September 26, 2017

Mr. Tom Brown
Chief Operating Officer
Gainesville Regional Utilities
301 SE 4th Avenue
Gainesville, Florida 32601

Re: GREC Independent Engineer's Report – Phase 2
Analysis of Operating Alternatives for GREC
Burns & McDonnell Project No. 101300

Dear Mr. Brown:

Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") was retained by Gainesville Regional Utilities ("GRU") to prepare an Independent Engineer's Report ("IE Report") on the Gainesville Renewable Energy Center ("Plant" or "GREC"). The Plant is a biomass-fired power production facility with a nameplate capacity of approximately 100 MW located in Gainesville, Florida. GRU is considering purchasing the Plant.

Burns & McDonnell recently completed the IE Report which evaluated whether the Plant was designed, permitted, and constructed in a manner that can provide a long-term, dependable power generating resource. In addition to the conclusions reached during the IE Report, GRU requested that Burns & McDonnell review potential operation and maintenance practices and engineering solutions that may allow GRU to better utilize GREC within its power supply fleet.

BACKGROUND

The Plant is a biomass-fired power production facility with a nameplate capacity of approximately 100 MW located in Gainesville, Florida, adjacent to GRU's Deerhaven Generating Station. The Plant includes one 100 percent woody biomass bubbling fluidized bed ("BFB") boiler with selective catalytic reduction ("SCR"), baghouse, sorbent injection, zero-liquid discharge ("ZLD"), and a steam turbine generator ("STG").

Burns & McDonnell reviewed the current staffing levels at the Plant to assess how the Plant's staffing may be incorporated into GRU's existing resources. Burns & McDonnell evaluated four operating scenarios that may allow GRU to better utilize GREC within its power portfolio.

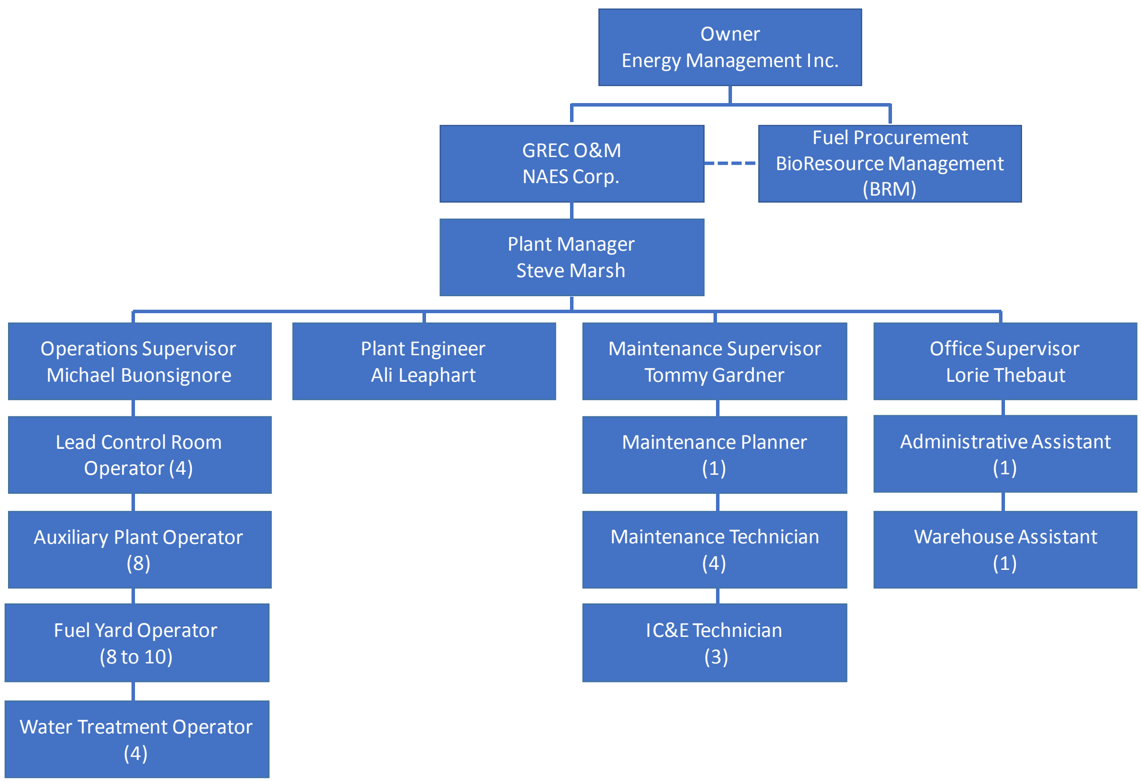
STAFFING AND OPERATIONS REVIEW

The current owner of the Plant, Energy Management, Inc ("EMI"), has contracted operation and maintenance activities for both the Plant and fuel supply to North American Energy Services, Inc. ("NAES") and Biomass Resource Management ("BRM"), respectively. A total of 39 employees currently make up the staff of NAES for GREC. BRM has a staff of four (4) employees dedicated to GREC. NAES provides all things necessary for the proper operation and maintenance of the Plant including day-to-day operation and maintenance, long-term maintenance planning, spare parts management, and other responsibilities required to maintain the Facility in proper working order.

In addition to the NAES staff, four employees are contracted through BRM for fuel management and procurement. The four employees consist of a Fuel Procurement Manager, Biomass Forester, Quality Control Technician, and Scale Attendant. BRM is charged with fuel procurement and delivery operations among other tasks.

The organizational structure of the Plant is included in Figure 1. The overall staffing of the Facility appears to be similar to other biomass projects within the industry.

Figure 1: Gainesville Renewable Energy Center Organizational Structure



After the acquisition of the Plant, GRU may have the ability to slightly reduce O&M costs specifically at GREC. Mainly, this is due to some of the roles and functions currently performed at the Plant having the ability to be provided by existing staff at other GRU facilities as part of a larger generation portfolio as opposed to a standalone plant. However, GRU indicated it has several positions that are currently unfilled across its overall staff for generation and operations. Personnel at either GREC or existing GRU facilities may need to be augmented to reduce O&M costs specifically at GREC after the acquisition while also filling the positions that are currently open and fulfilling those needs.

After the acquisition, GRU should assess the roles and functions that are currently performed at GREC as a standalone unit that may be able to be performed within GRU's portfolio. Additionally, GRU will need to assess the overall GREC staff to best position those personnel at either the Plant, GRU's other plants, or potentially in other roles within GRU's operations and maintenance staff that may currently be unfilled. Overall, the Plant is effectively and efficiently operated and maintained and Burns & McDonnell did not identify areas to significantly reduce the O&M costs.

ALTERNATIVE OPERATING SCENARIOS

GRU requested Burns & McDonnell evaluate several operating scenarios that GRU may be able to utilize the Plant within its portfolio, both in the short-term and long-term.

Burns & McDonnell developed screening level estimates for costs and performance parameters for three operating scenarios. These parameters are to be used by GRU to conduct financial analyses and valuation of these options. The scenarios that were evaluated include:

1. Retirement: This scenario evaluates the decommissioning and demolition of the Plant.
2. Long-term cold standby: This scenario evaluates placing the Plant in a status of cold-standby long-term, sometimes referred to a "mothballed" status.
3. Lower minimum load: This scenario evaluates potential capital improvements that can provide an increased amount of turndown to improve the operational flexibility of the Plant.

The following sections discuss each of these scenarios.

Retirement

The objective of the scenario was to develop a screening level cost estimate for decommissioning the plant and returning the site to a similar condition that existing prior to development.

Decommissioning Methods

For purposes of this Study, Burns & McDonnell has assumed that the site will be decommissioned as a single project, allowing the most cost-effective demolition methods to be utilized. A summary of the means and methods that could be employed is summarized in the following paragraphs. It would be the contractor's responsibility to determine means and methods that result in safely decommissioning the Plants at the lowest possible cost.

High grade assets would be removed from the site, to the extent possible. This would include items such as transformers, transformer coils, circuit breakers, electrical wire, condenser plates and tubes, and heater tubes. High grade assets include precious alloys such as copper, aluminum-brass tubes, stainless steel tubes, and other high value metals occurring in plant systems. High grade asset removal would occur up-front in the schedule to reduce the potential for vandalism, to increase cash flow, and for separation of recyclable materials to increase scrap recovery. Methods of removal vary with the location and nature of the asset. Small transformers, small equipment, and wire would likely be removed and shipped as-is for processing at a scrap yard. Large transformers, STG, and condensers would likely require some on-site disassembly prior to being shipped to a scrap yard.

Construction and Demolition ("C&D") waste includes items such as non-asbestos insulation, roofing, wood, drywall, plastics, and other non-metallic materials. C&D waste would typically be segregated from scrap and concrete to avoid cross-contaminating of waste streams or recycle streams. C&D demolition crews could remove these materials with equipment such as excavators equipped with material handling attachments, skid steers, etc. This material would be consolidated and loaded into bulk containers for disposal.

In general, the boiler and stack could be felled and cut into manageable sized pieces on the ground. First the structures around the boiler would need to be removed using excavators equipped with shears and grapples. Stairs, grating, elevators, and other high structures would be removed using an "ultra-high reach" excavator, equipped with shears. Following removal of these structures, the boiler would be felled, using explosive blasts. The boiler would then be dismantled using equipment such as excavators equipped with shears and grapples, and the scrap metal loaded onto trailers for recycling.

BOP structures and foundations would likely be demolished using excavators equipped with hydraulic shears, hydraulic grapples, and impact breakers, along with workers utilizing open flame cutting torches. Steel components would be separated, reduced in size, and loaded onto trailers for recycling. Concrete would be broken into manageable sized pieces and stockpiled for crushing on-site. Concrete pieces would ultimately be loaded in a hopper and fed through a crusher to be sized for on-site disposal.

Decommissioning Assumptions

The following general assumptions were made as the basis for the screening level decommissioning cost estimates.

1. The estimates are inclusive of all cost necessary to properly demolish all structures, equipment, boilers, tanks, conveying and ancillary buildings, and any other associated equipment and buildings to grade level. For purposes of this Study and the included cost estimates, the sites will be restored to a condition suitable for industrial use.

2. Pricing for all estimates is in 2017 dollars.
3. Site areas will be graded to achieve suitable site drainage to natural drainage patterns and seeded but grading will be minimized to the extent possible.
4. Valuation and sale of land and all replacement generation costs are excluded from this scope.
5. For purposes of this Study, it is assumed that none of the equipment will have a salvage value in excess of the scrap value of the materials in the equipment. All equipment, steel, copper, and other metals will be sold as scrap.
6. A 20 percent contingency is included on the direct costs in the estimates prepared as part of this study to cover unknowns. Owner's indirect costs are included as 5 percent of the direct costs.
7. Market conditions may result in cost variations at the time of contract execution.

Decommissioning Estimate

Burns & McDonnell has prepared a cost estimate in 2017 dollars for the decommissioning of the GREC. These cost estimates are summarized in Table 1. When GRU determines that the Plant should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a scrap contractor to offset a portion of the decommissioning costs. GRU will incur costs in the demolition and restoration of the site less the scrap value of equipment and bulk steel.

Table 1: Decommissioning Cost Summary (2017$)

Plant	Decommissioning Costs	Scrap Value	Total Project Cost
GREC	$9 million to $12 million	$4 million to $5 million	$5 million to $7 million

The total net project costs presented above include the costs to return the site to an industrial condition suitable for reuse for development of an industrial facility. Included are the costs to dismantle the power generating equipment at GREC as well as the costs to dismantle balance of plant ("BOP") facilities and grading and reseeding the site to return it to a condition usable for industrial use.

The decommissioning costs are based on an estimate model that Burns & McDonnell uses for decommissioning studies. The estimate model has been developed internally over the years using help from demolition contractors, as well as experience with actual contractor bids on projects where Burns & McDonnell has been the owner's engineer. Specifically, Burns & McDonnell used a decommissioning cost study model that was internally prepared for a similar sized unit and adjusted this for some GREC specific issues, such as the appropriate AQCS equipment. This was a screening level estimate to be used within planning studies.

Long-Term Cold Standby

The objective of the scenario was to develop a plan for economically placing the Plant into layup status, maintaining the equipment until it is called on to restart, and restarting the Plant when called upon during the layup period.

Initial Plant Layup

Burns & McDonnell estimated the overall one-time cost to place the Plant in a condition to restart later. Burns & McDonnell leveraged existing experience off evaluating long-term layups on similar facilities as the basis for this assessment.

The following general assumptions were the basis of the screening level cost estimate for placing the Plant in long-term layup status.

1. GRU will burn all biomass fuel in the storage yard prior to commencement of layup activities.
2. Any remaining chemicals will be removed from the site as part of the layup activities.
3. All rolling stock, remaining spare parts, tools, inventory, or minor equipment in the buildings will remain on-site to be available for future plant operation if necessary.
4. No hazardous material abatement will be performed as part of the plant layup activities.
5. The boiler, steam turbine, and steam cycle will be laid up dry with nitrogen from the on-site nitrogen generator, consisting of the following activities:
    a. Chemical clean boilers
    b. Inspect and repair fans
    c. Clean and patch ductwork
    d. Clean condenser water boxes
    e. Clean precipitator
    f. Clean ash handling system
    g. Purge hydrogen in generators with CO_2
    h. Clean and cap chimney
6. The on-site nitrogen generator is assumed to be used on the boiler, on the water/steam cycle system, and on the turbine. The systems will operate continuously throughout the layup period to prevent corrosion.
7. The circulating water system will be drained. The auxiliary cooling system will continue to draw water from wells to provide cooling to auxiliary equipment required to remain in operation during layup period.
8. The demineralized water treatment system will be taken out of service and the system drained. No demineralized water will be required during the layup period.
9. An allowance is included in balance of plant costs to cover modifications necessary for fire protection system modifications as needed. A specific plan has not been developed at this time. It will likely include modifications to the service water system and fire protection system to drain portions of the service water system not required to remain in service during the layup period and

either closing valves or installing blanking plates to isolate the closed portions of the system. All fire protection systems will remain in service.

10. No additional freeze protection has been included.
11. costs have been included to address site clean-up of contaminated soils, hazardous materials, or other conditions present on-site having a negative environmental impact. No allowances are included for unforeseen environmental remediation activities.
12. The fuel pile area and any ponds will remain as-is.
13. An allowance for indirect costs and contingency have been included for engineering, project management, and corporate overhead costs.
14. Pricing for all estimates is based on 2017 dollars.

Based on Burns & McDonnell's experience and the general assumptions provided above, a cost estimate range was prepared for the activities associated with placing the Plant into a long-term layup status. Burns & McDonnell estimates a one-time cost of approximately $750,000 to $1,250,000 to place the Plant in a condition to restart later.

Operations & Maintenance

GRU will need to address certain requirements and incur associated costs for operations and maintenance activities recommended for the Plant during the layup period. This will help preserve the long-term operation of the Plant. These steps outlined below are typically utilized with the intention of reducing equipment failure and overhauls required at the time of Plant restart. The following general assumptions serve as the basis of the screening level cost estimate range for operations and maintenance activities for the Plant during the layup period.

1. The plant will be staffed by three full-time employees that will perform routine operation and maintenance (O&M) activities on the equipment, including manually rotating small motors and pumps and maintaining equipment required to support the layup period.
2. An allowance for third-party costs are included to cover items such as stack inspections, CEMS maintenance, etc.
3. No costs are included in the third-party costs to cover the cost of power for station service or other utilities during the layup period. Although costs for station utilities have not been estimated by Burns & McDonnell, they should be considered in the operating and maintenance costs of the facility during the layup period. This will include station electric service, potable water, etc.
4. Due to its proximity to the existing Deerhaven Generating Station, security costs assume that the Deerhaven staff will be able to provide site security service.
5. Insurance costs have not been estimated by Burns & McDonnell, but will need to remain in place throughout the layup period. Specific insurance coverage and rates should be discussed with legal and insurance representatives to determine appropriate coverage levels.

6. Property tax costs have not been estimated by Burns & McDonnell, however property taxes are assumed to remain applicable during the layup period. Property tax costs may be subject to reduced rates during the layup period.
7. Permit renewals have not been estimated by Burns & McDonnell.
8. An allowance for indirect costs and contingency have been included for engineering, project management, and corporate overhead costs.
9. Pricing for all estimates is based on 2017 dollars.

Based on the assumptions provided above, a cost estimate was prepared for the O&M activities required during the layup period are approximately $500,000 to $750,000.

Plant Restart

Prior to restarting the Plant, GRU will have conduct some activities for restarting the Plant at the end of the layup period. The following assumptions were used as the basis of the screening level cost estimate range for restarting the Plant at the end of the layup period.

1. The restart costs outlined below are only inclusive of activities needed to be performed to take the plant out of layup status and return it to service. These costs do not include bringing in additional staffing to return the plant to pre-layup staffing levels or training new staff members.
2. Costs for fuel used during startup and revenue from power generation during startup are not included in this analysis.
3. Temporary systems put in place to support layup conditions will be left in place; however, modifications to the system will be made to support placing the Plant back into service. This will include taking the dehumidification equipment out of service but leaving the equipment in place, with necessary modifications to the boilers and steam turbines to return them to normal service. Similar provisions will be made to remove other systems from service, such as freeze protection, that have been installed as part plant layup.
4. Boilers will be flushed and refilled.
5. An allowance has been included in the costs to account for unexpected failure of miscellaneous balance of plant equipment upon restart.

Based on the general assumptions provided above, a cost estimate range was prepared for restarting the Plant at the end of the layup period and is approximately $1,000,000 to $1,500,000.

Lower Minimum Load

According to GREC, the minimum operating output for the Plant is 70 MW as defined within the power purchase agreement (“PPA”). Burns & McDonnell inquired with the staff whether the Facility would have the ability to operate at a lower turndown point than is currently defined within the PPA. GREC indicated the Facility is limited to a technical turndown point of approximately 60 MW due to a backend temperature requirement located at the injection point of the selective catalytic reduction (“SCR”) system.

The injection point of the SCR requires a minimum effective temperature of 375°F. If the unit is operating at less than approximately 60 MW, the backend temperature drops below 375°F and the SCR becomes ineffective. The installation of duct burners, heating coils, or an economizer bypass could be implemented as means to increase the overall temperature at lower load points, however this may require a modification to the air permit.

Burns & McDonnell developed screening level cost estimates ranges to make modifications to allow the plant to turn down to 25 MW (about 25 percent of full output), and corresponding performance characteristics. As identified above, the constraint on turning down the plant below its current lower limit of 60 MW is the temperature upstream of the SCR, which must be 375ºF or more for the catalyst to be sufficiently effective to meet emissions limits. Without considerations to the backend equipment the normal turndown for a BFB is 1:4, which would meet the GRU requirement. As the Plant turns down, the heat input into the boiler reduces, leading to lower flue gas temperature out of the boiler. These lower temperatures then lead to lower temperature into the SCR to the point that it gets too low for the SCR to effectively operate. Since eliminating the SCR is not feasible, some means must be implemented to maintain the flue gas temperature at sufficient levels into the SCR.

As mentioned above, three approaches were considered:

1. Adding natural gas-fired duct burners to the flue ducts before the SCR to take advantage of the remaining oxygen in the flue gas and elevate the temperature
2. Adding steam coils in the ducts themselves;
3. Adding a bypass duct around the economizer to reduce the heat extracted from the flue gas before it reaches the SCR.

All three are feasible in principle, although the details of their implementation would have to be further evaluated to determine whether would operate over the turndown range desired by GRU. For this assessment, Burns & McDonnell selected the auxiliary duct burners for further evaluation based on several reasons.

Duct Burner Modification

Duct burners are a proven technology that has been used for such purposes before which offer several advantages.

1. They require little additional space, as they can be inserted as a replacement section in the existing duct.
2. They can be easily modulated to warm up the flue gas to the required temperature.

3. There is existing natural gas infrastructure and supply at the Plant for startup that may be utilized since the startup burners are not required once biomass combustion is taking place.
4. They do not materially modify the boiler design, and therefore may avoid a potentially risk of upsetting the boiler operation and the overall heat balance as much as the other two methods would.
5. They are also very likely to be the least expensive to implement, as they avoid extensive piping and re-ducting and consequent routing and possible structural issues of the other two methods.

Based on consultation with a burner supplier, the screening cost range of this solution is approximately $2 million to $4 million. Regarding the heat rate, the impact should be minor with no more than 1 percent increase even at the lowest turndown, as the amount of natural gas required to maintain temperatures would be small. The ramp rate would not be affected as the burners operate independently of the boiler, and would remain relatively slow in the 2 to 4 MW/min range. The addition of duct burners would require air permit modifications.

Dual Fuel Capability

Much more flexibility could be gained if the boiler could be converted to burn natural gas instead of biomass, or in addition to it. This is a more complex and expensive solution that would need to be carefully studied. However, conversion to natural gas does appear to be feasible and offers significant advantages in overall flexibility. The burner supplier has had experience with the conversion to gas of two pet coke circulating fluidized bed ("CFB") boilers, which are more complicated than biomass BFBs. The main issue with the boiler is that heat transfer would change from the existing 60 percent radiant and 40 percent convective to the reverse. This could cause problems with the superheater tubes, which would experience higher temperatures and therefore may have to be replaced with higher strength/lighter weight alloys. Another possible issue is National Fire Protection Association ("NFPA") 85 furnace implosion considerations due to the quick fuel cutoff that occurs with natural gas, and the resulting negative furnace pressure excursions that could cause structural problems. This is a common issue with coal to gas conversions, and in Burns & McDonnell's experience it can be addressed with proper shutoff controls to limit the excursions. Furthermore, newer, modern furnaces are typically more robust and can take higher pressure differentials.

Conversion would involve the addition of low NOx burners in the intermediate section of the boiler, above the fluidized bed and below the first set of superheaters. Some of the water tube panels would have to be replaced to allow the insertion of the new burners, but that should not be a problem as the required surface area is reduced. Cofiring could be handled by means of a totalizer that adjust biomass addition and natural gas flow to achieve the desired output and ratio of fuels. According to the vendor, cofiring to 70 percent of capacity should be achievable, and possibly to 100 percent. The air for the new burners could be diverted from the primary air or new fans could be installed. The new fans would be relatively small and therefore not too difficult to install on an existing site. The natural gas supply piping may have to be replaced with a slightly larger size.

According to the vendor, the expected screening cost range for this approach is approximately $5 million to $8 million, plus $1 million if the super heater tube metallurgy needed to be upgraded. The heat rate when firing natural gas would probably deteriorate by 1 percent to 2 percent. Natural gas results in higher stack losses via water vapor due to its higher hydrogen content (it has a higher ratio of gross to net heating value), but it requires less excess oxygen and therefore less air for a stable combustion, which reduces losses. Ramp rates with natural gas should improve by almost a factor of 10 from the lower heat content biomass, to approximately 10 to 20 MW/min.

SUMMARY

Table 2 presents the overall summary of costs for each of the alternatives evaluated within this assessment.

Table 2: Summary of Costs

Alternative	Cost ($, 2017)
Retirement/Decommissioning	$5 million to $7 million
Long-Term Layup	
Initial Plant Layup	$750,000 to $1,250,000
Operations & Maintenance	$500,000 to $750,000
Plant Restart	$1,000,000 to $1,500,000
Lower Minimum Load	
Duct Burner Modifications	$2 million to $4 million
Dual Fuel Capability	$6 million to $8 million

If you have any questions regarding this information, please contact Mike Borgstadt at 816-822-3459 or mborgstadt@burnsmcd.com.

Sincerely,

Mike Borgstadt, PE
Project Manager

MEB/meb

cc: Dino De Leo, GRU