Design Review Committee Briefing #30

Subject: Biogas Resource Recovery Business Case Evaluation

Date: October 11, 2019

The Issue

The Design Review Committee (DRC) requested an analysis of potential biogas (gas produced from the anaerobic digestion process) resource recovery options for beneficial reuse. These options are being evaluated as they have the potential opportunity to provide a revenue source. In some cases, this cost offset can be greater than the capital and operating costs, yielding a positive return on investment.

Background and Analysis

The alternatives considered in this biogas resource recovery evaluation are described in the following list. These alternatives beneficially reuse digester gas produced by the anaerobic digesters at the treatment plant. Additional details and accompanying graphics can be found on each technology in Design Review Committee Briefing #26.

- **Alternative 1 – Cogeneration with internal combustion engine:** This alternative involves adding a new 1,100-kilowatt internal combustion cogeneration engine and associated supporting ancillary equipment and biogas conditioning equipment. The engine is fueled with conditioned biogas to create electricity and heat.
- **Alternative 2 – Biogas upgrade to renewable natural gas quality (RNG) for injection into pipeline:** This alternative involves adding gas conditioning and upgrading equipment and the associated pipeline connection requirements to inject upgraded biogas into the pipeline at natural gas quality. This alternative includes the estimated associated utility connection fees and a new natural gas pipeline. The City of Nampa (City) would earn revenue from the sale of the gas to the pipeline and by partnering with an organization that purchases renewable identification numbers (RINs) as part of the federal Renewable Fuel Standard Program.
- **Alternative 3 – Biogas upgrade to compressed natural gas (CNG) for use as vehicle fuel:** This alternative is similar to Alternative 2 but would provide CNG for vehicle fueling. This alternative would require the gas to be further compressed, stored on-site, and hauled regularly (typically daily) to a local CNG vehicle fueling center. It is assumed that the City would pay costs to upgrade a local CNG station in order to accept CNG from the City and enable the sale of the CNG. Similar to Alternative 2, the City would partner with an organization to sell RINs as part of the Renewable Fuel Standard Program.

Brown and Caldwell (BC) estimated capital costs, operating and maintenance (O&M) costs, and repair and replacement (R&R) costs for each of the alternatives. BC developed capital costs from vendor quotes and cost estimates for the required investments for each alternative. The O&M costs encompass the expected costs associated with labor, power, equipment rebuilds, media replacement and other consumables, and other items associated with each alternative. R&R costs are a direct reflection of the expected useful life of the capital improvements for each alternative and are largely tied to capital cost estimates.

Benefit costs were calculated for each alternative based on the potential revenue for that technology. Cogeneration provides revenue in the form of offset power consumption, reducing the City's electrical utility bills. Because power is relatively inexpensive in the region, cogeneration is not a favorable financial alternative. Alternatives 2 and 3 both earn revenue from selling the product gas (RNG for pipeline injection and CNG as vehicle fuel) and from selling RINs. Cogeneration cannot utilize RINs, reducing the benefits of that alternative.

Most of the risks for the alternatives are associated with selling the product and are handled with sensitivity analyses. The most critical risk for Alternatives 2 and 3 is RIN prices, discussed in more detail in the "Potential Consequences" section of this briefing.

Table 1 presents the results of the net present value (NPV) analysis consisting of capital outlay from 2021 through 2025 and equipment operation from 2026 through 2046. The results of the analysis indicate that Alternative 2 is the preferred alternative with a positive NPV. This is a result of the revenue from the sale of both RNG and RINs. Alternative 3, which is similar to Alternative 2, also shows a positive NPV. Conversely, Alternative 1 shows a negative NPV as the benefits of produced electricity do not outweigh the capital and operating costs.

Table 1. Biogas Resource Recovery BCE Summary

Alternative	Description	Capital	Benefits	O&M	Risks	R&R	NPV[2]
1	Cogeneration	$8,049,000	$10,758,000	$8,295,000	$16,000	$344,000	($5,945,000)
2	RNG to Pipeline	$8,477,000	$37,456,000	$10,046,000	$286,000	$773,000	$17,876,000
3	CNG for Vehicle Fuel	$10,850,000	$37,018,000	$12,212,000	$24,000	$1,035,000	$12,900,000

[1] Cells highlighted in green indicate the lowest cost alternative.

[2] Total costs are shown in 2019 dollars, represent the period 2021 through 2046, and are rounded to the nearest $1,000.

NPV = net present value.

Potential Consequences

The DRC should be aware of the potential consequences of each alternative that may not be readily apparent from the BCE results. The primary consequences from this evaluation are described in further detail below:

- **Value of RINs:** The results of the evaluation for Alternatives 2 and 3 are highly dependent on the value of RINs. Figure 1 and Figure 2 illustrate the effects of RIN value on NPV and time to pay back for Alternatives 2 and 3, while keeping all other assumptions the same. NPV is displayed by the upward sloping blue line and the time to pay back is shown by the red line. RIN values fluctuate from week to week and are susceptible to demand and regulatory intervention. High demand creates a higher RIN value improving the NPV, while lower demand reduces RIN values reducing the NPV. Since early-2018, RIN values have been in a steady decline. Before 2018, RIN values increased steadily. It is not possible to predict RIN values for the duration of this project, so assumptions based on the current available data are used to determine a reasonable RIN value estimate for the analysis. This analysis assumes D3 RIN values, which are a high value category of RINs that includes renewable natural gas fuels for both RNG and CNG. Figure 4 shows RIN values since the inception of the Renewable Fuel Standard Program.

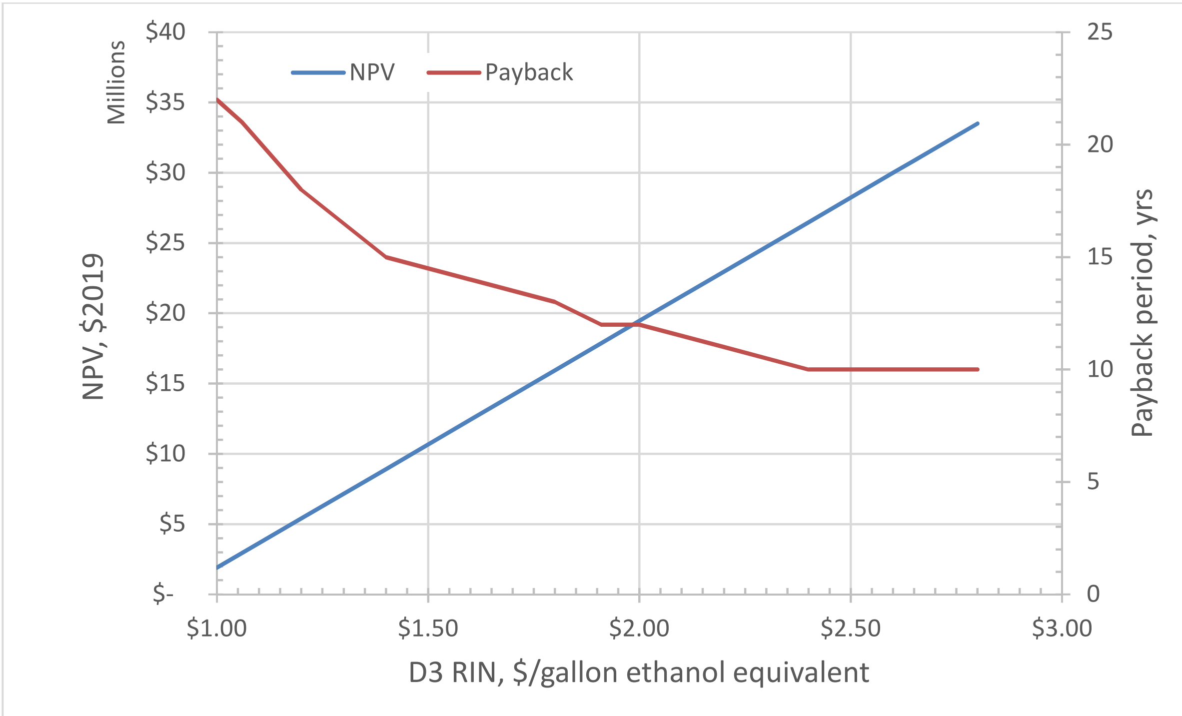

Figure 1. Alternative 2, RNG, RIN price sensitivity

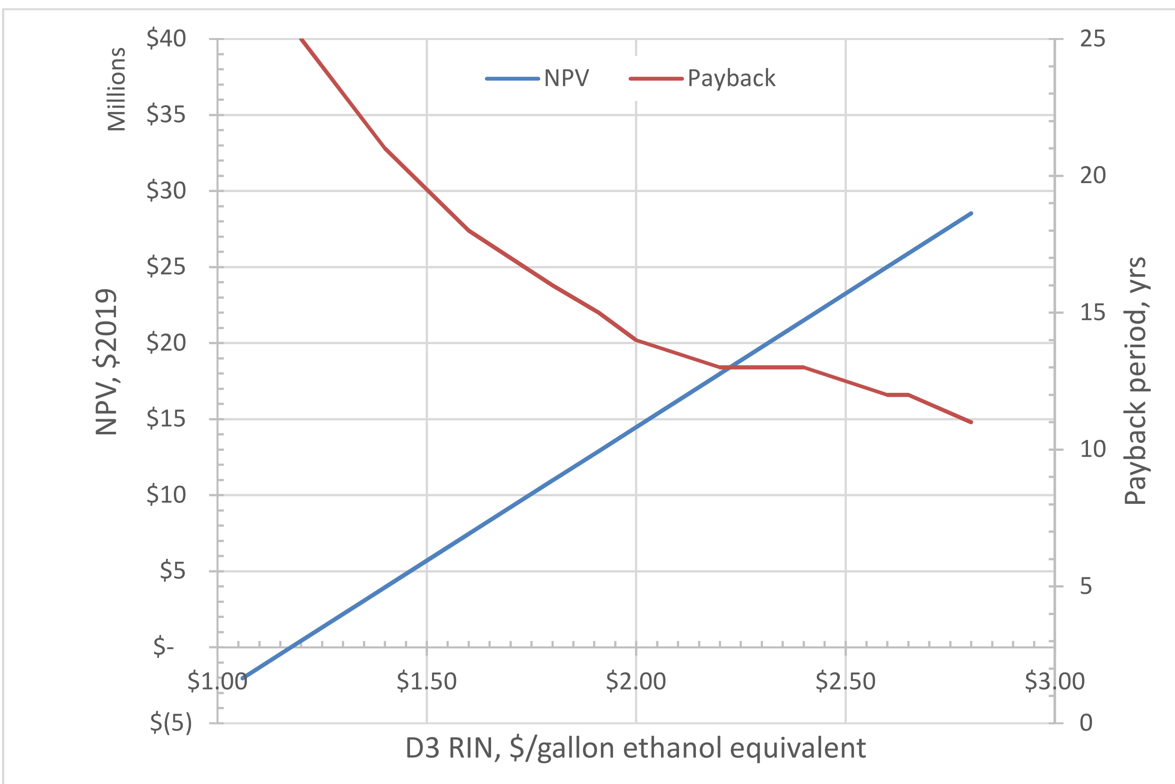

Figure 2. Alternative 3, CNG, RIN price sensitivity

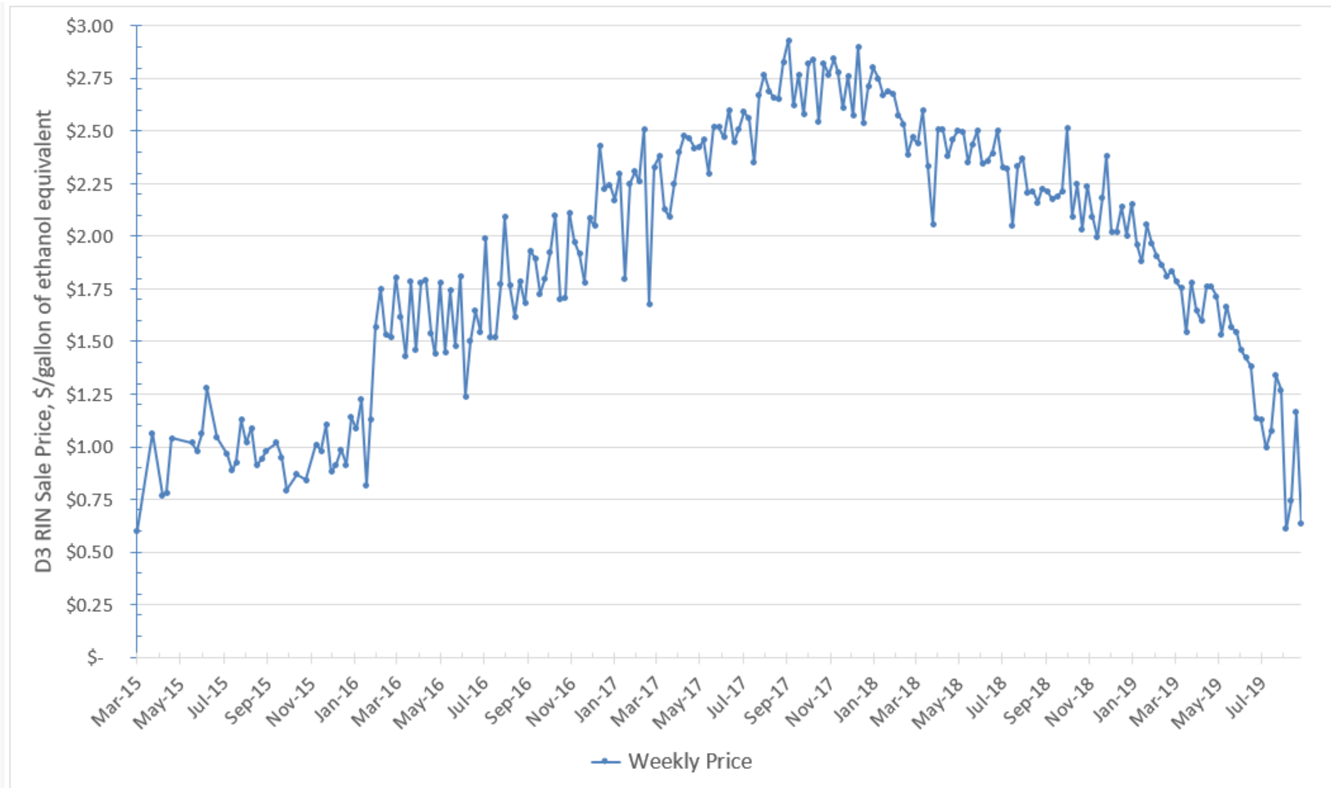

Figure 3. Weekly RIN value, 2015–Present

- **Value of RNG Fuel (Alternative 2):** The price at which the City can sell the RNG produced by Alternative 2 affects the NPV and payback. RNG sale pricing is tied to natural gas prices. As natural gas prices rise, the revenue from the sale of RNG increases. However, some of the additional revenue is offset by the requirement for the City to purchase natural gas for firing in the boiler to provide heat for the plant. Figure 4 illustrates the effects of RNG value on NPV and payback, while keeping all other assumptions the same. The NPV is displayed by the upward sloping blue line, and time to pay back is shown by the downward sloping red line. Based on the Henry Hub natural gas spot prices, natural gas prices have hovered between about $0.20 and $0.40 per therm over the past 10 years. Note that the positive NPV for Alternative 2 is less dependent on the value of RNG fuel than RIN value.

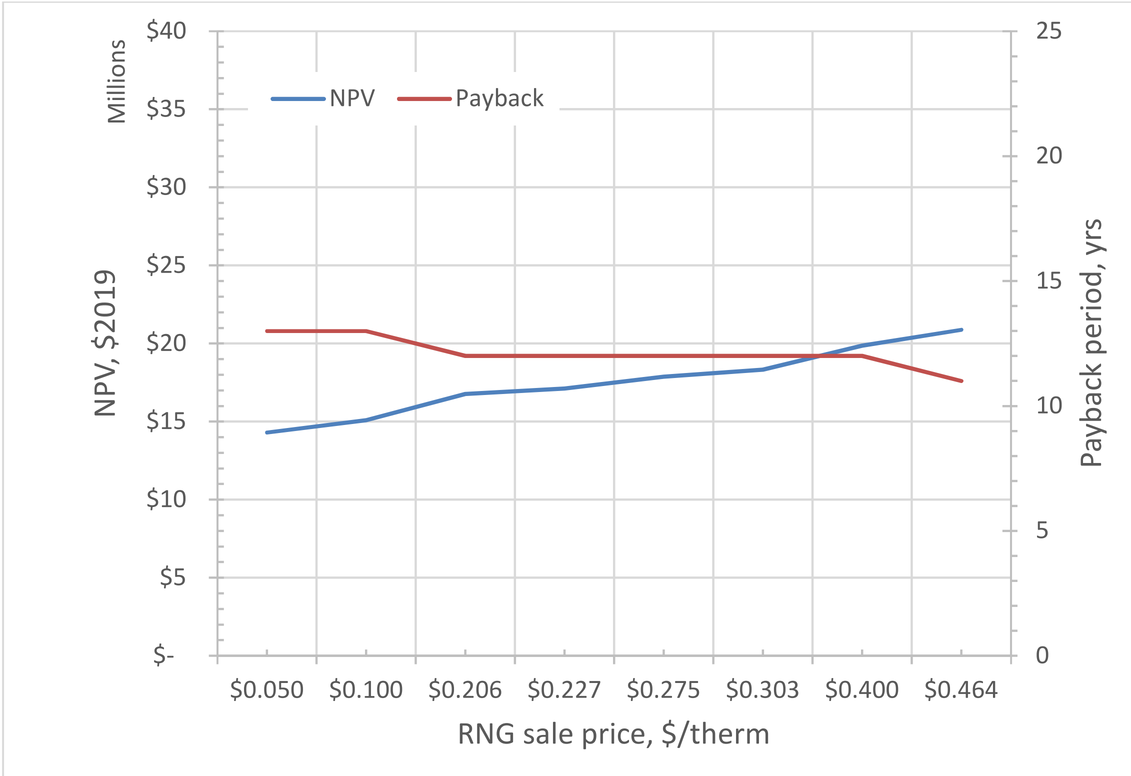

Figure 4. Alternative 2, RNG, RNG sale price sensitivity

- **Value of CNG Fuel (Alternative 3):** The price at which the City can sell the CNG produced by Alternative 3 affects the NPV and payback. CNG sale pricing is tied to natural gas prices because the local CNG station purchases natural gas from the local natural gas utility. As natural gas prices rise, the revenue from the sale of CNG increases. However, some of the additional revenue is offset by the requirement for the City to purchase natural gas for firing in the boiler to provide heat for the plant. Figure 5 illustrates the effects of CNG sale price on NPV and payback, while keeping all other assumptions the same. The NPV is displayed by the upward sloping curve and time to pay back is shown by the red line. Similar to Alternative 2, the positive NPV for Alternative 3 is less dependent on the value of CNG than the value of RINs.

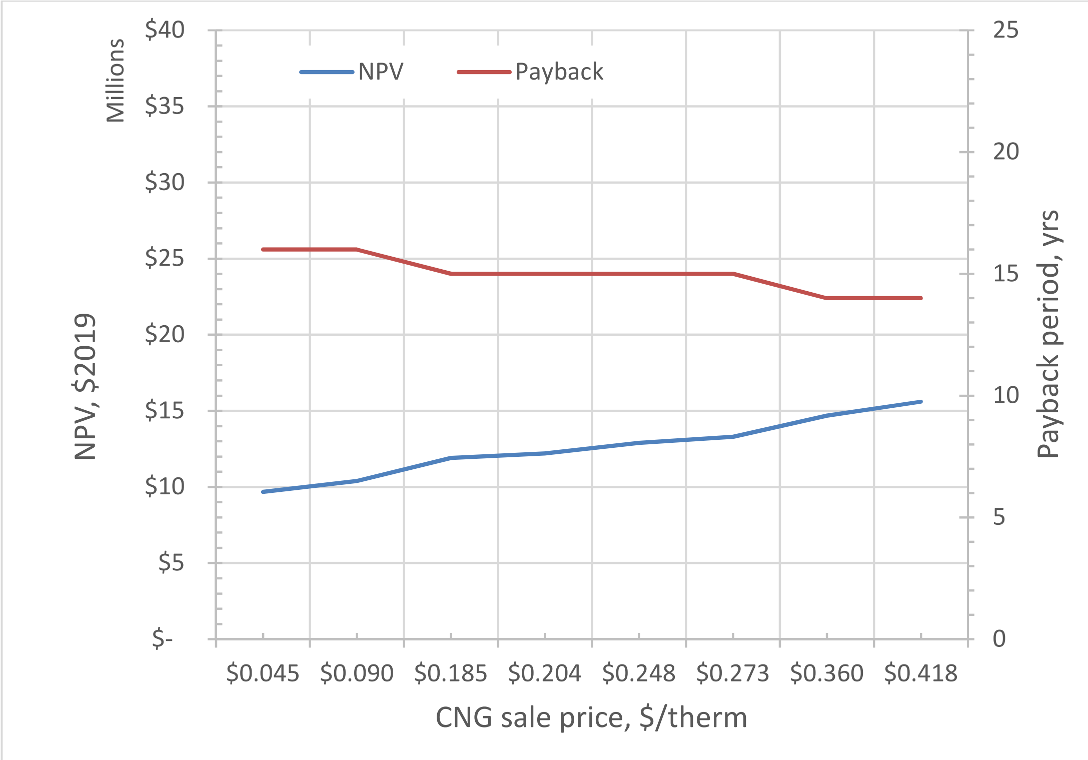

Figure 5. Alternative 3, CNG, CNG sale price sensitivity

- **End Users for CNG:** A major component of evaluating the feasibility of converting biogas to fleet vehicle fuel involves analyzing potential end users and availability of fleet vehicles to consume the product. Valley Regional Transit (VRT) currently operates about 50 busses on CNG while Republic Services operates around 120 refuse haulers on CNG in the area. Coordination would be needed with existing CNG vehicle fleet operators, and/or the City's fleet would need to be converted to CNG to fully realize the benefits of this alternative. The base business case evaluation assumes all the CNG will be purchased by Republic Services at its Nampa CNG station and subsequently consumed by existing fleet vehicles such as Republic Services refuse haulers and VRT busses. If Republic Services will not accept the CNG, modifications to Alternative 3 are required.

Recommendation

This briefing is intended to provide an overview of the general economics associated with biogas recovery. It appears that cogeneration (Alternative 1) is not a viable financial alternative. Therefore, BC recommends eliminating cogeneration as a potential alternative. Alternatives 2 and 3 have a positive NPV for most results from the sensitivity analyses, showing potential for providing a revenue source to the City. Results show Alternative 2, specifically, has a higher NPV than either of the other alternatives. Further work is required to advance the concepts described for each alternative. However, each of these approaches would require between $8M and $11M in additional capital funding for the Phase II Upgrades. Therefore, if the DRC is interested in pursuing this approach, BC recommends that this project be included at the end of the Phase II Upgrades to provide time to further develop costs for the original project scope.