Technical Memorandum

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Prepared for: King County Department of Natural Resources and Parks

Project Title: Task Order 7: South Plant Digester Gas Utilization Study

Project No.: 141326.007.050

Technical Memorandum 4

Subject: Decision Process Support Summary

Date: January 21, 2014

To: John Smyth, Project Manager

From: Ian McKelvey, Project Manager

Copy to: File

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List of Abbreviations

°F	degree(s) Fahrenheit
biogas	digester gas
Btu	British thermal unit(s)
CHP	combined heat and power
CNG	compressed natural gas
CO_2	carbon dioxide
County	King County
DCS	distributed control system
DNRP	Department of Natural Resources and Parks
EPA	U.S. Environmental Protection Agency
FOG	fats, oils, and grease
gpd	gallon(s) per day
H_2S	hydrogen sulfide
hr	hour(s)
IC	internal-combustion
kWt	thermal kilowatt(s)
kWh	kilowatt-hour(s)
lb-VS/day	pound(s) volatile solids per day
MMBtu	million British thermal unit(s)
MMBtu/hr	million British thermal unit(s) per hour
MMscfd	million standard cubic foot/feet per day
NPV	net present value
O&M	operations and maintenance
PSA	pressure swing adsorption
PSE	Puget Sound Energy
rCNG	renewable compressed natural gas
REC	Renewable Energy Credit
RIN	Renewable Identification Number
scfd	standard cubic foot/feet per day
SP	South Treatment Plant
study	South Plant Digester Gas Utilization Study
TM	technical memorandum
VOC	volatile organic compound
WTD	Wastewater Treatment Division
WWTP	wastewater treatment plant
yr	year(s)

Section 1: Introduction

The South Plant Digester Gas Utilization Study (study) evaluated the existing South Treatment Plant (SP) digester gas (biogas) management system, defined and evaluated potential capital projects to modify equipment and systems, and identified two preferred capital projects with the following objectives:

- improve system component performance, efficiency, and reliability
- maximize the cost-effectiveness and environmental benefit of the biogas end use
- contribute to the applicable targets and goals established in several King County (County) plans and ordinances

The study included three technical memoranda (TMs), which provide a step-by-step process in developing a capital project recommendation to enhance the functionality and efficiency of the SP biogas management system. A summary of the three TMs follows:

- TM 1: The existing SP biogas management and plant heating systems are described in TM 1, including capacities, operational modes, maintenance and reliability concerns, and operation and maintenance (O&M) costs.
- TM 2: The objectives of the County for the biogas management system, development of capital project alternatives, and screening of the initial alternatives based on the County's objectives are covered in TM 2. From the analysis performed, three alternatives are recommended for further evaluation in addition to the status quo.
- TM 3: The County's objectives and the selected alternatives were refined and compared in TM 3, culminating in the recommendation of two capital project alternatives. Refinement of the alternatives included more detailed capital cost estimates, equipment layouts, operational descriptions, and economic sensitivity analyses.

This document summarizes the three TMs and the conclusions from the study. Detailed descriptions of the following summaries can be found in the individual TMs provided as appendices.

Section 2: TM 1—South Plant Biogas Management Equipment and Systems

2.1 Existing Biogas Management System and Operation

The SP uses four active digesters to anaerobically digest thickened raw sludge at mesophilic temperatures of 95–99 degrees Fahrenheit [°F]. A fifth tank is used as a storage tank. The digesters are mixed through a combination of gas mixing and pump mixing. The digester gas produced as part of the anaerobic digestion process is either processed through the gas scrubbing system or flared in the waste gas burners.

The gas scrubbing system is a high-pressure water solvent type system that removes carbon dioxide (CO_2), hydrogen sulfide (H_2S), water, and other constituents to produce a final product gas that is equivalent to natural gas pipeline quality (i.e., pipeline-quality gas, termed biomethane). The biomethane is injected into the Puget Sound Energy (PSE) natural gas pipeline and sold to PSE under a continuing contract. Of the methane entering the scrubbing system in the raw biogas, about 95 percent leaves the system as pipeline-quality biomethane. The gas scrubbing system consists of two separate trains, each with a nameplate capacity of 1.2 million standard cubic feet per day (MMscfd): one installed in 1987 and the other in 1995. The biomethane quality is continually monitored for contract requirements and if non-conforming, the biomethane is flared. Biogas may also be flared if the gas scrubbing system capacity is inadequate for biogas production, such as when a compressor is out of service for maintenance.

The digesters and occupied spaces in the plant are primarily heated by a hot water loop, which derives its heat from a hot water boiler, an effluent heat extractor, or a combined heat and power (CHP) system. The hot water boiler is the primary heating device and is gas-fired with either biomethane or natural gas from the utility. The electricity-driven effluent heat extractor recovers heat from the plant's treated effluent to produce hot water. The CHP system consists of two gas turbines that burn biomethane or natural gas to produce both electricity and steam for heating.

2.2 Operation, Maintenance, and Reliability Concerns

Gas Scrubbing System. Because of its age, the gas scrubbing system currently requires significant maintenance, resulting in relatively high O&M costs and reduced system availability. The two compressors and pump/turbines installed in 1987 are approaching the end of their service life, and require replacement within the next 5 years. The remaining components in the system have 10 years or more of useful life left. Any upgrade to the gas scrubbing system would require a migration of the existing control system to Ovation, the new plant distributed control system (DCS). The gas scrubbing system has historically operated well and has required minimal day-to-day operator attention.

Combined Heat and Power. While in good condition, the gas turbines cannot run on raw biogas and have relatively poor efficiency at the biomethane flow rates that are produced by the digesters. The steam heating system takes one or more shifts to start up and shut down and is used only during extended periods of CHP system operation (e.g., when the boiler is out of service). The primary use of the CHP system is for electrical power demand reduction and system stability during winter storms as the electricity and heat produced by the CHP system are both relatively expensive to produce due to the cost of natural gas to run the gas turbines.

Effluent Heat Extractors. The four heat extractors installed in 1987 have all been decommissioned. The fifth heat extractor installed in 1995 is operated only during summer months, when heat loads are small, because the heat extractor is unable to produce hot water of sufficient temperature to meet winter heat demands.

Gas-Fired Boiler. The gas-fired boiler is in good condition, but is at its maximum capacity for the existing heating requirements. In addition, turndown of the boiler is limited during the summer months, when the hot water system heat demand is low. For most of the year, the only redundancy for plant heating is the CHP system, which is expensive and cumbersome to operate.

Notable information for the existing system includes where the biogas is used and the annual O&M costs to run the biogas utilization system in 2012. These are described in Tables 2-1 and 2-2.

Table 2-1. Biogas and Natural Gas Usage at South Plant in 2012

Parameter	Biogas [MMBtu/yr]		Natural gas [MMBtu/yr]
	Raw biogas	Biomethane	
Digester gas produced	272,000		
Gas scrubbing		243,000	
Sold to PSE		183,000	
Gas-fired boiler		47,000	200
CHP system		50	16,000
Waste gas burners	16,000	13,000	

Table 2-2. Annual Biogas Utilization System Costs in 2012					
Parameter	Operational costs [$]	Revenues/savings [$]	Maintenance costs [$]	Total cost [$]	Unit cost
Gas scrubbing	($435,000)	$796,000	($213,000)	$148,000	$0.2657/therm
Gas-fired boiler	($126,000)	$0	($95,000)	($221,000)	$0.59/therm
CHP system	($157,000)	$197,000	($18,000)	$22,000	$0.16/kWh
Waste gas burners	$0	$0	($10,000)	($10,000)	-
Heat extractors	($37,000)	$0	($22,000)	($59,000)	$0.80/therm

2.3 Summary

The existing biogas utilization system operates well to meet SP's needs and has flexibility to adapt to changing demands on SP and the County. In the future, however, age and the nature of the system installations will require improvements for the current system to continue operating. This includes equipment replacement for the gas scrubbing system in the near term, and improved redundancy for meeting the SP heating demands.

Section 3: TM 2—Development and Screening of South Plant Biogas Management Alternatives

3.1 King County Objectives

To compare the potential alternatives for the SP biogas utilization program, the County's objectives for the program were identified in a workshop setting with the following County staff:

- SP operations, process, and reliability-centered maintenance staff
- Wastewater Treatment Division (WTD) resource recovery, project planning and delivery, and project management staff
- Department of Natural Resources and Parks (DNRP) policy staff

The objectives identified, which were grouped into three categories, are summarized in Table 3-1.

Table 3-1. Objectives for South Plant Gas Utilization Program	
Financial objectives	Notes
1. Minimize capital costs	Costs associated with design, purchase, and installation of capital equipment
2. Minimize O&M costs	Costs associated with operating and maintaining equipment
3. Maximize revenues	Revenues associated with the sale of recovered resources
4. Maximize grants, credits, and incentives	Grants, credits, and incentives received by King County

Table 3-1. Objectives for South Plant Gas Utilization Program	
5. Minimize capital costs	Costs associated with design, purchase, and installation of capital equipment
Environmental objectives	Notes
1. Reduce use of energy [a,b,c,d]	Annual electrical energy consumption and natural gas consumption
2. Reduce greenhouse gas emissions [a,c,d]	Region-wide annual reduction in greenhouse gas production due to County operations
3. Increase production of renewable energy [a,b,c]	Renewable electrical production, biogas production, and recovered effluent heat
4. Increase consumption of renewable energy	Consumption of renewable electricity, biogas, and recovered effluent heat at the plant
5. Invest in alternative fuel transit and fleet vehicles [a,d]	Diesel fuel offset by sale of biogas for CNG production
Operational objectives	Notes
1. Maximize system redundancy and reliability	Indicates the level of downtime expected for each system and the options available if the chosen gas utilization system is not operational
2. Maximize system operational flexibility	Indicates the ability of each system to be modified to meet changes in gas utilization approach and future process changes
3. Minimize WTD labor requirements	Labor requirements for County staff to operate and maintain the systems
4. Minimize reliance on outside service contracts	Contracts with outside parties required to operate and maintain the systems chosen
5. Minimize technical risk	Indicates the relative frequency the systems being proposed are used at municipal WWTPs
6. Minimize air quality treatment requirements	Indicates the risk that post-combustion treatment would be required should air emissions regulations become more stringent in the future

a. King County Energy Plan (10/2010).
b. WTD Energy Plan (2/2010).
c. King County Strategic Climate Action Plan (12/2012).
d. King County Strategic Plan 2010–2014 (7/2010).

3.2 Biogas Management System and Heating Alternatives

Biogas management system and heating alternatives were developed based on process criteria for SP and applicable technologies to meet the process criteria. Each alternative is composed of multiple subsystems, which are divided into three categories that encompass the overarching purpose of the biogas utilization system: meet plant heat demand, achieve beneficial use of the biogas, and provide biogas treatment to facilitate beneficial use. High-level capital and operating cost estimates were developed for each of the alternative subsystems. The 20 alternatives compared in TM 2 are shown in Table 3-2. A description of the alternatives' subsystems follows in the sections below.

Table 3-2. Alternative Description per Category

Alt.	Primary heat source	Gas treatment	Beneficial end use
A1	Status quo (boilers)	Status quo scrubbing system	Status quo (sell gas to PSE)
A2	Status quo (boilers)	Status quo scrubbing system	Use some gas as rCNG
A3	Status quo (boilers)	Status quo scrubbing system	Sell gas to a third party
A4	Status quo (boilers)	New gas scrubbing system	Status quo (sell gas to PSE)
A5	Status quo (boilers)	New gas scrubbing system	Use some gas as rCNG
A6	Status quo (boilers)	New gas scrubbing system	Sell gas to a third party

Table 3-2. Alternative Description per Category			
Alt.	Primary heat source	Gas treatment	Beneficial end use
B1	Low-Btu boilers	Status quo scrubbing system	Status quo (sell to PSE)
B2	Low-Btu boilers	Status quo scrubbing system	Use some gas as rCNG
B3	Low-Btu boilers	New gas scrubbing system	Status quo (sell to PSE)
B4	Low-Btu boilers	New gas scrubbing system	Use some gas as rCNG
C1	Heat extractors	Status quo scrubbing system	Status quo (sell to PSE)
C2	Heat extractors	Status quo scrubbing system	Use some gas as rCNG
C3	Heat extractors	New gas scrubbing system	Status quo (sell to PSE)
C4	Heat extractors	New gas scrubbing system	Use some gas as rCNG
D1	CHP system (hot water)	Status quo scrubbing system	Produce electricity, hot water
D2	CHP system (hot water)	New gas scrubbing system	Produce electricity, hot water
D3	Low-Btu CHP system (hot water)	Gas conditioning system	Produce electricity, hot water
E1	Low-Btu IC engine cogeneration	Gas conditioning system	Produce electricity, hot water
E2	High-Btu IC engine cogeneration	Status quo scrubbing system	Produce electricity, hot water
E3	High-Btu IC engine cogeneration	New gas scrubbing system	Produce electricity, hot water

3.2.1 Primary Heat Sources

Boilers. The two alternatives for gas-fired boilers are to expand the plant's current heating capacity with boilers that burn high-British thermal unit (Btu) gas similar to the status quo, or to install new boilers with the capability to also burn low-Btu or raw digester gas. Providing multiple boilers meets the requirement from TM 1 to provide adequate redundancy for the SP heat supply.

Heat Extractors. This alternative assumes that one or more new high-temperature heat extractors are installed for year-round plant heating producing hot water at a temperature of 155°F or above (compared to 130°F from the existing heat extractors).

CHP System (Hot Water). This alternative assumes that one of the existing gas turbines is run full-time in a duty-standby fashion combusting conditioned biogas or biomethane, and that the heat recovery system is operated full-time for plant heating. The heat recovery system would be converted from a steam system to a hot water system to reduce operational requirements.

Internal-Combustion Engines for Cogeneration. This alternative includes the installation of new reciprocating internal-combustion (IC) engine-generators combusting conditioned biogas or biomethane for cogeneration of electricity and heat.

3.2.2 Gas Treatment

Status Quo Gas Scrubbing. The existing gas scrubbing system would remain, but compressors 1 and 2 and turbines/pumps 1 and 2 would be replaced. The gas scrubbing system control software would be migrated to Ovation.

New Gas Scrubbing. The new gas scrubbing system would be a pressure swing adsorption (PSA) type with all new compression and process equipment. The gas technology selection was preliminary and a full assessment should be conducted during the next phase of the project.

Gas Conditioning System. The IC engine cogeneration alternative or low-Btu CHP alternative assumes that a low-pressure or medium-pressure biogas conditioning system would be installed consisting of hydrogen sulfide, water, and siloxanes removal and compression.

3.2.3 Beneficial End Use

Status Quo (Sell Gas to PSE). The status quo alternative for biogas utilization would be to continue to sell to PSE all biomethane that is not consumed by the plant's hot water boilers.

Renewable Compressed Natural Gas (rCNG). With this alternative, the biomethane produced by the gas scrubbing process would be used on site via a CNG fueling system as an alternative vehicle fuel for two to three Loop trucks.

Sell Gas to a Third Party. The biomethane would be sold to a hypothetical third party that would pay a 10 percent higher rate for the green gas in this alternative.

Electricity Generation. The existing CHP system and new IC engine-generator alternatives would provide heat and electricity to offset plant costs.

3.3 Alternatives Comparison

All of the alternatives developed were compared for each of the County's objectives with equal weighting assigned to each objective category. An objective scoring system was developed for each individual objective with possible scores of 1 to 5. The scores were supported with quantitative analyses, including a net present value (NPV) analysis, a greenhouse gas emissions reduction analysis, and a renewable energy generation analysis. The individual objective total scores were summed into an overall total score for each alternative. The results showed relatively little difference between most of the alternatives. Noticeable trends included the following:

- The alternatives with a new gas scrubbing system tended to score higher than those with the status quo gas scrubbing system.
- The alternatives with heat extractors as the primary heat source did not perform well in financial terms but tended to score well in environmental and operational objectives.
- The alternatives with full-time CHP system operation or a new IC engine-generator cogeneration in general scored the lowest.

The two highest scores were those for alternatives B4 and C4 with a new gas scrubbing system and either boilers or effluent heat extractors for heating. The total scores are shown in Figure 3-1.

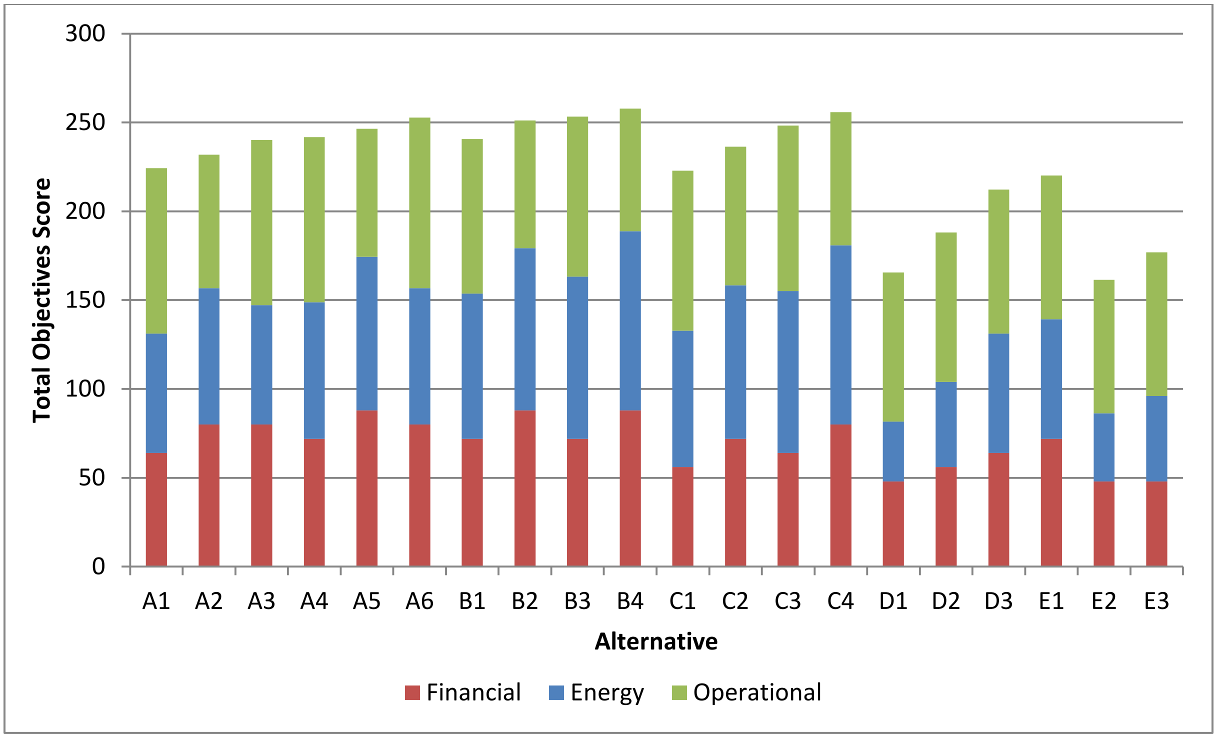

Figure 3-1. Comparison of alternatives based on total objectives

3.4 Conclusions

To provide the greatest variety of potential alternatives for the County to pursue, the three alternatives that are selected for further analysis encompass as many of the sub-systems evaluated as possible. This allows the County to mix and match sub-systems and rebuild an alternative that was not carried forward, should the more detailed analysis reveal that that alternative would be the preferred alternative. To this end, the following three alternatives and status quo alternative are recommended for further evaluation in TM 3:

- B4: low-Btu boilers and a new gas scrubbing system with sale of biomethane to PSE and limited production of rCNG
- C4: new heat extractors and a new gas scrubbing system with sale of biomethane to PSE and limited production of rCNG
- E1: low-Btu IC engines with a gas conditioning system
- A3: status quo with biomethane sale to a third party

Although Alternatives E1 and A3 are not among the highest-scoring alternatives, including them in the TM 3 analysis allows for each of the sub-systems described in Section 3 above to be evaluated further when costs and benefits are further refined.

Section 4: TM 3—Final Alternatives Evaluation and Recommendation

4.1 Objectives Weighting

An objectives-weighting workshop was held with County staff prior to the development of TM 3. At that workshop, the objectives for the analysis were refined and their relative weightings compared to each other were agreed upon, including the following:

- The financial objectives were considered more important than environmental and operational objectives.
- Environmental and operational objectives should be equal.
- Total scoring will be normalized to a 100-point scale with objective category weighting of 40 percent financial, 30 percent environmental, and 30 percent operational.

4.2 Alternatives Development

The three alternatives identified for further analysis in TM 2 were developed further with a focus on conceptual system layouts, interconnections, capacities, and anticipated operating modes. Operational issues, including potential O&M issues, impacts on other treatment plant processes, and permitting issues, were discussed. The alternatives were developed based on process assumptions outlined in Table 4-1 with a design year of 2036 and similar system redundancy to provide capacity for equipment outages.

Table 4-1. Process Assumptions for Digester Gas Utilization Alternatives

Criterion	2013	2036
Average sludge load, gpd [a]	289,000	342,000
Average sludge load, lb-VS/day [a]	132,000	157,000
Average digester gas production, scfd [a]	1,223,000	1,492,000
Average plant heating demands, kWt (MMBtu/hr) [b]	1,570 (5.4)	1,750 (6.0)
Peak heating demands, kWt (MMBtu/hr) [b]	3,030 (10.4)	3,260 (11.1)

a. *Based on sludge loading and digester gas production developed for South Plant Grease Co-Digestion Study (Task Order 2) with no FOG addition, completed in 2011.*

b. *Based on sludge loading developed for South Plant Co-Digestion Study (Task Order 2) with no FOG addition, completed in 2011, and digester and natural gas data for heating from 2012.*

4.3 Economic and Sensitivity Analyses

The alternatives were compared using numerous NPV analyses including sensitivity testing of the assumptions. The baseline NPV analysis results are shown in Table 4-2. The alternative with the best NPV is Alternative B4, the new gas scrubbing system and low-Btu boilers option, which is $0.2 million better than E1 and $1.0 million better than C4. At the level of accuracy associated with this level of design, the NPVs for B4 and E1 can be considered essentially equal. The status quo's NPV is $2.9 million worse than the best alternative. Alternative E1, which installs new IC engine-generators for cogeneration, had the highest capital cost.

Note that all of the NPVs are negative, indicating that none of the options are truly profitable, but all would have more favorable NPVs than that of simply meeting plant operating requirements and wasting the remaining biogas.

Table 4-2. Digester Gas Utilization Alternatives Economic Analysis, $2013					
Alt	Description	Capital cost	Annual O&M costs, 2018	Annual savings/ revenues, 2018	NPV
A3	Status quo	$10,130,000	$810,000	$990,000	($4,590,000)
B4	Low-Btu boilers, new gas scrubbing	$11,120,000	$550,000	$970,000	($1,650,000)
C4	New extractors, new gas scrubbing	$12,210,000	$840,000	$1,250,000	($2,670,000)
E1	Low-Btu IC engines, gas conditioning	$18,540,000	$820,000	$1,610,000	($1,840,000)

During the development of TM 3, the County decided to evaluate each alternative with value-added energy uses to enhance revenue. For the alternatives that resulted in sale of biomethane, the benefits of sale to a third-party, small-scale production of rCNG with onsite fueling, or wheeling the biomethane to an offsite vehicle fleet, were considered. The onsite rCNG fueling and offsite vehicle fleet options include potential revenue enhancement by producing Renewable Identification Numbers (RINs) as part of the U.S. Environmental Protection Agency's (EPA's) Renewable Fuels Standards program. This program currently has funding through 2022 but may be extended beyond the 2036 design year. As such, analyses with both the program ending in 2022 and ending after the 2036 design year were performed. For the electricity generating option, Renewable Energy Certificates (RECs) could be obtained by selling the electricity directly to PSE.

The NPVs for the gas scrubbing alternatives were greatly improved with the option of wheeling biomethane through the PSE pipeline to a CNG vehicle fleet and obtaining RINs. Wheeling gas to a third party for a 10 percent premium or obtaining RECs for renewable electricity produced had positive but fairly minor impacts on the gas scrubbing alternatives and new IC engine-generator alternative, respectively. The results are shown in Table 4-3.

Table 4-3. Net Present Values for Value-Added Options, $2013						
Alt	Description	Third-party biomethane sale	RECs value	rCNG fueling station [a]	RINs value through 2022 for gas into pipeline	RINs value through 2036 for gas into pipeline
A3	Status quo	($3,020,000)	($4,590,000)	($4,910,000)	($1,450,000)	$6,820,000
B4	Low-Btu boilers, new gas scrubbing	($120,000)	($1,650,000)	($1,970,000)	$1,410,000	$9,460,000
C4	New extractors, new gas scrubbing	($740,000)	($2,670,000)	($2,990,000)	$1,240,000	$11,460,000
E1	Low-Btu IC engines, gas conditioning	($1,840,000)	($80,000)	($1,840,000)	($1,840,000)	($1,840,000)

a. *Assumes RIN value extended through 2036. Option limited to fueling about 1.75 Loop trucks per day traveling a distance of 80 miles round trip on average.*

The sensitivities of the NPVs for each alternative were evaluated with the range of economic assumptions summarized in Table 4-5. The sensitivity analyses were conducted with only one variable changed at a time.

Table 4-4. Sensitivity Analysis Range		
Description	Low	High
Escalation rate	1.0 %	5.0 %
Discount rate	3.0 %	7.5 %
Electricity rate and REC escalation only	1.0 %	5.0 %
Natural gas rate escalation only	1.0 %	5.0 %
Diesel rate escalation only	1.0 %	5.0 %
Biomethane sale price and RIN escalation only	1.0 %	5.0 %
REC value for electricity	\$0.0025/kWh	\$0.015/kWh
RIN value for diesel offset	\$0.25/therm	\$1.50/therm
FOG gas production	0 scfd	350,000 scfd
Carbon credit	\$10/ton	\$20/ton

The comparative NPVs were not sensitive to the rate of escalation of natural gas; diesel prices; or gas production from a fats, oils, and greases (FOG) co-digestion program for the ranges assumed. The comparative NPVs of the alternatives were most strongly influenced by the following:

- escalation and discount rates
- electricity escalation rate
- biomethane value escalation rate
- REC value
- RIN value

Alternative E1 had the best NPV for the scenarios where the difference between escalation and discount rates were low, and where electricity escalation rate and RECs value were high. The NPV for Alternative C4 benefited the most where biomethane sale price escalated quickly or where RIN values were generated for all of the gas at a high value, but did not fare as well when electricity rates escalated quickly because of the large use of electricity by the heat extractors. Alternative B4 was similarly impacted but less sensitive to these assumptions than Alternative C4.

4.4 Comparison of Alternatives

The four alternatives were compared with the County's weighted objectives. The individual objective scores are summarized and totaled in Table 4-5. This comparison shows that the best alternative with respect to the County's objectives is Alternative C4, which had a score of 68. This alternative had the highest financial score, a good environmental score, and an average operational score. Alternative B4 was a very close second and also had the best NPV. Alternative A3 was third and scored 6 points less than Alternative C4. Alternative E1 was significantly lower, at a score of 56. Alternative E1 had the second-best NPV because of the significant electricity savings associated with this alternative, but had the lowest financial score because the capital costs objective carried a higher weight than that of the savings O&M and savings/revenues objective. The operational scores in Table 4-5 include minor revisions by the County made in January, 2014 which are not reflected in TM 3.

Table 4-5. Total Objective Comparison					
Objective	Weight	Alternative			
		A3	B4	C4	E1
Financial objectives					
Minimize capital costs	3.3	5	4	4	1
Minimize O&M and R&R costs	2.0	2	4	2	2
Maximize revenues	2.0	1	1	3	5
Maximize grants, credits and incentives	0.7	3	3	5	1
Total weighted financial score		25	25	27	18
Environmental objectives					
Reduce use of and expenditures for energy	1.6	2	4	1	5
Reduce greenhouse gas emissions	1.6	3	4	5	3
Increased consumption of renewable energy	0.6	2	2	2	4
Increase production of renewable energy	1.6	4	4	5	2
Invest in alternative fuel transit and fleet vehicles	0.6	3	3	3	1
Total weighted environmental score		17	22	21	19
Operational objectives					
Maximize system redundancy and reliability	1.3	3	3	5	2
Maximize system flexibility	0.6	2	3	2	5
Minimize WTD labor requirements	1.6	3	3	3	3
Minimize outside contracting requirements	0.3	5	3	2	4
Minimize technical risk	1.6	4	4	3	4
Minimize air quality treatment requirements	0.6	2	3	4	1
Total weighted operational score		19	20	20	19
Total score		61	67	68	56

4.5 Summary and Conclusions

Alternative C4 received the highest overall score of 68, while Alternatives B4 scored second with a score of 67. Either of these two top-scoring alternatives would be justifiable alternatives that would similarly meet the County's objectives and future needs. In addition, producing and selling biomethane to a third party and using part for rCNG are not mutually exclusive—both options can be pursued for Alternatives B4 and C4. With an overall score of 61, Alternative A3 scored appreciably lower than the top two alternatives. The low-Btu IC engine-generator cogeneration system had the lowest overall score of 56. While this alternative meets many of the objectives set forth by the County and has the second-best NPV behind Alternative B4, it is not the most suitable to meet the County's objectives.

Section 5: Final Recommendations

During Workshop III, the consensus among the County staff and Brown and Caldwell was to pursue Alternatives B4 and C4 during management review and predesign of the SP digester gas utilization system upgrade. These two alternatives addressed the County's objectives the best by having the highest financial and environmental scores and good operational scores. Alternative B4 allows for the County to improve its existing biogas management system by selling more of the biomethane produced without substantially altering the type of process heat supply used (i.e., continuing to use boilers to meet the plant's heat demand). Alternative C4 allows for the County to maximize its sale of biomethane and minimize its carbon footprint by using effluent heat extraction to meet the plant's heating needs. However, these benefits come with higher capital and O&M costs and higher electrical power consumption.

During predesign of a new biogas management system, further analysis can be done to refine the costs, implementation concerns, and operational requirements of these two alternatives to allow the County to select and move forward with the optimal system.

Attachment A: TM 1

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Technical Memorandum

Prepared for: King County Department of Natural Resources and Parks

Project Title: Task Order 7: South Plant Digester Gas Utilization Study

Project No.: 141326.007.020

Technical Memorandum 1

Subject: South Plant Biogas Management Equipment and Systems

Date: August 8, 2013

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°F	degree(s) Fahrenheit
A	ampere(s)
Btu	British thermal unit(s)
C3	treated effluent
CHP	combined heat and power
ETS	effluent transfer system
ft	foot/feet
gpd	gallon(s) per day
gpm	gallon(s) per minute
hp	horsepower
hr	hour(s)
HRSG	heat recovery steam generator
in. w.c.	inch(es) water column
kW	kilowatt(s)
kWh	kilowatt-hour(s)
lb	pound(s)
LSG	low-pressure sludge gas
MG	million gallon
mgd	million gallon(s) per day
MMBtu/hr	million Btu/hr
MMscf	million standard cubic feet
MVA	megavolt-ampere(s)
MW	megawatt
MWh	megawatt-hour(s)
NOx	nitrous oxide
PED	primary effluent distribution
ppm	part(s) per million
PSA	pressure swing adsorption
psig	pound(s) per square inch gauge
RUL	remaining useful life
scf	standard cubic foot/feet
scfd	standard cubic foot/feet per day
TS	total solids
TSA	temperature swing adsorption
UPS	uninterruptible power supply
WGB	waste gas burner
yr	year(s)

1 Purpose

This technical memorandum documents the existing biogas management system at King County's (County) South Treatment Plant (South Plant) in Renton, Washington. The existing systems are described to identify the available systems at the plant and their capacities. A discussion of the intended and actual operating modes follows to establish how the systems interact with each other and to describe operational issues that impact the use of the systems. Maintenance and reliability concerns are identified to establish the condition of the existing systems and maintenance requirements that impact the availability of the equipment. A summary of the entire gas management system operation and costs concludes this memorandum.

2 Existing Gas Management System

Treatment of municipal wastewater at South Plant is accomplished through an activated sludge process. Solids removed and/or generated from the wastewater treatment process are treated through the thickening, anaerobic digestion, and dewatering processes. A by-product of the anaerobic digestion process is digester gas, composed of approximately 60 percent methane (CH_4) and 40 percent carbon dioxide (CO_2) (by volume, dry), fully water-saturated, and with minor constituents such as ammonia and hydrogen sulfide (H_2S). To maintain the temperatures required for the mesophilic digestion process, as well as to meet space heating needs, the plant has a hot water loop that is heated primarily by a hot-water boiler burning the biogas produced by the digesters after being cleaned via a gas scrubbing process. Heat can also be supplied by electrically driven heat extractors that recover heat from the treated plant effluent. Scrubbed digester gas that is not consumed by the boilers is primarily sold to Puget Sound Energy (PSE), occasionally consumed in a combined heat and power (CHP) system, or destroyed in the waste gas burners (WGBs).

The following paragraphs describe each of the systems involved with this digester gas management system in greater detail with descriptions of the operation of each system described in Section 3.

2.1 Digesters and Gas Conveyance Systems

Currently South Plant processes thickened raw sludge through its mesophilic anaerobic digesters to produce digester gas and Class B biosolids. The digestion system consists of four active digesters, all of equal size (2.75 million gallons [MG] nominal), and one storage tank (variable operating volume up to 2.25 MG) operating at mesophilic conditions of 95–99 degrees Fahrenheit [°F]. The active digesters have floating covers and the storage tank has a fixed cover; see Figure 2-1. A recent study conducted by the County indicated that the combination of gas mixing and pumped mixing in the digesters achieves approximately 95 percent active volume. Table 2-1 summarizes the basic characteristics of the digestion system operated at South Plant, as reported by King County.

(a) (b)

Figure 2-1. Floating-cover digesters (a) and fixed-cover digested sludge storage tank (b) at South Plant

Table 2-1. Basic Characteristics of South Plant Digestion Process		
Parameter	**Value**	**Notes/comments**
Number of digester tanks	4	
Tank inner diameter (ft)	100	
Design volume (MG)	2.75	
Percent active volume (percent)	95	King County (2011)
Active volume (MG)	2.61	Design volume x percent active volume
Mixing type	Pump mix/gas mix	Both types in each tank
Digester cover type	Floating	
Storage tank cover type	Fixed	
Pressure relief valve setting (inches of water column)	14	King County (2011)
Biosolids product	Class B	
Operating temperature (°F)	95–99	
Digested sludge concentration (percent dry solids)	2.9–3.3	

Digester flows and loads decreased with the 2012 commissioning of the Brightwater Wastewater Treatment Plant (Brightwater). Because the decrease occurred recently, the amount of observed flow and load data with Brightwater operational is limited. As such, the current flows and loads are best estimated by reviewing observed flows prior to the startup of Brightwater and adjusting them by the expected portion of flow diverted from South Plant. A digester capacity analysis completed in 2011, prior to the commissioning of Brightwater, provides this information (“Digester Capacity for Acceptance of Brown Grease”, December 21, 2011). For that analysis, flows from the York and North Creek pump stations—which were diverted to Brightwater—were removed from the South Plant flows observed between 2007 and 2011 to account for the anticipated reductions. Prior to commissioning Brightwater, the flows from the York and North Creek pump stations usually went to South Plant during the 6 to 9 months of wet weather each year and to West Point Wastewater Treatment Plant for the remaining 3 to 6 months of dry weather. During the seasonal change, South Plant's dry weather flows and loads tended to be 15–20 percent less than flows and loads during the wet season with the York and North Creek flows. Thus, diverting York and North Creek flows to Brightwater year round was assumed to decrease South Plant flows and loads by 10–15 percent over an annual basis. Plant staff has indicated that, since the commissioning of Brightwater, observed flows have decreased by 10–15 percent, which is roughly in line with the predictions made in 2011.

A summary of the anticipated flows and loads is provided in Table 2-2.

Table 2-2. Anticipated Solids Flows and Loads on the South Plant Digestion Process

Average annual conditions	Value	Unit
Total solids load	156,245	lb-TS/day
Total volatile solids load	132,326	lb-VS/day
Total flow	288,552	gpd
Maximum 30-day conditions	**Value**	**Unit**
Total solids load	179,523	lb-TS/day
Total volatile solids load	151,404	lb-VS/day
Total flow	331,080	gpd
Maximum 14-day conditions	**Value**	**Unit**
Total solids load	183,665	lb-TS/day
Total volatile solids load	155,866	lb-VS/day
Total flow	349,157	gpd
Maximum day conditions	**Value**	**Unit**
Total solids load	211,320	lb-TS/day
Total volatile solids load	178,354	lb-VS/day
Total flow	392,256	gpd

Using the flows and loads in Table 2-2, since Brightwater has been commissioned the digester gas production at South Plant is estimated to have decreased from 1.50 million standard cubic feet per day (scfd) to 1.24 million scfd at annual average conditions. These values were calculated assuming that 62 percent of volatile solids are destroyed in the digestion process and that 15 scf of digester gas is generated for each pound of volatile solids destroyed.

Sampling of the raw digester gas for methane (CH_4), carbon dioxide (CO_2), and hydrogen sulfide (H_2S) is performed regularly at South Plant with continuous sampling of the scrubbed gas completed as part of the County's agreement with PSE. More infrequent but extensive samplings have been performed as part of capital and demonstration projects, such as the Fuel Cell project. The range of results from raw digester gas sampling from 2010–12 for CH_4, CO_2, and H_2S, and from samples taken in February 2003 for other constituents, were reported by the County and are summarized in Table 2-3 below.

Table 2-3. Raw Digester Gas Analysis Results

Parameter	Value	Unit
Methane	56–61	%-vol-dry
Carbon dioxide	37–41	%-vol-dry
Water vapor	5–6	%-vol
Hydrogen sulfide	90–225 [a]	ppm
Total siloxanes	1–2.8	lb/MMscf
Lower heating value	500–600	Btu/scf

a. *Range includes peak levels observed each year between August and October.*

No dedicated gas storage facilities are located at South Plant for either raw digester gas or scrubbed gas. Some digester gas storage is available in the headspace of the blended sludge storage tank with a liquid volume that can vary from 0 to 2.25 MG. Though digesters 1–4 also have a gas headspace, it is very limited given that the digesters' covers float on the liquid surface of the digesters. Pressure relief valves on the digester covers are set to relieve excessive gas pressure at 14 inches water column (in. w.c.).

The low-pressure sludge gas (LSG) piping at South Plant is stainless-steel pipe of varying schedules and diameters, ranging from 8 to 30 inches. Condensate that forms in the LSG piping is removed through five sediment traps and each digester has a dedicated gas flow meter with a heat exchanger to preheat the gas prior to flow measurement in order to prevent condensation in the meter. The high-pressure gas piping is stainless-steel pipe of varying schedules and diameters, ranging from 2 to 3 inches.

2.2 Digester Gas Scrubbing System

The digester gas scrubbing system, shown in Figure 2-2, is a high-pressure water solvent type system that removes CO_2, H_2S, water, and other constituents to produce a pipeline-quality gas. Of the methane entering the system in the raw digester gas, about 95 percent leaves the system as pipeline-quality biomethane. The original installation of the gas scrubbing system was completed in 1987 as part of Enlargement II. The system's capacity was doubled as part of Enlargement III in 1995. As such, two gas scrubbing trains share some common equipment and piping.

The gas scrubbing system (Table 2-4) comprises positive-displacement dual-stage compressors, water-based adsorption scrubbing towers, desiccant gas dryers with temperature/pressure swing adsorption (TSA/PSA), gas-quality instrumentation (measuring temperature, pressure, flow rate, specific gravity, dew point, and British thermal unit [Btu] content), and a gas odorizer (mercaptan addition). The water used in the gas scrubbing system is treated effluent (C3) that is pressurized with pumps partially powered by turbines recovering energy from the return water.

(a) (b)

Figure 2-2. Binax biogas scrubbing facility at South Plant: (a) water scrubbing towers and (b) gas compressor

The capacities listed in Table 2-4 represent the as-installed capacity for each component. Discussions with County staff regarding the actual production and operation of the equipment have indicated that the compressor capacities may have deteriorated since their installation. Compressor 3 and one of either compressor 1 or 2 are needed to compress an average of 1.2 million scfd, suggesting that the actual capacity for each compressor may be up to 30 percent less than the values shown in Table 2-4. Operation of the remaining equipment (scrubbing towers, scrubbing water pumps/turbines, and gas dryers) indicates that their capacities match observed operational requirements. See Section 3.2 for further discussion on the gas scrubbing system operation.

Table 2-4. Digester Gas Scrubbing System

Asset description	Asset number	Make	Model	Installed date	Flow	Pressure	Power
Gas scrubbing compressor 1	CP 222,230	Ingersoll Rand	2PHE-2	1987	0.6 MMscfd [a]	305 psig	150 hp
Gas scrubbing compressor 2	CP 222,240	Ingersoll Rand	2PHE-2	1987	0.6 MMscfd [s]	305 psig	150 hp
Gas scrubbing compressor 3	CP 222,245	Dresser-Rand	Custom	1995	1.2 MMscfd [s]	305 psig	350 hp
Gas scrubbing tower 1	PVL 222,250	Modular Products		1987	1.21 MMscfd		
Gas scrubbing tower 2	PVL 222,255	Modular Products		1995	1.21 MMscfd		
Scrubbing water pump 1	P 222,210	Ingersoll Rand	1080	1987	550 gpm	350 psig	200 hp
Scrubbing water pump 2	P 222,220	Ingersoll Rand	1080	1987	550 gpm	350 psig	200 hp
Scrubbing water pump 3	P 222,225	Ingersoll Rand	SCVN7	1995	600 gpm	350 psig	250 hp
Scrubbing water turbine 1	TBN 222,212	Ingersoll Rand	900	1987	330 gpm		40 hp
Scrubbing water turbine 2	TBN 222,222	Ingersoll Rand	900	1987	330 gpm		40 hp
Scrubbing water turbine 3	TBN 222,227	Ingersoll Rand	900	1995	400 gpm		40 hp

Table 2-4. Digester Gas Scrubbing System

Asset description	Asset number	Make	Model	Installed date	Flow	Pressure	Power
Gas dryer 1	ME 222,270	Henderson	EP-350T7XX	1995	1 MMscfd		
Gas dryer 2	ME 222,271	Henderson	EP-350T7XX	1995	1 MMscfd		
Gas dryer 3	ME 222,272	Henderson	EP-350T7XX	1995	1 MMscfd		
Gas metering equipment heater 1							11 A
Gas metering equipment heater 2							11 A
Gas metering equipment heater 3							18 A
Capacitor bank							33 A

a. These capacities are as installed. Observed operation indicates that actual capacity may be up to 30% lower.

2.3 Gas-Fired Hot Water Boiler

The primary source of heat for the plant's hot water loop is provided by an 11.7-million Btu/hr (MMBtu/hr) gas-fired hot water boiler, which is shown in Figure 2-3 and whose capacities are listed in Table 2-5. The boiler currently uses scrubbed gas as its primary fuel source. It is also connected to the plant's natural gas supply. The boiler system consists of a four-pass boiler, combustion air blower, and hot water recirculation pump.

Figure 2-3. Gas-fired hot water boiler at South Plant

Table 2-5. Hot Water Boiler System					
Asset information					
Asset description		Asset number	Make	Model	Installed date
Hot water boiler		BLR 232,513	Hurst	Series 500	2003
HRS boiler blower		B 232,513	Power Flame Burner	LNIC8-G-30	2003
HRR/HRS recirculation pump		P 232,514	Goulds	3196	2003
Capacity information					
Asset number	Output	Flow	Pressure	Power	Efficiency [%]
BLR 232,513	11.7 MMBtu/hr	0.68 MMscfd	4.3 ft w.c.		80
B 232,513			14.07 in. w.c.	15 hp	
P 232,514		350 gpm		10 hp	

2.4 Combined Heat and Power System

The CHP system at South Plant (Figure 2-4 and Table 2-6) is an 8-megawatt (MW) combined-cycle plant consisting of two 3.5 MW gas-fired turbines, two heat recovery steam generators, a 1.0 MW steam turbine, and a steam condenser. The gas turbines can burn scrubbed gas, natural gas, or a blend of scrubbed gas and natural gas as long as all fuel is supplied at a minimum pressure of 170 pounds per square inch gauge (psig). Power generated by the gas and steam turbines is used to power the plant's equipment and heat generated can be recovered and used by the plant's hot water loop.

Figure 2-4. CHP system at South Plant
(a) gas turbine and (b) steam turbine condenser

Table 2-6. Combined Heat and Power System						
Asset description	Asset number	Make	Model	Installed date	Output	Fuel flow
Turbine 1	GTG 250,420	Solar	Centaur 40 4701S	2006		2.1 MMscfd
Generator 1	G 250,420	Kato	AA2752700	2006	3.5 MW	
Steam generator 1	HRG 250,440	Victory Energy	VE-321	2006	16,700 lb/hr	
Process heater 1	HEX 250,610	ITT Industries	B300S13084-2	2006	12 MMBtu/hr	
Turbine 2	GTG 250,460	Solar	Centaur 40 4701S	2006		2.1 MMscfd
Generator 2	G 250,460	Kato	AA2752700	2006	3.5 MW	
Steam generator 2	HRG 250,480	Victory Energy	VE-321	2006	16,700 lb/hr	
Process heater 2	HEX 250,620	ITT Industries	B300S13084-2	2006	12 MMBtu/hr	
Steam turbine	STG 250,520	TGM Turbinas		2006		
Steam turbine generator	STG 250,250		TMC 5000	2006	1.0 MW	
Steam turbine condenser	STC 250,560	Graham		2006		

2.5 Waste Gas Burner System

Three waste gas burners at South Plant are used to safely dispose of gas that cannot be used on site or sold to PSE (Figure 2-5 and Table 2-7). The waste gas burners, installed in 2010, are fed by gas from the LSG system but diversions from the gas scrubbing system send scrubbed gas into the LSG pipeline that ultimately go to the waste gas burners.

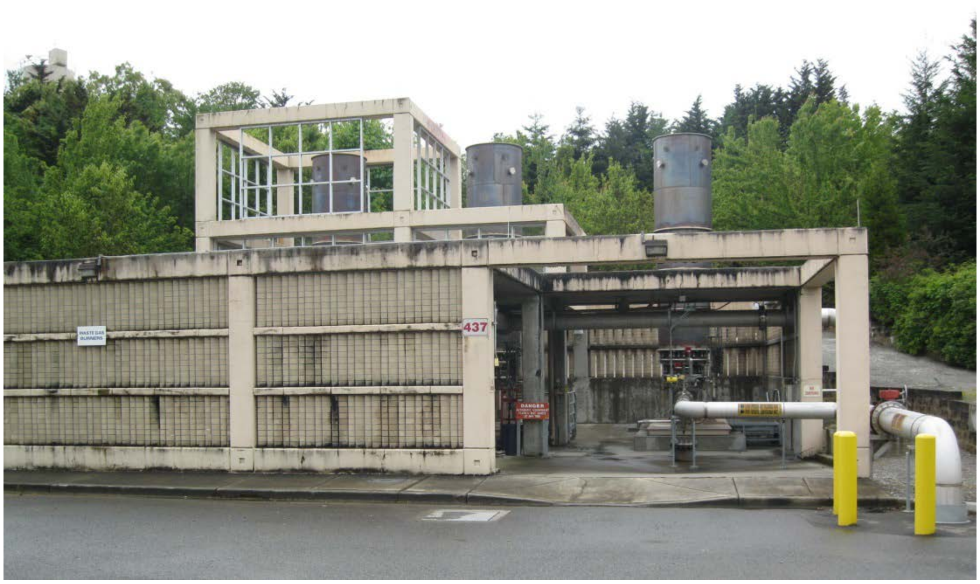

Figure 2-5. Waste gas burner system at South Plant

Table 2-7. Waste Gas Burner System						
Asset description	Asset number	Make	Model	Installed date	Flow [MMscfd]	Pressure [in. w.c.]
Waste gas burner 1	ME 222,440	Varec	244E	2010	0.81	8.5
Waste gas burner 2	ME 222,450	Varec	244E	2010	0.81	8.5
Waste gas burner 3	ME 222,460	Varec	244E	2010	0.81	8.5

2.6 Heat Loop System and Effluent Heat Extractors

The plant hot water loop supplies hot water to plant buildings and facilities for spacing heating and to process systems for process heating (e.g., the anaerobic digesters via sludge heat exchangers). Sludge heat exchangers are located on the thickened sludge blending tank, the four digesters, and the blending/storage tank. The digester sludge heat exchangers are rated for 2.2 MMBtu/hr each. Observed total plant heat load averages 5.7 MMBtu/hr over the year with a minimum monthly demand of 2.3 MMBtu/hr during summer months and maximum monthly demands of 11.8 MMBtu/hr during the winter. The range of heat loads is driven primarily by the range of wastewater and sludge temperatures across the year (from 54°F in winter months to 72°F in summer months), ambient air temperatures, and weather conditions.

Though five effluent heat extractors are currently installed at the plant (Figure 2-6 and Table 2-8), only heat extractor 5, the largest unit, is still operational. Heat extractors 1 through 4 have essentially been decommissioned and there is no plan to return them to service. The electrically driven heat extractor recovers heat from the plant's treated effluent. The system consists of a heat extractor, conditioned water (heat loop) pump, and C3 pump.

The first four heat extractors were installed in the late 1980s during Enlargement II using R-12 (Freon-12) as the refrigerant. The fifth heat extractor was added in 1995 during Enlargement III using R-134a as the refrigerant. The R-12 refrigerant used in heat extractors 1 through 4 was replaced with R-134a in 2000 following the ban on manufacture of R-12 as part of the Montreal Protocol. The switch in refrigerant dropped the temperature of the hot water available from the heat extractors from about 140°F to 130°F, significantly decreasing their capacity to provide process and facility heat throughout the year. The loss of heat extractor capacity, together with rising energy costs, was one of the main catalysts for installing the hot water boiler described in Section 2.3.

Figure 2-6. Effluent heat extraction system at South Plant
(a) heat extractor 5 and (b) effluent pumps for extractors 1–4

Table 2-8. Effluent Heat Extraction System

Asset description	Asset number	Make	Model	Installed date	Output	Power	COP
Heat extractor 1	HXT 221,050	McQuay	TEH079	1987 [a]	6 MMBtu/hr	429 kW	4.0
Heat extractor 1 C3 water pump	P 221,066	Goulds	3196MTX	1995 [a]	950 gpm	30 hp	
Heat extractor 1 conditioned water pump	P 221,242	Goulds	3196	1995 [a]	500 gpm	10 hp	
Heat extractor 2	HXT 221,051	McQuay	TEH079	1987 [a]	6 MMBtu/hr	429 kW	4.0
Heat extractor 2 C3 water pump	P 221,067	Goulds	3196MTX	1995 [a]	950 gpm	30 hp	
Heat extractor 2 conditioned water pump	P 221,243	Goulds	3196	1995 [a]	500 gpm	10 hp	
Heat extractor 3	HXT 221,052	McQuay	TEH079	1987 [a]	6 MMBtu/hr	429 kW	4.0
Heat extractor 3 C3 water pump	P 221,068	Goulds	3196MTX	1995 [a]	950 gpm	30 hp	
Heat extractor 3 conditioned water pump	P 221,244	Goulds	3196	1995 [a]	500 gpm	10 hp	
Heat extractor 4	HXT 221,053	McQuay	TEH079	1987 [a]	6 MMBtu/hr	429 kW	4.0
Heat extractor 4 C3 water pump	P 221,069	Goulds	3196MTX	1995 [a]	950 gpm	30 hp	
Heat extractor 4 conditioned water pump	P 221,245	Goulds	3196	1995 [a]	500 gpm	10 hp	
Heat extractor 5	HXT 221,054	Carrier	19EF2626427DDG	1995	6 MMBtu/hr	429 kW	4.1
Heat extractor 5 C3 water pump	P 221,070	Goulds	3196MTX	1995	950 gpm	30 hp	
Heat extractor 5 conditioned water pump	P 221,246	Goulds	3196	1995	500 gpm	10 hp	

a. This unit is existing but no longer in service.

3 System Operation

A simplified diagram showing the overall gas utilization system at South Plant is shown in Figure 3-1. Operation of each of the components is described below based on discussions with the original design groups and South Plant operations staff. When available, operational hours, energy consumption, and production numbers are provided to establish costs and revenues associated with each system. Feedback from plant staff during a site tour and subsequent conversations are summarized as well.

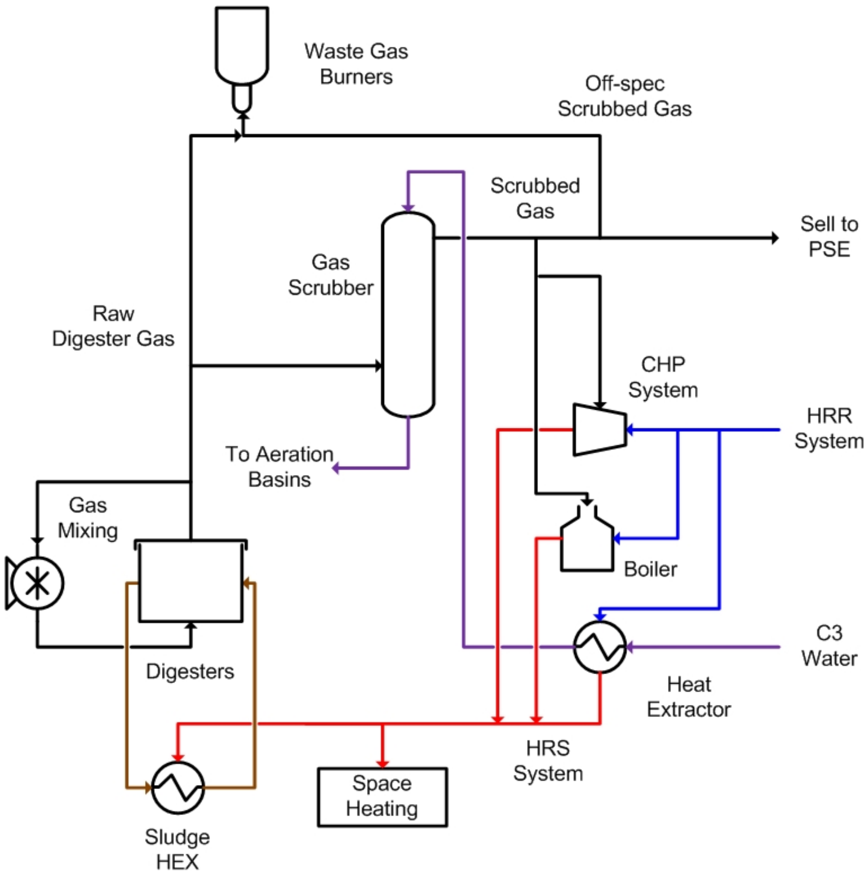

Figure 3-1. Gas utilization system overview

3.1 Solids Processing Impacts

Discussions with South Plant staff indicated that operations of the solids treatment processes do not significantly impact the gas production from the digesters. Specific processes discussed included the digester mixing system, solids dewatering process that follows digestion, and end use of the biosolids.

Digester mixing is accomplished by recirculation of digester gas and digested sludge through the digesters. Because the gas and sludge recirculate, this does not impact the volume of gas produced and operationally the treatment plant staff do not observe a change in gas quality based on the amount of gas and sludge mixing used.

Biosolids dewatering is achieved through the use of decanting centrifuges at South Plant. This process operates intermittently, with 4 days per week at two shifts per day and 3 days per week at one shift per day. Because solids are continuously fed to and withdrawn from the digesters, this intermittent dewatering operation requires biosolids to be stored in the storage tank between dewatering shifts. A small amount of storage is also available in the floating-cover digesters, though it is used infrequently. Plant staff indicated that they do not observe any changes in gas quality or quantity between periods of storage and dewatering.

Occasionally, winter snowstorms briefly block travel to eastern Washington, where the majority of King County biosolids are recycled. During these times, the plant cannot haul all of the dewatered biosolids to beneficial recycling sites and the solids must be stored in the digesters and storage tank until hauling is available again. With this increase in biosolids storage, an appreciable decrease in available gas storage occurs within the storage tank but plant staff indicated that they do not observe a corresponding change in gas quality or quantity when gas storage is reduced.

3.2 Gas Scrubbing System

This section describes the theory of operation, operational costs, and operational considerations for the gas scrubbing system.

3.2.1 Theory of Operation

A simplified diagram of the gas scrubbing system is shown in Figure 3-2 below. Low-Btu (i.e., 600 Btu/scf) gas from the digesters is compressed from approximately 8 in. w.c. to 300 psig through the two-stage compressors. The compressed gas is introduced to the bottom of the scrubbing towers while plant effluent, pressurized to 300 psig by the scrubbing water pumps, is introduced at the top of the scrubbing towers. Within the scrubbing towers is an inert media, which is used as the contact site for undesirable constituents within the digester gas (e.g., CO_2, H_2S, etc.) to be adsorbed by the scrubbing water. Methane is also absorbed into the scrubbing water at these high pressures, though the percentage is relatively small (about 5 percent of the methane entering the system). The scrubbing water leaving the scrubbing towers runs through the scrubbing water turbines to reduce the pressure of the water and to recover energy for pressurizing and pumping the scrubbing water. From the turbines the scrubbing water flows to a primary effluent distribution (PED) structure for mixing with primary effluent and solids return streams prior to introduction to the aeration basins.

The scrubbed gas leaving the contact tower is saturated with moisture. This moisture is removed in activated-alumina desiccant dryers before the gas runs through gas quality instrumentation. The quality of the dried, scrubbed gas is continuously monitored to confirm that PSE's gas quality specifications are being met. The gas quality requirements set by PSE are summarized in Table 3-1. Scrubbed, dried gas that does not meet PSE gas quality specifications is automatically diverted to the LSG pipeline for disposal by the waste gas burners. Gas that meets the quality specifications fuels the plant's boiler and CHP system, or is odorized by adding mercaptans and sold directly to PSE. Sold gas is injected into the 20-inch-diameter natural gas pipeline adjacent to the South Plant site. The County's gas sale agreement limits the amount of gas PSE will purchase at 1.3 million scfd, though the plant does not approach this limit (e.g., the daily maximum amount of scrubbed gas sold in 2012 was 0.75 million scf).

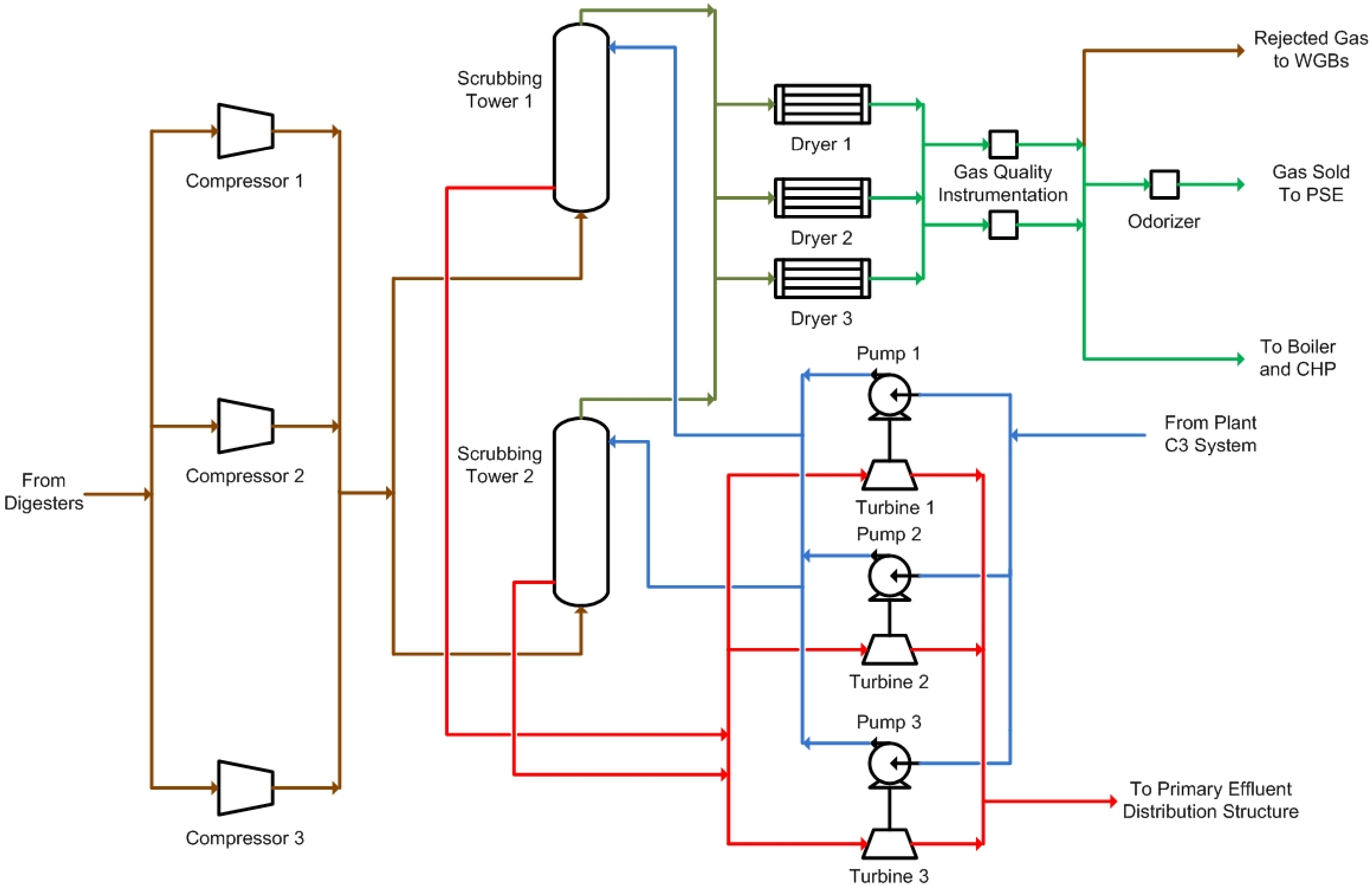

Figure 3-2. Simplified process diagram of the South Plant gas scrubbing system

Table 3-1. Scrubbed Gas Quality Requirements		
Parameter	Value	Unit
Lower heating value, min	985	Btu/scf
Specific gravity, max	0.585	
Dew point, max	14	°F
Pressure, min	200	psig

3.2.2 Operational Costs

In 2012, based on the estimated flows presented in Table 2-2, it is estimated that the digesters at South Plant produced approximately 453 million scf of raw digester gas. The gas scrubbing system converted this volume of raw digester gas into approximately 248 million scf per year of scrubbed gas, or 2.43 million therms. Of the scrubbed gas, 1.83 million therms were sold to PSE with the remainder going to the boiler, CHP, or waste gas burner systems.

Operation of the gas scrubbing system is energy-intensive due to the high pressure requirements for both the digester gas and scrubbing water. Direct measurement of the power requirements is difficult to obtain, but plant staff indicate that typical operation requires a large compressor and small compressor to be operating with two scrubbing water pumps/turbines. This connected load (950 horsepower [hp]) is roughly in line with readings from the solids-area substation power meter, which indicates that the gas scrubbing system uses about 0.75 MW when in operation.

Table 3-2 summarizes the revenues and costs associated with operating the gas scrubbing system in 2012. The price that PSE pays the County for scrubbed gas is the commodity price as defined in PSE's Gas Schedule 101. This schedule is usually revised annually (taking effect in October or November each year) after approval by the Washington State Utilities and Transportation Commission. The current rate of $0.4347/therm, which took effect in November 2012, is used in Table 3-2.

Table 3-2. Gas Scrubbing Operational Costs and Revenues in 2012		
Parameter	Value	Unit
Electric power consumption	6,208,000	kWh
Annual electrical power costs [a]	435,000	$
Scrubbed gas sold	1,831,000	Therms
Revenue from scrubbed gas [b]	796,000	$

a. *Electrical costs are $0.07/kWh, including demand charges and fees.*

b. *Scrubbed gas is sold to PSE at $0.4347/therm as of Nov. 2012.*

The current scrubbed gas sale rate of $0.4347/therm is the lowest price that the County has been paid for its scrubbed gas since 2004. In the intervening years, the price reached as high as $0.760/therm in 2009. Table 3-3 below shows average gas sale prices from 2004 to 2012 and the average cost of electricity over the same period. The fall in gas sale prices since 2009 while electrical prices have continued to rise suggests that the current rate for the scrubbed gas produced by the County may be unsustainably low and many County staff members reported that they expect the rate to rise in the future.

Table 3-3. Comparison Between Gas Sale Price and Electricity Purchase Price

Year	Average scrubbed gas sale price, [$/therm]	Average electricity purchase price, [$/kWh]
2004	0.4543	0.049
2005	0.5873	0.053
2006	0.6909	0.060
2007	0.7331	0.060
2008	0.7097	0.063
2009	0.7205	0.065
2010	0.5968	0.067
2011	0.5547	0.069
2012	0.4937	0.071

3.2.3 Operational Considerations

The plant occasionally observes instances when the scrubbed gas does not meet PSE's specifications and thus is rejected or diverted from entering the PSE natural gas system. This rejection can happen when the gas pressure, specific gravity, Btu content, or moisture content is outside the acceptable range of values. Once a deviation is measured, the system is required to reject gas until the system produces acceptable gas for a minimum of 30 minutes with the exception of pressure deviations. The minimum wait period is only 5 minutes if the rejection was based solely on the pressure requirement. The rejected or diverted scrubbed gas is diverted to the waste gas burners.

The plant has also observed a significant impact on gas scrubbing capacity based on the plant's effluent temperature. During summer months, when effluent temperatures increase from approximately 54°F to 72°F, the capacity of the scrubbing water to adsorb constituents is diminished. As a result, the overall scrubbing capacity is reduced by about 10 percent based on plant observations. Similarly, when the heat extractor system is operating and recovering heat from the plant's effluent, the scrubbing water temperature is reduced by about 8°F, allowing for increased adsorption and overall system capacity.

The plant has also observed process impacts in the aeration basins from the addition of water from the scrubbing towers. The scrubber water, while under pressure, is supersaturated with CO_2, H_2S, and other constituents adsorbed from the digester gas during the scrubbing process. As the scrubber water is released into the PED structure to mix with primary effluent, much of the dissolved gases come out of solution. These released gases are contained under channel covers and conveyed to the secondary odor wet scrubber. However, some amount of the dissolved gases stay in solution, depending on various factors. For example, H_2S is more likely to stay in solution when the primary effluent pH is 6.8 or greater. Below a pH of 6.8, H_2S prefers to exist as a gas so it comes out of solution. Though the scrubbing water contains a large amount of CO_2 from the digester gas, a vast majority of it is released in the PED structure while a small amount remains in solution. This addition of low-pH, low-alkalinity water may impact the plant's secondary process, especially the ability to nitrify and denitrify. Currently the plant is not required to remove nutrients but if this changes, the impact of adding scrubbing water to the liquid stream treatment process may need to be evaluated further.

3.3 Gas-Fired Hot Water Boiler

This section describes the theory of operation, operational costs, and operational considerations for the gas-fired hot water boiler.

3.3.1 Theory of Operation

The gas-fired boiler operates primarily on scrubbed digester gas but can operate on natural gas when scrubbed gas is unavailable. Fuel is burned within the boiler, stoked by air supplied by the boiler's blower. Water from the plant's hot water loop is heated by circulating through the boiler, driven by the recirculation pump. The boiler produces 195°F hot water, which is mixed using a three-way valve to maintain the plant's hot water loop temperature at 145° to 150°F. Stack temperatures were observed to be 220°F.

The original design intent for the gas-fired boiler was for it to operate as the primary heat source in the time period between switching refrigerants on the heat extractors and the completion of the CHP system. With the completion of the CHP system, the heat recovery steam generators were to become the plant's primary heat source because the turbines would be operating continuously as the primary source of the plant's electricity. However, significant changes in energy market prices as well as operational behaviors of the CHP system (discussed in further detail below) changed the economics of supplying electricity from CHP. Thus, the boiler system remains the plant's main heat source.

3.3.2 Operational Costs

In 2012, the gas-fired boiler consumed 466,000 therms of scrubbed gas and approximately 2,000 therms of natural gas. In general, the boiler is fed natural gas only when the gas scrubbing system is unavailable (estimated at 2–5 percent of the year; see Section 4.1.1). The plant does not measure boiler heat output directly. However, based on an assumed efficiency of 80 percent, the boiler produced 37,000 MMBtu in 2012 based on fuel input. The boiler operated for 8 months (250 days) in 2012. Heat extractor 5 provided hot water during the remainder of the year. Table 3-4 summarizes operational costs associated with the hot-water boiler in 2012.

Table 3-4. Gas-Fired Boiler Operational Costs in 2012

Parameter	Value	Unit
Natural gas consumption	2,000	Therms
Annual natural gas costs [a]	2,000	$
Scrubbed gas consumption	466,000	Therms
Cost to produce scrubbed gas [b]	124,000	$

a. Natural gas costs are $1.01/therm.

b. Scrubbed gas costs $0.2657/therm to produce.

3.3.3 Operational Considerations

The boiler operates near full capacity during winter months (especially the first three months of the year) when ambient, wastewater, and sludge temperatures are the lowest and the plant's heat demand is the highest. During the first 3 months of 2012, the average fuel input to the boiler was 10.7 MMBtu/hr with a maximum day fuel input of 12.7 MMBtu/hr. During summer months when the plant's heat demand is low, the boiler will start cycling and occasionally drop offline. Plant staff indicated that the boiler does not operate well while cycling as condensate forms in the fourth pass at low loads. Because of the problem with cycling and dropping off line, the boiler is turned off during the summer in favor of using heat extractor 5. In 2012, heat extractor 5 operated from mid-June to mid-October.

Heat demand at the plant is expected to be reduced from the demand seen in previous years due to the commissioning of Brightwater and the resulting reduction in flows and loads at South Plant. In addition, recent efforts to reduce struvite (magnesium ammonium phosphate) buildup in the sludge recirculation system (piping, elbows, valves, etc.) and equipment have enhanced the heat transfer to the plant's sludge, reducing the plant's overall heat demand.

3.4 Combined Heat and Power System

This section describes the theory of operation, operational costs, and operational considerations for the CHP system.

3.4.1 Theory of Operation

The CHP system operates by combusting natural gas, scrubbed gas, or a blend of the two gases in the gas turbine to drive the electric generator. These gases must be supplied at a minimum pressure of 170 psig to overcome the pressure of the ambient air supplied to the gas turbines. The exhaust gases from the gas turbines can be either rejected or run through the heat recovery steam generators (HRSG) prior to being rejected. Within the HRSG, water is vaporized into steam by the heat of the turbine exhaust. The resulting steam can be sent to either the steam turbine or the process heater. The steam turbine uses expansion of the steam to drive an electric generator. The wasted steam is then sent to the steam turbine condenser, where the steam condenses back to water and is recycled to the gas turbines. In the process heater, heat is recovered both directly from the steam as it condenses and from the hot condensate to provide heat to the plant's hot water loop. Figure 3-3 is a simplified diagram of the CHP system.

The original design intent for the CHP system was based on using the turbines to produce most of the plant's electrical power and all of the plant's heating needs. The plant averaged 7.57 MW in electrical power consumption in 2012 with a daily peak of 9.11 MW, indicating that the CHP system has the capacity to meet the plant's average power demand. During predesign of the CHP, high electrical prices and low natural gas prices indicated that a natural gas power plant would be a cost-effective means of meeting the plant's electrical demand while limiting the County's exposure to variations in electrical prices. Since its design, electrical prices have dropped and stabilized and natural gas prices have increased. Thus, operating the CHP system on scrubbed gas and/or natural gas has not been, and is not currently, a cost-effective approach to meeting the plant's electrical needs.

Though the original operating strategy for the CHP system was to operate it continuously to supply electricity and heat, it is worth noting that the decision to build the CHP was based primarily on the County's interest in returning South Plant to being a PSE Schedule 49 electrical customer (rather than buying electricity at higher rates from the spot market). PSE agreed to support South Plant's return to Schedule 49 as long as the plant installed generation equipment on site to account for the additional demand created by the equipment installed in Enlargement III.

Because of the changes in electrical and natural gas prices, and because one turbine would consume 100 percent of the plant's scrubbed gas production while operating at a partial load, the CHP system is not operated regularly. When it is operated, it is used for one of the following five purposes:

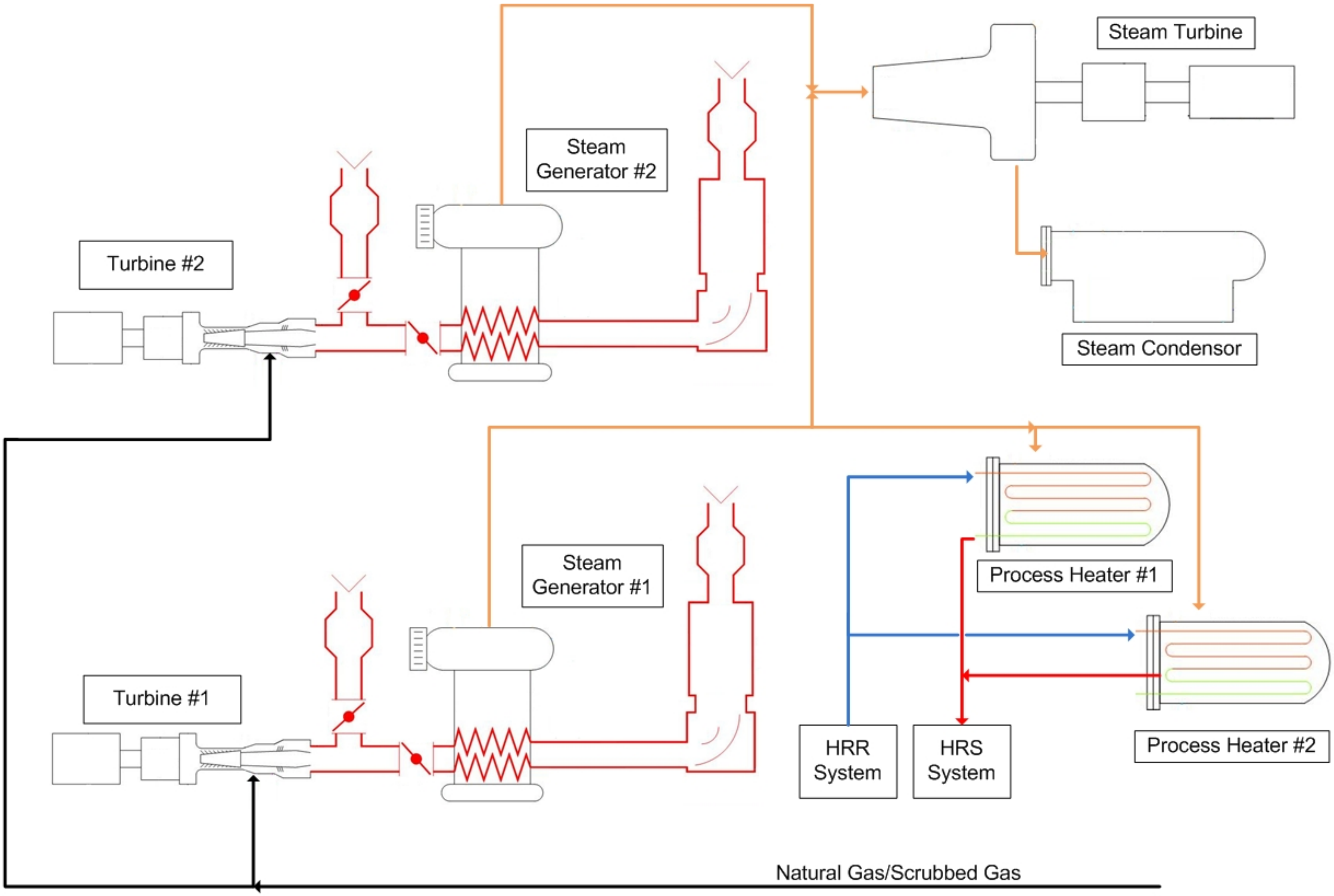

Figure 3-3. Simplified process diagram of the South Plant CHP system

1. To reduce the plant's peak electrical power demand on PSE and the associated demand charges. When plant flows exceed 140 million gallons per day (mgd), the peaking pumps on the effluent transfer system (ETS) are needed, dramatically increasing the plant's electrical demand. The total plant demand can reach as high as 22 MW as plant flows reach about 325 mgd. To reduce this peak demand and its associated charges, a gas turbine is turned on prior to starting the ETS peaking pumps. The second gas turbine is started after plant flows continue to increase above 220 to 240 mgd. The goal is to maintain the plant's peak demand on PSE's grid as low as possible and not greater than 15 megavolt-amperes (MVA), reducing the demand charge that the plant incurs from PSE.
2. To provide electrical system stability during storm events. Before the turbines were installed, the plant would suffer from brownouts and electrical system instability from the PSE electrical supply during winter storms. With a turbine operating at 1.5 to 2 MW during storm events, and better use of uninterruptible power supplies (UPS) throughout the plant, the plant rarely experiences these issues anymore.
3. To provide redundancy to the plant heating system. If the gas-fired boiler fails during a period when heat extractor 5 cannot meet the plant's heating demand, the gas turbines can be operated to generate steam for plant heating.
4. To provide standby power during a power outage. The plant has dual power feeds from PSE, which reduce the risk that grid power will be lost. In fact, plant staff indicated that since 1961, the plant has never lost power from both power feeds for more than 10 minutes. But in the event that a failure of the dual power supply from PSE ever occurs, the turbines can run on natural gas to provide sufficient power for raw sewage pumping, primary treatment, disinfection, and ETS pumping with duty pumps.
5. To exercise the system for regular maintenance.

3.4.2 Operational Costs

In 2012, the CHP system operated for 536 turbine-hours over 55 days and consumed 156,000 therms of fuel. Of this fuel, approximately 500 therms were scrubbed gas and the remainder was natural gas. The system produced 1.10 million kilowatt-hours (kWh) of power in 2012.

The very low use of scrubbed gas in 2012 was due to moisture buildup in the scrubbed gas pipeline that had the potential to damage the gas turbines. A sump pump system was installed on this pipeline in November 2012 to remove the moisture. With this ability to remove moisture from this pipeline, the County will likely use much more scrubbed gas in the CHP when it is needed in the coming years.

In 2012, no heat was recovered by the CHP and plant staff indicate that the heating system is rarely operated unless it will operate for an extended period of time. The best example of that occurred from December 2010 to April 2011, when the boiler and gas scrubbing system were damaged and not operational. One HRSG was operated during that time to provide process and facility heat. Direct measurement of the heat provided by the CHP system is not available but heat input from the CHP system can be calculated by identifying periods when the hot water boiler was not operating while the CHP system was operating. Between 2007 and 2011, the CHP system produced an estimated 8,000 MMBtu per year, with most of that heat being produced between December 2010 and April 2011.

Plant staff also reported that the plant can reduce the peak demand on PSE, and the resulting demand charges, by operating the CHP system when the ETS peaking pumps operate. Review of PSE's Schedule 49 and South Plant electrical bills indicates that reducing the plant's peak demand on PSE during winter months by 5 MVA saves approximately $120,000 per year in demand charges.

Table 3-5 below summarizes the revenues and costs associated with operating the CHP system in 2012. Plant staff indicated that the County, though it has a parallel operating interconnection agreement with PSE, does not have a contract with PSE to purchase excess electrical power if it is exported to the grid.

Table 3-5. CHP Operational Costs in 2012

Parameter	Value	Unit
Natural gas consumption	155,000	Therms
Annual natural gas costs [a]	157,000	$
Scrubbed gas consumption	500	Therms
Cost to produce scrubbed gas [b]	100	$
Electricity generated	1,104,000	kWh
Avoided electrical costs [c]	77,000	$
Avoided demand charges	120,000	$

a. Natural gas costs are $1.01/therm.

b. Scrubbed gas costs $0.2657/therm to produce.

c. Electricity costs are $0.07/kWh, including demand charges and fees.

3.4.3 Operational Considerations

Plant staff indicated that the gas turbines can be started in a matter of minutes. This is generally done using natural gas to avoid the sudden drop in pressure that occurs if it is attempted on scrubbed gas, knocking the gas scrubbing system offline. If it appears that the gas turbines will operate for 3 hours or more, operations staff is more likely to blend scrubbed gas with natural gas because the longer time span allows more operations attention to the CHP and gas scrubbing systems. The plant staff indicated that they have not observed any operational issues with operating a gas turbine at a partial load, although the plant tries to avoid operating below 1.5 MW as emissions of nitrous oxides (NOx) increase below this level. In addition, the electrical efficiency of the turbines drops from 28 percent at full load to 21 percent at 1.5 MW.

The system is always operated with some portion of the fuel flow as natural gas. This is done to maintain a constant fuel supply to the turbines and avoid increases and decreases in flow as the scrubbed gas flow varies during the day. Typically, the plant will add at least 300 kW to the turbines desired output beyond what the scrubbed gas system can provide (1.6 to 1.7 MW) to even out the fuel flow and maintain speed stability at the turbine.

The plant staff also indicated that the steam system is rarely used because of the extended time it takes to start and stop it. It takes a day to remove desiccant in the steam generator, a day to bring a steam turbine up to temperature, and 2 to 3 days to shut down and add desiccant back into the steam system. Consequently, the CHP system is used to generate heat only when the system will be operated over an extended period of time (i.e., a week or more). Because two turbines are required to operate to provide both heat for the plant and power the steam turbine, the steam turbine has never been operated since being commissioned.

3.5 Waste Gas Burner System

This section describes the theory of operation, operational costs, and operational considerations for the waste gas burner system.

3.5.1 Theory of Operation

The intended operation for the waste gas burner system is to have none of the burners operating, as the plant should be either selling or consuming all of the digester gas it produces. Therefore, the waste gas burners operate intermittently. Each waste gas burner has a pilot light fueled by propane. The pilot light is lit when pressure in the LSG piping begins to build but has not yet reached the point at which the gas in the piping requires disposal. Once the gas pressure exceeds a second set point, the gas valve opens and the waste gas is ignited by the pilot light. The gas valve closes once the pressure has decreased to a third set point. Propane for the pilot light is shut off at the same pressure set point that it turned on. Table 3-6 shows the current pressure set points for each waste gas burner.

Table 3-6. Waste Gas Burner Set Points			
	WGB 1	WGB 2	WGB 3
Pilot light	9.5 in. w.c.	8.5 in. w.c.	9.0 in. w.c.
Open gas valve	10.0 in. w.c.	11.0 in. w.c.	12.0 in. w.c.
Close gas valve	8.5 in. w.c.	8.5 in. w.c.	10.0 in. w.c.

3.5.2 Operational Costs

In 2012, the waste gas burner system consumed 41 million scf of gas. Of this, approximately 14 million scf was scrubbed gas and the remaining 27 million scf was raw digester gas. The only cost associated with operation of the waste gas burners is the consumption of propane for the pilot fuel. This cost is considered minimal.

3.5.3 Operational Considerations

Normal operation is to sequentially start one burner, then a second burner, and then a third waste gas burner as the LSG pressure set points shown in Table 3.5 are reached. This operating approach is usually adequate to maintain the LSG pressure below 14 in. w.c. (i.e., the digester pressure relief valve setting) however the plant does observe a 0.2 to 0.3 in w.c. difference between the LSG pressure at the digesters and the LSG pressure at the waste gas burners. However, if only scrubbed gas is going to the burners for an extended period of time, this strategy may cause the waste gas burners to burn so hot that there is a potential for equipment damage (due to the increased Btu content of scrubbed gas compared to unscrubbed gas, from 600 Btu/scf to 985 Btu/scf). During these infrequent conditions, a minimum of two waste gas burners will operate with the third burner starting when its pressure set point is reached.

Plant staff did not report any issues associated with turndown with the waste gas burners as they all work very well at starting up and shutting down as called for by the pressure set points.

3.6 Effluent Heat Extraction System

This section describes the theory of operation, operational costs, and operational considerations for the effluent heat extraction system.

3.6.1 Theory of Operation

The effluent heat extractor transfers heat from the plant's effluent to the plant hot water loop on the same principle as a refrigeration or air conditioning cycle:

1. Cool effluent heats the refrigerant (R-134a) in the heat extractor's evaporator
2. The evaporated refrigerant is then compressed
3. Heat is transferred to the heat loop when the refrigerant condenses in the condenser
4. The refrigerant condensate pressure is reduced before going back to the evaporator

The result is that the temperature of effluent passing through the heat extractor is reduced by 8°F and the heat loop water temperature increases by 15°F.

The original design intent for the heat extraction system was for the heat extractors to provide the entire plant heat supply. Concerns about permitting for the emissions from a boiler or cogeneration engine, combined with relatively inexpensive electrical prices and high natural gas prices in the 1980s, led to the decision to use recovered effluent heat to meet the plant's heating needs as part of Enlargement II. This approach to using the heat extractors as the main heat source was continued into Enlargement III, when heat extractor 5 was installed. However, the current operation of the heat extraction system is limited to a single heat extractor during summer months because of operational and maintenance considerations identified below.

3.6.2 Operational Costs

In 2012, the heat extraction system provided the plant with heat from mid-June to mid-October (4 months total). The heat extractor(s) operated only an average of 2 months per year between 2007 and 2011. Actual heat recovered was not directly measured but based on expected plant heat needs by month, the system recovered approximately 7,000 MMBtu of heat in 2012 while consuming 526 megawatt-hours (MWh) of electricity. Between 2007 and 2011, it is likely that the heat extractors recovered an average of 4,000 MMBtu/yr while consuming an average of 259 MWh/yr of electricity. Table 3-7 summarizes operational costs associated with the heat extraction system in 2012.

Table 3-7. Heat Extractor Operational Costs in 2012

Parameter	Value	Unit
Electric power consumption	526,000	kWh
Annual electrical power costs [a]	37,000	$/yr

a. Electricity costs are $0.07/kWh, including demand charges and fees.

3.6.3 Operational Considerations

Operational concerns associated with the heat extractors were investigated in detail during previous task orders. The technical memoranda from those investigations are included here as appendices. In summary, the heat extractors were originally designed to operate on R-12 refrigerant. Environmental concerns over the impact of R-12 on the ozone layer led to a change to R-134a refrigerant, with heat extractor 5 installed with R-134a in 1995 while heat extractors 1 through 4 were switched from R-12 to R-134a around 2000. The switch of refrigerant reduced the maximum output temperature the heat extractors could produce in the heat loop from 140°F to 130°F, significantly limiting the heat extractors' ability to meet the plant's heat needs. This fact, combined with flow balancing issues and large sludge heat exchanger step loads due to the use of open/close valves, has resulted in the heat extractors being effective only during the summer months when heat demands are low. The startup of Brightwater in 2012, which redirected wintertime flows from South Plant, should help to extend the period of time when heat extractor 5 has capacity to satisfy the plant's heating needs. In addition, the County's efforts to minimize the buildup of struvite and sludge within the sludge heat exchangers will increase the efficiency of the heat transfer from the plant's hot water system to the sludge, allowing for a more efficient heat loop.

4 System Maintenance and Reliability

The following sections describe the system reliability, maintenance requirements, and condition of the existing digester gas utilization equipment. Indications of remaining useful life (RUL) are estimated based on

County feedback on equipment's existing condition and an approximate service life based on Brown and Caldwell's experience with similar equipment.

4.1 Gas Scrubbing System

This section describes the system reliability, maintenance requirements, and condition of the gas scrubbing system.

4.1.1 System Reliability

Plant staff indicated that the gas scrubbing system typically is online a vast majority of the year. Staff also indicated that the current capacity of the large compressor (no. 3) and one small compressor could handle most, if not all, of the digester gas produced in 2012. If, according to the County, the gas scrubbing system was online 95 to 97 percent of the time in 2012 and the gas scrubbing system handled about 97 percent of the digester gas when in service in 2012, then the gas scrubbing system handled 93 to 95 percent of all the digester gas in 2012.

Though the scrubbing system is usually online, not all compressors are usually in service. In fact, one of the three compressors is often offline for overhauls and repairs, typically about 25 percent of the year. This indicates that though the system has a connected capacity for up to 25 percent more digester gas than was produced in 2012, firm capacity with the largest compressor unavailable is approximately 70 percent of the volume of digester gas produced in 2012.

To reduce scrubbing system downtime and lost revenue, annual maintenance and recertification (on items that are common to both scrubbing trains) are scheduled for 1 week per year. The water pumps/turbines are down for a similar amount of time but, as there is a fully redundant unit, they do not impact the capacity of the system.

4.1.2 Maintenance Requirements

Plant staff indicated that the compressors and water pumps/turbines currently require a rebuild every 3 to 4 years. From 2008 to 2012, the gas scrubbing system in its entirety cost an average of $213,000 per year to maintain. Comparing this to lifetime maintenance costs, this is a significant increase over the lifetime average of $90,000 per year. This may be largely due to the failure of the gas scrubbing system and the resulting repairs in 2011. But it also indicates that the system is requiring more frequent and expensive maintenance as it ages and reaches the end of its useful life. For maintenance activities, the plant has dedicated at least one Wastewater Treatment Division (WTD) maintenance staff member to the gas scrubbing system, and particularly the gas compressors.

4.1.3 System Condition

Compressors 1 and 2 and pump/turbines 1 and 2 were installed in 1987 and are approaching the end of their service life (estimated at 30 years), requiring replacement within the next 5 years. Gas compressor 3 and pump/turbine 3 (less its motor) are also assumed to have a service life of 30 years, leaving 12 years of useful life. Scrubbing tower 1 was installed in 1987 and reconditioned in 2009. It is assumed that this effort restored its condition to factory specifications. Thus, its RUL is probably 30 to 35 years. Scrubbing tower 2 was installed in 1995 and appeared to be in good condition based on a recent inspection. Thus, it can be assumed to have an RUL of 20 to 25 years. The drier system was also overhauled and updated within the last 2 years, and can be assumed to have an RUL of about 10 to 12 years. The gas quality instrumentation was replaced within the last 3 years and has its full useful life remaining. While the plant control system was recently upgraded to Ovation, the scrubbing system controls were not migrated due to high costs (estimated at $500,000) and a tight project budget. Plant staff indicated that future upgrades to the gas scrubbing system would require that the controls be migrated to Ovation as they are at the end of their useful life.

4.2 Gas-Fired Hot Water Boiler

This section describes the system reliability, maintenance requirements, and condition of the gas-fired hot water boiler.

4.2.1 System Reliability

The plant staff do not currently observe reliability issues associated with the boiler. Plant staff originally observed frequent shutdowns of the system when it was operated on raw digester gas. This usually occurred during a diversion of the scrubbed gas system when scrubbed gas was sent to the LSG header that the boilers pulled fuel from. When the high Btu-content gas reached the boiler, the boiler would shut down on low oxygen when the gas was burned. It would take numerous restart attempts (staff mentioned up to 6 hours of restart attempts) before the scrubbed gas was purged from the system. When the boiler was converted to run on scrubbed gas or natural gas in 2007, this issue was resolved. Maintenance staff has also focused on reducing boiler problems over the years via equipment and operational modifications (e.g., a complete overhaul of the tubes and tube sheet in 2010 to restore factory specifications, enhanced training, inspection and PM schedules in the late 2000's, migration of the boiler controls into the new Ovation control system in 2012). These modifications have helped to make the boiler a more reliable heat source.

The boiler needs annual maintenance to clean its tubes. With the flexibility to operate the heat extractor during summer months, this annual maintenance can be planned when heat loads are low. An outside contractor performs this annual maintenance.

4.2.2 Maintenance Requirements

From 2008 to 2012, maintenance costs for the gas-fired boiler system averaged $95,000 per year. This $95,000 includes a major rebuild that an outside contractor completed in 2010. An outside contractor also performs annual preventative maintenance on the boiler during the summer while WTD maintenance staff performs other routine maintenance of the system.

4.2.3 System Condition

The boiler was originally installed under the assumption that it would be the primary heat source for 3 years and then would operate as the backup to the CHP system when it came online. The boiler and its equipment are of sufficient quality that it still has 20 years of its 30-year service life available. Supporting controls and system flexibility will need to be corrected, however, if the system continues to be relied upon as the plant's primary heat source.

4.3 Combined Heat and Power System

This section describes the system reliability, maintenance requirements, and condition of the CHP system.

4.3.1 System Reliability

Due to its low number of operating hours, the CHP system requires minimal maintenance. Plant staff estimated that the CHP system has been operated a total of 9,136 hours since its commissioning in 2005. More frequent operation would require more frequent maintenance.

4.3.2 Maintenance Requirements

From 2008 to 2012, the CHP system required $18,000 per year to maintain. This does not match the lifetime maintenance costs, which have averaged $90,000 per year, indicating that some significant initial maintenance activities occurred prior to 2008 and since then activities have been more limited. The County originally purchased a maintenance contract with the turbine manufacturer to replace or rebuild the turbines every 5 years. However, the County decided not to renew this contract based on the limited use of the CHP system.

4.3.3 System Condition

Due to the light use of the equipment, the CHP system is assumed to have 75 percent of its RUL. Service life of a natural gas turbine is assumed to be 25 years, indicating that the CHP system has approximately 18 years of RUL. The RUL could be even longer if the CHP continues to be used as infrequently as it has, considering the low number of operating hours on each gas turbine.

4.4 Waste Gas Burner System

This section describes the system reliability, maintenance requirements, and condition of the waste gas burner system.

4.4.1 System Reliability

The waste gas burner system requires minimal maintenance and plant staff did not report any ongoing maintenance concerns. The plant staff did note that the original installation allowed condensate to collect in the LSG header at concentric reducers, impacting the capacity of the system. This condensate collection was sufficient to shut off gas flow to waste gas burner 1 and cause the pressure differential in the LSG system from the digesters to the waste gas burners to increase to 1 to 2 in w.c. To address this condensate build up, plant staff was draining the LSG piping by vactor truck approximately every week. A condensate pumping system was installed and the LSG feed to waste gas burner 1 was rerouted to address the issue and there have not been condensate collection issues since.

4.4.2 Maintenance Requirements

Given the short time frame since the new waste gas burners were installed (2010) and the amount of work by maintenance staff that has been driven by startup issues since then, relatively little information is available about ongoing maintenance costs and tasks on the new waste gas burners. Given this limited base of information, staff estimate that annual maintenance costs will be about $10,000 with more major maintenance required every 3 to 5 years. Maintenance is performed by WTD staff.

4.4.3 System Condition

The waste gas burners were installed recently and are considered in good condition. With a 25-year service life, the waste gas burners are assumed to have 20 years of RUL.

4.5 Heat Loop and Effluent Heat Extraction

This section describes the system reliability, maintenance requirements, and condition of the heat loop and effluent extraction system.

4.5.1 System Reliability

Before heat extractors 1 through 4 were decommissioned, the heat extractor system experienced a number of operational and maintenance issues, which are documented in the memoranda provided as appendices. Heat extractor 3 could be returned to service but this would require an expensive overhaul and it is thus considered non-operational. Plant staff indicated that the heat extractors were labor-intensive to maintain. This was because the heat extractors had two sets of heat exchanger tubes (one on the evaporator and one on the condenser), requiring maintenance and periodic replacement.

4.5.2 Maintenance Requirements

Annual maintenance cost data collected between 2008 and 2012 indicated that the heat extraction system incurred $22,000 per year in maintenance costs. Based on lifetime maintenance costs, the County has spent an average of $27,000 per year to maintain the heat extraction system, indicating relatively consistent maintenance needs. Maintenance is primarily done by an outside contractor. The County has had its challenges trying to find a contractor that does high-quality work on the heat extractors but the County recently hired a contractor it believes has those qualifications and will help to keep heat extractor 5 well maintained so it operates effectively.

4.5.3 System Condition

Heat extractor 5 is considered near its end of life but with minimal operation during only summer months, has a RUL of 15 years. Heat extractors 1 through 4 are no longer operational.

5 Summary

To summarize the overall system operation and costs, four aspects of the gas system parameters are presented: plant heat supply, gas consumption, system costs, and remaining equipment life.

5.1 Plant Heat Supply

The treatment process at South Plant requires that the digesters be maintained at mesophilic temperatures year round and the digester gas is preferentially used to meet this need. Table 5-1 summarizes the heat demand and sources at South Plant in 2012.

Table 5-1. South Plant Heat Demand and Heat Sources in 2012

Parameter	Heat [MMBtu]	Percent of demand
Plant demand	44,800	
Gas-fired boiler	37,400	83%
CHP system [a]	-	0%
Heat extractor [b]	7,400	17%

a. Between 2007 and 2011, the CHP system averaged 7,900 MMBtu/yr.

b. Between 2007 and 2011, the heat extraction system averaged 3,600 MMBtu/yr.

As expected, the gas-fired boiler provided a majority of the plant's heat supply with contribution from the heat extractor system. The CHP system did not provide any heat but operation during previous years indicates that the system can provide an appreciable portion of the plant's heat supply.

5.2 Gas Consumption

Table 5-2 summarizes the production and consumption of digester gas and natural gas at South Plant in 2012.

Table 5-2. Digester Gas and Natural Gas Usage at South Plant in 2012			
Parameter	Digester gas [MMBtu/yr}		Natural gas [MMBtu/yr]
	Raw gas	Scrubbed gas	
Digester gas produced	272,000		
Gas scrubbing		243,000	
Sold to PSE		183,000	
Gas-fired boiler		47,000	200
CHP system		50	16,000
Waste gas burners	16,000	13,000	

The gas usage numbers reflect the high availability of the gas scrubbing system as well as the need for the waste gas burners to dispose of scrubbed gas that cannot be sold to PSE. As expected, the gas-fired boiler consumes very little natural gas while the CHP system consumes very little scrubbed gas due to the times the County generally needs to operate it (i.e., during winter storms and high flow events).

5.3 Gas Utilization System Costs

Table 5-3 summarizes the total costs in 2012 for each of the gas utilization systems described. These costs summarize the operational costs and revenues/savings presented in Section 3 for each system and the maintenance costs presented in Section 4 for each system.

Table 5-3. Annual Gas Utilization System Costs in 2012					
Parameter	Operational costs [$]	Revenues/savings [$]	Maintenance costs [$]	Total cost [$]	Unit cost
Gas scrubbing	($435,000)	$796,000	($213,000)	$148,000	$0.2657/therm
Gas-fired boiler	($126,000)	$0	($95,000)	($221,000)	$0.59/therm
CHP system	($157,000)	$197,000	($18,000)	$22,000	$0.16/kWh
Waste gas burners	$0	$0	($10,000)	($10,000)	-
Heat extractors	($37,000)	$0	($22,000)	($59,000)	$0.80/therm

Gas scrubbing and the CHP system provide a net revenue to the plant. It is important to note, however, that a majority of the revenue from operating the CHP system comes from avoided demand charges that would not scale if the CHP system was operated more often.

Based on these costs and the operating practices in 2012, the following unit costs were calculated. Altering the operation practices for each system (e.g., consuming more or less natural gas than current practice) could impact the unit costs shown here.

- The gas scrubbing system spent $0.2657/therm to produce scrubbed gas. This compares favorably to the $0.4347/therm that PSE pays for scrubbed gas as well as to the $1.01/therm the County pays for natural gas.
- The CHP system produces electricity at a cost of $0.16/kWh. This is higher than the $0.07/kWh the County pays for electricity from PSE, indicating that full-time operation of the CHP system would not be cost-effective.

- The boilers produce heat at a cost of $0.59/therm. This is lower than the $1.01/therm the County pays for natural gas because the boiler uses mostly scrubbed gas, which costs $0.2657/therm to produce.
- The heat extractor produces heat at a cost of $0.80/therm, indicating that the system is less cost-effective than the gas-fired boiler while it consumes scrubbed gas. If the boiler were to be operated on natural gas, however, the heat extractor would be a more cost-effective means of providing heat.

5.4 Remaining Equipment Life

Table 5-4 summarizes the RUL for major components of the gas utilization systems. See Section 4 for further details on each system.

Table 5-4. Expected Remaining Useful Life for Gas Utilization Systems

System	Remaining useful life [yrs]	Anticipated year of replacement
Gas scrubbing system		
Compressors 1 and 2, water pump/turbines 1 and 2, control system	4	2017
Compressor 3, water pump/turbine 3, gas dryers, quality instrumentation	12	2025
Scrubbing towers 1 and 2	25	2038
Gas-fired boiler	20	2033
CHP system	18	2031
Waste gas burners	20	2033
Heat extractor 5	15	2028

Major components requiring replacement include the original gas compressors, water pump/turbines, and control system for the gas scrubbing system installed as part of Enlargement II. Gas scrubbing system components installed during the 1990s as part of Enlargement III will need replacement in the coming years, as will the heat extractor system. The gas-fired boiler does not require replacement soon but will likely require additional redundancy if it continues to be used as the plant's primary heat source and CHP continues to be expensive to operate on a long-term basis as a heat source.

Attachment B: TM 2

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Technical Memorandum

Prepared for: King County Department of Natural Resources and Parks

Project Title: Task Order 7: South Plant Digester Gas Utilization Study

Project No.: 141326.007.030

Technical Memorandum 2

Subject: Development and Screening of South Plant Biogas Management Alternatives

Date: August 16, 2013

To: John Smyth, Project Manager

From: Ian McKelvey, Project Manager

Prepared by: ________________________________
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Reviewed by: ________________________________
Jack Warburton, Vice President

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List of Abbreviations

°F	degree(s) Fahrenheit
Btu	British thermal unit(s)
FTE	full-time equivalent
gal	gallon(s)
gpd	gallon(s) per day
hp	horsepower
hr	hour(s)
kW	kilowatt(s)
kWt	thermal kilowatt(s)
kWh	kilowatt-hour(s)
kWh-t	thermal kilowatt-hour(s)
lb	pound(s)
m^3	cubic meter(s)
mg	milligram(s)
MMBtu	million British thermal unit(s)
MM scfd	million standard cubic foot/feet per day
mpg	mile(s) per gallon
MWh	megawatt-hour(s)
ppm	part(s) per million
psig	pound(s) per square inch gauge
scfd	standard cubic foot/feet per day
scfm	standard cubic foot/feet per minute
yr	year(s)

Section 1: Introduction

This Technical Memorandum 2 (TM 2) is part of a study being performed on the South Treatment Plant (South Plant) digester gas utilization program to identify the capacity and condition of the existing system, potential alternatives for gas utilization, and the preferred approach based on a net present value (NPV) analysis including life-cycle costs. Identification of the existing systems and their capacity, operation, and condition was completed previously under the title “Technical Memorandum 1: South Plant Biogas Management Equipment and Systems” (TM 1). TM 2 describes the objectives of the South Plant digester gas utilization program in order to compare potential alternatives in a repeatable, balanced manner. Potential alternatives are identified and briefly described to facilitate an initial screening of alternatives. Three alternatives are recommended for further evaluation during the NPV, to be documented in TM 3. Figure 1-1 provides a road map for the three following sections of TM 2.

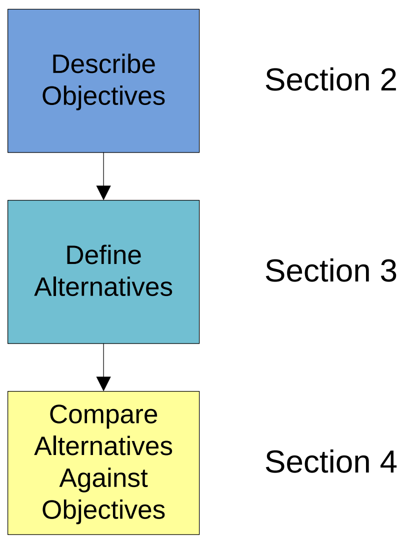

Figure 1-1. TM 2 road map

Section 2: King County Objectives

To compare the potential alternatives for the South Plant digester gas utilization program, it is first necessary to identify King County's (County) objectives for the program. Objectives were developed in a workshop setting with South Plant operations, process, and reliability-centered maintenance staff; Wastewater Treatment Division (WTD) resource recovery, project planning and delivery, and project management staff; and Department of Natural Resources and Parks (DNRP) policy staff. The following section describes the objectives identified and a potential means by which to compare alternatives based on these objectives.

2.1 Objectives Description

The objectives developed during workshops with County staff are described below. In an effort to facilitate discussion and group similar objectives together, the objectives identified were divided into the three categories: financial, energy, and operations.

2.1.1 Financial Objectives

The costs associated with delivering, operating, and maintaining gas utilization systems will be crucial to the NPV comparing potential alternatives. In addition, the County has identified pursuing sustainable funding as a part of the County and WTD Energy Plans. Changes to commodity prices can also impact the finances of the gas utilization program and were therefore included as a consideration. Table 2-1 below summarizes the financial objectives that were identified.

Table 2-1. Financial Objectives for South Plant Gas Utilization Program

Objective	Units	Scale	Notes
1. Maximize the program's net present value	$	5 = more than -2 million 4 = -2 million to -3 million 3 = -3 million to -4 million 2 = -4 million to -5 million 1 = less than -5 million	Costs associated with capital, operations, maintenance, replacement, and refurbishment are all included.
a. Minimize capital costs	$	5 = less than 7 million 4 = 7 million to 8.5 million 3 = 8.5 million to 10 million 2 = 10 million to 12 million 1 = more than 12 million	Costs associated with design, purchase, and installation of capital equipment
b. Minimize operational and maintenance costs	$	5 = less than 800,000 4 = 800,000 to 900,000 3 = 900,000 to 1 million 2 = 1 million to 1.2 million 1 = more than 1.2 million	Annual costs associated with operating and maintaining equipment
c. Maximize revenues	$	5 = more than 1.5 million 4 = 1.5 million to 1.25 million 3 = 1.25 million to 1.1 million 4 = 1.1 million to 1 million 5 = less than 1 million	Annual revenues associated with the sale of recovered resources or savings offset of purchased commodity (e.g., biogas, electricity, etc.)

Table 2-1. Financial Objectives for South Plant Gas Utilization Program			
Objective	Units	Scale	Notes
2. Maximize grants, credits, and incentives	1–5	5 = most opportunity for grants, credits, and incentives, 1 = least opportunity	From 2010 King County and WTD Energy Plans: "Pursue sustainable funding strategies for energy efficiency, renewable energy projects, waste-to-energy projects and greenhouse gas (GHG) reduction efforts"
3. Minimize sensitivity to commodity price changes	1–5	5 = least exposure, 1 = most exposure	Includes sensitivity to consumed natural gas, diesel, and electricity and produced biogas
a. Minimize sensitivity to consumed natural gas price	MMBtu/yr	5 = less than 10,000 4 = 10,000 to 14,000 3 = 14,000 to 17,000 2 = 17,000 to 20,000 1 = more than 20,000	Amount of natural gas consumed
b. Minimize sensitivity to consumed electricity price	kWh/yr	5 = less than -15 million 4 = -15 million to -5 million 3 = -5 million to 0 2 = 0 to 5 million 1 = more than 5 million	Amount of net electrical power consumed
c. Minimize sensitivity to produced biogas price	Therms/yr	5 = less than 500,000 4 = 500,000 to 1 million 3 = 1 million to 1.5 million 2 = 1.5 million to 2 million 1 = more than 2 million	Amount of scrubbed gas sold
d. Minimize sensitivity to diesel price	gal/yr	5 = more than 9,000 1 = less than 9,000	Amount of diesel offset

Several of the objectives are subcomponents of an overall NPV. This will be identified separately as additional information, but alternatives will be compared based on the NPV objective. Grants and credits are the exception, though, as the County specifically identified pursuing sustainable funding in its Energy Plans from 2010. As such, the potential grants, credits, and incentives will be included as a separate objective.

Sensitivity to commodity price changes is shown for the individual commodities but a single objective will be used to compare alternatives (i.e., the individual commodity sensitivities will carry zero weight). Because sensitivity to price changes cannot be quantified without performing a detailed NPV analysis, alternatives will be scored subjectively based on the consumption of the given commodity.

2.1.2 Energy and Sustainability Objectives

The energy and sustainability objectives during the workshops were derived from a review of strategic plans and energy plans published by King County. The energy and sustainability objectives identified in Table 2-2 below are a summary of the published goals with their source identified in the footnotes.

Table 2-2. Energy and Sustainability Objectives for South Plant Gas Utilization Program			
Objective	Units	Scale	Notes
1. Reduce use of and expenditures for energy [a,b,c,d]	kWh/yr, kWh-t/yr	5 = less than 6 million 4 = 6 million to 8 million 3 = 8 million to 9 million 2 = 9 million to 12.5 million 1 = more than 12.5 million	Annual electrical energy consumption and natural gas consumption
2. Reduce greenhouse gas emissions [a,c,d]	Tons of eCO_2/yr	5 = less than -10,000 4 = -10,000 to -6,000 3 = -6,000 to -3,000 2 = -3,000 to 0 1 = more than 0	Region-wide annual reduction in greenhouse gas production due to County operations
3. Convert waste to energy to reduce environmental and carbon footprint [a,b,d]	1–5	5 = less wasted energy and more recovered energy, 1 = more wasted energy and less recovered energy	Energy wasted through waste gas burners and energy recovered from effluent heat
4. Increase production of renewable energy [a,b,c]	kWh/yr, kWh-t/yr	5 = more than 60 million 4 = 60 million to 50 million 3 = 50 million to 30 million 2 = 30 million to 15 million 1 = less than 15 million	Renewable electrical production, biogas production, recovered effluent heat
5. Invest in alternative fuel transit and fleet vehicles [a,d]	kWh-t/yr	5 = more than 2 million 1 = less than 2 million	Diesel fuel offset by sale of biogas for CNG production

a. King County Energy Plan (10/2010).

b. WTD Energy Plan (2/2010).

c. King County Strategic Climate Action Plan (12/2012).

d. King County Strategic Plan 2010-2014 (7/2010).

These objectives reflect the County's desire to reduce energy consumption and greenhouse gas (GHG) emissions while promoting the use of renewable energy sources and alternative fuels. Each objective also has a means by which to measure the County's performance and compare potential alternatives to each other.

2.1.3 Operational Objectives

Operation of the gas utilization systems will play a role in determining the preferred alternative. A number of operational objectives were identified and are summarized in Table 2-3, but some objectives were not included because they were considered a basic requirement that all alternatives must meet. These include meeting process safety requirements, effluent and biosolids permit requirements, and process heating requirements. Any alternative that could not meet these basic requirements would not be considered, and therefore all of the considered alternatives would score similarly if these were included as objectives.

Table 2-3. Operational Objectives for South Plant Gas Utilization Program		
Objective	Units	Scale
1. Maximize system redundancy	1–5	5 = most redundancy, 1 = least redundancy
2. Maximize system reliability	1–5	5 = most reliability, 1 = least reliability
3. Maximize system operational flexibility	1–5	5 = most flexibility to changes, 1 = least flexibility
4. Minimize WTD labor requirements	FTEs	5 = fewer than 2 4 = 2.25 to 2 3 = 2.75 to 2.25 2 = 3 to 2.75 1 = 3 or more
5. Minimize reliance on outside service contracts	1–5	5 = fewest outside contracts, 1 = most outside contracts
6. Minimize WTD labor related to safety	1–5	5 = fewer labor requirements due to system safety requirements, 1 = more labor requirements due to system safety requirements
7. Minimize technical risk	1–5	5 = lowest technical risk, 1 = highest technical risk
8. Minimize air quality treatment requirements	1–5	5 = lowest risk of post-combustion treatment 1 = highest risk of post-combustion treatment

Many of the operational requirements are difficult to measure precisely so subjective scales are used where required. The system redundancy, reliability, and operational flexibility objectives represent the desire for a gas utilization program that has sufficient redundancy to meet the plant's process heat needs, can reliably operate year round with adequate turndown, and would be flexible to potential future process changes.

Objectives associated with WTD labor, outside contracts, and safety requirements reflect the reality of limited staff available for additional operations and maintenance (O&M) activities, especially if additional labor is required due to inherent safety requirements of a system. At the same time, the County prefers to not rely on the expertise and availability of outside entities to maintain operation of plant equipment.

The technical risk objective measures how commonly a system is applied at wastewater treatment facilities, how available expertise and parts would be available to assist with troubleshooting, and the relative certainty that the system will perform as intended. The air quality treatment objective is similar in that alternatives that require post-combustion treatment run an additional risk for future air permit changes and uncertainty in system performance.

2.2 Objectives Weighting

When comparing alternatives based on how well they meet each objective, the objectives could be weighted to reflect that the County prefers some objectives to be met before others. At present, the objectives have been weighted such that each category (financial, energy, and operations) is equally represented in the total score. Financial objectives were thus given a weight of 8, energy objectives were given a weight of 4.8, and operational objectives were given a weight of 3. This results in each of the three categories having a total possible score of 120 points (e.g., for the financial category, there are three objectives with a maximum score of 5 points; therefore, 3 x 5 x 8 = 120 points). Further refinement of the weighting to best reflect the priorities of the County will be held prior to the development of TM 3 to compare the final alternatives against each other.

Section 3: Alternatives Description

This section describes the digester gas utilization and heating alternatives considered in the evaluation. Alternatives are composed of multiple sub-systems to meet the plant's needs. To best convey the multiple alternatives developed by mixing and matching these subsystems, the subsystems are divided among three categories that encompass the overarching purpose of the gas utilization system: meet plant heat demand, achieve beneficial use of gas, and provide gas treatment to facilitate beneficial use.

Capital and operating cost estimates are developed for each of the alternative subsystems and presented in abbreviated tables in this section. More detailed capital cost estimate information is located in Appendix A (e.g., contractor markup assumptions). The capital costs are planning-level estimates based on recent, similar project cost estimates or County asset management data, and are intended to provide a high-level comparison of the alternatives. The cost estimates should not be construed as providing a preliminary design-level estimate. Cost estimates for the three selected alternatives will be refined in TM 3.

The alternatives are developed based on process assumptions outlined in Table 3-1, and the utility assumptions outlined in Table 3-2. Process assumptions are based on sludge loading and gas production estimates developed in 2011 as part of the South Plant Grease Co-Digestion Study (Task Order 2). Utility assumptions are based on data from Puget Sound Energy (PSE) for spring 2013. Natural gas and biomethane rates from spring 2013 have been increased by 23 percent to reflect the belief of County personnel that current rates are abnormally low and will increase in the future. The County expects that the higher rates will be typical during the NPV analysis period. Rates used in the NPV analysis are these values escalated at the same rate as inflation (2.5 percent per year).

Table 3-1. Process Assumptions for Digester Gas Utilization Alternatives

Criteria	2013	2036
Average sludge load, gpd [a]	289,000	342,000
Average sludge load, lb-VS/day [a]	132,000	157,000
Average digester gas production, scfd [a]	1,223,000	1,492,000
Average plant heating demands, kWt (MMBtu/hr) [b]	1,570 (5.4)	1,750 (6.0)
Peak heating demands, kWt (MMBtu/hr) [b]	3,030 (10.4)	3,260 (11.1)

a. *Based on sludge loading and digester gas production developed for South Plant Grease Co-Digestion Study (Task Order 2), completed in 2011.*

b. *Based on sludge loading developed for South Plant Co-Digestion Study (Task Order 2), completed in 2011 and digester and natural gas data for heating from 2012.*

Table 3-2. Utility Assumptions for Digester Gas Utilization Alternatives

Criteria	Value
Electricity cost, $/kWh	0.07
Natural gas cost, $/kWh-t ($/MMBtu)	3.64 (12.4)
Natural gas sale rate, $/kWh-t ($/MMBtu)	1.56 (5.347)

3.1 Meet Plant Heat Demand

This section describes potential subsystems as they pertain to meeting the plant's heat demand. As the plant's ability to meet Class B biosolids requirements requires that plant heat demand be met at all times, these alternatives are considered vital to the plant's treatment process.

Four subsystems could be used as the primary plant heat source: gas-fired boilers, effluent heat extractors, the gas-fired turbine-generator combined heat and power (CHP) system, or internal combustion (IC) engine-generators used for cogeneration (note that the terms combined heat and power and cogeneration are synonymous, but are used in this TM to differentiate between the existing turbine-generator system and a new IC engine-generator system).

3.1.1 Gas-Fired Boiler

The two alternatives for gas-fired boilers are to expand the plant heating capacity with boilers that burn high-Btu gas similar to the status quo, or to install new boilers with the capability to also burn low-Btu or raw digester gas.

3.1.1.1 Status Quo

The status quo heating system, as described in TM 1, is the use of a gas-fired boiler as the primary plant heat source with backup provided by the heat extractor system and CHP system. Based on County feedback during the development of TM 1, two new boilers are assumed to be required as part of the status quo alternative to provide system reliability and turndown capability. The new boilers are assumed to be 6.7 MMBtu/hr (200 horsepower [hp]) each, or about half the size of the existing boiler. Figure 3-1 shows a picture of two gas-fired hot water boilers.

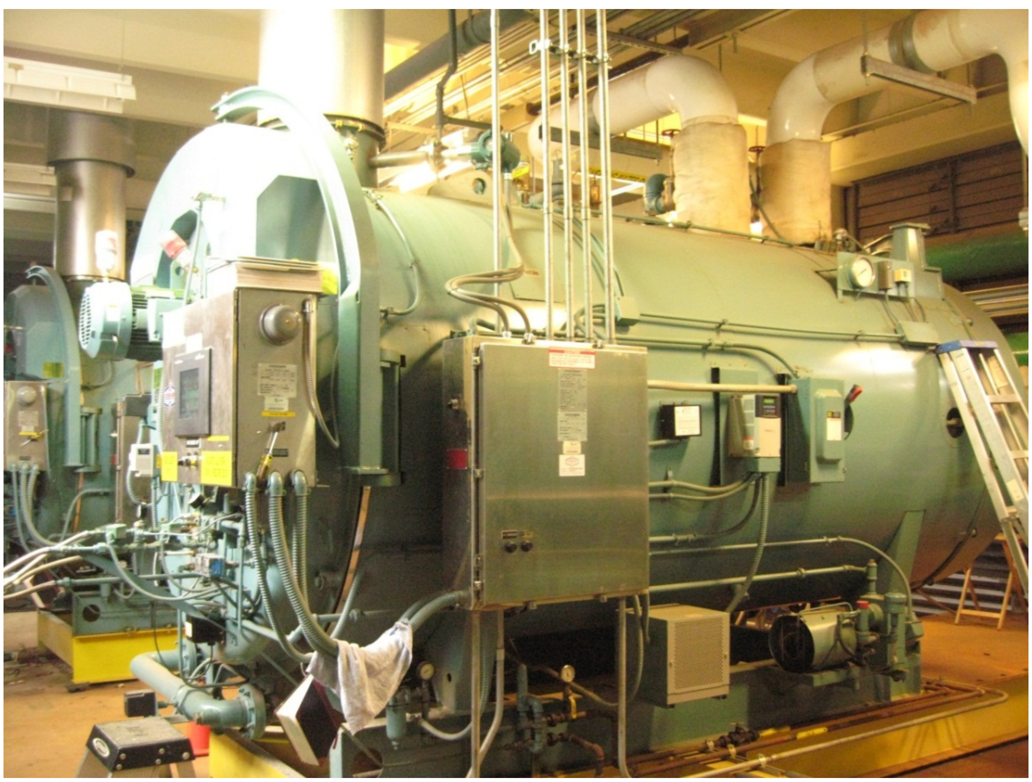

Figure 3-1. Gas-fired hot water boilers at the City of Tacoma Central Treatment Plant

The new boilers would provide similar capacity if the existing boiler were out of service for maintenance, and would also provide turndown for improved summertime operation. With the addition of these new boilers, the CHP system would not be required for backup heating needs and the heat extractor system would no longer be needed. Table 3-3 describes the capacity and operating data for the boilers.

Table 3-3. Existing and New Boiler Capacity and Operations Data		
Criteria	**Value**	**Notes**
Capacity, existing, kWt (MMBtu/hr)	3,429 (11.7)	See TM 1
Capacity, new, kWt (MMBtu/hr)	3,927 (13.4)	Total for two boilers
Efficiency, %	80	Typical for hot water boilers
Scrubbed gas (biomethane)/natural gas, %/%	99.6/0.4	Fuel source percentage; see TM 1
Natural gas cost, 2016, $/yr [a]	$2,900	Cost for natural gas only
Labor, parts, and maintenance, $/yr [b]	$143,000	Assumed as fixed cost
Plant heat demand , % [c]	100	Plant heating satisfied by boilers
Estimated full-time equivalents (FTEs)	0.75	

a. *Natural gas cost from PSE based on rate of $10.10/MMBtu.*

b. *Assumes a 50% increase in labor, parts, and maintenance costs for additional two boilers.*

c. *For simplification of the analysis, all plant heat is assumed to be provided by the boilers.*

The new boilers could be installed in a number of locations, including the following:

- in place of the existing heat extractors which are no longer used
- in place of the steam turbine equipment in the cogeneration building
- in a new building

Optimizing the location of the new boiler could be investigated in TM 3. However, the location should include consideration of natural gas availability, hot water system interconnection availability, area classification, building construction/modification costs, and ease of installation and servicing. For the purposes of this analysis, the new boilers are assumed to be installed in place of the existing heat extractors because both gas and hot water system interconnections are available at that site. Table 3-4 summarizes capital costs associated with the hot boiler system in the status quo alternative.

Table 3-4. New Boiler Capital Costs	
Equipment description	**Capital cost**
Hot water boilers 2 and 3	$1,520,000
Hot water pumps	
Three-way valves	

3.1.1.2 Digester Gas (Low-Btu) Boilers

As an alternative to the boiler system status quo, raw digester gas could be combusted in a new boiler instead of scrubbed gas or natural gas. The advantage to combusting raw digester gas would be that the high operational cost to scrub the gas would be avoided. Similar to the original installation of the existing boiler, the raw digester gas would be boosted in pressure with gas booster blowers and the liquid water would be separated prior to the boilers. One disadvantage to this operation is that the maintenance costs would increase because of the inherent acidity of the digester gas, impacting boiler tube replacement intervals. Table 3-5 summarizes the capacity information and O&M costs for two new raw digester gas boilers. The existing boiler is assumed to burn natural gas only, similar to current operation, and act as a backup to the two new boilers.

Table 3-5. New Digester Gas Boiler Capacity and Operations Data		
Criteria	Value	Notes
Capacity, new, kWt (MMBtu/hr)	3,927 (13.4)	Total for two boilers
Efficiency, %	80	Typical for hot water boilers
Labor, parts, and maintenance, $/yr [a]	214,000	Assumed as fixed cost
Annual blower power cost, 2016, $/yr [b]	19,000	Digester gas booster blowers
Plant heat demand , % [c]	100	Plant heating satisfied by low-Btu boilers
Estimated FTEs	1	

a. Assumes labor, parts, and maintenance increase by 50% from natural gas for burning raw digester gas. Includes maintenance for gas booster blowers.

b. Assumes a discharge pressure of 2 psig and 50% blower efficiency.

c. For simplification of the analysis, all plant heat is assumed to be provided by the low-Btu boilers.

The digester gas boilers could be installed in similar locations to the new high-Btu boilers discussed previously. The new boilers would have dual-fuel gas trains, allowing operation on digester gas or natural gas. It is assumed that boiler controls would be included that would switch boiler operation from digester gas to natural gas in the event that the diversion of scrubbed gas from the gas scrubbing system to the low-pressure sludge gas (LSG) header caused a heating value change in the digester gas. This feature could be investigated further during TM 3. Figure 3-2 shows a picture of the digester gas booster blower that was originally installed with the existing boiler.

Figure 3-2. Digester gas booster blower for existing boiler (currently not used)

The capital cost for the two new raw gas digester gas boilers includes gas separators and digester gas blowers with control valves. The capital costs are shown in Table 3-6.

Table 3-6. New Raw Digester Gas Boiler Capital Costs

Equipment description	Capital cost
Hot water boilers 2 and 3	$1,910,000
Hot water pumps	
Three-way valves	
Digester gas blowers with control valves	
Gas separators	

3.1.2 Effluent Heat Extractor System

This alternative assumes that one or more new high-temperature heat extractors are installed for year-round plant heating instead of heating primarily with boilers. High-temperature heat extractors can produce water at a temperature of 155 degrees Fahrenheit (°F) or above (compared to 130°F from the existing heat extractor) and include four U.S. manufacturers: York, Trane, McQuay (see Figure 3-3), and Multistack. The heat extractors could act as the primary heat source for the plant.

Figure 3-3. McQuay Templifier™ (photo copyright McQuay International, used with permission)

For King County mechanical on-call work order 2 in 2009, Brown and Caldwell identified a recommended configuration for one new high-temperature heat extractor and ancillary equipment for hydronic system improvement. In this work order report, one new heat extractor from York was identified. The York CYK unit has a capacity of 13.1 MMBtu/hr. This single-unit option is assumed in the analysis, but a configuration of multiple heat extractors with smaller capacities would also be possible. The operating cost of the new heat extractor is assumed to be similar to the existing heat extractors except for the coefficient of performance (COP). The COP for the new heat extractors would be slightly lower because of the higher-temperature hot water supply. Capacity and O&M information for the new heat extractor and equipment are shown in Table 3-7. Labor, parts, and maintenance are assumed to be constant similar to the constant trend identified in TM 1, but escalated for year-round operation.

Table 3-7. Heat Extractor Capacity and Operating Data		
Criteria	Value	Notes
Capacity, kWt (MMBtu/hr)	3,839 (13.1)	One heat extractor
Coefficient of performance (COP), -	3.5	Average operation
Annual electricity, 2016, kWh/yr	3,932,000	As primary heat source
Annual electrical power costs, 2016, $/yr [a]	275,000	As primary heat source
Labor, parts, and maintenance, $/yr [b]	132,000	Assumed as fixed cost
Plant heat demand , %	100	Plant heating satisfied by extractors
Estimated FTEs	1.0	

a. *Electricity costs are $0.07/kWh, fully loaded and COP of 3.0.*

b. *Labor, parts, and maintenance costs were increased by a factor of 6 from the costs identified in TM 1 for operation year-round versus the current operation of 2 months.*

The ancillary equipment identified in the previously mentioned work order included new hot water circulation pumps and three-way valves dedicated to each digester heat exchanger to control heat load applied to the hydronic system. It also included a tempering heat exchanger with secondary loop pumps for the new heat extractor lift control. Table 3-8 shows the capital costs associated with these improvements. Note that costs may improve with the availability of multiple high-temperature heat extractor vendors.

Table 3-8. New Heat Extractor Capital Costs	
Description	Capital cost
Digester circulation pumps	$3,500,000
Three-way valves	
Heat extractor	
Flow diverting control valve	
Tempering heat exchanger	
Condenser water side pumps	
Evaporator water side pumps	

3.1.3 Combined Heat and Power System

Three alternatives were investigated for the CHP system: to operate it in a status quo fashion, to operate it full-time for power and heat production on high-Btu scrubbed gas, or to modify it for low-Btu gas operation and operate it full-time on conditioned digester gas.

3.1.3.1 Existing System and Status Quo Operation

The existing CHP system at South Plant is a combined cycle plant consisting of two gas-fired turbines, two steam generators, two process heat recovery units, a steam turbine, and a steam condenser. The gas turbines can burn scrubbed gas, natural gas, or a blend of the two. Under the status quo operation, the gas turbines would run only for peak demand reduction and the steam turbine would never be operated. The CHP system would no longer be required to ever run for the sole purpose of providing heat because a new heat source would be installed with all alternatives. Because operation would typically be on an as-needed basis, it is expected that the gas source for operation would use minimal scrubbed gas and would not include heat recovery because utilizing these resources takes time and labor. Table 3-9 summarizes operations data on the existing CHP system; see TM 1 for additional information.

Table 3-9. CHP Capacity and Status Quo Operations Data

Criteria	Value	Notes
Capacity , kW	7,000	Total for two gas turbines
Scrubbed gas/natural gas, %/%	0.3/99.7	Fuel source percentage; see TM 1
Natural gas cost, 2016, $/yr	193,000	Assumed as fixed cost; see TM 1
Labor, parts, and maintenance, $/yr	58,000	Assumed as fixed cost with 0.5 FTE; see TM 1
Electricity savings, $/yr [a]	77,000	Assumed as fixed savings; see TM 1
Power demand savings, $/yr	120,000	Assumed as fixed savings; see TM 1
Plant heat demand , %	0	Plant heating satisfied by CHP (status quo)
Availability, %	100	Percent of time turbines are available
Estimated FTEs	0.5	

a. *Electricity savings are $0.07/kWh, fully loaded. These are the electricity savings generated when running the gas turbines for electrical demand reduction and power stability.*

3.1.3.2 Full-Time CHP Converted to Hot Water Heat Recovery

This alternative assumes that one of the gas turbines is run full-time on the biomethane available from gas scrubbing in a duty-standby fashion and that the heat recovery system is operated full-time for plant heating. Operating on biomethane alone would result in the gas turbines being run at a partial load (approximately 45 percent), resulting in an electrical efficiency of about 22 percent. The advantages to operating the CHP system full-time would be to produce electricity and heat from the biomethane without installing new equipment. The CHP system would be run for peak power demand reduction in the same fashion as the status quo alternative by supplementing the scrubbed gas with natural gas.

The County has noted that the existing control system for the gas turbines always requires some natural gas to supplement scrubbed digester gas. This is because digester gas production is not constant, and the gas turbines run at a constant output load that is set by the operator. The gas turbines are not able to vary the output load to match digester gas production in real time. In discussions with the gas turbine manufacturer, they indicated that this type of control is technically feasible, but that a modification to the control system would be required. With a control system modification the gas turbines would be able to modify system output to match digester gas production and maintain a constant digester gas pressure. Low pressure gas storage is assumed not to be required, but might be beneficial to operation. Gas storage should be reviewed if this alternative is selected for further evaluation in TM 3.

The O&M costs for this alternative would change from those associated with the status quo CHP operating costs. Running one of the gas turbines full-time would require additional operator time and maintenance. Maintenance would also likely include a maintenance contract through Solar, the turbine manufacturer, for turbine refurbishment. Solar provided a rough estimate for a maintenance contract of $30,000 annually per turbine. The heat recovery system is assumed to meet 95 percent of the plant heating while operating on biomethane requiring the boilers to be operated only during peak heat demand on natural gas. The full-time CHP capacity and operating data are identified in Table 3-10. Note that the boiler O&M costs is expected to be reduced because it would be used only during times of peak heating. Maintenance contract costs should be further coordinated with Solar if this alternative is selected for analysis in TM 3.

Table 3-10. CHP Full-Time Operating Data

Parameter	Value	Notes
Capacity, kW	3,500	Turbines operated as duty-standby
Electrical efficiency, %	28 to 21	Full load to 40% load
Annual electricity generated, 2016, kW/yr [a]	14,712,000	Including during peak demand reduction
Annual electrical savings, 2016, $/yr [b]	1,030,000	Including savings due to peak demand reduction
Labor, parts, and maintenance, $/yr [c]	200,000	In addition to status quo costs
Plant heat demand , %	95	Plant heating satisfied by CHP
Availability, %	100	Percent of time one turbine is available
Estimated FTEs	1.5	In addition to status quo FTEs
Boiler labor, parts, and maintenance, $/yr [d]	$24,000	Assumed as fixed cost

a. *During peak demand reduction it is assumed that only 80% of the status quo electrical savings are received with a corresponding 80% reduction in natural gas costs.*

b. *Electricity savings are $0.07/kWh, fully loaded.*

c. *Assumes maintenance plan costs and additional operators per year.*

d. *Assumes a 75% reduction from existing boiler O&M because boiler is used only during peak heating.*

This alternative also assumes that the heat recovery system is converted to a hot water heat recovery system. Converting the steam system to a hot water system would provide several advantages:

- The hot water system would be easier to bring on and off line because it would not require "moth-balling" after each use, thus reducing the heating accomplished by the boiler.
- The hot water system would not require an operator certified for high-pressure steam operation.
- The steam system could be removed to allow new equipment to be located in the CHP building.

The existing heat recovery steam generators that are located on one of two existing exhaust stacks of each gas-fired turbine could be replaced with heat recovery hot water generators to make the system easier to operate. The heat recovery hot water heaters would replace the existing heat recovery steam generators in kind. The new heaters would be run full-time to provide plant heating. The hot water heaters would require circulation pumps and three-way valves similar to a hot water boiler installation. The estimated capital costs associated with the new heat recovery hot water heaters and the ancillary equipment modifications are shown in Table 3-11. Note that new boilers are assumed to not be installed because the CHP system would act as the primary heat source.

Table 3-11. Estimated Capital Costs to Replace Heat Recovery on Gas Turbine Exhaust

Equipment description	Capital cost
Heat recovery HEX 1 and 2	$920,000
Pumps and three-way valves	

3.1.3.3 Full-time CHP Converted to Low-Btu Fuel and Hot Water System

The existing gas-fired turbines could be configured to burn conditioned digester gas, a low-Btu fuel, without the removal of carbon dioxide (CO_2). The gas turbines are currently configured to burn high-Btu scrubbed gas, natural gas, or a mixture of the two. Solar has identified that the fuel manifold and injectors may be able to be configured to burn either the low-Btu fuel or high-Btu fuels with the same fuel train components internal to the turbine (fuel manifold and fuel injectors). However, the existing SoloNox turbines would need to be replaced with conventional turbines to burn the low-Btu digester gas. Because the conventional turbines produce more NOx than the existing SoloNox turbines, obtaining a new air permit would be more difficult than the previous CHP alternatives described. The air authority may not issue a new air permit for higher emissions from the turbines and this would create a significant risk with this alternative. The digester gas would need to be conditioned to meet the fuel quality requirements of the gas turbines, including hydrogen sulfide (H_2S), moisture, and siloxane removal, and compression to 175 pounds per square inch gauge (psig). The gas conditioning system for the turbines is described in Section 3.3. Similar to the operation on scrubbed digester gas, it is assumed that the gas turbine control system could be designed so that the turbine output load would be varied based on digester gas production. Low pressure gas storage is assumed to not be required, but should be reviewed if this alternative is selected for further evaluation.

The advantage of this configuration would be to reduce the electrical power costs associated with running the gas turbines on scrubbed digester gas. One of the gas turbines would be run continuously on conditioned digester gas, creating electricity and heat for the plant. The full-time low-Btu CHP operating data are similar to that of the high-Btu alternative except that the CHP system would produce more electricity and heat because more gas would be available from the gas conditioning system. As described in TM 1, 4 to 6 percent of the methane gas is lost in the scrubbing process and the gas scrubbing system has a lower availability than a new gas conditioning system would. In addition to full-time operation of one turbine on conditioned digester gas, the second gas turbine would be run on natural gas for peak power demand. This would result in electrical peak demand savings and natural gas costs being reduced by 25 percent compared to the full-time CHP alternative on high-Btu scrubbed gas.

The estimated capital costs associated with the gas turbine modifications to run on a low-Btu fuel are identified in Table 3-12. The costs for replacing the turbine are based on County asset management data. The capital cost and ability to convert the existing turbines to operate on low-Btu fuel should be coordinated further with Solar if this alternative is selected for further analysis in TM 3. The O&M costs for the turbine to run on conditioned gas instead of scrubbed gas are assumed to go up by 10 percent because the fuel quality would not be as high (gas scrubbing and gas conditioning costs are discussed in Section 3.3 below).

Table 3-12. Estimated Capital Costs to Modify Gas Turbines for Low-Btu Operation

Description	Capital cost
Gas turbine modification total	$5,140,000

3.1.4 Internal Combustion Engine for Cogeneration

Similar to the gas turbine alternatives, IC engine-generators can also burn high-Btu gas and low-Btu gas. Both alternatives are investigated for a new IC engine-generator cogeneration system.

3.1.4.1 Lean-Burn IC Engine-Generators with Low-Btu Fuel

This alternative includes the installation of new reciprocating IC engine-generators for cogeneration of electricity and usable heat for the plant in the form of hot water. IC engine-generators are a proven technology for conditioned digester gas combustion. The cogeneration system would consist of lean-burn IC engine-generators that could be located in the existing CHP building, or in a new facility. Heat recovery from the engine jacket, turbo-charger intercooler, oil cooler, and exhaust would provide hot water at a minimum of 180°F. The digester gas would be conditioned by a new low-pressure system to remove H_2S, moisture, and siloxane, and with compression to 3–7 psig. Siloxane and H_2S removal may not be needed to successfully operate the IC engine-generators, but are conservatively included here until gas sampling confirms that they are not necessary. This gas conditioning system is described further in Section 3.3. The advantage of a new IC engine-generator cogeneration system would be the following:

- increased electrical efficiency when compared to the gas turbines, especially at turndown conditions
- hot water heat recovery without a steam system
- decreased digester gas conditioning O&M costs, especially electricity use

A schematic of the IC engine-generator cogeneration system is shown in Figure 3-4.

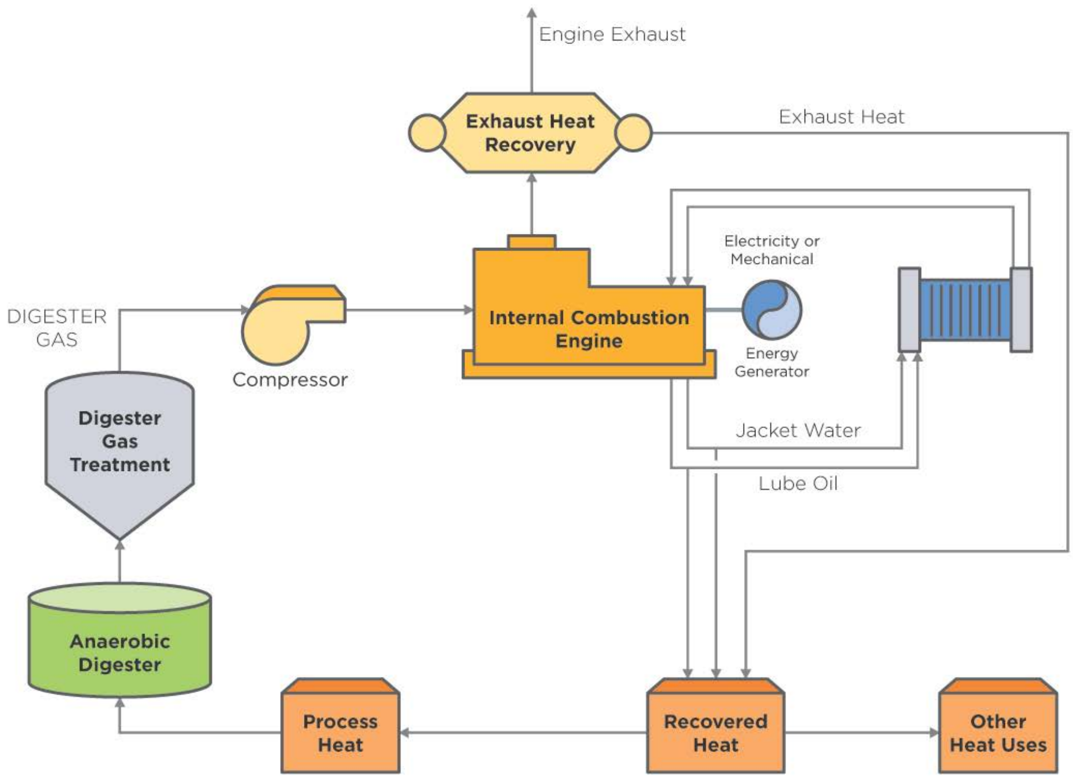

Figure 3-4. Schematic of IC engine cogeneration

The IC engine cogeneration system capacity is based here on the average annual gas production in 2036 of 1.5 million standard cubic feet per day (MM scfd). The capacity of the IC engine cogeneration system should consider average annual production now and in the future, maximum month gas production, and turndown capabilities when some digester gas is required for the boiler. The capacity of the system at an assumed electrical efficiency of 36 percent is about 3,300 kilowatts (kW) for this criterion. At an assumed thermal efficiency of 40 percent, the cogeneration system could produce about 13 MMBtu/hr in 2036, nearly enough for peak heating demand. At a startup condition in 2016, enough digester gas would be produced to generate about 2,800 kW and 10.5 MMBtu/hr under average annual conditions. The assumed cogeneration system capacity and O&M information is shown in Table 3-13. Labor, parts, and maintenance costs scale with electricity production. Note that the boiler O&M costs are expected to be reduced because the boiler would be used only during times of peak heating.

Table 3-13. IC Engine Generator Cogeneration System Capacity and Operating Data

Criteria	Value	Notes
Cogeneration electrical capacity, kW [a]	3,300	Combined capacity
Cogeneration thermal capacity, kWt (MMBtu/hr) [b]	3,810 (13)	As hot water for heating
Annual electricity generated, 2016, kWh/yr [a]	22,613,000	Electricity produced from digester gas
Annual electrical savings, 2016, $/yr [c]	1,583,000	Including savings during peak demand reduction
Percent of plant heating, %	95	When available
Labor, parts, and maintenance, 2016 $/yr [d]	384,000	
Availability, %	92	
Estimated FTEs	2	
Boiler labor, parts, and maintenance, $/yr [e]	$24,000	Assumed as fixed cost

a. *Assumes a 36% electrical efficiency.*
b. *Assumes a 40% thermal efficiency.*
c. *Electricity savings are $0.07/kWh, fully loaded.*
d. *Assumes $0.17/kWh for all O&M includes two FTEs for operation.*
e. *Assumes a 75% reduction from existing boiler O&M because boiler is used only during peak heating.*

A photograph of one of the IC engine-generators at King County's West Point Treatment Plant is shown in Figure 3-5.

The capital cost of the IC engine cogeneration is based on the installation of three 1.1 MW low-emission lean-burn reciprocating IC engine generators with heat recovery. Several manufacturers make engines at or very close to this capacity, including Jenbacher, MWM, Cummins, and Waukesha. An alternative for two engine-generators at about 1.6 or 1.7 MW should also be investigated if this alternative is selected for further analysis in TM 3. The estimated capital cost for this system is identified in Table 3-14.

Table 3-14. Estimated Capital Costs IC Engine Cogeneration System

Equipment description	Capital cost
Cogeneration units	$9,370,000
Heat exchangers	
Water pumps	
Silencers	

The estimated capital cost does not include post-combustion treatment for the IC engines, because very few digester gas-fired IC engine installations are currently operating in the country in this configuration. However, there is a risk that the air permitting authority would require post-combustion treatment to reduce NOx and carbon monoxide emissions.

Figure 3-5. Reciprocating IC engine-generator at West Point Treatment Plant

3.1.4.2 IC Engine-Generators with High-Btu Fuel

The existing gas scrubbing system or a new gas scrubbing system could be utilized to provide pipeline-quality gas to the IC engine-generator cogeneration system. This would eliminate the need for gas conditioning as described in Section 3.3 because the gas scrubbing system currently removes all of the contaminants from the raw digester gas. The capacity and capital cost of the IC engine-generator cogeneration system would be the same as described in the previous section.

The only difference with this option is that the IC engine-generators would produce less electricity and heat because less gas would be available from the gas scrubbing system. As described in TM 1, 4 to 6 percent of the methane gas is lost in the scrubbing process and the gas scrubbing system has a lower availability than a new gas conditioning system would. These losses are described in Section 3.3.

3.2 Beneficial Gas Utilization

Once the plant's heat demand is met, any remaining gas can be beneficially used. This section describes the alternatives as they pertain to beneficial gas utilization. There are two general categories of final gas use: sale of the gas or combustion of the gas to produce electricity (and heat simultaneously).

3.2.1 Sale of Scrubbed Gas (Biomethane)

Alternatives are investigated for the pipeline-quality scrubbed gas produced by the gas scrubbing system: to sell to PSE, to use as a vehicle fuel, and to sell to a third party. These alternatives were investigated to identify the potential revenue available from each source but the revenues available would be market-driven, as is the case with any commodity price.

3.2.1.1 Status Quo Gas Utilization

The status quo alternative for gas utilization would be to continue to sell to PSE all scrubbed gas that is not consumed by the plant's hot water boiler. Revenues generated by this end use are summarized in subsequent sections describing the gas scrubbing alternatives.

3.2.1.2 Renewable Compressed Natural Gas

The biomethane produced by the gas scrubbing process could be used on site or offsite as an alternative vehicle fuel. Renewable compressed natural gas (rCNG) refers to biomethane compressed to approximately 3,600 psig. By compressing the biomethane to high pressures, the energy density is increased, resulting in more energy being transported in a smaller volume. However, rCNG still only provides roughly 25 percent of the energy per gallon of volume when compared to diesel fuel. The rCNG vehicles available on the market (including refuse haulers and tractor-trailers) would typically have a range that is more limited than their diesel counterparts. In addition, rCNG vehicles have limited torque compared to their diesel counterparts and may not be able to haul similar loads over mountainous terrain. A typical rCNG storage capacity on a refuse hauler would be 70 diesel gallons equivalent (although alternative storage configurations can be made to increase this value). A storage capacity of 70 diesel gallons equivalent would provide a refuse hauler range of 210 to 350 miles at a fuel usage rate of 3 to 5 miles per gallon. Figure 3-6 shows a picture of CNG powered refuse haulers operated by Waste Management in Seattle.

Figure 3-6. Waste Management CNG refuse haulers in Seattle

Although the County's total digester gas production is enough to offset approximately 1.5 million gallons of diesel fuel per year, this amount of consumption by County vehicles may not be realistic. The County's loop trucks, however, offer a readily available onsite user for rCNG fuel. The County has 33 loop trucks for biosolids disposal, which transport approximately 3,558 loads per year. Of these loads, 13 percent (or 463 loads) are to areas in eastern King County, mostly for the forestry program and average 80 miles round trip. The rest of the loads are to eastern Washington, averaging between 400 and 450 miles round trip. Based on feedback from County staff associated with the Loop program, only the short-haul trips are considered viable for conversion to rCNG, representing about 1.75 trucks each weekday. Table 3-15 shows the operations data for CNG vehicle fuel operation.

Table 3-15. CNG Vehicle Fuel Operations Data		
Criteria	Value	Notes
Number of CNG trucks	3	Short haul vehicles
Diesel displaced, kWt-h/yr (gallon/yr) [a]	2,079,000 (9,250)	Heating value of diesel displaced
Diesel savings, $/yr [b]	37,000	From diesel fuel offset
Annual electrical power costs, 2016, $/yr [c]	700	Final compression power
Labor, parts, and maintenance, 2016 $/yr [d]	18,000	
Estimate FTEs	1/8	

a. *Assumes 80 miles round trip at 4 mpg for short haul trips.*
b. *At a cost of $4.00 per diesel gallon.*
c. *Electricity costs of $0.07/kWh, fully loaded.*
d. *Includes 0.25 FTE and annual maintenance cost at 2% of equipment.*

A CNG fueling station would be required on site to use the biomethane directly in the CNG loop trucks. Because only a few trucks would be converted to run on CNG to accommodate the short-haul trips, a fast-fill type fueling station would be installed to fill up the trucks on an as-needed basis. The additional cost for outfitting a new tractor-trailer engine from Peterbilt with a CNG fuel train and storage would be about $30,000 per vehicle. The estimated capital costs for a fast-fill CNG fueling station and the net difference in cost for three CNG loop trucks are shown in Table 3-16. Figure 3-7 is a picture of a fast-fill CNG station from GreenField.

Table 3-16. Estimated Capital Costs to Add Vehicle Fueling Station	
Description	Capital cost
Compressor packaged with acoustical enclosure (to 3,600 psig)	$1,180,000
Fast-fill station equipment for fuel dispensing (400,000 scfd)	
CNG fueling system for new loop trucks	

While not considered here, fueling the remaining loop trucks for the long-haul trips to eastern Washington would provide a potentially large fuel savings to the County. The remaining 87 percent of the truck loads represents about 345,000 diesel gallons per year or $1,380,000 annually at an average trip length of 400 miles and 4 miles per gallon (mpg). A CNG refueling station would be required somewhere in eastern Washington to give the hauling trucks enough range to make the trip back from eastern Washington. Because CNG from pipeline natural gas has recently been significantly less than diesel fuel, refueling with natural gas CNG for the trip back to King County would also provide operations savings. At a cost of about $1 million for a fueling station and another $1 million to convert the remaining loop trucks to CNG, it may be a worthwhile investment for the County to transition to CNG loop trucks.

Figure 3-7. Fast-fill fueling station from GreenField

3.2.1.3 Renewable Identification Numbers (RINs)

The Renewable Fuel Standard (RFS) adopted as part of the Energy Policy Act of 2005 requires that motor-vehicle fuel in the lower 48 states contain specific volumes of renewable fuel for each calendar year, beginning with 4 billion gallons of renewable fuel in 2006 and ratcheting up to 7.5 billion gallons by 2012. What is not generally understood, however, is how compliance with the standard will be measured. While projections are that renewable fuel volumes will easily exceed the RFS, compliance under the standard is nonetheless important. Under the compliance program, which was announced by the U.S. Environmental Protection Agency (EPA) in May 2011 and went into effect on September 1, 2011, any party—including refiners, blenders, and importers—that produces or imports gasoline for U.S. consumption, will be subject to a “renewable volume obligation,” the purpose of which is to measure the amount of renewable fuel making its way into motor vehicle fuel sold or introduced into U.S. commerce, and to ensure that it meets the RFS.

Under the EPA’s RFS program, every gallon of renewable fuel produced or imported into the United States will be assigned a renewable identification number (RIN). RINs are intended to represent proxies for the amount of renewable fuels actually blended into gasoline or otherwise used as a motor vehicle fuel. Each year, obligated parties—refiners, blenders, and importers—must acquire sufficient RINs to demonstrate compliance with their volume obligation. The RIN, in essence, is now a credit used as a method to keep score. If an obligated party blends more renewable fuel than its share, it generates excess RINs. These excess RINs can then be traded or sold to another company that finds it more economical to purchase RINs than to blend a renewable fuel with a nonrenewable fuel. Banking and trading of RINs as renewable fuel credits forms the basis for an open RIN market.

Ultimately, the RIN must end up in the hands of the petroleum refiner or gasoline importer to be used for compliance purposes. However, trading of RINs is not limited to just oil companies or renewable-fuel suppliers. In fact, any company can trade RINs, provided that it is registered with EPA to participate in the program. With the program now just getting started, RIN trading is still being conducted at the most basic level—between renewable fuel suppliers and oil companies. As the market matures, it is expected that more players will enter the market.

The RFS and the RIN programs are currently in their infancy. Most companies are still working on systems to handle the paperwork. The RIN is the heart of the RFS and it is expected to continue to be used and evolve as a commodity of value. The interest in RINs as a commodity of value may become even greater with Renewable Fuel Standard Program (RFS2) modifications as part of the Energy Independence and Security Act of 2007. Biogas converted to biomethane and used for vehicle fuel may be able to take advantage of the RIN marketplace to enhance the value of the biomethane produced. In fact, the outlook is good for biomethane used as vehicle fuel to command a premium value in the vehicle fuel marketplace. However, because of the uncertainty associated with the lack of maturity in the market, it is impossible to predict with accuracy exactly what this premium may be. Therefore, no value is assigned in this analysis, but the potential for generating revenue is an advantage for scrubbing the digester gas and injecting it into the natural gas pipeline.

3.2.1.4 Sell Scrubbed Gas to a Third Party

The biomethane currently being produced from the gas scrubbing system is sold to PSE. An alternative approach would be to sell the biomethane to a third party that would pay a higher rate for the gas. Third parties could include agencies in other localities or states that would purchase the gas through wheeling the gas through existing natural gas suppliers and transporters. This option was investigated in detail in a technical memorandum titled “Market Analysis for Sale of Biogas/Sale of Biomethane” (December 9, 2011). The memorandum is attached as an appendix.

One third-party option would be to scrub and sell biomethane to a local university by wheeling the biomethane through the natural gas pipeline. An example of this type of program is at the University of New Hampshire, where landfill gas is scrubbed and combusted in gas turbines on campus. The University of Washington has a natural gas-fired central plant, and may well pay a premium for biomethane instead of natural gas. A reasonable assumption is that the University of Washington would be willing to pay more for biomethane than the standard natural gas rate, resulting in a 10 percent premium to the County after wheeling fees taken by PSE.

An alternative third party would be a local user that would consume the gas directly. This third party would need to be located immediately near the site. As such, potential buyers would be limited. Based on the limited opportunities associated with this alternative, selling scrubbed gas to a local third party was considered fatally flawed and was not considered further.

3.2.2 Electrical Generation

The CHP system and IC engine-generator alternatives would provide heat and electricity. Electrical production is summarized in the preceding sections describing each alternative.

Renewable Energy Credits

Renewable Energy Credits (RECs) are tradable commodities that represent proof that energy is generated from renewable energy sources. Many power utilities are required to provide a percentage of their power from renewable energy sources through a Renewable Portfolio Standard (RPS). RECs have become the dominant mechanism for compliance with these policies and voluntary green power purchases. RECs are tradable commodities, separate from the electricity produced, that bundle the “attributes” of renewable electricity generation. Because they are unbundled from the electricity, RECs are not subject to transmission constraints. One REC typically represents the attributes of 1 megawatt-hour (MWh) of renewable electricity generation. The definition of “attributes” can vary across contracts, but likely includes any future carbon trading credits, emission reduction credits, and emission allowances. Once the REC is separated from the underlying electricity and sold to another party, claims to the attributes can be made only by the REC owner, and not by the electricity owner or the owner of the project. For example, the host of a digester gas cogeneration system may not be able to claim that it is using “green power” if it is selling the RECs generated by the project to another entity.

RECs are currently used by power companies to demonstrate compliance with regulatory requirements, such as renewable energy mandates (the “compliance market”), and by green power marketers and utilities to supply renewable energy products to end-use customers who voluntarily purchase RECs (the “voluntary market”). When companies like Intel or Pepsico announce that they are offsetting a percentage of electricity use with renewable energy, more often than not, the companies have purchased RECs in the voluntary market rather than installing wind turbines or photovoltaic (PV) systems on site.

REC prices are currently very low nationwide due to low interest from private firms. Prices have dropped from $4 to $5 per MWh in early 2008 to under $1 per MWh currently, depending on the type of technology generating the credit. The future values of the RECs are very speculative and are currently not large enough to affect the financial viability of the project. Therefore, the value of the potential RECs was not included in the economic analysis here.

3.3 Gas Treatment Alternatives

To meet the needs of the plant heat demand and beneficial gas utilization alternatives, various levels of gas treatment would be required. This section describes gas treatment alternatives. There are three options for gas treatment: the status quo gas scrubbing system, a new gas scrubbing system, or a gas conditioning system.

3.3.1 Status Quo Gas Scrubbing System

The digester gas scrubbing system compresses digester gas and scrubs it to pipeline-quality biomethane, which is sold to PSE or used on site by the CHP system and boilers. A detailed description is provided in TM 1.

Based on the County scheduled replacement and feedback on operation, the following upgrades to the gas scrubbing system would be required as capital expenditures for the status quo alternative:

- Digester gas compressors 1 and 2 are approaching the end of their life and would be replaced.
- Turbine pumps 1 and 2 are approaching the end of their life and would be replaced.
- The gas scrubbing system control software would be migrated to Ovation.

As an alternative to replacing the digester gas compressors 1 and 2 with compressors of equal capacity, these compressors could be replaced with compressors with larger capacities equal to that of compressor 3. As identified in TM 1, the digester gas compressors are the most maintenance-intensive components in the gas scrubbing system. When one of the compressors is down for scheduled or unscheduled maintenance, the available capacity of the gas scrubbing system is reduced and digester gas may be flared.

A number of changes to the gas scrubbing operations data are assumed with the gas scrubbing system upgrades. By installing new compressors with equal or near equal capacity to compressor 3, the gas scrubbing system would have increased reliability and therefore increased availability. The availability is assumed to increase to 98 percent. The annual maintenance cost would also be reduced for compressor overhaul because the newer equipment is assumed to provide longer duration between overhauls. The amount of time that scrubbed gas is sent to the flares is assumed to be the same as that of the existing system. As noted in TM 1, County data show that about 5 percent of the scrubbed gas was sent to the flares in 2012. Table 3-17 shows the capacity and operating data of the existing gas scrubbing system with these upgrades.

Table 3-17. Gas Scrubbing System Operations Data		
Criteria	Value	Notes
Capacity, MM scfd	2.4	See TM 1 for capacity description
Scrubbed gas produced, 2016, kWt-h/yr (MMBtu/yr)	70,337,000 (240,000)	Net higher heating value of scrubbed gas produced
Annual revenue, 2016, $/yr	968,000	After boiler and turbine scrubbed gas use
Annual electricity used, 2016, kWh/yr	5,985,000	Electricity used to produce scrubbed gas
Annual electrical power cost, 2016, $/yr[a]	419,000	
Labor, parts, and maintenance, 2016, $/yr [b]	186,000	See TM 1 for O&M description
Availability, %	98	Percent of time the system is available
Methane capture efficiency, %	95	Percent of methane entering system that is leaving as product gas
Scrubbed gas flared, %	5	Percent of scrubbed gas wasted to flares
Estimated FTEs	1	

a. *Based on data provided by King County.*

b. *Based on data documented in TM 1 with a 15% reduction for new compressors.*

c. *Based on rate provided by PSE in April 2013 of $0.4347/therm.*

The capital costs for the larger compressors would be higher than the equipment cost identified in the asset management system. The capital cost estimates for upgrading the gas scrubbing system with larger compressors, new turbine pumps, and Ovation upgrade are shown in Table 3-18.

Table 3-18. Gas Scrubbing System Capital Costs	
Description	Capital cost
Replace compressors 1 and 2 in kind	$4,560,000
Replace turbine pumps 1 and 2 in kind	
Ovation upgrade	

3.3.2 New Gas Scrubbing System

This alternative investigates the installation of a new biogas scrubbing system. The potential advantages to installing a new biogas scrubbing system would be the potential for lower O&M costs such as electricity and replacement of a system that has been operating for between 15 and 25 years. The existing scrubbing system would be replaced entirely except for the gas monitoring, odorizing, and diversion valves. This section includes an introduction to the biogas upgrading technologies and an economic comparison to determine which representative technology to carry forward for comparison.

3.3.2.1 Solvent Separation

Solvent systems for CO_2 separation work by selectively absorbing CO_2 from the biogas while allowing methane to pass. Absorption is the transfer process of a gas constituent into a liquid in which it is soluble. Except for amine systems, the separation process of CO_2 from biogas usually occurs at pressures greater than 100 psig to increase methane recovery rates. The compressed biogas flows upward through a packed tower while the solvent flows downward in a countercurrent fashion. The compressed biogas leaves the tower with CO_2 levels reduced to the required end-product quality. The solvent is chosen for being selective for CO_2 and often also H_2S. The selective absorption of CO_2 over methane allows the methane to pass through while removing CO_2. Regeneration of the solvent is required by reducing the pressure of the solvent and sometimes by heating. This process releases the CO_2, H_2S, and other residual gases, which are then burned in a flare, or scrubbed and vented. The regenerated solvent is cooled and pumped back to the top of the packed tower. Solvents that are used for biogas scrubbing include water, amines, and glycols.

3.3.2.1.1 Water Solvent System

The absorption of CO_2 into water is a physical process. Physical absorption has an advantage over chemical absorption in that regeneration of the solvent does not require heating, only pressure reduction. The regeneration can be aided by running the saturated water through another packed column and stripping the CO_2 and H_2S out of solution using air. The use of water has the advantage that the solvent makeup for a closed-loop system is readily available and requires no chemical handling.

Greenlane is a Canada-based company that has manufactured fully packaged water solvent systems for 25 years. Greenlane makes water absorption systems (Figure 3-8) for gas flow rates as small as 40 standard cubic feet per minute (scfm) and up to more than 1,800 scfm. The system size for South Plant of about 1,050 scfm falls squarely in this range. Greenlane has at least 30 projects throughout the United States, Canada, Europe, Japan, New Zealand, and other countries. Its first installation was in 1985 in New Zealand, and its first commercial project in North America began selling biomethane to the natural gas grid in Abbotsford, B.C., in 2010. The Greenlane systems have predesigned packages that cover a range of flow rates and offer service plans and remote monitoring. The smallest units are installed in iso-containers, and larger units can be in an iso-container or skid-mounted. The standardized design approach reduces design and installation costs.

Figure 3-8. Greenlane "Manuka" system for 40 scfm flow rate

3.3.2.1.2 Amine Solvent System

Amines are a chemical solvent used in absorption processes to remove CO_2 and H_2S (at moderate levels) from biogas and natural gas. The chemical absorption process is reversible and the solvents are typically very selective for acid gas separation (i.e., CO_2 and H_2S). The acid gas constituents chemically react with components of the liquid to form a loosely bound reaction product. The chemical reaction is reversible by reducing the pressure of the solvent and heating. The heating process adds a degree of complexity compared to physical solvents and a requirement for an external steam source. Amine systems have extremely high methane capture rates (99.9 percent) and the separation process can take place at low pressures because of the amine's high selectivity for CO_2 and H_2S at low pressures. Chemical solvents are used quite often at larger scales for natural gas processing and in some medium-scale biogas projects in Europe and landfills in the United States. A system from Läckeby Water is shown in Figure 3-9.

Figure 3-9. Purac Capture Amine System by Läckeby Water

Source: http://www.lackebywater.se/index3.html

3.3.2.2 Pressure Swing Adsorption

Most pressure swing adsorption (PSA) systems take advantage of the difference in equilibrium capacities of adsorbents for CO_2 at high and low pressures. Adsorbents are porous materials that naturally or through manufacturing have high surface areas per volume and are chosen for their selectivity for CO_2. The adsorption of CO_2 onto the surface of the adsorbent is a weak physical attraction by van der Waals forces and a molecular sieving process. The capacity of an adsorbent for CO_2 is the amount of CO_2 that can be adsorbed at an equilibrium condition. The capacities at high pressure are greater than those at low pressure. PSA systems are systems of multiple packed beds, which operate continuously by having one vessel "online" and the other(s) in a state of regeneration. In this process, the biogas typically is compressed to 100–150 psig and flows through the packed bed, where the CO_2 is removed by the adsorbent. When the online bed reaches its capacity it is isolated from the process, and the biogas flows through a newly regenerated bed. The spent bed is regenerated by depressurizing the vessel and typically using a dry regeneration gas free of CO_2 to further decrease the partial pressure of CO_2 (the driving force). Adsorbents used for CO_2 PSA systems include molecular sieves (Zeolites) and carbon molecular sieves. Waste gas produced by the separation process would be combusted in a thermal oxidizer.

Two companies currently offer standardized PSA system designs for biogas purification: Xebec and Guild Associates. Both companies have a number of digester gas and landfill gas plants currently in operation. Guild Associates has at least three operating systems at wastewater treatment plants (WWTPs), one of which is shown in Figure 3-10. Both offer packaged systems with compression at sizes of 70 scfm up to many thousand scfm.

Figure 3-10. Guild Associates biogas upgrading system in San Antonio, Texas

3.3.2.3 Membrane System

Membranes are thin, semi-permeable barriers that selectively separate CO_2 (also H_2S and water) from biogas. The driving force for the process is differential partial pressures with a high pressure on the process side and low pressure on the waste side. The CO_2 dissolves and diffuses through the thin non-porous membranes faster than methane does. In this process, the biogas is compressed to pressures of 150 psig or greater and sent into the membrane separation chamber, where CO_2 is selectively removed. The selectivity for CO_2 is not as high as adsorbents or solvents and usually a two-stage process is required to have methane capture efficiency comparable to a PSA system. The waste gas from the first stage is re-compressed, sent through another membrane separation chamber, and then re-injected into the first-stage membrane separation chamber. The membranes are subject to degradation if volatile organic compounds (VOCs) or H_2S are sent through the membranes. For this reason a separate gas treatment PSA or a non-regenerative activated carbon filter needs to be installed in front of the membranes for removal of VOCs and residual H_2S. Similar to the PSA system, the waste gas produced by the separation process would be combusted in a thermal oxidizer.

The largest supplier of membranes for biogas separation is Air Liquide's MEDAL (Membrane Systems DuPont Air Liquide), which was a joint venture of DuPont and Air Liquide originally. The Air Liquide MEDAL membranes are used in a number of landfill gas applications and two WWTP applications. The technology uses polymeric fibers for the membranes, which can remove CO_2, water, and about half of the oxygen (O_2) if present. At least 13 landfill gas plants use membrane separation to remove CO_2. A picture of a membrane separation system is shown in Figure 3-11. Air Liquide will package the pre-separation gas treatment and membranes together, but does not package compression. However, third-party packagers such as Unison Solutions and Cornerstone provide a complete packaged system.

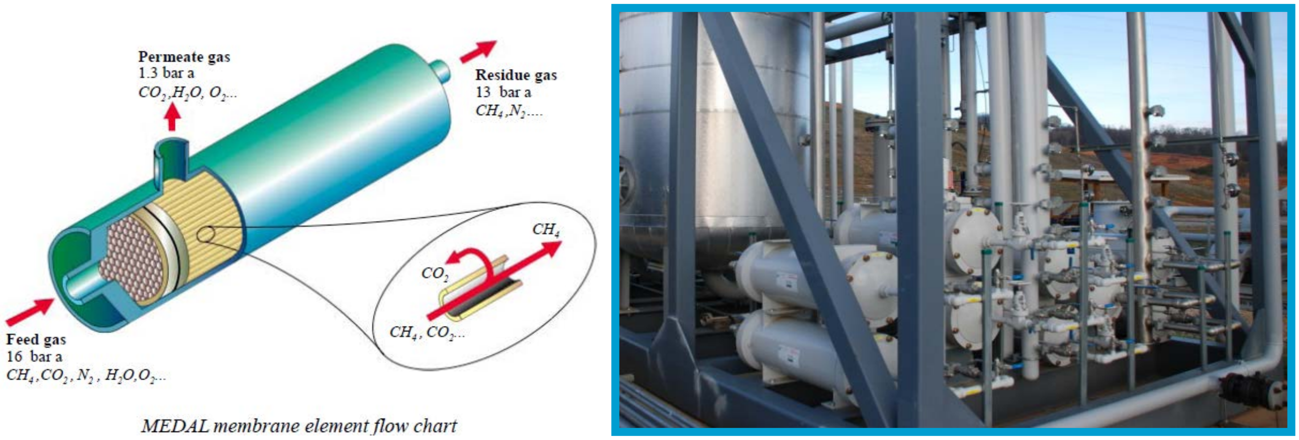

Figure 3-11. Air Liquide MEDAL membranes

3.3.2.4 Representative Technology for New Gas Scrubbing System

Two representative technologies were selected for this analysis: a water solvent system from Greenlane and a PSA system from Guild. These two technologies were compared because they represent two categories of a gas upgrading system: (1) higher capital and O&M costs, but with higher methane capture efficiencies, and (2) lower capital and O&M costs, but with lower methane capture efficiencies. The other technologies mentioned previously are expected to have results similar to these two technologies. If this alternative is selected, a thorough review of gas upgrading technologies should be completed during preliminary design. The two technologies were compared using the status quo alternative in an NPV analysis. The intent of the comparison is to select one new gas scrubbing technology to carry forward for comparison to the other digester gas utilization alternatives. Each system has parallel equipment that is rated at 50 percent capacity for critical application, such as the compression systems. This is expected to provide an availability of 98 percent of the total system capacity.

The Greenlane system has higher methane capture efficiency (thus higher revenues) than the Guild system and lower power costs. However, the Guild system has lower estimated maintenance costs. Each of the alternatives includes the cost for a manufacturer's maintenance plan and remote system monitoring. The capacity and estimated operating data for the Greenlane and Guild systems are shown in Table 3-19. The amount of scrubbed gas that is sent to the flares because of gas quality deviations is assumed to remain at 5 percent.

Criteria	PSA, Guild	Water solvent, Greenlane	Notes
Capacity, MM scfd	1.5	1.5	Capacity to meet 2036 average digester gas flow
Scrubbed gas produced, 2016, kWt-h/yr (MMBtu/yr)	67,116,000 (229,000)	72,685,000 (248,000)	Net higher heating value of scrubbed gas produced
Annual revenue, 2016, $/yr	739,000	824,000	After boiler and turbine scrubbed gas use
Annual electricity used, 2016, kWh/yr	3,521,000	3,106,000	Electricity used to produce scrubbed gas
Annual electrical power cost, 2016, $/yr[a]	246,000	217,000	Includes final compression to 250 psig
Labor, parts, and maintenance, 2016, $/yr [b]	88,000	141,000 [c]	Includes maintenance plans
Availability, %	98	98	Percent of time the system is available
Methane capture efficiency, %	92	98.5	Percent of methane entering system which leaves as product gas
Scrubbed gas flared, %	5	5	
Estimated FTE	0.5	0.5	

Table 3-19. Guild and Greenlane Capacity and Operating Data

a. Electricity costs of $0.07/kWh, fully loaded.
b. PSE purchase price of $0.43477/therm.
c. Includes H_2S removal media replacement costs.

The estimated capital costs for the two gas scrubbing systems are identified in Table 3-20.

Table 3-20. Estimated Capital Costs for Biomethane Upgrading Equipment

Equipment description	PSA, Guild capital cost	Water solvent, Greenlane capital cost
Packaged biogas upgrading systems cost	$7,740,000	$9,970,000
Product gas compressors cost		
Thermal oxidizer (for PSA only)		
H_2S removal/biofilter (for Water Solvent only)		

Comparing the NPV of each alternative reveals that the Guild PSA system has a distinct economic advantage for the conditions at South Plant. The PSA alternative will be carried forward for comparison to other digester gas utilization alternatives. The NPVs for the two technologies operating in the status quo manner between 2016 through 2036 are shown in Table 3-21. Note that the capital costs for the alternative shown reflect the cost for the upgrading equipment and the new boilers.

Table 3-21. New Gas Scrubbing System Comparison in Status Quo Manner

Description	Capital cost	Annual O&M costs, 2016	Annual savings/ revenues, 2016	NPV
Guild PSA	$9,260,000	$777,000	$1,106,000	($2,513,000)
Greenlane water solvent	$11,490,000	$804,000	$1,211,000	($3,315,000)

3.3.3 New Gas Conditioning System

The IC engine cogeneration alternative or low-Btu CHP alternative assumes that a low-pressure or medium-pressure digester gas conditioning system would be installed consisting of hydrogen sulfide, water, and siloxanes removal and compression. The constituents are removed with a digester gas conditioning system to meet the engine or turbine fuel requirements, reduce maintenance costs, and improve equipment longevity. Hydrogen sulfide would be removed with a dual-tank regenerable iron sponge system. The conditioning system would boost the gas pressure to 3 to 7 psig for final use by the IC engine-generators or to 175 psig for the gas turbines. The system would include duty-standby blowers or compressors for compression. The gas would be chilled to remove water and reheated prior to the siloxane removal vessels. The chillers would also be duty-standby. Siloxanes would be removed with a dual-vessel activated carbon system. The activated carbon system is not assumed to be regenerable. A schematic of the system is shown in Figure 3-12.

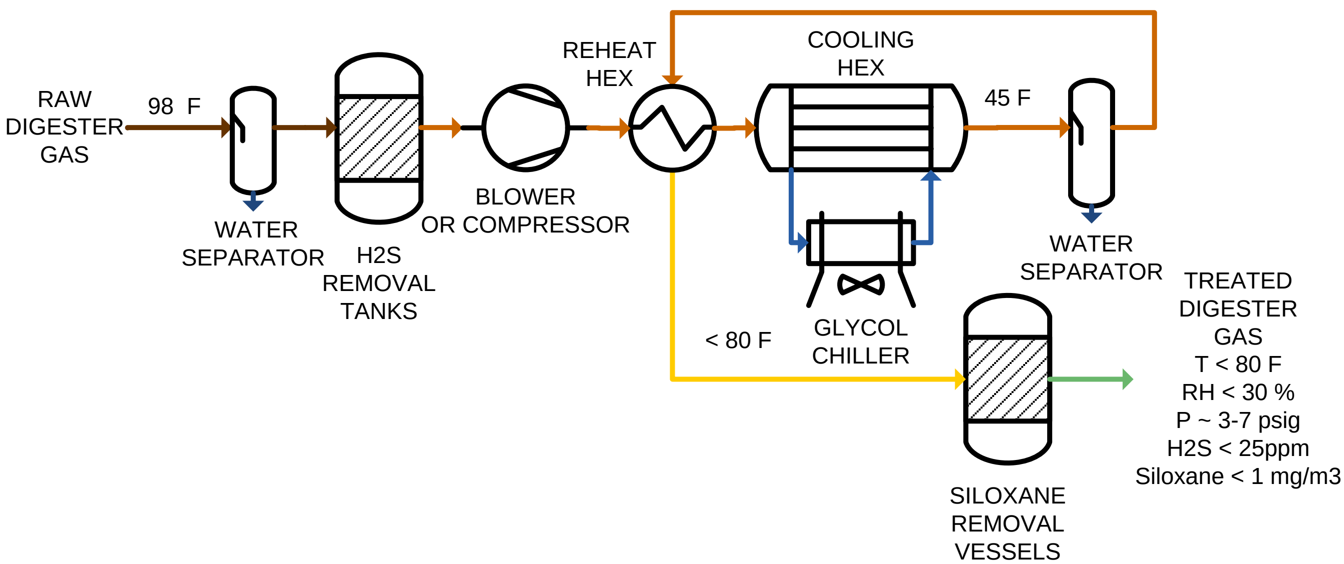

Figure 3-12. Conceptual process flow schematic of gas treatment for IC engine cogeneration

The cost to operate the system includes media replacement for hydrogen sulfide and siloxane removal, and power to operate the chillers and blowers or compressors. The capacity of the system would need to be about 1.5MM scfd to meet the 2036 average. The capacity and operating data for the system are summarized in Table 3-22.

Table 3-22. Gas Conditioning System Capacity and Operations Data		
Criteria	Value	Notes
Capacity, MM scfd	1.50	Capacity to meet 2036 average digester gas flow
Annual blower & chiller power, 2016, kWh/yr [a]	56,000	For low-pressure IC engine system
Annual compressor & chiller power, 2016, kWh/yr [b]	234,000	For medium-pressure turbine system
Labor, parts, and maintenance with blowers, 2016, $/yr [c]	54,000	For low-pressure IC engine system
Labor, parts, and maintenance with compressors, 2016 , $/yr [c]	58,000	For medium-pressure turbine system
Hydrogen sulfide media replacement, 2016, $/yr [d]	28,000	Includes labor cost
Siloxane media replacement, 2016, $/yr [e]	181,000	Includes labor cost
Availability, %	100%	With duty-standby critical equipment
Estimated FTEs	0.75	

a. Assumes compression to 5 psig.

b. Assumes compression to 175 psig.

c. Based on 2% of equipment capital cost and 0.5 FTE.

d. Based on an H_2S content of 250 ppm and one regeneration cycle of the iron sponge.

e. Based on a siloxane content of 25 mg/m^3 of digester gas.

The capital cost of the systems would differ based on whether low-pressure blowers or medium-pressure compressors were installed. Table 3-23 shows the estimated capital cost for a low-pressure gas conditioning system for the IC engine-generator cogeneration system.

Table 3-23. Estimated Capital Costs for Low-Pressure Gas Conditioning System	
Description	Capital cost
H_2S removal	$4,510,000
Siloxane removal	
Gas compression skid (low-pressure)	

Table 3-24 shows the estimated capital cost for a medium-pressure gas conditioning system for the gas turbines in the CHP system.

Table 3-24. Estimated Capital Costs for Medium-Pressure Gas Conditioning System	
Description	Capital cost
H_2S removal	$5,320,000
Siloxane removal	
Gas compression skid (high-pressure)	

3.4 Summary of Sub-Alternatives

A summary of all of the combinations from the three categories is presented in Table 3-25 below.

Table 3-25. Alternative Description per Category			
Alt.	Primary heat source	Gas treatment	Beneficial end use
A1	Status quo (boilers)	Status quo scrubbing system	Status quo (sell gas to PSE)
A2	Status quo (boilers)	Status quo scrubbing system	Use some gas as rCNG
A3	Status quo (boilers)	Status quo scrubbing system	Sell gas to third party
A4	Status quo (boilers)	New gas scrubbing system	Status quo (sell gas to PSE)
A5	Status quo (boilers)	New gas scrubbing system	Use some gas as rCNG
A6	Status quo (boilers)	New gas scrubbing system	Sell gas to third party
B1	Low-Btu boilers	Status quo scrubbing system	Status quo (sell to PSE)
B2	Low-Btu boilers	Status quo scrubbing system	Use some gas as rCNG
B3	Low-Btu boilers	New gas scrubbing system	Status quo (sell to PSE)
B4	Low-Btu boilers	New gas scrubbing system	Use some gas as rCNG
C1	Heat extractors	Status quo scrubbing system	Status quo (sell to PSE)
C2	Heat extractors	Status quo scrubbing system	Use some gas as rCNG
C3	Heat extractors	New gas scrubbing system	Status quo (sell to PSE)
C4	Heat extractors	New gas scrubbing system	Use some gas as rCNG
D1	CHP system (hot water)	Status quo scrubbing system	Produce electricity, hot water
D2	CHP system (hot water)	New gas scrubbing system	Produce electricity, hot water
D3	Low-Btu CHP system (hot water)	Gas conditioning system	Produce electricity, hot water
E1	Low-Btu IC engine cogeneration	Gas conditioning system	Produce electricity, hot water
E2	High-Btu IC engine cogeneration	Status quo scrubbing system	Produce electricity, hot water
E3	High-Btu IC engine cogeneration	New gas scrubbing system	Produce electricity, hot water

Descriptions of the subsystems included in each alternative are shown in Table 3-26.

Table 3-26. Alternative Description of Subsystems

Alt	Description	High-Btu gas-fired boilers	Low-Btu gas-fired boilers	High-temp effluent heat extractors	CHP: gas turbines steam heat recovery	CHP: gas turbines hot water heat recovery	IC engines with heat recovery	Gas scrubbing	Gas conditioning	Revenue/saving generation
A1	Status quo	Exist + new			✓ [a]			Existing		Gas to PSE, peak power reduction
A2	Status quo, gas to rCNG	Exist + new			✓ [a]			Existing		rCNG and gas to PSE, peak power reduction
A3	Status quo, gas to 3rd party	Exist + new			✓ [a]			Existing		Gas to 3rd party, peak power reduction
A4	Status quo, new gas scrubbing	Exist + new			✓ [a]			New		Gas to PSE, peak power reduction
A5	Status quo, new gas scrubbing, gas to rCNG	Exist + new			✓ [a]			New		rCNG and gas to PSE, peak power reduction
A6	Status quo, new gas scrubbing, gas to 3rd party	Exist + new			✓ [a]			New		Gas to 3rd party, peak power reduction
B1	Low-Btu boilers	Exist [a]	✓		✓ [a]			Existing		Gas to PSE, peak power reduction
B2	Low-Btu boilers, gas to rCNG	Exist [a]	✓		✓ [a]			Existing		rCNG and gas to PSE, peak power reduction
B3	Low-Btu boilers, new gas scrubbing	Exist [a]	✓		✓ [a]			New		Gas to PSE, peak power reduction
B4	Low-Btu boilers, new gas scrubbing, gas to rCNG	Exist [a]	✓		✓ [a]			New		rCNG and gas to PSE, peak power reduction
C1	New extractors	Exist [a]		✓	✓ [a]			Existing		Gas to PSE, peak power reduction
C2	New extractors, gas to rCNG	Exist [a]		✓	✓ [a]			Existing		rCNG and gas to PSE, peak power reduction
C3	New extractors, new gas scrubbing	Exist [a]		✓	✓ [a]			New		Gas to PSE, peak power reduction
C4	New extractors, new gas scrubbing, gas to rCNG	Exist [a]		✓	✓ [a]			New		rCNG and gas to PSE, peak power reduction
D1	Full-time CHP	Exist [a]				✓		Existing		Electricity, peak power reduction
D2	Full-time CHP, new gas scrubbing	Exist [a]				✓		New		Electricity, peak power reduction
D3	Full-time low-Btu CHP, gas conditioning	Exist [a]				✓			✓	Electricity, peak power reduction
E1	Low-Btu IC engines, gas conditioning	Exist [a]			✓ [a]		✓		✓	Electricity, peak power reduction
E2	High-Btu IC engines	Exist [a]			✓ [a]		✓	Existing		Electricity, peak power reduction
E3	High-Btu IC engines, new gas scrubbing	Exist [a]			✓ [a]		✓	New		Electricity, peak power reduction

a. *Backup heat source for this alternative.*

Section 4: Biogas Alternatives Comparison

The alternatives described in the previous section are compared here in three categories of objectives: financial, energy, and operations.

4.1 Financial Objective Comparison

The financial objectives of the project can be broken down into each alternative's NPV, the ability to get grants, credits, and incentives, and the sensitivity to commodity price changes. These sub-categories are described in this section. It is worthwhile to note that the relatively low cost of treated or scrubbed digester gas makes energy alternative evaluations and conclusions for South Plant significantly different from non-wastewater treatment facilities that must pay utility prices for natural gas.

4.1.1 Maximize the Program's Net Present Value

An NPV analysis is a holistic way to compare alternatives on an economic basis. NPV includes capital costs and recurring future costs and revenues on a common basis accounting for the time-value of money. While the NPV provides a complete economic comparison of alternatives, comparing the capital and recurring cost objectives separately can be of value if limitations exist for these expenditures. The following list describes the individual objectives of the economic variables:

- Minimize capital costs: The alternatives that use the status quo system, including the CHP system as a primary heat source, have the lowest capital cost. The highest capital cost alternatives are associated with installing new IC engine cogeneration systems or new gas scrubbing systems.
- Minimize operations, maintenance, and rehabilitation and replacement (R&R) costs: The new gas scrubbing alternatives generally fared better in O&M costs due to their reduced electrical power consumption and maintenance requirements. Meeting the plant's heat demand through either status quo boilers or new low-Btu boilers were the lowest O&M cost alternatives. New effluent heat extractors and new IC engines had the highest annual O&M costs.
- Maximize revenues/savings: The alternative with the highest revenue or savings are dependent on the commodity sale price. Currently, producing electricity from the digester gas provides a greater savings compared to sale of biomethane to PSE. However, use of the biomethane as rCNG for vehicle fuel or selling to a third party at a higher rate could generate more revenue for the plant.

An NPV analysis was completed for the alternatives selected. The analysis includes the following major assumptions in addition to those set forth in the body and other appendices of the TM:

- The systems are assumed to be installed in 2015 and operate between 2016 and 2036.
- An escalation rate of 2.5 percent and discount rate of 5 percent applies to all costs, savings, and revenues.
- All values are in 2013 dollars.

The capital, annual O&M, annual savings/revenues, and net present values for each of the alternatives are shown in Table 4-1 and Figure 4-1. The alternative with the best NPV is alternative A6, which includes status quo boilers with a new gas scrubbing system and sale of the scrubbed gas to a third party. This alternative is followed by A3. Alternatives B1, A4, and B3 are within $2 million of A6. The alternatives with the worst NPVs are E2, E3, D1, and C2, which include either combusting the digester gas or effluent heat extraction.

Table 4-1. Digester Gas Utilization Alternatives Economic Analysis					
Alt	Description	Capital cost	Annual O&M costs, 2016	Annual savings/ revenues, 2016	NPV
A1	Status quo	$6,080,000	$1,040,000	$980,000	($3,173,000)
A2	Status quo, gas to rCNG	$7,260,000	$1,060,000	$1,020,000	($4,028,000)
A3	Status quo, gas to 3rd party	$6,080,000	$1,040,000	$1,060,000	($1,499,000)
A4	Status quo, new gas scrubbing	$9,260,000	$780,000	$940,000	($2,513,000)
A5	Status quo, new gas scrubbing, gas to rCNG	$10,440,000	$790,000	$970,000	($3,368,000)
A6	Status quo, new gas scrubbing, gas to 3rd party	$9,260,000	$780,000	$1,010,000	($940,000)
B1	Low-Btu boilers	$6,470,000	$990,000	$1,000,000	($2,227,000)
B2	Low-Btu boilers, gas to rCNG	$7,650,000	$1,000,000	$1,040,000	($3,035,000)
B3	Low-Btu boilers, new gas scrubbing	$9,650,000	$800,000	$970,000	($2,627,000)
B4	Low-Btu boilers, new gas scrubbing, gas to rCNG	$10,830,000	$820,000	$1,000,000	($3,482,000)
C1	New extractors	$8,060,000	$1,310,000	$1,240,000	($4,245,000)
C2	New extractors, gas to rCNG	$9,240,000	$1,320,000	$1,270,000	($5,100,000)
C3	New extractors, new gas scrubbing	$11,240,000	$1,040,000	$1,190,000	($3,586,000)
C4	New extractors, new gas scrubbing, gas to rCNG	$12,420,000	$1,060,000	$1,220,000	($4,441,000)
D1	Full-time CHP	$5,480,000	$1,120,000	$1,150,000	($5,289,000)
D2	Full-time CHP, new gas scrubbing	$8,660,000	$890,000	$1,090,000	($4,382,000)
D3	Full-time low-Btu CHP, gas conditioning	$10,570,000	$960,000	$1,250,000	($4,641,000)
E1	Low-Btu IC engines, gas conditioning	$13,880,000	$1,260,000	$1,780,000	($3,720,000)
E2	High-Btu IC engines	$13,930,000	$1,400,000	$1,790,000	($6,520,000)
E3	High-Btu IC engines, new gas scrubbing	$17,110,000	$1,120,000	$1,720,000	($5,802,000)

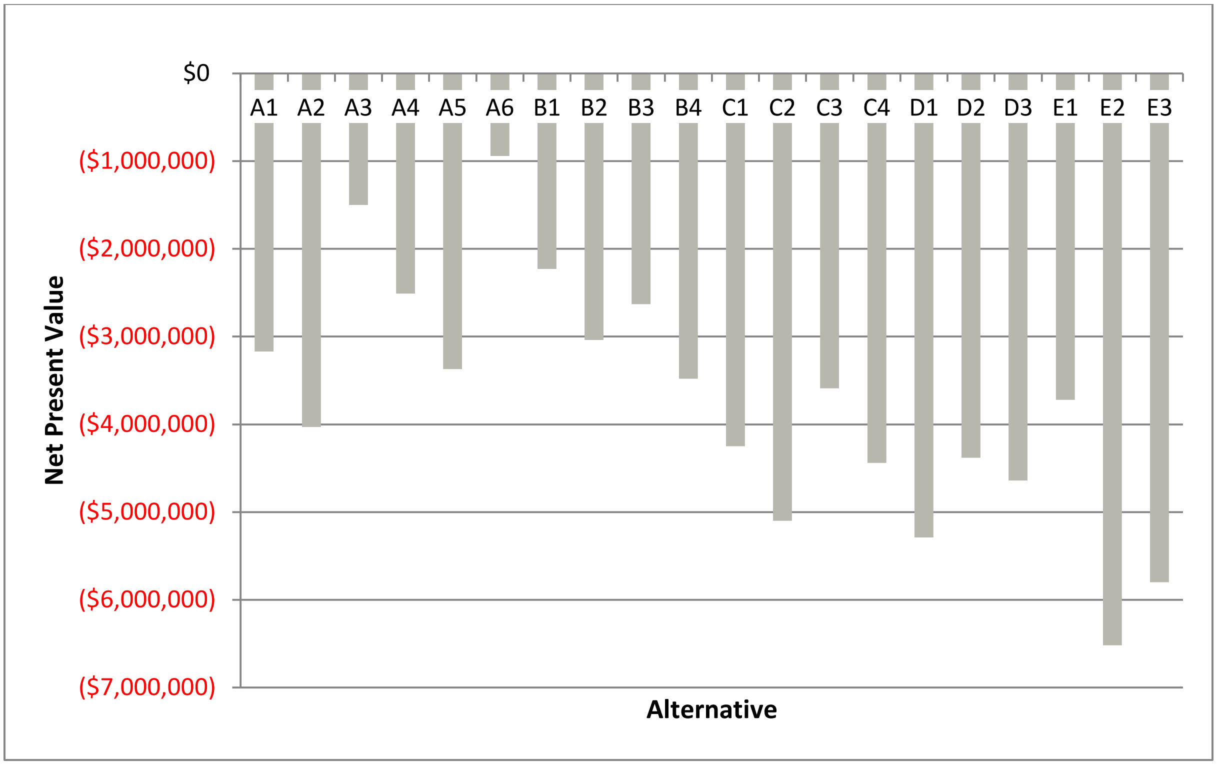

Figure 4-1. Net present value analysis of digester gas utilization alternatives

4.1.2 Maximize Grants, Credits, and Incentives

This objective includes the maximization of grants, credits, and incentives, which can come from both public and private sources.

Local utilities may offer energy conservation grants for renewable energy projects, which fill renewable energy portfolios or otherwise reduce the infrastructure burden on the utility. Conservation grants are probably not available for a new gas utilization system from PSE because of the existing system installations (already having CHP and gas scrubbing). However, PSE should be engaged during the design process to see if any grant programs may be available. Grants may be available for vehicle fuel use through programs to reduce air emissions in urban areas such as the following:

- **Diesel Emissions Reduction Act (DERA) program:** This program was created under the Energy Policy Act of 2005. It is a grant and loan authority run through the EPA as a competitive process. Although the original act was for fiscal years 2007 through 2011, it was recently extended for 5 more years. (http://epa.gov/cleandiesel/grantfund.htm)
- **Clean Cities:** Clean Cities is a government-industry partnership sponsored by the U.S. Department of Energy. (http://www1.eere.energy.gov/cleancities/projects.html)
- **State Energy Program (SEP) Special Projects program:** This is a program through the EPA that may provide a federal grant for natural gas stations. (http://www1.eere.energy.gov/wip/sep.html)
- **Clean Fuels Grant Program:** This program provides grant funding for designated areas of ozone and carbon monoxide air quality nonattainment including low-emission buses, alternative fuel stations, and some associated facilities. (http://fta.dot.gov/grants/13094_3560.html)

Standing incentive programs for renewable electricity from Washington State and the federal government are limited. Standard incentives and grants can be found at the Database of State Incentives for Renewables and Efficiency Web site (http://www.dsireusa.org/). No standard incentives exist that would apply to the digester gas alternatives and affect the economics of the alternatives.

Credits for renewable electricity and biomethane are available in the secondary market and discussed in section 3. RECs are likely not significant when compared to the NPV of the alternatives. Renewable identification numbers (RINs) as described previously have recently held significant value and would offer an advantage to the alternatives that use biomethane produced from gas scrubbing in vehicle fuels or that could otherwise sell the value of the RIN to a third party for vehicle fuel use.

Due to the inability to quantify the value of specific grants, credits, or incentives, none were included into the NPV analysis.

4.1.3 Minimize Sensitivity to Commodity Price Changes

Sensitivity to commodity price changes can cause exposure to unforeseen changes in operating costs or revenues. The following objectives describe sensitivities to commodity prices.

- Minimize sensitivity to consumed natural gas price: Minimizing sensitivity to natural gas prices means having the ability to minimize the use of natural gas if it is economically advantageous to do so. Natural gas is used by the boilers for heating and by the CHP system for electricity demand reduction and power stability.
  - Each alternative can use either digester gas or electricity for plant heating and therefore are equally insensitive to natural gas price changes for heating.
  - Each alternative can use either scrubbed or un-scrubbed digester gas for electricity production during electricity demand reduction and therefore are equally insensitive to natural gas price changes for demand reduction.
  - The low-Btu fuel alternatives require less natural gas than any of the other alternatives and are therefore the least sensitive to natural gas prices.
  - The alternatives with high-Btu IC engines are more sensitive to natural gas prices because they require the most natural gas consumption.
- Minimize sensitivity to consumed electricity price: The alternatives that use large amounts of electricity are sensitive to consumed electricity prices. Alternatives with gas scrubbing, effluent heat extraction, rCNG vehicle fuel, or a combination are sensitive to consumed electricity prices. Alternatives that produce electricity are the least sensitive.
- Minimize sensitivity to produced biomethane price: The alternatives that can use scrubbed or un-scrubbed digester gas for electricity production or heating would be less sensitive to biomethane price change because the biomethane could be used more on site. These include alternatives with cogeneration and boiler heating. Because all alternatives have the existing CHP system, this system is not a differentiator. Heat extractor alternatives benefit the most from the sale of scrubbed gas and are therefore the most sensitive to scrubbed gas sale prices.
- Minimize sensitivity to diesel consumption: Alternatives that produce rCNG reduce the County's diesel fuel consumption and are therefore the least sensitive to diesel price changes.

Each alternative was ranked from 1 to 5 for each of the financial objectives described in this section. An equal weighting was assigned to each objective except for the individual economic variables, and a total score was provided to each alternative. The financial objective rankings and final scores are shown in Table 4-2 and Figure 4-2.

Table 4-2. Financial Objectives Comparison [a]

Alt	Description	Net present value	a. Minimize capital costs	b. Minimize operational, maintenance, and R&R costs	c. Maximize revenues	Maximize grants, credits and incentives	Sensitivity to commodity price changes	a. Sensitivity to consumed natural gas price	b. Sensitivity to consumed electricity price	c. Sensitivity to produced biogas price	d. Sensitivity to diesel price	Total score
-	**Weighting**	8	0	0	0	8	8	0	0	0	0	-
A1	Status quo	3	5	2	1	3	2	3	2	2	1	64
A2	Status quo, gas to rCNG	2	4	2	2	5	3	3	2	2	5	80
A3	Status quo, gas to 3rd party	5	5	2	2	3	2	3	2	2	1	80
A4	Status quo, new gas scrubbing	4	3	5	1	3	2	3	2	2	1	72
A5	Status quo, new gas scrubbing, gas to rCNG	3	2	5	1	5	3	3	2	2	5	88
A6	Status quo, new gas scrubbing, gas to 3rd party	5	3	5	2	3	2	3	2	2	1	80
B1	Low-Btu boilers	4	5	3	2	3	2	3	2	2	1	72
B2	Low-Btu boilers, gas to rCNG	3	4	2	2	5	3	3	2	2	5	88
B3	Low-Btu boilers, new gas scrubbing	4	3	4	1	3	2	3	2	2	1	72
B4	Low-Btu boilers, new gas scrubbing, gas to rCNG	3	2	4	2	5	3	3	2	2	5	88
C1	New extractors	2	4	1	3	3	2	3	1	1	1	56
C2	New extractors, gas to rCNG	1	3	1	4	5	3	3	1	1	5	72
C3	New extractors, new gas scrubbing	3	2	2	3	3	2	3	1	1	1	64
C4	New extractors, new gas scrubbing, gas to rCNG	2	1	2	3	5	3	3	1	1	5	80
D1	Full-time CHP	1	5	2	3	2	3	3	4	5	1	48
D2	Full-time CHP, new gas scrubbing	2	3	4	2	2	3	3	4	5	1	56
D3	Full-time low-Btu CHP, gas conditioning	2	2	3	4	2	4	5	4	5	1	64
E1	Low-Btu IC engines, gas conditioning	3	1	1	5	2	4	5	5	5	1	72
E2	High-Btu IC engines	1	1	1	5	2	3	1	5	5	1	48
E3	High-Btu IC engines, new gas scrubbing	1	1	2	5	2	3	1	5	5	1	48

a. Refer to Table 2-1 for a description of the objective scoring scale.

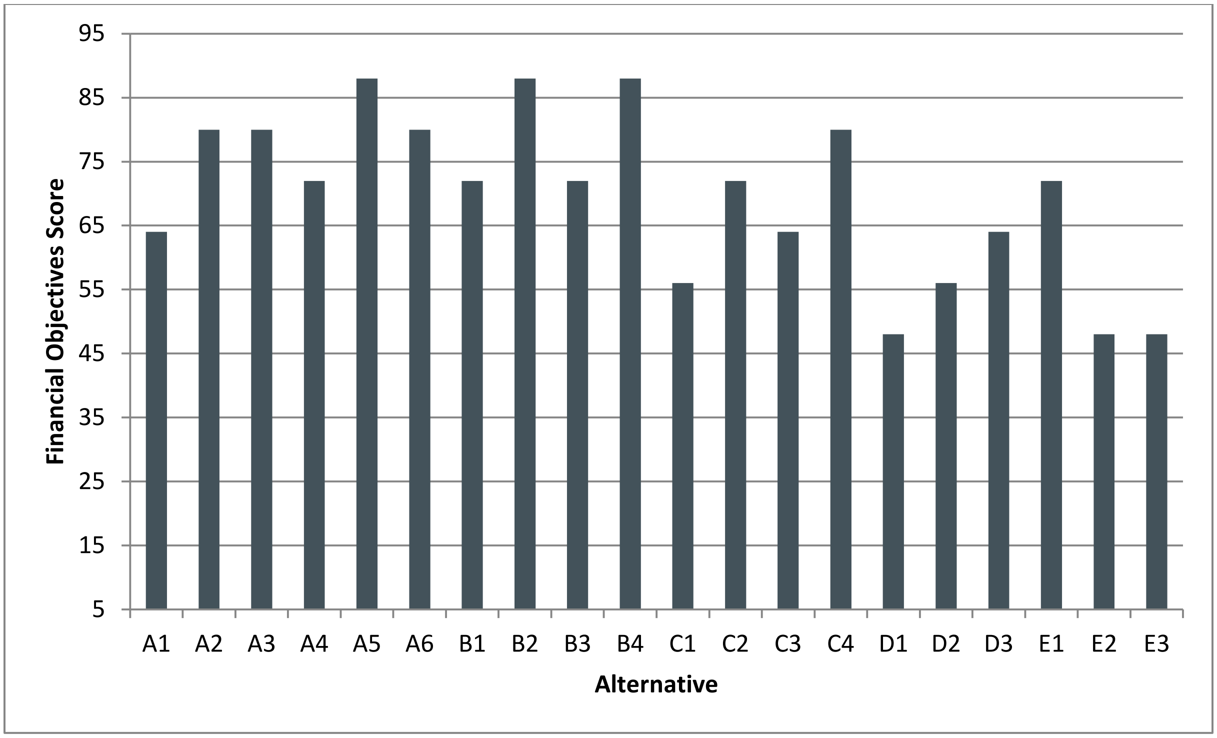

Figure 4-2. Comparison of alternatives based on financial objectives

With equal weighting for the financial objectives, the alternatives that generally scored the highest included those with rCNG loop trucks for diesel fuel offset and a new gas scrubbing system.

4.2 Energy Objective Comparison

The alternatives are compared against each other in this section in terms of the County's energy objectives described in Section 2.1.2.

4.2.1 Reduce Energy Use

This objective is to reduce peak electrical demand, electrical energy consumption, and natural gas consumption. Because each alternative includes the existing CHP system, which serves as the peak electrical demand reduction, this characteristic is assumed to be the same for all alternatives. The reduction of electrical energy consumption and natural gas consumption evolves from more efficient and more available utilization systems. Alternatives that reduce electricity consumption are those that use low-pressure gas treatment systems, which use less electricity, and those that use digester gas for heating (either directly in boilers or as recovered heat). Alternatives that use effluent heat extraction reduce natural gas consumption, but not electricity consumption.

4.2.2 Reduce Greenhouse Gas Emissions

Digester gas utilization alternatives investigated can reduce GHG emissions by providing a net offset of electricity, natural gas, or diesel fuel use. A high-level GHG comparison was completed focusing just on emissions associated with these energy inputs to the plant and methane emissions from gas scrubbing. The existing gas scrubbing system emits an estimated 5 percent of the methane that enters the system as the scrubbing water discharges to the mixing chamber in the plant liquid stream. These emissions have a significant impact on the net GHG reductions for the alternatives that utilize this system. The new gas scrubbing system, on the other hand, has negligible methane emissions in comparison and the largest net GHG emission reductions are when the biomethane from the scrubbing system offsets natural gas or diesel fuel use outside the plant boundary. Table 4-3 and Figure 4-3 summarize the net GHG emissions of the alternatives. A negative value represents a net reduction in GHG emissions.

Table 4-3. Estimated Net Greenhouse Gas Emission in 2016 [a, b, c, d]

Alt	Description	GHG emissions, ton-CO_2/yr
A1	Status quo	(3,070)
A2	Status quo, gas to rCNG	(3,090)
A3	Status quo, gas to 3rd party	(3,070)
A4	Status quo, new gas scrubbing	(7,760)
A5	Status quo, new gas scrubbing, gas to rCNG	(7,780)
A6	Status quo, new gas scrubbing, gas to 3rd party	(7,760)
B1	Low-Btu boilers	(4,630)
B2	Low-Btu boilers, gas to rCNG	(4,650)
B3	Low-Btu boilers, new gas scrubbing	(8,250)
B4	Low-Btu boilers, new gas scrubbing, gas to rCNG	(8,270)
C1	New extractors	(5,670)
C2	New extractors, gas to rCNG	(5,690)
C3	New extractors, new gas scrubbing	(10,360)
C4	New extractors, new gas scrubbing, gas to rCNG	(10,380)
D1	Full-time CHP	4,870
D2	Full-time CHP, new gas scrubbing	(260)
D3	Full-time low-Btu CHP, gas conditioning	(460)
E1	Low-Btu IC engines, gas conditioning	(1,750)
E2	High-Btu IC engines	3,960
E3	High-Btu IC engines, new gas scrubbing	(1,180)

a. *Includes GHG for energy inputs or offsets only, including electricity, natural gas and diesel fuel, and methane emissions from gas scrubbing only.*

b. *Methane emissions are assumed to have an impact 21 times that carbon dioxide from otherwise combusting the digester gas.*

c. *Natural gas and diesel fuel combustion emissions based on World Resources Institute GHG Calculation Tools for Stationary Emission Sources available at: http://www.ghgprotocol.org/templates/GHG5/layout.asp?type=p&MenuId=OTAx prior to October 2006. Note: Emissions based on high heating values where applicable.*

d. *Electricity emissions for Washington state 2009. Source: http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html.*

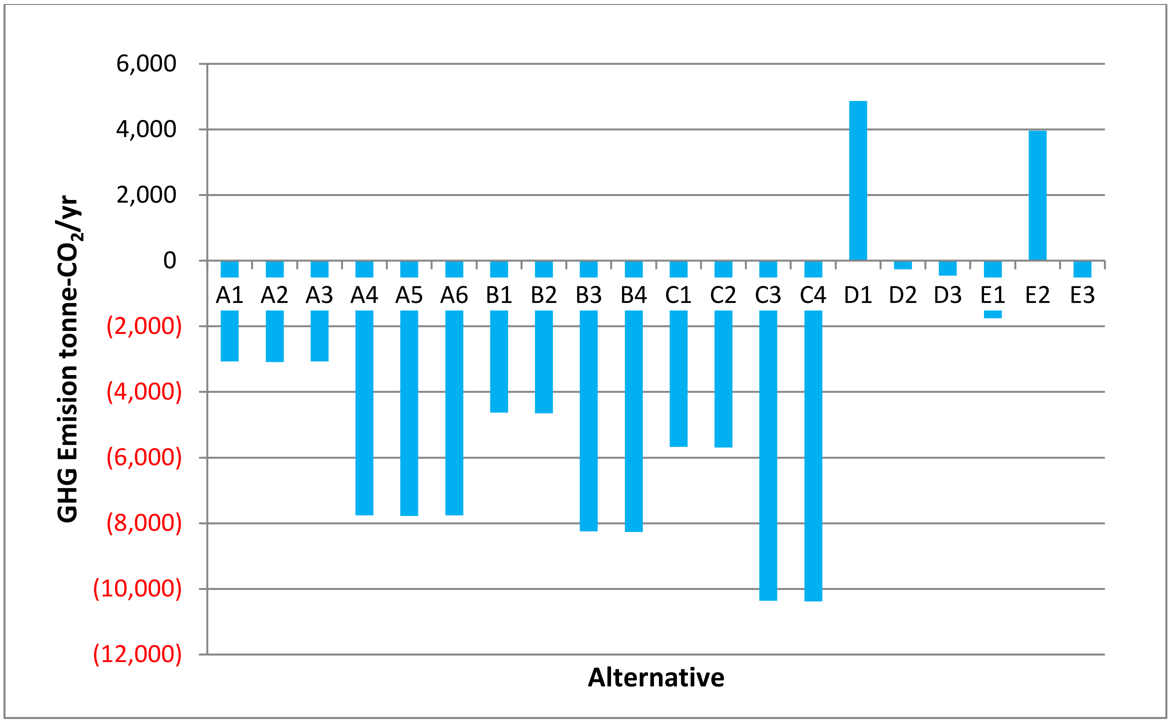

Figure 4-3. Estimated net greenhouse gas emissions in 2016

4.2.3 Convert Waste to Energy

Converting waste to energy covers two categories with respect to the digester gas utilization and plant heating system: reducing wasted energy in the form of gas sent to the waste gas burners, and capturing energy in the plant effluent through effluent heat recovery. Reducing digester gas sent to the waste gas burners is accomplished through a combination of adequate capacity and increased availability of the gas utilization system, and also decreased restrictions of the gas utilization system by outside entities (e.g., PSE). Alternatives that use effluent heat extractors recover heat from the effluent and therefore have an advantage in this category.

4.2.4 Increase Renewable Energy Production

This objective seeks to increase renewable electrical and heat production, biomethane production, and recovered effluent heat. The use of digester gas or effluent heat recovery for onsite heating is limited by the heat demands of the plant. The offsite sale of biomethane and the onsite use of digester gas for electricity are limited only by the volume of digester gas available. Because the amount of energy in sold biomethane is more than the energy captured by combusting biomethane, the alternatives that can increase offsite sale of biomethane have the largest renewable energy production. The alternatives that accomplish this include the effluent heat extractor alternatives and the status quo gas scrubbing system, which recovers more of the methane in the digester gas than a new gas scrubbing system. Figure 4-4 shows the potential renewable energy production for the general sub-systems if all of the digester gas produced at the plant is utilized (i.e., none is flared). Where electricity is consumed for scrubbing or heat extractors, the energy value is shown as a negative. Where recovered heat is beyond the peak heating of the plant, the heat is wasted.

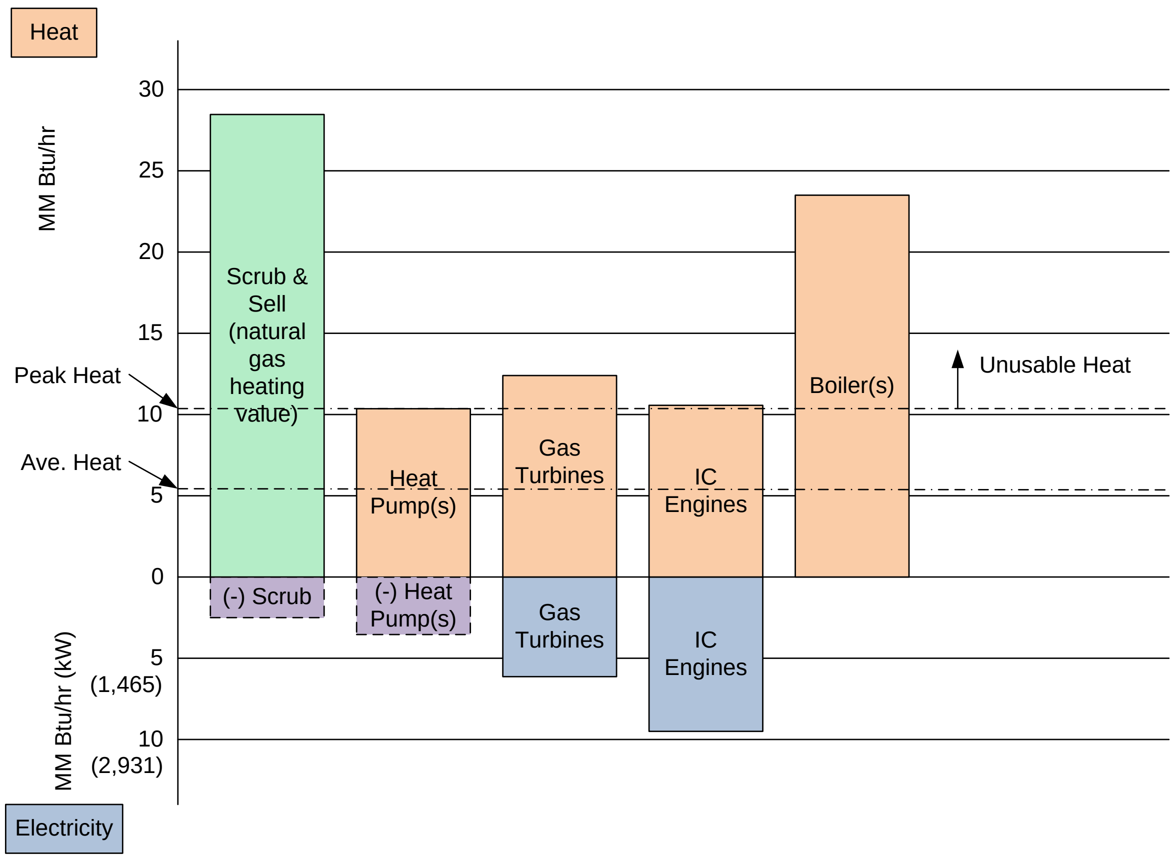

Figure 4-4. Comparison of energy production and energy use in 2013

4.2.5 Invest in Alternative Fuels

Only alternatives that include biogas upgrading can produce rCNG to offset diesel fuel or gasoline. However, CNG vehicles could be adopted by the County using nonrenewable natural gas to offset diesel fuel outside the scope of the South Plant digester gas utilization system.

4.2.6 Energy Objectives Comparison

Each alternative was ranked from 1 to 5 for each of the energy objectives described in this section. An equal weighting was assigned to each objective and a total score was provided to each alternative. The energy objective rankings and final scores are shown in Table 4-4 and Figure 4-5.

Table 4-4. Energy Objective Comparison [a]							
Alt	Description	Reduce use of and expenditures for energy	Reduce greenhouse gas emissions	Convert waste to energy to reduce environmental and carbon footprint	Increase production of renewable energy	Invest in alternative fuel transit and fleet vehicles	Total score
-	Weighting	4.8	4.8	4.8	4.8	4.8	-
A1	Status quo	2	3	2	4	3	67
A2	Status quo, gas to rCNG	2	3	2	4	5	77
A3	Status quo, gas to 3rd party	2	3	2	4	3	67
A4	Status quo, new gas scrubbing	3	4	3	3	3	77
A5	Status quo, new gas scrubbing, gas to rCNG	3	4	3	3	5	86
A6	Status quo, new gas scrubbing, gas to 3rd party	3	4	3	3	3	77
B1	Low-Btu boilers	3	3	4	4	3	82
B2	Low-Btu boilers, gas to rCNG	3	3	4	4	5	91
B3	Low-Btu boilers, new gas scrubbing	4	4	4	4	3	91
B4	Low-Btu boilers, new gas scrubbing, gas to rCNG	4	4	4	4	5	101
C1	New extractors	1	3	4	5	3	77
C2	New extractors, gas to rCNG	1	3	4	5	5	86
C3	New extractors, new gas scrubbing	1	5	5	5	3	91
C4	New extractors, new gas scrubbing, gas to rCNG	1	5	5	5	5	101
D1	Full-time CHP	2	1	2	1	1	34
D2	Full-time CHP, new gas scrubbing	3	2	3	1	1	48
D3	Full-time low-Btu CHP, gas conditioning	5	2	4	2	1	67
E1	Low-Btu IC engines, gas conditioning	5	3	3	2	1	67
E2	High-Btu IC engines	2	1	2	2	1	38
E3	High-Btu IC engines, new gas scrubbing	2	2	3	2	1	48

a. *Refer to Table 2-2 for a description of the objective scoring scale.*

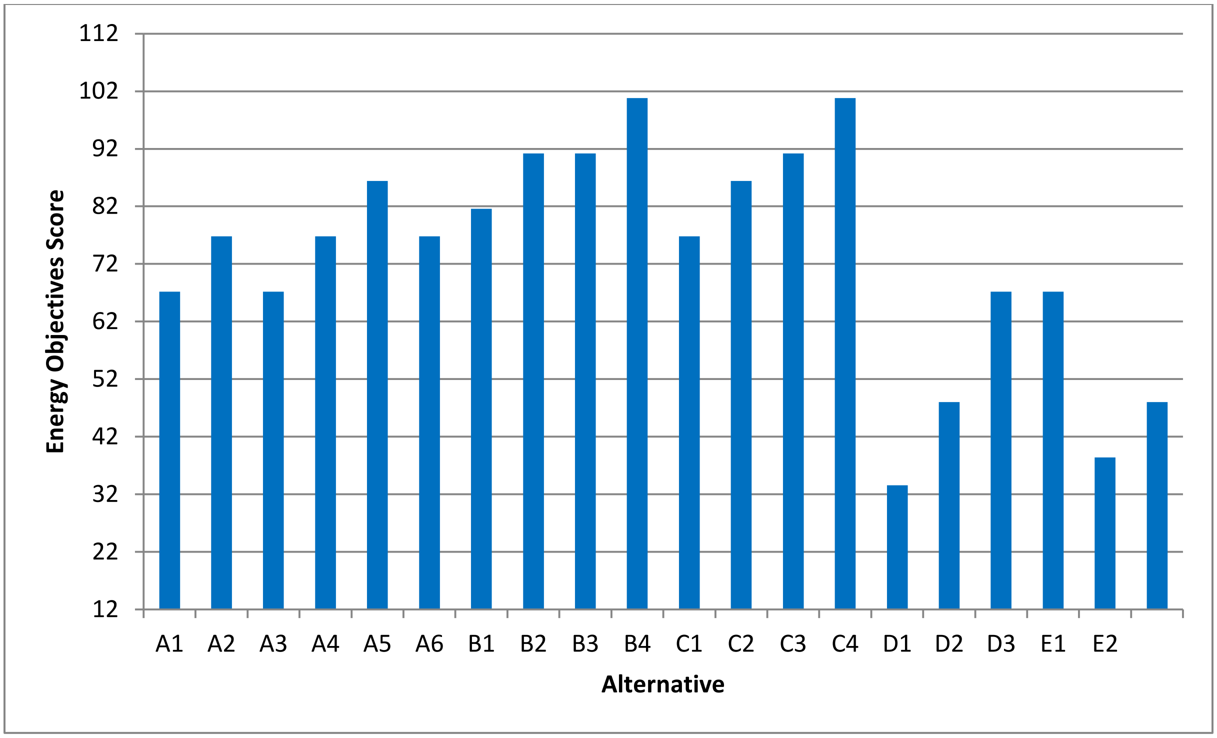

Figure 4-5. Comparison of alternatives based on energy objectives

The top five alternatives in the energy objective category are alternatives B4, C4, B2, B3, and C3—most of which include a new gas scrubbing system. Two of the five include effluent heat extraction and the remaining three include low-Btu gas-fired boilers. Three of the five include sale of scrubbed gas as rCNG.

4.3 Operational Objective Comparison

Scoring for each of the alternatives based on the operational objectives identified in Section 2.1.3 is presented here. A short explanation for the scoring of each of the objectives is provided as well.

4.3.1 System Redundancy

System redundancy compared the alternatives against each other by considering the plant's alternatives should the systems in each alternative no longer be available. It was assumed for all of the alternatives that the subcomponents would be designed to accommodate a similar level of redundancy. So this measure identifies the redundancy required for an unexpected failure of an entire system.

Alternatives that included effluent heat extractors scored the best due to the multiple alternatives the plant would have if the heat extractors were not available (e.g., existing boiler system and CHP system). Alternatives in which scrubbed gas was sold to a third party scored higher than other beneficial gas use alternatives as it was assumed that if sale to the third party was not available, the agreement with PSE to wheel the gas would include a backup provision allowing the County to sell the gas to PSE instead.

Low-redundancy alternatives were the low-Btu CHP system and low-Btu IC engine-generator system. In these alternatives, because gas scrubbing would no longer be available, a failure of the CHP or IC engine-generator system would leave the County without an alternative beneficial end use for the gas and would require that the plant operate the backup boiler on natural gas. High-Btu CHP alternatives had slightly more redundancy because they still required scrubbing and thus the backup boiler could operate on scrubbed gas. High-Btu IC engine-generators fared even better as it was assumed that the existing CHP system would still be available as a backup source of heat and power.

4.3.2 System Reliability

System reliability compared each alternative based on the relative availability of the component systems. The existing boilers and a gas conditioning skid were assumed to be the heating and gas treatment options that were the most reliable. Due to the feedback from plant staff during the development of TM 1, selling gas to PSE or through PSE to a third party were assumed to have less availability than the rCNG and CHP/IC engine-generator options. This was because the rCNG and CHP/IC engine-generator options, though still having their own gas quality requirements, will no longer need to meet PSE's more stringent gas quality requirements that have resulted in rejection of gas injection to the natural gas utility grid.

4.3.3 System Flexibility

To capture the relative flexibility of each alternative to potential changes in the plant's processes or flows, each alternative was evaluated for its ability to meet changing demands. For this objective, alternatives involved with selling gas were considered less flexible than alternatives in which the gas is burned to produce electricity and heat. This is due to the relative inflexibility of PSE, third-party, or CNG end users to accept changing conditions whereas the plant can accept any additional power the CHP or IC engine-generator alternatives produce.

For meeting the plant's heat demand, the alternatives with new effluent heat extractors were assumed to have less flexibility than those with boilers, CHP, or IC engine-generators based on the County's experience with the existing effluent heat extractors. The existing operational issues could be resolved with new heat extractors but new issues could develop that would require modification to a new heat extractor system to meet.

Of the gas treatment options, a gas conditioning system was assumed to have the most operational flexibility, then a new gas scrubbing system, and lastly the status quo scrubbing system.

4.3.4 Minimize WTD Labor Requirements

WTD labor requirements are estimated in Section 3 for each component. By adding the full-time equivalents (FTEs) for each component in the alternatives, the alternatives could be compared to each other. The alternative with the greatest labor requirement (estimated at 3 FTEs) was the alternative using high-Btu IC engine-generators with the status quo scrubbing system. Low labor requirement alternatives (estimated at 1.75) were the alternatives with the status quo boilers and a new gas scrubbing system. This was due to the assumption that the status quo boilers would require the least amount of labor to meet the plant's heating needs and a new gas scrubbing system would include an outside service contract (captured in the following objective), thus reducing the WTD labor requirement.

4.3.5 Minimize Outside Contracting Requirements

For this objective, alternatives with subcomponents that included an outside service contract were scored lower than those without. The following systems were assumed to include some level of outside service contract:

- effluent heat extractors (existing system includes an outside service contract)
- CHP (existing system includes a turbine maintenance contract)
- new scrubbing system (new systems include a maintenance plan as part of their contract)
- gas conditioning system (would include media replacement contracts)

Alternatives with multiple components requiring outside service contracts (e.g., new heat extractors, a new scrubbing system, and use as rCNG fuel) scored worse than those with few or none (e.g., status quo and low-Btu boiler alternatives).

4.3.6 Minimize Labor Related to Safety Requirements

All of the alternatives proposed would be designed to meet all safety regulations and requirements. But some alternatives may require additional training or specialized access procedures. To capture this, the alternatives utilizing the status quo scrubbing or a new scrubbing system were assumed to require more safety labor than a gas conditioning system. Of the gas end use options, the use as rCNG fuel was assumed to require more safety hours than consumption in the CHP/IC engine-generator systems or sale to PSE or a third party. None of the options for meeting the plant's heat demand were assumed to require more safety training than the others.

4.3.7 Minimize Technical Risk

This objective identifies alternatives that expose the County to additional risk that the system may not perform as intended, may have limited suppliers resulting in potentially increased costs, and may require custom maintenance should the technology no longer be widely available in the future.

Of the heat supply options, the heat extractors and low-Btu fueled turbine/IC engine-generator options were assumed to be more technically risky than the status quo boilers or low-Btu boilers. Among the gas treatment options, the gas conditioning system was considered less technically risky than the status quo or new scrubbing systems. For the beneficial end use options, the use as rCNG was assumed to have the most technical risk but the use for cogeneration of power and heat was also assumed to have more technical risk than sale to PSE or a third party.

4.3.8 Minimize Air Quality Treatment Requirements

The potential for future air quality treatment was identified as a concern that the County would like to minimize. This objective does not identify the need for air permitting or whether or not the required air permit could be met; it was assumed as a barrier to entry that all alternatives considered would be technically feasible and would meet all necessary permits and regulations. Instead, this objective identifies alternatives that may require extensive air quality treatment requirements or may be susceptible to future air quality regulation changes.

Alternatives in which there was a potential for future air quality restrictions were limited to the alternatives that changed the manner in which the County is currently combusting digester gas. Alternatives that included adding another boiler (including the status quo), modifying the existing CHP system (e.g., from high-Btu fuel to low-Btu fuel), or adding an IC engine would all require air permitting changes. In addition, the new gas scrubbing system proposed combusts methane in a thermal oxidizer and would also require air permitting.

The ranking of alternatives for this objective identified high-Btu IC engines and converting the CHP system to run on low-Btu fuel as being the most technically challenging to permit and the most susceptible to future regulations. Low-Btu IC engines followed as slightly less difficult to permit while additional boilers (high-Btu or low-Btu) and the thermal oxidizer in a new scrubbing system were considered easier to permit. New heat extractors and the existing gas scrubbing system would not require any permit changes and scored the highest.

4.3.9 Operational Objectives Comparison

Each alternative was ranked from 1 to 5 for each of the operational objectives described in this section. An equal weighting was assigned to each objective and a total score was provided to each alternative. The operational objective rankings and final scores are shown in Table 4-5 and Figure 4-6.

Table 4-5. Operational Objective Comparison [a]

Alt	Description	System redundancy	System reliability	System flexibility	Minimize WTD labor requirements	Minimize outside contracting requirements	Minimize labor related to safety requirements	Minimize technical risk	Minimize air quality treatment requirements	Total score
-	Weighting	3	3	3	3	3	3	3	3	-
A1	Status quo	3	4	3	3	5	4	5	4	93
A2	Status quo, gas to rCNG	3	4	3	3	4	2	2	4	75
A3	Status quo, gas to 3rd party	4	4	2	3	5	4	5	4	93
A4	Status quo, new gas scrubbing	3	4	3	5	4	4	5	3	93
A5	Status quo, new gas scrubbing, gas to rCNG	3	4	3	4	3	2	2	3	72
A6	Status quo, new gas scrubbing, gas to 3rd party	4	4	3	5	4	4	5	3	96
B1	Low-Btu boilers	3	2	3	3	5	4	5	4	87
B2	Low-Btu boilers, gas to rCNG	3	4	3	2	4	2	2	4	72
B3	Low-Btu boilers, new gas scrubbing	3	4	3	4	4	4	5	3	90
B4	Low-Btu boilers, new gas scrubbing, gas to rCNG	3	4	3	3	3	2	2	3	69
C1	New extractors	5	2	2	3	4	5	4	5	90
C2	New extractors, gas to rCNG	5	4	2	2	3	3	2	5	78
C3	New extractors, new gas scrubbing	5	4	2	4	3	5	4	4	93
C4	New extractors, new gas scrubbing, gas to rCNG	5	4	2	3	2	3	2	4	75
D1	Full-time CHP	2	4	4	2	4	4	3	5	84
D2	Full-time CHP, new gas scrubbing	2	4	5	3	3	4	3	4	84
D3	Full-time low-Btu CHP, gas conditioning	1	4	5	4	3	5	4	1	81
E1	Low-Btu IC engines, gas conditioning	1	4	5	3	4	5	4	1	81
E2	High-Btu IC engines	3	4	4	1	5	4	3	1	75
E3	High-Btu IC engines, new gas scrubbing	3	4	4	3	4	4	3	2	81

a. *Refer to Table 2-3 for a description of the objective scoring scale.*

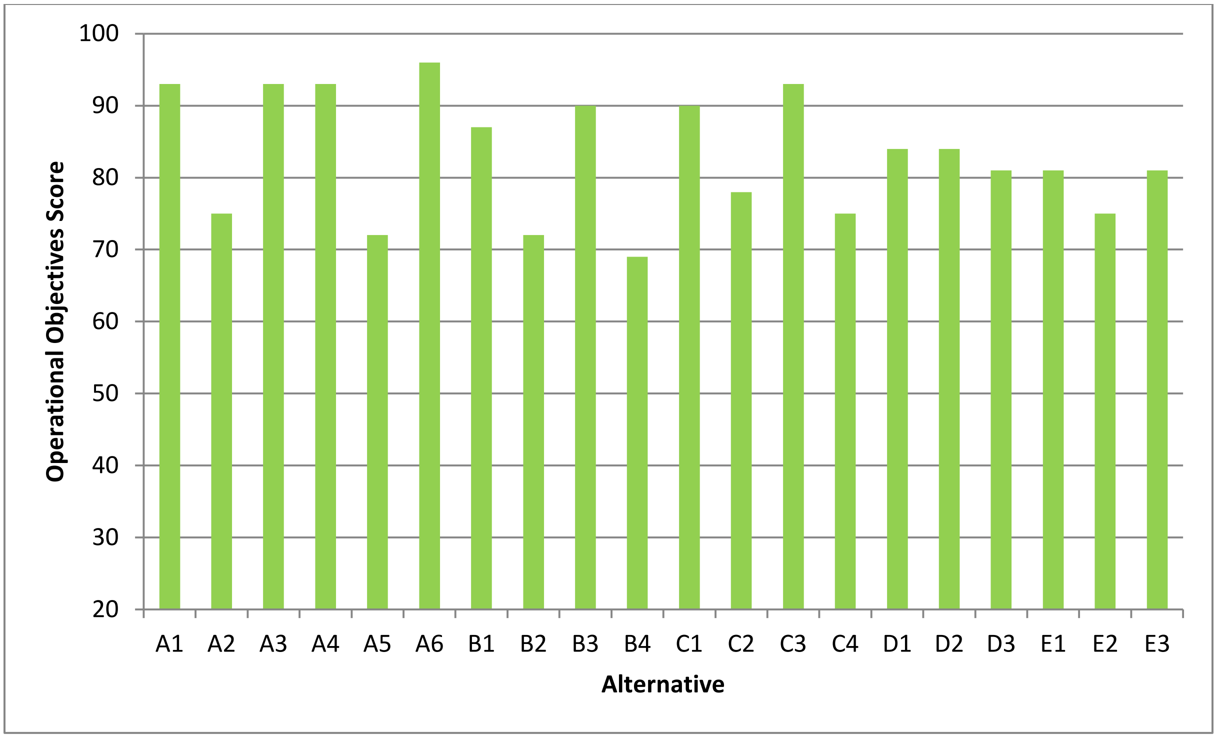

Figure 4-6. Comparison of alternatives based on operational objectives

The comparison indicates that the alternatives using boilers (and in particular the status quo boilers) and heat extractors score the best while the alternatives that use the gas as an rCNG fuel or to fuel a turbine or IC engine score poorly.

4.4 Overall Comparison Matrix

The individual objective total scores with equal weighting assigned to each objective were summed into an overall alternative total score. The results of this total comparison show little difference between most of the alternatives. Noticeable trends include the following:

- The alternatives to sell scrubbed gas to a third party tended to score higher than for rCNG or sale to PSE.
- The alternatives with new gas scrubbing tended to score higher than those with existing gas scrubbing.
- The heat extractors did not perform well in financial terms but tended to score well in energy and operational objectives.
- The alternatives with full-time CHP and IC engines in general scored the least.

With equal objectives weighting, the two highest scores are alternatives B4 and C4 with a new gas scrubbing system and either boilers or effluent heat extractors for heating. The total scores are shown in Table 4-6 and Figure 4-7.

Table 4-6. Total Objective Comparison					
Alt	Description	Financial objective score	Energy objective score	Operational objective score	Total score
A1	Status quo	64	67	93	224
A2	Status quo, gas to rCNG	80	77	75	232
A3	Status quo, gas to 3rd party	80	67	93	240
A4	Status quo, new gas scrubbing	72	77	93	242
A5	Status quo, new gas scrubbing, gas to rCNG	88	86	72	246
A6	Status quo, new gas scrubbing, gas to 3rd party	80	77	96	253
B1	Low-Btu boilers	72	82	87	241
B2	Low-Btu boilers, gas to rCNG	88	91	72	251
B3	Low-Btu boilers, new gas scrubbing	72	91	90	253
B4	Low-Btu boilers, new gas scrubbing, gas to rCNG	88	101	69	258
C1	New extractors	56	77	90	223
C2	New extractors, gas to rCNG	72	86	78	236
C3	New extractors, new gas scrubbing	64	91	93	248
C4	New extractors, new gas scrubbing, gas to rCNG	80	101	75	256
D1	Full-time CHP	48	34	84	166
D2	Full-time CHP, new gas scrubbing	56	48	84	188
D3	Full-time Low-Btu CHP, gas conditioning	64	67	81	212
E1	Low-Btu IC engines, gas conditioning	72	67	81	220
E2	High-Btu IC engines	48	38	75	161
E3	High-Btu IC engines, new gas scrubbing	48	48	81	177

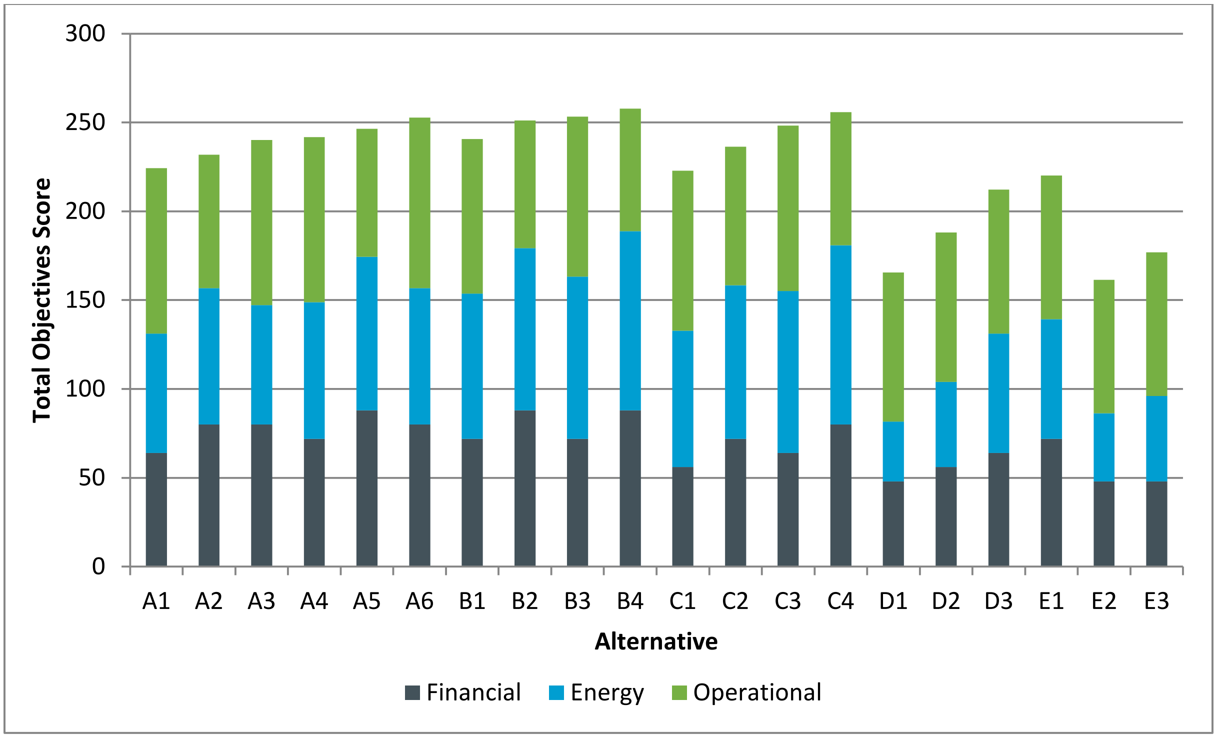

Figure 4-7. Comparison of alternatives based on total objectives

Section 5: Summary and Conclusions

This technical memorandum is the second in a series to assess the existing South Plant digester gas utilization program and to select alternatives for capital improvement projects. In conjunction with Workshop 1 held on May 30, 2014, TM 2 serves the following purposes:

- establish objectives for the South Plant digester gas utilization program to compare potential alternatives in a repeatable, balanced manner
- establish and describe potential alternatives, including an NPV analysis, to facilitate an initial screening of alternatives
- compare the alternatives using the weighted objectives developed to recommend three alternatives for further evaluation in TM 3

Based on the results of the analysis described in Section 4, the low-Btu boiler scores the best of the options to meet the plant's heat demand, a new gas scrubbing system is the highest scoring alternative for gas treatment, and sale of gas to a third party is the best-scoring beneficial gas utilization option (followed by production of rCNG). This is reflected in the fact that the five highest-scoring alternatives are as follows:

1. B4: low-Btu boilers and new gas scrubbing system with sale of scrubbed gas and production of rCNG
2. C4: new heat extractors and new gas scrubbing system with sale of scrubbed gas and production of rCNG
3. B3: low-Btu boilers and new gas scrubbing system with sale of scrubbed gas
4. A6: status quo heating with a new gas scrubbing system and sale of scrubbed gas to a third party
5. B2: low-Btu boilers and status quo gas scrubbing system with sale of scrubbed gas and production of rCNG

For the evaluation to be completed in TM 3, three alternatives will be analyzed further along with the status quo alternative. To provide the greatest variety of potential alternatives for the County to pursue, the three alternatives chosen should encompass as many of the sub-systems evaluated as possible. This would allow the County to mix and match sub-systems and rebuild an alternative that was not carried forward, should the more detailed analysis reveal that that alternative would be the preferred alternative. To this end, the following three alternatives and status quo alternative will be investigated further in the evaluation for TM 3:

- B4: low-Btu boilers and new gas scrubbing system with sale of scrubbed gas and production of rCNG
- C4: new heat extractors and new gas scrubbing system with sale of scrubbed gas and production of rCNG
- E1: low-Btu IC engines with a gas conditioning skid
- A3: status quo with scrubbed gas sale to a third party

Although alternatives E1 and A3 were not among the highest-scoring alternatives, including them will allow each of the sub-systems described in Section 3 above to be evaluated further in TM 3 when costs and benefits can be further refined.

Attachment A: Capital Cost Estimates

Attachment A
Capital Cost Estimates

The capital costs are planning-level estimates based on recent, similar project cost estimates or County asset management data. The cost estimates should not be construed as providing a preliminary design level estimate.

Table A-1 shows cost development for upgrading the existing gas scrubbing system.

Table A-1. Gas Scrubbing System Capital Costs

Criteria	Value	Notes
Equipment costs		
Replace compressors 1 and 2	$1,300,000	
Replace turbine pumps 1 and 2	$50,000	
Total equipment	$1,350,000	
Equipment installation costs (including 12% contractor markup, no electrical)	$230,000	Installation assumed at 20% of equipment
Demo, concrete, and piping costs (including 12% contractor markup)	$40,000	
Electrical and I&C cost (20% of equipment subtotal, 18% of concrete, etc.)	$780,000	Including Ovation upgrade
Total installed cost	$2,400,000	
Contractor general conditions (15% of subtotal)	$360,000	
Startup testing, bonds, insurance (10% of subtotal)	$280,000	
Sales tax (8.5% of subtotal)	$260,000	
Engineering (15% of subtotal)	$500,000	
Contingency (20% of subtotal)	$760,000	
Total project cost	$4,560,000	

Table A-2 shows the cost development for new gas-fired hot water boilers.

Table A-2. New Boiler Capital Costs

Criteria	Value	Notes
Equipment costs		
Hot water boilers 2 and 3	$500,000	Total for two boilers and flue stacks
Hot water pumps	$6,000	Total for two hot water pumps
Three-way valves	$20,000	Total for two valves
Total equipment	$526,000	
Equipment installation costs (including 12% contractor markup, no electrical)	$120,000	Installation assumed at 20% of equipment
Demo, concrete, and piping costs (including 12% contractor markup)	$40,000	
Electrical and I&C cost (20% of equipment subtotal, 18% of concrete, etc.)	$110,000	
Total installed cost	$800,000	
Contractor general conditions (15% of subtotal)	$120,000	
Startup testing, bonds, insurance (10% of subtotal)	$90,000	
Sales tax (8.5% of subtotal)	$90,000	
Engineering (15% of subtotal)	$170,000	
Contingency (20% of subtotal)	$250,000	
Total project cost	$1,520,000	

Table A-3 shows the cost development for new digester gas-fired hot water boilers.

Table A-3. New Raw Gas Boiler Capital Costs		
Criteria	Value	Notes
Equipment costs		
Hot water boilers 2 and 3	$500,000	Total for two boilers and flue stacks
Hot water pumps	$6,000	Total for two hot water pumps
Three-way valves	$20,000	Total for two valves
Digester gas blowers with control valves	$85,000	
Gas separators	$20,000	
Total equipment	$631,000	
Equipment installation costs (including 12% contractor markup, no electrical)	$140,000	Installation assumed at 20% of equipment
Demo, concrete, and piping costs (including 12% contractor markup)	$90,000	Includes new LSG piping in yard
Electrical and I&C cost (20% of equipment subtotal, 18% of concrete, etc.)	$140,000	
Total installed cost	$1,000,000	
Contractor general conditions (15% of subtotal)	$150,000	
Startup testing, bonds, insurance (10% of subtotal)	$120,000	
Sales tax (8.5% of subtotal)	$110,000	
Engineering (15% of subtotal)	$210,000	
Contingency (20% of subtotal)	$320,000	
Total project cost	$1,910,000	

Table A-4 shows the cost development for a new heat extractor.

Table A-4. New Heat Extractor Capital Costs

Criteria	Value	Notes
Equipment costs		
Digester circulation pumps	$14,000	
Three-way valves	$40,000	
Heat extractor	$875,000	
Flow diverting control valve	$35,000	
Tempering heat exchanger	$22,000	
Condenser water side pumps	$12,000	
Evaporator water side pumps	$10,000	
Total equipment	$1,008,000	
Equipment installation costs (including 12% contractor markup, includes electrical)	$840,000	
Total installed cost	$1,850,000	
Contractor general conditions (15% of subtotal)	$280,000	
Startup testing, bonds, insurance (10% of subtotal)	$210,000	
Sales tax (8.5% of subtotal)	$200,000	
Engineering (15% of subtotal)	$380,000	
Contingency (20% of subtotal)	$580,000	
Total project cost	$3,500,000	

Table A-5 shows the cost development for a new IC engine-generator cogeneration system.

Table A-5. Estimated Capital Costs for Three IC Engine Cogeneration System

Criteria	Value	Notes
Equipment costs		
Cogeneration units [a]	$3,300,000	
Heat exchangers	$40,000	
Water pumps	$20,000	
Silencers	$20,000	
Total equipment	$3,380,000	
Equipment installation costs (including 12% contractor markup, no electrical)	$760,000	Installation assumed at 20% of equipment
Demo, concrete, and piping costs (including 12% contractor markup)	$110,000	
Electrical and I&C cost (20% of equipment subtotal, 18% of concrete, etc.)	$700,000	
Total installed cost	$4,950,000	
Contractor general conditions (15% of subtotal)	$740,000	
Startup testing, bonds, insurance (10% of subtotal)	$570,000	
Sales tax (8.5% of subtotal)	$530,000	
Engineering (15% of subtotal)	$1,020,000	
Contingency (20% of subtotal)	$1,560,000	
Total project cost	$9,370,000	

Table A-6 shows the cost development for a low-pressure digester gas conditioning system (used only for the low-Btu IC engine alternative).

Table A-6. Estimated Capital Costs for Low-Pressure Gas Conditioning System		
Criteria	Value	Notes
Equipment costs		
H_2S removal	$550,000	
Siloxane removal	$300,000	
Gas compression skid	$680,000	
Total equipment	$1,530,000	
Equipment installation costs (including 12% contractor markup, no electrical)	$340,000	Installation assumed at 20% of equipment
Demo, concrete, and piping costs (including 12% contractor markup)	$170,000	
Electrical and I&C cost (20% of equipment subtotal, 18% of concrete, etc.)	$340,000	
Total installed cost	$2,380,000	
Contractor general conditions (15% of subtotal)	$360,000	
Startup testing, bonds, insurance (10% of subtotal)	$270,000	
Sales tax (8.5% of subtotal)	$260,000	
Engineering (15% of subtotal)	$490,000	
Contingency (20% of subtotal)	$750,000	
Total project cost	$4,510,000	

Table A-7 shows the cost development for a medium-pressure digester gas conditioning system (used only for the low-Btu turbine alternative).

Table A-7. Estimated Capital Costs for Medium-Pressure Gas Conditioning System

Criteria	Value	Notes
Equipment costs		
H_2S removal	$550,000	
Siloxane removal	$300,000	
Gas compression skid	$980,000	
Total equipment	$1,830,000	
Equipment installation costs (including 12% contractor markup, no electrical)	$410,000	Installation assumed at 20% of equipment
Demo, concrete, and piping costs (including 12% contractor markup)	$170,000	
Electrical and I&C cost (20% of equipment subtotal, 18% of concrete, etc.)	$400,000	
Total installed cost	$2,810,000	
Contractor general conditions (15% of subtotal)	$420,000	
Startup testing, bonds, insurance (10% of subtotal)	$320,000	
Sales tax (8.5% of subtotal)	$300,000	
Engineering (15% of subtotal)	$580,000	
Contingency (20% of subtotal)	$890,000	
Total project cost	$4,940,000	

Table A-8 shows the cost development for two new gas scrubbing system: a PSA system from Guild and a water solvent system from Greenlane.

Table A-8. Estimated Capital Costs for Biomethane Upgrading Equipment			
Equipment costs	PSA Guide, $	Water Solvent Greenlane. $	
Equipment costs			
Packaged biogas upgrading systems cost (1,440,000 scfd)	$1,940,000	$2,600,000	
Product gas compressors cost (to 250 psig)	$500,000	$500,000	
Thermal oxidizer (for removed CO_2 gas)	$400,000	--	
H_2S removal/biofilter [d]	--	$600,000	
Total equipment	$2,840,000	$3,700,000	
Equipment installation costs (including 12% contractor markup, no electrical)	$480,000	$620,000	Installation assumed at 15% of equipment
Demo, concrete, and piping costs (including 12% contractor markup)	$170,000	$170,000	
Electrical and I&C cost (20% of equipment subtotal, 18% of concrete, etc.)	$600,000	$770,000	
Total installed cost	$4,090,000	$5,260,000	
Contractor general conditions (15% of subtotal)	$610,000	$790,000	
Startup testing, bonds, insurance (10% of subtotal)	$470,000	$610,000	
Sales tax (8.5% of subtotal)	$440,000	$570,000	
Engineering (15% of subtotal)	$840,000	$1,080,000	
Contingency (20% of subtotal)	$1,290,000	$1,660,000	
Total project cost	$7,740,000	$9,970,000	

Table A-9 shows the cost development for replacing the heat recovery steam generators on the gas turbines with heat recovery hot water heaters.

Table A-9. Estimated Capital Costs to Replace Heat Recovery on Gas Turbine Exhaust

Criteria	Value	Notes
Equipment costs		
Heat recovery HEX 1 and 2	$200,000	
Pumps and three-way valves	$30,000	
Total equipment	$230,000	
Equipment installation costs (including 12% contractor markup, no electrical)	$80,000	Installation assumed at 30% of equipment
Demo, concrete, and piping costs (including 12% contractor markup)	$110,000	
Electrical and I&C cost (20% of equipment subtotal, 18% of concrete, etc.)	$70,000	
Total installed cost	$490,000	
Contractor general conditions (15% of subtotal)	$70,000	
Startup testing, bonds, insurance (10% of subtotal)	$60,000	
Sales tax (8.5% of subtotal)	$50,000	
Engineering (15% of subtotal)	$100,000	
Contingency (20% of subtotal)	$150,000	
Total project cost	$920,000	

Table A-10 shows the cost development for installing a CNG vehicle fueling station and the cost addition for three new loop trucks as CNG fueled.

Table A-10. Estimated Capital Costs to Add Vehicle Fueling Station

Criteria	Value	Notes
Equipment costs		
Compressor packaged with acoustical enclosure (to 3,600 psig)	$210,000	
Fast-fill station equipment for fuel dispensing (400,000 scfd)	$170,000	
Total equipment	$380,000	
Equipment installation costs (including 12% contractor markup, no electrical)	$90,000	Installation assumed at 20% of equipment
Demo, concrete, and piping costs (including 12% contractor markup,)	$20,000	
Electrical and I&C cost (20% of equipment subtotal, 18% of concrete, etc.)	$80,000	
Total installed cost	$570,000	
Contractor general conditions (15% of subtotal)	$90,000	
Startup testing, bonds, insurance (10% of subtotal)	$70,000	
Sales tax (8.5% of subtotal)	$60,000	
Engineering (15% of subtotal)	$120,000	
Contingency (20% of subtotal)	$180,000	
CNG fueling system for new loop trucks	$90,000	
Total project cost	$1,180,000	

Table A-11 shows the cost development for modifying the existing gas turbines for low-Btu operation.

Table A-11. Estimated Capital Costs to Modify Gas Turbines for Low-Btu Operation		
Criteria	Value	Notes
Equipment costs		
Gas turbine modification	$2,000,000	
Total equipment	$2,000,000	
Equipment installation costs (including 12% contractor markup, no electrical)	$220,000	Installation assumed at 10% of equipment
Demo, concrete, and piping costs (including 12% contractor markup)	$80,000	
Electrical and I&C cost (20% of equipment subtotal, 18% of concrete, etc.)	$410,000	
Total installed cost	$2,710,000	
Contractor general conditions (15% of subtotal)	$410,000	
Startup testing, bonds, insurance (10% of subtotal)	$310,000	
Sales tax (8.5% of subtotal)	$290,000	
Engineering (15% of subtotal)	$560,000	
Contingency (20% of subtotal)	$860,000	
Total project cost	$5,140,000	

Attachment C: TM 3

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Technical Memorandum

Prepared for: King County Department of Natural Resources and Parks

Project Title: Task Order 7: South Plant Digester Gas Utilization Study

Project No.: 141326.007.040

Technical Memorandum 3

Subject: Final Alternatives Evaluation and Recommendation

Date: October 14, 2013

To: John Smyth, Project Manager

From: Ian McKelvey, Project Manager

Prepared by: ___________________________________
Eron Jacobson, Senior Engineer, 47085, 7/8/2015

Reviewed by: ___________________________________
Gary Newman, Vice President

Limitations:

This document was prepared solely for King County DNRP in accordance with professional standards at the time the services were performed and in accordance with the contract between King County DNRP and Brown and Caldwell dated May 7, 2013. This document is governed by the specific scope of work authorized by King County DNRP; it is not intended to be relied upon by any other party except for regulatory authorities contemplated by the scope of work. We have relied on information or instructions provided by King County DNRP and other parties and, unless otherwise expressly indicated, have made no independent investigation as to the validity, completeness, or accuracy of such information.

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List of Abbreviations

°F	degree(s) Fahrenheit
AACEI	Association for the Advancement of Cost Engineering International
BC	Brown and Caldwell
Btu	British thermal unit(s)
CH_4	methane
CHP	combined heat and power
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
COP	coefficient of performance
County	King County
EPA	U.S. Environmental Protection Agency
FOG	fats, oils, and grease
FTE	full-time equivalent
gal	gallon(s)
gpd	gallon(s) per day
H_2S	hydrogen sulfide
hr	hour(s)
HRR	heat reservoir return
HRS	heat reservoir supply
IC	internal-combustion
I&C	instrumentation and controls
kV	kilovolt(s)
kW	kilowatt(s)
kWt	thermal kilowatt(s)
kWh	kilowatt-hour(s)
kWh-t	thermal kilowatt-hour(s)
lb	pound(s)
LSG	low-pressure sludge gas
m^3	cubic meter(s)
MCC	motor control center
mg	milligram(s)
MMBtu	million British thermal unit(s)
MM scfd	million standard cubic foot/feet per day
mpg	mile(s) per gallon
MVA	megavolt-ampere(s)
MW	megawatt(s)
NO_x	nitrogen oxide
NPV	net present value
OC	oxidation catalyst
O&M	operations and maintenance
ppm	part(s) per million
PSA	pressure swing adsorption
PSCAA	Puget Sound Clean Air Authority
PSE	Puget Sound Energy
psig	pound(s) per square inch gauge
rCNG	renewable compressed natural gas
REC	Renewable Energy Credit
RIN	Renewable Identification Number
scfd	standard cubic foot/feet per day
SCR	selective catalytic reducer
South Plant	South Treatment Plant
TM	technical memorandum
VOC	volatile organic compound
WRF	water reclamation facility
WTD	Wastewater Treatment Division
yr	year(s)

Section 1: Introduction

This Technical Memorandum 3 (TM 3) is part of a study being performed on the South Treatment Plant (South Plant) digester gas utilization program to identify the capacity and condition of the existing system, potential alternatives for gas utilization, and the preferred approach based on a net present value (NPV) analysis including life-cycle costs and other considerations. Two tasks and associated TMs have already been completed. TM 1, titled "South Plant Biogas Management Equipment and Systems," identified the existing systems and their respective capacity, operation, and condition. TM 2, titled "Development and Screening of South Plant Biogas Management Alternatives," described the objectives and identified potential biogas utilization alternatives to facilitate an initial screening. Three alternatives and the status quo were recommended for further evaluation.

TM 3 further refines the King County (County) objectives and the alternatives selected in TM 2 for further analysis. Refinement of the alternatives includes more detailed costs, layouts, and operational description. It also includes modifications to the three gas scrubbing alternatives to make the sale of the scrubbed gas to Puget Sound Energy (PSE) the baseline assumption; value-added end uses such as onsite vehicle fueling are analyzed separately. Economic and sensitivity analyses for different variable assumptions that make up the NPV analyses are also provided. Figure 1-1 provides a road map for the three following sections of TM 3.

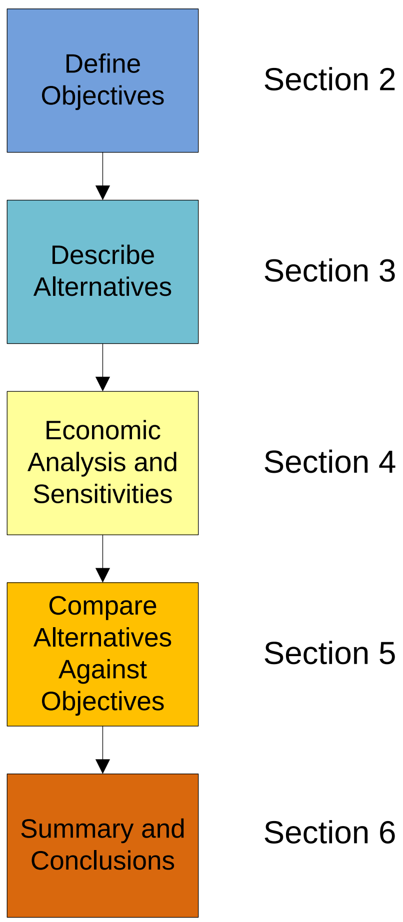

Figure 1-1. TM 3 road map

Section 2: King County Objectives

The County's objectives for the gas utilization program are described in detail in TM 2 and are described briefly here. The following section identifies the objectives, the means by which they are measured, and the weighting applied to each objective. In an effort to facilitate discussion and group similar objectives together, the objectives identified were divided into three categories: financial, environmental, and operations.

An objective weighting workshop was held with County staff prior to development of this TM. The choice of which objectives to use and their relative weightings compared to each other were agreed upon at that workshop and forms the basis for the descriptions provided below.

2.1 Financial Objectives

The costs associated with delivering, operating, and maintaining gas utilization systems are crucial to the NPV analysis comparing the alternatives. To measure costs, the County identified four cost objectives, as delineated in Table 2-1.

Table 2-1. Financial Objectives for South Plant Gas Utilization Program

Objective	Notes
1. Minimize capital costs	Costs associated with design, purchase, and installation of capital equipment
2. Minimize operational and maintenance costs	Costs associated with operating and maintaining equipment
3. Maximize revenues	Revenues associated with the sale of recovered resources
4. Maximize grants, credits, and incentives	Grants, credits, and incentives received by King County

An overall NPV for each alternative takes into account these four factors: capital costs, operating and maintenance costs, revenues, and grants/credits/incentives. An overall NPV will be provided capturing the overall financial impact of each alternative, but the direction received during the objectives weighting workshop was to compare alternatives based on each element of the NPV instead of based on the overall NPV. This was done to reflect the additional value the County places on some of the financial objectives (e.g., minimizing capital costs) as compared to others (e.g., maximizing grants, incentives, and credits).

An objective to identify the sensitivity to commodity price changes for each alternative was included in TM 2. During the objective weighting workshop with the County, it was decided that the sensitivity analysis completed as part of the NPV analysis should not be an objective but should be presented along with the financial data to provide a frame of reference for the certainty in the values shown.

2.2 Environmental Objectives

The environmental objectives were derived from a review of strategic plans, ordinances, and energy plans published by King County. The objectives identified in Table 2-2 below are a summary of the published goals with their source identified in the footnotes.

Consumption of renewable power was not included in the original objectives listed in TM 2 but discussions during the objective weighting workshop indicated that the County was considering adding this as a goal. As such, it was added to the objectives for this analysis. In addition, the environmental objectives in TM 2 included an objective for converting waste to energy to reduce the County's carbon footprint. This objective has been removed here based on feedback that the remaining objectives capture the intent of this goal (e.g., reduction of greenhouse gas emissions).

Table 2-2. Environmental Objectives for South Plant Gas Utilization Program	
Objective	Notes
1. Reduce use of energy [a,b,c,d]	Annual electrical energy consumption and natural gas consumption
2. Reduce greenhouse gas emissions [a,c,d]	Region-wide annual reduction in greenhouse gas production due to County operations
3. Increase production of renewable energy [a,b,c]	Renewable electrical production, biogas production, and recovered effluent heat
4. Increase consumption of renewable energy	Consumption of renewable electricity, biogas, and recovered effluent heat at the plant
5. Invest in alternative fuel transit and fleet vehicles [a,d]	Diesel fuel offset by sale of biogas for CNG production

a. King County Energy Plan (10/2010).
b. WTD Energy Plan (2/2010).
c. King County Strategic Climate Action Plan (12/2012).
d. King County Strategic Plan 2010–2014 (7/2010).

2.3 Operational Objectives

Impacts from operation of the gas utilization systems will play a large role in determining the preferred alternative. A number of operational objectives were identified and are summarized in Table 2-3, but some objectives were not included because they were considered a basic requirement that all alternatives must meet. These objectives include meeting safety requirements, effluent and biosolids permit requirements, and process heating requirements. All considered alternatives must meet these basic requirements, and therefore all of the considered alternatives would score similarly if these were included as objectives.

Table 2-3. Operational Objectives for South Plant Gas Utilization Program	
Objective	Notes
1. Maximize system redundancy and reliability	Indicates the level of downtime expected for each system and the options available if the chosen gas utilization system is not operational.
2. Maximize system operational flexibility	Indicates the ability of each system to be modified to meet changes in gas utilization approach and future process changes
3. Minimize WTD labor requirements	Labor requirements for County staff to operate and maintain the systems
4. Minimize reliance on outside service contracts	Contracts with outside parties required to operate and maintain the systems chosen
5. Minimize technical risk	Indicates the relative frequency the systems being proposed are used at municipal WWTPs
6. Minimize air quality treatment requirements	Indicates the risk that post-combustion treatment would be required should air emissions regulations become more stringent in the future

All of the alternatives being considered will have an appropriate level of redundancy (typically capacity to meet peak heat loads and to process 65 to 75 percent of average gas flows at the design year with the largest unit out of service), will be reliable, have minimal technical risk, and meet all air quality regulations. But some of the objectives listed in Table 2-3 indicate the degree to which the alternatives exceed these basic requirements. For instance, minimizing air quality treatment requirements measures the fact that, though all of the alternatives would meet current air permitting requirements, some alternatives are more likely than others to require post-combustion treatment in the future should air emissions regulations become more stringent.

2.4 Objectives Weighting

The original objective weighting used in TM 2 weighed each of the three categories of objectives (financial, environmental, and operational) equally for the first screening of alternatives. During the objectives weighting workshop, specific weights were assigned to each objective as the result of a comparison of the objectives that indicated the County's preferences and values for each objective. This comparison resulted in some of the objectives being weighted higher than others. In addition, to allow for the scoring to be completed on a normalized 100-point scale and to account for the fact that financial objectives are considered more important than environmental and operational objectives, the weights were developed such that the maximum score for the financial category is 40 points while the environmental and operational categories each have a maximum score of 30 points. After Workshop III, the financial objectives for minimizing operations and maintenance (O&M) costs and maximizing revenues were adjusted to be equal based on feedback received from the County.

Table 2-4 lists the objectives, the scale used to measure them, and their relative weightings. The scales for Financial Objectives 1 and 2 were respectively increased by $4 million and decreased by $300,000 from TM 2 to account for the updated capital and operating cost ranges.

Table 2-4. Scale and Weighting for the Objectives for South Plant Gas Utilization Program

Objective	Units	Scale	Weight
Financial Objectives			
1. Minimize capital costs	$	5 = less than 11 million 4 = 11 million to 12.5 million 3 = 12.5 million to 14 million 2 = 14 million to 16 million 1 = more than 16 million	3.3
2. Minimize operational and maintenance costs	$/yr	5 = less than 500,000 4 = 500,000 to 600,000 3 = 600,000 to 700,000 2 = 700,000 to 900,000 1 = more than 900,000	2.0
3. Maximize revenues	$/yr	5 = more than 1.5 million 4 = 1.5 million to 1.25 million 3 = 1.25 million to 1.1 million 2 = 1.1 million to 1 million 1 = less than 1 million	2.0
4. Maximize grants, credits, and incentives	1-5	5 = high value, high probability 3 = high value, low probability or low value, high probability 1 = low/no value, low probability	0.7

Table 2-4. Scale and Weighting for the Objectives for South Plant Gas Utilization Program			
Objective	Units	Scale	Weight
Environmental Objectives			
1. Reduce use of energy	kWh/yr, kWh-t/yr	5 = less than 6 million 4 = 6 million to 8 million 3 = 8 million to 9 million 2 = 9 million to 12.5 million 1 = more than 12.5 million	1.6
2. Reduce greenhouse gas emissions	Tons of eCO2/yr	5 = less than -10,000 4 = -10,000 to -6,000 3 = -6,000 to -3,000 2 = -3,000 to 0 1 = more than 0	1.6
3. Increase production of renewable energy	kWh/yr, kWh-t/yr	5 = more than 60 million 4 = 60 million to 50 million 3 = 50 million to 30 million 2 = 30 million to 15 million 1 = less than 15 million	1.6
4. Increase consumption of renewable energy	kWh/yr, kWh-t/yr	5 = more than 40 million 4 = 40 million to 30 million 3 = 30 million to 20 million 2 = 20 million to 10 million 1 = less than 10 million	0.6
5. Invest in alternative fuel transit and fleet vehicles	kWh-t/yr	5 = more than 2 million 1 = less than 2 million	0.6
Operational Objectives			
1. Maximize system redundancy and reliability	1–5	5 = most redundancy and reliability 1 = least redundancy and reliability	1.3
2. Maximize system operational flexibility	1–5	5 = most flexibility to changes 1 = least flexibility	0.6
3. Minimize WTD labor requirements	FTEs	5 = fewer than 2 4 = 2.25 to 2 3 = 2.75 to 2.25 2 = 3 to 2.75 1 = 3 or more	1.6
4. Minimize reliance on outside service contracts	1–5	5 = fewest outside contracts 1 = most outside contracts	0.3
5. Minimize technical risk	1–5	5 = lowest technical risk 1 = highest technical risk	1.6
6. Minimize air quality treatment requirements	1–5	5 = lowest risk of post-combustion treatment 1 = highest risk of post-combustion treatment	0.6

Using the scale and weights above, the alternatives can be compared to each other and a final recommendation can be made.

Section 3: Alternatives Description

This section describes the alternatives selected in TM 2 for utilizing digester gas and meeting plant heating needs at South Plant. Alternatives are composed of multiple sub-systems to meet the main process goals of utilizing digester gas in a beneficial manner and providing heat in the form of hot water to meet plant heat demands. The alternatives are described in detail in TM 2. The alternatives are intended to represent a range of viable approaches that include the key technologies identified as appropriate for South Plant digester gas utilization. It was acknowledged that the final preferred approach might contain elements from multiple evaluated alternatives. As requested by the County, the gas scrubbing alternatives were modified to include the baseline assumption of selling scrubbed gas to PSE to better compare these configurations on a common basis.

This TM briefly summarizes the alternatives and focuses on conceptual system layouts, interconnections, capacities, and anticipated operating modes. Operational issues, including potential O&M issues, impacts on other treatment plant processes, and permitting issues, are also discussed. Each alternative is also evaluated with value-added energy uses to enhance revenue. For the alternatives that result in sale of biomethane, the benefits of sale to a third party, small-scale production of renewable compressed natural gas (rCNG) with onsite fueling, or wheeling the biomethane to an offsite vehicle fleet were considered. The onsite rCNG fueling and offsite vehicle fleet options include potential revenue enhancement by producing Renewable Identification Numbers (RINs) as part of the U.S. Environmental Protection Agency's (EPA's) Renewable Fuels Standards program. For the electricity generating option, Renewable Energy Certificates (RECs) could be obtained by selling the electricity directly to PSE.

Capital cost estimates are developed for each alternative and presented in abbreviated tables in this section. More detailed capital cost estimate information is located in Appendix A (e.g., contractor markup assumptions). The capital costs are based on a Class 4 cost estimate per the Association for the Advancement of Cost Engineering International (AACEI), which carry a level of accuracy of -30 percent to +50 percent. O&M costs were developed in TM 2 and are presented in summary tables for each alternative. Capital cost assumptions are summarized in Table 3-1.

Table 3-1. Capital Cost Estimate Assumptions

Criterion	Rate (%)
Net cost markups	
Labor (employer payroll burden)	10
Materials and process equipment	8
Equipment (construction-related)	8
Subcontractor	5
Sales tax (excise-gross receipts-contract value)	9.5
Materials shipping and handling	2
Gross cost markups	
Startup, training, and O&M	2
Construction contingency	30
Process equipment contingency	15
Builders risk, liability, and auto insurance	2
Performance and payment bonds	1.5
Escalation to midpoint of construction	15

The alternatives were developed based on process assumptions outlined in Table 3-2. Process assumptions are based on baseline sludge loading and gas production estimates developed in 2011 as part of the South Plant Grease Co-Digestion Study (Task Order 2). Each alternative is capable of meeting the peak heating needs of the plant. The digester gas utilization systems are sized for about 1.1 times the average annual gas flow in 2036 or 1.65 million standard cubic feet per day (MM scfd) to account for gas production variability. While this capacity may not capture all gas peaks, previous analyses by Brown and Caldwell (BC) have shown that this capacity would likely capture more than 99 percent of the digester gas produced and is consistent with plant staff estimates for peak hour gas production identified in Task Order 2.

Table 3-2. Process Assumptions for Digester Gas Utilization Alternatives

Criterion	2013	2036
Average sludge load, gpd [a]	289,000	342,000
Average sludge load, lb-VS/day [a]	132,000	157,000
Average digester gas production, scfd [a]	1,223,000	1,492,000
Average plant heating demands, kWt (MMBtu/hr) [b]	1,570 (5.4)	1,750 (6.0)
Peak heating demands, kWt (MMBtu/hr) [b]	3,030 (10.4)	3,260 (11.1)

a. *Based on sludge loading and digester gas production developed for South Plant Grease Co-Digestion Study (Task Order 2), completed in 2011.*

b. *Based on sludge loading developed for South Plant Co-Digestion Study (Task Order 2), completed in 2011, and digester and natural gas data for heating from 2012.*

If supplemental feedstocks such as fats, oils, and grease (FOG) are added to the digestion system, the digester gas utilization system capacity would need to increase to use the additional gas produced. The additional capital and O&M costs associated with the increased capacity of the system are identified in the sensitivity analysis for FOG addition in Section 4.2.9. Task Order 2 identifies other digestion system upgrades that would be necessary beyond the digester gas utilization system.

3.1 Alternative A3: Status Quo

In the status quo alternative, digester gas is compressed and scrubbed to biomethane via two water-solvent type gas scrubbing towers and then either sold to PSE or used in the boiler or combined heat and power (CHP) gas turbines. Even though this alternative includes a number of replacements and upgrades to the existing systems, it is referred to as the "status quo" alternative because the existing system without any replacements and upgrades is considered a fatally flawed alternative. Continued operation of the existing gas scrubbing system would require replacement of two of the water pump/turbines and replacement of the two 0.6 MM scfd biogas compressors with two slightly larger (0.7 MM scfd) biogas compressors. In TM 2, replacement of the two 0.6 MM scfd compressors with one 1.2 MM scfd compressor was proposed, but this was later determined to be unrealistic because of excessive floor loads associated with the large compressor. The 0.7 MM scfd compressors are less than half the weight of the 1.2 MM scfd compressor and together they would be capable of compressing about 85 percent of the available biogas while the 1.2 MM scfd compressor is being serviced. The gas scrubbing system control would also be migrated to Ovation to better integrate the system. The new equipment would be located in place of the existing equipment. In addition, two new 6.7-million British thermal unit per hour (MMBtu/hr) high-Btu gas hot water boilers would be installed to provide turndown and backup capacity to the existing high-Btu gas hot water boiler.

There are two technology options for replacement of the existing compressors. Both reciprocating compressors (like the existing compressors), and oil-flooded screw compressors, are suitable for this application. The County currently operates oil-flooded screw compressors at the West Point Wastewater Treatment Plant for compression of digester gas, although these units operate at a much lower pressure than is necessary in this application (70 psig as compared to 300 psig). The reciprocating compressors would be a replacement in kind. The screw compressors would require two stages of compression with intercooling similar to the reciprocating compressors. The sizes and weights of the two compressor types for the same capacity are similar (within 10 percent), but the costs of the two technologies are significantly different. The screw compressors cost less than half as much as reciprocating compressors. In addition, the screw compressors would require much smaller equipment pads because of the smaller and balanced rotating mass compared to a reciprocating unit. This TM assumes that reciprocating compressors are selected because it matches the existing technology, but if this alternative is selected for detailed design, both technologies should be considered for the best overall economy and suitability to the operating conditions.

The water pump/turbines would be a replacement in kind. The proposed compressor and pump/turbine locations are shown in Figure 3-1.

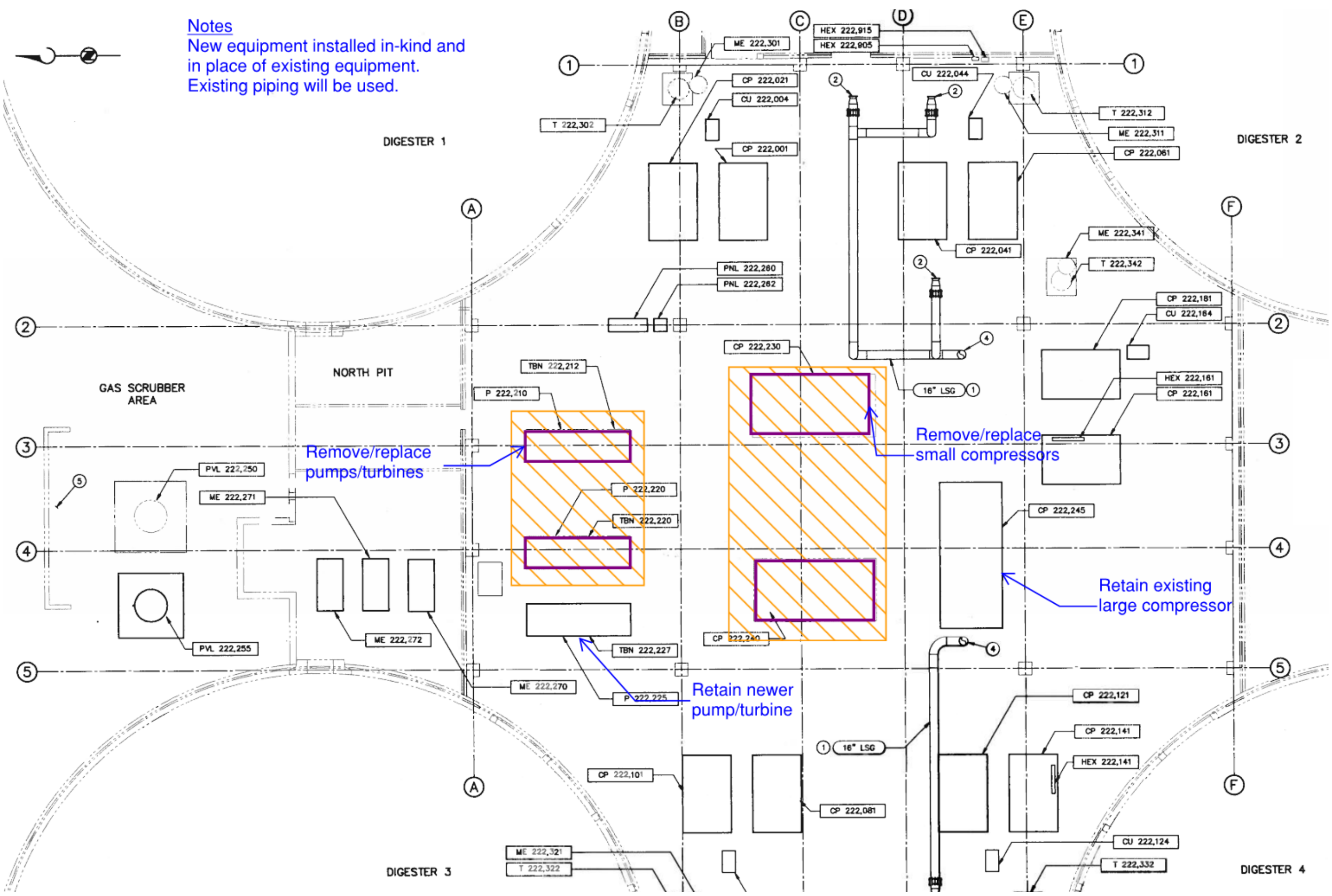

Figure 3-1. Compressor and pump/turbine replacement locations

The new high-Btu hot water boilers would be located in a new boiler building west and south of the motor control center (MCC) building. Each boiler would have a hot water circulation pump and a three-way valve to control heat load to the primary heat loop. A master boiler control panel would coordinate boiler firing and maintain the operating primary heat loop hot water supply temperature at 150 to 155 degrees Fahrenheit (°F) or higher for sludge heating. New buried or overhead scrubbed gas and/or natural gas pipelines would be routed from the digester control building to the new boiler building. Power and control for the new boiler building would be fed from the solids MCC building.

Heat reservoir return (HRR) and heat reservoir supply (HRS) lines for the high-temperature heat loop are located in the nearby tunnel. The high-temperature loop is the secondary heat loop where the existing boiler, fuel cell, and CHP heat recovery systems tie into the primary heat loop. These pipelines would be extended to the boiler building through buried insulated piping. The building's footprint would be approximately 40 by 50 feet (Figure 3-2). Figure 3-3 shows the conceptual location of the new boiler building with the gas lines and the extended HRR and HRS lines.

An alternative to install the new boilers in the sludge room of the digester control building was reviewed in a walkthrough with plant staff. While this may be possible, space restrictions for flue gas piping may make it just as costly of an option as a new building. The boiler building would be located where future digester capacity is planned but a digester expansion is not anticipated until after 2036, at which point the boilers would be at the end of their service lives and would require replacement anyway.

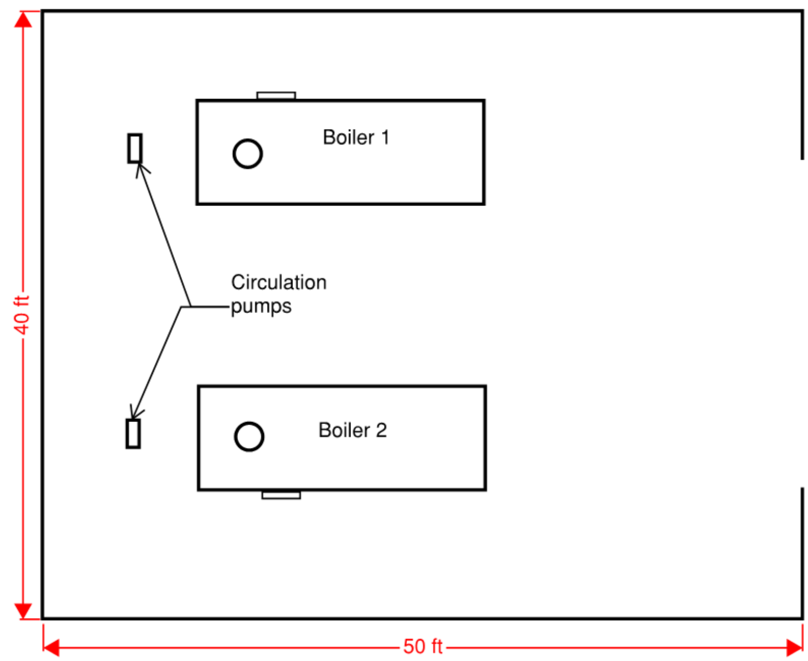

Figure 3-2. Boiler building layout

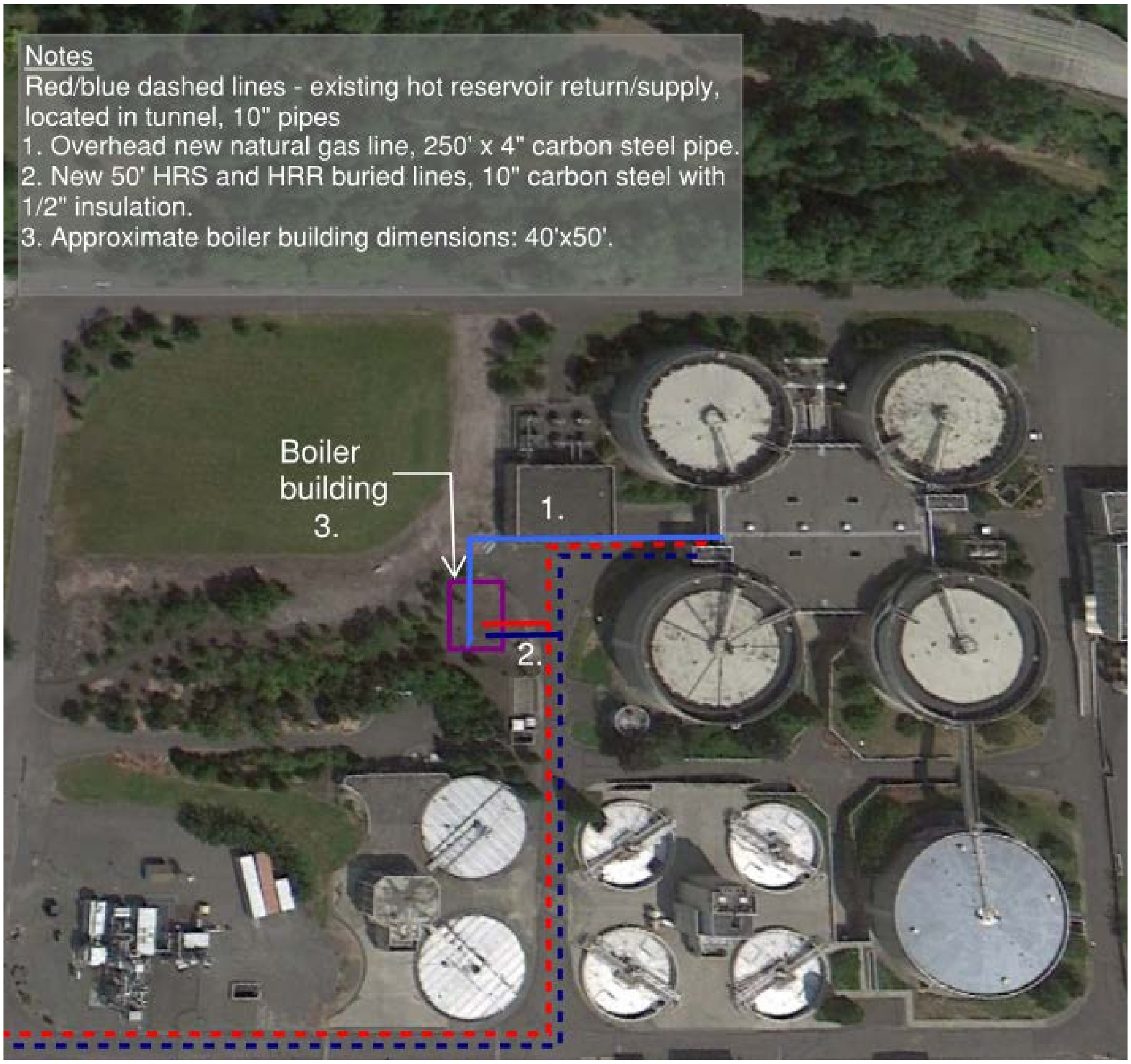

Figure 3-3. New boiler building and interconnecting piping

Because the temperature of the return water to the boilers at the plant would be more than 135°F, non-condensing boilers are assumed here because condensing boilers are typically economical only at return water temperatures of about 120°F or below (Carbon Trust, 2011). Condensing boilers could be considered in detailed design if this alternative is selected.

The new boilers would be point sources of emissions and would require a notice of construction application with the Puget Sound Clean Air Authority (PSCAA). Low-nitrogen oxide (NO_x) emission versions of boilers are readily available that would provide emissions at 20–30 parts per million (ppm) of NO_x from multiple manufacturers. Ultra-low NO_x boilers may be required to reduce NO_x emissions to 9 ppm, but because these boilers are not large (i.e., < 20 MMBtu/hr), low-NO_x boilers are assumed here.

A summary of the capital costs associated with the status quo alternative are given in Table 3-3.

Table 3-3. Status Quo Capital Cost Summary	
Component	Cost
Biogas compressors [a]	$5,948,000
Two pumps/turbines	$645,000
Boilers	$1,637,000
Demolition	$144,000
Boiler building	$723,000
Electrical and I&C	$1,038,000
Total	$10,135,000

a. *Note that equipment cost for screw compressors would be $1,500,000 versus $3,200,000 for reciprocating type.*

Operating costs for the status quo alternative were developed and described in TM 2. The capacity of the existing gas scrubbing system was adjusted to reflect TM 1 findings, and operating information was updated to 2018 because this is a more likely year for the system to come on line than 2016. The capacity and operating data are shown in Tables 3-4 and 3-5 for the boilers and gas scrubbing system, respectively.

Table 3-4. Existing and New Boiler Capacity and Operations Data		
Criterion	Value	Notes
Capacity, existing, kWt (MMBtu/hr)	3,429 (11.7)	See TM 1
Capacity, new, kWt (MMBtu/hr)	3,927 (13.4)	Total for two boilers
Efficiency, %	80	Typical for hot water boilers
Scrubbed gas (biomethane)/natural gas, %/%	99.6/0.4	Fuel source percentage; see TM 1
Natural gas cost, 2018, $/yr [a]	$ 2,900	Cost for natural gas only
Labor, parts, and maintenance, $/yr [b]	$143,000	Assumed as fixed cost
Plant heat demand, % [c]	100	Plant heating satisfied by boilers
Estimated full-time equivalents (FTEs)	0.75	

a. *Natural gas cost from PSE based on rate of $1.242/therm, reference Workshop II results memo, July 16, 2013.*

b. *Assumes a 50% increase in labor, parts, and maintenance costs from existing costs for additional two boilers.*

c. *For simplification of the analysis, all plant heat is assumed to be provided by the boilers.*

Table 3-5. Gas Scrubbing System Operations Data		
Criterion	**Value**	**Notes**
Capacity, MM scfd	2.15	See TM 1 for capacity description
Scrubbed gas produced, 2016, kWt-h/yr (MMBtu/yr)	71,509,000 (244,000)	Net higher heating value of scrubbed gas produced
Annual revenue, 2018, $/yr [a]	$994,000	After boiler and turbine scrubbed gas use
Annual electricity used, 2018, kWh/yr	6,105,000	Electricity used to produce scrubbed gas
Annual electrical power cost, 2018, $/yr [b]	$427,000	
Labor, parts, and maintenance, 2018, $/yr [c]	$190,000	See TM 1 for O&M description
Availability, %	98	Percent of time the system is available
Methane capture efficiency, %	95	Percent of methane entering system that is leaving as scrubbed gas
Scrubbed gas flared, %	5	Percent of scrubbed gas wasted to flares
Estimated FTEs	1	

a. Assumes PSE purchase price of $0.5347/therm, reference Workshop II results memo, July 16, 2013, and Workshop III notes, September 19, 2013.

b. Based on data provided by King County.

c. Based on data documented in TM 1 with a 15% reduction for new compressors.

Alternative A3 as defined in TM 2 includes the sale of scrubbed gas to a third party via the PSE natural gas pipeline. Because any of the Alternatives A3 (status quo), B4, and C4 could benefit from the sale of gas to a third party, the County preferred to keep the base case for the status quo as a sale of scrubbed gas to PSE. The sale of the scrubbed gas to a third party is assumed separately in the NPV analysis in Section 4.1 for all three gas scrubbing alternatives.

3.2 Alternative B4: Digester Gas Boilers and New Gas Scrubbing

Alternative B4 provides heat to the plant with two new digester gas-fired hot water boilers. The remaining digester gas would be scrubbed with a new gas scrubbing system and sold to PSE. The new gas scrubbing equipment is assumed to be a pressure swing adsorption (PSA) type located in or near the digester control building, but if this alternative is selected for design, detailed evaluation of gas scrubbing technologies should be conducted during pre-design.

The new digester gas-fired hot water boilers would be located in their own building west and south of the MCC building, similar to the status quo alternative. A digester gas pipeline would be routed from the digester control building to the boiler building to transport digester gas to the new boilers. Digester gas blowers for the boilers would be located in the gas handling room of the digester control building and would be designed for the electrically classified space. The blowers would draw gas from upstream of the feed compressor of the gas scrubber to avoid variations in energy content when the gas from the scrubbing system is diverted to the waste gas burners by PSE. The remainder of the boiler installation would be the same as the status quo alternative. No biogas conditioning is needed to use biogas in the boilers, nor are the boilers more expensive than natural gas boilers. Figure 3-4 shows the location of the digester gas blowers in the existing gas equipment room. The existing high-Btu boiler would remain in this alternative as a backup to the new boilers.

The PSA requires smaller rotating machinery than the current gas scrubbing system, although the footprint of the outdoor vessels is larger. The rotating machinery associated with the PSA would be located in place of the existing gas scrubbing system compressors and water pump/turbines. The PSA rotating equipment would include two oil-flooded screw type feed compressors (rated at 70 percent of flow), two oil ring vacuum pumps (70 percent rated), and two oil-flooded or reciprocating type final compressors (70 percent rated). With any one piece of equipment out of service, the system would be able to provide between 1.1 and 1.2 MM scfd capacity. This provides the same level of service or better than the status quo gas scrubbing system. A similar size system at the Dos Rios Water Reclamation Facility (WRF) in San Antonio operates with 98 percent uptime. This system includes only one feed and one product gas compressor. In addition, the rotating equipment would be standard products from manufacturers rather than custom-built equipment. A spare compressor head or vacuum pump could be purchased to limit the impacts of rebuild time. Digester gas and cooling water interconnections would be similar to the existing gas scrubbing equipment. Power and control would be from the solids MCC building, similar to the existing equipment. The rotating equipment and PSA have very good turndown and could operate at 20 to 30 percent of design capacity. Figure 3-4 shows the location of rotating equipment inside the digester control building.

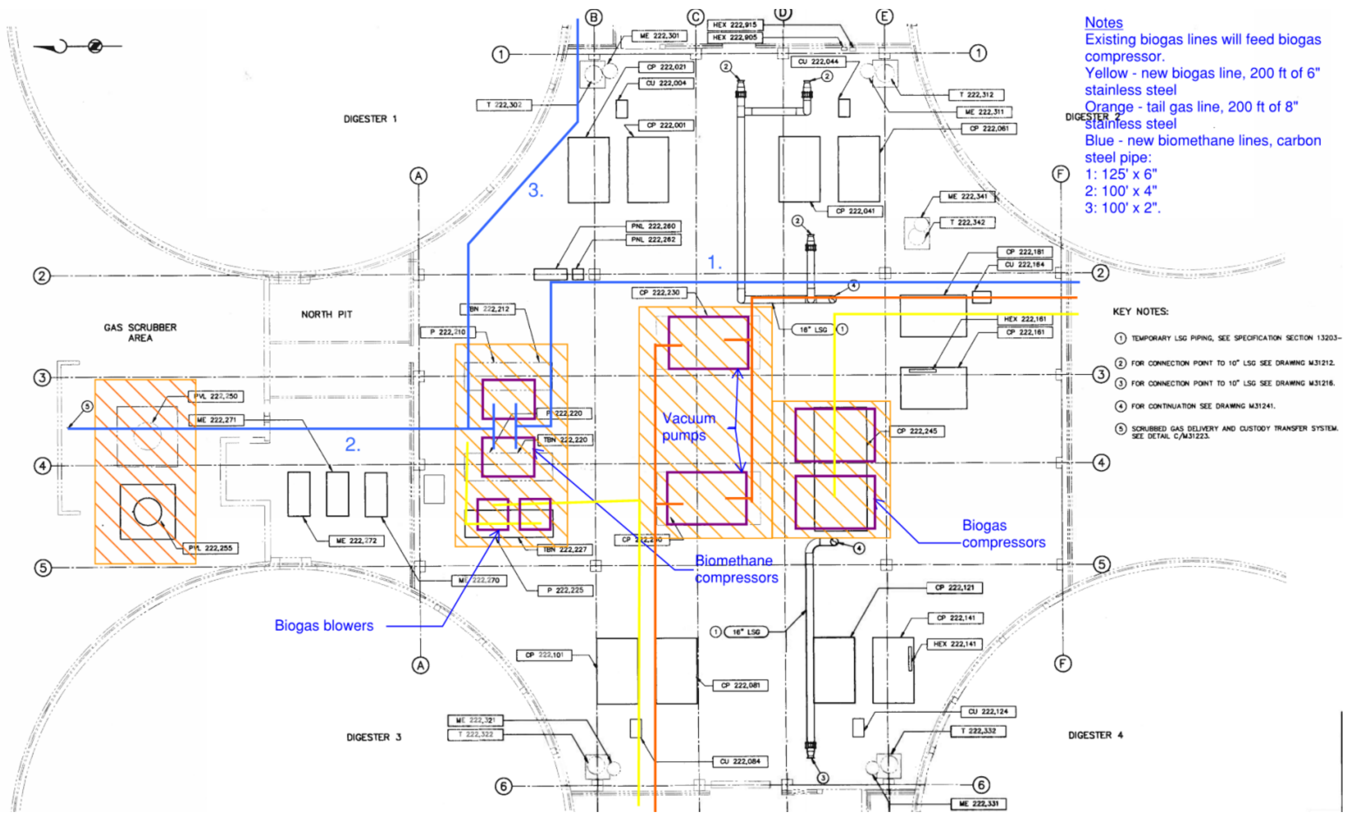

Figure 3-4. PSA rotating equipment and biogas blowers inside gas equipment room

The PSA vessels and buffer vessels would be located south of digester 2's exterior. The area is currently landscaped at a 15 percent slope and would need to be leveled. A thermal oxidizer would be installed west of the MCC building to incinerate waste gas from the PSA system. Overhead gas pipelines would be used to supply all outdoor equipment. Because the outdoor PSA equipment can be noisy, plant operators expressed the need for the equipment to be located away from the plant's boundaries, but the location of the PSA equipment with respect to its vacuums and compressors should be as close as practical. The existing gas scrubbing towers and gas dryers would be demolished, but the gas monitoring equipment and gas odorizer would be reused. Figure 3-5 shows the location of equipment outside the digester control building. Figure 3-6 and Figure 3-7 show pictures of the PSA, buffer vessels, and thermal oxidizer installed at the Dos Rios WRF.

Figure 3-5. Locations of PSA buffer vessels and thermal oxidizer

Figure 3-6. PSA and buffer vessels at Dos Rios WRF

Figure 3-7. Thermal oxidizer at Dos Rios WRF

The thermal oxidizer would require a notice of construction application to be submitted with PSCAA because it would be a new point source emission. In general, thermal oxidizers have very high destruction efficiencies of methane (CH_4) and volatile organic compounds (VOCs), and their emissions of nitrogen oxides and carbon monoxide (CO) are very low. The hydrogen sulfide (H_2S) that is present in the digester gas would be combusted in the thermal oxidizer producing sulfur oxides, which may affect the plant's overall emissions quantity. However, hydrogen sulfide in the raw digester gas is very low compared to most wastewater treatment plants and therefore the sulfur dioxide emissions would probably not cause additional permitting requirements. Because the hydrogen sulfide and carbon dioxide (CO_2) would no longer be sent back to the liquid stream process, odors and acidity would be reduced.

A summary of the capital costs associated with Alternative B4 are given in Table 3-6.

Table 3-6. Alternative B4 Capital Cost Summary

Component	Cost
Boilers	$1,829,000
PSA system	$7,102,000
Demolition	$289,000
Boiler building	$723,000
Electrical and I&C	$1,179,000
Total	$11,968,000

Operating costs for Alternative B4 were developed in TM 2. The capacity of the gas scrubbing system was updated to 1.65 MM scfd and the operating data were updated to a start date of 2018. The rest of the operating costs are the same as in TM 2. The capacity and operating data are shown in Tables 3-7 and 3-8 for the boilers and gas scrubbing system, respectively.

Table 3-7. New Digester Gas Boiler Capacity and Operations Data

Criterion	Value	Notes
Capacity, new, kWt (MMBtu/hr)	3,927 (13.4)	Total for two boilers
Efficiency, %	80	Typical for hot water boilers
Labor, parts, and maintenance, $/yr [a]	$ 214,000	Assumed as fixed cost
Annual blower power cost, 2018, $/yr [b]	$ 19,000	Digester gas booster blowers
Plant heat demand, % [c]	100	Plant heating satisfied by low-Btu boilers
Estimated FTEs	1	

a. *Assumes labor, parts, and maintenance increase by 50% from natural gas for burning raw digester gas. Includes maintenance for gas booster blowers.*

b. *Assumes a discharge pressure of 2 psig and 50% blower efficiency.*

c. *For simplification of the analysis, all plant heat is assumed to be provided by the low-Btu boilers.*

Table 3-8. New Gas Scrubbing System (Guild PSA) Capacity and Operating Data

Criterion	PSA, Guild	Notes
Capacity, MM scfd	1.65	Capacity to meet 2036 average digester gas flow
Scrubbed gas produced, 2018, kWt-h/yr (MMBtu/yr)	55,977,000 (191,000)	Net higher heating value of scrubbed gas produced
Annual revenue, 2018, $/yr	$965,000	After boiler and turbine scrubbed gas use
Annual electricity used, 2018, kWh/yr	3,263,000	Electricity used to produce scrubbed gas
Annual electrical power cost, 2018, $/yr [a]	$228,000	Includes final compression to 250 psig
Labor, parts, and maintenance, 2018, $/yr [b]	$93,000	Includes limited maintenance plan
Availability, %	98	Percent of time the system is available
Methane capture efficiency, %	92	Percent of methane entering system that leaves as product gas
Scrubbed gas flared, %	5	
Estimated FTE	0.5	

a. *Electricity costs of $0.07/kWh, fully loaded, including demand charges.*

b. *Assumes PSE purchase price of $0.5347/therm reference Workshop II results memo, July 16, 2013, and Workshop III notes, September 19, 2013.*

3.3 Alternative C4: New Heat Extractors and New Gas Scrubbing

This alternative would provide heat to the plant by replacing the five existing heat extractors with dual two-stage heat extractors. The existing gas scrubbing system would be replaced with a PSA gas scrubbing system as described in Alternative B4 and the biomethane would be sold to PSE.

Heat extractors from Trane, York, and McQuay were considered for this application. The dual-stage heat extractors proposed by Trane are assumed here because they would be able to accommodate step loading better than the existing heat extractors and would produce higher-temperature hot water than single-stage configurations. The new two-stage units would provide hot water at 170°F. These heat extractors have screw compressors and are more tolerant to the large step loads that cause the current heat extractors to shut down; in addition, three-way valves and circulation pumps would be installed on the digester heat exchangers to reduce these step loads. The capability of the new heat extractors will improve the functional performance of the primary heat loop operation.

The new heat extractors would be installed in the area vacated by the five existing heat extractors (Figure 3-8). Hot water connections would be made in a similar manner to the existing units. The new heat extractors would be powered and controlled from existing heat extractor locations. Existing heat extractor pumps for C3 water and HRR/HRS water would be removed and replaced. Each heat extractor is 85 inches tall and can be installed through the sludge pump room utility door if 6 inches of clearance is sufficient. If more clearance is necessary, the heat extractors could be partially disassembled and reassembled inside the sludge pump room.

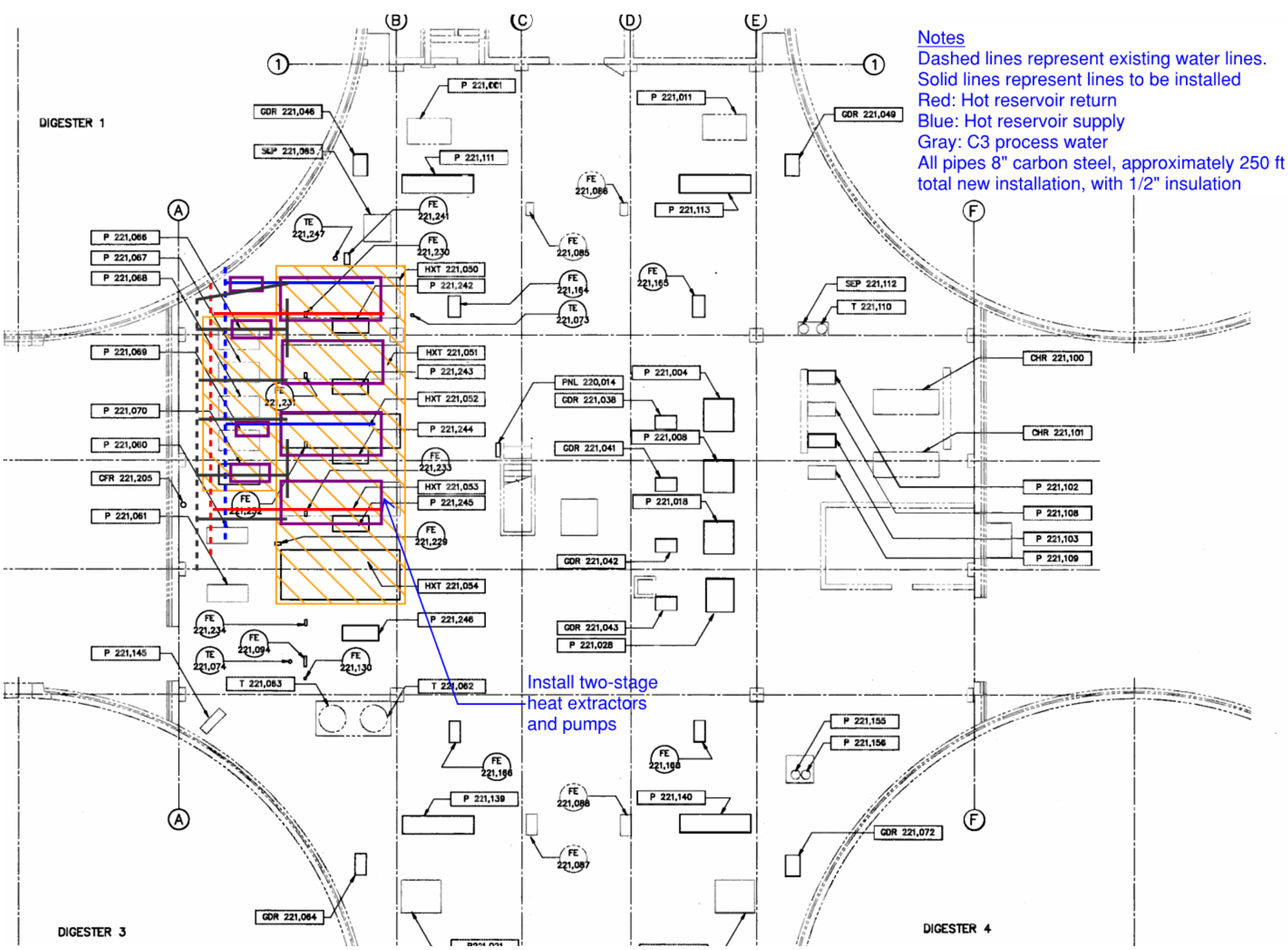

Figure 3-8. Heat pump layout in sludge handling room

Additional modifications would include a controls upgrade for primary heat loop pump control. This control would automatically adjust the pump speed to better match primary heat loop flow with heat extractor loop flow. This control would maintain the supply temperature of the heat reservoir at 150 to 155°F minimum. Alternate modifications could include additional passes being added to the sludge heat exchanger accompanied by new sludge pumps for the higher head, although this modification is not assumed here. The existing boiler would act as a backup to the new heat extractors.

The installation of the new gas scrubbing system would be identical to Alternative B4. The capital costs associated with Alternative C4 are summarized in Table 3-9.

Table 3-9. Alternative C4 Capital Cost Summary

Component	Cost
Heat extractor [a]	$3,439,000
PSA system	$7,141,000
Demolition	$289,000
Electrical and I&C	$1,342,000
Total	$12,211,000

a. *Including pump and three-way valve modifications for sludge heat exchangers.*

The heat extractor capacity and operating data developed in TM 2 are shown in Table 3-10. The capacity and operating data for the new gas scrubbing system are similar to Alternative B4, but represent additional gas flow through the system because the plant's heat supply does not use digester gas. These data are shown in Table 3-11.

Table 3-10. Heat Extractor Capacity and Operating Data

Criterion	Value	Notes
Capacity, kWt (MMBtu/hr)	3,604 (12.3)	Total for two heat extractor systems in winter
Coefficient of performance (COP), -	3.0	Average operation
Annual electricity, 2018, kWh/yr	4,587,000	As primary heat source
Annual electrical power costs, 2018, $/yr [a]	$321,000	As primary heat source
Labor, parts, and maintenance, $/yr [b]	$132,000	Assumed as fixed cost
Plant heat demand , %	100	Plant heating satisfied by extractors
Estimated FTEs	1.0	

a. *Electricity costs are $0.07/kWh, fully loaded, including demand charges and average COP of 3.0.*

b. *Labor, parts, and maintenance costs were increased by a factor of 6 from the costs identified in TM 1 for operation year round versus the current operation of 2 months.*

Table 3-11. New Gas Scrubbing System (Guild PSA) Capacity and Operating Data

Criterion	Value	Notes
Capacity, MM scfd	1.65	Capacity to meet 2036 average digester gas flow
Scrubbed gas produced, 2018, kWt-h/yr (MMBtu/yr)	68,286,000 (233,000)	Net higher heating value of scrubbed gas produced
Annual revenue, 2018, $/yr [a]	1,242,000	After boiler and turbine scrubbed gas use
Annual electricity used, 2018, kWh/yr	4,196,000	Electricity used to produce scrubbed gas
Annual electrical power cost, 2018, $/yr [b]	$294,000	Includes final compression to 250 psig
Labor, parts, and maintenance, 2018, $/yr	$88,000	Includes limited maintenance plan
Availability, %	98	Percent of time the system is available
Methane capture efficiency, %	92	Percent of methane entering system that leaves as product gas
Scrubbed gas flared, %	5	
Estimated FTE	0.5	

a. *Assumes PSE purchase price of $0.5347/therm, reference Workshop II results memo, July 16, 2013, and Workshop III notes, September 19, 2013.*

b. *Electricity savings are $0.07/kWh, fully loaded, including demand charges*

3.4 Alternative E1: Cogeneration Facility with Internal-Combustion Engine-Generators

Alternative E1 makes use of the biogas in combustion engines that generate electricity and heat for the plant. The plant's current digester gas production is 1.2 MM scfd and the design capacity in 2036 is 1.65 MM scfd. These flows would accommodate three 1,200- to 1,400-kilowatt (kW) engine-generators, depending on electrical efficiency, and would exceed the plant's heat requirements with more than 14 MMBtu/hr to the primary heat loop when operating at full capacity. Three 1,200 kW engine-generators are assumed for this study, but the number and capacity of the engine-generators would need to be reviewed during preliminary design. With one engine-generator out of service, about 65 percent of the design flow could be accommodated. The existing natural gas boiler would be retained and used as a standby heat source using natural gas as its fuel.

A digester gas conditioning system is assumed to be required to remove moisture, hydrogen sulfide, and siloxanes from the digester gas prior to combustion in the engine-generators. Redundant blowers and chillers would be included in the system. Detailed gas sampling and contaminant limits from manufacturers may remove the need for hydrogen sulfide and siloxane treatment if this alternative is carried forward to final design.

The new cogeneration system would require a new building because of its size and complexity. The ideal location of the facility would be in place of the existing fuel cell. An alternative location would be on the west side of the future digester complex, where future digesters 7 and 8 would be located. Based on the size of the cogeneration facility at the West Point WWTP, the building would require a footprint of approximately 140 feet by 90 feet, with a height of 25 feet.

The cogeneration building would include the engine-generators, exhaust heat recovery silencers, hot water pumps, electrical room for switchgear and MCCs, control room, and shop. The building would include an overhead bridge crane for maintenance of large equipment. The digester gas blowers and heat exchangers for the gas conditioning system would also be located inside the new cogeneration building. Media vessels for the digester gas conditioning system would be located outside to facilitate media replacement. Waste heat radiators would also be located outside the building. The layout of the cogeneration building with major equipment is shown in Figure 3-9.

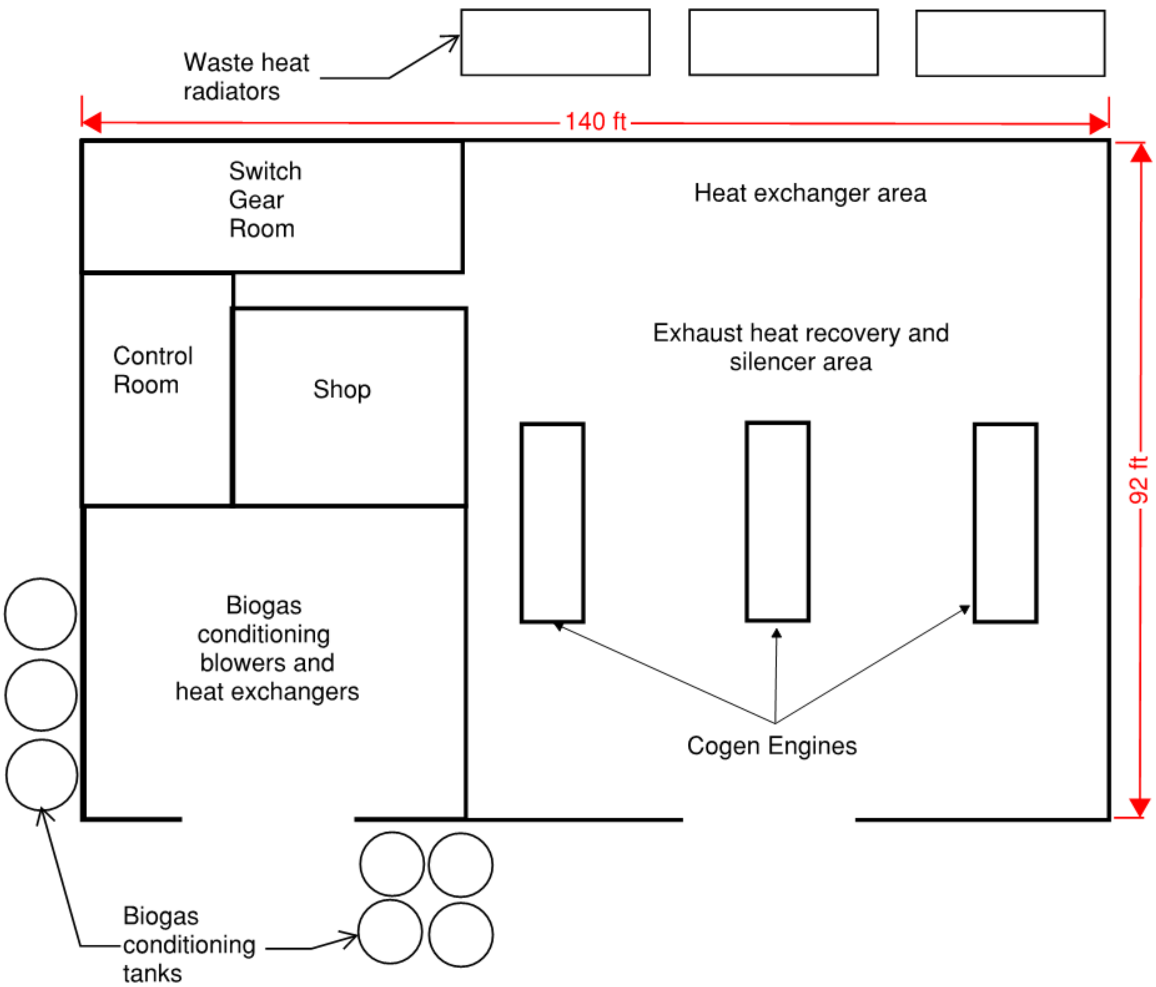

Figure 3-9. Cogeneration building layout

The high-temperature loop HRS and HRR lines already run to the existing fuel cell area and CHP building. The new cogeneration facility would connect to these existing HRS/HRR lines. A new buried low-pressure sludge gas (LSG) line would be routed from the buried LSG line to the waste gas burners. The electricity generated by the new cogeneration facility would include transformers to step up generator voltage from 4.16 kilovolts (kV) to 13.09 kV. The interconnection pipes are shown in Figure 3-10.

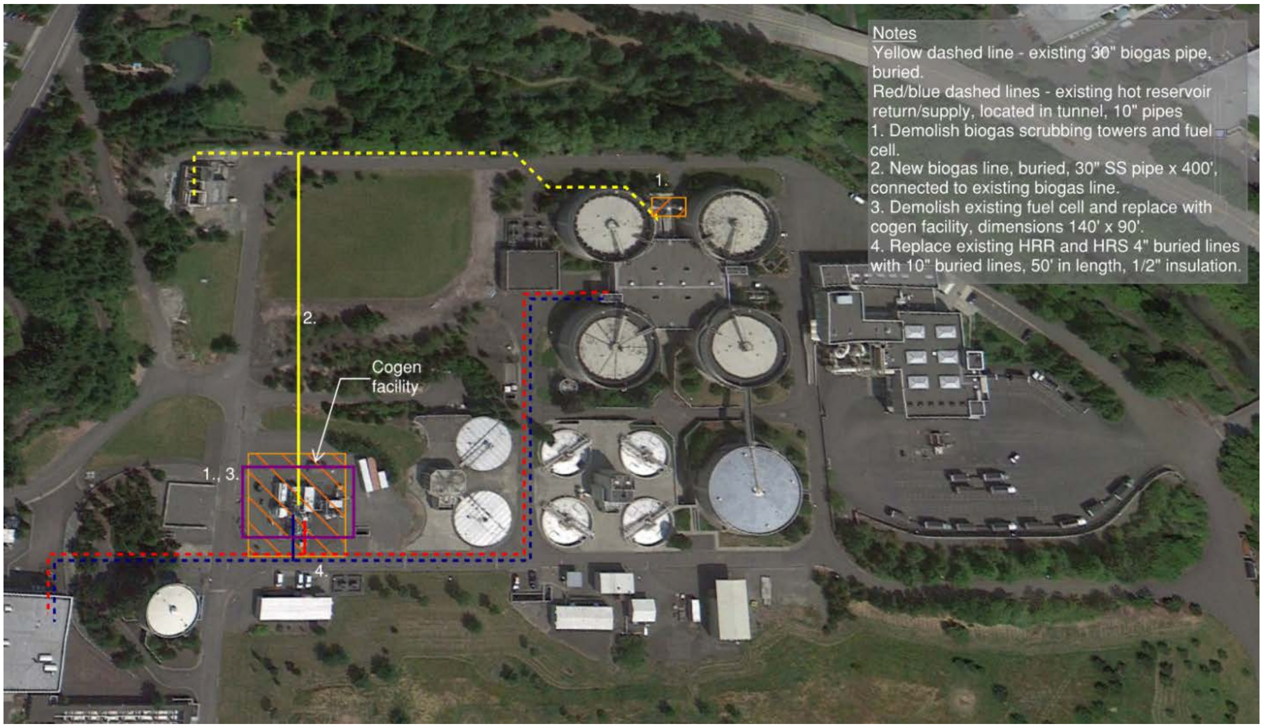

Figure 3-10. Interconnecting piping for new cogeneration building

There are several potential alternatives for connecting the new cogeneration system to the plant power distribution system. The new cogeneration system would need to connect to the 13.09 kV electrical system to distribute power to the plant. Potential alternatives for 13.09 kV interconnections are described below:

- The first interconnection alternative would be to route a new duct bank from the new cogeneration building to the unused electrical room in the existing CHP building as identified by the County. Alternatively, the steam turbine circuit breaker may potentially be used if it is no longer operated or another breaker is added in the existing electrical switchgear room. Dual 13.09 kV feeders connect the existing CHP system to the plant dual 13.09 kV incoming switchgear buses per Figure 3-12. Each set of feeders has a rated capacity of approximately 8-megawatt (MW)/9.8-megavolt-ampere (MVA) cogeneration output. The gas turbines total 7 MW of nameplate power, not including the steam turbine. If the gas turbines are both feeding one bus, this leaves only 1 MW of additional capacity assuming the steam turbine is not used. If the gas turbines are each feeding their associated buses separately, then the new cogeneration could be tied to either bus in addition to the gas turbine on that bus. This leaves the following three options for connection at the existing CHP building:
  - program the circuit breakers to disallow new cogeneration operation if the gas turbines are both feeding the same bus, or program the cogeneration controls to limit the total combined output capacity to the feeder capacity when it is operating on a single bus
  - increase the existing feeder sizes to allow the combined capacity of the existing and new cogeneration to be carried on either bus, although this would provide comparatively little value for a significant capital cost
  - assuming there are spare chases in the duct bank from the CHP building to the plant main switchgear, add new parallel feeders in these chases to increase the combined cogeneration capacity

- The second interconnection alternative would reuse the fuel cell duct bank to route the new feeder from the fuel cell installation to the plant main switchgear. This may be possible if the required increased capacity can be carried in that existing duct bank.
- The last interconnection alternative would be through a new duct bank run from the new cogeneration site to the plant substation, connected at the spare breaker formerly occupied by the fuel cell.

A simplified electrical one-line diagram is shown in Figure 3-11 identifying the two locations for interconnection.

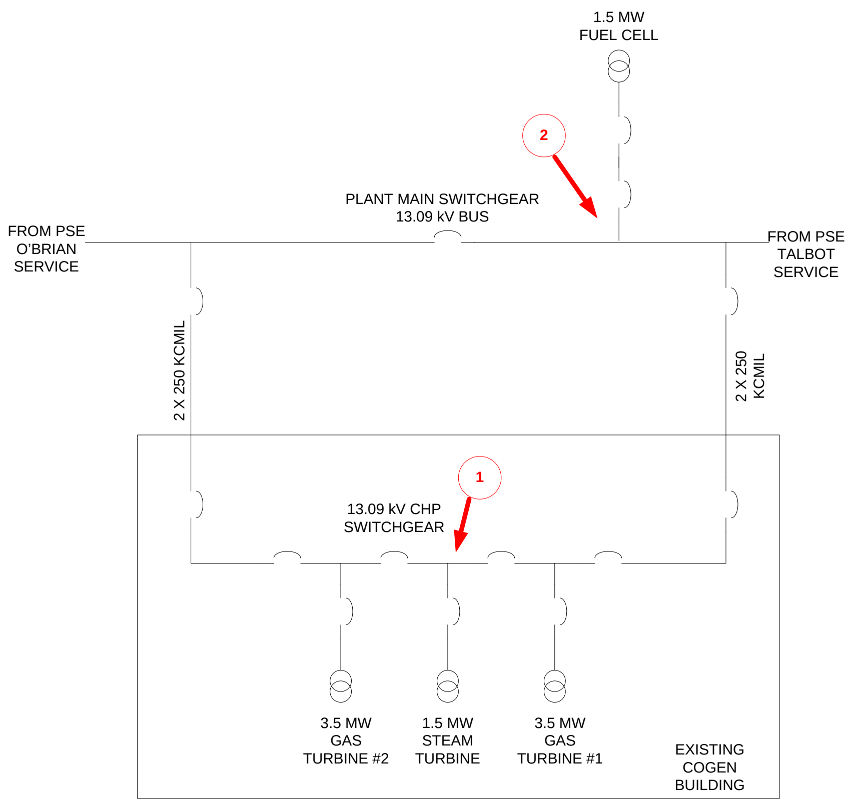

Figure 3-11. Simplified one-line diagram for interconnection

The costs of the interconnection options are relative to the length of new duct bank or new feeders that would be required. Figure 3-12 shows the physical location for interconnections on the site.

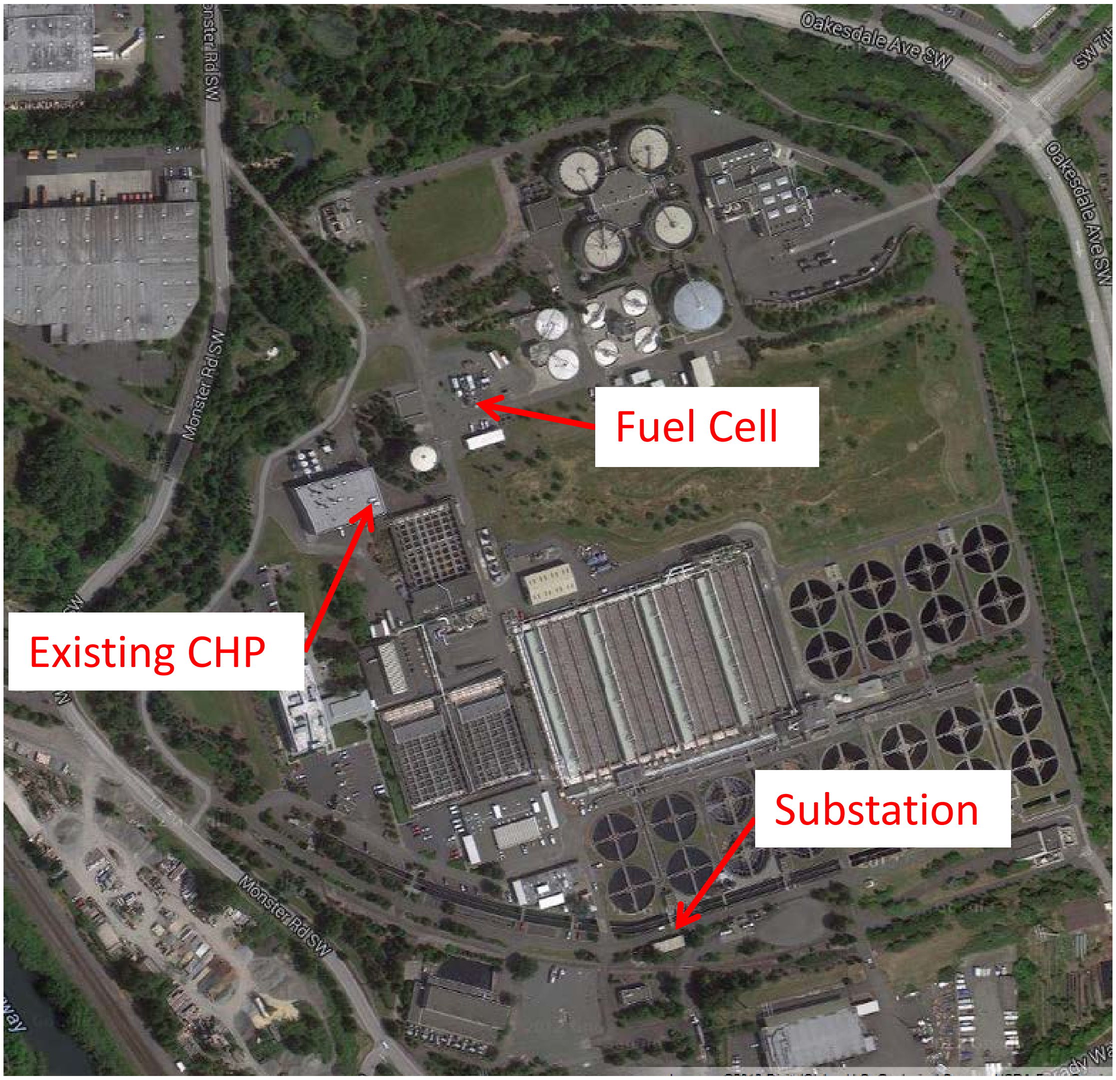

Figure 3-12. Electrical interconnection locations on the plant site

The assumption made in this analysis is to route a new duct bank from the new cogeneration building to the existing CHP building, and to program the existing CHP controls to disallow simultaneous operation of both gas turbines and new cogeneration from feeding one bus or to limit the total capacity output when feeding to one bus only. This assumption carries some capital cost and is considered conservative. However, if this energy utilization alternative is selected for detailed design, the other options for electrical interconnection should be investigated in more detail. By tying the new cogen into the existing CHP cogen switchgear, it is assumed that the existing power utility company interface protection functions that are normally required for paralleled interconnection are preexisting and will require little or no modification.

Connection directly to the PSE utility outside the plant boundary and entering into a power purchase agreement with PSE may be a possible option, but if the renewable power is sold to PSE, this may not be advantageous for the County's goal of using more renewable power.

The new engine-generators would require a notice of construction application to PSCAA. As described in TM 2, there is a risk that PSCAA would require post-combustion treatment to reduce NO_x and CO emissions. Post-combustion treatment could include selective catalytic reducer (SCR) and oxidation catalyst (OC). The post-combustion treatment would have a significant capital and operating cost. Equipment costs might be on the order of $225,000 per engine with O&M costs approximately three to four times this amount over 20 years to account for consumables, testing, and catalyst replacement. In addition, capital and operating costs for the digester gas conditioning system would increase to prevent breakthrough of hydrogen sulfide or siloxanes which, when combusted, can poison the catalysts, leading to more frequent catalyst replacement.

While most lean-burn engine-generators can meet EPA Part 60 requirements for digester gas-fired engines without post-combustion treatment, BC knows of two biogas internal-combustion (IC) engine-generator installations in Washington State with post-combustion treatment. One installation is at the Cedar Hills Landfill, where engine-generators burn landfill gas that first goes through a pipeline-quality scrubbing system owned by Bioenergy Washington. The other installation is at the County's West Point WWTP, where the influent pump engines are undergoing a retrofit for digester gas treatment and post-combustion treatment. While relatively uncommon at this point, it may become increasingly likely that post-combustion treatment would be required in the future, especially for an installation of the size described in this section.

The capital costs associated with Alternative E1 are summarized in Table 3-12. Demolition of the fuel cell and gas scrubbing system incurs $1 million to the cost of this alternative. Locating the cogeneration facility in another location that would not require fuel cell demolition would require additional piping installation costs to get to the location and additional electrical interconnection costs to interconnect, but overall would probably reduce the capital cost.

Table 3-12. Alternative E1 Capital Cost Summary

Component	Cost
Cogeneration and biogas conditioning system	$11,003,000
Demolition	$1,033,000
Cogeneration building	$4,457,000
Electrical interconnection	$1,143,000
Electrical and I&C	$904,000
Total	$18,540,000

The electrical and thermal capacities of the cogeneration system were adjusted from TM 2 to reflect three 1,200 kW engine-generators being installed instead of three 1,100 kW engine-generators. The power output of these generators represents less than half the current average power consumption of South Plant and about two-thirds the current minimum power consumption. The remainder of the operating data for the IC engine-generators and gas treatment system are assumed to be the same and are shown in Table 3-13 and Table 3-14. Operating data are updated to the year 2018.

Table 3-13. IC Engine Generator Cogeneration System Capacity and Operating Data		
Criterion	**Value**	**Notes**
Cogeneration electrical capacity, kW [a]	3,600 to 4,200	Combined capacity
Cogeneration thermal capacity, kWt (MMBtu/hr) [b]	3,160 (14)	As hot water for heating
Annual electricity generated, 2018, kWh/yr [a]	23,068,000	Electricity produced from digester gas
Annual electrical savings, 2018, $/yr [c]	$1,615,000	
Percent of plant heating, %	95	When available
Labor, parts, and maintenance, 2016 $/yr [d]	$392,000	
Availability, %	92	
Estimated FTEs	2	
Boiler labor, parts, and maintenance, $/yr [e]	$24,000	Assumed as fixed cost
Boiler natural gas cost, 2018, $/yr [f]	$95,000	For peak heating and when IC engine-generators are unavailable

a. *Assumes a 36% to 42% peak electrical efficiency with an average operating efficiency of 36%.*
b. *Assumes a 40% thermal efficiency.*
c. *Electricity savings are $0.07/kWh, fully loaded, including demand charges.*
d. *Assumes $0.017/kWh for all O&M including two FTEs for operation.*
e. *Assumes a 75% reduction from the existing boiler O&M costs because the boiler is used only during peak heating.*
f. *Natural gas cost from PSE is based on rate of $1.242/therm, reference Workshop II results memo, July 16, 2013.*

Table 3-14. Gas Conditioning System Capacity and Operations Data		
Criterion	**Value**	**Notes**
Capacity, MM scfd	1.65	Capacity to meet 2036
Annual blower and chiller power, 2018, kWh/yr [a]	$57,000	
Labor, parts, and maintenance, 2016, $/yr [b]	$54,000	
Hydrogen sulfide media replacement, 2016, $/yr [c]	$26,000	Includes labor cost
Siloxane media replacement, 2018, $/yr [d]	$170,000	Includes labor cost
Availability, %	100%	With duty-standby critical equipment
Estimated FTEs	0.5	

a. *Assumes compression to 5 psig.*
b. *Based on 2% of equipment capital cost and 0.5 FTE.*
c. *Based on an H_2S content of 250 ppm and one regeneration cycle of the iron sponge.*
d. *Based on a siloxane content of 25 mg/m^3 of digester gas.*

3.5 Renewable Compressed Natural Gas Station

As defined in TM 2, Alternatives B4 and C4 included an rCNG fueling station and Alternative A3 did not. However, an rCNG fueling station could be added to each of these alternatives because the scrubbed gas would be of the same quality for all three alternatives (Alternative E1 could not include rCNG fueling as the gas is not scrubbed). In the interest of comparing Alternatives A3, B4, and C4 with common assumptions, the rCNG fueling station is included as a separate additional facility in terms of capital and O&M costs in the NPV analysis.

The rCNG station would be installed along the eastern edge of the dewatering building parking area. Three Loop hauling trucks for local sludge transport would be powered by natural gas engines that would utilize the rCNG station. The CNG Loop trucks would replace existing trucks when they are due for replacement. The rCNG compressor, storage, and fuel dispenser have a fairly small footprint, making its installation location flexible. The equipment and dispenser could be installed in a convenient location for filling the Loop trucks. The compressor would be provided in an acoustical enclosure so that noise would not be a large concern. A small-diameter carbon-steel pipeline would route product gas from the PSA to the rCNG compressor. Power and control interconnection would be made out of the dewatering building. The fueling station would likely require a notice of construction application to be submitted to PSCAA because such notices are typically required for any type of fueling station. The location of the rCNG fueling facility is shown in Figure 3-13. Pictures of a CNG compressor and fuel dispenser are shown in Figure 3-14.

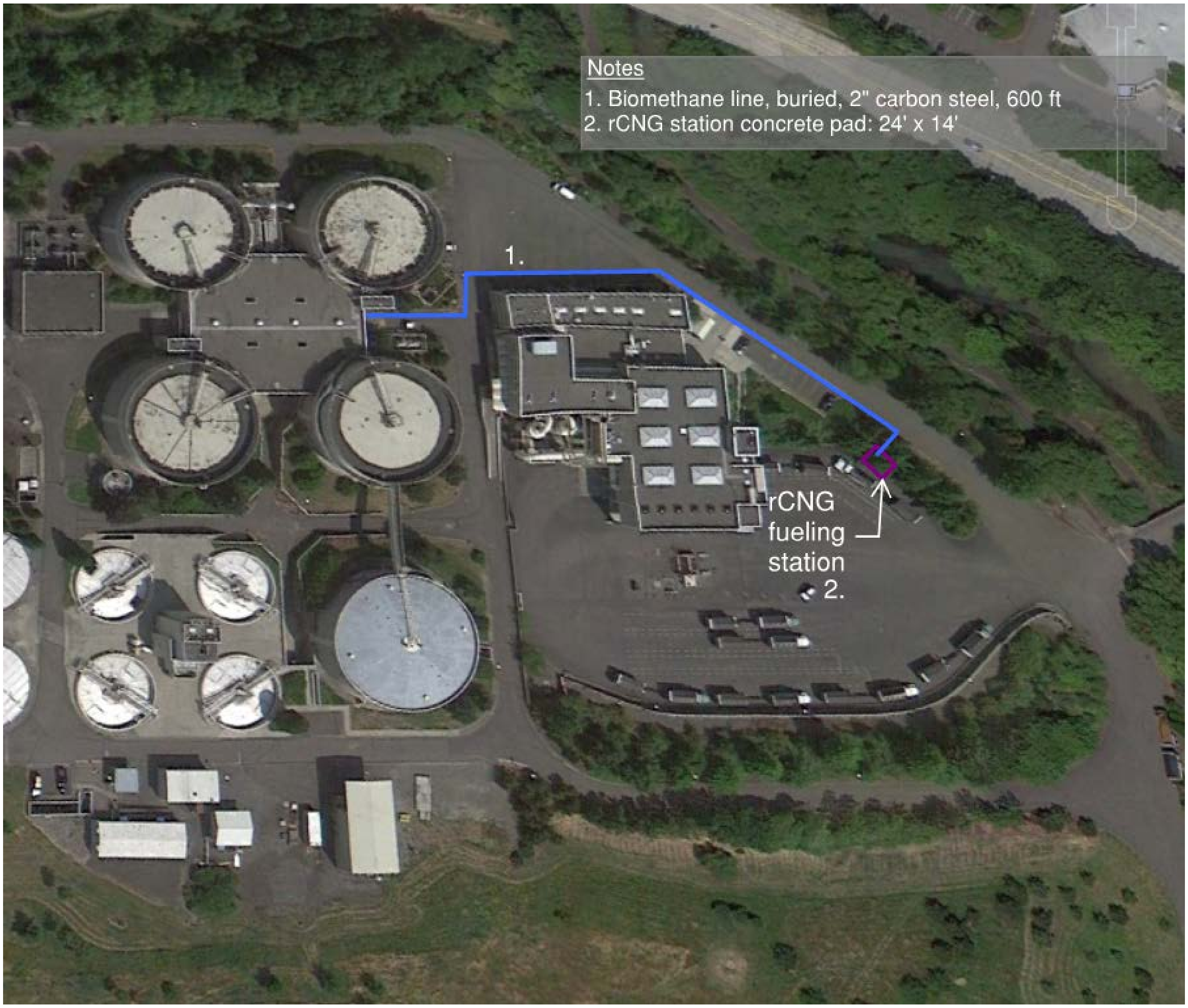

Figure 3-13. Locations of rCNG fueling station

Figure 3-14. CNG compressor and fuel dispenser

The capital cost for the rCNG fueling station, including the additional capital cost differential associated with purchasing three new Loop trucks with a CNG fueling system rather than diesel, is shown in Table 3-15.

Table 3-15. Alternative B4 Capital Cost Summary	
Component	Cost
CNG fueling station [a]	$847,000
Total	$847,000

a. Includes cost differential for CNG fueling system on three new Loop trucks.

Operating costs for the rCNG station were developed in TM 2 and updated in Table 3-16 for year 2018 operation. Based on County feedback during Workshop II, the CNG vehicle fuel operations data were updated to include the value of RINs.

Table 3-16. CNG Vehicle Fuel Operations Data		
Criterion	Value	Notes
Number of CNG trucks	3	Short haul vehicles
Diesel displaced, kWt-h/yr (gal/yr) [a]	424,000 (9,440)	Heating value of diesel displaced
Diesel savings, $/yr [b]	$38,000	From diesel fuel offset
Annual electrical power costs, 2018, $/yr [c]	700	Final compression power
Labor, parts, and maintenance, 2018 $/yr [d]	18,000	
Annual RIN income, 2018 $/yr [e]	$5,000	Income generated by RINs
Estimated FTEs	1/8	

a. Assumes 80 miles round trip at 4 mpg for short-haul trips.

b. At a cost of $4.00 per diesel gallon.

c. Electricity costs of $0.07/kWh, fully loaded, including demand charges.

d. Includes 0.25 FTE and annual maintenance cost at 2% of equipment.

e. Based on County provided data of $0.39/therm. Does not include administrative fees associated with registering RINs.

Section 4: Economic Analysis and Sensitivities

The alternatives described in the previous section are compared using an NPV analysis. Selected assumptions in the NPV analysis are modified to investigate sensitivities of the NPVs to these assumptions.

4.1 Net Present Value

An NPV analysis was completed for the alternatives selected. The analysis includes the major assumptions outlined in Table 4-1, in addition to those set forth in the body and other appendices of the TM.

Table 4-1. NPV Assumptions	
Component	NPV assumption
Construction	2016–18
Operating period	2018–37
Escalation rate	2.5%
Discount rate	5%
Electricity rate	$ 0.07/kWh
Natural gas rate	$ 1.242/therm
Biomethane sale rate to PSE	$ 0.5347/therm

4.1.1 NPV Results

The results of the baseline NPV analysis are shown in Table 4-2. The alternative with the highest capital cost is the new IC engine-generator cogeneration installation, Alternative E1. The alternative with the best NPV is Alternative B4, the new gas scrubbing system and low-Btu boilers, which is about $190,000 better than E1 and about $1.2 million better than C4. At the level of accuracy associated with this level of design, the NPVs for B4 and E1 are essentially equal. The status quo's NPV is about $2.95 million worse than the best alternative. As mentioned in Section 3.1, if screw compressors can be used in place of the reciprocating compressors, the capital cost of alternative A3 and the associated NPV from that shown in Table 4-2.

Note that all of the NPVs are negative, indicating that none of the options are truly profitable for the assumptions made in Table 4-1. However, to simply meet the plant heating requirement with biogas or natural gas boilers and flare the remainder of the digester gas would have negative NPVs of $5 million and $15 million, respectively, when factoring in the cost to operate, maintain, and install new boilers. Therefore, all of the alternatives considered have more favorable NPVs than minimally meeting plant operating requirements.

Table 4-2. Digester Gas Utilization Alternatives Economic Analysis, $2013

Alt	Description	Capital cost	Annual O&M costs, 2018	Annual savings/ revenues, 2018	NPV
A3	Status quo	$10,130,000	$810,000	$990,000	($4,590,000)
B4	Low-Btu boilers, new gas scrubbing	$11,120,000	$550,000	$970,000	($1,650,000)
C4	New extractors, new gas scrubbing	$12,210,000	$840,000	$1,250,000	($2,670,000)
E1	Low-Btu IC engines, gas conditioning	$18,540,000	$820,000	$1,610,000	($1,840,000)

4.1.2 Value-Added End Use Options and NPV Results

A number of value-added end use options are analyzed in separate NPV analyses in this section. These options represent possible end-use opportunities to the County that are not included in the baseline analysis. The options include the possibility to sell scrubbed gas to a third party at a higher rate than to PSE, the possibility to generate and sell RECs, and the possibility to generate and sell RINs.

Identification of a third party that is willing to pay more than PSE for the biomethane was not completed as part of this study, but several potential end users were identified in the Market Analysis for Sale of Biogas/Sale of Biomethane (Task Order 3) in 2011. Discussions with these parties could be opened to identify the viability of wheeling the County's biomethane through PSE's natural gas grid to an interested third party. As identified in TM 2, it is assumed that a third party would pay a net premium of 10 percent over the value received from the sale to PSE.

The County would have the ability to generate and sell RECs from Alternative E1, the IC engine-generator cogeneration alternative. The electricity produced would be considered to be from a renewable energy source. The County identified a potential REC value of $0.005/kWh, which is applied to all electricity produced by the IC engine-generators.

There are two potential ways for the County to generate and sell RINs. One way is to install an rCNG fueling station for CNG Loop hauling trucks, as described in section 3.5. This would result in a small amount of scrubbed gas being used for diesel offset and a small number of RINs generated. The other way would be to contractually wheel the scrubbed gas to a CNG vehicle fleet offsite through the PSE pipeline. The second option would potentially produce RINs for the entire quantity of scrubbed gas put into the PSE pipeline and is currently being pursued by the County. The EPA's Web site for questions and answers on changes to renewable fuel standard program notes that "wheeling" the biomethane is valid because, "Tracking of individual molecules is not required"
(source: http://www.epa.gov/otaq/fuels/renewablefuels/compliancehelp/rfs2-aq.htm#13). Each of these potential end-use options is investigated separately. In addition, this value-added option is assessed for the

current life of the renewable fuel standard program through 2022 and also for the assumption that the program will be extended through the end of the analysis in 2036. The County identified a potential RIN value of $0.39/therm.

The value-added end use assumptions for the NPV analyses are shown in Table 4-3.

Table 4-3. Value Added NPV Assumptions

Component	NPV assumption
Value added: diesel rate	$ 4.00/gal
Value added: biomethane sale to third party	$0.588/therm
Value added: REC value for electricity	$0.005/kWh
Value added: RIN value for diesel offset	$0.39/therm

The NPV analysis results for each of the value-added end use options are shown in Table 4-4. Conclusions that can be drawn from these analyses include the following:

- Sale of scrubbed gas to a third party at a 10 percent premium results in Alternative C4 having the best NPV, but by only about $70,000 over Alternative B4. These two alternatives are more than $1.7 million better than Alternative E1 and about $3 million better than the status quo. The higher value of scrubbed gas improves the NPV for Alternative C4 the most because it produces the largest net quantity of scrubbed gas for sale. Alternative E1 is unaffected as no sale of scrubbed gas is included in this alternative.
- Receiving even a half-cent value for RECs improves Alternative E1 by about $1.75 million, making it the best alternative by about $1.55 million over Alternative B4. The three other alternatives are unaffected.
- The installation of an rCNG fueling station and fueling two to three Loop hauling trucks per day would result in the NPVs for the three gas scrubbing alternatives decreasing by about $300,000. The CNG vehicles are too few to recoup the capital investment for the rCNG fueling station.
- If the County receives a RIN value of $0.39/therm for all of the scrubbed gas injected into the PSE pipeline through 2022, the NPV of Alternative B4 would be the best by about $170,000 over Alternative C4. All three gas scrubbing alternatives would have better NPVs than Alternative E1 and Alternatives B4 and C4 would have a positive NPV.
- If the RIN value is extended through 2036, the gas scrubbing alternatives would have very large positive NPVs. The NPV for Alternative C4 is more than $2.0 million better than B4 and about $13.3 million better than E1.

Table 4-4. Net Present Values for Value-Added Options, $2013

Alt	Description	Third party scrubbed gas sale	RECs value	rCNG Fueling Station [a]	RINs value through 2022 for gas into pipeline	RINs value through 2036 for gas into pipeline
A3	Status quo	($3,020,000)	($4,590,000)	($4,910,000)	($1,450,000)	$6,820,000
B4	Low-Btu boilers, new gas scrubbing	($120,000)	($1,650,000)	($1,970,000)	$1,410,000	$9,460,000
C4	New extractors, new gas scrubbing	($740,000)	($2,670,000)	($2,990,000)	$1,240,000	$11,460,000
E1	Low-Btu IC engines, gas conditioning	($1,840,000)	($80,000)	($1,840,000)	($1,840,000)	($1,840,000)

a. Assumes RIN value extended through 2036.

4.2 Sensitivities Analysis

This section describes the results of the NPV analysis when individual economic assumptions are changed within a reasonable range. The NPV of the previous sections are subject to several assumptions of economic parameters, which are difficult to predict. Alternatives that have good NPVs over a range of economic assumptions can provide additional stability during volatile market conditions. The range of economic assumptions compared is summarized in Table 4-5. The following sections present sensitivity analyses where only one variable is changed at a time.

Table 4-5. Sensitivity Analysis Range

Description	Low	High
Escalation rate	1.0 %	5.0 %
Discount rate	3.0 %	7.5 %
Electricity rate and REC escalation only	1.0 %	5.0 %
Natural gas rate escalation only	1.0 %	5.0 %
Diesel rate escalation only	1.0 %	5.0 %
Biomethane sale price and RIN escalation only	1.0 %	5.0 %
REC value for electricity	$0.0025/kWh	$0.015/kWh
RIN value for diesel offset	$0.25/therm	$1.50/therm
FOG gas production	0 scfd	350,000 scfd
Carbon credit	$10 / ton	$20 / ton

4.2.1 Escalation Rate Sensitivity

In general a higher escalation rate improves the NPVs of all options because the net revenues or savings the alternatives generate improve. Alternative E1 becomes the best NPV at a high escalation rate of 5 percent because it is the alternative with the highest annual savings (or revenues), but remains second at the lower escalation rate. Alternative B4 is either the best or second-best alternative over the range (Table 4-6).

Table 4-6. Escalation Rate Sensitivity, $2013

Alt	Description	1% escalation, NPV	5% escalation, NPV
A3	Status quo	($4,750,000)	($3,980,000)
B4	Low-Btu boilers, new gas scrubbing	($2,460,000)	$450,000
C4	New extractors, new gas scrubbing	($3,400,000)	($750,000)
E1	Low-Btu IC engines, gas conditioning	($3,330,000)	$1,950,000

4.2.2 Discount Rate Sensitivity

A lower discount rate improves the NPVs for all alternatives and a higher discount rate decreases the NPV of all alternatives. Similar to the escalation rate sensitivity, the discount rate has the most impact on alternatives with higher annual O&M costs and revenues. Thus, Alternative E1 is again impacted the most relative to the other alternatives with this alternative scoring either the best or second-worst option at high and low discount rates. The comparative ranking of the remaining alternatives remains the same (Table 4-7).

Table 4-7. Discount Rate Sensitivity, $2013			
Alt	Description	3% discount, NPV	7.5% discount, NPV
A3	Status quo	($4,140,000)	($4,800,000)
B4	Low-Btu boilers, new gas scrubbing	($70,000)	($2,820,000)
C4	New extractors, new gas scrubbing	($1,230,000)	($3,720,000)
E1	Low-Btu IC engines, gas conditioning	$1,020,000	($4,000,000)

4.2.3 Electricity Rate Escalation Sensitivity

Both the relative and absolute values of the NPVs of the alternatives are significantly affected by the plant's electricity rate. If the electricity rate escalates by only 1 percent, then Alternative C4 (heat extractors) will have nearly an equal NPV to Alternative B4 (low-Btu boilers) and Alternative E1 (IC engine-generators) will have an NPV over $5.3 million worse than these two alternatives (Table 4-8). However, if the electricity rate escalates at 5 percent, Alternative E1 will result in significant annual savings and a positive NPV. The NPV for Alternative E1 is $11.5 million better than the next-best alternative.

Table 4-8. Electricity Rate Escalation Sensitivity, $2013			
Alt	Description	1% electricity rate escalation, NPV	5% electricity rate escalation, NPV
A3	Status quo	($3,360,000)	($7,350,000)
B4	Low-Btu boilers, new gas scrubbing	($930,000)	($3,260,000)
C4	New extractors, new gas scrubbing	($960,000)	($6,550,000)
E1	Low-Btu IC engines, gas conditioning	($6,290,000)	$8,240,000

4.2.4 Natural Gas Rate Escalation Sensitivity

The escalation rate of natural gas between 1 percent and 5 percent does not have a very significant impact on the difference in the NPVs (Table 4-9). Natural gas is used as a backup to the boiler firing scrubbed gas or as a backup to heat produced from cogeneration. Only Alternative E1 has significant NPV sensitivity to natural gas rates having the best NPV with a 1 percent escalation rate, but the third-best NPV at 5 percent natural gas escalation.

Table 4-9. Natural Gas Rate Sensitivity, $2013			
Alt	Description	1% natural gas escalation, NPV	5% natural gas escalation, NPV
A3	Status quo	($4,580,000)	($4,610,000)
B4	Low-Btu boilers, new gas scrubbing	($1,650,000)	($1,650,000)
C4	New extractors, new gas scrubbing	($2,670,000)	($2,670,000)
E1	Low-Btu IC engines, gas conditioning	($1,580,000)	($2,420,000)

4.2.5 Diesel Fuel Escalation Sensitivity

The rate of diesel fuel escalation varies the NPVs of value-added end use options for which biomethane is being used in rCNG vehicles (Alternatives A3, B4 and C4), but the effect is minor (Table 4-10). The alternative with the best NPV changes between B4 and E1 if the escalation rate were to change from 1 percent to 5 percent. The overall impact of the diesel fuel escalation rate is minor because of limited diesel fuel use by the three Loop trucks being converted to rCNG. However, if more biomethane was used in additional Loop trucks or other rCNG vehicles, it could significantly improve the NPV of Alternatives B4 and C4.

Table 4-10. Diesel Fuel Escalation Sensitivity, $2013

Alt	Description	1% diesel fuel escalation, NPV	5% diesel fuel escalation, NPV
A3	Status quo	($5,100,000)	($4,740,000)
B4	Low-Btu boilers, new gas scrubbing	($2,160,000)	($1,800,000)
C4	New extractors, new gas scrubbing	($3,180,000)	($2,830,000)
E1	Low-Btu IC engines, gas conditioning	($1,840,000)	($1,840,000)

If the entire Loop truck fleet were converted to rCNG, the diesel fuel escalation rate could potentially have a much more significant impact. For example, Table 4-11 shows the NPV for the entire Loop truck fleet converted to rCNG while displacing 100 percent of the diesel fuel used by the trucks. An additional $1.5 million capital cost is included for installing a CNG fueling station on the east side of the state, and an additional $70,000 for each of the 33 Loop trucks to account for the CNG upgrade and an increase in engine size to travel over the mountain passes. The NPV assumes a vehicle phase-in over 5 years starting in 2018 with a RIN value of $0.39/therm through 2022. The impact on the gas scrubbing NPVs of a high diesel escalation rate compared to a low rate is about $10 million.

Table 4-11. Diesel Value Sensitivity with Entire rCNG Loop Truck Fleet, $2013

Alt	Description	1% diesel fuel escalation, NPV	5% diesel fuel escalation, NPV
A3	Status quo	$9,070,000 [a]	$19,420,000 [a]
B4	Low-Btu boilers, new gas scrubbing	$11,880,000 [a]	$22,230,000 [a]
C4	New extractors, new gas scrubbing	$11,720,000 [a]	$22,070,000 [a]
E1	Low-Btu IC engines, gas conditioning	($1,840,000)	($1,840,000) [a]

a. *Includes capital of $3,810,000 for additional fueling station and Loop truck conversions. Fuel usage is assumed to be phased in over 5 years from 2018 to 2022. RIN value is assumed at $0.39/therm through 2022.*

4.2.6 Biomethane Sale Price Escalation Sensitivity

The rate of escalation of the value of the biomethane and associated RINs has a substantial impact on the NPVs, second only to electricity rate. If the revenues associated with scrubbed gas sale escalate at 5 percent, Alternative C4 would have the highest positive NPV at over $5.3 million (Table 4-12) because it exports the most biomethane of all the alternatives. If biomethane revenues do not escalate significantly, then the IC engine-generator alternative has an NPV more than $2.6 million higher than the other alternatives.

Table 4-12. Biomethane Sale Rate Escalation Sensitivity, $2013			
Alt	Description	1% biomethane sale rate escalation, NPV	5% biomethane sale rate escalation, NPV
A3	Status quo	($7,470,000)	$1,930,000
B4	Low-Btu boilers, new gas scrubbing	($4,450,000)	$4,710,000
C4	New extractors, new gas scrubbing	($6,240,000)	$5,390,000
E1	Low-Btu IC engines, gas conditioning	($1,840,000)	($1,840,000)

4.2.7 Renewable Energy Certificate Value Sensitivity

The REC value could have a significant impact on the IC engine-generator alternative if REC values are high. At a REC value of $0.0025 per kilowatt-hour (kWh), Alternative E1 would generate $56,000 per year in revenue, resulting in the best NPV, albeit still a negative one (Table 4-13). At a REC value of $0.015/kWh, the revenue for the cogeneration alternative would generate $340,000 per year, resulting in a positive NPV of $3.4 million. The remaining alternatives would be unaffected by REC value.

Table 4-13. REC Value Sensitivity, $2013			
Alt	Description	REC value of $0.0025/kWh, NPV	REC value of $0.015/kWh, NPV
A3	Status quo	($4,590,000)	($4,590,000)
B4	Low-Btu boilers, new gas scrubbing	($1,650,000)	($1,650,000)
C4	New extractors, new gas scrubbing	($2,670,000)	($2,670,000)
E1	Low-Btu IC engines, gas conditioning	($960,000)	$3,440,000

4.2.8 Renewable Identification Number Value Sensitivity

The RIN value has a significant impact on the gas scrubbing alternatives. At a low RIN value of $0.25/therm valid only through 2022, Alternative B4 has a slightly better NPV than C4 and it is positive. Alternative C4 would have the second-best NPV, by about $1.6 million better than E1. At a high RIN value of $1.50/therm, all of the gas scrubbing alternative NPVs would be positive with C4 being the best by about $2.2 million. The results of the sensitivity analysis are shown in Table 4-14.

Table 4-14. RIN Value through 2022 Sensitivity, $2013			
Alt	Description	RIN value of $0.25/ therm, NPV	RIN value of $1.50/ therm, NPV
A3	Status quo	($2,580,000)	$7,480,000
B4	Low-Btu boilers, new gas scrubbing	$310,000	$10,110,000
C4	New extractors, new gas scrubbing	($163,000)	$12,390,000
E1	Low-Btu IC engines, gas conditioning	($1,840,000)	($1,840,000)

With the RINs extended through 2036, the gas scrubbing alternatives are more sensitive to the RIN value as shown in Table 4-15. Even at a low RIN value of $0.25/therm, all of the gas scrubbing alternatives are better than the cogeneration alternative. Alternative C4 would have the best NPV by about $0.9 million. At a high RIN value, Alternative C4 would be more than $10.5 million better than B4 and all of the gas scrubbing alternatives would have high NPVs.

Table 4-15. RIN Value through 2036 Sensitivity, $2013			
Alt	Description	RIN value of $0.25/ therm, NPV	RIN value of $1.50/ therm, NPV
A3	Status quo	$2,720,000	$39,280,000
B4	Low-Btu boilers, new gas scrubbing	$5,480,000	$41,080,000
C4	New extractors, new gas scrubbing	$6,390,000	$51,700,000
E1	Low-Btu IC engines, gas conditioning	($1,840,000)	($1,840,000)

To better understand at what RIN value the NPV for Alternative C4 becomes better than that for B4, further analyses were completed. The results of the analyses are shown in Figures 4-1 and 4-2. These two figures show that Alternative C4 has a better NPV than B4 with a RIN value of $0.50/therm through 2022 only and a RIN value of $0.15/therm if the RINs are extended through 2036.

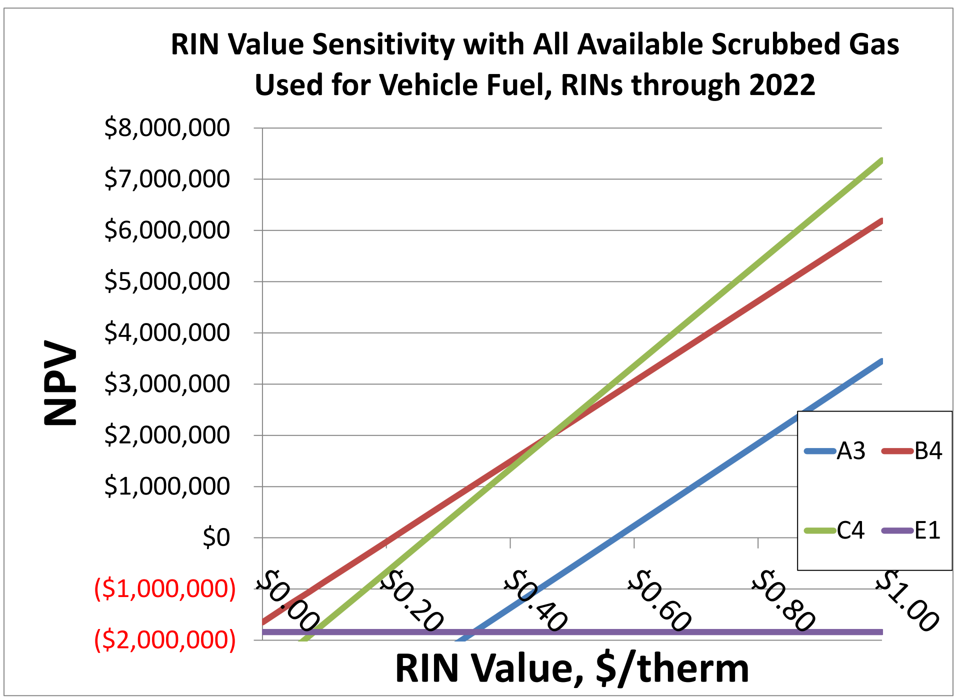

Figure 4-1. RIN value sensitivity with all available scrubbed gas used for vehicle fuel, RINs through 2022

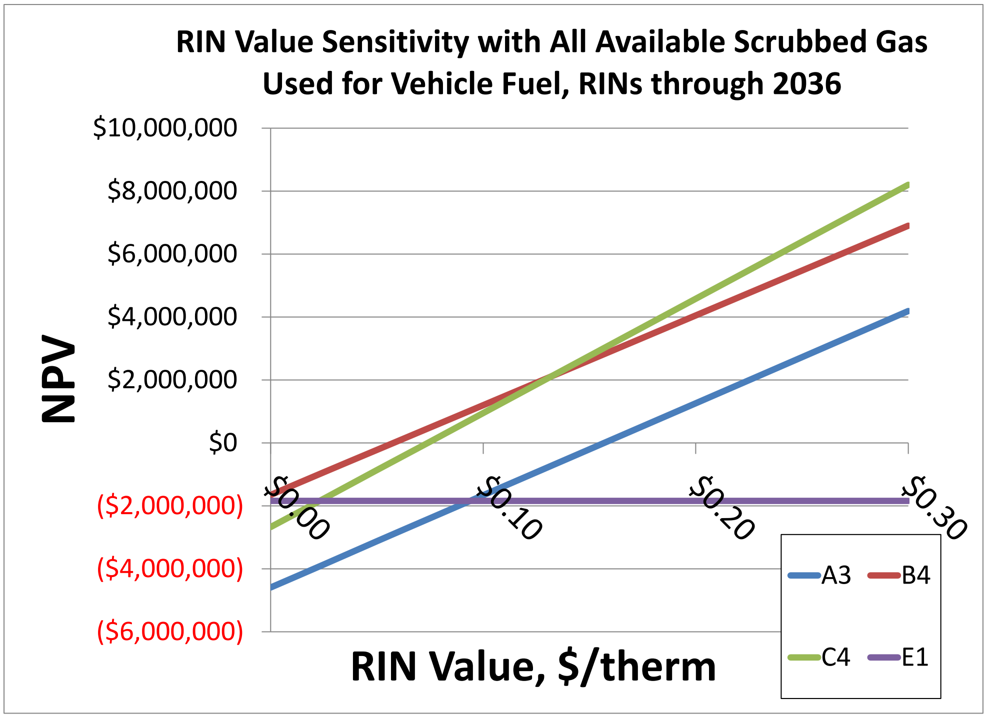

Figure 4-2. RIN value sensitivity with all available scrubbed gas used for vehicle fuel, RINs through 2036

4.2.9 Fats, Oils, and Grease Gas Production Sensitivity

The digester gas production increase from FOG addition is estimated at the high end to be 350,000 scfd, resulting in a total gas flow of 2.0 MM scfd. The South Plant Grease Co-Digestion Study (Task Order 2 in 2011) found that the digester organic loading limit resulted in a maximum achievable digester gas production of 2.0 MM scfd. This represents an increase in gas production by about 21 percent from the average gas flow in 2036. The heating equipment capacities and heating requirements are assumed to increase by only 10 percent to accommodate the additional heating load requirements for FOG addition to the digesters. The actual heating requirements would vary based on the percent solids and temperature of the FOG.

In order to accommodate the increase in FOG and resulting digester gas flow, the capital costs for the gas utilization and heating equipment was scaled. The approach to scaling the capital cost was to use the power rule. In this approach the capital costs affected by capacity increases were scaled by the ratio of capacities taken to an exponential power less than 1. This approach accounts for economies of scale as equipment and systems increase in size. The following analysis and assumptions were used:

- A budgetary quote was obtained for a new gas scrubbing system with a capacity of 2.0 MM scfd. This quote showed that the cost scales at a power of 0.82. For the alternatives with the new gas scrubbing system, the capital cost for this system was scaled at 0.82.
- An additional IC engine-generator and larger gas treatment was found to add about 29 percent additional cost for the equipment with an increase in capacity of 33 percent. This correlates to scaling the capital cost at a power of 0.88.
- The biogas compressors, pump/turbines, boilers, and heat extractors were assumed to increase at a cost scale of 0.75.

The rest of the capital costs, including demolition, buildings, and electrical and instrumentation and controls (I&C) subcontracts, were assumed to remain unchanged.

O&M costs and revenues were adjusted to reflect the increased digester gas production and heating demands. The resulting capital costs and NPVs for the alternatives with FOG addition are shown in Table 4-16. While all of the NPVs improved with FOG addition to the digesters, the difference between the alternatives changed only slightly. The IC engine-generator Alternative E1 improved the most and has the best positive NPV by about $300,000. The status quo alternative did not improve as much as the other alternatives. Note that because this study is focused on the digester gas and heating system only, no FOG receiving facility capital costs, O&M costs, or tipping fees were included in this analysis.

Table 4-16. Fats, Oils, and Grease Economic Analysis, $2013

Alt	Description	Capital cost	Annual O&M costs, 2018	Annual savings/ revenues, 2018	NPV
A3	Status quo	$11,280,000	$990,000	$1,330,000	($3,370,000)
B4	Low-Btu boilers, new gas scrubbing	$12,470,000	$650,000	$1,290,000	$540,000
C4	New extractors, new gas scrubbing	$13,640,000	$970,000	$1,600,000	($680,000)
E1	Low-Btu IC engines, gas conditioning	$20,840,000	$960,000	$2,070,000	$830,000

4.2.10 Carbon Credit Sensitivity

To this point in this study, no monetary value has been assigned to GHG reductions created by the alternatives. While monetization of carbon credits may not be commonplace in Washington State, it is a worthwhile investigation to review how the monetization of GHG reductions (or carbon credits) would impact the NPVs of the alternatives. The limited GHG emissions analysis completed in TM 2 is used to quantify carbon credit value in a sensitivity analysis.

If GHG emissions reductions are assigned a monetary value, the NPV of all alternatives improve, but the NPV for alternative C4 would improve the most because it has the largest reduction in GHG emissions. Table 4-17 shows that a carbon credit value of $10/metric ton makes the NPV for Alternative B4 about $1.1 million better than that for Alternative E1. At a carbon credit value of $20/metric ton, alternative C4 has nearly an equal NPV to Alternative B4. If Loop trucks were converted to run on biomethane, the NPVs for Alternatives A3, B4, and C4 would improve further.

Table 4-17. Carbon Credit Sensitivity, $2013

Alt	Description	Carbon credit of $10/metric ton CO2e, NPV	Carbon credit of $20/metric ton CO2e, NPV
A3	Status quo	($3,990,000)	($3,390,000)
B4	Low-Btu boilers, new gas scrubbing	($300,000)	$1,050,000
C4	New extractors, new gas scrubbing	($930,000)	$810,000
E1	Low-Btu IC engines, gas conditioning	($1,450,000)	($1,060,000)

Section 5: Evaluation of Alternatives

This section compares the selected four alternatives with the County's weighted objectives for the three categories: financial, environment, and operations.

5.1 Financial Objectives

The financial objectives were based on the revised NPV analysis and sensitivity analyses. These results were used for scoring the alternatives against each other for each of the financial objectives. The approach to the scoring was developed in TM 2 and applied here. The results of the scoring for each objective and the total score with the weights applied from the objectives weighting workshop and subsequent comments from the County are shown in Table 5-1. The NPV objective has a weighting multiplier of zero, but the respective scores were still included if the County later desires to assign a value to this objective. Because Alternative A3 has a maximum score of 5 for minimizing capital costs, the use of screw compressors, which would reduce the capital cost by about $1.5 million, would not influence the score here. Similarly, the demolition costs for the existing fuel cell installation are not large enough to impact the capital cost score for Alternative E1.

Table 5-1. Financial Objectives Comparison [a]

Alt	Description	a. Minimize capital costs	b. Minimize operational and maintenance costs	c. Maximize revenues	Maximize grants, credits and incentives	Total score [b]
-	Weighting multiplier	3.3	2.0	2.0	0.7	-
A3	Status quo	5	2	1	3	25
B4	Low-Btu boilers, new gas scrubbing	4	4	1	3	25
C4	New extractors, new gas scrubbing	4	2	3	5	27
E1	Low-Btu IC engines, gas conditioning	1	2	5	1	18

a. *Refer to Table 2-1 for a description of the objectives scoring scale.*

b. *The total score is calculated by summing the products of the objectives scores and their weighting multipliers; refer to Table 2-4.*

5.2 Environmental Objectives

The approach to scoring the environmental objectives was developed in TM 2. The environmental impacts of the alternatives did not change from the analysis in TM 2 for the most part and therefore the scores have not changed. The two exceptions are the new objective to increase consumption of renewable energy and the consideration that all gas scrubbing alternatives could produce vehicle fuel (although this is not part of the baseline assumption). For the new renewable energy consumption objective, the alternatives were scored based on how much renewable energy is consumed by the plant in the form of renewable electricity, biogas and recovered effluent heat. The weighting of the objectives was also changed in the objectives weighting workshop. The new weighting and total weighted scores are shown in Table 5-2.

Table 5-2. Environmental Objectives Comparison [a]

Alt	Description	Reduce use of and expenditures for energy	Reduce greenhouse gas emissions	Increase consumption of renewable energy	Increase production of renewable energy	Invest in alternative fuel transit and fleet vehicles	Total score [b]
-	**Weighting multiplier**	1.6	1.6	0.6	1.6	0.6	-
A3	Status quo	2	3	2	4	3	17
B4	Low-Btu boilers, new gas scrubbing	4	4	2	4	3	22
C4	New extractors, new gas scrubbing	1	5	2	5	3	21
E1	Low-Btu IC engines, gas conditioning	5	3	4	2	1	19

a. Refer to Table 2-2 for a description of the objectives scoring scale.

b. The total score is calculated by summing the products of the objectives scores and their weighting multipliers; refer to Table 2-4.

5.3 Operational Objectives

Similar to the environmental objectives, the scores for the operational objectives are the same as those developed in TM 2 with the exception of those noted below:

- The redundancy and reliability score was changed to be a combined score based on the separate objective scores for reliability and redundancy in TM 2.
- The air quality and permitting requirement objective for Alternative A3 was decreased to recognize that methane emissions that are generated by the process may be regulated in the future.
- The technical risk scores for Alternatives B4 and C4 were increased because the rCNG fueling station is not part of the baseline alternative.

The operational objective scores are shown in Table 5-3.

Table 5-3. Operational Objectives Comparison [a]								
Alt	Description	System redundancy and reliability	System flexibility	Minimize WTD labor requirements	Minimize outside contracting requirements	Minimize technical risk	Minimize air quality treatment requirements	Total score [b]
-	Weighting multiplier	1.3	0.6	1.6	0.3	1.6	0.6	-
A3	Status quo	4	2	3	5	5	3	23
B4	Low-Btu boilers, new gas scrubbing	3	3	3	3	4	3	20
C4	New extractors, new gas scrubbing	5	2	3	2	3	4	20
E1	Low-Btu IC engines, gas conditioning	2	5	3	4	4	1	19

a. *Refer to Table 2-3 for a description of the objectives scoring scale.*

b. *The total score is calculated by summing the products of the objectives scores and their weighting multipliers; refer to Table 2-4.*

5.4 Overall Comparison Matrix

The individual objective scores are summarized and totaled in Table 5-4. This comparison shows that the best alternative with respect to the County's objectives is Alternative C4, which had a score of 68. This alternative had the highest financial objectives score and average environmental and operational scores. Alternative B4 was a very close second and also had the best NPV. Alternative A3 was third and scored only 3 points less than Alternative C4. Alternative E1 was significantly lower, at a score of 56. Alternative E1 had the second-best NPV because of the significant energy savings associated with this alternative, but had the lowest financial objective score because the capital costs objective carried a higher weight than that of the savings O&M and savings/revenues objective.

Table 5-4. Total Objective Comparison					
Alt	Description	Financial objective score	Environmental objective score	Operational objective score	Total score
A3	Status quo	25	17	23	65
B4	Low-Btu boilers, new gas scrubbing	25	22	20	67
C4	New extractors, new gas scrubbing	27	21	20	68
E1	Low-Btu IC engines, gas conditioning	18	19	19	56

Section 6: Summary and Recommendations

This TM is the third in a series to assess the existing South Plant digester gas utilization program and to select an alternative for capital improvement projects. TM 3 serves the following purposes:

- describes the layouts, interconnections, capacities, and operations associated with each alternative
- analyzes sensitivities of the alternatives to NPV assumptions and value-added energy uses
- provides a refined analysis to assess the performance of each alternative with respect to the County's financial, environmental, and operational objectives, to facilitate a decision on an alternative

Three alternatives were analyzed along with the status quo alternative. To provide the greatest variety of potential alternatives for the County to pursue, the three alternatives chosen encompassed as many of the sub-systems evaluated in TM 2 as possible. This allows the County to mix and match sub-systems and build an alternative that was not considered herein, if desired. The following three alternatives and status quo alternative were investigated in the evaluation for TM 3:

- A3: status quo
- B4: low-Btu boilers and new gas scrubbing system with sale of scrubbed gas
- C4: new heat extractors and new gas scrubbing system with sale of scrubbed gas
- E1: low-Btu IC engines with a biogas conditioning skid

Each of the alternatives was analyzed with value-added end use options. The NPVs for the gas scrubbing alternatives were greatly improved with the option of wheeling biomethane through the PSE pipeline to a CNG vehicle fleet and obtaining RINs. Wheeling gas to a third party for a 10 percent premium or obtaining RECs for renewable electricity produced had positive but fairly minor impacts on the gas scrubbing alternatives and new IC engine-generator alternative, respectively.

The sensitivities of the NPVs for each alternative were evaluated. The comparative NPVs were not sensitive to the rate of escalation of natural gas or diesel prices for the ranges assumed. The comparative NPVs of the alternatives were most strongly influenced by the following:

- escalation and discount rates
- electricity escalation rate
- biomethane value escalation rate
- REC value
- RIN value

Alternative E1 had the best NPV for the scenarios where the difference between escalation and discount rates were low, and where electricity escalation rate and RECs value were high. The NPV for Alternative C4 benefitted the most where biomethane sale price escalated quickly or where RIN values were generated for all of the gas at a high value, but did not fare as well when electricity rates escalated quickly because of the large use of electricity by the heat extractors. Alternative B4 was less sensitive to these assumptions than Alternative C4.

Alternative C4 received the highest overall score of 68, while Alternatives C4 and A3 scored second and third with scores of 67 and 65, respectively. Any of these three top-scoring alternatives would be justifiable alternatives that will similarly meet the County's objectives and future needs. In addition, producing and selling scrubbed gas to a third party and using part for rCNG are not mutually exclusive—both options can be pursued for Alternatives A3, B4, and C4. The low-Btu IC engine-generator cogeneration system had the lowest overall score of 56. While this alternative meets many of the objectives set forth by the County and has the second-best NPV behind Alternative B4, the other three alternatives are more suitable overall to the County's objectives.

During Workshop III, the consensus among the County staff and Brown and Caldwell was to pursue Alternatives B4 and C4 during management review and pre-design of the South Plant digester gas utilization system upgrade.

References

Micro-CHP Accelerator: Final Report, “Condensing boilers,” Carbon Trust, 2011, p. 13.