Feasibility Study: Energy Generation from Forest Biomass

Completed for:
Mooretown Rancheria
Oroville, California

THE BECK GROUP

Project Report
July2015

FEASIBILITY STUDY: ENERGY GENERATION FROM FOREST BIOMASS

MOORETOWN RANCHERIA
OROVILLE, CALIFORNIA

PROJECT REPORT
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TABLE OF CONTENTS

PAGE

CHAPTER 1 – EXECUTIVE SUMMARY

1.1 INTRODUCTION

Mooretown Rancheria (MR) is a federally recognized Native American Tribe near Oroville, California. The Rancheria is located on approximately 316 acres of tribal property held in trust by the Bureau of Indian Affairs (BIA). MR currently operates a gaming casino, hotel, and small brewery on the property. MR also operates a tribal enterprise that carries out hazardous forest fuel management treatments (e.g., thinning and firefighting) on public and private lands in the region surrounding the Rancheria.

MR retained the services of The Beck Group (BECK), a forest products planning and consulting firm located in Portland, Oregon, to investigate the feasibility of developing a small scale biomass cogeneration facility on the Rancheria. The concept to be investigated is a facility that would utilize the forest biomass materials generated by MR's forestry crew and other sources to generate heat for the hotel and casino and renewable power to be sold to the electrical grid. Use of certain types of biomass to produce heat, power, or both would qualify MR for a feed-in-tariff program to be offered by Pacific Gas & Electric (PG&E).

Each of the following executive summary subsections describes various key aspects of the plant's feasibility. Greater detail about each topic is found in the body of the report.

BECK was assisted on this project by Bill Carlson, principal of Carlson Small Power Consultants (CSPC) of Redding, California. BECK and CSPC appreciate the opportunity to assist on this important project.

1.2 PG&E SB 1122 PROGRAM

Investor Owned Utilities in California were recently required to purchase power from small scale biomass facilities. The law mandating those purchases is referred to as SB 1122. The existence of this law and its provisions for paying certain power producers higher than market value rates for power are critical to MR's small scale biomass project being considered feasible.

The rules for participation in the SB 1122 program are very complex, but several key aspects are of particular importance for MR. They include:

1. No single facility can be larger than 3 MW in capacity and the utilities must purchase a total of 50 MW of power from such facilities.
2. The biomass fuel used for the program must be produced from sustainable forest management treatments (i.e., urban wood residues, orchard residues, mill residues, etc. cannot be used).
3. The power sales rate (i.e., the price at which MR would sell power to the utility) remains constant for the 10 to 20 year term of the Power Purchase Agreement (PPA). This rate is called the Levelized Cost of Electricity (LCOE).
4. MR would contract to sell a specified amount of power to PG&E annually. The contract would last 10 to 20 years. A key stipulation of the contract is that during every 2 year

period the power plant must produce a minimum of 180 percent of its annual energy commitment, or face penalty charges for non-compliance.

5. When a minimum of three small scale biomass project developers enter the queue to enroll in the program, the LCOE offered by the utilities will initially be posted at about $128/megawatt hour (MWH). If no developers take the contract at the opening price, it will begin adjusting upward periodically until it reaches a level acceptable to one of the developers. If one developer accepts the offered price, the queue must expand to 5 developers before further price adjustments are possible.
6. If the LCOE value reaches $197/MWH with no project developers accepting the offer, it will trigger an automatic review of the program by the California Public Utilities Commission (CPUC).

A more detailed description of SB 1122 program requirements and implementation protocol is provided in Chapter 2 of this report.

1.3 TECHNOLOGY EVALUATION

BECK's project scope included a review of direct combustion, gasification, and organic Rankine cycle technologies and making a recommendation about which technology is most appropriate for MR. Therefore, BECK analyzed each of those technologies within the context of MR's ongoing casino, hotel, and forestry businesses and within the parameters of California's SB 1122 program. BECK's conclusion is that direct combustion technology is most appropriate for MR.

The key reasons for this decision are that while gasification technology has the benefit of producing byproducts that could enhance revenues, there are no installations BECK is aware of that are successfully using the forest derived fuels required by the SB 1122 program. The inherent variability in those fuels (e.g., heating value, moisture content, species, and ash content) contribute to serious doubts about the ability of gasification technology reliably operating at the production levels required by the SB 1122 program. In addition, the limited installations of gasification technology using forest derived biomass fuel means that little hard data is available to verify capital and operating costs and there is difficulty identifying manufacturers who are willing guarantee equipment performance.

In contrast, direct combustion technology has been: installed at many sites; successfully proven to accommodate use of forest derived fuels; and used on projects of the same scale as is dictated by the SB 1122 program. In addition, there are multiple, well-established direct combustion equipment vendors capable of supplying the equipment and willing to guarantee its performance.

Details of BECK's analysis regarding these technologies are presented in Chapter 3 of this report.

1.4 BIOMASS SUPPLY AND DELIVERED COST ASSESSMENT

BECK analyzed the supply of biomass fuel available within a 50 mile radius of MR. The estimate categorizes the fuel supply into a "total" amount and a "recoverable" amount. The difference between the two is that the total is everything that is estimated to be produced annually, whereas the recoverable amount is what is judged to be practically and cost-effectively available (i.e., it excludes material that cannot be readily accessed because of road and terrain limitations and material that is too expensive to collect, process, and transport).

Table 1.1 shows the estimated annual volume for the total and practically recoverable categories. A biomass facility at MR, as conceived for this study, would consume 24,500 to 26,000 bone dry tons[1] (BDT) of fuel annually depending on whether it was a stand-alone[2] plant or a cogeneration plant, respectively. Thus, the amount of fuel that would be consumed by the plant annually is substantially lower than the estimated annual supply. Note, however, that BECK has included estimates from a variety of potential biomass fuel sources. Importantly, for the prospective plant to qualify for the SB 1122 program, it could only use fuel from rows labeled Logging Slash and Fuel Reduction Treatments in **Table 1.1**. Despite that limitation, the estimated recoverable fuel volume from just those two sources is still nearly five times greater than the plant's annual biomass fuel consumption.

Using logging slash as a fuel source is an issue that needs further investigation. At question is whether it qualifies for the SB 1122 program. BECK's interpretation of the program language is that it would qualify since the forest management activities in the region on both public and private lands are certified as sustainable. Since logging slash is a byproduct of those sustainable forest management activities it should qualify. However, this should be verified with the California Public Utilities Commission and CalFire, the entity that wrote the program language.

Table 1.1 – Estimated Total and Recoverable Annual Biomass Supply (BDT/year)

Fuel Type	**Estimated Total Volume (BDT/Year)**	**Estimated Recoverable Volume (BDT/Year)**
Mill Byproducts	662,600	246,600
Orchard Residues	213,100	76,200
Urban Wood Waste	318,000	79,600
Non SB 1122 Subtotal	*1,193,700*	*402,400*
Logging Slash	216,000	108,000
Fuel Reduction Treatments	24,000	15,800
SB 1122 Subtotal	*240,000*	*123,800*
Grand Total	**1,433,700**	**526,200**

[1] Bone Dry Ton is a unit of measure used in the biomass industry. It is a measure of the weight of wood material after accounting for the amount of moisture in the material. For example, a volume of wood weighing 2 tons (4,000 pounds) that is 50 percent moisture would be equal to 1 bone dry ton since 50 percent of the weight is water.

[2] Stand-Alone refers to a power plant fueled by biomass, which only produces power (i.e., none of the heat produced in the process of generating power is used). Cogeneration, on the other hand, refers to a plant that produces power, and at the same time, uses the heat produced in the process for heating a building, industrial process, or both. As explained in Section 1.7, BECK modeled both types of plants for this study.

In addition to having an adequate supply of biomass, it is also important to understand the fuel's delivered to the plant cost. **Table 1.2** displays estimated delivered costs for the recoverable volumes of logging slash and fuel reduction treatments.

As shown in the table, the delivered cost ranges from a low of $40 per bone dry ton to a high of $64 per bone dry ton depending on the source fuel type and its location. Given the early stage of planning for this project and the uncertainty about where specifically the fuel will be sourced, BECK elected to use an average delivered fuel price of $45 per bone dry ton in the financial modeling for the project.

Please note that it was assumed that logging slash would accumulate on log landings (i.e., no cost for collecting the material) and, since it is otherwise not being utilized, there is no cost for purchasing the material. In other words, the cost estimate is based on the cost of processing and hauling the logging slash. The fuel reduction fuel cost estimate is based on the cost of harvesting, processing and transporting the fuel.

Further details of BECK's fuel supply and fuel cost analysis can be found in Chapter 4 of this report.

Table 1.2 – Estimated Delivered Fuel Costs from Logging Slash and Fuel Reduction Treatments ($/BDT)

County	Supply Source	Annual Volume From Source (BDT)	Delivered Cost From Source ($/BDT)	Cumulative Volume (BDT)	Cumulative Delivered Average Delivered Cost ($/BDT)
Yuba	Logging Slash	8,000	40	8,000	40
Butte	Logging Slash	18,000	40	26,000	40
Sutter	Logging Slash	0	n/a	26,000	40
Glenn	Logging Slash	500	45	26,500	40
Nevada	Logging Slash	7,000	46	33,500	41
Colusa	Logging Slash	500	46	34,000	41
Sierra	Logging Slash	11,000	48	45,000	43
Placer	Logging Slash	20,500	48	65,500	45
Plumas	Logging Slash	42,500	53	108,000	48
Plumas	Fuel Reduction	15,800	64	123,800	50
Total		**123,800**			

1.5 PERMITTING

MR's status as a tribal entity creates a somewhat unique situation in that BECK understands federal agencies will have jurisdiction over permitting issues rather than state or local authorities. For example, with regard to air quality, which is often the most significant permitting issue for biomass plants, BECK contacted the Butte County Air Quality Management District and was referred to the U.S. Environmental Protection Agency (USEPA) Region 9 office. BECK contacted to USEPA Region 9 office, but phone calls were not returned before this report was completed. Thus, additional follow-up is needed to verify who has jurisdiction. Regardless of which entity has jurisdiction, BECK's current understanding, based on discussions with the Butte County Air Quality Management District staff, is that the small scale of the project and the pollution control equipment that is included in this study will result in the project being able to obtain the required air quality permits.

Similarly, other permitting issues such as water use, water discharge, building permits, etc. are expected to fall under the jurisdiction of the Department of Interior Bureau of Indian Affairs. Nevertheless, jurisdiction for these permits should be verified. BECK has been in contact with the Butte County Planning commission regarding the matter, but the issue has not been resolved prior to publication of this report. In any event, BECK anticipates the project using and discharging water through the existing municipal water and wastewater service systems. Thus, water related permitting is not expected to be a significant hurdle to the project.

Finally, MR has completed a draft environmental assessment regarding the development of a Loop Road on the property where the biomass plant will be located. That study identified a number of mitigation measures that can be used to limit impacts to land, water, air, living, and cultural resources and to assure permitting for future project development is a streamlined process. BECK recommends that development of a biomass facility follow the same recommended mitigation protocols.

Permitting issues are discussed in greater detail in Chapter 5 of this report.

1.6 INCENTIVES

BECK has included two key incentives in the feasibility analysis. The first is the inclusion of a New Market Tax Credit (NMTC) in the financing of the project. The NMTC program allows a lender servicing low income communities to take a sizeable tax credit. The program is designed to spur investment in new and operating businesses in low-income communities. The U.S. Census Tract where MR is located qualifies the biomass project for the program.

The program provides tax credits to Community Development Entities (CDEs) that lend money to projects in the low income communities. The advantage to the loan recipient is that the loan is made at a below market rate, and the lender supplies equity to the project that does not have to be repaid by the loan recipient. BECK has experience with the impact of this financing method from another recent small bioenergy project. In that case, the lender was willing to supply $5 million in equity to a $32 million project and provide debt at 1.9 percent interest over 20 years. BECK has used these same metrics in evaluating a project at MR, with the result being that the required power price to obtain the same equity return is nearly $20/MWH less than if the project uses conventional financing.

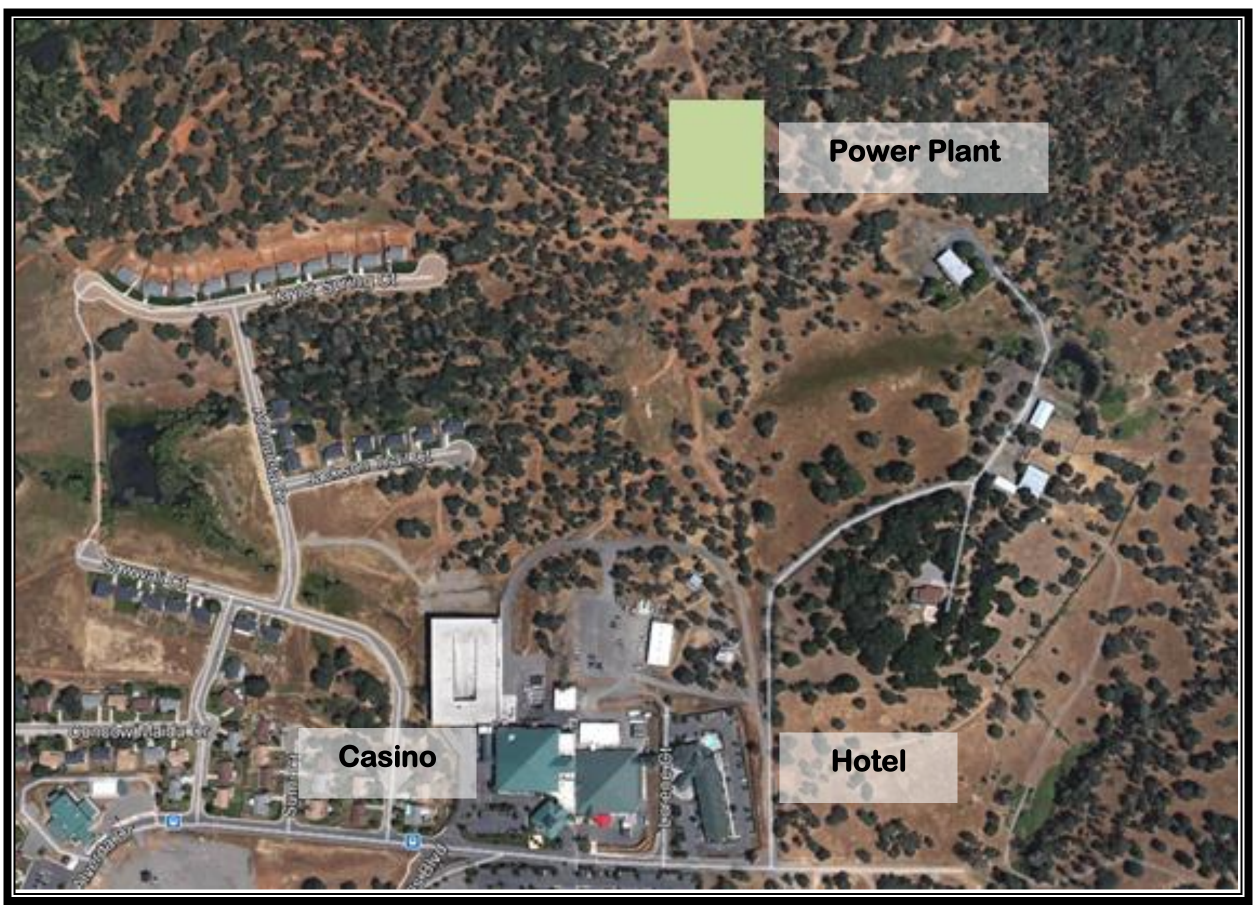
The second incentive used in the analysis is that BECK assumed MR would be able to obtain a total of $1 million in grants from various government agencies (e.g., U.S. Department of Agriculture, U.S. Department of Interior, U.S. Department of Energy, etc.) that would be used in support of the project for the purposes of project planning, engineering, etc.

A more detailed description of these and other incentives is provided in Chapter 6 of this report.

1.7 FINANCIAL ANALYSIS

Regarding the prospective site, the light green rectangle in **Figure 1.1** illustrates the approximate location that MR has chosen for the prospective biomass plant. It is about 2,000 feet north of the existing casino and northeast of the housing area. The site appears suitable – it is flat to gently sloping, is somewhat remote from neighbors, is not visible to the general public, can easily interconnect to PG&E's distribution grid, and allows good truck access off a well-traveled road. Butte County has no extraordinary air quality issues and has had other bioenergy facilities operating in the area in the past.

Figure 1.1 – Approximate Location of Prospective Mooretown Rancheria Biomass Plant



BECK completed a financial analysis for two power plant scenarios:

1. A 3 MW net, stand-alone biomass power plant using a direct combustion boiler/steam turbine system
2. A 3 MW net, cogeneration biomass power plant using a direct combustion boiler/steam turbine system

The rationale for considering two scenarios is that if MR elects not to proceed with an expansion of the brewery and the addition of a greenhouse, the hotel and casino heating cost savings would not be large enough to justify the capital expense for adding cogeneration capability to the plant. In that case, a stand-alone facility would be considered.

Another key aspect of the financial analysis is that BECK identified the power sales price that would provide MR with a 12 percent Internal Rate of Return on the equity invested in the project. **Table 1.3** displays the key results of the financial analysis for each scenario. As shown in the table, both scenarios require a significant capital investment of nearly $23 to $25 million. BECK assumed the project would be financed with 35 percent owner equity and 65 percent long-term debt. The cogeneration scenario requires a slightly higher equity investment by MR, but allows for a lower required sales price to achieve the 12 percent return. Additional details about BECK's financial analysis can be found in Chapters 7 and 8 of this report.

Table 1.3 – Biomass Facility Financial Analysis Key Parameters

Parameter	Stand-Alone	Cogeneration
Capital Cost ($ in millions)	22.932	24.982
Equity ($ in millions)	6.434	7.046
Annual Fuel Needed (bone dry tons)	24,488	25,876
Average Delivered Fuel Price ($/BDT)	45	45
Required Power Sales Price ($/MWH)	186	182
First Year O&M Cost ($ in millions)	2.52	2.60
First Year Thermal Revenue ($ in millions)	0	0.287

1.8 CONCLUSIONS & RECOMMENDATIONS

The 3 MW biomass cogeneration scenario as conceived in this study is feasible and would provide MR with a 12 percent return on the equity invested in the project. The key aspects contributing to the feasibility conclusion are:

- The value of power sold to PG&E through the SB 1122 feed-in-tariff program needs to rise to about $180 to $185/MWH to achieve feasibility.
- The biomass plant will sell an average of 3,400 pounds of steam per hour at a rate of $10.70 per thousand pounds in year 1. The steam sales rate will escalate at 2.5 percent annually.

- MR will use the New Market Tax Credit program to finance the project.
- MR will secure $1 million in grants to be applied toward project planning and development costs.
- MR will contribute a little over $7 million in equity to the project.
- MR will use the more reliable direct combustion technology to assure the project can deliver a minimum of 180 percent of its annual power production commitment during every two year period of the contract.
- MR will use forest derived fuels available in the form of logging slash and fuel from fuels reduction treatments to meet the requirements of the SB 1122 program.
- The initial delivered cost of the fuel will average $45 per bone dry ton.

BECK recommends MR complete the following tasks as next steps in the planning and development of the biomass project:

- Prepare an interconnection application under PG&E's Fast Track Process. This is necessary to be part of the SB 1122 queue when it opens.
- Research the CDFI NMTC process to determine qualification and availability of funds through one or more CDEs.
- Begin the air quality permitting process. Because the lead agency will likely be the USEPA, Region 9 in San Francisco, it should be expected that this process will take longer than usual and perhaps result in additional environmental documentation.
- Approach the U.S. Forest Service regarding a long term fuel treatment commitment, such as a 10 year stewardship contract. While MR currently has short term contracts with the USFS to carry out fuel reduction treatments, lenders will require secure long term access to necessary volumes of qualifying fuel. This action will also allow a more precise estimate of the delivered fuel cost if the specific types and locations of fuels to be used are identified.
- Since logging slash is the lowest cost fuel considered in the analysis and weighs heavily in the use of a $45 per bone dry ton delivered fuel cost in financial modeling, MR should verify with the CPUC/CalFire that logging slash produced from sustainably managed lands does indeed qualify for the SB 1122 program as has been assumed in this study.
- Begin preliminary engineering to define site characteristics, develop layout drawings and verify BECK's capital cost estimates.
- Complete all requirements to place the project in PG&E's SB 1122 queue as soon as it opens. By all appearances, there will be few projects in the initial queue, and it may be the Mooretown project that becomes the critical third project that allows the price ratcheting process to begin.

CHAPTER 2 – PG&E (SB 1122) PROGRAM ANALYSIS

2.1 INTRODUCTION TO SB 1122

California, through the provisions of SB 1122 (Rubio, 2012), placed a requirement on California Investor Owned Utilities (IOUs) to purchase modest amounts of electricity from various small (3 MW or less) biomass facilities. Included in that mandate was the requirement to purchase 50 MW of electricity from the byproducts of sustainable forest management. SB 1122 is a Bioenergy Feed-In-Tariff (FIT) program. A FIT is an economic policy created to promote active investment in and production of renewable energy sources. Such programs typically make use of long-term agreements and pricing tied to cost of production for renewable energy producers. SB 1122 will likely create a scenario that allows small scale biomass generation to make economic sense when such small facilities are not competitive in the larger wholesale electric marketplace.

2.2 LEVELIZED COST OF ELECTRICITY FROM SB 1122 PROJECTS

The SB 1122 legislation is being implemented by the California Public Utilities Commission (CPUC). The CPUC, through the help of a consultant (Black and Veatch)[3], projected the Levelized Cost of Electricity (LCOE) from 3 MW forest biomass projects. As shown in **Table 2.1,** the costs are estimated to range between $148/MWH and $281/MWH depending on assumptions about the project's capital costs ($/kilowatt of capacity), non-fuel operating costs ($/KW per year), and fuel costs ($/bone dry ton).

Table 2.1 – Small Scale Forest Biomass Projects Levelized Cost of Electricity (LCOE)

	Low Estimate	Medium Estimate	High Estimate
Capital Cost ($/KW)	5,000	6,000	7,500
Non-fuel Operating Cost ($/KW/year)	347	553	590
Size (MW)	3	3	3
Feedstock Cost ($/dry ton)	30	45	60
LCOE ($/MWH)	**148**	**219**	**281**

[3] Small-Scale Bioenergy: Resource Potential, Costs, and Feed-in Tariff Implementation Assessment. Black and Veatch. October 2013. Accessed at: http://www.cpuc.ca.gov/NR/rdonlyres/F95D0DD7-DEB3-4725-81B1-A24BAA8AE245/0/CPUCBioenergyReport10_31.pdf

The financial assumptions used in the Black and Veatch model were that the facility would be owned by a private taxpaying entity and that no tax advantages, credits, or low cost financing would be available. Some of the key metrics in the Black and Veatch model were:

- Debt/Equity ratio of 60/40
- Debt rate of 7 percent for 15 years
- Equity Cost of 12 percent
- Depreciation using 7 year MACRS (Modified Accelerated Cost Recovery System) on all capital costs
- Federal/State combined tax rate of 40 percent
- 2 percent annual inflation on operating, maintenance, and fuel costs
- Annual capacity factor of 85 percent
- Heat rate (mid-range) of 16,500 BTU/KWH
- 3 MW net generating capacity
- Gasification technology combined with three 1 internal combustion engines
- No value given for other byproducts
- No unusual interconnection issues or costs
- Following startup, no annual capital expenditures
- Project life of 20 years with no terminal value or cost
- 2013 dollars

It is likely that some of the assumptions used in the Black and Veatch study will not apply to all projects. For example, some of the projects that are being contemplated utilizing the SB 1122 program are located in economically depressed rural communities, which would make them eligible for New Market Tax Credits (NMTC) and typically have some government agency financial involvement. Those two factors are mechanisms for lowering debt costs and equity requirements, which were not accounted for in the Black and Veatch study. In addition, some proposed technologies would produce byproducts with value, and some would have thermal customers – neither of which was included in the Black & Veatch study. Additionally some, like MR, pay no income or property taxes. Therefore, BECK estimates that a 3 MW rural project could accept a LCOE price lower than the medium estimate shown in **Table 2.2** for a 15 to 20 year agreement.

2.3 SB 1122 ALLOWABLE FUEL TYPES

Four types of fuel have been determined to be acceptable in the SB 1122 program; all of the fuel must be from among the four categories, and at least 80 percent of the fuel for a given project must be sourced from a single one of these categories. In addition, recordkeeping/reporting must be completed annually to provide verification. The four categories are:

1. Fire Threat Reduction– biomass feedstock which originates from fuel reduction activities identified in a fire plan approved by CAL FIRE or other appropriate state, local or federal agency. On federal lands this includes fuel reduction activities approved under 36 CFR 220.6(e)(6)ii and (12) –(14).
2. Fire Safe Clearance Activities– biomass feedstock originating from fuel reduction activities conducted to comply with PRC Sections 4290 and 4291. This would include biomass feedstocks from timber operations conducted in conformance with 14 CCR 1038(c) (150’ Fuel Reduction Exemption) as well as projects that fall under 14 CCR 1052.4 (Emergency for Fuel Hazard Reduction), 14 CCR 1051.3-1051.7 (Modified THP for Fuel Hazard Reduction), and 14 CCR 1038(i) (Forest Fire Prevention Exemption), and categorical exclusions on federal lands approved under 36 CFR 220.6(e)(6)ii and (12) –(14).
3. Infrastructure Clearance Projects– biomass feedstock derived from fuel reduction activities undertaken by or on behalf of a utility or local, state or federal agency for the purposes of protecting infrastructure, including but not limited to: power lines, poles, towers, substations, switch yards, material storage areas, construction camps, roads, railways, etc. This includes timber operations conducted pursuant to 14 CCR 1104.1(b),(c),(d),(e),(f) &(g).
4. Other Sustainable Forest Management – biomass feedstock derived from sustainable forest management activities that accomplish one or more of the following: 1) forest management applications that maintain biodiversity, productivity, and regeneration capacity of forests in support of ecological, economic and social needs; 2) contributes to forest restoration and ecosystem sustainability; 3) reduces fire threat through removal of surface and ladder fuels to reduce the likelihood of active crown fire and/or surface fire intensity that would result in excessive levels of mortality and loss of forest cover or; 4) contributes to restoration of unique habitats within forested landscapes.

2.4 SB 1122 IMPLEMENTATION

The CPUC codified the process by which projects enter the SB 1122 program. The drafting and reviewing of rules and regulations occupied nearly two years at the CPUC, and a final order was approved by CPUC Commissioners on December 18, 2014. It is very complex, but several key points are that the project must be in the service territory of one of the Investor Owned Utilities (i.e., Southern California Edison – SCE, Pacific Gas & Electric – PG&E, or San Diego Gas & Electric – SDG&E) who are required to comply with the legislation. Since PG&E’s service territory is the most heavily forested, that utility is responsible for 47 MW of the 50 MW requirement.

The initial levelized price offered to project developers will be $127.72 per MWH. If there are at least 3 projects in the queue and none of the three can accept a PPA at the price, then the price begins to ratchet upward bimonthly by a predetermined amount and schedule. The price will continue increasing until it reaches a level acceptable to one of the projects. This price adjustment process is called ReMAT (Renewable Market Adjusting Tariff). If the offered price reaches $197/MWH without any takers, it will trigger a price cap investigation by the CPUC.

On December 18, 2014, the CPUC decision (D-14) codified much of the previous information and laid out the following program for implementing the 50 MW sustainable forest management portion of SB 1122. Key provisions include:

- Program to begin immediately, with IOUs given 45 days to submit details for approval (now lapsed)
- 50 MW total requirement (47 MW of which is PG&E's responsibility)
- $127.72/MWH project levelized starting price, with statewide price pool
- Use of Renewable Marketing Adjusting Tariff (ReMAT) mechanism to adjust prices
- Minimum of 3 projects in initial queue to allow price change modification to begin
- Once first 1 MW accepts a contract price, the minimum number of projects in the queue for the price change modification to again go into effect increases to 5 projects
- Use of existing ReMAT PPAs for contracting
- Program terminates 60 months after first offering
- PG&E, SCE to offer 6 MW in each auction, SDG&E to offer 3 MW
- Project must be in service territory of one of IOUs
- Transmission upgrades must not exceed $300,000 per project unless bought down to that level by developer
- Must be connected to IOU distribution system
- 3 MW maximum "nameplate" rating
- Must qualify at California Energy Commission (CEC) for California Renewable Portfolio Standard (RPS)
- Must be a Federal Energy Regulatory Commission (FERC) Qualifying Facility (QF)
- CPUC staff to review maximum price if it rises to $197/MWH

The general ReMAT program has been in place for several years to satisfy other requirements and is used by the IOUs to purchase small (3 MW or less) renewable power of all types. In PG&E's case there are a set of preconditions that must be satisfied before a project will be allowed to be placed into the ReMAT queue. Those preconditions include:

- Must be physically located in IOU territory
- Must be an Eligible Renewable Resource (ERR)
- Must be a federal Qualifying Facility (QF)
- Contract Capacity cannot exceed 3 MW

- Interconnection study, in some form, must be completed to indicate interconnection is feasible
- Must have 100 percent site control
- At least one member of development team must have experience with same technology/size project
- This must be the only project being developed at the site
- Cannot have accepted incentives from California Solar Initiative
- Cannot be doing Net Energy Metering at site

Once the initial queue is complete, the IOU will hold the first bimonthly subscription of 6 MW of PPAs. Queue position is determined by date of acceptance or by random drawing if on same date. The initial price will be $127.72/MWH for the PPA duration. The IOU will offer PPAs to the first 6 MW of projects in the queue. If no takers, they will go through the queue with the offering.

Assuming there are no takers among the 3 or more projects in the queue, the following bimonthly sequence will occur:

- First Bimonthly Adjustment: Original price + $4/MWH
- Second Bimonthly Adjustment: Revised price + $8/MWH
- Third Bimonthly Adjustment: Revised price + $12/MWH
- Fourth and Subsequent Bimonthly Adjustment: Revised price + $12/MWH

The price can also go <u>down</u> according to the same schedule if the 6 MW is fully subscribed. One unique feature in the bioenergy ReMAT will be that once 1 MW is subscribed, the queue must expand to 5 projects before the price can begin to move again. BECK estimates it is likely the ReMAT will be in effect for about 12 months before the price reaches levels that are acceptable. Note, however, a 12 month ReMAT period would escalate the price to a level close to the trigger price ($197/MWH) at which the CPUC would investigate a price cap.

Once an acceptable price is reached, the project will have 10 days to accept/reject the award. Once accepted, the project will be offered the standard ReMAT PPA. Some of the key provisions of this PPA are:

- Term of 10, 15 or 20 years
- Price fixed for term of PPA
- All sales net of station service
- Contract can be buy all/sell all or excess sales only
- Contract Capacity (CC) cannot exceed 3,000 KW
- Time of day pricing is applicable

- Can deliver up to 110 percent of CC in an hour
- Can deliver up to 120 percent of Contract Quantity (CQ) annually
- All Green Attribute & Resource Adequacy benefits to power purchaser
- 2 year energy guarantee of 180 percent of CQ
- Subject to California ISO forecasting, scheduling, penalties
- Project to post $20/KW collateral for life of contract
- Project on line within 24 months of PPA signing
- Typical definition of Green Attributes, so that any fuel emission related GHG benefits, for instance, would remain with project and not power purchaser

2.5 SB 1122 ANALYSIS AND IMPLICATIONS

The full implementation of SB 1122 may well be the only near term opportunity to expand biomass utilization from forest derived fuels in California. It comes at a time when, ironically, low wholesale electric prices and contract expirations are causing the shuttering of numerous larger biomass power facilities, several in forested areas. However, with only a 50 MW limit, the new facilities will not replace those being lost in terms of processing capability; they will be more targeted geographically and may be configured to produce other high valued byproducts.

These small projects could not hope to compete economically in the California wholesale power market without a program such as SB 1122. These will be, essentially, community scale projects designed to support local efforts to lower fire risk and restore the local forests to health and vitality. They will be small enough that they will not require guaranteed access to large swaths of federal forests over extended periods, something very difficult for federal land managers to provide.

Although sponsoring groups may have hoped to base their projects on the production of newer biofuels or biochar, it will be the standard production of electricity from biomass that allows a long term assured revenue stream so that financing can be obtained. If California "doubles down" on a long term commitment to greenhouse gas reduction, the facilities can transition to other uses, but will likely begin life as electric power producers with perhaps small quantities of other byproducts.

In putting together a project to compete for a SB 1122 ReMAT contract, the benefits of finding a legitimate steam host so that a Combined Heat & Power (CHP) project can be proposed are quite substantial. As shown elsewhere in this report, the financial benefits of CHP would allow the proposed project to accept a price earlier in the ReMAT schedule than would have otherwise been possible. In addition, there are other benefits. This would move the project up in the IOU queue, and it may be able to start construction ahead of a "power only" project. It is BECK's experience that community scale CHP projects that displace fossil fuel also have much wider public acceptance than stand-alone projects.

The bottom line is that SB 1122 is without a doubt the only contracting vehicle that would lead to a viable bioenergy project at MR in the foreseeable future. Accepted contract price will be at least 3 times current wholesale power prices. If MR wishes to proceed with a project at the conclusion of this feasibility study, it should qualify its potential project for PG&E's upcoming SB 1122 queue as soon as it is available. It does not appear to BECK that there will be a large number of projects proposed, and so MR's participation may be needed to allow price ratcheting to begin.

CHAPTER 3 – TECHNOLOGY EVALUATION

The following sections provide a review of three technologies for converting biomass into heat and power, including:

1) Direct combustion boiler/steam turbine;
2) Gasification/internal combustion (IC);
3) Direct combustion boiler/organic Rankine cycle as the prime mover

Initially BECK's scope of work was to evaluate direct combustion and gasification technologies for producing heat and power. However, midway through the project, MR requested that BECK also review organic Rankine cycle technology. Therefore, the following chapter is organized as follows: Section 3.1 provides a comparison between direct combustion and gasification technologies within the context of small-scale biomass power production under California's SB 1122 program. Section 3.2 offers a discussion focused solely on organic Rankine cycle technology. Section 3.3 provides the rationale for selecting direct combustion as the technology most appropriate for Mooretown Rancheria.

3.1 DIRECT COMBUSTION AND GASIFICATION TECHNOLOGY COMPARISON

Direct combustion is the process of burning biomass. Combustion occurs in a chamber where volatile hydrocarbons are released and burned, which creates heat energy in the form of hot flue gases. Typically, those flue gases are fed into a boiler to create steam. That steam, in turn, can be used to heat a building, supply heat to a manufacturing process, or generate electricity.

Gasification is the process of breaking down biomass fuels by heating them in an oxygen starved environment. The heating process produces a combustible gas called syngas, or producer gas. The syngas is collected, cleaned (tars and particulate matter are removed), and then it is combusted in an internal combustion engine/generator system. The material "leftover" after all of the syngas has been produced is biochar.

Gasification of sustainably produced biomass has been touted by some as the preferred method of creating power and combined heat and power for small scale biomass projects. The perceived advantages are:

1. Gasification produces, as a byproduct, biochar that can create an additional revenue stream.
2. Gasification has a lower emission profile than direct combustion, and thus the cost of cleanup is less.
3. Gasification, with gases directed to a modified internal combustion engine, has a lower capital cost than a traditional boiler/steam turbine combination.
4. Gasification generates waste heat from: a) gas cooling and treatment; b) IC engine cooling; and c) IC engine exhaust that can be captured and used for process heat.

5. Gasification is inherently simpler than direct combustion (e.g., no high pressure steam), and thus operator training/certification requirements are not as high.

These perceived advantages are discussed relative to a direct combustion boiler/steam turbine system project in the context of a facility whose first, and most important, duty is serving as the prime mover for a 3 MW SB 1122 contract with a very high electric price.

3.1.1 Compatibility with Thermal Load

In the gasification context, a gasification unit would be continually producing sufficient syngas so that after cleaning it would be capable of producing 3 MW in one or, more likely, two internal combustion engines. The waste heat that must be captured off such a system is essentially a fixed amount at all times. BECK estimates it represents 60 to 70 percent of the incoming energy (BTUs) in the fuel. To produce 3 MW net for sale, biomass fuel containing an estimated 35-40 million BTUs per hour must be introduced to the gasifier. This means that up to 28 million BTUs (70 percent of 40 million BTUs) per hour appear as waste heat that must either be captured or disposed of.

From an analysis of MR's utility records, the maximum nameplate capacity of all gas-fired hot water heating units at MR is just over 8 million BTUs (aggregate capacity) per hour of thermal output. On an annual basis, these units produce less than an average of 2 million BTUs per hour of heat. Thus, a gasifier would produce much more heat (up to 28 million BTUs) than could be used by the existing MR facilities (about 2 million BTUs per hour). As a consequence, a gasifier/IC engine system at MR would need heat rejection equipment in the form of radiators and a cooling tower. The IC engine exhaust would likely not be utilized at all. Even with potential expansion of an added brewery, hotel, and greenhouse an estimated less than 20 percent of a gasification system's waste heat would be utilized. The bottom line is that the MR's existing heat load is not well matched to a 3 MW SB 1122 generator.

In contrast, a traditional direct combustion boiler/steam turbine arrangement utilizes an extraction condensing steam turbine-generator (TG) to tailor the amount of process heat to the demand at the time. A turbine steam extraction can supply a hot water heat exchanger with just the amount of heat required by the Mooretown complex. In a typical system, the low grade stack gas heat and condenser inflow would not be captured, with the excess heat from the condenser rejected to a wet (or dry) cooling tower. The boiler would simply burn less fuel in the summer and more in the winter to match actual heat load.

3.1.2 Fuel Efficiency

It is difficult to get good efficiency figures on the few gasifier/IC engine projects that are in operation. In a power generation only mode, expected efficiencies seem to fall in the 25 to 31 percent range, with perhaps 27 percent being a reasonable assumption for the average. This is a heat rate of 12,640 BTUs of fuel input per KWH produced. For a direct combustion boiler/steam turbine combination, with the fuel expected at MR, a 24 percent overall conversion efficiency would be expected, or a heat rate of 14,220 BTU/KWH. When converted to annual tons of fuel, the gasification unit theoretically would use 2,000 bone dry tons (BDT) per year less fuel.

3.1.3 Capital Expense

The gasification/IC engine combination is expected (from the CPUC Black & Veatch Study[4]) to have a capital cost of $5,000 to $7,000/KW, or $15 to $21 million for a 3 MW installation. This is lower than some recently announced smaller gasification installations, which cluster more in the $8,000 to $10,000/KW range. BECK projects a capital cost for a Wellons complete boiler/steam turbine combination (minus process heat costs) of $21 million, or $7,000/KW net. Please note that both of the capital costs just provided are at a high-level, and given the overlap between the estimates, BECK considers both technologies to be roughly equal in terms of capital expense.

3.1.4 Environmental Performance

Regarding environmental performance, one would expect gas leaving a gasification unit to have less NOx, more CO and the same particulate matter relative to gas leaving a direct combustion boiler. However, gas leaving the gasifier is cleaned of tars and some particulates by cooling/condensation. The “clean” gas is then combusted in an IC engine, which should destroy the CO, but will likely boost the NOx. The IC engine would have no effect on particulates.

Larger gasification units are typically equipped with an electrostatic precipitator (ESP) for particulate control, as is a biomass boiler. Smaller units of 3 MW capacity typically do not have supplemental controls for CO or NOx unless located in an area with extraordinary pollution issues. Thus, one would expect a gasification/IC engine facility and a boiler/steam turbine facility of 3 MW size to have the same pollution control package.

3.1.5 Staffing

In terms of staffing and staff qualifications, the expectation would be that both facilities would be staffed on a 24x7 basis by at least one person per shift. With MR having 24x7 Security that can be contacted by biomass plant staff in the event of an emergency, the risk of having a lone staffer at night is low. Somewhat surprisingly, California has no licensing requirement for power unit operators. With numerous closures of larger biomass units in the north (Burney, Westwood, Oroville, Anderson) and more to come, experienced operators should be available to MR. It would be expected that the staffing levels for the two technologies would be similar and that qualified staff would be available.

3.1.6 Revenue Sources

It is expected that a gasification facility could indeed produce a fair quantity of biochar as a byproduct, if markets warrant. Biochar is a form of charcoal, but potentially has a market value

[4] Small-Scale Bioenergy: Resource Potential, Costs, and Feed-In Tariff Implementation Assessment. Accessed at: http://www.cpuc.ca.gov/NR/rdonlyres/9ABE17A5-3633-4562-A6DA-A090EB3F6D07/0/SmallScaleBioenergy_DRAFT_04092013.pdf

as a low volume soil amendment. However, BECK recommends caution in overvaluing the biochar as it appears the specialty soil amendment market could be easily saturated by several large plants coming on line.

In the longer term, the role for biochar is likely to be as a form of carbon sequestration when introduced into the soil. As carbon markets become more robust in California, and a protocol is approved for sequestration via biochar, this can likely produce another stable revenue stream for a gasification project.

However, it is important to note that the production of a high carbon biochar does not occur for free as the BTUs in the carbon of the biochar are not recovered as heat and electricity. Work by BECK on another project has shown that when biochar is produced from forest waste, carbon prices must be above $40/ton of CO2e before the carbon as biochar becomes a positive income contributor. Currently, carbon markets in California are in the $10 to $12 per ton range, and they have consistently been at that level since AB32 was implemented. Carbon markets may well reach $40 per ton or more in the 2020s, but by then the breakeven cost will also have risen due to inflation of fuel prices.

An oversized gasifier with a 3 MW IC engine could also allow for some syngas, post treatment, to be diverted to the production of transportation fuels, for instance, without dropping the 3 MW production. This may have great potential in a low carbon world, but the timing, technology, and economics all remain unknowns. Absent more definitive information, inclusion of excess capacity in a 2015 project is simply raising initial capital cost with an unknown, if any, return.

3.1.7 Proven Technology

The natural conclusion from the preceding discussion is that, all things being equal, the potential slightly higher overall efficiency of gasification/IC engine technology and the potential byproduct markets would push a decision in favor of gasification. However, all things are not equal. The boiler/steam turbine combination burning forest and mill biomass has been demonstrated in hundreds of installations over decades, at scales both larger and smaller than 3 MW. Multiple vendors will provide firm prices and will provide bonded guarantees of completion, performance, and environmental compliance. The fuel specification for the unit will be broad, accepting various moisture contents, species, piece sizes and heating contents. If one knows in advance the basics of the fuel supply (i.e., piece geometry, heating values, and moisture content), the purchased boiler/turbine combination will burn it reliably and produce the 3 MW plus process heat.

In the gasification/IC engine world, the outcome is far more uncertain. There is much literature regarding the sensitivity of gasifiers, particularly fixed bed gasifiers, to both particle size and moisture content. Much literature, including MR's DOE study, indicates that the fuel should be dried to provide a consistent moisture content to the gasifier. There is virtually no experience with gasification of mixed forest waste direct from the field (i.e., varied piece geometry and varied moisture content). It is not known whether the constant variation in content between bark, needles, twigs and the tree bole can be consistently gasified, as well as how the wide variations in seasonal moisture content will affect the operation of the equipment.

In addition, the gas cleanup equipment ahead of the IC engine is also suspect. Failures in this part of the gasification process have defeated all attempts, over many decades, to successfully operate a gas turbine off clean syngas. IC engine technology is clearly more forgiving and has become the industry standard. Still, there is very limited information concerning long term operation of IC engines on cleaned syngas. Anecdotally, it has been reported that these systems typically have shortened runs between what would be considered normal maintenance cycles, which would lead one to believe that the engines may have a shorter useful life than might be expected.

3.1.8 Capacity and Reliability

One of the issues facing those seeking an SB 1122 contract is that the Power Purchase Agreement (PPA) will specify that baseload technologies must produce 180 percent of their annual contract quantity every two years or be subject to a penalty for the shortfall. This is basically a requirement that you annually produce 90 percent of the expected amount of power. This requirement can be softened by not pledging to operate at a high capacity factor. However, that strategy is flawed because then the facility is “trapped” at that lower amount (i.e., PG&E will not accept more than 120 percent of the contract quantity annually). In a contract capped at 3 MW, the facility’s revenue potential is inherently limited and, therefore, the facility must produce as much as possible at all times. Since gasification of mixed forest waste without drying is unknown, there is limited experience with IC engines firing cleaned syngas, and the PG&E contract imposes penalties for relatively slight drops in expected power output. Therefore, BECK cannot recommend that MR install a gasification/IC engine facility as a response to an SB 1122 solicitation.

3.2 BIOMASS COMBUSTION/ORGANIC RANKINE CYCLE (ORC)

MR has requested that BECK evaluate organic Rankine cycle (ORC) as a possible technology for application in MR’s prospective CHP project under SB 1122. ORC is a technology that uses an organic working fluid, such as pentane or toluene, in place of water. Organic fluids have a lower boiling point than water and, as a consequence, the operation can be carried out at lower temperatures and pressures than would be possible for a comparable steam/water system.

The ORC technology was developed primarily in Europe and has its roots in: very small units designed to capture waste heat, in geothermal brines, and in biomass district heating systems. ORC has been fairly widely deployed internationally. There are currently an estimated 600 units generating about 2,000 MW in total.

There are many similarities between direct combustion steam heat/power generation and ORC technology. Both would use a biomass burner equipped with the same pollution control and back end heat recovery equipment. However, in an ORC "boiler", the primary heat recovery is completed without the necessity for boiler steam/water separation drums and without the necessity for a separate superheater as in a steam system.

A typical system would use a hot oil heat recovery fluid in the boiler at atmospheric pressure. This hot oil would give up its heat to a lighter organic working fluid in a heat exchanger and that working fluid would be expanded through a turbine-generator. After leaving the turbine, the fluid would be condensed in another exchanger, giving up its heat to water to be used for process/heating needs. The working fluid would then be pressurized by being pumped back to the heat exchanger, similar to the function of the boiler feed pump in a steam/water system.

Other differences of an ORC system are that an onsite water treatment system is not needed, nor is there a need for a deaerator to remove oxygen from the system.

3.2.1 Applications

Most ORC units deployed internationally are in applications involving recovery of low grade heat from industrial facilities, heat recovery from geothermal brines that are too low grade to be used directly, and biomass CHP systems with the thermal portion supporting a district heating system. Biomass represents over half the total installations, but has an average electrical size of less than 1 MW.

In North America, the concept of ORC has advanced primarily within the Canadian forest products industry. There, as opposed to steam in the U.S., lumber producers use ambient pressure hot oil to dry their lumber. Hot oil is used primarily because boiler operators do not have to be licensed as they would if they were operating a pressurized steam system. Since a hot oil combustor sized for winter peak drying requirements has a lot of unused capacity at other times of the year, and since a sawmill typically has a lot of low-value wood waste (e.g., bark and sawdust) to dispose of, the addition of an ORC unit makes good economic sense.

The summary of installations that BECK has reviewed shows that most ORC installations tend to be sized for the thermal application, not the electrical. Because of the thermal focus and low temperature/pressure applications, an integrated ORC unit has an efficient thermal delivery system, but a relatively inefficient electrical conversion.

3.2.2 Relative Capital Cost

An extensive review of ORC CHP systems published in 2013 in Europe shows that complete ORC systems in the 3 MW range cost $3,500 to $4,000 Euro per KW to install. With the 2013 dollar to Euro exchange rates and an additional 2 years of escalation added, the 2015 capital cost range would be $5,000 to $5,750/KW. This compares to BECK's 2015 estimate for a steam system of about $7,000. It would be expected that the ORC unit would cost less since it has no drums, no superheater, and no deaerator or water treatment system as does the steam system.

3.2.3 Operation & Maintenance Cost

One of the selling points of the ORC technology is that the combustion and primary heat recovery are carried out at ambient pressure, and thus licensed steam plant operators are not required and, in fact, the smaller systems may be unmanned. It is beyond reason to expect that MR would leave the unit unmanned. The fuel delivery, ash removal and environmental compliance systems alone will require round the clock staffing of the unit. Thus, there are likely to be no differences in staffing between technologies, and since California has no licensing requirement for plant operators, no difference in labor cost.

BECK does not have enough detailed information on ORC systems to project a difference in maintenance cost. However, since the high maintenance areas of the plant (fuel delivery, fuel handling, fuel processing, ash removal, and pollution control) are similar, major differences are not expected. Nevertheless, one would expect ORC to be slightly lower overall since the heat transfer operation takes place at lower temperatures/pressures.

3.2.4 Fuel Cost

The fuel quality requirements of the steam and ORC technologies are identical, and so no per ton cost difference would exist. Because of the lower electrical efficiency of the ORC unit, as explained below, the ORC unit will require more fuel. The combined impact of lower turbine efficiency and higher pumping requirements means that the ORC unit will need 40 to 50 percent more fuel.

Biomass is unique among fuels in that the more of it used, the more expensive the fuel gets at the margin. Delivered biomass fuel costs for locations without on-site fuel (such as MR) are delivery cost dominated. In general, each additional ton required is slightly further away. This is especially true in the SB 1122 program where fuel must meet stringent origin requirements. Consequently, the ORC system would have both higher average fuel cost per ton and a higher annual fuel requirement.

3.2.5 Environmental

Both combustion systems will be identical, so air emissions per ton of fuel should be the same. Since the ORC unit will burn substantially more fuel, the total emissions will be greater with ORC.

Water used would be virtually nonexistent with the ORC unit if electrical and thermal loads were balanced. However, that is not the case as MR will obviously maximize electrical production, meaning that the ORC unit would also need a wet (cooling tower) or dry (air cooled condenser) heat rejection system after the turbine (as does the steam system). The ORC system would still use less water, however, as it has no need for water treatment backwash or boiler blowdown.

In terms of toxic and greenhouse gas issues, however, the conventional steam system is clearly superior. The working fluids of the ORC system, both hot oil and lighter organics, are considered toxic and subject to elaborate release/containment plans. If released due to leakage, they would also have greenhouse gas implications that would have to be reported and potentially offset.

3.2.6 ORC Application at Mooretown

The driving force behind the project at Mooretown is the SB 1122 program, which should produce extremely high electrical prices for up to 3 MW of capacity fueled by the products of sustainable forest management. The fuel from Mooretown's forestry operation is a good qualifying complement to the SB 1122 program, but will be relatively expensive when delivered to MR's prospective facility. The thermal component of heating, and potentially cooling, the casino/hotel/brewery/greenhouse is of a much smaller scale and will be designed to enhance the economics of the SB 1122 unit, but is not the project driver.

The combination of high electric prices, high fuel prices, and modest seasonal heating/cooling load mean that the installed technology should maximize the efficiency and reliability of the electrical generation. This is not the forte of an ORC installation. The electrical conversion efficiency of an ORC unit is only about 18 to 20 percent due to low net heat transfer from the working fluid across the turbine-generator. By contrast, the steam system will typically convert 27 to 30 percent of the BTUs entering the turbine to electricity. In addition, pumping of the working fluid in an ORC system consumes some 4 to 10 percent of the power produced, while in a steam system it is only 1 to 2 percent.

The bottom line is that for an electric driven system with high fuel costs, as is the case at MR, the steam cycle is a better choice than ORC technology.

3.3 OVERALL TECHNOLOGY REVIEW CONCLUSION

Beginning with a greenfield site, which is the case with MR, ORC offers no real advantages over a steam boiler/turbine combination. ORC shines when applied to a low temperature resource, such as geothermal brine, or in a true waste heat application. The lower boiling point/condensation point of the organic working fluid makes the technology viable in these applications. However, the low temperature differentials handicap the power generation side, leading to an overall conversion efficiency (fuel to electricity) of only 18 to 20 percent versus 25 to 30 percent for a direct combustion boiler/steam turbine system. The relatively high delivered fuel cost of forest waste makes this efficiency difference impossible for ORC to overcome economically.

The draft power purchase agreement (PPA) accompanying the SB 1122 program for small forest-derived biomass (3 MW or less) contains a provision that base load projects generate 180 percent of the expected annual output over every two year period or face penalties and potential loss of the contract. With the proposed forest derived fuel virtually untested in a gasification/IC engine setting, this creates a large financial risk in adopting this technology. Loss of the dramatically over-market SB 1122 PPA due to nonperformance would be catastrophic to MR.

While acknowledging that some upside financial potential is foregone due to potential markets for gasification byproducts (i.e., biochar), BECK does not recommend that MR select gasification/IC engine technology for the project at this time. BECK does, however, recommend this technology be monitored to determine if successful use of forest derived fuels is achieved.

For cogeneration projects such as MR, an extraction/condensing turbine-generator (T-G) has proven to be a flexible and efficient way to provide process steam or hot water. As opposed to other technologies that produce a fixed amount of heat at each generation level, the extraction-condensing T-G produces only that amount of process heat needed at the moment while maintaining a flat output of electricity. The swings in requirements are taken instead by the boiler.

Given the preceding findings, BECK recommends that Mooretown utilize direct combustion boiler/steam turbine technology. Projects deploying this technology and utilizing mixed forest waste are well proven in the 3 MW size range. Multiple vendors offer projects with commercial guarantees and plants that have been proven reliable and able to meet the requirements of the proposed SB 1122 PPA. BECK has requested design details and a budgetary estimate for a suitable project for MR. The details of the estimate are described in **Appendix A** of this report.

3.4 DIRECT COMBUSTION/ STEAM TURBINE DETAILED DESCRIPTION

Given BECK's recommendation of a standard direct combustion steam boiler/steam turbine combination, the following section provides a more detailed description of the equipment and how it will operate.

3.4.1 Overview

In virtually all biomass cogeneration applications in the United States, a standard steam boiler/steam turbine-generator combination is used. This combination is moderately efficient, robust, available from several substantial vendors, and can be purchased with commercial guarantees of completion, operational performance and environmental performance.

3.4.2 Boiler Operation

The steam boiler combusts the fuel on a grate (fixed or traveling) or in suspension with an inert material (bubbling or circulating fluidized bed). In the case of Mooretown, either a traveling grate (rotating, shaker, linear) or a bubbling fluidized bed is the logical choice. Fixed grates are rarely employed today for new installations, particularly with higher ash fuels such as forest waste. The circulating fluidized bed (CFB) is too complex and costly for a small operation such as Mooretown.

At the boiler size range considered for Mooretown (30,000 to 40,000 pounds of steam per hour), the likely boiler steam pressures range from 400 to 900 pounds per square inch (psig). The steam temperature will be superheated to allow for more efficient turbine operation, with potential temperature ranges of 700 to 900 Fahrenheit.

The fuel will be distributed across the grate (or fluidized bed) by an air assisted stoker that creates a uniform fuel bed depth. The grate or bed will be self-cleaning, with ash falling below the grate and being conveyed automatically to ash storage bins. The heat of combustion will be captured first in wall tubes containing water, followed by the superheater and convection section, and finally by the economizer and air heater. The goal of these devices is to capture from the steam some 70 to 75 percent of the theoretical heating value (BTU/pound) of the incoming wood fuel.

3.4.3 Pollution Control

Wood combustion creates air emissions that must be minimized by pollution control equipment. Particulate matter is one form of air emissions associated with wood combustion. It is typically controlled by a cyclonic collector (multiclone), followed by an electrostatic precipitator (ESP). Volatile organic compounds (VOCs) and carbon monoxide (CO) are other emission types. They are generally controlled by injecting multiple levels of heated overfire air into the combustion zone to assure more complete combustion. Nitrogen oxides (NOx), another pollutant, may be controlled by staged combustion[5], but often require injection of ammonia or urea into the combustion zone in what is referred to as Selective Non-catalytic NOx reduction (SNCR). The use of these devices may vary depending on the plant size and severity of air quality issues in the local jurisdiction.

3.4.4 Turbine-Generator/Cooling System

The turbine-generator is typically a multistage rotor spinning at 3,600 – 8,000 RPM. If the turbine is directly connected to the generator it will spin at 3,600 RPM (60 cycles/sec). If a reduction gear is installed between the two, the rotation speed is typically 5,500 – 8,000 RPM. The generator spins at 3,600 RPM (2 pole generator) or 1,800 RPM (4 pole generator). A typical generation voltage for small units, such as Mooretown is considering, is 4,160 V. This voltage would be increased to distribution line voltage (12KV) in an on-site step-up transformer.

In cogeneration mode, the turbine will have one or more steam extractions at points in the process that match the requirements of the thermal customer. In that way, power can be generated by the steam in the turbine down to the point at which it is needed for thermal uses.

The steam not needed for thermal uses is condensed under a high vacuum in a surface condenser by contacting tubes cooled by water circulating from a cooling tower. Substantial water is evaporated in the cooling tower that must be replaced. If water availability/cost is a serious issue, the condenser and cooling tower can be replaced by an air cooled condenser that uses no water. The air cooled condenser is more costly, however, and overall system efficiency is reduced.

Biomass cogeneration systems using steam as the working fluid have been in use in the forest products industry for over 80 years. A well designed system should operate at full load for 8,200 – 8,400 hours annually. Though such systems are typically designed to allow electricity production to sag when thermal loads are high, a system at Mooretown Rancheria would likely have an oversized boiler such that the maximum 3 MW output could be maintained at all thermal demands.

[5] Staged Combustion refers to a method of combusting biomass in which hot gases are produced in an initial combustion step followed by a second step where the gases are more fully combusted. This combustion method has been found to reduce CO and NOx emissions.

3.4.5 Fuel System

Because of the small size and required reliance on a single fuel source, the Mooretown fuel receiving, processing and delivery system will be relatively simple and straightforward. The only sizeable variable in the design will be the amount of fuel storage, which will be dictated by the seasonality of the woods fuel required by SB 1122 to be utilized as fuel.

The annual fuel requirements at the biomass plant will be approximately 26,000 bone dry tons per year (BDT/year). Given that relatively small size, a permanent truck dump installation will not be necessary. Instead, self-unloading trailers can be utilized for the required 1,800 loads annually. A fleet of 4 trailers, each making 2 round trips on weekdays can satisfy the fuel requirements for the plant.

The trucks would unload using a power take off driven hydraulic walking floor system (**Figure3.1**). The fuel would discharge into a hopper feeding a rubber belt that would carry the fuel to an elevated tower containing a disc screen which would reject oversized pieces to a Hammermill for size reduction. The combined streams are carried to the storage pile by belt conveyer.

Figure 3.1 – Self Unloading Walking Floor Trailer

Fuel would be moved from the storage pile to reclaim by mobile equipment. The reclaim system will likely be an in ground series of chains over which a substantial volume of fuel (1-2 hours run time) could be piled. The parallel reclaim chains would discharge onto a belt conveyer that would carry the fuel to the multiple hoppers feeding the boiler. These hoppers would be equipped with level detection equipment to prevent overfilling and would start/stop the fuel delivery system to maintain fuel level.

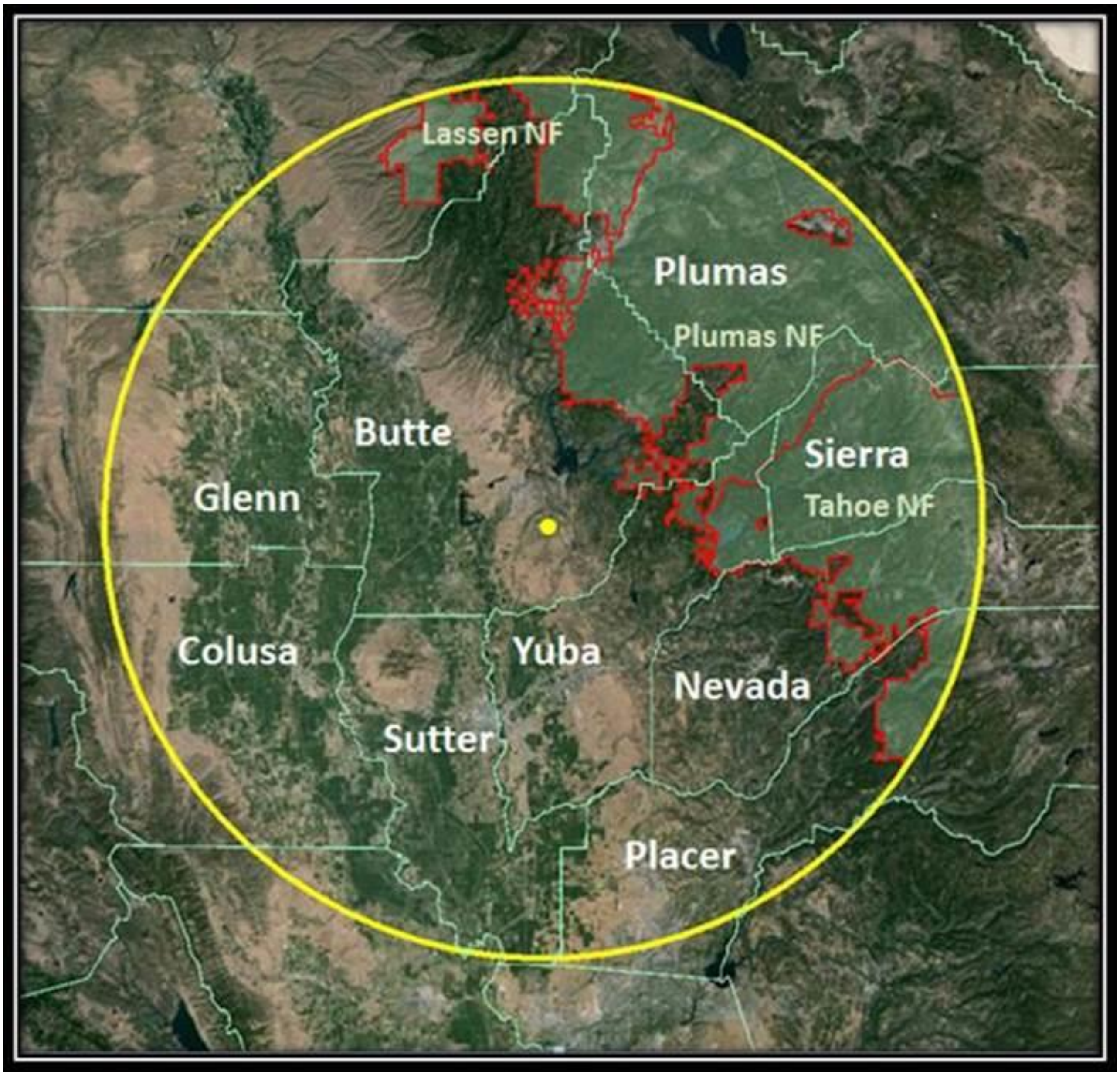
It is likely that MR, due to seasonal fuel availability, will be required to store as much as two months of fuel (4,000 bone dry tons) on site prior to the start of winter. This fuel, piled 20 feet deep, would occupy a space of about 34,000 square feet (3/4 acre). Thus, the total site size for the facility would be approximately two acres.

CHAPTER 4 – BIOMASS RESOURCE ASSESSMENT

4.1 INTRODUCTION

BECK assessed the available supply and delivered cost of fuel for the prospective MR biomass cogeneration project. The geographic scope of this effort was a 50 mile radius circle (centered on Mooretown – the small yellow dot),as shown in **Figure 4.1**. The large yellow circle denotes the perimeter of the supply area and the names in white lettering are the counties in the supply area. The light green shaded areas are publicly owned lands in the supply area that include portions of the Lassen, Plumas and Tahoe National Forests.

Figure 4.1 – Mooretown Rancheria Biomass Supply Area



The sources of fuel considered in the analysis include: 1) mill residues (byproducts of sawmills); 2) orchard residues; 3) urban wood waste; and 4) forest derived fuels (fuel reduction treatments and logging slash). Please note that while all the preceding fuel sources were analyzed, if MR is to participate in the SB 1122 program, that law requires the use of only forest derived fuels.

Also note that for all of the fuel sources, BECK has estimated a “total” available volume and a “practically” recoverable volume. The total available volume is the total amount of fuel estimated to be produced annually. However, because of limitations in the ability to gather, process, or transport all that is produced, due to excessive cost, or because the material has a higher value use in some other application, BECK has also estimated the volume that is practically available on an annual basis. There is no well-defined methodology for estimating the difference between the total volume and practically available volume. Thus, it is largely an estimate based on judgment from prior experience.

4.2 MILL RESIDUE SUPPLY

Table 4.1 displays the estimated volume of Mill Residues (chips, sawdust, shavings, bark) produced in the region of Mooretown Rancheria. As shown, 246,000 bone dry tons of material is estimated to be potentially available annually after accounting for material that is consumed at each mill’s cogeneration facility. Please note that the radius for mill residuals was extended beyond 50 miles because those materials are frequently transported distances significantly greater than 50 miles. This practice is common because the cost of “collecting” the material is zero. In other words, the sawmill, by virtue of the production of lumber, has collected the mill residues in a central location. This, in turn, means that the materials can be transported a longer distance and still be delivered at or below a given cost relative to other fuels sources, such as forest derived material.

Table 4.1 – Estimated Volume of Mill Residues in MR Supply Area (BDT)

Facility	Location	Road Miles to MR	Annual Lumber Production (MBM)	Total Mill Residual Volume Estimate (BDT)	Estimated Volume Required for Cogen (BDT)	Potentially Available Mill Residual Volume (BDT)
Sierra Pacific Industries	Oroville, CA	3.7	91,000	81,400	0	81,400
Sierra Pacific Industries	Lincoln, CA	52.4	273,000	243,100	160,000	83,100
Sierra Pacific Industries	Quincy, CA	69.6	180,000	160,000	160,000	0
Collins Pine	Chester, CA	92.3	200,000	178,100	96,000	82,100
Total			**744,000**	**662,600**	**416,304**	**246,600**

4.2.1 Mill Residue Methodology

BECK estimated the annual production of mill residues using factors that relate the production of lumber to the production of chips, sawdust, shavings, and bark. The factors are derived from BECK's Western U.S. sawmill industry benchmarking studies. The factors used were 0.52 BDT of chips, 0.10 BDT of sawdust, 0.11 BDT of shavings, and 0.17 BDT of bark per thousand board feet of lumber produced.

Also, as shown in **Table 3.1**, three out of the four mills that BECK identified in the Mooretown region have cogeneration biomass power plants on site. BECK understands that all of those plants are fed with mill residuals from the respective mills. The Sierra Pacific mills in Lincoln and Quincy both have 20 MW cogeneration facilities located at the sawmill sites. Collins Pine sawmill in Chester has a 12 MW facility on site. A general rule of thumb for feedstock required to feed a cogeneration biomass plant is 8,000 BDT/MW per year. Therefore approximately 160,000 BDT of mill residuals are required at each of Sierra Pacific Industries sites, and 96,000 BDT of residuals are required at Collins Pine to run their cogeneration operation. Those volumes were subtracted from the total volume of mill residuals produced to arrive at the potentially available mill residue estimate.

4.3 ORCHARD RESIDUE SUPPLY

Table 4.2 illustrates the estimated volume of biomass produced from the removal and replacement of orchard crops annually. As shown, an estimated 231,000 BDT of material is produced annually in the 9 counties in the MR Supply Area.

Table 3.2 – Estimated Volume of Orchard Residues in MR Supply Area (BDT)

County	Acres of Orchards	Acres of Feedstock Removed	Total BDT of Feedstock from Removal	Recoverable Volume (BDT)
Yuba	28,572	1,429	18,600	6,100
Butte	93,629	4,681	60,900	20,100
Sutter	75,020	3,751	48,800	16,100
Glenn	94,701	4,735	61,600	20,300
Nevada	559	28	400	100
Colusa	59,424	2,971	38,600	12,700
Sierra	0	0	0	0
Placer	1,752	88	1,100	400
Plumas	1,752	88	1,100	400
Total	**355,409**	**17,770**	**231,100**	**76,200**

4.3.1 Orchard Residue Methodology

The Orchard waste fuel supply estimate shown in **Table 4.2** is based on the following methodology. According to the 2012 Census of Agriculture, the acreage of orchards in Butte, Plumas, Sierra, Nevada, Yuba, Placer, Sutter, Colusa and Glenn counties totals 355,409 acres. Based on interviews with BECK's biomass industry contacts in California, orchard removal operations are conducted on 5 percent of the commercial orchards annually, and those operations yield an average of 13 bone dry tons of biomass per acre. Thus, the available volume was calculated by assuming that 5 percent of the total orchard acres in the 9 counties in the MR Supply Area would be replaced with new crops each year and that each acre would yield 13 BDT of biomass. A safety factor of 0.33 was applied to the total volume to estimate the practically recoverable volume as a proportion of the total volume.

Waste due to thinnings and pruning on orchard land equals 1 green ton per acre per year. However, BECK's biomass industry contacts in California reported that it is generally not cost effective to collect the orchard thinning and pruning material. Therefore, those additional volumes of material were not included in the supply estimate.

4.4 URBAN WOOD RESIDUE SUPPLY

Table 4.3 shows an estimated 79.6 thousand bone dry tons of urban wood waste available in the MR Supply Region annually.

Table 4.3 – Estimated Volume of Urban Wood Residues in MR Supply Area (BDT)

County	Residents (Number)	Municipal Solid Wood Waste (BDT)	Industrial Wood Waste (BDT)	Construction & Demolition (BDT)	Estimated Total Volume (BDT)	Estimated Recoverable Volume (BDT)
Yuba	73,966	15,500	3,700	5,900	25,100	6,300
Butte	224,241	47,100	11,200	17,900	76,200	19,100
Sutter	95,847	20,100	4,800	7,700	32,600	8,100
Glenn	27,955	5,900	1,400	2,200	9,500	2,400
Nevada	98,893	20,800	4,900	7,900	33,600	8,400
Colusa	21,419	4,500	1,100	1,700	7,300	1,800
Sierra	3,003	600	200	200	1,000	300
Placer	371,694	78,100	18,600	29,700	126,400	31,600
Plumas	18,606	3,900	900	1,500	6,300	1,600
Total	**935,624**	**196,500**	**46,800**	**74,700**	**318,000**	**79,600**

4.4.1 Urban Wood Residue Methodology

There are 3 types of urban wood waste:

1. **Municipal Solid Waste (MSW) –** refers to the range of material collected by public and private trash hauling services in metropolitan areas. Yard trimmings and miscellaneous waste wood typically make up about 25 percent of MSW. While most MSW is destined for landfill, some regions sort MSW for recycling. The wood material recovered from the sorting can be used for a number of applications, including as hog fuel, mulch, or by combining the material with bio solids from wastewater plants to make compost. A study by Wiltsee found that across the U.S. metropolitan areas, the average amount of wood waste in the MSW is 0.21 bone dry tons per person per year.

2. **Industrial Wood Waste –** is material such as wood scraps from pallet recycling, wood working shops and lumber yards. The Wiltsee study found that this material is produced, on average, at a rate of 0.05 bone dry tons per person per year.

3. **Construction and Demolition Waste –**is wood waste produced during the construction and demolition of buildings and from land clearing associated with new construction. The Wiltsee study found that this material is produced at an average rate of 0.08 bone dry tons per person per year.

The urban wood wastes per person per year factors described above were applied to the populations of the nine counties surrounding Mooretown Rancheria. According to the U.S. Census, the populations for these nine counties total 935,624 people. The largest county (by population) of the nine counties is Butte County, which is where Mooretown Rancheria is located. Butte County has a population of 224,241 people, as estimated in 2014. Other counties include: Plumas (18,606), Sierra (3,003), Nevada (98,893), Yuba (73,966), Placer (371,694), Sutter (95,847), Colusa (21,419), and Glenn (27,955). A safety factor of 0.25 was applied to the total urban wood waste volume to arrive at the practically available wood waste volume. The application of the safety factor accounts for urban wood that may not currently have efficient collection systems or that may already be utilized by other cogeneration facilities.

4.5 FOREST DERIVED RESIDUE SUPPLY

Forest derived fuels include trees that are harvested as part of thinning projects that are aimed at reducing wildfire risk and improving forest health. Since the trees harvested in such treatments are typically small diameter (i.e., less than 12” in diameter at breast height), they are generally too small to be utilized by a sawmill or veneer mill. Other utilization options for such trees include manufacturing them into posts and poles and chipping them for use in paper making. However, California has very few post and pole manufacturers and no remaining paper mills. Therefore, one of the only utilization options for small diameter trees is chipping/grinding them and then burning the resulting chips to produce heat and/or power.

In addition, forest derived fuels can include logging slash, which is the limbs, tops, and otherwise unutilized parts of trees that are produced from saw timber harvesting operations. Such operations harvest larger diameter trees, which are manufactured into saw logs. The process of creating sawlogs involves removing all of the limbs from the tree trunk and cutting off the top of the tree at the point where its diameter is the minimum size allowed by sawmills. The resulting unutilized limbs and tops are referred to as logging slash.

The following section provides an estimate of the volume of small diameter material and logging slash.

4.5.1 Area of Timberland

In assessing the supply of small diameter trees and logging slash it is first useful to understand the total area of timberland[6] in the project's supply area, who owns the timberland, and how thickly it is stocked with trees. To estimate these factors, BECK used the U.S. Forest Service's Forest Inventory and Analysis database, which allows users to enter the coordinates of a given area to retrieve data about the area's timber resources.

In this case BECK used a 50 mile radius around Mooretown Rancheria. As shown in **Table 4.4,**there is an estimated total of 1.645 million acres of timberlands in MR's supply area. There are about 5.0 million total acres of land in the supply area. Thus, timberland accounts for just over 30 percent of the land area in MR's supply area. The table also shows that National Forest accounts for nearly 60 percent of the timberland in the region, and privately owned timberland is nearly 39 percent. Finally, the table shows that nearly 13 percent of the timberland acres in the region is judged to be overstocked. Such lands are most in need of thinning to reduce risk from insect, disease, and wildfire.

Table 4.4 - Timberland Acres by Ownership Class and Stocking level (50 mile radius from Mooretown)

Ownership class	Overstocked	Fully stocked	Medium stocked	Poorly stocked	Non stocked	Total
National Forest	154,417	514,899	239,771	59,441	16,362	984,889
Bureau of Land Mgmt.	1,491	10,136	0	0	0	11,627
County and Municipal	0	12,727	0	0	0	12,727
Private	56,688	290,766	176,153	105,759	6,620	635,986
Total	**212,595**	**828,529**	**415,925**	**165,200**	**22,981**	**1,645,230**

6 Timberland refers to forest capable of producing at least 20 cubic feet per acre per year of industrial wood and not withdrawn from timber utilization by statue or regulation.

4.5.2 Volume of Standing Material on Timberland

To begin understanding the volume of biomass material potentially available, **Table 4.5** displays the average estimated bone dry tons of standing volume per acre by ownership class and stocking level. As would be expected, the standing volume on overstocked acres is significantly higher than the volumes in the other categories. On just the 212,595 acres estimated to be overstocked, there are an estimated 23.7 million bone dry tons of standing timber.

Table 4.5 - Average BDT/acre by Ownership Class and Stocking Level on Timberland (50 mile radius from Mooretown)

Ownership class	Overstocked	Fully stocked	Medium stocked	Poorly stocked	Non stocked
National Forest	125.2	85.8	30.6	16.1	0.1
Bureau of Land Mgmt.	79.2	71.2	0.0	0.0	0.0
County and Municipal	0.0	52.3	0.0	0.0	0.0
Private	75.8	59.8	29.3	13.8	1.9
Total	**111.7**	**76.0**	**30.0**	**14.6**	**0.6**

Table 4.6 more fully illustrates the total volume of standing timber currently estimated in the supply area. As shown, the total for all stocking classes is over 101 million bone dry tons. Of that amount, about 70 percent is on National Forests and about 19 percent is in overstocked stands on National Forests. Privately owned lands, which generally have been more actively managed over the last several decades, contain a much lower proportion of overstocked acres/volume.

Table 4.6 - Total BDT Standing Timber (live and dead) within a50 Mile Radius of Mooretown Rancheria (by ownership class and stocking level)

Ownership class	Overstocked	Fully stocked	Medium stocked	Poorly stocked	Non stocked	Total
National Forest	19,325,823	44,164,192	7,331,534	954,085	1,056	71,776,690
Bureau of Land Mgmt.	118,143	721,450	0	0	0	839,593
County and Municipal	0	666,104	0	0	0	666,104
Private	4,294,723	17,376,586	5,156,253	1,455,406	12,292	28,295,261
Total	**23,738,689**	**62,928,332**	**12,487,787**	**2,409,491**	**13,348**	**101,577,647**

Table 4.7 on the following page also shows the estimated volume of standing timber in the 50 mile radius supply area. However, instead of reporting volume by ownership class and stocking level, it is reported by species and diameter class. As shown in the table, Douglas fir and True Firs account for about 55 percent of the total volume. Only about 15 percent of the total standing volume is comprised of trees that are less than 13.0 inches in diameter at breast height.

Table 4.7 – Estimated Standing Timber Volume in 50 Mile Radius Supply Area by Species and Diameter Class (Millions of Bone Dry Tons)

	Diameter Class (Diameter at Breast Height in inches)									
Species	**5.0-6.9**	**7.0-8.9**	**9.0-10.9**	**11.0-12.9**	**13.0-14.9**	**15.0-16.9**	**17.0-18.9**	**19.0-20.9**	**>21.0**	**Total**
Douglas-fir	0.52	0.70	0.91	1.06	1.31	1.10	1.36	1.39	15.60	23.96
Ponderosa Jeffrey pine	0.19	0.24	0.45	0.42	0.55	0.58	1.07	1.23	10.48	15.23
True fir	0.54	0.87	1.31	1.39	1.87	2.26	2.43	2.36	19.17	32.18
Sugar pine	0.03	0.07	0.09	0.11	0.15	0.20	0.35	0.29	7.69	8.97
Western white pine	0.00	0.01	0.01	0.01	0.01	0.02	0.09	0.06	0.17	0.40
Incense-cedar	0.22	0.31	0.44	0.42	0.39	0.46	0.62	0.56	4.55	7.95
Lodgepole pine	0.01	0.02	0.09	0.08	0.16	0.07	0.07	0.03	0.17	0.69
Other western softwoods	0.01	0.02	0.02	0.01	0.02	0.04	0.02	0.02	0.08	0.24
Red alder	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
Oak	0.55	1.05	0.95	1.12	0.75	0.66	0.79	0.38	2.35	8.61
Other western hardwoods	0.18	0.31	0.33	0.48	0.36	0.44	0.34	0.11	0.72	3.27
Total	**2.25**	**3.59**	**4.60**	**5.09**	**5.59**	**5.83**	**7.14**	**6.43**	**61.06**	**101.58**

4.5.3 Standing Timber Volume Available Annually

BECK interviewed USFS staff from the Plumas National Forest regarding planned and ongoing fuel reduction treatments. The staff indicated that there are two projects in place where biomass from fuel reduction treatments would be available – the Keddie Ridge Project and the Wildcat Project. MR's forestry crew holds contracts for both projects and they include treatments where trees between 3" and 9" in diameter at breast height must be harvested; trees smaller than 3" in diameter at breast height must be cut, hand-piled, and burned; and in some areas trees must be masticated. Detailed information about the biomass volume resulting from those treatments was not readily available from the USFS contacts since the material is not currently utilized.

BECK was, however, able to obtain an estimate of the average volume of biomass per acre from Mr. David Kinateder, fire ecologist on the Plumas National Forest. According to Mr. Kinateder, the USFS completed over 400 stand exam plots for an upcoming fuel treatment project called the Butterfly Twain Fuels Reduction Treatment Project. That data indicates an average of 13 bone dry tons of biomass trees per acre in trees less than 10 inches in diameter at breast height. BECK used that factor to combined with the average number of acres treated per year for the Wildcat and Keddie Ridge projects to estimate that a total of 24,000 bone dry tons of fuel reduction material would be produced annually. Of that amount, a safety factor of 67 percent was applied to account for material that isn't cannot be cost effectively accessed or processed to arrive at an estimated recoverable volume of 15,800 bone dry tons per year.

It should be noted that the 13 bone dry tons per volume assumed in the preceding analysis is significantly lower than the average per acre standing timber volume (111.7 BDT/acre) on the overstocked areas (see **Table 4.5**). Thus, it is likely that the presence of a market for biomass material would result in different treatment prescriptions that would raise the amount of biomass produced per acre from the fuel reduction treatments.

Also, from discussions with the USFS staff, there are currently significant volumes of biomass material (trees with diameters ranging between 3 and 9 inches) that have been harvested, but which have no current commercial value. Those trees are currently sitting in large log decks in the woods until they can be burned or until a market develops. That material could be used as fuel by MR, but it was not counted in the estimates since the volumes are unknown. More research on this issue is recommended since the volumes are apparently significant.

4.5.4 Logging Slash

Another source of biomass fuel is logging slash, which are the limbs, tops, and otherwise unused portions of stems harvested for use as sawlogs. A general rule of thumb for forests in the Western U.S. is that there are 0.9 bone dry tons of logging slash produced for every thousand board feet of sawlogs produced. California's Board of Equalization (BOE) collects timber harvest data by county and year. In addition, the harvest is tracked by whether it occurred on public or private property. BECK gathered BOE timber harvest data for the period 2010 through 2014 for the nine counties in the MR supply area. The average volume harvested (thousand board feet a.k.a. MBF) and the total and recoverable volumes of logging slash associated with those harvests are shown in **Table 4.8.** An issue that needs further investigation regarding logging slash is whether it qualifies for the SB 1122 program. BECK's interpretation of the program language is that it would qualify; however, this should be verified with CalFire, the entity that wrote the program language adopted by the CPUC.

Table 4.8 – Historic Timber Harvest by County (MBF) and Estimated Total and Recoverable Logging Slash Volumes (BDT)

County	Public Harvest (MBF)	Private Harvest (MBF)	Total Harvest (MBF)	Total Logging Slash (BDT)	Recoverable Logging Slash (BDT)
Butte	2,485	37,605	40,091	36,000	18,000
Colusa	349	208	556	1,000	500
Glenn	407	781	1,188	1,000	500
Nevada	956	14,317	15,273	14,000	7,000
Placer	17,553	27,564	45,118	41,000	20,500
Plumas	28,836	66,156	94,993	85,000	42,500
Sierra	8,516	15,807	24,323	22,000	11,000
Sutter	0	0	0	0	0
Yuba	2,759	15,317	18,076	16,000	8,000
Total	61,861	177,756	239,617	216,000	108,000

4.6 BIOMASS SUPPLY SUMMARY

Table 4.9 shows a summary of the total and recoverable biomass supply from all sources.

Table 4.9 – Estimated Total and Recoverable Annual Biomass Supply (BDT/Year)

Fuel Type	Estimated Total Volume (BDT/Year)	Estimated Recoverable Volume (BDT/Year)
Mill Byproducts	662,600	246,600
Orchard Residues	213,100	76,200
Urban Wood Waste	318,000	79,600
Non SB 1122 Subtotal	*1,193,700*	*402,400*
Logging Slash	216,000	108,000
Fuel Reduction Treatments	24,000	15,800
SB 1122 Subtotal	*240,000*	*123,800*
Grand Total	**1,433,700**	**526,200**

4.7 DELIVERED COST ESTIMATES

In addition to assessing the supply of biomass fuel, it is also important to estimate the delivered cost of biomass fuel. The delivered cost of fuel is dependent on several variables. First is the cost of transporting the material from its origin to MR's biomass facility. Transportation cost is almost always part of the cost calculation for facilities that are not also integrated with an operation that produces fuel (e.g., a cogeneration plant co-located at a sawmill that produces sawdust and bark that can be used as fuel). Second is the cost of gathering and processing the fuel. These costs are generally not part of the calculation for mill residues, but are incurred for most other fuel types. Finally, in some cases (especially for mill residues), the fuel may already have a market value for some other use. Thus, the market value of the fuel must be included in the delivered cost of that fuel if it is to be used at Mooretown. All of these costs are included as appropriate in the following analysis.

4.8 MILL RESIDUE ESTIMATED DELIVERED COSTS

As shown in **Table 4.10** the estimated delivered cost of Mill Residues ranges between $14 and $43 per bone dry ton depending on the location of the origin of the mill residual and the type of mill residual.

For the analysis it was assumed that mill residuals had the following market values (f.o.b. the mill's bin): Chips $25/BDT, Shavings $15/BDT, Sawdust $10/BDT, and Bark $20/BDT. The balance of the delivered costs shown in the table are a function of transportation cost, which was calculated on the basis of trucks having a 54,000 pound payload, an hourly operating cost of $85/hour, an average travel speed of 45 miles per hour, and a combined load/unload time of ½ hour. Chips, sawdust, and bark were all assumed to have an average moisture content of 50 percent. Shavings were assumed to have an average moisture content of 20 percent. The chip vans for hauling were assumed to have a 4,000 cubic foot capacity. Chips were assumed to have a solid-wood to chip-form expansion factor of 2.25. Sawdust was assumed to have a solid-wood to sawdust-form expansion factor of 2.75. Shavings and bark were assumed to have an expansion factor of 3.2.

Table 4.10 – Estimated Delivered Fuel Costs for Mill Residuals ($/BDT)

Residual Type and Location	Annual Volume Per Mill (BDT)	Delivered Cost for Residual Type and Location ($/BDT)	Cumulative Volume (BDT)	Cumulative Weighted Average ($/BDT)
Mill Residual Sawdust, Oroville	9,000	14	9,000	14
Mill Residual Shavings, Oroville	10,000	19	19,000	17
Mill Residual Bark, Oroville	15,000	24	34,000	20
Mill Residual Chips, Oroville	47,000	29	81,000	25
Mill Residual Chips, Chester	82,000	39	163,000	32
Mill Residual Chips, Lincoln	83,000	43	246,000	36

4.9 ORCHARD FUEL ESTIMATED DELIVERED COST

Table 4.11 displays the estimated delivered cost for orchard residuals from each county in MR's Supply Area. As shown, the delivered cost ranges from about $30 per BDT to about $45/BDT, depending on the source county. However, the weighted average delivered cost for all orchard residues ranges between about $30 per BDT and $33 per BDT.

Table 4.11 – Estimated Delivered Fuel Costs for Orchard Residues ($/BDT)

County	Annual Volume Per County (BDT)	Delivered Cost from Each County ($/BDT)	Cumulative Volume (BDT)	Cumulative Weighted Average ($/BDT)
Yuba	6,100	30	6,100	30
Butte	20,100	30	26,200	30
Sutter	16,100	32	42,300	31
Glenn	20,300	36	62,600	32
Nevada	100	37	62,700	32
Colusa	12,700	37	75,400	33
Sierra	0	39	75,400	33
Placer	400	40	75,800	33
Plumas	400	45	76,200	33

Please note the assumptions used in estimating the delivered fuel costs of orchard residues were as follows. The grinding cost averages nearly $19.00 per bone dry ton and includes a 15 percent profit margin for the grinding contractor as well as the depreciation cost for the contractor's equipment. The average moisture content of the material was assumed to be 50 percent. All other hauling assumptions were the same as those used for mill residues. Other key assumptions with orchard wood delivered costs are that there are no collection costs or market values associated with these fuels.

4.10 URBAN WOOD ESTIMATED DELIVERED COST

Table 4.12 displays the estimated delivered cost of urban wood waste fuel from each county in MR's Supply Area. As shown, the delivered cost ranges from about $26 per BDT to about $36 per BDT. The assumptions associated with the urban wood waste delivered costs are identical to orchard residues other than the average moisture content is assumed to be 20 percent versus 50 percent for orchard residues. This difference contributes to the lower overall delivered costs of urban wood relative to orchard residues because lower moisture content translates into lower transportation costs.

Table 4.12 – Estimated Delivered Fuel Costs for Urban Wood Waste ($/BDT)

County	Annual Volume Per County (BDT)	Delivered Cost from Each County ($/BDT)	Cumulative Volume (BDT)	Cumulative Weighted Average ($/BDT)
Yuba	6,300	26	6,300	26
Butte	19,100	27	25,400	27
Sutter	8,100	28	33,500	27
Glenn	2,400	30	35,900	27
Nevada	8,400	31	44,300	28
Colusa	1,800	31	46,100	28
Sierra	300	32	46,400	28
Placer	31,600	33	78,000	30
Plumas	1,600	36	79,600	30

4.11 FOREST RESIDUE ESTIMATED DELIVERED COST

Table 4.13 displays the estimated delivered cost of logging slash and fuel reduction treatment fuel from each county in MR’s Supply Area. As shown, the delivered cost ranges from a low of $40 per BDT to a high of $64 per BDT. The assumptions associated with the estimates are that the logging slash would accumulate at log landings as part of the normal process of harvesting saw logs. Thus, there would be no cost associated with collecting the material for processing. Also, since the material is currently unutilized, there would be no cost for acquiring the material. Regarding, biomass from fuel reduction treatments, BECK assumed that the costs included harvest, collection, processing, and transport, though, in a typical treatment, some of this cost would be offset by payment from the landowner to the thinning contractor.

Table 4.13 – Estimated Fuel Costs - Logging Slash &Fuel Reduction Treatments ($/BDT, Del.)

County	Supply Source	Annual Volume (BDT)	Delivered Cost ($/BDT)	Cumulative Volume (BDT)	Cumulative Delivered Average Delivered Cost ($/BDT)
Yuba	Logging Slash	8,000	40	8,000	40
Butte	Logging Slash	18,000	40	26,000	40
Sutter	Logging Slash	0	n/a	26,000	40
Glenn	Logging Slash	500	45	26,500	40
Nevada	Logging Slash	7,000	46	33,500	41
Colusa	Logging Slash	500	46	34,000	41
Sierra	Logging Slash	11,000	48	45,000	43
Placer	Logging Slash	20,500	48	65,500	45
Plumas	Logging Slash	42,500	53	108,000	48
Plumas	Fuel Reduction	4,000	64	112,000	48
Total		**112,000**			

4.12 DELIVERED COST SUMMARY

Table 4.14 shows the average delivered fuel costs for each fuel type.

Table 4.14 – Average Delivered Fuel Cost Estimate by Fuel Type ($/BDT)

Supply Source	Annual Volume (BDT)	Delivered Cost ($/BDT)	Cumulative Volume (BDT)	Cumulative Delivered Average Delivered Cost ($/BDT)
Urban Wood Waste	79,600	30	79,600	30
Orchard Residues	76200	33	155,800	31
Mill Residues	246600	35	402,400	34
Forest Residue	112,000	48	514,400	37

4.13 MOORETOWN RANCHERIA FORESTRY PROGRAM

MR has established a tribal enterprise that carries out wildfire firefighting activities and fire hazard fuel reduction treatments. The program currently has several contracts in place to complete treatments for the U.S. Forest Service. BECK's understanding is that those programs are supported by a treasury transfer (i.e., the USFS transfers funds to the BIA, which in turn are used to pay for the cost of the treatments). The current amount of the transfer is $1.2 million. The existence of the transfer is beneficial for the prospective biomass plant because those funds pay for the treatments, which produce woody biomass that can be used as fuel. Thus, they have the effect of offsetting the delivered cost of fuel for the project.

It is important to note, however, that BECK has not included those funds as offsets to delivered fuel costs in the analysis used in this report. The reason for this is that BECK's understanding of the treasury transfer programs is that they are contingent on the annual funding levels available from the U.S. Forest Service. Thus, there is no guarantee of long-term funding to continue to carry out forest management treatments.

Should MR elect to continue pursuing this project, BECK recommends that MR approach the U.S. Forest Service to begin discussions about planning a long-term stewardship type contract. This could potentially lead to securing longer term funding commitments. Also, regardless of whether funding commitments become available, demonstrated access to secure, long-term fuel supply agreements (e.g. 10 year minimum) will be required by project financiers.

CHAPTER 5 – PERMITTING

Development of a biomass heat and power facility will require a variety of permits from various government agencies. Normally, permitting for a small scale biomass heat and power plant would fall under the jurisdiction of state and local authorities. However, BECK's current understanding is that MR, as a Native American Tribe with 316 acres of land held in trust by the Bureau of Indian Affairs, would cause project permitting to fall under the jurisdiction of federal laws. The following sections describe the permitting process likely to be encountered in developing a biomass facility at MR.

5.1 AIR QUALITY

Air quality permitting is typically the most important permitting issue for biomass projects. Therefore, BECK devoted the majority of the permitting analysis effort to developing an understanding of this issue for MR's prospective project.

MR is located in the Sacramento Valley Air Basin (**Figure 5.1**), which is comprised of nine air districts. MR is located within the Butte County Air Quality Management District.

Figure 5.1 – Sacramento Valley Air Basin Map

CHAPTER 5 – PERMITTING

Given the location of MR's project within the Butte County Air Quality Management District, BECK contacted Mr. David Lusk at the district office regarding air quality permitting for the prospective MR biomass project. Mr. Lusk initially stated that he believes the MR project will fall under federal jurisdiction for air quality. Therefore, Mr. Lusk referred BECK to Mr. Gerardo Rios of the U.S. Environmental Protection Agency Region 9. BECK attempted to contact Mr. Rios to discuss the project, but was not able to reach him prior to publication of this report.

Mr. Lusk later stated the project may be under the local air management district's jurisdiction and that his office was investigating the jurisdiction issue. Therefore, the following information is based on a combination of discussions with Mr. Lusk, information provided from the biomass equipment vendor, the EPA Region Nine air quality website, and the Butte County Air Quality Management District website.

Federal air quality standards have been established for seven pollutants:

1. Carbon Monoxide
2. Lead
3. Nitrogen Dioxide
4. Ozone
5. Respirable particulate matter less than 10 microns in diameter (PM10)
6. Respirable particulate matter less than 2.5 microns in diameter (PM2.5)
7. Sulfur Dioxide

In addition, the State of California has standards for all of the above pollutants plus four additional pollutants:

1. Sulfates
2. Hydrogen Sulfide
3. Vinyl chloride (chloroethene)
4. Visibility reducing particles

From the preceding list of State and Federal pollutants, of concern for a biomass plant are carbon monoxide, nitrogen dioxide, particulate matter, and sulfur dioxide. In addition, volatile organic compounds (VOCs) are produced from the combustion of biomass. The other pollutants for which state or federal standards have been developed are generally not produced from the combustion of woody biomass.

Table 5.1 shows the status of Butte County Air Quality Management District air quality in 2014 with respect to both the State and Federal air quality standards.

Table 5.1 Butte County – State and Federal Ambient Air Quality Attainment Status

Pollutant	State Designation	Federal Designation
1-hour Ozone	Nonattainment	n/a
8-hour Ozone	Nonattainment	Nonattainment
Carbon Monoxide	Attainment	Attainment
Nitrogen Dioxide	Attainment	Attainment
Sulfur Dioxide	Attainment	Attainment
24 Hour PM10	Nonattainment	Attainment
24 Hour PM2.5	No Standard	Nonattainment
Annual PM10	Attainment	No Standard
Annual PM2.5	Nonattainment	Attainment

Despite the Butte County Air Quality Management District being in nonattainment status for several of the pollutants, Mr. Lusk felt that the relatively small scale of the proposed MR biomass plant and the pollution control equipment that would be included would allow the project to be permitted. Note, however, that U.S. EPA Region 9 will likely be responsible for the final determination of permitting. BECK recommends that MR follow up with Mr. Rios at the EPA Region 9 office to confirm Mr. Lusk's opinion.

BECK has estimated the air quality pollutant levels that will be produced by the prospective facility based on the assumption that the biomass boiler being considered for the MR project (cogeneration scenario) will have a heat input of about 54 million BTUs per hour and it will operate 8,200 hours per year. The boiler would be equipped with the following features for controlling emissions:

- A multiclone mechanical collector for large particulate matter (PM) removal
- A 3 field electrostatic precipitator for fine PM control
- Multiple levels of overfire air for carbon monoxide (CO) and volatile organic compound (VOC) control
- An air heater to heat incoming combustion air, which lowers CO and VOC emissions

- A Selective Non-Catalytic Reduction (SNCR) system (possibly including urea injection) to control NOx
- A complete set of continuous emissions monitors for NOx, CO, CO2, and O2

Given the expected operating conditions of the plant and the pollutant emission level commercial guarantees offered by boiler equipment vendors, **Table 5.2** shows the estimated annual emissions (tons per year) for the pollutants typically of concern at a biomass facility and the typical commercial guarantees on emission limits from equipment manufacturers for each pollutant.

Table 5.2 – Estimated Annual Emissions from the Prospective MR Biomass Facility

Pollutant	Commercial Guarantee (pounds per MMBTU)	Estimated Annual Emissions (tons per year)
PM2.5	0.015	3.4
Carbon Monoxide	0.22	50.5
Nitrogen Oxides	0.15	34.4
Volatile Organic Compounds	0.005	1.1
Sulfur Dioxide	0.01	2.3

5.2 WATER USE AND WATER DISPOSAL

The MR biomass heat and power plant (cogeneration scenario) as conceptualized in this study would consume approximately 50 gallons per minute of make-up water and would dispose of about 10 gallons per minute of waste water. Since these are relatively modest amounts, BECK has assumed that the South Feather Water & Power Agency (MR's utility) will be able to provide and dispose of water as needed for the operation of the facility. The waste water discharge from biomass boilers does not have any organic contaminants, but may have slightly elevated mineral levels and is typically relatively warm in temperature. The cost of water and wastewater disposal has been included in the financial model for the project using escalated current rates.

Given the assumption of using municipally supplied water, no permitting issues are anticipated with regard to water use and water disposal. However, BECK recommends that MR contact South Feather Water & Power to notify the utility of the biomass facility plans.

5.3 SOLID WASTE DISPOSAL

The MR biomass heat and power plant as conceptualized in this study, would generate approximately 800 tons of ash per year from the combustion of biomass. This ash consists of bottom ash from under the boiler grates and fly ash collected in pollution control equipment downstream of the combustion process. A typical split is 50 percent each of bottom and fly ash.

The bottom ash consists of sand and gravel that was embedded in the wood as it was handled in the field. This clean material, almost indistinguishable from a sand and gravel operation, typically can be disposed of by transporting it to a local aggregate supplier who will incorporate it into his normal products. The material will then become such things as road base, pipeline bedding or part of the recipe for asphalt or concrete.

The fly ash portion is much finer and contains a certain percentage of unburned carbon. It is typically high in pH and is often utilized in agricultural operations as a soil amendment. The material has excellent moisture retention capabilities, is often used as a "liming" agent on low pH agricultural soils, and possesses certain beneficial trace minerals. Thus, disposal of the fly ash as a soil amendment is a probability. The material can also be used as a cover material at landfills, incorporated into commercial soil amendments or simply be returned to the land from which the fuel originated. In many regions, the ash has no market value, but can be disposed of for the cost of transporting it to its intended use (e.g., aggregate and low-grade agricultural mineral).

The preceding uses of fly ash have all been demonstrated at other biomass facilities in California. Therefore, BECK believes those options would exist for the fly ash produced at MR's prospective facility. However, if none of the preceding disposal options are available, a fall back option would be disposing the material in a landfill. In any event, no major obstacles related to ash disposal are anticipated in the permitting process. The plant will also produce a small quantity of typical commercial/industrial trash and recyclable material, which will be disposed of through the normal MR solid waste system.

5.4 OTHER PROJECT DEVELOPMENT ISSUES

Project development issues, such as land use compatibility, zoning, issuance of building permits, storm water discharge permits, etc., are typically handled by a local city or county planning office. However, in this case, because of MR's status as a federally recognized Native American Tribe, BECK believes permitting for those types of project development issues would not be handled by local authorities. Instead, project development would be subject to MR's own internal protocols (i.e., BIA). BECK attempted to verify this with the Butte County Planning office, but as of the time of the completion of this report, the planning office has not responded.

Again, no major permitting obstacles are anticipated for issues such as building permits, stormwater discharge, etc.

5.5 DRAFT ENVIRONMENTAL ASSESSMENT

In July 2014, MR completed a draft environmental assessment for 90 acres of property at Mooretown Rancheria regarding future development of a Loop Road through the parcel that would provide a means of accessing the land for potential economic development projects, including a water bottling facility, wildlands fire-fighting center, and biomass plant. The objective of the draft environmental assessment was to determine whether development of the Loop Road would result in any significant impacts to the Human Environment. In addition, the existence of a completed environmental assessment for the Loop Road project is expected to expedite the permitting process for any of the subsequent economic development activities within the 90 acre area.

From the environmental assessment, the recommendations for mitigating the impact of road development were:

Land Resources - All exposed soil areas shall be stabilized and re-seeded with appropriate native plant species. Stockpiles of unsuitable or excess soil shall be removed and disposed of at approved sites.

Land Resources - Interim erosion control measures shall be implemented during construction, including such facilities as temporary dikes, filter fences, hay bales and retention basins, as necessary.

Land Resources - Revegetated areas shall be properly maintained to ensure adequate establishment and growth.

Water Resources- Runoff from development of Loop Road shall be retained on the site by using appropriate techniques, such as a detention basin. Detention basins or other means for retaining surface water on site shall be designed prior to grading and construction of the Loop Road. The detention system shall be constructed concurrent with project construction.

Water Resources -The post-construction runoff and the volume and velocity of the 100-year storm event shall be equal to or less than the existing condition (pre-construction runoff volume and velocity).

Water Resources -Existing drainage patterns shall not be significantly modified and drainage concentrations shall be avoided.

Water Resources -No discharge of silt, waste materials, toxic substances or other deleterious matter to surface waters shall be permitted. Surface water shall be detained on site, as described above, utilizing available Best Management Practices for water quality.

Water Resources - Because construction of the Loop Road will encompass an area greater than one acre, the Tribe shall submit an application to the U.S. EPA for a NPDES permit pursuant to the provisions of the Clean Water Act. The NPDES permit application must be submitted to the EPA at least two days prior to the commencement of grading. The application must include a Stormwater Pollution Prevention Control Plan and construction should incorporate Best Management Practices for runoff control and erosion prevention to control release of sediment to the natural drainage system.

Air Quality - Water active grading areas, including unpaved roads used for site access, at least twice daily and pave the proposed roadways as early as feasible.

Air Quality - The Tribe will extend temporary or permanent electric power to the construction site in order to minimize or eliminate the use of gas or diesel powered electric generators.

Living Resources - To ensure that no impacts occur to nesting American peregrine falcons or any migratory birds, site disturbance shall occur outside of the avian breeding season. In northern California, this season generally lasts from February 1st to August 31st. Therefore, site preparation shall occur between September 1st and January 31st. If work is proposed to occur during the avian breeding season between February 1st and August 31st, then a qualified biologist shall survey the impact area to determine the presence or absence of nesting bird species protected under the MBTA. This survey shall occur within 5-7 days of commencement of work activities. If active nests of such birds are found, then work shall not commence until the eggs have hatched and the birds have fledged. If no active nests are found within the impact area, then work activities associated with site preparation can commence.

Cultural Resources - If any cultural, historic or archaeological resources are discovered during construction of the Loop Road, then work shall be halted and the Tribe, BIA and a qualified archaeologist shall be consulted to evaluate the significance of the resource.

It is BECK's opinion that any environmental permitting issues aside from those already discussed in earlier sections of this chapter will not be significant obstacles to the development of a biomass facility at MR.

CHAPTER 6 – INCENTIVES

In general, power derived from small biomass and other renewable sources is more costly to produce than power generated by large-scale, non-renewable sources. Therefore, to encourage development of renewable and sustainable power sources, such as biomass, a variety of state and federal incentive programs are available. The following subsections describe the various incentives available to biomass fueled heat and power projects.

The status of these incentive programs tend to change frequently as Congress often allows incentives to expire, reinstates incentives, or develops new incentives. Therefore, BECK recommends that MR closely monitor the status and availability of incentives as planning for the biomass project moves forward. A good resource for monitoring is the Database of State Incentives for Renewables & Efficiency (DSIRE). The database is maintained by the North Carolina State University Clean Energy Technology Center. Information from the database is available from the website (www.dsireusa.org).

6.1 INCENTIVES FOR MOORETOWN RANCHERIA

A list of potential incentives for a biomass project at MR are listed in **Table 6.1.** Some incentives in the list are unique to Tribal entities. In addition, BECK has eliminated from the list, for clarity, those incentives that do not provide cash value (i.e., those that provide information/technical resources are not included). Thus, the list includes those programs that may result in substantial grants, low cost financing, or loan guarantees for MR's biomass project.

In addition, BECK has included the incentives that have tax benefits even though MR is a non-taxable entity. The reason for including tax benefit incentives is that, at the time a project is initiated, the tax benefits offered by an incentive may be so substantial that MR may wish to solicit a tax-paying entity as a tax equity partner in the biomass project. The tax equity partner concept is explained on page 53.

Table 6.1 – Incentive Programs Potentially Available to Mooretown Rancheria

Program	Agency	Description
504 Loan Program	Small Business Administration	Provides growing Businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings
Clean Renewable Energy Bonds ("New CREBs")	Dept. of Treasury (IRS)	Issues tax-credit bonds to deploy renewable energy projects
Community Development Financial Institutions Fund (CDFI Fund)	Department of Treasury (CDFI)	Seeks to increase the access to credit, capital, and financial services in Native communities through the creation and expansion of CDFIs primarily serving Native communities
Community Development Financial Institutions Fund (CDFI Fund) New Markets Tax Credit (NMTC) Program	Department of Treasury: Community Development Financial Institution	Helps small- and medium- sized businesses in low-income communities access financing that is flexible and affordable. Financing from CDEs can apply to a wide range of projects, including housing developments, renewable energy installations and facilities that provide community services
Community Facility Grants	Department of Agriculture: Rural Development	Provides funds to construct, enlarge, or improve community facilities for health care, public safety, and community and public services. This can include the purchase of equipment required for a facility's operation
Loan Guarantee Program (LPO)	Department of Energy: Loan Guarantee Program	Supports innovative clean energy technologies that are typically unable to obtain conventional private financing due to high technology risks, including hydrogen, solar, wind/hydropower, nuclear, advanced fossil energy coal, carbon sequestration practices/technologies, electricity delivery and energy reliability, alternative fuel vehicles, industrial energy efficiency projects, and pollution control equipment
Loan Guaranty Insurance, and Interest Subsidy Program	Department of Interior: Indian Energy and Economic Development	Encourages eligible borrowers to develop viable Indian businesses through conventional lender financing, which helps lenders reduce excessive risks on loans they make and helps borrowers secure conventional financing that might otherwise be unavailable
Native American Business Development	Department of Commerce: Minority Business Development Administration	Provisions direct services to American Indian and Alaska Natives, fosters intergovernmental and industry collaboration, and promotes economic and business development opportunities in Indian Country
Rural Business Development Grants	Department of Agriculture: Rural Development	Promotes sustainable economic development in rural communities with exceptional needs through provision of training and technical assistance for business development, entrepreneurs, and economic development officials and to assist with economic development planning
Rural Energy for America Program Guaranteed Loan Program (REAP LOANS)	Department of Agriculture: Rural Development	Encourages the commercial financing of renewable energy (bioenergy, geothermal, hydrogen, solar, wind, and hydropower) and energy efficiency projects. Under the program, project developers will work with local lenders who can apply for a loan guarantee on up to 85% of the loan amount
Tribal Energy Program	Department of Energy: Energy Efficiency and Renewable Energy	Offers financial assistance to Tribes to help them deploy renewable energy resources and reduce their energy consumption through efficiency and weatherization
Modified Accelerated Cost Recovery System (MACRS)	U.S. Internal Revenue Service	A program allowing businesses to recovery investments in certain property through depreciation deductions
Unsolicited Proposal Process	Department of Energy: Economic Impact and Diversity	Assists DOE and the Office of Economic Impact and Diversity in meeting National Energy Conservation Policy Act mandates to provide technical assistance and opportunities for minorities, minority educational institutions, and minority business enterprises to participate in DOE's energy programs

The following sections provide additional detail about the incentive programs listed in the preceding table that, in BECK's judgment, are most significant and potentially applicable to the MR project. The incentives have been categorized by incentive type including grants, financing, loan guarantees, and tax benefits.

6.1.1 Federal Programs

The federal level, can have a variety of incentives, including grants, tax credits, and low interest rate loans. Each of the following sections describes federal incentives in each category.

Grants - Each year the USDA Forest Service offers the Wood Innovation Grant Program (formerly known as the Woody Biomass Utilization Grant or WBUG). The program is aimed at supporting projects throughout the United States that help expand and accelerate wood energy and wood products markets, which, in turn, will support forest management needs on National Forests and other lands. The typical cycle is that a request for proposals is issued in the mid-fall (October) with proposals from applicants being due in January. The proposals are then reviewed and applicants are notified of the results in mid-spring (March). Funds are awarded to the selected projects shortly after announcement of the results.

Applicants apply for the grant in one of two categories:

1) Expansion of Wood Energy Markets – projects in this category will stimulate, expand, or support wood energy markets that depend on forest residues or forest byproducts generated from all land types. Preference will be given to projects that make use of low –value wood generated from the National Forest System and other forest lands with high wildfire risk.

2) Expansion of Wood Products Markets – projects in this category will promote markets that create or expand the demand for non-energy based wood products. Preference will be given to projects that support commercial building markets or other markets that use existing or innovative wood products.

From 2007 to 2013 the program was managed by the State and Private Forestry Technology Marketing Unit located at the U.S. Forest Products Laboratory in Madison, WI. During those years a total of about $4 million was available annually. The cap on funding for an individual project was $250,000. Prerequisites to application are a completed feasibility and fuel supply study. BECK's work on this project for MR satisfies both requirements.

In 2014 the program was renamed and the scope expanded beyond just wood to energy. Administration of the program was also shifted to the U.S. Forest Service Wood Education and Resource Center (WERC) in Morgantown, West Virginia. Applicants from California are requested to first consultant with the U.S. Forest Service Region 5 Biomass Coordinator, Larry Swan, to assist in developing proposals that align with Forest Service Regional/Area priorities and State Forest Action plans. Additional information about the California application process is included in **Appendix B**. BECK knows Mr. Swan well and can assist in coordinating meetings and discussions should MR pursue the biomass project.

Another USDA administered grant program offered through Rural Development is called REAP (Renewable Energy for America Program). It provides matching grants to project developers to allow them to purchase, install, and construct renewable energy systems. Grants awarded under this program are limited to 25 percent of the project cost or $500,000, whichever is less. A total of $280 million was available through this program. Also, the project must incorporate "commercially available"[7] technology. Eligible applicants include units of state, tribal or local governments, colleges, universities, rural electric cooperatives and public power entities, and conservation and development districts.

Tax Credits and Depreciation - Many renewable heat and power incentives come in the form of tax credits and special rules for depreciating assets. Unfortunately, MR, as a non-taxable entity, is not able to take direct advantage of these incentives. Nevertheless, a discussion of several key tax incentives is included in this report because there are still ways for non-taxable entities to take advantage of these programs. Typically, the method used to accomplish receiving these tax credits is to bring in a "Tax Equity Investor." This type of arrangement is described in greater detail beginning on page 53.

Bonus Depreciation and Modified Accelerated Cost Recovery System (MACRS) are two federal incentives that allow for deducting a certain portion of a project's capital cost each year from income prior to calculating income tax liability. In the case of biomass projects, MACRS allows the boiler and fuel handling portion of the plant to be depreciated over just 5 years, the power generation equipment over 20 years, and the land and improvements over 15 years. Biomass projects typically have 50 to 60 percent of the total capital cost included in the boiler and fuel handling equipment, so it is a powerful incentive.

Last summer (2014), the House of Representatives voted to pass a bill that would permanently extend the bonus depreciation tax break for businesses. Bonus depreciation is an extension of the MACRS concept by adding "bonus depreciation" under which 50 percent of the total capital cost of the facility, in addition to normal MACRS depreciation, is available to the project to be depreciated in the first tax year. This allows nearly two-thirds of the total project cost to be depreciated in year one. Even though these depreciation amounts can be carried forward into future tax years, if this deduction cannot be utilized in the first tax year, the net present value will be reduced. The Senate did not take up this legislation, however, but a permanent extension has again been introduced in the current Congress. Thus, the status of bonus depreciation as an incentive for biomass projects is uncertain at the current time.

In addition to accelerated depreciation, a key tax credit incentive for biomass heat and power projects is the Section 45 Production Tax Credit (PTC). It is a federal incentive that provides an $11 federal income tax credit for every megawatt hour of renewable biomass power produced.

[7] Commercially Available is defined as a domestic or foreign system that: has for at least on year specific to the proposed application, both a proven and reliable operating history and proven performance data; is based on established design and installation procedures and practices and is replicable; has professional service providers, trades, large construction equipment providers and labor who are familiar with installation procedures and practices; has proprietary and balance of system equipment and spare parts that are readily available; has service that is readily available to properly maintain and operate the system; has an existing established warranty that is valid in the United States for major parts and labor; and a domestic or foreign Renewable Energy System that has been certified by a recognized industry organization whose certification standards are acceptable to the Agency.

The credit escalates with the Consumer Price Index (CPI) annually and lasts for the first 10 years of commercial operation. The credit is restricted in that it cannot be transferred to a non-owner and is not available to non-taxpaying entities. Non-taxpaying entities have a replacement program, the Renewable Energy Production Incentive (REPI), which pays them an amount equivalent to the benefit they would have received utilizing the PTC. However, it is subject to annual appropriation and is chronically underfunded. This tax credit expired at the end of2014, and legislation has been introduced in both Houses of Congress to extend it through 2016. Its status is pending as of the date of this report.

A final tax credit that is not specific to renewable power projects is the Section 48 Advanced Energy Credit for combined heat and power projects, which comes in the form of an investment tax credit equal to 10 percent of total capital cost. Under this program, an energy project (regardless of fuel type) that uses the same energy source to simultaneously generate electrical, mechanical, or shaft power in combination with useful thermal energy and does so in a manner that exceeds 60 percent thermal efficiency and which is placed in service before January 1, 2017would qualify. This credit cannot be taken in conjunction with the Section 45 PTC described above. Since biomass projects cannot typically achieve 60 percent overall thermal efficiency, even as a CHP, there is a mechanism for biomass to qualify for a reduced credit as a function of efficiency. Since the MR project could not be completed prior to January 1, 2017, an extension of this credit would be necessary.

Low Interest Rate Loans and Loan Guarantees - Financing biomass power projects in today's credit market is challenging, with fewer debt and equity financiers interested in providing financing than a decade ago. Still, obtaining financing is feasible provided the project is strong in several key areas: a strong fuel plan, known and creditworthy power off-taker, and a proper partnership structure that allows for the full monetization of all incentives and tax advantages.

There are a number of federal programs that provide either low interest rate loans or loan guarantees to biomass heat and power projects to assist in project financing. They include Qualified Energy Conservation Bonds (QECBs), which are tax credit bonds that can be used by state and local governments to finance renewable energy projects. Typically, only the principal is repaid under this program. Another program is the Loan Guarantee program administered by the Department of Energy. It allows the DOE to provide loan guarantees to projects that increase energy efficiency, renewable energy projects, and advanced transmission and distribution projects. Full repayment of the loan amount is required under the DOE program. The USDA REAP program mentioned earlier also has a loan guarantee section. Finally, the Treasury Department administers the Community Development Financial Institutions Fund (CDFI) for low income community investment that is so powerful in the case of MR that it warrants its own section below.

Tax Equity Investor - As previously described, biomass projects, because they are considered renewable power, qualify for tax credits and deprecation that are not available to non-renewable energy projects. Integrating a tax equity investor into a project proposed by a non-tax paying entity to utilize these benefits is a complicated task. Therefore, the following section provides a more detailed explanation of how this type of arrangement typically functions.

Many government incentive programs in the energy field, both at the state and federal levels, rely on income tax credits and rapid depreciation treatments (another form of tax reduction) as inducements. To a Tribal entity such as MR, these incentives are worthless as MR has no tax liability. In some cases, in recognition of the inability of non-tax entities to use such programs, the government will offer an alternative, such as the Renewable Energy Production Incentive(REPI) as a replacement for the federal Production Tax Credit (PTC). Because these replacements require an outlay of funds (as opposed to a reduction in inflow of taxes) they are often left underfunded or unfunded and are thus not typically acceptable replacements.

More certain use of these incentive programs is accomplished by partnering with a tax paying entity or by serving as a host site for a private entity. If a partnership is struck, the tax paying entity will inject equity into the project reflective of the discounted value of the incentives (tax credits). Through that process the tax equity investor becomes an initial 99 percent owner in the project and will monetize the credits until an agreed upon return on partner's equity invested is reached. At that time, a flip in ownership will occur, and MR would become the 99 percent owner, with the investor receiving a one percent share going forward. In this way, the capital requirements of the Tribe are reduced, and all tax credits are utilized.

In the other scenario, where MR acts as the host site, MR would be the lead in the design/sizing of the facility. MR would contract for steam or electricity from the project, or both. MR would also supply other services (operation, maintenance, water, security, and wastewater) at cost. The agreement would specify that at some point in the future (10 years for example) MR could obtain title to the facility for a reduced payment. The payment by MR would extinguish all outstanding debt on the project.

Because of the uncertainty of credits and depreciation treatment in the future, the concept of a tax equity investor was not utilized in the modeling. However, if Congress acts to renew credits, and they are available at the time a project is financed, use of this financing method would further increase the returns and shorten the payback.

6.1.2 State Programs

The following section provides an overview of state-level incentives for renewable energy. Unlike the incentives listed at the federal level, the incentives presented in this section, do not necessarily provide a direct financial benefit to a biomass project at MR.

Renewable Portfolio Standard – Enacted in 2002, California's renewable portfolio standard requires electric utilities in the state to have 33 percent of their retail sales derived from eligible renewable energy sources in 2020 and all subsequent years. The eligible technologies include solar, thermal electric, wind, geothermal, ocean wave/thermal/tidal, fuel cells using renewable fuels, landfill gas, certain hydroelectric, municipal solid waste conversion, and certain biomass resources. California Governor Jerry Brown recently called for increasing the percent of power from renewables to 50 percent by 2030.

Those suggested changes by Governor Brown have yet to be adopted into law, but they are likely. In the meantime, the utilities generally have met the current requirements for renewables. As a result, California's RPS mandate is presently not a driving force in stimulating the market for renewable power. Should Governor Brown's proposed increase to 50 percent renewables be adopted, it would create new demand for renewable power. However, a small scale project (e.g., MR's prospective biomass plant)would very likely not be cost competitive against other, larger plants or other renewable technologies.

Renewable Market Adjusting Tariff (ReMAT)–This incentive (also known as SB 1122) is described in detail in Chapter 2.

6.2 COMMUNITY DEVELOPMENT FINANCIAL INSTITUTIONS FUND (CDFI)

Like the SB 1122 incentive described in detail in Chapter 2, the CDFI Fund represents a significant incentive for MR's biomass project. Therefore, it is described in detail in the following paragraphs.

The CDFI Fund, administered by the U.S. Treasury, has strong programs that support lending in low income communities. The Fund has a Native Initiatives program that is applicable for an MR project, and it awards New Market Tax Credit (NMTC) authority to various financing bodies.

The census tract in which Mooretown Rancheria is located (06007003300) qualifies a lender to receive NMTCs for specified investments within that tract. A small bioenergy facility at Mooretown would qualify a lender to receive NMTCs. A lender who receives a NMTC allocation can receive a federal income tax credit of 39 percent of the amount invested taken over 7 years on the basis of the schedule show in **Table 6.2.**

Table 6.2 – New Market Tax Credit Schedule

Year	1	2	3	4	5	6	7	Total
Tax Credit (%)	5	5	5	6	6	6	6	39

The advantage to the loan recipient is that the loan is made at a below market rate, and the lender supplies equity to the project that does not have to be repaid by the loan recipient. BECK has experience with the impact of this financing method from assisting on another recent small bioenergy project. In that case, the lender was willing to supply $5 million in equity to a $32 million project and provide debt at 1.9 percent interest over 20 years. BECK has used these same metrics in evaluating a project at MR, with the result being that the required power price to obtain the same equity return is nearly $20/MWH less than if the project used conventional financing.

Awards of NMTC allocations from the 2014 program were just announced on June 15, 2015. Several California entities were awarded NMTC allocations, and they are listed in **Table 6.3**.

Table 6.3 – NMTC Program Award Recipients in California

Entity	Amount Awarded ($ in millions)
Bank of America	55
Chase Bank	60
Citibank	55
Local Initiatives Support Corporation	70
Low Income Investment Fund	60
Northern California Community Load Fund	45
Opportunity Fund Northern California	40
U.S. Bank	55
Wells Fargo Bank	75

If MR decides to proceed with project planning, BECK encourages MR to contact one or more of the above entities early in the process. Use of NMTC financing is both competitive and complicated. The transaction involves having a third party, the Community Development Entity (CDE), stand between the lender and developer.

Having a strong entity issuing the Power Purchase Agreement, such as PG&E, is a real positive in obtaining NMTC financing. Other positives in MR's favor include use of proven conventional technology and having other tribal revenue generating activities (such as the casino).

6.3 INCENTIVES SELECTED FOR FINANCIAL MODELING

The financial models described in Chapter 8 assume that MR will be able to assemble a total of $1 million in grants from a combination of USDA and DOI sources. For a project of this type fueled solely by forest byproducts important to Federal agencies, this is a fairly conservative assumption.

The second incentive selected is the project’s ability to attract CDFI/NMTC funding through the existing Department of Treasury program. This assumption results in debt financing at 1.9% interest for 20 years and an equity infusion into the project of $3.55 to $3.85 million, which does not need to be repaid.

CHAPTER 7 – BIOMASS PLANT CONCEPTUAL DESIGN

BECK's analysis for the MR project culminates in a presentation of the financial projections for a biomass cogeneration facility at Mooretown Rancheria. However, prior to presenting the financial analysis, the following chapter provides a conceptual description of how the facility would be developed with respect to cogeneration, interconnection, the SB 1122 program, financing options, etc.

7.1 IDENTIFICATION OF THERMAL ENERGY APPLICATIONS

The feasibility of biomass power projects can often be enhanced by also selling steam to one or more thermal hosts. Therefore, it is important to identify potential uses for the thermal energy that could support operation of MR's prospective facility as a cogeneration plant. MR has identified three potential thermal energy applications for the bioenergy facility being analyzed. They are:

1. Displacement of all/some of the gas-fired hot water heating systems at the existing casino, hotel and brewery.
2. Thermal energy supply to a new, expanded brewery adjacent to the bioenergy facility.
3. Thermal energy supply to a one acre greenhouse to be constructed adjacent to the bioenergy facility.

The following sections describe each potential application.

7.1.1 Existing Casino/Hotel/ Brewery Heating System

The existing casino, hotel and brewery are served by a series of small modern natural gas-fired hot water heating systems. These systems send 160 degree Fahrenheit hot water to a series of radiators for space heating or to process needs in the brewery and kitchen. A listing of the locations and sizes are shown in **Table 7.1.**

Table 7.1 – MR's Existing Thermal Loads

Location	Number	Size(BTU/Hour)
Kitchen Area	1	630,000
Casino Offices	1	336,000
Mechanical Room 1	2	1,275,000
Mechanical Room 2	1	1,440,000
Mechanical Room 3	1	831,600
Hotel Third Floor	2	850,000
Total		**7,488,000**

The first and second floors of the hotel have individual room electric HVAC units, so are not available for displacement by a thermal energy system. The two third floor lodge units described in the preceding table serve heating needs of the common areas and third floor of the hotel.

All of the heating units listed in the preceding table purchase natural gas from Pacific Gas & Electric (PG&E). The gas bills are differentiated between the casino and hotel, but not between individual heating units. MR has supplied utility bills for the most recent annual period for purposes of analysis by BECK.

Analysis of the utility bills shows that the hotel and casino combined consumed 127,914 therms of natural gas at a total cost of $106,553 during the period July 2013 through June, 2014. This is an average cost of $0.883/therm or $8.33/million BTU (MMBTU). Applying a combustion efficiency of 80 percent to the small heating units means that the cost of supply heat to the system is $10.41/MMBTU of hot water.

When analyzing the billed gas quantities versus the system installed capacity, it can be seen that the heating system has a utilization rate of only about 16 percent annually. This is not unexpected for a system primarily doing space heating.

The modest size and usage of the gas-fired heating system means that it would not be cost effective to displace in total this gas usage with heat from the bioenergy facility when such facility is located nearly 2,000 feet away from the nearest point of the casino. This is because the capital cost of the needed steam extraction, heat exchanger and piping supply/return system would not have a reasonable payback. In this case, however, there are other proposed thermal uses (brewery, greenhouse) that can share the capital expense. In addition, both the existing and proposed uses are for hot water (as opposed to steam). This means that the turbine extraction already included for deaerator heating can be utilized for serving the thermal load. For the reasons outlined above, this study will include in the analysis the thermal loads shown in **Table 7.2.**

Table 7.2 – MR's Existing Thermal Loads

Location	Number	Size(BTU/Hour)
Mechanical Room 1	2	1,275,000
Mechanical Room 2	1	1,440,000
Mechanical Room 3	1	831,600
Hotel Third Floor	2	850,000
Total		**6,522,000**

These loads are chosen for displacement because all mechanical rooms are close to each other and near the closest point to the bioenergy facility (north wall of casino). The hotel loads are together on the third floor, and the system would also serve a mentioned potential hotel expansion. These loads represent 87 percent of the total installed heating capacity and thus 87 percent of current natural gas usage.

Total 2013–14 usage for these heating units would be 111,300 therms (87 percent of total). On an 8,200 hour/year bioenergy plant operating basis, this is 13.57 therms per hour of usage, or 10.86 therms of heat output (80 percent efficiency). This 10.86 therms (1.086 million BTU/hour) will be added to the thermal load analysis of the bioenergy facility.

7.1.2 Brewery Expansion

MR, as part of the study, wishes to provide in the design of the facility the ability to supply thermal energy for both an expansion of the existing brewery and a one acre greenhouse, both located adjacent to the bioenergy facility. The brewery would be at least a 10 fold increase in size from the existing brewery facility.

In evaluating the thermal needs of breweries, there is a substantial amount of useful metrics included in the publication Energy Efficiency Improvements for Breweries, issued by Lawrence Berkeley National Laboratories for the U.S. EPA (LBNL-50934). In this publication each step of the brewing process is analyzed for thermal energy use.

In the case of a MR brewery expansion, none of the key parameters have been defined. Thus, it is reasonable for BECK to assume from the study an overall thermal energy use for small breweries of 250,000 BTUs per barrel produced. Lacking other information, a 50,000 barrel per year production volume was chosen. Thus, the overall thermal energy use in the expanded MR brewery was assumed to be 12,500 million BTUs annually or 1.53 million BTU/hour when spread over the 8,200 hour/year operation of the bioenergy cogeneration facility.

The design of the bioenergy cogeneration facility will include the capability to supply 1.53 million BTU/hour of hot water to the expanded MR brewery operation at the specifications required by the brewery.

7.1.3 Greenhouse Addition

Mooretown has requested that BECK include in the design of the bioenergy cogeneration facility the capability to heat a one acre in size (43,560 square feet) greenhouse located adjacent to the bioenergy facility. For determining the heating requirements of the greenhouse facility, BECK has drawn heavily on two documents: Greenhouses: Heating, Cooling and Ventilation (B792) from the University of Georgia and Basics for Heating and Cooling Greenhouses for Tobacco Transplant Production (ID-131) from the University of Kentucky.

To match the requirements of MR's chosen site and minimize grading, BECK has decided to analyze two greenhouse buildings, each 275 feet long and 80 feet wide with a total floor area of 44,000 square feet. The buildings would have 8 foot sides and a roof peak at 16 feet. The facility would be double paned glass.

The greenhouse design manuals specify a minimum design temperature of 15 degrees Fahrenheit below the average minimum January low temperature. The average January low temperature for Oroville is 37 degrees Fahrenheit. This means that the design criteria for the greenhouse heating system is that it have the capability of maintaining a 65 degree Fahrenheit temperature during a 22 degree Fahrenheit day (37 - 15).

The annual average maximum temperature in Oroville is 75.2 degrees Fahrenheit, with an average annual minimum of 48.8 degrees Fahrenheit. The average of these two numbers makes the average annual temperature 62 degrees Fahrenheit. For the types of plants considered by MR, a good growing environment is provided with nighttime temperatures of 65 degrees Fahrenheit and daytime temperatures of 85 degrees Fahrenheit, or a daylong average of 75 degrees Fahrenheit. This means that the greenhouse heating will, on average, be providing 13 degrees Fahrenheit (75-62) of heating to the greenhouse.

The calculation of heat losses through conduction, convection and radiation dictates a heating system sized at 2 million BTU/HR. From that system size, applying the average heat load of 13 degrees Fahrenheit reduces the annual average use of the system to 0.65 million BTU/Hour.

The steam extraction system and heat exchanger sized for the bioenergy facility can provide for both the peak and average thermal energy requirements of the greenhouse.

In this example, the greenhouse heating system employs the same steam to hot water heat exchanger used to supply 160-170 degree Fahrenheit water to the brewery and casino/hotel complex. Upon further study, however, it may be determined that the hot water side of the cooling tower water, typically 85 – 105 degrees Fahrenheit has sufficient energy to heat the greenhouse. If feasible, this would be a lower cost option for heating the greenhouse, and thus the current analysis is likely a worst case example.

One other consideration in subsequent greenhouse design is that plant growth rates may benefit by venting some of the carbon dioxide (CO_2) rich flue gas from the boiler directly into the greenhouse. The flue gas contains roughly 12 percent CO_2 while atmospheric CO_2 levels are less than 0.05 percent. Thus, even a small amount of flue gas could easily double greenhouse CO_2 levels. Since CO_2 is the "fuel" for photosynthesis, other greenhouses have found that elevated CO_2 levels can increase growth rates.

7.1.4 Cogeneration Facility System Design

The turbine-generator employed at MR would have a low pressure steam extraction to supply the necessary energy to boil the incoming feedwater to remove most oxygen. That extraction would be at approximately 5 psig, delivering steam at about 230 degrees Fahrenheit at nearly saturated conditions.

For a hot water system with maximum temperatures in the range of 160-170 degrees Fahrenheit, this 5 psig source should have a sufficient driving force to operate the system. It would be a simple matter to expand the 5 psig extraction to supply energy to the various businesses being investigated by Mooretown. A simple shell and tube heat exchanger would be employed, keeping the highly treated boiler water separate from the process heating water. Condensate from the condensing of the 5 psig steam would be returned to the condenser hotwell in the range of 160-180 degrees Fahrenheit.

Given the preceding analysis of existing heat loads and the projected heat loads of the brewery expansion and the greenhouse addition, the total average anticipated use of hot water energy by Mooretown is shown in **Table 7.3**.

Table 7.3 – Average Anticipated Use of Hot Water Energy by Mooretown Rancheria

Use	Average Heat Load (MMBTU/Hour)
Casino/Hotel Heating	1.09
New Brewery	1.53
Greenhouses	0.65
Total	**3.27**

To meet this heat load, additional steam would be extracted at 5 psig, with an enthalpy[8] of 1156.3 BTU/pound (or slightly above if still superheated). The condensate returned from the heat exchanger at 170 degrees Fahrenheit would have an enthalpy of 138 BTU/pound. Thus, each pound of steam extracted would provide 1,018.3 BTU (1156.3 – 138) to the hot water system.

To provide the 3.27 million BTU/hour of energy to the hot water system in a 95 percent efficient heat exchanger would require 3,380 pounds per hour of extraction steam. The extraction system should be sized to provide at least twice this amount during high demand periods.

7.1.5 Thermal Energy Pricing

In order to evaluate the economics of providing process heat, it is necessary to establish a reasonable price for the thermal product.

As mentioned earlier, Mooretown bought gas from PG&E for $8.33/MMBTU, with the 80 percent efficient combustion process delivering gas-fired energy to the hot water product for $10.41/MMBtu ($8.33÷0.8). In the bioenergy cogeneration case, a single pound of extraction steam delivers 967 BTUs to the hot water in a 95 percent efficient heat exchanger (1018.3 x 0.95). Thus, a price of $0.0107/pound of steam ($10.70/1000 pounds) would make the bioenergy fueled system equivalent in price to the gas-fired system. Therefore, this amount will be added as a revenue stream in the financial model of the bioenergy cogen system.

[8] Enthalpy is a thermodynamic quantity equivalent to the total heat content of a system. It is equal to the internal energy of the system plus the product of pressure and volume.

Thermal energy priced at the cost of the natural gas equivalent is a good deal for the thermal users as well. The users receive thermal energy at the previous gas rate but avoid hot water pumping costs, incremental capital cost and the operation and maintenance cost of the gas-fired system.

In the heat and material balance prepared for a stand-alone plant with no thermal customers (shown in Chapter 8), the amount of steam delivered to the turbine to allow a net (after auxiliary power use) delivery of 3.0 MW to the grid was calculated to be 31,750 pounds per hour of 600 psig/750°F steam. Therefore, a plant was sized and priced at 35,000 pounds per hour capability.

In the cogeneration application, it would be necessary to increase boiler size to 40,000 pounds per hour to accommodate system peaks and an average flow of 33,550 pounds per hour, as well as to add a heat exchanger and supply/return piping. **Table 7.4** shows the estimated capital cost increases for these revisions.

Table 7.4 – Estimated Capital Cost for Cogeneration Capability

Use	Capital Cost ($)
Increase Boiler from 35K to 40K pounds of steam/hour	1,000,000
Heat Exchanger	100,000
Supply/Return Piping	800,000
Total	**1,900,000**

This incremental capital cost is shown in the bioenergy cogen financial model developed as part of this study. Additional incremental operational costs (fuel, ash disposal, maintenance) are captured in the model as well.

As proposed, the 40,000 pounds per hour boiler in the cogeneration case has an extraction capability of 8,250 pounds per hour or nearly 2.5 times the average thermal load. This should be a sufficient capacity to allow MR to pursue several additions requiring thermal energy.

7.1.6 Cooling System Addition

One other discussion item for future engineering evaluation is the addition of steam absorption chilling to replace the electric chiller system currently employed by Mooretown.

Mooretown currently has a modern chiller system consisting of three Trane 425 KW chillers and an ice storage system to allow off peak use of the electric chillers. The chillers take electricity from a common feed and are not metered separately from other casino electrical loads. Thus, it is not possible to know the duty cycle of the chillers and therefore estimate the savings with a steam absorption chiller.

The primary driver in a steam absorption chiller evaluation is the fact that other thermal energy loads peak in the winter, while the chiller load peaks in the summer. As a consequence, the cogeneration option will include a boiler sufficient in size to supply a summer chiller load with no increase in infrastructure beyond the chiller and piping.

A steam absorption chiller is an inherently inefficient device. That inherent inefficiency combined with the fact that Mooretown can operate its existing chillers on lower priced off-peak electricity would likely lead to MR's sticking with the existing system in a straight-up economic evaluation.

However, electric rate structures can change, and new incentives may be put in place for the displacement of electric use or for the further use of renewable biomass fuels. These could change the economic outcome in favor of a steam absorption chiller. Fortunately, should that change occur, Mooretown's installation of a boiler with the capability to serve winter peaking thermal loads will also have the capability to serve summer chilled water loads.

7.2 STAND-ALONE PLANT VERSUS COGENERATION

BECK prepared heat and material balances and developed financial models for both a stand-alone power plant only scenario and a cogeneration scenario. The following section provides a description of the considerations involved in determining the preferred scenario.

The cogeneration option (also known as Combined Heat & Power or CHP) was based on supplying nearly 90 percent of existing casino and hotel heat loads currently supplied by natural gas. In addition, it was assumed that MR would develop a one acre greenhouse and expand its brewery, both of which would be adjacent to the power facility and both heated by hot water from the power facility. **Table 7.5** shows a side-by-side comparison of the key parameters for the two options.

Table 7.5 – Stand-Alone vs. Power Only Key Parameter Comparison

Parameter	Power Only	Cogeneration
Capital Cost ($ in millions)	22.932	24.982
Annual Fuel (bone dry tons)	24,488	25,876
Auxiliary Power (% of gross load)	9.5	10
Required Power Price ($/MWH)	186	182
First Year O&M Cost ($ in millions)	2.52	2.60
First Year Thermal Revenue ($ in millions)	0	0.287

As illustrated in the preceding table, the cogeneration option is $2 million more expensive from a capital cost standpoint. That capital is split evenly between the incremental cost of a larger boiler (35,000 vs. 40,000 pounds per hour) and the cost of the steam/hot water heat exchanger and piping to serve thermal loads.

The annual fuel requirement increases by 1,400 bone dry tons/year, or about 6 percent, when cogeneration is added. Power facility water and sewer use actually drop slightly in the cogen case because less of the total steam must be cooled by the cooling tower. The auxiliary power use for the facility increases slightly (9.5 vs 10 percent of total) as it is assumed that the hot water system pumping power will be supplied by the cogeneration facility.

The total annual operation and maintenance (O&M) cost increases by $80,000 annually, or 3 percent, primarily due to the extra fuel required. However, annual revenue increases by $287,000 annually or nearly 4 times the incremental cost.

The higher revenue from thermal energy sales allows the project to accept a slightly lower power price from PG&E ($182/MWH vs $186/MWH) in order to obtain the same equity return (12 percent). This small difference might allow the project to begin construction two months earlier under the Bioenergy ReMAT program.

While the savings from installing a cogeneration system are relatively modest, there are other reasons for MR to pursue this option. First, in BECK's experience, a cogeneration project has a much higher degree of public acceptability. The general public has an inherent understanding and acceptance of the need to replace fossil fuel use with the use of renewable and sustainable fuels. A cogeneration project also removes the argument that the project is "portable" and therefore should be put somewhere other than the proposed location.

Second, in future greenhouse gas compliance schemes in California, the continued displacement of fossil fuels with renewable fuels may generate a continued revenue stream from the sale of carbon offsets. Though such a protocol is not currently in place, it is a logical extension of current programs, as are carbon credits for use of forest waste materials. Currently, the cogeneration project may be able to initially sell a 10 year stream of carbon credits due to the offset of current fossil fuel use, but the revenue from such a sale is very modest and is not included in the financial model presented later in this chapter.

Third, there are grant opportunities that are available to biomass (renewable) fueled cogeneration projects that are not available to stand-alone projects. In addition, though both schemes may qualify for various competitive grant programs, the cogeneration aspects of the program would allow the cogeneration projects to score substantially higher in an agency evaluation.

Fourth, MR has initially identified both a greenhouse and a brewery expansion that will likely be pursued in the near future. The cogeneration facility would be designed to accommodate these thermal loads, as well as the heating loads of the existing casino and hotel. The proposed cogen system would have the capability to add additional thermal loads that cannot currently be identified by MR, but could be economically significant in the future.

One such opportunity may be to add cooling loads, as well as thermal loads, to the duty cycle of the cogeneration facility. MR has an efficient electric driven chilled water system that takes advantage of lower off-peak electric prices to chill a large water storage tank. These electric chillers could be replaced by a steam absorption chiller utilizing low pressure steam from the cogeneration facility. However, the combination of low off peak electric prices, relatively inefficient steam absorption chilling, and a steam absorption chiller capital cost make this an unattractive option for MR today.

Nevertheless, in the future a change in PG&E's rate structure or an increase in chilled water requirements may change the economic equation in favor of steam absorption chilling. By pursuing the cogeneration option initially Mooretown preserves the ability to add cooling loads to the cogeneration facility's duty cycle. Since the space cooling requirements run countercyclical to the space heating requirements, this additional thermal load could be accommodated within the initial design capacity of the cogeneration facility.

Finally, the addition of a cogeneration facility provides a hedge against higher natural gas prices, which have been proven to be highly cyclical in the past and are projected by the Energy Information Administration (EIA) to increase in price long term by 2 percent above general inflation.

Since MR's plans for additional businesses supported by the bioenergy facility are still in their infancy, BECK felt it was important to also include the stand-alone option in the economic analysis. If the only heating need were the existing casino/hotel/brewery, the economics would likely dictate sticking with the existing heating system. Consequently, MR needs to know what the economics are for a stand-alone facility when approaching PG&E's SB 1122 program.

7.3 UTILITY INTERCONNECTION

One of the key issues in the development of a small power project is obtaining an interconnection with the utility. In this case, PG&E (MR's electric utility) will go to great lengths to assure the project will create no disturbances on its distribution/transmission system that could cause safety hazards, problems for other customers, or both.

The interconnection application process is often long, expensive, and frustrating. However, for small projects such as that envisioned by MR, PG&E has developed a Fast Track Process that should yield an interconnection feasibility study, design, and estimate within a few weeks for a cost of only perhaps $2,000.

In Mooretown's case, the existing facilities are currently served by PG&E's 12,000 volt (12KV) Wyandotte 1109 distribution line out of the Wyandotte substation, which is located a few miles northwest of MR's site. The 12KV line runs along Lower Wyandotte Road. The 12KV tie to the Mooretown facilities is located overhead around the east edge of the Rancheria, turning west and terminating at a 12KV/480 volt transformer just north of the northeast corner of the casino. The Wyandotte 1109 line can also be supported, if necessary, out of the Palermo substation a mile or so south of Mooretown Rancheria.

The Wyandotte 1109 circuit has a current circuit capacity of 13 MW and a projected peak capacity of 12.1 MW. The transformer bank serving the Wyandotte 1109 circuit (and others) has a rating of 45 MW.

The existence of a 3 MW generator along the Wyandotte 1109 circuit will actually reduce the amount of electricity flowing through the Wyandotte substation transformers, making actual line capacity higher during plant operation. The portion of the Wyandotte 1109 circuit fronting the MR along Lower Wyandotte Road is rated as having "high capacity" by PG&E. The tie line from lower Wyandotte Road to the 12KV/480 volt transformer behind the casino is rated as only "low capacity". Thus, it will likely be necessary to reconductor[9] the 12KV line back to Lower Wyandotte Road, though the existing poles can probably be used. This is not an expensive requirement.

PG&E's analysis will result in the requirement that MR be able to automatically separate from the distribution system for a variety of causes (overvoltage, under frequency, faults, etc.), both internal to the plant or from the outside. The capital estimate that BECK obtained for the project includes the automatic sensing and isolation equipment (for automatic separation from the distribution system) that likely will be required, as well as the actual on site substation.

PG&E will analyze whether the project could "island" certain portions of its system when power is lost from the outside. Islanding occurs when the output of a project just matches remaining circuit load when that circuit is isolated, and thus the project continues to serve circuit load and does not trip. This is a dangerous situation and one that PG&E will not allow. If islanding is judged to be possible, an expensive "transfer trip" scheme is required to be added at the expense of the developer. The Wyandotte 1109 circuit is very heavily loaded, however, and so a small project such as that of MR may not be capable of islanding.

BECK's estimate for the cost of interconnection is $500,000 in addition to the facilities included in the Engineer Procure Construct (EPC) estimate. This would cover the cost of studies, the interconnection agreement, the roughly 2000 feet of 12KV line to the point of Interconnection and the upgrade cost back to lower Wyandotte Road. It does not include the transfer trip hardware should it be necessary. An interconnection to Wyandotte 1109 should be feasible without extensive upgrades to PG&E's system.

If MR wishes to participate in PG&E's SB 1122 program when it is announced, it is imperative that Mooretown file for an interconnection as quickly as possible since an interconnection study is a requirement for participation. BECK is helping another entity prepare an interconnection application for the SB 1122 program and so has assembled the technical information for a 3 MW generator that could be duplicated for MR's situation.

[9] Reconductor refers to replacing the cable or wire on an electric circuit, typically a high voltage transmission line.

CHAPTER 8 – FINANCIAL ANALYSIS

The following sections present BECK's financial analysis of a biomass project at Mooretown Rancheria. BECK has modeled both a stand-alone (power only) facility and a cogeneration facility.

8.1 CAPITAL EXPENSE/EQUIPMENT DESCRIPTION

The capital costs for the MR project are being developed using the Engineer Procure Construct (EPC) method of development. In an EPC contract, a competent experienced contractor takes on the responsibility of providing a complete plant on a turnkey basis, including guarantees of performance, environmental compliance, and scheduled completion.

In this case, Wellons, Inc., an experienced, large supplier of biomass cogeneration systems, is supplying a budgetary estimate for the construction of a 40,000 pound per hour boiler and 3 MW turbine generator (T-G) using the EPC method. This estimate was originally supplied in late 2014 to another entity evaluating participation in the SB 1122 program. Wellons has agreed to allow BECK to use the estimate and description for the purposes of MR's prospective project. The budgetary quote is supplied in **Appendix A**. However, BECK has modified the original estimate for differences in the Mooretown situation, as shown in **Table 8.1**.

Table 8.1 – Modifications to Wellons Budgetary Quote for Mooretown Rancheria

Expense Item	Power Only ($)	Cogeneration ($)
Original Estimate – complete plant ($)	19,950,000	19,950,000
Remove 2 fuel storage silos	(1,500,000)	(1,500,000)
Drop boiler size to 35K for Power Only	(1,000,000)	0
Add NOx and CO continuous monitors	100,000	100,000
Add 3rd ESP module for 0.015 standard	400,000	400,000
Add SNCR for NOx control	100,000	100,000
Total – Revised EPC Estimate	**18,050,000**	**19,050,000**

The two silos were considered unnecessary for Mooretown given the nature of staffing and the expected type of fuel reclaim system. The original Wellons cost estimate was for a project in a very remote California location. With the more urban setting of MR and the involvement of EPA, it is expected that air emission limits and monitoring requirements will be more stringent, thus explaining the last three items added to **Table 8.1**. The stand-alone version of Mooretown needs only a 35,000 pound per hour boiler versus the 40,000 pound per hour boiler in the original estimate. This is a savings in EPC cost estimated to be $1,000,000. The revised totals shown in **Table 8.1** are the values BECK used in the financial modeling for this project.

Based on BECK's experience in numerous completed projects, **Table 8.2** lists the additional capital expenses that are not part of Wellons' EPC estimate.

Table 8.2 – Modifications to Wellons Budgetary Quote for Mooretown Rancheria

Expense Item	Power Only ($)	Cogeneration ($)
Project Management/Permitting	400,000	400,000
Site Prep/Fencing/Roads	250,000	250,000
Utility Interconnection	500,000	500,000
Heat Exchanger and Pipeline	n/a	900,000
Fuel Receiving/Delivery	1,500,000	1,500,000
Working Capital	500,000	500,000
Contingency (5% of total)	1,060,000	1,150,000
Interest During Construction	233,000	254,000
Debt Issuance Cost	439,000	478,000
Total – Revised EPC Estimate	**4,882,000**	**5,932,000**
Wellons EPC Estimate	**18,050,000**	**19,050,000**
Grand Total	**22,932,000**	**24,982,000**

8.2 OPERATING EXPENSE

BECK developed the operation and maintenance (O&M) cost estimates based on the heat and material balance for each scenario in **Figure 8.1** and **Figure 8.2**. The heat and material balance estimates determine fuel, water, and wastewater volumes, and gross generation. Given that information, BECK also estimated other operating expenses (labor, supplies, repair & maintenance, etc.) based on its experience in preparing over 135 feasibility studies. The full detail of the operating expenses is shown in **Tables 8.3 and 8.4** on pages 73 and 74, respectively.

Please note that after developing the O&M estimates for MR, BECK cross checked them against actual operating cost data from a recently completed biomass cogeneration facility in Montana that uses the same technology and has an identically sized boiler/T-G (40,000 pounds per hour, 3 MW). Based on this comparison, BECK determined its MR O&M cost estimate to be slightly above actual costs experienced in Montana. BECK elected to not adjust the estimates to make the estimate slightly conservative and to account for typically higher operating costs in California versus Montana.

Figure 8.1 – Mooretown Rancheria 3 MW Cogeneration Plant Heat Balance

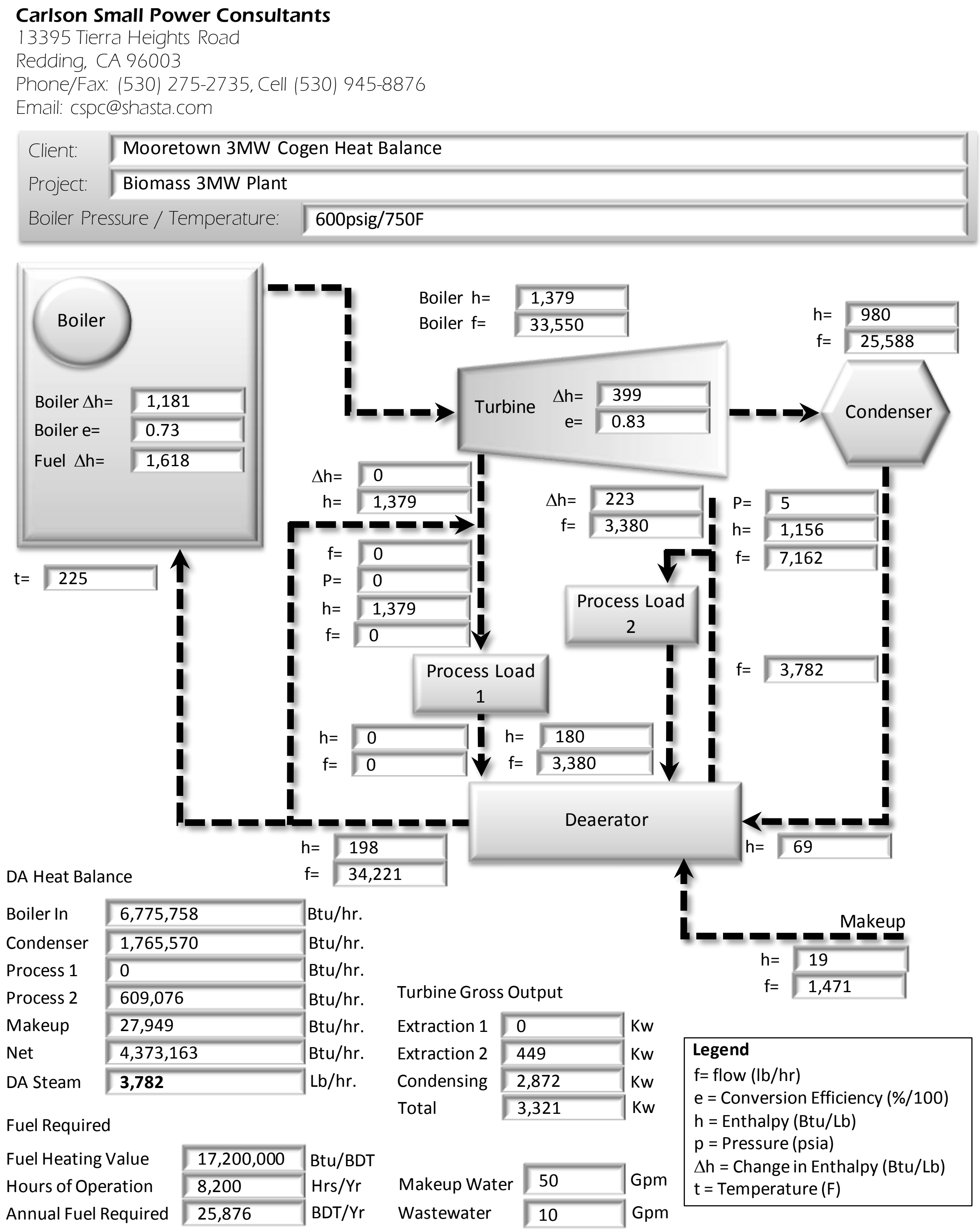
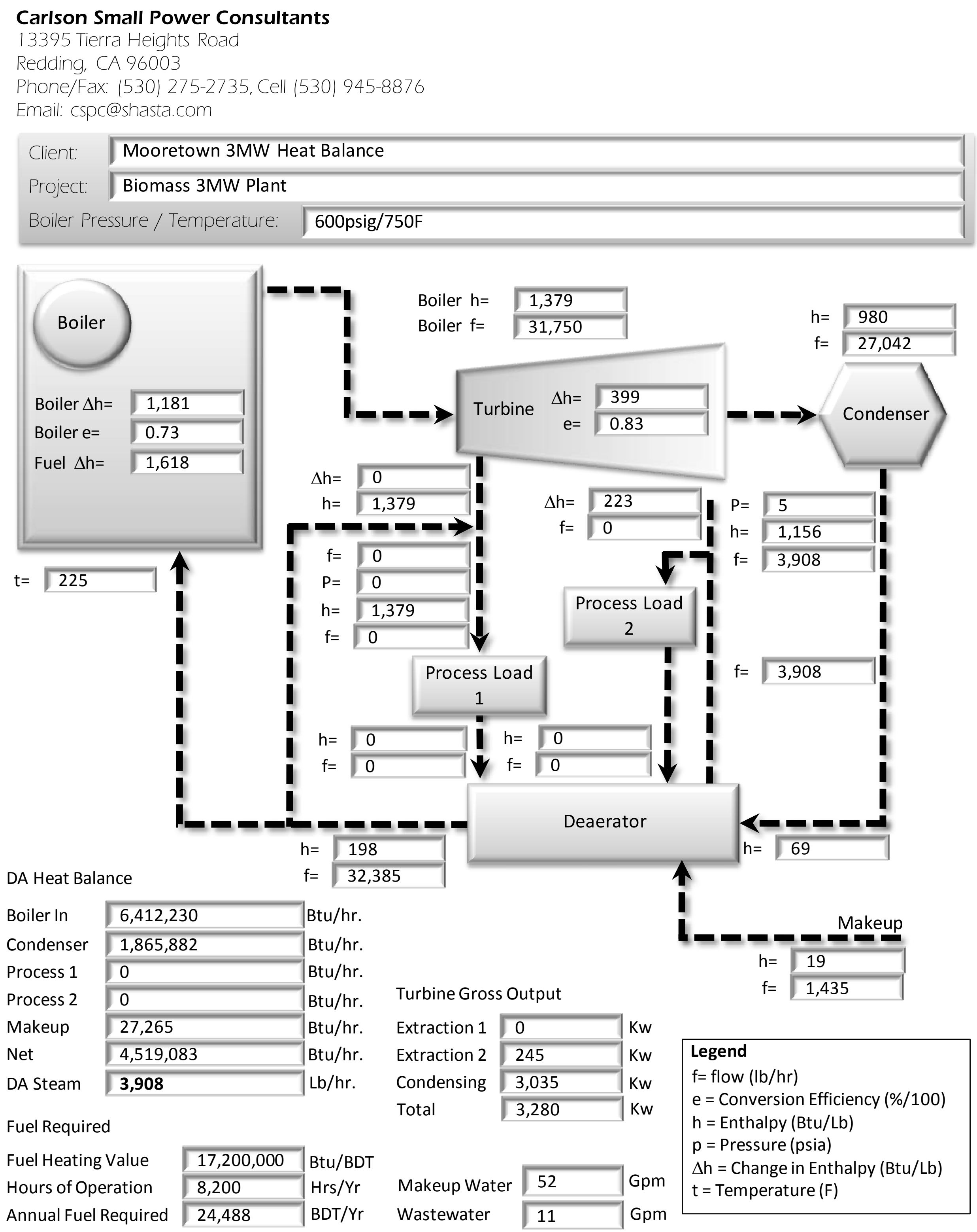


Figure 8.2 – Mooretown Rancheria 3 MW Stand-Alone Plant Heat Balance



8.3 KEY ASSUMPTIONS

The following sections summarize the financial analyses for both the cogeneration and stand-alone scenarios. The key assumptions associated with the analyses are:

Start Date – In both scenarios the plant would begin operating in 2018.

Operating Schedule – In both scenarios it was assumed the plant would operate 8,200 hours per year or about 94 percent uptime (8,200 hours uptime out of 8,760 total hours per year).

Capacity – The gross output of the cogeneration plant scenario would be 3.32 MW. Of that amount, 0.33 MW would be consumed by the station's own load (10.0% of gross output). The average annual net output of the plant after accounting for the station load and for the plant operating hours per year (8,200) is 2.80 MW.

The gross output of the stand-alone plant scenario would also be 3.28 MW. Of that amount, 0.31 MW would be consumed by the station's own load (9.5% of gross output). Thus, average annual net output of the stand-alone plant after accounting for station load and for the plant operating hours per year is 2.78 MW.

Capital Cost – The all-inclusive capital cost estimate for the cogeneration plant scenario is $24.982 million. This includes $19.050 million for equipment purchase and installation. The balance of $5.932 million is a combination of costs for site prep, project management, working capital, utility interconnection, fuel receiving and processing, and financing costs.

The all-inclusive capital cost estimate for the stand-alone plant scenario is $22.932 million. This includes $18.050 million for equipment purchase and installation. The balance of $4.882 million is a combination of costs for site prep, project management, working capital, utility interconnection, fuel receiving and processing, and financing costs.

Financing – For the cogeneration plant scenario, a credit of $3.85 million from the New Market Tax Credit program was applied against the capital cost. In addition, it was assumed that MR would be able to obtain another $1.0 million in grants from USDA and DOI sources. This resulted in a net cost of $20.132 million. It was further assumed the owner's equity in the project would be 35 percent of the net cost or $7.046 million. The balance of $13.086 million would be financed for 20 years at 1.9 percent interest. Issuance costs associated with financing were assumed to be $487 thousand (3 percent of the total project cost of $24.982 million).

For the stand-alone plant scenario, a credit of $3.55 million from the New Market Tax Credit program was applied against the capital cost. Again, it was assumed that an additional $1.0 million in grants would be obtained. This resulted in a net cost of $18.382 million. It was further assumed the owner's equity in the project would be 35 percent of the net cost or $6.434 million. The balance of $11.948 million would be financed for 20 years at 1.9 percent interest. Issuance costs associated with financing were assumed to be $447 thousand (3 percent of the total project cost of $22.932 million).

Heat and Power Sales Rates – For the cogeneration scenario, a power sales rate of $182.00/MWH was calculated in order to obtain a 12 percent equity return. Per the SB 1122 program rules, that power sales price was not escalated over the 20 year modeling period. Steam sales were valued at $10.07 per thousand pounds and escalated at 2.5 percent annually. An average of 3,400 pounds of steam per hour for 8,200 hours per year was assumed to be sold. Note that the combination of power sales and steam sales values at those levels combined after all of the costs are subtracted, are the rates that are required to provide the developer with a 12 percent Internal Rate of Return on MR's equity investment in the project.

For the stand-alone plant scenario, a power sales rate of $186/MWH was calculated in order to obtain the same 12 percent equity return. No steam sales are included in the stand-alone plant scenario.

Fuel Consumption and Cost – For the cogeneration plant scenario, it was calculated that the facility would consume 25,876 bone dry tons of fuel annually at an average delivered to the plant cost of $45 per bone dry ton.

For the stand-alone plant scenario, it was calculated that the facility would consume 24,488 bone dry tons of fuel annually at an average delivered to the plant cost of $45.00 per bone dry ton.

In both scenarios the fuel cost was assumed to escalate at 2.5 percent annually.

Ash Disposal – In both scenarios it was assumed that the volume of ash produced by the facility would be equal to 3 percent of the incoming fuel volume or about 750 tons per year. It was assumed that the ash could be disposed of as a soil amendment or aggregate for the cost of transportation, which was assumed to be $15/ton.

Staffing – In both scenarios it was assumed that a staff of 8 people would be required to operate the facility. This includes 1 facility manager, 1 maintenance technician, 4 steam plant operators, and 2 fuel operators. The Year 1 cost for these employees was assumed to be $888,753 dollars, including fringe benefit loadings (39.64 percent of salaries/hourly labor costs).

Property Tax – It was assumed that there would be no property tax

Table 8.3 shows a pro forma income statement for the cogeneration scenario. **Table 8.4** shows a pro forma income statement for the stand-alone scenario.

Table 8.3 – Cogeneration Scenario: 20 Year Pro Forma Income Statement

	Year 0	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
REVENUE																						
Electric Sales		4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	4,449	88,990
Steam Sales		279	286	293	301	308	316	324	332	340	349	357	366	375	385	394	404	414	425	435	446	7,130
Green Tag Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Credit Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue		**4,729**	**4,736**	**4,743**	**4,750**	**4,758**	**4,765**	**4,773**	**4,781**	**4,790**	**4,798**	**4,807**	**4,816**	**4,825**	**4,834**	**4,844**	**4,854**	**4,864**	**4,874**	**4,885**	**4,896**	**96,119**
EXPENSES																						
Operating (including chemicals)		1,151	1,180	1,209	1,239	1,270	1,301	1,333	1,366	1,400	1,435	1,470	1,507	1,544	1,582	1,621	1,661	1,703	1,745	1,788	1,832	29,338
Maintenance		269	276	283	290	297	304	312	320	328	336	344	353	362	371	380	390	399	409	420	430	6,872
Fuel (gas)		1,166	1,195	1,225	1,256	1,287	1,319	1,352	1,386	1,421	1,456	1,493	1,530	1,568	1,608	1,648	1,689	1,731	1,774	1,819	1,864	29,790
Ash Disposal		14	14	15	15	15	16	16	17	17	17	18	18	19	19	20	20	21	21	22	22	357
Total Operating Expenses		**2,601**	**2,666**	**2,732**	**2,800**	**2,869**	**2,941**	**3,014**	**3,089**	**3,166**	**3,244**	**3,325**	**3,408**	**3,493**	**3,580**	**3,669**	**3,760**	**3,854**	**3,950**	**4,048**	**4,149**	**66,357**
OPERATING INCOME		**2,128**	**2,070**	**2,011**	**1,950**	**1,888**	**1,825**	**1,759**	**1,692**	**1,624**	**1,554**	**1,482**	**1,408**	**1,332**	**1,254**	**1,175**	**1,093**	**1,010**	**924**	**837**	**747**	**29,763**
Interest		249	238	228	217	206	195	184	172	160	148	136	124	111	98	85	71	57	44	29	15	2,766
Depreciation		2,498	2,498	2,498	2,498	2,498	2,498	2,498	2,498	2,498	2,498	0	0	0	0	0	0	0	0	0	0	24,982
Pretax Income		**(619)**	**(666)**	**(715)**	**(765)**	**(816)**	**(869)**	**(922)**	**(978)**	**(1,035)**	**(1,093)**	**1,346**	**1,284**	**1,221**	**1,157**	**1,090**	**1,022**	**952**	**881**	**807**	**732**	**2,015**
Taxes (before federal/state credits)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income - Book		**(619)**	**(666)**	**(715)**	**(765)**	**(816)**	**(869)**	**(922)**	**(978)**	**(1,035)**	**(1,093)**	**1,346**	**1,284**	**1,221**	**1,157**	**1,090**	**1,022**	**952**	**881**	**807**	**732**	**2,015**
PROJECT CASH FLOW & BENEFITS																						
Pretax Income		(619)	(666)	(715)	(765)	(816)	(869)	(922)	(978)	(1,035)	(1,093)	1,346	1,284	1,221	1,157	1,090	1,022	952	881	807	732	2,015
Plus: Book Depreciation		2,498	2,498	2,498	2,498	2,498	2,498	2,498	2,498	2,498	2,498	0	0	0	0	0	0	0	0	0	0	24,982
Less: Loan Principal		(544)	(554)	(565)	(576)	(586)	(598)	(609)	(621)	(632)	(644)	(657)	(669)	(682)	(695)	(708)	(721)	(735)	(749)	(763)	(778)	(13,086)
Pretax Cash Flow		**1,335**	**1,277**	**1,218**	**1,158**	**1,096**	**1,032**	**967**	**900**	**831**	**761**	**689**	**615**	**539**	**462**	**382**	**301**	**217**	**132**	**44**	**(46)**	**13,911**
Debt Service Coverage Ratio		**2.7**	**2.6**	**2.5**	**2.5**	**2.4**	**2.3**	**2.2**	**2.1**	**2.0**	**2.0**	**1.9**	**1.8**	**1.7**	**1.6**	**1.5**	**1.4**	**1.3**	**1.2**	**1.1**	**0.9**	**1.9**
Taxes/Credits/Grants																						
State Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
State Credits/Grants		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Credits/Grants		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NET CASH FLOWS																						
Capital Investment	(24,982)																					(24,982)
Amount to Finance	13,086																					13,086
Operating Pretax Cash Flows		1,335	1,277	1,218	1,158	1,096	1,032	967	900	831	761	689	615	539	462	382	301	217	132	44	(46)	13,911
STATE CREDITS / TAXES	4,850	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4,850
FEDERAL CREDITS / TAXES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CASH FLOW BENEFITS	**(7,046)**	**1,335**	**1,277**	**1,218**	**1,158**	**1,096**	**1,032**	**967**	**900**	**831**	**761**	**689**	**615**	**539**	**462**	**382**	**301**	**217**	**132**	**44**	**(46)**	**6,865**
Cumulative Cash Flow		**1,335**	**2,613**	**3,831**	**4,989**	**6,085**	**7,117**	**8,083**	**8,983**	**9,814**	**10,575**	**11,264**	**11,880**	**12,419**	**12,881**	**13,263**	**13,564**	**13,782**	**13,913**	**13,957**	**13,911**	

Table 8.4 – Stand-Alone Scenario: 20 Year Pro Forma Income Statement

	Year 0	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
REVENUE																						
Electric Sales		4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	4,530	90,597
Steam Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Green Tag Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Credit Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue		**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**4,530**	**90,597**
EXPENSES																						
Operating		1,144	1,172	1,201	1,231	1,261	1,292	1,324	1,357	1,391	1,425	1,460	1,496	1,533	1,571	1,610	1,650	1,691	1,733	1,776	1,820	29,138
Maintenance		257	263	270	277	284	291	298	305	313	321	329	337	346	354	363	372	382	391	401	411	6,565
Fuel (gas)		1,105	1,133	1,161	1,190	1,220	1,251	1,282	1,314	1,347	1,381	1,415	1,450	1,487	1,524	1,562	1,601	1,641	1,682	1,724	1,767	28,238
Ash Disposal		13	14	14	14	15	15	15	16	16	17	17	17	18	18	19	19	20	20	21	21	339
Total Operating Expenses		**2,519**	**2,582**	**2,646**	**2,712**	**2,780**	**2,849**	**2,920**	**2,992**	**3,067**	**3,143**	**3,221**	**3,301**	**3,383**	**3,468**	**3,554**	**3,642**	**3,733**	**3,826**	**3,921**	**4,019**	**64,279**
OPERATING INCOME		**2,011**	**1,948**	**1,883**	**1,818**	**1,750**	**1,681**	**1,610**	**1,538**	**1,463**	**1,387**	**1,309**	**1,229**	**1,146**	**1,062**	**976**	**887**	**797**	**704**	**609**	**511**	**26,318**
Interest		227	218	208	198	188	178	168	157	146	135	124	113	101	89	77	65	52	40	27	13	2,525
Depreciation		2,293	2,293	2,293	2,293	2,293	2,293	2,293	2,293	2,293	2,293	0	0	0	0	0	0	0	0	0	0	22,932
Pretax Income		**(510)**	**(563)**	**(618)**	**(674)**	**(731)**	**(790)**	**(851)**	**(913)**	**(976)**	**(1,042)**	**1,185**	**1,116**	**1,045**	**973**	**899**	**822**	**744**	**664**	**582**	**497**	**861**
Taxes (before federal/state credits)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Income - Book		**(510)**	**(563)**	**(618)**	**(674)**	**(731)**	**(790)**	**(851)**	**(913)**	**(976)**	**(1,042)**	**1,185**	**1,116**	**1,045**	**973**	**899**	**822**	**744**	**664**	**582**	**497**	**861**
PROJECT CASH FLOW & BENEFITS																						
Pretax Income		(510)	(563)	(618)	(674)	(731)	(790)	(851)	(913)	(976)	(1,042)	1,185	1,116	1,045	973	899	822	744	664	582	497	861
Plus: Book Depreciation		2,293	2,293	2,293	2,293	2,293	2,293	2,293	2,293	2,293	2,293	0	0	0	0	0	0	0	0	0	0	22,932
Less: Loan Principal		(497)	(506)	(516)	(526)	(535)	(546)	(556)	(567)	(577)	(588)	(600)	(611)	(623)	(634)	(646)	(659)	(671)	(684)	(697)	(710)	(11,948)
Pretax Cash Flow		**1,287**	**1,224**	**1,160**	**1,094**	**1,026**	**957**	**887**	**814**	**740**	**663**	**585**	**505**	**423**	**339**	**252**	**164**	**73**	**(20)**	**(115)**	**(213)**	**11,844**
Debt Service Coverage Ratio		**2.8**	**2.7**	**2.6**	**2.5**	**2.4**	**2.3**	**2.2**	**2.1**	**2.0**	**1.9**	**1.8**	**1.7**	**1.6**	**1.5**	**1.3**	**1.2**	**1.1**	**1.0**	**0.8**	**0.7**	**1.8**
Taxes/Credits/Grants																						
State Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
State Credits/Grants		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Credits/Grants		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NET CASH FLOWS																						
Capital Investment	(22,932)																					(22,932)
Amount to Finance	11,948																					11,948
Operating Pretax Cash Flows		1,287	1,224	1,160	1,094	1,026	957	887	814	740	663	585	505	423	339	252	164	73	(20)	(115)	(213)	11,844
STATE CREDITS / TAXES	4,550	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4,550
FEDERAL CREDITS / TAXES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CASH FLOW BENEFITS	**(6,434)**	**1,287**	**1,224**	**1,160**	**1,094**	**1,026**	**957**	**887**	**814**	**740**	**663**	**585**	**505**	**423**	**339**	**252**	**164**	**73**	**(20)**	**(115)**	**(213)**	**5,411**
Cumulative Cash Flow		1,287	2,511	3,670	4,764	5,791	6,748	7,635	8,449	9,188	9,851	10,436	10,941	11,364	11,703	11,955	12,119	12,192	12,172	12,057	11,844	

CHAPTER 9 – CONCLUSIONS AND RECOMMENDATIONS

The development of a 3 MW net stand-alone or cogeneration project, using forest fuels, represents a major capital investment for the MR. Because of unique and specialized programs such as the forest biomass set aside under SB 1122 and the CDFI New Markets Tax Credit, MR has the potential opportunity to develop a viable project with a minimum net present value return on equity of 12 percent.

The project would have several benefits for MR, including:

1. An opportunity to diversity its investment portfolio
2. An excellent complement to MR's existing forestry management operations
3. A hedge against rising fossil fuel prices (fossil fuels are currently used to heat its existing operations)
4. An opportunity to provide thermal energy to future proposed tribal businesses
5. The potential to cool MR’s existing and future businesses by displacing electric powered chillers with steam absorption cooling
6. Creation of an opportunity to participate in future carbon credit markets by further displacement of fossil fuels and by use of forest fuels that are currently otherwise burned in the open

The SB 1122 program, when initiated and implemented by PG&E, will represent a unique opportunity for MR to develop a small stand-alone or cogeneration project using specified forest derived fuels. The initial power purchase rates offered under the program will be double the rates available for renewable power in other markets and will have to move up further yet to attract developers. MR will need to wait in the initial PG&E queue for a year of price ratcheting in order to obtain power rates (i.e., $182 to $186 per MWH) that would support the capital investment associated with project development.

After PG&E implements the SB 1122 program, BECK expects power sales prices to ratchet upward per the SB 1122 protocol with no takers. During that time MR should expect PG&E to begin agitating to be relieved of its responsibility under the SB 1122 program. This will likely reach a crescendo if the mandatory program review power price levels are reached, which are $197/MWH. Fortunately, it appears that MR will be able to accept rates below that threshold. This will be a major benefit to MR over other potential SB 1122 program participants.

The proposed Power Purchase Agreement (PPA) under the program has two features that represent substantial risks to a Tribal project:

1. The power rates remain flat for the 10-20 year term of the PPA.
2. During every 2 year period of the contract, the project must produce 180 percent of its annual energy commitment.

The flat power pricing means that inflation of fuel and operating expenses will eat away at positive margins as the project progresses in time. BECK modeled the economics of the project using a 2.5 percent general inflation rate for all commodities, which is a slightly conservative measure of actual U.S. inflation over the last 25 years. Using traditional financing (20 year debt, flat annual payments), the project develops a slightly negative cash flow and unacceptable debt service coverage ratios in the last few years of the 20 year periods. These issues can be overcome by shortening the debt or establishing reserve accounts, but these measures will slightly raise power price to keep equity returns at the 12 percent minimum.

The issue of meeting high guaranteed production levels is addressed by using proven commercial power generation technology with guarantees. This is in contrast to other proposed SB 1122 community projects, which appear to be planning to use gasification technology, with power produced in a modified internal combustion (IC) engine. Even the preliminary U.S. DOE study done for MR utilized this technology choice. Gasification technology choice offers the opportunity to maximize production of byproducts such as biochar and additional syngas for transportation fuel production. However, the market value of those products is unknown and therefore financing entities give no credit for this potential. Nevertheless, these byproducts may indeed add substantial value in the future.

BECK has been unable to gain a comfort level with the gasification technology choice to allow recommending it to MR. Gasification technology simply has no track record with mixed forest fuels and its use in the SB 1122 context relies on speculative drying of the feedstock material. In addition, BECK has not been able to develop hard capital, efficiency, or operating cost data for gasification technology, nor has BECK found commercial guarantees of the operation as a whole when using gasification technology. Finally, the types of acceptable fuels under SB 1122 are quite limited, and much more information is needed showing that these fuels could be utilized effectively across their range of natural variability (heating value, ash, moisture, and species) when using gasification technology.

Therefore, BECK recommends the use of conventional steam boiler/steam turbine-generator technology since it can be applied successfully against the PPA production requirements, is financeable, and preserves much of the potential upside from future carbon programs. For example, if carbon credits are granted for forest fuel use, the two technologies would share equally in the upside. If biochar, ash, or both are given carbon sequestration credit, conventional combustion would capture a portion of the credit.

One other risk factor in the project that bears mentioning is the use of a wet cooling tower to condense steam from the turbine. Heat and material balances for the two options show a water usage of 50 to 52 gallons per minute (GPM). In the drought California is currently experiencing, water usage at those levels may become an issue for MR. If so, the project could be configured with dry cooling in the form of an air cooled condenser, or use a hybrid system. These options raise capital cost by roughly 5 percent and lower efficiency slightly, but are not a threat to overall project viability.

The economics developed in the financial models, a power price of $182/MWH for a cogeneration project and $186/MWH for a stand-alone project, are predicated on obtaining the benefit of financing under the Community Development Financial Institution's New Market Tax Credit (NMTC) program. The NMTC program offers an estimated equity infusion of $3.85 million (cogeneration) or $3.55 million (stand-alone) and an interest rate of 1.9 percent for 20 years. Both of those NMTC program benefits are necessary to keep prices below the SB 1122 $197/MWH mandatory review level. It was also assumed that an additional $1 million in grants can be obtained from the Departments of Agriculture, Interior or Energy. With conventional financing, as opposed to the NMTC package described above, the required power prices would be about $20/MWH higher to obtain the same equity return. Thus, it is imperative − if MR wishes to proceed further − for MR to immediately verify their qualification for the program and find a Community Development Entity (CDE) with unallocated capital.

Because the projected thermal loads for future MR additions are so low, the advantage of having a cogeneration operation over a stand-alone operation are reduced to a difference in power selling price of only $4.50/MWH to produce equivalent equity returns. There are other advantages to having cogeneration potential, however, which should push a decision in that direction. It is always advantageous to have a hedge against rapidly rising fossil fuel prices, as has happened repeatedly in the recent past. Cogeneration also has permitting and public acceptance advantages that are explained in more detail in Chapter 7. Finally, many of the potential carbon credit revenues would flow from the cogeneration aspects of the project.

9.1 RECOMMENDATIONS

The combination of the SB 1122 program and the availability of CDFI/NMTC financing create an opportunity for Mooretown to invest in a small bioenergy facility utilizing forest fuels. There are several next steps that should be taken quickly if the decision is to move forward. Now that a feasibility study has been completed, the tribe is in a position to obtain additional grants to move the project through the following next steps:

1. Prepare an interconnection application under PG&E's Fast Track Process. This is necessary to be part of the SB 1122 queue when it opens.
2. Research the CDFI process to determine qualification and availability of funds through one or more CDEs.
3. Begin the air quality permitting process. Because the lead agency will likely be the USEPA, Region IX in San Francisco, it should be expected that this process will take longer than usual and perhaps result in additional environmental documentation.
4. Approach the U.S. Forest Service regarding a long term fuel treatment commitment, such as a 10 year stewardship contract. Lenders will require long term access to necessary volumes of qualifying fuel. This action will also allow a more precise estimate of the delivered fuel cost if the specific types and locations of fuels to be used are identified.
5. Since logging slash is the lowest cost fuel considered in the analysis, MR should verify with the CPUC/CalFire that logging slash produced from sustainably managed lands does indeed qualify for the SB 1122 program as has been assumed in this study.

6. Begin preliminary engineering to define site characteristics, develop layout drawings and verify BECK's capital cost estimates.
7. Complete all requirements to place the project in PG&E's SB 1122 queue as soon as it opens. By all appearances, there will be few projects in the initial queue, and it may be the Mooretown project that becomes the critical third project that allows the price ratcheting process to begin.

CHAPTER 10 – APPENDICES

Appendix A

BUDGETARY ESTIMATE

PREPARED FOR

[redacted]

[redacted], CALIFORNIA

FOR

40,000 PPH BOILER

WITH A

NOMINALLY RATED 3,000 KW

TURBINE-GENERATOR SYSTEM

Budgetary Estimate No. [redacted]

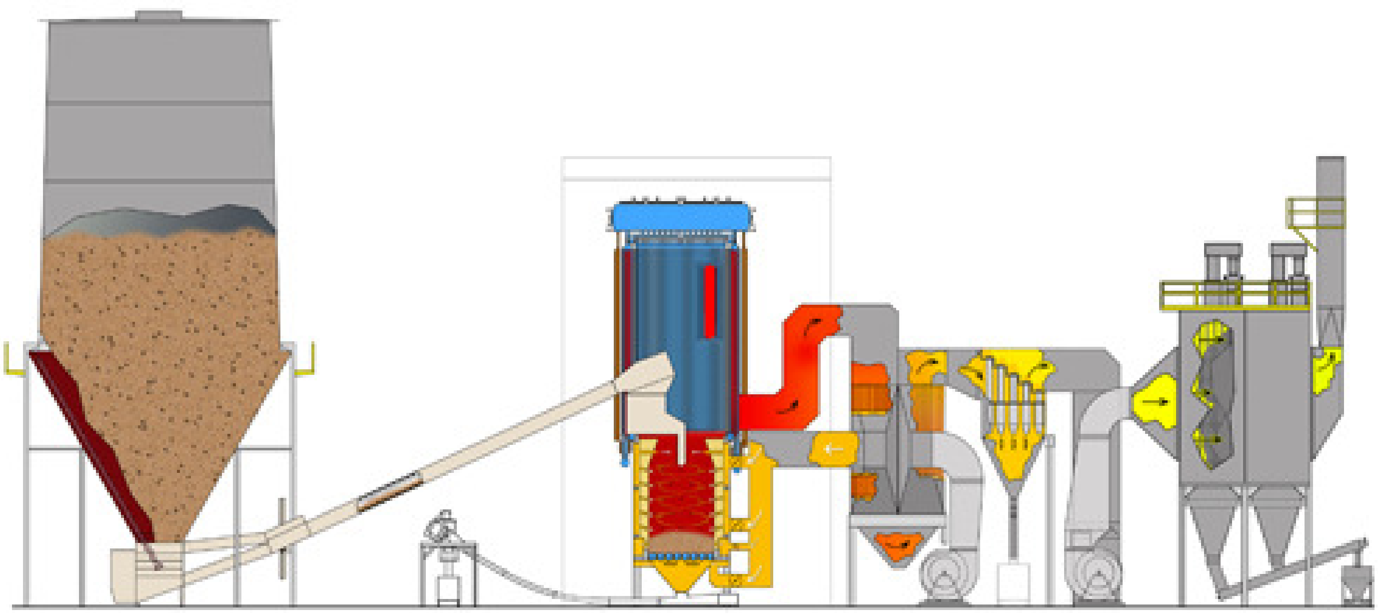
September 30, 2014

I. GENERAL DESCRIPTION

The following work description and budgetary estimate has been prepared to assist [redacted] in the evaluation and review of a nominally rated 3,000 KW wood waste-fired electrical generation power plant prior to a definitive proposal being prepared.

The system is based on a Wellons wood-fired steam boiler and fuel storage components, a turbine-generator, the balance of plant components, all systems and design engineering, and construction activities required to provide an operable plant.

All of the boiler and turbine-generator system components will be located in a building of Wellons' design and manufacture. Fuel storage will be adjacent to the boiler building. The cooling tower will be located in a down-wind location from the power plant, but within 50 feet of the condenser. Equipment layout within the turbine-generator and boiler building will be such to facilitate proper operation and maintenance.



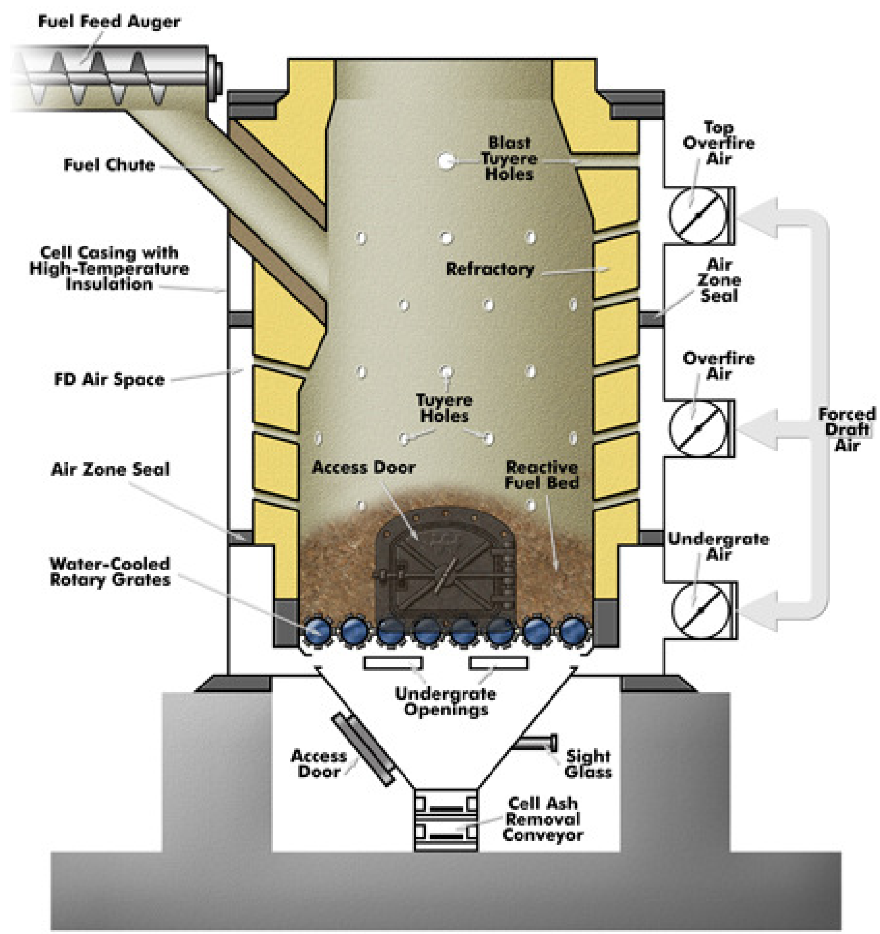
II. FUEL STORAGE AND HANDLING

Two (2) Wellons Model A-30-40 severe duty fuel storage bins, each with 152 units of capacity, complete with roof, cone bottom section, level switches and controls, silo roof conveyor, and a conveyor to the boiler system are included.

Item	Wellons	Purchaser	Optional
Fuel Storage and Handling System			
Two (2) A30-40 Fuel Storage Silos	✓		
Primary Fuel Conveyor	✓		
Mixing Conveyor	✓		
Silo Roof Conveyor	✓		

III. STEAM GENERATING SYSTEM

The steam generating system consists of a Wellons 40,000 PPH steam boiler, operating at 650 psig, 725ºFTT with a watertube boiler, single cell furnace with water-cooled grates and mulite based shotcrete refractory cell lining. A metal building will enclose the boiler and be complete with lighting, stairways, catwalks, doors, windows and vents.



The combustion air is provided by forced draft and induced draft fans through an air preheater, with all electrical and pneumatic controls, dampers, air compressor and breeching included, and exhausts through an electrostatic precipitator (ESP) into an uptake stack.

Ash handling is automated and consists of an ash conveying system to convey ash from the economizer, air preheater hopper, multiple cone collector hopper and ESP hoppers, removing ash from the drop-outs to purchaser's tote bins. Cell cleanout is automatic.

The feedwater system consists of two (2) multi-staged motor-driven centrifugal pumps (one [1] for standby), two (2) gratewater pumps (one [1] for standby), water level controls and a deaerator. The feedwater system provides for necessary chemical treatment utilizing a reverse osmosis demineralizing system.

The following equipment is included:

Item	**Wellons**	**Purchaser**	**Optional**
Watertube Boiler System			
Boiler Pressure Vessel	✓		
Boiler Casing and Insulation	✓		
Boiler Accessories	✓		
Sootblowers	✓		
Feedwater Control System	✓		
Supporting Structure	✓		

Item	Wellons	Purchaser	Optional
Furnace System			
Single Cell Furnace System	✓		
Metering Surge Bin	✓		
Furnace Fuel Feed Screw	✓		
Self-Cleaning Rotary Grates	✓		
Combustion Air Handling System			
Forced Draft Fan	✓		
Ducting and Insulation	✓		
Exhaust Gas Handling System			
Combustion Air Preheater	✓		
Economizer	✓		
Multiple Cone Collector	✓		
Ducting and Insulation	✓		
Induced Draft Fan	✓		
Computerized Control System			
Computer Equipment and Peripherals	✓		
Proprietary Software	✓		
Supplemental Equipment			
Electric Motors	✓		
Motor Control Centers	✓		
Boiler System Piping	✓		
Blowdown Heat Exchanger	✓		
Water Treatment Equipment	✓		
Feedwater and Deaeration System	✓		
Boiler Feedwater Pumps	✓		
Boiler Gratewater Pumps	✓		
Ash Handling	✓		
Ash Receivers		✓	
Opacity monitor	✓		
Continuous Emissions Monitoring		✓	
SNCR Urea Injection		✓	

Item	Wellons	Purchaser	Optional
Boiler Walkways, Stairs, and Decks	✓		
Air Compressor	✓		
Boiler and Turbine-Generator Building	✓		
Electrostatic Precipitator			
General Structure	✓		
Precipitator Internal Components	✓		
Electrical Equipment and Control	✓		
Safety Key Interlock System	✓		
Ash Handling System	✓		

IV. ELECTRICAL GENERATING SYSTEM

The electrical generating system consists of a, new steam turbine-generator and condenser, and selected plant mechanical and electrical equipment, operating at 650 psig, 725ºFTT with a nominal rating of 3,000 KW at .80 power factor. The unit is a condensing extraction type turbine (50 psig), exhausting at approximately 3 in HgA.

The turbine-generator and auxiliary machinery are installed on a concrete pedestal foundation in a metal lean-to addition to the boiler building, complete with concrete and steel grating operating floor, stairways, catwalks, doors, etc. The building has a mechanical bridge crane of sufficient capacity to handle on-going maintenance.

The major piping systems (steam lube oil, service water, etc.) complete with hangers and valves are provided, along with PRV stations, drain tanks, etc. Motor starters, wire, conduit and miscellaneous electrical fittings are also provided, together with generator protective relaying and metering, one (1) generator circuit breaker, DC power supply, neutral grounding, main power transformer, and the turbine-generator control panel.

A single-cell, wave formed PVC filled cooling tower, with variable speed fan and two (2) centrifugal circulating pumps, each rated at half flow, are provided. The interconnection piping between the tower basin and condenser is also provided. The tower is built on a concrete basin.

Equipment includes:

Item	Wellons	Purchaser	Optional
Electrical Generation System			
Steam Turbine	✓		
Condenser	✓		
Air Ejector	✓		
Lube Oil System	✓		

Item	Wellons	Purchaser	Optional
Condensate Pumps	✓		
Cooling Tower	✓		
Circulating Pumps	✓		
Generator and excitor	✓		
Piping assemblies and valves	✓		
Switchgear	✓		
DC Power System	✓		
Electric Motors	✓		
Motor Control Center	✓		
Control Panels	✓		
Switchyard equipment	✓		
Generator Breaker and Relays	✓		
Electrical Wiring and Conduit	✓		
Turbine Building	✓		
Turbine Room Bridge Crane	✓		
Main Power Transformer	✓		
Auxiliary Power Supply		✓	
Generator Protective Relaying & Metering	✓		
Grounding Grid	✓		
Utility Interface		✓	

V. PROJECT SERVICES

Wellons will engineer, design, construct, and erect all of the equipment and material as defined in this work description and equipment list. This includes all engineering and design for the plant components.

Installation, including foundations, will be complete with all labor, tools, equipment, technical direction and supervision being provided. Equipment orientation and system operational training with operation and maintenance manuals are included.

Item	Wellons	Purchaser	Optional
Project Services			
System Design and Engineering	✓		
Foundation Design (No Pilings)	✓		
Foundation Construction (No Pilings)	✓		
Grounding Grid Design	✓		
Installation Drawings	✓		
Mechanical Installation	✓		
Electrical Installation	✓		
Start-up and Training	✓		
Operation and Maintenance Manual	✓		
General Spare Parts List	✓		
Freight to Site	✓		
Touch-up Painting	✓		

VI. PURCHASER TO PROVIDE

The Purchaser is responsible for providing certain items, such as:

Item	Wellons	Purchaser	Optional
Site preparation (3,000-psf soil bearing capacity).		✓	
Emergency Power Supply		✓	
All permits and regulatory filings		✓	
Building furnishings / outside lighting and site finishing.		✓	
Electrical connection to the local utility		✓	
Secondary pollution control equipment		✓	
Clean water supply		✓	
Electrical power to connections at MCC		✓	
Wood fuel to silo roof conveyor		✓	
Construction Utilities		✓	

VII. BUDGETARY PRICE

A. BASE EQUIPMENT AND SERVICES

For the equipment and services defined in the work description for the steam supply and electrical generation system.

Budgetary Price, including California sales tax..........................$[redacted]

F.O.B. [redacted], California

This budgetary estimate is subject to review and price adjustment, if necessary, at the time of order placement.

The above budgetary pricing does not include any duties, additional taxes, import/export fees, and costs for permits, bonding or other special requirements.

Budgetary Estimate No. [redacted]

September 30, 2014

Appendix B

Additional Information

California Applicants to the 2015 USDA Forest Service Request for Proposals:
2015 Wood Innovations Funding Opportunity

The following additional information is provided to help California applicants to the 2015 USDA Forest Service Request for Proposals: 2015 Wood Innovations Funding Opportunity (Federal Register, Vo. 79, No. 207, Monday, October 27, 2014).

Application Process

Applicants should consult with the appropriate Forest Service Regional Biomass Coordinator to develop proposals that align with Forest Service Regional/Area priorities and State Forest Action Plans.

U.S. Forest Service, Region 5 (Pacific SW Region), Leadership Intent for Ecological Restoration (paraphrased from http://www.fs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb5351674.pdf):

- Ecological restoration will be the central driver of wildland and forest stewardship in the Pacific Southwest Region, across all program areas and activities.
- This will require an expanded effort to engage tribes, partners, and neighbors, and to work in closer coordination with other agencies.
- It is our intent to increase forest resilience through treatments, such as prescribed fire and thinning, to benefit approximately 9 million acres of national forest system lands within the next 15-20 years (i.e. at least 450,000 ac per year).

California Dept. of Forestry and Fire Protection (Cal Fire), California's Forests and Rangelands: 2010 Strategy Report (http://frap.fire.ca.gov/data/assessment2010/pdfs/Strategyreport7-157FINAL.pdf)

> The primary goals of *California's Forests and Rangelands 2010 Strategy* are to improve forest health and community protection, and preserve and enhance California's forests and rangelands in the face of increased threats from wildfire, disease, insects, and expanding development. Specific strategies include:
>
> Emerging Markets for Forest and Rangeland Products and Services (Excerpts, p. 5-6)
> - Facilitate development of sustainable biomass harvest practices to grow, collect and utilize forest and range biomass as feedstock to biomass markets.
> - Facilitate the expansion of biomass markets through improved infrastructure (e.g. transmission lines), monetization of external benefits (e.g. hazard reduction), feedstock collection, and generation capacity.