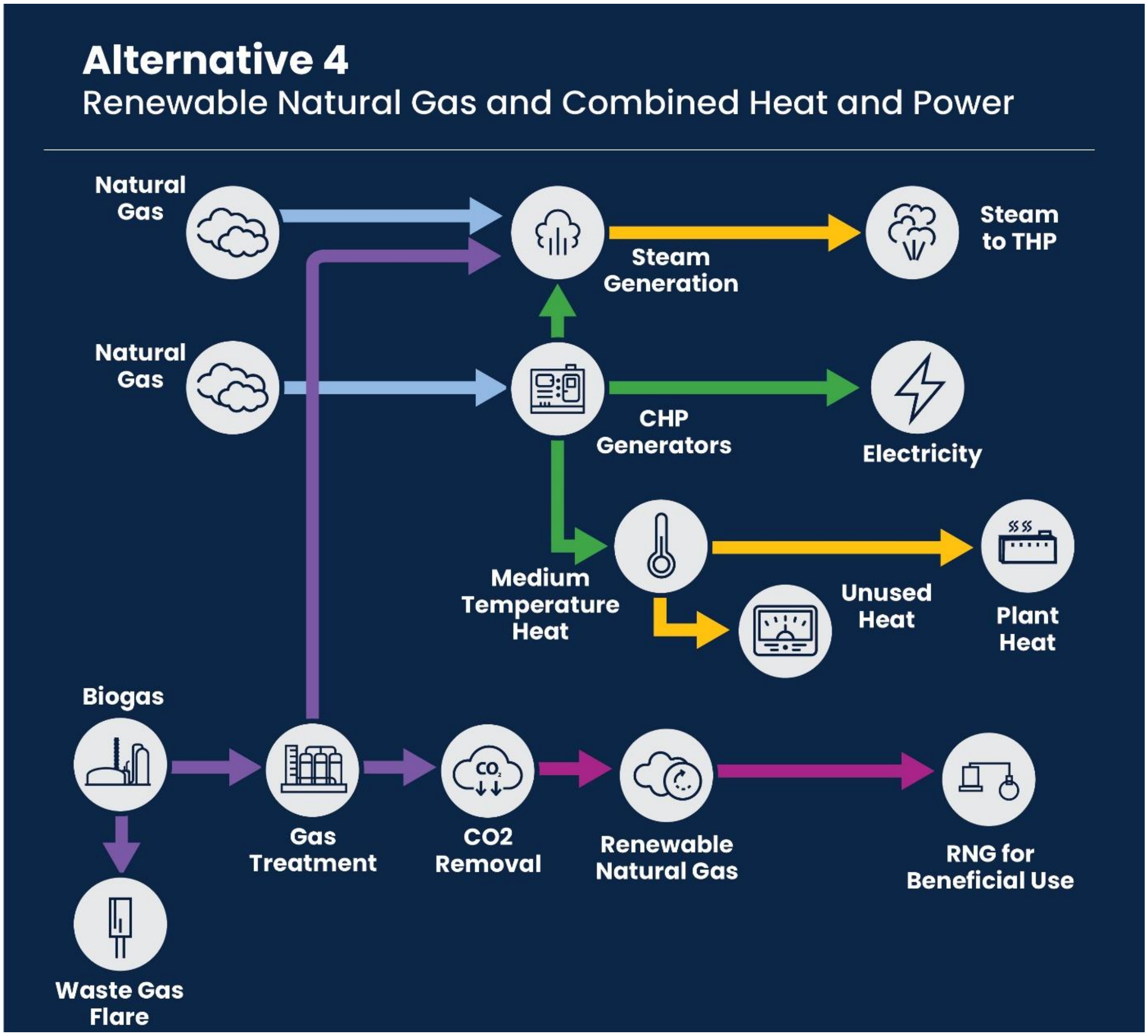
Figure 18: Alternatives 3A and 3B: RNG



3.1.4 Alternative 4: RNG and CHP

Alternative 4, as shown schematically in Figure 19, combines using the biogas as RNG for vehicle fuels with an NG–fueled CHP system to produce power and recover heat. Similar to Alternative 2, the CHP could be provided with internal-combustion engines or gas turbines. The CHP sizing is based on providing the process and building heating necessary. Similar to Alternative 3, during the RNG system downtime, biogas would be diverted to the CHP system to minimize flaring and NG purchases. The downtimes for the CHP are also similar to Alternative 2, so that when the CHP system is down, natural gas is diverted directly to the composite boiler or HRSG depending on the CHP system.

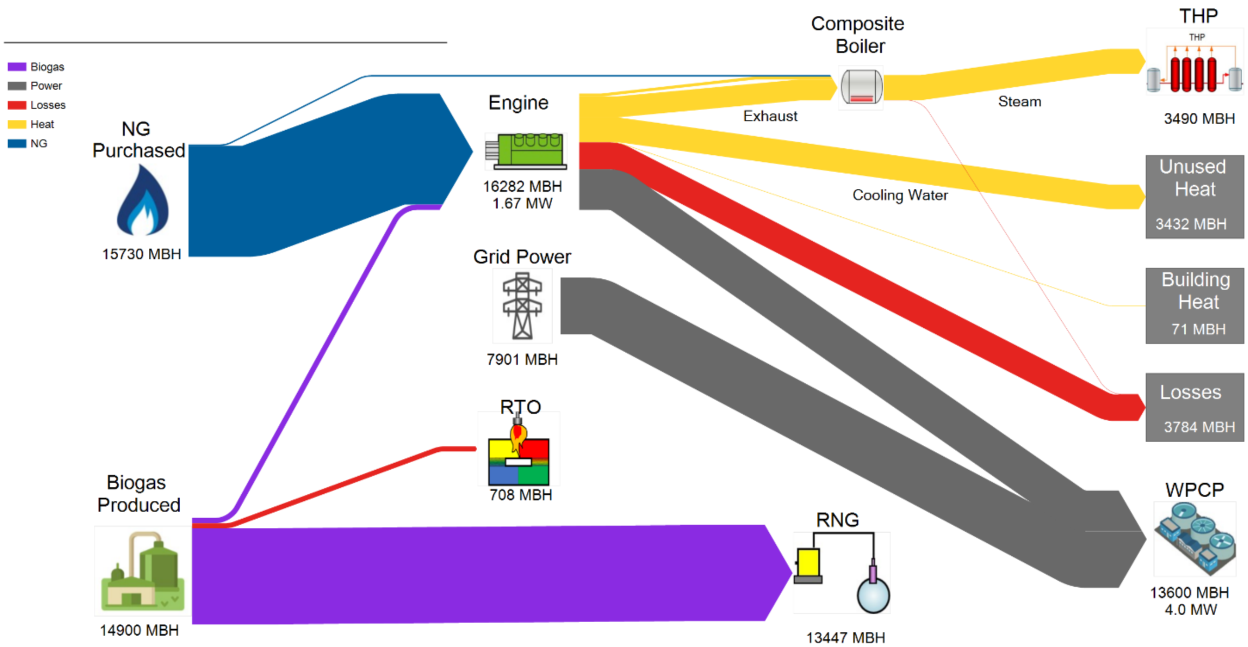
Figure 19: Alternative 4: Renewable Natural Gas and Combined Heat and Power



3.1.4.1 Alternative 4A: RNG with Engines

The energy balance for Alternative 4A is shown in Figure 20 and results in 13,447 MBH of RNG production, similar to Alternative 3. The energy production from the engines is sized to meet the heating requirement and results in 1.67 MW of power production, which is slightly higher than Alternative 2A. The natural gas required to fuel the engines during cogeneration and the composite boiler when an engine is offline is 15,730 MBH.

Figure 20: Alternative 4A: RNG with Engines

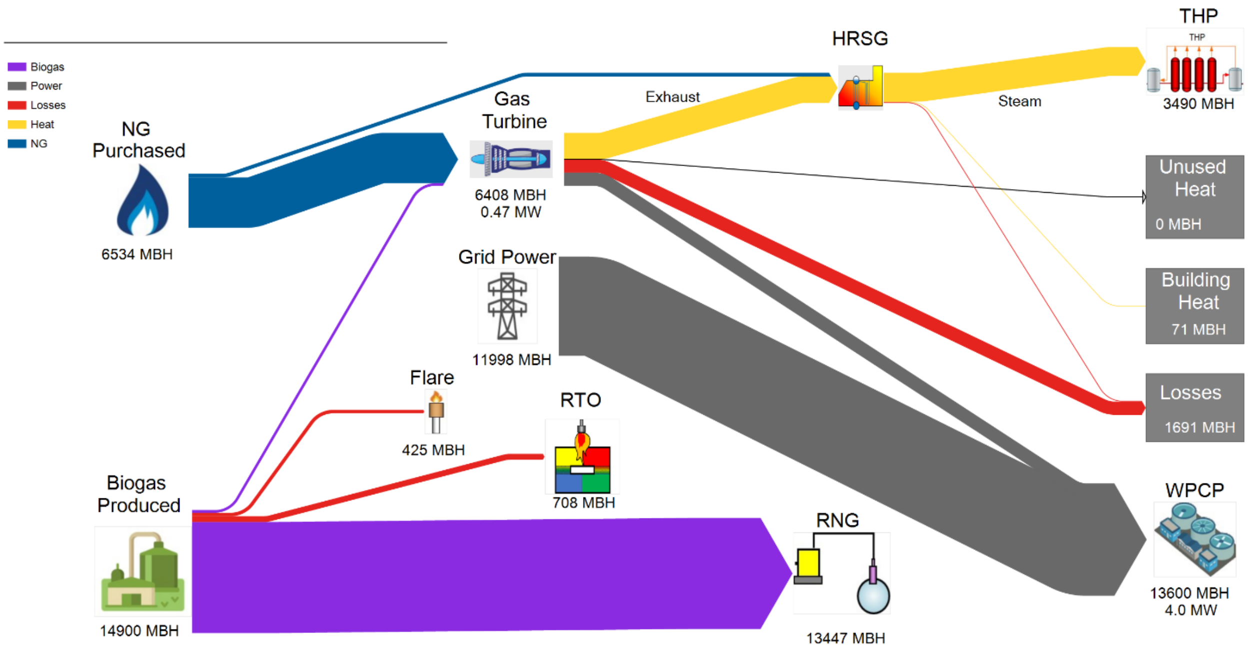


3.1.4.2 Alternative 4B: RNG with Gas Turbine

The energy balance for Alternative 4B is shown in Figure 21 and results in 13,447 MBH of RNG production, similar to Alternative 3. The energy production from the turbines is sized to meet the heating requirement and results in 0.47 MW of power production, which is lower than Alternative 2B because the turbine capacity is reduced to match the heat recovered with the steam production. The natural gas required to fuel the turbine during cogeneration and the HRSG when the turbine is offline is 6,534 MBH.

Biogas is conditioned to RNG quality with an equipment uptime of 95 percent. During periods of downtime biogas is used in the gas turbine. However, the biogas production exceeds the design capacity of the gas turbine and only 43 percent of the biogas diverted during the RNG downtime can be used effectively for CHP. The remaining 57 percent during that 5 percent per year is flared. Therefore, the flared amount due to downtime is 425 MBH and the amount flared in the tail gas is 708 MBH for a total flared amount of 1,133 MBH.

Figure 21: Alternative 4B: RNG with Gas Turbine



3.2 Biogas Utilization Alternative Summary

A summary of the energy balances for each alternative/sub-alternative is presented in Table 12. A more detailed breakdown of the energy balances is provided in Appendix B .

Table 12: Alternatives Energy Summary

Alternative		1	2A	2B	3A/3B	4A	4B
Description		Process and building heating	CHP with engines	CHP with gas turbine	RNG	RNG with engines	RNG with gas turbine
Energy source/use	Unit						
Heat required total	MBH	3,561	3,561	3,561	3,561	3,561	3,561
Steam (hot)	MBH	3,064	3,064	3,064	3,064	3,064	3,064
Hot water							
Building	MBH	71	71	71	71	71	71
Boiler preheat	MBH	427	427	427	427	427	427
Steam total	MBH	3,490	3,490	3,490	3,490	3,490	3,490
Biogas production	MBH	14,900	14,900	14,900	14,900	14,900	14,900
Biogas used							
Boiler total	MBH	4,452	801	445	222	0	0
CHP	MBH	0	13,577	13,410	0	745	320
RNG	MBH	0	0	0	13,447	13,447	13,447
Waste gas flare	MBH	10,449	522	1,045	522	0	426
Tail gas combusted	MBH	0	0	0	708	708	708
Heat production	MBH	3,561	6,343	7,061	3,561	6,993	3,561
Boiler total	MBH	3,561	641	356	3,561	154	357
CHP							
Steam	MBH	0	2,444	6,705	0	2,931	3,204
Hot water	MBH	0	3,258	0	0	3,908	0
Capacity CHP	MBH	0	13,577	13,410	0	16,282	6,408
NG purchased, total	MBH	0	0	0	4,230	15,730	6,534
Boiler	MBH	0	0	0	4,230	193	446
CHP	MBH	0	0	0	0	15,537	6,088
Heating losses, total	MBH	712	3,283	3,442	712	3,783	1,691
Boiler	MBH	712	160	89	712	39	89
CHP	MBH	0	3,123	3,353	0	3,745	1,602
Unused heat	MBH	0	2,782	3,500	0	3,431	0
WPCP Electricity required	MBH	13,600	13,600	13,600	13,600	13,600	13,600
Electricity produced	MBH	0	4,752	3,353	0	5,699	1,602
Equivalent cap. CHP	MW	0.00	1.39	0.98	0.00	1.67	0.47
Electricity purchased	MBH	13,600	8,848	10,248	13,600	7,901	11,998

3.3 Biogas Conditioning

The level of biogas conditioning required is directly related to the end use of the biogas. Using the biogas on site as an NG replacement for building and process heating would likely require treatment for H_2S prior to use in boilers for heating and other uses. The CHP alternatives will require moisture and siloxane removal in addition to H_2S removal, and any of the RNG alternatives will require treatment to NG quality, which includes the treatments above plus CO_2 removal, volatile organic compound (VOC) removal, compression, and tail gas disposal. Finally, all the biogas utilization alternatives will require a waste gas flare to combust the biogas as a backup should all beneficial uses be offline or over capacity. Table 13 presents a summary of the biogas conditioning equipment needed for each of the end uses being considered.

These conditioning technologies were used to develop the capital costs and O&M costs that inform the life-cycle cost analysis presented in this Biogas Utilization Report. Appendix D presents an overview of biogas treatment and conditioning systems available to meet the intended end-use requirements.

Table 13: Biogas Conditioning Equipment Requirements

Alternative/	Removal Equipment						Pressure Boosting	Tail Gas Disposal	Waste Gas Flare
	H_2S[a]	Moisture (Drying)	Siloxanes	VOCs	CO_2	O_2 +N_2			
Alternative 1	✓	✓							✓
Alternative 2A	✓	✓	✓				✓		✓
Alternative 2B	✓	✓	✓				✓		✓
Alternative 3A	✓	✓	✓	✓	✓	✓	✓	✓	✓
Alternative 3B	✓	✓	✓	✓	✓	✓	✓	✓	✓
Alternative 4A	✓	✓	✓	✓	✓	✓	✓	✓	✓
Alternative 4B	✓	✓	✓	✓	✓	✓	✓	✓	✓

a. H_2S concentrations at the WPCP are anticipated to be low because of the amount of ferric chloride currently being added for phosphorus removal but could be needed in the future if this practice changes.

4 Financial Analysis

ARLINGTON RE-GEN

The present financial value analysis presented in this section includes the anticipated capital costs, O&M costs, avoided costs from electricity generation, and RNG revenues for each alternative. These are summarized for each alternative along with the major assumptions in the sections below.

4.1 Conceptual Capital Costs

Conceptual capital cost estimates for the different biogas utilization alternatives are based on a combination of equipment quotes, estimates based on similar projects, building type, and building square footage. The costs are in 2021 dollars. The conceptual capital costs accounted for are not meant to be detailed cost estimates but are meant to capture the relative differences in costs between the alternatives.

4.1.1 Equipment Costs

The development of the capital cost estimates starts with the major equipment costs for each alternative. These costs are summarized below. All the costs reflect providing a redundant steam supply for the THP. This includes a redundant boiler for CHP alternatives as well as redundant deaerators, which preheat and condition the boiler feed water to remove oxygen and prevent corrosion in the boiler and steam piping systems.

4.1.1.1 Alternative 1: Process and Building Heating

The equipment costs for Alternative 1, summarized in Table 14, include two 350-horsepower (hp) steam boilers, two deaerator and feed pump packages, and H_2S and drying biogas treatment.

Table 14: Alternative 1 Equipment Costs

Item	Cost	Quantity	Subtotal
Boiler	$205,000	2	$410,000
Deaerator	$90,000	2	$180,000
Biogas conditioning	$2,000,000	1	$2,000,000
Total			**$2,590,000**

4.1.1.2 Alternative 2A: CHP with Engines

The equipment costs for Alternative 2A, summarized in Table 15, include two 847-kilowatt (kW) CHP generators; one 350 hp composite boiler; one 350 hp boiler; two deaerator and feed pump packages; and H_2S, siloxane, and drying biogas treatment.

Table 15: Alternative 2A Equipment Costs

Item	Cost	Quantity	Subtotal
CHP engines	$425,000	2	$851,000
Composite boiler	$690,000	1	$690,000
Boiler	$205,000	1	$205,000
Deaerator	$90,000	2	$180,000
Biogas conditioning	$3,000,000	1	$3,000,000
Total			**$4,926,000**

4.1.1.3 Alternative 2B: CHP with Gas Turbine

Alternative 2B equipment, summarized in Table 16, includes one 1,204 kW turbine CHP generator with HRSG; one 350 hp boiler; two deaerators and feed pump package; and H_2S, siloxane, and drying biogas treatment.

Table 16: Alternative 2B Equipment Costs

Item	Cost	Quantity	Subtotal
Turbine with HRSG	$3,810,000	1	$3,810,000
Boiler	$205,000	1	$205,000
Deaerator	$90,000	2	$180,000
Biogas conditioning	$3,000,000	1	$3,000,000
Total			**$7,195,000**

4.1.1.4 Alternative 3A: RNG into the NG Pipeline

Alternative 3A equipment, summarized in Table 17, includes two 350 hp steam boilers; two deaerator and feed pump packages; H_2S, siloxane, moisture, and CO_2 removal biogas treatment; and a connection to the NG utility. For this analysis it is assumed that the CO_2 removal is performed with a membrane treatment system, which is likely the most conservative and highest-cost system.

Table 17: Alternative 3A Equipment Costs

Item	Cost	Quantity	Subtotal
NG utility interconnect	$5,000,000	1	$5,000,000
Boiler	$205,000	2	$410,000
Deaerator	$90,000	2	$180,000
Biogas conditioning	$5,000,000	1	$5,000,000
Total			**$10,590,000**

4.1.1.5 Alternative 3B: RNG with CNG

Alternative 3B equipment, summarized in Table 18, includes two 350 hp steam boilers; two deaerator and feed pump packages; H_2S, siloxane, moisture, and CO_2 removal biogas treatment; and a connection to ART and/or WMATA. The equipment costs for Alternative 3B are roughly $4 million less expensive than those for Alternative 3A because of the savings on the interconnect to the NG utility. It is not known at this time what improvements, if any, would be required at the bus depots to effectively use all the RNG, and all such improvements are excluded from this evaluation. Such improvements could include additional fueling stations, compression, and storage.

Table 18: Alternative 3B Equipment Costs

Item	Cost	Quantity	Subtotal
ART/WMATA interconnect	$1,000,000	1	$1,000,000
Boiler	$205,000	2	$410,000
Deaerator	$90,000	2	$180,000
Biogas conditioning	$5,000,000	1	$5,000,000
Total			**$6,590,000**

4.1.1.6 Alternative 4A: RNG and CHP with Engines

Alternative 4A equipment, summarized in Table 19, includes two 1,141 kW CHP gensets; one 350 hp composite boiler; one 350 hp steam boiler; two deaerators and feed pump package; H_2S, siloxane, moisture, and CO_2 removal biogas treatment; and a connection to the NG utility.

Table 19: Alternative 4A Equipment Costs

Item	Cost	Quantity	Subtotal
NG utility interconnect	$5,000,000	1	$5,000,000
CHP engines	$502,000	2	$1,004,000
Composite boiler	$690,000	1	$690,000
Boiler	$205,000	1	$205,000
Deaerator	$90,000	2	$180,000
Biogas conditioning	$5,000,000	1	$5,000,000
Total			**$12,079,000**

4.1.1.7 Alternative 4B: RNG and CHP with Gas Turbine

Alternative 4B equipment, summarized in Table 20, includes one 1,204 kW turbine CHP genset with HRSG; one 350 hp steam boiler; two deaerators and feed pump package; H_2S, siloxane, moisture, and CO_2 removal biogas treatment; and a connection to the NG utility.

Table 20: Alternative 4B Equipment Costs

Item	Cost	Quantity	Subtotal
NG utility interconnect	$5,000,000	1	$5,000,000
Turbine with HRSG	$3,810,000	1	$3,810,000
Boiler	$205,000	1	$205,000
Deaerator	$90,000	2	$180,000
Biogas conditioning	$5,000,000	1	$5,000,000
Total			**$14,195,000**

4.1.2 Building Costs

Building layouts and footprints were developed for each alternative/sub-alternative. Alternative 1 has the lowest building cost, which consists of a 4,000-square-foot (SF) building to house the boilers, a 288 SF slab on grade for biogas drying and compression, and two 12-foot-diameter slabs on grade for H_2S vessels. Alternative 3 has the same footprint but with the addition of a 500 SF slab on grade for CO_2 removal. The CHP Alternatives 2 and 4 require a larger, 6,000 SF building to house the CHP equipment and standby boilers. Alternatives 2A and 2B have the same biogas treatment footprint as Alternative 1 while Alternatives 4A and 4B have the same biogas treatment footprint as Alternative 3.

For pricing buildings during this planning phase, a simplified price per square foot method was used. For the buildings a price of $1,150/SF was used and is meant to include all building systems. The slabs on grade are assumed to be $50/SF. The building costs for the various alternatives are summarized in Table 21.

Table 21: Summary of Building Costs

Item	Alternative 1	Alternatives 2A and 2B	Alternatives 3A and 3B	Alternatives 4A and 4B
Building structure (SF)	4,000	6,000	4,000	6,000
H_2S and siloxane treatment slab (SF)	226	226	226	226
Biogas drying and compression slab (SF)	288	288	288	288
CO_2 treatment slab (SF)	0	0	504	504
Total cost	**$4.6 million**	**$6.9 million**	**$4.7 million**	**$7.0 million**

4.1.3 Total Conceptual Construction Costs

The multipliers listed in Table 22 were used for total conceptual construction cost.

Table 22: Construction Multiplier Summary

Item	Multiplier
Contractor overhead and profit	15.0%
Contingency	20.0%
Mobilization, staging, bonds, and insurance	8.0%

For each alternative the multipliers are applied to the sum of the building and equipment costs.

Table 23 below shows the conceptual construction costs for each alternative with the multipliers applied. The capital costs in the table are for the equipment for each alternative (CHP, boilers, and biogas treatment equipment) and a building space to house the equipment.

Table 23: Total Conceptual Construction Costs

Alternative	Cost
1: Process and building heating	$10.8 million
2A: CHP with engines	$17.7 million
2B: CHP with gas turbine	$21.1 million
3A: RNG injected into the NG pipeline	$22.7 million
3B: RNG used as CNG	$18.7 million
4A: RNG and CHP with engines	$28.4 million
4B: RNG and CHP with gas turbine	$31.5 million

Alternative 1—using the biogas to generate steam for process and building heating—can be considered the lowest-cost investment to beneficially use a portion of the biogas. However, this alternative uses only 30 percent of the biogas produced by the digesters, while the rest is flared, which does not meet the goals of the Program.

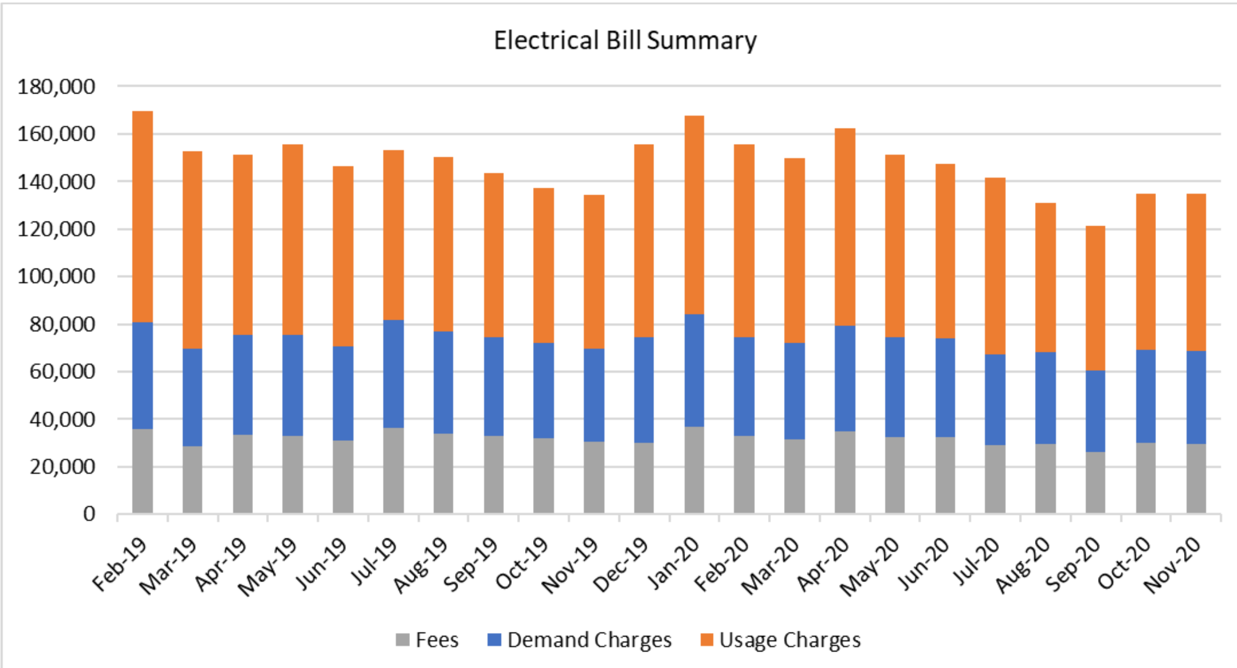
4.2 Electrical Costs

The production of electrical power through CHP will result in a reduction of electricity purchased from the power utility. To adequately account for these reductions, an understanding of the current electrical rate structure is needed.

4.2.1 Electrical Billing Rate Structure

Figure 22 below illustrates the breakdown of the WPCP electrical charges from February 2019 to November 2020. The usage charges, shown in orange, are the portion of the bill that is proportional to consumption. The demand charge, shown in blue, is based on a peak demand during the billing cycle and minimally fluctuates. The fees, shown in gray, are fixed with little variation. The total historical monthly amount paid for electricity divided by the usage comes to $0.06/kWh. Because of the billing rate structure of the existing Dominion Energy (Dominion) service, only about $0.03/kWh is linked to usage.

Figure 22: Electrical Billing Summary

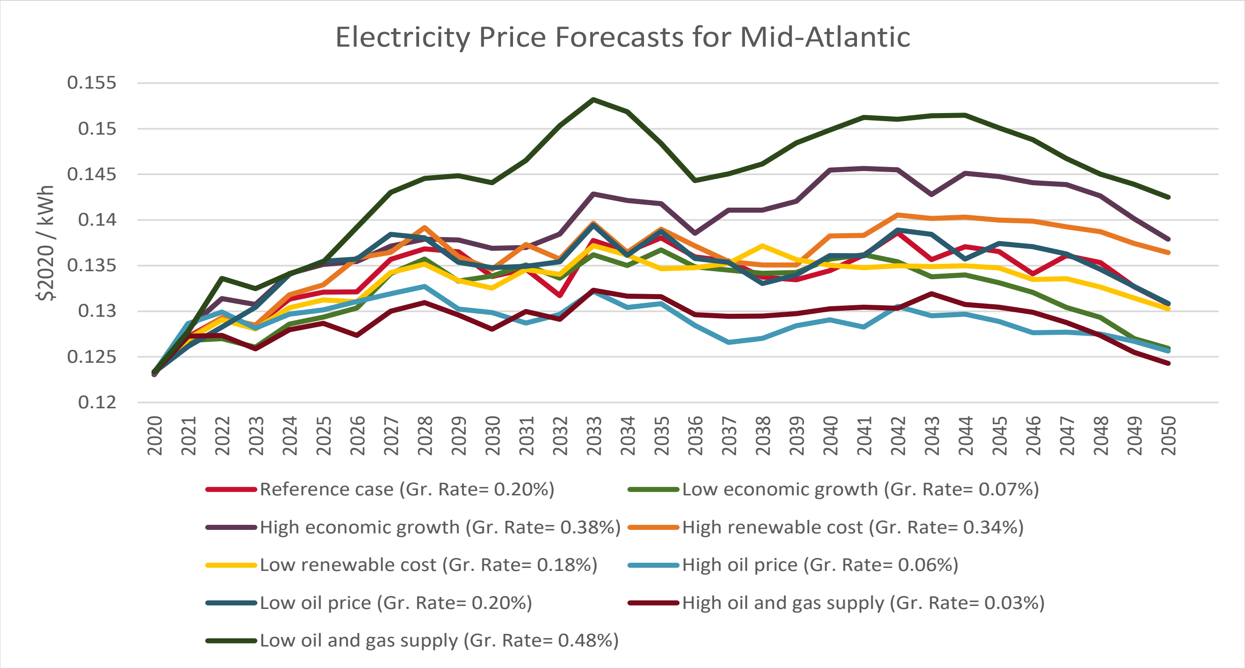


With the current billing rate structure, the CHP alternatives would be offsetting electricity at a rate of $0.03/kWh. To maximize the financial benefit of CHP electrical production the Facilities would want to enter a billing rate structure that is 100 percent based on consumption. Note: in early 2022 the County was notified that there would be an approximately 30 percent increase in total electrical costs from Dominion for Arlington County, which would raise Arlington County's average electrical cost at the WPCP to $0.078/kWh. For purposes of this Report, it is assumed that the rate structure with Dominion could be changed to consumption-only at a rate of $0.078/kWh.

4.2.2 Electricity Price Forecast

Various factors cause electricity prices to vary over time including macroeconomic conditions, fuel stock costs and supplies, technological innovations, and policies. The U.S. Energy Information Administration (EIA) is the key federal source for modeling electricity pricing forecasts. EIA develops alternative forecasts from different scenarios of future conditions, such as high and low economic growth, oil and gas supplies, renewable energy costs, and other factors. Figure 23 presents several of EIA's real price forecasts (in terms of year 2020 dollars per kWh, without adjusting for potential inflation) for the Mid-Atlantic region through 2050. In all scenarios, prices are expected to rise at least through the next 10 years. From that point, prices could rise (e.g., low oil and gas supply), remain flat (e.g., high renewable energy costs), or potentially decline (other scenarios). Through 2050, annualized growth rates could range from 0.03 percent to 0.48 percent, reflecting EIA's high and low oil and gas supply scenarios, respectively. The prices shown on Figure 23 are average retail pricing. Arlington County benefits from negotiated pricing through the Virginia Energy Purchasing Governmental Association and should expect to pay substantially less than the retail forecasts. As noted above, Arlington County's current electrical rate is assumed to be $0.078/kWh. The projected price escalation forecasts from EIA were used in model simulations starting from the County's current electrical rate.

Figure 23: Forecasts of Real Electricity Prices, EIA



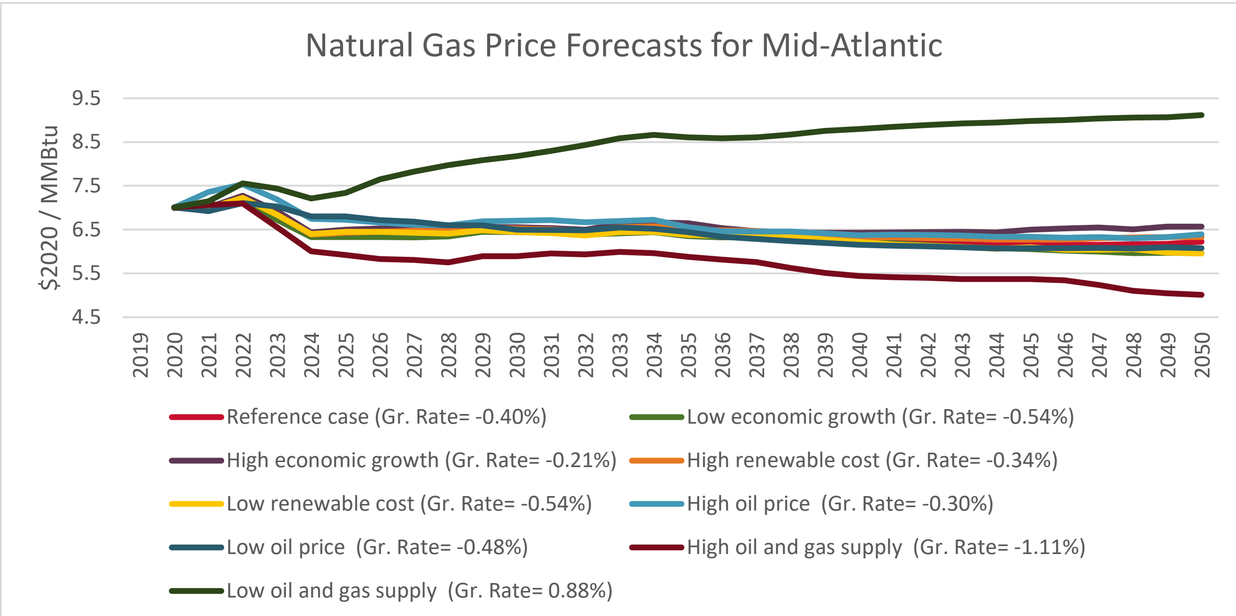
Source: U.S. Energy Information Administration.

4.3 RNG Revenue

As discussed in Section 2.4.4, the revenues from the sale of RNG will likely be a combination of environmental attributes as well as the commodity value of natural gas. The composite value of the environmental attributes is in the range of $5/MMBtu to $25/MMBtu, with 15 percent deducted for marketing the RNG, plus a commodity value of $2.50/MMBtu.

Similar to electricity prices described above, EIA also produces scenario-based forecasts for gas prices. Figure 24 presents EIA's real gas price forecasts (in year 2020 dollars per MMBtu) for the Mid-Atlantic region through 2050. The price shown reflects commodity and transportation costs (as compared to commodity value only in Table 9). In most scenarios, prices are expected to rise in 2022, then drop significantly through 2024. Real prices would then generally remain flat for at least a decade before potentially declining. However, two extreme cases of low and high oil and gas supply would tell a different story. Low supplies could directly drive up prices while high supplies would have the opposite effect. Considering these extreme cases in oil and gas supply, real annual price changes through 2050 could range from a 1.11 percent decline to a 0.88 percent increase. Other scenarios are also possible within these boundaries.

Figure 24: Forecasts of Real Gas Prices (EIA)



Source: U.S. Energy Information Administration.

Table 24 shows the RNG revenue for select years through the life of the Program based on the anticipated range of RNG values. This revenue uses an RNG inflation rate of 0.0 percent and an NG inflation rate of -0.3 percent.

Table 24: Anticipated Range of RNG Revenues at Various Environmental Attribute (RIN) Values

Parameter	2028	2037	2052
RNG produced, MBH	12,400	13,400	15,200
RNG produced, MMBtu/yr	108,000	118,000	133,000
$5/MMBtu	$730,000	$800,000	$900,000
$10/MMBtu	$1,190,000	$1,300,000	$1,470,000
$15/MMBtu	$1,650,000	$1,800,000	$2,040,000
$20/MMBtu	$2,110,000	$2,300,000	$2,600,000
$25/MMBtu	$2,570,000	$2,800,000	$3,170,000

4.4 Renewable Energy Credits

For the alternatives that include CHP (Alternatives 2 and 4), it is likely that the County could either sell Renewable Energy Credits (RECs) for the electricity produced or defer purchase of RECs for other County needs. The County currently purchases RECs at a cost of $4,500/kWh and it is assumed that all CHP alternatives would be able to sell RECs for all of the electricity produced at that value.

4.5 O&M Costs

Each alternative has a cost to operate and maintain. Generally, the simpler a system is, the less it costs to maintain. Factoring in the O&M cost and comparing for each alternative is important for a thorough comparison. The annual O&M costs presented in this section are all expressed in 2020 dollars. These O&M costs are based on historical trends in the industry normalized to capacity. The electrical demand and other O&M costs all scale proportionally with the biosolids production. The Monte Carlo analysis in Section 5.4.1 illustrates how different inflation and discount rates affect the O&M costs. In this case, the discount rate refers to the interest rate used in a discounted cash flow analysis to determine the present value of future cash flows. Each yearly cash flow is discounted by this rate compounded annually by the number of years from present.

4.5.1 Alternative 1: Process and Building Heating

Alternative 1, which would use biogas to fuel boilers to produce steam for THP, has the lowest O&M cost. The key assumptions used for the O&M costs of Alternative 1 are as follows:

- Maintenance costs averaged year to year of $15,000/year in 2020 dollars. This cost includes periodic fire tube replacement.
- Operating costs are based on boiler electrical usage (burners and feed water pumps).
- Biogas conditioning cost for boilers of $0.63/MMBtu for operations, and maintenance and $0.15/MMBtu for electricity.

The O&M breakdown for Alternative 1 for select years is shown in Table 25.

Table 25: Alternative 1: Boiler and Process Heat Annual O&M

Item	2028	2037	2052
Natural gas	N/A	N/A	N/A
Electrical	$20,000	$23,000	$26,000
Boiler maintenance	$15,000	$15,000	$15,000
Biogas conditioning	$23,000	$25,000	$28,000
Total	**$58,000**	**$63,000**	**$69,000**

4.5.2 Alternatives 2A/B: CHP

Engine and turbine CHP systems are complex with high-speed, moving components that wear out and require periodic replacement and overhauls. For engines this maintenance would occur on site and would include removal of the heads, replacement of the cylinder liners, and new piston rings. Turbine overhaul would occur off site in a shop certified by the manufacturer and without a redundant turbine the facility would flare 70 percent of the biogas produced during this exercise. The following assumptions were used for CHP O&M costs:

- Maintenance costs for engines of $0.025/kWh in 2020 dollars.
- Avoided electrical costs are credited at $0.06/kWh assuming a consumption-based rate structure.
- Biogas conditioning cost for boilers of $0.63/MMBtu for operations, and maintenance and $0.15/MMBtu for electricity.
- Natural gas is $0.85/therm in 2020 dollars. For Alternative 2A, it is assumed that a fraction of the biogas bypasses CHP to fire the boiler directly instead of purchasing natural gas to supplement the CHP heat.

Table 26 and Table 27 present Alternative 2A engine O&M costs and Alternative 2B gas turbine O&M costs, respectively.

Table 26: Alternative 2A: CHP with Engine Annual O&M

Item	2028	2037	2052
Natural gas	N/A	N/A	N/A
Electrical offset	($844,000)	($937,000)	($1,098,000)
Electrical RECs	($48,000)	($52,000)	($59,000)
Electrical usage	$36,000	$40,000	$47,000
Engine maintenance	$266,000	$289,000	$328,000
Boiler maintenance	$15,000	$15,000	$15,000
Biogas conditioning	$72,000	$78,000	$89,000
Total	**($503,000)**	**($567,000)**	**($678,000)**

Table 27: Alternative 2B: CHP with Gas Turbine Annual O&M

Item	2028	2037	2052
Natural gas	N/A	N/A	N/A
Electrical offset	($627,000)	($696,000)	($815,000)
Electrical RECs	($32,000)	($36,000)	(40,000)
Electrical usage	$36,000	$40,000	$47,000
Turbine maintenance	$178,000	$193,000	$219,000
Boiler maintenance	$15,000	$15,000	$15,000
Biogas conditioning	$68,000	$74,000	$84,000
Total	**($362,000)**	**($408,000)**	**($490,000)**

4.5.3 Alternatives 3A/B: RNG

Removal of carbon dioxide from the raw biogas is required to create RNG. The removal of carbon dioxide increases the concentration of methane, thus increasing the specific energy of the biogas from 580 Btu per cubic foot (CF) to a near-NG level of 1,000 Btu/CF. The financial analysis assumes that this step is performed by a membrane treatment system. A more detailed analysis of different treatment options is provided in Appendix D .

The main O&M costs for an RNG membrane biogas upgrading system are electricity, natural gas, and the NG upgrading. The breakdown of the biogas upgrading O&M cost is shown below in Table 28.

Table 28: RNG Equipment Annual O&M

Item	O&M Cost
H_2S, siloxane, and drying treatment excluding electricity	$0.63/MMBtu
Electricity for H_2S, siloxane, and drying treatment	$0.15/MMBtu
Electricity for boosting	$1.07/MMBtu
Other	$0.73/MMBtu

The total H_2S, siloxane, and drying O&M cost is the same $0.78/MMBtu used for the boiler and CHP treatment alternatives. The comparatively high $1.07/MMBtu additional cost for electricity reflects the energy-intensive biogas compression required for CO_2 removal and pipeline injection. The $0.73/MMBtu other cost represents the cost for labor, general maintenance, and media replacement. Note that these costs are represented per MMBtu of biogas processed.

The following additional assumptions were used for RNG O&M costs:

- Natural gas purchased is $0.85/therm ($8.50/MMBtu) in 2020 dollars
- RNG commodity (sale) price of $2.50/MMBtu
- RNG environmental attributes of $15.00/MMBtu
- County share of environmental attribute of 85 percent to account for broker assistance

Table 29 shows the breakdown of the revenue for Alternatives 3A and 3B.

Table 29: Alternatives 3A and 3B: RNG Annual O&M

Item	2028	2037	2052
Natural gas	$282,000	$298,000	$320,000
Electrical used	$207,000	$230,000	$269,000
Boiler maintenance	$15,000	$15,000	$15,000
Biogas conditioning	$140,000	$152,000	$172,000
RNG revenue	($1,642,000)	($1,778,000)	($2,002,000)
Total	**($998,000)**	**($1,083,000)**	**($1,226,000)**

4.5.4 Alternative 4A/B: RNG with CHP

The O&M costs for Alternatives 4A/B include purchase of natural gas for running the engines, electricity offsets for the generation of electricity, and other O&M costs included in Alternatives 2 and 3, as appropriate.

Table 30 shows the breakdown of the revenue for Alternative 4A.

Table 30: Alternative 4A: RNG and Engine Annual O&M

Item	2028	2037	2052
Natural gas	$1,049,000	$1,106,000	$1,194,000
Electrical offset	($1,058,000)	($1,174,000)	($1,376,000)
Electrical RECs	($60,000)	($66,000)	($74,000)
Electricity used	$207,000	$230,000	$269,000
Engine maintenance	$333,000	$363,000	$412,000
Boiler maintenance	$15,000	$15,000	$15,000
Biogas conditioning	$140,000	$152,000	$172,000
RNG revenue	($1,642,000)	($1,778,000)	($2,002,000)
Total	**($1,016,000)**	**($1,151,000)**	**($1,390,000)**

Table 31 shows the breakdown of the revenue for Alternative 4B. Alternative 4B would generate less power than Alternative 4A but also would use less natural gas.

Table 31: Alternative 4B: RNG and Gas Turbine O&M

Item	2028	2037	2052
Natural gas	$427,000	$460,000	$486,000
Electrical offset	($294,000)	($333,000)	($382,000)
Electrical RECs	($17,000)	($18,000)	($21,000)
Electricity used	$207,000	$230,000	$269,000
Turbine maintenance	$93,000	$103,000	$114,000
Boiler maintenance	$15,000	$15,000	$15,000
Biogas conditioning	$140,000	$152,000	$172,000
RNG revenue	($1,642,000)	($1,778,000)	($2,002,000)
Total	**($1,071,000)**	**($1,169,000)**	**($1,349,000)**

4.6 Results of Analysis

A first-stage analysis of all alternatives focuses on the financial costs only over a 6-year period of construction and 25-year period of subsequent operations. Table 32 presents the original conceptual construction cost (inclusive of contractor overhead and profit [O&P], mobilization and other preliminary costs, and contingency), and total present value of all capital and net operating costs through 2052, assuming a 3 percent discount rate.

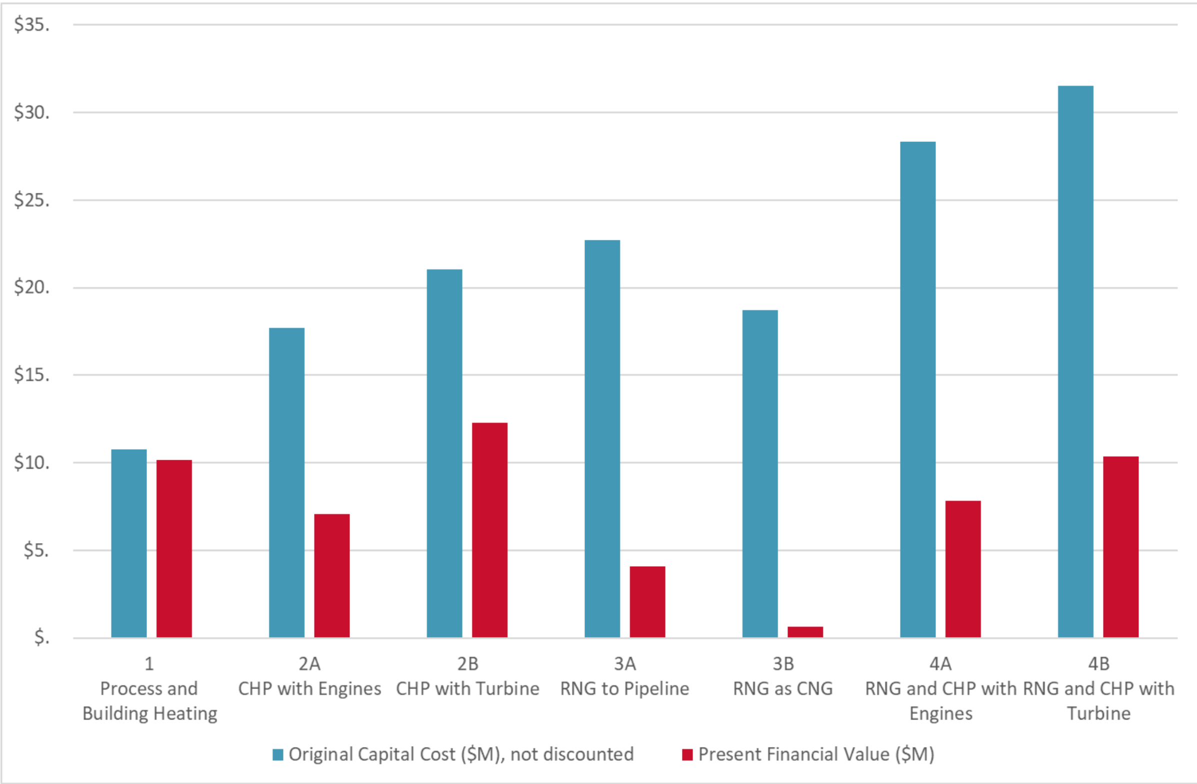
Table 32: Financial Analysis Results

Alternative	1 Process and Building Heating	2A CHP with Engines	2B CHP with Turbine	3A RNG into the NG Pipeline	3B RNG with CNG	4A RNG and CHP with Engines	4B RNG and CHP with Turbine
Conceptual construction cost, $M	$10.8	$17.7	$21.1	$22.7	$18.7	$28.4	$31.5
	Present Financial Value ($M)						
Capital cost	$9.3	$15.3	$18.2	$19.6	$16.2	$24.5	$27.2
Equipment O&M	$0.8	$6.1	$4.6	$5.7	$5.7	$10.9	$7.1
NG cost	$0.0	$0.0	$0.0	$4.2	$4.2	$15.8	$6.4
Electrical offset and RECs	$0.0	($14.2)	($10.5)	$0.0	$0.0	($17.8)	($5.0)
RNG revenue	$0.0	$0.0	$0.0	($25.5)	($25.5)	($25.5)	($25.5)
Total present value	$10.1	$7.1	$12.3	$4.1	$0.6	$7.9	$10.3

Figure 25 shows a comparison of these results graphically.

The base cost analysis indicates that although Alternatives 3A and 3B (RNG alternatives) do not have the lowest capital cost, they do have the lowest total present-value cost due to the anticipated value of the RNGs. In comparison, Alternatives 4A and 4B (RNG and CHP alternatives) would entail larger capital costs and comparable present-value costs when compared to Alternatives 2A and 2B (CHP alternatives).

Figure 25: Capital Costs and Total Present Values ($M) of Alternatives



4.7 Alternatives Selected for Further Review

The initial present-value financial analysis supports eliminating Alternatives 4A and 4B for future consideration because of high capital costs, high overall complexity, significant use of natural gas, and comparable present financial values to Alternatives 2A and 2B. Alternatives 2A, 2B, 3A, and 3B are further analyzed for risk and non-financial factors in the following sections.

5 Shortlisted Alternatives Analyses

5.1 Non-Financial Analysis

The selection of a biogas utilization option is not driven solely by the financial analysis, as the new facilities will need to be operated and maintained by the County. In addition, the facilities could impact local stakeholders in different ways. To account for these factors, a comprehensive non-financial analysis was completed, as described in this section for the shortlisted alternatives.

5.1.1 Evaluation Criteria

The evaluation criteria for the non-financial analysis were developed in conjunction with County staff as part of Workshop 3.2 on May 10, 2021.

Table 33 presents the criteria and descriptions that were used in the subsequent weighting and scoring of the biogas utilization alternatives.

Table 33: Non-Financial Criteria Descriptions

Criterion	Description
Localized emissions	Produces emissions at WPCP site that may negatively impact air permitting requirements, cause neighborhood issues, or result in poor air quality in immediate area
Noise	Generates excess noise that may impact neighbors or result in costly noise reduction measures
Visual aesthetics	Is acceptable to the neighbors and general Arlington County community from a visual aesthetics standpoint
Footprint	Sufficient space for operations and maintenance; does not take land space from current needs or potential future add-ons
Potential for flaring	Provides multiple outlets for use of biogas or redundancy options to minimize the amount of biogas sent to the waste flare
Operational complexity	Complexity of equipment and facilities in operation
Maintenance complexity and reliability	Reliability of equipment and facilities, ongoing maintenance requirements, annual downtime for maintenance, number of components that could fail resulting in failure of system
Safety	Risks for operation of system, including leaks, pressures, number of components, etc.
Resilience	Provides for additional resilience benefits for the WPCP and solids handling systems

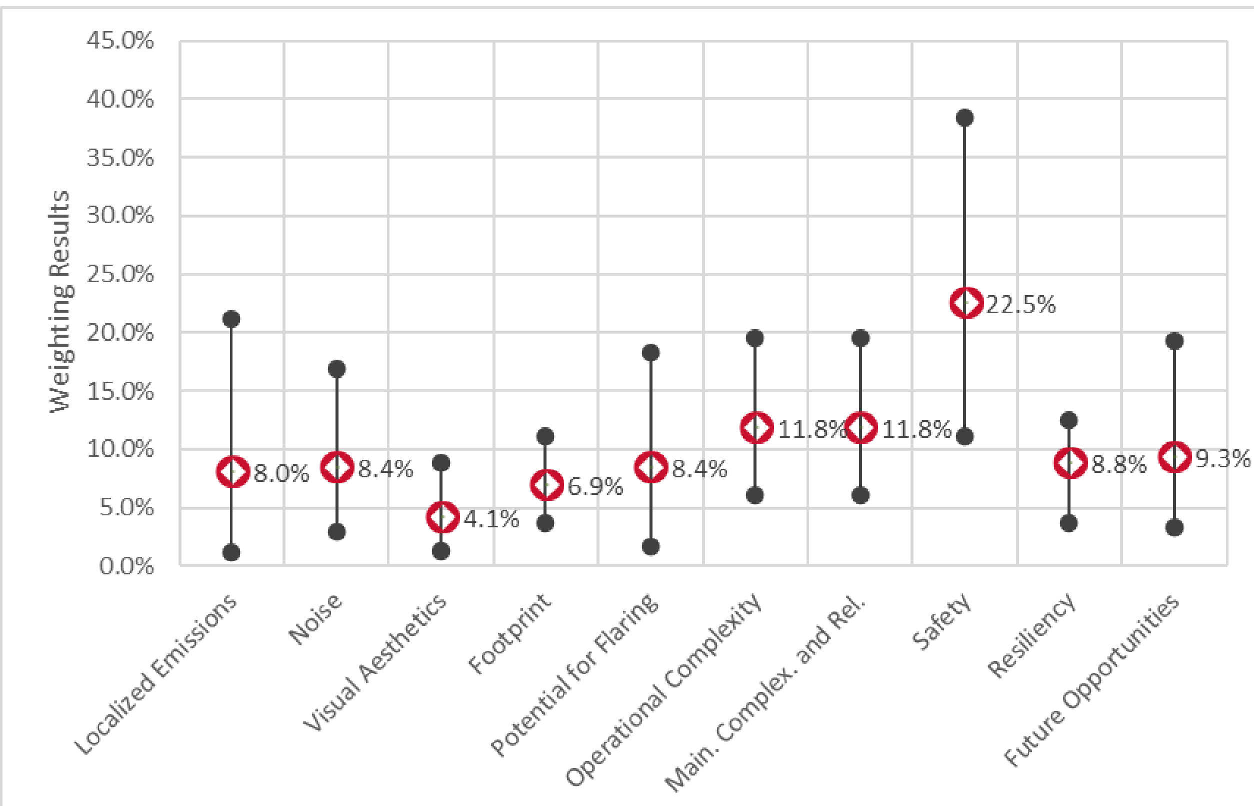
Criterion	Description
Future opportunities	Maintains flexibility for modifying approach should market conditions change

5.1.1.1 Weighting

During Workshop 3.2 on May 10, 2021, the HDR team introduced the alternatives summary sheets and scoring worksheets and provided instructions for completing a pairwise scoring comparison. In the pairwise analysis, participants compared “pairs” of criteria and selected which of those criteria was more important. For example, for evaluating biogas utilization alternatives, is “safety” more important than “operational complexity”? Each participant made a subjective selection, and then compared the remaining pairs. For this exercise, 14 County employees participated in the scoring exercise.

The results of the non-financial criteria weighting are presented in Figure 26. The percentage listed represents the geometric mean for that criterion of all the participants scores. The range bars represent the range of individual weights for each criterion.

Figure 26: Non-Financial Criteria Weighting



5.1.1.2 Alternatives Scoring

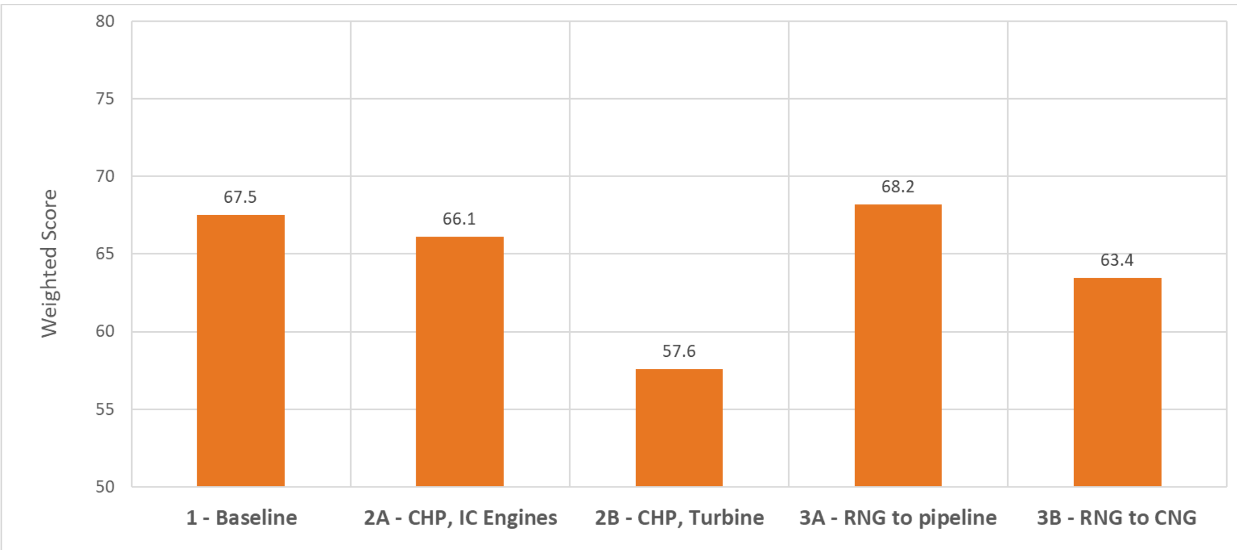
Participants were then asked to weight each biogas utilization alternative for effectiveness in achieving a particular evaluation criterion. For example, is Alternative 2A, CHP with engines, more effective than Alternative 3B, RNG sent to ART/WMATA, for achieving “long-term resilience?” Scoring values, from a scale of 1 (very low) to 5 (very high), were made for all five alternatives and for each evaluation criterion. The summary sheets were distributed electronically to all participants, with guidance for each scoring value listed for each criterion, to assist them in making a subjective selection. Guidance for the scoring of the criteria is presented in Table 34.

Table 34: Non-Financial Criteria Scoring Guidelines

Title	Characteristics	1 - Very Low	2 - Low	3 - Moderate	4 - High	5 - Very High
Localized Emissions	Produces emissions at plant site that may negatively impact air permitting requirements, cause neighborhood issues, or result in poor air quality in immediate area.	Visual emissions impact to existing communities, puts project at risk.	Known emissions are modeled with some impacts to surrounding areas but permitable.	Community understanding of approach and emissions.	Minimal increase in local emissions.	No increase in local emissions.
Noise	Generates excess noise that may impact neighbors or result in costly noise reduction measures	Noise leaving plant site 24/7.	Increase in noise leaving plant site intermittently.	Noise impacts are mittigatable through additional cost. May be periodic excess noise during maintenance activities.	No mitigation impacts required. May be periodic excess noise during maintenance activities.	No excess noise leaving plant site.
Visual Aesthetics	Is acceptable to the neighbors and general Arlington County community from a visual aesthetics standpoint.	Industrial nature, seen as factory with visible emissions.	Industrial nature, but no visible emissions.	Screened from one side but industrial from Route 1. Exposed piping throughout.	All new facilities are screened. Exposed piping throughout.	All facilities inside and/or enclosed. No exposed visible piping.
Footprint	Sufficient space for operations and maintenance, does not take land space from current needs or potential future add ons.	Overly constrained site, not adaptable to other site requirements, prevents future add ons.	Tight site for operations and maintenance, not adaptable to other site requirements and limits future opportunities.	Adequate space for operations and maintenance but still constrains site for future opportunities and lacks site synergies.	Adequate space for all new facilities and takes advantages of site synergies, but limited space for future opportunities.	Small footprint, able to take advantages of site synergies, allows for future opportunities.
Potential for Flaring	Provides multiple outlets for use of biogas or redundancy options to minimize the amount of biogas sent to the waste flare.	All biogas except that used for boiler is flared.	Biogas is benefically used in areas other than boiler but equipment failures and lack of redundancy result in significant flaring.	Biogas is beneficially used in areas other than boiler with flaring for offspec gas and systems offline. No additional outlets.	Biogas is beneficially used with flaring for offspec gas but is minimized through equipment redundancy.	Biogas has multiple outlets and only is flared when all outlets fail.
Operational Complexity	Complexity of equipment and facilities in operation.	Highly complex systems with multiple control points and sensors. Requires external resources to operate.	Complex systems with multiple control points and sensors with some annual downtime and/or Requires specialized training and some reliance on external resources to maintain operation.	Complex systems with multiple control points and sensors with some annual downtime. Requires specialized training but no external resources to maintain operation.	Less complex operational systemswith fewer control points. Minimal training and current staff can operate.	Standard systems with standard operational requirements. Current staff have the skillsets to operate all equipment.
Maintenance Complexity and Reliability	Reliability of equipment and facilities, ongoing maintenance requirements, annual downtime for maintenance, number of components that could fail resulting in failure of system.	Systems with non-standard maintenance requirements and limited redundancy, leading to downtime and system failures.	Non-standard maintenance requirements and some annual downtime. Requires external resources to operate and/or maintain all new gas handling systems.	Non-standard maintenance and some annual downtime. Systems other than boiler requires specialized staff to operate and maintain but no external resources.	Generally standard maintenance requirements. Systems other than boilers require some specialized training that current staff can take to operate and maintain.	Standard maintenance requirements. Current staff have the skillsets to operate and maintain all equipment.
Safety	Risks for operation of system, including leaks, pressures, number of components, etc.	Multiple high pressure systems(>100 psi) with multiple locations of potential failures.	Single high pressure system (>100 psi) with fewer locations for potential failures.	Single high pressure system with limited length of pressurized lines.	Lower pressure gas system with fewer components and potential leakage points.	Standard gas systems with safety components in place.
Resiliency	Provides for additional resiliency benefits for the WPCP and solids handling systems.	No change in gas or electrical resiliency.	Provides only natural gas resiliency to Solids Area	Provides only electrical resiliency to Solids area	Provides natural gas resiliency to multiple areas or both electric and natural gas resiliency to solids area	Provides electrical resiliency to multiple areas.
Future Opportunities	Maintains flexibility for modifying approach should market conditions change.	Locks-in treatment and biogas utilization options with no ability to adapt in the future	Provides limited treatment and biogas utilization flexibility in the future - may be possible but would require significant rework of infrastructure put in place.	Flexibility to add new end uses but at significant cost beyond the new technology.	Flexibility to add new end uses without paying a premium	Has multiple end uses now and flexibility to pivot should markets change.

At Workshop 4.2 on June 24, 2021, the scoring of each alternative was discussed to develop consensus. The participants discussed each criterion and their perspective on scores to develop the consensus. Figure 27 presents the average scores for each alternative. The average score is represented by multiplying the consensus score by the average weighting results presented in Figure 26. Alternative 3A had the highest non-financial score at 68.2, followed by Alternative 1 at 67.5. Alternative 2B had the lowest non-financial score of 57.6.

Figure 27: Non-Financial Scoring Results



The main differentiators between the RNG alternatives (Alternatives 3A/3B) and CHP alternatives (Alternatives 2A/2B) were that the RNG alternatives had:

- Lower localized emissions
- Reduced noise
- More outlets for beneficial use of the biogas and ability to reduce flaring
- Lower maintenance complexity and reliability
- Adaptability to future opportunities

5.2 Sustainability Criteria

In addition to financial and non-financial considerations, the Program is tasked with reviewing the sustainability, or environmental impact, of the alternatives identified. This was accomplished using the anticipated reductions of GHG emissions (namely CO_2) for each alternative and using a social cost of GHG approach to monetize the reductions. Note, this social cost of GHG is a monetization of the social impacts of the GHG emissions based on economic loss over time—it does not represent a true financial value to the County. However, by monetizing the value of the GHG offsets, the results can be combined with the financial and non-financial results to develop a composite comparison for each.

5.2.1 Basis of Greenhouse Gas Evaluation

A comparative greenhouse gas summary was developed for the biogas utilization alternatives. The summary in the sections below includes only the emissions from electricity and NG utilization associated with the biogas portion of the Program (regardless of where the end user of the biogas is located) including reductions from avoided electricity purchase or avoided fossil fuel-based NG usage. A complete comprehensive GHG emissions evaluation including biosolids hauling and chemical usage will be provided in a separate TM.

5.2.1.1 Electrical Use

The Arlington WPCP buys its electrical power from Dominion. From Dominion's Sustainability Report, included in Appendix C , the GHG emissions (expressed as MT carbon dioxide equivalent [CO_2e] per net MWh) from Dominion-provided power in Virginia has been steadily decreasing from 0.637 MT/net megawatt-hours (MWh) in 2000 to 0.285 MT/net MWh in 2019, as shown in Figure 28. This is due to the gradual reduction in power production from coal to more renewable sources and natural gas. The breakdown of Dominion's energy sources in 2019 is presented in Figure 29.

Figure 28: Dominion Emissions Trend

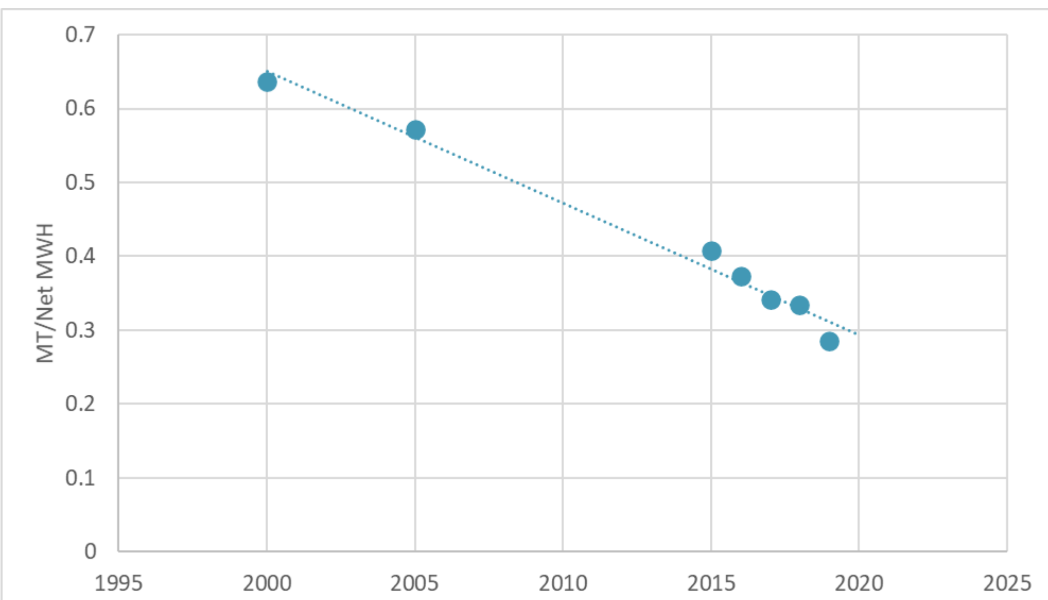
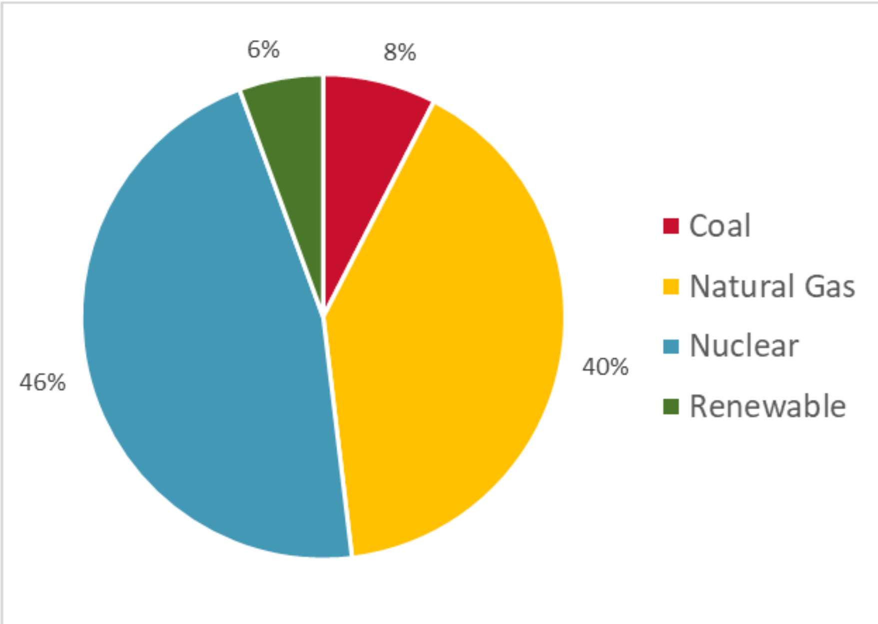


Figure 29: Dominion Energy Sources, 2019



5.2.1.2 Natural Gas Use

As summarized in Section 2.3.1, the WPCP currently uses approximately 7,800 therms or 780 MMBtu of natural gas per year. From EIA, the combustion of natural gas results in 53.07 kilograms (kg) of carbon dioxide per MMBtu. Therefore, the GHG emissions from NG use at the WPCP are approximately 40 MT/yr.

5.2.2 Changes in GHG Emissions

In addition to differences in energy production and costs, each biogas utilization alternative results in a different amount of total net GHG emissions. The net GHG change presented herein is solely for the biogas utilization equipment, not the entire Re-Gen/Biosolids Program. Table 35 below provides a breakdown of what areas contribute to GHG additions and offsets for the various components of each alternative:

Table 35: Impacts of Alternatives on Net GHG Emissions

Alternative	Electricity Use	Electricity Production	NG Used On Site for Steam Production	Biogas Displaces Fossil Fuel-Based NG On Site	Biogas Displaces Fossil Fuel-Based NG Off Site
1: Process and building heat	+			-	
2A: CHP with IC engines	+	-		-	
2B: CHP with turbines	+	-		-	
3A: RNG to pipeline	+		+		-
3B: RNG used as CNG	+		+		-

GHG emissions from removal of carbon dioxide in the biogas, combustion of biogas on site for steam generation, combustion on site in CHP, or flaring are not included, as the carbon dioxide being emitted is biogenic.

With Alternative 1, steam generation would be solely through using biogas in boilers. This would also eliminate current combustion of fossil fuel-based NG and thus reduce emissions by 40 MT/yr. However, this alternative also would require an increase in electricity use over current usage, which would lead to 80 MT/yr of additional GHG emissions. Therefore, a net increase over current emissions of 40 MT/yr would result.

For Alternative 2A the biogas would be used to produce 1.39 MW of electricity or 12,185 MWh/yr. Combined with additional electricity use for this alternative, GHG emissions for electricity would be reduced by 3,330 MT/yr based on the current Dominion Energy CO_2 emission profile. Steam generation for THP will come solely from heat recovery from the engines or biogas combustion. In addition, the heat recovery from the engines would eliminate current fossil fuel-based NG consumption and the corresponding emissions of 40 MT/yr. Therefore, the total GHG emissions reduction of 3,370 MT/yr.

Because of the lower efficiency of the gas turbine, Alternative 2B would produce only 0.98 MW of electricity or 8,585 MWh/yr, reducing GHG emissions by 2,310 MT/yr. Similar to Alternative 2A, the heat recovery from the turbine would reduce NG purchases by another 40 MMBtu/yr, resulting in a total net GHG emission reduction of 2,350 MT/yr.

Alternatives 3A and 3B, which involve selling all the biogas produced as RNG, would generate the most emissions reductions, even though some natural gas would be purchased for the steam boiler. Alternatives 3A and 3B result in an emissions reduction of 6,240 MT/yr from the displacement of fossil-fuel based NG off site. The use of NG on site in steam boilers would result in an additional 1,970 MT/yr of emissions. The additional electrical usage for the biogas conditioning system results in 770 MT/yr of additional emissions. When these are added together, the total net GHG emissions reductions for these alternatives amount to 3,500 MT/yr in 2037.Table 36 presents net change in GHG emissions for each of the sources of energy for 2037. Overall, Alternatives 2A, 3A, and 3B have greater emissions reductions than Alternatives 1 and 2B.

Table 36: Total Change in Net GHG Emissions (MT CO_2e) in Year = 2037

Alternative	Net Electricity Use	Biogas Production (Offsets NG Purchases)	NG Purchased	Total Change in Emissions
1: process and building heat	80	-40	0	40
2A: CHP with IC engines	-3,330	-40	0	-3,370
2B: CHP with turbines	-2,310	-40	0	-2,350
3A: RNG to pipeline	770	-6,240	1,970	-3,500
3B: RNG used as CNG	770	-6,240	1,970	-3,500

Note: Negative values are reductions and positive values are increases in emissions.

Note, GHG reductions for Alternatives 2A and 2B are based on the current Dominion Energy emission profile, which includes a combination of fossil-fuel and renewable energy sources described above. Electricity usage for Arlington County operations is projected to be 100 percent renewable by 2025, in which case the GHG reduction for net electricity production would be zero. However, the generation of renewable power at the WPCP may allow for currently forecast renewable sources to be used elsewhere.

5.2.3 Environmental Value of Greenhouse Gas Emission Savings

Annual GHG emissions reductions can be converted into monetary terms by applying the dollar values per metric ton that have been established by the Interagency Working Group (IWG) on Social Cost of Greenhouse Gases of the U.S. government.[1] The IWG analysis accounts for a wide range of climate change impact studies that assess losses to the U.S. and world economies over time. These future losses are discounted to the present and normalized on a per metric ton of CO_2 emissions basis.

Results of the analysis are formalized in tables and charts. Because of uncertainty in future impacts and uses of the results, several dollar values are produced. Generally, monetary values can be combined with a change in GHG emissions to reveal the benefits of a change.[2] Table 37 presents two sets of dollars per ton by year to illustrate the range of values. The “most likely” value represents the best estimate for potential

[1] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). February 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. United States Government Publication. (Link)
[2] Note that if emissions increase, the monetary value would be considered a loss or “negative” benefit.

damage caused by GHG emissions, given the analyses considered by the IWG. A high value is also computed and represents a much more significant level of future economic damage from GHG emissions.[3] The analysis of emissions reduction for the Program applies the most likely values.

Table 37: Social Cost of GHG, per Metric Ton of CO_2, by Year, at a 3% Discount Rate

Year	$/MT (Most Likely Value)	$/MT (High Value)
2020	$51	$152
2025	$56	$169
2030	$62	$187
2035	$67	$206
2040	$73	$225
2045	$79	$242
2050	$85	$260

The value of net GHG emissions reductions is presented in Table 38. The first column shows the same forecast value of GHG emissions reductions from Table 37 above. Next to it on the right is the corresponding monetary value of these reductions for year 2037, which have an estimated value of $69.34/MT for that year. The second set of columns to the right show the discounted total value of all GHG emissions reductions over a 25-year period of operations. These results show that reductions from Alternatives 3A, 3B, and 2A are all similar in total value with Alternatives 3A and 3B, with the highest at $3.62 million. The total discounted monetary value of emissions reductions can be combined with capital and financial costs to determine a total project value.

Table 38: Total Net CO_2 Emissions Reductions Value, $Millions

Alternative	Tons Reduced, Year 2037 Only	Most Likely Value Reduced, Year 2037 Only	Total Value, 25-Year Total (Discounted at 3%)
1	40	-$0.003	-$0.04
2A	-3,370	$0.23	$3.5
2B	-2,350	$0.16	$2.4
3A	-3,500	$0.24	$3.6
3B	-3,500	$0.24	$3.6

[3] Technically, this high value characterizes damage levels for which there is only a 5% chance that the future could be any worse. At this more extreme level of potential damage, the dollar value is correspondingly higher than an average damage condition in the future.

5.2.4 GHG Offsets

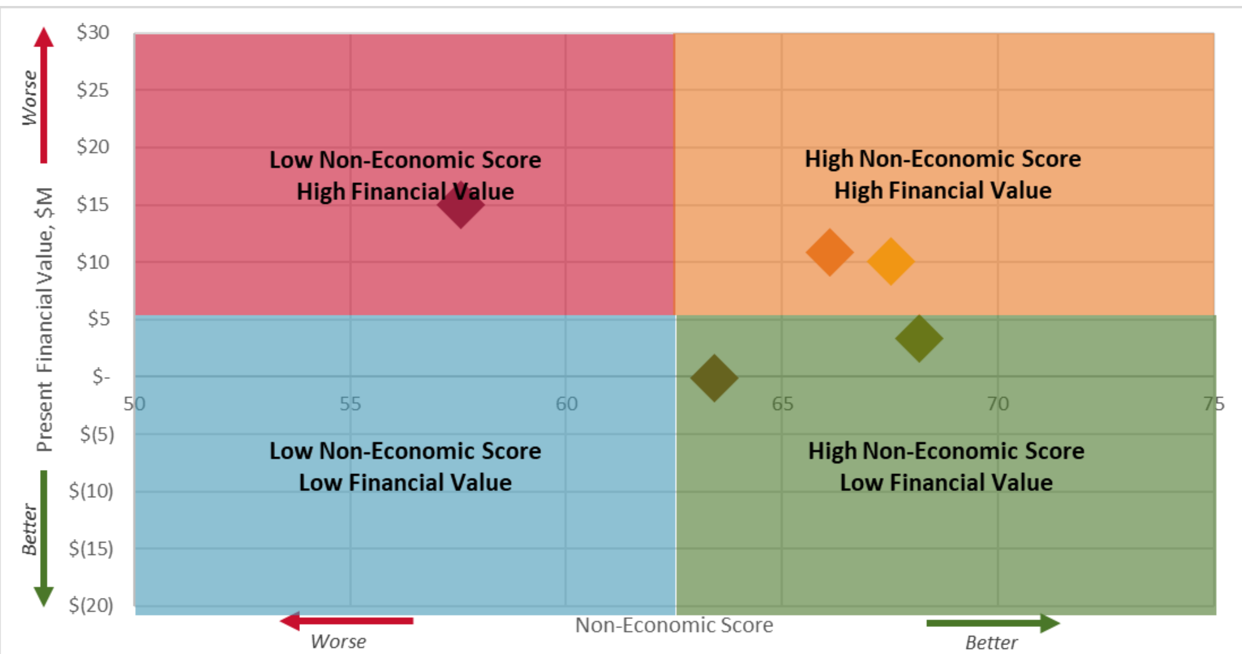
As discussed in Section 2.4.3, the GHG emission reductions associated with RNG will likely be realized by the ultimate purchaser of the RNG for use as transportation fuel. If that purchaser is within Arlington County, these emission reductions could be counted toward Arlington County's Carbon Neutrality goals.

However, if that purchaser is outside of Arlington County, the County might want to consider using some of the revenue brought in from RNG to purchase carbon credits on the open market. At the current market rate of approximately $15/MT of CO_2e, it would cost Arlington approximately $100,000 per year to purchase GHG credits equivalent to those attributable to the RNG. This purchase would not materially impact the financial evaluations presented.

5.3 Composite Results

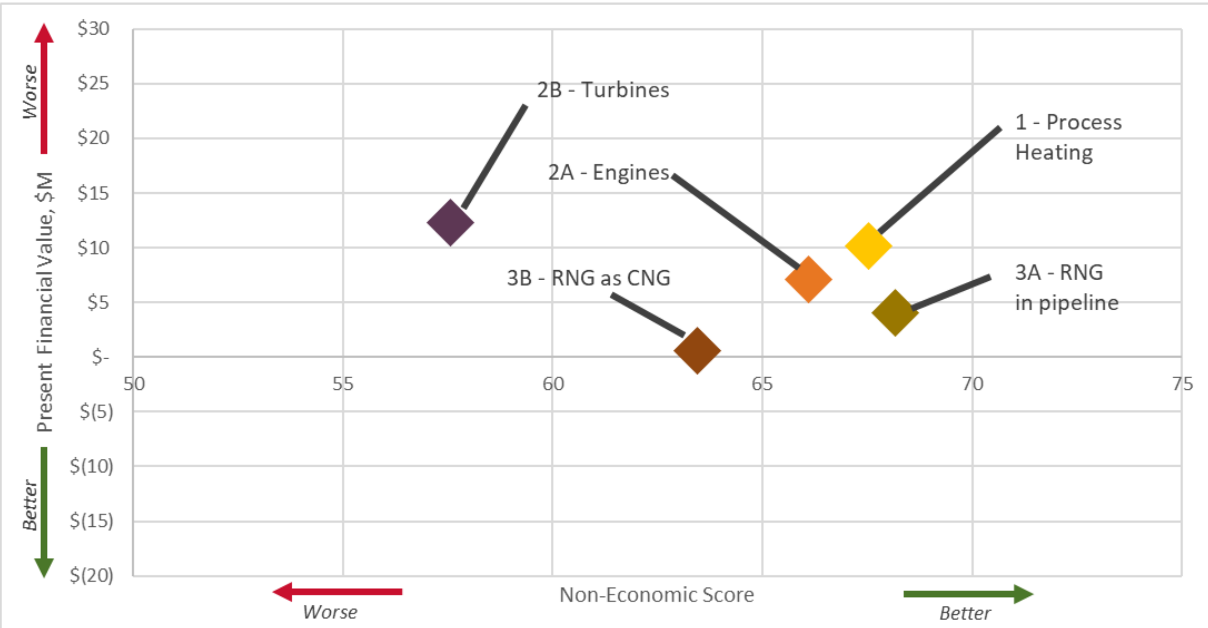
To further evaluate the financial results and non-financial scoring, the results of both efforts are combined into plots to illustrate the composite results for each alternative. By plotting the non-financial scores on the x-axis and the present financial values on the y-axis, a clearer picture of the most beneficial alternative can be achieved. With this approach alternatives that are located in the lower-right quadrant have higher non-financial scores and lower present financial values (better). Conversely, alternatives in the upper left quadrant have lower non-financial scores and higher present financial values (worse). Figure 30 illustrates this methodology.

Figure 30: Composite Scoring Methodology



When the non-financial scores from Figure 27 above are combined with the present financial values from Figure 25, the composite results can be developed; see Figure 31. These results represent the current electrical price of $0.078/kWh and an average RIN market value of $15/MMBtu, and do not include any social cost of carbon.

Figure 31: Base Scenario ($0.078/kWh, No GHG, RIN = $15/MMBtu)



For this base scenario, without considering the social cost of carbon, Alternative 3A had the highest non-financial score and the second lowest present financial value.

The results of several other scenarios were developed to help illustrate the potential impact of electrical costs, social cost of carbon, and RNG pricing on the composite results. The conditions and present financial values for each of these scenarios are presented in Table 39. The low RIN value represents the lowest weekly RIN value seen in the market over the last 6 years. The high RIN value represents the average weekly RIN value seen in the market over the last 6 years. The RIN market value as of October 2021 was $38/MMBtu. A high electrical scenario, with electricity at $0.117/kWh (50% over current), was also developed to reflect the impact of potential higher electric prices, although no such jump increase is forecast by the EIA projections.

Table 39: Present Financial Values for Other Scenarios

Condition	Base Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Original Capital Cost ($M), Not Discounted
Electrical, $/kWh	$0.078	$0.078	$0.078	$0.078	$0.117	
GHG value	0	Most-Likely	Most-Likely	Most-Likely	Most-Likely	
RIN market value, $/MMBtu	$15	$15	$23.35 (average)	$6.38 (min)	$15	
Alternative	Present Financial Value ($M)					
1	$10.2	$10.2	$10.2	$10.2	$10.3	$10.8
2A	$7.1	$3.6	$3.6	$3.6	$1.6	$17.7
2B	$12.3	$9.9	$9.9	$9.9	$8.4	$21.1
3A	$4.1	$0.5	($11.5)	$12.8	$1.0	$22.7
3B	$0.6	($3.0)	($15.0)	$9.4	($2.5)	$18.7

Figure 32 shows the Scenario 1 composite results when the most-likely value for the social cost of carbon (GHG value) is included. The main impact is that Alternative 1 becomes less attractive because of the present value of the other alternatives being lowered. The relative differences between the other alternatives remain the same.

Figure 32: Scenario 1 ($0.078/kWh, Most-Likely GHG, RIN = $15/MMBtu)

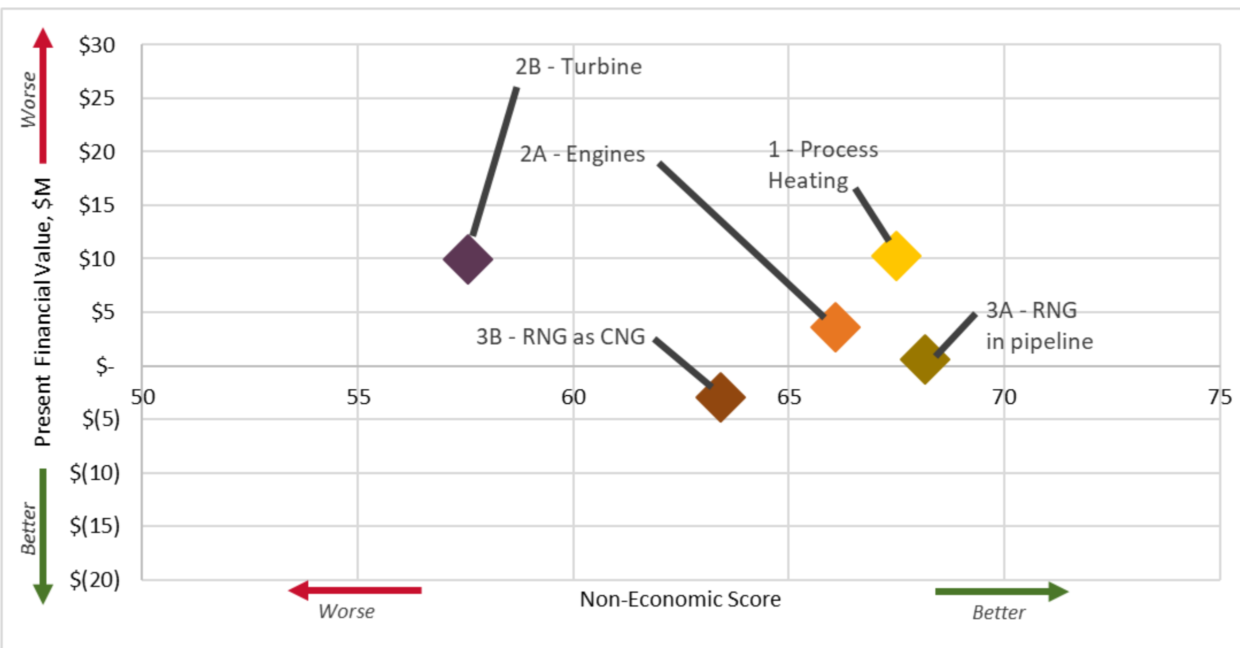


Figure 33 shows the Scenario 2 results including the social cost of GHG and the average RIN value for the past 6 years of $23.35/MMBtu. This RIN value furthers the financial advantage of the RNG alternatives.

Figure 33: Scenario 2 ($0.078/kWh, Most-Likely GHG, RIN = $23.35/MMBtu)

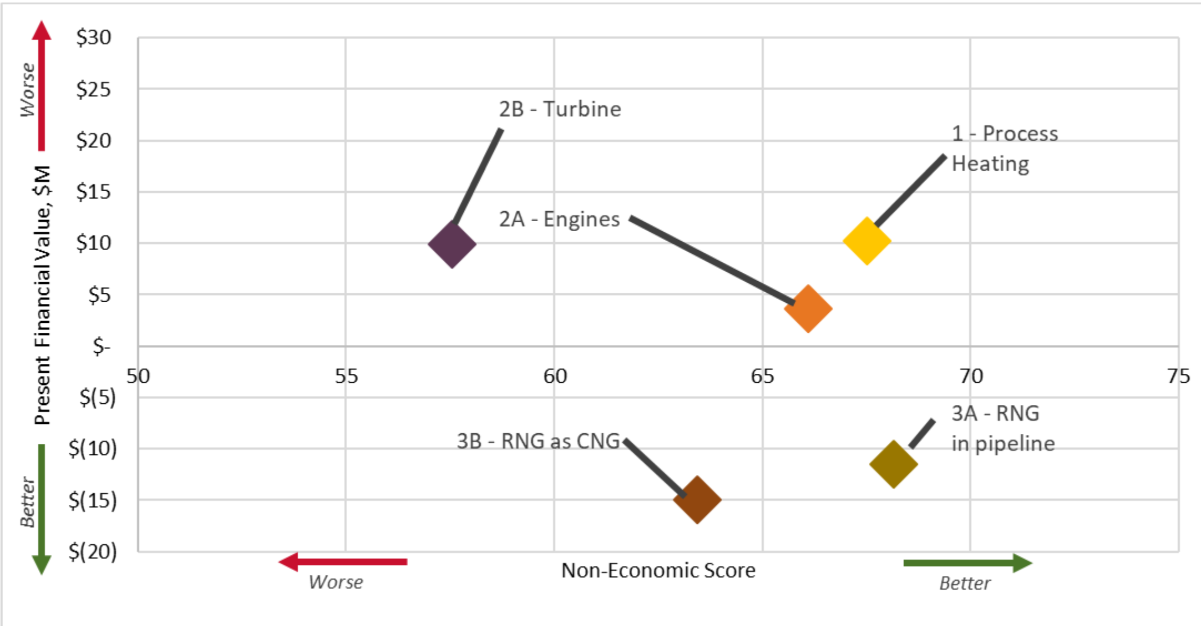
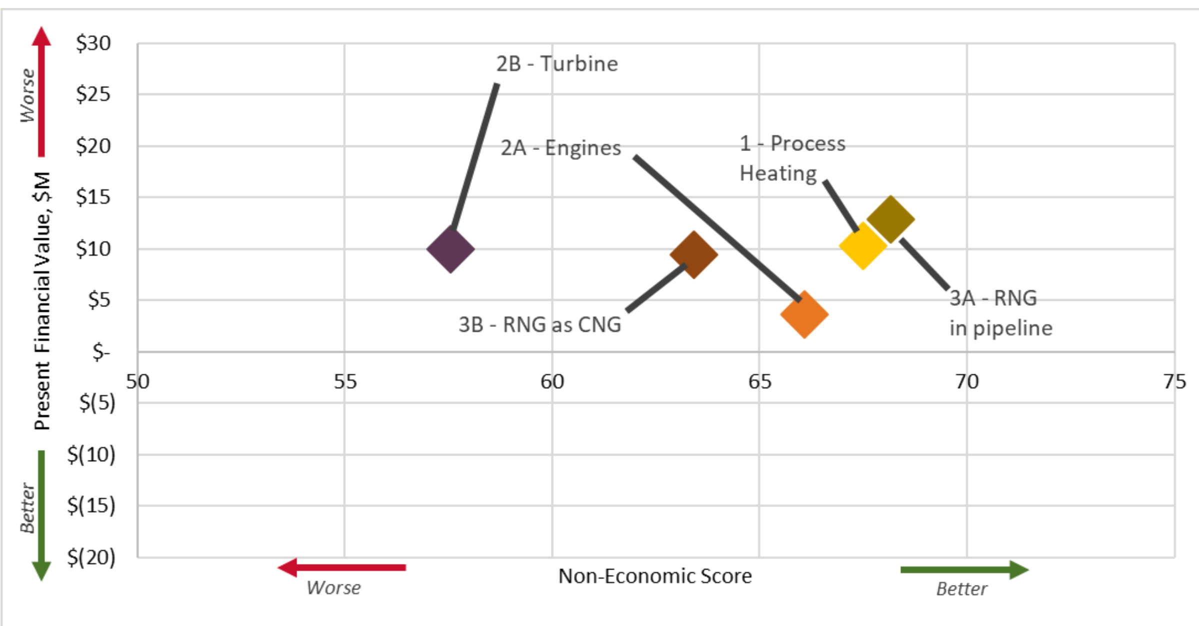


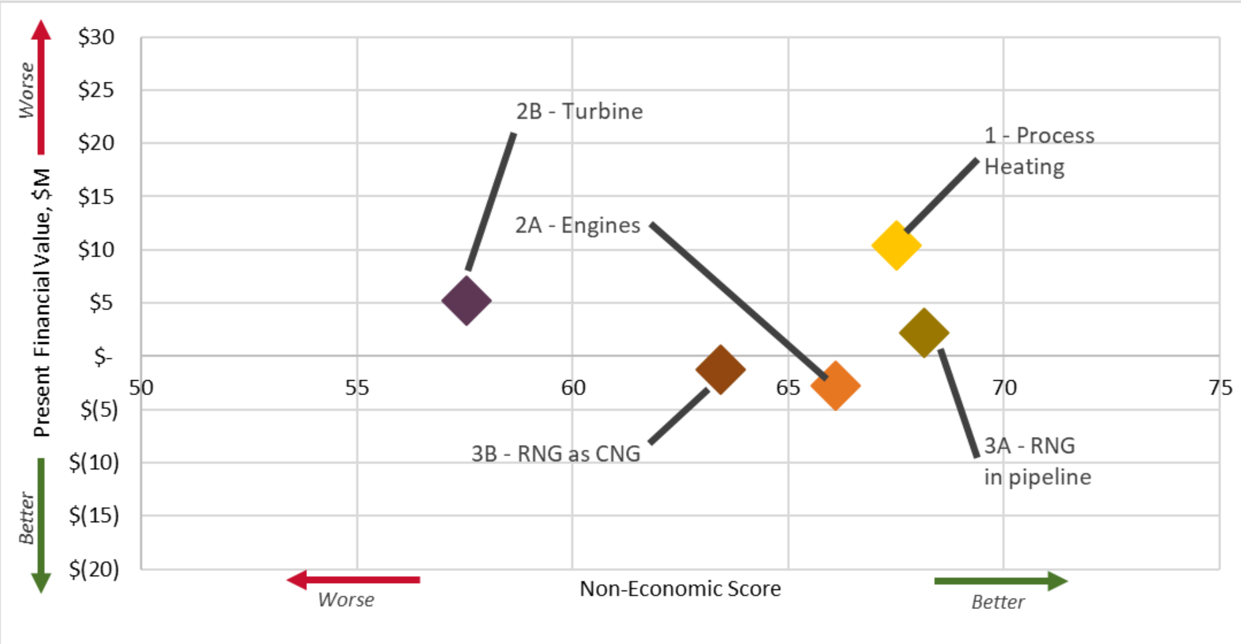
Figure 34 provides the same analysis including the social cost of GHG and the lowest weekly RIN value over the last 6 years of $6.38/MMBtu. In this scenario, Alternative 2A (CHP with engines) becomes more financially advantageous than Alternative 3A (RNG in pipeline). Note that this represents the RIN value averaging the minimum value for the entire 25-year analysis.

Figure 34: Scenario 3 ($0.078/kWh, Most-Likely GHG, RIN = $6.38/MMBtu)



Finally, when the electrical cost is increased to $0.117/kWh, the composite score of the CHP alternatives becomes more favorable than the RNG alternatives (see Figure 35).

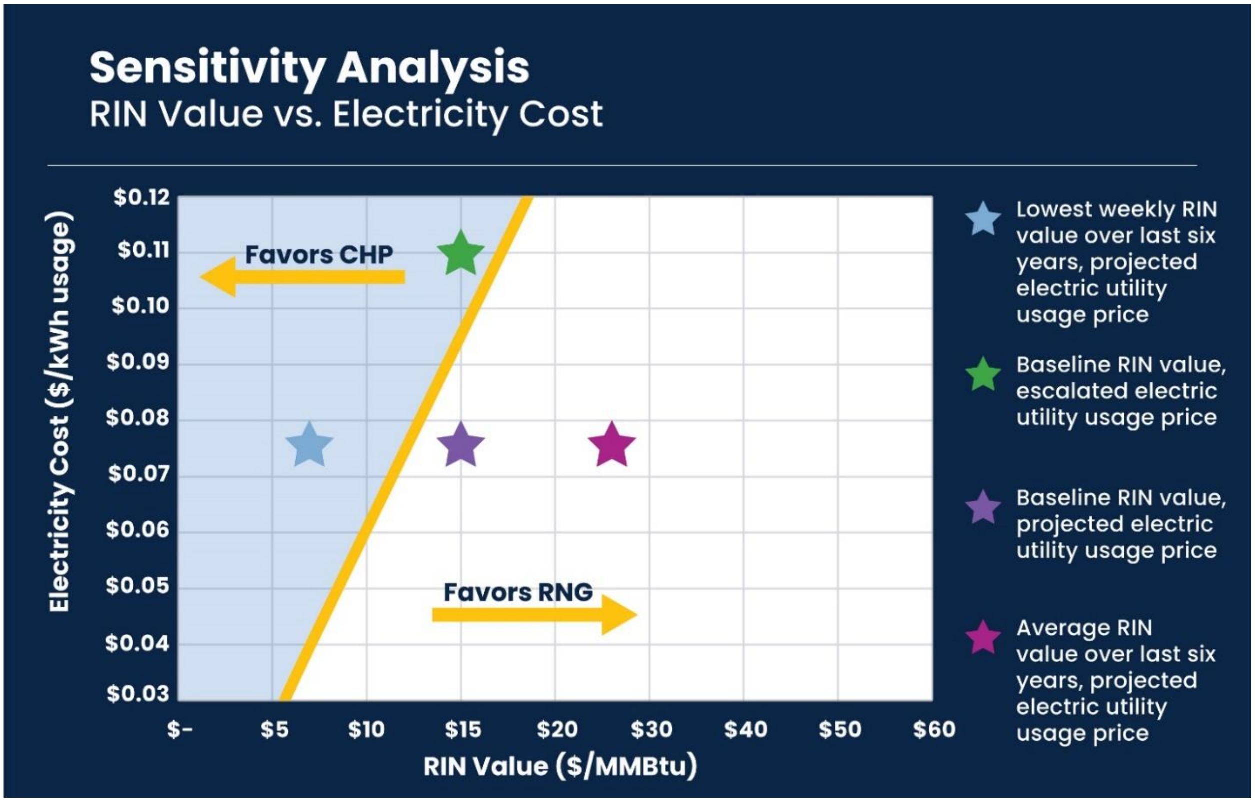
Figure 35: Scenario 4 ($0.117/kWh, Most-Likely GHG, RIN = $15/MMBtu)



5.4 Sensitivity Analysis

The financial analysis makes it clear that the main drivers in the comparison are the cost of electricity and the value of the RIN market. A break-even analysis was completed to identify the point at which Alternative 2A (CHP with engines) is financially equal to Alternative 3A (RNG into pipeline). This break-even analysis is shown on Figure 36, with the scenarios completed above identified.

Figure 36: Sensitivity Analysis of RIN Value vs. Electricity Cost



In addition to the sensitivity analysis described above, a more computationally rigorous approach, using Monte Carlo simulation methods, was completed to assess the combined impact of changing several factors at once.

5.4.1 Simulation Assumptions

Monte Carlo simulation involves defining input parameters as probability distributions of possible values, instead of one or several possible scenario values. For example, Figure 37 shows the probability distribution of annual growth rates (in percentage terms) for real electricity prices in the Mid-Atlantic region. This probability distribution was obtained by examining a variety of forecast scenarios produced by EIA (Figure 23) and identifying the lowest, baseline, and highest annual growth rates over a 30-year period.[4]

[4] The distribution was formed using a "Pert" distribution, a reasonable distributional form for engineering and economic analyses such as this.

Figure 37: Probability Distribution of Annual Growth Rates in Real Electricity Prices

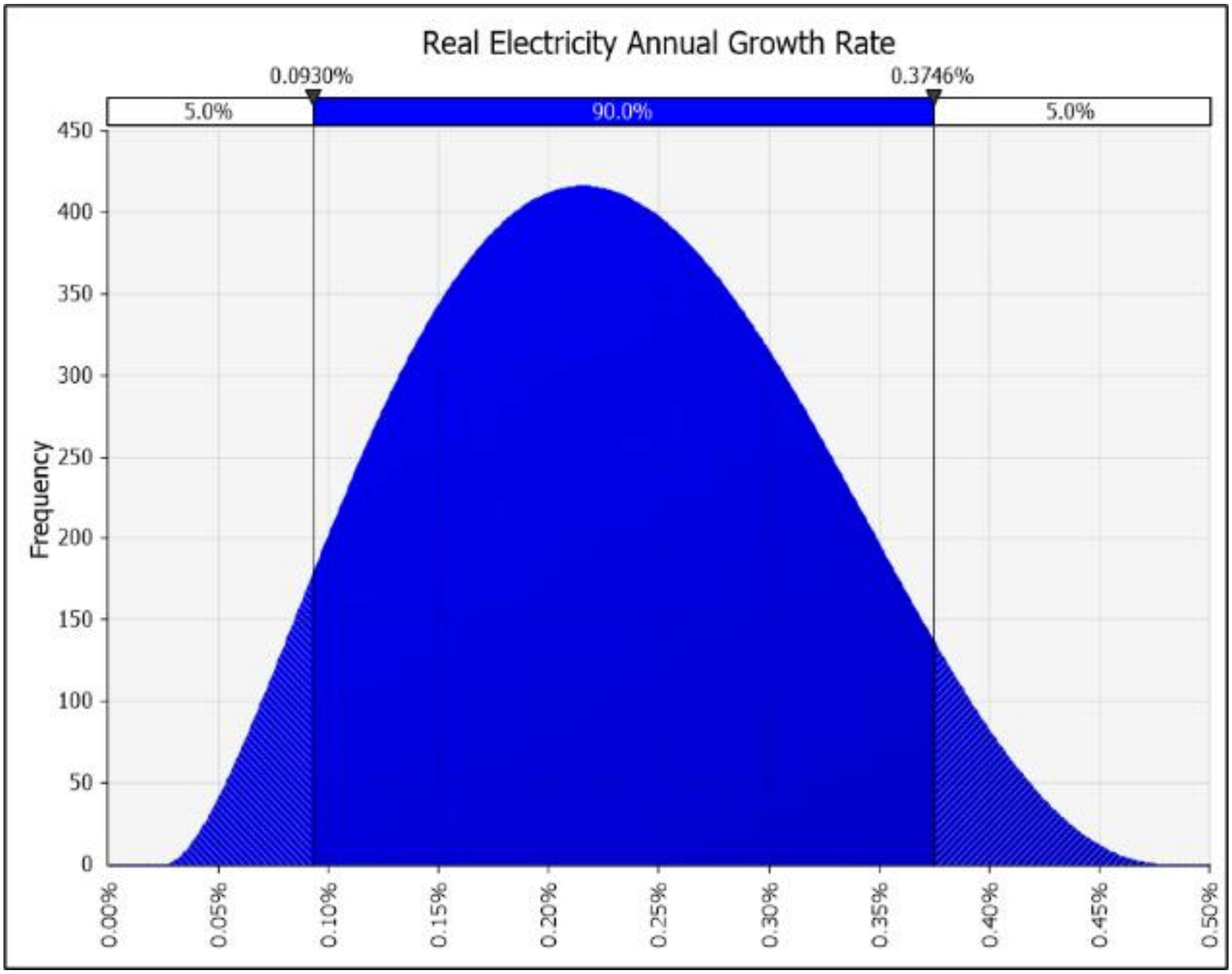


Table 40 presents the lower limit, estimated, and upper limit for the uncertain factors that are included in the model. Separate probability distributions are formed for each of these factors, using the same functional form as electricity price growth rates. The sources for these distributions include HDR assumptions and existing data.

Table 40: Monte Carlo Probability Distribution Parameter Values

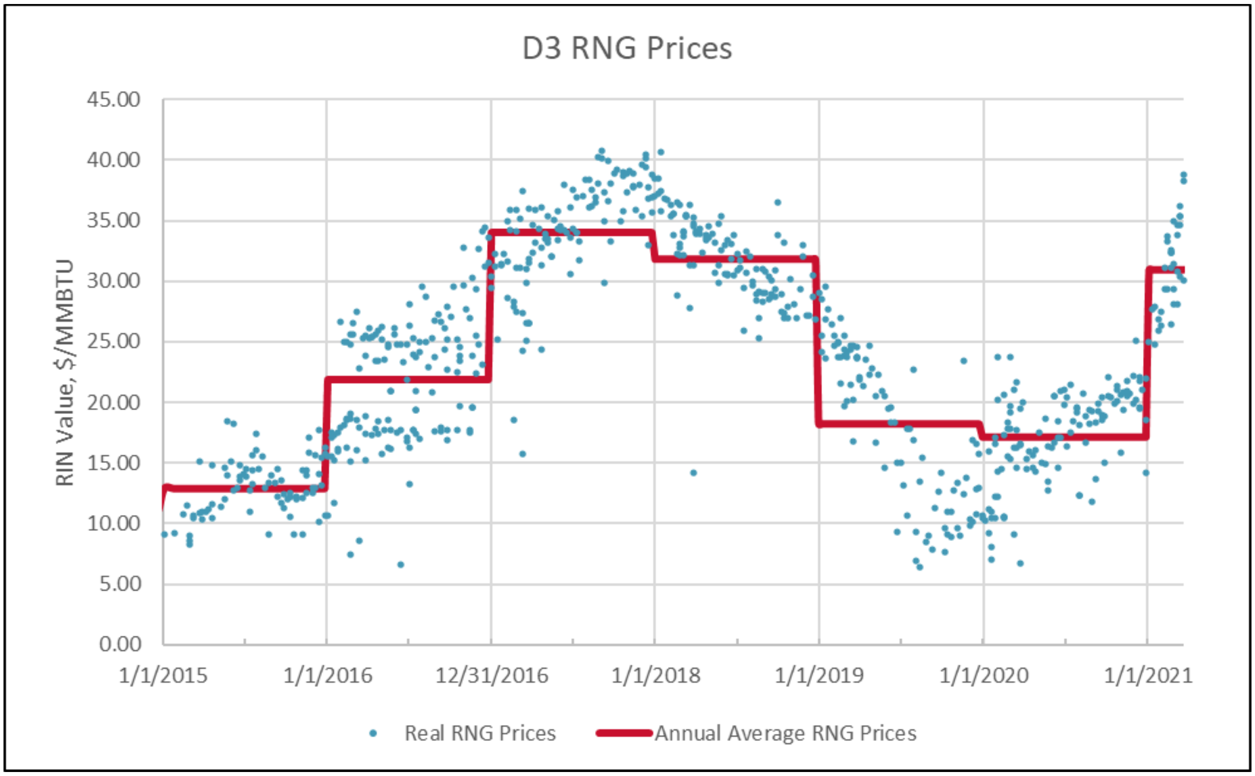
Uncertain Parameter	Lower Limit	Estimated Value	Upper Limit	Data Source
Energy Prices				
Electricity inflation (annual real rate)	0.03%	0.22%	0.48%	EIA
NG inflation (annual real rate)	-1.11%	-0.34%	0.88%	EIA
RIN price inflation (annual real rate)	0.00%	0.00%	2.18%	EPA
RIN market value (distribution for simulation)	$3	$22.36	$47	EPA
Capital Costs				
Contractor O&P (percentage of estimated cost)	12%	15%	18%	HDR
Contingency (percentage of estimated cost)	15%	20%	30%	HDR
Mobilization, bonds, and insurance (percentage of estimated cost)	6%	8%	10%	HDR
Building price, $/SF	$1,000	$1,150	$1,300	HDR
Slab-on-grade price, $/SF	$40	$50	$60	HDR
Performance				
Engine availability (annual probability)	90%	95%	97%	HDR
Turbine availability (annual probability)	85%	90%	95%	HDR
RNG treatment availability (annual probability)	85%	95%	95%	HDR

With a probability distribution of potential parameter values, such as the one shown in Figure 37 above, the model produces a full range of outcomes along with the likelihood that those values could occur.[5] When a model includes several uncertain parameters and each one is defined by its own independent probability distribution, the results will have fully accounted-for possible outcomes.

[5] A full range of model outcomes is achieved by the simulation process. Monte Carlo simulation methods involve performing thousands of iterations of model solutions whereby each iteration applies random draws of parameters from each probability distribution to solve the model.

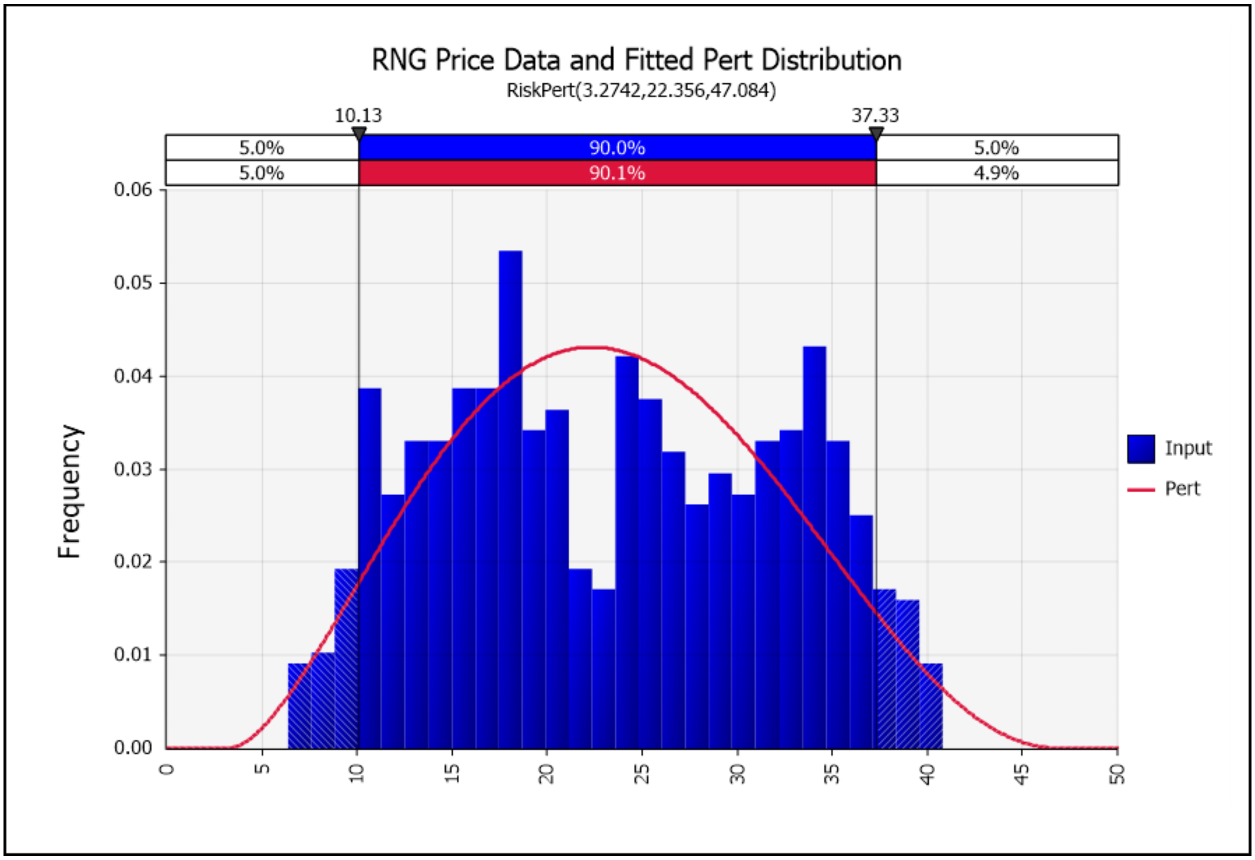
The parameter with the most significant influence on model results is RIN growth rates. The RIN distribution was estimated with a curve-fitting tool using the Palisade company's commercial @Risk software employed with Microsoft Excel. RIN prices for the past several years obtained from EPA records are shown in Figure 38. The curve-fitting approach assumes that all instances of RIN prices are independent of each other, as a group.[6] The resulting distribution is shown in Figure 39. The model uses the distribution to select a single annual price.

Figure 38: D3 RIN Prices (EPA)



[6] While trends may exist in the data, these were not evaluated at this stage. In fact, this approach is wider than the range of average annual values, which is how the data are used in the model.

Figure 39: Curve-fitted Probability Distribution of D3 RIN Prices



5.4.2 Simulation Results

Results from a Monte Carlo simulation are a probability distribution of possible outcomes, given the range of possible inputs of uncertain parameters. Figure 40 shows the distributions of possible present values of total financial and social outcomes for all five alternatives, in both probability density function (PDF) and cumulative density function (CDF).[7] The CDF has a useful interpretation for decision making because it can clearly indicate the probability that a condition holds, such as having a total present value of benefits exceeding costs.

[7] A PDF often appears to be bell-shaped; a CDF adds probabilities together for each value and appears as an S-curve.

Figure 40: Monte Carlo Simulation Results: Present Financial and Environmental Values of Alternatives

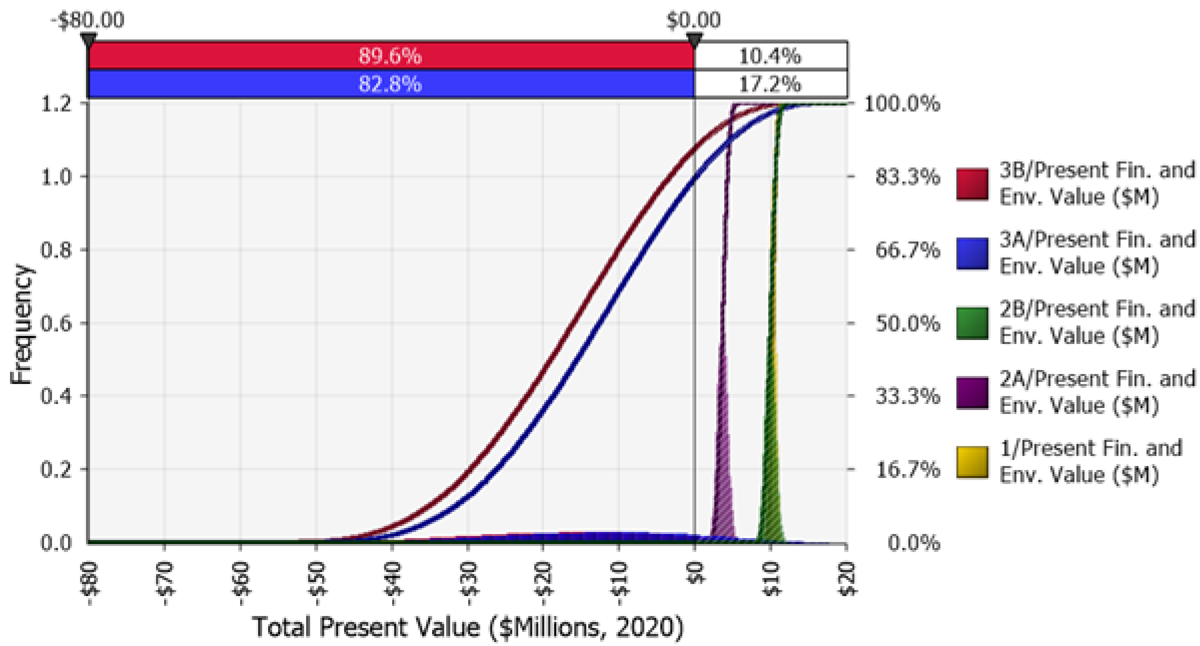
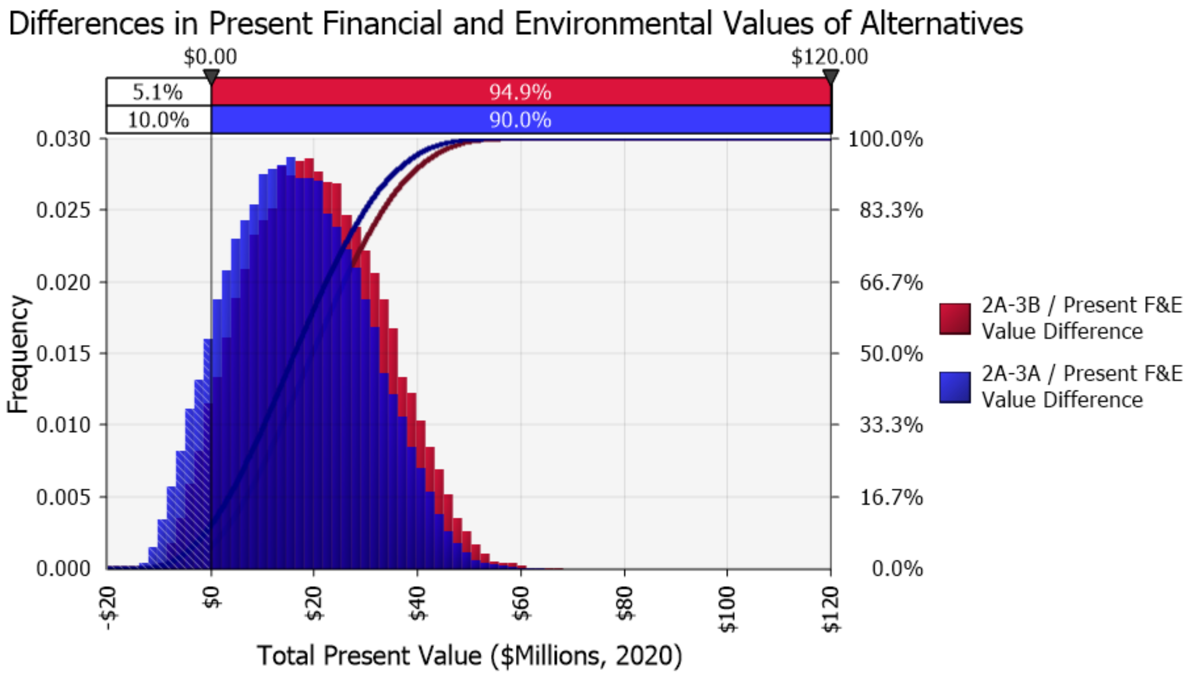


Figure 40 shows that Alternatives 1, 2A and 2B all have a very narrow range of potential financial values, and that these financial values are always positive (i.e., costs exceed benefits for the modeled parameters). Alternatives 3A and 3B have a wide range of potential financial values, which is a function of the uncertainty in the RNG market. However, even with the wide range, a majority of the model runs indicate a negative financial value (i.e., benefits exceed costs for the modeled parameters). Note, it is not a stated goal of the Program to be "cash positive" and many additional factors impact the overall Program cost. The analysis completed here is for the biogas utilization portion of the Program only.

A more direct comparison between alternatives can be performed by evaluating a distribution of the difference in present financial and social values. Figure 41 shows the results of the PDFs and CDFs of differences between Alternatives 2A and 3A, as well as Alternatives 2A and 3B. In both cases, there is a very low probability that the value of Alternative 2A would exceed that of Alternative 3A or 3B as shown on the top bar of Figure 41. For example, Alternative 2A has only a 5.1 percent chance of being a better value than Alternative 3B given the range of possible input values. Alternative 2A has a slightly better chance of being a better value than Alternative 3A, at 10 percent.

Figure 41: Monte Carlo Simulation Results: Differences in Present Financial and Environmental Values



6 Biogas Utilization Recommendation

Based on the analyses presented, the Water Pollution Control Bureau (WPCB) recommends proceeding with Alternative 3 (RNG) as the selected biogas utilization approach. The basis for this recommendation is as follows:

- The RNG alternatives have the lowest net present value (i.e., lowest total cost to the County) for the baseline conditions using conservative capital and operating costs.
- Alternative 3A (RNG into pipeline) scored the highest in the County's non-financial scoring. In particular, the County found that the RNG alternatives would be less complex and result in fewer localized impacts (noise and emissions) than the CHP alternatives.
- A sensitivity analysis concluded that when considering multiple variables, including RIN volatility and changes to electrical rates, Alternative 3A (RNG into pipeline) had a very high likelihood of being more financially advantageous than Alternative 2A.
- The County has the ability to retain GHG credits if the biogas is used within Arlington County for transportation purposes. Should the biogas be used outside of Arlington County, the revenue from the RINs could be used to purchase an equivalent amount of GHG credits on the open market.
- Biogas can be used on site for generation of steam in lieu of natural gas. This would slightly impact the financial analysis, as it would reduce the RNG being produced and the RINs generated. However, it would also eliminate the purchase of natural gas for the steam boilers and allow for effective use of the biogas if the RNG system is out of service.
- Benefits of on-site CHP are limited because the CHP size would not be sufficient to power the entire WPCP and the existing WPCP is already protected with two independent power feeds and backup generators.

Should the RFS program be terminated, CHP could be added at the WPCP in the future. In addition, the County is monitoring other programs - such as eRINs through the RFS and novel technologies that recover hydrogen and sequester carbon - that could be implemented in the future. The eRINs program could allow for the use of RNG off site for electrical generation to provide energy to electric vehicle fleets.

The County's current preference is for Alternative 3A (RNG into pipeline) over Alternative 3B (RNG as CNG) due to the uncertain future of ART and WMATA fueling stations and the lack of a match between fueling times and gas production times (resulting in the need for additional storage). However, the final decision to inject RNG into the NG utility pipeline or use CNG will be made in the future as more discussions with the stakeholders are conducted. Issues that need to be reviewed as the Program is further defined include the following:

- **Additional negotiations with the NG utility regarding offtake agreements, monitoring requirements, and cost of interconnection facilities:** The analysis made some assumptions regarding these items based on what is known today about the required gas specification and anticipated interconnection costs. These items need to be refined as the Program proceeds.

- **RNG market values:** While a sensitivity analysis was performed on the RNG market values based on historical values, these markets should be monitored closely in the future as they are impacted by political and regulatory pressures.
- **The long-term viability of ART and WMATA using RNG (as CNG) for fleet fueling:** Based on preliminary discussions, both transit systems have decarbonization goals, which adds risk to the CNG options. The NG utility has indicated that RNG can be part of its portfolio at the WPCP regardless of the ultimate decision for the CNG stations.

In addition to these items, a biogas conditioning technology needs to be selected for implementation. The financial analysis performed as part of Chapter 4 assumed the cost of membrane treatment, which is the most conservative capital cost. A detailed life-cycle cost, site visits, and discussions with equipment vendors are needed to make a final recommendation of the selected technology (refer to Appendix D for additional information on biogas conditioning).

APPENDICES

Appendix A

ART Fuel Specification

(/qs3/pubsys2/xml/en/manual/4021650/4021650-titlepage.html)

General Information

Cummins® natural gas engines provide a low emission alternative for various applications. In order for the engines to continually provide extremely low emission levels and provide the best durability and reliability, Cummins Inc. has developed several fuel standards. Operators of Cummins® natural gas engines should provide the standard or specification to the potential suppliers and request confirmation as to local availability.

For all Cummins® natural gas engines, the methane number based on Society of Automotive Engineers (SAE) 922359, and the higher or lower heating value (as appropriate) **must** equal or exceed those shown in the table below. As new ratings are developed and released, these values may change based on engine ratings.

These specifications apply to fuel as it is delivered to the engine, regardless of whether its origin was liquid or gaseous. Liquefied Natural Gas (LNG) is an acceptable fuel, provided the on-board fuel storage and supply system delivers proper pressure, temperature, and complete vaporization to the engine fuel system inlet. These specifications are **not** intended to cover certification requirements. The fuel **must not** contain water, dust, sand, dirt, oils, or any other substance or component in an amount that is detrimental to the operation of the engine. More specifications and test methods are detailed in these standards.

Cummins® natural gas engines are designed and adjusted to meet performance and emissions standards with fuel meeting these specifications. The engine may operate on fuels possessing a wide range of properties, but performance and emissions will be affected. In extreme cases, fuel with characteristics outside of these specifications can cause engine reliability or durability issues. Cummins Inc. assumes no responsibility for the use of fuels that do **not** meet these specifications. Engine damage caused by fuel **not** meeting these specifications is **not** covered by warranty.

Operators **must** be alert for sudden changes in engine operation, power levels, or the presence of knock. Each of these issues can be a sign of substandard fuel. If an issue related to fuel quality is suspected, ask the fuel supplier to sample and analyze the fuel in the vehicle. Contact a Cummins® Authorized Repair Location for information regarding calculating methane numbers, higher heating values, and lower heating values.

Fuel Standards for Cummins® Natural Gas Engines			
Standard	**Engine Family**		
	B5.9 G, C8.3 G	**ISB5.9 G B Gas International, B Gas Plus, C Gas Plus, L Gas Plus**	**ISL G ISX12 G**
Cummins® Engineering Standards (CES) 14604 Minimum Methane Number: 80 Minimum Higher Heating Value: 975 British Thermal Unit (BTU)/Standard Cubic Feet	Yes		
CES 14624 Minimum Methane Number: 75 Minimum Lower Heating Value: 37448.6 kJ/kg (16100 BTU/lbm)			Units 5054-5257 and 5281-5299 Yes
CES 14608 Minimum Methane Number: 65 Minimum Lower Heating Value: 37448.6 kJ/kg (16100 BTU/lbm)		Units 5258 - 5279 Yes	

The table below shows the basic chemical composition for CES 14604, CES14624, and CES 14608. More information for each standard will follow the chart.

Table 9: CES 14604, CES 14624, and CES 14608 Chemical Composition	
Constituents	**Test Method**
Methane (CH_4)	American Society of Testing and Materials (ASTM) D1945
Ethane (C_2H_6)	ASTM D1945

Table 9: CES 14604, CES 14624, and CES 14608 Chemical Composition	
Constituents	**Test Method**
Propane (C_3H_8)	ASTM D1945
Butane and Heavier (C_4H_{10}+)	ASTM D1945
Carbon Dioxide and Nitrogen (CO_2 + N_2)	ASTM D1945
Hydrogen (H_2)	ASTM D2650
Carbon Monoxide (CO)	ASTM D2650
Oxygen (O_2)	ASTM D1945
Sulfur (S)	Title 17 CCR Section 94112 Method 16

CES 14604 applies to B5.9 G and C8.3 G. For CES 14604, the methane number shall **not** be below 80 and the higher heating value shall **not** be below 975 BTU/Standard Cubic Foot. The methane number and higher heating value are calculated values. For more detail on CES 14604, contact an approved Cummins® authorized repair location.

CES 14624 applies to ISL G and ISX12 G. For CES 14624, the methane number shall **not** be below 75 and the lower heating value should **not** be below 16,100 BTU/lbm. The methane number and lower heating value are calculated values. For more detail on CES 14624, contact an approved Cummins® authorized repair location. The table below specifies the four constitutes in the natural gas mixture that **must** meet certain requirements to be used in the ISL G and ISX12 G engines.

CES 14608 applies to ISB5.9 G, B Gas International, B Gas Plus, C Gas Plus, and L Gas Plus engines. For CES 14608, the methane number shall **not** be below 65 and the lower heating value should **not** be below 16,100 BTU/lbm. The methane number and lower heating value are calculated values. For more detail on CES 14608, contact an approved Cummins® authorized repair location. The table below specifies the four constitutes in the natural gas mixture that **must** meet certain requirements to be used in ISB5.9 G, B Gas International, B Gas Plus, C Gas Plus, and L Gas Plus engines.

CES 14608 and CES 14624 Maximum Allowable Hydrogen, Hydrogen Sulfide, Sulfur, and Siloxanes		
Constituents	**Requirements**	**Test Method**
Hydrogen (H_2)	0.03 percent volume maximum	ASTM D2650
Hydrogen Sulfide (H_2S)	0.0006 percent volume maximum	ASTM D4084
Siloxanes	0.0003 percent volume maximum	Environmental Protection Agency (EPA) TO-14, 15 GC/ELCD,GC/AED, GC/MS

CES 14608 and CES 14624 Maximum Allowable Hydrogen, Hydrogen Sulfide, Sulfur, and Siloxanes		
Constituents	**Requirements**	**Test Method**
Sulfur (S)	0.001 percent weight maximum	Title 17 CCR Section 94112 Method 16

This table is an example using CES 14604 to determine if the fuel meets the fuel standards.

Test Fuel Data Input (See Notes at Right)			
Location (Description)		**Certified Fuel**	**Notes**
Methane	CH_4	90.20 percent	Fuel requirements for automotive spark-ignited gas engines **only**.
Ethane	C_2H_6	4.03 percent	Fuel as delivered to engine, regardless if liquid or gaseous.
Propane	C_3H_8	1.76 percent	The maximum allowable sulfur content is equal to 0.001 percent of the weight.
Butane	C_4H_{10}	0.01 percent	Fuel **must not** contain water, dust, sand, dirt, oils, or any substance that can harm the engine.
Pentane	C_5H_{12}	0.01 percent	
Hexane	C_6H_{14}	0.00 percent	
Heptane	C_7H_{16}	0.00 percent	
Octane	C_8H_{18}	0.00 percent	
Carbon Dioxide	CO_2	0.00 percent	
Nitrogen	N_2	3.99 percent	
Oxygen	O_2	0.00 percent	
Sum of Components		100 percent	
Methane Number:		89.76	**PASS** (Minimum Methane Number: 80)

Test Fuel Data Input (See Notes at Right)		
Location (Description)	**Certified Fuel**	**Notes**
Higher Heating Value (BTU/Standard Cubic Feet)	1024.50	**PASS** (Minimum Higher Heating Value is equal to 975 BTU/Standard Cubic Feet)

Note : Both the methane number and higher heating value criteria **must** be met to pass a given fuel.

L10 G		
CES 20067 Chemical Composition of Fuel		
Constituents	**Requirements**	**Test Method**
Methane (CH_4)	90.0 percent volume minimum	ASTM D1945
Ethane (C_2H_6)	4.0 percent volume maximum	ASTM D1945
Propane (C_3H_8)	1.7 percent volume maximum	ASTM D1945
Butane and Heavier (C_4H_{10}+)	0.7 percent volume maximum	ASTM D1945
Carbon Dioxide (CO_2)	3.0 percent volume maximum	ASTM D1945
Nitrogen (N_2)	3.0 percent volume maximum	ASTM D1945
Hydrogen (H_2)	0.1 percent volume maximum	ASTM D2650
Carbon Monoxide (CO)	0.1 percent volume maximum	ASTM D2650
Oxygen (O_2)	0.5 percent volume maximum	ASTM D1945
Sulfur (S)	0.001 percent weight maximum	Title 17 CCR, Section 94112, Method 16
Wobbe Index	1300 to 1377	ASTM D3588

For further details and discussion of fuels for Cummins® engines, refer to Fuels for Cummins® Engines, Bulletin 3379001 (/qs3/pubsys2/xml/en/bulletin/3379001.html).

This section presents the specifications for liquefied petroleum gas (LPG) engines.

CES 14612 and 14613 have been developed as a specification for LPG fueled engines. Operators of Cummins® LPG engines **must** refer the standard/specification to the potential fuel suppliers and request confirmation as to the local availability.

The requirements apply to fuel as it is delivered to the engine. This specification is **not** intended to cover certification requirements. The fuel **must not** contain water, dust, sand, dirt, oils, or any other substance or component in an amount that is detrimental to the operation of the engine. More specifications and testing methods are detailed in the standard.

- B5.9 LPG engines require fuels which conform to CES 14612.
- B LPG Plus engines include knock sensing and control. Fuels conforming to CES 14612 or CES 14613 can be used with these engines.

CES 14612 Chemical Composition		
Constituents	**Requirements**	**Test Method**
Propane (C_3H_8)	90.0 percent volume minimum	ASTM D 2163
Propylene (C_3H_6)	5.0 percent volume maximum	ASTM D 2163
Butane and Heavier (C_4H_{10}+)	2.5 percent volume maximum	ASTM D 2163
Hydrogen Sulfide (H_2S)	Pass	ASTM D 2420
Sulfur (S)	123 parts per million weight (ppmw)	ASTM D 2784
Oxygen (O_2)	0.5 percent weight maximum	ASTM D 1945
Carbon Dioxide and Nitrogen (CO_2 + N_2)	3.0 percent volume maximum	ASTM D 1945
Vapor Pressure with a gas temperature of 38°C [100°F]	1430 kPa [208 psig] maximum	ASTM D1267
Volatile residue temperature at 95% evaporation	-38.3°C [-37°F] maximum	ASTM D1837
Moisture Content	Pass	ASTM D2713
Copper corrosion strip test	Number 1 maximum	ASTM D1838

CES 14613 Chemical Composition		
Constituents	**Requirements**	**Test Method**
Propane (C_3H_8)	85.0 percent volume minimum	ASTM D 2163
Propylene (C_3H_6)	10.0 percent volume maximum	ASTM D 2163
Butane and Heavier (C_4H_{10}+)	5.0 percent volume maximum	ASTM D 2163
Hydrogen Sulfide (H_2S)	Pass	ASTM D 2420
Sulfur (S)	80 parts per million weight (ppmw)	ASTM D 2784

CES 14613 Chemical Composition		
Constituents	**Requirements**	**Test Method**
Vapor Pressure with a gas temperature of 38°C [100°F]	1430 kPa [208 psig] maximum	ASTM D1267
Volatile residue temperature at 95% evaporation	-38.3°C [-37°F] maximum	ASTM D1837
Moisture Content	Pass	ASTM D2713
Copper corrosion strip test	Number 1 maximum	ASTM D1838

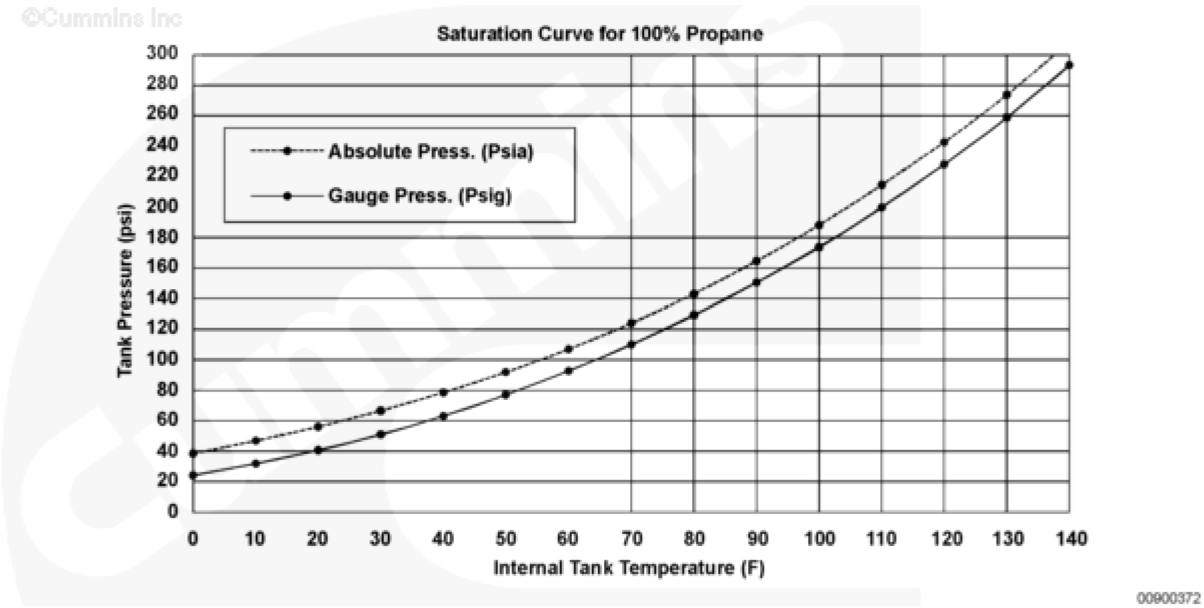
Cummins® LPG engines are designed and adjusted to meet performance and emissions standards with fuel meeting these specifications. The engine may be able to operate on fuels possessing a wide range of properties, but performance and emissions will be affected, and in extreme cases, fuel with characteristics outside of these specifications can cause engine reliability or durability issues. Cummins Inc. assumes no responsibility for the use of fuels that do **not** meet this specification. Engine damage caused by fuel **not** meeting this specification is **not** covered under warranty.

The vehicle supply hose to the engine **must** be approved for use with liquid phase propane (CGA Type III Approved). Engine damage, service issues, or performance issues that occur due to the use of other products are **not** considered a defect in workmanship or material as supplied by Cummins Inc. and can **not** be compensated under the Cummins Inc. warranty.

Operators **must** be alert for sudden changes in engine operation, power levels, or pre-ignition. Each of these can be a sign of substandard fuel. If you suspect an issue related to fuel quality, ask your fuel supplier to sample and analyze the fuel in the vehicle, or contact a Cummins® Authorized Repair Location for assistance.

Fuel pressure control is vital to proper engine operation. Liquid phase propane **must** be supplied to the engine at a steady pressure (+/- 5 psi) under all conditions (temperature and fuel flow rates). Fuel pressure will vary as a function of temperature. Fluctuations can **not** occur rapidly. Reference the engine data sheet for pressure and flow requirements.

For cold weather operation (less than 2°C [35°F]), a pressure assist fuel system may be needed to meet the fuel pressure requirements. The figure: Vehicle LPG Tank - Cold Ambient Effects, shows the pressure/temperature correlation for 100 percent propane.



Vehicle LPG Tank - Cold Ambient Effects

Last Modified: 18-Feb-2016

Appendix B

Detailed Energy Balance

Alternative		1	2A	2B	3A/3B	4A	4B
Description		Process and building heating	CHP with engines	CHP with gas turbine	RNG	RNG with engines	RNG with gas turbine
Thermal Efficiency							
Boilers		80%	80%	80%	80%	80%	80%
CHP							
Steam		0%	18%	50%	0%	18%	50%
Hot Water		0%	24%	0%	0%	24%	0%
Electrical Efficiency		0%	35%	25%	0%	35%	25%
Downtime							
CHP		0%	5%	10%	0%	5%	10%
RNG		0%	0%	0%	5%	5%	5%
RNG % Methane Use		0%	0%	0%	5%	5%	5%
Energy source/use	Unit						
Heat required total	MBH	3,560	3,560	3,560	3,560	3,560	3,560
Steam (hot)	MBH	3,060	3,060	3,060	3,060	3,060	3,060
Hot water							
Building	MBH	70	70	70	70	70	70
Boiler preheat	MBH	430	430	430	430	430	430
Steam total	MBH	3,490	3,490	3,490	3,490	3,490	3,490
Biogas production	MBH	14,870	14,870	14,870	14,870	14,870	14,870
Biogas used							
Boiler total	MBH	4,450	800	450	220	0	0
CHP	MBH	0	13,550	13,410	0	740	320
RNG	MBH	0	0	0	13,420	13,420	13,420
Waste gas flare	MBH	10,420	520	1,010	520	0	420
Tail gas combusted	MBH	0	0	0	710	710	710
Heat production	MBH	3,560	6,330	7,070	3,560	6,990	3,560
Boiler total	MBH	3,560	640	360	3,560	150	360
CHP							
Steam	MBH	0	2,440	6,710	0	2,930	3,200
Hot water	MBH	0	3,250	0	0	3,910	0
Capacity CHP	MBH	0	13,580	13,410	0	16,280	6,410
NG purchased, total	MBH	0	0	0	4,230	15,730	6,540
Boiler	MBH	0	0	0	4,230	340	450
CHP	MBH	0	0	0	0	15,390	6,090
Heating losses, total	MBH	890	3,280	3,440	44	3,745	1,602
Boiler	MBH	890	160	90	44	0	0
CHP	MBH	0	3,120	3,350	0	3,745	1,602
Unused heat	MBH	0	2,750	3,510	0	3,430	0
WPCP Electricity required	MBH	13,600	13,600	13,600	13,600	13,600	13,600
Electricity produced	MBH	0	4,740	3,350	0	5,699	1,602
Equivalent cap. CHP	MW	0	1.39	0.98	0	1.67	0.47
Electricity purchased	MBH	13,600	8,860	10,250	13,600	7,901	11,998

Appendix C

Dominion Energy Sustainability Report

Dominion Energy

Our Company

Metrics

Our story in numbers.

Environmental

Dominion Energy Portfolio

YEAR Baseline	2000 Baseline	2005	2015	2016	2017	2018	2019
Dominion Energy Virginia and Contracted Generation Owned Nameplate Generation Capacity at end of year (MW)	15,147	25,910	22,774	24,604	25,101	25,117	23,768
Coal	5,992	7,937	4,406	4,406	4,402	4,406	3,684
Natural Gas	1,800	7,107	7,836	9,256	9,297	9,187	8,413
Nuclear	3,253	5,726	5,349	5,349	5,349	5,349	5,349
Petroleum	2,476	3,219	2,171	2,171	2,168	2,155	2,143
Total Renewable Energy Resources	1,587	1,921	2,997	3,407	3,870	4,005	4,179
Biomass/Biogas		80	236	236	236	236	153
Geothermal							
Hydroelectric	1,587	1,841	2,120	2,126	2,126	2,124	2,124
Solar			359	763	1,226	1,363	1,752
Wind			282	282	282	282	150
Other	39		15	15	15	15	

Dominion Energy

Our Company

Metrics

YEAR Baseline	2000 Baseline	2005	2015	2016	2017	2018	2019
Dominion Energy South Carolina Owned Nameplate Generation Capacity at end of year (MW)	4,483	5,776	5,240	5,239	5,239	5,708	5,651
Coal	2,720	2,590	1,789	1,789	1,789	1,789	1,704
Natural Gas	372	1,719	2,004	2,003	2,003	2,507	2,513
Nuclear	635	644	647	647	647	647	650
Petroleum							
Total Renewable Energy Resources	756	823	800	800	800	765	784
Biomass/Biogas							
Geothermal							
Hydroelectric	756	823	800	800	800	765	784
Solar							
Wind							
Other							
Combined Owned Nameplate Generation Capacity at end of year (MW)	19,630	31,686	28,014	29,843	30,340	30,825	29,419
Coal	8,712	10,527	6,195	6,195	6,191	6,195	5,388
Natural Gas	2,172	8,826	9,840	11,259	11,300	11,694	10,926
Nuclear	3,888	6,370	5,996	5,996	5,996	5,996	5,999
Petroleum	2,476	3,219	2,171	2,171	2,168	2,155	2,143
Total Renewable Energy Resources	2,343	2,744	3,797	4,207	4,670	4,770	4,963
Biomass/Biogas		80	236	236	236	236	153
Geothermal							
Hydroelectric	2,343	2,664	2,920	2,926	2,926	2,889	2,908
Solar			359	763	1,226	1,363	1,752
Wind			282	282	282	282	150
Other	39		15	15	15	15	

Metrics

YEAR	2000 Baseline	2005 Baseline	2015	2016	2017	2018	2019
Dominion Energy Virginia and Contracted Net Generation Production for the data year (MWH)	71,536,133	109,328,723	98,455,046	108,368,094	102,060,029	100,659,937	94,855,233
Coal	37,772,810	51,607,246	22,613,052	21,947,757	15,376,307	12,302,427	7,177,447
Natural Gas	3,698,671	7,728,873	28,858,084	38,370,996	37,654,007	38,838,261	38,386,925
Nuclear	26,552,901	44,164,092	42,888,281	43,951,909	44,548,239	43,541,335	43,833,345
Petroleum	3,021,949	4,710,344	847,768	459,162	271,644	626,111	123,323
Total Renewable Energy Resources	489,802	1,118,168	3,247,861	3,638,270	4,209,832	5,351,803	5,334,193
Biomass/Biogas		540,007	1,193,180	1,266,746	1,163,454	1,196,101	1,007,679
Geothermal							
Hydroelectric	489,802	578,161	613,069	771,100	488,627	850,529	690,754
Solar			747,748	934,322	1,983,498	2,686,996	3,037,885
Wind			693,864	666,103	574,253	618,177	597,876
Other							
Dominion Energy South Carolina Net Generation Production for the data year (MWH)	22,459,240	25,493,722	23,282,862	22,793,374	22,016,656	23,523,302	23,223,220
Coal	17,501,201	17,867,835	10,352,062	8,565,143	8,760,962	8,580,257	6,481,671
Natural Gas	90,882	2,063,550	7,477,292	7,892,092	8,178,640	9,519,949	10,970,384
Nuclear	4,240,198	4,979,600	4,743,582	5,772,294	4,610,254	4,910,880	5,483,003
Petroleum							
Total Renewable Energy Resources	626,959	582,737	709,926	563,845	466,800	512,217	288,162
Biomass/Biogas	382,880	154,836	321,718	312,548	305,081	150,181	
Geothermal							
Hydroelectric	244,079	427,901	388,208	251,297	161,719	362,036	288,162
Solar							
Wind							
Other							

Metrics

YEAR	2000 Baseline	2005 Baseline	2015	2016	2017	2018	2019
Combined Net Generation Production for the data year (MWH)	93,995,373	134,822,445	121,737,908	131,161,469	124,076,685	124,183,240	118,078,453
Coal	55,274,011	69,475,081	32,965,114	30,512,900	24,137,269	20,882,684	13,659,118
Natural Gas	3,789,553	9,792,423	36,335,376	46,263,088	45,832,647	48,358,209	49,357,309
Nuclear	30,793,099	49,143,692	47,631,863	49,724,203	49,158,493	48,452,215	49,316,348
Petroleum	3,021,949	4,710,344	847,768	459,162	271,644	626,111	123,323
Total Renewable Energy Resources	1,116,761	1,700,905	3,957,788	4,202,116	4,676,632	5,864,020	5,622,355
Biomass/Biogas	382,880	694,843	1,514,898	1,579,294	1,468,535	1,346,282	1,007,679
Geothermal							
Hydroelectric	733,881	1,006,062	1,001,277	1,022,397	650,346	1,212,565	978,916
Solar			747,748	934,322	1,983,498	2,686,996	3,037,885
Wind			693,864	666,103	574,253	618,177	597,876
Other							

YEAR	2017	2018	2019
Miles Distribution Lines-Electric (regulated utility)	58,277	58,300	85,000
Miles Transmission Lines-Electric (regulated utility) Includes circuit miles, including overhead and underground lines	6,600	6,700	10,400

Air[1]

YEAR	2000 Baseline	2005 Baseline	2015	2016	2017[2]	2018[3]	2019
Carbon Emissions Dominion Energy Virginia & Contracted Generation							
Total generation (net MWh) (by ownership)	71,536,133	109,328,723	98,455,046	108,368,094	102,060,029	100,659,937	94,855,233
Total CO_2 emissions (MT) (by ownership)	41,989,458	57,262,200	33,761,475	36,659,419	29,945,097	27,659,008	21,854,373
CO_2 intensity rate (MT/net MWh) (by ownership)	0.587	0.524	0.343	0.338	0.293	0.275	0.230
Total CO_2e emissions (MT) (by ownership)	42,298,827	58,025,709	34,253,305	37,186,655	30,155,246	27,763,387	21,982,856
CO_2e intensity rate (MT/net MWh) (by ownership)	0.591	0.531	0.348	0.343	0.295	0.276	0.232

[1] Reported carbon emissions (CO_2) includes emissions from electric generating units (EGUs). Carbon equivalent emissions (CO_2e) includes emissions from EGUs and other minor combustion sources, such as ancillary and auxiliary equipment, associated with electric generation operations. Note: This excludes sulfur hexafluoride reported as CO_2e, which includes emissions from power delivery transmission and delivery operations.

[2] By way of clarification and transparency, the company is restating its 2017 emissions as a result of a calculation update.

[3] By way of clarification and transparency, the company is restating its 2018 intensity rate as a result of updated MWhs.

Air[1] (continued)

YEAR	2000 Baseline	2005 Baseline	2015	2016	2017[2]	2018[3]	2019
Carbon Emissions Dominion Energy South Carolina							
Total generation (net MWh) (by ownership)	22,459,240	25,493,722	23,282,862	22,793,374	22,016,656	23,523,302	23,223,220
Total CO_2 emissions (MT) (by ownership)	16,115,664	17,035,669	12,008,478	11,081,704	11,426,554	11,522,827	9,820,746
CO_2 intensity rate (MT/net MWh) (by ownership)	0.718	0.668	0.516	0.486	0.519	0.490	0.423
Total CO_2e emissions (MT) (by ownership)	17,727,230	18,739,236	12,087,352	10,930,629	11,494,249	11,644,685	9,907,987
CO_2e intensity rate (MT/net MWh) (by ownership)	0.789	0.735	0.519	0.480	0.522	0.495	0.427
Carbon Emissions Combined							
Total generation (net MWh) (by ownership)	93,995,373	134,822,445	121,737,908	131,161,469	124,076,685	124,183,240	118,078,453
Total CO_2 emissions (MT) (by ownership)	58,105,122	74,297,869	45,769,953	47,741,123	41,371,652	39,181,835	31,675,119
CO_2 intensity rate (MT/net MWh) (by ownership)	0.618	0.551	0.376	0.364	0.333	0.316	0.268
Total CO_2e emissions (MT) (by ownership)	60,026,057	76,764,945	46,340,656	48,117,284	41,649,495	39,408,072	31,890,844
CO_2e intensity rate (MT/net MWh) (by ownership)	0.639	0.569	0.381	0.367	0.336	0.317	0.270

Air[1] (continued)

YEAR	2000 Baseline	2005 Baseline	2015	2016	2017[2]	2018[3]	2019
Purchased Power[4] Emissions (Net MWH) Dominion Energy Virginia	16,753,741	18,987,726	14,656,975	7,486,404	13,419,239	18,600,961	15,607,678
Total Purchased Generation CO_2 Emissions (MT)	12,159,115	13,780,442	10,637,376	5,443,297	8,399,959	10,968,543	8,637,107
Total Purchased Generation CO_2 Emissions Intensity (MT/Net MWH)	0.73	0.73	0.73	0.73	0.63	0.59	0.55
Carbon Dioxide Equivalent (CO_2e)							
Total Purchased Generation CO_2e Emissions (MT)	13,604,038	15,418,034	11,901,464	6,078,960	9,239,955	12,065,397	9,500,818
Total Purchased Generation CO_2e Emissions Intensity (MT/Net MWH)	0.812	0.812	0.812	0.812	0.69	0.65	0.61
Purchased Power[5] Emissions (Net MWH) Dominion Energy South Carolina	2,338,904	831,683	1,219,892	1,986,931	2,195,328	1,332,503	1,144,067
Total Purchased Generation CO_2 Emissions (MT)	1,547,978	478,330	535,759	942,564	971,451	161,986	114,343
Total Purchased Generation CO_2 Emissions Intensity (MT/Net MWH)	0.662	0.575	0.439	0.474	0.443	0.122	0.100
Carbon Dioxide Equivalent (CO_2e)							
Total Purchased Generation CO_2e Emissions (MT)	1,702,776	526,163	589,335	1,036,821	1,068,596	178,185	114,974
Total Purchased Generation CO_2e Emissions Intensity (MT/Net MWH)	0.73	0.63	0.48	0.52	0.49	0.13	0.10
Purchased Power Emissions (Net MWH) Combined	19,092,645	19,819,409	15,876,867	9,473,335	15,614,567	19,933,464	16,751,745
Total Purchased Generation CO_2 Emissions (MT)	13,707,093	14,258,772	11,173,135	6,385,861	9,371,410	11,130,529	8,751,450
Total Purchased Generation CO_2 Emissions Intensity (MT/Net MWH)	0.72	0.72	0.70	0.67	0.60	0.56	0.52
Carbon Dioxide Equivalent (CO_2e)							
Total Purchased Generation CO_2e Emissions (MT)	15,306,814	15,944,197	12,490,799	7,115,781	10,308,551	12,243,582	9,615,792
Total Purchased Generation CO_2e Emissions Intensity (MT/Net MWH)	0.80	0.80	0.79	0.75	0.66	0.61	0.57

[4]DEVA Purchased power and non-utility generators (NUGs) emissions are calculated based on PJM's CO_2 Emissions Intensity Factor published annually. CO_2e calculated using a conversion factor.

[5]DESC Purchased power emissions are calculated using EPA's eGRID (https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid) factors for the North American Electric Reliability Corporation (NERC) subregion. CO_2e calculated using a conversion factor.

Air[1] (continued)

YEAR	2000 Baseline	2005 Baseline	2015	2016	2017[2]	2018[3]	2019
Owned Generation + Purchased Power[4] Emissions (Net MWH) Dominion Energy Virginia & Contracted Generation	88,289,874	128,316,449	113,112,021	115,854,498	115,479,268	119,260,898	110,462,911
Total Owned + Purchased Generation CO_2 Emissions (MT)	54,148,573	71,042,641	44,398,851	42,102,716	38,345,056	38,627,551	30,491,480
Total Owned + Purchased Generation CO_2 Emissions Intensity (MT/Net MWH)	0.613	0.554	0.393	0.363	0.332	0.324	0.276
Carbon Dioxide Equivalent (CO_2e)							
Total Owned + Purchased Generation CO_2e Emissions (MT)	56,223,338	73,443,743	46,154,769	43,265,615	39,395,201	39,828,784	31,483,674
Total Owned + Purchased Generation CO_2e Emissions Intensity (MT/Net MWH)	0.637	0.572	0.408	0.373	0.341	0.334	0.285
Owned Generation + Purchased Power[5] Emissions (Net MWH) Dominion Energy South Carolina	24,798,144	26,325,405	24,502,754	24,780,305	24,211,984	24,855,805	24,367,287
Total Owned + Purchased Generation CO_2 Emissions (MT)	17,663,642	17,513,999	12,544,237	12,024,268	12,398,005	11,684,813	9,935,089
Total Owned + Purchased Generation CO_2 Emissions Intensity (MT/Net MWH)	0.712	0.665	0.512	0.485	0.512	0.470	0.408
Carbon Dioxide Equivalent (CO_2e)							
Total Owned + Purchased Generation CO_2e Emissions (MT)	31,331,268	19,265,399	12,676,687	11,967,450	12,562,845	11,822,870	10,022,961
Total Owned + Purchased Generation CO_2e Emissions Intensity (MT/Net MWH)	1.263	0.732	0.517	0.483	0.519	0.476	0.411
Owned Generation + Purchased Power[2] Emissions (Net MWH) Combined	113,088,018	154,641,854	137,614,775	140,634,804	139,691,252	144,116,704	134,830,198
Total Owned + Purchased Generation CO_2 Emissions (MT)	71,812,215	88,556,641	56,943,089	54,126,984	50,743,062	50,312,364	40,426,569
Total Owned + Purchased Generation CO_2 Emissions Intensity (MT/Net MWH)	0.635	0.573	0.414	0.385	0.363	0.349	0.300
Carbon Dioxide Equivalent (CO_2e)							
Total Owned + Purchased Generation CO_2e Emissions (MT)	87,554,606	92,709,142	58,831,455	55,233,064	51,958,046	51,651,654	41,506,635
Total Owned + Purchased Generation CO_2e Emissions Intensity (MT/Net MWH)	0.774	0.600	0.428	0.393	0.372	0.358	0.308

[4]DEVA Purchased power and non-utility generators (NUGs) emissions are calculated based on PJM's CO_2 Emissions Intensity Factor published annually. CO_2e calculated using a conversion factor.

[5]DESC Purchased power emissions are calculated using EPA's eGRID (https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid) factors for the North American Electric Reliability Corporation (NERC) subregion. CO_2e calculated using a conversion factor.

Dominion Energy

Our Company

Metrics

Air[1] (continued)

YEAR	2015	2016	2017[2]	2018[3]	2019
Methane Emissions Dominion Energy					
Methane Emissions from Gas Operations* (MT)	53,328	60,838	62,625	63,543	59,996
Methane Emissions Dominion Energy South Carolina					
Methane Emissions from Gas Operations* (MT)	3,621	3,771	3,958	3,905	3,910
Methane Emissions Combined					
Methane Emissions from Gas Operations* (MT)	56,949	64,609	66,583	67,448	63,906

*As reported in EPA's GHG reporting program. In 2016, Dominion Energy began reporting additional emissions from pipeline blowdowns, gathering and boosting as part of EPA's reporting program.

YEAR	2000 Basline	2005 Baseline	2015	2016	2017[2]	2018[3]	2019
Other Air Emissions Dominion Energy Virginia & Contracted Generation							
Nitrogen oxide, sulfur dioxide and mercury generation basis for calculation (MWH)	71,421,615	108,511,203	97,958,771	108,050,001	101,775,887	100,374,893	94,710,520
Nitrogen oxide emissions (MT) (by ownership)	132,895	101,106	15,361	13,883	10,559	10,621	7,121
Nitogen oxide emissions intensity (MT/net MWH) (by ownership)	0.001861	0.000932	0.000157	0.000128	0.000104	0.000106	0.000075
Sulfur dioxide emissions (MT) (by ownership)	372,732	283,213	12,921	9,665	5,490	7,439	2,956
Sulfur dioxide emissions intensity (MT/net MWH) (by ownership)	0.005219	0.002610	0.000132	0.000089	0.000054	0.000074	0.000031
Mercury emissions (kg) (by ownership)	2,194	931	54	52	32	31	33
Mercury emissions intensity (kg/net MWH) (by ownership)	0.0000307	0.0000086	0.0000006	0.0000005	0.0000003	0.0000003	0.0000004
Sulfur hexafluoride (MT)			2.36	1.9	1.66	1.75	1.68
CO_2e of sulfur hexafluoride (MT)			53,819	42,847	37,841	39,900	38,338

Air[1] (continued)

YEAR	2000 Baseline	2005 Baseline	2015	2016	2017[2]	2018[3]	2019
Other Air Emissions Dominion Energy South Carolina							
Nitrogen oxide, sulfur dioxide and mercury generation basis for calculation (MWH)	22,459,240	25,493,722	23,282,862	22,793,374	22,016,656	23,523,302	23,223,220
Nitrogen oxide emissions (MT) (by ownership)	165,190	125,517	20,582	18,795	15,743	15,749	12,094
Nitogen oxide emissions intensity (MT/net MWH) (by ownership)	0.007355	0.004923	0.000884	0.000825	0.000715	0.000670	0.000521
Sulfur dioxide emissions (MT) (by ownership)	432,702	354,976	16,309	11,181	7,449	9,031	4,326
Sulfur dioxide emissions intensity (MT/net MWH) (by ownership)	0.019266	0.013924	0.000700	0.000491	0.000338	0.000384	0.000186
Mercury emissions (kg) (by ownership)	1,253	1,034	63	59	40	42	42
Mercury emissions intensity (kg/net MWH) (by ownership)	0.0000558	0.0000406	0.0000027	0.0000026	0.0000018	0.0000018	0.0000018
Sulfur hexafluoride (MT)			0.521	0.457	0.167	0.542	0.467
CO_2e of sulfur hexafluoride (MT)			11,455	10,049	3,678	11,914	10,265
Other Air Emissions Combined							
Nitrogen oxide, sulfur dioxide and mercury generation basis for calculation (MWH)	93,880,855	134,004,925	121,241,633	130,843,375	123,792,543	123,898,196	117,933,740
Nitrogen oxide emissions (MT) (by ownership)	298,085	226,623	35,943	32,678	26,302	26,370	19,214
Nitogen oxide emissions intensity (MT/net MWH) (by ownership)	0.003175	0.001691	0.000296	0.000250	0.000212	0.000213	0.000163
Sulfur dioxide emissions (MT) (by ownership)	805,434	638,189	29,230	20,846	12,939	16,470	7,282
Sulfur dioxide emissions intensity (MT/net MWH) (by ownership)	0.008579	0.004762	0.000241	0.000159	0.000105	0.000133	0.000062
Mercury emissions (kg) (by ownership)	3,447	1,965	117	111	72	73	76
Mercury emissions intensity (kg/net MWH) (by ownership)	0.0000367	0.0000147	0.0000010	0.0000008	0.0000006	0.0000006	0.0000006
Sulfur hexafluoride (MT)			2.881	2.357	1.827	2.292	2.148
CO_2e of sulfur hexafluoride (MT)			65,274	52,896	41,519	51,814	48,604

Water

YEAR	2000 Baseline	2005 Baseline	2015	2016	2017	2018	2019
Dominion Energy Virginia							
Water reused/recycled (million liters) (by ownership)			2,097	5,598	5,066	4,194,700	3,139,995
Water reused/recycled (million liters/net MWH) (by ownership)			0.00002	0.00005	0.00005	0.041	0.033
Fresh water withdrawn (billion liters)			7,984	7,760	7,625	6,885	6,815
Fresh water consumed (billion liters)			33.2	38	29	16.7	20
Water withdrawals - consumptive (billion liters/net MWH)	0.0000006	0.00000007	0.00000026	0.0000004	0.00000003	0.00000017	0.00000021
Water withdrawals - non-consumptive (billion liters/net MWH)	0.000142	0.000133	0.000082	0.0000703	0.000074	0.000068	0.000072
Dominion Energy South Carolina							
Water reused/recycled (million liters) (by ownership)			3,186,805	6,193,075	4,997,274	5,457,708	5,804,755
Water reused/recycled (million liters/net MWH) (by ownership)			0.27	0.62	0.48	0.47	0.59
Fresh water withdrawn (billion liters)			1,896	1,770	1,435	1,777	1,807
Fresh water consumed (billion liters)			18.1	17.7	18.9	16.2	5.3
Water withdrawals - consumptive (billion liters/net MWH)			0.00000074	0.00000071	0.00000078	0.00000069	0.00000023
Water withdrawals - non-consumptive (billion liters/net MWH)			0.000077	0.000071	0.000059	0.000071	0.000078
Combined							
Water reused/recycled (million liters) (by ownership)			3,188,902	6,198,673	5,002,340	9,652,408	8,944,750
Water reused/recycled (million liters/net MWH) (by ownership)			0.27	0.62	0.48	0.51	0.62
Fresh water withdrawn (billion liters)			9,880	9,530	9,060	8,662	8,622
Fresh water consumed (billion liters)			51.3	55.7	47.9	32.9	25.3
Water withdrawals - consumptive (billion liters/net MWH)			0.00000042	0.00000042	0.00000039	0.00000026	0.00000021
Water withdrawals - non-consumptive (billion liters/net MWH)			0.000081	0.000073	0.000073	0.000069	0.000073

*The significant increase is due to the inclusion of Bath County Pumped Storage and the Nuclear facilities that withdrawal/discharge water from the same source as reused/recycled water, in addition to improved accounting.

Recycled and Reused Materials

YEAR	2015	2016	2017	2018	2019
Dominion Energy					
Coal combustion byproducts (tons)*	776,765	718,257	433,927	340,695	399,901
Gypsum (tons)	193,747	191,071	110,503	97,157	319,516
Biomass combustion products (tons)	13,896	7,473	7,110	6,564	13,066
Oils, fluids for reclamation/recovery (tons)	10,241	12,335	11,151	10,481	832
Scrap metals (tons)	8,145	20,553	17,661	18,973	15,431
Paper, cardboard, plastic, glass (tons)	721	495	528	724	4,543
E-waste (tons)	14	34	50	54	4.41
Dominion Energy South Carolina					
Coal combustion byproducts (tons)*	474,139	538,330	507,294	377,973	387,769
Gypsum (tons)	135,481	129,626	129,835	48,851	159,401
Biomass combustion products (tons)	0	0	0	0	0
Oils, fluids for reclamation/recovery (tons)	1,071	916	787	861	564
Scrap metals (tons)	11,694	17,273	5,273	3,415	4,911
Paper, cardboard, plastic, glass (tons)	499	544	540	493	614
E-waste (tons)	22.26	17.06	12.14	16.25	41.90
Combined					
Coal combustion byproducts (tons)*	1,250,904	1,256,587	941,221	718,668	787,670
Gypsum (tons)	329,228	320,697	240,338	146,008	478,917
Biomass combustion products (tons)	13,896	7,473	7,110	6,564	13,066
Oils, fluids for reclamation/recovery (tons)	11,312	13,251	11,938	11,342	1,397
Scrap metals (tons)	19,839	37,826	22,934	22,388	20,342
Paper, cardboard, plastic, glass (tons)	1,220	1,039	1,068	1,217	5,157
E-waste (tons)	36.26	51.06	62.14	70.25	46.31

*The amount of CCB material recycled includes material from newly generated CCB, reuse of deposited material, and material from storage unit closures.

Other

YEAR	2015	2016	2017	2018	2019
Dominion Energy					
Coal ash produced / reused (million tons) (by ownership)	3.3/0.6	3.2/0.5	2.53/0.5	2.21/0.34	1.2/0.08
Coal combustion byproducts produced / reused (million tons) (by ownership)	3.4/0.8	3.4/0.7	2.53/0.5	2.31/0.44	1.62/0.4
Percent of coal combustion byproducts reused / recycled (by ownership)	24%	21%	20%	19%	25%
Hazardous waste produced (million lbs) (by ownership)	2.39	3.67	3.56	3.72	11.1
Notices of violation (NOVs)	12	11	15	18	19
Environmental penalties paid	$447,732	$404,415	$175,124	$485,111	$168,200
Dominion Energy South Carolina					
Coal ash produced / reused (million tons) (by ownership)	0.42/0.34	0.38/0.4	0.44/0.37	0.43/0.33	0.29/0.23
Coal combustion byproducts produced / reused (million tons) (by ownership)	0.59/0.47	0.53/0.54	0.59/0.51	0.61/0.38	0.4/0.39
Percent of coal combustion byproducts reused / recycled (by ownership)	81%	101%*	86%	62%	98%
Hazardous waste produced (million lbs) (by ownership)	< 0.05	0.015	0.044	0.016	0.005
Notices of violation (NOVs)	2	1	2	0	1
Environmental penalties paid	$0	$0	$3,200	$0	$10,000
Combined					
Coal ash produced / reused (million tons) (by ownership)	3.7/0.9	3.5/0.9	2.9/0.8	2.6/0.6	1.5/0.3
Coal combustion byproducts produced / reused (million tons) (by ownership)	3.99/1.27	3.9/1.2	3.1/1.0	2.9/0.78	2.01/0.79
Percent of coal combustion byproducts reused / recycled (by ownership)	32%	31%	32%	27%	39%
Hazardous waste produced (million lbs) (by ownership)	2.39	3.69	3.60	3.74	11.10
Notices of violation (NOVs)	14	12	17	18	20
Environmental penalties paid	$447,732	$404,415	$178,324	$485,111	$178,200

*The amount of CCB material recycled includes material from newly generated CCB, reuse of deposited material, and material from storage unit closures.

Appendix D

Biogas Conditioning Technical Memo

Technical Memorandum No. 16

Date:	November 30, 2022
Project:	Arlington County Biosolids Program Management Services
To:	Mary Strawn Lisa Racey
From:	HDR
Subject:	Biogas Conditioning Evaluation

Contents

Tables

Figures

1.0 Introduction

This introductory section presents the background and purpose of this project and the biogas conditioning evaluation, followed by a description of the evaluation approach.

1.1 Background and Purpose

Arlington County (County) is implementing a program of biosolids management improvements at the Arlington Water Pollution Control Plant (WPCP). Currently, solids handling includes primary sludge (PS) and waste activated sludge (WAS) thickening, dewatering, and Class B lime stabilization of undigested solids. Planned improvements will replace the existing lime stabilization process with a Class A THP and anaerobic digestion, as recommended in the 2018 Solids Master Plan report (Master Plan) for the WPCP.

The purpose of this biogas conditioning evaluation is to further assess requirements and technologies for biogas conditioning. The results of this evaluation will inform a final decision on which technology will be chosen for biogas conditioning.

1.2 Evaluation Approach

A suite of alternatives using various biogas conditioning technologies was developed. Conceptual process conditions, configurations, cooling technology sizing, and conceptual operation costs were prepared and then presented and reviewed at the July 22, 2021 and August 30, 2021 project workshops with the County. In this evaluation, the technologies are evaluated and compared based on budgetary capital equipment costs, conceptual operating cost estimates, and non-cost considerations including space requirements and noise. A 20-year life-cycle cost analysis was also completed.

2.0 Biogas Conditioning

The level of biogas conditioning required is directly related to the end use of the biogas. With the recommended alternative of upgrading the biogas to renewable natural gas, the required biogas conditioning will include H_2S, moisture, siloxane, carbon dioxide, and volatile organic compound (VOC) removal with compression and tail gas disposal. Emergency biogas disposal will be through a waste gas flare.

2.1 Hydrogen Sulfide Removal

Hydrogen sulfide removal would be required for any of the gas utilization alternatives considered. When hydrogen sulfide (H_2S) is combusted (either onsite in boilers or engines or offsite as RNG), sulfur dioxide forms. This can condense into sulfuric acid with the presence of water vapor and cause significant corrosion issues. Removing H_2S prior to combustion reduces the likelihood of corrosion. Hydrogen sulfide is typically removed by precipitating the dissolved sulfide in the anaerobic digesters (thus preventing its formation in the biogas) or by directly removing the hydrogen sulfide from the biogas in a biogas scrubber. Removal with biogas scrubbers requires the gas to be fully saturated with moisture to reduce safety concerns (fires) associated with the exothermic nature of the treatment process. Therefore, hydrogen sulfide is normally the first constituent removed from raw biogas in traditional biogas uses as the raw biogas is fully saturated,

The Arlington WPCP currently uses iron salt addition, in the form of ferric chloride ($FeCl_3$), to provide chemical phosphorus removal in the liquid stream process. $FeCl_3$ is added at multiple locations in the process including the primary clarifiers and secondary clarifiers to precipitate dissolved orthophosphate, which ends up in the solids treatment train. At the current high dosage levels, it is anticipated that a significant amount of dissolved hydrogen sulfide in the digesters will also be precipitated along with the phosphate, which will significantly lower the H_2S concentrations in the biogas. If this practice continues, the H_2S concentrations in the biogas may be below 200 ppm, in which case no further removal would be required for any of the alternatives. However, if the facility were to move away from chemical phosphorus removal to an enhanced biological phosphorus removal (EBPR) approach, hydrogen sulfide concentrations would increase and additional treatment would be required. For the purposes of this alternative, H_2S removal is retained in all alternatives. Pilot testing currently being conducted by Virginia Tech will provide data on potential H_2S concentrations in the biogas and ultimately inform the final design.

2.1.1 Precipitation with Iron Salt Addition

Iron salts combine chemically with dissolved sulfide to form relatively insoluble metal sulfides that precipitate from the wastewater, thus preventing the release of H_2S gas. Iron sulfide precipitates exist as soft, black, or reddish-brown flocs that usually do not settle well in the collection system but are easily removed at treatment plants. Sulfur precipitation with iron salts has the following advantages and disadvantages:

- Advantages:
  - Long residuals can be maintained to precipitate sulfides as they are generated.
  - Iron salts Iron salts can be used to treat sludge or full wastewater flows.
  - Reaction by-products are harmless.
  - The precipitates are beneficial to downstream treatment processes because they help increase settling and remove phosphorus.
- Disadvantages:
  - Precipitates can dissociate at lower pH levels (less than 6.5), allowing sulfides to release back into the wastewater.
  - Dissolved sulfide cannot be decreased to much lower than 0.2 to 0.5 milligram per liter (mg/L) using iron salts.
  - Iron salts can form a film on pipe walls, instrument sensors, and ultraviolet treatment equipment.
  - Precipitates increase sludge production.

As stated previously, the Arlington WPCP currently uses iron salt addition, in the form of FeCl3, to provide chemical phosphorus removal in the liquid stream process. A stoichiometric dose of 3.3 to 4.9 pounds of FeCl3 is required per pound of sulfide. However, field and laboratory experiments indicate that the typical required dose to remove sulfide in domestic wastewater is between 3 and 7 pounds of FeCl3 per pound of sulfide removed. In the near term, it is anticipated that the WPCP will continue to utilize FeCl3 optimized for phosphorus (not sulfide removal). Impacts of this $FeCl_3$ dosing strategy on biogas H_2S removal will be evaluated in on-going pilot tests with Virginia Tech.

2.1.2 Adsorptive Media

Adsorptive media is commonly used to remove hydrogen sulfide from biogas ahead of downstream unit processes. Hydrogen sulfide is removed by chemical adsorption in the fixed-media vessel using metal oxides. Common media types include iron sponge, Sulfatreat™, and other proprietary products.

Iron sponge media is typically wood chips impregnated with iron oxide. The iron oxide reacts with the hydrogen sulfide and binds to the media as iron sulfide and water. The metal sulfides are contained within the media. Once the media is spent, it must be replaced. Engineered iron oxide media, such as Sulfatreat™, is also available for H_2S removal. This media is typically more expensive than iron sponge but is easier to remove once the media is exhausted. The primary advantages of the solid media technology are the passive operation, simple use, and reliability. If the $FeCl_3$ addition continues, the County's low H_2S concentrations will likely require infrequent media replacement.

Several companies manufacture the adsorptive media treatment systems for installation in the United States. Common iron sponge providers for installation at wastewater treatment plants include Unison Solutions, Marcab, Varec Biogas, and DMT Clear Gas Solutions. Figure 1 shows a photo of an adsorptive media system installation.

Figure 1. Adsorptive Media Installation Example

Table 1 below presents the advantages and disadvantages of the H_2S removal technologies.

Table 1. Advantages and Disadvantages of H_2S Removal Technologies

Alternative	Advantages	Disadvantages
Iron salt addition	• Already used at WPCP • Improves phosphorus removals and odor control • Can achieve good H_2S removal with high doses	• Safety considerations with storage and feed facilities • May not be used in the future if WPCP switches to biological phosphorus removal • High costs of chemicals
Adsorptive media (iron sponge)	• Proven technology with many installations • Simple configuration with no moving parts • Removes sulfur from the system • Lower media replacement costs at concentrations anticipated with iron salt addition	• Higher media replacement costs at anticipated H_2S levels without iron salt addition • Media can combust

2.2 Moisture Removal

Biogas is saturated with moisture as it leaves the digester and nearly all end uses require at least some level of moisture removal. For RNG, moisture must be nearly completely removed to meet injection specifications. It is recommended that a two-step process be used for moisture removal, where the first step is mechanical refrigeration for the bulk of the moisture, followed by an adsorption technology for final biogas drying. Figure 2 presents an example of a moisture removal installation.

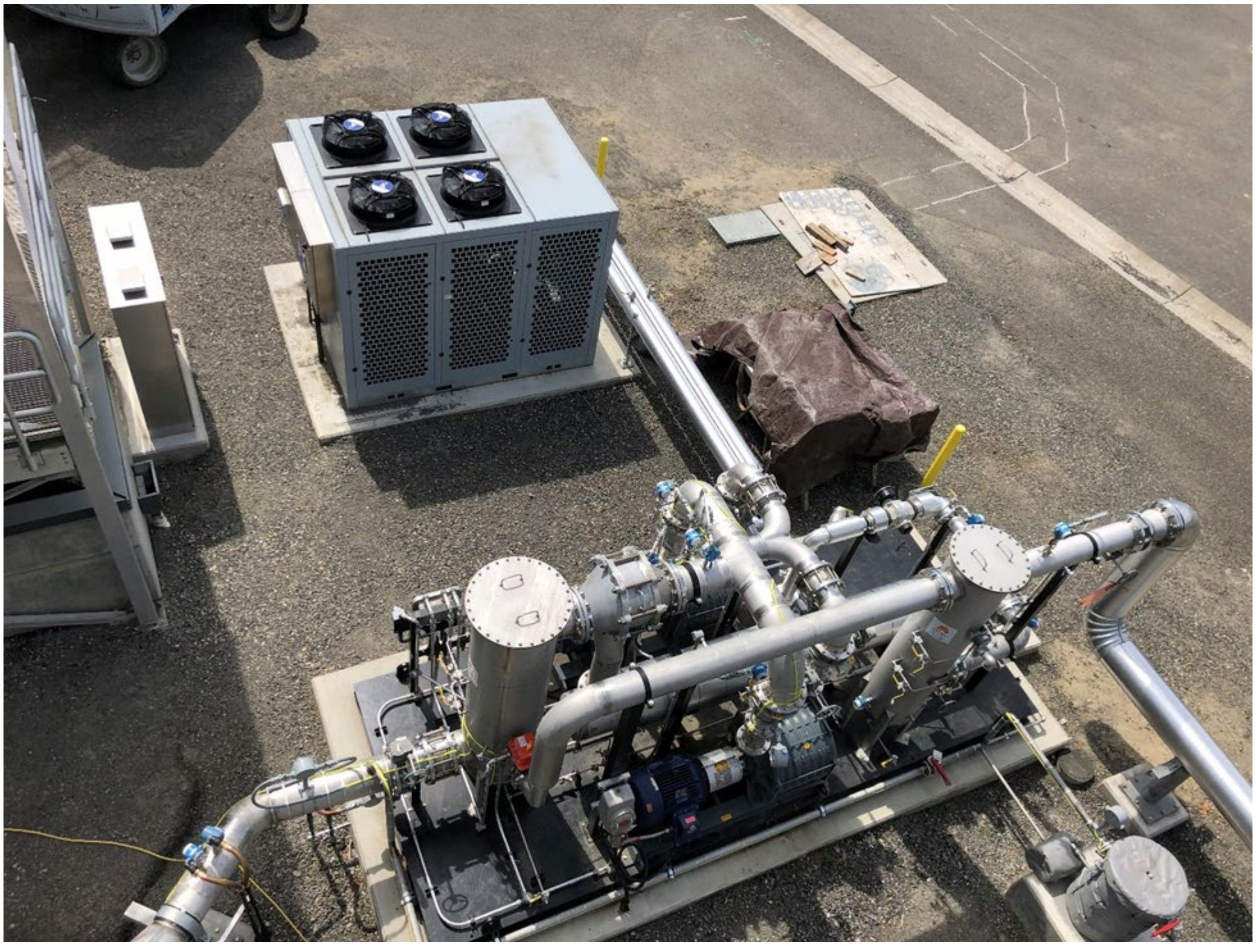


Figure 2. Moisture Removal Installation Example

2.3 Siloxane and VOC Removal

Siloxanes and VOCs are typically removed following moisture removal and initial compression, as the vessels have higher head loss and require a dry gas environment to work properly. Siloxanes and VOCs at normal levels within biogas (between 1 and 5 parts per million by volume [ppmv]) are removed using similar solid sorptive media as with hydrogen sulfide, described above. The most common media choice is activated carbon. In addition to siloxane removal, the media also serves as polishing to remove residual hydrogen sulfide and VOCs that may be in the biogas. Because of this polishing, the media is exhausted as much by residual hydrogen sulfide and VOCs as it is by siloxanes. Figure 3 presents an example of siloxane removal equipment and media.

Figure 3. Siloxane Removal Equipment and Media

Caution should be used with media selection because gas flow is very important for effective removal. If the media size is too large, at lower gas flow rates the flow will channelize, resulting in breakthrough occurring because media is exhausted in a concentrated area, while the overall bed is in good condition. Small media size will distribute flow better. However, if flows are higher, small media size will result in high pressure drops and potentially fluidizing the bed, leading to carry-over of media out of the treatment vessel. Careful coordination between the engineers and vendors on the range of gas flows is important for selection of media size.

2.4 Carbon Dioxide Removal

Biogas treatment to natural gas quality requires the removal of carbon dioxide from the biogas stream. Several technologies are available to condition the biogas to RNG quality, including water wash, pressure swing adsorption (PSA), and membranes. These technologies are described in more detail later in this Chapter, but Table 2 provides a summary of the advantages and disadvantages of each.

Table 2. Biogas Storage Scenarios

Alternative	Advantages	Disadvantages
Water wash	• Proven technology with many installations • No media to be replaced • High CH_4 recovery (98%) at design efficiency point	• More appropriate for larger installations (>750 scfm) • Requires high-pressure water (~150 psig) and water cooling • Requires post-scrubbing drying • Reduction in CH_4 recovery efficiency at turndown • Moderate energy use
PSA	• Proven technology with many installations • Regenerative adsorbent has long media life	• Lowest CH_4 recovery (95%) • Continuous actuation of vessel valves during operation is loud and causes mechanical wear of equipment • Moderate energy use
Membrane	• Proven technology with many installations • Highest CH_4 recovery (99%) with three-pass system • Fewer moving parts • Modular design • Good for smaller installations (<600 scfm)	• Requires separate upstream treatment of H_2S, VOCs, and siloxanes • Requires multiple passes to get higher CH_4 recovery • Higher energy use

2.5 Waste Gas Management

In addition to biogas treatment options, there are alternatives for how to properly dispose of waste gas generated at the WPCP. Below are the viable options for waste gas management at Arlington County WPCP.

2.5.1 Enclosed Waste Gas Flares

The most common method of waste gas disposal is with a waste gas flare. Waste gas flares are mostly used to combust raw biogas or off-spec RNG that is higher in heating value, or Btu content, and can provide self-sustaining direct combustion. Waste gas flares are always provided at anaerobic digestion facilities as a safety provision to be able to dispose of the flammable biogas during system downtime regardless of the biogas utilization method. Because of the visibility of the WPCP and footprint constraints an enclosed waste gas flare is recommended for the Arlington WPCP. An example of an enclosed flare is shown in Figure 4.

Figure 4. Enclosed Waste Gas Flare

2.5.2 Regenerative Thermal Oxidizers

For lower-Btu waste gases, or tail gas, produced as a by-product from the processing of RNG, RTOs are often used. RTOs provide higher efficiencies than regular thermal oxidizers when the waste gas does not have the Btu content to provide self-sustaining combustion. They provide this efficiency with a common combustion chamber and two sets of ceramic media with switching valves to capture and reuse the heat provided by the combustion to preheat the incoming waste gas. Once the heat is recovered from one combustion cycle the waste gas flow is reversed with the valves to recover heat from the recently combusted gas. An RTO is shown in Figure 5 and Figure 6.

Like any other form of thermal oxidation, a startup burner (fueled by natural gas) is employed to raise the temperature of the unit to proper destruction conditions. Once at the proper temperature, the process gas can be introduced and blended with the correct amount of dilution/combustion air, and the RTO cycles through the combustion sequence. The burner provides supplemental fuel to maintain the combustion chamber temperature should the heat content fall below that required for self-sustaining operation. Using a hot-gas bypass can expand the range of possible operating conditions by diverting some of the combusted air directly to atmosphere, rather than sending it through the heat-recovery media.

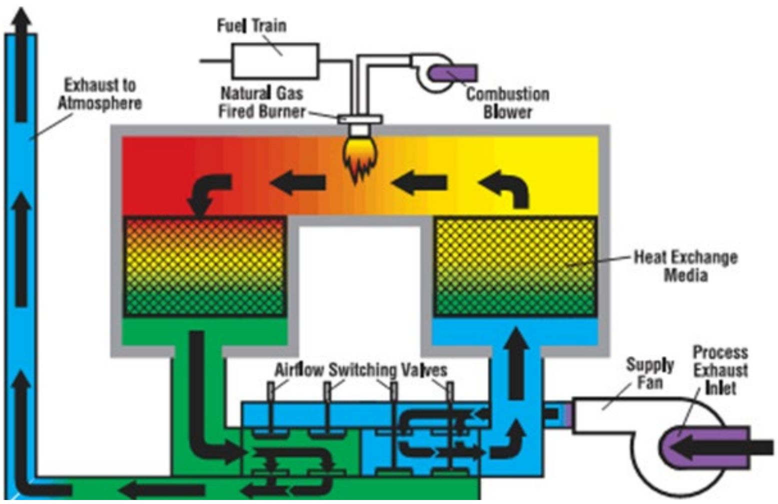


Figure 5. Regenerative Thermal Oxidizer

Figure 6. Regenerative Thermal Oxidizer

2.6 Pressure Boosting

Digester pressure is typically around 6 to as much as 20 inches of water column (in WC) or 0.2 to 0.7 psig. There are a wide range of pressure requirements for end use and for the associated treatment requirements described above that must be considered as part of a project. Depending on the technology used for biogas upgrading, a large range of pressure requirements are necessary to account for pressure losses through pipelines and the treatment system and achieve the required delivery pressure of the biogas equipment. Different RNG upgrading equipment technologies require a range between 100 and 250 psig for CO_2 removal. Typically, the upgrading equipment includes a compressor that can increase pressure necessary to the full requirement of that system. If there is pipeline injection, then it is also possible that an additional compressor would be needed to meet the requirement of the natural gas pipeline pressure for injection. Figure 7 shows an example of a biogas compression skid.

Figure 7. Biogas Compression Equipment Example

3.0 Biogas Upgrading Alternatives

With the recommended alternative of conditioning the biogas to be used as RNG off site, an additional analysis is needed to select the most appropriate carbon dioxide removal conditioning technology. There are three main types of biogas conditioning to produce RNG: membrane separation, pressure swing adsorption, and water wash scrubbing. The following sections provide additional descriptions of each technology followed by a life-cycle cost analysis to compare the three types and make a recommended selection for the Arlington WPCP.

3.1 Membrane Treatment

Membrane treatment systems consist of bundles of hollow membrane fibers fashioned together in canisters to remove carbon dioxide and other contaminants from the methane. The pores in the membrane fibers are sized to allow CO_2 molecules to pass through, while retaining the CH_4 molecules, as shown in Figure 8. Biogas is pressurized to 150 to 200 psig and conveyed through a series of canisters in a multi-pass configuration to improve CH_4 recovery and maintain a high CH_4 content in the product gas.

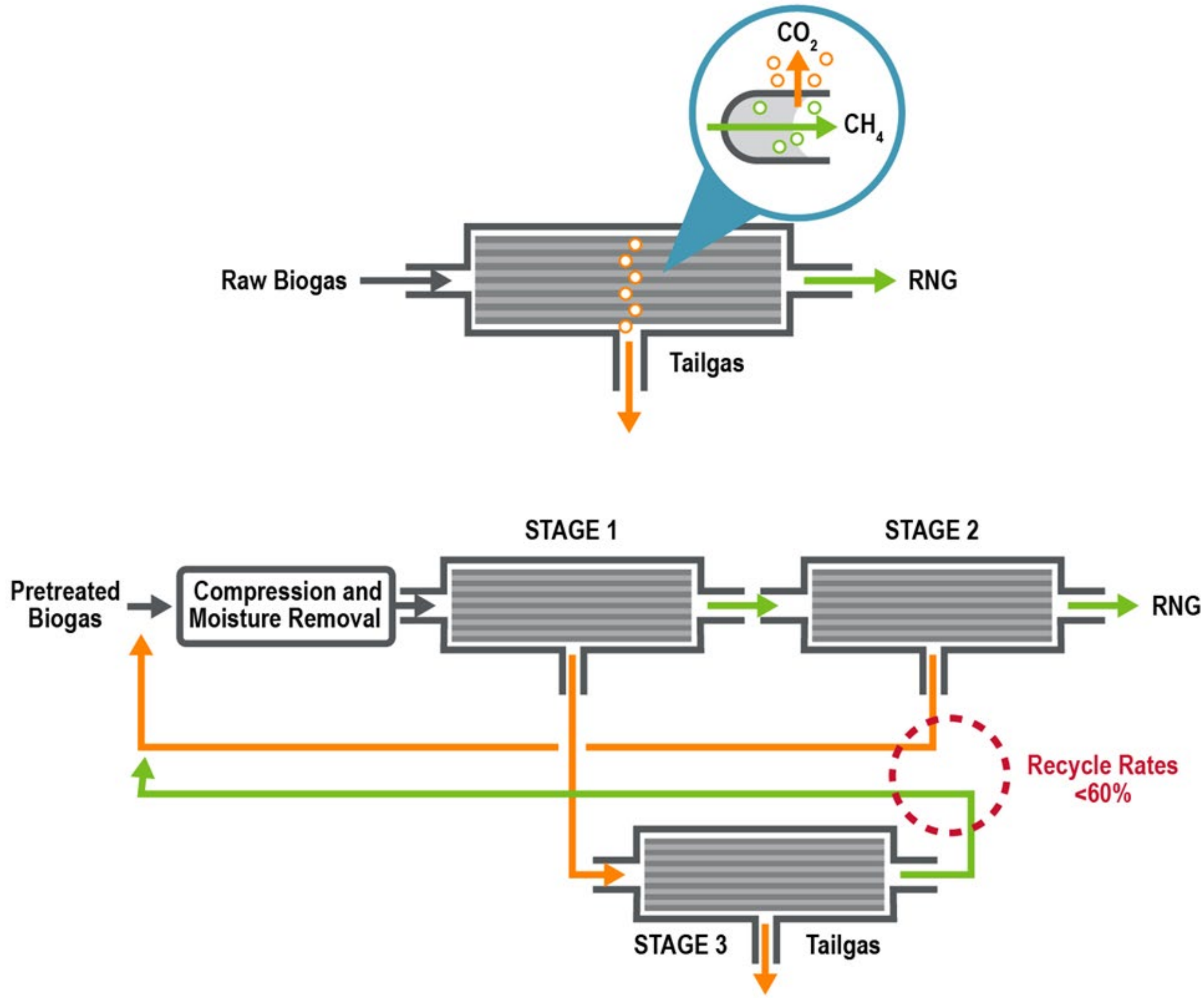


Figure 8. Membrane Treatment Schematic

Membrane systems must be used in combination with other technologies to remove hydrogen sulfide, siloxanes, moisture, and VOCs ahead of the membranes to protect the integrity of the fibers. The number of membrane filtration steps, or passes, determines the quality of the RNG and the methane recovery of the system. With additional membrane steps, higher finished gas quality is produced and/or more methane is captured from the waste tail gas stream. Gas typically passes through the membranes two to three times.

Currently, several companies manufacture membrane systems for installation in the United States: Unison Solutions, DMT Clear Gas Solutions, Greenlane Biogas, Air Liquide, and Pentair. A simplified schematic of a typical membrane system with mass balance is shown Figure 9. Figure 10 shows a photo of a typical membrane system installation.

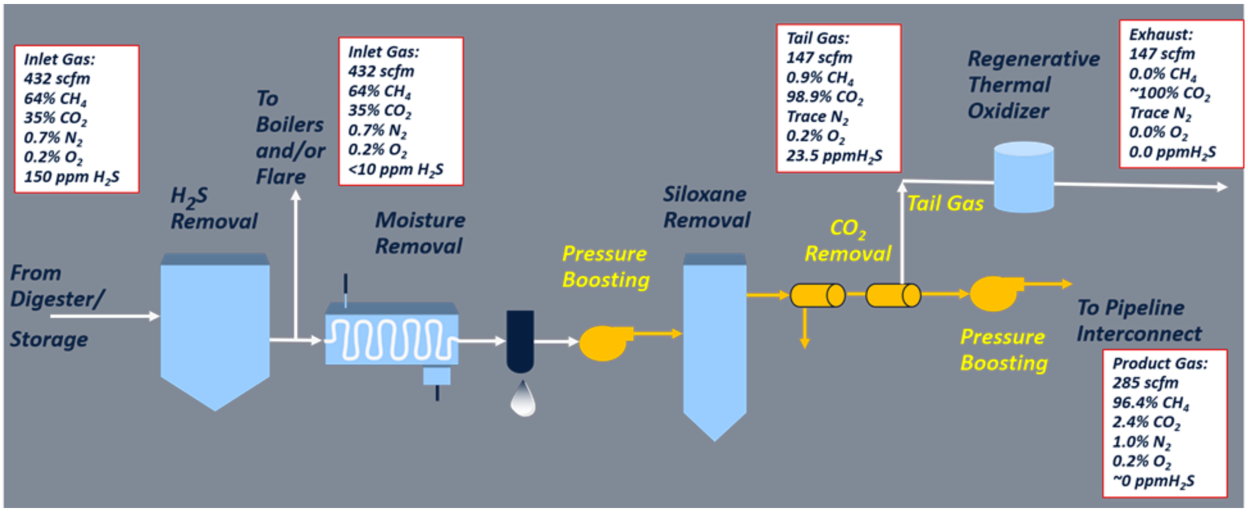


Figure 9. Membrane Treatment Process Flow Diagram

Figure 10. Typical Membrane Treatment Installation

3.2 Pressure Swing Adsorption

PSA systems remove hydrogen sulfide, carbon dioxide, and siloxanes in a single vessel by the adsorption of contaminants onto media under pressure (approximately 100 psig) and then regenerating the media under a vacuum. The systems operate with multiple pressure vessels so that the batch process of pressurizing the vessel, treating, and vacuum regeneration can be done while allowing for continuous operation. Figure 11 shows a schematic of the PSA treatment process. The systems are cost-effective; however, they typically have lower methane recovery rates (95 percent) compared to other gas upgrading systems being considered.

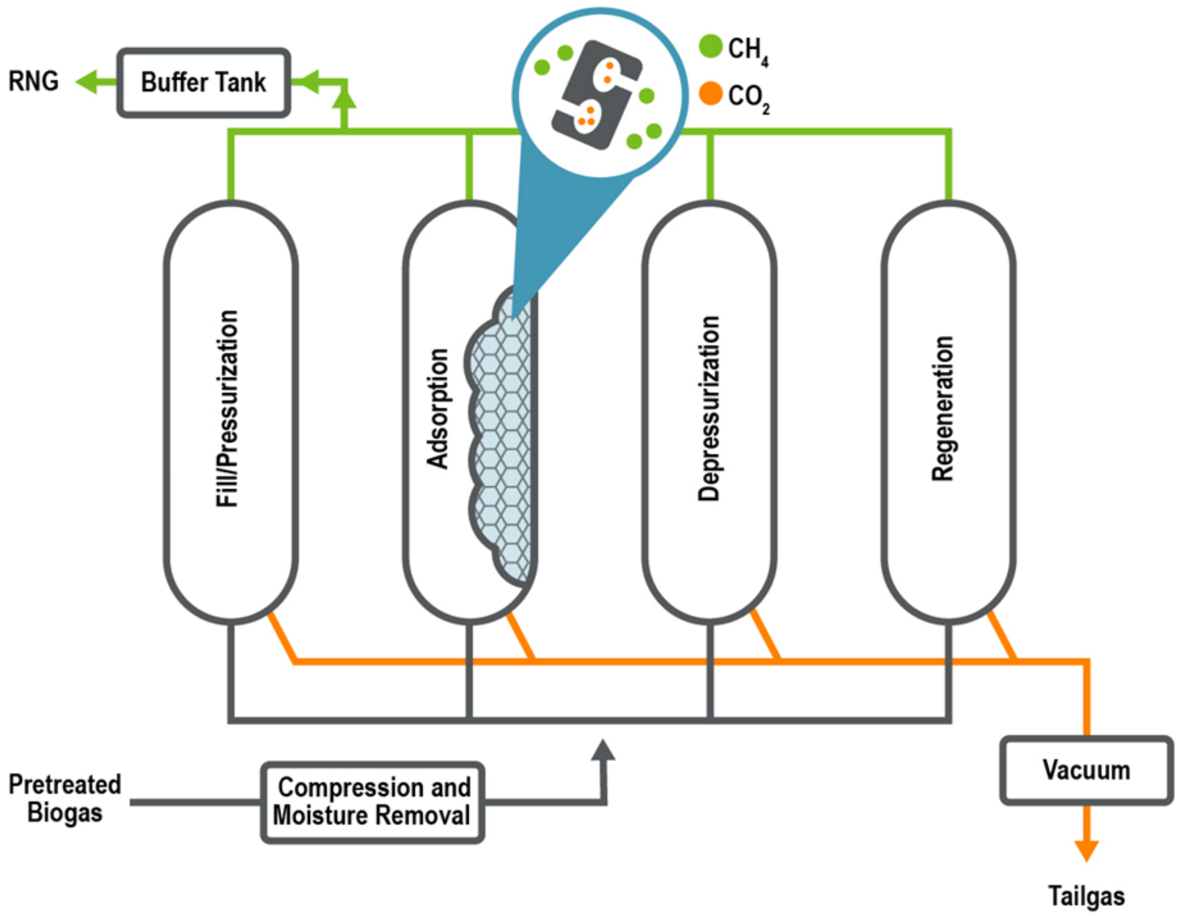


Figure 11. PSA Treatment Schematic

H_2S removal could occur upstream of the PSA or on the waste tail gas stream. The level of treatment provided will determine if an RTO or flare on the tail gas stream is needed to convert remaining hydrogen sulfide to sulfur oxides or if the stream can be vented to the atmosphere.

Currently, four companies manufacture PSAs for installation in the United States: Greenlane Biogas, Guild Associates, Xebec, and BioFERM. A simplified process flow diagram of a typical PSA system with mass balance is shown in Figure 12. Figure 13 shows a photo of a PSA system installation.

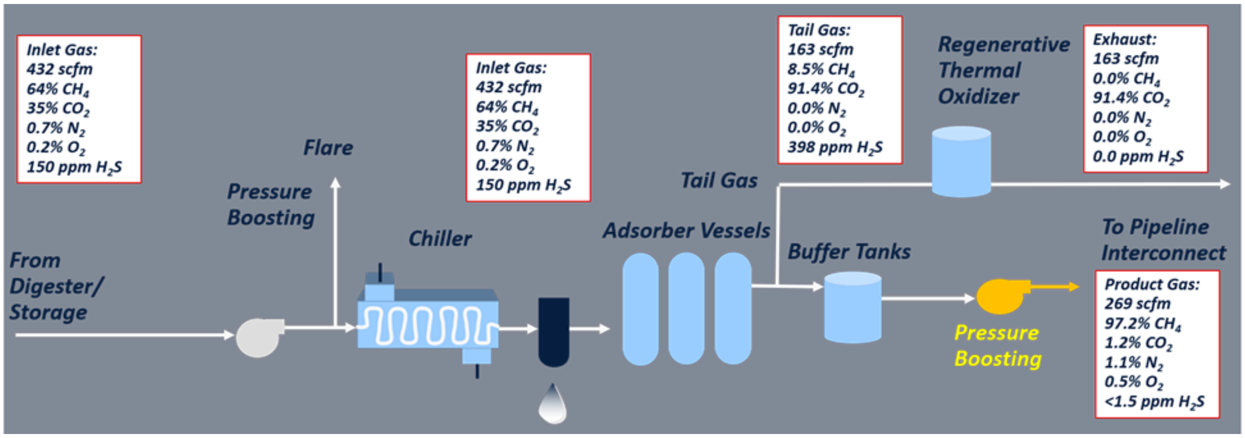


Figure 12. PSA Treatment Schematic

Figure 13. Typical PSA Installation

3.3 Water Wash Scrubber

The water wash, or water scrubber, treatment system dissolves carbon dioxide and other impurities in water to separate the CH_4 gas stream. Biogas compressed to approximately 150 psig enters the bottom of the scrubber vessel and flows upward through packing media as chilled water sprays downward. The carbon dioxide and other gas impurities (hydrogen sulfide, siloxanes, and VOCs) are dissolved in the water, the methane exits through the top of the scrubbing tower, and moisture is removed with a drier. The water, now saturated with carbon dioxide, is then depressurized in the flash tank, which operates as an intermediate step to release and recycle any methane that may have been absorbed in the water. The flash tank water is sent to the stripper vessel where pressure is lowest within the system. Lowering the pressure releases the carbon dioxide and contaminants into the tail gas waste stream. A schematic of the water wash treatment process is shown in Figure 14. A defoaming, antimicrobial, and pH adjustment solution may be fed to the water wash system to improve performance.

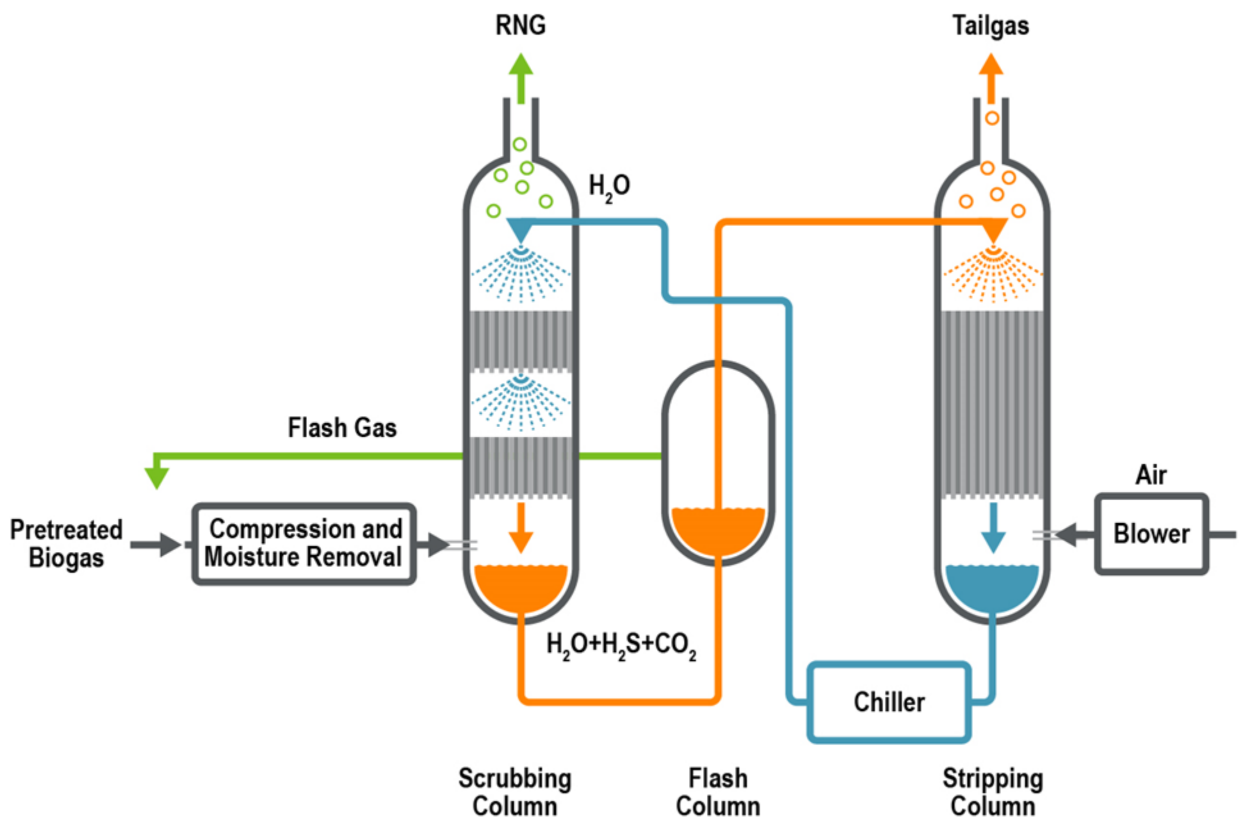


Figure 14. Water Wash Treatment

It should be noted that while the water wash systems remove hydrogen sulfide from the methane stream, the process does not actually treat it to a final product. The H_2S removal could occur upstream of the water wash process or on the waste tail gas stream. The level of treatment provided will determine if an RTO on the tail gas stream is needed to convert remaining hydrogen sulfide to sulfur oxides or if the stream can be vented to the atmosphere.

Water wash systems can achieve CH_4 recovery rates of up to 98 percent. However, this recovery rate drops when the system is operating below the designed best efficiency point.

Currently, two companies manufacture water wash systems for installation in the United States: Greenlane Biogas and Dürr Megtec. A simplified schematic of a typical water wash system with mass balance is shown in Figure 15. Figure 16 shows a photo of a water wash system installation.

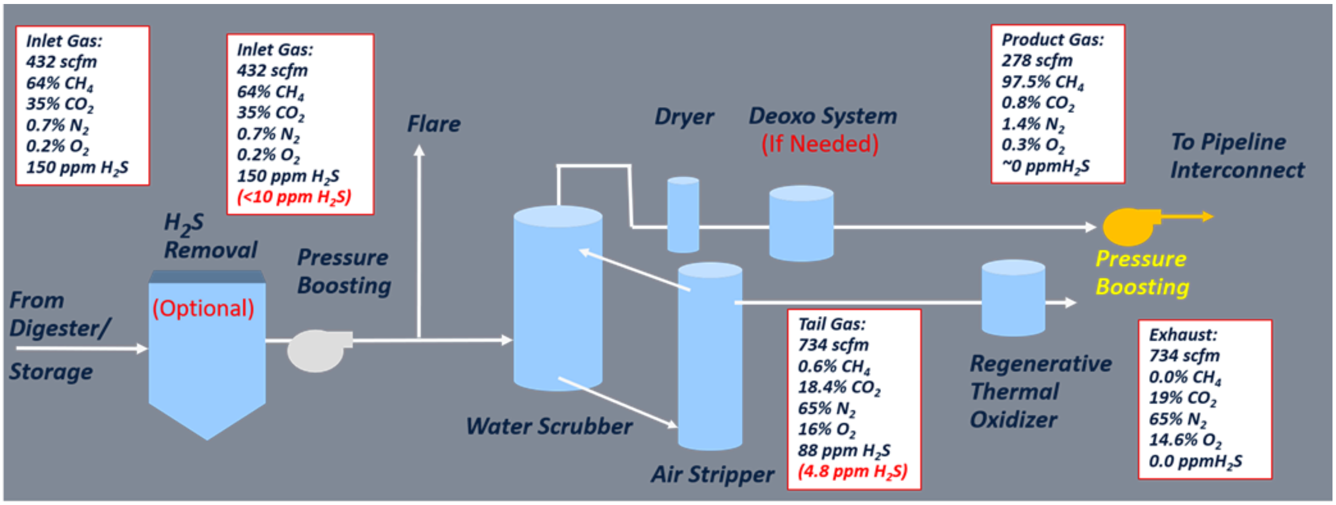


Figure 15. Water Wash System Process Flow Diagram

Figure 16. Typical Water Wash systems Installation
Source: HDR, Portland, Oregon.

4.0 Life-Cycle Cost Comparison

Similar to the gas utilization alternatives analysis, a life-cycle cost comparison was developed to evaluate and compare the three technologies from a capital and O&M cost basis.

4.1.1 Conceptual Capital Costs

Conceptual capital costs have been developed for each biogas conditioning alternative. Manufacturers for each equipment type were contacted for budgetary equipment pricing. The following multiplier percentages were used in the capital cost development:

- Electrical and instrumentation/controls: 28 percent
- Sitework/general civil: 15 percent
- Specialty piping: 5 percent
- Contractor general requirements (O&P, mobilization, etc.): 23 percent
- Contingency: 20 percent

No salvage or deep foundation costs or engineering, legal, and administrative costs are included in the cost estimates.

Capital costs are associated with the interconnection to the natural gas utility pipeline injection. These costs typically include the custody transfer station and the pipeline to the tie-in location. An estimated cost of $5 million is applied to all RNG injection alternatives and is based on preliminary feedback from the gas utility. This cost will be confirmed as additional discussions with the natural gas utility are conducted.

It is assumed that the natural gas pipeline will require post-treatment compression to 600 psig to inject RNG into the pipeline. Each pipeline injection alternative includes capital cost for this pressure increase. Each CO_2 removal technology discharges RNG at a different pressure, between 80 and 190 psig, so the compression needs vary for each alternative.

Capital costs for the conditioning alternatives are summarized in Table 3. The vendor quotes for each alternative are included in Appendix D.

Table 3. Biogas Conditioning Conceptual Capital Costs

Item		Membrane	PSA	Water Wash
Boilers		$0.60M	$0.60M	$0.60M
Building requirements		$2.45M	$2.45M	$2.45M
Pretreatment H_2S and siloxane removal		$0.50M	$0.00M	$0.00M
Inlet conditioning		$0.27M	$0.27M	$0.27M
CO_2 removal		$3.53M	$3.39M	$3.86M
Tail gas handling		$0.15M	$0.15M	$0.25M
Compression to delivery		$0.49M	$0.49M	$0.49M
Custody transfer station and pipeline		$5.00M	$5.00M	$5.00M
Total direct costs		$7.98M	$7.34M	$7.92M
Markups				
Electrical, instrumentation/controls	28%	$2.24M	$2.06M	$2.22M
Sitework	15%	$1.20M	$1.10M	$1.19M
Specialty piping	5%	$0.40M	$0.37M	$0.40M
Contingency	20%	$2.36M	$2.17M	$2.34M
Contractor general requirements	23%	$3.26M	$3.00M	$3.23M
Conceptual Capital costs		**$22.44M**	**$21.04M**	**$22.30M**
Compared to minimum		107%	100%	106%

4.2 O&M Costs

Similar to the capital costs, O&M costs have been estimated from vendor proposals, reference project experience, and the County's historical cost information. Anticipated O&M costs were developed and are presented in Table 4. Assumptions include costs related to operations labor, maintenance labor, labor parts, power requirements, water use, media replacement, and chemical costs. The common values used across all alternatives include the following:

- Power cost: $0.06/kWh
- Natural gas cost: $0.85/therm
- Operations labor: $80/hr
- Maintenance labor: $60/hr

Annual O&M cost summaries for the conditioning alternatives are provided in Table 4.

Table 4. Annual Biogas Conditioning O&M Costs at Start-up

Item	Membrane	PSA	Water Wash
Pretreatment H_2S and siloxane removal	$29,700	$0	$0
Inlet conditioning	$25,900	$25,900	$25,900
CO_2 removal	$237,500	$197,000	$252,600
Tail gas H_2S treatment	$0	$0	$0
Tail gas handling	$12,000	$12,000	$12,900
Compression to delivery	$17,900	$17,900	$17,900
Total O&M	**$323,000**	**$252,800**	**$309,300**
Total O&M $/MMBtu	**$2.45**	**$1.91**	**$2.34**

The membrane system has the highest annual O&M cost of the three options because of the higher power requirements and also media costs associated with H_2S and siloxane removal systems.

4.3 Present Values

The net present financial values for each technology option were calculated using the same heating requirements, biogas production quantities, annual costs, and financial assumptions as Alternatives 3A and 3B presented in Chapters 04 and 05 of the Arlington Re-Gen Biogas Utilization Report. These included the same WPCP energy costs for electricity and natural gas, O&M inflation, discount rate, and planning period.

Table 5 presents the present financial values for Alternatives 1, 3A, and 3B for each of the biogas conditioning technologies. The present financial values are presented for a range of RIN market values from $5/RIN to $35/RIN. The main differences between the options are the specific capital and O&M costs presented above as well as the methane capture for each of the technologies.

This analysis shows that the PSA technology has the lowest net present financial value as compared to the membrane and water wash system. This is mostly due to the difference in capital costs and slightly lower O&M costs for the PSA system. Even with the higher percentage methane capture for membranes and water wash, the difference in capital and O&M cannot be overcome through RNG revenue.

Table 5. Net Financial Values, $M

Item	Membrane	PSA	Water Wash
Conceptual Capital Cost	$22.4M	$21.0M	$22,3M
Annual Operating and Maintenance Costs	($0.32M)	($0.25M)	($0.31M)
Annual RIN Revenue at $15/MMBtu	$1.85M	$1.78M	$1.84M
Total Net Present Value	$3.46M	$1.92M	$3.32M

4.4 Summary

Overall, the three biogas conditioning technologies are very comparable in present value and performance; however, some differences should be discussed before the final decision is made.

Table 6 presents these differences graphically. The membrane system has the highest capital and O&M costs, but also the highest methane capture while the PSA has the lowest capital and O&M costs and the lowest methane capture. From an uptime perspective, all the technologies are similar. The PSA equipment will likely by louder and will not have the flexibility to simply add CHP in the future (additional pre-treatment would be required). The noise production of the PSA will be evaluated as part of the future site visits. Water wash has similar challenges and also will be less aesthetically pleasing because of its height, and tail gas management would be more costly because of higher gas flows. Membranes will be similar to or better than PSA and water wash in all of these categories.

Table 6. Technology Comparison

Criterion	Membranes	PSA	Water Wash
Capital cost	↑	↓	↑
O&M cost	↑	↓	↓
Methane capture	↑	↓	↑
Uptime	↔	↔	↔
Noise	↓	↑	↓
Aesthetics	↑	↑	↓
Flexibility for future CHP	↑	↓	↓
Tail gas management	↑	↑	↓

5.0 Recommended Alternative

Based on the analysis presented, it was recommended that the Program continue to pursue all three biogas treatment technologies until more understanding of the day-to-day operations and maintenance can be obtained. This was accomplished with additional discussions with the equipment vendors and site visits to existing installations to see the equipment in person and talk to O&M staff who have experience with the equipment options. Recommended next steps for the biogas utilization equipment selection included:

- Schedule technical brown bag sessions with equipment suppliers for the membrane, water wash, and PSA conditioning systems. This next step is currently in progress and potential dates and times are being discussed. *These technical brown bag sessions were conducted over three lunch and learn sessions in October 2021.*
- Identify potential facilities to perform in-person site visits. The equipment suppliers have provided lists of relevant installations, but additional facilities are currently being identified. A preliminary list of facilities that are being considered is shown in Table 7. The site visits should have relevance to the Arlington WPCP

where biogas from domestic wastewater digestion is conditioned to natural gas quality. Facilities of similar size and biogas conditioning capacity will be preferred.

- Schedule and perform site visits. It is anticipated that this will occur sometime in late 2021 or early 2022 depending on COVID-19 protocols. *Site visits to representative installations were conducted in October 2022.*
- Select a technology for implementation based on the results of the vendor discussions, site visits, and further refinement of the WPCP requirements as part of the Program.

Based on the results of this analysis, lessons learned from vendor presentations and discussions with operations and maintenance staff during site visits at representative installations, the preferred biogas treatment technology for implementation at the WPCP is membrane separation. The final technology and manufacturer selection will be determined during the detailed design phase of the Program.

Table 7. Technology Installation Lists

Water Wash (Greenlane)	PSA (Guild)	Membrane (Unison/Air Liquide)
Fair Oaks, Indiana (manure)	San Antonio, Texas (muni)	Atlanta, Georgia (LFG)
Perris, California	Dayton, Ohio (muni)	Pittsburgh, Pennsylvania (LFG)
Canton, Michigan	Newark, Ohio (muni)	Waste Management (LFG: multiple locations)
Weld County, Colorado (manure, food waste)	Des Moines, Iowa (muni)	Avondale, Louisiana (LFG)
Portland, Oregon (muni) startup end of 2021		Lincoln, Nebraska (muni)