Beneficial Use of Digester Gas at the Regional Water Reclamation Facilities

October 2017

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List of Acronyms

Abbreviation	Definition
AQMD	Air Quality Management District
BTU	British Thermal Unit
CARB	California Air Resources Board
CHP	Combined heat and power
CI	Carbon intensity
CNG	Compressed natural gas
DG	Digester gas
EBAT	Hazen’s Energy Balance and Analysis Tool
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FOG	Fats, oils, grease
GHG	Greenhouse gas
HAP	Hazardous air pollutant
HSW	High strength waste
LCA	Life cycle cost/benefit analysis
LCFS	Low carbon fuel standard
PSA	Pressure swing absorption
RFS2	Renewable Fuel Standards
RICE	Reciprocating internal combustion engine
RIN	Renewable identification number
RNG	Renewable natural gas
RVO	Renewable volume obligations
SCAQMD	South Coast Air Quality Management District
RWRF	Regional water reclamation facility
VOC	Volatile organic compound

0. Executive Summary

The purpose of this study is to explore alternate digester gas utilization strategies that would provide a more sustainable long-term digester gas utilization solution for EMWD's regional water reclamation facilities. The information presented in the report is intended to provide EMWD with the information and planning tools needed to make informed decisions on developing long term utilization strategies for each plant. The digester gas utilization alternatives evaluated in this study are:

> Alternative 1 – Use digester gas for digester heating and flare excess gas. This alternative is considered the baseline alternative that requires the least amount of capital investment. This alternative assumes digester gas would be used for digester heating for the plants that currently have digester gas fueled boilers (PVRWRF and SJVRWRF).
>
> Alternative 2 - Digester gas to electricity using internal combustion engines. This alternative is based on the use of a biogas fueled reciprocating internal combustion engine (RICE) configured in a combined heat and power (CHP) system to generate a combination of electric and thermal energy. The electric energy is used to offset the purchased utility power at the current retail rate. Thermal energy is recovered from the exhaust and engine cooling system to provide the digester/building heating demands.
>
> Alternative 3 – Digester gas to renewable natural gas (RNG). Digester gas undergoes an advanced treatment process to condition the biogas to natural gas pipeline quality (RNG), to be used as a transportation fuel. It is assumed RNG would reach the end use customer via injection into the Southern California Gas pipeline network.

0.1.1 Baseline studies

Existing digester gas utilization operations were evaluated to determine the overall digester gas utilization efficiency for each plant. These studies established the economic baseline for the cost/benefit evaluations included herein. The utilization efficiency was based on the ratio of the beneficial energy produced from the digester gas (i.e. electricity, aeration air, heat) to the total digester produced. The digester gas utilization efficiencies for each plant are summarized in **Table 0.1** below.

Table 0.1: Digester Gas Utilization Efficiency Summary

Plant	Overall Digester Gas Utilization Efficiency
PVRWRF	11%
MVRWRF	43%
TVRWRF	47%
SJVRWRF	14%

The digester utilization efficiency results indicate digester gas utilization efficiencies can be significantly improved by implementing more effective utilization strategies. MVRWRF and TVRWRF have the highest utilization efficiencies due primarily to the efficient operation of the digester gas fueled blowers. It is anticipated that MVRWRF can maintain the current level of utilization efficiency by maintaining the operations of its SCAQMD Rule 1110.2 compliant digester gas engine driven blower. The digester gas fueled engine driven blowers at TVRWRF and SJVRWRF cannot operate in compliance with Rule 1110.2 after 1/1/2019 without the installation of gas pretreatment systems and additional emission control technologies.

0.1.2 Economic Considerations

The 20-year net present value of the alternatives evaluated are summarized in **Table 0.2**. **Table 0.2** shows that the RNG alternatives have a much wider range of long term economic outcomes resulting in a higher level of payback risks when compared to the CHP alternatives. The wide of range of economic outcomes for the RNG alternatives is primarily attributed to the high level of uncertainty in the renewable fuels commodities markets (i.e. RIN and LCFS markets).

As discussed in **Section 6**, the RNG alternative requires a stable pathway (i.e. RNG customer) to the transportation fuels market to generate sufficient revenue to support the RNG alternative. **Table 0.2** assumes stable market pathways exist and does not represent losses associated with disruptions to the RNG market pathway such as a loss of end use customer or non-compliant RNG production. The CHP alternatives carry lower market pathway risks since EMWD would be their own customer by using 100% of the electricity produced.

Table 0.2: NPV for All Plants and Alternatives

Plant	CHP			RNG			Flare Gas		
	High	Base	Low	High	Base	Low	High	Base	Low
PVRWRF	$2,890,000	$2,590,000	$2,290,000	$15,630,000	$10,130,000	$4,720,000	($2,290,000)	($2,240,000)	($2,200,000)
MVRWRF (Ex. Engine)	$3,720,000	$3,520,000	$3,320,000	$4,450,000	$1,110,000	($2,210,000)	($1,830,000)	($1,760,000)	($1,690,000)
MVRWRF (New Engine)	$1,330,000	$1,150,000	$970,000	See Above	See Above	See Above	See Above	See Above	See Above
TVRWRF	$880,000	$650,000	$410,000	$10,490,000	$6,100,000	$1,760,000	($1,920,000)	($1,800,000)	($1,690,000)
SJVRWRF	$610,000	$410,000	$220,000	$3,370,000	$170,000	($2,960,000)	($60,000)	($55,000)	($50,000)

0.1.3 Regulatory Considerations

The regulations that will have the greatest impacts on the digester gas utilization strategies are SCAQMD Rule 1110.2 (Emissions from Gaseous and Liquid-Fueled Engines), SCAQMD Rule 1118.1 (Control of Emissions from Refinery Flares), and SCE Rule 21 (Interconnection Requirements). SCAQMD Rule 1110.2 and SCE Rule 21 are expected to have the largest impacts on the CHP alternative costs if future versions of the SCAQMD rule require capital investments in emission reduction equipment to meet emission limits. For the purposes of this evaluation, it is assumed that SCAQMD will impose additional emission limits on reciprocating internal combustion engines. SCAQMD has demonstrated in the past that their rulings do not exceed the capabilities of the available emission control technologies at the time of implementation. For the purposes of this evaluation, it is assumed that add-on technologies such as gas pre-treatment and exhaust after treatment systems would meet future SCAQMD Rule 1110.2 requirements. The costs for the future investments for emission compliance are described in **Section 5**. While the RNG alternatives carry a high economic risk, there are regulatory benefits that could support the RNG alternatives. Injecting RNG into the pipeline is an offsite utilization strategy that does not carry the regulatory compliance burden (i.e. SCAQMD Rule 1110.2) associated with onsite electricity generation. However, RNG must meet the requirements of SCG rules 30 and 39. Regulatory considerations are further explained in **Sections 4**, **5**, and **6** for each option.

0.1.4 Criteria Evaluation

The digester gas utilization alternatives were subjected to a multi-criteria evaluation to score the overall suitability of each digester gas utilization alternative as a feasible long term means to beneficially utilize digester gas. Each utilization alternative was scored with respect to the following primary evaluation categories:

1. Technology maturity and risks;
2. Environmental and social impacts;
3. Economic feasibility; and
4. Process/O&M impacts.

Each primary category included subcategories that were weighted and rated to develop a final score for each utilization alterative. The criteria evaluation was performed in close collaboration with EMWD's staff during Workshops 2, 3, and 4 to ensure all stakeholders had input on the scoring. The results are summarized in **Figure 0.1** below.

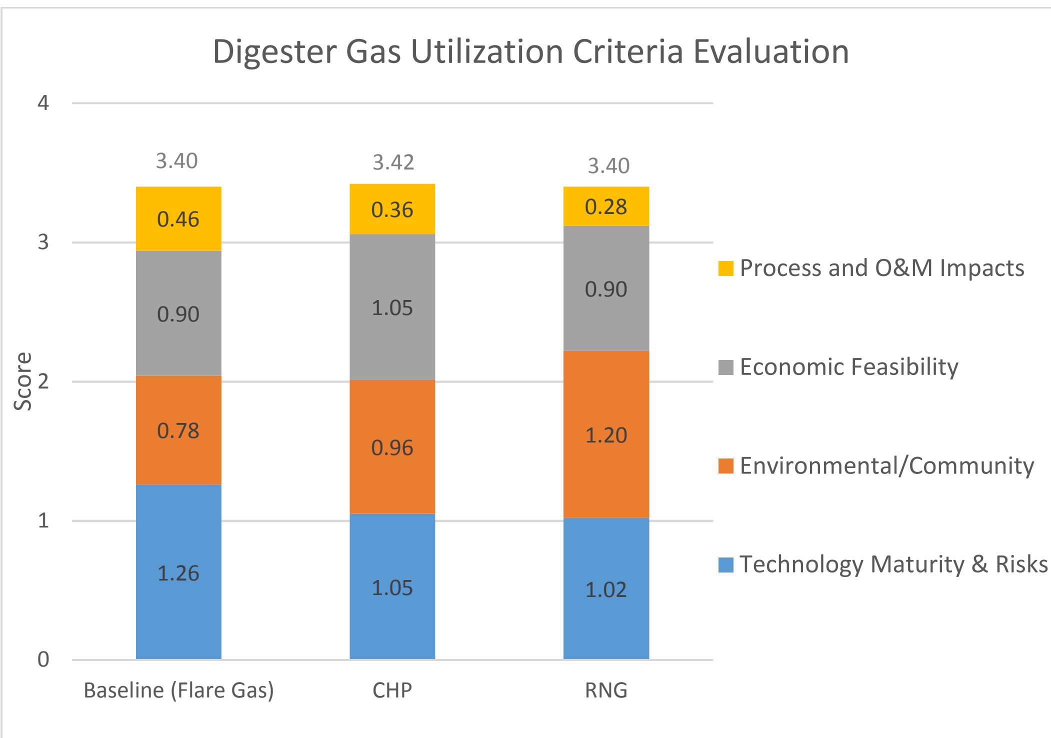


Figure 0.1: Criteria Evaluation Results Summary

Total weighted score for each alternative evaluated in this study were similar and deviated no more than 1% from the mean score.

The results of the criteria analysis scores indicate each alternative can be considered similar with respect to their overall feasibility as a viable digester gas utilization alternative. The results of a sensitivity analysis on the criteria indicated that the emissions, regulatory sensitivity and market risks had the highest impact on the outcome of the criteria analysis.

0.1.5 Results and Recommendations

The results from this study conclude that there is not a clear "winning" single digester gas utilization alternative solution for all facilities. In general, the RNG alternatives have a higher revenue generation potential over the other evaluated alternatives, however, the benefit is highly dependent on the market demands for renewable fuels (i.e. RIN and LCFS markets). At the time of this report, the market demand for RNG is strong primarily due to the escalations of renewable fuels requirements under the Renewable Fuel Standards and CA Low Carbon Fuels Standards. These markets are expected to remain viable over the next 10 years, however external forces such as renewable energy policy changes, low market growth, or technology developments could significantly impact the benefit from RNG production. The revenue from electric energy generation (CHP) is mostly dependent on the electric energy market which is much more stable and predictable over the market for RNG thus making the revenue generation much more predictable and lower risk.

The optimal gas utilization strategy will depend on many variable factors such as renewable fuels commodity market conditions, availability of project funding, existing equipment life cycle, and regulatory requirements/future developments. Given the high level of uncertainty and variability of the factors, it is recommended EMWD take additional incremental steps in evaluating opportunities to mitigate the regulatory and market risks before making a final utilization alternative decision such as;

- Bypass market risks by exploring the possibility of long term RNG purchasing contracts with RNG customers or other 3rd party entities. EMWD may work with a 3rd party RIN/LCFS marketer to better understand the long term market demands for digester gas derived renewable fuels and the potential terms of an extended period RNG purchasing agreement.
- Explore installing pipelines for direct sales of digester gas or RNG to nearby industries.
- Explore alternative project delivery strategies such as third party RNG System ownership and operation agreements to mitigate market and performance risks.
- Explore green energy funding opportunities to reduce the financial risks of the CHP and RNG alternatives.
- Monitor proposed SCAQMD 1110.2 rule changes and reciprocating engine emission management technologies advancements.
- Perform preliminary pipeline interconnection studies with SCG to better understand the pipeline extension costs for the RNG alternatives.

- Collaborate with SCE to determine if additional facility costs for Rule 21 compliance would needed to facilitate additional parallel onsite power generation for the CHP alternative.
- Contract with SCG to perform preliminary pipeline interconnection studies to better understand the likely RNG injection point and costs for the interconnection piping for all 4 facilities. Based on conversations with SCG, the estimated cost of the preliminary studies is ~$5,000.
- Monitor renewable fuels market condition indicators that would provide insight on the long term outlooks of the RIN and LCFS markets

To support EMWD with the digester gas utilization decision making process, a "road map" was developed for each plant that outlined the most feasible utilization solutions based on market/regulatory conditions, funding availability and plant conditions. The intent of the road maps is to define the conditions over time that would support a specific utilization strategy so that EMWD can make more informed decisions with regards to market conditions, funding availability and regulatory conditions. An overview of the roadmap structure is shown on **Figure 0.2**.

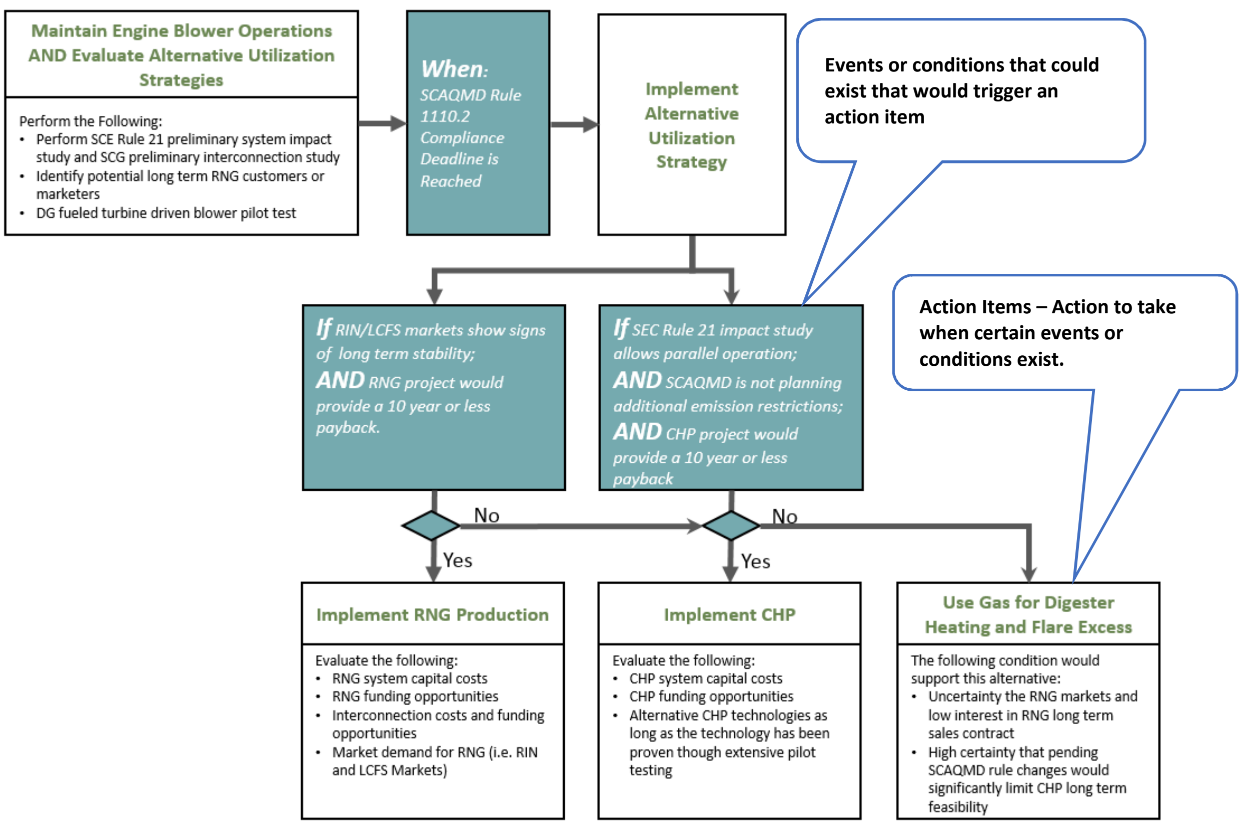


Figure 0.2: Digester Gas Utilization Roadmap Overview

To supplement the roadmaps, a Digester Gas Value Evaluation Tool was also developed to show the relationship between capital costs, revenue generation, and payback period for the RNG and CHP utilization alternatives. This tool is intended to be used to identify the approximate payback period for each alternative given the specific value of the digester gas (based on market conditions) and the project capital costs. The Digester Gas Value Evaluation Tool is included in **Appendix M.**

A pros/cons summary for the alternatives evaluated in this study are presented in **Table 0.3**.

Table 0.3: Alternatives Pros/Cons

Alternative	Pros	Cons
Alternative 1 (Flare Gas)	• Low Capital Costs • Familiar technology • Low O&M impact	• No revenue generation • High carbon footprint • Low environmental stewardship
Alternative 2 (CHP)	• Predictable long-term revenue generation (low risk) • Moderate capital costs • Familiar technology	• Unknown impacts from future SCAQMD rules developments • Interconnection requirements under SCE Rule 21
Alternative 3 (RNG)	• Higher revenue generation potential if renewable fuels markets remain viable • Low regulatory risk • Funding opportunities	• Highly dependent on renewable fuels markets (high risk) • High capital costs • Smaller equipment support network compared to engines • Risks associated with establishing long term RNG/RIN customers

1. Background and Purpose

The Eastern Municipal Water District (EMWD) owns and operates four (4) regional water reclamation facilities (RWRFs):

- Moreno Valley Regional Water Reclamation Facility (MVRWRF)
- Perris Valley Regional Water Reclamation Facility (PVRWRF)
- San Jacinto Valley Regional Water Reclamation Facility (SJVRWRF)
- Temecula Valley Regional Water Reclamation Facility (TVRWRF)

Each WRWF produces digester gas (DG) as part of their solids management processes. Currently, DG is utilized in one of the following methods: burned in flare, digester heating, in internal combustion engines running blowers, and energy generation from fuel cells.

EMWD is facing several barriers with their current DG utilization strategies that include:

- Compliance with the South Coast Air Quality Management District's increasing emission regulations for internal combustion engines under Rule 1110.2 (Emissions from Gaseous and Liquid-Fueled Engines) requires significant emission control system investments.
- Long-term support for the existing DG fueled fuel cells after the existing fuel cell maintenance and operations contracts expire.

The purpose of this study is to explore alternate digester gas utilization strategies that would provide a more sustainable long-term digester gas utilization solution for EMWD's regional water reclamation facilities. This information presented in the report is intended to provide EMWD with the information and planning tools needed to make informed decisions on their DG utilization strategies for each plant that are in the best interests of EMWD's rate payers.

During the study workshops, it was agreed that the following digester gas utilization alternatives and technologies would be included in this study:

- Alternative 1 ("Flare Gas") - The baseline alternative requires the least amount of capital investment. It maintains the current utilization strategies until regulatory deadlines expire, existing operating contracts expire, or existing equipment reaches the end of its useful life. Excess biogas is flared once existing utilization equipment is no longer usable.
- Alternative 2 (CHP) - This utilization alternative is based on the use of a biogas fueled reciprocating internal combustion engine (RICE) configured in a combined heat and power system to generate a combination of electric and thermal energy. The electric energy is used to offset the purchased utility power at the current retail rate. Thermal energy is recovered from the exhaust and engine cooling system to provide the digester/building heating demands. The new engines will require gas pre-treatment and post-treatment to meet the emission requirements in SCAQMD Rule 1110.2. The CHP alternative requires compliance with Southern California

Edison (SCE) interconnection requirements. Further details of the CHP alternative are provided in **Section 5**.

- Alternative 3 (RNG) – For this alternative, digester gas undergoes an advanced treatment process to condition the biogas to natural gas pipeline quality (RNG), to be used as a transportation fuel. The following scenarios are evaluated for the RNG alternative:

  1. Biogas used for digester heating with the remaining used in the production of RNG
  2. All digester gas used for RNG production with purchased natural gas used to meet heating demands

  Revenue for the RNG alternative will come from methane sales, Renewable Fuel Standard (RSF2) renewable identification number (RIN) credits, and California Low Carbon Fuel Standard (LCFS) Carbon offsets. The RNG alternative requires compliance with Southern California Gas (SCG) Rules 30 and 39. Further details of the RNG alternative are provided in **Section 6**.

1.1 Plant Overviews

An overview of the four (4) EMWD plants included in this study are below.

1.1.1 PVRWRF

PVRWRF includes primary, secondary, and tertiary treatment and has a rated capacity of 22 MGD. The secondary process is comprised of two parallel activated sludge plants (Plant 2 and Plant 3). Plant 1 has been “mothballed”. Digester gas produced by the anaerobic digesters are used to fuel on-site fuel cells to generate electricity and to fuel a dual fuel boiler for digester heating. Unused digester gas is flared.

1.1.2 MVRWRF

MVRWRF includes primary, secondary, and tertiary treatment and has a rated capacity of 14 MGD. The secondary process is comprised of two parallel activated sludge plants (Plant 1 and Plant 2). Digester gas produced by the anaerobic digesters are used to fuel on-site fuel cells to generate electricity and to fuel an engine driven blower. Unused digester gas is flared.

1.1.3 TVRWRF

TVRWRF includes primary, secondary, and tertiary treatment and has a rated capacity of 18 MGD. The existing secondary process is comprised of two parallel activated sludge plants (Plant 1 and Plant 2). A plant expansion is currently underway to construct Plant 3 (MBR) to bring TVRWRF capacity to 23 MGD. Digester gas produced by the anaerobic digesters is used to fuel two (2) engine driven blowers. Unused digester gas is flared.

1.1.4 SJVRWRF

SJVRWRF includes primary, secondary, and tertiary treatment and has a capacity of 14 MGD. The secondary process is comprised of two parallel activated sludge plants (Plant 1 and Plant 2). Plant 1 (aeration basins 1-5) is currently not operated and all flow is treated in the Plant 2 activated sludge facility. A digestion facility is utilized to reduce sludge volume produced at Plant 2 and generate methane and heat for onsite use. Digester gas produced by the anaerobic digesters is used to fuel one (1) engine driven blower and one boiler. Unused digester gas is flared.

2. Study Methodology

The methodology used in this study was specifically designed to evaluate the digester gas utilization alternatives with respect to:

- Economic feasibility
- Environmental and community impacts
- Process and O&M impacts
- Technology maturity and risks

Each alternative was evaluated using historical process and operations data provided by EMWD as well as data and information collected during field visits. This study was performed over a 20-year life cycle using high and low market growth scenarios to understand the full range of long term outcomes for each alternative.

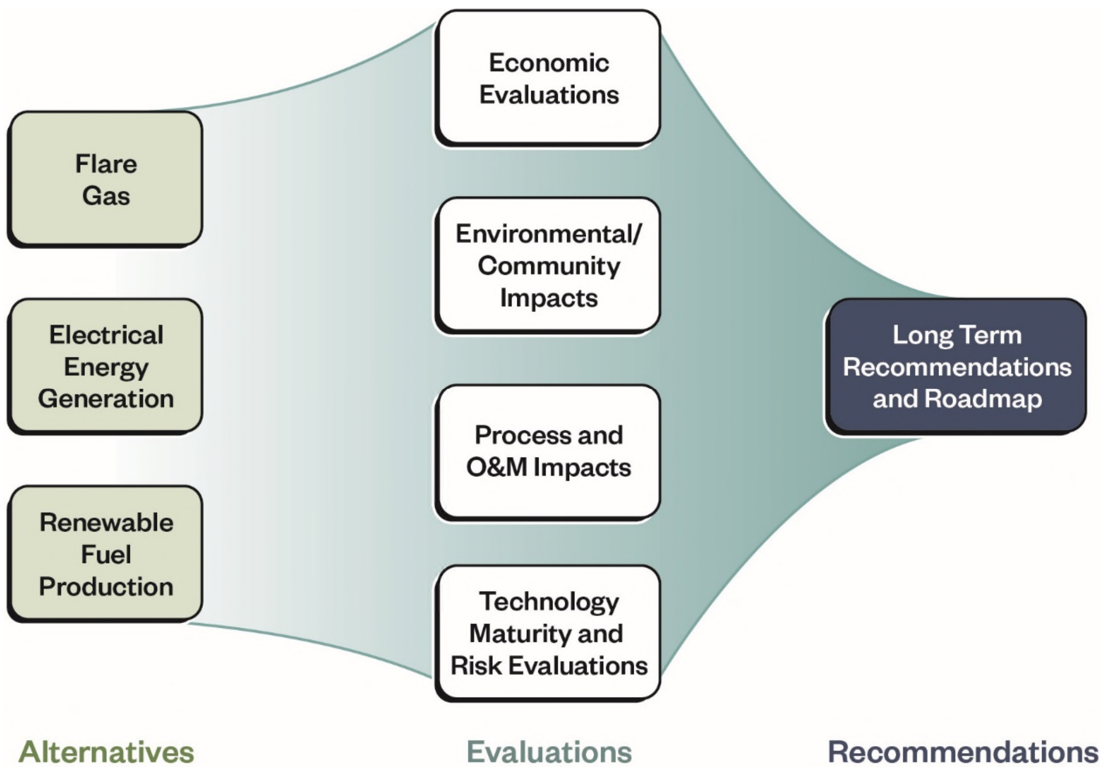


Figure 2.1: Digester Gas Utilization Study Methodology

2.1 Alternatives and Technologies

Digester gas utilization alternatives and technologies were screened with the District during the coordination workshops. The alternatives and technologies evaluated in the study were selected based on the District's digester gas utilization objectives and previous experience with alternative technologies.

Table 2.1 below summarizes the technologies explored and the action taken in this study.

Table 2.1: Technology Screening Results

Utilization Technology/Strategy	Used in Study (Y/N)	Justification
CHP - Digester Gas to Electricity using Reciprocating Internal Combustion Engines (RICE)	Yes	• Familiar technology with a history of success at EMWD's facilities. • Established technology with a robust support network
RNG - Digester Gas to Renewable Natural Gas (RNG)	Yes	• Evolving technology gaining traction in the water and wastewater industry. • Minimal regulation by the South Coast Air Quality Management District (AQMD). • High economic benefit potential from the renewable fuels markets under the federal Renewable Fuel Standards (RFS2) and the California Low Carbon Fuel Standards (LCFS)
Digester Heating Only. Flare Excess Digester Gas	Yes	• Low capital costs • Low process operations and maintenance impacts
Fuel Cells	No	• Minimal success when used in biogas applications • Concerns with long-term equipment support
Heat Engines	No	• Low efficiency • Concerns with long-term equipment support • Very little traction in the water and wastewater industry
Microturbines	No	• Concerns with long-term equipment support • Very little traction in the water and wastewater industry
Steam Turbines	No	• Low efficiency • Concerns with long-term equipment support • Very little traction in the water and wastewater industry

2.2 Energy Modeling

The digester utilization feasibility evaluations were performed using Hazen's Energy Balance and Analysis Tool (EBAT), which models the complex relationship between energy production, energy demands, and energy costs to provide accurate long-term cost/benefit assessments for multiple biogas utilization alternatives. The EBAT model was used to generate a 20-year Life Cycle Cost/Benefit Analysis (LCA) for each of the biogas utilization alternatives. The 20-year LCA incorporates energy savings, purchased energy costs, parasitic loads, O&M costs, and energy cost escalations to calculate the true 20-year life cycle cost/benefit for each alternative. The EBAT model also accounts for long term market and economic growth impacts by performing the cost/benefit calculations for high and low market conditions so the full range of economic outcomes for the biogas utilization alternatives can be understood.

2.3 Evaluation Assumptions

The digester gas utilization alternatives were evaluated over a 20-year planning period. The present worth analysis for each alternative and accounts for the time value of money, assuming a 2% inflation rate and a 2.5% interest rate. The key assumptions used in this study are listed below.

2.3.1 Operational and Management Assumptions

- Evaluation will be performed over a 20-year planning period beginning in 2019.
- Based on discussion with EMWD staff, the fuel cells will remain in service until the contractional obligations for the fuel cell system funding are met and the maintenance and operations contract expires
- Existing fuel cell pre-treatment systems can be reused for gas pretreatment as applicable to the utilization alternatives included in this study
- Additional co-digestion of high strength waste streams will not be included in the study.
- EMWD would own and operate the gas utilization facilities proposed in the study
- Plant flows and loading projections will be based on the projections described in the latest version of the plant's respective master plans

2.3.2 "Numerical" Assumptions

The numerical assumptions such as energy costs, interest rates, and cost escalations are provided in **Appendix A.**

2.4 Criteria Evaluation

The utilization alternatives were evaluated and scored based on four (4) primary criteria categories developed by Hazen and EMWD. The purpose of the criteria evaluation is to compare the overall "suitability" of each alternative as a feasible long-term means to beneficially utilize digester gas. The results of the criteria evaluation are not intended to be used to identify the optimal long-term gas utilization strategy for each plant; however, it will be used to support the final recommendations and road maps. The criteria evaluations include the following primary criteria:

- Technology Maturity and Risks - Focuses on the elements that can impact the ability of the technology to perform its intended function. This includes conditions that are inherent to the technology, such as maturity and history of success as well as external factors such compliance emission regulations (SCAQMD) and long-term support availability.

- Environmental/Community Impacts - Focuses on elements that impact the overall carbon footprint (scopes 1 and 2) and elements that could cause a social nuisance (i.e. odors, noise, dust, viewshed, etc.). The carbon footprint is based on the changes in the direct site emissions (scope 1) as well as the indirect emissions resulting from the additional or offset purchased energy source (scope 2).

- Economic Feasibility - Evaluates the ability of the technology's ability to provide a revenue stream and an acceptable payback period. This includes the long-term balance between costs, revenue generation and payback risks for each alternative. Revenue generation includes energy production, O&M costs, parasitic energy costs.

- Process and O&M Impacts - Evaluates the impact to operations resources (i.e. labor, materials, etc.) needed to operate the system.

2.5 Digester Gas Utilization Road Map and Evaluation Tool

During the course of this study, it was found that the optimal gas utilization strategy depended on many variable factors such as renewable fuels commodity market conditions, availability of project funding, existing equipment life cycle, and regulatory requirements/future developments. Given the uncertainty of these variable factors, a “Road Map” was developed for each plant that outlined the most feasible utilization solutions based on market conditions, funding availability and plant conditions. The intent of the road maps is to define the conditions that would support a specific utilization strategy so that EMWD can make more informed decisions with regards to market conditions, funding availability and regulatory conditions. The roadmaps are tailored to each plant’s unique conditions. The roadmaps are shown in **Section 8**.

Given the highly variable market conditions, a Digester Gas Value Evaluation Tool (**Appendix M**) was also developed to show the relationship between capital costs, revenue generation, and payback period for the RNG and CHP utilization alternatives. This tool is intended to provide a means of identifying an acceptable capital cost for each alternative for a given value of the digester gas (based on market conditions).

3. Existing Conditions and Baselines

Existing conditions and baseline data were developed using operating data supplied by EMWD and utility billing data from SCE and SCG. The purpose of the baseline data is to set the current condition benchmark to compare with alternative utilization technologies evaluated herein. **Table 3.1** highlights some of the key baseline data for each plant.

Table 3.1: EMWD Key Baseline Data Summary

Plant	Overall Digester Gas Utilization Efficiency	Electric Energy Costs	Natural Gas Costs	Electric Energy Offsets	Blower Efficiency
PVRWRF	11%	$0.11/kWh	$6.50/MMBTU	$0.075/kWh	N/A
MVRWRF	43%				43%
TVRWRF	47%				41%
SJVRWRF	14%				19%

The electric energy offset is used for the CHP alternative for the electric energy generated by the digester gas fueled RICE. The energy produced on site is energy that does not need to be purchased from the electric utility. It is assumed that the benefit gained from offsetting the purchased electric energy under the retail rate would be from the energy usage component of the total utility bill, only to account for the loss of demand offset from CHP system downtime. Through utility billing data provided by EMWD, the calculated value is listed above.

3.1 Current Digester Gas Utilization Strategies

Several different technologies utilize the digester gas at each plant, such as fuel cells, engine driven blowers, and boilers. Each technology provides different benefits, such as thermal energy (heat), air, and electricity. These technologies are summarized in the subsections below.

3.1.1 Utilization Technology Overview and Efficiency (i.e. engines, flares, fuel cells, boilers)

Engine Driven Blowers

MVRWRF, TVRWRF, and SJVRWRF use digester gas fueled engine driven blowers to utilize the digester gas resource. **Table 3.2** below provides a summary of the engine driven blowers at the three EMWD plants.

Table 3.2: EMWD Engine Driven Blower Summary

Plant	Digester Gas Engine Driven Blower Quantity	Natural Gas Engine Driven Blower Quantity
TVRWRF	2	1
MVRWRF	1	1
SJVRWRF	1	2

Fuel Cells

Fuel cells utilize conditioned digester gas to produce electrical power through an electrochemical reaction. The result of the reaction is electricity and heat. Fuel cells convert approximately 42% of the energy input to electricity and another 30% of the input is converted to recoverable heat. The electrical energy produced by the fuel cell can be used by the plant while the heat can be recovered and used for digester and building heating as needed. Based on information provided by EMWD, the fuel cell operating costs are approximately $36,000/month, which includes the cost of the operations and maintenance contract with FuelCell Energy

Fuel cells are used at MVRWRF and PVRWRF. **Table 3.3** below provides a summary of the fuel cells at the EMWD plants.

Table 3.3: EMWD Fuel Cell Summary

Plant	Fuel Cell Quantity	Fuel Cell Rating (Each)	Total Fuel Cell Rating
PVRWRF	2	300kW	600kW
MVRWRF	3	300kW	900kW

Boilers

Digester gas and natural gas fueled boilers are used at all four (4) plants included in this study. Boiler efficiency and O&M costs are assumed to be 80% and $0.25/MMBTU respectively.

Table 3.4 below provides a summary of the boilers and the associated fuel at the four EMWD plants.

Table 3.4: EMWD Boilers

Plant	Natural Gas Boilers	Digester Gas Boilers	Duel Fuel Boilers	Ratings (MMBTU/Hr)
PVRWRF	1		1	1.9, 5.0
MVRWRF	2			1.9
TVRWRF	1			1.9
SJVRWRF	1	1		5.0

Storage

All EMWD plants included in this study have digester gas storage to provide operational flexibility and gas supply consistency. **Table 3.5** below summarizes the storage capabilities of each plant.

Table 3.5: EMWD Digester Gas Storage

Plant	Low Pressure Holder	High Pressure Storage
PVRWRF	X	
MVRWRF		X
TVRWRF		X
SJVRWRF		X

With the exception of PVRWRF, all of the EMWD plants have a high-pressure gas storage sphere that stores digester gas using a gas compressor. Due to operational constraints at SJVRWRF and TVRWRF, the gas compressor can't keep up with the digester gas production and engine blower digester gas demands, however, projects are underway to address these constraints.

Flare

All EMWD plants utilize the flares to combust excess digester gas. The flares are rated for a minimum and maximum gaseous fuel flow. In cases where the digester gas flow does not meet the minimum flare rating, purchased natural is added to meet the minimum flare rating. At MVRWRF, natural gas is only added to the acid flare.

Gas Conditioning

SJVRWRF, PVRWRF, and MVRWRF all have various levels of gas conditioning systems. TVRWRF and SJVRWRF use iron sponge systems for hydrogen sulfide (H_2S) treatment. The fuel cell gas conditioning equipment at PVRWRF and MVRWRF are part of the fuel cell system and provide a high level of gas conditioning suitable for use in the fuel cells. The fuel cell treatment systems include moisture removal, H2S removal, and siloxane removal. The SCAQMD compliant blower at MVRWRF is connected downstream of the fuel cell gas conditioning system.

Table 3.6 summarizes the gas conditioning systems at the EMWD plants included in this study.

Table 3.6: EMWD Gas Conditioning Systems

Plant	Iron Sponge	Fuel Cell Conditioning Equipment
PVRWRF		X
MVRWRF		X
TVRWRF		
SJVRWRF	X	

3.2 Digester Gas Production and Utilization Overview

Biogas production was calculated based on gas flow data provided by EMWD. **Table 3.7** summarizes the average monthly biogas production for each plant used in the evaluation.

Table 3.7: Average Monthly Biogas Production (2014-2016)

	Average Monthly Biogas Production (cuft/Month)			
Month	**PVRWRF**	**MVRWRF**	**TVRWRF**	**SJVRWRF**
January	7,544,277	6,144,397	6,279,736	5,145,000
February	6,567,228	5,154,197	6,483,379	4,960,000
March	8,576,272	5,577,379	6,370,233	5,880,500
April	7,590,814	5,429,973	6,593,426	4,688,000
May	8,398,890	4,678,454	6,800,262	4,828,000
June	7,583,743	5,045,704	6,471,239	4,528,500
July	7,284,883	4,176,529	6,382,463	4,485,500
August	7,858,191	4,611,838	6,185,591	4,584,500
September	7,010,888	5,160,139	5,707,076	4,379,500
October	7,699,177	5,847,214	5,978,276	4,414,500
November	7,297,690	5,993,372	6,231,652	4,888,500
December	8,336,659	6,316,101	6,625,318	5,238,000

Each plant utilizes the digester gas it produces in a different way, depending on the equipment at the plant. Details for gaseous fuel end use at each plant are provided below.

3.2.1 Engine Blower Gas Utilization Efficiency

An evaluation of the exiting engine driven blowers was performed to better understand their feasibility as a long-term digester gas utilization strategy. This evaluation compared the diurnal air production to the diurnal air demand to gain an overall assessment of their operational efficiency. The South Coast Air Quality Management District (SCAQMD or AQMD) requires the engines to operate at a minimum of 90% of the rated output. This condition was accounted for in this evaluation.

Influent water quality data for each plant (MVRWRF 1/2013 – 12/2016; SJVRWRF 4/2015 – 3/2017; TVRWRF 1/2016 – 3/2017) was evaluated and diurnal aeration demands were determined with a Hazen-developed dynamic aeration model. The model determines the diurnal process oxygen demand through calculating the hourly diurnal BOD and TKN loadings at each facility. The model incorporates site specific climate information and process configurations to predict hourly oxygen demand.

At the time of the evaluation, only diurnal influent flow data was available from SJVRWRF. Following discussions with EMWD regarding the availability of similar data for the other facilities, it was determined this data was not available at the time of request, and that Hazen would utilize the SJVRWRF diurnal flow pattern for MVRWRF and TVRWRF evaluations. The engine driven blower operation discussed in this section is based on review of operation data and discussions with the lead operators of the respective facilities.

MVRWRF

Based on data provided by EMWD, the primary use for digester gas is the engine driven blower. Additional digester gas not used by the blower is sent to the fuel cell. The engine driven blower and fuel cells meet most of the heating demands over the course of the year. When additional heating is required, purchased natural gas is sent to the boiler. All unused digester gas is flared.

MVRWRF operates the TECOGEN engine driven blower and one (1) Neuros NX300 blower during a majority of the day with a second NX300 brought on-line in the late afternoon to evening depending on facility loading. Since the TECOGEN and Neuros blower design pressures are 8.8 psig, these blowers are compatible of operating in parallel. A graph of the average diurnal air flow at MVRWRF is shown in **Figure 3.1**. As shown in **Figure 3.1**, the diurnal air demands overlap with the majority of the blower operating ranges, resulting in minimal excessive air production. There appears to be a small operational gap in the transition to 2 Neuros blowers. Dissolved oxygen data provided for Plant 2 indicates that the concentration in the last zone is approximately 2.0 mg/L.

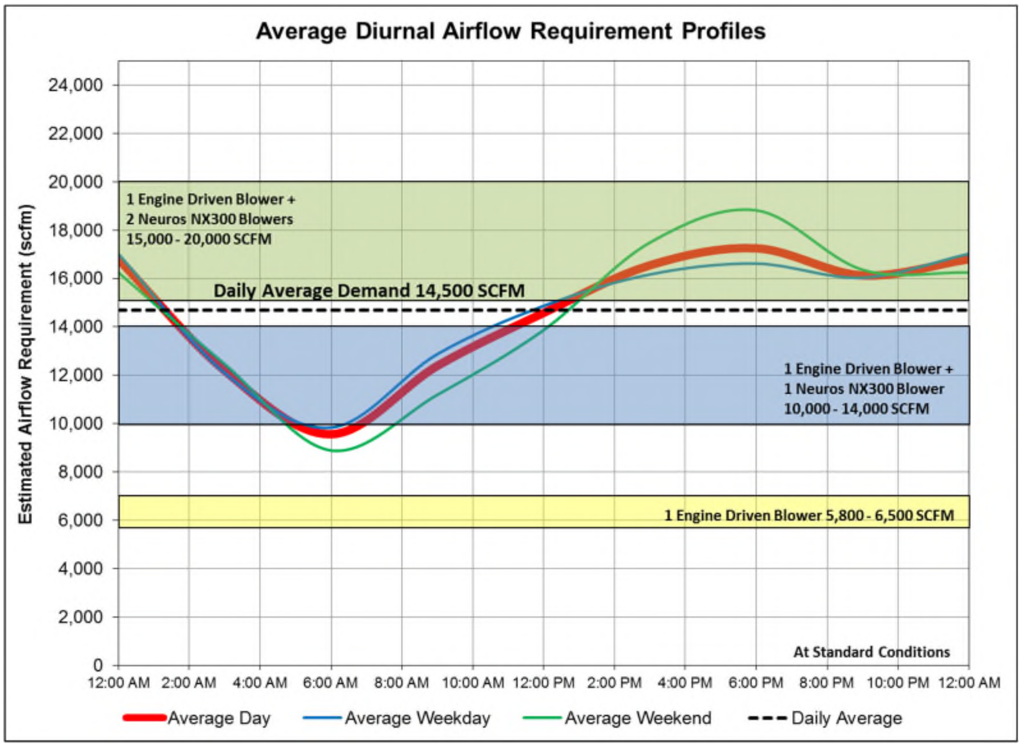


Figure 3.1: MVRWRF Average Diurnal Airflow Requirements and Air Production

TVRWRF

Based on data provided by EMWD, the primary use for digester gas are the engine driven blowers, which meet most of the heating demands during the year. In the winter, additional heat is required. The additional heat is provided by a natural gas boiler. All unused digester gas is flared.

Blower operation at TVRWRF typically includes operation of three (3) engine driven blowers during a majority of the day. Depending on the facility loading in the early evening, 1 Neuros NX300 is brought into service in parallel with the 2 engine driven blowers.

To prevent excessive dissolved levels, approximately 13% of the air produced is blown off, resulting in a reduced biogas utilization efficiency. The orange shaded field in **Figure 3.2** below indicates the duration when air in excess of the oxygen demand is produced by the engine driven blowers and is blown off from the process. According to conversations with plant staff, the TVRWRRF engine driven blowers are operated at a minimum of 90% of the rated capacity to meet permit requirements. There is a small operational gap in the transition from 2 engine driven blower to the addition of one (1) Neuros NX300 blower in parallel. Dissolved oxygen data provided for Plant 1 and Plant 2 indicates that the concentration in the last zone is approximately 2.5 mg/L with periodic events greater than 4.0 mg/L. This evaluation indicates improvements in “gas to air” efficiency could be achieved with additional blower turndown.

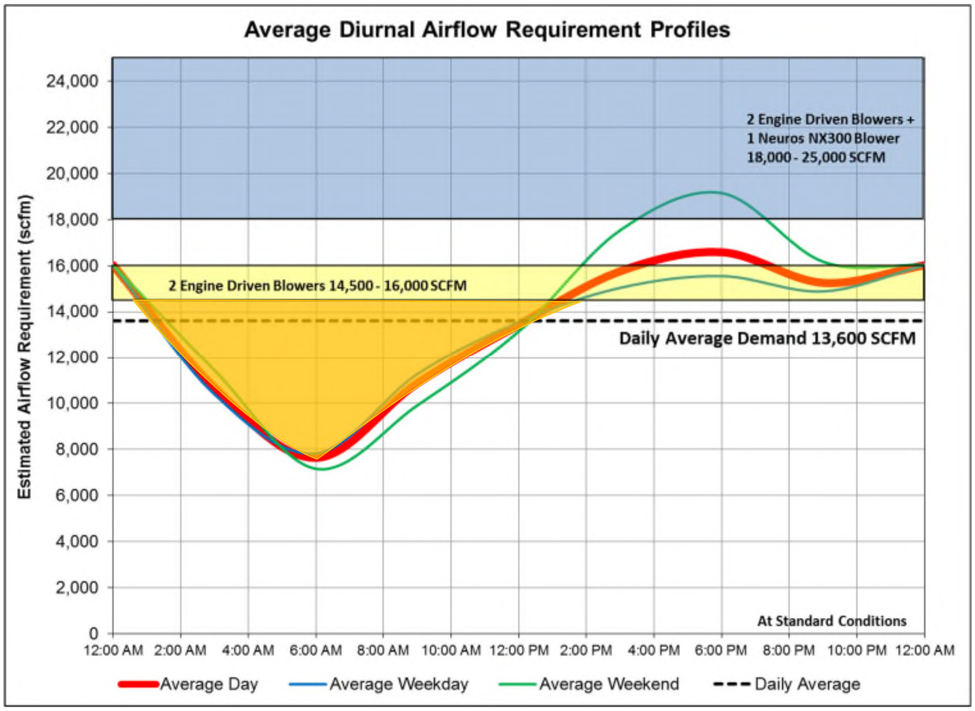


Figure 3.2: TVRWRF Average Diurnal Airflow Requirements and Air Production

SJVRWRF

Based on data provided by EMWD, the primary use for digester gas is the engine driven blower. Additional digester gas not used by the blower is sent to a boiler. The engine driven blower does not have heat recovery so the heating demands are met using both the natural gas and digester gas boilers. All unused digester gas is flared.

Typical blower operation at SJVRWRF includes operation of one (1) engine driven blower and two (2) Neuros blowers (1 NX300 and 1 NX350) during the day based on reviewing blower operational data and discussions with SJVRWRF operations staff. The orange shaded field in **Figure 3.3** below indicates the duration when air in excess of the oxygen demand is produced by the engine driven blowers and is blown off from the process. Approximately 16% of the air produced on an annual average case is blown off and results in a reduced biogas utilization efficiency.

Based on discussions with the plant staff, the digester gas fueled blower is not operated frequently due to the operational conflict with the electric blowers (blowers operate at different pressures). The combination of these operational conflicts, and excessive air production indicates a more effective digester gas utilization alterative should be implemented.

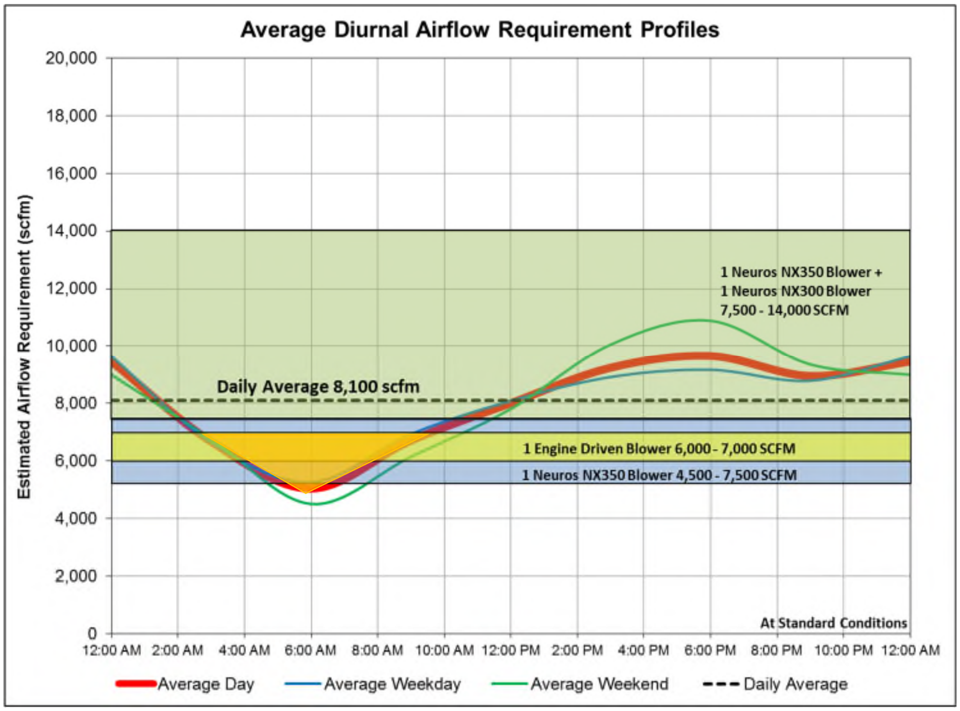


Figure 3.3: SJVRWRF Average Diurnal Airflow Requirements and Air Production

3.2.2 Plant Energy Balance (Heating Demands vs. Heat Production)

Seasonal digester heating demands were calculated based on the digester volume, construction, sludge class, and ambient conditions. A summary of the heating demands at each plant is provided in **Table 3.8**.

Table 3.8: Average Monthly Heating Demands (2016)

	Average Monthly Heating Demands (MMBTU/Hr)			
Month	**PVRWRF**	**MVRWRF**	**TVRWRF**	**SJVRWRF**
January	0.76	1.18	0.99	0.54
February	0.73	1.04	0.88	0.52
March	0.68	1.09	0.91	0.48
April	0.64	1.05	0.88	0.45
May	0.57	0.94	0.79	0.40
June	0.48	0.89	0.74	0.33
July	0.41	0.84	0.70	0.28
August	0.38	0.85	0.70	0.25
September	0.43	0.89	0.74	0.29
October	0.51	0.99	0.83	0.34
November	0.61	1.09	0.92	0.42
December	0.73	1.19	1.00	0.52

The diagrams in **Appendix C** show the relationship between the heat energy production and heat demands. This evaluation concludes that the heat energy available from the digester gas fueled engines will meet the seasonal digester heating demands.

3.3 Energy Balance Evaluations

3.3.1 Purchased Natural Gas Summary

Natural gas billing data provided by EMWD was evaluated to understand the quantity used and average cost for all four plants included in the study. **Table 3.9** summarizes the average natural gas purchased for each plant, including plant processes, building heating, boilers, generators, and any other natural gas fueled devices.

Table 3.9: Average Monthly Purchased Natural Gas (2014-2016)

	Average Monthly Natural Gas Consumption (cuft/Month)			
Month	**PVRWRF**	**MVRWRF**	**TVRWRF**	**SJVRWRF**
January	3,516,732	1,180,867	577,538	74,000
February	3,041,370	1,590,742	595,777	278,000
March	3,877,573	1,130,573	483,517	469,000
April	3,563,032	1,833,779	345,859	377,300
May	3,388,190	2,568,425	434,284	498,000
June	2,404,787	1,763,532	214,719	346,000
July	2,634,413	1,673,916	73,427	281,000
August	2,888,242	2,103,918	98,244	255,000
September	2,763,038	1,562,598	53,139	280,000
October	1,592,118	2,160,903	1,313	328,000
November	2,359,864	2,174,496	318,777	56,000
December	1,783,888	1,741,088	903,152	321,000
Total	**33,813,247**	**21,484,837**	**4,099,746**	**3,563,300**

PVRWRF and MVRWRF purchase more natural gas than TVRWRF and SJVRWRF. PVRWRF and MVRWRF both have fuel cells and the natural gas is used to maintain a higher output rating of the fuel cells while the majority of their digester gas is flared.

3.3.2 Digester Gas Utilization Efficiency Evaluations

The overall energy balance between the energy purchased, produced, and utilized was calculated to understand how effectively each plant was using their digester gas resources. The data from the evaluation was used to determine the overall digester gas utilization efficiency. Digester gas utilization efficiency measures the ratio of digester gas produced to the amount of useful energy produced from the digester gas resource. The Sankey diagrams below illustrate the overall energy balance for each plant. **Figure 3.4** summarizes the digester gas utilization efficiency results.

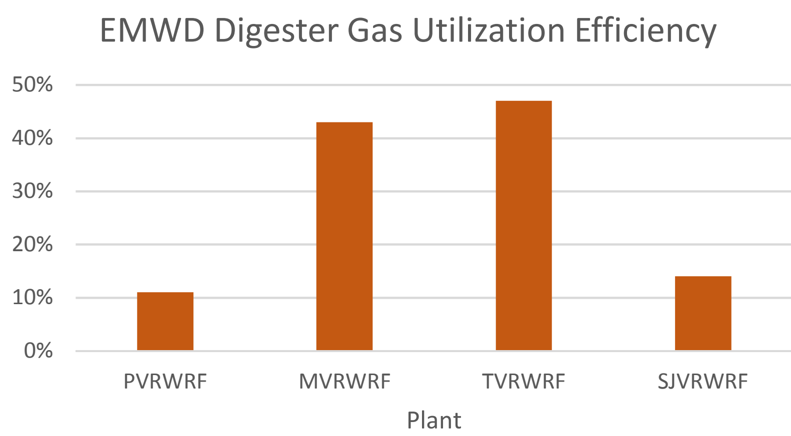


Figure 3.4: EMWD Digester Gas Utilization Efficiency Summary

PVRWRF

A Sankey diagram showing the energy balance for PVRWRF (2016) is shown in **Figure 3.5** below.

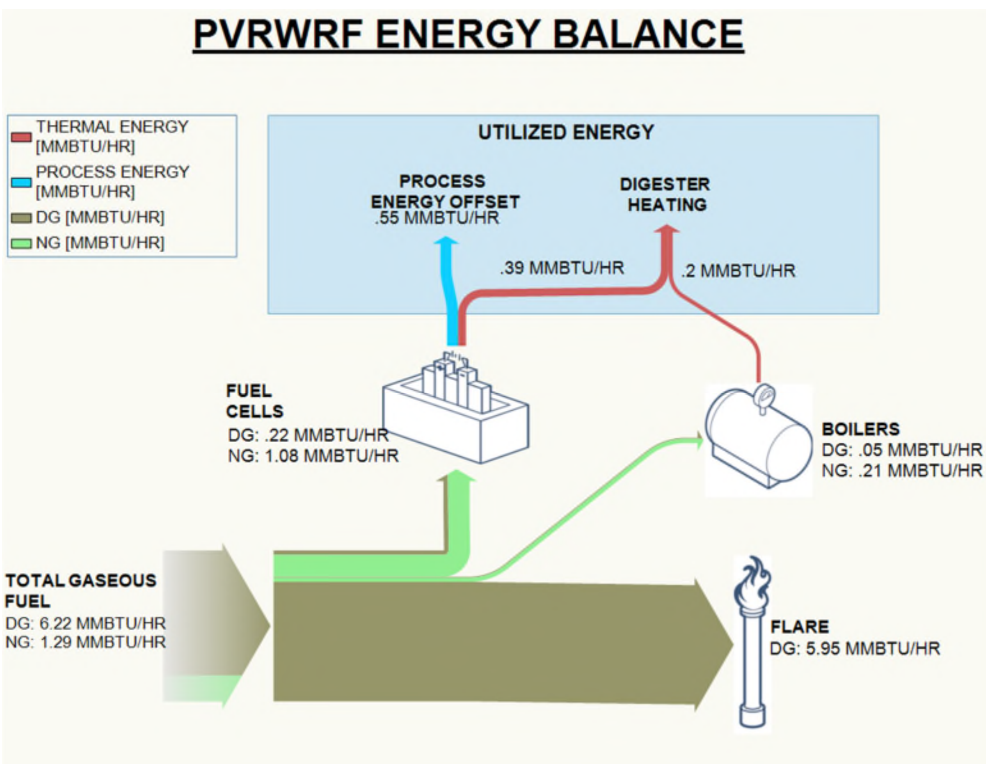


Figure 3.5: PVRWRF Energy Balance

Under current conditions at the PVRWRF plant, digester gas is 3% utilized. Primary factors contributing to this utilization are the fuel cell uptime, fuel cell digester gas utilization fraction, fuel cell thermal efficiency, and the boiler digester gas utilization fraction. The utilization fractions are a percentage of the total gas going to a specific endpoint. A summary of the PVRWRF digester gas utilization factors are provided in **Table 3.10**.

Table 3.10: PVRWRF Digester Gas Utilization

	Utilization Fraction	Conversion Efficiency	Total Utilization
Fuel Cell	5%	40%	2%
Boiler	1%	80%	0.8%
Flare	94%	0%	0%

MVRWRF

A Sankey diagram showing the energy balance for MVRWRF (2016) is shown in **Figure 3.6** below.

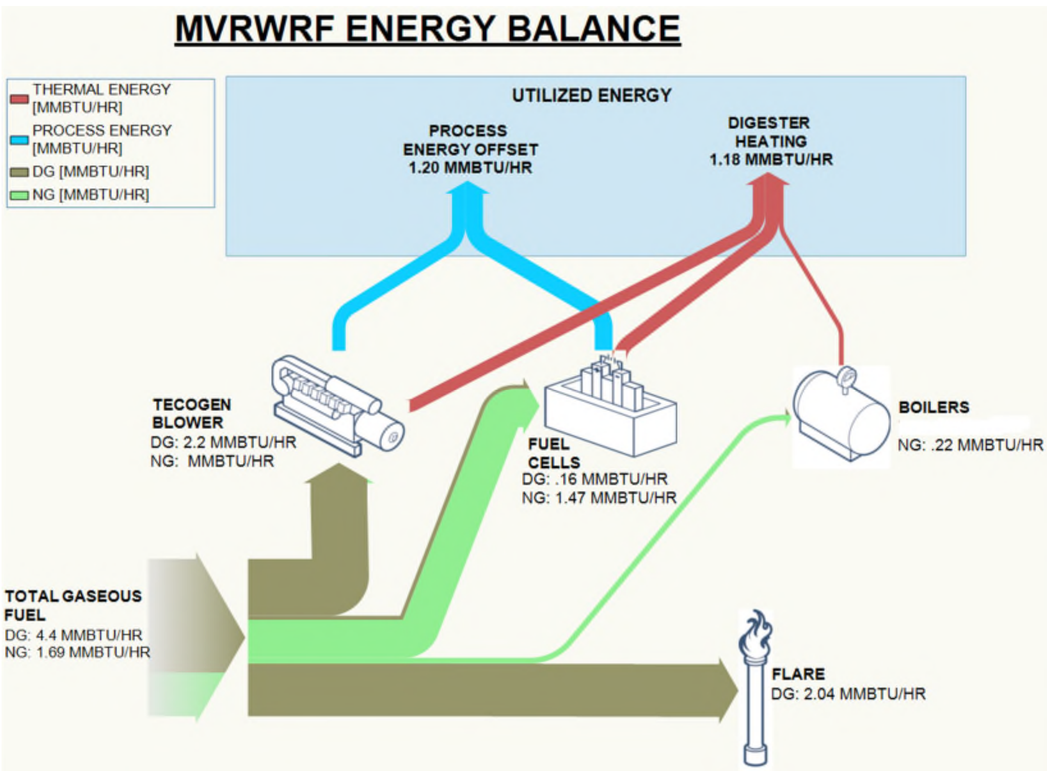


Figure 3.6: MVRWRF Energy Balance

Under current conditions at the MVRWRF plant, digester gas is 25% utilized. Factors contributing to this utilization are the fuel cell uptime, engine driven blower uptime, fuel cell digester gas utilization fraction, fuel cell thermal efficiency, engine driven blower thermal efficiency, and the boiler digester gas utilization fraction. A summary of the MVRWRF digester gas utilization factors are provided in **Table 3.11**. Note that the flare shown above represents only the Zink flare, it does not include the Bekaert acid gas flare.

Table 3.11: MVRWRF Digester Gas Utilization

	Utilization Fraction	Conversion Efficiency	Total Utilization
Fuel Cell	4%	72%	3%
Blower	50%	43%	22%
Boiler	0%	0%	0%
Flare	46%	0%	0%

TVRWRF

A Sankey diagram showing the energy balance for TVRWRF (2016) is shown in **Figure 3.7** below.

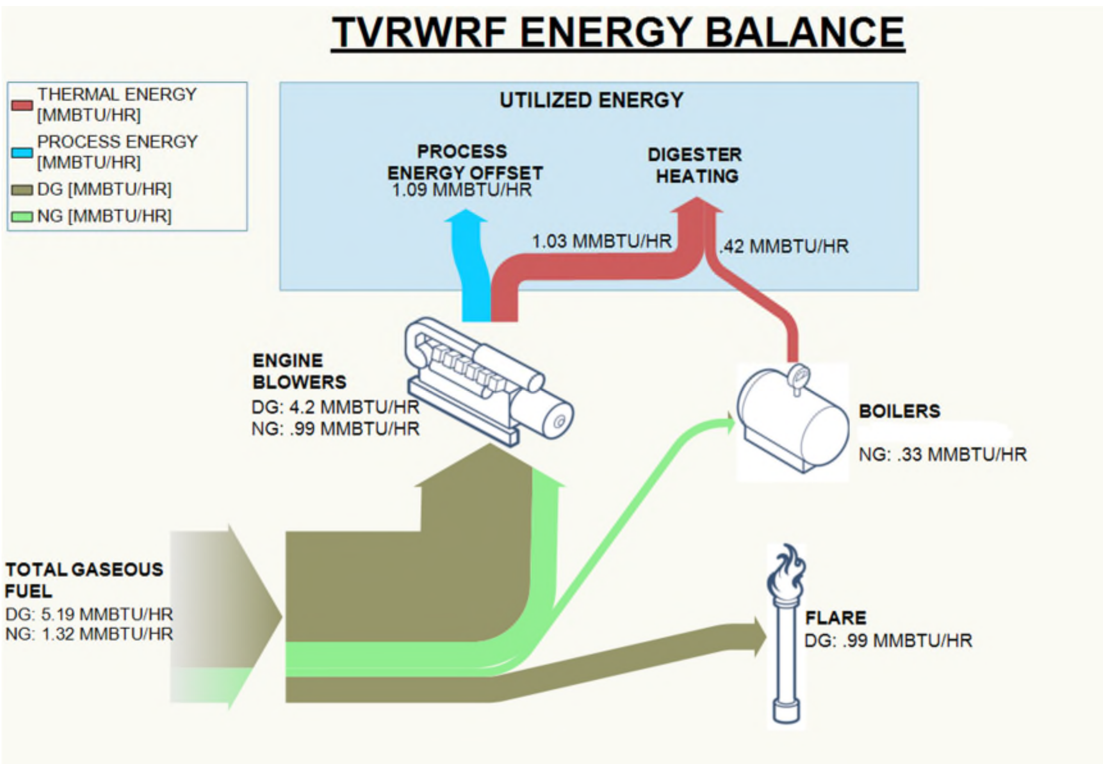


Figure 3.7: TVRWRF Energy Balance

Under current conditions at the TVRWRF plant, digester gas is 33% utilized. Factors contributing to this utilization are the engine driven blower uptime and the engine driven blower digester gas utilization fraction. A summary of the TVRWRF digester gas utilization factors are provided in **Table 3.12**. The electrical energy efficiency conversion will be described further in **Section 4.2** below.

Table 3.12: TVRWRF Digester Gas Utilization

	Utilization Fraction	Conversion Efficiency	Total Utilization
Blower	81%	41%	33%
Boiler	0%	0%	0%
Flare	19%	0%	0%

SJVRWRF

A Sankey diagram showing the energy balance for SJVRWRF (2016) is shown in **Figure 3.8** below.

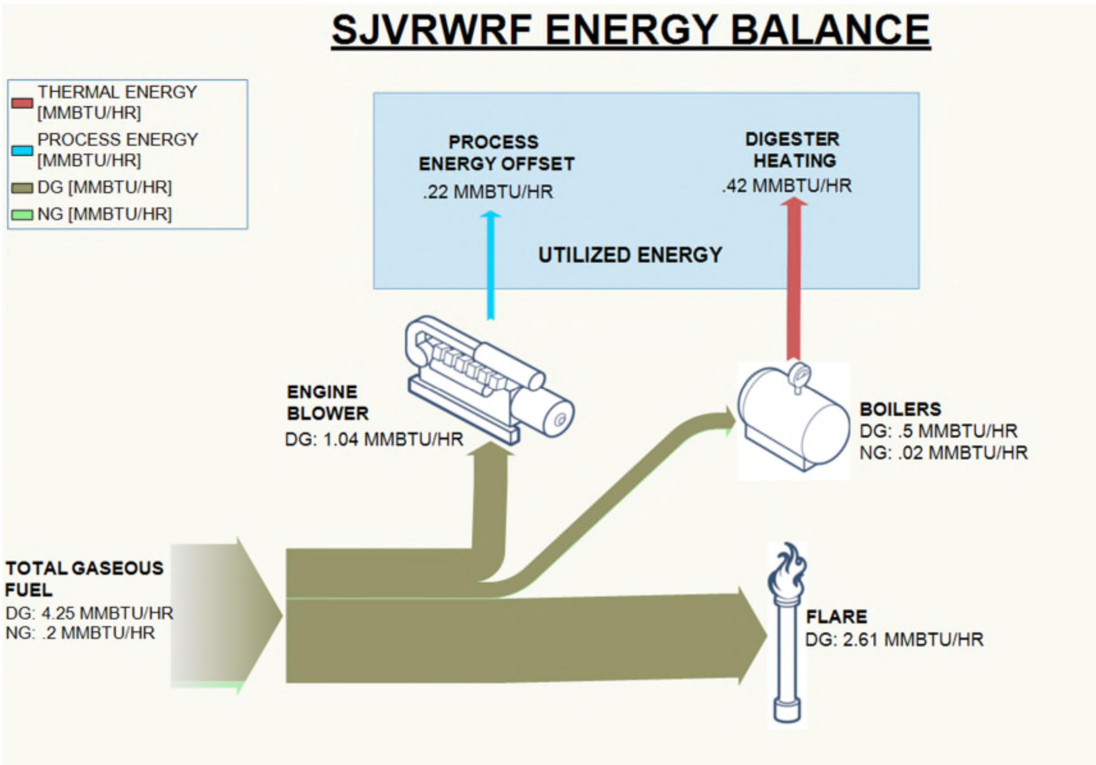


Figure 3.8: SJVRWRF Energy Balance

Under current conditions at the SJVRWRF plant, digester gas is 15% utilized. Factors contributing to this utilization are the engine driven blower uptime, the engine driven blower thermal efficiency, the engine driven blower digester gas utilization fraction, and the boiler digester gas utilization fraction. A summary of the SJVRWRF digester gas utilization factors are provided in **Table 3.13**. The electrical energy conversion efficiency will be described further in **Section 4.2** below.

Table 3.13: SJVRWRF Digester Gas Utilization

	Utilization Fraction	Conversion Efficiency	Total Utilization
Blower	26%	19%	5%
Boiler	12%	80%	10%
Flare	62%	0%	0%

3.4 Purchased Energy Costs and Assumptions

An evaluation of the electric utility and natural gas billing data was performed to determine the financial benefit from offsetting these energy sources. An analysis of this rate schedule and the historical utility billing data indicated that the average cost of energy for EMWD facilities is approximately $0.11/kWh. A summary of the plant rate schedules, energy charges and demand charges are found in **Table 3.14**. Energy utility cost escalations used in these evaluations were derived using California energy forecasting data from the Energy Information Administration (EIA) and are summarized in **Table 3.15**. The EIA collects, analyzes, and provides energy information to promote efficient markets and a comprehensive public understanding of the markets. Approximately 35% of the energy costs are from demand charges, with the remaining 65% being from energy and static charges.

Table 3.14: EMWD Electric Utility Summary

Plant	Rate Schedule	Energy Charges	Demand Charges
PVRWRF	TOU-8-B	56%	44%
MVRWRF	TOU-8-B	52%	48%
TVRWRF	TOU-PA3B	66%	34%
SJVRWRF	TOU-8-B	54%	46%

Natural gas for EMWD is supplied by Southern California Gas Company (SCG). Based on data natural gas utility billing data provided, EMWD pays an average of $6.50/MMBTU for cost of natural gas. Natural gas cost escalations are summarized in **Table 3.15**. The natural gas pricing and escalation factors used in this study were obtained from the regional retail natural gas cost data published by the Energy Information Administration (EIA).

Table 3.15: EMWD Utility Cost Escalations

Utility	Base Case Conditions	High Growth Conditions	Low Growth Conditions
Electric	2.5%	2.8%	2.2%
Natural Gas	3.0%	3.3%	2.7%

EMWD provided master plans for all plants, which were used to determine future digester gas production as well as heating demand escalations. The digester gas production and heating demand escalation numbers are used in the EBAT model to forecast future digester gas production and heating demands. A summary of the EMWD plant digester gas production and heating demand escalations is provided in **Table 3.16**.

Table 3.16: EMWD Digester Gas Production and Heating Demand Escalations

Plant	Base Case Conditions	High Growth Conditions	Low Growth Conditions
PVRWRF	3.3%	3.7%	3.0%
MVRWRF	1.0%	1.1%	0.9%
TVRWRF	2.9%	3.2%	2.6%
SJVRWRF	1.1%	1.2%	1.0%

The general inflation rate and interest rate used in the economic analysis are 2% and 2.5%, respectively.

3.5 Future Events

Fuel Cells

The fuel cells at PVRWRF and MVRWRF are under ten-year maintenance and operation contracts with Fuel Cell Energy. The contract at PVRWRF runs through December 2023 and the contract at MVRWRF runs through December 2022. Once the contracts end, it is anticipated that the fuel cells will be removed from each plant due to operational and equipment support issues. The digester gas that was previously being sent to the fuel cells will be available for an alternative utilization strategy.

Blowers

The engine driven blowers at TVRWRF and SJVRWRF are expected to be removed in 2019 as they will no longer be compliant under AQMD Rule 1110.2. The engine driven blower engine at MVRWRF will remain in service as it already has a gas treatment system and emission treatment system in place that meets the requirements of Rule 1110.2. For TVRWRF and SJVRWRF, it is assumed that the engine driven blowers will be decommissioned and these plants will rely on existing and potentially new electric blowers to provide the aeration demands.

4. Regulatory Considerations

4.1 Overview of applicable regulations

Each of the proposed alternatives will be subject to regulations/rules that will vary with the type(s) of equipment used to treat/control the digester gas and the associated emissions. The alternatives under consideration are (1) the "Flare Gas" alternatives; (2) the CHP alternatives; and (3) the digester gas to boiler and renewable natural gas production alternatives.

Table 4.1 provides an overview of some of the most directly relevant rules/regulations that could affect the feasibility of each alternative. **Table 4.1** is not meant to cover all possible regulatory requirements; rather, other requirements may apply.

Table 4.1: Relevant Rules and Regulations

Agency	Rule	"Do Nothing"	CHP	Digester Gas to Boiler and Renewable Natural Gas Production
SCAQMD	1118.1	X	X	X
SCAQMD	1146.x[1]	X		X
SCAQMD	1147 / 219			X
SCAQMD	1110.2	X	X	

4.1.1 SCAQMD Rule 1118.1

Continued use of the existing flares under these alternatives may be affected by the pending Rule 1118.1, "Control of Emissions from Non-Refinery Flares". SCAQMD held the first Working Group Meeting for this rule on August 25, 2017. At this time, any discussion of the requirements that will be in the final rule would be speculative and the adoption hearing is targeted for Spring, 2018[2]. However, the 2016 Air Quality Management Plan (AQMP) did provide a brief description of the control measure this rule will implement[3]:

> "CMB-03 – EMISSION REDUCTIONS FROM NON-REFINERY FLARES: Flare NOx emissions are regulated through NSR and BACT, but there are currently no source-specific rules regulating NOx emissions from existing flares at non-refinery sources, such as organic liquid loading stations, tank farms, and oil and gas production, landfills and wastewater treatment facilities. This control measure proposes that, consistent with the all feasible control measures, all non-refinery flares meet current BACT for NOx emissions and thermal oxidation of VOCs. The preferred method of control would involve capturing the gas that would typically be flared and converting it into an energy source (e.g.,

[1] As it relates to digester gas.

[2] http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1118.1/pr1118-1wgm1.pdf?sfvrsn=8. Accessed August 28, 2017.

[3] http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2016-air-quality-management-plan/final-2016-aqmp/final2016aqmp.pdf?sfvrsn=15. Page 196 of 473. Accessed August 28, 2017.

> transportation fuel, fuel cells, facility power generation). If gas recovery is not cost-effective or feasible, the installation of newer flares utilizing clean enclosed burner systems implementing BACT will be considered."

The presentation from the first Working Group Meeting for Rule 1118.1 indicates that BACT for emissions of NOx from 'biogas' flares would be 0.025 lb/mmBtu. If Rule 1118.1 implements the control measure as-is and allows the continued use of the existing flares, both for 'full-service' consumption of digester gas and consumption of waste gas from any current/future digester gas clean-up equipment, the John Zink flares at MVRWRF, SJVRWRF, and TVRWRF may eventually need to be retrofit or replaced as each of these flares is subject to a NOx limit of 0.06 lb/mmBtu. For the purposes of this study, it is assumed the flares will require replacement regardless of the utilization alternative selected. Since the flare replacement will be incurred for all alternatives, the replacement cost was not considered in the feasibility calculations.

4.1.2 SCAQMD Rules 1146.x

The SCAQMD Rule 1146 series apply to both existing and future boilers. The Rule 1146 series consists of three (3) rules, each applying to units of a given range of heat inputs. Rule 1146.2 applies to units with heat input less than or equal to 2 mmBtu/hr; Rule 1146.1 applies to units with heat input greater than 2 mmBtu/hr and less than 5 mmBtu/hr; and Rule 1146 applies to units with heat input greater than or equal to 5 mmBtu/hr.

PVRWRF and SJVRWRF each have a Rule 1146-subject boiler permitted to consume digester gas and natural gas. These boilers could be affected by future changes to Rule 1146. Rule 1146 was last amended in 2013. We are not aware of any proposed changes to the emission limits in this rule or difficulty in complying with the current emission limits.

4.1.3 SCAQMD Rules 1147/219

To our knowledge, neither MVRWRF or TVRWRF operate boilers that consume digester gas. If the projected heat input ratings for the 'Digester Gas to Boiler and Renewable Natural Gas Production' alternatives are less than or equal to 2 mmBtu/hr, this could subject equipment used under these alternatives to permitting requirements as the general permit exemption for combustion equipment does not include equipment that consumes digester gas[4].

Further, if the equipment proposed to be used under this alternative will have heat input less than or equal to 2 mmBtu/hr, it is possible that the applicable SCAQMD rule would be Rule 1147 rather than 1146.2. Rule 1146.2 applies to equipment "… fired with or … designed to be fired with natural gas …" This could be interpreted to mean that Rule 1146.2 does not apply. If Rule 1146.2 does not apply, then the equipment would potentially be subject to Rule 1147, as Rule 1147 applies to "… owners, and operators of … other combustion equipment with nitrogen oxide emissions that require a District permit and are not

[4] http://www.aqmd.gov/docs/default-source/rule-book/reg-ii/rule-219.pdf?sfvrsn=8. Rule 219(b)(2). "Boilers … a rated maximum heat input capacity of 2,000,000 Btu per hour (gross) or less and are equipped to be heated exclusively with natural gas, methanol, liquefied petroleum gas, or any combination thereof …"

specifically required to comply with a nitrogen oxide emission limit by other District Regulation XI rules. …" The lowest NOx limit in the current (July 7, 2017) version of Rule 1147 is 30 ppmv[5] @ 3% O_2. This rule contains multiple options for demonstrating compliance with the applicable NOx emission limit.

4.1.4 SCAQMD Rule 1110.2

SCAQMD Rule 1110.2 applies to "All stationary … engines over 50 rated brake horsepower …". Rule 1110.2 limits emissions of NOx, VOC, and CO from internal combustion engines and contains detailed monitoring and recordkeeping requirements for demonstrating compliance with these limits. Rule 1110.2 was last amended in June, 2016.

MVRWRF expects to maintain the existing aeration blowers in the "Do Nothing" alternative. The MVRWRF aeration blowers will continue to be subject to Rule 1110.2.

The cogeneration engines that would be installed under the CHP alternatives would be subject to this rule.

4.1.5 SCE Rule 21

Southern California Edison has a governing rule (Rule 21) for facilities that generate electricity, while remaining connected to the utility grid (parallel operation). SCE Rule 21 requires electrical protective and disconnect devices to be included at the plant service entrance to protect against the on-site generation sources from supplying power to the grid (reverse power) and to safeguard against inadvertently energizing the SCE facilities while they are in a de-energized state (i.e. power outage). The addition of new on-site electricity generation will require new utility interconnection studies at each plant that proceeds with the CHP alternative. Further details regarding this rule are provided in **Section 5**.

4.1.6 SCG Rules 30 and 39

Southern California Gas has two governing rules for adding upgraded digester gas to the natural gas pipeline – Rules 30 and 39.

Rule 30 specifies the quality of gas delivered into the pipeline. It addresses specific parameters such as temperature, heating value, liquid content, etc. To meet the requirement, the gas being injected into the pipeline much be continuously monitored and tested, ensuring the gas meets all quality requirements.

Rule 39 governs access to the pipeline. It requires that the interconnector must pay for the equipment necessary to deliver upgraded gas to the pipeline. Further details regarding this rule are provided in **Section 6**.

4.2 Anticipated Future Regulatory Compliance Requirements

In the 2016 AQMP, SCAQMD provided a Table, Table ES-1, that summarized the South Coast Air Basin's (SCAB) degree of nonattainment for five (5) National Ambient Air Quality Standards (NAAQS).

[5] Note: BACT for a digester gas-fueled boiler of this size could be lower than 30 ppmv @ 3% O_2. Rules 1146 and 1146.1 require 15 ppmv @ 3% O_2.

Table ES-1 is provided as **Table 4.2**. The 'Latest Attainment Year' column in **Table 4.2** is the year that attainment must be demonstrated with projected emission reductions.

Table 4.2: Relevant Rules and Regulations

Standard	Concentration	Classification	Latest Attainment Year
2008 8-hour Ozone	75 ppb	Extreme	2031
2012 Annual $PM_{2.5}$	12 μg/m^3	Moderate Serious	2021 2025
2006 24-hour $PM_{2.5}$	35 μg/m^3	Serious	2019
1997 8-hour Ozone	80 ppb	Extreme	2023
1979 1-hour Ozone	120 ppb	Extreme	2022

SCAQMD uses the degree of nonattainment with ambient air quality standards to develop control measures that are intended to reduce emissions of criteria pollutants from specific activities and/or equipment categories to levels that are projected to result in compliance with the applicable ambient air quality standards by the 'Latest Attainment Year.' If the control measures proposed in the AQMP are approved, SCAQMD will develop rules that implement the reductions proposed by the control measures.

NOx and VOC are precursors of ozone. The SCAB's Extreme nonattainment status for three (3) ozone standards means that additional NOx/VOC reductions may be needed from sources already subject to existing regulations. These reductions could potentially come from, for example, a more stringent, future version of Rule 1110.2.

4.2.1 Anticipated Rule 1110.2 Emissions Regulation Expansion

Rule 1110.2 was first adopted in 1990. At the time of its adoption, Rule 1110.2 contained exhaust emission limits for NOx, VOC, and CO. The most significant reduction in emission limits occurred around 2010. **Table 4.3** shows this data, along with the % reductions from the original version of the rule.

Table 4.3: Relevant Rules and Regulations

Rule Version	NOx (ppmv @ 15% O_2)	VOC (ppmv @ 15% O_2)	CO (ppmv @ 15% O_2)
1990	36	250	2,000
~2010	11	30	250
% Reduction from Original Version	70%	88%	88%

For perspective, new gas turbines are currently required to meet exhaust emission limits of 2 ppmv @ 15% O_2 for NOx, VOC, and CO. For engines, compliance with these emission limits would correspond to reductions of about 82%, 93%, and 99%, respectively, from the ~2010 version of Rule 1110.2. While these are significant reductions, over the course of another 20 years it is conceivable that reciprocating engine and/or add-on control technology will advance to the point of being able to achieve these emission levels.

5. Digester Gas to Electricity (CHP) Feasibility

The CHP alternative explores technologies and strategies that utilize digester gas to produce electric energy to offset purchased energy and thermal energy that can be recovered for digester heating. As stated in **Section 2.1.2**, reciprocating internal combustion engines are assumed in this study for the CHP alternative. EMWD has a large installed base of natural gas and digester gas fueled reciprocating internal combustion engines at the treatment plants and pumping stations. EMWD also has well developed engine maintenance and operations team that will enable them to effectively operate and maintain a biogas fueled CHP system. A major concern to using reciprocating internal combustion engines to utilize digester gas is they are subjected to the emission requirements under SCAQMD Rule 1110.2 which will require costly digester gas pre-treatment systems and emission post-treatment. A typical CHP process diagram is shown below in **Figure 5.1**.

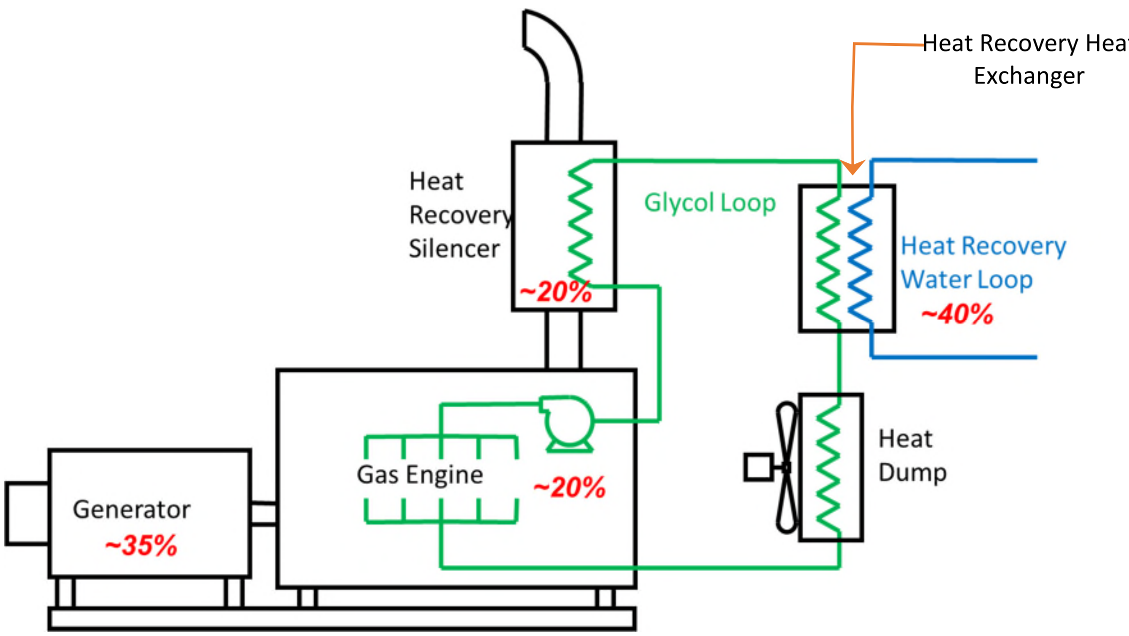


Figure 5.1: CHP Process Diagram

5.1 Technology Description and Assumptions

This utilization alternative is based on the use of digester gas fueled reciprocating internal combustion engines with heat recovery to generate a combination of electric and thermal energy. The electric energy is used to offset the purchased utility power at the current retail rate. Thermal energy is recovered from the exhaust and engine cooling system to provide the digester/building heating demands. CHP systems convert 35% of their energy input to electricity and 40% to heat, making them nearly 75% efficient.

As described in **Section 3**, it was assumed that the benefit gained from offsetting the purchased electric energy under the retail rate would be from the energy usage component of the total utility bill, only to account for the loss of demand offset from CHP system downtime. It was determined the electric energy offset benefit would be approximately $0.075/kWh for the CHP alternative.

A summary of the assumptions used in the CHP benefit evaluations are included in **Table 5.1** below

Table 5.1: CHP Benefit Evaluation Assumptions

Item	Description
Electric Energy Offset Benefit	$0.075/kWh
O&M Costs	$0.02/kWh of electric energy generated
Thermal Efficiency	40%
Electrical Efficiency	35%
CHP System Average Uptime	90% (10% Downtime)
Digester Gas Pre-Treatment Requirements	Moisture, hydrogen sulfide, and siloxane treatment systems required
Electrical Interconnection	Continuous parallel operation with plant electrical distribution system.
System Construction	"Containerized" system with weather proof enclosure
Thermal Energy Recovery	Heat recovery from engine cooling jacket and exhaust system. Heat is rejected to plant's existing hot water loop
Engine Parameters	1800 or 1200 RPM rich burn with three-way catalyst

5.2 Preliminary Sizing Calculations

Preliminary CHP system sizing calculation were performed using the current and projected gas production. **Table 5.2** summarizes the results. The preliminary sizing evaluations sized the engine to operate at 90% of the rated output, under the current conditions. The 20-year projected outputs for each plant is summarized in graphs shown in **Appendix B.** As shown in **Appendix B**, supplemental natural gas will be required for some facilities to meet 90% of rated operations in the initial years of operation. The evaluation assumes the CHP system ratings in **Table 5.2** will remain constant over the 20-year planning horizon.

Table 5.2: EMWD CHP System Ratings

Plant	CHP System Rating (kW)
PVRWRF	800
MVRWRF	500
TVRWRF	650
SJVRWRF	500

5.3 Energy Balance Evaluation

5.3.1 Digester Heating Demands

The energy balance evaluations compare the CHP system thermal energy production to the plant heating demands over the 20-year planning period. **Table 5.3** summarizes the average monthly CHP heating production and peak heating demands (winter) for each plant for the initial conditions. The radial graphs shown in **Appendix C** compare the 20-year heating demands and heating production for each plant. As shown on these graphs, the heating demands do not exceed the heat production capacity over the 20-year planning period. It should be noted that all four (4) RWRF's have very low heating requirements due to the local climate. During the site visits with the plant staff, it was noted that in some cases, the digesters would maintain mesophilic temperatures without an external heat source in the summer months.

Table 5.3: Average Monthly Heating Production and Demands

Month	Average Monthly Heating Production and Demands (MMBTU/Hr)							
	PVRWRF		MVRWRF		TVRWRF		SJVRWRF	
	Production	Demands	Production	Demands	Production	Demands	Production	Demands
January	2.53	0.76	1.62	1.18	2.05	0.99	1.58	0.54
February	2.53	0.73	1.62	1.04	2.05	0.88	1.58	0.52
March	2.53	0.68	1.62	1.09	2.05	0.91	1.58	0.48
April	2.53	0.64	1.62	1.05	2.05	0.88	1.58	0.45
May	2.53	0.57	1.62	0.94	2.05	0.79	1.58	0.40
June	2.53	0.48	1.62	0.89	2.05	0.74	1.58	0.33
July	2.53	0.41	1.62	0.84	2.05	0.70	1.58	0.28
August	2.53	0.38	1.62	0.85	2.05	0.70	1.58	0.25
September	2.53	0.43	1.62	0.89	2.05	0.74	1.58	0.29
October	2.53	0.51	1.62	0.99	2.05	0.83	1.58	0.34
November	2.53	0.61	1.62	1.09	2.05	0.92	1.58	0.42
December	2.53	0.73	1.62	1.19	2.05	1.00	1.58	0.52

As the CHP system reaches it rated output and during periods of CHP system downtime, any digester gas not utilized by the CHP system will be flared. **Appendix D** shows the overall balance between the digester gas utilized by the CHP system and the gas flared. As expected, the amount of digester flared will increase over the 20-year planning period as gas production exceeds the fuel demand.

Revenue evaluations for the CHP alternative will be covered in **Section 7**.

5.3.2 Digester Heating System Integration

Each plant uses a hot water heat recovery loop to recover thermal energy from the existing engines and fuel cells for digester heating. A preliminary evaluation shows that new CHP engines can be integrated into the existing heat recovery hot water loops without major modifications to the existing facilities. It is anticipated that a heat recovery heat exchanger (shown in **Figure 5.1**) will be used to transfer thermal energy from the CHP system engine and exhaust silencer to the existing heat recovery loop. In the event the heat demands are less than the CHP system heat production, a heat dump heat exchanger will maintain the engine cooling loop temperature to prevent engine overheating. It is assumed the existing boilers are sufficient to maintain digester heating during CHP system downtime.

5.3.3 Revenue Generation Potential

Figure 5.2 compares the 20-year net present value (NPV) (including debt service) for all four (4) plants for the CHP alternative. PVRWRF and MVRWRF have higher 20 Year NPV compared to TVRWRF and SJVRWRF due to the capital cost saving by using the existing fuel cell pre-treatment systems for the new CHP applications. New gas pretreatment systems would be required for TVRWRF and SJVRWRF which reduces the 20 Year NPV for these facilities.

As described herein, MVRWRF already has a SCAQMD Rule 1110.2 compliant digester gas engine driven blower. For reference, the 20-year NPV for a new CHP system and the 20-year NPV for continued use of the existing engine driven blower (Tecogen blower) are included on **Figure 5.2**. The continued use of the Tecogen blower has a higher 20-year NPV due to the low/zero capital costs associated with this alternative.

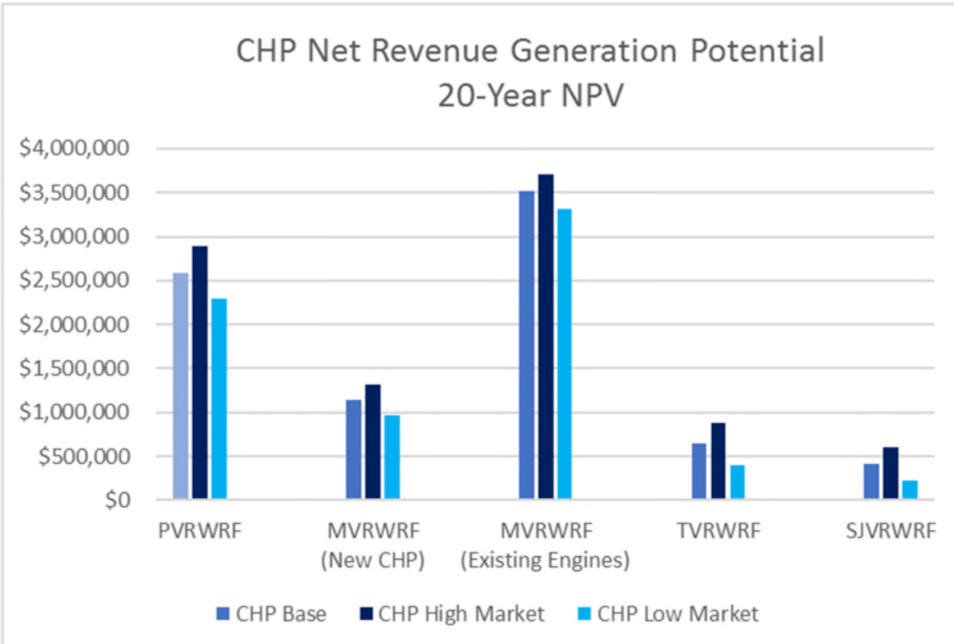


Figure 5.2: CHP 20-Year NPV

5.4 Regulatory Considerations

The CHP alternative will require compliance with two governing bodies – SCAQMD and SCE. Both have rules governing CHP systems. SCAQMD governs the emissions that a CHP engine will emit to the atmosphere, while SCE governs the facility interconnection to the grid when the facility operates in parallel with SCE's system. Requirements for each governing body are explained in detail below.

5.4.1 SCAQMD Rule 1110.2 Compliance

As discussed in **Section 4**, digester fueled engines will be required to meet the emission limits mandated by SCAQMD Rule 1110.2. Compliance with the rule will require a high level of gas pre-treatment to remove contaminates such as hydrogen sulfide (H_2S), siloxanes, and moisture as well as post-treatment (exhaust) to remove oxides of nitrogen (NOx), carbon monoxide (CO), and other volatile organic compounds (VOC). The District has successfully implemented emission control systems that meet the SCAQMD Rule 1110.2 requirements for the MVRWRF digester gas engines by using systems manufactured by Tecogen ™.

Digester gas pre-treatment equipment to remove hydrogen sulfide, moisture, and siloxanes is included for all CHP alternatives examined in the analysis. The digester gas pre-treatment equipment includes an iron-oxide based hydrogen sulfide removal system, compression/chilling systems for moisture removal, and a fixed bed carbon media system to remove siloxane compounds. The high level of gas pre-treatment is required to minimize the contamination of the exhaust oxidation catalysts required to remove CO and NOx emissions. The pre- and post-treatment systems needed for SCAQMD compliance was included in the study cost estimates for this alternative for SJVRWRF and TVRWRF. PVRWRF and MVRWRF both can utilize the existing pre-treatment systems currently used by the fuel cells. The fuel cell pre-treatment systems have the capability to treat the digester gas to a very high level and is assumed to compatible with exhaust treatment catalysts that will meet Rule 1110.2 requirements.

For the purposes of this evaluation, it is assumed that SCAQMD will impose additional emission limits on reciprocating internal combustion engines. SCAQMD has demonstrated in the past that their rulings do not exceed the capabilities of the available emission control technologies at the time of implementation. Therefore, for the purposes of this evaluation, it is assumed that add-on technologies such as gas pre-treatment and exhaust after treatment systems would meet future Rule 1110.2 requirements. It is assumed that future emission compliance can be achieved through modifications to the existing pre-treatment and exhaust treatment systems, which are estimated to cost approximately $400,000 to $600,000 depending on the size of the system. **Figure 5.3** below summarizes the NPV of the CHP alternative, including the future investments for emissions compliance.

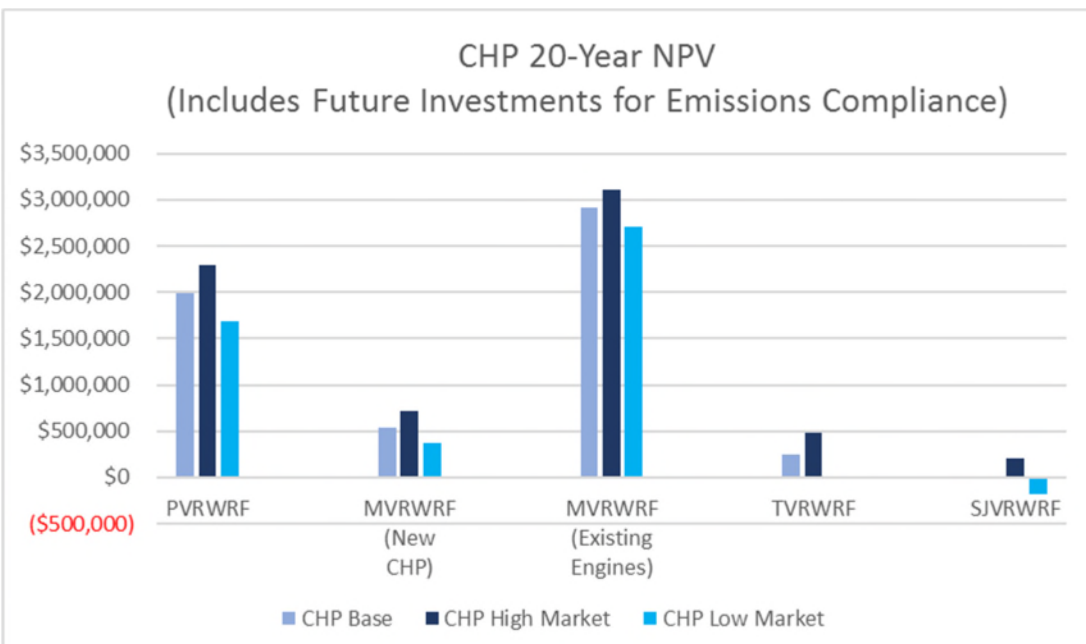


Figure 5.3: CHP 20-Year NPV with Future Investments for Emission Compliance

5.4.2 Southern California Edison (SCE) Rules and Compliance Requirements (Rule 21)

Southern California Edison has a governing rule (Rule 21) for facilities that generate electricity, while remaining connected to the utility grid (parallel operation). SCE Rule 21 requires electrical protective and disconnect devices to be included at the plant service entrance to protect against the on-site generation sources from supplying power to the grid (reverse power) and to safeguard against inadvertently energizing the SCE facilities while they are in a de-energized state (i.e. power outage). SCE will require an interconnection study to be performed to ensure the facility meets the electrical protection requirements and that the new parallel source will not adversely impact their facilities. All the EMWD plants in this study have executed interconnection agreements with SCE and comply with the generation facility requirements described in Rule 21, Section H for the solar arrays. However, the addition of new on-site parallel generation will require a new interconnection study, which costs approximately $50,000 per site. This cost was included in the study cost estimates for this alternative. It is possible that the addition of the CHP system power generation in combination with the existing solar energy generation could require modifications to SCE's facilities to support the CHP alternative. The cost to modify to SCE's facilities (if required) would likely be borne by EMWD. An interconnection study has not been performed at the time of this study, therefore, the scope and cost of any modifications to SCE's facilities are unknown.

5.5 Preliminary Equipment Siting Alternatives

Preliminary site options for the CHP engines have been evaluated at each plant are shown in **Appendix G.** The potential locations shown were selected for their proximity to a suitable connection point to the electrical distribution system and proximity to gas handling and heat recovery infrastructure. In general, PVRWRF, MVRWRF, and SJVRWRF have minimal site constraints. The existing fuel cell locations at PVRWRF and MVRWRF are ideal locations for the new CHP system since electrical connections, gas piping, and heat recovery loop infrastructure all exist at these locations and are of sufficient capacity for the proposed CHP systems. TVRWRF is the most congested site and will require a detailed site evaluation to determine if the locations shown in **Figure G.3** are feasible.

5.6 Cost Estimates

A list of the CHP system components and existing infrastructure modifications are found below:

- Packaged Engine/Generator with gas blending and engine controls to meet Rule 1110.2 requirements
- Exhaust Emissions Controls (Similar to the MVRWRF Tecogen™ system)
- Continuous Emissions Monitoring Systems (CEMS) for engines over 1,000 bhp.
- Heat Recovery Heat Exchanger
- Gas Pre-treatment Skid (Includes H2S, Moisture, and Siloxane treatment) [SJVRWRF and TVRWRF only]
- Hot Water Recirculation Pump
- Existing Electrical Distribution Modifications
- Existing Piping Modifications

- Site Work/Modifications
- Existing Instrumentation and Control Modifications
- SCE Interconnection Study

Cost estimates for each plant are summarized in **Table 5.4**. Detailed cost estimates are provided in **Appendix H**.

Table 5.4: CHP System Cost Estimates

Plant	CHP Cost Estimate	Gas Pre-Treatment Assumption
PVRWRF	$4,060,000	Existing Fuel Cell System
MVRWRF	$3,020,000	Existing Fuel Cell System
TVRWRF	$4,660,000	New Pre-Treatment System
SJVRWRF	$3,630,000	New Pre-Treatment System

6. Digester Gas to Renewable Natural Gas (RNG)

For this alternative, digester gas is treated (or “upgraded”) to natural gas pipeline quality (RNG) and compressed for injection into SCG’s natural gas pipeline network. The RNG produced will generate revenue through methane sales to SCG and through the generation of renewable energy commodities that can be traded/sold to parties obligated to meet the renewable energy requirements under the EPA Renewable Fuel Standards (RFS2) and California’s Low Carbon Fuel Standards (LCFS). Based on discussions with various 3rd party RNG marketing companies, RNG can also be sold as a renewable material to corporations who manufacturer goods from natural gas such as plastics and chemicals.

The RNG production and utilization scenarios evaluate in this study are

- Digester gas used for digester heating with the remaining used to generate RNG.
- All digester gas used for RNG production with purchased natural gas used to meet heating demands.

The RNG alternative requires compliance with SCG Rules 30 and 39, which will be explained in further detail below.

6.1 Digester Gas Upgrading Technologies

Upgrading raw digester gas to natural gas standards requires the removal of carbon dioxide (CO_2), which makes up approximately 40% of the digester gas by volume. Other contaminants such as moisture, sulfides of hydrogen (H_2S), and silica compounds (Siloxanes) must also be removed. The commonly available technologies for CO_2 removal are:

- Pressure Swing Adsorption (PSA)
- Selective Membranes
- Water Scrubbing
- Chemical Scrubbing (Amine)

6.1.1 Pressure Swing Adsorption (PSA)

Pressure swing adsorption (PSA) systems pass raw digester gas through multiple vessels containing adsorbent media. The PSA system media adsorbs specific gas constituents (i.e. CO_2) under high pressure. These constituents are released from the media during the decompression stage (blowdown) of the PSA cycle. Typical adsorbent media include activated carbon, natural and synthetic zeolites, and molecular sieves. These adsorbents can be used to remove CO_2, H_2S, and volatile organic carbons (VOCs), including siloxanes. **Figure 6.1** shows the basic components of a typical PSA system.

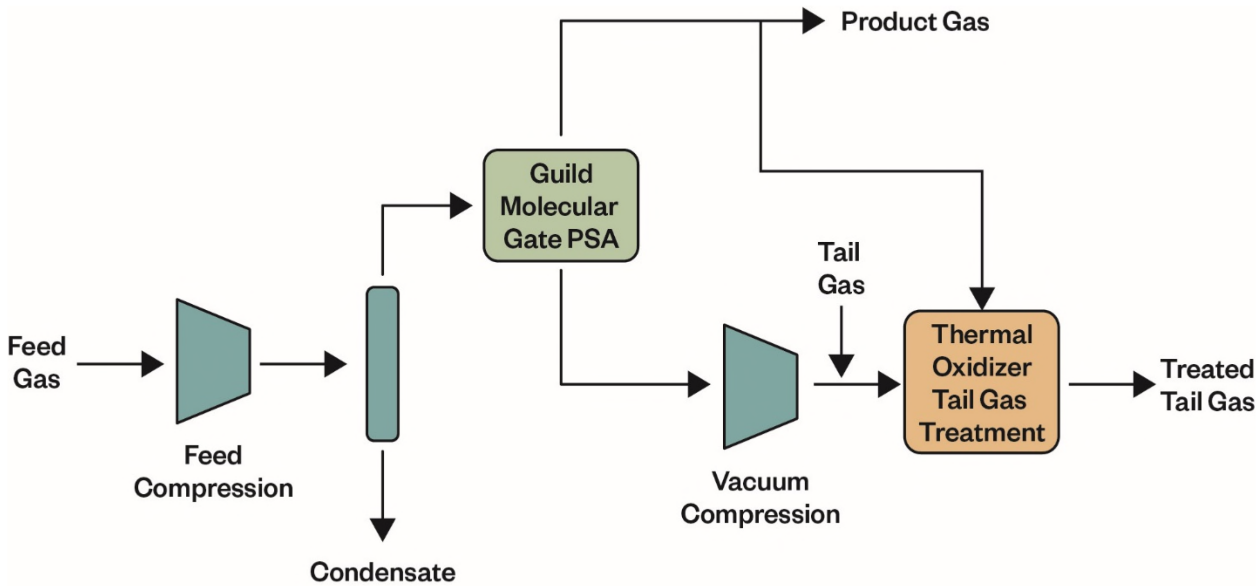


Figure 6.1: Typical PSA Process Flow Diagram (Guild Associates Molecular Gate™ Example)

Common manufacturers of PSA systems include:

- Guild Associates
- Greenlane
- Carbotech
- Xebc

The basic operating principal is the same for these manufactures. However, it should be noted that different adsorbents are used depending on the manufacturer most of which are proprietary to the system manufacturer. For example, Guild Associates offers a molecular sieve type media that removes H_2S, siloxanes, and CO_2 in a single unit; reducing the level of gas pre-treatment required. Other manufacturers use activated carbon or similar adsorbing media which may require an additional treatment step to remove H_2S and siloxanes. The typical PSA cycle is as follows:

- Digester gas is pretreated to remove contaminants (i.e. moisture, H_2S, siloxanes, etc.) as required by the specific PSA process.
- Pretreated gas is compressed (typically around 100psi using liquid ring compressors) and chilled to remove water vapor and other condensable contaminants. Some manufacturers may treat for H_2S and siloxane during this step also.
- Compressed gas is fed to the PSA unit where contaminants (i.e. CO_2) are adsorbed by the adsorptive media. The treated gas exits the process at a slightly lower pressure (typically around 90psi). Some manufacturers require the gas to be preheated prior to this step.
- After a determined operating period, the contaminants are desorbed by depressurizing the PSA vessel and then purging with treated gas. The purged material is known as "tail gas".

- The tail gas is oxidized in a thermal oxidizer.

Thermal oxidation is a method of air pollution control, which decomposes hazardous gases at a high temperature and releases them to the atmosphere. Thermal oxidation is typically used to destroy hazardous air pollutants (HAPs) and VOCs by thermal combustion to form CO_2 and H_2O.

The number and size of PSA and pretreatment vessels depend on the digester gas quantity and contaminants and will vary with each manufacturer.

6.1.2 Selective Membranes

Selective membranes create a semi-permeable barrier to separate methane and CO_2. Compressed digester gas (typically around 200psi) travels through the membranes, allowing CO_2, O_2, H_2O and H_2S to permeate at a high rate while methane molecules permeates at a slower rate. The faster permeation of the undesirable constituents, along with the slower permeation of methane results in a product leaving the membrane module, which is rich in methane but with low concentrations of the other gases. Pre-treatment is typically used before the membranes to remove moisture, H_2S, siloxanes, and other undesirable contaminants. **Figure 6.2** shows the basic components of a typical selective membrane system.

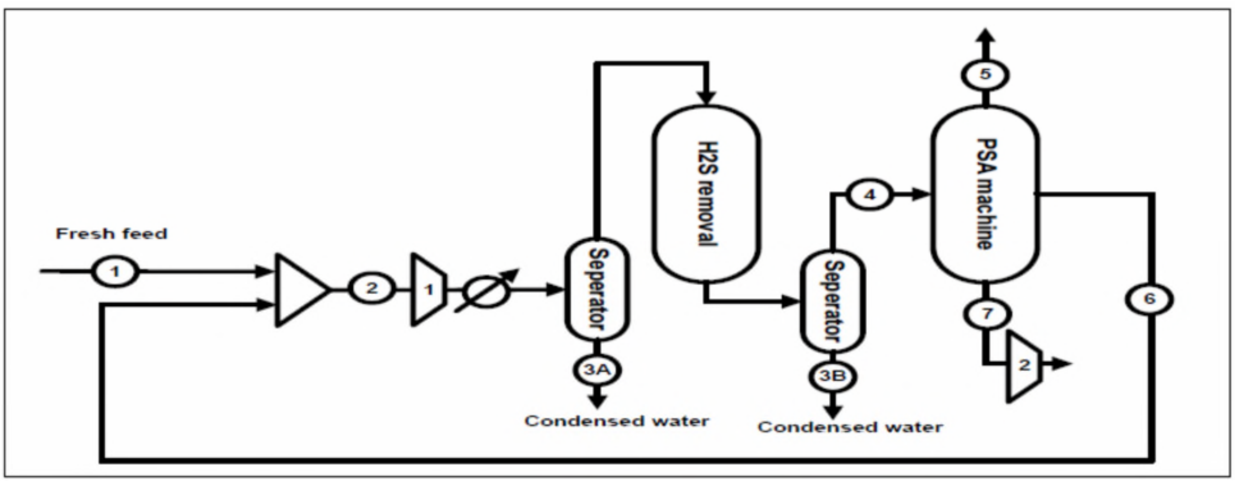


Figure 6.2: Typical Membrane Process Flow Diagram (Courtesy of Xebec)

Common manufacturers of selective membrane systems include:

- Xebec
- Hitachi Zosen Inova (HZI)
- DMT

The basic operating principal is the same for these manufactures with the primary difference being the type of membrane and the level of pre-treatment used before the membranes. The typical membrane treatment cycle is described below:

- Digester gas undergoes pre-treatment to remove H_2S, VOCs, siloxanes, and other undesirable containments.
- Pre-treated gas is compressed (typically around 200 – 350psi) and chilled to remove water vapor and other condensable contaminants. Some manufacturers may provide additional H_2S and siloxane treatment during this step.
- For some manufacturers, gas undergoes a catalytic oxygen removal step before the membranes
- Gas is fed through the membranes for CO_2 and other gas constituent removal.
- Treated gas is provided around 200 – 350psi.
- The membrane treatment by-product (tail gas, or sometimes referred to as “lean gas” for membrane systems) is typically oxidized in a thermal oxidizer.

6.1.3 Water Scrubbing

Water scrubbing systems use water to absorb CO_2 and H_2S by taking advantage of the fact that methane is much less soluble in water than CO_2 and H_2S. Gas is compressed to around 100 to 150 psig (to increase the amount of CO_2 that can be dissolved in the water) and enters an absorption column. CO_2, in addition to a very small proportion of methane, is dissolved in water within the column. The CO_2 laden water is sent to a desorption column, where air (at atmospheric pressure), is added to strip CO_2 from the water. Both columns are filled with packing material to maximize contact between the gas and the water. Because water leaving the absorption column contains some methane, a flash column is used, which operates at low pressure to remove methane from the water. The methane is then returned to the raw gas feed. **Figure 6.3** shows the basic components of a typical water scrubbing system.

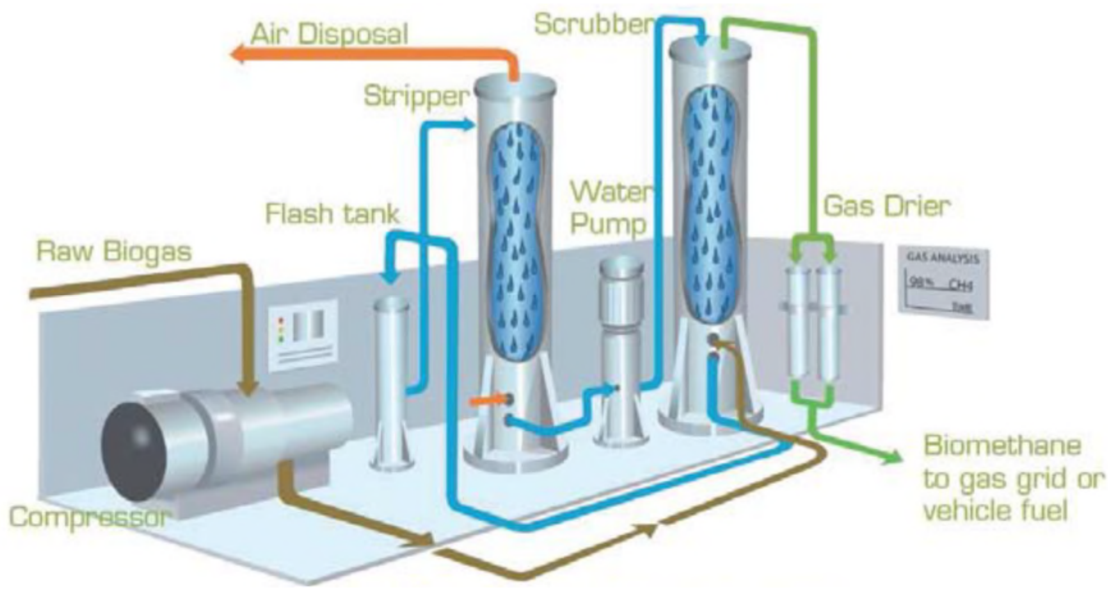


Figure 6.3: Typical Water Scrubbing Process Flow Diagram (Courtesy of Greenlane)

Common manufacturers of water scrubbing systems include:

- Greenlane

Water scrubbing systems are relatively tolerant of gas contaminants and biogas can often be processed without prior removal of moisture, H_2S, and VOCs. Air leaving these systems will, however, contain H_2S and other gas contaminants and often the air stream may require treatment to avoid environmental issues (e.g. using adsorptive media in an adsorption vessel or using a thermal oxidizer).

6.1.4 Chemical Scrubbing (Amine)

Chemical scrubbing works on a similar principle to water scrubbing, except that the solvent used to remove CO_2 is a water-based solution of methyldiethanolamine (MDEA). The amine reacts with CO_2 dissolved in the water, which increases the rate at which CO_2 is removed. Chemical scrubbing improves the removal efficiency as compared to water scrubbing. Common manufacturers of chemical scrubbing systems include:

- Purac Puregas

As with water scrubbing, it is not necessary to remove H_2S prior to amine scrubbing for the process to function. However, H_2S removal is often utilized anyway for environmental reasons. While amine scrubbing is very efficient, its use is much less common than other technologies discussed, due primarily to higher life cycle cost.

6.1.5 Preliminary Technology Comparison

Table 6.4 provides a summary of the digester gas upgrading technologies described.

Table 6.4: Digester Gas Upgrading Technology Summary

Digester Gas Upgrading Technology	Treatment Method	Pre-treatment Requirements	Consumables	Comments
PSA	Adsorption media	Varies with Manufacturer	Pretreatment media and some adsorption media (i.e. activated carbon).	Most common technology. Large footprint and high noise
Selective Membranes	Molecular Permeation	Yes	Pretreatment media	Small footprint, simple operations
Water Scrubbing	Water Solvent	No	Make up water	No consumables except water. Not able to absorb some containments.
Chemical Scrubbing	Water and Amine Solvent	No	Make up water and chemicals	Highly effective CO2 removal. Chemical consumption

For this evaluation, a PSA system is used as the basis of the RNG evaluations since PSA is one of the most common technologies used for biogas upgrading. Even though some manufacturers do not require gas pre-treatment, it is assumed that upstream H_2S and siloxane removal will be required and the waste gas would be burned in a thermal oxidizer. It should be noted that it is not the intent of this study to identify the most beneficial RNG production technology but to evaluate the overall feasibility of RNG production. It is recommended that a detailed technology study should be performed if EMWD decides to pursue RNG production as a long-term digester gas utilization strategy.

6.2 RNG Utilization Strategies

This study assumes the RNG produced will be used as a transportation fuel to gain the benefit from the RIN and LCFS commodities markets. The pathway to the transportation fuels market can be accomplished by the following two pathways:

- Pathway 1 – Direct Vehicle Fueling. RNG would be compressed and stored for onsite vehicle fueling.
- Pathway 2 – Pipeline Injection. RNG would be injected into SCG's pipeline and "wheeled" through SCG's distribution system to transportation fuel customers.

Direct vehicle fueling is the simplest and most direct pathway to the fuels market. Fueling EMWD's fleet with the RNG produced at their RWRFs would provide a high level of benefit by offsetting purchased CNG fuels as well as generating RIN/Carbon Offset credits. However, there are many barriers associated with this alternative:

- EMWD would need a CNG vehicle fleet large enough to use the majority of the RNG produced for direct vehicle fueling. At the time of this study, EMWD has a small vehicle fleet that is capable of using a small fraction of the total RNG production capacity for all 4 plants.
- There could be logistical challenges with fueling the vehicles given the location of the CNG fleet and the plant sites. A study of EMWD's current and project CNG vehicle fleet will be required to fully understand the logistics involved with meeting the fleet fueling needs.
- Fueling the vehicles directly would be an intermittent use of the RNG produced. Since digester gas is produced continuously, compressed RNG storage would be required during periods when the fleet vehicles are fully fueled or not in use (i.e. nights, weekends, holidays).

Pipeline injection overcomes many of the direct vehicle fueling logistical and production barriers. For example, RNG can be injected into the pipeline continuously, allowing around the clock production. In addition, the RNG production quantity and schedule would not be limited to EMWD's fleet demands and operations. Pipeline injection also enables the RNG produced to reach a wide network of RNG customers. Pipeline injection does however pose a few barriers that must be considered:

- A pipeline extension from the RNG facility to a connection point approved by SCG could be a significant cost, depending on the location of the facilities and the current pipeline infrastructure. <u>A formal pipeline interconnection study has not been performed at the time of this study.</u>
- To establish the pathway to the transportation fuel market, EMWD must develop a contractual agreement with an end use customer that demonstrates the fuel produced is used as a transportation fuel. Use of biogas as a transportation fuel is a key requirement of the LCFS and the RFS2 and will be explained in further detail below.

- A high level of gas monitoring, metering, and reporting must be installed to ensure the RNG meets SCG's gas quality requirements described in SCG Rule 30 to prevent non-compliant gas from entering the pipeline.
- Odorizing system must be installed to odorize the injected RNG per SCG's requirements (Rule 30 and 39).

6.2.1 Renewable Fuels Markets – Renewable Identification Numbers (RINs)

Using RNG as a transportation fuel qualifies it to generate renewable transportation fuel credits, known as "Renewable Identification Numbers" (RINs). RINs are tradable renewable fuel commodities that are used to for compliance with the EPA's "Renewable Fuel Standards" (RFS2). RNG produced from municipal anaerobic digester gas qualifies as an "advanced cellulosic biofuel" or "D3" RIN, which can be sold to obligated parties, who are required to comply with the renewable volume obligations (RVOs) under the RFS2 requirements. The RFS2 sets a target volume of 36 billion gallons of renewable fuels to be blended in the United States transportation fuel market by 2022. As shown in **Figure 6.5** below, the RVOs are comprised of different fuel types, which are formed from different feed stocks.

Cellulosic biofuels (D3) must be produced from feed stocks that produce a fuel that has a 60% overall lifecycle GHG reduction compared to non-renewable fuels. The EPA has developed a pathway (Pathway Q) that establishes municipal wastewater digester gas as a cellulosic biofuel that would generate a D3 RIN if used in the transportation fuels market. It should be noted that the EPA recognizes biogas generated from waste digesters (i.e. food waste, FOG, etc.) as an "advance biofuel" that qualifies to generate a D5 RIN. This segregation of municipal sludge/digester and waste digester could cause concern when identifying the RIN code for gas produced from co-digesting waste products, such as food waste and fats oils and grease with municipal sludge.

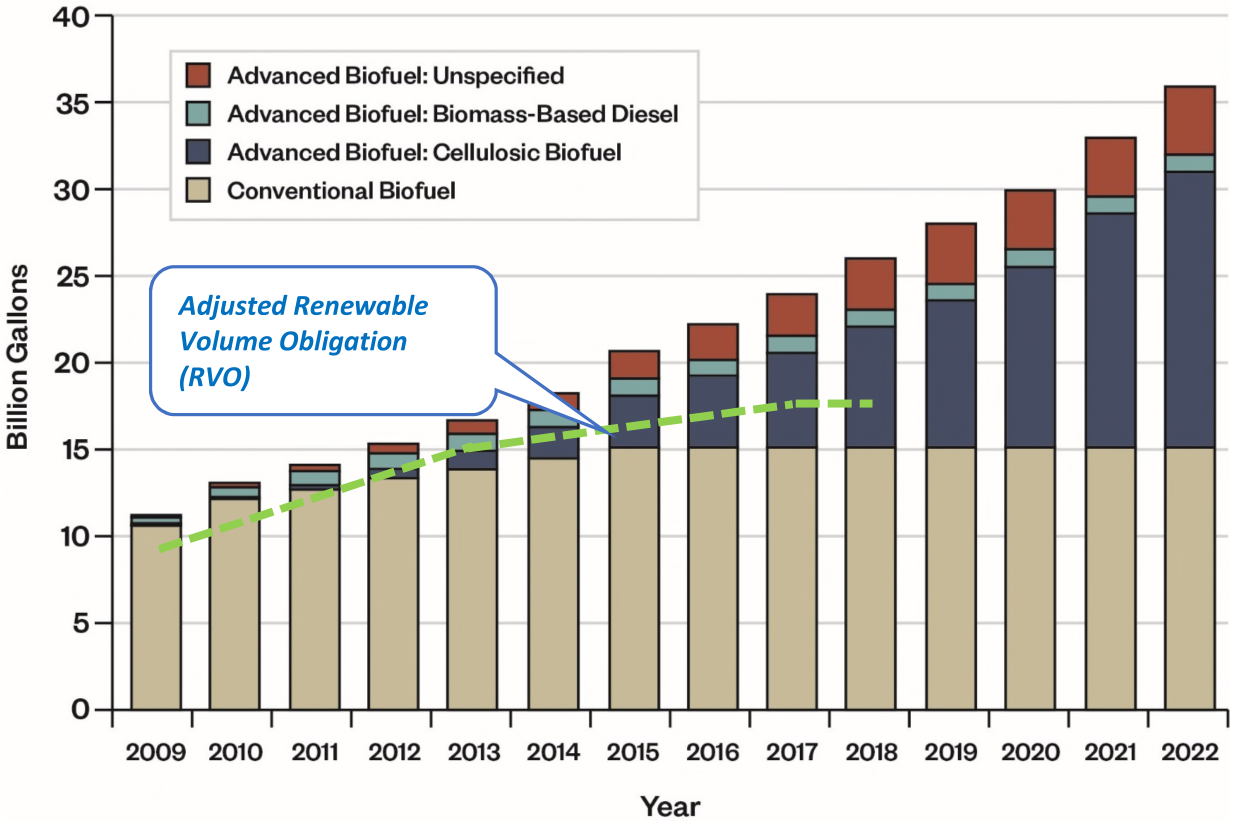


Figure 6.5: RFS2 Renewable Fuel Target

The historical trading prices for D3 and D5 RINs are shown in **Figure 6.6.**

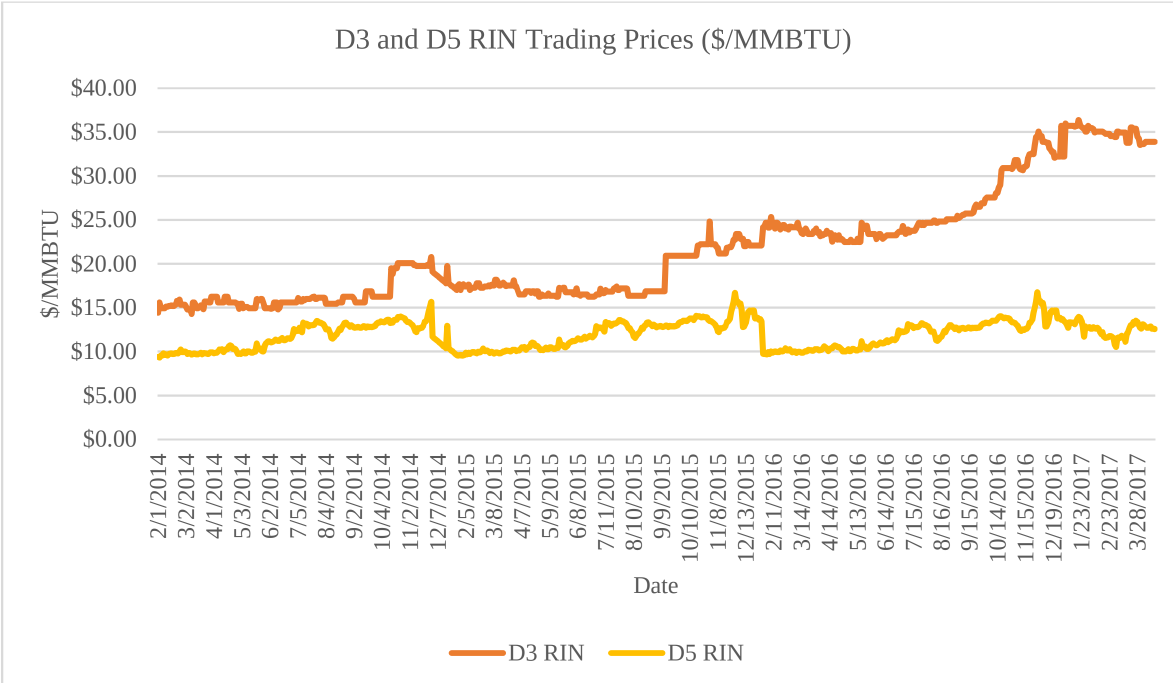


Figure 6.6: Historical D3 and D5 RIN Prices

For the purposes of this study, it is assumed that RNG produced would meet the requirements of a cellulosic biofuel that would qualify for the production of D3 RINS. For this evaluation, the projected base RIN values are assumed to be $20.00/MMBTU.

The demand for cellulosic biofuels are anticipated to continue to grow until the renewable volume for the cellulosic biofuels are met. The EPA calculates and modifies the RVO for each renewable fuel category each year based on the fuel availability and growth demands. To date, the annual compliance RVOs for cellulosic biofuels has been reduced below the standard projections due to the low availability of qualifying fuels. **Figure 6.5** shows the adjusted RVO thru 2018. As shown in **Figure 6.5**, the renewable volume obligations set by the EPA for years 2014 to 2017 have fallen behind the RVOs projected in the standard. If this trend continues, it would delay the final RVO objectives well beyond the 2022 goal.

6.2.2 Renewable Fuels Markets – California Low Carbon Fuels

Using RNG as a transportation fuel also qualifies it as a "Low Carbon Fuel", which can generate carbon credits that can be sold to obligated parties under California's Low Carbon Fuel Standards (LCFS). At the time of this report, LCFS carbon offset credits are trading at approximately $98.00/ton of CO_2 equivalents (CO_2e). The amount of CO_2e offset credits gained from biogas derived RNG depends on its carbon intensity (CI) compared to the CI of standard gasoline and diesel fuels. Based on data published by the California Air Board (CARB), RNG produced from EMWD's biogas will have a CI of approximately 20 grams of CO_2e per Mega joule (gCO_2e/MJ). Based on CARB data and RNG case studies, it is estimated that the value of the LCFS carbon offset credits will be approximately

$10.00/MMBTU of RNG produced that is used for vehicle fueling. It should be noted that this value is a realistic but conservative approximation and that a detailed CI study will be required to determine the actual carbon offset credit value. The long-term LCFS credit prices for the high and low market conditions are assumed to be $10.00/MMBTU and $6.00/MMBTU, respectively.

6.2.3 Pipeline Extension and Interconnection Requirements

The pipeline interconnection includes two primary components:

- The point in the SCG owned pipeline facilities where the RNG can be injected (“point of receipt”)
- The pipeline extension from the EMWD plant site to the point of injection.

The pipeline network injection point must have the capacity to accept the maximum supply of RNG produced by EMWD. The connection point distance from the plant can have a significant impact on the RNG project capital costs. An interconnection study must be performed by SCG to identify the nearest suitable injection point per the requirements of SCG Rule 39. The interconnection study includes the following general steps:

1. High level utility pipeline assessment – Identifies the nearest likely connection point to SCG’s pipeline networks and length of gas interconnection pipeline.
2. Interconnection Capacity Study – Determines SCG’s gas acceptance capacity and cost estimate for extension pipeline. The study would be funded by EMWD.
3. Interconnection Engineering Studies - More detailed study which includes cost estimate for Gas Quality Monitoring and Measurement Facilities. Describes all costs of construction, develop complete engineering construction drawings, and prepare all permit applications.
4. SCG Interconnection Authorization and Construction

It should be noted that the interconnection study has not been initiated at the time of this study. Based on conversations with SCG, it is likely (but not certain) that the injection point will be on their high-pressure distribution pipelines. To gain an approximate cost of the pipeline extension, SCG’s high pressure distribution pipeline locations in relation to the plant locations were evaluated using SCG’s pipeline mapping service. The results are summarized in **Table 6.7** below.

Table 6.7: Pipeline Extension Length

Plant	Assumed Pipeline Extension Length (Ft.)
PVRWRF	1,000
MVRWRF	3,550
TVRWRF	500
SJVRWRF	9,450

Screenshots of the mapping service used to estimate the extension lengths are shown in **Appendix I**.

6.3 RNG Evaluations

6.3.1 Preliminary Sizing Calculations and Gasoline Gallons Per Year (GGE) Production

Table 6.8 summarizes the RNG system ratings and the gasoline gallon equivalent (GGE) for the EMWD plants It should be noted that the RNG system ratings vary with the manufacturers. The most commonly available RNG system at the time of this report are rated ~400SCFM (input). Based on discussions with various manufacturers, there is a trend towards manufacturing small more modular units which may be a better fit for EMWD's facilities.

Table 6.8: RNG Production

Plant	Minimum RNG System Input Rating (CFM)	Gasoline Gallon Equivalent / Year (GGE) (2019)	Gasoline Gallon Equivalent / Year (GGE) (2039)
PVRWRF	250	378,000	540,000
MVRWRF	150	275,000	330,000
TVRWRF	200	315,000	435,000
SJVRWRF	150	252,000	314,000

6.3.2 Assumptions

For this alternative, the digester gas will be upgraded to natural gas pipeline quality and will either be used for on-site vehicle fueling or injected into the pipeline to be used by a contractually obligated partner that will the gas as a transportation fuel. Approximately 85% of the methane input is converted into usable RNG and the systems must operate at a minimum of 25% of their rating.

5% parasitic electrical load reduction accounted for in the amount of gas available as CNG. Operation and maintenance (O&M) costs are expected to be approximately $2.00/MMBTU. These costs are included in the revenue graphs and tables provided.

6.3.3 Energy Balance Evaluations

The RNG conversion process does not produce recoverable heat. For the RNG alternatives, digester heating demands are supplied from the digester heating boilers. Since the benefit from the RNG production exceeds the cost of natural gas, the energy balance and benefit calculations assume natural gas is used for digester heating to free up as much digester gas as possible for RNG production. **Appendix J** shows the overall digester gas utilization balance for each plant under the RNG alternatives.

Alternative A represents the alternative where digester gas is first sent to the digester heating boiler to provide thermal energy for the digester processes and remaining digester gas is upgraded to pipeline quality and injected into the SCG pipeline. During gas upgrading system downtimes, digester gas is flared. Also, digester gas will be flared once the amount of gas produced is above the upgrading system rating.

Alternative B represents the alternative where natural gas is purchased for use in the digester heating boiler to provide thermal energy for the digester processes and all digester gas is upgraded to pipeline quality and injected into the SCG pipeline. During gas upgrading system downtimes, digester gas is flared. Also, digester gas will be flared once the amount of gas produced is above the upgrading system rating.

6.3.4 Revenue Generation Potential

The value of the RNG production is summarized in **Figure 6.7** and compared to the value of electric energy generation. For the purposes of this study it is assumed that 30% of the RIN and LCFS carbon offset value would be consumed as marketing expenses such as the cost of a 3rd party marketer.

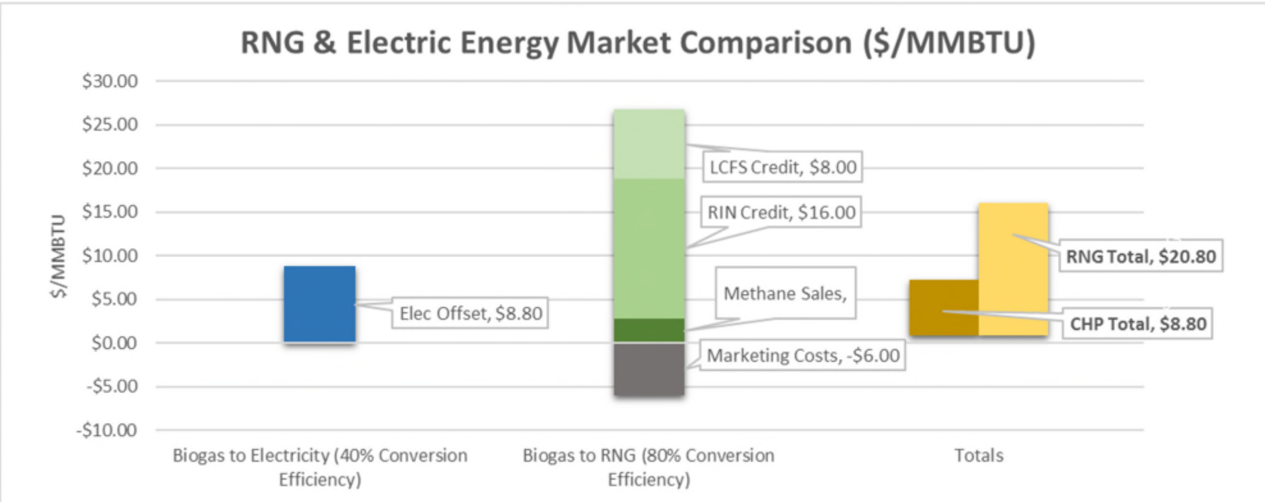


Figure 6.7: RNG and Electric Energy Market Comparison

Appendix L shows the 20-year cumulative revenue from RNG production for each plant over the 20-year planning period. The cumulative cash flow accounts for all operating/maintenance costs and revenue generation. The cumulative revenue curves do not include debt payments for the system capital costs. The horizontal line represents the estimated cost for each alternative. The point where the cash flow curves intersect the capital cost line shows the approximate payback range for the specific economic/market conditions.

Figures 6.8 and **6.9** compares the 20-year net present value (NPV) (including debt service) for all four (4) plants for the RNG alternatives.

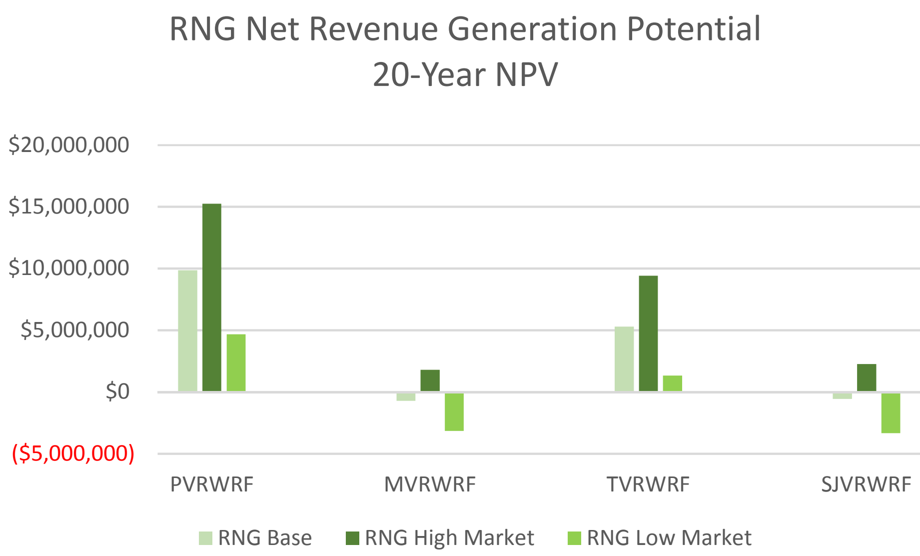


Figure 6.8: RNG(A) 20-Year NPV Revenue Generation Potential

(Digester gas used for digester heating with remaining used for RNG production)

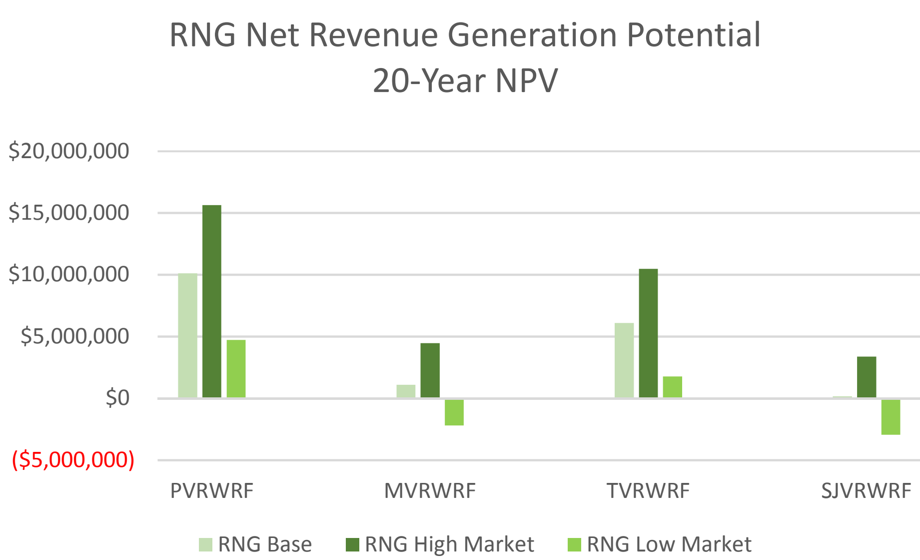


Figure 6.9: RNG(B) 20-Year NPV Revenue Generation Potential

(All DG used for RNG production. NG purchased for digester heating)

6.4 Regulatory Compliance Requirements

The RNG alternative will require compliance with two governing bodies – SCAQMD and SCG. Both have rules governing the process of converting digester gas to renewable natural gas. SCG governs the pipeline interconnection from the facility that is adding natural gas to the pipeline. Requirements for each governing body are explained in detail below.

6.4.1 Applicability to SCAQMD rules overview

The production of RNG is not directly regulated by SCAQMD; however, the emissions resulting from the RNG production tail gas would be regulated under the best achievable control technology (BACT) rules that currently apply to EMWD's flares. The low BTU content of the tail gas typically requires a thermal oxidizer to combust the tail gas which will also be subjected to SCAAMD's BACT rules. The RNG cost estimates include thermal oxidizers for the tail gas.

6.4.2 Southern California Gas (SCG) Rules and Compliance Requirements (Rules 30 and 39)

Sothern California Gas Company has a few governing rules for injecting upgraded digester gas into the natural gas pipeline. The governing rules are Rules 30 and 39, described in detail below.

Rule 30

SCG Rule 30 governs the transportation of customer-owned gas. It specifies the quality of gas delivered into the pipeline. Specifically, it addresses the heating value, temperature, and maximum amounts of the following: liquid content, hazardous substances, H_2O, H_2S, CO_2, O_2, CH_4, Mercaptan Sulfur, Total Sulfur, O, Inerts, and Hydrocarbons. To continuously meet the requirements of this rule, the interconnector injecting gas into the pipeline must test, continuously monitor, and prevent gas that does not meet requirements from entering the pipeline.

Rule 39

SCG Rule 39 governs the access to the SCG pipeline system. It specifies that the interconnector shall pay for the equipment necessary to deliver gas to the pipeline system.

The interconnector may be eligible for monetary incentives from a group of utilities of up to 50% of the cost (up to $3 million) per connection. The incentive is in place for projects built before December 31, 2021 or until the incentive is exhausted. It should be noted that in addition to the Rule 30 and 39 requirements, EMWD will also be responsible for metering the gas at the injection point to SCG's networks and the offtake point from SCG's network to document the physical pathway of the gas to the end use customer.

6.5 Preliminary Equipment Siting Alternatives

Preliminary site options for RNG have been evaluated at each plant, while taking the master plan for each plant into account. It is important for the RNG system to be near the digester gas piping and the electrical facilities. PVRWRF, TVRWRF and SJRWRF have open areas that would likely facilitate the RNG system layout. The TVRWRF site is the most congested of the 4 plants.

Preliminary siting locations for each plant are provided in **Appendix G**.

6.6 Cost Estimates

A list of the RNG system components and existing infrastructure modifications are found below:

- PSA Treatment System
- Thermal Oxidizer
- Gas Monitoring w/ sulfur analyzer
- Gas Piping
- Condensate Drain Piping
- Electrical and Mechanical Distribution Modifications
- Existing Piping Modifications
- Site Work/Modifications
- Pipeline Interconnect
- Odorize System
- Existing Instrumentation and Control Modifications

Cost estimates for each plant are summarized in **Table 6.9**. Detailed cost estimates are provided in **Appendix K**.

Table 6.9: RNG System Cost Estimate Summary

Plant	RNG Cost Estimate
PVRWRF	$8,290,000
MVRWRF	$9,160,000
TVRWRF	$8,020,000
SJVRWRF	$10,240,000

7. Criteria Analysis

The digester gas utilization alternatives were subjected to a criteria evaluation to understand each alternative's unique balance of costs, benefits and risks and to score the overall "suitability" of each alternative as a feasible long term means to beneficially utilize digester gas. The results of the criteria evaluation are used to support the final recommendations and road maps. The criteria categories and sub-criteria were developed in close coordination with EMWD's staff and reviewed/refined during Workshops 2, 3, and 4 to ensure all stakeholders had input to the criteria development and final scoring. The main criteria categories are described below.

1. Technology Maturity and Risks – These criteria focus on the elements that can impact the ability of the technology to perform its intended function. This includes conditions that are inherent to the technology such as maturity and history of success as well as external factors such compliance emission regulations (i.e. SCAQMD) and long-term support availability.

2. Environmental and Community Impacts - These criteria focus on elements that impact the overall carbon footprint (scopes 1 and 2) and elements that could cause a public nuisance (i.e. odors, noise, dust, viewshed, etc..). The carbon footprint is based on the changes in the direct site emissions (scope 1) as well as the indirect emissions resulting from the additional or offset purchased energy source (scope 2).

3. Economic Feasibility - Evaluates the ability of the technology's ability to provide a revenue stream and an acceptable payback period. This includes the long-term balance between costs, revenue generation and payback risks for each alternative. Revenue generation includes energy production, O&M costs, parasitic energy costs.

4. Process and O&M Impacts - Evaluates the impact to operations resources (i.e. labor, materials, etc..) needed to operate the system. Sub-criteria examples include resources needed for equipment operation, impacts to up and down stream processes, and EMWD's familiarity with the technology operations

The main criteria and associated sub criteria were assigned weighting factors that corresponded to the level of importance and criticality that EMWD placed on each criteria evaluation point. Each sub criteria was scored based on the performance of each alternative to generate a final weighted score for the primary criteria categories. The results of the criteria evaluation are shown in **Table 7.1**.

Table 7.1: Alternatives Criteria Analysis Summary

Criteria/Sub-criteria	Weight	Scoring Basis (1 to 5, low to high)	Alternatives - Score		
			Baseline (Flare Gas)	CHP	RNG
Technology Maturity & Risks	**30%**				
Viability of Technology	30%	History of W/WW industry performance and maturity	5	5	3
Sustainability of Technology	30%	Long term support/parts availability	5	4	3
Regulatory Sensitivity	40%	Feasibility impact from evolving regulations	3	2	4
	100%	Criteria Score	4.2	3.5	3.4
		Weighted Score	1.3	1.1	1.0
Environmental/Community Impacts	**30%**				
Net emissions	80%	Includes emissions produced and avoided emissions	2	3	4
Community Acceptance	20%	Noise, Odors, Viewshed	5	4	4
	100%	Criteria Score	2.6	3.2	4
		Weighted Score	0.8	1.0	1.2
Economic Feasibility	**30%**				
Return on Investment (ROI)	50%	Revenue vs. capitol cost	1	3	4
Market Sensitivity/Risk	50%	Potential for unforeseeable risks to 10-year ROI & operation costs	5	4	2
	100%	Criteria Score	3	3.5	3
		Weighted Score	0.9	1.1	0.9
Process and O&M Impacts	**10%**				
Extend of Resources Required	40%	Resources needed to operate the new technology	4	3	2
Operational Impacts	40%	Impacts to up and down stream processes	5	4	4
Technology Familiarity	20%	EMWD’s familiarity with the technology & training requirements	5	4	2
	100%	Criteria Score	4.6	3.6	2.8
		Weighted Score	0.5	0.4	0.3
	100%	**Total Weighted Score**	**3.40**	**3.42**	**3.40**

7.1 Criteria Analysis Summary

A summary of the criteria evaluation scores are found in **Table 7.1**. The total weighted score for each alternative evaluated in this study deviated no more than 1% from the mean score, which indicates that each alternative could be considered similar with respect to their overall feasibility as a viable digester gas utilization alternative. The similar scores are primarily due to each alternative having their distinct advantages/disadvantages in separate categories. A discussion of each primary evaluation criteria is summarized below.

7.1.1 Technology Maturity Risks

Baseline Alternative **-** The baseline alternative (flare gas) scored highest in this category since the technologies (flares and boilers) are well established technologies with a strong support network that pose very little risk of obsolescence. As described in **Section 4**, the digester heating boilers and gas flares do carry a moderate level of regulatory compliance risk from the evolution of SCAQMD Rule 1118.1 (Emission Reduction from Non-Refinery Flares) and Rule 1146.1 which could require future capital investments to meet emission limits. At the time of this report, the boilers and flares are compliant with the SCAQMD Rules.

CHP – The CHP alternative scored slightly behind the baseline alternative primarily due to the high regulatory compliance risks. While biogas fueled, engines are a well-established technology with a robust support network, future emission restrictions from SCAQMD Rule 1110.2 could pose the same compliance challenges EMWD is currently experiencing with the latest Rule 1110.2 revision. If SCAQMD further reduced the allowable emissions from stationary emissions (i.e. NOx, CO, VOC, PM, etc), engines installed today would likely require additional investments in exhaust after treatment and gas pre-treatment equipment to comply. As described in **Section 5**, compliance with SCE Rule 21 interconnection requirements is also a regulatory risk that could impact this alternative.

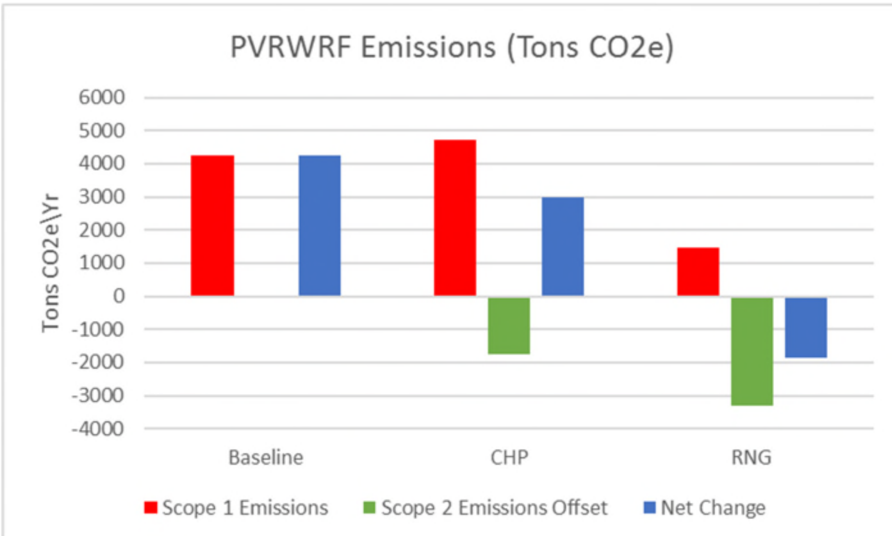
RNG – The RNG alternative scored lowest in this category due to the low wastewater industry track record and proprietary nature of the technology. It should be noted that RNG upgrading technologies are gaining traction with approximately 50-70 digester and landfill gas upgrading systems in operation in the US. It should also be noted that RNG upgrading systems use highly proprietary components (i.e. PSA media, membranes, etc..) and have little aftermarket support outside of the manufacturer. The combination of RNG upgrading systems proprietary nature and relatively small market share could also cause long term manufacturer support concerns.

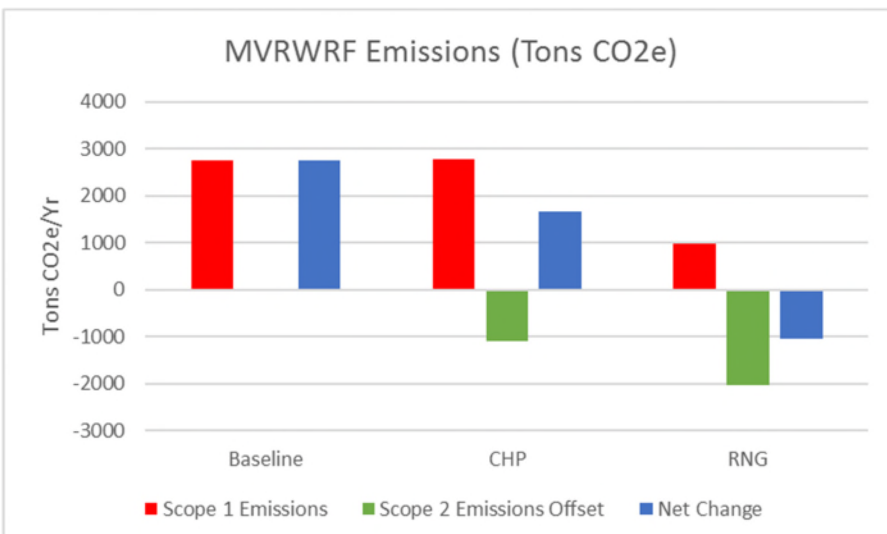
RNG scored the highest in the regulatory sensitivity category. By injection the produced RNG into the pipeline or fueling CNG capable vehicles, the RNG is combusted “off-site” and does not contribute to the site emissions. In addition, SCAQMD does not RNG upgrading systems as stringently as stationary internal combustion engines. The only significant regulatory hurdle could be compliance with SCG’s rules for gas conditioning and injection (Rule 30 and 39) into their natural gas network. This risk can be mitigated by using SCG’s RNG upgrading system construction and operation services to provide and operate the RNG upgrading system. Additional information regarding this alternative is included in **Section 6**.

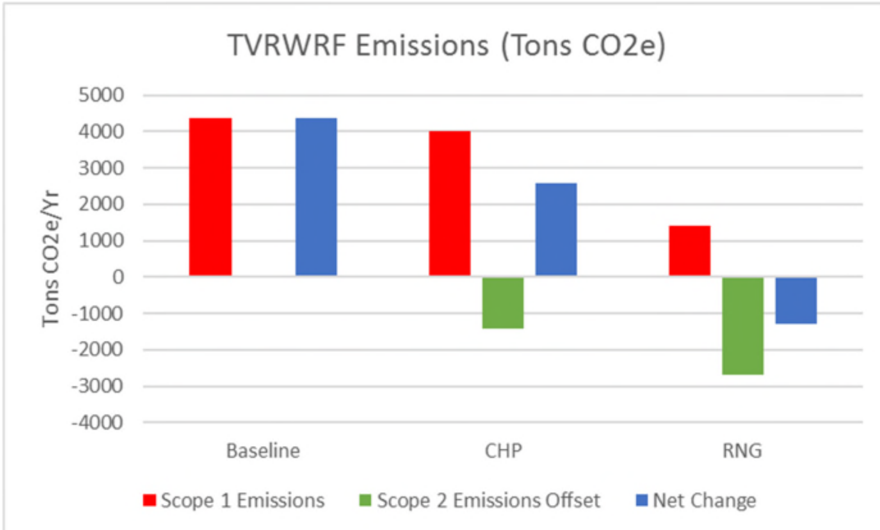
7.1.2 Environmental and Social Impacts

Baseline Alternative – The baseline alternative has the highest overall environmental (carbon) footprint since the majority of the digester gas is unutilized and is flared to the atmosphere and does not offset purchased energy. An emission evaluation was performed for each alternative to compare the direct emissions (Scope 1) and indirect emissions resulting from the purchased energy offset (Scope 2) for each alternative. The emission evaluations include the overall balance between the site emissions produced and the purchased energy profiles for each alternative. The results are summarized in units of carbon dioxide equivalent emission in **Figure 7.1** below. As expected, the baseline alternatives have the highest level of carbon emissions compared to CHP and RNG alternatives. Only emissions associated with the digester gas utilization processes (i.e. engines, RNG, flares, boilers) are accounted for in these emission calculations. Overall site emissions are not included in the graph below.

CHP & RNG – The CHP and RNG alternatives each have a lower overall carbon footprint, which would also be seen favorable by the public. The RNG alternatives had a “negative” carbon meaning that it has a positive environmental benefit by offsetting conventional gasoline and diesel fuels with a very low carbon intensity fuel (RNG). Other community impacts such as view shed and noise are similar for these alternatives.







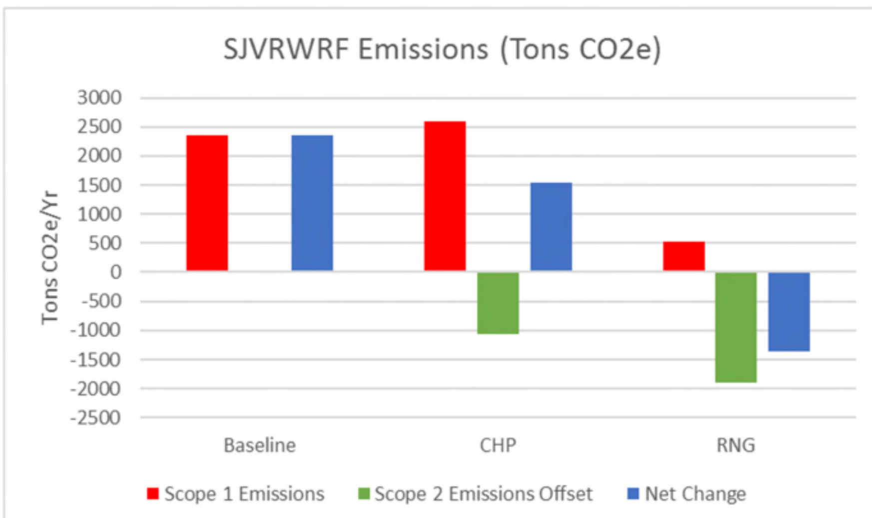


Figure 7.1: Plant Emission Impacts

7.1.3 Economic Feasibility

The economic feasibility criteria was evaluated based on the overall balance between revenue generation potential, capital costs, and market sensitivity/risks. The final score shows the balance between the return on investment (ROI) and market risks that could reduce the long-term ROI. A summary of the 20-year NPV for each alternative is included in **Section 8**. The base line alternatives were driven by their low capital costs and low market risks whereas CHP and RNG were driven by the higher revenue generation potential. The CHP alternative scored highest for this category due to the combination of moderate return on investment and low market sensitivity/risks. As described in **Section 8**, the electric energy markets are much more stable and predictable than the markets for RNG (RIN and LCFS markets). The long-term RIN and LCFS market uncertainty resulted in low market sensitivity/risk score for the RNG alternatives. The flare gas alternatives scored lower for this category due to the lack of revenue generation.

7.1.4 Process and O&M Impacts

The baseline alternative had the lowest process and O&M impacts and was scored highest in this category. RNG and CHP scored lower in this category for the following reasons:

- RNG and CHP requires additional facilities that require additional O&M labor. It is estimated that RNG and CHP would require ~1 full time staff member.
- RNG and CHP will use the majority of the digester gas produced, however, there will be the need to flare a small amount of gas during RNG/CHP system downtime and during periods where the digester gas produced exceeds the utilization capability of the RNG/CHP systems. The existing flares are sized to handle the full gas production rates. Per our discussions with the flare manufacturers (John Zink Hamworthy), the minimum firing rate for EMWD's flares is approximately 50% of the rated firing rate. In some cases, the minimum flare firing rate exceeds the projected digester gas that will be sent to the flare once the preferred utilization technology is implemented. This could cause some operational challenges if the available digester gas flow to the flare is below the minimum flare firing rate.. On-site digester gas storage, as found at MVRWRF, SJVWRF, and TVRWRF, could alleviate some of the challenges, allowing some of the digester gas to build up in storage before flaring. PVRWRF has limited gas storage which could result in the flare cycling on/off frequently.

Graphs showing the minimum flare operating point and amount of gas flared for each plant can be found in **Appendix F**.

7.2 Criteria Analysis Conclusions

The total weighted scores are summarized in **Figure 7.2**. The total weighted score for each alternative evaluated in this study were similar and deviated no more than 1% from the mean score. The criteria analysis demonstrate that each digester gas utilization alternative has a unique balance of costs, benefits and risks and concludes there is <u>no compelling evidence that supports a single digester gas utilization strategy for all facilities under the current energy markets and regulatory conditions</u>.

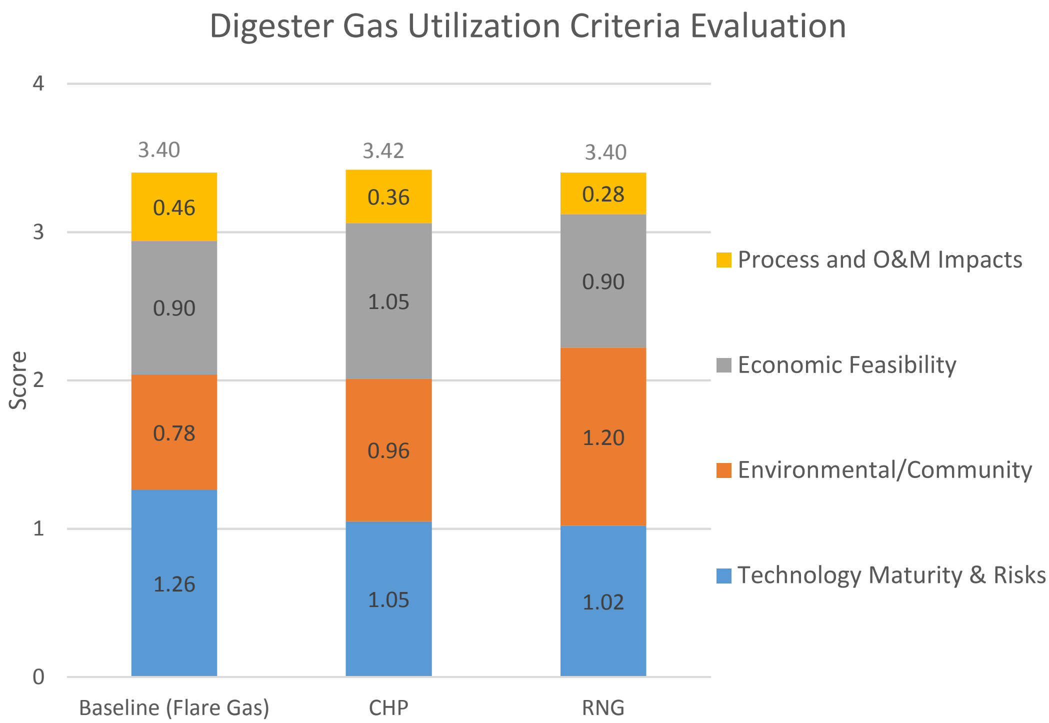


Figure 7.2: Criteria Evaluation Results Summary

8. Recommendations and Roadmaps

As stated in **Section 7**, the total weighted score for each alternative evaluated in this study deviated no more than 1% from the mean score, which indicates that each alternative could be considered similar with respect to their overall feasibility as a viable digester gas utilization alternative. The criteria evaluation is mostly based on the merits of each utilization alternative but does not account for the unique conditions and characteristics for each facility included in the study. To further refine the evaluation, each facility was evaluated to develop recommendations and long-term road maps tailored to each facility's unique conditions and operations.

The optimal gas utilization strategy depends on many variable factors such as renewable fuels commodity market conditions, availability of project funding, existing equipment life cycle, and regulatory requirements/future developments. Given the uncertainty of these variable factors, a "Road Map" was developed for each plant that outlined the most feasible utilization solutions based on market conditions, funding availability and plant conditions. The intent of the road maps is to define the conditions that would support a specific utilization strategy so that EMWD can make more informed decisions with regards to market conditions, funding availability and regulatory conditions. The road maps are included at the end of this section.

In general, the RNG alternatives have a higher revenue generation potential over the other evaluated alternatives, however, the benefit is highly dependent on the market demands for renewable fuels (i.e. RIN and LCFS markets). At the time of this report, the market demand for RNG is strong primarily due to the escalations of renewable fuels requirements under the Renewable Fuel Standards and CA Low Carbon Fuels Standards. These markets are expected remain viable over the next 10 years, however external forces such as renewable energy policy changes, low market growth, or technology developments could significantly impact the benefit from RNG production. The revenue from electric energy generation (CHP) is mostly dependent on the electric energy market which is much more stable and predictable over the market for RNG thus making the revenue generation much more predictable and lower risk.

While the RNG alternatives carry a high economic risk, there are regulatory and funding benefits that should be considered. Injecting RNG into the pipeline is an offsite utilization strategy that does not carry the regulatory burden (i.e. SCAQMD Rule 1110.2) associated with onsite electricity generation. Funding opportunities for RNG projects are also widely available, which could mitigate the economic risks for RNG.

8.1 Recommendations

A sensitivity analysis was performed on the criteria analysis described in Section 7 by observing how the weighted scores change for each alternative when each criteria point was altered. The results confirmed the emissions, regulatory sensitivity, and market risks had the highest impact on the CHP and RNG alternatives. Since the regulatory sensitivity and market risks had the highest levels of uncertainty at the time of this study, it is recommended EMWD take incremental steps in evaluating opportunities to mitigate the regulatory and market risks before making a final utilization alternative decision. Risk mitigating opportunities include:

- Bypass market risks by exploring the possibility of long term RNG purchasing contracts with RNG customers or other 3rd party entities. EMWD may work with a 3rd party RIN/LCFS marketer to better understand the long term market demands for digester gas derived renewable fuels and the potential terms of an extended period RNG purchasing agreement.
- Explore installing pipelines for direct sales of digester gas or RNG to nearby industries.
- Explore alternative project delivery strategies such as third party RNG System ownership and operation agreements to mitigate market and performance risks.
- Explore green energy funding opportunities to reduce the financial risks of the CHP and RNG alternatives.
- Monitor proposed SCAQMD 1110.2 rule changes and reciprocating engine emission management technologies advancements.
- Perform preliminary pipeline interconnection studies with SCG to better understand the pipeline extension costs for the RNG alternatives.
- Collaborate with SCE to determine if additional facility costs for Rule 21 compliance would needed to facilitate additional parallel onsite power generation for the CHP alternative.
- Contract with SCG to perform preliminary pipeline interconnection studies to better understand the likely RNG injection point and costs for the interconnection piping for all 4 facilities. Based on conversations with SCG, the estimated cost of the preliminary studies is ~$5,000.
- Monitor renewable fuels market condition indicators that would provide insight on the long term outlooks of the RIN and LCFS markets. Market indicators include:
    - The renewable volume obligations (RVO) set annually by the EPA for D3 and D5 renewable fuels to understand the fraction of the congressional renewable fuel targets are being realized. RVOs consistently below the congressional targets could indicate a stronger market demand for D3 and D5 renewable fuels. See Section 6 for additional information
    - RIN and CA LCFS credit commodities pricing volatility.

- Increase in long term renewable fuels and RIN/LCFS credits purchasing agreements between obligated parties and renewable fuel producers
- Regulatory changes that extend or expand renewable fuels requirements.

8.2 PVRWRF

The CHP and RNG alternatives are both feasible for PVRWRF. **Figure 8.2** compares the 20-year net present value (NPV) (includes debt service) for the PVRWRF digester gas utilization alternatives. The RNG alternative shows a higher revenue generation potential compared to the other plants for the following reasons:

- PVRWRF is site is adjacent to a SCG main distribution pipeline which would likely minimize the pipeline extension from the RNG system to the injection point. It should be noted that a formal interconnection study with SCG should be completed to confirm the injection point.
- PVRWRF produces more gas than the other plants, which improves the economy of scale of the RNG upgrading system.

EMWD has a unique opportunity to sell raw or treated digester gas produced at PVRWRF to a nearby private party who is already producing RNG and has an RNG/CNG fueled vehicle fleet. In addition to the CHP and RNG alternatives, EMWD sould explore a long-term gas sales agreement with the nearby private party. At the time of this report the terms of a long-term contract are not known, however discussions with the private party have been initiated.

Per discussions with EMWD, the fuel cells at PVRWRF must remain in service until the end of the operations and maintenance agreement per the requirements of the funding for the fuel cells. It is assumed the fuel cells will remain the primary digester gas utilization alternative until the end of the fuel cell operations and maintenance contract (2023). EMWD has stated that the fuel cells will be removed at the end of the operations and maintenance contract.

As a cost saving measure, the existing fuel cell gas treatment system can be repurposed for digester gas pre-treatment for the CHP alternative. It may be possible to reuse the existing pre-treatment system to pretreat raw gas before the RNG upgrading system, however, some RNG upgrading system manufacturers have indicated that this is not a necessary step and will have little impact on the system cost. The use of the existing pre-treatment system should be reevaluated if the RNG alternative is pursued.

The key recommendations outlined in the PVRWRF road map are listed below:

- Continue to explore the possibility of a gas purchase agreement with a nearby private party. EMWD can use the Digester Gas Value Tool (Appendix M) included with this report to compare the gas purchase price proposed by the 3rd party to the value of the gas under the RNG and CHP alternatives. Implement 3rd party gas sales if an agreement can be reached that benefits both parties.

- Continue to monitor the evolution of SCAQMD's Rule 1110.2. If information from SCAQMD reveals that future emission requirements can be met cost effectively and there is still uncertainty in the RNG markets, then the CHP would likely be the feasible alternative.
- Pilot test new digester gas utilization technologies (i.e. biogas fueled turbine driven blowers) to determine the feasibility as a long-term gas utilization technology.
- Continue to monitor the market demand for RNG. Engauge 3rd party RNG marketers to explore long term services and contracts that would provide a higher level of certainty on the long-term revenue generation potential from RNG production. If a long-term agreement can be reached or there is a sufficient level of certainty on the long-term market demand for RNG, implement the RNG alternative.
- Flare digester gas if RNG market demand is uncertain and there is high certainty that pending SCAQMD rule changes would significantly limit CHP long term feasibility.

8.3 MVRWRF

MVRWRF has the advantage of already operating a SCAQMD Rule 1110.2 compliant digester gas fueled engine driven blower (Tecogen blower). As stated in **Section 3**, the Tecogen blower operates efficiently when operating with other blowers and does not supply excessive air to the process. **Figure 8.2** compares the 20-year net present value (NPV) (includes debt service) for the MVRWRF digester gas utilization alternatives.

As shown in **Figure 8.2**, maintaining the existing Tecogen blower operations after the fuel cell contract is terminated is the most cost-effective gas utilization alternative due to the low/zero capital costs and relatively efficient operations. The MVRWRF long term roadmap is shown on **Figure 8.6**.

The key recommendations outlined in the MVRWRF road map are listed below:

- Maintain existing Tecogen Blower operations until it nears the end of its useful life or if significant investments are needed to maintain its operation. Explore alternate utilization strategies when operating the existing Tecogen Blower is no longer feasible.
- Continue to monitor the evolution of SCAQMD's Rule 1110.2. If information from SCAQMD reveals that future emission requirements can be met cost effectively and there is still uncertainty in the RNG markets, then the CHP would likely be the feasible alternative.
- Continue to monitor the market demand for RNG. Engage 3rd party RNG marketers to explore long term services and contracts that would provide a higher level of certainty on the long-term revenue generation potential from RNG production. If a long-term agreement can be reached or there is a sufficient level of certainty on the long-term market demand for RNG, implement the RNG alternative.
- Flare digester gas if RNG market demand is uncertain and there is high certainty that pending SCAQMD rule changes would significantly limit CHP long term feasibility

8.4 TVRWRF

RNG production and electric energy production are both feasible alternatives for TVRWRF. **Figure 8.3** compares the 20-year net present value (NPV) (includes debt service) for the TVRWRF digester gas utilization alternatives. The CHP 20-year NPV is lower compared to PVRWRF and MVRWRF since TVRWRF does not the economic advantages of having an existing robust gas pretreatment system (i.e. fuel cell treatment) or a SCAQMD Rule 1110.2 compliant engine. TVRWRF is located close to a SCG distribution line which would be a likely connection point for RNG injection thus supporting the RNG alternative for the facility. The TVRWRF site is the most congested of the plants and will require a more detailed site evaluation to determine suitable locations for site modifications. The key recommendations outlined in the TVRWRF road map are listed below:

- Continue to monitor the evolution of SCAQMD's Rule 1110.2. If information from SCAQMD reveals that future emission requirements can be met cost effectively and there is still uncertainty in the RNG markets, then the CHP would likely be the feasible alternative.
- Continue to monitor the market demand for RNG. Engage 3rd party RNG marketers to explore long term services and contracts that would provide a higher level of certainty on the long-term revenue generation potential from RNG production. If a long-term agreement can be reached or there is a sufficient level of certainty on the long-term market demand for RNG, implement the RNG alternative.
- Flare digester gas if RNG market demand is uncertain and there is high certainty that pending SCAQMD rule changes would significantly limit CHP long term feasibility

8.5 SJVRWRF

RNG production and electric energy production are both feasible alternatives for SJVRWRF**. Figure 8.4** compares the 20-year net present value (NPV) (includes debt service) for the SJVRWRF digester gas utilization alternatives. Similar to TVRWRF, the CHP 20-year NPV is lower compared to PVRWRF and MVRWRF since SJVRWRF does not the economic advantages of having an existing robust gas pretreatment system (i.e. fuel cell treatment) or a SCAQMD Rule 1110.2 compliant engine. SJVRWRF is also not located close to a SCG distribution line which would be a likely connection point for RNG injection which lowers the RNG feasibility for the facility.

CHP will be the likely recommendation if funding for the interconnection pipeline is not available. The key recommendations outlined in the SJVRWRF road map are listed below:

- Continue to monitor the evolution of SCAQMD's Rule 1110.2. If information from SCAQMD reveals that future emission requirements can be met cost effectively and there is still uncertainty in the RNG markets or interconnection pipeline funding is not available, then the CHP would likely be the feasible alternative.
- Continue to monitor the market demand for RNG. Engage 3rd party RNG marketers to explore long term services and contracts that would provide a higher level of certainty on the long-term revenue generation potential from RNG production. If a long-term agreement can be reached or

there is a sufficient level of certainty on the long-term market demand for RNG, implement the RNG alternative.

- Flare digester gas if RNG market demand is uncertain or pipeline funding is not available and there is high certainty that pending SCAQMD rule changes would significantly limit CHP long term feasibility.

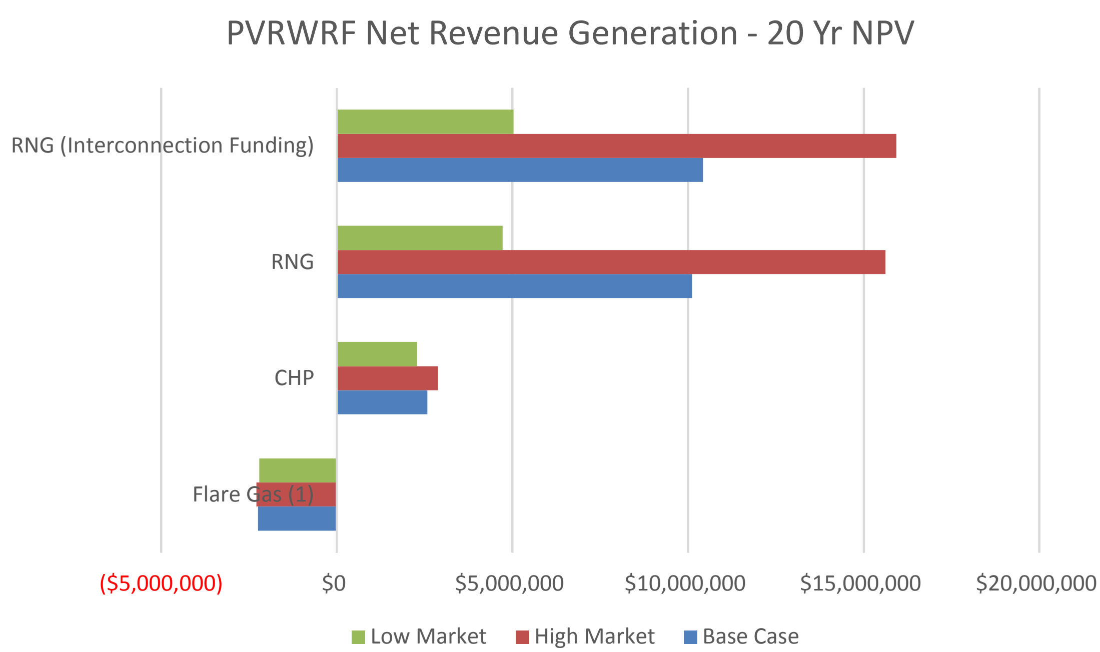


Figure 8.1: PVRWRF Net Revenue Generation (NPV)

(1) – Flare gas scenario includes fuel cell operations until year 2023

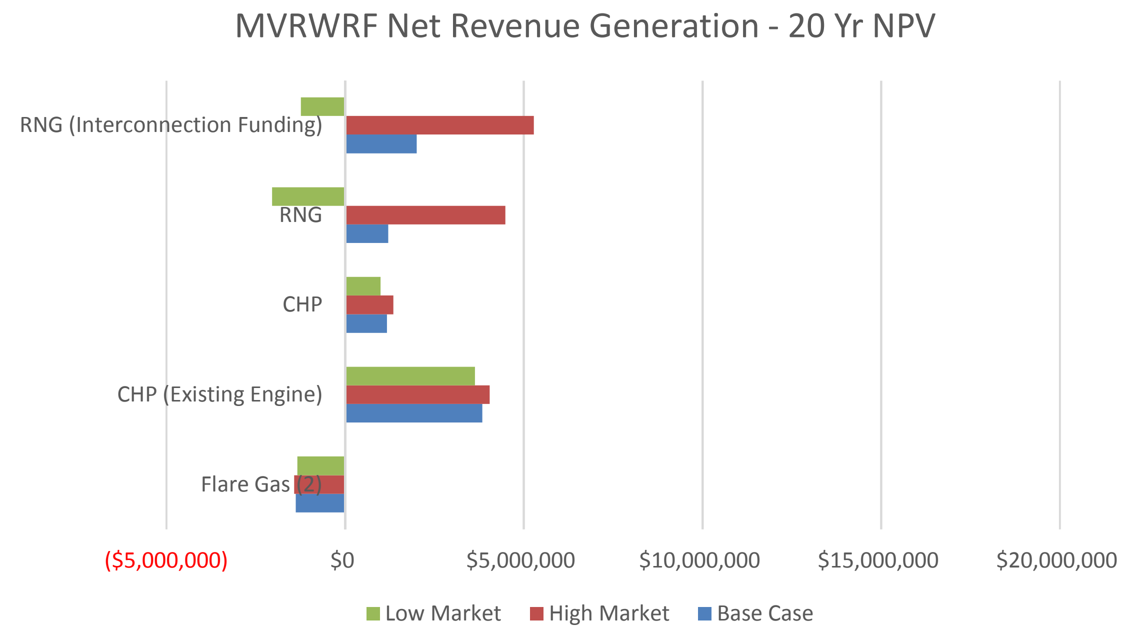


Figure 8.2: MVRWRF Net Revenue Generation (NPV)

(2) – Flare gas scenario includes fuel cell operations until year 2022

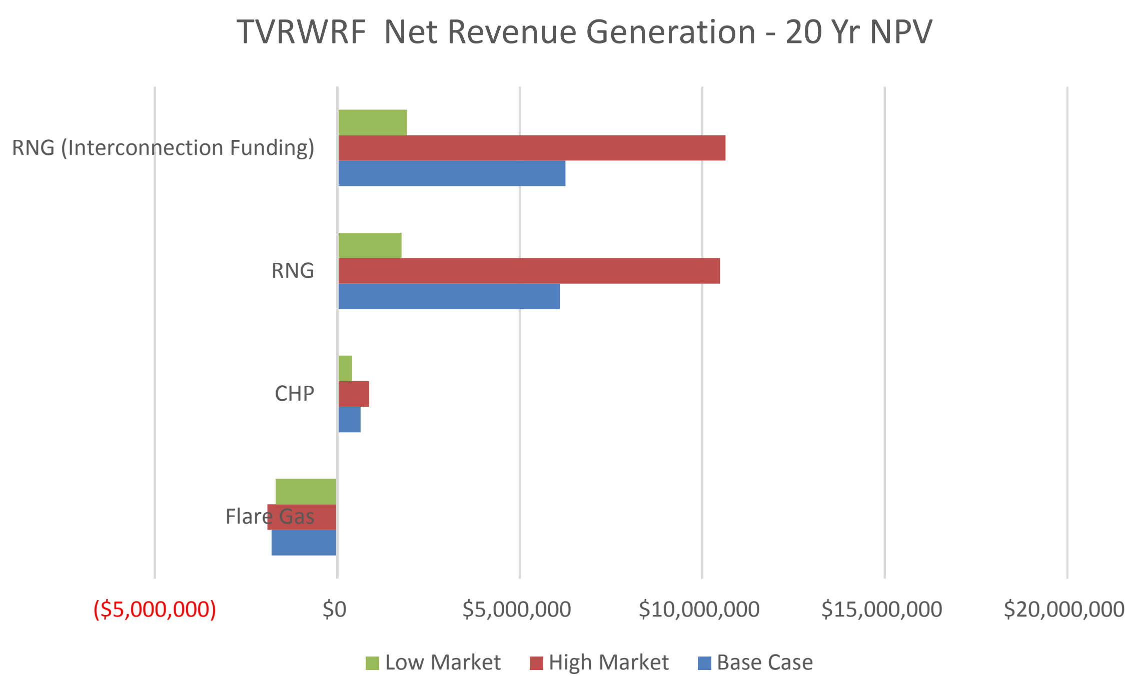


Figure 8.3: TVRWRF Net Revenue Generation (NPV)

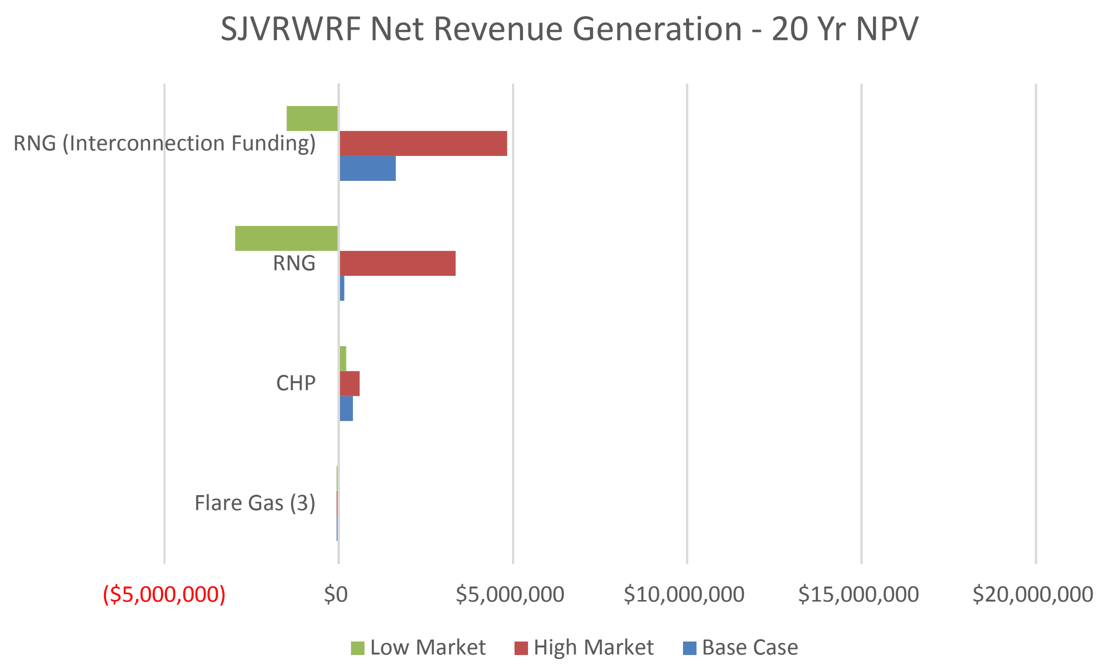


Figure 8.4: SJVRWRF Net Revenue Generation (NPV)

(3) – Flare gas scenario includes benefit from digester gas boiler operations

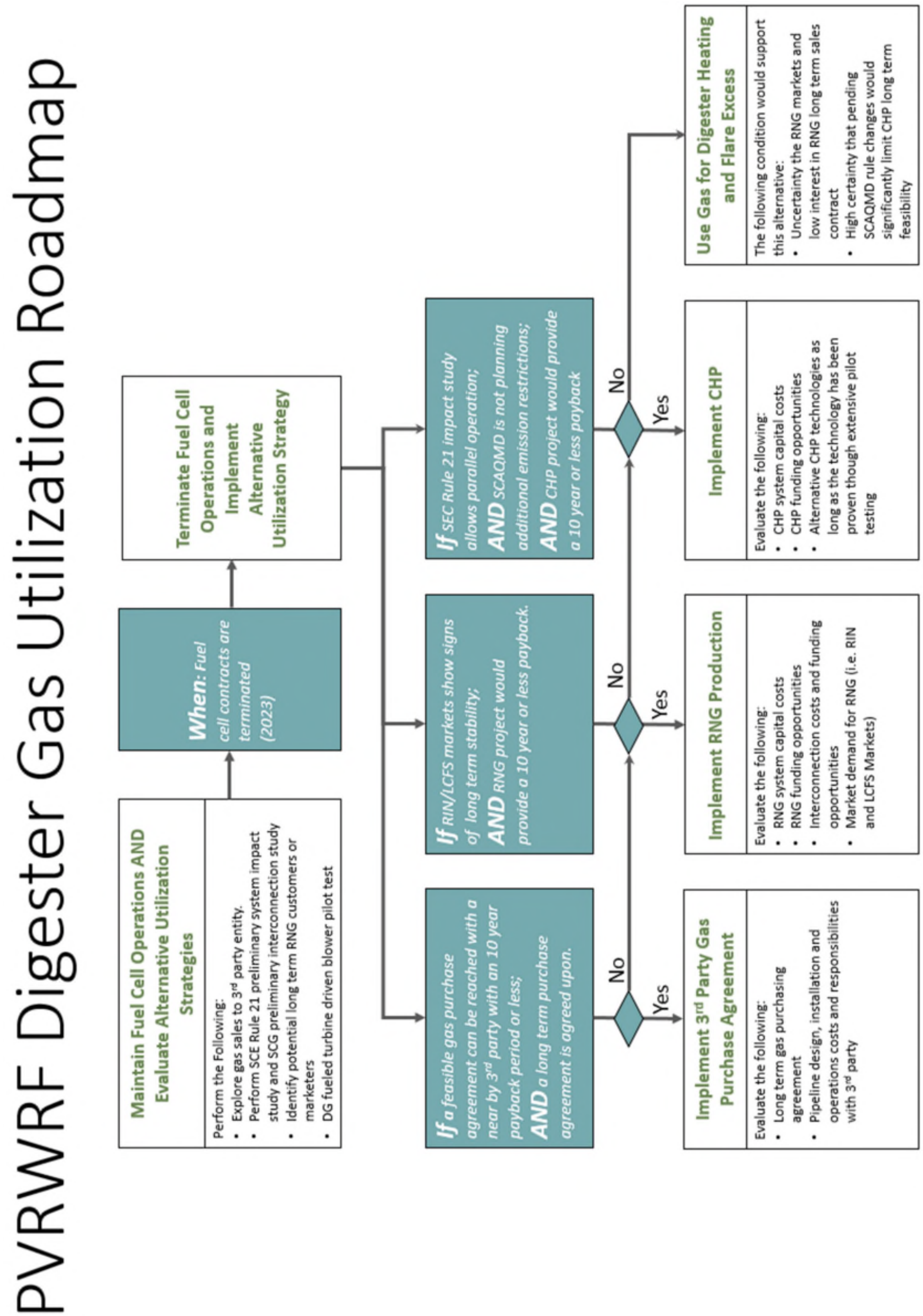


Figure 8.5: PVRWRF Digester Gas Utilization Roadmap

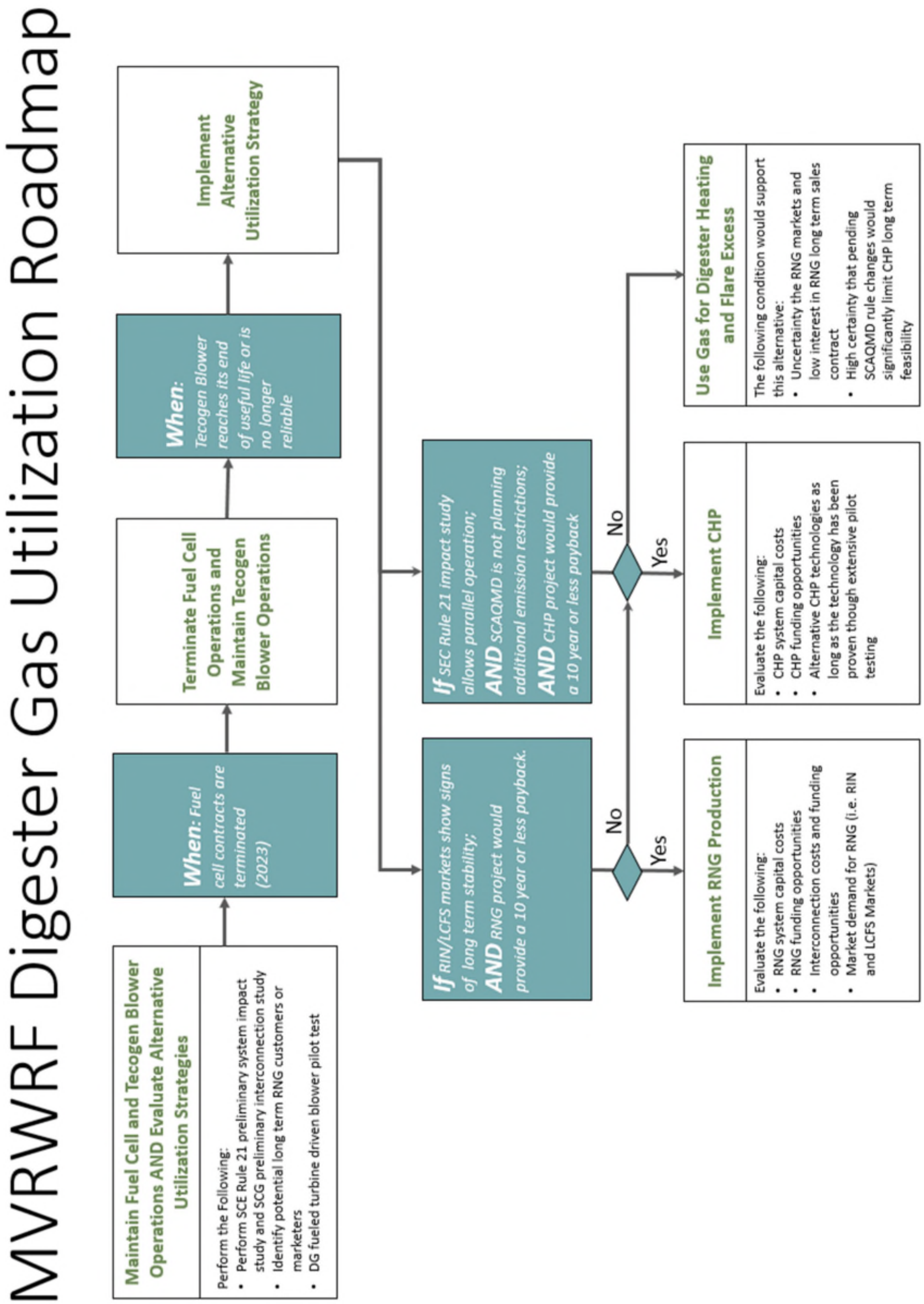


Figure 8.6: MVRWRF Digester Gas Utilization Roadmap

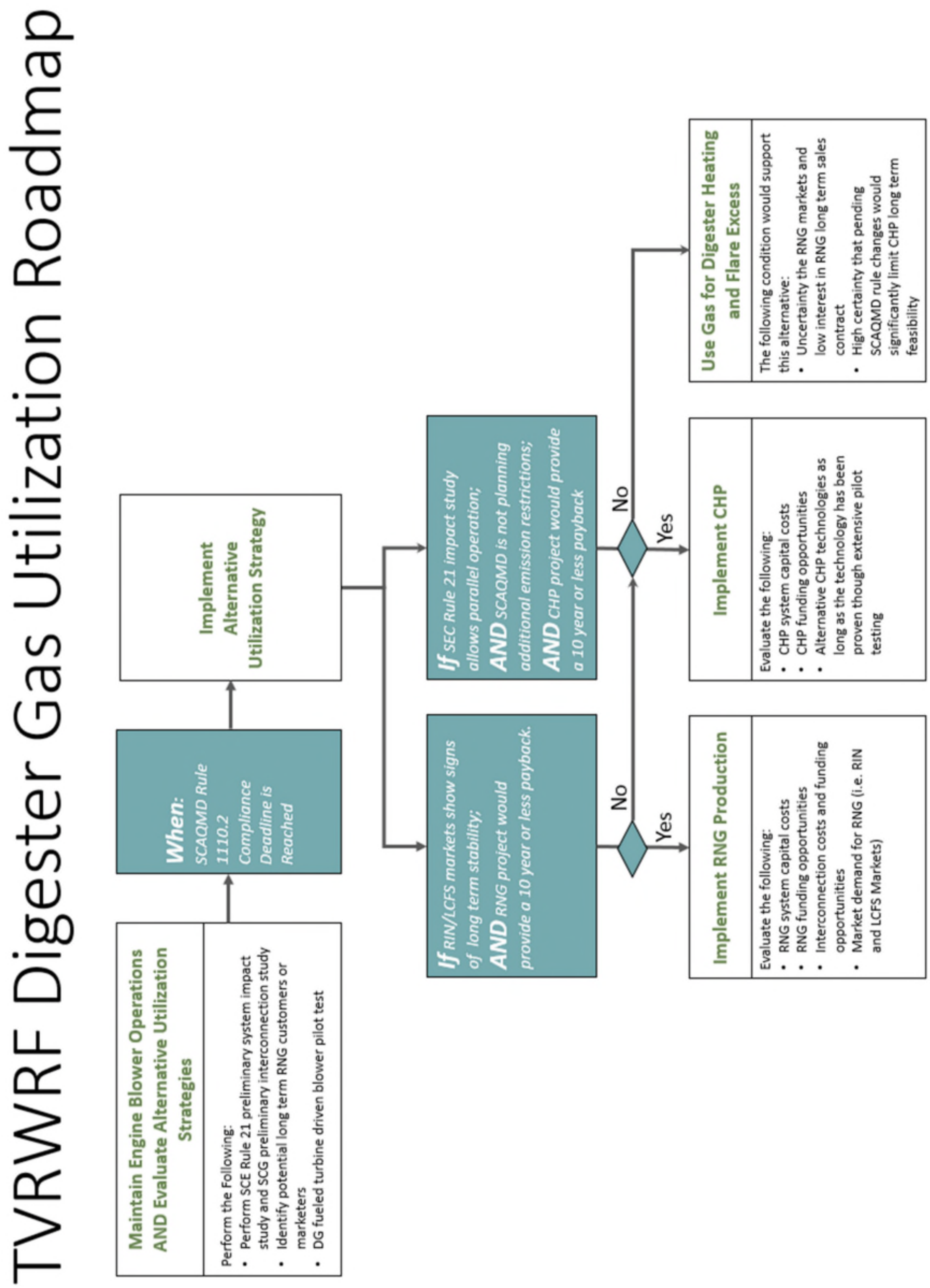


Figure 8.7: TVRWRF Digester Gas Utilization Roadmap

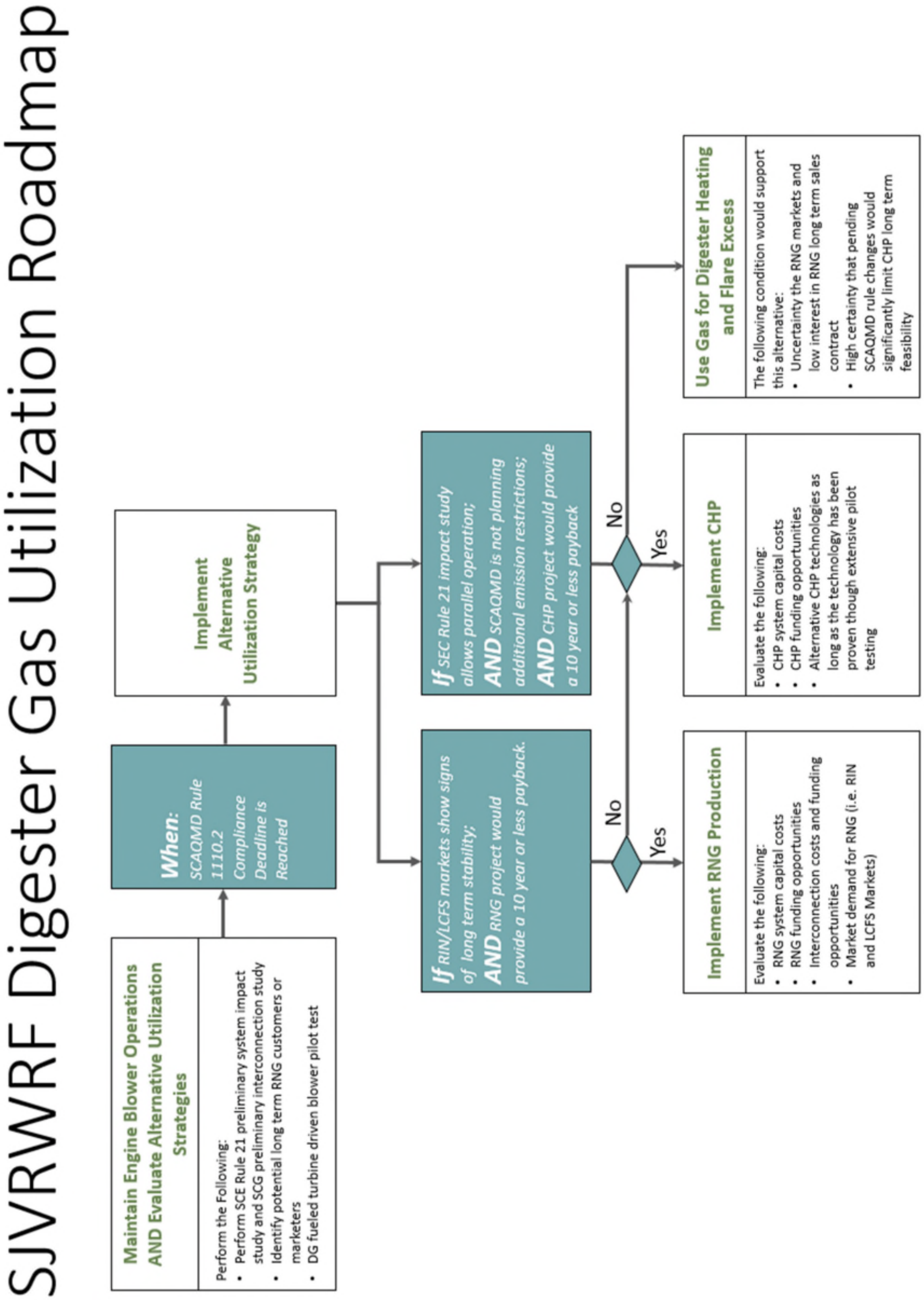


Figure 8.8: SJVRWRF Digester Gas Utilization Roadmap

Appendix A: EBAT Model Inputs Assumptions

Table A.1: EBAT Model Inputs

Assumption/EBAT Input	Unit	Value
Purchased Energy Costs (Annual Average)	$/KWH	$0.110
Purchased Energy Costs (Annual Average)	$/MMBTU	$32.24
Elec Energy Offset Benefit (Annual Average)	$/KWH	$0.075
Elec Energy Offset Benefit (Annual Average)	$/MMBTU	$21.98
Electricity Cost Escalation (Nominal)		2.5%
Natural Gas Costs	$/MMBTU	$6.50
Natural Gas Cost Escalation (Nominal)		3.0%
Boiler Efficiency		80%
Boiler & Gas Treatment O&M	$/MMBTU	$0.25
CHP Electrical Generation Efficiency		35%
CHP Thermal Efficiency		40%
CHP & Gas Treatment O&M	$/KWH	$0.020
CHP Unit Availability		90%
CO2e Emission Offset (Electricity Generation)	lb CO2/kWh	0.5705
CNG Conversion Efficiency		85%
CNG O&M	$/MMBTU	$2.00
Parasitic Electrical Load (CNG Only)		5.0%
CO2 Emission Offset (Biogas CNG)	gCO2e/MJ	55.7
General Inflation		2.0%
Cost of Capital (Interest Rate)		2.5%
Annual Heating Demand Escalation		1.1%

Appendix B: CHP Electrical Energy Output

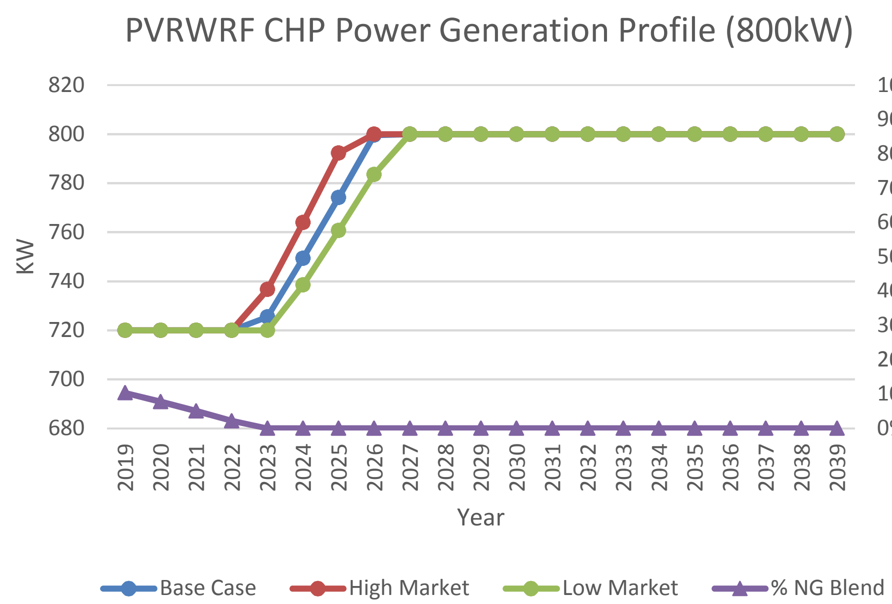


Figure B.1: PVRWRF CHP Power Generation

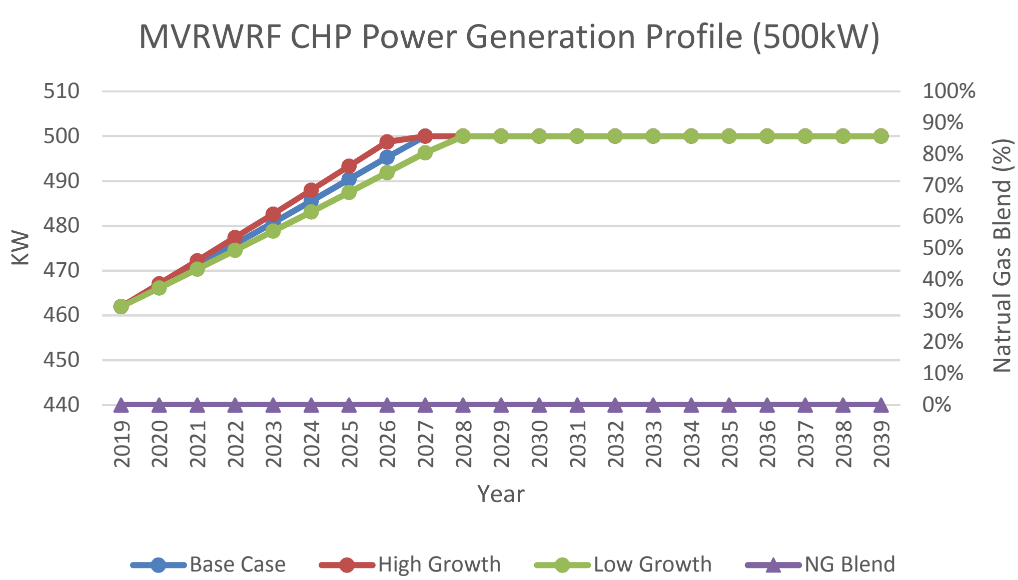


Figure B.2: MVRWRF CHP Power Generation

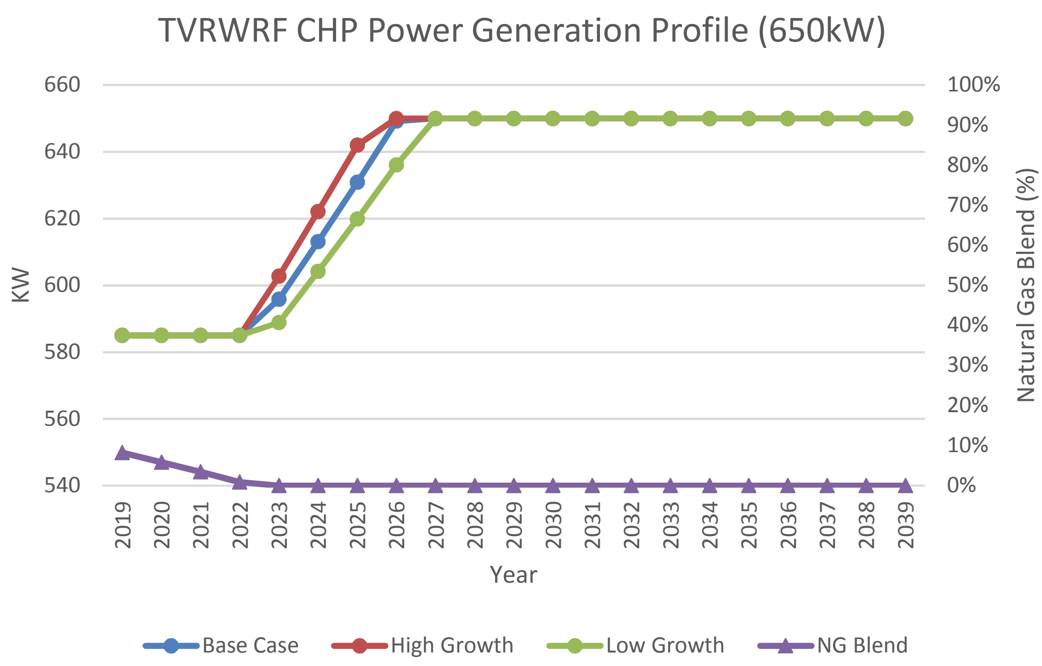


Figure B.3: TVRWRF CHP Power Generation

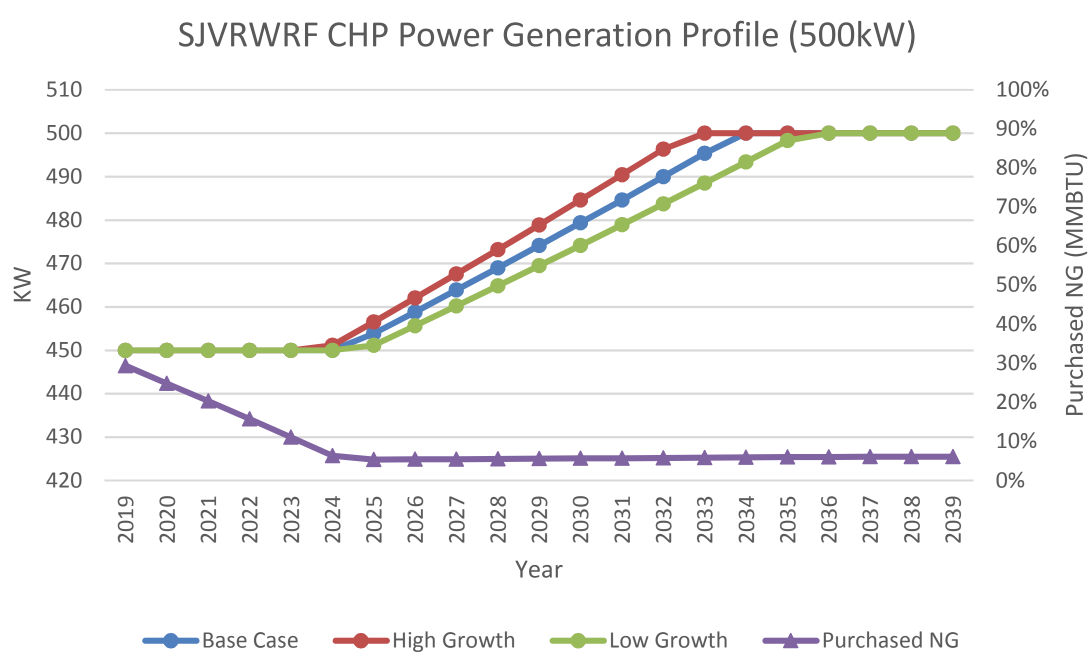


Figure B.4: SJVRWRF CHP Power Generation

Appendix C: Annual Heating Demands and CHP Heating Production

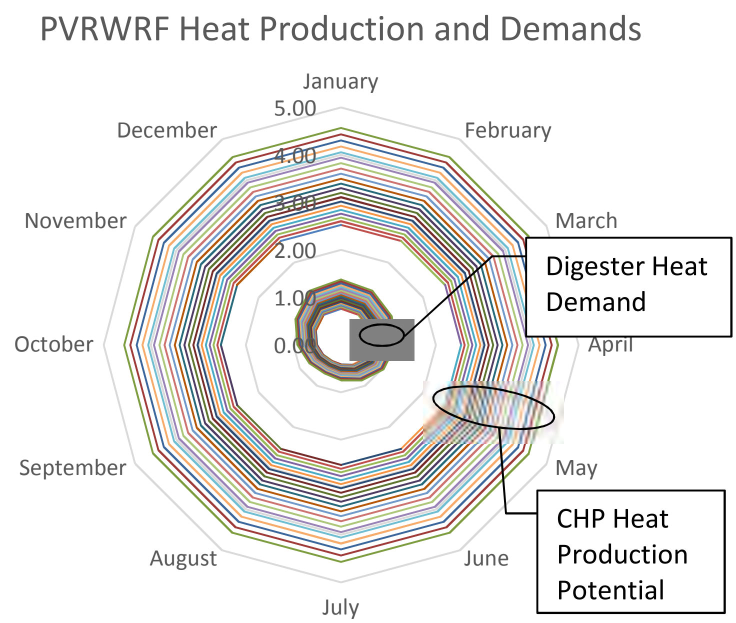


Figure C.1: PVRWRF Heating Demands and Production

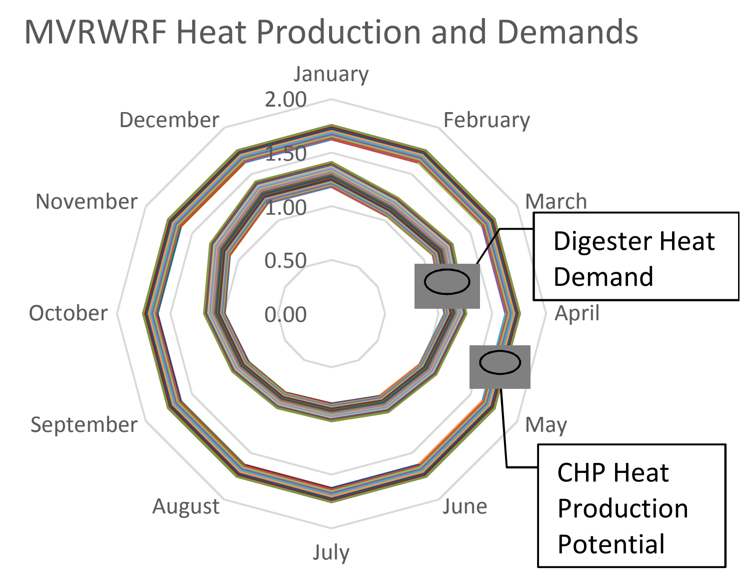


Figure C.2: MVRWRF Heating Demands and Production

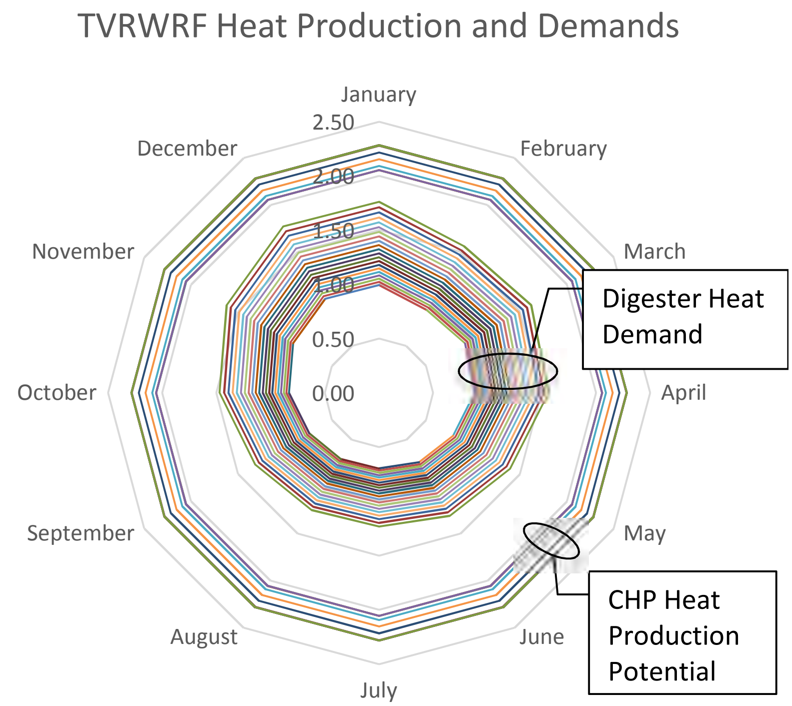


Figure C.3: TVRWRF Heating Demands and Production

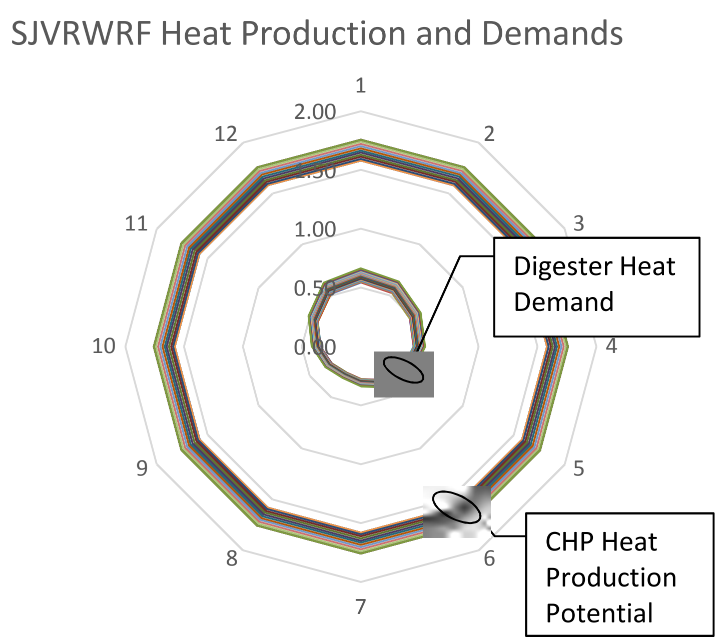


Figure C.4: SJVRWRF Heating Demands and Production

Appendix D: CHP Digester Gas Utilization

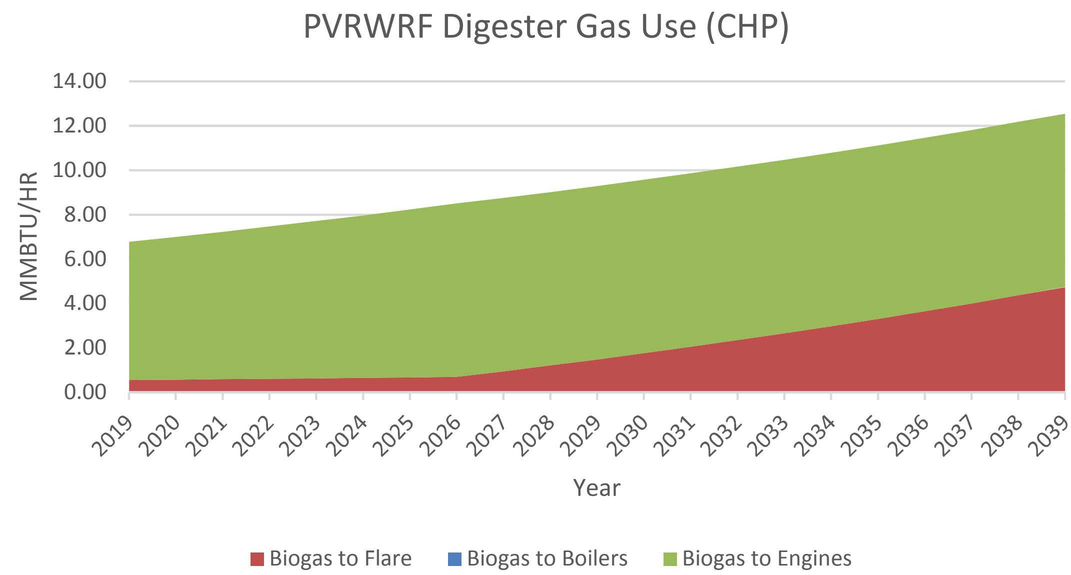


Figure D.1: PVRWRF CHP Digester Gas Utilization

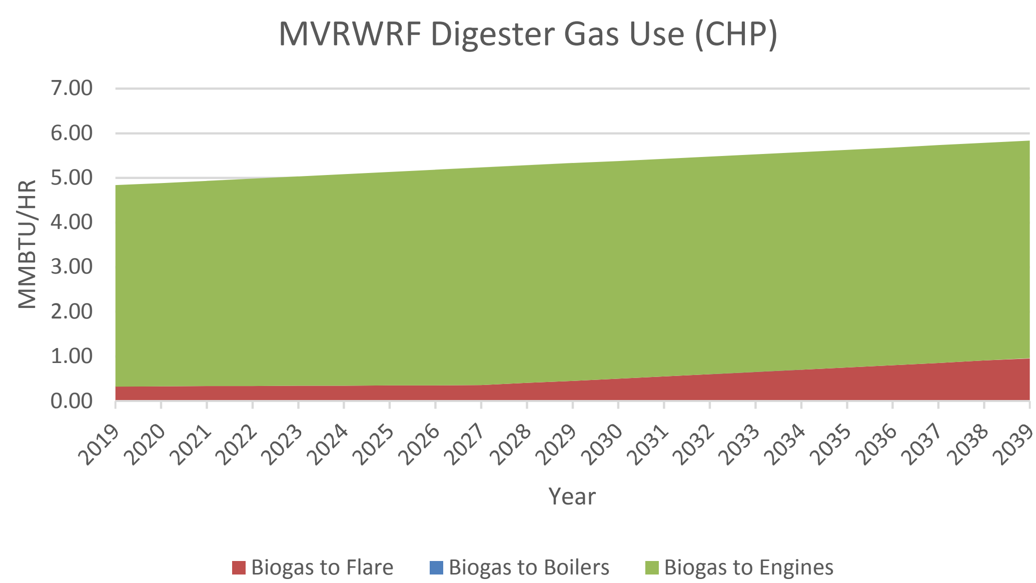


Figure D.2: MVRWRF CHP Digester Gas Utilization

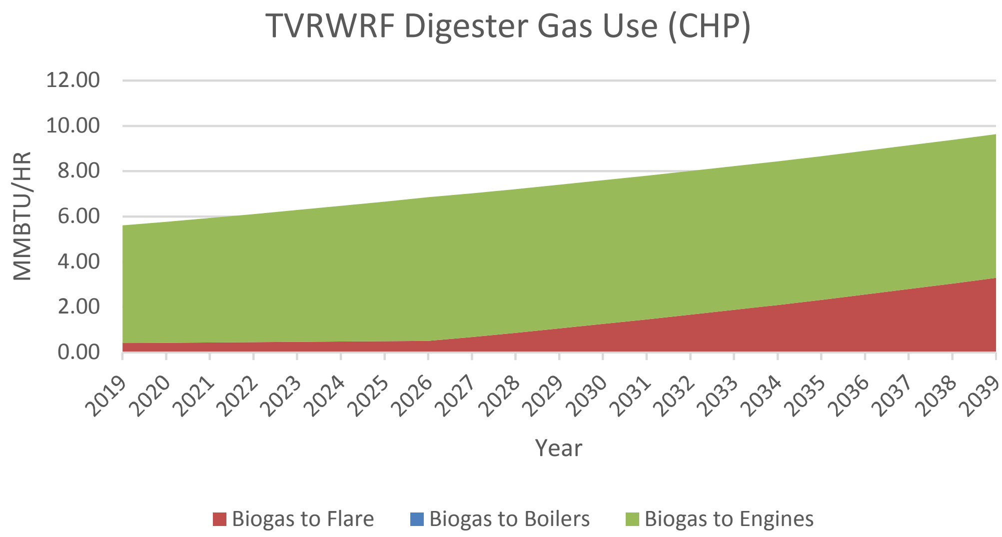


Figure D.3: TVRWRF CHP Digester Gas Utilization

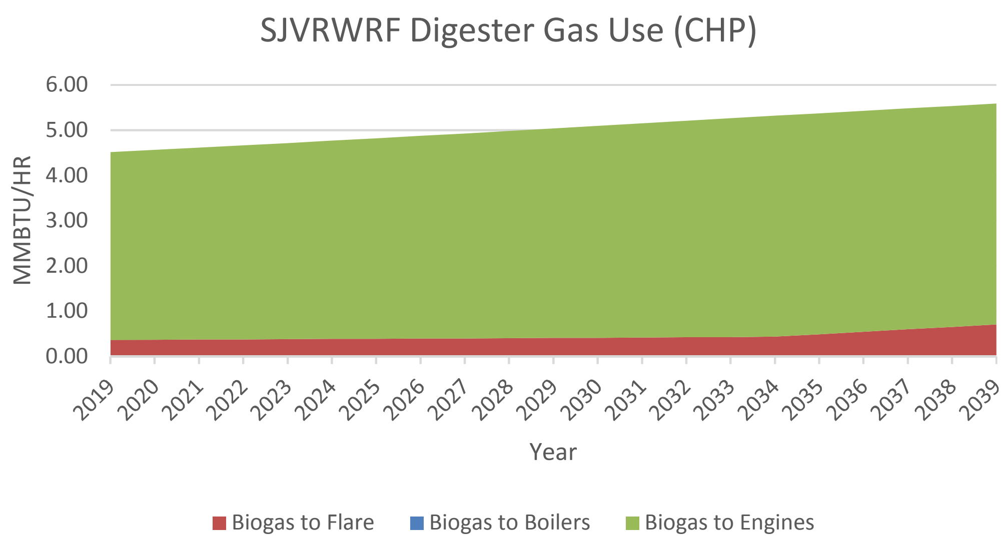


Figure D.4: SJVRWRF CHP Digester Gas Utilization

Appendix E: CHP Cumulative Revenue Graphs

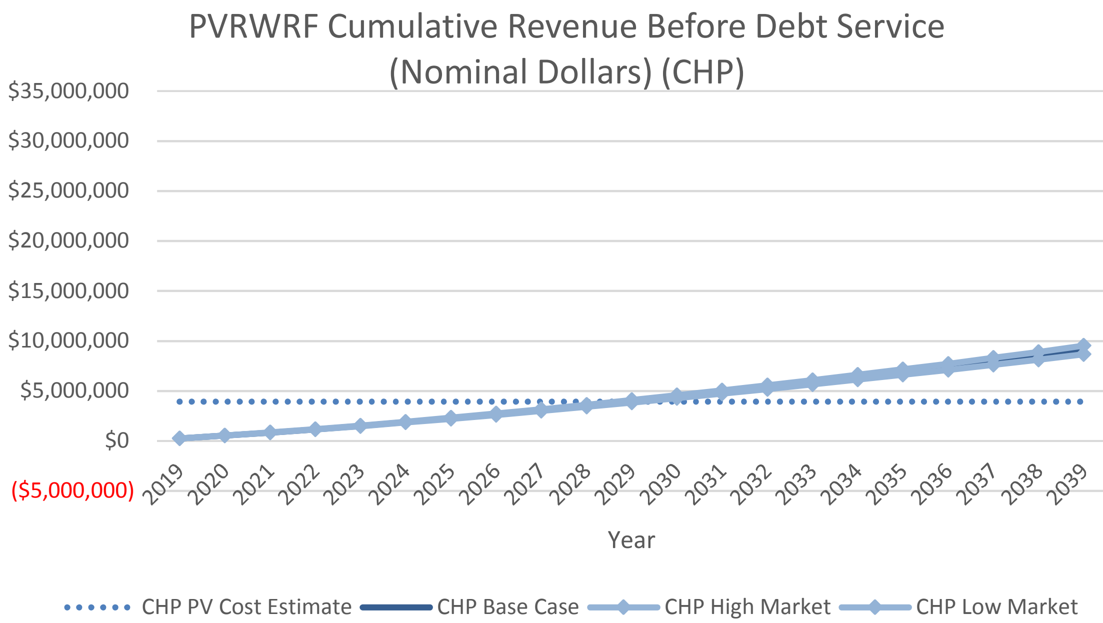


Figure E.1: PVRWRF CHP Cumulative Revenue

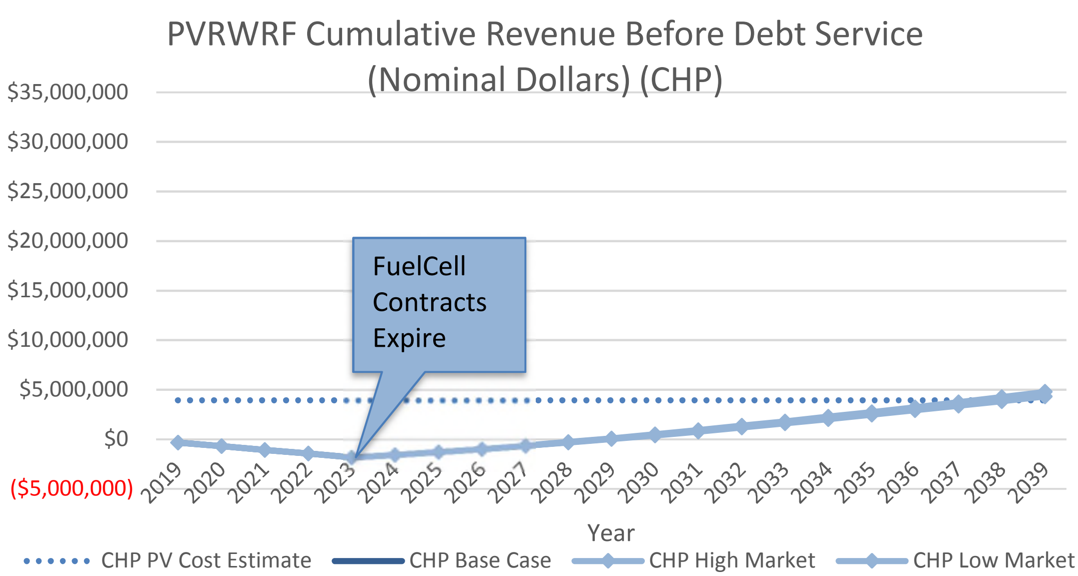


Figure E.2: PVRWRF CHP Cumulative Revenue (Delayed)

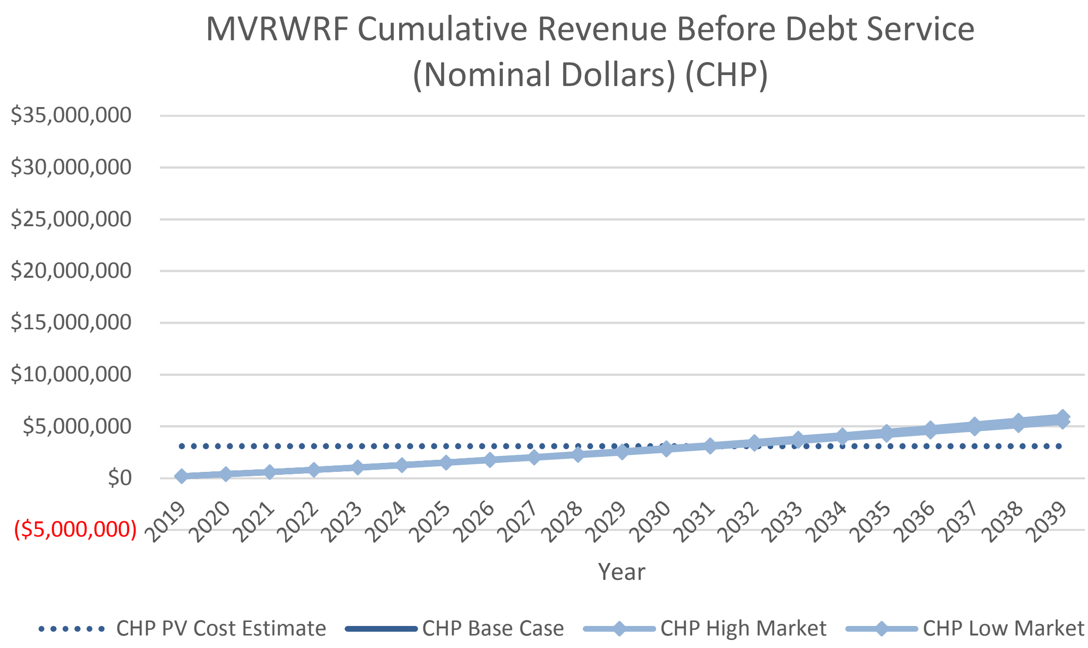


Figure E.3: MVRWRF CHP Cumulative Revenue

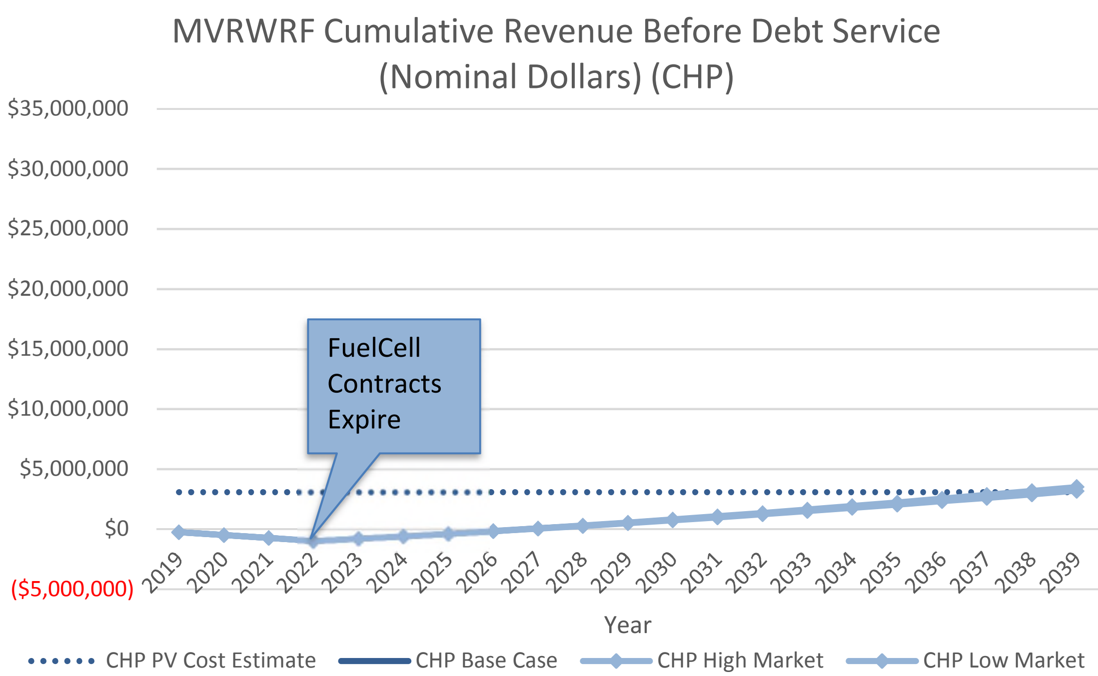


Figure E.4: MVRWRF CHP Cumulative Revenue (Delayed)

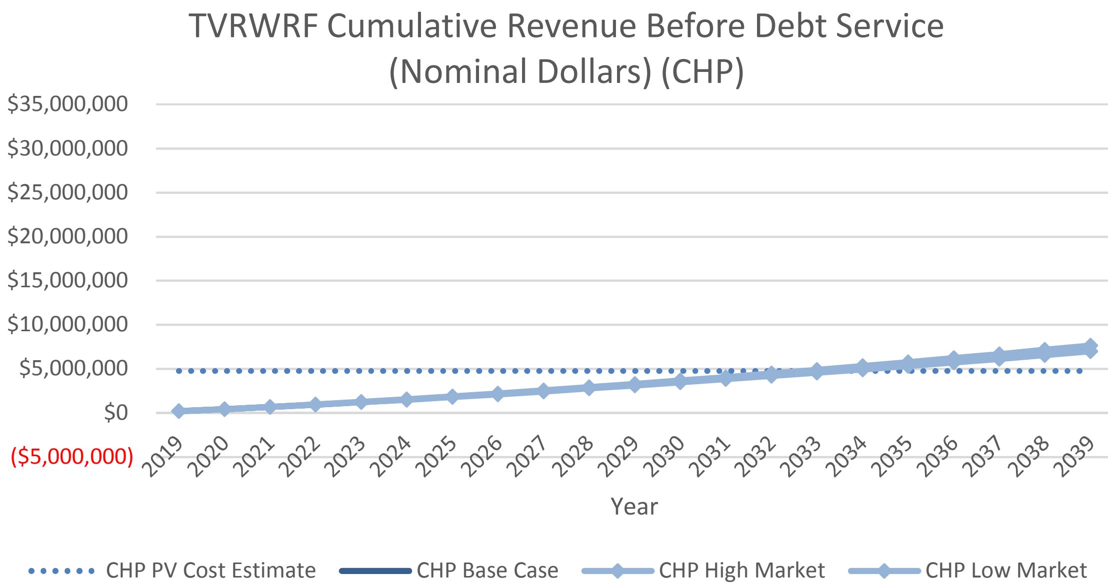


Figure E.5: TVRWRF CHP Cumulative Revenue

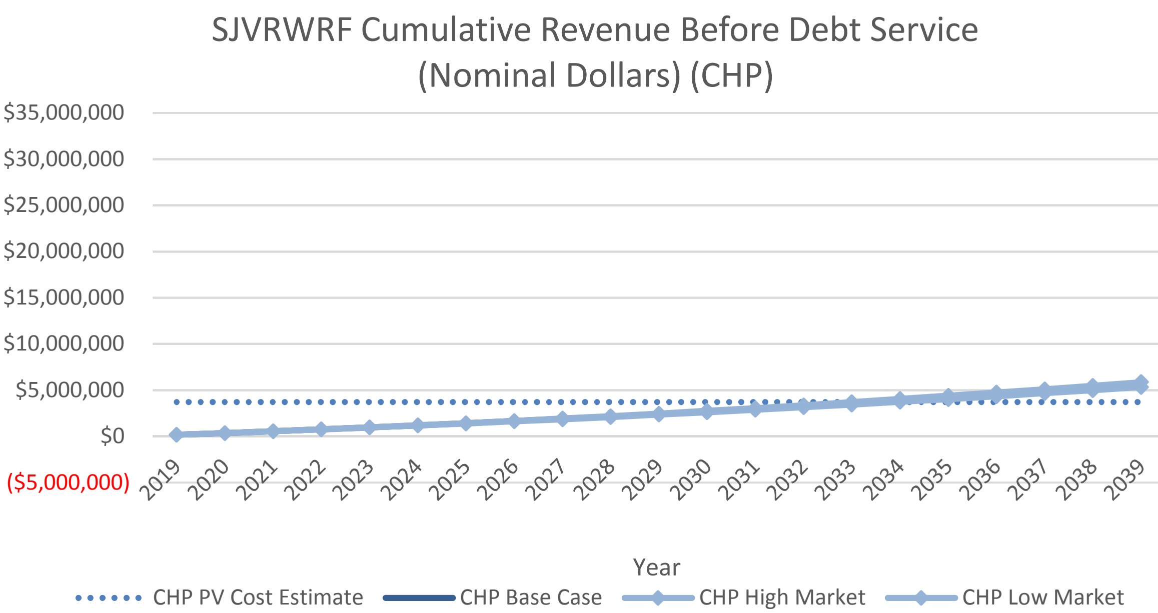


Figure E.6: SJVRWRF CHP Cumulative Revenue

Appendix F: CHP Gas Flaring

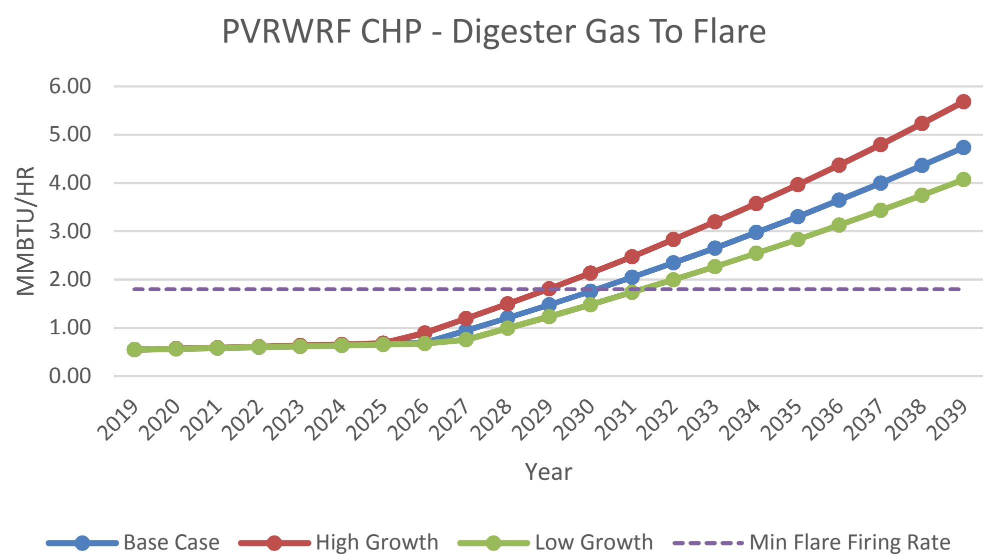


Figure F.1: PVRWRF CHP Gas Flaring

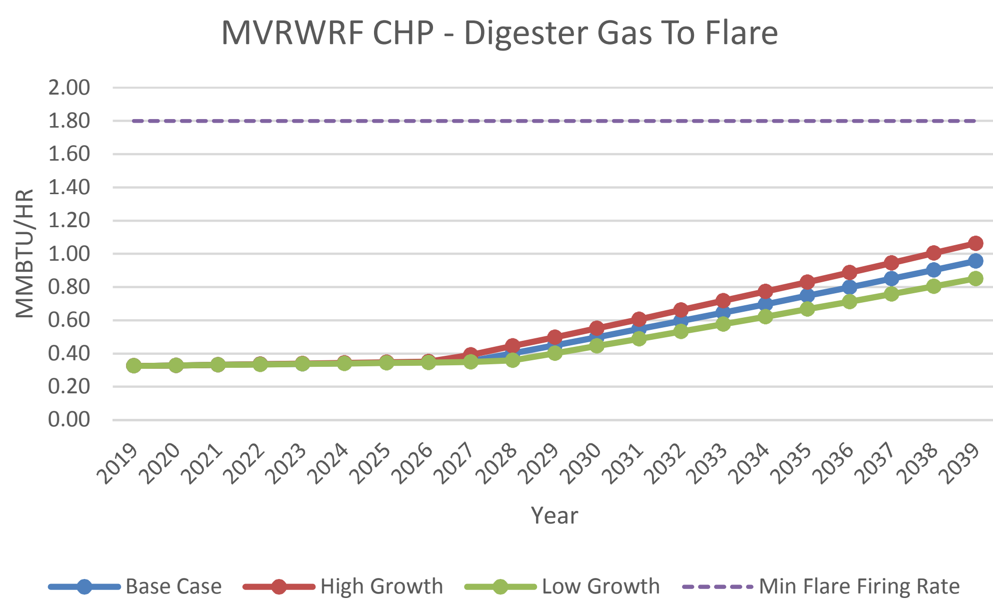


Figure F.2: MVRWRF CHP Gas Flaring

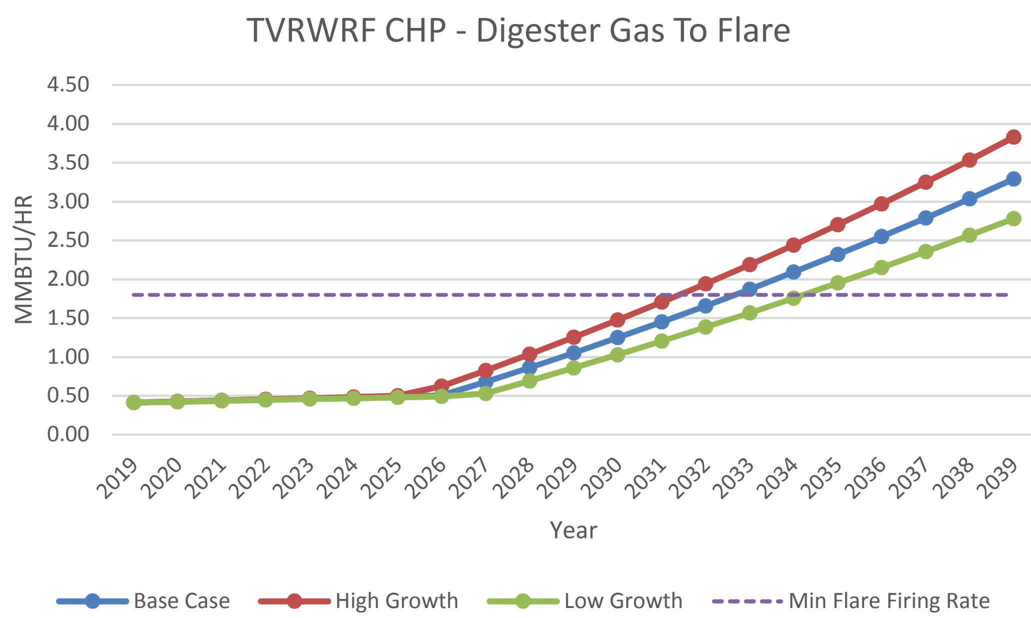


Figure F.3: TVRWRF CHP Gas Flaring

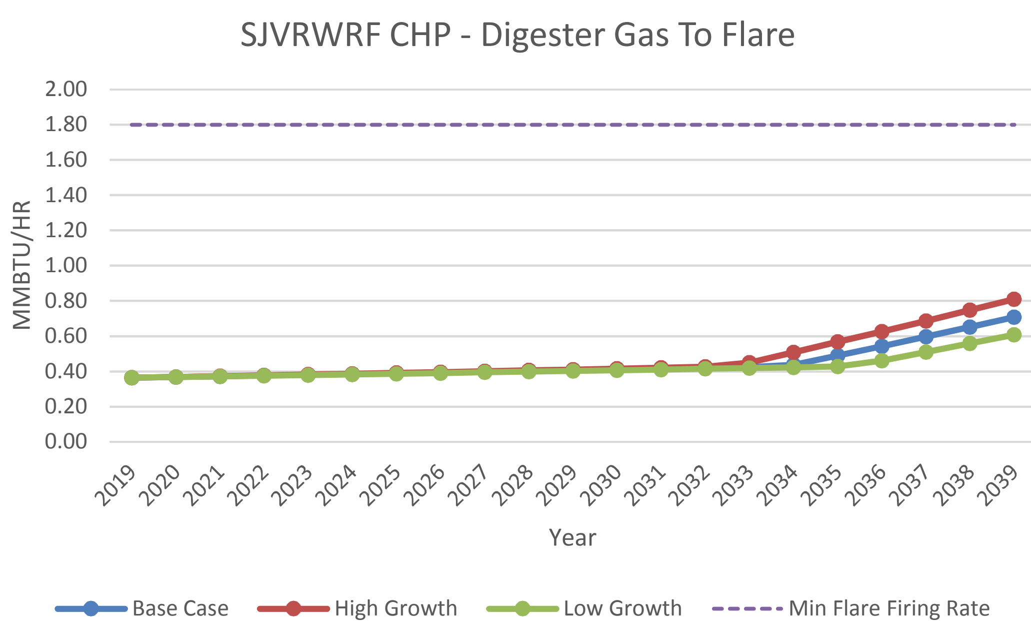


Figure F.4: SJVRWRF CHP Gas Flaring

Appendix G: CHP and RNG Siting

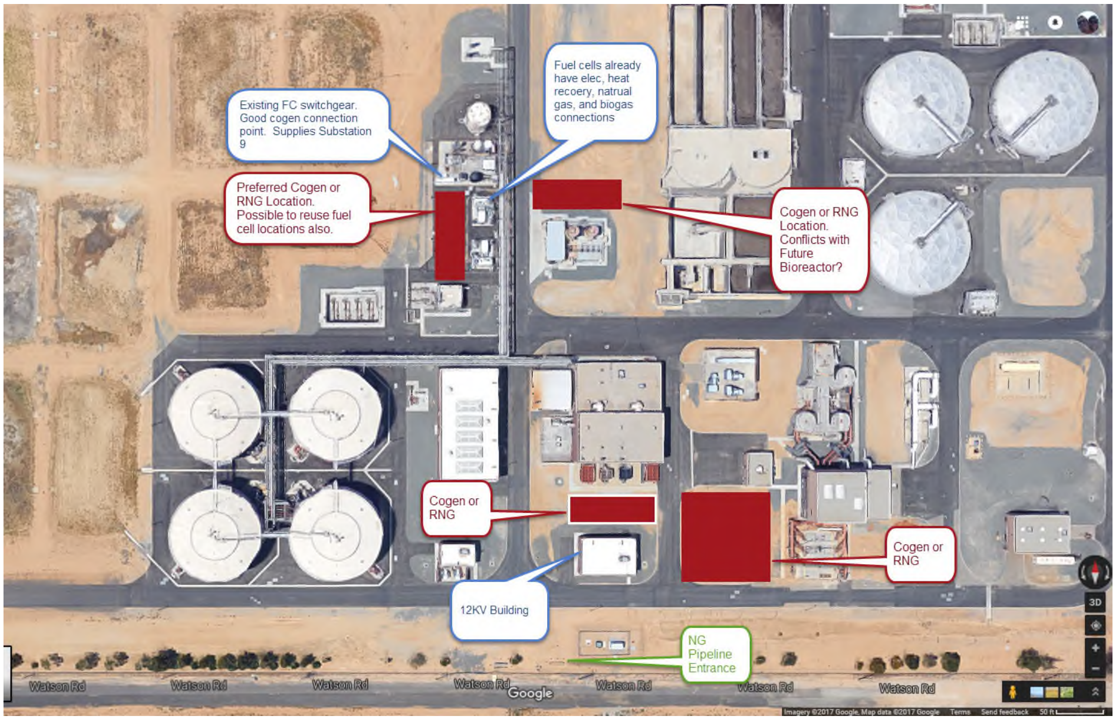


Figure G.1: PVRWRF CHP and RNG Siting

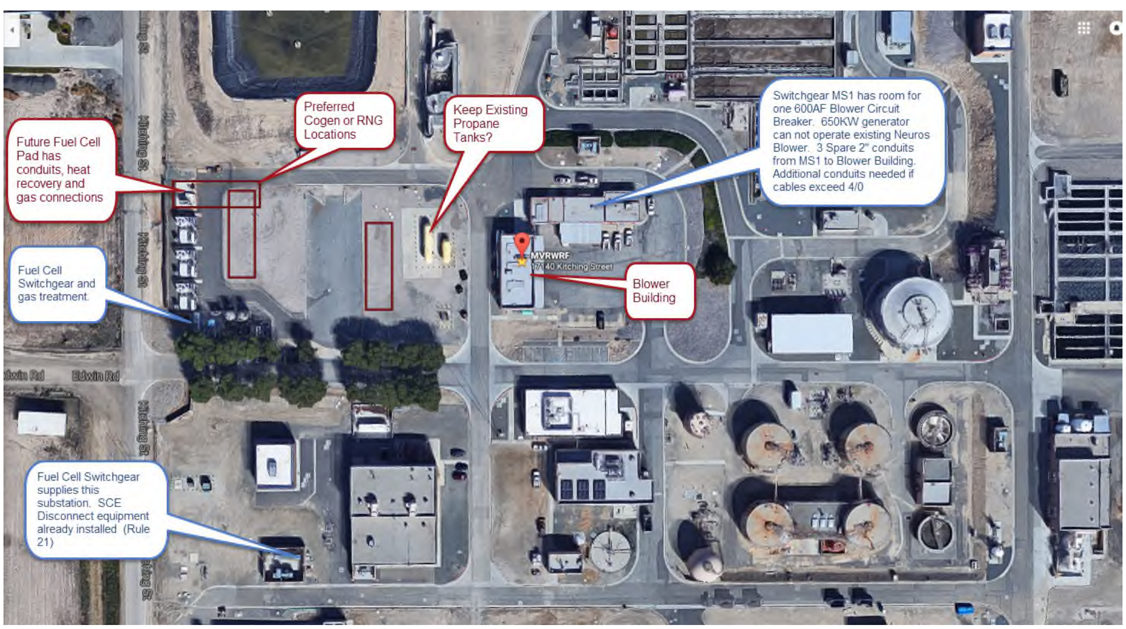


Figure G.2: MVRWRF CHP and RNG Siting

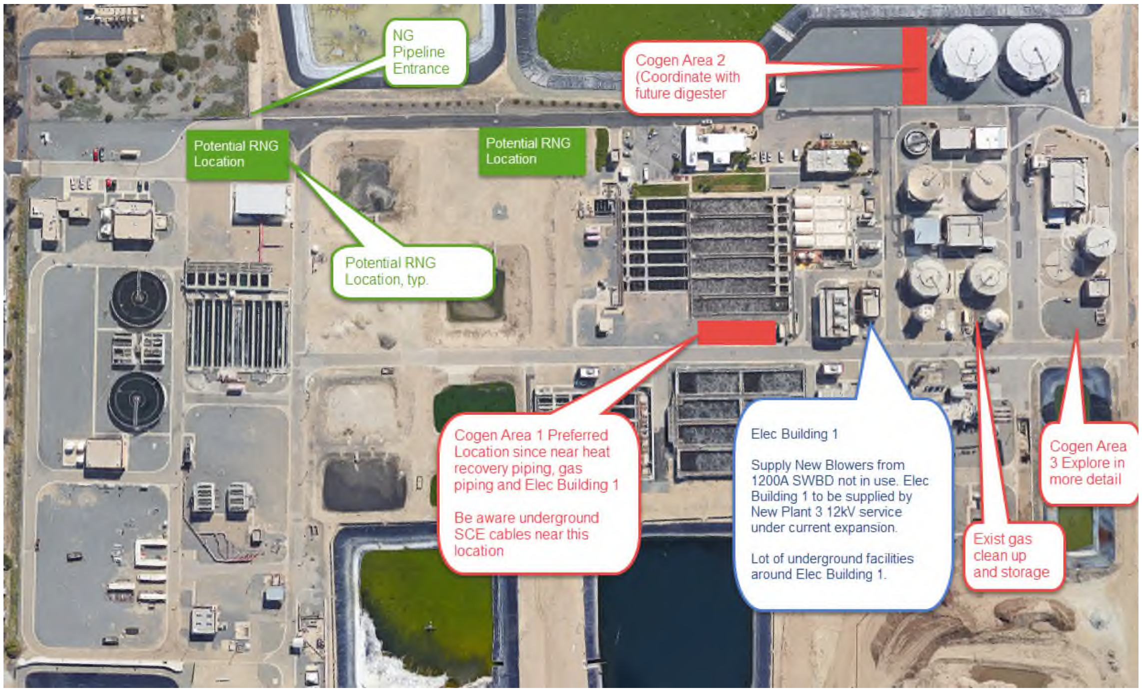


Figure G.3: TVRWRF CHP and RNG Siting

Figure G.4: SJVRWRF CHP and RNG Siting

Appendix H: Detailed CHP Cost Estimates

Table H.1: PVRWRF Detailed CHP Cost Estimate

Item	Units	Quantity	Materials	Labor	Construction Total
Packaged Engine/Generator (~800KW)	EA	1	$800,000	$200,000	$1,000,000
4" Water Piping	LF	250	$150	$38	$46,875
4" Biogas Piping	LF	250	$150	$38	$46,875
Shell in Tube Heat Exchanger	EA	2	$15,000	$3,750	$37,500
Heat Recovery Piping Modifications	LS	1	$15,000	$3,750	$18,750
Gas Cleaning Skid (Siloxane and H2S)	EA	0	$750,000	$187,500	$0
Continuous Emissions Monitoring System (CEMS)	EA	1	$100,000		
Hot Water Recirculation Pump	EA	1	$10,000	$2,500	$12,500
Electrical Swgr Modifications	LS	1	$50,000	$12,500	$62,500
Emission Control (SCAQMD Rule 1110.2 or similar)	LS	1	$100,000	$25,000	$125,000
Concrete Pad & Site Prep	LS	1	$50,000	$12,500	$62,500
Curb and Gutter	LS	1	$10,000	$2,500	$12,500
Electrical Ductbank	LS	1	$50,000	$12,500	$62,500
Mechanical/Elec Misc (25%)	LS	1	$462,575	$115,644	$578,219
Interconnection Study	EA	1	$50,000	$0	$50,000
I&C Integration	LS	1	$25,000	$50,000	$75,000
			Total Estimate Cost		$2,315,719
			Contractor OH/Profit (20%)		$463,144
			Contingencies (30%)		$694,716
			Engineering & CA (25%)		$578,930
			Total		**$4,052,508**

Table H.2: MVRWRF Detailed CHP Cost Estimate

Item	Units	Quantity	Materials	Labor	Construction Total
Packaged Engine/Generator (~500KW)	EA	1	$500,000	$125,000	$625,000
4" Water Piping	LF	250	$150	$38	$46,875
4" Biogas Piping	LF	250	$150	$38	$46,875
Shell in Tube Heat Exchanger	EA	2	$15,000	$3,750	$37,500
Heat Recovery Piping Modifications	LS	1	$15,000	$3,750	$18,750
Gas Cleaning Skid (Siloxane and H2S)	EA	0	$750,000	$187,500	$0
Hot Water Recirculation Pump	EA	1	$10,000	$2,500	$12,500
Electrical Swgr Modifications	LS	1	$50,000	$12,500	$62,500
Emission Control (SCAQMD Rule 1110.2 or similar)	LS	1	$100,000	$25,000	$125,000
Concrete Pad & Site Prep	LS	1	$50,000	$12,500	$62,500
Curb and Gutter	LS	1	$10,000	$2,500	$12,500
Electrical Ductbank	LS	1	$50,000	$12,500	$62,500
Mechanical/Elec Misc (25%)	LS	1	$387,575	$96,894	$484,469
Interconnection Study	EA	1	$50,000	$0	$50,000
I&C Integration	LS	1	$25,000	$50,000	$75,000
			Total Estimate Cost		$1,721,969
			Contractor OH/Profit (20%)		$344,394
			Contingencies (30%)		$516,591
			Engineering & CA (25%)		$430,492
			Total		**$3,013,445**

Table H.3: TVRWRF Detailed CHP Cost Estimate

Item	Units	Quantity	Materials	Labor	Construction Total
Packaged Engine/Generator (~650KW)	EA	1	$600,000	$150,000	$750,000
4" Water Piping	LF	250	$150	$38	$46,875
4" Biogas Piping	LF	250	$150	$38	$46,875
Shell in Tube Heat Exchanger	EA	2	$15,000	$3,750	$37,500
Heat Recovery Piping Modifications	LS	1	$15,000	$3,750	$18,750
Gas Cleaning Skid (Siloxane and H2S)	EA	1	$650,000	$162,500	$812,500
Hot Water Recirculation Pump	EA	1	$10,000	$2,500	$12,500
Electrical Swgr Modifications	LS	1	$50,000	$12,500	$62,500
Emission Control (SCAQMD Rule 1110.2 or similar)	LS	1	$100,000	$25,000	$125,000
Concrete Pad & Site Prep	LS	1	$50,000	$12,500	$62,500
Curb and Gutter	LS	1	$10,000	$2,500	$12,500
Electrical Ductbank	LS	1	$50,000	$12,500	$62,500
Mechanical/Elec Misc (25%)	LS	1	$387,575	$96,894	$484,469
Interconnection Study	EA	1	$50,000	$0	$50,000
I&C Integration	LS	1	$25,000	$50,000	$75,000
			Total Estimate Cost		$2,659,469
			Contractor OH/Profit (20%)		$531,894
			Contingencies (30%)		$797,841
			Engineering & CA (25%)		$664,867
			Total		**$4,654,070**

Table H.4: SJVRWRF Detailed CHP Cost Estimate

Item	Units	Quantity	Materials	Labor	Construction Total
Packaged Engine/Generator (~500KW)	EA	1	$400,000	$100,000	$500,000
4" Water Piping	LF	250	$150	$38	$46,875
4" Biogas Piping	LF	250	$150	$38	$46,875
Shell in Tube Heat Exchanger	EA	2	$15,000	$3,750	$37,500
Heat Recovery Piping Modifications	LS	1	$15,000	$3,750	$18,750
Gas Cleaning Skid (Siloxane and H2S)	EA	1	$500,000	$125,000	$625,000
Hot Water Recirculation Pump	EA	1	$10,000	$2,500	$12,500
Electrical Swgr Modifications	LS	1	$50,000	$12,500	$62,500
Emission Control (SCAQMD Rule 1110.2 or similar)	LS	1	$75,000	$18,750	$93,750
Concrete Pad & Site Prep	LS	1	$50,000	$12,500	$62,500
Curb and Gutter	LS	1	$10,000	$2,500	$12,500
Electrical Ductbank	LS	1	$50,000	$12,500	$62,500
Mechanical/Elec Misc (25%)	LS	1	$298,825	$73,456	$367,281
Interconnection Study	EA	1	$50,000	$0	$50,000
I&C Integration	LS	1	$25,000	$50,000	$75,000
			Total Estimate Cost		$2,073,531
			Contractor OH/Profit (20%)		$414,706
			Contingencies (30%)		$622,059
			Engineering & CA (25%)		$518,383
			Total		**$3,628,680**

Appendix I: RNG Pipeline Connections

Figure I.1: PVRWRF Pipeline Connection

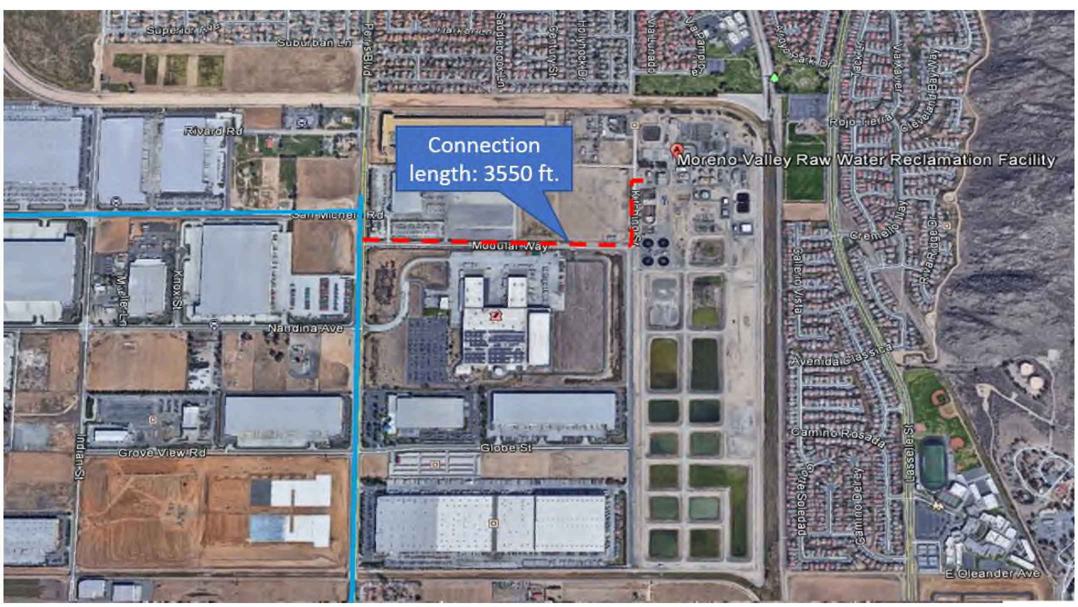


Figure I.2: MVRWRF Pipeline Connection

Figure I.3: TVRWRF Pipeline Connection

Figure I.4: SJVRWRF Pipeline Connection

Appendix J: RNG Digester Gas Utilization

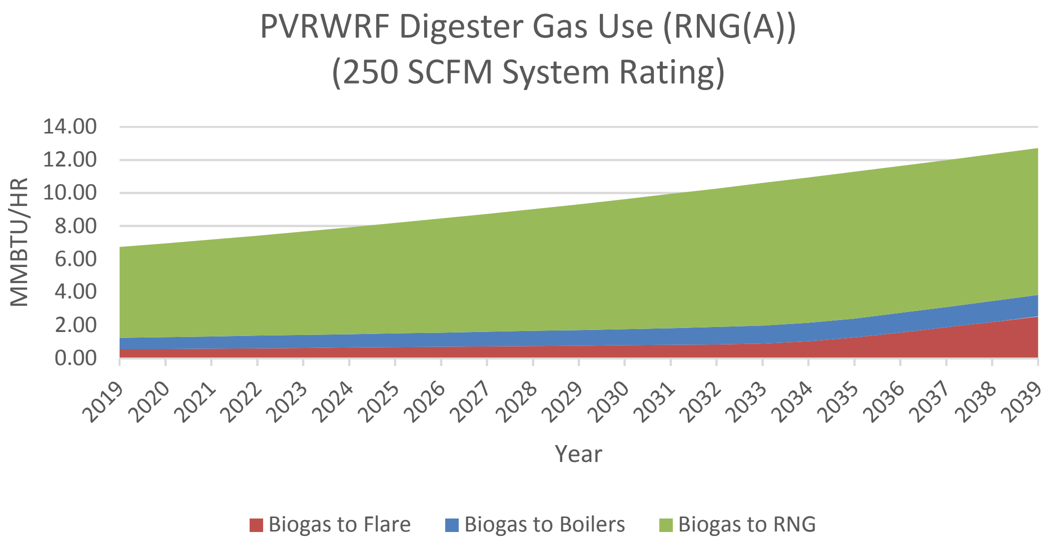


Figure J.1: PVRWRF Digester Gas Utilization for RNG(A)

(DG used for digester heating first with remaining used for RNG production)

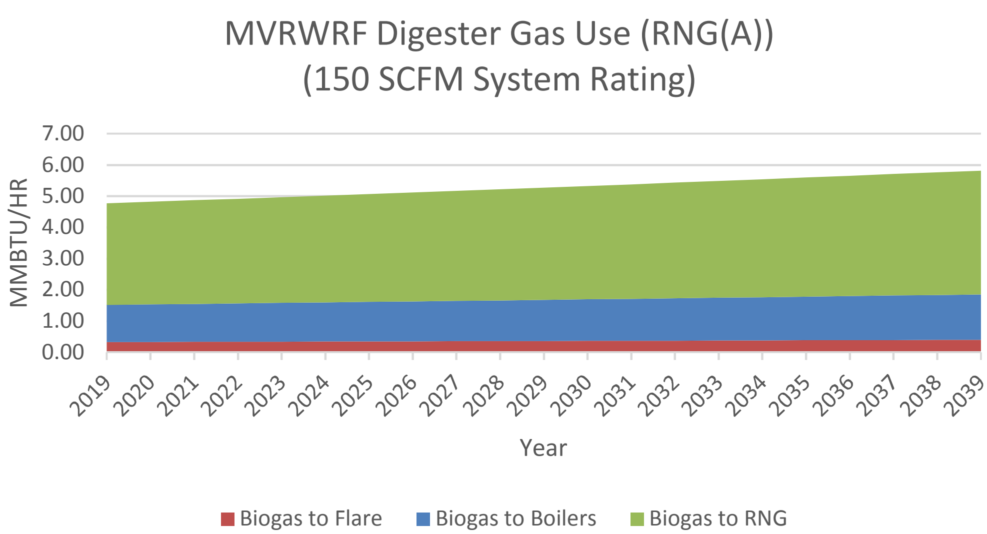


Figure J.2: MVRWRF Digester Gas Utilization for RNG(A)

(DG used for digester heating first with remaining used for RNG production)

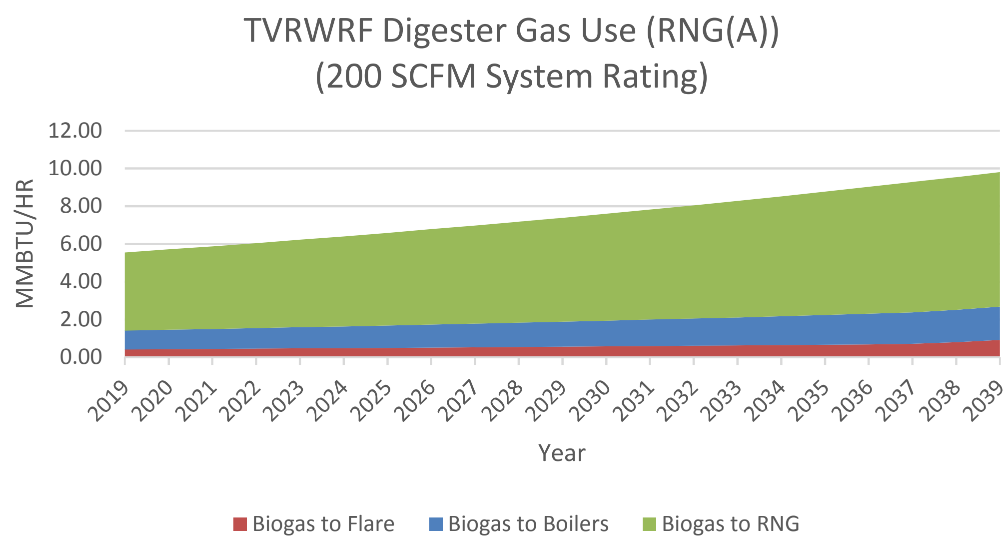


Figure J.3: TVRWRF Digester Gas Utilization for RNG(A)

(DG used for digester heating first with remaining used for RNG production)

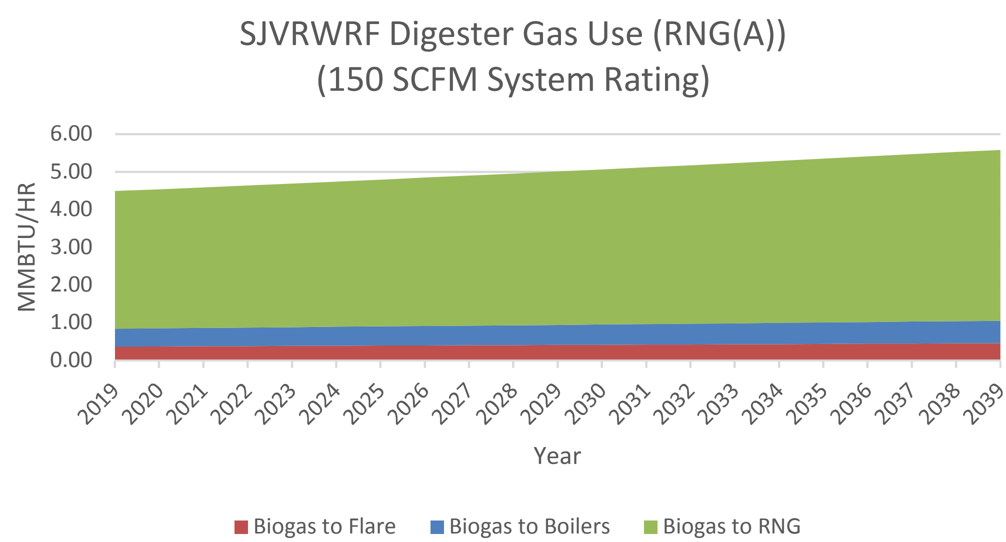


Figure J.4: SJVRWRF Digester Gas Utilization for RNG(A)

(DG used for digester heating first with remaining used for RNG production)

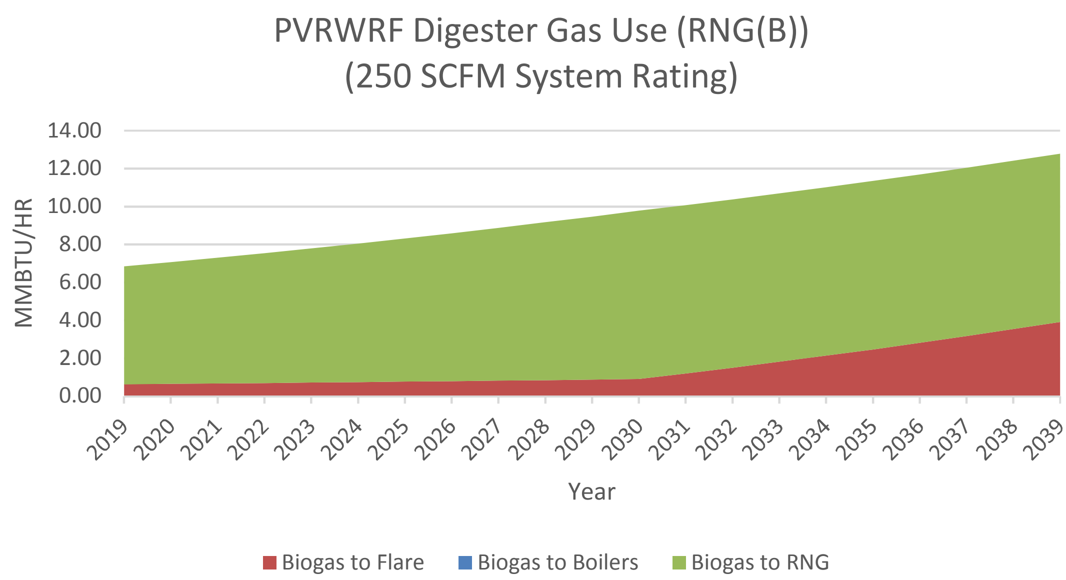


Figure J.5: PVRWRF Digester Gas Utilization for RNG(B)

(All DG used for RNG production. NG purchased for digester heating)

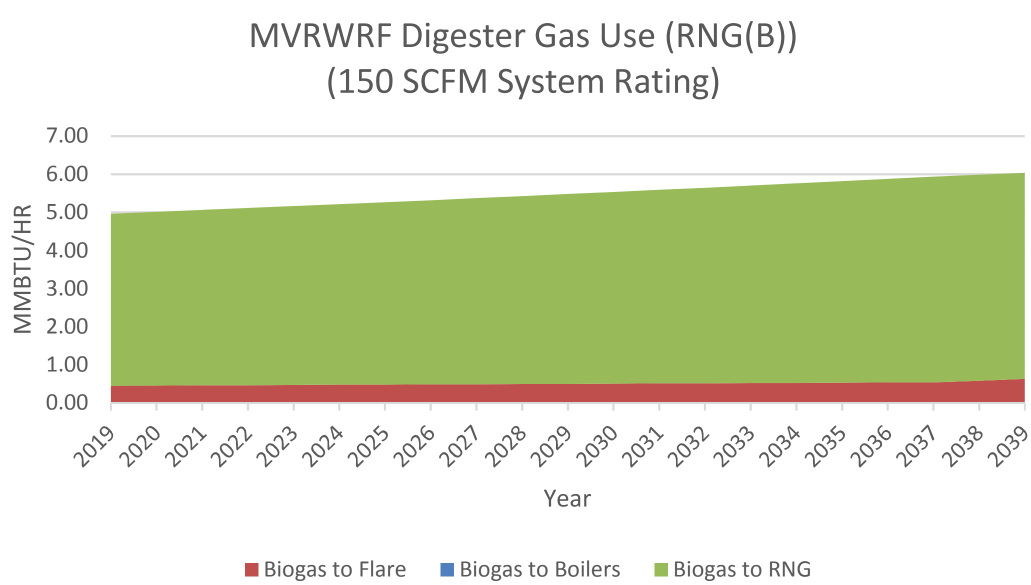


Figure J.6: MVRWRF Digester Gas Utilization for RNG(B)

(All DG used for RNG production. NG purchased for digester heating)

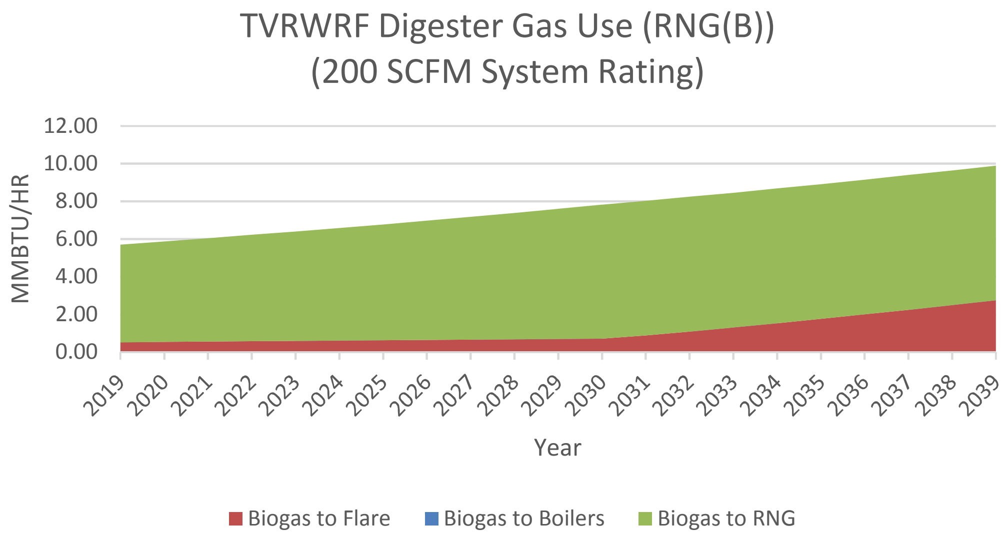


Figure J.7: TVRWRF Digester Gas Utilization for RNG(B)

(All DG used for RNG production. NG purchased for digester heating)

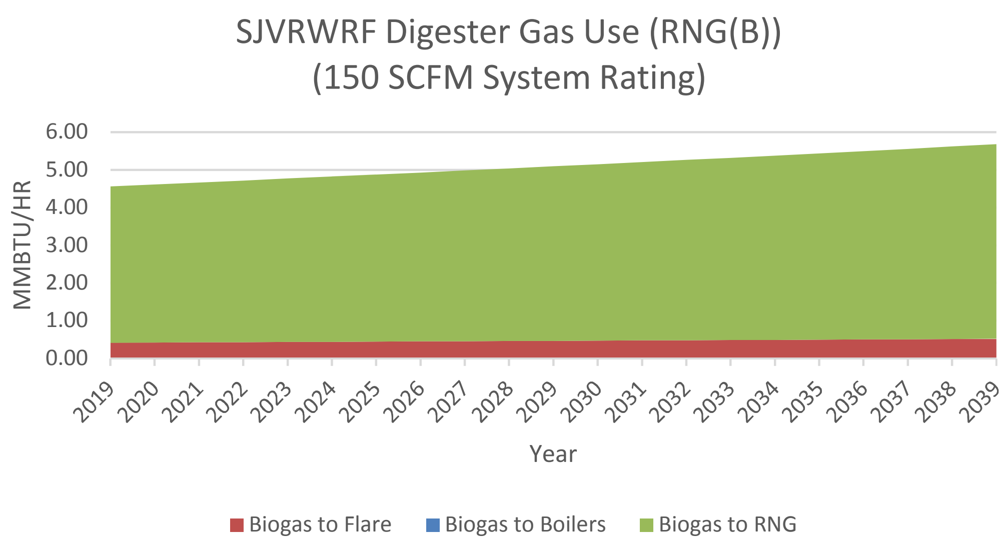


Figure J.8: SJVRWRF Digester Gas Utilization for RNG(B)

(All DG used for RNG production. NG purchased for digester heating)

Appendix K: Detailed RNG Cost Estimates

Table K.1: PVRWRF Detailed RNG Cost Estimate

Item	Units	Quantity	Materials	Labor	Construction Total
PSA Treatment System	EA	1	$1,500,000	$750,000	$2,250,000
Thermal Oxidizer	EA	1	$450,000	$225,000	$675,000
Gas Monitoring w/ sulfur analyzer	EA	1	$150,000	$75,000	$225,000
4" Gas Piping	LF	200	$150	$75	$45,000
4" Condensate Drain Piping	LF	500	$150	$75	$112,500
Concrete Pad & Site Prep	LS	1	$100,000	$50,000	$150,000
Curb and Gutter	LS	1	$50,000	$25,000	$75,000
Pipeline Interconnect*	FT	1000	$200	$100	$300,000
Odorize System	EA	1	$20,000	$10,000	$30,000
Mechanical/Elec Misc (25%)	LS	1	$567,625	$227,050	$794,675
I&C Integration	LS	1	$25,000	$50,000	$75,000
			Total Estimate Cost		$4,732,175
			Contractor OH/Profit (20%)		$946,435
			Contingencies (30%)		$1,419,653
			Engineering & CA (25%)		$1,183,044
			Total		**$8,281,306**

Table K.2: MVRWRF Detailed RNG Cost Estimate

Item	Units	Quantity	Materials	Labor	Construction Total
PSA Treatment System	EA	1	$1,500,000	$750,000	$2,250,000
Thermal Oxidizer	EA	1	$450,000	$225,000	$675,000
Gas Monitoring w/ sulfur analyzer	EA	1	$150,000	$75,000	$225,000
4" Gas Piping	LF	200	$150	$75	$45,000
4" Condensate Drain Piping	LF	500	$150	$75	$112,500
Concrete Pad & Site Prep	LS	1	$100,000	$50,000	$150,000
Curb and Gutter	LS	1	$50,000	$25,000	$75,000
Pipeline Interconnect*	FT	3550	$150	$75	$798,750
Odorize System	EA	1	$20,000	$10,000	$30,000
Mechanical/Elec Misc (25%)	LS	1	$567,613	$227,045	$794,658
I&C Integration	LS	1	$25,000	$50,000	$75,000
			Total Estimate Cost		$5,230,908
			Contractor OH/Profit (20%)		$1,046,182
			Contingencies (30%)		$1,569,272
			Engineering & CA (25%)		$1,307,727
			Total		**$9,154,088**

Table K.3: TVRWRF Detailed RNG Cost Estimate

Item	Units	Quantity	Materials	Labor	Construction Total
PSA Treatment System	EA	1	$1,500,000	$750,000	$2,250,000
Thermal Oxidizer	EA	1	$450,000	$225,000	$675,000
Gas Monitoring w/ sulfur analyzer	EA	1	$150,000	$75,000	$225,000
4" Gas Piping	LF	200	$150	$75	$45,000
4" Condensate Drain Piping	LF	500	$150	$75	$112,500
Concrete Pad & Site Prep	LS	1	$100,000	$50,000	$150,000
Curb and Gutter	LS	1	$50,000	$25,000	$75,000
Pipeline Interconnect*	FT	500	$200	$100	$150,000
Odorize System	EA	1	$20,000	$10,000	$30,000
Mechanical/Elec Misc (25%)	LS	1	$567,625	$227,050	$794,675
I&C Integration	LS	1	$25,000	$50,000	$75,000
			Total Estimate Cost		$4,582,175
			Contractor OH/Profit (20%)		$916,435
			Contingencies (30%)		$1,374,653
			Engineering & CA (25%)		$1,145,544
			Total		**$8,018,806**

Table K.4: SJVRWRF Detailed RNG Cost Estimate

Item	Units	Quantity	Materials	Labor	Construction Total
PSA Treatment System	EA	1	$1,500,000	$750,000	$2,250,000
Thermal Oxidizer	EA	1	$450,000	$225,000	$675,000
Gas Monitoring w/ sulfur analyzer	EA	1	$150,000	$75,000	$225,000
4" Gas Piping	LF	200	$150	$75	$45,000
4" Condensate Drain Piping	LF	500	$150	$75	$112,500
Concrete Pad & Site Prep	LS	1	$100,000	$50,000	$150,000
Curb and Gutter	LS	1	$50,000	$25,000	$75,000
Pipeline Interconnect*	FT	9450	$150	$75	$1,417,500
Odorize System	EA	1	$20,000	$10,000	$30,000
Mechanical/Elec Misc (25%)	LS	1	$567,600	$227,040	$794,640
I&C Integration	LS	1	$25,000	$50,000	$75,000
			Total Estimate Cost		$5,849,640
			Contractor OH/Profit (20%)		$1,169,928
			Contingencies (30%)		$1,754,892
			Engineering & CA (25%)		$1,462,410
			Total		**$10,236,870**

Appendix L: RNG Cumulative Revenue Graphs

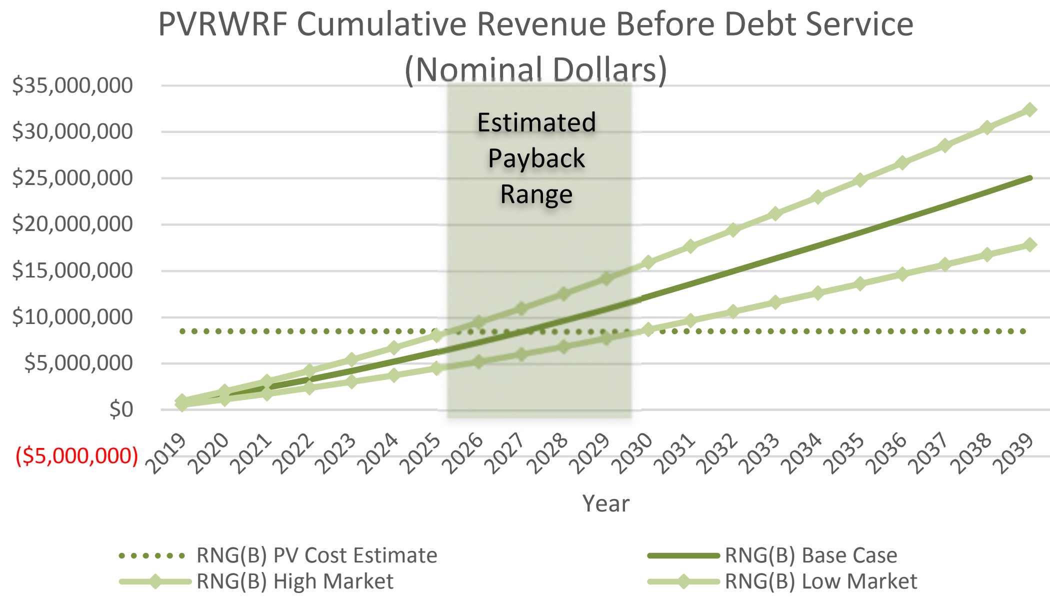


Figure L.7: PVRWRF RNG Cumulative Revenue (Immediate Implementation)

(All DG used for RNG production. NG purchased for digester heating)

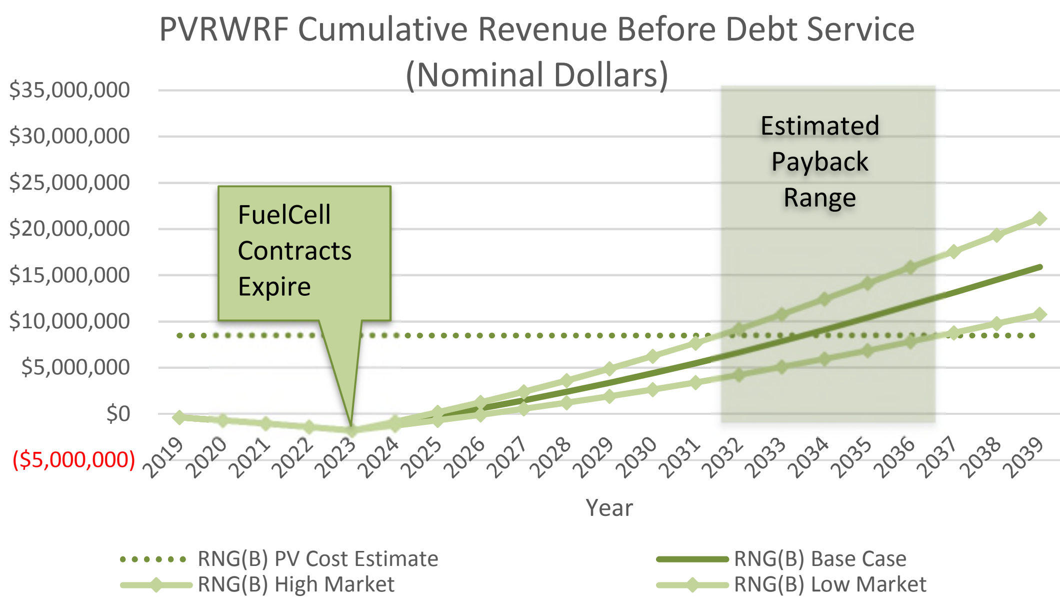


Figure L.8: PVRWRF RNG Cumulative Revenue

(All DG used for RNG production. NG purchased for digester heating)

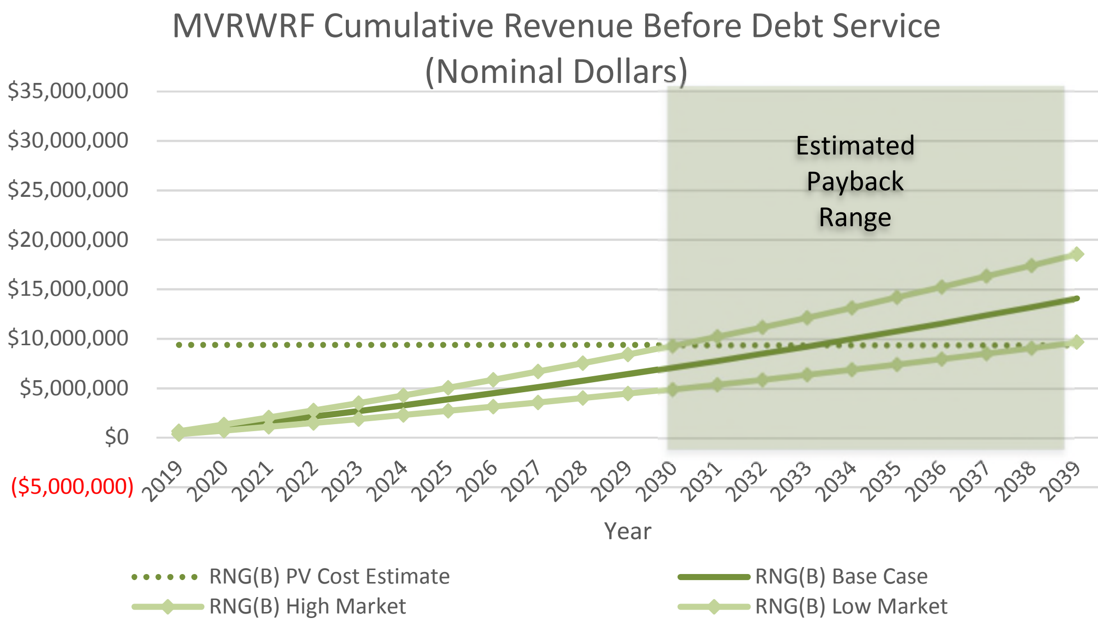


Figure L.9: MVRWRF RNG Cumulative Revenue (Immediate Implementation)

(All DG used for RNG production. NG purchased for digester heating)

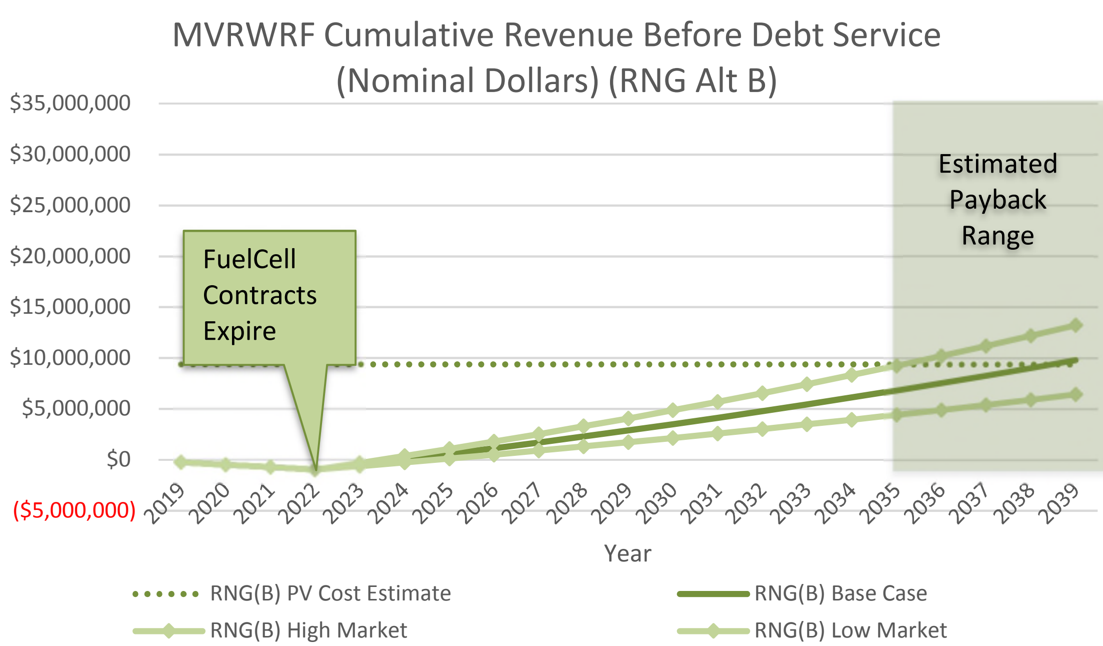


Figure L.10: MVRWRF RNG Cumulative Revenue

(All DG used for RNG production. NG purchased for digester heating)

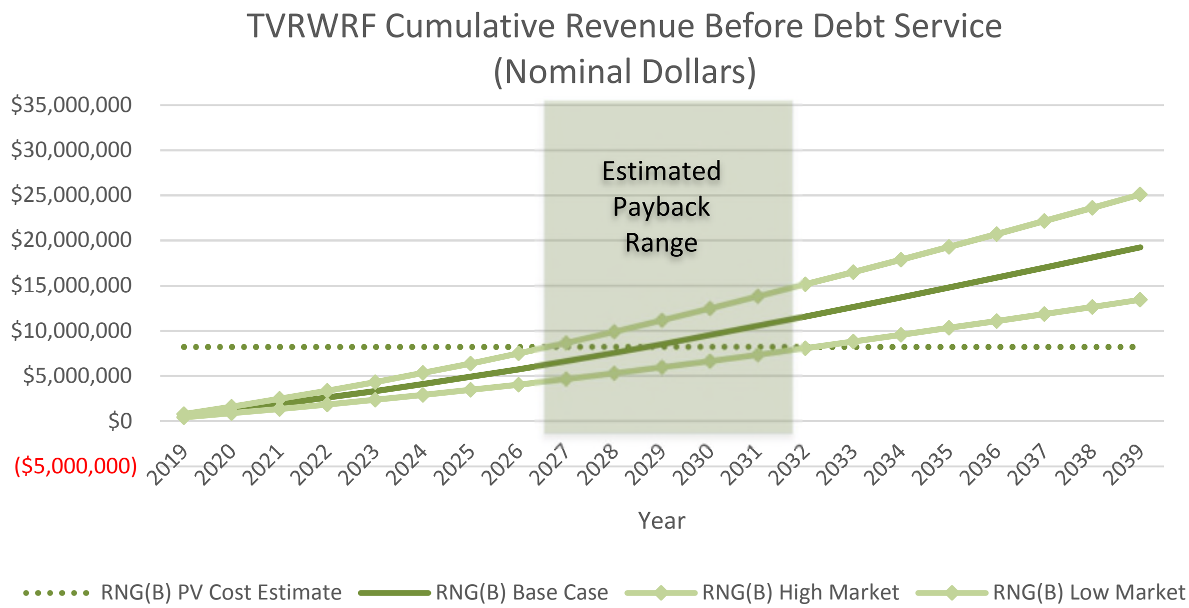


Figure L.11: TVRWRF RNG Cumulative Revenue

(All DG used for RNG production. NG purchased for digester heating)

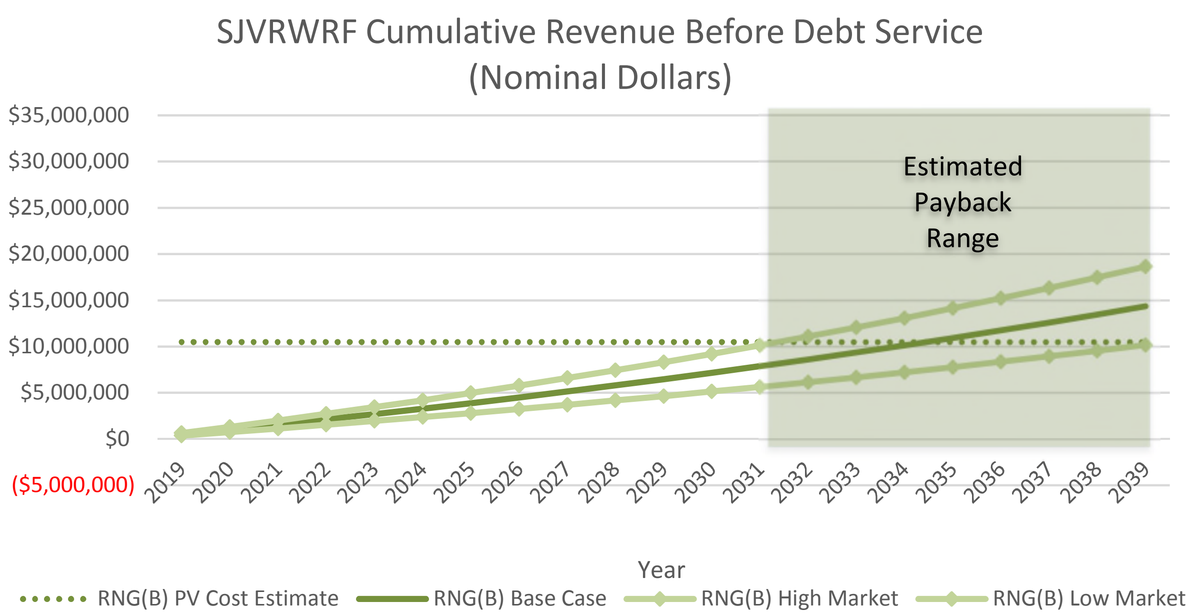


Figure L.12: SJVRWRF RNG Cumulative Revenue

(All DG used for RNG production. NG purchased for digester heating)

Appendix M: Digester Gas Value Evaluation Tool

The Digester Gas Value Evaluation Tool shows the relationship between capital costs, revenue generation, and payback period for the RNG and CHP utilization alternatives. It is intended to be used to identify the approximate payback period for each alternative given a specific value of the digester gas, based on market conditions and capital costs.

Using the PVRWRF Digester Gas Value Evaluation Tool (**Figure M.1** below) as an example and the market conditions shown on the line marked “Example”, it is estimated that the RNG value of the gas is $19.25/MMBTU. This line is represented by the cumulative revenue graph line labeled RNG-3. When parasitic losses and downtime are taken into account, it is estimated that the value of the raw, unprocessed digester gas is $14.73/MMBTU. If arrangements can be made with a third party to purchase the raw digester gas at a value higher than $14.73/MMBTU, that is a better option than the given set of market conditions and would be a favorable approach to utilize the digester gas.

It is anticipated that the RNG system capital cost will be $7M-$10M. The break-even point is where the line representing a given set of market conditions rises above the anticipated capital cost estimate. Using a 10-year payback as the maximum, a capital cost of up to ~$11M will meet the 10-year payback requirement. However, using the example market conditions above and the capital cost estimate, it is expected that the break-even point is around year 8.

If the market conditions are more favorable, using the line marked “High Mkt”, the value of the gas increases, resulting in a faster payback period. Using the associated “RNG-5” cumulative revenue line and the same RNG cost estimate, the break-even point is between years 5 and 6.

A similar analysis can be performed for the CHP alternative and is shown on the the same axis for comparison.

The Digester Gas Value Evaluation Tool for each plant can be used in a similar manner to understand the break-even point with a given capital cost and market conditions.

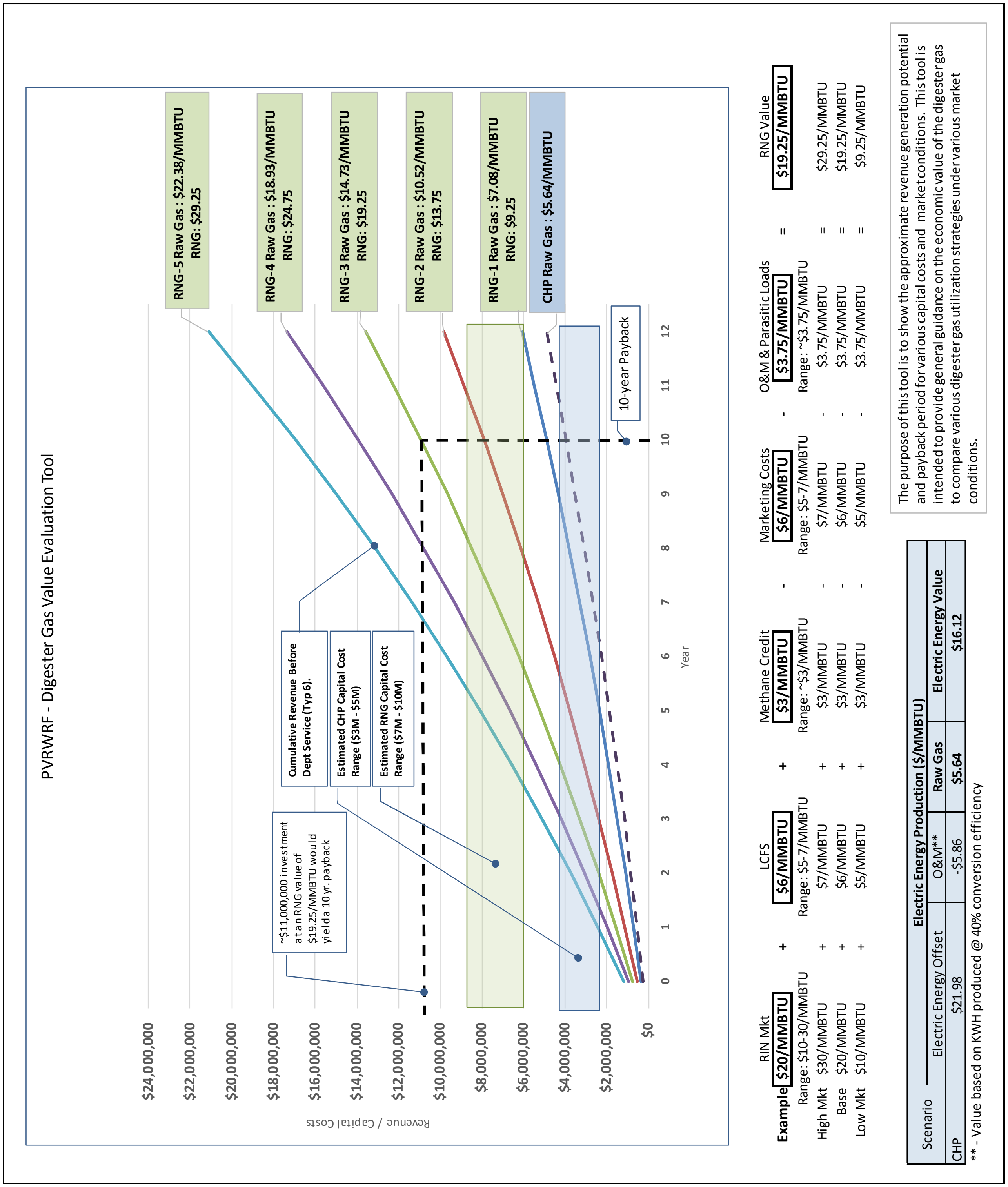


Figure M.1: PVRWRF Digester Gas Value Evaluation Tool

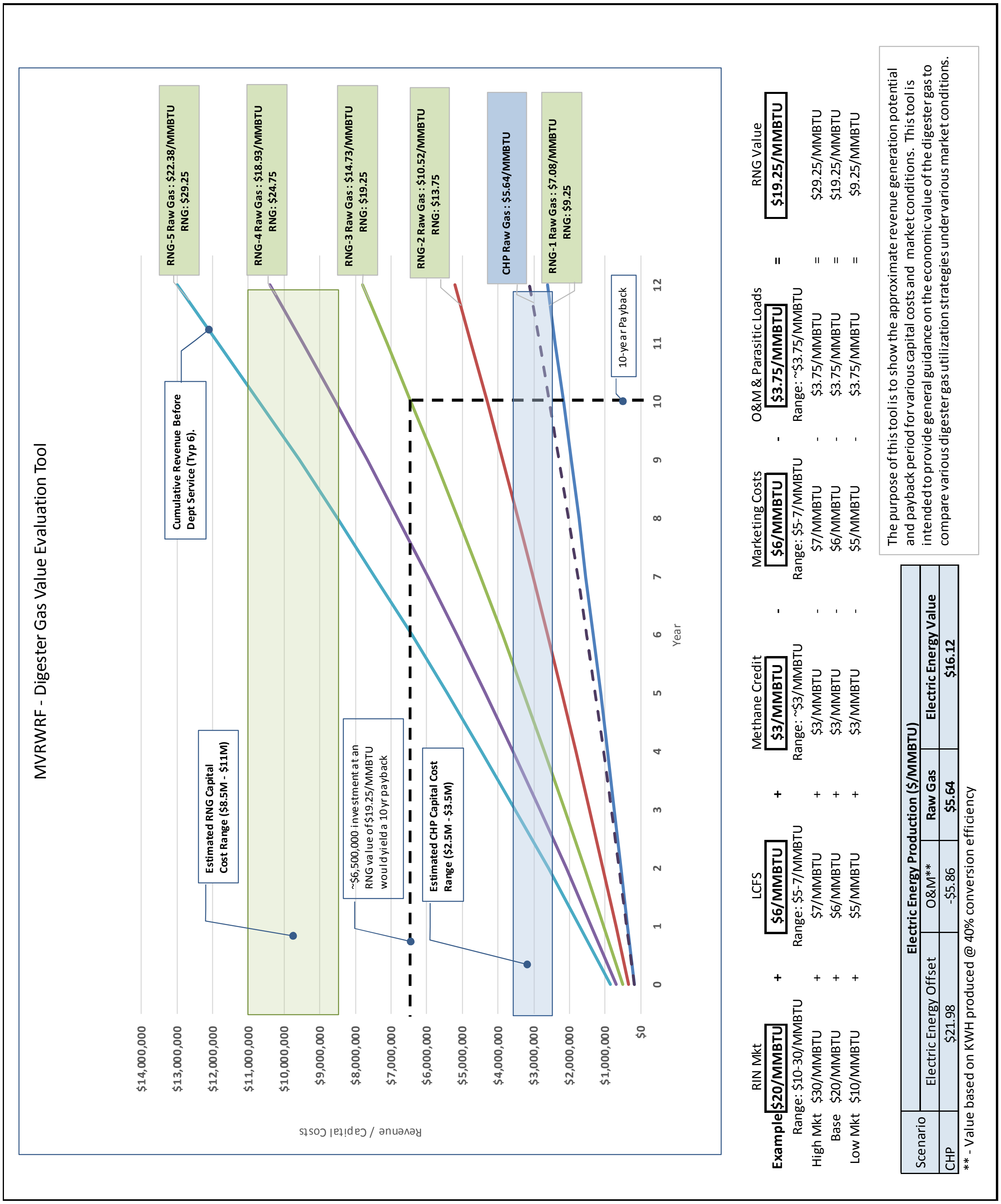


Figure M.2: MVRWRF Digester Gas Value Evaluation Tool

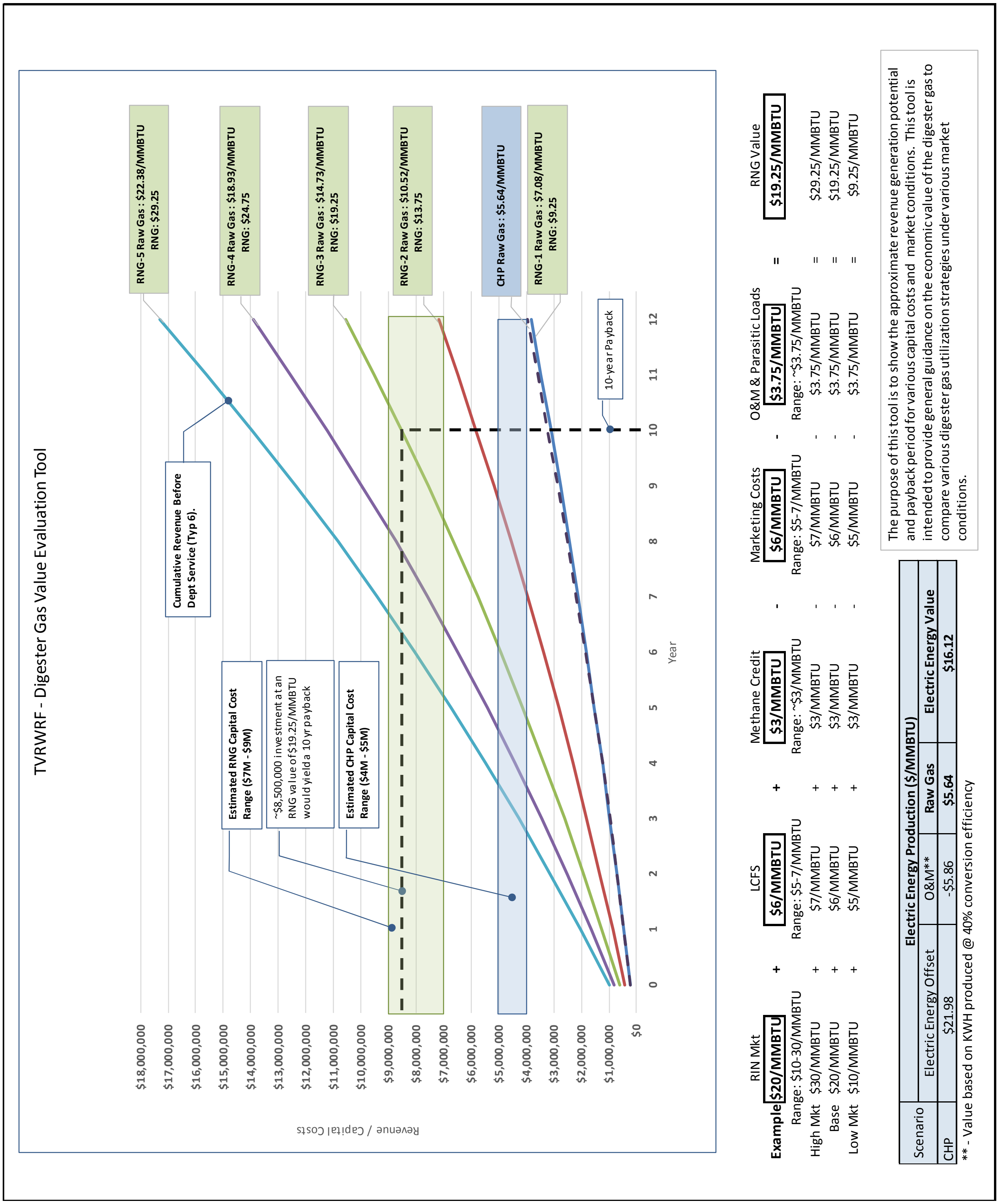


Figure M.3: TVRWRF Digester Gas Value Evaluation Tool

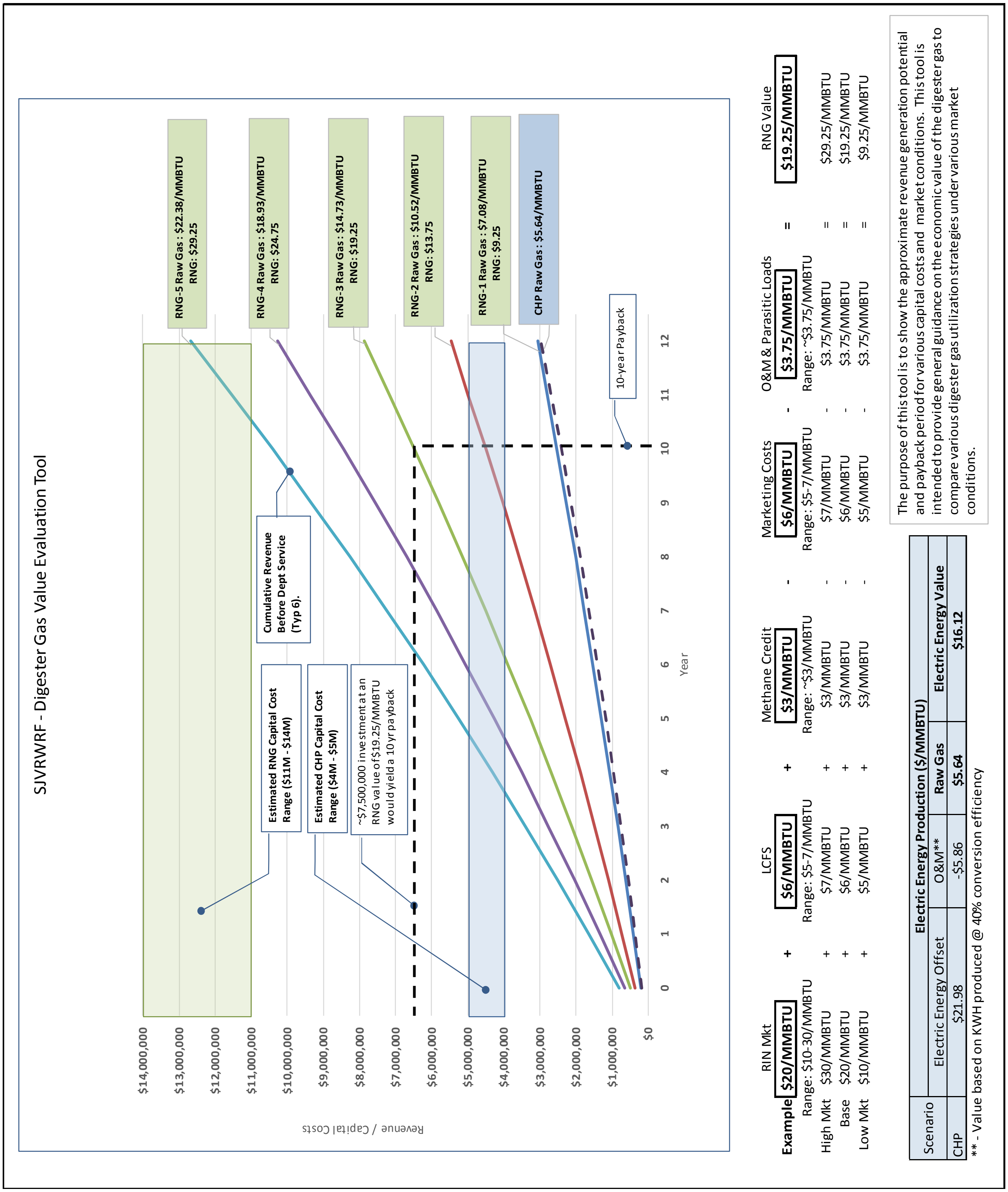


Figure M.4: SJVRWRF Digester Gas Value Evaluation Tool