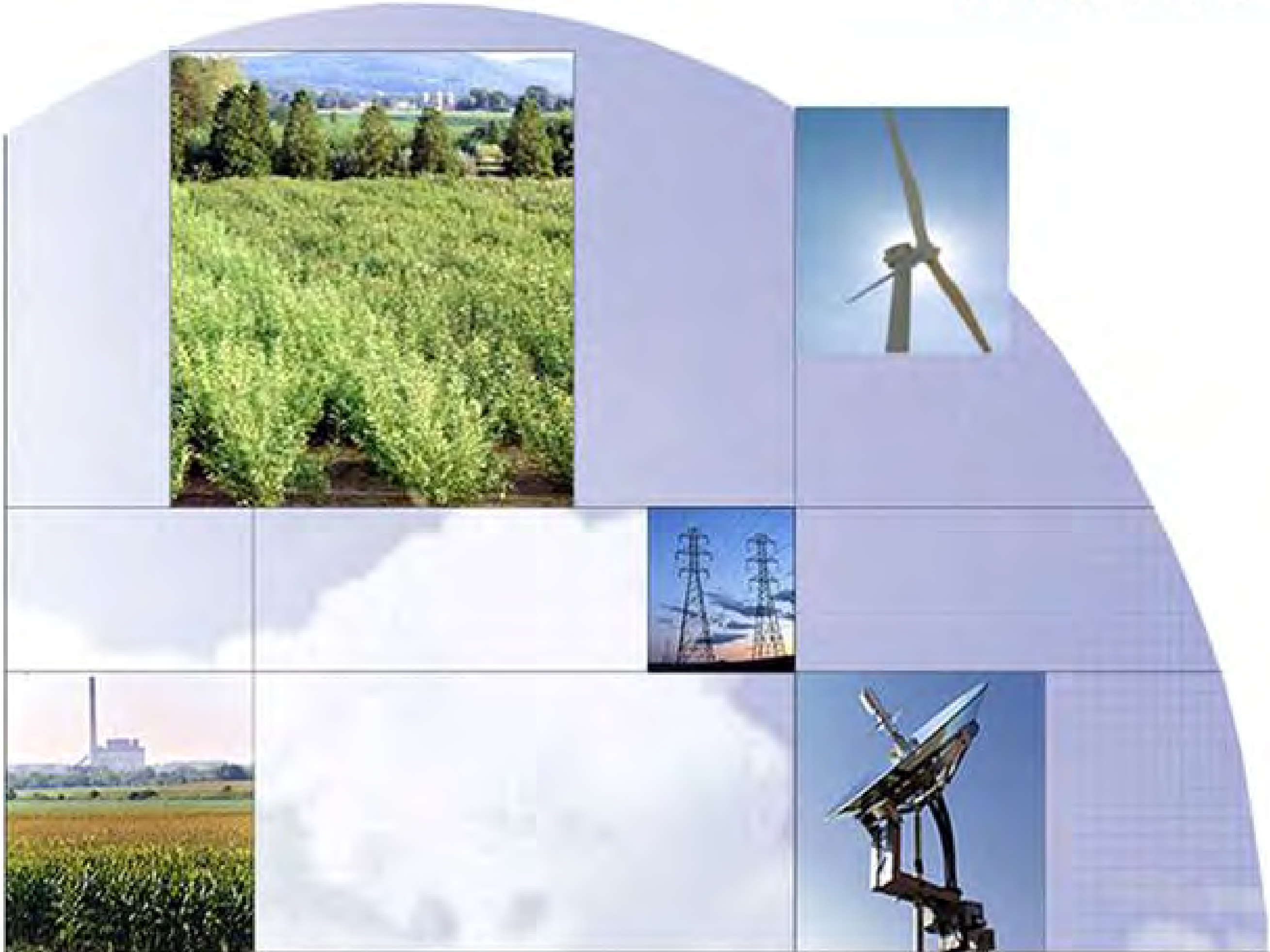

Renewable Energy Feasibility Study Final Report

Prepared for: Gila River Indian Community

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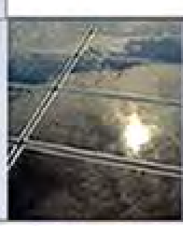

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EXECUTIVE SUMMARY

Introduction

The Gila River Indian Community (GRIC or the Community) contracted the ANTARES Group, Inc. ("ANTARES") to assess the feasibility of solar photovoltaic (PV) installations. A solar energy project could provide a number of benefits to the Community in terms of potential future energy savings, increased employment, environmental benefits from renewable energy generation and usage, and increased energy self-sufficiency.

The study addresses a number of facets of a solar project's overall feasibility, including:

- Technical appropriateness
- Solar resource characteristics and expected system performance
- Levelized cost of electricity (LCOE) economic assessment

ANTARES previously provided GRIC with a technical characterization report which provided information about a range of solar technology options. Commercially available solar technologies were screened to identify the ones that could be economically viable for GRIC in the near term. This report builds on the knowledge in the technical characterization report, by taking the technical solutions deemed to have potential and applying them to specific project locations identified through site visits and discussions with the GRIC representatives.

Technical Feasibility Analysis

Although there are a number of possible locations at GRIC that meet all or most of the selection criteria for a solar PV project, only four of the best sites are included in the detailed feasibility analysis, two roof areas and two ground areas. The buildings considered for roof mounted projects include the Wild Horse Pass Hotel and Casino and the Tribal Governance Center. The ground areas include the San Tan Brownfield and the area near the Lone Butte Substation. All of these selected sites are on Community owned facilities and lands. This can help ensure that any renewable energy project would benefit the Community and provide a long term stable energy supply. Furthermore, both of the selected buildings have flat roof area available, and the roofs are relatively new and in good condition. The selected ground areas are level and do not have significant obstructions that would hinder development. They are also fairly close to grid interconnection points. It is also worth noting that the analysis results for the arrays at the selected sites will be representative of other potential projects at GRIC, in terms of system performance (electricity generated per unit capacity) and expected capital costs. Although the economics may change somewhat for a particular site, such as if additional site work was needed for project development or the electrical interconnection required additional equipment or costs, it is expected that the results from the selected projects will help to gauge overall project viability. This is also why a range of project configurations was explored in this study.

The potential PV system configurations were developed at the selected locations based on the physical space available and selected mounting method. All considered roof mounted arrays used ballasted fixed tilt racking systems, with both polycrystalline silicon (p-Si) and thin film Cadmium Telluride (CdTe) modules in different configuration options. The ground mount arrays all used CdTe modules which are less sensitive to high temperatures and reduced output due to panel soiling from dust. These systems differed in other ways, by varying system sizes and racking configurations. Although most arrays used fixed tilt racking, one of the ground mount systems has a single axis (1-X) tracking system to increase system output. Since the locations considered for ground mount arrays did not have highly constrained areas, a variety of different configurations were evaluated in order to determine the impact that different sizes and mounting methods would have on the overall techno-economic performance.

Each of the considered PV system options were then modeled using PV Design Pro software in order to provide a detailed estimate of the expected electricity generation throughout the course of a year. The results of this analysis are summarized in Exhibit 1. The results of the technical analysis were used in the economic evaluation to determine financial viability. The estimated output values presented in the table correspond to expected performance for the first year, and do not include any system degradation impacts associated with output reductions over time.

Exhibit 1. Performance Modeling for PV Arrays

Option	Location / Description	Module Type	Racking Type	Tilt Angle (degrees)	Orientation (degrees)*	System Capacity (kW_{DC})	Estimated Output (kWh/yr)
Roof Mount Systems							
1A	Tribal Governance Center	p-Si	Ballasted	10	180	491	898,398
1B		CdTe	Ballasted	5	180	458	863,142
2A	Wild Horse Pass Hotel & Casino	p-Si	Ballasted	10	162	437	815,520
2B		CdTe	Ballasted	5	162	450	850,889
Ground Mount Systems							
3A	San Tan Brownfield	CdTe	Fixed Tilt	25	180	1,109	2,276,318
3B		CdTe	Fixed Tilt	25	180	5,544	11,381,592
4A	Lone Butte Substation	CdTe	Fixed Tilt	25	180	5,544	11,381,592
4B		CdTe	1-X tracking (E-W)	varies	varies	5,638	14,533,073

** An orientation angle of 180° corresponds to due south, while a 270° orientation points directly west and a 90° orientation points directly east.*

Project Concepts

One of the key considerations for development of a solar energy project is electricity distribution and sales agreements, to determine the end user or purchaser of the electricity generated by the system. Electricity generated from a PV system on Community land or buildings could be used to directly serve the GRICUA customers and offset existing grid electricity purchases from other utilities. There are a number of other utilities that serve some areas of the Community, but interconnection with the GRICUA distribution system is the primary power off-take arrangement considered in this analysis because the employment, economic and environmental benefits of a cost-effective renewable energy technology deployment to the GRIC are maximized when that generation project is owned by the Community.

Project ownership and potential partnerships are another important consideration for project development. Although a renewable energy project at GRIC could have a number of different partner and ownership structures, GRIC has stated that they would prefer to have a tribal entity own the project. However, a partnership scenario could bring some benefits in terms of up front project funding and availability of federal tax incentives. There are a few potential alternatives that may present a way for GRIC to maintain ownership and control of the project while benefiting from the tax incentives. One of these options is a "pass through lease," in which a tax equity investor (such as a financial institution) would be the lessee, and would make rent payments to the tribe in exchange for benefiting from the investment tax credit. Another possible option would be to have a tax equity investor that is a partner rather than a lessee. In this case GRIC would both own and operate the project while taking advantage of the tax benefits through the participation of a passive investor.

Economic Analysis and LCOE Results

A levelized cost of electricity (LCOE) analysis was performed for the considered PV configurations in order to compare the cost-effectiveness of potential projects. The LCOE provides the average cost of power over the lifetime of the project, and is useful in gauging the cost of producing electricity and comparing it to the electric production costs for other technologies and utility supplied power. Inputs to the LCOE calculation include system output (kWh generated), capital costs, O&M costs, financing assumptions, and any applicable incentives.

Both current and constant LCOE figures are calculated in the analysis.[1] Key financial input variables include a 25 year project lifetime, a long term general inflation of 2%, and a weighted average cost of capital of 6.6%.[2] The LCOE analysis was performed in two ways; the base analysis (Case 1) does not include any incentives, and an alternate analysis (Case 2) includes all potentially available incentives that could apply to a PV project developed with a partner. The evaluation with incentives assumes there is a project partner with a tax burden that can take advantage of the tax credits and depreciation benefits. The incentives included in the Case 2 assessment are the Federal Investment Tax Credit (equivalent to a 30% upfront capital cost reduction benefit), AZ Wind and Solar Tax Credit (capital cost reduction of $25,000 per project), and MACRS accelerated depreciation. In addition, the value for Renewable Energy Certificates (RECs) that could be sold to help support the project are considered for all project options in both cases (with and without incentives). Since the REC market varies widely and values have decreased significantly in recent years, RECs are valued at a conservative but reasonable price of $2/MWh.

The analysis was performed both with and without system degradation impacts, which results in a slight reduction in expected output of the system each year it operates (between 0.5%-0.7% reduced kWh generated per year, depending on the module type).

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[1] The current LCOE includes the rate of inflation, while the constant LCOE does not.

[2] The long term general inflation rate is based on financial parameter guidance for the federal government, based on the Annual Supplement to NIST Handbook 135 (U.S. Department of Commerce, NIST, 2012). The weighted average cost of capital is based on the average rate used for the U.S. Energy Information Administration's Annual Energy Outlook 2013.

Exhibit 3 summarizes the results of the economic analysis, when system degradation is included. The roof mounted systems all had very similar LCOE results, ranging from $0.13-$0.16/kWh without incentives, and $0.10-$0.13/kWh with incentives. The ground mounted systems all have lower LCOEs than the roof mounted systems, mostly due to the economies of scale benefits of these larger systems that lead to lower per unit installed costs. The LCOE for the ground mounted projects range from $0.09-$0.10/kWh without incentives, and $0.07-$0.09 with incentives. The Lone Butte Substation array with single axis tracking (Option 4B) was found to be the best performing project overall. Although it has the highest per-unit capital costs of the ground mount systems, the performance benefits from the tracking system more than make up for the added costs. In general, the system degradation results in around a 5% reduction in system output over the lifetime of the system, and increases the LCOE values by about $0.01/kWh relative to the assessment that does not include degradation.

Sensitivity analyses were performed to address uncertainties in specified cost parameters and evaluate the affect that varying these values will have on the overall project economics. This analysis varied key input factors determined to be critical to project economics, including capital cost, O&M costs, and weighted average cost of capital (WACC). Each of these factors was varied individually (i.e., one at a time), across a range of +/- 50% from the base value to evaluate the impact on the LCOE value for each project. In addition, solar radiation was varied by +/- 25% to account for uncertainty in the solar resource, which can be used to evaluate the impact performance varying from expectations for other reasons as well. All sensitivity analysis results do include system degradation considerations.

Exhibit 2 shows the results of the sensitivity analysis for the best performing project, Option 4B for the case without incentives. The sensitivity charts for all project options display similar trends. The projects are most sensitive to changes in the capital costs, and least sensitive to changes in O&M costs. The projects are also sensitive to the WACC and solar radiation. Overall, changes in the capital cost and/or the discount rate used on the cash flows could have the greatest impact on the projects' success.

Exhibit 2. LCOE Sensitivity Analysis for Option 4B (Lone Butte Substation, 1-X tracking)

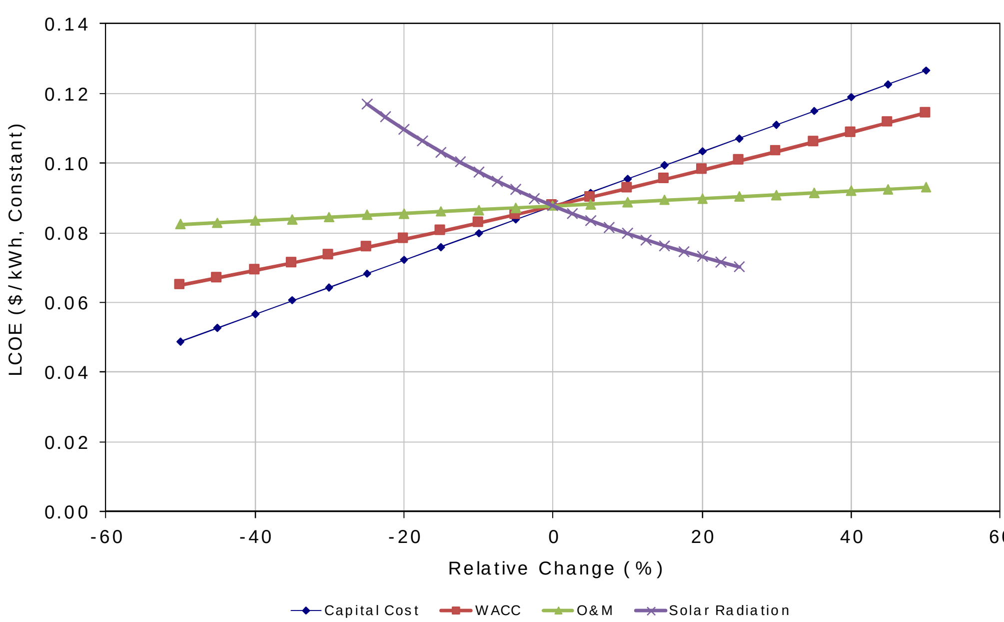


Exhibit 3. Summary of Results for Considered PV Systems

Option	System Location / Description	Module Type	System Capacity (kW_{DC})	Estimated Output (kWh/yr) [a]	Base Total Installed Cost [b]	LCOE (constant) No Incentives w/ Degradation $/kWh [c]	LCOE (constant) With Incentives w/ Degradation $/kWh [c]
Roof Mounted Systems							
1A	Tribal Governance Center	p-Si	491	898,398	$1,469,018	$0.131	$0.102
1B	Tribal Governance Center	CdTe	458	863,142	$1,415,407	$0.133	$0.104
2A	WHP Hotel & Casino	p-Si	437	815,520	$1,308,052	$0.129	$0.101
2B	WHP Hotel & Casino	CdTe	450	850,889	$1,392,132	$0.133	$0.104
Ground Mounted Systems							
3A	San Tan Brownfield	CdTe	1,109	2,276,318	$2,909,946	$0.106	$0.084
3B	San Tan Brownfield	CdTe	5,544	11,381,592	$13,551,874	$0.099	$0.079
4A	Lone Butte Substation	CdTe	5,544	11,381,592	$13,551,874	$0.091	$0.073
4B	Lone Butte Substation (1-X)	CdTe	5,638	14,533,073	$15,130,402	$0.088	$0.070

Notes: (a) First year performance results, does not include system degradation impacts. (b) Total Installed Cost includes the base system cost and the extended inverter warranty. It does not include any incentives. (c) LCOE includes all considered costs and benefits throughout the 25-year economic life of the system. The LCOE results presented here do include the impact of system degradation over time (0.5% per year for arrays with silicon modules, and 0.7% per year for arrays with CdTe modules).

Project Development Considerations

There are a number of steps that would need to be taken to move forward with a PV installation at the Community. The steps required for a turnkey, GRIC-owned project are described below (not necessarily in order, as some items occur concurrently and process will depend on timeline for some steps). Additional steps will be needed if a partner is involved, or a separate engineer and construction contractor are selected for project development.

1. Select preferred system size and location based on results of this study and preferences of Community decision makers.
2. Obtain approval from tribal government.
3. Secure funding for the project.
4. Coordinate with the electric utility early on in the development process for grid-tied renewable energy systems (even if they are not funding the project).
5. Coordinate environmental study and review, as required.
6. Select preferred contract type and develop a scope of work for the project. The results of this feasibility study can be used as the basis for the scope of work for the engineering phase of the project.
7. Develop and issue a request for proposal (RFP) to solicit proposals for project development.
8. Evaluate proposals for the project. Evaluation criteria should be developed prior to issuing RFP. Standard evaluation approaches include best value; low price, technically acceptable; or low price.
9. Award contract to winning bidder.
10. Project developer / system designer designs project based on specifications in the scope of work. Design reviews should be performed by a third party, qualified solar design expert at various levels of completion in order to ensure site requirements are met.
11. Project developer constructs the system. A third-party should inspect and commission the system to make sure it has been installed properly and is operating to specification.

Conclusions and Recommendations

The LCOE analysis showed that all of the projects are more expensive than the current price of electricity, which is around $0.05/kWh. However, there are other benefits to the solar projects and GRIC must decide if those are worth the higher cost of production. One of the goals of an investment in renewable energy is to hedge against rising natural gas costs. If natural gas costs do rise, that could tip the balance of the economics and make solar power more favorable in select cases.

As an example of what electricity prices could look like going forward, ANTARES applied natural gas escalation rates to the price of electricity over the 25-year lifetime of the project. Since the GRICUA electricity prices are tied to natural gas rates, this analysis provides insight into future power costs. Over the 25 year project period, the current $0.05/kWh cost of electricity is expected to escalate to $0.08/kWh, which is competitive with select cases of the solar analysis. Given this result and the fact that PV capital costs are declining,[3] the PV systems could be a prudent investment. The tribe may also be eligible for federal grants or loan guarantees that could further improve the economic outlook for a PV system.

If GRIC is interested in pursuing a project on-site, ANTARES would recommend installing a large (5 MW) ground mount array with a single axis tracking system such as Option 4B, based on the financial analysis results. Although the tracking system adds complexity and additional maintenance requirements, the additional performance benefits more than make up for the added cost. However, if a simpler system was desired, a large fixed tilt ground mount system could also be beneficial. In either case, a 5 MW PV is a very expensive project ($13-$15 million), so selecting a project of this size will also largely depend on securing project financing and finding a project partner with a tax burden to take advantage of available incentives.

Although the roof mounted systems would have a somewhat higher LCOE rate, these systems may have other benefits that would be attractive to GRIC such as being able to directly offset electricity consumption at the site, and possibly higher visibility by site staff and tourists for demonstration purposes if an informational kiosk or poster was installed in conjunction with the project (since the selected building locations have more activity than the ground mount areas). These roof mounted systems also have lower upfront capital costs as they are smaller than the considered ground mount projects, which could make it easier to finance a project.

[3] Installed prices for residential and commercial PV systems have been shown to decrease by about 40% in the U.S. from 2008-2012, and the downward trend continues. While much of the recent decline can be attributed to reduced PV module prices, future decreases are expected to focus on reducing balance of system (non-module) costs.

1 INTRODUCTION

1.1 PROJECT BACKGROUND AND OBJECTIVES

The Gila River Indian Community (GRIC) commissioned a study by the ANTARES Group Inc. (ANTARES) to accomplish the following objectives:

1. Identify available solar and biomass energy resources,
2. Characterize solar and biomass energy technologies, and
3. Conduct detailed technical and economic analysis of potentially viable projects.

The project purpose is to provide sufficient information on solar and biomass energy technologies to allow the Community to make informed decisions about investment in energy generation resources. The GRIC manages its own electric distribution system and delivers electricity to residential, commercial/institutional and industrial customers through the Gila River Indian Community Utility Authority (GRICUA).

GRICUA does not currently own any generation resources. GRICUA has a long-term purchase agreement that ensures it will have access to the power capacity that the Community needs to satisfy future growth. However, the price of power is tied to the price of natural gas, so the possibility of increasing energy self-sufficiency through the use of renewable energy resources, the costs of which are independent of natural gas, could prove attractive to the Community. There are other significant environmental and economic benefits associated with renewable energy use. Any solar or biomass energy project option has to provide sufficient benefits to the Community in terms of energy savings, increased employment, environmental benefits and/or energy self-sufficiency that are compelling and are comparable to or greater than other energy, infrastructure or public works projects that the GRIC is considering.

While GRICUA serves most of the electric customers in the GRIC, development of any power project on the GRIC would have to take into account the potential technical and financial implications that could affect other power providers that service utility customers. Arizona Public Service (APS), Salt River Project (SRP), and the San Carlos Irrigation Project (SCIP) provide electric service to a small number of customers in the GRIC, some of which are industrial end users.

Early in the study, ANTARES provided GRIC with a technical characterization report which provided information about a range of biomass and solar technologies. The technologies were screened to identify the ones that could be economically viable for GRIC in the near term.

This report addresses the detailed analysis of the potential for solar energy projects in the GRIC. It builds on the knowledge in the technical characterization report. It takes the technical solutions deemed to have potential and applies them to specific projects identified for the GRIC energy assessment. A companion report addresses biomass project technical and economic feasibility.

1.2 OVERVIEW OF WORK PERFORMED

The project objectives were achieved through the following series of activities:

- Identify potential projects
  - Renewable energy resource analysis was performed to provide inputs on project sizing, technical performance and financial analysis.
  - Detailed site visits were performed to characterize the locations considered for projects.
  - Meeting with key project stakeholders to collect the data required for detailed analysis.
  - Screening technologies based on their commercial readiness.[4] In addition to off-the-shelf technologies, next generation technologies were identified that may not be currently viable. Information is given on what future developments are needed for them to make sense in the future.
  - Applying technical and financial site selection criteria to further narrow the list of technology and siting options.
- Evaluate project concepts
  - Technical performance assessment for options selected for detailed technical analysis
  - Characterize project site/technology choices based on available area, markets for energy and environmental attributes, economic performance, regulatory compliance, aesthetics and environmental impacts.
- Project development planning
  - Identify equipment vendors,
  - Evaluate funding sources,
  - Assess ownership models, and
  - Build financial models to assess the economic performance of the projects.

Conclusions and recommendations were given to GRIC on which projects (if any) meet their organizational goals and what steps to take next in the development process.

The candidate projects were selected based on their technical and economic merits as well as their ability to address the concerns and requirements of the tribal Community.

[4] Results of this effort are contained in a technology characterization report that complements the detailed project-specific analysis documented in this report.

2 Solar Project Site Selection

The *Renewable Energy Technology Characterization* report submitted previously identified power production using solar photovoltaics (PV) at a variety of scales and locations (ground-mounted and roof-mounted) as the best potential technology for the GRIC. There are a number of considerations for selection of a preferred site for a solar photovoltaics (PV) array. The major initial selection criteria for PV array siting include:

- Large available flat or south-facing area in order to facilitate array design
- No shading from nearby trees or structures
- Close proximity to electrical load centers or substations so that PV array can be tied into existing electrical system
- Available area is does not have extraordinary security concerns or restricted access
- For building mounted systems:
    - Minimal mechanical equipment located on selected rooftop areas
    - The roof on the building is in good condition or has been recently installed.
    - Array design would be compatible with the existing architecture and facility design
    - Area is not planned for demolition or major renovations within the lifetime of the system

In addition to general siting considerations, there are also a number of factors that impact PV array development and selection of appropriate technology type, size, and overall project configuration. In most cases, economics will be a primary concern for project development. The site specific considerations for a roof mounted PV project will include the roof age, condition, roofing material, loading capacity (evaluated by a structural analysis), aspect (orientation of roof area relative to the solar path), pitch, obstructions, shading, power end user (before or after meter), and other possible uses for the roof area including solar thermal applications. A ground mounted system will have other important consideration for project development and configuration, such as access to distribution lines and distance to interconnection points, ground slope, alternative land uses, land ownership, and environmental and cultural impacts. For both ground mounted and roof mounted systems, the aesthetic impacts of the PV array can be a key consideration as well.

A screening analysis was performed as part of the previous report, which included a high level cost of electricity calculation to determine the economic benefits of solar energy projects of different configurations and sizes. The evaluated options included PV systems ranging from 50 kilowatts (kW) to 20 megawatts (MW) in scale, considering monocrystalline silicon (m-Si) modules, polycrystalline silicon (p-Si) modules, thin film cadmium-telluride (CdTe) modules, and various mounting options (roof and ground mounted fixed tilt arrays at different tilt angles, as well as a single axis tracking ground mount system). The results of the analysis showed that in general the larger systems have lower year 1 cost of electricity, mostly due to the economies of scale benefits that decreases the per-unit installation costs as system capacity increase. Furthermore, the analysis also showed that thin film arrays generate more electricity per year than the equivalently sized crystalline silicon arrays due to reduced sensitivity to high temperatures, although they do require more area for a similar capacity. The thin film also has demonstrates reduced sensitivity to cell shading from dust accumulation on the panels. As such, ANTARES recommends considering CdTe or other thin film technologies in places where area is not constrained.

Although there are a number of possible project sites at GRIC that meet all or most of the selection criteria, only four of the best sites are included in the detailed feasibility analysis. Note that this site selection is focused on commercial / industrial sites which are most likely to be cost effective; no residential sized projects are considered. The chosen sites and general configuration characteristics selected for evaluation are summarized below, including approximate system sizes.

Selected Solar PV Arrays – Roof Mount

1. Tribal Governance Center
    (a) 500 kW p-Si modules (max size based on available area)
    (b) 450 kW CdTe modules (max size based on available area)
2. Wild Horse Pass Hotel & Casino
    (a) 450 kW p-Si modules (max size based on available area)
    (b) 450 kW CdTe modules (max size based on available area)

Selected Solar PV Arrays – Ground Mount

3. San Tan, Tannery Brownfield area
    (a) CdTe modules, 1 MW system, fixed tilt
    (b) CdTe modules, 5 MW system, fixed tilt
4. Lone Butte Substation area
    (a) CdTe modules, 5 MW system, fixed tilt
    (b) CdTe modules, 5 MW system, 1-X tracking

Land for each of the selected areas is tribally owned, and there is sufficient unshaded space available for array development. Both of the selected buildings have flat roof area available, and the roofs are relatively new and in good condition. The selected ground areas are level and do not have significant obstructions that would hinder development. They are also fairly close to grid interconnection points. The following chapter discusses the modeled configuration options in more detail.

Other considered buildings included the Sheraton Resort, Department of Corrections, and the Vee Quiva casino. These were not selected for the detailed analysis for a number of reasons such as aesthetic constraints or concerns for development, or limited space available on the roof for a PV installation. The Department of Corrections buildings in particular have a significant amount of equipment on the roofs that will severely limit the array size. However, it should be noted that in general the modeled arrays at the selected buildings will provide some indication of the potential benefits and costs for an array on these other buildings as well. Based on the available area identified from aerial imagery and information collected from the sites, it appears that the Sheraton Resort could support a PV system sized at approximately 320 kW_{DC},[5] while the new Vee Quiva Casino building roof could hold a slightly smaller system at around 290 kW_{DC}.

If is also important to note that there are also many other ground areas that could support PV development, but the selected locations are the most ideal development areas, due to proximity to interconnection and accessibility. Other brownfield areas could also support a PV system but require additional site remediation and grading that would increase costs. This is the case for the Dela Tek industrial brownfield site located in the southeast corner of the GRIC. There are also some concerns about potential safety and security of a system at the Dela Tek site, which would likely increase system costs for added security measures.

[5] DC refers to direct current. Unless otherwise noted, system capacity is given in terms of direct current in this report.

3 Solar Project Technical Analysis

The different solar energy systems evaluated in the analysis are discussed in detail below, organized by location and project type. Each project discussion includes a summary of the selected candidate locations and project considerations, including orientation, space constraints, and shading concerns. Exhibit 4 summarizes the selected project locations and various module types and mounting arrangements considered at the sites. All of the roof mounted systems considered are on flat roofs, so ballasted systems are the preferred mounting option for minimizing roof penetrations. The fixed tilt ground mount systems use racking systems oriented at a higher tilt angle in order to optimize annual electricity generation. A single-axis (1-X) tracking system that follows the sun from the East to the West (E-W) throughout the day to optimize system output is also considered for the Lone Butte Substation ground mount option.

Exhibit 4. Mounting Configurations for Selected Sites

Option		Location / Description	Module Type	Mounting Configuration	Tilt Angle (degrees)	Orientation* (degrees)
1	A	Tribal Governance Center, roof mount	p-Si	Ballasted racking	10	180
	B		CdTe	Ballasted racking	5	180
2	A	Wild Horse Pass Hotel & Casino, roof mount	p-Si	Ballasted racking	10	162
	B		CdTe	Ballasted racking	5	162
3	A	San Tan Brownfield, ground mount	CdTe	Fixed Tilt Racks	25	180
	B		CdTe	Fixed Tilt Racks	25	180
4	A	Lone Butte Substation, ground mount	CdTe	Fixed Tilt Racks	25	180
	B		CdTe	1-X tracking (E-W)	-	-

** An orientation angle of 180° corresponds to due south, while a 270° orientation points directly west and a 90° orientation points directly east.*

In addition to siting details, the subsections below also present system sizing and performance modeling results for each options, as well as a discussion of electrical interconnection considerations. The following methodology was used to determine the potential system capacities and performance.

1. Evaluate the approximate area available for each selected location using satellite imagery, photos, as well as site map and roof plans when available.
2. Select commercially available PV modules and appropriate inverters for each configuration/system size.[6]
3. Estimate the physical configuration of potential arrays for each site based on module sizes, spacing requirements, available (unshaded) area, and inverter matching.

[6] Modules were paired with the appropriate inverters for each potential location using the number of modules that could fit in the available physical space for each building and industry standard string sizing parameters.

4. Determine the power generation capacity of PV systems based on performance specifications of selected commercially available modules.
5. Evaluate system performance (annual electricity generation) using PV Design Pro modeling software.

Exhibit 5 summarizes the key technical details for the selected modules. (It is important to note that although specific commercially available PV modules and inverters were selected for the initial system design and detailed performance modeling, other commercially available modules and inverters with similar sizes and properties could be used instead of the ones selected for this analysis.) The Hanwha SolarOne HSL72 module is used for all arrays using polycrystalline technology while the First Solar FS-387 Cadmium Telluride (CdTe) module is used for all thin-film configurations. These module were selected based on market popularity and availability. Additional information about the solar energy equipment selected for the analysis is provided in Appendix A, and Section 3.5 below includes a discussion of alternate equipment selection considerations.

Exhibit 5. Summary of Specifications for Selected PV Module

PV Module	Rated output (W)	Width (ft)	Length (ft)	Weight (lbs)	Cell Type
Hanwha SolarOne HSL72	290	3.26	5.38	44.1	monocrystalline silicon
First Solar FS-387	87	1.97	3.94	26.46	cadmium-telluride

Each array requires an inverter to convert the DC electricity produced by the modules into alternating current (AC) electricity that can be used to meet building loads or fed back to the grid. Power-One and Advanced Energy inverters were selected for all arrays in this analysis. Each inverter was selected to best fit its associated array's capacity and electrical characteristics while maximizing inverter efficiency and economy. Additional information about the selected inverters is provided in Appendix A. The properties of the selected inverters are used to estimate the appropriate number of modules in each array string, as well as to determine expected system performance. However, it is important to note that while these selections are important for modeling purposes, they are not critical to overall analysis results. There is a wide range of alternative modules and inverters that could be selected for installation at the facility without significantly impacting the performance or costs.

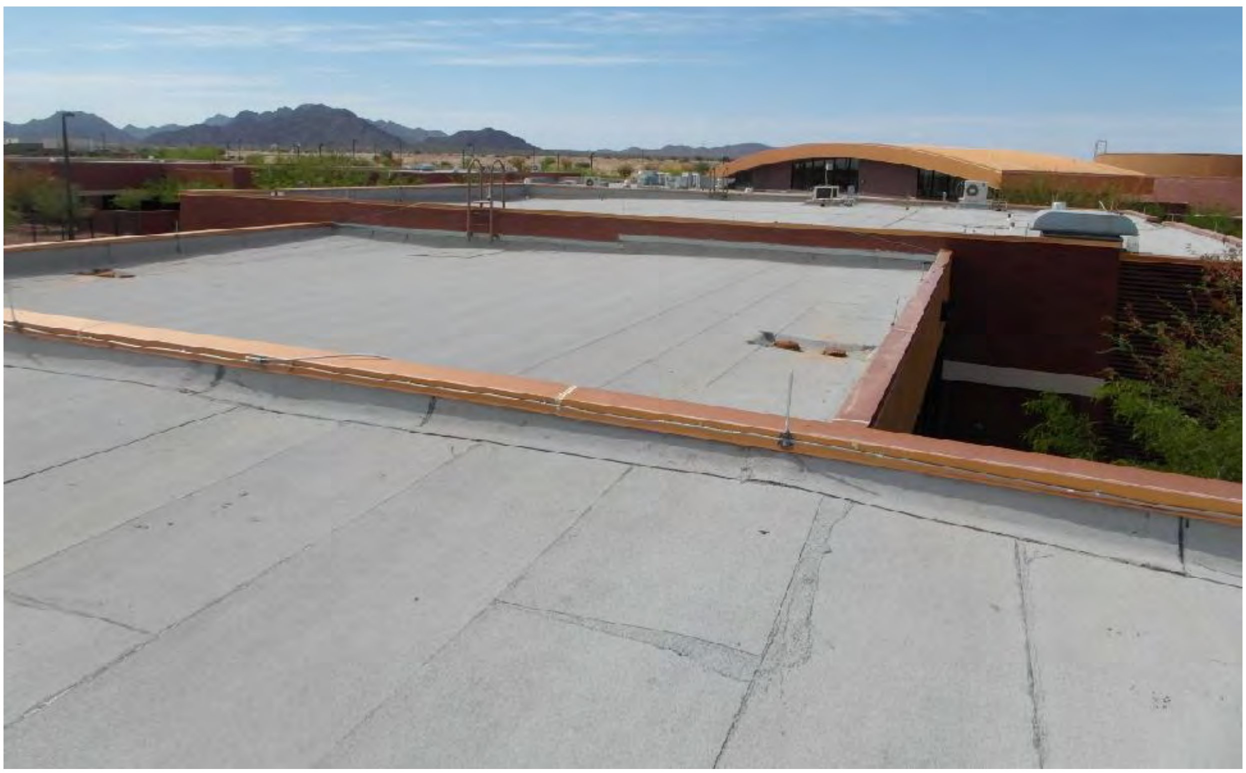
3.1 TRIBAL GOVERNANCE CENTER

3.1.1 OVERVIEW

The roof of the Tribal Governance Center in Sacaton consists of numerous flat roof sections separated by low parapet walls. Exhibit 6 shows part of the north area of the roof, facing in a southern direction. All roof sections are covered by an asphalt roofing material. The roof nearly 10 years old, as it was installed in 2004.

There are no adjacent buildings or structures that are expected to cause significant shading. Much of the roof is clear and free of obstructions, although there are some vents and other mechanical equipment in some sections that would need to be avoided in PV system design. The parapet walls will also cause some shading, although this is not expected to result in significant additional size constraints due to required setbacks from roof edges that will prevent module placement close to the walls. There is some shading from the lobby area near the center of the building, where there is a raised section of the roof which extends higher level than the surrounding roof area.

Exhibit 6. View of Tribal Governance Center Roof (facing South)

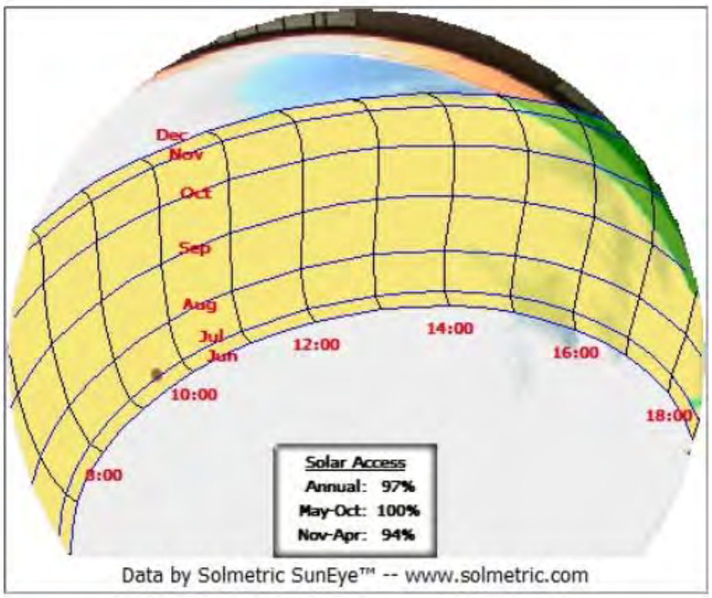


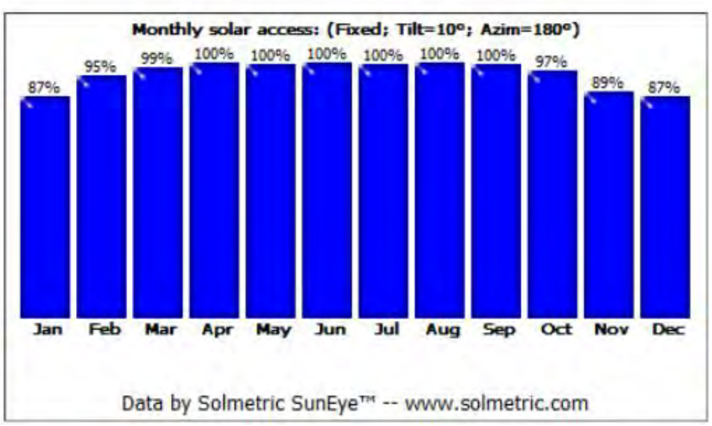
Potential shading from the structures and equipment on the roof are evaluated with a shading model, so that the system can be designed to maximize system capacity while avoiding shading that can severely impact system performance.

The Solmetric SunEye is an industry standard instrument that uses a specialized camera and associated software to estimate the site-specific power output from a PV system throughout the year while taking into account shading impacts on system performance. SunEye shading measurements were also taken during the site visit to help determine what areas will be shaded. Exhibit 7 provides an example SunEye measurement taken for the center section of the rooftop. The yellow areas in the figure indicate times during the year in which the area of interest will receive no shading, while the green areas indicate times during the year that the area will be shaded. In this case, the shading shown is due to the higher level roof area noted earlier. This shading only occurs in the late afternoon hours when the solar insolation is less intense; there are no losses in the optimal solar window of 9 AM – 3 PM. Nevertheless, this area and other areas with possible shading concerns are avoided in system design to the extent possible.

Exhibit 7. SunEye Measurement for Center Portion of the Tribal Governance Center

Panel Orientation: Tilt=10° -- Azimuth=180° -- **Skyline Heading=191°**
Solar Access: Annual: 97% -- Summer (May-Oct): 100% -- Winter (Nov-Apr): 94%
TSRF: 91% -- TOF: 94%





A fixed tilt racking system was selected as an ideal solar application for this building. In particular, a ballasted PV system is used as it will significantly limit the number of required roof penetrations.

Furthermore, this arrangement is low profile and will have little visibility from the ground. The analysis assumes that the modules would be mounted to the ballasted racking structure at a fixed tilt of either 10° or 5°, for polycrystalline and thin-film configurations, respectively, which will optimize annual energy production year round while balancing the need to minimize system payback periods. Note that a detailed engineering report outside the scope of this study must be performed to assess the weight capacity of the roof prior to system installation. The roof was stated to be in good condition, and no replacement is anticipated at this time. However, it is ideal to install a PV system on a roof that is expected to last for the 25 year lifetime of the system in order to minimize costs and maintain PV system integrity. As such, if any major repairs or replacements are expected in the near future it would be best to coordinate PV system installation at the same time.

3.1.2 Solar Models

Two different system configurations were evaluated for this location, one which uses polycrystalline silicon modules and another that uses thin-film CdTe modules. A summary of the array configurations is provided in Exhibit 8. Rendered images showing the modeled system layouts are provided in Exhibit 9 and Exhibit 10.

Exhibit 8. Summary of Selected Array Configurations at Tribal Governance Center

Option	No. of Modules	Module Type	Inverter	System Capacity (kW_{DC})	Tilt Angle (degrees)	Orientation
1A	1,694	Hanwha SolarOne HSL72	Advanced Energy AE500TX	491.3	10	south
1B	5,264	First Solar FS-387	Power-One PVI-Central 300; Power-One PVI-Central 100	458.0	5	south

Exhibit 9. Model of Potential p-Si System on Tribal Governance Center Roof (Option 1A)

Exhibit 10. Model of Potential CdTe System on Tribal Governance Center Roof (Option 1B)

3.1.3 Performance Analysis Results

PV Design Pro software modeling for the considered system configurations provides a detailed estimate of the expected annual electricity generation.

Option 1A: Tribal Governance Center Roof Mounted p-Si Array

The Option 1A array could be interconnected to the building's service at 277/480V via a supply-side tap, as the selected (500 kW) inverter exceeds the back-feed bus-bar rating of the facility's largest switchgear. Exhibit 11 summarizes the net expected output (first year of operation) and compares it to the facility's 2012 electricity use. Exhibit 12 provides this information in a graph. It is expected that this array will generate 898 megawatt-hours (MWh) per year, or 23.95% of the facility's 2012 annual electricity consumption.

Exhibit 11. Expected Performance for Tribal Governance Center p-Si Array (491 kW_{DC})

Month	Facility Electricity Consumption (kWh)	Facility Peak Demand (kW)	PV System Generation			
			Net Monthly Output (kWh)	% of Facility Consumption	System Peak Output (kW) [a]	Peak Shaving (kW) [b]
January	198,679	442	51,105	25.72%	355	20
February	203,482	485	58,498	28.75%	394	40
March	242,495	566	75,841	31.28%	422	74
April	284,586	688	89,818	31.56%	432	13
May	374,637	919	98,891	26.40%	424	144
June	442,436	988	93,726	21.18%	409	107
July	461,183	1,017	92,964	20.16%	409	126
August	481,706	985	87,854	18.24%	401	109
September	363,039	879	78,449	21.61%	408	65
October	296,392	777	70,314	23.72%	370	97
November	206,159	541	53,751	26.07%	342	57
December	196,851	411	47,187	23.97%	318	32
Annual Total	**3,751,644**	-	**898,398**	**23.95%**	-	

Notes: [a] The peak output from the PV system is the highest generation value for the array for any given month, and is not necessarily coincident with the facility's peak load. [b] Peak shaving represents the estimated reduced peak demand from the PV system, based on the expected output and 2012 hourly usage data for the facility.

Exhibit 12. Model Results for Tribal Governance Center p-Si Array (491 kW_{DC})

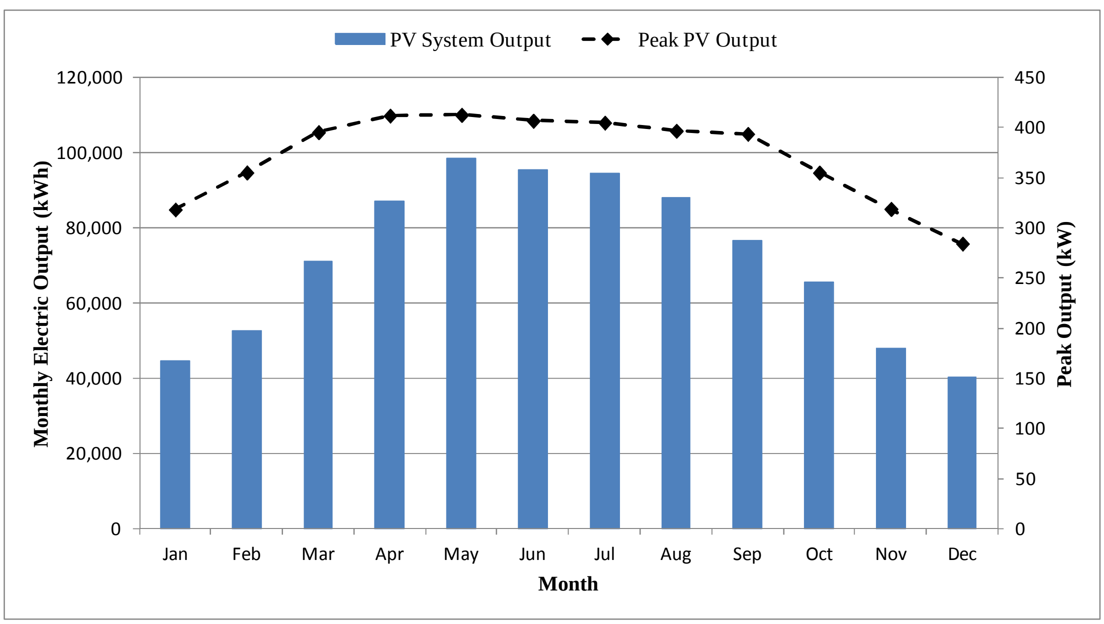


Figure shows total monthly electric output and peak output values in terms of AC kW.

It is important to point out that while all kWh of electricity generated by the PV system and used to serve on-site loads will directly reduce the grid electricity purchases (and associated electric commodity costs), the reduction in peak electric demand (and associated costs) is not as straightforward. The PV system will only reduce peak demand to the extent that it generates electricity that offsets consumption during the peak usage period for each month. The considered array is expected to result in some peak shaving, thereby reducing utility costs somewhat. The estimated peak shaving associated with the system is shown in the last column of Exhibit 11 for reference. Actual costs will depend on usage patterns and solar resources. The overall the energy cost benefit from the system needs to be evaluated based on customer electric usage and applicable rate schedule.

Option 1B: Tribal Governance Center Roof Mounted CdTe Array

The energy produced by the Option 1B array using CdTe modules could be fed into two of the building's four 3000A switchgear at 277/480V. Exhibit 13 summarizes the net expected monthly output (first year of operation) and compares it to the facility's current electricity usage. Exhibit 14 presents this information. It is expected that this array will generate 863 MWh per year, which is equivalent to 23.01% of the annual electricity consumption at this facility for 2012. As noted above, the actual cost savings associated with a PV system must be evaluated based on PV system generation, customer electric usage patterns, and the applicable rate schedule.

Exhibit 13. Expected Performance for Tribal Governance Center CdTe Array (458 kW_{DC})

Month	Facility Electricity Consumption (kWh)	Facility Peak Demand (kW)	PV System Generation		
			Net Monthly Output (kWh)	% of Facility Consumption	Peak Output* (kW)
January	198,679	442	44,695	22.50%	318
February	203,482	485	52,498	25.80%	355
March	242,495	566	71,212	29.37%	396
April	284,586	688	87,204	30.64%	412
May	374,637	919	98,603	26.32%	413
June	442,436	988	95,439	21.57%	407
July	461,183	1,017	94,463	20.48%	405
August	481,706	985	88,081	18.29%	397
September	363,039	879	76,701	21.13%	394
October	296,392	777	65,666	22.16%	355
November	206,159	541	48,160	23.36%	319
December	196,851	411	40,421	20.53%	284
Annual Total	**3,751,644**	**-**	**863,142**	**23.01%**	**-**

* The peak output from the PV system is the highest generation value for the array for any given month, and is not necessarily coincident with the facility's peak load.

Exhibit 14. Model Results for Tribal Governance Center CdTe Array (458 kW_{DC})

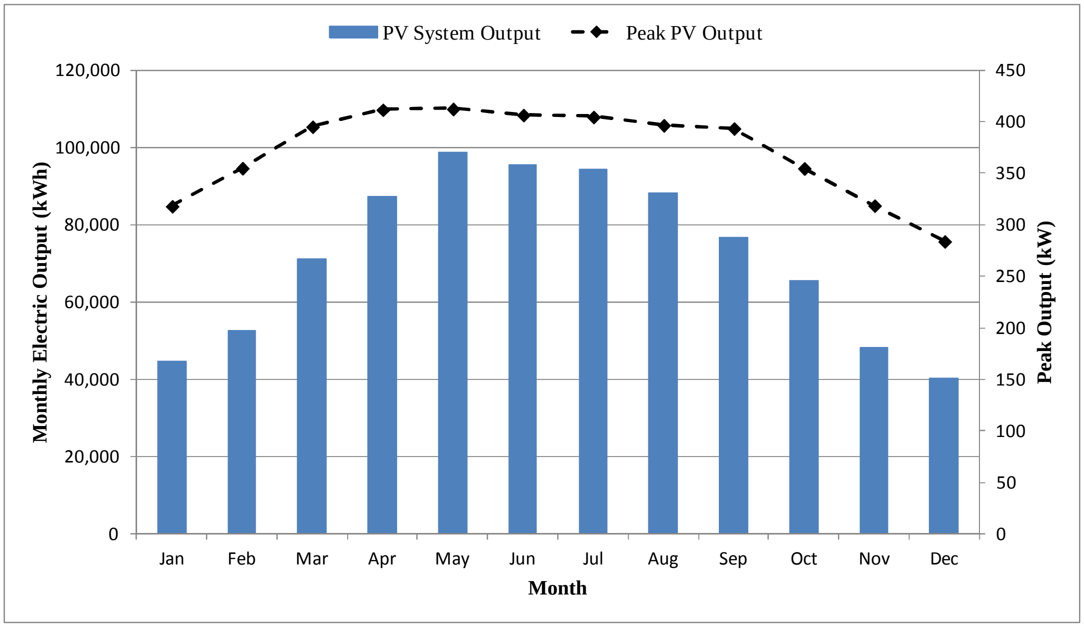


Figure shows total monthly electric output and peak output values in terms of AC kW.

3.1.4 Electrical Interconnection

It is important to consider the preferred electrical interconnection point for the PV arrays in order to determine if any upgrades to the electrical load centers will be needed to handle the electricity generated by the PV system. In general, the smallest possible distance between the array and the interconnection point is preferred in order to minimize wiring losses; however, in the event a long wiring run cannot be avoided, larger wire sizing can be implemented to minimize these losses.

Based on the size of the considered systems, it is expected that back-feeding the energy from the solar PV inverter to the existing service infrastructure should not be an issue. ANTARES inspected the load center at the Tribal Governance Center, and it appears that no upgrades will be needed as the existing service has a sufficient capacity rating. Whether the PV system is interconnected through the existing switchgears or through a supply side-tap will depend on the final inverter configuration. If the particular system configurations used for modeling at this facility were installed as-is, Option 1A would require a supply-side tap while Option 1B would be required to be installed on separate switchgears as the combination of both inverters exceeds the allowable bus-bar loading as per NEC requirements. For either interconnection method, all electricity produced by the roof-mounted arrays could be used on-site. However, during certain conditions, particularly at peak solar hours in the winter months, PV system generation may exceed building usage delivering power back to the grid.

The inverters may be located in the main electrical center near the point of interconnection, space permitting, or on the building exterior, preferably adjacent to or near the main electrical center and electrical point of entry to minimize wiring losses to the interconnection point. Inverters installed on the building exterior may require enclosures or a shade structure if they are in the path of direct sunlight.

3.2 WILD HORSE PASS HOTEL AND CASINO

3.2.1 OVERVIEW

The Wild Horse Pass (WHP) Hotel and Casino roof consists of various flat roof sections at different levels. Exhibit 15 shows a satellite image of the roof area from above. The hotel room wing located in the southwest section (to the left of the round copper colored area in the image) is the tallest part of the building, which rises about 10 stories above ground level. The right-most section with white roof is part of the casino and is one of the lowest level areas. The gray structure to the right of that is the parking garage. A photo of the eastern sides of the roof (taken from the hotel roof) is shown in Exhibit 16. All roof sections are covered by a white foam roofing material. The roof is fairly new, as it was completed in 2009.

There are no adjacent buildings or structures that are expected to cause significant shading. Much of the roof is clear and free of obstructions, although there are vents and other mechanical equipment in some areas that will need to be avoided in PV system design. The parapet walls will also cause some shading, although this is not expected to result in additional sizing constraints for a PV system due to required setbacks from roof edges that will prevent module placement close to the walls. The most significant cause of shading is from the taller adjacent roof sections, particularly the hotel wing.

Exhibit 15. Wild Horse Pass Hotel and Casino Roof Overview

Image Courtesy of Google Maps

Exhibit 16. Wild Horse Pass Hotel and Casino Roof (facing East)

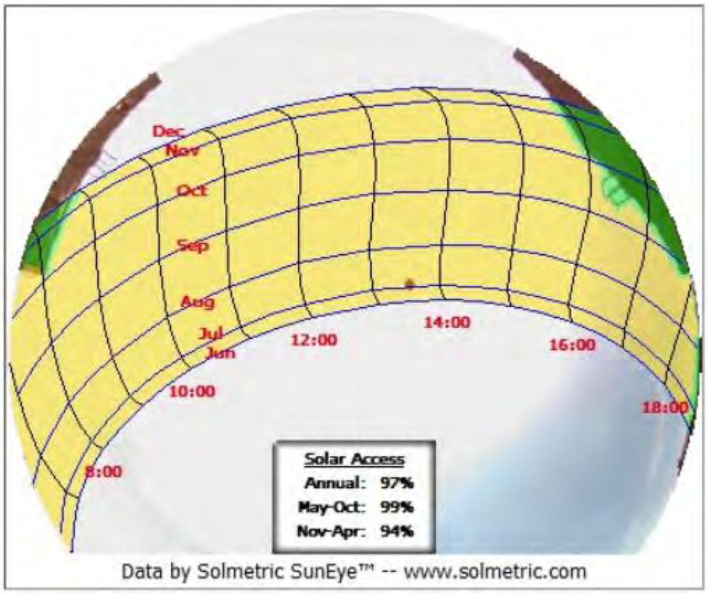
Potential shading from these structures and equipment on the roof were evaluated with a shading model, so that the PV arrays can be designed to maximize system capacity while avoiding shading that can severely impact system performance. SunEye shading measurements were taken at select areas during the site visit to help determine what areas will be shaded throughout the year. An example SunEye measurement taken for the center open area of the hotel wing roof (southwest portion of the building) is shown in Exhibit 17. The yellow areas in the figure indicate times during the year in which the area of interest will receive no shading, while the green areas indicate times during the year that the area will be shaded. In this case, there is some shading due to adjacent structures, however it mostly only occurs in the early morning and late afternoon hours when the solar resource is less intense; there are no losses in the optimal solar window of 9 AM – 3 PM. Nevertheless, areas such as this with possible shading concerns are avoided in system design to the extent possible.

Exhibit 17. SunEye Measurement for Wild Horse Pass Hotel Roof

Panel Orientation: Tilt=10° -- Azimuth=180° -- **Skyline Heading=191°**

Solar Access: Annual: 97% -- Summer (May-Oct): 99% -- Winter (Nov-Apr): 94%

TSRF: 91% -- TOF: 94%



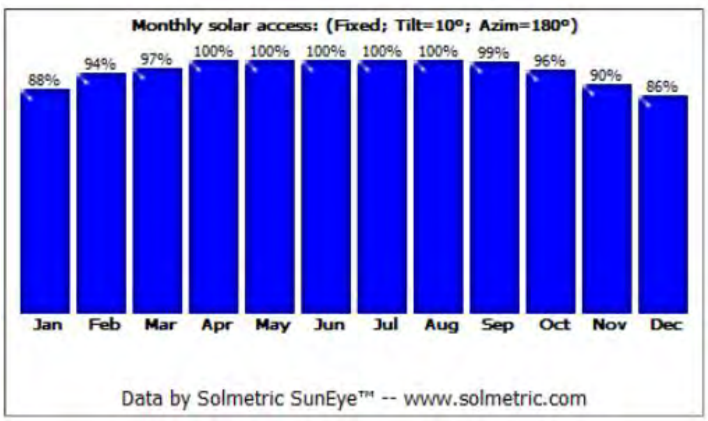


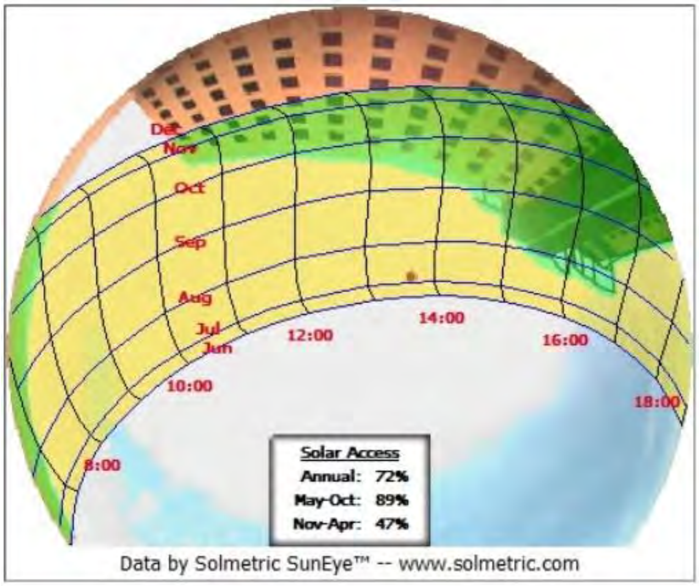
Exhibit 18 shows a SunEye measurement taken at one of the lower sections just north of the hotel wing. Since the shading in this area is very significant, no solar modules will be placed in this section of the roof.

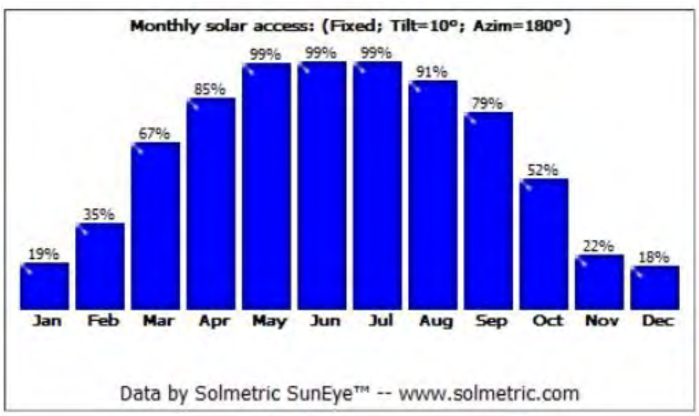
Exhibit 18. SunEye Measurement for Wild Horse Pass Casino Roof

Panel Orientation: Tilt=10° -- Azimuth=180° -- **Skyline Heading=191°**

Solar Access: Annual: 72% -- Summer (May-Oct): 89% -- Winter (Nov-Apr): 47%

TSRF: 67% -- TOF: 94%





A fixed tilt racking system was selected as an ideal solar application for this building. A ballasted PV system will significantly limit the number of required roof penetrations. Furthermore, this arrangement is low profile and will have little visibility from the ground. The analysis assumes that the modules would be mounted to the ballasted racking structure at either 10° or 5°, for polycrystalline and thin-film configurations, respectively. These tilt angles will help to optimize annual energy production year round while balancing the need to minimize system payback periods. Note that a detailed engineering report outside the scope of this study must be performed to assess the weight capacity of the roof prior to system installation.

3.2.2 SOLAR MODELS

Two system configurations were evaluated, one which uses polycrystalline silicon modules and another that uses thin film CdTe modules. A summary of the array configurations is provided in Exhibit 19. Rendered images showing the modeled system layouts are provided in Exhibit 20 and Exhibit 21.

Exhibit 19. Summary of Selected Array Configurations at Wild Horse Pass Hotel and Casino

Option	No. of Modules	Module Type	Inverter	System Capacity (kW_{DC})	Tilt Angle (degrees)	Orientation
2A	1,507	Hanwha SolarOne HSL72	Power-One PVI-Central 300; Power-One PVI-Central 100	437.0	10	south
2B	5,176	First Solar FS-387	Power-One PVI-Central 300; Power-One PVI-Central 100	450.3	5	south

Exhibit 20. Model of Potential p-Si System on Wild Horse Pass Hotel and Casino Roof (Option 2A)

Exhibit 21. Model of Potential CdTe System on Wild Horse Pass Hotel and Casino Roof (Option 2B)

3.2.3 Performance Analysis Results

The considered system configurations were modeled using PV Design Pro software in order to provide a detailed estimate of the expected annual electricity generation.

Option 2A: Wild Horse Pass Hotel and Casino Roof Mounted p-Si Array

The energy produced by the Option 2A array could be fed into two of building's switchgears rated at 3600A and 1600 at 277/480V. Exhibit 22 summarizes the net expected monthly output for this array (first year of operation) and compares it to the facility's current electricity usage (total usage from all four utility meters). Exhibit 23 presents this information in a graph. It is expected that this array will generate 816 MWh per year, which is equivalent to 4.48% of the facility's average annual electricity consumption for 2012.

As noted previously, while all kWh of electricity generated by the PV system and used to serve on-site loads will directly reduce the grid electricity purchases (and associated electric commodity costs), the reduction in peak electric demand (and associated costs) is not as straightforward. The PV system will only reduce peak demand to the extent that it generates electricity that offsets consumption during the peak usage period for each month. The estimated peak shaving associated with the system is shown in the last column of Exhibit 22 for reference. The considered PV array is only expected to result in minor peak shaving, since this facility is a casino which has high energy demand during the night when the PV array is not producing any electricity. This helps to illustrate the importance of evaluating the overall the energy cost benefit from the system based on customer electric usage and applicable rate schedule prior to system implementation.

Exhibit 22. Expected Performance for Wild Horse Pass Hotel and Casino p-Si Array (437 kW_{DC})

Month	Facility Electricity Consumption (kWh)	Facility Peak Demand (kW)	PV System Generation			
			Net Monthly Output (kWh)	% of Facility Consumption	System Peak Output (kW) [a]	Peak Shaving (kW) [b]
January	1,341,931	2,379	46,432	3.46%	321	70
February	1,270,766	2,230	53,210	4.19%	357	2
March	1,384,040	2,388	68,683	4.96%	381	5
April	1,416,335	2,558	81,772	5.77%	390	37
May	1,580,765	2,578	89,770	5.68%	384	31
June	1,637,258	2,776	85,176	5.20%	369	33
July	1,773,569	2,910	84,234	4.75%	369	93
August	1,796,566	2,848	79,701	4.44%	362	10
September	1,638,602	2,794	71,300	4.35%	368	4
October	1,531,158	2,745	63,671	4.16%	333	71
November	1,405,252	2,480	48,664	3.46%	309	0
December	1,413,713	2,304	42,906	3.03%	286	0
Annual Total	**18,189,953**	-	**815,520**	**4.48%**	-	

Notes: [a] The peak output from the PV system is the highest generation value for the array for any given month, and is not necessarily coincident with the facility's peak load. [b] Peak shaving represents the estimated reduced peak demand from the PV system, based on the expected output and 2012 hourly usage data for the facility.

Exhibit 23. Model Results for Wild Horse Pass Hotel and Casino p-Si Array (437 kW_{DC})

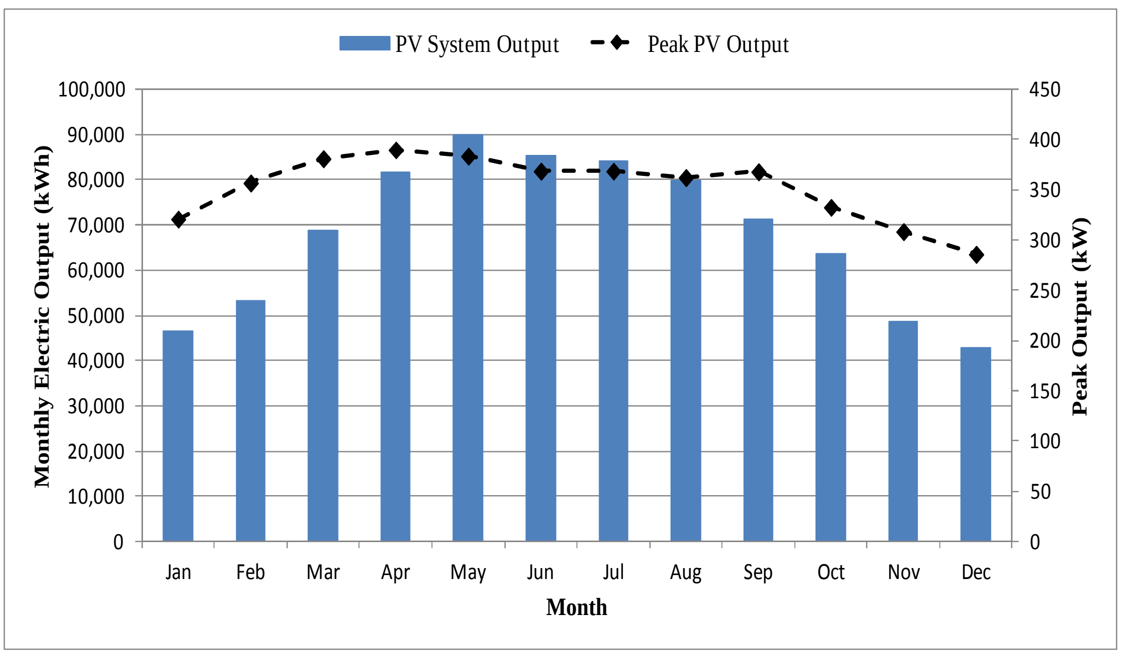


Figure shows total monthly electric output and peak output values in terms of AC kW.

Option 2B: Wild Horse Pass Hotel and Casino Roof Mounted CdTe Array

The energy produced by the Option 2B array could be fed into the same interconnection point, two of the building's switchgears rated at 3600A and 1600A at 277/480V. The net expected monthly output for this array (first year of operation) is summarized in Exhibit 24 and compared to the facility's current electricity usage. The information is also presented graphically in Exhibit 25. It is expected that this array will generate 851 MWh per year, which is equivalent to 4.68% of the facility's 2012 electricity consumption. The overall system energy cost benefit needs to be evaluated based on customer electric usage and applicable rate schedule.

Exhibit 24. Expected Performance for Wild Horse Pass Hotel and Casino CdTe Array (450 kW_{DC})

Month	Facility Electricity Consumption (kWh)	Facility Peak Demand (kW)	PV System Generation		
			Net Monthly Output (kWh)	% of Facility Consumption	Peak Output* (kW)
January	1,341,931	2,379	44,075	3.28%	314
February	1,270,766	2,230	51,761	4.07%	351
March	1,384,040	2,388	70,111	5.07%	390
April	1,416,335	2,558	86,106	6.08%	399
May	1,580,765	2,578	97,227	6.15%	400
June	1,637,258	2,776	94,215	5.75%	398
July	1,773,569	2,910	93,092	5.25%	398
August	1,796,566	2,848	86,841	4.83%	392
September	1,638,602	2,794	75,677	4.62%	388
October	1,531,158	2,745	64,632	4.22%	350
November	1,405,252	2,480	47,354	3.37%	313
December	1,413,713	2,304	39,799	2.82%	279
Annual Total	**18,189,953**	-	**850,889**	**4.68%**	-

** The peak output from the PV system is the highest generation value for the array for any given month, and is not necessarily coincident with the facility's peak load.*

Exhibit 25. Model Results for Wild Horse Pass Hotel and Casino CdTe Array (450 kW_{DC})

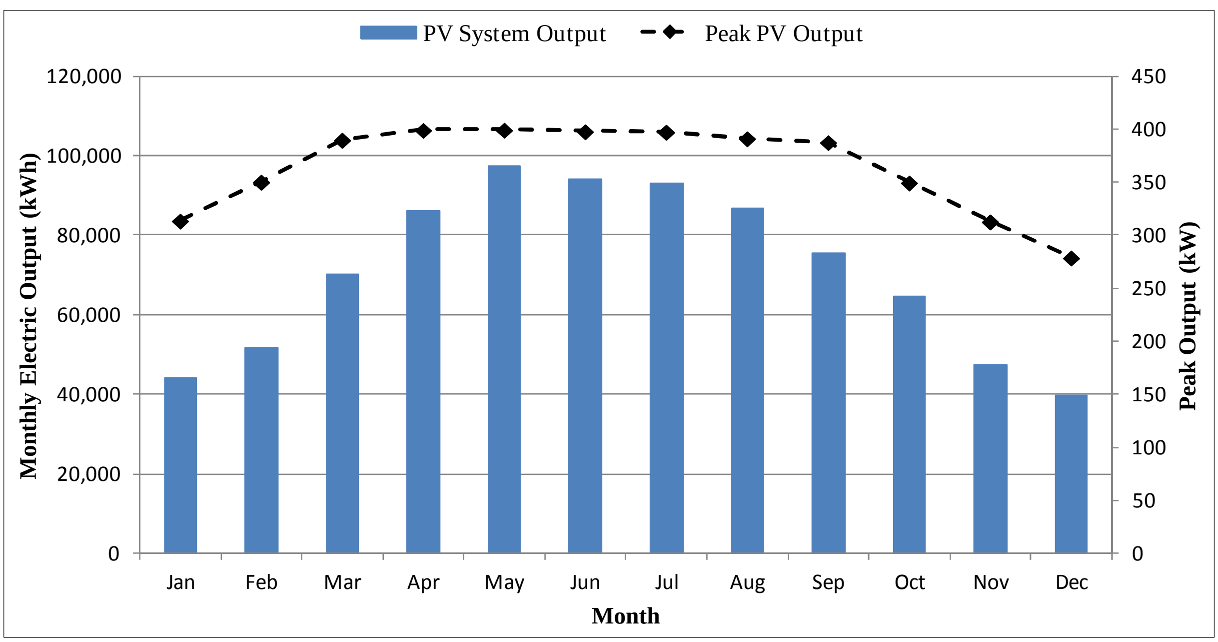


Figure shows total monthly electric output and peak output values in terms of AC kW.

3.2.4 ELECTRICAL INTERCONNECTION

With the relatively small size of the roof-mounted PV systems, back-feeding the energy from the solar PV inverter to the existing service infrastructure should not be an issue. ANTARES inspected the load center at the Wild Horse Pass Hotel and Casino. It appears that no upgrades will be needed for the considered PV systems, as the existing service has a sufficient capacity rating. Whether the PV system is interconnected through the existing switchgears or through a supply side-tap will depend on the final inverter configuration. If the particular system configurations used for modeling at this facility were installed as-is each would be required to be installed on separate switchgears as the combination of both inverters exceeds the allowable bus-bar loading as per NEC requirements. For either interconnection method, all electricity produced by the roof-mounted arrays could be used on-site. Analysis of the facility's usage and PV system output show that it is highly unlikely that PV generation will ever exceed facility usage and, therefore, the system would not back-feed onto the grid. If possible, the PV system should be interconnected to the switchgear associated with account 400088103 as this is the meter with the highest energy and demand load. Interconnection to account 400088102 may be possible as well, however, the other two accounts should be avoided as peak output from the array may exceed the load demand at these meters.

The inverters may be located in the main electrical room near the point of interconnection, space permitting, or on the exterior of the building, preferably located adjacent or in the vicinity of the electrical room and electrical point of entry in order to minimize wiring losses to the interconnection point. Inverters installed on the exterior of the building may require enclosures or a shading structure if they are in the path of direct sunlight.

3.3 SAN TAN INDUSTRIAL PARK

3.3.1 OVERVIEW

The San Tan Industrial Park has two brownfield areas that are not currently in use, as well as some land that is actively used for industrial purposes. The area of most interest for a PV project at this location is the space previously occupied by the Arizona Tanning Company, identified by the larger red outline on the left in Exhibit 26. The Tannery location includes a roughly rectangular parcel of land approximately 50 acres in size. An Environmental Site Assessment was previously completed for this area. Remediation activities have already been performed, leaving a large, flat tract of land with no structures or other shading concerns (Exhibit 27). As such, this is a good site for a PV array installation.

Exhibit 26. San Tan Industrial Park Overview

Note: The tannery structures shown in the red outlined area in the right of the image have been removed.

Exhibit 27. San Tan Tannery Ground Area

3.3.2 Solar Models

Two different systems were evaluated for this location, one sized at around 1 MW_{AC} capacity and the other at about 5 MW_{AC} capacity. As DC arrays are typically oversized to achieve best year-round economy, the DC array size can exceed the AC nameplate by as much as 20%. Both systems use thin film CdTe modules and fixed tilt racking systems. Each system was designed in modular sub-arrays with individual commercial-scale inverters and transformers. This configuration is not required, and there are others that may be suitable depending project goals, equipment pricing, and interconnection logistics.

A summary of the considered array configurations is provided in Exhibit 28. Rendered images showing the modeled system layouts are provided in Exhibit 29 and Exhibit 30.

Exhibit 28. Summary of Selected Array Configurations at San Tan Brownfield

Option	No. of Modules	Module Type	Inverter	System Capacity (kW_{DC})	Tilt Angle (degrees)	Orientation
3A	12,744	First Solar FS-387	(2) Advanced Energy AE 500TX	1,108.7	25	south
3B	63,720	First Solar FS-387	(10) Advanced Energy AE 500TX	5,543.6	25	south

Exhibit 29. Model of Potential 1 MW_{AC} array at San Tan Brownfield Area (Option 3A)

Exhibit 30. Model of Potential 5 MW_{AC} array at San Tan Brownfield Area (Option 3B)

3.3.3 PERFORMANCE ANALYSIS RESULTS

The considered system configurations were modeled using PV Design Pro software in order to provide a detailed estimate of the expected annual electricity generation.

Option 3A: San Tan Brownfield 1 MW_{AC} Ground Mount Array

The energy produced by the Option 3A array will be fed into local 12 kV distribution lines via step-up transformers. The net expected monthly output (for the first year of operation) for this array is summarized in Exhibit 11 and Exhibit 12 in tabular and graphical form. It is expected that this array will generate a total of 2,276 MWh per year.

Exhibit 31. Expected Performance San Tan Brownfield Option 3A Array (1 MW_{AC})

Month	PV System Generation	
	Net Monthly Output (kWh)	Peak Output (kW)
January	145,893	970
February	159,582	1,000
March	193,989	1,000
April	217,953	1,000
May	229,984	1,000
June	215,370	966
July	217,365	963
August	212,081	977
September	200,528	1,000
October	191,131	957
November	153,764	929
December	138,678	899
Annual Total	**2,276,318**	-

Exhibit 32. Model Results for San Tan Brownfield Option 3A Array (1 MW_{AC})

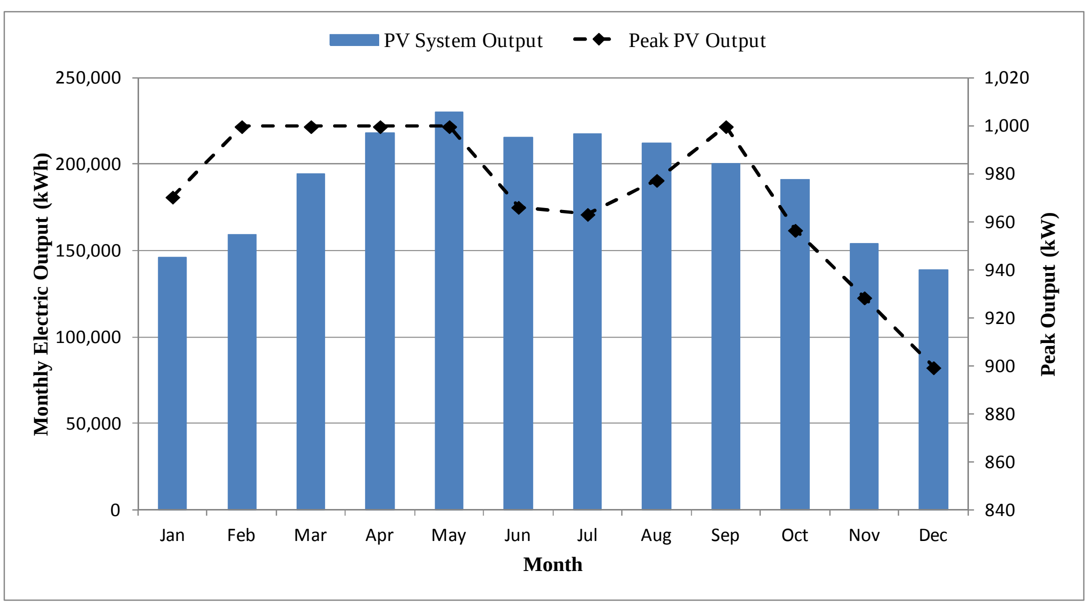


Figure shows total monthly electric output and peak output values in terms of AC kW.

The drop in peak output in the summer is due mostly to the tilt angle of the array. While a high tilt angle (25°) optimizes year-round energy production, it corresponds to a non-ideal angle of incidence during times of the year when solar irradiance is highest. Since PV modules perform best when the Sun's rays are perpendicular to the surface, the change in solar elevation throughout the year have a significant impact on the peak output of the system.

Option 3B: San Tan Brownfield 5 MW_{AC} Ground Mount Array

The energy produced by the Option 3B array will also be fed into the local 12 kV distribution lines via step-up transformers. Exhibit 33 and Exhibit 34 summarize the net expected monthly array output (for the first year of operation). The drop in peak output in the summer is due mostly to the tilt angle of the array which is optimized for annual electricity generation rather than peak production in the summer.

Exhibit 33. Expected Performance for San Tan Brownfield Option 3B Array (5 MW_{AC})

Month	PV System Generation	
	Net Monthly Output (kWh)	Peak Output (kW)
January	729,466	4,852
February	797,912	4,999
March	969,945	4,999
April	1,089,765	4,999
May	1,149,920	4,999
June	1,076,851	4,831
July	1,086,825	4,816
August	1,060,404	4,887
September	1,002,640	4,999
October	955,654	4,783
November	768,822	4,643
December	693,388	4,497
Annual Total	**11,381,592**	-

Exhibit 34. Model Results for San Tan Brownfield Option 3B Array (5 MW_{AC})

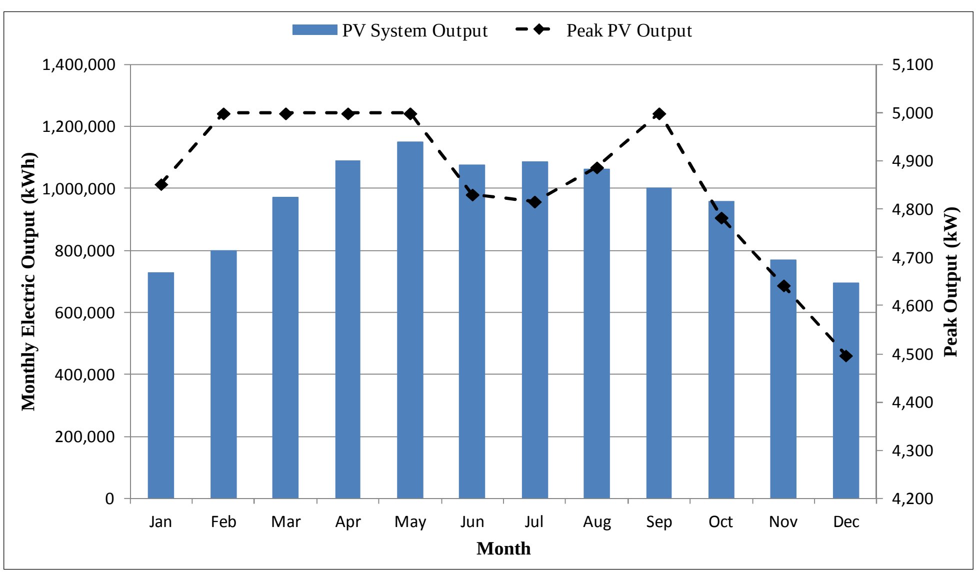
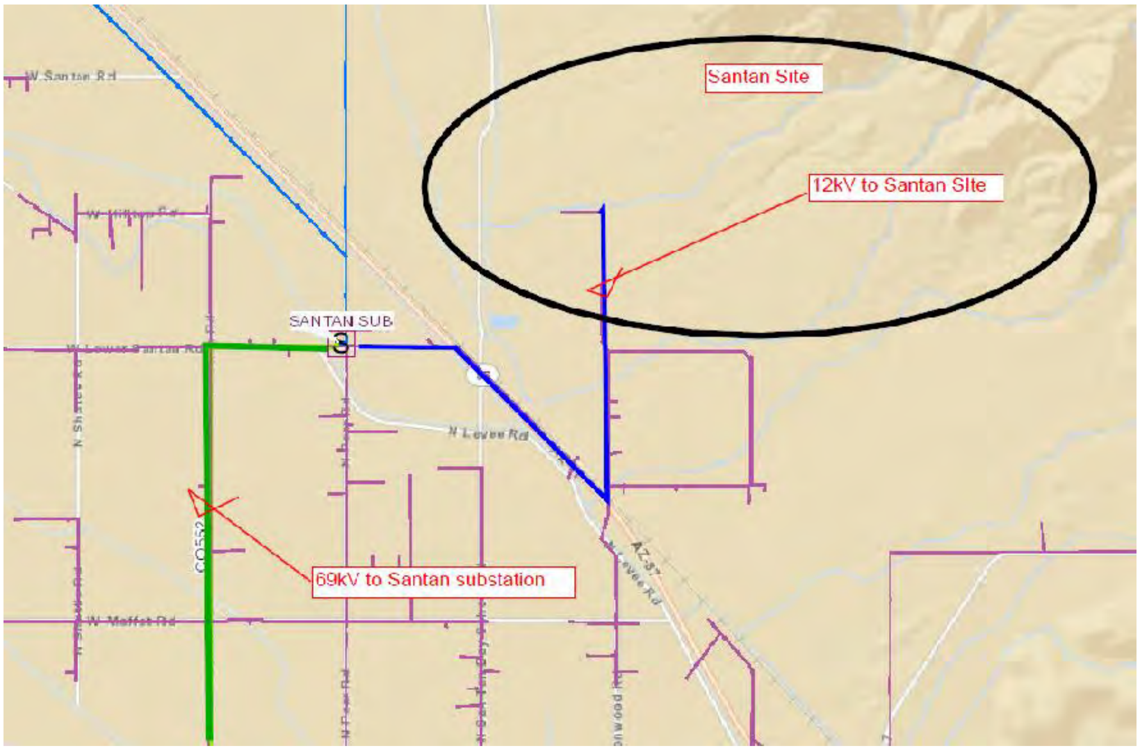


Figure shows total monthly electric output and peak output values in terms of AC kW.

3.3.4 Electrical Interconnection

Interconnection to the local grid will to be made at the point of closest existing infrastructure. Exhibit 35 shows the existing available grid conductors for interconnection in the vicinity of the project site.

Exhibit 35. Existing Grid Infrastructure in Vicinity of Project Site



An existing radial 12 kV line runs from the local San Tan Substation, eventually terminating along Ironwood Road north of Route 87. This represents the most viable location of interconnection to the San Tan project site at a distance of roughly 0.5 miles. High-voltage infrastructure will be required at the project site, including step-up transformers and medium voltage switchgear. Further information regarding the existing high-voltage lines will be required in order to specify specific interconnection design. Final interconnection design is subject to NEC requirements up to the current-transformer (CT) cabinet; design past this point is subject to NESC requirements.

3.4 LONE BUTTE SUBSTATION

3.4.1 OVERVIEW

The Lone Butte Substation (Exhibit 36) is located in the Wild Horse Pass area, south of the Sheraton Resort and golf course. Although the resort is very sensitive to aesthetic concerns and visibility impacts from any development near the site, the Lone Butte Substation is located near the outskirts of the land and a PV array in this area would mostly likely not be highly visible from the resort grounds. The Lone Butte Substation is a 230 kV to 69 kV to 12 kV substation, and has Western 230 kV ties to transformers owned by GRICUA and SCIP. GRICUA has 69 kV and 12 kV lines in the substation. Multiple electric transmission lines from different directions connect at this substation.

The site has a large quantity of open, fairly flat ground area that could support a large scale PV array. There are no alternate uses for the land currently being considered due to the proximity to the electrical lines. Furthermore, there are no major shading concerns except for the transmission towers which can be avoided in system design.

Exhibit 36. Lone Butte Substation Overview

Image courtesy of Google Maps

Exhibit 37. Lone Butte Substation Photos

3.4.2 Solar Models

Two different systems were evaluated for this location, one using fixed tilt racking and another with single axis tracking. Both systems use thin film CdTe modules and are sized at around 5 MW_{AC} (nominally). As DC arrays are typically oversized to achieve best year-round economy, the DC array size can exceed the AC nameplate by as much as 20%. Each system was designed in modular sub-arrays with individual commercial-scale inverters and transformers. This configuration is not required, and other options may be suitable depending project goals, equipment pricing, and interconnection logistics. The single-axis tracking array uses an East-West with a fixed flat tilt angle in the North-South axis. This tracking system configuration, such as provided by RayTracker, is well established in the industry with proven applications in thin-film array integration. Zero-tilt East-West single axis trackers provide a highly efficient means of increasing energy production per kW_{DC} capacity while requiring a lower spacing requirement relative to other tracking configurations, therefore maintaining power density and reducing land use-associated project costs.

Exhibit 38 summarizes the array configurations. Rendered images showing the modeled system layouts are provided in Exhibit 39 and Exhibit 40.

Exhibit 38. Summary of Selected Array Configurations near Lone Butte Substation

Option	No. of Modules	Module Type	Inverter	System Capacity (kW_{DC})	Tilt Angle (degrees)	Orientation
4A	12,744	First Solar FS-387	(10) Advanced Energy AE 500TX	5,543.6	25	south
4B	64,800	First Solar FS-387	(10) Advanced Energy AE 500TX	5,637.6	varies	varies

Exhibit 39. Model of Potential 5 MW_{AC} Fixed Tilt Array at Lone Butte Substation (Option 4A)

Exhibit 40. Model of Potential 5 MW_{AC} 1-X Tracking Array at Lone Butte Substation (Option 4B)

3.4.3 PERFORMANCE ANALYSIS RESULTS

The considered system configurations were modeled using PV Design Pro software in order to provide a detailed estimate of the expected annual electricity generation.

Option 4A: Lone Butte Substation Fixed Tilt Ground Mount Array

The energy produced by the Option 4A array will be fed into the local Lone Butte substation. The net expected monthly output for this 5,544 kW_{DC} array (for the first year of operation) is summarized in

Exhibit 41 and Exhibit 42. It is expected that this array will generate 11,382 MWh per year. This array has a reduced peak output in the summer months due to the selected tilt angle which is optimized for overall annual electric generation.

Exhibit 41. Expected Performance Lone Butte Substation Fixed Tilt Array (5 MW_{AC})

Month	PV System Generation	
	Net Monthly Output (kWh)	Peak Output (kW)
January	729,466	4,852
February	797,912	4,999
March	969,945	4,999
April	1,089,765	4,999
May	1,149,920	4,999
June	1,076,851	4,831
July	1,086,825	4,816
August	1,060,404	4,887
September	1,002,640	4,999
October	955,654	4,783
November	768,822	4,643
December	693,388	4,497
Annual Total	**11,381,592**	-

Exhibit 42. Model Results for Lone Butte Substation Fixed Tilt Array (5 MW_{AC})

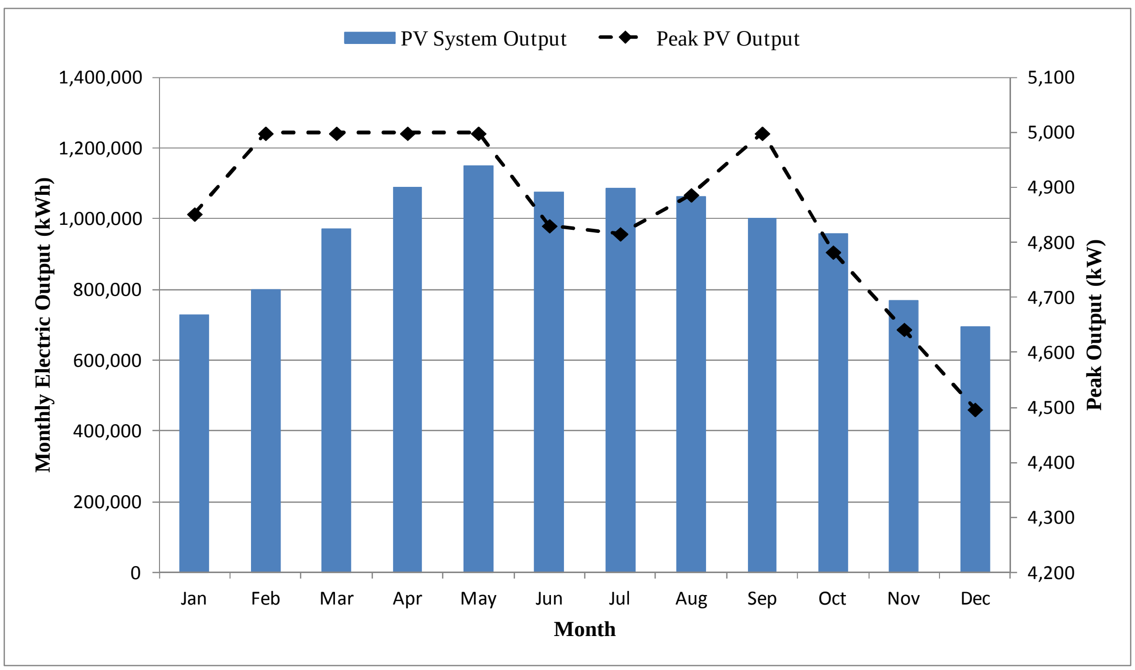


Figure shows total monthly electric output and peak output values in terms of AC kW.

Option 4B: Lone Butte Substation 1-X Tracking Ground Mount Array

The energy produced by the Option 4B array will also be fed into the local Lone Butte substation infrastructure. The net expected monthly output for this 5,638 kW_{DC} array (for the first year of operation) is summarized in Exhibit 43 and Exhibit 44. It is expected that this array will generate a total of 14,533 MWh per year.

Exhibit 43. Expected Performance for Lone Butte Substation 1-X Tracking Array (5 MW_{AC})

Month	PV System Generation	
	Net Monthly Output (kWh)	Peak Output (kW)
January	735,364	4,156
February	907,372	4,524
March	1,208,333	4,821
April	1,491,286	4,999
May	1,666,542	4,999
June	1,603,046	4,953
July	1,510,511	4,893
August	1,442,967	4,757
September	1,304,076	4,773
October	1,144,141	4,468
November	823,213	4,037
December	696,221	3,749
Annual Total	**14,533,073**	-

Exhibit 44. Model Results for Lone Butte Substation 1-X Tracking Array (5 MW_{AC})

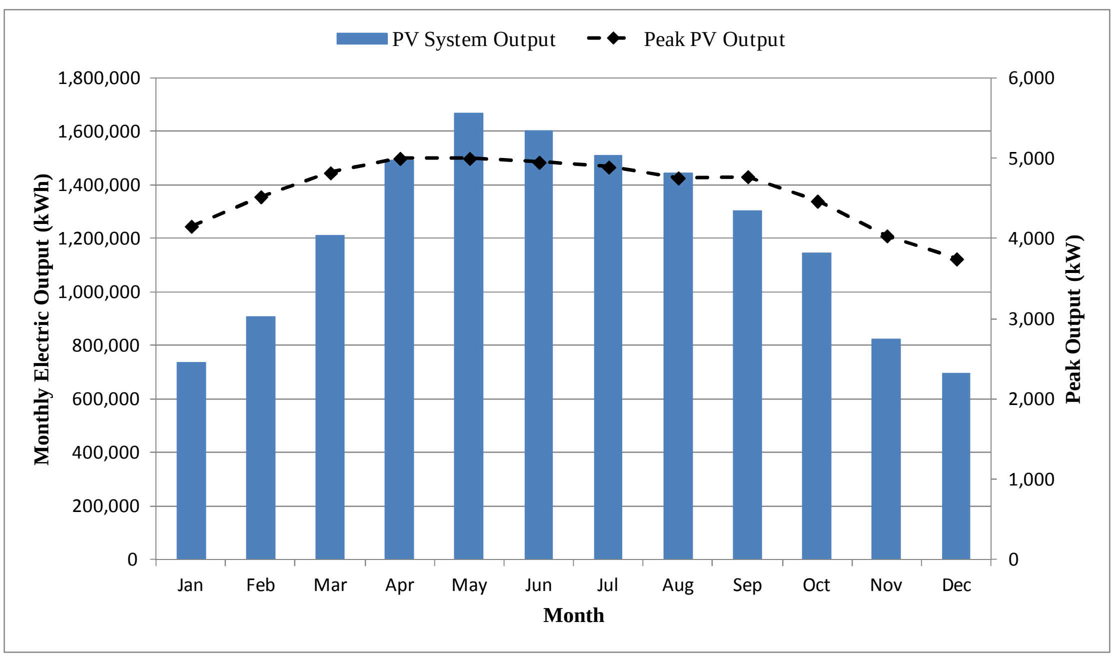
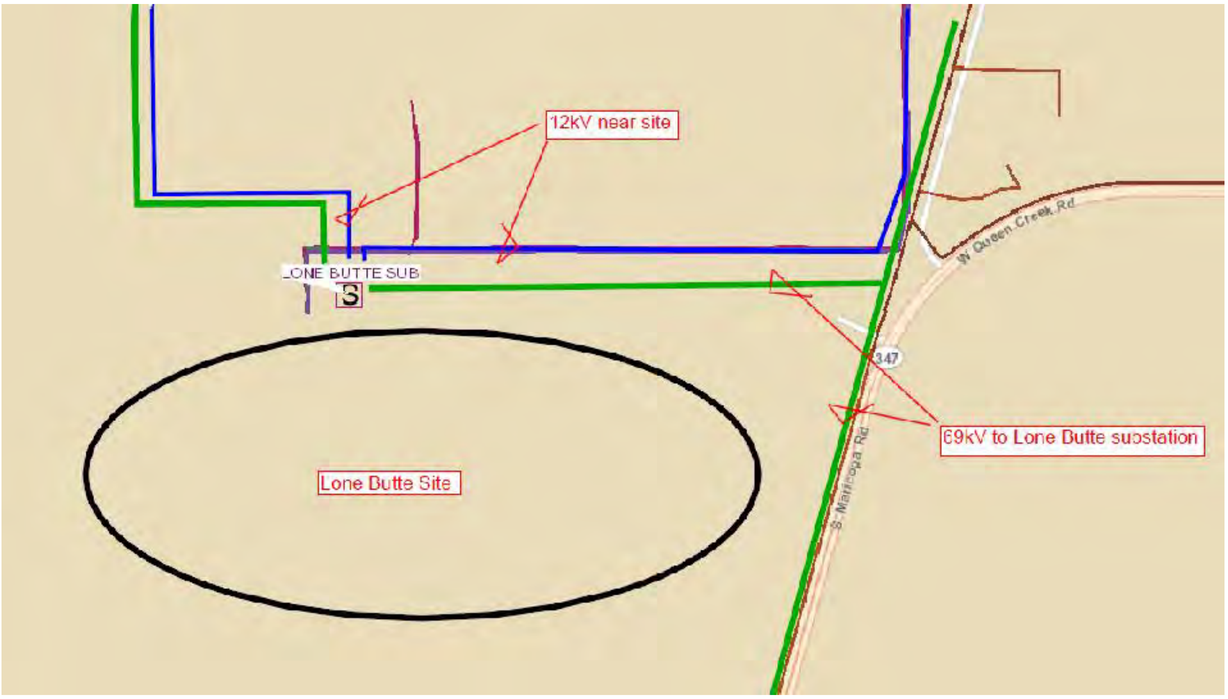


Figure shows total monthly electric output and peak output values in terms of AC kW.

3.4.4 ELECTRICAL INTERCONNECTION

Interconnection to the local grid will to be made at the point of closest existing infrastructure. Exhibit 35 below shows the existing available grid conductors for interconnection in the general vicinity of the project site.

Exhibit 45. Existing Grid Infrastructure in Vicinity of Project Site



The adjacent Lone Butte substation operates at 69 kV and 12 kV at distribution level. This represents the most viable location of interconnection to the Lone Butte project site at a distance of roughly 500 feet. Medium-voltage infrastructure will be required at the project site, including step-up transformers and medium voltage switchgear. Further information regarding the existing high-voltage lines and existing substation will be required in order to specify specific interconnection design, however, it is anticipated that a step-up transformer at the existing substation will be the tie point to the grid. Final interconnection design is subject to NEC requirements up to the current-transformer (CT) cabinet; design past this point is subject to NESC requirements.

3.5 PV SYSTEM EQUIPMENT CONSIDERATIONS

Although all of the arrays considered in the detailed technical analysis utilized specific available PV modules and inverters for modeling purposes, other commercially available modules and inverters with similar sizes and properties could be used instead. In fact, typically during project development the system designer or the EPC (Engineering, Procurement and Construction) contractor selects the module, inverter, and racking equipment from their preferred vendors in the detailed system design phase. Typically, this ensures that the contractor can secure ideal pricing, the savings of which is passed on to the system developer. GRIC or the project owner may have the right to approve or reject specific equipment, depending on the agreement.

The solar market is currently very competitive, and there are a lot of reputable companies with a large set of equipment to choose from. Part of the difficulty in selection is the vast number of choices available and a lack of consistent data available on equipment quality and durability over time.

Ultimately, the selection of preferred vendors will likely be narrowed based on technical and logistical details, such as type of module, manufacturing location, and availability. There are numerous high quality module manufacturers, many of which have been in business for many years and have a solid foothold in major markets. One important thing to consider is that higher quality modules and equipment may cost more up front, but could be a worthwhile investment over the lifetime of the system. The modules in a PV system are typically intended to last for 25 years, and it can be a hassle and financial drain on the project if they fail sooner. While equipment is generally protected to some extent by long term warranties, recouping costs or obtaining new equipment will be much more difficult if the company is out of business. This is a significant reason to select a high quality supplier that is also expected to stay in business for many years to come, if possible. For this reason, the financial strength and stability of each considered supplier should be reviewed before approving any selected equipment vendor.

While a full assessment of the various equipment options and preferred vendors is outside of the scope of this study, some recommended manufacturers are provided below for reference. Although it is by no means a comprehensive list, and the market may change significantly in the near term, these recommendations may help to provide some guidance for a future project development. These sample companies all have good reputations for high quality products and likely staying power in the market.

- Silicon PV Modules: LG Electronics, Kyocera Solar, Canadian Solar, SunPower, Sharp, SolarWorld, Yingli, Trina Solar, REC Group
- CdTe PV Modules: First Solar (market leader, dominates the market for this technology)
- PV Inverters: SMA Solar Technology America, and ABB / Power-One are market leaders. Other good options in the North American market include Solectria, Advanced Energy Industries, Schneider Electric USA, and Kaco New Energy.

4 EVALUATE PROJECT CONCEPTS

This chapter provides an overview of some key considerations for solar project development. This includes a summary of electric interconnection and potential off-takers in the GRIC area, available incentives, and potential ownership structures. These factors will all ultimately impact project economics and selection of preferred system size and arrangement selected for development.

4.1 POWER MARKET ASSESSMENT

The GRICUA is an enterprise of the Gila River Indian Community, serving residential, commercial and agricultural electric customers in a 332 square mile service area within the GRIC reservation. GRICUA serves about 80% of the Community, with the majority of the customers in Districts 1-5 and part of District 6 served by either GRICUA or SCIP (San Carlos Irrigation Project)[7]. SRP (Salt River Project) serves some of the customers on the boundaries of these areas, as well as many of the remaining areas in District 6 and nearly all of District 7.[8] APS (Arizona Public Service Company) also serves a small number of customers on Community land, primarily in District 6.

Electricity generated from the considered solar energy project on Community land could be used to directly serve the GRICUA customers and offset existing grid electricity purchases from other utilities. This is the primary power off-take arrangement considered in this analysis because the employment, economic and environmental benefits of a cost-effective renewable energy technology deployment to the GRIC are maximized when that generation project is owned by the Community.

GRICUA will have a 25-year contract with the Southwest Public Power Resources (SPPR) Group for up to 30 MW of capacity starting in 2015. The future electricity costs will be largely tied to natural gas prices, as 80-85% of the energy supply will be sourced from natural gas plants. GRICUA also has a contract for hydropower from Western Area Power Administration (WAPA).

4.1.1 INTERCONNECTION

The project would interconnect to the GRICUA distribution system. Interconnection of the ground mount arrays must consider the potential impacts of the system not only to the GRICUA system, but also to the utilities from which GRICUA purchases electricity.

GRICUA receives power at the Lone Butte Substation, the new Wild Horse Substation, and via a 12 kV service delivery point with SRP. GRICUA has an entitlement to power from the Salt Lake City Area Integrated Project (SLCA/IP) from WAPA, SRP, and uses other providers as necessary.

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[7] Several industrial end users in the Lone Butte Industrial Park buy power directly from SCIP, such as Kaiser, which has two large aluminum extrusion plants located at the Chandler site.

[8] The Vee Quiva Casino and several other end users in the northeast portion of the Community are served by SRP.

Power from WAPA is transmitted to the Lone Butte Substation via the WAPA Parker-Davis transmission system, the Pacific Northwest- Pacific Southwest Intertie transmission system, and the Colorado River Storage Project (CRSP) transmission system. From the Lone Butte Substation, power is stepped down and distributed over equipment owned and operated by GRICUA, or wheeled from the Department of Interior, Bureau of Indian Affair's utility at 12 kV to GRICUA-owned facilities or to directly metered customers. Power received from SRP at the 12 kV interconnection point is delivered via GRICUA owned and operated equipment (Gila River Indian Community Utility Authority, 2009).

Although GRICUA is not regulated and therefore not subject to such standards, information about the Arizona Corporation Commission (ACC) interconnection procedures is provided here for reference. The ACC oversees the electric power industry in Arizona, and initiated a process in 2007 to establish interconnection standards for distributed generation systems up to 10 MW in capacity that operate in parallel with the public utility system. Although the rulemaking process is still in progress, the ACC recommends that regulated utilities use the proposed interconnection guidelines.[9]

The ACC's Interconnection procedures are summarized below, and are detailed in pages 15-30 of the draft Interconnection Document, which is included in Appendix C.

- Level 1: Super Fast Track: Certified Inverter-based facilities that have a power rating of 10 kW or less, are interconnected on a radial line, and meet screens (e) and (f) in Section 4.2. Refer to Section 4.3 for additional details.
- Level 2: Fast Track: Generating Facilities that have a power rating of 2 MW or less, are interconnected on a radial line, and meet screens (a) through (i) in Section 4.2. Refer to Section 4.4 for additional details.
- Level 3: Study Track: Generating Facilities that have a power rating of 10 MW or less that do not meet the criteria or screens for other Levels. Interconnection studies may be required. Refer to Section 4.5 for additional details.

GRICUA does not currently have a procedure in place for interconnection of distributed generation projects, but has stated that they would develop a process prior to detailed system design, once the proposed systems are better defined. Regardless of the project scope, any process or procedure will involve GRICUA working with SCIP to ensure that system reliability and integrity is maintained.

The SRP is not regulated by the ACC on utility matters ((Arizona Corporation Commission, n.d.). SRP independently developed interconnection guidelines for distributed generation project and an interconnection agreement, based on draft rules and a report released by the ACC in 1999 and 2000, respectively. SRP's rules include technical protection requirements, a flow chart of interconnection

[9] The draft interconnection guidelines for distributed generation facilities can be found here: http://images.edocket.azcc.gov/docketpdf/0000074361.pdf

procedures and a two-page interconnection application. The rules establish separate requirements for units based on system capacity:[10]

- Class I: 50 kilowatts (kW) or less, single or three-phase
- Class II: 51 kW to 300 kW, three-phase
- Class III: 301 kW to five megawatts (MW), three-phase
- Class IV: greater than 5 MW, three-phase

Tucson Electric Power (TEP) and Arizona Public Service (APS) -- the other two major electric utilities in Arizona -- have similarly established their own interconnection procedures for DG systems. It is likely that Arizona's regulated utilities will adopt the ACC's interconnection standards when the final rules are adopted.

If GRICUA did not use the power to satisfy a portion of its own internal needs, the most likely third party off-takers for electricity or RECs generated by a solar project at GRIC include APS, SRP, and the San Carlos Irrigation Project. These three entities are discussed in more detail below. The project developer must begin working with other utilities early in the development process to gauge interest in the project and to prevent potential difficulties with interconnection. The base assumption for this project is that the power off-taker will be GRICUA because interconnection with the transmission system will translate into higher interconnection costs, transmission costs and may not offer any additional revenue. The general practice for other utilities in the region to meet renewable energy requirements is to build very large ground-mount solar systems (e.g., SRP's Copper Crossing 20 MW plant in Florence, AZ and APS's multiple large solar projects in Gila Bend, Arizona). APS has announced plans to partner with Abengoa Solar to construct a 280MW concentrating solar project in Gila Bend at a cost of $2 billion which would be the largest of its kind in the world.

Arizona Public Service (APS)

APS is the primary subsidiary of Pinnacle West Capital Corporation, an energy holding company that is based in Phoenix. As Arizona's largest electric company, APS serves 1.1 million customers,[11] with a reach extending to most areas of the state. APS expects that renewable energy will supply 12% of electricity by 2015. In the 2012 Corporate Responsibility Report, APS detailed a portfolio that included 348 MW of installed solar capacity, with another 423 MW under development (Pinnacle West Corporation, 2012). APS also owns several small scale solar projects and purchases solar power from other projects under long term PPA. The 2012 Integrated Resource Plan evaluated four portfolio simulations for the year 2027, with renewables contributing between 1,141 and 1,427 MW; these scenarios include a Base Case and a Coal Retirement case, as well as an "Enhanced Renewables" case where 30% of the utility's energy needs were met by renewable (Arizona Public Service Company, 2012).

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[10] SRP's technical requirements for interconnecting distributed generation facilities are available here: http://www.srpnet.com/electric/pdfx/interconnect_guidelines.pdf

[11] http://www.aps.com/en/ourcompany/aboutus/companyprofile/Pages/home.aspx

Currently, APS purchases RECs from customers who install grid-connected PV systems through its Renewable Incentive Program. These RECs are counted towards APS's compliance with the Arizona Renewable Energy Standard. This program is discussed in more detail in Section 4.2.

Salt River Project (SRP)

The Salt River Project Agricultural Improvement and Power District, commonly known as Salt River Project (SRP), provides electricity to 2 million people living in central Arizona.[12] It has ownership interest in 12 major natural gas and coil fired power plants, as well as and numerous other generating stations, which also include nuclear, hydroelectric, solar, wind and geothermal energy sources. The following solar resources are listed in SRP's Integrated Resource Plan for FY 2013:[13]

- 20 year PPA with PSEG[14] Solar Source for electricity generated by the 19 MW Queen Creek Solar project, located in Pinal County.
- 25 year PPA with Iberdrola Renewables for electricity generated by the 20 MW Copper Crossing Solar Ranch in Pinal County.
- 1,012 kW of solar PV installed on SRP facilities
- 324 kW of solar PV installed on partnering facilities
- Planned 1 MW project in partnership with Arizona State University and SunPower Corp., to be constructed at ASU's Polytechnic campus in Mesa, Arizona.

SRP's Sustainable Portfolio Resolution has a target of supplying 20% of retail energy sold in the year 2020 with sustainable resources, and also reducing emissions intensity by 15% relative to 2006 values by 2020.[15] Purchased RECs cannot account for more than 25% of the total sustainable portfolio. Although SRP has exceeded its FY 2012 target of 9% renewable energy, the Integrated Resource Plan for FY 2013 states that an additional 273 MW of sustainable energy will likely be needed by 2020 from sources such as wind, geothermal, solar, and distributed generation projects.[16]

San Carlos Irrigation Project (SCIP)

In the San Carlos Irrigation Project (SCIP) 5-year Integrated Resource Plan dated Jan 26th 2012, the utility acknowledges that there has been an increased interest among its customers to integrate distributed renewable energy generation (San Carlos Irrigation Project, State of Arizona, 2012). SCIP at this time is in preliminary discussions with the Bureau of Indian Affairs to support working directly with its customers on PV installations, and they are working towards developing incentives and/or support mechanisms to ease the process. SCIP has limited experience with this but the report also noted that in 2010 SCIP worked with the National Park Service to install a solar array to serve the needs of the Casa Grande Ruins National Monument. The National Park Service and SCIP went into a bill crediting agreement as part of this effort.

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[12] http://www.srpnet.com/menu/About/generalinformation.aspx
[13] p20-21 (Salt River Project, Town of Gilbert, Ft. McDowell Yavapati Nation, Salt River Pima-Maricopa Indian Community, 2012)
[14] PSEG stands for Public Service Enterprise Group Inc.
[15] P24, (Salt River Project, 2012)
[16] p34, (Salt River Project, Town of Gilbert, Ft. McDowell Yavapati Nation, Salt River Pima-Maricopa Indian Community, 2012)

4.2 APPLICABLE PROJECT INCENTIVES

Various resources and contacts were consulted in order to present a complete picture of the incentives potentially available to solar energy projects. Tax incentives, of those identified, often add the most value to a project and while businesses operated by Native American tribes are not subject to federal income tax there are multiple mechanisms potentially available to allow the tribe to get value from these incentives, as summarized below. The federal government also offers a number of grants and loan guarantees that could apply for renewable energy projects on tribal lands. Although no such funding is currently available, future funding cycles could result in additional money available that could support a project on-site.

One way that renewable energy has been developed on tribal land has been through tribes leasing land to private developers. This allows the tribe to benefit from lease payments while the private developer can take advantage of all tax incentives. This has the downside that the tribal government does not own the project, and while they would avoid upfront capital expenses they would also not get nearly as much benefit or value from the project. There is a potential alternative based on a recent private letter ruling from the IRS[17], which may present a way for GRIC to maintain ownership and control of the project while also receiving the value of the tax incentives. The ruling found that the American Indian tribe who requested the ruling could "pass through" the investment tax credits to tax equity investors. This arrangement would be called a "pass through lease." The tax equity investor, typically a financial institution, would be the lessee, and would make rent payments to the tribe in exchange for benefiting from the investment tax credit. In this arrangement the investment tax credit is valued based on the fair market value of the project, typically determined by a third party appraiser rather than the actual costs incurred. Lease agreements need to be at least five years. This arrangement is officially only applicable to the specific case the private letter ruling was generated in response to, but it did set a precedent that the tribe could leverage. This issue would need to be further evaluated with tax professionals and the tribe would need to solicit a private letter ruling of their own, a process that can take two or more months.

Federal Incentive: Section 48 ITC: Section 48 of Title 26 of the Internal Revenue Code allows owners of qualified renewable energy equipment, to take a percentage of the system's total capital cost as an Investment Tax Credit (ITC) against federal income tax during the first year of operation liability. The tax credit for solar technologies is equivalent to 30% of the total capital cost, with no system size restrictions or maximum credit (applies for PV and solar thermal electric). These credits are for projects placed in service before December 31, 2016; after that point the solar ITC will decrease to 10%.

17 The test of the pass-through ruling can be found at: http://www.irs.gov/pub/irs-wd/1310001.pdf. Additional background on tax credit pass-through is available from: http://www.renewableenergyworld.com/rea/news/article/2013/05/solar-tax-credit-opportunity-for-indian-tribes

There are several key considerations for a project to qualify for the ITC:

1. The power must be "sold by the taxpayer to an unrelated person during the taxable year" (IRC Sec 45 (a)(2)(B)). Since GRIC is not a taxpayer, this incentive would only have value under alternative financing strategies, whereby a taxpaying third-party partner has ownership, or if a pass through lease (described above) can be arranged and approved by the IRS.
2. The recipient (the third-party taxpaying partner) of the ITC must decrease its depreciation base of the investment for tax purposes. Specifically, the taxpayer must decrease the depreciation base of the investment by 50% of the credit amount.

Federal Incentive: MACRS Accelerated Depreciation: Under 26 USC § 168, the federal government offers a 5-year accelerated depreciation option (MACRS) for certain renewable energy equipment, including solar PV and thermal systems.[18] This accelerated depreciation allows the owner to deduct larger amounts of the asset cost earlier on in the project's life. Accelerated depreciation can only be claimed by a taxable entity; public utility property is not eligible.[19] Before calculating depreciation, the adjusted basis of the project must be reduced by one-half of the amount of any federal energy credits (such as the Section 48 ITC) for which the project qualifies. This scenarios.

Federal Incentive: Tribal Energy Program: The federal government supports tribal renewable energy development is through the Tribal Energy Program, which offers financial and technical assistance to Indian Tribes. Since 2002, the Tribal Energy Program has invested $48.1 million in 175 tribal energy projects across the nation. To date program funding has been focused on energy efficiency improvements but more recently there have been more efforts to support renewable energy development. RFPs are issued once or twice a year and award grants for project planning and implementation and range in value from $50 thousand to $1 million. There are currently no open funding opportunities.[20]

Rural Energy for America Program (REAP) Grants and Loan Guarantees: – The USDA offers grants and loan guarantees to rural small businesses through the Rural Energy for America Program to promote energy efficiency and the use of renewable energy technologies. A tribal small businesses, or municipal utility such as GRICUA, would be most eligible for the program. The maximum grant incentive is 25% of project costs cost up to $500,000; however, in combination with loan guarantees, the program can finance up to 75% of total project costs. Awarded amounts in 2013 ranged from $2.5k to $500k. At present time, no funding has been allocated beyond FY 2013.

Qualified Energy Conservation Bonds (QECBs) and New Clean Renewable Energy Bonds (New CREBs): Funding under these two programs is allocated by the U.S. Treasury, for use as a financing mechanism for energy efficiency and renewable energy projects.

QECBs were originally authorized by the Tax Extenders and Alternative Minimum Tax Relief Act of 2008 (Pub. L.110-343), and are allocated by the U.S. Treasury to state governments on the basis of

[18] DSIRE, U.S. Code Title 26 Internal Revenue Code, http://www.dsireusa.org/documents/Incentives/US06F.htm
[19] IRS, Electing the Section 179 Deduction, http://www.irs.gov/publications/p946/ch02.html#en_US_publink1000107395
[20] Announcements of funding opportunities with the Tribal Energy Program are posted to: http://apps1.eere.energy.gov/tribalenergy/financial_opportunities.cfm

population. In turn, states then allocate funding for QECBs to municipalities with populations larger than 100,000 (according to the Census Bureau's 2007 municipal population data). Municipalities that do not intend to issue QECBs must reallocate their bond cap back to the State. State, local and tribal governments can issue QECBs, with a minimum of 70% of a states' allocation used for governmental purposes, and the remaining 30% eligible for financing private projects. The most recent round of funding was allocated in 2009; there is no deadline for eligible entities to issue QECBs. On the basis of the federal guidance, the Arizona Commerce Authority allocated $119,759.65 to GRIC; of this, $83,831.75 can be used for government projects, and a maximum of $35,927 can be used for private activities.[21] It is unclear if any remaining funds are available from these QECBs that could be used for the project. Currently, the Arizona Commerce Authority does not have any additional QECBs available, although that may change if any jurisdiction relinquishes their allotment.

Funding for New CREBS was authorized by the Energy Improvement and Extension Act of 2008 (26 USC § 54A). In 2009, the U.S. Treasury allocated funding for New CREBs on a competitive basis. The bonds could be issued by public power utilities, electric cooperatives, and government entities including tribal governments) to finance renewable energy projects. The most recent round of funding was awarded in October 2009, with a requirement than bonds be issued by the end of October 2012. In September 2010, the IRS subsequently solicited applications from cooperative electric companies for the remaining volume cap that was not awarded during the initial round. The IRS is not currently accepting applications for new CREB bond volume. There currently is no funding available for this program and no indication that future funding will be available.

Arizona Non-Residential Solar & Wind Tax Credit: An additional incentive that could be available for solar projects is the Arizona Non-Residential Solar & Wind Tax Credit. The tribe would be eligible for the credit, as it is explicitly stated that for tax exempt entities this credit may be passed through third parties who install or manufacture the system, or financing entities. The value of the incentive is equivalent to 10% of the installed system cost, up to $25,000 for one building (or array) and $50,000 per business in a single year. There are no size restrictions to this tax credit, which does not expire until the end of 2018. The incentive recipient must receive approval from the Arizona Commerce Authority's Solar Committee.

Renewable Energy Credits: Another way the tribal government can gain value from a renewable energy project is through the sale of Renewable Energy Certificates (RECs). RECs are a tradable commodity that represent the non-energy of the generation of 1 MWh of renewable electricity. There are both voluntary markets for RECs and compliance markets, compliance market RECs are used to meet state Renewable Portfolio Standard (RPS) policies.[22] The value of RECs vary by technology and market, but a price between $1-$5/MWh is typical for the voluntary market under current regulatory conditions. RECs from renewable energy projects on tribal lands that are sold to a federal agency are eligible for a doubling bonus towards meeting federal renewable energy requirements (U.S. DOE FEMP, 2008). This added value could potentially be passed along to the tribal government, providing additional revenue to

[21] http://www.azcommerce.com/qecb/, http://www.azcommerce.com/assets/qecballocation.pdf

[22] A listing of REC marketers can be found here: http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=2

the project. The Western Area Power Administration facilitates the acquisition of RECs by federal agencies through their website.[23]

SRP EarthWise Solar Energy Incentive Program: SRP offers a solar incentive to eligible customers, including tribal governments, within its service territory. Small commercial systems are eligible for up to $30,000. The incentive level changes over time, but current level for Nonprofit, School, and Government PV systems is $0.04/kWh of first year performance, for a value of $40/REC for the first 20 years of the project.[24] Ownership of the project's RECs are transferred to SRP for 20 years. This and other utility incentives are only available to utility customers.

The APS Renewable Energy Incentive Program: provides an upfront incentive in exchange for RECs. APS uses the RECs to demonstrate compliance with the state's Renewable Energy Standard (RES) program. APS revises the incentive value on an annual basis; currently, incentives for grid-tied PV projects are up to $0.10/watt, and the value will decrease as more customers participate in the program. The incentive for a commercial system is capped at $75,000, or 40% of system costs, whichever is less. This incentive is part of a utility rebate program, and may only be applied for customers that pay an RES Surcharge as part of their bill. This and other utility incentives are only available to utility customers (Arizona Public Service Company, 2013).

4.3 PARTNER AND OWNERSHIP STRUCTURE SCENARIOS

A renewable energy project at GRIC could have a number of different partner and ownership structures. A number of potential arrangements are summarized below. Since GRIC has stated that they would prefer to have a tribal entity own the project, most of the considered scenarios include at least partial ownership or control of the system.

The most likely tribal entity to own and operate a large (e.g., at least 1 MW or larger) PV project such as the ground mount PV arrays evaluated in this study is GRICUA. It is also possible that a project sited at San Tan Industrial Park could be owned by Lone Butte Industrial Development Corporation or a non-tribal third party who would lease property at the industrial park and sell the power to GRICUA. The Pima Leasing and Finance Corporation is an additional entity that may be involved in any project sited on trust land in the GRIC. Pima Leasing & Financing Corporation is responsible for managing land leases on tribal trust land. They could be involved if a project needs to lease any trust land adjacent to a ground-mount system located at the GRICUA owned substation.

Roof-mounted systems could also be owned by GRICUA. However, a casino could also own and operate a PV system on their facility and use it to offset their internal power use. It is likely that this would represent an increase in their electricity costs compared to what they are currently paying for power delivered by GRICUA, so the decision to do so would have to be based on other considerations such as a desire to enhance their corporate image in terms of environmental responsibility. This would also reduce power sales revenues to GRICUA. In the short term, this could impact GRICUA's ability to offer

[23] http://ww2.wapa.gov/sites/Western/renewables/pmtags/Pages/pmtagspurchase.aspx.
[24] Applicable incentive level as of May 1, 2013.

electricity to other users at their current low rates since their fixed costs would be distributed over a smaller overall volume of power sales. Therefore, the overall benefit of this option to the Community as a whole must be considered carefully. Any project owned by a casino would most likely be owned by the Gila River Gaming Enterprises Inc. Meanwhile, a PV project at the Tribal Governance Center would most likely be owned by the Community as a whole (or a part of the government), and could be operated and maintained by on-site building maintenance staff. The system could directly offset grid electricity consumption. As with the casino ownership option, the facility operating costs would not decrease in the short term as a result of deploying PV technology.

The Investment Tax Credit (ITC) and MACRS accelerated depreciation are key incentives to making solar projects in the United States financially viable. However, they require a taxable entity to take advantage of them. Federal income tax is not imposed on businesses operated by American Indian tribes, therefore GRIC would normally not be able to take advantage of the tax incentives. Several partnership models exist to help renewable energy projects on tribal land benefit from federal tax incentives.

Many tribes lease land to private developers to provide a way to develop renewable energy projects on tribal land that can take advantage of tax incentives. In this arrangement, the developer pays the capital costs to build the project and the tribe collects a lease payment for the use of their land. The downside for the tribe is that since they do not own the project, they will not receive any of the benefits associated with the project beyond the revenue for a land lease. GRIC has evaluated this type of scenario before and noted that this is not a preferred scenario for an on-site PV project.

There are a few alternatives that may present a way for GRIC to maintain ownership and control of the project while benefiting from the tax incentives. One alternative was suggested in a recent IRS private letter ruling, which allowed a tribe to obtain the tax benefits under a "pass through lease" arrangement. In this case, a tax equity investor (such as a financial institution) would be the lessee, and would make rent payments to the tribe in exchange for benefiting from the investment tax credit. Another alternative may allow for the tribe to take advantage of the tax benefits and avoid the leasing scenario stated above. A private letter ruling could be requested from the IRS to allow GRIC to pass through the benefits to a tax equity investor that is a partner rather than a lessee. The partner would likely be a financial institution but could likely be any qualified corporation or even a venture capital firm. A partner with a large tax burden would be ideal because they would benefit most from the tax credit. The percent ownership between GRIC and the partner would need to be negotiated, but the tax benefit could be shared with GRIC either through equity or in the revenue generated by the project. The benefit of this scenario is that GRIC would both own and operate the project while taking advantage of the tax benefits through the participation of a passive investor. To ANTARES' knowledge there is no precedent for this arrangement, but it may be an option worth pursuing, especially in light of the previously mentioned private letter ruling.

An Energy Savings Performance Contract (ESPC) is an arrangement where a project partner provides the upfront capital cost and is paid back over time from the energy savings. ESPCs are a commonly used contracting vehicle for federal agencies to implement renewable energy, energy savings, or water savings projects. An Energy Savings Company (ESCO) is the partner in an ESPC arrangement. In this scenario, the risk for the tribe would be lowered because the ESCO pays all initial costs and guarantees energy savings.

A summary of the potential ownership scenarios and the pros and cons for each option is provided in Exhibit 46.

Exhibit 46. Overview of Potential Ownership Scenarios

Ownership Scenario	Pros	Cons
GRIC owns and operates 100% of the project (entities could include GRICUA, Gila River Gaming or Tribal Government)	GRIC has full control of the project. GRIC receives all revenue generated or cost savings. The project stays within the tribe.	As a non-taxable entity, GRIC is not able to take advantage of the federal incentives available for solar projects.
GRIC owns the project and leases it to a 3rd party (assuming a private letter ruling is obtained from IRS)	GRIC owns the project and collects lease payments from the 3rd party. GRIC is also able to take advantage of tax benefits by passing them through to the lessee.	GRIC does not operate the project, the lessee does. The tax benefits and value from the power are likely shared with the 3rd party.
GRIC owns the project with a partner (assuming a private letter ruling is obtained from IRS)	GRIC own and operates the project. GRIC is able to take advantage of tax benefits by passing them through to a partner.	Ownership is shared with a partner. Project revenues and tax benefits are shared as well. GRIC loses some control.
An ESPC arrangement is entered into between GRIC and an ESCO	There is little risk for GRIC. Energy savings are guaranteed. The upfront capital is paid for by the ESCO.	The ESCO owns the project and receives the tax benefits. Additional energy savings may go to the ESCO. Additional contracting and negotiations necessary to initiate project.

4.4 ADDITIONAL FINANCING CONSIDERATIONS AND RESOURCES

There are a number of governmental programs and resources geared towards assisting tribes with renewable energy and energy efficiency projects on their lands. The Tribal Energy Program, part of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, provides financial and technical assistance to tribes to promote energy self-sufficiency.[25] Their website has information about project development and implementation, funding opportunities, case studies on project supported through the program and other resources. In addition, the U.S. Department of Energy Office of Indian Energy Policy and Programs, or Office of Indian Energy, also provides support and programs to assist tribes with energy development projects.[26] Another useful resource for tribal energy projects is the *Renewable Energy Development in Indian Country: A Handbook for Tribes*, which was commissioned by the National Renewable Energy Laboratory in 2010 (MacCourt, 2010).

[25] Tribal Energy Program website, http://apps1.eere.energy.gov/tribalenergy/
[26] Office of Indian Energy website, http://energy.gov/indianenergy/office-indian-energy-policy-and-programs

If GRIC decides to implement a project on-site, it may also be helpful to connect with other tribes that have gone through the process already, in order to get information about their experience and any lessons learned. Some other tribes that are pursuing solar arrays or have recently installed PV systems in Arizona and nearby states are listed below for reference.[27]

- San Carlos Apache Tribe in Arizona is planning to build a 1.1 MW PV system on tribal land that is leased to the tribal casino. They have received assistance from DOE Strategic Technical Assistance Response Team (START) program, and as of May 2013 were in the process of reviewing financing options for the project.
- Pinoleville Pomo Nation in Ukiah, California plans to install a 3 MW solar project to provide electricity for tribal administrative buildings and a subdivision.
- Southern Ute Indian Tribe of Ignacio, Colorado is planning a PV array project with single axis tracking, which will provide power for tribal facilities and residences.
- Jemez Pueblo tribe in New Mexico has been planning a 4 MW PV array since 2010. This ground mount PV system is expected to cost $22 million, and will cover 30 acres. The most recent DOE grant funding will be used to complete project development activities, including acquiring a power purchase agreement, completing site-related requirements such as surveys, and finalizing financing.
- To'Hajiilee, New Mexico, which is part of the non-contiguous part of the Navajo Nation, is in the process of developing a 33 MW solar project. The Shandiin Solar Farm will be one of the largest utility-scale PV arrays on tribal land in the US. The project is expected to cost $124 million to build, and has received a $300,000 DOE grant to secure funding. SunPower Corp. is helping the To'Hajiilee's economic development team develop the project and negotiate with utilities for the power purchase agreement.

It is likely that GRIC will need to secure a financing partner in order to develop a large scale solar project. In addition to banks and standard investment companies, there are a vast array of financers and investors who specialize in solar and other renewable energy projects. Some integrated PV companies may also offer financing was well as turnkey EPC services for large scale solar systems.

The following list includes a number financing companies that have been involved with solar project development in Arizona in recent years, based on currently available data from the Solarbuzz US Deal Tracker (Solarbuzz, 2013). Note that this list is not comprehensive, and the companies have not been reviewed or vetted by ANTARES at this time. However, this may be useful as a starting point for GRIC if a solar PV project is pursued.

- SolarCity, PPA Financing or solar lease (http://www.solarcity.com/)
- Blue Renewable Energy (http://laffertyelectrictechnologies.com/companies/blue-renewable-energy/)
- Clean Energy Capital (http://cleanenergycapitalllc.com/clean-energy-capital-overview/)
- Seminole Financial Services, LLC (http://www.seminolefinancialservices.com/)
- MP^2 Capital (http://www.mp2capital.com/)
- Tioga Energy (http://www.tiogaenergy.com/)

[27] Sources: (DOE Office of Indian Energy Policy and Programs, 2013) (Meehan, 2013) (Barber, 2012)

- SunEdison (http://www.sunedison.com/wps/portal/memc/business/)

The Renewable Energy Finance & Investment Network (REFIN) is a directory of sources of finance for renewable energy and energy efficiency in the US. Although the most recent version is from 2004, it may also be a useful reference. The directory is available for download at http://community-wealth.org/sites/clone.community-wealth.org/files/downloads/tool-acore-directory.pdf

5 Regulatory and Environmental Requirements

5.1 POTENTIAL ENVIRONMENTAL AND CULTURAL RESOURCE ISSUES

No potential environmental issues that would hinder a PV project for the roof-mounted options were identified during the site visit. Foundation and soil issues do not need to be addressed for PV arrays mounted on the roofs of existing buildings. For these systems, roof structure and loading capacity is the main concern. Furthermore, since there are no known underground tanks or environmental concerns in the area considered for the ground mount arrays, these systems are unlikely to cause significant environmental issues. Since the San Tan Brownfield area has recently been remediated, it is assumed that this site is ready for new development.

For ground-mount systems a variety of considerations must be considered. Three primary potential impacts include:

- Viewshed or aesthetic impacts
- Threatened and endangered species habitat
- Cultural resources

The potential viewshed impacts of a large PV array (especially from the perspective of potential resort or casino patrons) is a concern expressed by the Wild Horse Pass Development Authority and resort managers. This is not likely to impact the San Tan Industrial Park site, but it could be a potential concern for the Lone Butte substation location if the array is visible from the resort grounds. The system rendering provided in this report partly addresses this issue, but a subsequent effort to address potential line-of-sight issues from the high-rise hotel complex could help allay any potential concerns.

Development of large PV arrays in desert environments will require a site survey to determine if the project would impact habitat for federally or state threatened or endangered species.[28] Some potential species in Pinal and Gila counties that could be impacted include the lesser long-nosed bat (in areas with columnar cacti or agave for food), and the Tucson shovel-nosed snake. The Sonoran desert tortoise is often cited as a species of concern but its habitat is typically located in rocky hillsides. It should be considered nonetheless.

As part of any project development activity, a cultural resources assessment must be performed for a ground mount solar PV array located on land adjacent to the Lone Butte substation. It is likely that no significant cultural resources would be impacted at the San Tan brownfields site since it has already undergone significant evaluation and redevelopment.

[28] Federally listed species are listed on-line at http://www.fws.gov/southwest/es/arizona/Threatened.htm

5.2 SAFETY ISSUES AND CRITERIA

PV systems are generally quite safe when operating, although anything that generates or uses electricity can cause shock or fires if not handled appropriately. Furthermore, since it is not possible to turn off a PV panel, they will continue to generate DC electricity any time the sun is shining. Solar system installers must take extra care to deal with this live electricity, as well as the risks associated with installing heavy equipment at height for roof mounted systems. Standard safety procedures and guidelines should be followed during installation and maintenance of the PV system. Licensed installers and electric contractors will be trained in these procedures. Roof mounted systems also must be designed to ensure that there is no negative impact on the strength or integrity of the building structure or roof.

Safety of PV systems requires correct system design and installation, as well as periodic system inspection and testing during annual maintenance. Some general recommendations include:

- PV systems should be marked to provide appropriate warning to work around and isolate the solar electric system during maintenance and emergency situations. Interior and exterior DC conduit, raceways, enclosures, cable assemblies, and junction boxes should all be marked.
- Access and spacing requirements should be observed to provide adequate pathways and access to roofs (for roof mounted systems).
- There should be a DC disconnect on the site side of the inverter. This disconnect cuts the power to the inverter, which prevents it from exporting power to the electrical service panel. This will prevent service or maintenance workers on the utility side of the panel from being harmed by any solar electricity.
- There also may be an AC disconnect at the service panel, unless the main breaker provides this level of disconnect.

Wind loading concerns should be addressed in detailed system design. The Solar America Board for Codes and Standards (Solar ABCs) published a report which explains wind loading calculations for roof mounted arrays, and recommends structural design standards.[29] Wind loading may affect the ballasted PV system configurations on the flat roof buildings, since these systems do not use roof penetrations. In areas with high wind, ballasted systems may need to be installed at lower tilt angles.

Vandalism and theft are another consideration for PV systems. This is an unfortunate reality in some areas, since PV panels have a significant monetary value. Ground-mounted systems are the most vulnerable due to ease of access, while roof and poles mounted units are generally less vulnerable. For ground mount systems the electrical wiring must not be readily accessible in order to prevent anyone from walking up to the array and touching the wires. In general, installation of security fences around the array will help with both safety considerations and to deter theft ground-mounted systems. Although this will lead to some additional expense and visual impact to the project, it is a precaution well worth taking.

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[29] Solar America Board for Codes and Standards, Wind Load Calculations for PV Arrays Report, http://www.solarabcs.org/about/publications/reports/wind-load/index.html

5.3 PERMITTING REQUIREMENTS

Permitting for the construction for a roof mounted PV system falls under the jurisdiction of the GRIC Tribal Project Building Safety department (phone number: 520-562-6080). Any roof mounted system will require a building and electrical permit that includes a description of the project and associated engineering drawings. Permit applications are reviewed on a regular basis, and should be submitted early in the project development phase during the final engineering process. Fees were not determined through ANTARES' communication with Tribal Projects, but they are expected to be fairly minimal. Permitting requirements for ground mount systems should follow the standard procedures for construction and development required by the Community.

Although GRIC is not subject to Arizona permitting statutes, it is worth mentioning that there is an Arizona permitting standard for solar photovoltaic systems labeled A.R.S. § 9-468.

The statue states:

A. Municipalities shall adopt the following standards for issuing permits for the use of certain solar energy devices:

1. For construction with solar photovoltaic systems that are intended to connect to a utility system, the following apply:

(a) The location of the photovoltaic system installation shall be indicated on the construction plans, including the roof plan and elevation.

(b) Photovoltaic panel mounting details shall be included in the installation plans.

(c) The electrical diagrams shall include one-line and three-line diagrams.

(d) For direct current to alternating current conversions, the cut sheet and listings for inverters shall be included in the plans.

(e) A municipality shall not require a stamp from a professional engineer for a solar photovoltaic system unless an engineering stamp is deemed necessary. If an engineering stamp is deemed necessary, the municipality shall provide the permittee a written explanation of why the engineering stamp is necessary.

Understanding local standards may prove beneficial should GRIC move forward with a PV project.

6 ECONOMIC ANALYSIS

6.1 ANALYSIS METHODS AND INPUTS

A levelized cost of electricity (LCOE) analysis was performed for the considered PV configurations in order to compare the cost-effectiveness of potential projects. The LCOE provides the average cost of power over the lifetime of the project. This analysis is useful in gauging the cost of producing electricity and can readily be compared against electric production costs for other technologies and utility supplied power. Inputs to the calculation include system output (kWh generated), capital costs, O&M costs, financing assumptions, and any applicable incentives.

Both current and constant LCOE figures are calculated in the analysis. The current LCOE is also known as the nominal LCOE because it includes the rate of inflation. The constant LCOE removes the effects of inflation and shows the LCOE is real dollars. Where the rate of inflation is greater than zero (as it is in this analysis), the constant LCOE will be lower than the current LCOE.

Although the base LCOE analysis does not include any incentives, there are a number of incentives that could be included in the partner scenarios. A partner scenario could take many forms with complex arrangements for sharing the value of a project. Some of these opportunities were discussed previously in Section 4.3. Possible business models for partner projects could include revenue sharing or lease structures. Additionally, a partner with a tax burden may be able to take advantage of a projects' depreciation benefits. Such complex scenarios may hide the practical outcomes from each project option. In an effort to make it simpler to judge the viability of each project, ANTARES modeled the incentives cases so that the value of the incentives is rolled into the LCOE figure. For example, the larger the depreciation, the lower the LCOE. This assumes that the benefit of the incentives will generally be fully passed on to the project itself. This may not perfectly replicate the LCOE in a real-world partnership scenario (where the partner may claim a higher portion of the benefits), but it makes it possible to compare apples to apples and easily evaluate the outcome of each project.

The key analysis tools used in the LCOE analysis included an in-house excel spreadsheet tool used to aggregate economic input data and calculate levelized costs and metrics. Key assumptions used as inputs to the model include:

- A 25-year project lifespan and economic life. This time frame is based on the expected life of the PV system and associated equipment, based on information from recent projects and industry data.
    - The 25-year period would begin in 2014 and end at the close of 2039. This assumes that construction would begin in 2013.
- All costs are adjusted to the appropriate time frame. Future costs are escalated by adjusting for inflation and equipment cost escalation. The total future cost of the project is adjusted to its present value using the discount rate (including inflation).

These analysis tools were applied to the selected configuration options identified as part of the detailed technical analysis described in Chapter 3 of this report. As noted above, two scenarios were developed and evaluated for each option; the base case (Case 1) assumes no incentives will be obtained by the project; and Case 2, which assumes that the project will be able to obtain a variety of potentially available incentives. A sensitivity analysis is also performed on key variables (capital costs, O&M costs, and weighted average cost of capital) to provide a more thorough understanding of the impact that these values could have on the project's economics.

The following subsections describe the methods and assumptions used in the base case and alternative financing analyses.

6.1.1 Key Financial Analysis Parameters

The financial assumptions for the LCOE and LCC analyses are presented in Exhibit 47 for Case 1 (no incentives) and Case 2 (with incentives). An explanation for key parameters follows.

Exhibit 47. Key Financial Parameters

	Case 1 (no incentives)	Case 2 (with incentives)
General inflation (per year)	2.0%	2.0%
Federal Tax Rate	N/A	35%
State Tax Rate	N/A	5.05%
Combined State and Federal Tax Rate	N/A	38.25%
Economic Life (years)	25	25
Weighted Average Cost of Capital	6.6%	6.6%
REC Price	$2/MWh	$2/MWh
Investment Tax Credit	N/A	30% of capital costs
Arizona Wind and Solar Tax Credit	N/A	$25,000
Depreciation	N/A	5-year MACRS

Taxes: Taxes are not included in the case without incentives because GRIC does not have a tax burden. Combined Federal and State taxes for the case with incentives are 38.25% which is typical for a corporation which may act as a project partner.

Weighted Average Cost of Capital (WACC): The WACC is the average of the debt and equity financing costs. The WACC is commonly used as the discount rate for investment opportunities, and was used in this manner for the analysis. Also called the hurdle rate, it is a measure of the anticipated present value of future cash flows. It serves as a benchmark for a project's profitability, and is usually set based on an investor's anticipated return on other projects available for investment. The interest rate earned by a university endowment, for example, is often the university's discount rate when it is presented with alternative projects for investment. If the project will earn more than adding the same amount of money to the endowment, then it is considered profitable.

As no specific WACC was requested by GRIC, ANTARES assigned a value of 6.6%. This is the rate used in the U.S. Energy Information Administration's Annual Energy Outlook 2013 publication for levelized costs across various generation technologies. It is important to note that in a partner scenario, the partner may evaluate the project with their own WACC. Taking this into consideration, and the fact that the chosen WACC has a large effect on the LCOE, sensitivity charts are presented to show the LCOE across a range of WACC assumptions.

Financing: The base case scenario assumes that the projects would be 100% debt financed. Tribes and businesses organized as arms of government aren't subject to federal income tax, therefore GRIC would not be able to take advantage of tax deductions for interest paid on debt. This is not the case for the alternative analysis (Case 2), which assumes a project partner with a tax burden will maintain at least part ownership of the system.

Other Incentives (RECs, ITC, AZ Wind and Solar Tax Credit, MACRS): As discussed in Section 4.2, there are various incentives that could benefit a solar project, including the Federal ITC, AZ Wind and Solar Tax Credit, and MACRS depreciation. These were all included in Case 2, and their values for each considered project are shown in Exhibit 48. No incentives were included in Case 1.

Exhibit 48. Incentive Values Included in Case 2 for Each Project Option

Option	ITC Value ($)	AZ Wind & Solar Tax Credit ($)	Depreciation
1A – Tribal Governance Center	$440,705	$25,00	5-yr MACRS
1B – Tribal Governance Center	$424,622	$25,00	5-yr MACRS
2A – WHP Hotel & Casino	$392,416	$25,00	5-yr MACRS
2B – WHP Hotel & Casino	$417,640	$25,00	5-yr MACRS
3A – San Tan Brownfield	$872,984	$25,00	5-yr MACRS
3B – San Tan Brownfield	$4,065,562	$25,00	5-yr MACRS
4A – Lone Butte Substation	$4,065,562	$25,00	5-yr MACRS
4B – Lone Butte Substation (1-X)	$4,539,120	$25,00	5-yr MACRS

6.1.2 Total Installed Costs

Exhibit 49 summarizes the total installed cost estimates for each PV configuration option. These costs were developed based on recent vendor quotes, ANTARES experience, and cross-referenced with Solarbuzz's U.S. Deal Tracker data from June 2013.[30] Base installed costs for the data set were found by averaging per unit costs for projects of similar size and configuration to the systems considered here, including plants completed and under construction from the beginning of 2012 to the present. Although it is likely that the actual per-unit installed costs for the considered systems vary somewhat, these differences are not expected to be very large or significantly affect the overall project economics. As all

[30] The US Deal Tracker includes key project metrics including installed system costs for a rolling database of planned, installed, and decommissioned PV projects in the United States.

configurations are for general PV installations, a 20% contingency factor has been included into each vendor quote to account for any unforeseen factors and variations in system configuration for the specific cases considered here. Where sufficient data was not available from Solarbuzz, the major deviations in base costs for different configuration types were found between the vendor quotes (including contingency factor) and the data set.

Exhibit 49. Estimated Capital Costs for Selected Configurations

Option	System Location	System Capacity (kW_{DC})	Capital Cost ($/W)	Capital Cost ($)	Extended Inverter Warranty ($)
1A	Tribal Governance Center	491	$2.94	$1,444,304	$24,714
1B	Tribal Governance Center	458	$3.04	$1,392,223	$23,184
2A	Wild Horse Pass Hotel and Casino	437	$2.94	$1,284,868	$23,184
2B	Wild Horse Pass Hotel and Casino	450	$3.04	$1,368,948	$23,184
3A	San Tan Brownfield	1,109	$2.58	$2,860,518	$49,428
3B	San Tan Brownfield	5,544	$2.40	13,304,736	$247,138
4A	Lone Butte Substation	5,544	$2.40	$13,304,736	$247,138
4B	Lone Butte Substation (1X tracking)	5,638	$2.64	$14,883,264	$247,138

The base capital cost represents the all-in cost of installation of each system and includes the following:

- Application Engineering Services – standard engineering services required to install on a typical rooftop, jurisdictional permitting, inverter-direct monitoring system, and interconnection and upkeep documents.
- Solar Equipment and Materials – commercial grade silicon crystalline modules, inverters and control system, standard aluminum racking and associated structural fastening system, tracking system as applicable, and wiring, conduit, and associated required electrical infrastructure.
- Installation Services – federal labor wages including all subcontracting labor costs

Several inverter manufacturers offer the extended warranties, which guarantee continued operations for up to 20 years without requiring an inverter replacement. As such, the cost of purchasing an extended, 20 year inverter warranty is included in the economic analysis. The life cycle cost analysis also assumes inverter replacement at year 21 for all systems.

6.1.3 Operation and Maintenance

The annual O&M cost are estimated based on the annual power production of each system. The cost for annual maintenance for each system was estimated to be $0.01/kWh of generation. This value is based on ANTARES experience and industry standards.

6.2 LEVELIZED COST OF ELECTRICITY (LCOE) ANALYSIS RESULTS

In order to evaluate the economic viability of the PV projects, an LCOE analysis was performed to estimate the levelized cost of the electricity generated by the system. A summary of the inputs for each considered case is presented in the following subsection, followed by the analysis results. Sensitivity analysis results are also presented.

6.2.1 SUMMARY OF INPUTS FOR CONSIDERED CONFIGURATION

They key inputs for economic analysis are shown in Exhibit 50 and Exhibit 51 for the roof mount and ground mount configurations, respectively. It is important to note that only first year costs for O&M and RECs are shown in the table (since they do not include inflation or escalation). In addition, only the first year electricity generation values are shown; output for subsequent years is reduced according to the average degradation rates noted in the tables. The value of the incentives for the Case 2 analysis for all options was shown previously in Exhibit 48.

Exhibit 50. Summary of Inputs for Roof Mount PV Systems

	Option 1A	Option 1B	Option 2A	Option 2B
PV System Capacity (kW_{DC})	491	458	437	450
First Year Net Electricity Generation (kWh/yr)	898,398	863,142	815,520	850,889
Annual degradation rate (%/yr)*	*0.6%*	*0.7%*	*0.6%*	*0.7%*
Base Capital Cost ($)	$1,444,304	$1,392,223	$1,284,868	$1,368,948
Extended Warranty ($)	$24,714	$23,184	$23,184	$23,184
Inverter Replacement (Year 21)	$130,465	$128,215	$128,215	$128,215
Annual O&M Costs ($/yr)	$8,984	$8,631	$8,509	$8,509
Annual REC Value ($/yr)	$1,797	$1,726	$1,702	$1,702

Long term annual average degradation rates based on (Jordan & Kurtz, 2012) *for silicon modules, and* (Strevel, Trippel, & Gloeckler, 2012) *for CdTe modules.*

Exhibit 51. Summary of Inputs for Ground Mounted PV Systems

	Option 3A	Option 3B	Option 4A	Option 4B
PV System Capacity (kW_{DC})	1,108	5,543	5,543	5,637
First Year Net Electricity Generation (kWh/yr)	2,276,318	11,381,592	11,381,592	14,533,073
Annual degradation rate (%/yr)*	*0.7%*	*0.7%*	*0.7%*	*0.7%*
Base Capital Cost ($)	$2,860,518	$13,304,736	$13,304,736	$14,883,264
Extended Warranty ($)	$49,428	$247,138	$247,138	$247,138
Inverter Replacement (Year 21)	$260,930	$1,304,650	$1,304,650	$1,304,650
Annual O&M Costs ($/yr)	$22,763	$113,816	$113,816	$145,331
Annual REC Value ($/yr)	$4,553	$22,763	$22,763	$29,066

Long term annual average degradation rates based on (Strevel, Trippel, & Gloeckler, 2012) *for CdTe modules.*

6.2.2 Economic Analysis Results

The calculated LCOE results for each site and configuration are shown in Exhibit 52 and Exhibit 53 . Both constant and current LCOE values are shown for each project, as well as the values before and after system degradation is applied. (Results are shown with and without system degradation in order to show the impact it has on the economics and to provide additional basis for future comparisons.)

Exhibit 52. LCOE Results for Roof Mounted PV Systems ($/kWh)

	Case 1 No Incentives No Degradation	Case 1 No Incentives With Degradation	Case 2 With Incentives No Degradation	Case 2 With Incentives With Degradation
Tribal Governance Center - Option 1A				
Current LCOE	$0.147	$0.158	$0.116	$0.124
Constant LCOE	$0.122	$0.131	$0.095	$0.102
Tribal Governance Center - Option 1B				
Current LCOE	$0.148	$0.161	$0.116	$0.127
Constant LCOE	$0.122	$0.133	$0.095	$0.104
Wild Horse Pass & Casino – Option 2A				
Current LCOE	$0.145	$0.156	$0.114	$0.123
Constant LCOE	$0.120	$0.129	$0.093	$0.101
Wild Horse Pass & Casino – Option 2B				
Current LCOE	$0.148	$0.161	$0.116	$0.126
Constant LCOE	$0.122	$0.133	$0.095	$0.104

Exhibit 53. LCOE Results for Ground Mounted PV Systems ($/kWh)

	Case 1 No Incentives No Degradation	Case 1 No Incentives With Degradation	Case 2 With Incentives No Degradation	Case 2 With Incentives With Degradation
San Tan – Option 3A				
Current LCOE	$0.117	$0.128	$0.094	$0.102
Constant LCOE	$0.097	$0.106	$0.077	$0.084
San Tan – Option 3B				
Current LCOE	$0.110	$0.120	$0.089	$0.097
Constant LCOE	$0.091	$0.099	$0.073	$0.079
Lone Butte Substation – Option 4A				
Current LCOE	$0.110	$0.110	$0.089	$0.089
Constant LCOE	$0.091	$0.091	$0.073	$0.073
Lone Butte Substation – Option 4B				
Current LCOE	$0.097	$0.106	$0.079	$0.086
Constant LCOE	$0.080	$0.088	$0.065	$0.070

The calculated LCOEs for the roof mounted systems are very similar, with results in the range of $0.13-$0.16/kWh for Case 1 (when system degradation is considered). The Case 2 results for these systems are also very close, with constant LCOE values around $0.10/kWh for all considered options. The incentives provide a roughly $0.02-0.03/kWh overall benefit for the roof mounted systems in terms of the constant LCOE values. The system degradation results in around a 5% reduction in system output over the lifetime of the system, and increases the LCOE values by about $0.01/kWh relative to the assessment that does not include degradation.

The ground mounted systems all have lower LCOEs than the roof mounted systems, mostly due to the economies of scale benefits of these larger systems that lead to lower per unit installed costs. The LCOE for these projects range from around $0.09-$0.10/kWh for Case 1 without incentives (when system degradation is considered), and $0.07-$0.09 for Case 2 when incentives are included. Lone Butte Substation Option 4B was the best performing project in all cases. San Tan Option 3A on the other hand had the highest LCOE for the ground mount systems, because it is the smallest array and therefore has somewhat higher capital costs than the other fixed tilt systems. Although the Lone Butte Substation Option 4B has the highest per-unit capital costs, the performance benefits from the tracking system more than make up for the added costs. As such, this array performs best in the LCOE evaluation.

6.2.3 Sensitivity Analysis Results

Sensitivity analyses can be used to address uncertainties in specified cost parameters, in order to see the affect that varying these values will have on the overall project economics. In this case, the capital cost, O&M costs, solar radiation, and weighted average cost of capital were determined to be the most critical inputs to the project economics. The capital and O&M cost variations can account for uncertainty in the costs of system installation and maintenance, future price reductions, or the availability of additional grants that help to reduce the up-front cost of the project. The WACC was varied to demonstrate the effects of different financing assumptions. In the sensitivity analysis, each of the input factors was varied individually (i.e., one at a time), across a range of +/- 50% from the base value. The solar radiation was varied by +/- 25% to account for uncertainty in the solar resource, which can be used to evaluate the impact performance varying from expectations for other reasons as well.

Results of the sensitivity analysis for the best (i.e. the projects with the lowest LCOE) roof and ground mounted options are provided in Exhibit 54 and Exhibit 55. Constant LCOE values are displayed on the y-axis of all exhibits. The charts represent the cases that do not include incentives (i.e. Case 1). Appendix B includes sensitivity charts for all considered projects options, including the Case 2 evaluations that include incentives. All sensitivity analysis results do include system degradation considerations.

The sensitivity charts all display similar trends. The projects are most sensitive to changes in the capital costs, and least sensitive to changes in O&M costs. It was determined that a 4-5% change in capital costs results in a nearly 5% change in the LCOE. The WACC also has a large effect on the results, where a 5% change in the WACC results in around a 3- 4% change in LCOE for the considered cases. Changing the solar radiation by 5% results in a roughly 2-3% change in the LCOE. The projects are not quite as sensitive to changes in the O&M costs as these costs are a relatively small component of the system lifecycle costs. A 5% change in the O&M cost drives a change of about 1% in the LCOE values. This analysis reveals that changes in the capital cost and/or the discount rate used on the cash flows have the greatest impact on the projects' success.

Exhibit 54. Sensitivity Analysis – Option 2A, Wild Horse Pass Hotel & Casino

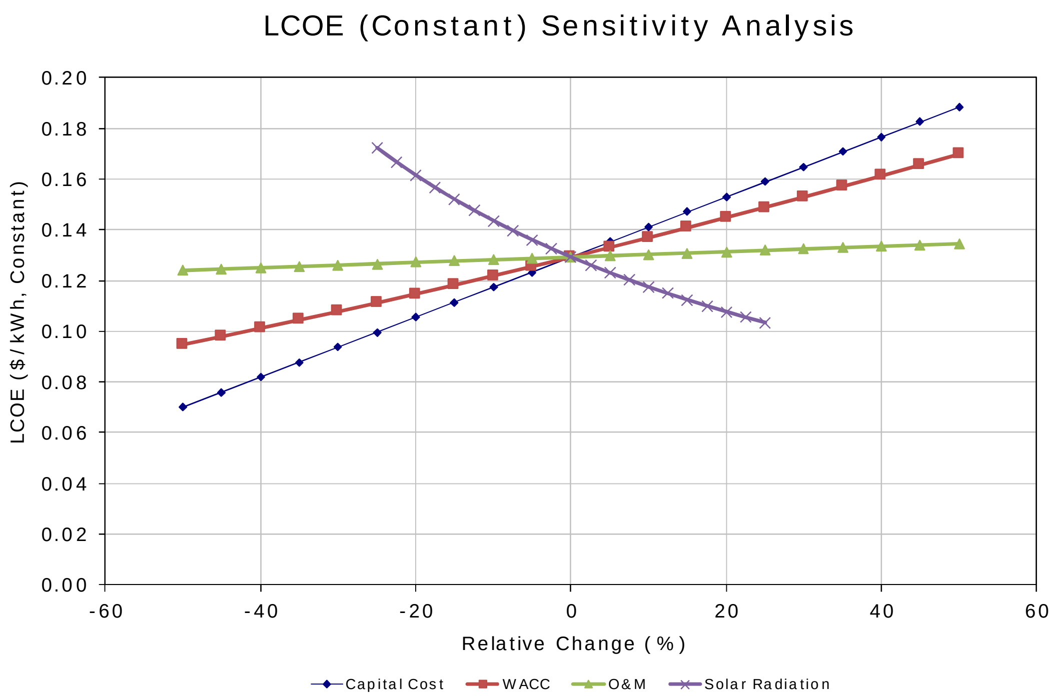
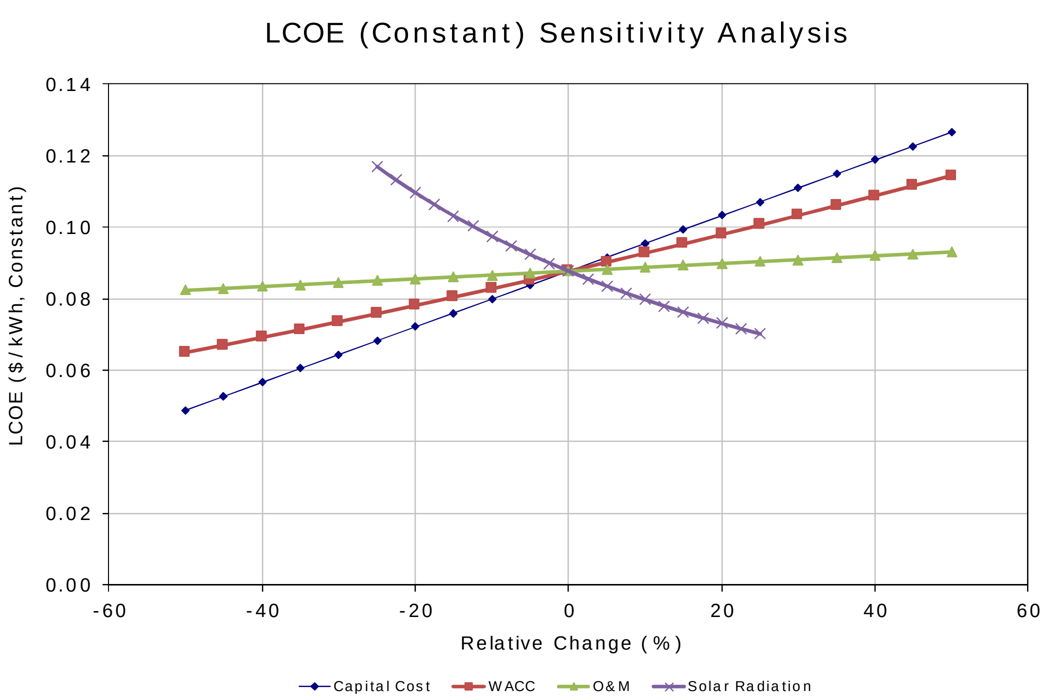


Exhibit 55. Sensitivity Analysis – Option 4B, Lone Butte Substation



6.2.4 LCOE Analysis Conclusions

The constant LCOE values for Case 1 without incentives range from a low of $0.09/kWh (Option 4B) to a high of $0.13/kWh (Options 1B & 2B), when system degradation is included. The constant LCOE values for Case 2 which includes incentives range from a low of $0.07/kWh (Option 4B) to a high of $0.10/kWh (Options 1B & 2B), including system degradation impacts. The Lone Butte Substation 5MW project with single axis tracking performs the best in both cases, with the lowest LCOE results. As expected, all of the incentives cases perform better than their respective cases without incentives cases, as the incentives benefit the projects and help to reduce the upfront system costs. Furthermore, the ground mount systems overall have lower cost of electricity than the roof mount systems because they benefit from larger economies of scale, resulting in lower per unit installation costs relative to the roof mount systems.

The sensitivities analyses show that the projects are especially sensitive to changes in the capital cost and WACC. A small change in these factors makes a large difference in the LCOE. The solar resource also has a large effect on the LCOE results. O&M on the other hand has a much smaller influence.

All of the projects are more expensive than the current price of electricity, which is around $0.05/kWh. However, there are other benefits to the solar projects and GRIC must decide if those are worth the higher cost of production. One of the goals of an investment in renewable energy is to hedge against rising natural gas costs. If natural gas costs do rise, that could tip the balance of the economics and make solar power more favorable in select cases.

As an example of what electricity prices could look like going forward, ANTARES applied natural gas escalation rates to the price of electricity over the 25-year lifetime of the project. Electricity prices are tied to natural gas rates so this analysis provides insight into future power costs. Natural gas rates were sourced from the Department of Energy's Building Life-Cycle Cost (BLCC) program. Using region-specific natural gas escalation rates from BLCC, the current $0.05/kWh cost of electricity is expected to escalate to $0.08/kWh after 25 years, which is competitive with select cases of the solar analysis.

It is also important to point out that PV installation costs have been declining significantly in recent years, and the downward trend is expected to continue in the near future. For example, from 2008-2012 median installed costs for commercial PV systems greater than 100 kW in the U.S. decreased by about 40% (Exhibit 56). Utility scale system costs have been declining even more rapidly, with a 45% decrease in just the last two years (from the first quarter of 2011 to the first quarter of 2013), as shown in Exhibit 57.[31] Since it is expected that prices will continue to drop, albeit likely at a slower rate than recent years, it may be prudent for GRIC to wait for costs to decline further before pursuing a project. However, the ultimate decision for PV project development should weigh the potential economic benefits associated with a reduced system cost against the current availability of incentives, relatively

[31] Similar data for non-residential systems from the same source showed a decrease of 24% in installed prices during that period.

low interest rates for financing, and obtaining other project benefits such as electric rate stability, job creation, reduced emissions and environmental benefits in the near term.

Exhibit 56. Residential and Commercial Installed PV System Price Trends

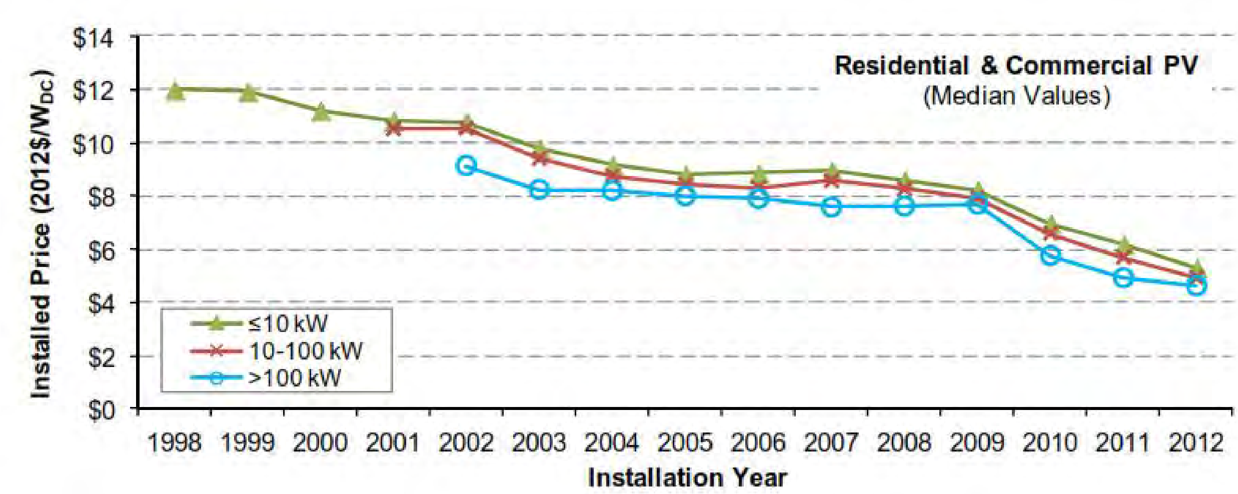


Image Source: (Lawrence Berkeley National Laboratory, 2013)

Exhibit 57. Average Installed Price for PV Systems in the US

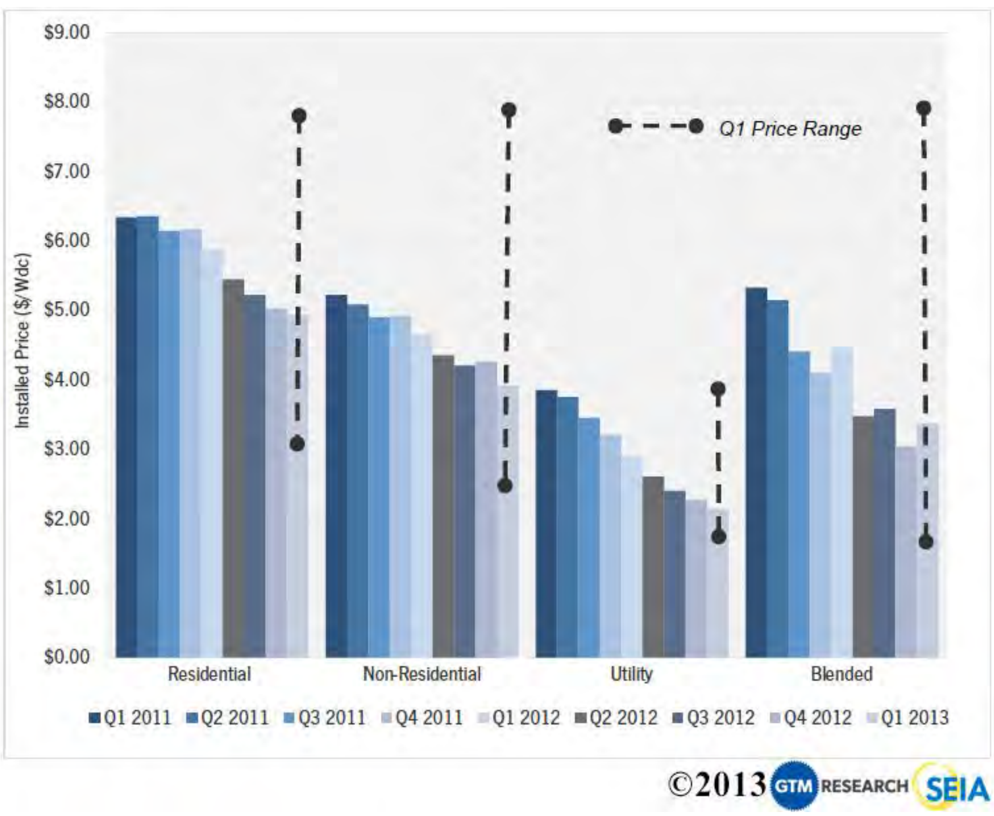


Image Source: (Solar Energy Industries Association, 2013)

7 Conclusions and Recommendations

The project identified multiple potential solar PV applications for the Gila River Indian Community. Four of the best sites were included in the detailed feasibility analysis, two roof areas and two ground areas. The buildings considered for roof mounted projects include the Wild Horse Pass Hotel and Casino and the Tribal Governance Center, while the considered ground areas include the San Tan Brownfield and the area near the Lone Butte Substation. All of these selected sites are on tribally owned facilities and lands, which is expected to be beneficial for meeting GRIC goals. Both of the selected buildings have flat roof area available, and the roofs are relatively new and in good condition. The selected ground areas are level and do not have significant obstructions that would hinder development. They are also fairly close to grid interconnection points.

Exhibit 58 summarizes the key technical and economic results for each PV system analyzed in detail, for the assessment with system degradation is included. All considered roof mounted arrays used ballasted fixed tilt racking systems, with both polycrystalline silicon (p-Si) and thin film Cadmium Telluride (CdTe) modules in different configuration options. The ground mount arrays all used CdTe modules which are less sensitive to high temperatures and reduced output due to panel soiling from dust. These systems differed in other ways, by varying system sizes and racking configurations. Although most arrays used fixed tilt racking, one of the ground mount systems has a single axis (1-X) tracking system to increase system output.

The roof mounted systems all had very similar LCOE results, ranging from \$0.13-\$0.16/kWh without incentives, and \$0.10-\$0.13/kWh with incentives (when system degradation impacts are included). The ground mounted systems all have lower LCOEs than the roof mounted systems, mostly due to the economies of scale benefits of these larger systems that lead to lower per unit installed costs. The LCOE for the ground mounted projects range from \$0.09-\$0.10/kWh without incentives, and \$0.07-\$0.09 with incentives (when system degradation impacts are included). The Lone Butte Substation array with single axis tracking (Option 4B) was found to be the best performing project overall. Although it has the highest per-unit capital costs of the ground mount systems, the performance benefits from the tracking system more than make up for the added costs. In general, the system degradation results in around a 5% reduction in system output over the lifetime of the system, and increases the LCOE values by about \$0.01/kWh relative to the assessment that does not include degradation. Sensitivity analyses showed that the project LCOE results are closely tied to the capital costs and weighted average cost of capital, so reductions in either parameter would have a significant impact on the overall economics. The projects are also fairly sensitive to solar radiation, and only somewhat sensitive to O&M costs.

Exhibit 58. Summary of Results for Considered PV Systems

Option	System Location / Description	Module Type	System Capacity (kW_{DC})	Estimated Output (kWh/yr) [a]	Base Total Installed Cost [b]	LCOE (constant) No Incentives w/ Degradation $/kWh [c]	LCOE (constant) With Incentives w/ Degradation $/kWh [c]
Roof Mounted Systems							
1A	Tribal Governance Center	p-Si	491	898,398	$1,469,018	$0.131	$0.102
1B	Tribal Governance Center	CdTe	458	863,142	$1,415,407	$0.133	$0.104
2A	WHP Hotel & Casino	p-Si	437	815,520	$1,308,052	$0.129	$0.101
2B	WHP Hotel & Casino	CdTe	450	850,889	$1,392,132	$0.133	$0.104
Ground Mounted Systems							
3A	San Tan Brownfield	CdTe	1,109	2,276,318	$2,909,946	$0.106	$0.084
3B	San Tan Brownfield	CdTe	5,544	11,381,592	$13,551,874	$0.099	$0.079
4A	Lone Butte Substation	CdTe	5,544	11,381,592	$13,551,874	$0.091	$0.073
4B	Lone Butte Substation (1-X)	CdTe	5,638	14,533,073	$15,130,402	$0.088	$0.070

Notes: (a) First year performance results, does not include system degradation impacts. (b) Total Installed Cost includes the base system cost and the extended inverter warranty. It does not include any incentives. (c) LCOE includes all considered costs and benefits throughout the 25-year economic life of the system. The LCOE results presented here do include the impact of system degradation over time (0.5% per year for arrays with silicon modules, and 0.7% per year for arrays with CdTe modules).

The LCOE analysis results showed that all of the projects are more expensive than the current price of the energy component of the electricity, which is around $0.05/kWh. However, there are other benefits to the solar projects and GRIC must decide if those are worth the higher cost of production. One of the goals of an investment in renewable energy is to hedge against rising natural gas costs. If natural gas costs do rise, that could tip the balance of the economics and make solar power more favorable in select cases. As an example of what electricity prices could look like going forward, ANTARES applied natural gas escalation rates to the price of electricity over the 25-year lifetime of the project. Since the GRICUA electricity prices are tied to natural gas rates, this analysis provides insight into future power costs. Over the 25 year project period, the current $0.05/kWh cost of electricity is expected to escalate to $0.08/kWh, which is competitive with select cases of the solar analysis. Given this result and the fact that PV capital costs are declining, the PV systems could be a prudent investment. The tribe may also be eligible for federal grants or loan guarantees that could further improve the economic outlook for a PV system.

If GRIC is interested in pursuing a project on-site, ANTARES would recommend installing a large (5 MW) ground mount array with a single axis tracking system such as Option 4B, based on the financial analysis results. Although the tracking system adds complexity and additional maintenance requirements, the additional performance benefits more than make up for the added cost. However, if a simpler system was required, a large fixed tilt ground mount system could also be beneficial. Although the roof mounted systems would have a somewhat higher LCOE rate, these systems may have other benefits that would be attractive to GRIC such as being able to directly offset electricity consumption at the site, and possibly higher visibility by site staff and tourists for demonstration purposes if an informational kiosk or poster was installed in conjunction with the project. These roof mounted systems also have lower upfront capital costs as they are smaller than the considered ground mount projects.

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Biomass Energy Feasibility Assessment

Final Report

October 29, 2013

Prepared for: Gila River Indian Community

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Table of Contents

TABLE OF EXHIBITS

ACRONYM LIST

ACC	Arizona Corporation Commission
AD	Anaerobic Digestion
ANTARES	ANTARES Group Inc.
AQMP	Air Quality Management Plan
ASU	Arizona State University
BACT	Best Available Control Technology
BIA	Bureau of Indian Affairs
BTU	British thermal unit
C&D	Construction and demolition
CFR	Code of Federal Regulations
CHP	Combined Heat and Power
DEQ	Department of Environmental Quality
DOE	Department of Energy
EPA	Environmental Protection Agency
ESCO	Energy Savings Company
ESP	Electrostatic Precipitator
ESPC	Energy Savings Performance Contract
FEMP	Federal Energy Management Program
GHG	Greenhouse Gas
GIS	Geographic Information Systems
GRIC	Gila River Indian Community
GRICUA	Gila River Indian Community Utility Authority
HAP	Hazardous Air Pollutant
HHV	Higher Heating Value
HR	Hour
IB MACT	Industrial Boiler Maximum Available Control Technology
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ITC	Investment Tax Credit
KPPH	Thousand Pounds per Hour
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelized Cost of Electricity
LHV	Lower Heating Value
MACRS	Modified Accelerated Cost Recovery System
MGD	million gallons per day
MMBtu	million Btu (British thermal unit)
MSW	Municipal Solid Waste
MW	Megawatt
MWh	Megawatt-hours

NO_X	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
ORC	Organic Rankine cycle
OSB	Oriented strand board
PM	Particulate Mater
PSD	Prevention of Significant Deterioration
psia	Pounds per Square Inch Absolute
psig	Pounds per Square Inch Gauge
PTE	potential to emit
REC	Renewable Energy Certificate
RES	Renewable Energy Standard
RPS	Renewable Portfolio Standard
SCIP	San Carlos Irrigation Project
USC	United States Code
USGS	U.S. Geological Survey
VOC	Volatile Organic Compound
WACC	Weighted Average Cost of Capital
WWT	Waste Water Treatment
WWTP	Waste Water Treatment Plant
YR	Year

1 EXECUTIVE SUMMARY

Introduction

The Gila River Indian Community (GRIC or the Community) contracted the ANTARES Group, Inc. ("ANTARES") to prepare a biomass resource assessment study and evaluate the feasibility of a bioenergy project on Community land. A biomass project could provide a number of benefits to the Community in terms of increased employment, environmental benefits from renewable energy generation and usage, and increased energy self-sufficiency.

The study addresses a number of facets of a biomass project's overall feasibility, including:

- Resource analysis and costs
- Identification of potential bioenergy projects
- Technical and economic (levelized cost of energy) modeling for selected project configuration

ANTARES previously provided GRIC with a technical characterization report which provided information about a range of biomass technology and configuration options. Commercially available biomass technologies were screened to identify the ones that could be economically viable for GRIC in the near term. This report builds on the knowledge in the technical characterization report, by taking the technical solutions deemed to have potential and applying them to specific project locations identified through site visits and discussions with the GRIC representatives. ANTARES also completed a complementary *Solar Energy Feasibility Study*, which considered the feasibility of solar energy projects on GRIC lands and facilities and was submitted concurrently with this report.

Biomass Resource Assessment and Supply

There are three key components of the biomass supply available to a potential end user in the Community:

- Clean, untreated urban wood waste from the larger Phoenix metropolitan area
- Byproducts from the processing of guayule into natural rubber
- Saltcedar from expansion of riparian area restoration

Each of these potential resources were evaluated in this study. The urban resource assessment identified a number of potential future suppliers of biomass fuels, including several aggregators that recover wood from urban activities. However, only one of these aggregators, No-Waste Grindings, expressed interest in being a potential supplier. They are estimated to have the capacity to supply up to 20,000 tons of wood chips per year. It is important to note that special permission would be needed to bring this material on tribal land, since there is a tribal ordinance that restricts waste products from being brought into the Community.

Another potential fuel stream is guayule bagasse from Yulex, which is the residual by-product of a natural rubber production process. The Yulex production facility is located on GRIC land within the Lone Butte Industrial Park. It was estimated that approximately 5,000 tons of guayule material could be available for a bioenergy project annually.

The study also evaluated the quantity of biomass materials that could be generated as part of a riparian restoration program to remove saltcedar (e.g. Tamarix), an invasive species that has infested some areas of the Community, particularly around the Gila River in the northwestern area of the GRIC land. A GIS analysis was used to determine the acreage and associated estimate of the quantity of saltcedar that could potentially be recovered and used for a bioenergy project. This assessment identified about 17,500 acres of infested area in District 6 and 7, about a third of which is densely infested. The amount of saltcedar that could be collected annually depends on the treatment program, which in turn depends on budget priorities. The saltcedar removal and subsequent land restoration process is a time intensive, multi-year effort which would be quite costly, as experienced by GRICs efforts to date. For reference, the overall cost to treat and fully restore heavily infested areas can be $15,000 to $20,000 per acre, based on GRIC's efforts to date and experience from other riparian restoration programs. It is estimated that only about 5 to 10 tons of saltcedar could be obtained per acre of land in the densely infested areas. Due to these extensive costs and relatively small annual biomass supply that would likely be generated by a riparian restoration project, this potential fuel supply stream was not included in the bioenergy assessment. Although it would not be economical for bioenergy production, removal of saltcedar from the infested areas could certainly benefit the local environment if riparian restoration funding could be secured from an alternative source. The recovered saltcedar material could then potentially be used for firewood or another other end product.

Technical Feasibility Analysis

A number of different potential bioenergy projects and configurations were considered for GRIC, but only one project configuration was selected for detailed analysis – a biomass power plant. Although cogeneration or combined heat and power (CHP) systems tend to be more economical for small bioenergy project, no suitable thermal end users were identified that could take advantage of the useful heat energy generated by a CHP system. There are several facilities that appear to have large and consistent process thermal energy loads in the Lone Butte Industrial Park, including cement brick and vermiculite manufacturers, but these processes have very high temperature requirements (1000-1500 °F), which exceed the capabilities of a typical biomass boiler project that would usually rely on steam to provide process heat. While such loads could be met with a gasification project or hybrid system, there are a number of technical and economic challenges that would be difficult to overcome. A biomass heating and cooling project was also considered for the Cultural Resource Center, which is one of the larger tribally owned buildings. However, a high level analysis of such a project (provided in Section 3.2.2 of the report) showed that would not likely be any net energy cost savings for the project. As such, this type of project was not deemed feasible at this time.

Instead, the detailed technical analysis considered a biomass power plant at the Lone Butte Industrial Park, sized to utilize all of the likely available biomass fuel supply. A biomass power project would help to meet some of the GRIC project goals to develop renewable energy project that benefits the Community and provides a long term stable energy supply. It is assumed that the facility would be located at or near the Yulex facility, as they would provide a portion of the biomass feedstock from guayule residues. The rest of the feedstock would come from wood chips from recovered urban wood waste.

The selected power plant configuration uses a high pressure boiler to generate steam that will be expanded in a condensing steam turbine. Based on the available biomass feedstock supply, a 1,000 horse-power (hp) boiler was selected, which will operate at 425 pounds per square inch gauge (psig), and the condenser will operate at 2 pounds per square inch absolute (psia). This system was modeled using Thermoflex, a commercially available heat and mass balance software package, in order to evaluate expected performance. The key results from this analysis are provided in Exhibit 1. The overall system efficiency is fairly low (14.4%), which is typical for a power-only, small-scale biomass power project. Because of resource limitations, this project is much smaller than most stand-alone biomass power plants, which typically start at 25 MW and may consume 300,000 tons of fuel per year or more. Bigger plants with larger generating capacities are generally more economic, as they obtain economies of scale that help to reduce the per-unit installation and operating costs.

Exhibit 1. Biomass Power Project Performance Summary

Output Description	Quantity
Boiler fuel input rate (tons/hr)	6.25
Steam flow output rate (kpph)	31.25
Gross Power (kW)	2,010
Net Power (kW)	1,757
Annual Net Energy Output (MWh)	14,056
Annual Biomass Fuel Input (tons/yr)	20,000 (clean wood chips) 5,000 (guayule bagasse)
Net Heat Rate, HHV (Btu/kWh)	23,676
Net Electric Efficiency (HHV)	14.4%

Electricity generated from the considered biomass project on Community land could be connected directly to the GRICUA distribution lines and used to serve the GRICUA customers. This is the primary arrangement considered in this analysis, it is expected that a direct connection to the GRICUA would be most beneficial to the Community. If the biomass system was located at the Lone Butte Industrial park, it could supply a number of the park tenants.

Project ownership and potential partnerships are another important consideration for project development. Although a renewable energy project at GRIC could have a number of different partner and ownership structures, GRIC has stated that they would prefer to have a tribal entity own the project. However, a partnership scenario could bring some benefits in terms of up front project funding and availability of federal tax incentives. There are a few potential alternatives that may present a way for GRIC to maintain ownership and control of the project while benefiting from the tax incentives. One of these options is a "pass through lease," in which a tax equity investor (such as a financial institution) would be the lessee, and would make rent payments to the tribe in exchange for benefiting from the investment tax credit. Another possible option would be to have a tax equity investor that is a partner rather than a lessee. In this case GRIC would both own and operate the project while taking advantage of the tax benefits through the participation of a passive investor.

Economic Analysis and LCOE Results

A levelized cost of electricity (LCOE) analysis was performed for the biomass power plant in order to evaluate the cost-effectiveness of the project. The LCOE provides the average cost of power over the lifetime of the project, and is useful in gauging the cost of producing electricity and comparing it to the electric production costs for other technologies and utility supplied power. Inputs to the LCOE calculation include system output (kWh generated), capital costs, O&M and fuel costs, financing assumptions, and any applicable incentives.

Both current and constant LCOE figures are calculated in the analysis.[1] Key financial input variables include a 25 year project lifetime, a long term general inflation of 2%, and a weighted average cost of capital of 6.6%.[2] The LCOE analysis was performed in two ways; the base analysis (Case 1) does not include any incentives, and an alternate analysis (Case 2) includes all potentially available incentives that could apply to a biomass power project developed with a partner. The evaluation with incentives assumes there is a project partner with a tax burden that can take

[1] The current LCOE includes the rate of inflation, while the constant LCOE does not.
[2] The long term general inflation rate is based on current target set by the Federal Reserve. The weighted average cost of capital is based on the average rate used for the U.S. Energy Information Administration's Annual Energy Outlook 2013.

advantage of the tax credits and depreciation benefits. The incentives included in the Case 2 assessment are the Federal Investment Tax Credit (equivalent to a 30% upfront capital cost reduction benefit)[3], and MACRS (Modified Accelerated Cost Recovery System) accelerated depreciation. In addition, the value for Renewable Energy Certificates (RECs) that could be sold to help support the project are considered for the Case 2 assessment.

Exhibit 2 summarizes the key inputs and results of the economic analysis. It is important to note that only first year costs for O&M and RECs are shown in the table (since they do not include inflation or escalation). The value of the incentives for the Case 2 analysis is also shown in this table. The incentives provide a roughly $0.02/kWh overall benefit for the systems. However, the results show that the electricity provided by a biomass power project would be much more expensive than the current electric commodity costs, which is around $0.05/kWh, regardless of whether incentives are included.

Exhibit 2. Summary of Inputs for Biomass Power Project

	Case 1 No Incentives	Case 2 With Incentives
Key Economic Inputs		
System Capacity, gross (kW)	2,010	2,010
Net Electricity Generation (MWh/yr)	14,056	14,056
Base Capital Cost ($)	$14,967,000	$14,967,000
ITC Value ($)	-	$4,490,000
Net Installed Cost ($)	$14,967,000	$10,476,900
Annual Non-Fuel O&M Costs ($/yr)	$1,213,746	$1,213,746
Annual Biomass Feedstock Cost ($/yr)	$1,105,000	$1,105,000
Annual REC Value ($/yr)	-	$28,112
LCOE Results		
Current LCOE ($/kWh)	$0.284	$0.264
Constant LCOE ($/kWh)	$0.235	$0.216

Sensitivity analyses were performed to address uncertainties in specified cost parameters and evaluate the affect that varying these values will have on the overall project economics. The results of this analysis showed that the LCOE is most sensitive to capital costs and biomass fuel cost, such that a 5% change in of these factors results in a 2% change in the LCOE. The economics are somewhat less sensitive to the WACC, as a 5% change in this value results in 1% change in the LCOE. Nevertheless, even with a 50% reduction in fuel costs or capital costs, the constant LCOE is still around $0.20/kWh for Case 1.

There are a number of factors that lead to the poor economic results for the biomass power project. The first is that a power-only project has a fairly low fuel to electricity conversion efficiency. Although the overall energy conversion efficiency could be greatly improved with a cogeneration project that is able to recover and use heat that would otherwise be rejected, no good opportunities to utilize recovered thermal energy were identified in this study. Another reason for the high LCOE is the relatively small size of the system. Larger biomass systems benefit from

[3] Note that the ITC benefit for biomass power projects is set to expire on December 31, 2013. However, it was included in this alternative analysis anyway, in order to evaluate the benefit it could have on a project in case the incentive is extended or renewed in the future.

economies of scale and are able to drive down the cost of electricity. Since this project was constrained by feedstock availability, it is not able to take advantage of economies of scale. High feedstock costs is another factor that increases the LCOE values. Based on ANTARES experience, most biomass projects seek fuel at a cost of $30/ton or less. The average estimated fuel cost for the GRIC biomass power project is $44.2/ton, which is equivalent to $3.29/MMBtu for the considered fuel types. For comparison, the average 2012 natural gas prices in Arizona for industrial customers was about $5.70/MMBtu.[4] Although these per-unit biomass costs are lower than the natural gas prices, the $2.41/MMBtu price difference does not leave a lot of room for the differences in conversion efficiency or the additional capital and operating costs required for a biomass facility. The availability of incentives that would help drive down the project costs, of finding a source of cheaper opportunity feedstocks could help make the project more attractive in the future. However, it is unlikely that the LCOE for such a project will ever be competitive with the current electric costs.

Conclusions and Recommendations

The resource analysis identified a limited supply of low cost biomass fuel in the GRIC area. The most likely sources of fuel are clean wood chips from urban wood waste recovery activities, and guayule bagasse residues. Combined, these resources are estimated to be able to provide up to about 25,000 tons of biomass per year, at a relatively high delivered cost of around $45/ton. Due to the high cost and low yield from saltcedar remediation activities, riparian area restoration would not be feasible as a source for biomass fuel. However, removal of saltcedar from the infested areas could certainly benefit the local environment if riparian restoration funding could be secured from an alternative source. This activity would also provide community jobs and wildlife habitat benefits.

The technical analysis considered a biomass boiler system with a 2 MW steam turbine to generate electricity. It was assumed that the facility would be located in the Lone Butte Industrial Park, near the Yulex facility where the guayule is processed. The considered system would generate around 14,056 MWh of electricity per year, with a fairly low overall system efficiency (14.4%), as is typical for a power-only project. A number of technical and economic challenges were identified for the project. Guayule was found to be a potentially problematic boiler fuel in terms of alkali and ash content, although using only a portion of this fuel mixed with clean wood chips could mitigate the negative effects somewhat. However, mixing these different fuel streams may require separate feedstock processing and handling systems which would add further expense to the installation costs that were not included in this assessment. Furthermore, air emissions for a facility of this size may trigger Title V permitting requirements unless a fluidized bed boiler is used which would add more expense.

The economic analysis showed that at current prices, biomass power project will not be cost effective as the LCOE is much higher than current (or projected future) energy costs, even without the potential added capital costs that may be necessary as noted above. The LCOE results were also much higher than for the solar PV projects considered in the complimentary *Solar Energy Feasibility Study* report submitted separately to GRIC. Furthermore, a biomass project is a lot more complicated and has a lot more risk than a solar PV project in terms of operations, fuel supply availability and cost, and other potential unforeseen costs. Although a biomass project would provide more new jobs that would benefit the Community, if a renewable energy project is pursued on-site a solar PV project seems to be a better choice overall.

[4] Energy Information Administration Natural Gas price data from (EIA 2013).

2 BIOMASS SUPPLY LOGISTICS AND PLANNING

2.1 OVERVIEW OF KEY ELEMENTS OF BIOMASS SUPPLY CHAIN

There are three key components of the biomass supply available to a potential end user in the Community:

- Clean, untreated urban wood waste from the larger metropolitan area
- Byproducts from the processing of guayule into natural rubber
- Saltcedar from expansion of riparian area restoration

A high level characterization and assessment of these resources was provided previously in the *Renewable Energy Technical Characterization* report. This report chapter provides details regarding the planning and logistics associated with providing a reliable biomass fuel supply from one or a combination of these three sources. In particular, this chapter discusses how saltcedar removed from riparian areas could make up a higher cost component of a biomass fuel supply and partially subsidize riparian area restoration efforts. Separate chapter subsections discuss fuel quality considerations and issues with fuel procurement including contracting, receiving and storage and quality control.

2.2 URBAN BIOMASS

This section provides information on key suppliers of urban biomass. There are currently three large aggregators within reasonable proximity to GRIC: No-Waste Grindings, Gro-Well (Green Organics Recycling), and Yulex. Available information about these potential suppliers is summarized below, including data from interviews and site visits with Yulex and No-Waste Grindings. It is important to note that special permission would be needed to bring this material on tribal land, since there is a tribal ordinance that restricts waste products from being brought into the Community.

YULEX

Yulex Corporation processes locally grown guayule into biomaterials such as rubber and resin at its facility in the Lone Butte Industrial Park in Chandler, Arizona. Guayule is a flowering shrub in the aster family, native to the Southwest, which is grown as a perennial crop along the Gila River and at other locations within a 50 mile radius of the manufacturing plant. The rubber produced is non-allergenic, as opposed to latex, and has many end uses.

There are three potential biomass feedstock streams from guayule: the entire shrub[5], bagasse, and leaves and stems. Of these, guayule bagasse (a finely ground material that remains after the rubber material is extracted) is the most attractive for bioenergy usage, as it is already cleaned and processed. It would not be economical to utilize the entire shrub as a biomass feedstock, as Yulex grows these plants specifically for producing rubber. Furthermore, the leaves and stems would require additional processing to make them suitable for a fuel stream, and would have a higher ash content that makes it challenging to use as a fuel source.

The manufacturing facility currently operates one shift per day, five days per week (Monday through Friday). They are planning to increase production by 2015, by operating two shifts per day. Since very little weight is lost during the extraction process, the amount of bagasse generated is essentially equivalent to the quantity of material processed. The facility currently generates about 15-25 tons of guayule bagasse per day, for a single shift operation. Therefore, the total

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[5] Above ground woody materials, including stems, leaves, and bark.

annual biomass production is approximately 5,000 tons per year. Adding a second shift would increase biomass production to approximately 10,000 tons per year.

The bagasse has a fairly high moisture content of about 50% (by weight) after the processing step. However, it also has a fairly high heating value of about 8,500-10,000 Btu/lb on a dry basis (HHV). There is no issue with ash content of the bagasse; most of the ash from analyzed samples is a result of dirt that is mixed in with the guayule during harvest. During the site visit, ANTARES took samples of the bagasse and sent to Hazen for analysis (results are provided in Section 2.4).

Currently, most of the bagasse material is used as a composted soil amendment and weed inhibitor, which is applied to the Yulex guayule plots in the nearby area. Leaves, branches, and other residual materials from the plant are combined with the bagasse waste stream to generate this compost. Yulex places a value of $100/ton on the bagasse as a soil amendment, calculated as avoided cost for purchasing equivalent amendments and herbicides or mulch. Yulex has also experimented with making a particle board type of material with the bagasse, and has found it is capable of producing a termite resistant, high-value product.

Since a bioenergy project could not compete with these prices for higher-value products, this assessment only considers utilizing the additional bagasse material that will be available when Yulex increases production by changing to a 2-shift operation in 2014. It is assumed that doubling operational time will also double the amount of material process and the associated bagasse, thereby resulting in 5,000 tons per year of material available for a bioenergy project. The price associated with this fuel stream is estimated to be similar to other urban fuel materials. Potential biomass projects to be developed in partnership with Yulex are discussed in more detail in Section 3.2.

NO-WASTE GRINDINGS

No-Waste Grindings is one of the key potential suppliers for clean wood waste generated from urban-sources such as recycled pallets, clean construction and demolition, and other wood scrap materials. ANTARES staff visited the No Waste Grinding southern facility and met with Lee Craig during the site visit in July 2013. The facility currently collects biomass material from a number of small companies throughout the Phoenix area.

The company currently produces about 75,000-80,000 cubic yards of wood chip material per year (equivalent to about 17,500-20,000 tons per year). The wood is very dry, typically around 10% moisture content or less (by weight). Much of this material is used as horse bedding, which has very strict requirements to be clean and free of debris. Some of the wood chip material also used for playground material and mulch. The company also sells chips sporadically to Garrick, which supplies material to the biomass facility at the Frito Lay plant located in Casa Grande, Arizona.[6] Mr. Craig stated that the company would prefer to sell to one large customer with requirements that are not as strict, and they were definitely interesting in being considered as a potential supplier. No Waste Grindings produces wood chips that are 3” and 2” minus, although different sizes could potentially be generated as needed. A magnet is used to remove metals, and material can also be screened if needed.

A cost estimate for the wood chips is about $9-$11/cubic yard, which is equivalent to about $36 to $44/ton, for material picked up at the facility. For delivered materials, loading and unloading and transporting the wood materials would add additional cost. Total transportation charges are generally done by the hour.[7] The total transportation cost to the Lone

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[6] The Frito Lay plant has a biomass plant that is used to generate energy for the production facility. The plant has a fairly high biomass consumption rate, using approximately 60,000 lb/hr of wood.

[7] For example, trucking costs are estimated to be around $125/hour. A standard tractor trailer can holds around 20-25 tons of wood chips.

Butte Industrial Park is estimated to be $4/ton, as it is very close to the No-Waste Grindings facility. This would result in a total delivered cost of the material of about $44/ton to this location.

No-Waste Grindings is willing to sign a long term contract, and does not have any specific contract requirements. They currently use container trailers for transport, but would be willing to get a walking floor trailer if it would have lots of use for new customer with large demand.

OTHER POTENTIAL SUPPLIERS

A few other large urban wood waste collectors were identified as potential suppliers, including Garrick and Gro-Well. However, neither company responded to ANTARES repeated attempts to contact them for additional information, so their interest in supplying wood waste for a bioenergy project at GRIC is unknown. Nevertheless, an overview of the information collected from public resources is provided below for reference.

The City of Phoenix states that one million tons of solid waste goes to the city's landfill located on SR85 each year, with 50% from residences. This amount is equivalent to approximately one ton of garbage per resident per year, although it does not include refuse taken to private landfills or other cities within the Phoenix metropolitan area (City of Phoenix 2013). A 2003 waste characterization study of single-family residential waste quantified the composition of the city's refuse in great detail (Cascadia Consulting Group, Inc. 2003). The study concluded that 28.1% was compostable yard waste, such as leaves and prunings, while 7.3% was construction and demolition wastes (1.8% of which is dimensional lumber, crates and boxes, pallets, or other untreated wood). Compostable yard waste is estimated to be 122,258 tons annually, while construction and demolition (C&D) waste is estimated to be 31,614 tons annually, of which 7,835 tons is untreated wood, (including dimensional lumber, crates and boxes, pallets, or other untreated wood), 1,787 tons is treated wood, and 2,570 tons is contaminated wood.

Currently, green waste from the city of Phoenix is managed by Gro-Well /Green Organics Recycling, which operates a mulching processing plant on 20 acres of city-owned land. Gro-Well also contracts with the Salt River Pima Maricopa Indian Landfill, which collects approximately 40,000 tons a year of green waste. Rich Allen at the Salt River Landfill stated that to his knowledge, Gro-Well is always looking for new off-takers of processed biomass, especially since the Snowflake biomass power plant closed in March 2013 (Worth 2013). The 24 MW Snowflake plant opened in 2008 and is located 180 miles northeast of Phoenix; it previously supplied power to the now-closed Catalyst Paper Mill.

There are a large number of municipal and private landfills in the Phoenix area managed by Waste Management; the company collects green waste from the company's landfills and transfer stations. In partnership with Garrick LLC,[8] this waste is processed into at the Maricopa Organics Recycling Facility, located at the Sierra Estrella Landfill. The processed biomass material is primarily sold to Frito-Lay to run its Casa Grande facility, although mulch and compost is also produced for local use (Garick 2012).

Many of the smaller municipalities are not currently segregating wood waste and green organics materials, although they have done so in the past. Some, such as Glendale, stopped collecting this material due to budget issues. Ernie Reese, the acting Superintendent of the Glendale Landfill, stated that the city would likely be interested if a future opportunity arose for the city to generate revenue from wood waste while also keeping the waste out of the landfill. Tucson's Los Reales landfill also ceased segregation of green wood waste, which was used by the city for mulch; this waste is now incorporated into the landfill, which they find to be beneficial for the landfill.

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[8] Waste Management Inc. purchased a majority interest in Garrick LLC in 2010.

2.2.1 Feasibility of Expansion of Separation of Clean Wood From C&D and MSW Streams

While the technical feasibility of separating clean wood fuel from the construction & demolition (C&D) and municipal solid waste (MSW) streams has been demonstrated to work successfully for other biomass projects, there are several significant hurdles that must be overcome during project development, financial due diligence and engineering phases. These could affect the overall feasibility of development or alter the capacity (due to changes in fuel supply suitability) or costs of environmental controls and operation of the facility.

No-Waste Grindings, the major potential supplier, can likely guarantee that its existing supply is suitable for use as a fuel. It also can expand production by increasing recovery efforts. However, an additional waste characterization will be required to verify that the sources of wood waste do not contain excessive quantities of treated wood, plastics or other inorganic materials. The U.S. EPA released new guidance for the use of C&D wood that suggests that C&D wood fuels meet the criteria for exemption from more strict emissions requirements under revised Boiler MACT regulations (Environmental Protection Agency 2012, 312). However, the same guidance specifies that C&D wood fuel must be produced using best practices as part of a comprehensive collection system. This leaves room for local interpretation of what the acceptable quantity of contaminants in a fuel wood supply is. Some of the common concerns regarding air emissions associated with combustion of C&D wood waste include emissions of non-metal hydrocarbons and metals. Often, best practices dictate 1 percent or less contamination of fuel supplies with inorganic materials, treated wood, or other post-consumer wastes to reduce some of these concerns but that value differs from application to application.

The project may also need to meet other requirements depending on the level of contaminants present in the fuels, if the project is seeking to meet state renewable energy requirements and/or obtain financial incentives from the sale of RECs. Wood fuel processing, quality and testing requirements are often developed on a case-by-case basis with regulators and third-party bodies that certify power from renewable energy projects as eligible for RECs. GRIC has its own legal definition of hazardous waste that should be used to ensure any biomass material used for fuel is not characterized as a hazardous substance. If the project intends to sell any RECs into the Arizona state market, the requirements under Arizona's Renewable Energy Standard (RES) must be met.[9]

Therefore, while the perception that production of biomass fuel may result in relaxed fuel quality standards compared to production of animal bedding and playground ground cover, the reality is that the supply chain management and testing requirements for producing a fuel quality chip and meeting requirements set by GRIC (as well as Arizona's RES and/or third-party certification companies if RECs will be sold into the state or voluntary markets) that may result in increased fuel supply costs.

Outreach and education is required to provide Community leaders and citizens with the information they need to understand what types of fuels will be used and how fuel quality will be maintained to guard against negative environmental consequences of waste wood combustion. This outreach effort can only be done effectively after significant effort has been made to develop fuel quality specification and protocols for the separation of clean, untreated wood waste and monitoring have already been made. This outreach effort could result in opposition to the project that could require significant additional changes to the fuel supply strategy (and project scale) if concerns cannot be met.

[9] For example, for biomass projects the Arizona RES permits the use of non-hazardous plant matter waste material that is segregated from other waste. This may not preclude the presence of some contaminants in the fuel stream, but would limit the use of painted, treated, or pressurized wood, wood contaminated with plastics or metals, tires, or recyclable postconsumer waste paper in fuel streams in biomass generators eligible for compliance with RES standards. (Arizona Corporation Commission 2006)

2.3 SALTCEDAR (TAMARIX SPP.)

Tamarisk species, also known as Saltcedar (*Tamarix ramosissima* and other *Tamarix* species) is an aggressive invasive shrub species that in many areas of the desert southwest, grows in dense stands (as many as 3,000 plants per acre (Tamarisk Coaltion 2012)) and crowds out native riparian species such as willows, cottonwoods, grasses and forbs. There is significant infestation of saltcedar on GRIC lands, particularly near the Gila River in the northwest portion of the Community. Evaluating the removal of this invasive species and utilization of the biomass material for an energy fuel was a key driver for GRIC's interest in undergoing a bioenergy feasibility study. This section of the report describes the process to quantify the potential biomass resource available from saltcedar removals, as well as an indication of costs and procedures necessary for such an effort including the restoration of lands disturbed by the removals.

Establishing a riparian area restoration program is a multi-year process that requires significant stakeholder outreach and education, consensus building, fundraising, vegetation inventory and analysis, adaptive management (i.e., trial and error) and a long-term commitment to site monitoring. The outcome can include the restoration of degraded sites to conditions that function and look like the ecosystems that were displaced long ago. Restored sites can have reduced wildfire risks, support a greater diversity of native plant and animal species and can result in improved water quality.

2.3.1 SALTCEDAR RESOURCE ASSESSMENT

A GIS analysis was performed to determine the acreage, and associated volume/tonnage of saltcedar available to supply a biomass project. During site visits and through consultation with the tribe, ANTARES staff concluded that the primary areas of interest for saltcedar harvest are along the Gila River corridor in the northwest of the Community.

The GIS analysis utilized data from the U.S. Geological Survey, which was downloaded from the Nation Map Seamless Server. This data dates to 2010, and is considered to be the "best available" orthoimagery (geometrically corrected aerial images with uniform scale that can therefore be used for accurate distance measurements) from the USGS. The Spatial Analyst extension of ArcGIS was used to identify the areas within GRIC that are highly infested with saltcedar. The area identified in this analysis is indicated in Exhibit 3 and Exhibit 4. Additional details on the analysis methodology are provided in Appendix A.

Using the assessment above, the total acreage of saltcedar infestation was estimated to be 17,461 acres, located in District 6 and 7 of the GRIC. About one third of that acreage is very densely infested. The geographic focus of resource inventory and treatment should emphasize highly dense saltcedar infestations with a high probability of treatment success, high-value wildlife habitat and high potential for recreational use. An annual inventory program that evaluates and recommends high-priority treatment would evaluate approximately two quarter sections[10], or 320 acres per year. The quarter-quarter[11] section data can be provided to GRIC separately in spreadsheet format as desired. The total annual treatment acreage would need to be determined based on program treatment and budget priorities. This is discussed in light of riparian area treatment costs in the next subsection. Treatment could proceed in conjunction with development of environmental education and recreation opportunities.

[10] A quarter section is an area of one-fourth of a square mile, equivalent to 160 acres.
[11] A quarter-quarter section is a quarter of a quarter section, which is equivalent to 40 acres.

Exhibit 3. Area of Interest of Interest for Saltcedar Harvest and Riparian Restoration

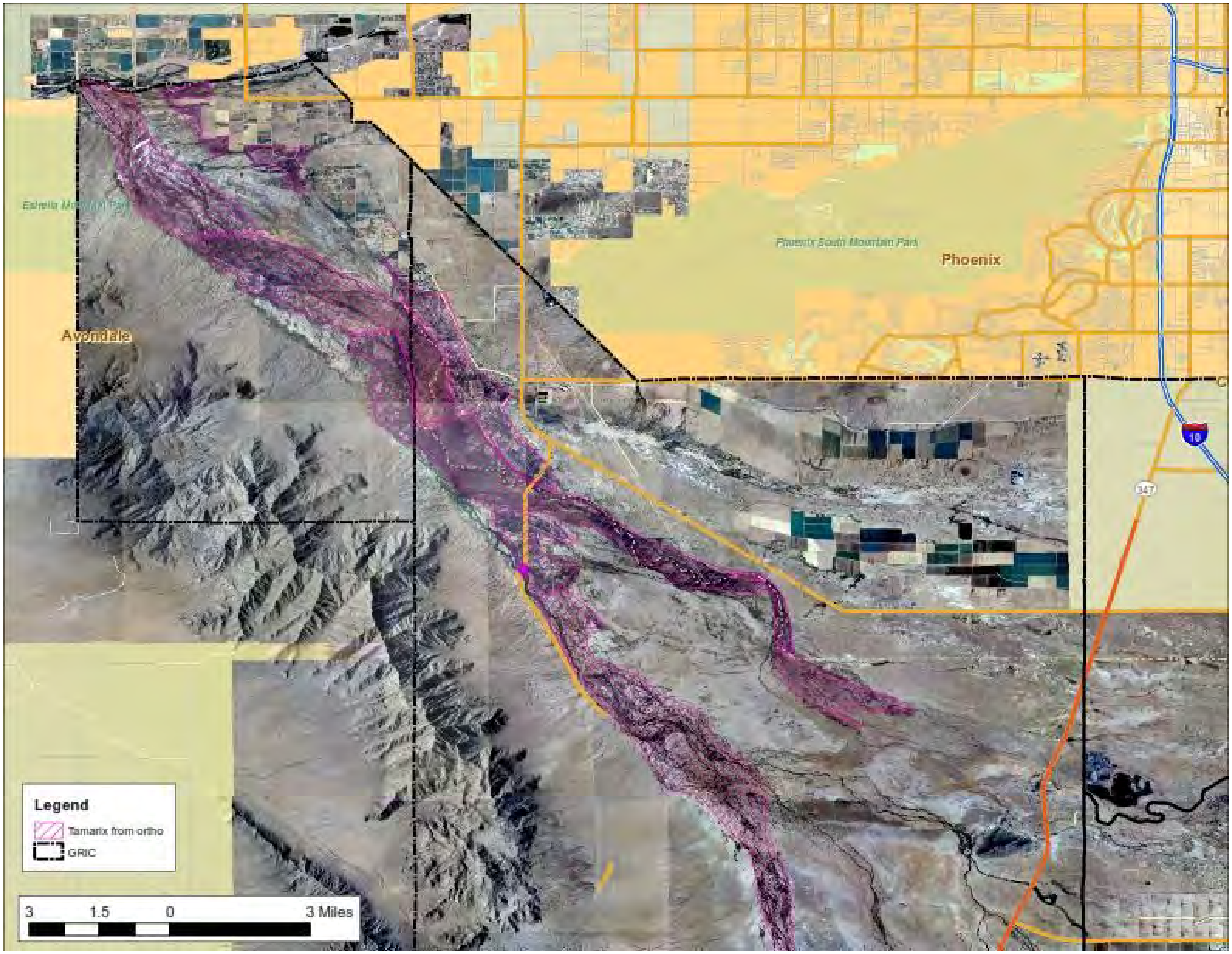
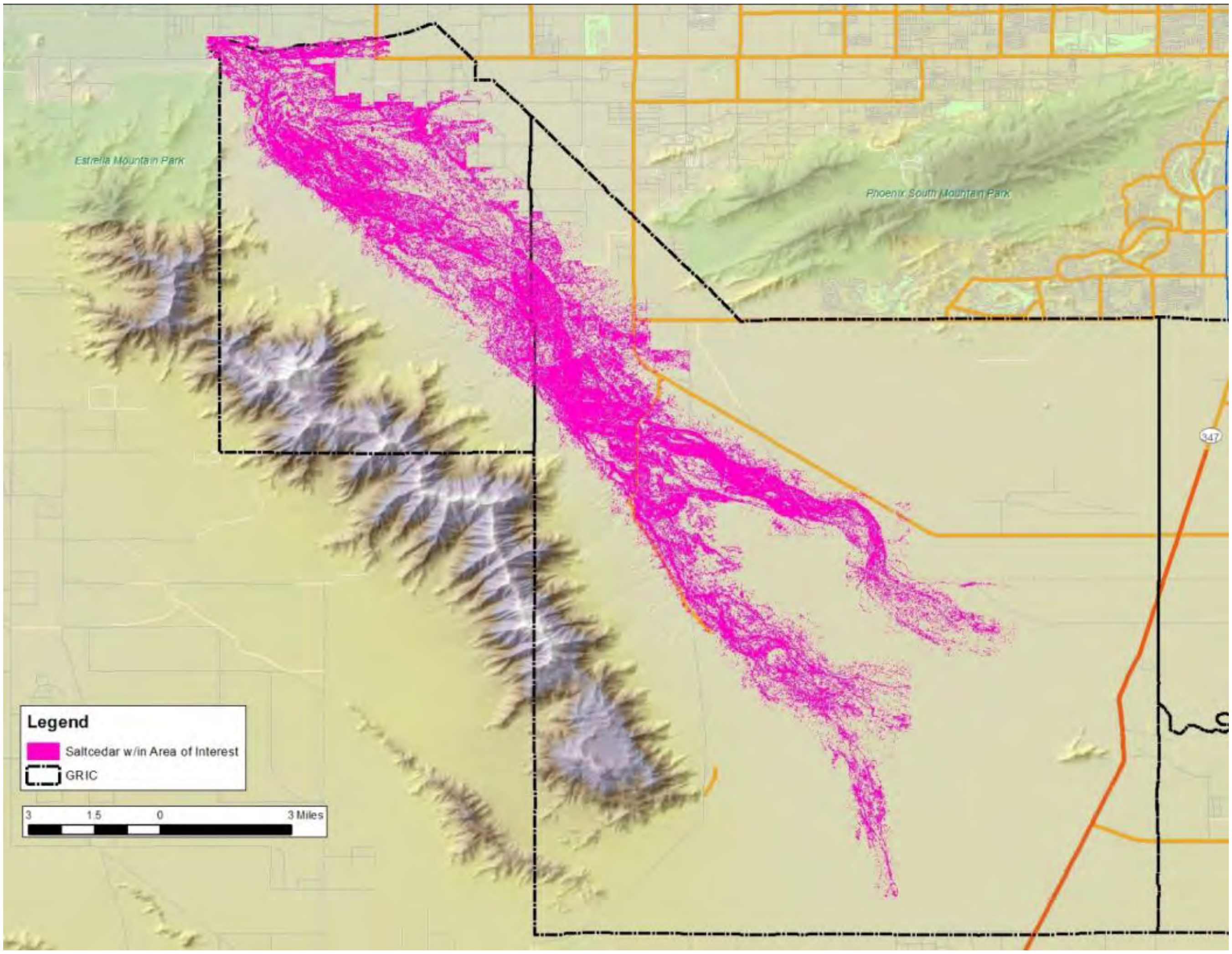


Exhibit 4. Areas of Saltcedar Infestation



The potential for biomass from saltcedar treatment varies extensively from site to site. The range of reported biomass yield values ranges from 4 tons per acre (Sandia National Laboratory 2011) to as high as 15 tons per acre (Nackley Lloyd et al 2012). However, in densely invested riparian areas, saltcedar removal typically provides between 5 and 10 tons of biomass per acre (Duncan 2013).

2.3.2 PROGRAM PLANNING AND RESOURCE REQUIREMENTS

There are up-front capacity building, planning and fundraising tasks associated with building a riparian ecosystem management program. The Department of Environmental Quality (DEQ) Water Quality Program, through the hard work of Charles Enos and his colleagues, has already established field trials for saltcedar removal and revegetation over a number of years. Any future program should build upon those efforts, but will likely require the expansion of staff and financial resources devoted to basic research, planning, fundraising and administration.

The first step is to obtain approval to evaluate the feasibility of program development via the appropriate committees within the Community government. This would most likely require development and approval of a resolution or other approval from the Natural Resources Standing Committee. A program "champion" within the Community must lead the effort. Going into that Community meeting, the program champion will need to clearly define the nature and scope of the problem the program would seek to address and the benefits associated with doing so.

The program champion should have the decision-making clout to represent the program at the relevant committees and ability to direct staff resources and volunteer resource in subsequent steps of program development.

The initial program formation steps would likely have to be done with a limited outlay of Community financial and staff resources and require a significant amount of volunteer effort. An alternative would be to hire a part-time program coordinator with natural resource management and grant-writing experience.

The program champion should convene a steering committee with the objective of establishing high-level program goals and objectives. Exhibit 5 provides a preliminary list of contacts for the program steering committee. Once program goals and objectives are determined, treatment priorities and funding needs can be established and grants and other funding resources can be explored. The overall restoration goals for the Gila River riparian area are likely to require multiple treatment methods; the steering committee should remain open to use of multiple approaches and will need to develop a level of comfort with competing priorities and opinions among steering committee members.

Exhibit 5. Potential Steering Committee Members

Name	Affiliation	Phone	Email
Charles Enos	Environmental Quality	(520) 610-0789	Charles.Enos@gric.nsn.us
Janet Bollman	Environmental Quality	(520) 562-2234	Janet.Bollman@gric.nsn.us
Terrance Evans	Natural Resources Committee	(520) 562-9729	Terrance.Evans@gilariver-nsn.gov
Errol Blackwater	Land & Water Resources	520-562-6003	Errol.Blackwater@ gric.nsn.us
Rusty Lloyd	Tamarisk Coalition	(970) 256-7400	rlloyd@tamariskcoalition.org
Alan Sinclair	BIA Fire Management	(520) 562-3974	
Heather Bateman	ASU Polytechnic Campus, Mesa AZ	(480) 727-1131	heather.l.bateman@asu.edu http://hbateman.faculty.asu.edu/

Examples of high-level program objectives based on the Missouri River Watershed Coalition restoration program include:

- Foster the adoption of innovative conservation approaches to invasive riparian plant management to improve riparian system health and function and enhance natural resources
- Use bioenergy technologies to promote utilization of invasive plant biomass
- Transfer project findings, products and technologies to a broad range of regional stakeholders and promote exchange of information between stakeholders

Based on the costs or riparian restoration and the inherent challenges associated with revegetation in arid climates, it is advisable to conduct an inventory of the most densely infested saltcedar areas and prioritize a subset of parcels that have several key characteristics:

- High value to the Community in terms of use by residents and visitors,
- High likelihood of revegetation success, and
- High potential for restoration of habitat and riparian ecosystem function.

The overall size of the area to be treated would be subject to funding availability. Because the overall cost to treat and fully restore heavily invested areas can be $15,000 to $20,000 per acre, treating approximately 5 to 10 percent of the heavily impacted area using mechanical means, with the potential to increase the overall treatment acreage using less intensive chemical and biological treatment methods, could be a reasonable long-term program goal. An overall annual treatment acreage goal could be 30 acres per year, with a goal of treating 10 percent of highly dense saltcedar impacted areas over a 20 year period. The annual biomass quantity produced from this treatment would range from 90 to 120 tons per year. Per acre treatment costs may also decline as the efficiency of operations increases. The biomass yields from this level of treatment may be significantly lower than if the entire treatable acreage is targeted, but the potential for biomass utilization can still offset treatment costs even on a smaller scale. Total treatment area could be increased using non-mechanical treatment options such as introduction of the saltcedar leaf beetle, although the costs for establishing new vegetation will still be incurred and biological control methods can take multiple years to implement.

There are existing models to guide the development of program goals and objectives, vegetation inventories, site selection protocols and overall saltcedar management plans. Some program resources and templates can be accessed through the resources provided below.

Recommendations:

- Take advantage of relatively low-cost networking and training resources available through organizations such as the Tamarisk Coalition. Start by attending the February 2014 Tamarisk Coalition Conference in Grand Junction, Colorado: http://www.tamariskcoalition.org/announcements/save-date-2014-tamarisk-coalition-conference
- Review other models for sustainably funding long-term riparian management programs such as that prepared for the Colorado River Basin: http://www.tamariskcoalition.org/sites/default/files/files/Sustainable_Funding_Options_for_a_Comprehensive_Riparian_Restoration_Initiative_in_the_Colorado%20River%20Basin_2011.pdf
- Review funding and other resources available through the Riparian Restoration Connection website: http://www.riparianrestorationconnection.com/

2.3.3 Business Model for Saltcedar Eradication Program

The costs for riparian restoration can vary extensively depending on a number of factors, including the density of the saltcedar infestation and the type of revegetation program. The treatment costs shown in Exhibit 6 for field trials ongoing on GRIC land (according to program experience by Charles Enos, DEQ) provide a good indication of what typical restoration costs would be. In the mid- and long-term efficiencies could be gained as experience and knowledge regarding what works and what doesn't is improved. However, at least for the first several years of program implementation, these are reasonable values for riparian area restoration without installation of irrigation equipment. Irrigation installation greatly improves the likelihood of treatment success but can cost an additional $15,000 per acre to install irrigation distribution lines plus $15,000 per project for well installation.

Exhibit 6. Estimated Saltcedar Eradication Costs

COST ESTIMATES for SALTCEDAR REMOVAL and NATIVE PLANT REVEGETATION

Cost estimates base on Gila River Wetlands Revegetation Pilot Project

6/14/2013 ce

Description	*Cost per Tree*	*Cost per Acre*	*Notes*
Saltcedar Extraction & Grinding	*n/a*	*$ 1,775.00*	*depends on density*
Tallpot tree planting (30 ft centers)	*$ 20.00*	*$ 980.00*	*Est. 60% success rate*
Tree Shelter and Supplies	*$ 4.71*	*$ 231.00*	
DriWater tree installation Supplement	*$ 19.70*	*$ 965.00*	
Tree Installation Labor	*$ 73.00*	*$ 3,577.00*	
River Shoreline Revegetation (bulrush, salt brush, saltgrass)	*n/a*	*$ 816.00*	*linear planting area good success rate*
River Shoreline Revegetation Plant installation Labor	*n/a*	*$ 3,030.00*	
	Total Cost per Acre	***$ 11,374.00***	

Source: Charles Enos, GRIC DEQ

Up front capital equipment costs are not a major factor for the Community as major pieces of equipment (excavators, specialized shears, horizontal grinders) are likely to be owned by contractors. Based on the annual treatment acreage expected for the GRIC (even at a high end of 100 acres per year based on funding received by other similar programs through the Natural Resources Conservation Service and other sources), the project cannot financially justify purchasing these pieces of equipment. The above costs are for custom restoration contractors for saltcedar extraction and grinding.

The potential revenues available through the sale of biomass for fuel or other sources (at saltcedar biomass removal rates of 5 to 10 tons per acre, at an artificially high rate of $100 per ton designed to offset treatment costs) would range from $500 to $1,000 per acre, a small amount compared to likely treatment costs. Therefore, sale of biomass for fuel, firewood or other end products should be viewed as a minor factor in considering the scope of riparian area restoration.

2.4 FUEL QUALITY CONSIDERATIONS

2.4.1 Description of Sample Collection and Testing

Saltcedar samples were collected from some of the fairly densely infested areas along the Gila River that were accessible by road. The location is near Laveen, AZ and southwest of the intersection of West Pecos Road and South 51st Avenue. The area has a very dense saltcedar population. Samples were collected from two locations in the area to measure diversity. At each location, samples were collected from three different trees. Older trees were selected and loppers were used to cut the branches. Three to four branch segments approximately 10” long were put into resealable plastic bags and sent to the Hazen Research, Inc. laboratory for compositional testing.

Exhibit 7. Saltcedar growth in the area where samples were collected

In addition, samples of the guayule biomass material were collected from the Yulex manufacturing facility. Two samples were taken from a single bagasse pile, which were also placed into plastic bags and sent to the lab for testing.

2.4.2 Results of Fuels Testing

Samples of guayule and saltcedar were collected and sent to Hazen Research Inc., a professional analytical services company. Hazen performed testing on the samples to determine their content. A summary of the results are shown in Exhibit 8 through Exhibit 10. The full testing reports from Hazen are provided in Appendix B.

Exhibit 8. Lab Test Results for Guayule Samples

	As Received Material			Dried Material		
	Average	Low	High	Average	Low	High
Proximate Analysis						
Moisture	52.76%	48.92%	56.59%	0.00%	0.00%	0.00%
Ash	2.75%	2.58%	2.91%	5.82%	5.70%	5.93%
Volatile	38.14%	35.16%	41.11%	80.75%	80.49%	81.01%
Fixed C	6.37%	5.67%	7.06%	13.44%	13.06%	13.81%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
BTU/lb (HHV)	4,796	4,468	5,123	10,162	10,031	10,292
BTU/lb (LHV)	3,968	3,617	4,319	9,559	9,442	9,676
Ultimate Analysis						
Moisture	52.76%	48.92%	56.59%	0.00%	0.00%	0.00%
Carbon	26.12%	24.10%	28.13%	55.30%	55.07%	55.52%
Hydrogen	3.07%	2.88%	3.25%	6.50%	6.35%	6.64%
Nitrogen	0.29%	0.25%	0.32%	31.79%	0.58%	63.00%
Sulfur	0.07%	0.04%	0.09%	0.13%	0.08%	0.17%
Ash	2.75%	2.58%	2.91%	5.82%	5.70%	5.93%
Oxygen	14.97%	13.56%	16.38%	31.67%	31.25%	32.08%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Chlorine	0.001%	0.068%	0.078%	0.002%	0.152%	0.157%

Exhibit 9. Lab Test Results for Saltcedar Samples

	As Received Material			Dried Material		
	Average	Low	High	Average	Low	High
Proximate Analysis						
Moisture	33.69%	27.98%	45.02%	0.00%	0.00%	0.00%
Ash	6.34%	4.91%	7.31%	9.57%	7.13%	10.65%
Volatile	55.24%	42.98%	62.38%	83.04%	78.16%	87.51%
Fixed C	4.73%	2.00%	7.01%	7.39%	2.81%	12.51%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
BTU/lb (HHV)	5,009	4,162	5,525	7,554	7,443	7,730
BTU/lb (LHV)	4,360	3,435	4,903	7,096	6,982	7,281
Ultimate Analysis						
Moisture	33.69%	27.98%	45.01%	0.00%	0.00%	0.00%
Carbon	30.29%	25.04%	33.06%	45.66%	45.05%	47.15%
Hydrogen	3.27%	2.84%	3.60%	12.43%	4.74%	50.00%
Nitrogen	6.76%	0.25%	39.00%	26.57%	0.37%	62.00%
Sulfur	1.07%	0.67%	1.28%	1.61%	1.22%	1.89%
Ash	6.34%	4.91%	7.31%	9.57%	7.13%	10.65%
Oxygen	25.02%	20.95%	27.02%	37.73%	36.76%	39.26%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Chlorine	0.504%	0.36%	0.67%	0.775%	0.51%	1.21%

Exhibit 10. Additional Saltcedar Analysis for Each Sample Location

Test Name	Location 1	Location 2
Air Dry Loss, %	20.21%	40.42%
Residual Moisture, %	14.63%	7.70%
As Received Moisture, %	31.88%	45.01%
Mercury (Air Dry Basis), mg/kg	< 0.01	< 0.01
Mercury (as Received Basis), mg/kg	< 0.008	< 0.006
Mercury (Dry Basis), mg/kg	< 0.01	< 0.01
Metals in Ash		
Cadmium, mg/kg	9	10
Lead, mg/kg	9	7

In reviewing the test results there are several areas of concern for the use of either of these feedstocks as boiler fuel. Focusing first on the saltcedar, the chlorine and sulfur are above the recommended limits for a biomass boiler. The presence of either one of these components even in small quantities (0.25%-0.5%) can lead to deterioration of the boiler and combustion chamber materials. The chlorine would cause condensing on the boiler surfaces and corrode the boiler tubes. The sulfur would cause corrosion problems and create large SOx emissions.

The major issue for the guayule is the alkali content. While not specifically tested for in this analysis, Yulex provided ANTARES with previous test results which included analysis of the alkali, showing levels ranging from 0.44-2.96 lb/MMBTU. This would exceed the threshold where it becomes problematic in a boiler, 0.4 lbs/MMBTU.

In addition, the ash content is high for both the guayule and the saltcedar. A typical ash content for boiler fuel is 1-2%. The guayule has a high of 2.91% and the saltcedar has a high of 7.31% (both in terms of the as received material). This is higher than desired and would require a combustion chamber with automatic ash extraction in order to handle the volume of ash if these fuels were fired on their own.

Due to its chlorine, sulfur, and ash content, saltcedar would not make an ideal boiler fuel if used on its own. It could potentially be used if mixed as a small percentage with another fuel, such as clean woods chips, however the boiler equipment should be closely monitored for damage. The saltcedar was not considered as a fuel for detailed technical and economic analysis presented in this report.

The guayule was included as a fuel in the detailed analysis, and was estimated to make up 20% of the total annual fuel input by weight. The balance of the fuel stream for the considered project is clean wood chips. Utilizing only a portion of guayule as a boiler fuel should help to negate some of the effects of the high ash and alkali content, although the fuel could still cause problems. The effect of using a fuel with undesirable properties is that it raises the cost of operations and causes interruptions in generation. There may be capital upgrades available, such as use of a different energy conversion technology, which could alleviate the problems stemming from guayule. This would add significantly to the capital costs and there are no guarantees that the fuel would not cause issues. More testing is recommended before proceeding with the saltcedar or guayule as a fuel to ensure that it is compatible with a biomass boiler system or other biomass energy conversion system.

3 PROJECT SITE SELECTION

3.1 SITING CRITERIA

This section provides an overview of key siting criteria for a biomass energy project, as discussed in the *Renewable Energy Technology Assessment* report submitted previously. Potential project locations for GRIC are discussed in the following section, in order to select the preferred opportunities for a detailed assessment.

Site selection for a biomass energy plant is complex and highly site specific since the conversion of biomass fuels to heat, power or both requires a variety of support infrastructure that is simply not required with other renewable energy technologies. Solid fuel systems typically include extensive support infrastructure including fuel receiving and handling systems, fuel storage, energy conversion systems, ash handling and thermal/electric delivery systems. The key selection criteria selected for solid fuel systems is provided below:

- **Available Space –** Space is a critical requirement for any solid fuel project. Space is required for fuel unloading, processing/screening (for quality), conveyance and storage. Generally, the less space available, the more reliable, regular and higher quality fuel deliveries must be to ensure the project is available to provide energy as needed. In combination, this may mean that facilities that are very short on space may have to rely on expensive and/or energy dense fuels like wood pellets to be practical.
- **Current Fuel Used (Combined heat and power/Heat only) –** While some biomass fuels may be relatively inexpensive as compared to most fossil fuels (wood chips versus fuel oil for example), the added costs (capital and operating) to receive and handle the fuels can be significant. Additionally, because of the relatively high moisture content of some biomass fuels, conversion efficiencies will generally be lower for biomass fuels than for fossil fuels. For these reasons, biomass plants that displace fossil fuels in heat only or combined heat and power (CHP)[12] applications tend to be easier to justify economically if they are displacing high priced fuels such as propane and fuel oil. These fuels can be more than 5 times as expensive as biomass fuels on an energy basis.
- **Electricity Costs (CHP) –** For bioenergy projects that produce power, the existing cost or value of electricity is an important factor in economic viability. The higher the cost of procuring electricity through the grid or other means, the more likely that biomass energy project can generate power competitively. For plants that only produce electricity, the wholesale price of power generally needs to be above $80/MWh (even when considering incentives) to offer an opportunity for return on investment. For cogeneration projects, the avoided cost of power can be lower depending on values assigned for the plant's thermal output.
- **Current Steam/Hot Water Demand (not for domestic hot water loads) –** As noted above, the cost of building and operating a solid-fuel biomass energy plant is higher than those for an equivalently sized liquid or gaseous-fired fossil energy plant. Therefore, it is critical that the investment be utilized to its fullest capacity to generate an economic return. This usually includes finding a valuable end-use for as much of the plant's thermal output for as many hours per year as possible. Special care and precaution should be exercised during the feasibility stage in situations that propose building a bioenergy plant if the plant's full capacity is not usable year round.
- **Existing Boilers (Redundant Systems) –** Redundancy is an important consideration in building any new energy plant, particularly when thermal energy is a critical output such as for process loads. While the electric grid may

[12] CHP and cogeneration are terms that are used interchangeably in this report and refer to the simultaneous production of useful heat and electrical energy.

provide a reliable source of electrical redundancy, thermal energy redundancy (to provide heat in emergency or peak demand situations) often requires on-site systems. Depending on the age, condition and configuration of existing energy assets, it may be possible to avoid the additional cost of new redundant systems and use the existing assets for this purpose.

- **Fuel Supply/Cost –** Availability of the appropriate type of fuel at prices and in quantities necessary to support the project over long periods (often 15-20 years) is critical requirement. If fuels are potentially scarce or very expensive in the short-term, financing for a project may be very difficult to secure.
- **Proximity to Infrastructure –** Generally, projects that are located near existing utility tie points will be less expensive to build and maintain than those that are further away. Trenching costs to bury underground piping or wires is expensive and it may be difficult to leverage existing plant staff if the new energy plant is located at a significant distance from existing infrastructure.
- **O&M Staff Capability –** Minimizing operating costs for a new biomass energy plant is both challenging and critical to achieving optimal economic performance. The capabilities of existing staff as well as their availability to take on the extra demands of a new plant should be carefully assessed.
- **Environmental Permitting –** New or modified environmental permits will be required for a new bioenergy plant. Depending on the type or status of existing permits, a new project may subject the existing facility to additional regulatory scrutiny or review. This fact should be carefully considered in the evaluation of potential sites.
- **Historic Designation –** As a new bioenergy plant is likely to include new buildings or extensive modifications to existing buildings, a review of historic building/land impacts will usually be required. Sites with negative past experiences on this front should consider this carefully.

3.2 POTENTIAL PROJECT OPPORTUNITIES

A number of different potential bioenergy projects and configurations were considered for GRIC. This section summarizes these considered projects, with a discussion describing reasons and high level analyses used to select the preferred options for more detailed analysis. The main types of bioenergy projects considered include combined heat and power (CHP), power-only, and heating and cooling.

3.2.1 LONE BUTTE INDUSTRIAL PARK

The Lone Butte Industrial Park is the only area identified within GRIC where there are likely to be consistently large process heating loads. Yulex, one of the Industrial Park tenants, has shown interest in a bioenergy project at their facility, and has biomass feedstock available that could help support bioenergy project. Yulex previously evaluated converting guayule into energy at their manufacturing facility. That study considered a modular biomass close-coupled gasification system combined with an organic Rankine cycle (ORC) system to generate power. Although the system evaluated looked potentially appealing to Yulex, further development was stalled due to the time and resource commitment needed for the development, permitting, and interconnection process.[13] Furthermore, Yulex has explored a number of possible uses for the Guayule bagasse residues, and found other higher value streams that could be implemented such as pressing the material to generate particle board/OSB (oriented strand board)-like building materials. In fact, since using the material to generate energy appears to be the lowest-value option, Yulex has considered bioenergy primarily as a back-up plan, or as a potential use for any byproducts that do not have any other higher value use.

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[13] The study determined that a 1 to 2 MW system would generate more electricity than needed; an evaluation of potentially exporting excess electricity to the grid did not progress beyond the initial discussions with GRICUA.

Nevertheless, Yulex seemed interested in considering a bioenergy project either on-site (for a small facility) or nearby elsewhere in the industrial park complex.[14] In addition, they were open to combining some of the guayule residues with wood chips to support a larger project if there would be a business case for doing so.[15] Yulex would also consider processing saltcedar on-site for a larger project, although additional lot area would be needed from Lone Butte Development Corporation. Land could also be rented from Lone Butte to store material. If feedstock is stored outside, dust storms could be an issue for material contamination. In addition, due to the heat generated by composting, storing piles of bagasse can be a fire hazard.

As described in detail in the *Renewable Energy Technology Characterization* Report, biomass cogeneration projects designed to serve a steady heat load tend to be economically preferable over other types of bioenergy systems, as they are able to offset a higher cost energy load. However, the only process heating load at the Yulex facility consists of the electric ovens are used for drying the rubber products. This is a fairly small and intermittent load, which is met using a diesel-fired generator that produces electricity.[16] This load is not a good match for a biomass cogeneration project, as there would be very limited value in serving that load. As such, alternative thermal end uses would need to be found in order to consider a cogeneration project. Potential options include:

- Providing steam to other industrial park tenants. Potential off-takers include:
    - Superlight Block, a brick maker located adjacent to Yulex at the Lone Butte Industrial Park. This facility uses lot of thermal energy in their natural gas fired rotary kiln, and has expressed interest in using high pressure steam as an alternate energy source. Yulex has a good relationship with this company.
    - Thermorock is a perlite and vermiculite generating facility in another area of the Lone Butte Industrial Park, about one-half a mile away from Yulex. They currently use natural gas to meet their process heat demands.
- Drying guayule residue for generation of OSB/particle board type product, which needs to be 10% moisture, or pre-drying the portion of the material intended for use as a bioenergy feedstock to increase energy production

Although the industrial facilities noted above have large thermal energy demands, using a biomass cogeneration system to serve these loads would be very challenging. Both cement and vermiculite manufacturing processes require very high temperatures, typically around 1,000-1,500°F. One potential method to serve a portion of these loads with biomass feedstocks would be to preheat raw materials and combustion air utilizing a stand-alone biomass boiler. It may also be possible to fire biomass directly in a kiln, although the equipment would need to be modified to use solid fuels, and the biomass would need to be pre-cleaned and processed into a uniform fuel (pulverized, crushed, or pressed into briquettes or pellets).[17] Another way to meet some of the process heat load would be to use a biomass gasifier to generate syngas, which could then be fired directly in the kiln along with natural gas. However, any of these methods would require significant changes to the current facility operations, and would be very costly to implement.

[14] There is one acre of land just north of the current Yulex processing facility that could be used for a biomass plant (including biogeneration unit, and fuel handling, processing, and storage).

[15] In other words, if it there was some benefit to Yulex for providing guayule residues to a larger bioenergy project, such reduction in electricity costs, or an additional revenue stream for materials that are not otherwise used or needed. Another possible benefit would be helping to meet corporate sustainability goals from additional renewable energy production.

[16] ANTARES estimates that the oven's energy demand is about 1 MMBtu/hr, and is only operated for about 625 hours per year based on the current 1-shift operation schedule.

[17] Solid fuel firing also presents a challenge in terms of ash content, which is expensive to scrub out at these temperatures.

The other potential use for thermal energy is to drying guayule residue, which has limited value. Furthermore, to ANTARES' knowledge, Yulex has no definite plans for particle board production at this time.

Since no good options for a thermal host have been identified in this area, which would be necessary to consider a cogeneration biomass project, ANTARES opted to evaluate a biomass power generation facility in the detailed assessment as presented in the following chapter. Such a project could be located near the existing Yulex facility (where some of the feedstock is expected to come from), or elsewhere in the park. The electricity generated from the project could be used to serve Yulex or other industrial park tenants, or some or all of the electricity could be connected to the grid and used to serve other GRICUA customers.

3.2.2 Cultural Resource Center

The Cultural Resource Center was identified as the best candidate to consider biomass heating in combination with absorption chilling for a biomass energy project that could operate year-round. The building is a relatively large tribally owned building, and it is expected to have larger energy loads than most other building areas considered.[18] A larger biomass system will have some economies of scale benefits, improving economics. Furthermore, many of the building's existing heat pumps are near end of service life and may need to be replaced soon anyway. There also appears to be sufficient space for biomass project at this site (including some wood fuel storage).

A high level analysis was performed in order to determine if this project warranted a more in-depth evaluation in the detailed assessment. This first step in the analysis was to estimate the building's monthly heating and cooling loads. This was accomplished using temperature profile data for Phoenix, AZ, to determine how many hours the currently installed system would run, and at what capacities. The heating and cooling loads were determined using a bin analysis, in which the average hourly temperature for every hour of each month is aggregated into numerical bins. Each bin spans two degree temperature increments, such as 100-102°F, 98-100°F, etc. The bins are a numerical construct used to simplify the loads, by counting how many hours in each month the average temperature falls within the given range for each bin.

The hottest hour of the year was assumed to be when the installed unit operated at peak load for cooling. The operating capacity of the existing heat pump units was then scaled linearly between the hottest temperature bin and the 60°F to 62°F degree bin, beyond which no cooling is needed. A similar process was performed for the heating loads. These bins were then used to determine an estimated total monthly ton-hours of space conditioning needed. This resulted in a total annual chiller load of around 240,000 ton-hours (equivalent to 2875 MMBtu), and a total annual heating load of 425 MMBtu.

The estimated heating and cooling loads were then used to estimate the associated cost savings to utilize biomass heating and absorption chillers instead of a heat pump system. The chiller calculation was based on the performance specifications for a commercial 100 ton absorption chiller, assuming a 10 degree change in water temperature from inlet to outlet. The heat pump efficiency was estimated to be 0.85 kW/ton, based on commercial units in this size. Other key assumptions used in the analysis include:

- Estimated biomass boiler efficiency of 70%
- Biomass fuel consists of dry wood chips, with a 10% moisture content and an estimated heating value of 7,200 Btu/lb (HHV)
- Biomass feedstock cost of $45/ton ($3.13/MMBtu)
- Average all-in cost for avoided electricity $0.08/kWh

[18] ANTARES considered a number of other tribally owned buildings and complexes in the Sacaton area, including the Executive Ke, Council Ke, Gila River Wellness Center, and the District 3 Service Center.

The results of the analysis are shown in Exhibit 11. The system would require about 424 tons of biomass per year, and would offset about 234 MWh in electricity purchases. The results show there are no net energy savings with a biomass heating and cooling system. Furthermore, this calculation only considers the fuel costs for the different configuration options. A biomass system with an absorption chiller would also have higher annual operation and maintenance costs than a conventional heat pump system. The installation costs would also be significantly higher than for replacement of the existing heat pumps. As such, this project would not be economically viable and no additional analysis was conducted.

Exhibit 11. Summary of Biomass Heating and Cooling

Item Description	Value
Cooling	
Hot water to meet chiller load (MMBtu)	3,847
Biomass input (MMBtu)	5,496
Biomass input (ton/yr)	382
Annual Biomass Expense ($/yr)	$17,174
Avoided Electricity Consumption (kWh)	203,534
Electricity Savings ($/yr)	$16,283
Heating	
Heating load (MMBtu)	426
Biomass input (MMBtu)	608
Biomass input (ton/yr)	42
Annual Biomass Expense ($/yr)	$1,901
Avoided Electricity Consumption (kWh)	30,160
Electricity Savings ($/yr)	$2,413
TOTAL NET SAVINGS	-$380

3.2.3 WWTP Anaerobic Digestion

The only potential anaerobic digestion (AD) project location identified in the GRIC area is the City of Chandler waste water treatment plant (WWTP) in the Wild Horse Pass area. Based on the results of the high level screening analysis performed in the *Renewable Energy Technology Characterization Report*, anaerobic digestion at waste water treatment facilities is typically only feasible for facilities with a high level of throughput, preferably greater than 30 million gallons per day (MGD), but 5 MGD at a minimum.

A number of project challenges were identified that precluded this location from being considered in the detailed analysis. ANTARES contacted the Chandler Waste Water Treatment Superintendent, John Pinkston, about the Chandler waste water treatment facility in Lone Butte, who informed ANTARES that the Chandler facility uses two facultative lagoons, with the capacity to process 10 MGD although actual operations are typically between 4-7 MGD. Facultative ponds (a type of stabilization pond used to treat wastewater) are typically designed to encourage oxygen transfer near the surface, to avoid anaerobic conditions. There is no anaerobic digestion taking place at this location. This facility configuration would require an additional anaerobic lagoon or other higher cost treatment system in order to implement an AD project.

GRIC has a water treatment plant to the east of the facility, but it does not treat waste water and the configuration is not compatible with AD. GRIC also operates a lagoon to the southwest of the Chandler facility which uses the effluent from the Chandler process, however it is only a storage lagoon. No actual treatment takes place there and the water is distributed to farms in the area.

Since the size of the Chandler facility (4-7 MGD) is on the lowest end of the threshold to consider AD, and is significantly lower than the typical size needed for an economically beneficial project (30 MGD), an AD system is not expected to be economically feasible. Furthermore, the benefits for the Community would significantly depend on the adjacent GRIC water facility purpose and energy demand. There are no other buildings near enough to the WWTP to consider piping steam or hot water (piping costs and energy losses will make this not economic), which could limit energy recovery. Based on all these factors, an AD project at the City of Chandler WWTP has been ruled out at this time.

4 BIOMASS PROJECT TECHNICAL ANALYSIS

This chapter presents the technical analysis results for a biomass power generation project located in the Lone Butte Industrial Park. It is assumed that the facility would be located at or near the Yulex facility, as they would provide a portion of the biomass feedstock from guayule residues.

4.1 PLANT SIZING

The amount of feedstock found to be reliably available within a reasonable level of cost was the limiting factor in terms of system sizing. As such, ANTARES modeled the potential electrical generation capability of using the total available woody biomass supply in a stand-alone power plant. Key characteristics of the feedstock supply are summarized below in Exhibit 12. The guayule heating value and moisture content data is based on laboratory analysis of samples collected during the site visit in July 2013 (as discussed in Section 2.4), and the urban resource wood chip information is based on typical values used for this type of resource in the biomass industry.

Exhibit 12. Fuel Supply Summary

	Guayule Bagasse	Wood Chips
Feedstock Source	Yulex	urban residues
Quantity (tons/year, as received)	5,000	20,000
Heating Value, HHV (Btu/lb, dry)	9,500	8,000
Moisture Content	50%	10%

As discussed in Section 2.2, the guayule bagasse is what remains after Yulex processes the guayule and extracts the material for making natural rubber. The bagasse is a finely ground material with a fairly high moisture content, giving it a consistency somewhat like wet sawdust. Very little mass is removed during processing, so each operational load results in a large fraction of residues. It is assumed that 5,000 tons per year of bagasse material could be available for a bioenergy project, based on the additional supply expected when Yulex doubles production in 2014.

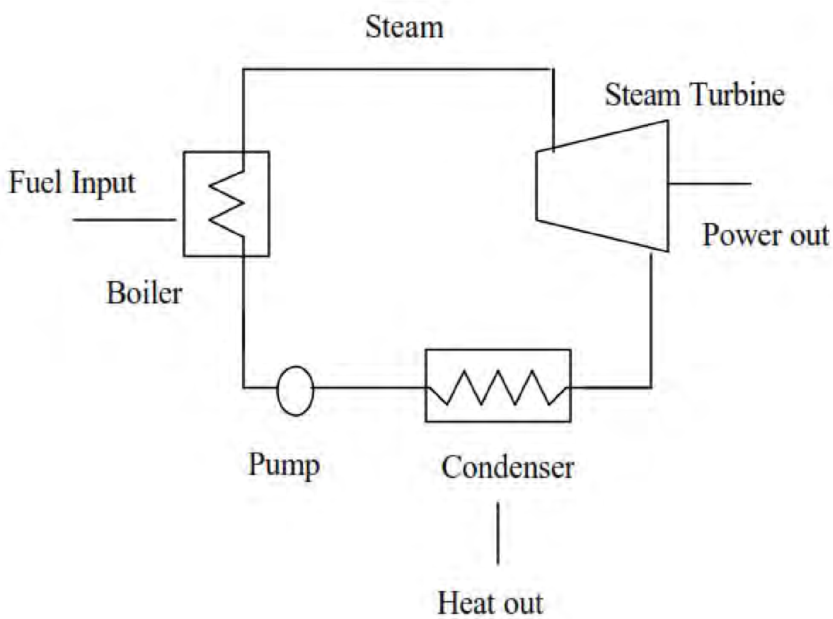
The estimated quantity of wood chips from urban resources is based on the information provided by No-Waste Grindings, who was the only potential supplier that provided data for the analysis. Although they were willing to expand their operations as needed to meet the facility demand, 20,000 tons per year is approximately how much they currently sell. As such, a portion of this supply may come from their existing sources, with the rest representing expansion of their business to meet demand. The material largely consists of very dry wood from recycled pallets, clean C&D wastes, and other residual waste wood streams. It is expected that additional material could be sourced for a bioenergy project, but it would have to either be diverted from existing high-value end uses such as mulch and horse bedding, or would come from much further distances. In either case, the delivered cost of the feedstock would increase significantly.

It is important to note that this analysis assumes that the wood chip and guayule bagasse fuels can be mixed at the boiler. However, these materials are very different and may require separate or specially designed conveyors, processing equipment, and boiler metering screws. These technical challenges would need to be addressed prior to pursuing such a project, and could add additional upfront costs to project design and installation that are not accounted for in this study.

4.2 EQUIPMENT CONFIGURATION

The selected power plant configuration uses a high pressure boiler to generate steam that will be expanded in a condensing steam turbine. A steam turbine is a mechanical device that converts the thermal energy to mechanical energy, which is then used to drive a generator for power production. Many of the biomass power plants currently in commercial operation use this type of technology. A condensing steam turbine exhausts steam at sub-atmospheric pressures, thus extracting the maximum available thermal energy from the steam. This helps to maximize the electric generation for a power-only plant. A general process flow schematic for this type of configuration is shown in Exhibit 13.

Exhibit 13. Power Generation Using Steam Turbine Technology



The facility configuration includes a biomass preparation yard which is used to receive, process, and store the incoming biomass fuel. It is assumed that the wood fuel will be delivered in walking floor trailers which are self-unloading, in order to avoid the high expense of a truck tipper.[19] There would likely be around 3-4 truckloads delivered per day on average, assuming each truck has a 22-ton payload and deliveries are only made on weekdays. The fuel prep yard equipment would typically include conveyors, stackers, reclaimers, screens and metal separators, covered storage area, and fuel metering bins.

Based on the available biomass feedstock supply, a 1,000 horse-power (hp) boiler was selected, which will operate at 425 psig, and the condenser will operate at 2 psia. An air cooled condenser is used in this analysis, which is appropriate for facilities in the southwest where water is a precious and limited resource. The steam turbine will on-average generate approximately 2.0 MW of electricity for sale for the 8,000 annual hours of operation (91% availability).

[19] Although No-Waste Grindings does not currently have walking floor trailers, they were willing to consider purchasing such equipment, depending on the level of supply and a long term contract.

4.3 PERFORMANCE ANALYSIS RESULTS

The performance analysis was conducted using Thermoflex, a commercially available heat and mass balance software package. The heat and mass balance model is shown below, in Exhibit 15. The model used an average fuel input of 3.1 tons/hr of woody biomass input, with a split of 20% Guayule and 80% clean wood chips from C&D debris. This project was sized based on the available woody biomass in the area, which was limited to the 25,000 tons per year. The key technical performance outputs are listed below in Exhibit 14.

Exhibit 14. Biomass Power Project Performance Summary

Output Description	Quantity
Boiler fuel input rate (tons/hr)	6.25
Steam flow output rate (kpph)	31.25
Gross Power (kW)	2,010
Net Power (kW)	1,757
Annual Net Energy Output (MWh)	14,056
Annual Biomass Fuel Input (tons/yr)	20,000 (clean wood chips) 5,000 (guayule bagasse)
Net Heat Rate, HHV (Btu/kWh)	23,676
Net Electric Efficiency (HHV)	14.4%

The overall system efficiency is fairly low (14.4%), which is typical for a power-only project. It is also worth noting that this project is much smaller than most stand-alone biomass power plants, which typically start at 25 MW. Bigger plants with larger generating capacities are generally more economic, as they obtain economies of scale that help to reduce the per-unit installation and operating costs. The system economics will be evaluated in detail in the next chapter.

Exhibit 16 summarizes the monthly annual electric consumption and peak demand for Yulex, based on the 2012 usage data provided by GRICUA. This information is considered in the context of having all or part of the electric loads met by an on-site biomass facility, which is one potential option for using the electricity. The facility's total annual consumption is about 796 MWh, with 57% of the usage attributed to the office and the rest from the processing facility ("Plant"). The peak demand for the office varied from a low of 86 kW in May and August, to a high of 159 kW in September. The Plant has lower overall electric (kWh) consumption, but higher peak demands, due to the variable nature of their operations. The Plant peak demand ranged from a low of 51 kW in February to a high of 389 kW in January.

Based on these values, on a monthly basis Yulex would only consume around 5-10% of total biomass facility output, based on current operations. If there is a higher level of activity in future due to increased production as planned, Yulex could utilize a larger percentage of the generated electricity. It is estimated that the all-in average annual electric cost that Yulex currently pays GRICUA is around $0.11/kWh. Additional discussion about potential off-takers and uses for the electricity is provided in the following chapter.

Exhibit 15. Biomass Power Project Heat and Mass Balance Model

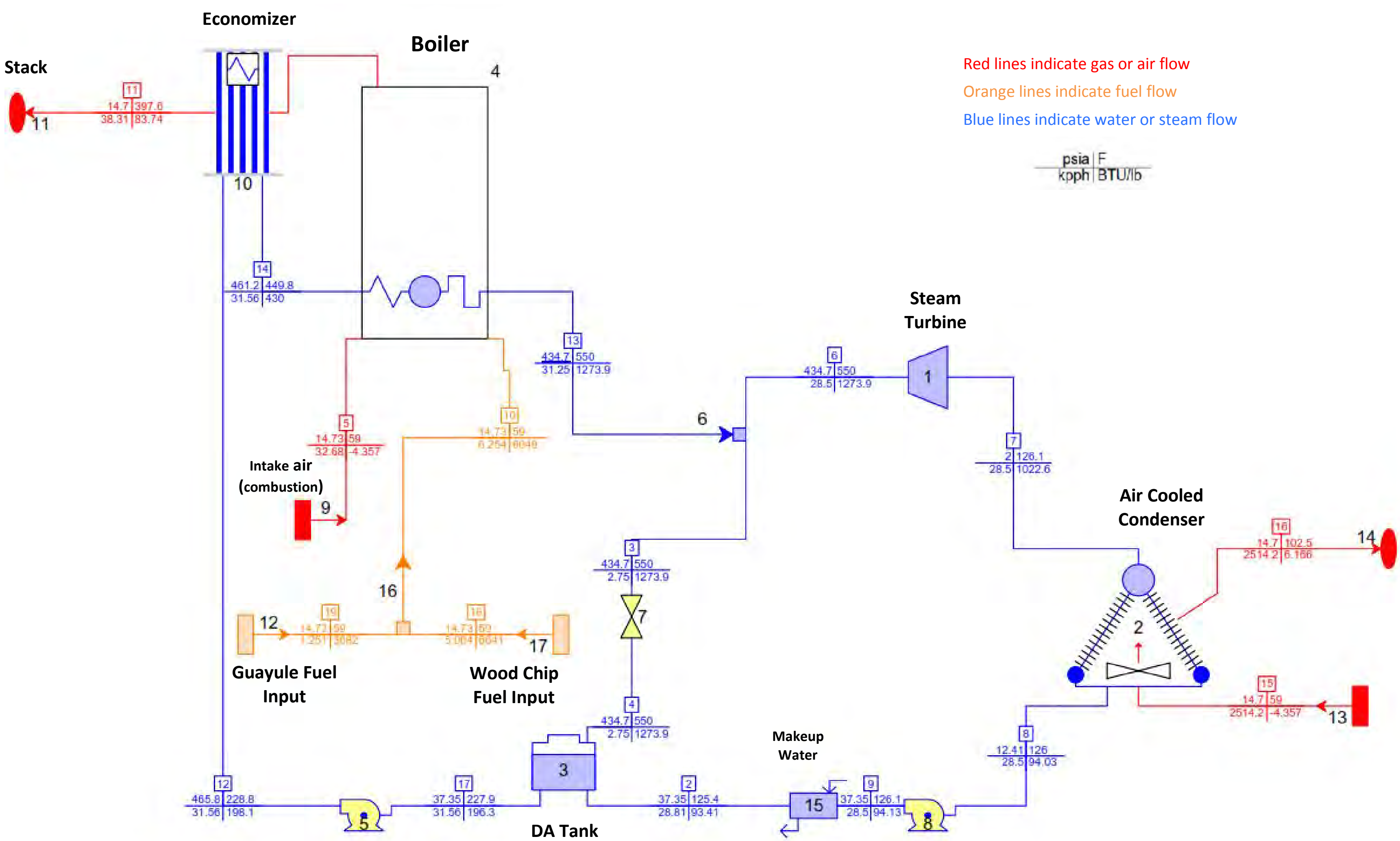
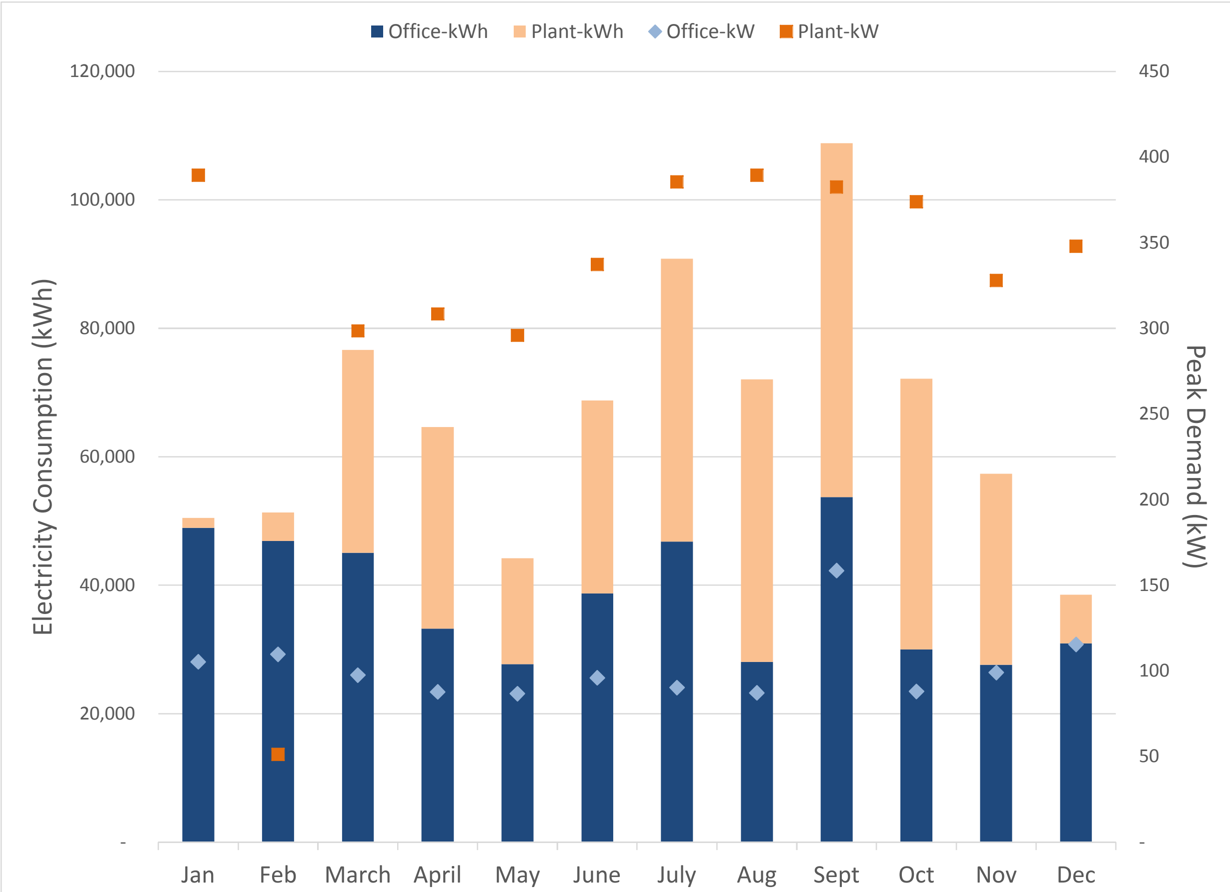


Exhibit 16. Yulex 2012 Electric Consumption



4.4 ELECTRICAL INTERCONNECTION

Electricity generated from the considered biomass project on Community land could be used to directly serve the GRICUA customers and offset existing grid electricity purchases from other utilities. This is the primary power off-take arrangement considered in this analysis because the employment, economic and environmental benefits of a cost-effective renewable energy technology deployment to the GRIC are maximized when that generation project is owned by the Community.

A biomass system located at the Lone Butte Industrial park could supply a number of the park tenants. If the project were located at Yulex, power could be fed into Yulex's meters to supply them with power. However, the project would generate more power than needed to serve the Yulex electricity demand so an interconnection will be needed with the GRICUA distribution system. Although there are other electric utilities in the area (for example, several industrial end users in the Lone Butte Industrial Park buy power directly from SCIP), it is expected that a direct connection to the GRICUA would be most beneficial to the Community and the most expeditious to achieve

GRICUA does not currently have an agreement in place for interconnection of distributed generation projects, but has stated that they would develop the agreements prior to detailed system design, once the proposed systems are better defined. Regardless of the project scope, any process or procedure will involve GRICUA working with SCIP to ensure that system reliability and integrity is maintained.

5 ECONOMIC ASSESSMENT

This chapter provides information on the detailed economic analysis that was performed for the biomass power project configuration described previously. A discussion of the potential ownership structures is presented first in order to give context on the possible partnership scenarios as they impact the financial situation for a biomass project. The methodology and key inputs to the economic analysis are then presented, followed by the levelized cost of electricity (LCOE) analysis results.

5.1 PARTNER AND OWNERSHIP STRUCTURE SCENARIOS

A renewable energy project at GRIC could have a number of different partner and ownership structures. Some of the most likely potential arrangements are summarized below (these were described in more detail in the *Solar Energy Feasibility Study* report, submitted separately). Since GRIC has stated that they would prefer to have a tribal entity own the project in order to capture much of the benefit associated with a project, most of the considered scenarios include at least partial ownership or control of the system.

The most likely tribal entity to own and operate a biomass power project is GRICUA. It is also possible that a project sited at Lone Butte Industrial Park could be owned by Lone Butte Industrial Development Corporation or a non-tribal third party who would lease property at the industrial park and sell the power to GRICUA.

The federal Investment Tax Credit (ITC) and MACRS (modified accelerated cost recovery system) accelerated depreciation are key incentives that help make renewable energy projects in the United States financially viable (see Section 5.2.2 for details). However, they require a taxable entity to take advantage of them. Federal income tax is not imposed on businesses operated by American Indian tribes, therefore GRIC would normally not be able to take advantage of the tax incentives on their own. That said, there are several partnership models that exist to help renewable energy projects on tribal land benefit from federal tax incentives. These opportunities were described in detail in the *Solar Energy Feasibility Study* report, and are summarized below.

- Lease tribal land to private developers who are eligible for tax incentives to develop renewable energy projects. The developer is responsible for the capital outlay for the project, and retains full ownership and benefits. The tribe collects a lease payment for the use of their land, but does not obtain any direct benefits for the project.
- Partner with a third party entity to develop the project, and obtain private letter ruling from the IRS to establish eligibility for incentives. This could take the form of a "pass through lease" arrangement, in which a tax equity investor (such as a financial institution) would be the lessee, and would make rent payments to the tribe in exchange for benefiting from the investment tax credit. Another potential arrangement would be to obtain a tax equity investor that is a partner rather than a lessee. The partner could be a financial institution, venture capital firm, or any qualified corporation (ideally with a high tax burden).
- Pursue an Energy Savings Performance Contract (ESPC), an arrangement where a taxable Energy Savings Company (ESCO) project partner provides the upfront capital cost and is paid back over time from the energy savings. ESPCs are a commonly used contracting vehicle for federal agencies to implement renewable energy, energy savings, or water savings projects. In this scenario, the risk for the tribe would be lowered because the ESCO pays all initial costs and guarantees energy savings. However, the ESCO would require a reasonable return on investment for any project outlay.

Note that although it is anticipated that Yulex will be involved in the project, it is not expected that they would be interested in having full control and responsibility of owning and operating a power plant. However, they could be considered as potential partners if a mutually beneficial agreement could be reached. This could potentially help the project to obtain federal tax benefits, for which GRIC is not eligible.

It is worth pointing out that even for third party ownership, a biomass energy project could benefit the Community by providing jobs for plant operation, as well as fuel supply infrastructure (such as biomass feedstock trucking). In this way, some of the money for energy costs that currently goes outside entities that generate power would be kept within the Community.

5.2 ANALYSIS METHODS AND INPUTS

A levelized cost of electricity (LCOE) analysis was performed for the considered biomass power configuration in order to evaluate its economic viability. The LCOE provides the average cost of power over the lifetime of the project. This analysis is useful in gauging the cost of producing electricity and can readily be compared against electric production costs for other technologies and utility supplied power. Inputs to the calculation include system output (kWh generated), capital costs, O&M costs, financing assumptions, and any applicable incentives.

Both current and constant LCOE figures are calculated in the analysis. The current LCOE is also known as the nominal LCOE because it includes the rate of inflation. The constant LCOE removes the effects of inflation and shows the LCOE in real dollars. Where the rate of inflation is greater than zero (as it is in this analysis), the constant LCOE will be lower than the current LCOE.

Although the base case LCOE analysis does not include any incentives, there are a number of incentives that could be included in the partner scenarios. A partner scenario could take many forms with complex arrangements for sharing the value of a project. Possible business models for partner projects could include revenue sharing or lease structures. Additionally, a partner with a tax burden may be able to take advantage of a projects' depreciation benefits. However, such complex evaluation scenarios may make it difficult to compare the cases due to different inputs. As such, in an effort to make it simpler to judge the viability of each project, ANTARES modeled the incentives cases so that the value of the incentives is rolled into the LCOE figure. For example, the larger the depreciation, the lower the LCOE. This assumes that the benefit of the incentives will generally be fully passed on to the project itself. This may not perfectly replicate the LCOE in a real-world partnership scenario (where the partner may claim a higher portion of the benefits), but it does allow for reasonable comparisons and a reasonable starting point for analysis.

The key analysis tools used in the LCOE analysis included an in-house excel spreadsheet tool used to aggregate economic input data and calculate levelized costs and metrics. Key assumptions used as inputs to the model include:

- A 25-year project lifespan and economic life. This time frame is based on the expected useful life of the biomass system and associated equipment. The 25-year period would begin in 2014 and end at the close of 2039. (The project start date does not have a large impact on the economic results though, so a delay in project initiation for a year or two wouldn't make much difference in the overall results.)
- All costs are adjusted to the appropriate time frame. Future costs are escalated by adjusting for inflation and equipment cost escalation. The total future cost of the project is adjusted to its present value using the discount rate (including inflation).

As noted above, two scenarios were developed and evaluated for each option; the base case (Case 1) assumes no incentives will be obtained by the project; and Case 2, which assumes that the project will be able to obtain a variety of potentially available incentives. A sensitivity analysis is also performed on key variables (capital costs, biomass fuel costs, and weighted average cost of capital) to provide a more thorough understanding of the impact that these values could have on the project's economics.

The following subsections describe the methods and assumptions used in the base case and alternative financing analyses.

5.2.1 Key Financial Analysis Parameters

The financial assumptions for the LCOE analysis are presented in Exhibit 17 for Case 1 (no incentives) and Case 2 (with incentives). An explanation for key parameters follows.

Exhibit 17. Key Financial Parameters

	Case 1 (no incentives)	Case 2 (with incentives)
General inflation (per year)	2%	2%
Federal Tax Rate	N/A	35%
State Tax Rate	N/A	5.05%
Combined State and Federal Tax Rate	N/A	38.25%
Economic Life (years)	25	25
Weighted Average Cost of Capital	6.6%	6.6%
REC Price	N/A	$2/MWh
Investment Tax Credit	N/A	30% of capital costs
Depreciation	N/A	5-year MACRS

Inflation: A 2% long term inflation rate is used in this analysis, based on the current target set by the Federal Reserve (Why does the Federal Reserve aim for 2 percent inflation over time? 2013).

Taxes: Taxes are not included in the case without incentives because GRIC does not have a tax burden. Combined Federal and State taxes for the case with incentives are 38.25% which is typical for a corporation which may act as a project partner.

Weighted Average Cost of Capital (WACC): The WACC is the average of the debt and equity financing costs. The WACC is commonly used as the discount rate for investment opportunities, and was used in this manner for the analysis. Also called the hurdle rate, it is a measure of the anticipated present value of future cash flows. It serves as a benchmark for a project's profitability, and is usually set based on an investor's anticipated return on other projects available for investment. The interest rate earned by a university endowment, for example, is often the university's discount rate when it is presented with alternative projects for investment. If the project will earn more than adding the same amount of money to the endowment, then it is considered profitable.

As no specific WACC was requested by GRIC, ANTARES assigned a value of 6.6%. This is the rate used in the U.S. Energy Information Administration's Annual Energy Outlook 2013 publication for levelized costs across various generation technologies. It is important to note that in a partner scenario, the partner may evaluate the project with their own WACC. Taking this into consideration, and the fact that the chosen WACC has a large effect on the LCOE, sensitivity charts are presented to show the LCOE across a range of WACC assumptions.

Financing: The base case scenario assumes that the projects would be 100% debt financed at an interest rate of 6.6%. Tribes and businesses organized as arms of government aren't subject to federal income tax, therefore GRIC would not be able to take advantage of tax deductions for interest paid on debt. This is also why the interest rate is the same as the WACC. The WACC factors in tax rates, but there are no taxes in a scenario with 100% tribal ownership.

The interest rate used for the incentives case is 10.7%. After factoring in taxes, this results in a WACC of 6.6%. The actual interest rate for a project partner will likely be different than what was assumed, but the resulting 6.6% WACC allows for an even comparison between the scenarios with and without incentives.

5.2.2 Applicable Incentives

There are various incentives that could benefit a biomass project, which are described below. The identified federal tax incentives that add the most value to a project, would not apply for a GRIC-owned project as the tribe is not subject to federal income tax. However, there are multiple mechanisms potentially available to allow the tribe to get value from these incentives, such as leasing land to private developers for project development, or arranging a pass through lease with a taxable third party upon approval from the IRS.

In order to determine the overall impact that the potential incentives could have on project economics, they are all included in Case 2 only. No incentives were included in the base case analysis (Case 1).

Federal Incentive: Section 48 ITC: Section 48 of Title 26 of the Internal Revenue Code allows owners of qualified renewable energy equipment, to take a percentage of the system's total capital cost as an Investment Tax Credit (ITC) against federal income tax during the first year of operation liability. The tax credit for biomass technologies is currently equivalent to 30% of the total capital cost, with no system size restrictions or maximum credit. However, this credit for biomass projects is currently set to expire at the end of 2013; in order to claim the credit a project must have initiated construction by December 31, 2013. Although this is not likely for the considered GRIC project, this incentive is still considered in the analysis in case the deadline is extended or the credit is reinstated at a future date. There is a precedent suggesting such actions are possible, since this has happened several times in the past.

There are several key provisions that must be met for a biomass project to qualify for the ITC:

1. The power must be "sold by the taxpayer to an unrelated person during the taxable year" (IRC Sec 45 (a)(2)(B)). Since GRIC is not a taxpayer, this incentive would only has value under alternative financing strategies, whereby a taxpaying third-party partner has ownership, or if a pass through lease (described above) can be arranged and approved by the IRS.
2. It has to be a new project, or add a new increment of power to an existing facility.
3. The project cannot use any fossil fuels beyond those required for startup and stabilization.
4. Only property that is an "integral part" of the biomass facility is eligible. For example, roadways and paved areas of the facility can be eligible for the incentive if they are used for transport of material and equipment, but not if it is solely for employee/visitor parking. Property used for unloading, transfer, storage, or preparation is eligible.
5. ITC is subject to recapture if the original taxpayer disposes of the property w/in 5 years of placed in service date.
6. The recipient (the third-party taxpaying partner) of the ITC must decrease its depreciation base of the investment for tax purposes. Specifically, the taxpayer must decrease the depreciation base of the investment by 50% of the credit amount.

Federal Incentive: MACRS Accelerated Depreciation: Under 26 USC § 168, the federal government offers a 5-year accelerated depreciation option (MACRS) for certain renewable energy equipment, including bioenergy systems (UNITED STATES CODE TITLE 26. INTERNAL REVENUE CODE n.d.). This accelerated depreciation allows the owner to deduct larger amounts of the asset cost earlier on in the project's life. Accelerated depreciation can only be claimed by a taxable entity; public utility property is not eligible (Publication 946 (2012), How To Depreciate Property n.d.). Before calculating depreciation, the adjusted basis of the project must be reduced by one-half of the amount of any federal energy credits (such as the Section 48 ITC) for which the project qualifies.

Renewable Energy Credits: Another way the tribal government can gain value from a renewable energy project is through the sale of Renewable Energy Certificates (RECs). RECs are a tradable commodity that represent the non-energy of the generation of 1 MWh of renewable electricity. There are both voluntary markets for RECs and compliance markets, compliance market RECs are used to meet state Renewable Portfolio Standard (RPS) policies (Renewable resources for Federal agencies n.d.). The value of RECs vary by technology and market, but a price between $1-$5/MWh is typical for the voluntary market under current regulatory conditions. RECs from renewable energy projects on tribal lands that are sold to a federal agency are eligible for a doubling bonus towards meeting federal renewable energy requirements (U.S. DOE FEMP 2008). This added value could potentially be passed along to the tribal government, providing additional revenue to the project. The Western Area Power Administration facilitates the acquisition of RECs by federal agencies through their website. A mid-range all-in value of $2/MWh is used in this analysis (Case 2).

5.2.3 Total Installed Costs

The capital requirements for the stand-alone biomass power project include the following major items:

- Fuel preparation yard (automated biomass receiving and handling system, and storage yard)
- Steam boiler system and emissions control (ESP)
- Steam turbine-generator
- Building and site work (boiler house, site improvements)
- Process controls
- Construction and commissioning services

The estimated capital cost was developed based on in-house resources and vendor quotes for projects with similar configurations and sizes collected from previous studies. This resulted in a total capital cost estimate for the project of $14,967,000. The relatively high per-unit cost of $4,446 per kW capacity is due to the technology type and small size of the project; a larger project would have lower per unit costs due to economies of scale benefits. A breakout of the expected major installation cost items is provided in the table below. The prime mover cost includes the cost for an air cooled condenser, which is significantly more expensive than a water cooled condenser.

Exhibit 18. Capital Cost Summary

Cost Component	Unit Cost	Labor	Equipment and Materials	Total
Boiler, Pollution Control and Fuel Handling		$2,211,000	$5,396,237	$7,607,000
Prime Mover		$467,000	$2,023,989	$2,491,000
Building and Structures		$233,000	$330,000	$563,000
Electrical Interconnect		$6,000	$23,000	$29,000
Engineering Fees	10%			$1,069,000
Environmental Fees	5%			$535,000
Legal and Financial	5%			$535,000
Contingencies	20%			$2,138,000
Total				**$14,967,000**

5.2.4 Operations and Maintenance

The operations and maintenance (O&M) costs calculated in this study are initial estimates intended for analyzing life cycle costs and comparing with the current facility costs. The non-fuel O&M costs are categorized as fixed and variable, and the fixed costs include both labor and non-labor costs. A summary of the estimated O&M costs is shown in Exhibit 19.

The labor portion of fixed O&M is based on the number of employees needed to operate and maintain the plant. The labor requirements for a 2 MW stand-alone steam turbine biomass power plant is estimated to include a total of 11 staff, including 8 boiler attendants for a 24/7 operation, 1 wood yard operator, 1 maintenance person, and 1 plant manager / fuel procurement person.[20] The total cost for staffing the facility is based on the personnel salaries plus overhead costs (i.e. direct and indirect labor costs). The non-labor fixed O&M includes all other costs independent of energy production, which includes insurance for the facility, and the cost for spare parts and maintenance equipment, assumed to be 2% of the capital cost. The variable O&M is based on the cost of consumables such as chemicals, water, and electricity needed to run the equipment at the prep yard, as well as ash disposal costs. These are assumed to collectively equal 15 mils/kWh ($0.015/kWh).

Exhibit 19. Summary of Biomass Project O&M Costs

Cost Category	Cost ($/yr)
Fixed Labor ($/yr)	$710,000
Fixed Non-Labor ($/yr)	$299,340
Variable O&M ($/yr)	$204,400
TOTAL Non-Fuel O&M ($/yr)	$1,213,740

Fuel costs

The total delivered cost for the wood chips are estimated to be $44/ton (as-received), which is equivalent to about $3.06/MMBtu. This is based on the gate price provided by the potential feedstock suppliers and an estimated delivery cost.

The guayule residues are valued at $45/ton ($4.74/MMBtu). Although this material does not have any associated delivery costs, the estimated cost is still relatively high due to the other potential high value uses for the feedstock. Yulex will want fair compensation for their feedstock, so it was assumed to be approximately equivalent to the wood chip cost.

5.3 LEVELIZED COST OF ELECTRICITY (LCOE) ANALYSIS RESULTS

An LCOE analysis was performed to estimate the levelized cost of the electricity generated by the considered biomass system in order to evaluate economic viability. A summary of the inputs for each considered case is presented in the following subsection, followed by the analysis results. Sensitivity analysis results are also presented.

5.3.1 Summary of Inputs for Considered Configuration

They key inputs for economic analysis are shown in Exhibit 20. The value of the incentives for the Case 2 analysis is also shown in this table. It is important to note that only first year costs for O&M and RECs are shown in the table (since they do not include inflation or escalation).

[20] Although it may be possible to get by with fewer boiler attendants, additional staff are needed to ensure that there is at least 2 people on site at all times in order to meet standard practices for plant safety.

Exhibit 20. Summary of Inputs for Biomass Power Project

	Case 1 No Incentives	Case 2 With Incentives
System Capacity, gross (kW)	2,010	2,010
Net Electricity Generation (MWh/yr)	14,056	14,056
Base Capital Cost ($)	$14,967,000	$14,967,000
ITC Value ($)	-	$4,490,000
Net Installed Cost ($)	$14,967,000	$10,476,900
Annual Non-Fuel O&M Costs ($/yr)	$1,213,746	$1,213,746
Annual Biomass Feedstock Cost ($/yr)	$1,105,000	$1,105,000
Annual REC Value ($/yr)	-	$28,112

5.3.2 Economic Analysis Results

The calculated LCOE results (constant and current) for the considered configuration is shown in Exhibit 21.

Exhibit 21. LCOE Results for Biomass Project

	Case 1 No Incentives	Case 2 With Incentives
Stand Alone Biomass Power		
Current LCOE ($/kWh)	$0.284	$0.264
Constant LCOE ($/kWh)	$0.235	$0.216

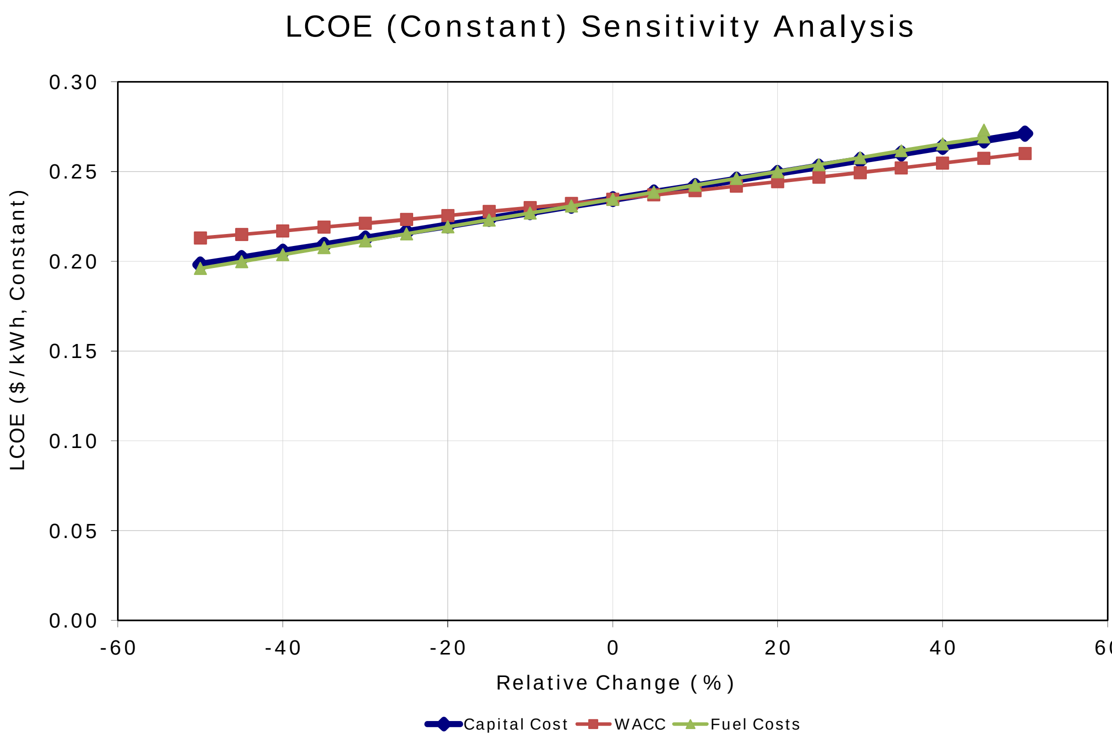
The incentives provide a roughly $0.02/kWh overall benefit for the systems.

5.3.3 Sensitivity Analysis Results

Sensitivity analyses can be used to address uncertainties in specified cost parameters, in order to see the affect that varying these values will have on the overall project economics. In this case, the capital cost, fuel costs, and weighted average cost of capital (WACC) were determined to be the most critical inputs to the project economics. In the sensitivity analysis, each of the input factors was varied individually (i.e., one at a time), across a range of +/- 50% from the base value. The capital cost variations can account for uncertainty in the costs of system installation, future price reductions, or the availability of additional grants that help to reduce the up-front cost of the project. The fuel cost illustrates the impact that sourcing different types of fuels could have on the project, while the WACC was varied to demonstrate the effects of different financing assumptions.

Results of the sensitivity analysis for the Case 1 assessment (no incentives) are shown in Exhibit 22. Constant LCOE values are displayed on the y-axis. The sensitivity chart shows that the project is most sensitive to changes in the capital costs and fuel costs, and somewhat less sensitive to changes in the WACC. The sensitivity of the capital costs and fuel costs are nearly identical. It was determined that a 5% change in these figures results in a 2% change in the LCOE. Similarly, a 5% change in the WACC results in 1% change in the LCOE. This analysis suggests that changes in the capital costs and fuel costs will have the greatest impact on the projects' success.

Exhibit 22. Sensitivity Analysis for Biomass Project



5.3.4 LCOE Analysis Conclusions

As it stands, this project is not economically viable because of the high LCOE compared to current energy costs. The constant LCOE value for Case 1 without incentives is $0.235/kWh. The constant LCOE values for Case 2 which includes incentives is $0.216/kWh. As expected, the incentives cases perform better than the case without incentives, as the incentives benefit the projects and help to reduce the upfront system costs. Nevertheless, the electricity provided by a biomass power project would be much more expensive than the current electric commodity cost, which is around $0.05/kWh, regardless of whether incentives are included.[21] This is due to a number of reasons. The first is that a power-only project has a fairly low fuel to electricity conversion efficiency. Although the overall energy conversion efficiency could be greatly improved with a cogeneration project that is able to recover and use heat that would otherwise be rejected, no good opportunities to utilize recovered thermal energy were identified in this study. Another reason for the high LCOE is the relatively small size of the system. Larger biomass systems benefit from economies of scale and are able to drive down the cost of electricity. Since this project was constrained by feedstock availability, it is not able to take advantage of economies of scale. High feedstock costs is another factor that increases the LCOE values. The availability of incentives that would help drive down the project costs, of finding a source of cheaper opportunity feedstocks could help make the project more attractive in the future. However, it is unlikely that the LCOE for such a project will ever be competitive with the current electric costs.

[21] The electric commodity cost of $0.05/kWh is the current rate that GRICUA pays for energy purchased from the wholesale market and existing contracts.

Ultimately, these results show that a biomass power project is not only more expensive than the current energy costs, but also much more expensive (higher LCOE) than the solar PV projects considered in the complimentary *Solar Energy Feasibility Study* report submitted separately to GRIC. Furthermore, a biomass project is a whole lot more complicated and has a lot more risk than a solar PV project in terms of operations, fuel supply availability and cost, and other potential unforeseen costs. On the other hand, a biomass project would provide more new jobs, for plant operations as well as fuel procurement and supply, which would be an added benefit to the Community.

6 REGULATORY AND ENVIRONMENTAL REQUIREMENTS

This chapter provides a summary of the regulatory requirements and potential environmental issues that must be considered for development of a biomass energy project. Air emissions restrictions and permitting requirements are the main source of regulations that must be considered for a biomass boiler such as the power-only project evaluated in the detailed analysis. Since this project used an air cooled condenser system (instead of water-cooled), a storm water or National Pollutant Discharge Elimination System (NPDES) permit is unlikely to be needed. The air emissions considerations are summarized in the following subsection. Other considerations for project development are presented afterward. Because GRIC is not regulated by the state, it is not subject to the requirements set by the ACC or Arizona DEQ. As such, project developers will generally need to defer ensure that they are following tribal requirements and processes.

6.1 AIR EMISSIONS REQUIREMENTS

Emissions limits for power plant facilities are (generally) set by federal and state regulations, and can vary significantly based on site location.[22] Non-attainment zone areas have especially strict regulations for air emissions, which can make it extremely difficult or impossible to install a new power generating facility. Of note for this effort is that EPA has granted GRIC the authority to manage their own air quality plan, so the permitting process and requirements are set at the tribal level. Exhibit summarizes emissions rates that would be expected based on AP-42 references for a biomass fired steam boiler. Emissions for various natural gas fired systems are also included for reference and comparison. The following criteria air pollutants are included in the tables below: Nitrogen Oxides (NOx), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), Volatile Organic Compounds (VOC), Total Particulate Matter (PM_{Total}). The emissions associated with an uncontrolled biomass boiler project are higher than for a natural gas system are largely due to the differences in the fuel types, as biomass has higher fuel bound NOx and SO_2, PM components.

Exhibit 23. Comparison of Emissions Rates for Various Technologies (AP-42)

Emissions	Natural Gas-Fired Steam Boiler	Natural Gas-Fired Reciprocating Engine	Natural Gas-Fired Turbine (Uncontrolled)	Biomass Fired Steam Boiler
NO_X (lb_m/MMBtu)	0.098 (A)	0.847 (B)	0.32 (C)	0.22
SO_2 (lb_m/MMBtu) (D)	0.001	0.001	0.001	0.025
CO (lb_m/MMBtu)	0.082	0.557 (B)	0.082 (C)	0.6 (E)
VOC (lb_m/MMBtu)	0.005	.118	0.0021	0.017
PM_{Total} (lb_m/MMBti)	0.007	0.0010	0.0066	0.4 (F)

Notes: (A) NO_X emissions for small boilers (<100 MMBTU/hr) that are uncontrolled. With a low NOx burner, it would have half the emissions rate of an uncontrolled boiler.
(B) Reciprocating engine emissions based on 4-stroke lean burn engine, <90% load.
(C) Applies to units operating at high loads (>80%).
(D) Assumes less than 0.1% (% weight) total sulfur in natural gas fed to unit
(E) Emission factor applies to stoker boilers. Fluidized bed combustors emission rate is 0.17 lb/MMBtu.
(F) Uncontrolled emission rate. With ESP, the PM emissions rate is expected to be 0.03 lb/MMBtu.

[22] Some of the Federal regulations that need to be considered include: Federal Prevention of Significant Deterioration (PSD) Requirements; Federal Maximum Available Control Technology (MACT) and Best Available Control Technology (BACT); and New Source Performance Standards (NSPS).

The expected criteria pollutant emissions for the considered biomass boiler project for GRIC are summarized in Exhibit 24. The expected biogenic CO_2 emissions are also included in this table, since due to a recent court ruling the greenhouse gas emissions from biomass facilities are subject to review for permitting. Specifically, new stationary sources that will generate more than 100,000 tons per year of CO2e emissions (including biogenic CO2 emissions) will have to obtain a Prevention of Significant Deterioration (PSD) permit prior to construction. Among other things, a PSD permit requires the application of Best Available Control Technology (BACT) for emissions including GHGs. The GHG emissions for the biomass boiler considered for GRIC are lower than the threshold and would not trigger this requirement.

Exhibit 24. Annual Fuel Usage and Emissions Levels for 1000 HP Biomass Boiler

Emissions	Annual Potential to Emit (PTE)	Est. Annual Emissions
Fuel In (MMBtu/yr)	366,551	335,500
NO_X (tons/yr)	40.3	36.9
SO_2 (tons/yr)	4.6	4.2
CO (tons/yr)	110.0 (stoker) 31.2 (fluidized bed)	100.7 (stoker) 28.5 (fluidized bed)
VOC (tons/yr)	3.1	2.9
PM_{Total} (tons/yr)*	5.5	5.0
CO_2 (tons/yr)	37,901	34,691

* Particulate emissions assume an electrostatic precipitator (ESP) is used.

6.1.1 Tribal Air Permits

In January 2011, the EPA approved a proposal by GRIC to manage their own air quality plan. The document that GRIC proposed is known as the "Gila River Indian Community Tribal Implementation Plan." The plan is a framework that includes permitting, air monitoring, and an emissions inventory among other topics. The plan is seen as a model for other tribes because of its scope and depth. State or county permitting requirements do not apply for facilities located on tribal land. The local authorities would only have jurisdiction if there was a tribal building on private property.

A biomass project on GRIC land must comply with the air quality standards listed in the GRIC Air Quality Management Plan (AQMP). There are two different types of permits that are issued: A Title V Permit and a Non-Title V Permit. A Title V Permit is required for any major source prior to construction. To trigger the need for a Title V permit, a source must emit 100 tons per year or more of any regulated air pollutant. Regulated air pollutants are define by the Clean Air Act and include NOx, PM, SO2, CO, Ozone, and VOCs.

A Non-Title V Permit is required for smaller sources that do not need a Title V Permit. There are three categories for Non-Title V Permits: Individual Permit, Synthetic Minor Individual Permit, and General Permit. For individual permits, the following limits determine whether a Non-Title V Permit is required:

- 75 tons per year but less than 100 tons per year for any single pollutant;
- Three tons per year of any single hazardous air pollutant (HAP);
- Five tons per year of any combination of HAPs; or
- 300 pounds per year of any single or any combination of ultra-hazardous air pollutants.

Synthetic Minor permits are for sources that wish to avoid a Title V permit. The owner may voluntarily agree to cut back hours or accept other operating limitations in order to avoid Title V classification. General permits are intended for smaller sources that have many similar facilities. These sources may be able to register with the DEQ and comply with general requirements. They are able to avoid an individual permit as long as they do not continuously violate the ordinance's requirements.

As reported in Exhibit 24, as currently proposed the GRIC biomass project would emit just over 100 tons per year (tpy) as a stoker system. This would require the project to obtain a Title V Permit as it is over the limit for regulated air pollutants. They could potentially apply for a synthetic minor permit by reducing operations slightly. An alternative scenario is to use a different boiler technology, since a fluidized bed system would produce significantly less emissions. Under this scenario, the carbon monoxide emissions would be roughly 30 tpy, well below the threshold for triggering a Title V Permit. The drawback is that a fluidized bed system is more expensive than a stoker system.

EPA Boiler MACT

In December 2012 the EPA finalized the Industrial Boiler Maximum Available Control Technology MACT standards (IB MACT) rule which will reduce emissions of toxic air pollutants from existing and new industrial, commercial, and institutional boilers located at area source facilities. Biomass boiler units are subject to these requirements. The required actions and emission limits for a facility depend on whether it is characterized as a major source or an area source facility.

The biomass boiler considered for GRIC would be categorized as an area source facility (as listed in 40 CFR Part 63 Subpart JJJJJJ), which emits or has the potential to emit less than 10 tons per year (tpy) of any single air toxic or less than 25 tpy of any combination of air toxics. A new area source biomass boiler with a nameplate capacity greater than or equal to 10 MMBtu/hr (such as the unit considered for GRIC) must keep PM emissions at 0.03 lb/MMBtu or less (which can be accomplished by utilizing an electrostatic precipitator). The facility is also expected to employ best management practices, and must complete biannual tune-up and reporting. Depending on what type of emissions control device is used, the facility must either meet an opacity limit (<10% via COMS), or install and operate a detection system (such as bag leak detection for a fabric filter). It is expected that particulate emission control through an electrostatic precipitator (ESP) likely will be required.

6.2 OTHER CONSIDERATIONS

An environmental assessment may be needed for the area considered for a biomass power plant. A study should evaluate for any environmental concerns for the site, such as any indication of a release, past release, or potential for release of petroleum or hazardous substances at the proposed project site; or any past or current materials, processes, fuel storage requirements or facilities that could pose an environmental hazard. In this case, since the project is being considered at an already developed area which is set up for leasing of lots to industrial users (Lone Butte Industrial Park), no significant environmental issues for project development are anticipated.

The preservation of historic and cultural resources is required by federal, state and local legislation. Any activities that have the potential to affect properties designated as historic in the National Register of Historic Places or equivalent state historic lists must consult with the appropriate state and local officials in their decision making process. This process would typically take place between a state historic preservation officer and the project developer during the environmental assessment. Impact on cultural activates or places should also be considered through GRIC staff. Although there does not appear to be any historic or cultural properties in the Lone Butte Industrial Park, it will be important to ensure that no other designated areas of significance will be affected.

6.3 SAFETY ISSUES AND CRITERIA

Any biomass energy project will have important safety issues that will need to be addressed. For example, the facility design and construction must meet local building codes. The power plant must provide adequate space to allow for proper inspection and maintenance of the new equipment. The conceptual designs allow for these spacing requirements and anticipate the use of ladders, catwalks, and safety railing as required around the equipment.

Another important consideration is fire suppression requirements. Sufficient fire suppression equipment must be included in all areas, including in the fuel storage area for the biomass feedstocks. This equipment would need to be inspected upon installation.

In addition, proper guards will need to be in place around all conveying equipment including augers, conveyors and walking floors. Operations personnel can be easily trained in the operation, routine maintenance, and safety procedures involved with a new biomass plant. This training is available as part of the boiler install and startup service. The biomass option will also present a modest increase in truck traffic to the site. A conceptual design must consider traffic routing, among other factors, into account to minimize safety and operational impacts. For safety reasons the deliveries should only occur during daylight hours and operations staff should coordinate and oversee deliveries as necessary to maintain a safe working environment. Furthermore, following standard safety protocols will require at least two people to be on-site at all times, in order to provide assistance in the case of an emergency.

7 Conclusions and Recommendation

This study included a biomass resource assessment study and evaluation of the feasibility of a bioenergy project located on Community land. The resource analysis identified a limited supply of low cost biomass fuel in the GRIC area. The most likely sources of fuel are clean wood chips from urban wood waste recovery activities, and guayule bagasse residues. Combined, these resources are estimated to be able to include up to about 25,000 tons of biomass per year, at a relatively high delivered cost of around $45/ton.

The study also evaluated the quantity of biomass fuel that could be generated as part of a riparian restoration program to remove saltcedar (e.g. Tamarix) from GRIC land. A GIS analysis showed that there are approximately 17,500 acres of saltcedar infested area in District 6 and 7, about a third of which is densely infested. The saltcedar removal and subsequent land restoration process is a time intensive, multi-year effort which would be quite costly, estimated at around $15,000 to $20,000 per acre, and would only provide a relatively small amount of biomass fuel on the order of 5 to 10 tons per acre from densely infested areas. Due to the high cost and low yield, such an effort would not be feasible as a source for biomass fuel. In addition, laboratory compositional analysis testing of the saltcedar showed that this material would be problematic to use as a biomass boiler fuel. However, removal of saltcedar from the infested areas could certainly benefit the local environment if riparian restoration funding could be secured from an alternative source. This activity would also provide Community jobs and wildlife habitat benefits.

A number of different potential bioenergy projects and configurations for GRIC were considered in the technical analysis. However, although cogeneration systems tend to be more economical for small bioenergy project, no suitable thermal end users were identified that could take advantage of the useful heat energy generated by the system. As such, the detailed analysis focused on a power-only biomass project, sized to use the potentially available resource supply from wood chips and guayule bagasse. Biomass heating and cooling for the tribal buildings was considered, but ultimately ruled out in a high level screening assessment as being too expensive.

The technical analysis considered a biomass boiler system with a 2 MW steam turbine to generate electricity. It was assumed that the facility would be located in the Lone Butte Industrial Park, near the Yulex facility where the guayule is processed and the bagasse is generated. The considered system would generate around 14,056 MWh of electricity per year, with a fairly low overall system efficiency (14.4%), as is typical for a power-only project.

The considered project has a number of technical and economic challenges. The guayule bagasse was found to be a potentially problematic boiler fuel in terms of alkali and ash content. Although the considered configuration would only utilize a portion of guayule as a boiler fuel which should help to reduce some of the negative effects, the fuel could still cause problems. The mixing of different fuel streams may also be a complication in terms of feedstock handling and input to the boiler. In addition, air emissions for a facility of this size may trigger Title V permitting requirements unless a fluidized bed boiler is used which would add additional expense. Furthermore, bringing the wood chip on GRIC lands would require special permission from the tribe, as there is an ordinance that restricts bringing any type of waste material on-site.

The economic analysis showed that at current prices, biomass power project will not be cost effective as the LCOE is much higher than current (or projected future) energy costs. This could be improved if a lower cost feedstock material was available, a larger project was possible (i.e. increased low-cost fuel supply), or a thermal energy end user was found that could support development of a cogeneration project which would result in higher efficiencies.

Nevertheless, even if the biomass energy project economics improved, it does not seem likely that they would be able to compete with current energy costs. The LCOE results were also much higher than for the solar PV projects considered in the complimentary *Solar Energy Feasibility Study* report submitted separately to GRIC. Furthermore, a biomass project is a lot more complicated and has a lot more risk than a solar PV project in terms of operations, fuel supply availability and cost, and other potential unforeseen costs. Although a biomass project would provide more new jobs that would benefit the Community, if a renewable energy project is pursued on-site a solar PV project seems to be a better choice overall.

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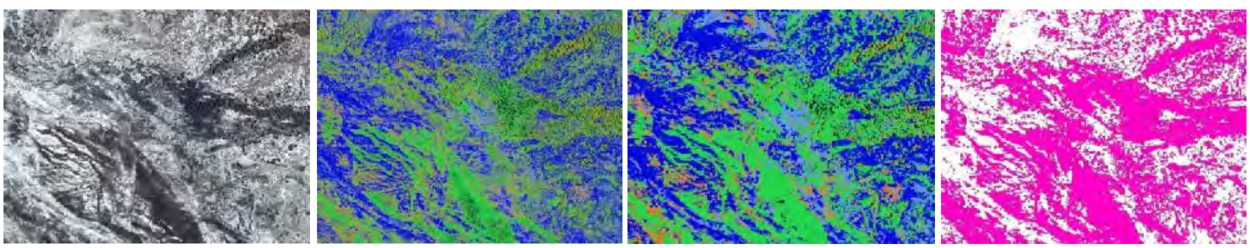
Appendix A

Saltcedar GIS Analysis Methodology

The GIS analysis utilized 4-band, 1 meter resolution National Agriculture Imagery Program (NAIP) data from the U.S. Geological Survey, which was downloaded from the Nation Map Seamless Server. This data dates to 2010, and is considered to be the “best available” orthoimagery from the USGS. Using the Spatial Analyst extension of ArcGIS, the imagery was converted into distinct vector zones so that the areas of saltcedar infestation could be extracted. First, an unsupervised maximum likelihood classification was performed on the imagery to identify land cover classes within the image. To minimize processing, the raster imagery was resampled to 2 meters, and then processed through a majority filter to further generalize the resulting output image. The areas of the resulting raster that corresponded with tamarix coverage were exported and converted to a polygon shapefile. This process is depicted in Exhibit 1.

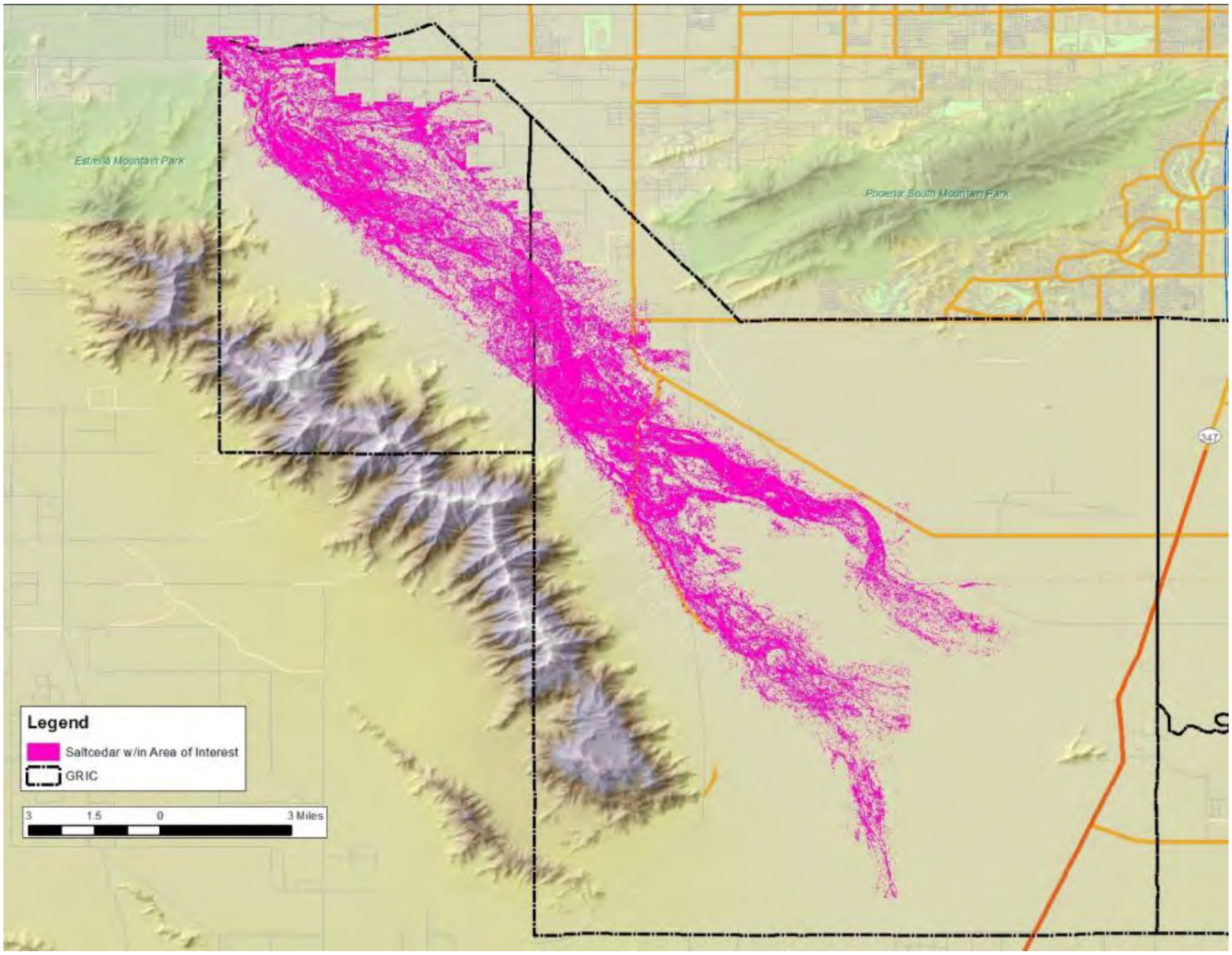
Exhibit 1. Progression from 4-band NAIP Raster Image to Polygon of Saltcedar Coverage



1. Four-band NAIP Orthoimagery
2. Reclassified to five-zone raster.
3. Five-zone raster after resampling and majority filter.
4. Resulting polygon of saltcedar coverage

To facilitate the creation of a riparian area management plan, the generated polygon was merged with shapefiles that correspond to the township, range, section, and quarter-quarter sections of the Public Land Survey System. Finally, acreage was calculated for the resulting saltcedar polygons, and the data was exported to an Excel spreadsheet. The entire area of saltcedar within the previously identified corridor, as calculated from the orthoimagery, is depicted in Exhibit 2.

Exhibit 2. Areas of Saltcedar Infestation



Appendix B

Fuel Testing Analysis Results

Hazen Research, Inc.
4601 Indiana Street
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

Date:	July 31, 2013
Project No:	002-FLQ
Control No:	G207/13
Received:	07/19/13
PO Number:	

Antares Group, Inc.
Anneliese Schmidt
1601 Corporate Circle #7263
Petaluma, CA 94955

Sample Number: G207/13	-4	-7
Sample Identification:	Salr Cedar-01-B	Salt Cedar-02-B
Air Dry Loss, %	20.21	40.42
Residual Moisture, %	14.63	7.70
As Received Moisture, %	31.88	45.01
Mercury (Air Dry Basis), mg/kg	< 0.01	< 0.01
Mercury (As Received Basis), mg/kg	< 0.008	< 0.006
Mercury (Dry Basis), mg/kg	< 0.01	< 0.01
Metals in Ash		
Cadmium, mg/kg	9	10
Lead, mg/kg	9	7

The ash was prepared at 600 degrees Celsius.

By:

Gerard H. Cunningham
Fuel Laboratory Manager

Hazen Research, Inc.
4601 Indiana Street
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

Date	July 30 2013
HRI Project	002-FQL
HRI Series No.	G207/13-1
Date Rec'd.	07/19/13
Cust. P.O.#	

Antares Group, Inc.
Anneliese Schmidt
1536 Baywood Drive
Petaluma, CA 94954

Sample Identification
Guayule-07162013-A

-

Reporting Basis >	As Rec'd	Dry	Air Dry
Proximate (%)			
Moisture	56.59	0.00	3.43
Ash	2.58	5.93	5.73
Volatile	35.16	81.01	78.23
Fixed C	5.67	13.06	12.61
Total	100.00	100.00	100.00
Sulfur	0.036	0.084	0.081
Btu/lb (HHV)	4468	10292	9939
Btu/lb (LHV)	3617	9676	
MMF Btu/lb	4595	10998	
MAF Btu/lb		10941	
Ultimate (%)			
Moisture	56.59	0.00	3.43
Carbon	24.10	55.52	53.62
Hydrogen	2.88	6.64	6.42
Nitrogen	0.25	0.58	0.56
Sulfur	0.04	0.08	0.08
Ash	2.58	5.93	5.73
Oxygen*	13.56	31.25	30.16
Total	100.00	100.00	100.00
Chlorine**	0.068	0.157	0.152

Air Dry Loss (%) 55.05

Forms of Sulfur,as S,(%)

	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	0.04	0.08

Water Soluble Alkalies (%)

Na2O
K2O

Lb. Alkali Oxide/MM Btu=	
Lb. Ash/MM Btu=	5.77
Lb. SO2/MM Btu=	0.16
Lb. Cl/MM Btu=	0.15
As Rec'd. Sp.Gr.=	
Free Swelling Index=	
F-Factor(dry),DSCF/MM Btu=	9,221

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.

HAZEN
Hazen Research, Inc.
4601 Indiana Street
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Tel: (303) 279-4501
Fax: (303) 278-1528

Date July 30 2013
HRI Project 002-FQL
HRI Series No. G207/13-2
Date Rec'd. 07/19/13
Cust. P.O.#

Antares Group, Inc.
Anneliese Schmidt
1536 Baywood Drive
Petaluma, CA 94954

Sample Identification
Guayule-07162013-B

Reporting Basis >	As Rec'd	Dry	Air Dry
Proximate (%)			
Moisture	48.92	0.00	3.23
Ash	2.91	5.70	5.52
Volatile	41.11	80.49	77.89
Fixed C	7.06	13.81	13.36
Total	100.00	100.00	100.00
Sulfur	0.087	0.171	0.165
Btu/lb (HHV)	5123	10031	9707
Btu/lb (LHV)	4319	9442	
MMF Btu/lb	5288	10691	
MAF Btu/lb		10638	
Ultimate (%)			
Moisture	48.92	0.00	3.23
Carbon	28.13	55.07	53.29
Hydrogen	3.25	6.35	6.15
Nitrogen	0.32	0.63	0.61
Sulfur	0.09	0.17	0.17
Ash	2.91	5.70	5.52
Oxygen*	16.38	32.08	31.03
Total	100.00	100.00	100.00
Chlorine**	0.078	0.152	0.147

Air Dry Loss (%) 47.22

Forms of Sulfur, as S, (%)

	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	0.09	0.17

Water Soluble Alkalies (%)

Na2O
K2O

Lb. Alkali Oxide/MM Btu=	
Lb. Ash/MM Btu=	5.69
Lb. SO2/MM Btu=	0.34
Lb. Cl/MM Btu=	0.15
As Rec'd. Sp.Gr.=	
Free Swelling Index=	
F-Factor(dry),DSCF/MM Btu=	9,253

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.

HAZEN

Hazen Research, Inc.
4601 Indiana Street
Golden, CO 80403 USA
Tel: (303) 279-4501
Fax: (303) 278-1528

Date	July 30 2013
HRI Project	002-FQL
HRI Series No.	G207/13-3
Date Rec'd.	07/19/13
Cust. P.O.#	

Antares Group, Inc.
Anneliese Schmidt
1536 Baywood Drive
Petaluma, CA 94954

Sample Identification
Salt Cedar-01-A

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Reporting Basis >	As Rec'd	Dry	Air Dry
Proximate (%)			
Moisture	31.20	0.00	16.16
Ash	4.91	7.13	5.98
Volatile	59.96	87.15	73.07
Fixed C	3.93	5.72	4.79
Total	100.00	100.00	100.00
Sulfur	0.862	1.252	1.050
Btu/lb (HHV)	5318	7730	6481
Btu/lb (LHV)	4688	7281	
MMF Btu/lb	5599	8370	
MAF Btu/lb		8324	
Ultimate (%)			
Moisture	31.20	0.00	16.16
Carbon	32.44	47.15	39.53
Hydrogen	3.33	4.84	4.06
Nitrogen	0.25	0.37	0.31
Sulfur	0.86	1.25	1.05
Ash	4.91	7.13	5.98
Oxygen*	27.01	39.26	32.91
Total	100.00	100.00	100.00
Chlorine**	0.382	0.555	0.465

Air Dry Loss (%) 17.94

Forms of Sulfur, as S, (%)		
Sulfate		
Pyritic		
Organic		
Total	0.86	1.25

Water Soluble Alkalies (%)

Na2O
K2O

Lb. Alkali Oxide/MM Btu=	
Lb. Ash/MM Btu=	9.23
Lb. SO2/MM Btu=	3.24
Lb. Cl/MM Btu=	0.72
As Rec'd. Sp.Gr.=	
Free Swelling Index=	
F-Factor(dry),DSCF/MM Btu=	9,376

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
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Date July 30 2013
HRI Project 002-FQL
HRI Series No. G207/13-4
Date Rec'd. 07/19/13
Cust. P.O.#

Antares Group, Inc.
Anneliese Schmidt
1536 Baywood Drive
Petaluma, CA 94954

Sample Identification
Salt Cedar-01-B

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Reporting Basis >	As Rec'd	Dry	Air Dry
Proximate (%)			
Moisture	31.88	0.00	14.63
Ash	7.25	10.65	9.09
Volatile	57.25	84.05	71.75
Fixed C	3.62	5.30	4.53
Total	100.00	100.00	100.00
Sulfur	1.285	1.886	1.610
Btu/lb (HHV)	5081	7459	6368
Btu/lb (LHV)	4453	7020	
MMF Btu/lb	5485	8420	
MAF Btu/lb		8348	
Ultimate (%)			
Moisture	31.88	0.00	14.63
Carbon	30.83	45.26	38.64
Hydrogen	3.23	4.74	4.04
Nitrogen	0.26	0.39	0.33
Sulfur	1.28	1.89	1.61
Ash	7.25	10.65	9.09
Oxygen*	25.27	37.07	31.66
Total	100.00	100.00	100.00
Chlorine**	0.591	0.868	0.741

Air Dry Loss (%) 20.21

Forms of Sulfur,as S,(%)

	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	1.28	1.89

Water Soluble Alkalies (%)

Na20
K20

Lb. Alkali Oxide/MM Btu=
Lb. Ash/MM Btu= 14.27
Lb. S02/MM Btu= 5.06
Lb. Cl/MM Btu= 1.16
As Rec'd. Sp.Gr.=
Free Swelling Index=
F-Factor(dry),DSCF/MM Btu= 9,459

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.

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Date	July 30 2013
HRI Project	002-FQL
HRI Series No.	G207/13-5
Date Rec'd.	07/19/13
Cust. P.O.#	

Antares Group, Inc.
Anneliese Schmidt
1536 Baywood Drive
Petaluma, CA 94954

Sample Identification
Salt Cedar-01-C

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Reporting Basis >	As Rec'd	Dry	Air Dry
Proximate (%)			
Moisture	27.98	0.00	11.58
Ash	7.31	10.16	8.98
Volatile	59.79	83.02	73.41
Fixed C	4.92	6.82	6.03
Total	100.00	100.00	100.00
Sulfur	1.262	1.753	1.550
Btu/lb (HHV)	5525	7672	6783
Btu/lb (LHV)	4903	7208	
MMF Btu/lb	5975	8612	
MAF Btu/lb		8539	
Ultimate (%)			
Moisture	27.98	0.00	11.58
Carbon	33.06	45.91	40.59
Hydrogen	3.60	5.00	4.42
Nitrogen	0.30	0.42	0.37
Sulfur	1.26	1.75	1.55
Ash	7.31	10.16	8.98
Oxygen*	26.49	36.76	32.51
Total	100.00	100.00	100.00
Chlorine**	0.577	0.802	0.709

Air Dry Loss (%) 18.55

Forms of Sulfur,as S,(%)

	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	1.26	1.75

Water Soluble Alkalies (%)

Na2O
K2O

Lb. Alkali Oxide/MM Btu=	
Lb. Ash/MM Btu=	13.24
Lb. SO2/MM Btu=	4.57
Lb. Cl/MM Btu=	1.05
As Rec'd. Sp.Gr.=	
Free Swelling Index=	
F-Factor(dry),DSCF/MM Btu=	9,463

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.

Hazen Research, Inc.
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Date	July 30 2013
HRI Project	002-FQL
HRI Series No.	G207/13-6
Date Rec'd.	07/19/13
Cust. P.O.#	

Antares Group, Inc.
Anneliese Schmidt
1536 Baywood Drive
Petaluma, CA 94954

Sample Identification
Salt Cedar-02-A

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Reporting Basis >	As Rec'd	Dry	Air Dry
Proximate (%)			
Moisture	28.72	0.00	11.27
Ash	6.90	9.68	8.59
Volatile	62.38	87.51	77.65
Fixed C	2.00	2.81	2.49
Total	100.00	100.00	100.00
Sulfur	1.277	1.792	1.590
Btu/lb (HHV)	5308	7448	6608
Btu/lb (LHV)	4681	6982	
MMF Btu/lb	5710	8309	
MAF Btu/lb		8246	
Ultimate (%)			
Moisture	28.72	0.00	11.27
Carbon	32.11	45.05	39.97
Hydrogen	3.58	5.03	4.46
Nitrogen	0.39	0.54	0.48
Sulfur	1.28	1.79	1.59
Ash	6.90	9.68	8.59
Oxygen*	27.02	37.91	33.64
Total	100.00	100.00	100.00
Chlorine**	0.361	0.506	0.449

Air Dry Loss (%) 19.67

Forms of Sulfur,as S,(%)

	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	1.28	1.79

Water Soluble Alkalies (%)

Na2O
K2O

Lb. Alkali Oxide/MM Btu=	
Lb. Ash/MM Btu=	13.00
Lb. SO2/MM Btu=	4.81
Lb. Cl/MM Btu=	0.68
As Rec'd. Sp.Gr.=	
Free Swelling Index=	
F-Factor(dry),DSCF/MM Btu=	9,516

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.

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Golden, CO 80403 USA
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Date	July 30 2013
HRI Project	002-FQL
HRI Series No.	G207/13-7
Date Rec'd.	07/19/13
Cust. P.O.#	

Antares Group, Inc.
Anneliese Schmidt
1536 Baywood Drive
Petaluma, CA 94954

Sample Identification
Salt Cedar-02-B

-

Reporting Basis >	As Rec'd	Dry	Air Dry
Proximate (%)			
Moisture	45.01	0.00	7.70
Ash	5.13	9.33	8.61
Volatile	42.98	78.16	72.14
Fixed C	6.88	12.51	11.55
Total	100.00	100.00	100.00
Sulfur	0.673	1.224	1.130
Btu/lb (HHV)	4162	7569	6986
Btu/lb (LHV)	3435	7090	
MMF Btu/lb	4388	8412	
MAF Btu/lb		8348	
Ultimate (%)			
Moisture	45.01	0.00	7.70
Carbon	25.04	45.54	42.03
Hydrogen	2.84	5.17	4.77
Nitrogen	0.36	0.66	0.61
Sulfur	0.67	1.22	1.13
Ash	5.13	9.33	8.61
Oxygen*	20.95	38.08	35.15
Total	100.00	100.00	100.00
Chlorine**	0.667	1.213	1.120

Air Dry Loss (%) 40.42

Forms of Sulfur, as S, (%)

	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	0.67	1.22

Water Soluble Alkalies (%)

Na2O
K2O

Lb. Alkali Oxide/MM Btu=	
Lb. Ash/MM Btu=	12.32
Lb. SO2/MM Btu=	3.23
Lb. Cl/MM Btu=	1.60
As Rec'd. Sp.Gr.=	
Free Swelling Index=	
F-Factor(dry),DSCF/MM Btu=	9,479

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.

HAZEN

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Date	July 30 2013
HRI Project	002-FQL
HRI Series No.	G207/13-8
Date Rec'd.	07/19/13
Cust. P.O.#	

Antares Group, Inc.
Anneliese Schmidt
1536 Baywood Drive
Petaluma, CA 94954

Sample Identification
Salt Cedar-02-B

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Reporting Basis >	As Rec'd	Dry	Air Dry
Proximate (%)			
Moisture	37.36	0.00	14.80
Ash	6.54	10.45	8.90
Volatile	49.09	78.37	66.77
Fixed C	7.01	11.18	9.53
Total	100.00	100.00	100.00
Sulfur	1.081	1.725	1.470
Btu/lb (HHV)	4662	7443	6341
Btu/lb (LHV)	3998	6997	
MMF Btu/lb	4990	8382	
MAF Btu/lb		8311	
Ultimate (%)			
Moisture	37.36	0.00	14.80
Carbon	28.23	45.07	38.40
Hydrogen	3.01	4.81	4.09
Nitrogen	0.39	0.62	0.53
Sulfur	1.08	1.73	1.47
Ash	6.54	10.45	8.90
Oxygen*	23.39	37.32	31.81
Total	100.00	100.00	100.00
Chlorine**	0.443	0.707	0.602

Air Dry Loss (%) 26.48

Forms of Sulfur, as S, (%)

	As Rec'd	Dry
Sulfate		
Pyritic		
Organic		
Total	1.08	1.73

Water Soluble Alkalies (%)

Na2O
K2O

Lb. Alkali Oxide/MM Btu=	
Lb. Ash/MM Btu=	14.04
Lb. SO2/MM Btu=	4.64
Lb. Cl/MM Btu=	0.95
As Rec'd. Sp.Gr.=	
Free Swelling Index=	
F-Factor(dry),DSCF/MM Btu=	9,451

Report Prepared By:

Gerard H. Cunningham
Fuels Laboratory Supervisor

* Oxygen by Difference.
** Not usually reported as part of the ultimate analysis.