Lincoln County, NV

and

A-Power Energy Generation Systems, Ltd.

Biomass Heat and Power Feasibility Study

DRAFT

THE BECK GROUP

Project Report
December 2010

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List of Acronyms Used in This Report:

$/BDT	Dollars per Bone Dry Ton
$/MWh	Dollars per Megawatt hour
ACC	air cooled condenser ()
Acre-ft./yr.	Acre Feet per Year
A-Power	A-Power Energy Generation Systems, Ltd
BAPC	Bureau of Air Pollution Control
BDT/Acre	Bone Dry Tons per Acre
BDTs	Bone Dry Tons
BECK	The Beck Group
BLM	Bureau of Land Management
BTU	British Thermal Units
BTU/BDT	British Thermal Units per Bone Dry Ton
BWM	Bureau of Waste Management
BWQP	Bureau of Water Quality Planning
cents/KWh	Cents per Kilowatt hour
CHP	Combined Heat and Power
CHP ITC	Combined Heat and Power Investment Tax Credit
CO	Carbon Monoxide
CSPC	Carlson Small Power Consultants
EIA	Energy Information Agency
EIS	Environmental Impact Statement
Ely RMP	Ely Resource Management Plan
EPA	Environmental Protection Agency
EPC	Engineering Procurment and Construction
EPS	Energy Portfolio Standard
EWG	Exempt Wholesale Generator
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information System
HAPs	Hazardous Air Pollutants
ITC	Investment Tax Credit ()
KV	Kilovolt
KW	Kilowatt
KWh	Kilowatt hours
LC	Lincoln County
LCPD	Lincoln County Power District
LCPD	Lincoln County Power District No. 1
MACRS	Modified Accelerated Cost Recovery System ()
MDF	Medium-density fiberboard
MPR	Market Price Referent

List of Acronyms Used in This Report:

MVa	Megavolt ampere
MW	Megawatt
MWh	Megawatt hours
MWh	Megawatt hour
NDEP	Nevada Division of Environmental Protection
NEPA	National Environmental Protection Act
NMTCs	New Market Tax Credits ()
NO_x	Nitrogen Oxides
OATT	Open Access Transmission Tariff
OSB	Oriented-strand board
PEC	Portfolio Energy Credit
PEC/KWh	Portfolio Energy Credit per Kilowatt hour
P-J	Pinyon-Juniper
PM-10	Particulate less than 10 microns
PSD	Prevention of Significant Deterioration
psig	Pounds per Square Inch Gauge
PTC	Production Tax Credit
PUC	Public Utilities Commission
PURPA	Public Utility Regulatory Policies Act
QFs	Qualifying Facilities
RECs	Renewable Energy Credits
RFP	Request for Proposals
RPS	Renewable Portfolio Standards
RUS	Rural Utilities Service ()
SAP	stand alone power ()
SCPPA	Southern California Public Power Authority
T-G	Turbine Generator
TPY	Tons Per Year
TRECs	Tradable Renewable Energy Credits
USDOE	U.S. Department of Energy
WECC	Western Electricity Coordinating Council

CHAPTER 1 – EXECUTIVE SUMMARY

1.1 INTRODUCTION

This report explores the feasibility of developing a sustainable, Pinyon-Juniper (P-J) fueled power plant at two prospective sites (Prince and Pony Springs Substations) in Lincoln County, Nevada. Participants in the study included Lincoln County (LC); A-Power Energy Generation Systems, Ltd (A-Power); Lincoln County Power District No. 1 (LCPD); and the Bureau of Land Management (BLM). LCPD and BLM provided data on the supply of biomass, the cost of planning and administering vegetative treatments, and the ability of the existing LCPD transmission lines to transmit power. With this high-quality data and cooperation, the project study team analyzed all aspects of the feasibility of developing biomass energy in Lincoln County, Nevada. This Executive Summary briefly recaps the findings in each area of analysis, as well as the high-level recommendations about the feasibility of biomass fueled power in Lincoln County.

The rationale for siting a biomass fueled power plant in Lincoln County is two-fold: First, it is envisioned that the BLM can administer a long-term stewardship contract aimed at restoring and rehabilitating the 2.91 million acres of P-J woodlands in the region that the BLM's Ely Resource Management Plan (Ely RMP) has identified as overmature. As part of the restoration process, the stewardship contracts would also allow for biomass fuel to be supplied to the prospective power plant. Second, one of the project sponsors, A-Power has recently started a manufacturing facility in Southern Nevada with a relatively large requirement for power. A-Power is interested in the feasibility of supplying that facility with renewable power or selling renewable power to the power grid.

1.2 KEY REPORT FINDINGS

1.2.1 Review of Previous Studies

A number of prior studies have examined the cost of treating P-J forests. In general, those studies reported costs in terms of dollars per acre. While that information is useful to land managers, it is of limited use for the purposes of this study because costs must be known on a dollars per ton basis. Nevertheless, the previous research provided insights that created a beginning point for understanding critical factors such as fuel volumes per acre and the equipment typically used to treat P-J.

1.2.2 Review of Alternate Products

From a technology perspective, there are many products that could be made from P-J, including mulch, animal bedding, wood pellets, panel products, pulp chips, etc. However, from a cost perspective, there are significant limitations on what products can cost effectively be made from P-J. This is because the cost of delivering P-J biomass to a facility can range between $75 to nearly $175 per bone dry ton, depending on the characteristics of the woodlands from which it was harvested. Even at the low end of that scale, the costs are high relative to wood fiber that can be obtained from other sources (e.g., roundwood from timber harvests and by-products from sawmilling operations).

Despite the cost limitation, there are several products that can most likely feasibly utilize P-J. These include firewood, posts and poles, and rustic furniture. The upside for firewood is that it is available locally and, therefore, is likely a lower cost alternative than firewood shipped in from other regions. Limitations of the firewood option are that a large-scale operation is not likely because the character of the wood (many limbs and twisted and bent logs) makes it difficult for mechanized firewood processing equipment to effectively handle the material, and local markets for which it has a cost advantage are very limited. The same is true of using P-J to make posts and poles. On the other hand, there is likely a market among certain agricultural producers seeking to minimize the presence of chemicals from preservative treated wood posts and poles. In any case, it does not appear that these products could be produced on a large enough scale to allow landscape level vegetative management treatments.

1.2.3 Biomass Fuel Supply Assessment

There is an estimated 4.8 million bone dry tons of fuel within 50 miles of the Pony Springs Substation and an estimated 5.4 million bone dry tons of fuel within 50 miles of the Prince Substation. The 10 MW power plant considered in this study would consume about 67,300 bone dry tons[1] of fuel annually. Thus, fuel supply is not a limiting factor to the feasibility of biomass power in Lincoln County. In the vegetative management scenario considered in this study, that amount of fuel would come from the treatment of approximately 9,800 acres of P-J each year (approximately 6.9 bone dry tons of fuel per acre).

The cost of delivering that P-J biomass to a prospective power plant is more problematic, however. In the first year of plant operation, the all inclusive cost for delivering P-J fuel is estimated to be about $96.50 per bone dry ton. This includes costs of about $79.00 per bone dry ton for harvesting, skidding, chipping and transporting, $2.50 per bone dry ton for rehabilitating treated areas, and a $15.00 per bone dry ton cost incurred by the BLM for planning and administering a stewardship contract designed to simultaneously restore P-J woodlands and provide fuel to the prospective facility.

[1] Throughout this report, biomass volume is expressed in units of bone dry tons. This convention is used in the biomass industry because it eliminates moisture as a variable when describing fuel volumes. In actual practice, all biomass contains some level of moisture, which can typically range from as low as 20 percent to over 50 percent of the total weight. For this study, it was assumed that biomass would average 40 percent moisture when delivered to the power plant. Thus, the actual weight of biomass fuel as received is the bone dry volume divided by 0.60. For example, 66,000 bone dry tons equals 110,000 green tons.

The estimated delivered costs are significantly higher than fuel costs observed in projects in other regions. The project team has not discovered a reasonable scenario under which a power generation project in Lincoln County could afford to pay the all inclusive cost of P-J restoration treatments.

1.2.4 Review of Potential Plant Sites

Two potential plant sites were selected prior to the start of this study – the Prince and Pony Springs Substations of the LCPD. Both substations connect directly to the main 69 KV transmission line that forms the backbone of the LCPD power distribution system. The Prince Substation currently has a 15 MVa transformer, whereas the Pony Springs Substation has only a 3 MVa transformer.

Both existing transformers receive power at 69 KV and step it down to 24.9 KV when it leaves the main transmission line. Tying a generation project onto this system with additional transformation is somewhat problematic since most generators matched to a 10 MW power plant generate power at either 12.47 KV or 13.8 KV.

Other considerations in plant siting include proximity to fuel, permitting issues, water availability, and the presence (or lack thereof) of heat customers. Based on all of those considerations, the Prince Substation site appears more favorable.

1.2.5 Review of Thermal Energy Users

While several potential thermal energy users exist in Lincoln County, none possess the characteristics that would make them ideal (e.g., use of 10 percent or more of the residual heat, use of low pressure steam to allow for maximizing power generating efficiency, and only limited variation in demand). Of the existing thermal energy users, the largest would consume only one half of one percent of the thermal energy available from turbine extraction or exhaust. For this reason, the decision was made not to site the facility at a location with an identified thermal energy user, but to instead site the facility at an effective interconnection point and in the center of the available fuel supply.

1.2.6 Transmission Infrastructure

The LCPD's main transmission line is 69 KV and is radial. The peak load of the system is about 18 MW. Unless loads are particularly heavy, all power comes from an allocation on the federal hydroelectric system on the Colorado River. The radial nature of the system means that it is interconnected with the power grid only in the vicinity of Las Vegas, but not "looped" or interconnected with the power grid at the far northern end of the line. Substantial line loss is a characteristic of radial systems that transmit power over long distances (9-10 percent of all power in this case). Thus, the development of a power plant in Lincoln County would benefit LCPD in terms of lowering line loss. Any power sold from the prospective project would travel south to the Reid Gardner Substation of NV Energy. From there, it could be wheeled through various interconnections to Southern California or other interconnected locations in the West. This is a positive finding for the prospective power plant.

1.2.7 Markets for Renewable Power

A number of laws affect the market price of other power with which biomass power must compete. The Public Utilities Regulatory Policies Act (PURPA) requires utilities to purchase power from qualifying independent facilities at the utility's avoided cost. Avoided cost is the incremental cost an electric utility avoids incurring by purchasing an equivalent amount of power from a Qualifying Facility (QF). A facility only qualifies if the fuel used to generate the power is renewable or is waste derived. In Nevada, the Public Utilities Commission (PUC) does the calculation of the utility's avoided cost, but has no jurisdiction over LCPD who has a very low "avoided cost" for nearly all of the year.

Subsequent laws also required public utilities and power marketing agencies to "wheel" power across their systems to other buyers, if requested. The cost of wheeling is regulated.

Finally, Nevada passed a Renewable Portfolio Standard (RPS) in 2009 that requires NV Energy to obtain 15 percent of its power from renewable sources by 2011 – 2012, 18 percent during 2013 – 2014, 20 percent during 2015 – 2019, 22 percent during 2020 – 2024, and 25 percent after 2025.

NV Energy has responded to the RPS with Requests for Proposals (RFPs) for renewable power. NV Energy then selects projects for development from the proposals. Recent winning bidders among non-solar projects have been awarded contracts in the range of $81 – $98/MWh with a 1 percent annual escalation. For solar projects, which have a separate RPS requirement, the prices have been from $132 – $135/MWh with the same 1 percent escalator. For this study a power price of $95 per MWh was assumed.

1.2.8 Environmental Permitting & Regulatory Requirements

The permitting of a 10MW project at the Prince substation should present no unusual permitting challenges. The Lincoln County Special Use Permit process will cover all local issues with respect to access, noise, traffic, aesthetics, etc. and will require several months to complete. The Nevada Division of Environmental Protection (NDEP) has a streamlined process for the permitting of renewable energy facilities. With the use of dry cooling, the issues of water and wastewater are rendered minor, and it is assumed that the moderate volumes of ash produced will be reused.

The air emission control equipment proposed will require a Class I permit from NDEP, which will likely require in excess of one year to obtain due to the necessity to model emissions using representative long term meteorological data. All of eastern Nevada, north of Las Vegas, is in compliance with all ambient air quality standards, simplifying the permitting process.

1.2.9 Technology Assessment

A boiler with a moving-grate, air-swept stoker system is appropriate for combusting P-J woody biomass. That technology is mature and proven. In addition, the base case scenario considered in this project assumes use of an air-cooled condensing system. The advantage of such a system is that it virtually eliminates the need for water at the prospective plant. However, the penalty paid for such a system is that it raises the capital cost of the project by about 10 percent and lowers the efficiency of the electrical generation process by about 6 percent. Conservatism dictated that an air cooled system be the base case, but a wet cooled system is included in the sensitivity analysis.

1.2.10 Incentive Programs and Project Financing

The capital investment of $47.5 million for the biomass power plant modeled in this study will be a major financing effort and will require substantial financial strength and strong financial packaging expertise by the developer.

Numerous state and federal programs can help facilitate the financing of alternative energy projects. There are state sales tax credits and a property tax reduction for renewable production facilities of 10MW or more in Nevada. At the federal level, an investment tax credit/production tax credit election is available, but the election feature is programmed to disappear at the end of 2010, and no extension is foreseen. Also potentially available are a CHP Tax Credit, accelerated depreciation, and other federal grant/loan guarantee programs.

In some instances, other programs may be layered on to support project financing. These including New Markets Tax Credits, Rural Utilities Service Loan Program, Local Revenue Bonds, U.S. Department of Agriculture Loan Guarantee, U.S. Department of Energy Loan Guarantee, Site Lease to a Third Party Developer, Partnership with Purchasing Utility, and Prepayment for Power, as appropriate in each individual case.

1.2.11 Financial Analysis

The capital cost, including the required equipment, project management, site preparation, working capital, interconnection, fuel receiving, etc. is estimated to be $47.5 million. That information, along with operating costs, was entered into a "base case" financial model. The financial model was structured to return a fuel cost at which the power plant would provide the project's investors with a 15 percent net present value after tax return on their equity.

The result of the analysis was that the "allowable" fuel cost was $27.00 per bone dry ton, which is nearly $70.00 per bone dry ton less than the estimated all inclusive delivered fuel price finding in the fuel supply analysis. This means that the annual fuel cost would have to be $4.71 million lower than projected for the project to generate a return that would be acceptable to a private investor.

In addition to the “base case” scenario, a “best case” scenario was modeled in which key assumptions about financing, owner’s equity, and the required rate of return were loosened. Despite the modifications, the “best case” scenario still returned an “allowable” fuel cost of $52.00 per bone dry ton, which is still roughly $44.00 per bone dry ton less than the all inclusive estimated delivered cost.

1.3 CONCLUSIONS AND RECOMMENDATIONS

This study demonstrated that there is an adequate supply of biomass fuel available from the P-J woodlands in Lincoln County. In addition, the BLM has indicated a willingness to enter into long-term supply agreements through stewardship contracts. Other key factors such as transmission, interconnection, permitting, and technology provide no significant obstacles to the development of a biomass fueled power plant. However, the high cost of delivering P-J fuel to the prospective facility severely limits the feasibility of the project. It is clear that a biomass plant in Lincoln County cannot be developed using the traditional model of the power project paying the complete cost of P-J removal as a fuel cost. Cost sharing models must be pursued if such a project is to go forward, and a larger plant should be investigated further as well as mechanisms to enhance the value of P-J generated power in NV.

CHAPTER 2 – INTRODUCTION

2.1 PROJECT DESCRIPTON

Lincoln County is located in Southeastern Nevada and has a total land area of 10,637 square miles or approximately 6.8 million acres. The area is characterized by two climate types: 1) arid desert – mainly in the southern third of the county and 2) semi-arid steppe – mainly in the northern two-thirds of the county.

Woodlands comprised of Single-leaf Pinyon Pine and Utah Juniper, known collectively as Pinyon-Juniper (P-J), cover a significant portion of the land area in Lincoln County. While both species can be found growing together, Pinyon Pine is generally the dominant species at higher elevations, while Juniper is more likely to be found at lower elevations that are usually more likely to face drought conditions. Trees of both species are normally no more than 25 feet tall.

The Bureau of Land Management (BLM) is a federal agency of the Department of Interior that is responsible for managing and conserving public land, including P-J woodlands. In Lincoln County, BLM lands are managed by the Ely District Office and the Caliente Field Office. According to the Ely Resource Management Plan (Ely RMP)[2], the Ely District, which includes both White Pine and Lincoln Counties, contains a total of about 3.6 million acres of P-J. Of that total, 2.91 million P-J acres are currently classified as overmature. The Ely RMP states that the desired condition is for only 179,000 acres of overmature P-J woodlands to exist.

Those statistics illustrate a widespread trend in the Great Basin region; P-J woodlands are expanding both in extent and density. It is estimated that P-J woodlands in Nevada expand by 100,000 acres annually. The impacts of these changing conditions include: increased susceptibility to wildfire, disease, and insects and reduced viability of native plant species that provide feed, water, cover, and living space for animal species. To mitigate these adverse impacts, the BLM (through the Ely RMP) is proposing vegetative treatment prescriptions aimed at establishing healthy, productive, and diverse populations of native or desirable nonnative plant species.

It is envisioned that these vegetative treatments, as well as other land management activities, could be accomplished through long term stewardship contracts. Stewardship contracting is a relatively new approach to federal land management in which management treatments are accomplished by allowing private organizations or businesses to remove forest products (e.g., trees, biomass, etc.) in exchange for

[2] Ely Proposed Resource Management Plan/Final Environmental Impact Statement, November 2007. Available at: http://www.blm.gov/nv/st/en/fo/ely_field_office/blm_programs/planning/ely_rmp_2007.html

performing services to restore and maintain healthy ecosystems. For example, mechanical thinning may be used to reduce tree densities to desired levels. In exchange for the cost of completing such activities, private organizations or businesses would be allowed to sell the resulting biomass or forest products.

Historically, a difficulty in implementing mechanical thinning projects in P-J woodlands is the cost. Thus, a secondary objective of this study is to identify the value returned to the land by the vegetative treatment of P-J forests and the subsequent sale of biomass for energy generation purposes.

Since biomass can be used to generate renewable power, the economics of mechanical thinning may change as demand for renewable power develops. The need for renewable power is being driven by the adoption of Renewable Portfolio Standards (RPS) throughout the United States. An RPS is a law that requires certain utilities in a state to get a certain percentage of their power from renewable sources by a certain date. Nevada's RPS calls for 25 percent renewable power by the year 2025. Power generated from the combustion of woody biomass qualifies as renewable.

Thus, given the need to develop renewable power and given the biomass available from the restoration of P-J forests, Lincoln County (LC) and A-Power Energy Generation Systems, Ltd. (A-Power) have agreed to jointly fund a study to determine the feasibility of constructing and operating a P-J fueled electric generating facility at two prospective sites – the Prince Substation (located near Caselton, NV) and the Pony Springs Substation (located about 30 miles north of Pioche, NV). A-Power is supporting this study because they recently began operating a manufacturing facility in Southern Nevada. Given that facility's need for power, they are interested in the feasibility of using renewable power generated by this prospective project to supply the facility. In addition, A-Power is interested in the feasibility of selling renewable power to the power grid.

LC and A-Power have retained the services of The Beck Group (BECK), a Portland, Oregon based forest products and bioenergy planning and consulting firm. BECK is assisted in its work by Mr. Bill Carlson, Principal of Carlson Small Power Consultants (CSPC) of Redding, California.

The following report contains the complete findings of BECK and CSPC. Both BECK and CSPC appreciate the opportunity to assist on this important project.

2.2 BIOMASS POWER

A biomass-fueled power plant produces useable heat and electrical power through the combustion of wood fiber. More specifically, biomass materials are combusted in a furnace. The biomass materials typically combusted include: 1) forest residues (thinning and restoration biomass); 2) mill by-products – bark, sawdust, planer shavings, and pulp chips; and 3) urban wood waste – construction and demolition waste, industrial wood waste, and municipal wood waste. The walls of the furnace are lined with water filled pipes, so as the biomass is combusted, the high pressure water in the pipes boils to steam. The steam is then heated to a higher temperature before exiting the boiler and entering the turbine generator (T-G).

The T-G is a rotating multi-stage unit that drops the steam temperature and pressure at each stage as thermal energy is converted into mechanical energy and eventually into electricity in the generator. In some cases, steam is extracted from the T-G at an appropriate pressure for use in heating applications (e.g., heat for drying lumber, or some other manufacturing process, or space heating). When some steam is used in a heat application, it is called cogeneration, or combined heat and power (CHP). When the heat is not utilized, it is called stand alone power (SAP). In this report, BECK uses the term power plant and does not differentiate between the two facility types.

Through the process just described, biomass fuel is converted into electricity and useful heat. Historically, the cost of producing biomass-fueled power relative to the cost of fossil fuel and hydro-generated power has been a stumbling block. However, this situation is changing with the advent of RPSs and an associated appreciation in the value of renewable power, as well as with the introduction and continuation of government incentives for the development of renewable power. All of these factors have combined to increase the viability of biomass energy projects.

2.3 PROJECT ORGANIZATION

This report explores the feasibility of developing a sustainable, biomass-fueled power plant in the vicinity of Pioche, Nevada. The project has been organized into a series of tasks, each of which addresses a particular aspect of biomass power feasibility. The tasks and their corresponding chapter in this report are listed below.

Task 1	Compile and Review Previous Background Information and Relevant Research (Chapter 3)
Task 2	Review of Alternative Markets and Products (Chapter 4)
Task 3	Biomass Fuel Supply Assessment (Chapter 5)
Task 4	Assessment of Potential Plant Sites (Chapter 6)
Task 5	Identification of Thermal Energy Uses in Lincoln County (Chapter 7)
Task 6	Review of Power Transmission Infrastructure (Chapter 8)
Task 7	Market Analysis of Power Sales (Chapter 9)
Task 8	Evaluation of Optimal Facility Scale (Chapter 10)
Task 9	Environmental Permitting & Regulatory Requirements (Chapter 11)
Task 10	Evaluation of Energy Production Technology (Chapter 12)
Task 11	Incentive Programs (Chapter 13)
Task 12	Financial Analysis of Biomass Power Generation Facility at the Preferred Site (Chapter 14)

CHAPTER 3 – REVIEW OF PREVIOUS STUDIES

3.1 INTRODUCTION

In recent years, several studies have been completed relating to the management and utilization of P-J biomass in Lincoln County. These include:

- *Pinyon-Juniper Biomass Utilization Study* – August, 2004, and a 2005 update
- *Pinyon-Juniper Biomass Utilization Study – Cost Documentation Report* – August, 2004
- *Industrial Utilization of Pinyon-Juniper Biomass Resulting From Thinning Treatments in White Pine and Lincoln Counties* – June, 2005
- *Analysis of Potential Industrial Demands of Pinyon-Juniper Resources in Lincoln and White Pine Counties* – January, 2006

This section summarizes the key findings of this prior research regarding the P-J resource. While the objectives of these studies differ from this current study, they do provide insights and information that are useful and relevant to the current biomass cogeneration feasibility study.

3.2 PINYON-JUNIPER RESOURCE

The woodland in Lincoln County is comprised of two major species: Utah Juniper (Juniperus osteosperma) and Single-leaf Pinyon (Pinus monophylla). Based on the sample plots examined in the P-J Biomass Utilization Study completed in 2004, the average tree density was 271 trees per acre, and the average tree canopy cover was estimated to be approximately 40 percent. The tallest trees were in the range of 21 to 25 feet in height. In the sample plots, the above ground tree biomass was estimated to be 23,090 pounds or 11.5 bone dry tons per acre. The woodlands were typically comprised of about 2/3 juniper and 1/3 pine.

3.3 COST OF HARVESTING, SKIDDING AND CHIPPING P-J

The following sections provide a summary of three studies that evaluated the costs associated with the harvesting, skidding (moving felled trees to a central processing area), and chipping of trees in P-J woodlands.

3.3.1 Lincoln County Study Plot

During the P-J biomass study completed in 2004, the costs associated with the treatment application methods were compiled and reported in the Cost Documentation Report. A brief description of the treatment activities completed during this project is presented in Table 1.

Approximately 12 acres of P-J woodland near the Pony Springs area were part of the study plot. In the study, all mature trees were cut down and removed to determine how existing understory plants and newly seeded plants would respond to different vegetative management treatments. Most trees were cut and harvested by feller-bunchers. Trees larger than 16 inches in diameter at the base were hand-cut with chain saws. Cut trees were placed into small piles so they could be skidded (i.e., pulled along the ground to a central location). Skidding was accomplished by using a rubber-tired skidder equipped with a grapple. Whole trees were chipped with a 27-inch whole-tree chip-harvester, with the chips being stockpiled at the landing and later spread over the test plots.

TABLE 1: SUMMARY OF OPERATIONAL COSTS FOR LINCOLN COUNTY STUDY PLOT

Operation	Acres	Total Cost ($)	Cost per Hour per Machine ($)	Cost per Acre ($)	Volume Produced (Cubic Yards)	Cost per Cubic Yard of Chips ($)
Cutting and Piling	12	3,120	89.66	260		
Skidding	12	1,740	42.65	145		
Chipping	12	3,420	168.63	285	1,415	2.42
Total	**12**	**8,280**		**690**	**1,415**	**2.42**

3.3.2 Mt. Wilson Fuels Reduction Project

Another P-J project, known as the *Mount Wilson Fuels Reduction Project*, was completed in 2004 under the direction of the BLM. The contract involved thinning P-J stands on 740 acres to a density of about 25 large trees per acre. Rubber-tired feller-bunchers were used to cut and bunch the trees. Rubber-tired grapple skidders and a front end loader with forks were used to move the material to the chipper. A 27-inch chipper was used to convert the trees into chips. The chips were subsequently hauled 2 – 3 miles to an old airplane landing strip where they were stockpiled. A summary of the contract items associated with this project are presented in Table 2.

TABLE 2: SUMMARY OF CONTRACT ITEMS FOR MT. WILSON FUEL REDUCTION PROJECT

Operation	Cost Per Acre ($)
Cutting	260
Skidding	145
Chipping	285
Subtotal	**690**
Hauling (with chip van 2 – 3 miles)	115
Total	**805**

The BLM reported that the estimated biomass removed was 5 – 7 tons per acre on the lower elevation sites that consisted mostly of juniper and 10 tons per acre on steeper terrain that contained both Juniper and Pinyon.

3.3.3 Ward Mountain Fuels Reduction Project

Another relevant project was undertaken in 2004 under the direction of the BLM's Ely office. It was known as the *Ward Mountain Fuels Reduction Project*. The project involved the thinning, removal, and chipping of 345 acres of P-J. The woodland was thinned to an approximate density that left 25 larger trees per acre. 82 acres were treated by BLM crews felling with chainsaws and a mechanized shear. The remaining acres were treated by a private contractor using rubber-tired feller bunchers for thinning and biomass removal, with a front-end loader used to feed the chipper. Chips were loaded into 20 cubic yard capacity belly dump trucks and were transported offsite using a 26 mile round trip haul distance. Table 3 summarizes the costs associated with the project.

TABLE 3: SUMMARY OF COSTS FOR WARD MOUNTAIN FUEL REDUCTION PROJECT

Operation	Cost per Acre ($)
Cutting and piling	800.87
Slash Collection	12.87
Slash Chipping	12.87
Whole-log chipping	249.29
Subtotal	**1,075.90**
Hauling (with belly dump trucks – 26 miles roundtrip)	179.71
Total per Acre Cost	**1,255.61**

The contractor indicated the cutting and piling operational costs were artificially high and some of the other items somewhat low. The slash collection and chipping costs were the result of the hand felling and would not be necessary if all the thinning was performed mechanically. The average yield was estimated to be 8.5 tons per acre.

In a somewhat similar project, the Nevada Division of Forestry's Pioche Conservation crew created fire breaks and thinned an additional strip of land along private roads in the Mount Wilson community. The total cost per acre was estimated to be $1,455.84, of which $183.60 was for chipping.

Table 4 summarizes the costs observed during the various projects.

TABLE 4: SUMMARY OF PREVIOUS PINYON-JUNIPER HARVESTING AND CHIPPING PROJECTS

	Cost per Acre ($)			
Operation	**Lincoln County Study Plot**	**Mt. Wilson Fuel Reduction Project**	**Ward Mountain Fuel Reduction Project**	**Mt. Wilson Fire Break Project**
Cutting, skidding and piling	405	405	801	
Chipping	285	285	249	184
Total	**690**	**690**	**1,050**	
Tons per Acre	20.6	5 – 10	8.5	
Calculated Cost ($ per Ton)	33.50	69 – 138	127.64	

3.4 SUMMARY

Based on the past projects referenced in this section, it is evident that there is substantial variability in the cost per acre for the harvesting and chipping of P-J. This is because a number of factors affect the cost, including how many trees per acre are removed, the terrain being treated, the equipment that is used, the extent of hand labor that is required/used, and how effectively the equipment is operated.

Another important consideration in the previous studies is that the cost is always expressed in terms of dollars per acre. While expressing costs on that basis is useful for land managers, it is not useful for power plant managers who need to know costs on a dollars per bone dry ton basis. In the prior studies, the volume per acre values are estimates based on conversions from other units of measure (e.g. cubic yards) rather than actual measured weights of biomass removed. In addition, it is not always clear whether the volumes described are green tons (including moisture) or bone dry tons.

For these reasons, in BECK's opinion, these figures should be viewed with some caution, particularly the tons removed per acre.

CHAPTER 4 – REVIEW OF ALTERNATE PRODUCTS

4.1 INTRODUCTION

The P-J resource in Lincoln County has long been utilized in various forms by residents of the region. The traditional uses have included firewood (i.e., fuelwood) for heating and cooking, fence posts, mine timbers, logs for livestock enclosures, Christmas trees and production of charcoal for use in local smelters. Pinyon pine trees have been a source of pine nuts used for food.

A number of other products can conceivably be produced from the P-J resource. Those products/end uses are discussed in a later section of this chapter. A key focus is to provide insights into the likely viability of these products/end uses.

4.1.1 Economic and Market Considerations

While there is a market for many of the products that could be manufactured from P-J, the real question is whether they can be made at prices that are competitive in the marketplace. These include:

- Raw material cost and volume
- Distance to market/transportation issues
- Competitiveness of the industry/other producers
- Substitute products
- Marketing, sales and distribution
- Market conditions and outlook

One of the most important factors in determining whether a given product can be produced from P-J and sold at competitive prices is the cost of delivering the fiber to a manufacturing facility. Based on research completed as part of this project and the experience of others, the costs of P-J harvested and skidded to the landing ranges from $25 to $80 per bone dry ton. The wide range is caused by differences in equipment productivity when operating in areas with differing tree density. In areas with more trees per unit of area, costs are lower.

Chipping costs are estimated to be $13 per bone dry ton and hauling costs are estimated to range between $7.50 and $33.00 per bone dry ton depending on haul distance. This means the cost of P-J delivered to a plant site in the area can range from as low as $75 to nearly $175 per bone dry ton. Based on raw material costs at those levels, several of the potential products/end-uses for P-J would become non-competitive (due to high prices) in the marketplace.

The cost of transportation to market is particularly important when the freight cost represent a significant portion of the product value. This means the lower the value of the product, the shorter the distance that product can be shipped to market. Conversely, a high value product can be shipped longer distances to market.

For many wood products, if the existing producers/industry has significant excess production capacity, the probability that new producers can successfully enter the market is greatly reduced. Similarly, if the existing producers are having difficulty meeting demand, there is a higher chance of success for new entrants.

In many cases, products that could be made from P-J must compete with substitute products. For example, in the southwest, bark mulch must compete with gravel/small rocks in some landscaping applications.

Manufacturing products is only one aspect of creating and maintaining a successful enterprise. Marketing and sales are equally, if not more, important. Having a strong sales person or staff is critical.

4.1.2 Assessment of Product/End Use Markets

The following section provides insight about alternate uses for P-J.

4.1.2.1 Mulch and Related Products

Mulch is generally produced from bark or other low value material (e.g., urban wood waste, tree trimmings, etc.). With the relatively high cost of P-J fiber, it will likely be too costly. In addition, wood mulch reportedly has a tendency in dry climates to dry out, which in turn allows wind to blow it away. There appears to be a very limited local market for this material. The other two logical markets would be Las Vegas (which is currently very depressed) and the Salt Lake City area. There is a least one mulch producer in Salt Lake City with whom BECK staff members have talked that produces regular and colored mulch from tree trimmings and other urban waste that they receive at no cost.

4.1.2.2 Animal Bedding and Litter

Shavings and sawdust are often used as animal bedding for horses, chickens, turkeys, etc. To a lesser extent chips can also be used. The market value of this material is relatively low, and when sold in bulk, transportation costs can be somewhat high (on a per ton basis) since it has low density on a cubic basis, therefore limiting the distance it can be hauled economically. There may be some possibility of using ground or shredded P-J fiber as a filling inside a pet bed/pillow as is done with western red cedar, but this would likely be a niche market and require only modest amounts of P-J.

4.1.2.3 Densified Fuel

Densified fuel generally comes in three different forms: pellets, briquettes (larger pieces of "pressed" wood made into shapes likely hockey pucks) and fire logs (e.g., presto-logs). Currently, most densified fuel sold in the U.S. is in the form of pellets for residential heating. The pellets require very clean, bark-free fiber that, when burned, produces little ash. The ash content of Pinyon may be an issue for residential pellets. Nearly all the residential pellets and briquettes produced in the U.S. are made from wood fiber that is a by-product of lumber manufacturing (e.g., shavings or sawdust). This fiber is much less costly than fiber derived from chipping logs. Currently, an oversupply situation exists in the U.S. for residential pellets. This has resulted in lower prices paid to producers. It would appear possible to produce industrial pellets or briquettes that would accept a much higher bark content that would be more suitable for P-J. These pellets would be suitable for heating schools or other non-residential buildings with boilers that could burn biomass. Unfortunately, with the high wood cost for P-J wood fiber, the price of industrial pellets would likely be higher than alternative fuels.

4.1.2.4 Wood Composites

In the last decade or so a number of products (e.g., decking) that contain wood fiber and other materials, particularly plastics, have emerged**.** These are sometimes referred to as "plastic wood". In nearly all instances, the percentage of wood fiber is relatively low. The wood fiber is typically sawdust and would have a cost much lower than would be possible utilizing P-J. Even if possible, the volume of P-J that would be required would be low. The major plastic lumber producers (e.g., Trex) have extensive distribution networks that would be a significant barrier to new entrants. Another type of composite material is a cement board that is a combination of cement and wood. In reality, cement board is comprised mostly of cement with only a relatively small percentage of wood fiber used to reduce weight and provide better board properties (e.g., machinability)

4.1.2.5 Cellulosic/Wood Ethanol

In recent years, there has been significant research and development to produce ethanol from wood (as opposed to corn). To date, commercialization of cellulosic ethanol in the U.S. has been very limited. None of the bench scale producers has used P-J fiber, so testing would be required to determine the suitability of the fiber as a feedstock. The capital costs for a cellulosic ethanol plant are very high, and a producer would require a long-term, secure, affordable fiber supply. The long-term outlook for ethanol is uncertain since the economics have been dependent on government subsidies/incentives, and currently there is over capacity in the corn ethanol industry.

4.1.2.6 Biodiesel

This product reportedly can be produced from a variety of different types of biomass and agricultural waste. P-J fiber, because of its high cost, would not serve as an affordable feedstock for this product.

4.1.2.7 Wood-based Panels

Oriented-strand board (OSB) is a structural panel produced from softwood and hardwood logs. The producing plants are large and require a large volume of relatively inexpensive logs (e.g., pulpwood). It is unclear if P-J would be suitable. In addition, the OSB industry has a very significant problem with excess capacity. Particleboard is a non-structural board that is made from small particles of dried wood (i.e., sawdust). Particleboard is almost exclusively made from residual wood fiber and not chips. Raw material costs from P-J likely would be too high and field produced chips would not meet the quality specifications. Medium-density fiberboard (MDF) has problems similar to those of particleboard and is viewed as not an appropriate end-use for P-J fiber.

4.1.2.8 Other Chemicals

While a number of chemicals (e.g., furfural, levulinic acid, formic acid) can be produced/extracted from P-J, the high fiber cost would likely make these products not economical in the marketplace.

4.1.2.9 Absorbent Material

While P-J fiber could be used as absorbent material that can be used to clean up spills and provide barriers required to protect the environment at construction sites, it is likely that fiber cheaper than P-J is available.

4.1.2.10 Pulp Chips

While it may be possible to make good quality pulp chips from P-J trees (if the bark can be fully removed), there are no pulp mills within at least 1,000 miles of the region. The cost of transporting chips to Oregon or Washington would likely be prohibitive, particularly when coupled with the high cost of harvesting and chipping.

4.1.2.11 Other Products

It appears feasible to produce rustic log furniture from juniper, as it is with other species such as lodge pole pine. The development of this type of business would require individuals who have the design aptitude and skill needed to craft the products. In addition, it would require artisans/craftsmen that are willing to do the design and manufacturing work. It will also require the location of firms (i.e., dealers) that are willing to sell the products in a retail setting in a more populous location.

Traditional fence posts could be produced from P-J, as has been done for many years. However, it does appear that there is little demand in the local area since most of the fences are constructed with steel posts. A related item that may have some market potential is agricultural posts, particularly those that are used in vineyards. These can be used as an alternative to pressure treated wood posts that are used to support rows of grapes. The juniper, as a member of the cedar family, has some natural resistance to rot. This characteristic is particularly appealing for vineyards that focus on being organic since the posts would not contain the preservative of treated posts.

It may be possible to produce sawn lumber from the Utah juniper similar to that sawn from Western juniper. Western juniper, however, is typically much larger in size than the Utah juniper found in eastern Nevada. If it is feasible to produce lumber from Utah juniper, there would be an opportunity to produce furniture (e.g., tables), paneling, decking and strip flooring. These markets would likely be niche markets that would be small and specialized.

Firewood continues to be a market for P-J. It may be somewhat difficult to produce firewood on a large scale from pinyon since it does not split well using commercial firewood splitters due to the character of the wood.

In BECK's view, veneer does not appear to be a feasible production option for P-J

4.1.2.12 Co-firing in an Existing/Proposed Coal Plant

The concept of co-firing biomass in coal-fired plants as a supplemental or replacement fuel has been attempted for decades by various utilities in the U.S. The results are typically that, while it is technically feasible and has emission benefits, the percentage of coal that can be replaced by biomass without unit derating (lowering the output of the power plant) is low, and the fuel preparation cost is high and uncertain.

The problem lies in the inherent difference between the characteristics of wood and coal. Coal shatters when struck with a hard object. That shattering can be followed by grinding to produced a fine powder, which can be burned in suspension in a standard utility boiler. The shattering and grinding processing steps require relatively little energy and therefore moderate cost. The anatomy of wood, in contrast, requires multiple processing steps in order to reduce particle size and moisture to achieve a state where it can be burned in suspension. All of that processing is both energy intensive and expensive.

Relative to coal, other problems with using wood are that it has higher moisture content and lower heating value. Both factors cause the unit derating mentioned above. On the other hand, wood has less sulfur than coal and burns with a lower flame temperature (less NOx generation), both positives from an environmental standpoint. Wood is also typically more expensive than coal on a delivered cost per million BTU basis due to the necessity of having to gather it from across the landscape and then deliver the low BTU product over a long distance.

Coal co-firing is a potential use of P-J from Lincoln County. The Reid Gardner coal-fired power plant of NV Energy sits south of the Lincoln County line in Moapa. This four unit plant has a total generating capacity of 587 MW. Converting even one of the older 114 MW smaller units to biomass co-firing could consume all the likely P-J produced by a large scale restoration project in Lincoln County. In addition, the fuel could be delivered by rail from Caliente and thus could avoid the large capital investment required for a standalone biomass power facility.

There are two problems with this alternative: technology and cost. Regarding technology, all four Reid Gardner units use pulverized coal technology, meaning that prior to firing, the coal particles are reduced to a fine powder, which allows suspension burning (no boiler grate). Wood simply cannot achieve the level of fineness required for suspension burning without a tremendous investment in energy for processing.

Regarding cost, the cost for wood would be higher than the cost of coal. The Energy Information Agency (EIA) of USDOE published the 2009 price for coal delivered to Nevada power plants as $47.37/ton. In the case of Reid Gardner, this is Utah coal. For a typical Utah bituminous coal of 12,600 BTU/LB., as received with 5 percent moisture, the cost would be $1.88 per million Btu delivered.

In the case of Lincoln County biomass delivered to a Caliente railhead, a cost of $25/BDT would cover chipping and transport to Caliente, but would cover none of the cost of cutting or skidding the P-J to roadside. Adding rail loading and delivery to Moapa would likely raise the delivered price to $40/BDT at Moapa. This is $2.23/million BTU for a lower heating value product arriving in chipped form. Accounting for the lower combustion efficiency of biomass (74 percent vs. 85 percent) raises the equivalent price to $2.56/million BTU. This price still does not include the cost to prepare the biomass for firing. It does not appear that P-J biomass delivered to Reid Gardner would represent a near term business opportunity for NV Energy.

There are other coal combustion technologies, such as grate firing and fluidized bed combustion, which do not require the size reduction of pulverized coal combustion. These technologies could use the P-J in the chipped form size in which it arrives. Nevada has two other coal-fired plants, the NV Energy North Valmy facility (525 MW) near Battle Mountain and Newmont Mining's TS Ranch plant (240MW) in Eureka County, but both again use pulverized coal technology. The same is true of the Intermountain Power Project (1,614 MW) near Delta, Utah, the closest Utah coal-fired plant.

As a consequence of all the preceding factors, coal co-firing does not appear to represent an economic alternative use for Lincoln County P-J at this time. Future carbon legislation could change that outcome, but is not part of today's decision making.

4.2 Summary of Market Options

Based on the analysis completed for this project, the market options for products that could be produced from P-J are rustic log furniture, posts, firewood and potentially lumber. There is a firm located in Klamath Falls, Oregon near the California border called JMAR that produces a variety of products from Western Juniper, including square posts, peeled posts, lumber, decking and paneling. JMAR is a non-profit that provides employment opportunities for persons with disabilities and receives support (and was built with funds) from local wood products companies. The firm has been operating on a limited basis in recent months due to lack of market demand. More information about JMAR can be found at their website: http://juniperwoodproducts.com.

Figure 1 shows peeled juniper posts used in an agricultural setting. It may be possible to used posts that are not sawn or peeled.

FIGURE 1: PEELED JUNIPER POSTS USED IN AN AGRICULTURAL SETTING

It is appears that this mill has had some modest success in producing and marketing products from Western juniper since its inception a few years ago. However, this appears to be due to the financial support of local industry and other benefactors. It is unclear if the Utah juniper (due to its smaller size) could support the manufacture of similar products such as sawn 6” x 6” posts for vineyards or other applications. Another important factor in this operation is that there is a well established forest products industry in the area that provides timber harvesting resources and ready markets for the wood waste produced by the mill. Due to the characteristically knotting and twisting of Juniper logs, a large percentage of the timber brought to the plant ends up as waste.

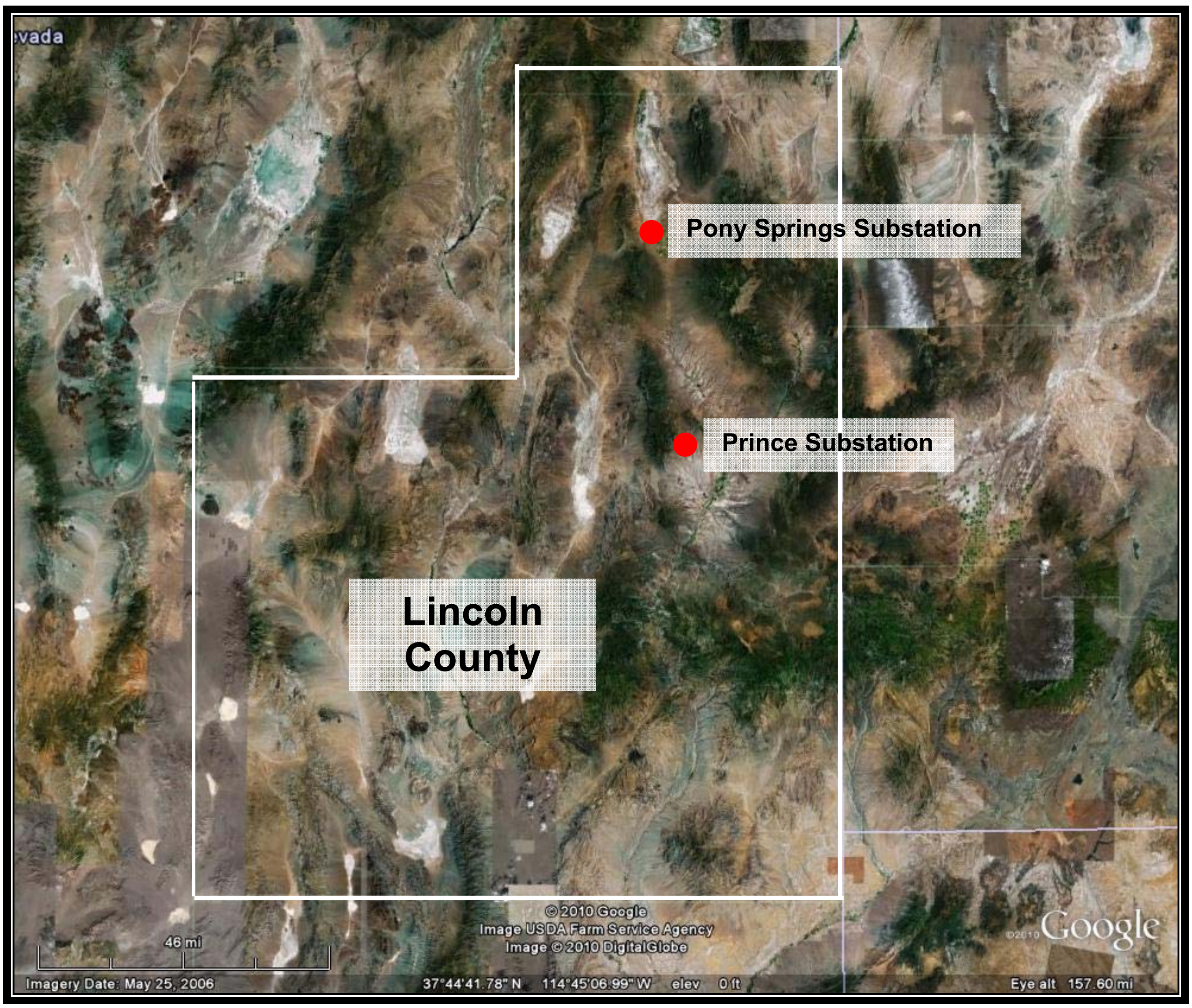
Finally, JMAR is strategically located with good access to the growing wine industry in northern California and Southern Oregon.

In summary, while there may be some market opportunity for products that can be produced from P-J, these will likely be small, specialized products that can be produced by local entrepreneurs that have an interest in developing these potential business opportunities. None will likely consume the output of the landscape level treatments envisioned by the federal agencies in Lincoln County.

CHAPTER 5 – BIOMASS FUEL SUPPLY ASSESSMENT

The biomass supply assessment is focused on two prospective power plant sites – the Prince Substation (located near the town of Caselton, NV) and the Pony Springs Substation (located about 30 miles north of Pioche, NV) (see Map 1). These sites were selected prior to the commencement of the study. The two sites were chosen primarily because they were judged to minimize the cost of interconnecting the power plant to the power grid. The substation site selections were made by the Lincoln County Power District (LCPD) and by personnel at Lincoln County and A-Power.

MAP 1: PROSPECTIVE POWER PLANT LOCATIONS



A critical aspect of any biomass fueled power plant is identifying the supply and delivered cost of biomass fuel. Accordingly, BECK has organized this chapter into four subsections described as follows:

1. **Supply Area Estimate** – an estimate of the area (acres) capable of supplying fuel.

2. **Supply Volume Estimate** – an estimate of the volume (bone dry tons) per unit of area.

3. **Delivered Cost Estimate (direct costs)** – an estimate of the costs directly associated with BLM vegetative management treatments aimed at restoring P-J forests to historic conditions. This includes costs such as harvesting trees, moving (skidding) them to a central processing area, chipping the material into a form suitable for use as fuel, and transporting the fuel to the prospective biomass plant. It also includes the cost of rehabilitating treated lands.

4. **Administrative Cost Estimate (indirect costs)** – an estimate of the indirect costs associated with the BLM planning and administering all of the activities associated with stewardship contracting efforts aimed at restoring P-J forests.

5. **Total Cost Estimate (all inclusive)** – the sum of both the direct and indirect costs associated with vegetative management treatments on P-J forests.

5.1 SUPPLY AREA ESTIMATE

In this section of the report, BECK describes the methods used to estimate the biomass supply area and the number of acres judged to be accessible for the vegetative treatment of P-J. BECK also classifies the acres into categories, which are differentiated by the volume of P-J per acre.

The criteria used to estimate the accessible number of acres were:

- From both the Pony Springs and Prince Substations, a supply circle with a 50-mile radius was assumed. Based on BECK's experience with biomass projects throughout North America, a 50-mile radius is a good general rule of thumb because material transported from distances beyond that radius quickly become cost prohibitive.

- BECK used Geographic Information System (GIS) data from the Bureau of Land Management's (BLM) Ely District to identify acres classified as P-J within each 50-mile working circle.

- The total number of P-J acres provided by the BLM data was filtered to estimate the accessible number of P-J acres. Any P-J acres that fell into any of the following categories were excluded from the accessible acreage estimate:
  - Acres that fell within a wilderness area.
  - Acres that were in areas with slopes exceeding 30 percent.
  - Acres that had been burned in a fire since 1981.
  - Acres on private land. Note that this filter had minimal impact since, per the U.S. Forest Service Forest Inventory and Analysis database[3], private forestland in all of Lincoln County is estimated to be only 29,900 acres out of a total of 1.848 million acres.

Note from the **Prince Substation** map (Appendix 1) and **Pony Springs Substation** map (Appendix 2) that each 50-mile radius circle extends into Utah. This means that some of the potential supply area falls within land managed by other BLM administrative units and some also falls within the Dixie National Forest, which is managed by the U.S. Forest Service. BECK contacted staff at the BLM's St. George Field Office regarding the availability of inventory data for the area within the 50 mile working circle in Utah. While data is available, it will not likely be obtainable before the results of this study are due.

As will be shown in the following sections, the supply estimates indicate ample biomass exists without including the area in Utah. Therefore, BECK has elected to complete the study without the inventory data from Utah. Another reason for this course of action is that involving more BLM administrative units makes the administration of any potential stewardship contracts more difficult.

Based on the preceding criteria, Table 5 shows the estimated number of accessible acres at various distance increments from each prospective location.

TABLE 5: ESTIMATED NUMBER OF ACCESSIBLE ACRES AT VARIOUS DISTANCE INCREMENTS FROM PRINCE AND PONY SUBSTATIONS

Distance Increment (Miles from Center Point)	Pony Springs (Accessible Acres within Increment)	Pony Springs (Accessible Acres Cumulative Totals)	Prince (Accessible Acres within Increment)	Prince (Accessible Acres Cumulative Totals)
0 to 10	73,900	73,900	34,100	34,100
11 to 20	169,500	243,400	122,800	156,900
21 to 30	122,000	365,400	328,700	485,600
31 to 40	114,800	480,200	198,500	684,100
41 to 50	159,600	639,800	38,000	722,100

[3] Forest Inventory and Analysis database. Maintained by the USDA Forest Service, accessed at: http://www.fia.fs.fed.us/.

5.1.1 Classifying Accessible Acres by Tree Density

The next step in BECK's analysis involved classifying accessible acres into groups sorted by tree density. The classification system used is described in a rangeland fuels guide[4]. Each classification category is defined as follows:

Phase 1 Trees are present on the site, but the shrub and herb layers are the dominant influence on ecological processes (hydrologic, nutrient, and energy cycles). The total average volume per acre in this category is 3.5 bone dry tons per acre.

Phase 2 Trees are co-dominant with shrub and herb layers. All three layers influence ecological processes. The total average volume per acre in this category is 10.2 bone dry tons per acre.

Phase 3 Trees are the dominant vegetation and the primary layer influencing ecological processes. The total average volume per acre in this category is 23.0 bone dry tons per acre.

BECK assigned the total accessible P-J acres at each location (shown in Table 5) into one of the three preceding Phase Classifications. This was completed on the basis of findings from a study[5] on the age and structure of P-J forests across the Intermountain West in combination with direct input from BLM staff and one of the study's authors, Dr. Robin Tausch, Supervisory Range Scientist and Plant Ecologist at the USDA Forest Service Rocky Mountain Research Lab in Reno, Nevada. According to Dr. Tausch, the P-J forest in Lincoln County is 25 percent Phase I, 50 percent Phase II, and 25 percent Phase III. Given that breakdown of total acres by phase category, Table 6 and Table 7 show the number of acres at each location by Phase classification.

[4] *Guide for Quantifying Fuels in the Sagebrush Steppe and Juniper Woodlands of the Great Basin.* A publication of the Sagebrush Steppe Treatment Evaluation Project. Accessed at: http://www.sagestep.org/pubs/fuelsguide.html.

[5] Age Structure and Expansion of Pinyon-Juniper Woodlands: A Regional Perspective in the Intermountain West. USDA Forest Service, Rocky Mountain Research Station, Research Paper Report RMRS-RP-69. Accessed at: http://www.fs.fed.us/rm/pubs/rmrs_rp069.pdf.

TABLE 6: ACCESSIBLE P-J ACRES AT PRINCE CLASSIFIED BY PHASE

Distance Increment (miles from center point)	Phase I Acres	Phase II Acres	Phase III Acres	Total Within Zone Acres	Cumulative Acres
0 to 10	8,500	17,100	8,500	34,100	34,100
11 to 20	30,700	61,400	30,700	122,800	156,900
21 to 30	82,200	164,300	82,200	328,700	485,600
31 to 40	49,600	99,300	49,600	198,500	684,100
41 to 50	9,500	19,000	9,500	38,000	722,100
Total	**180,500**	**361,100**	**180,500**	**722,100**	n/a

TABLE 7: ACCESSIBLE P-J ACRES AT PONY SPRINGS CLASSIFIED BY PHASE

Distance Increment (Miles from Center Point)	Phase I Acres	Phase II Acres	Phase III Acres	Total within Zone Acres	Cumulative Acres
0 to 10	18,500	36,900	18,500	73,900	73,900
11 to 20	42,400	84,700	42,400	169,500	243,400
21 to 30	30,500	61,000	30,500	122,000	365,400
31 to 40	28,700	57,400	28,700	114,800	480,200
41 to 50	39,900	79,800	39,900	159,600	639,800
Total	**160,000**	**319,800**	**160,000**	**639,800**	n/a

5.2 SUPPLY VOLUME ESTIMATE

In addition to understanding the area that is accessible for the vegetative treatment of P-J, it is also important to understand the volume (expressed in bone dry tons) of P-J that can be obtained from those acres. In this section of the report, BECK describes the methods used to estimate the biomass supply and provides volume estimates.

5.2.1 Volume Estimate Methodology

Regarding the methodology used to estimate volume, Table 8 shows the key assumptions made regarding: 1) the volume per acre in each phase, and 2) the thinning intensity that would occur during treatment of those acres.

TABLE 8: P-J VOLUME PER ACRE ESTIMATES (BDT/ACRE)

Phase Classification	Total Volume (BDT/Acre)	Thinning Intensity (% of Volume Removed)	Harvested Volume (BDT/Acre)
Phase I	3.5	75	2.6
Phase II	10.2	50	5.1
Phase III	23.0	75	17.3

The total volume per acre estimates shown in Table 8 are taken directly from the fuels guide publication.[6] As described in that study, the volume per acre estimates are based on data collected during transects of woodlands of each phase type. Data collected along the transects include tree count (trees per acre) and tree size (height and diameter). That information was then used to calculate the average tree volume (expressed in bone dry tons per acre).

Regarding the thinning intensity values shown in Table 8, those are based on a combination of discussions between BECK, BLM staff, and Dr. Tausch about how heavily the woodlands of each phase type would be thinned in order to achieve the vegetative management objectives described in the Ely RMP.

Other things to note about the information presented in Table 8 are that the net volume per acre estimates account for losses from factors such as tree breakage during harvesting and processing. Also note that since the volume estimates shown in the tables are expressed in bone dry tons, the actual weight of the biomass harvested and removed from the site is likely to be 1.33 to 1.66 times higher (depending on the moisture content of the trees when harvested). This is not because a greater number of trees will be harvested, but is simply the difference associated with expressing the volume on a bone dry basis versus a green (water included) basis.

Given the acres shown in Table 6 and Table 7 and the volume per acre values shown in Table 8, Table 9 and Table 10 illustrate that nearly **5.44 million bone dry tons** of biomass are estimated to be available within a 50 mile radius of the Prince Substation and nearly **4.82 million bone dry tons** are estimated to be available within a 50 mile radius of the Pony Springs Substation, respectively.

This means that a 10 MW power plant (which would consume 67,300 bone dry tons annually) could be supplied from the currently accessible fuel at the Prince location for 81 years. Similarly, enough currently accessible fuel is available surrounding the Pony Springs location to supply that plant for 72 years.

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[6] *Guide for Quantifying Fuels in the Sagebrush Steppe and Juniper Woodlands of the Great Basin.* A publication of the Sagebrush Steppe Treatment Evaluation Project. Accessed at: http://www.sagestep.org/pubs/fuelsguide.html.

TABLE 9: PRINCE SUPPLY VOLUME ESTIMATE (BONE DRY TONS)

Distance Increment (Miles from Center Point)	Phase I (BDTs)	Phase II (BDTs)	Phase III (BDTs)	Total within Zone (BDTs)	Cumulative (BDTs)
0 to 10	22,300	87,200	147,100	256,600	256,600
11 to 20	80,600	313,100	531,100	924,800	1,181,400
21 to 30	215,800	837,900	1,422,100	2,475,800	3,657,200
31 to 40	130,200	506,400	858,100	1,494,700	5,151,900
41 to 50	24,900	96,900	164,400	286,200	5,438,100
Total	**473,800**	**1,841,500**	**3,122,800**	**5,438,100**	n/a

TABLE 10: PONY SPRINGS SUPPLY VOLUME ESTIMATE (BONE DRY TONS)

Distance Increment (miles from center point)	Phase I (BDTs)	Phase II (BDTs)	Phase III (BDTs)	Total Within Zone (BDTs)	Cumulative (BDTs)
0 to 10	48,600	188,200	320,100	556,900	556,900
11 to 20	111,300	432,000	733,500	1,276,800	1,833,700
21 to 30	80,100	311,100	527,700	918,900	2,752,600
31 to 40	75,300	292,700	496,500	864,500	3,617,100
41 to 50	104,700	407,000	690,300	1,202,000	4,819,100
Total	**420,000**	**1,631,000**	**2,768,100**	**4,819,100**	n/a

5.3 DELIVERED COST ESTIMATE (DIRECT COSTS)

Another critical aspect of the fuel supply is the cost of harvesting, processing, and transporting the fuel to the prospective power plant. In this section, BECK describes the methods used to assess the various costs and provides cost estimates separated into the various processing/rehabilitation functions.

5.3.1 Costing Methodology

This section describes the methodology used to estimate the cost of conducting vegetative treatments using mechanized equipment, including a list of the equipment required to conduct vegetative treatments.

A mechanized approach is required to cost-effectively treat P-J woodlands. Thus, based on BECK's experience in the areas of biomass harvesting and processing technology and based on interviews of contractors currently producing biomass fuel from Juniper woodlands, BECK assumed that a tracked feller-buncher would be used to harvest the trees, a grapple skidder would be used to transport the felled trees to a central processing area, a drum chipper would be used to chip the felled trees into fuel, and chip vans would be used to transport the fuel from the treatment area to the power plant. Figure 2 provides pictures of the various pieces of equipment.

FIGURE 2: MECHANIZED EQUIPMENT USED TO HARVEST, PROCESS, AND TRANSPORT P-J BIOMASS

Tracked Feller Buncher – This piece of equipment operates on tracks to minimize soil impacts. It fells the trees to be harvested and then accumulates the felled trees into bunches. Typically, each bunch consists of about 8 trees.

Grapple Skidder – This piece of equipment operates on four rubber tires and is equipped with a large grapple for grabbing and holding onto a group of trees that have been felled and bunched. The grapple securely holds the trees as they are transported from the harvest site to a central processing area.

Chipper – This piece of equipment processes whole trees into small chips, which are suitable for burning in most boiler systems. The chipper is often accompanied by a tracked excavator equipped with a grapple-head for feeding the trees into the chipper.

Chip Van – The chipper typically blows the chips directly into a chip van, which is a piece of equipment designed to transport the chips from the harvest area to the power plant. Some chip vans have a walking floor for self-unloading, while others rely on a truck dumper at the final destination to empty the trailer.

Regarding the methodology used to estimate the costs, BECK utilized a combination of interviews with existing contractors who process Western Juniper into biomass fuel and who provided information about their costs. In addition, BECK "built-up" cost estimates based on key factors such as hourly machine operating costs and hourly productivity. The hourly operating costs used include costs such as fuel, labor, repair and maintenance, loan amortization, and depreciation. Also included is a profit margin for the contractor. With respect to the "built-up" cost estimates, BECK obtained hourly machine operating costs from various sources. [7,8,9]

5.3.2 Costs Expressed on a Per Unit Basis

A key finding from BECK's analysis is that machine productivity, and therefore cost, is affected by the number of trees per acre. In other words, machine productivity decreases (on a bone dry tons per hour basis) in areas with fewer trees per acre (e.g., Phase I acres). This means that biomass from Phase I acres is more expensive than biomass from Phase II or Phase III acres. Similarly, biomass from Phase III acres (which has more trees per acre) is lower cost than biomass from Phase I and II acres. For this reason, BECK has developed different cost estimates for material originating from each Phase. Table 11 shows BECK's estimated costs on a dollars per bone dry ton basis.

TABLE 11: P-J DELIVERED COST ESTIMATE
(DOLLARS PER BONE DRY TON)

Cost Category	Phase I Cost Estimate ($/BDT)	Phase II Cost Estimate ($/BDT)	Phase III Cost Estimate ($/BDT)
Felling and Bunching	78.75	49.38	24.52
Skidding	33.24	20.84	12.16
Chipping	13.41	13.41	13.41
Transport*	7.50 to 33.00	7.50 to 33.00	7.50 to 33.00
Total	**132.90 to 158.40**	**91.13 to 116.63**	**57.59 to 83.09**

* The transport cost depends on the travel time between the treatment location and the power plant. The values shown are the high and low ranges.

[7] Fuel Cost Reduction Simulator, a spreadsheet-based forest harvesting cost simulation model. Accessed at: http://www.fs.fed.us/pnw/data/frcs/frcs.shtml.

[8] Production, Cost, and Soil Compaction Estimates for Two Western Juniper Extraction Systems. Accessed at: http://www.cas.umt.edu/facultydatabase/FILES_Faculty/1111/WJAFJuniper.pdf.

[9] A Comparison of Harvesting Systems for Western Juniper. Beth Dodson, International Journal of Forest Engineering. January 2010.

As previously described, the following key assumptions about operating costs and productivity are from a combination of interviews with existing contractors and from values in published studies. More specifically the key assumptions are:

- The hourly operating cost of the feller buncher was assumed to be $110 per hour. Machine productivity was calculated for each phase type based on the average amount of time needed for the machine to move (or reach) from tree to tree, sever the tree, and finally accumulate harvested trees in bunches of approximately 8.
- The hourly operating cost of the grapple skidder was assumed to be $80 per hour. For each phase type, the machine productivity was calculated based on an average of 8 trees per skid and approximately 6 to 7 minutes per skidding cycle, depending on phase type.
- Biomass material accumulated at the landing through the actions of the feller buncher and grapple skidder would be chipped with a drum chipper. The chipper was assumed to have an operating cost of $295 per hour and an average productivity of 22.0 bone dry tons per hour.
- Trucking costs were calculated on the basis of a $90.00 per hour operating cost and an average payload of 15.0 bone dry tons per truckload. Given those parameters, transportation costs were calculated for round-trip travel times for each 10 mile increment in a 50 mile radius working circle.

5.3.3 Rehabilitation Costs

Up to this point in the analysis no cost has been included for rehabilitating areas after vegetative treatments (e.g., reseeding treated areas with preferred grasses, shrubs, and forbs). Based on data provided by the BLM, the cost for rehabilitation is $50 per acre. Since costs need to be expressed on a dollars per ton basis for the analysis of power plant feasibility, Table 12 shows the $50 cost per acre converted to cost per ton for each phase.

TABLE 12: P-J VOLUME PER ACRE ESTIMATES (BDT/ACRE)

Phase Classification	Rehabilitation Cost ($/Acre)	Harvested Volume (BDT/Acre)	Rehabilitation Cost ($/BDT)
Phase I	50	2.6	19.23
Phase II	50	5.1	9.80
Phase III	50	17.3	2.89

It is important to note that costs per bone dry ton shown in the preceding table cannot just be added to the delivered costs shown in the preceding section because according to BLM staff not all treated acres need rehabilitation. Under the assumption that 10 percent of the total fuel will come from Phase I acres, 40 percent from Phase II acres and 50 percent from Phase III acres and assuming that 10 percent of the Phase I acres require rehabilitation, 33 percent of the Phase II acres require rehabilitation, and 66 percent of the Phase III acres require rehabilitation, **the weighted average rehabilitation cost would be $2.44 per bone dry ton.**

5.4 ADMINISTRATIVE COST ESTIMATE (INDIRECT COSTS)

In addition to the costs directly associated with conducting vegetative treatments, other administrative costs must also be considered. These include costs incurred by the BLM in the planning and administration of vegetative treatments. According to data provided to BECK by the BLM, this would include funding for additional staff consisting of a project lead, fuels planner, archeologist, ecologist, wildlife biologist, and field technician. The total cost to the BLM for the additional staff and existing staff required to carry out vegetative treatments would be $850,000 in Year 1 and $670,000 in each subsequent year.

The BLM would also incur costs for contracting with private entities to complete cultural inventories and to meet the requirements of the National Environmental Protection Act (NEPA). The BLM has estimated the cost for cultural inventories to be $35 per acre. For the NEPA work, BLM has estimated the cost to be $29,000 per year. Table 13 summarizes all of the preceding costs and expresses them on a dollars per bone dry ton basis. For the purpose of converting dollars per acre costs to dollars per bone dry ton, it was assumed that 9,600 acres would be treated annually (10 percent Phase I, 40 percent Phase II, and 50 percent Phase III).

TABLE 13: SUMMARY OF INDIRECT COSTS ($/BDT)

Cost Category	Annual Cost ($)	Bone Dry Tons	Year 1 Staffing Cost ($/BDT)	Subsequent Years Staffing Cost ($/BDT)
Cultural Inventory	336,000	67,300	4.99	4.99
Staffing (Year 1)	850,000	67,300	12.63	n/a
Staffing (subsequent years)	670,000	67,300	n/a	9.96
NEPA	29,000	67,300	0.43	.43
Total Year 1	**1,215,000**		**18.05**	
Total (Subsequent Years)	**1,035,000**			**15.38**

5.5 Total (All Inclusive) Cost Estimate

In the preceding sections, the various costs associated with managing P-J forests have been examined individually. The following section provides information on the delivered cost of P-J fuel when considered all inclusively (i.e., harvesting, skidding, chipping, and hauling, rehabilitation, and administrative).

5.5.1 Supply Cost Curve

Since the delivered cost varies depending on travel time, Table 14 and Table 15 show the amount of fuel available at various cost levels for each location broken out by travel time (distance) from the prospective plant location.

TABLE 14: PRINCE SUPPLY COST CURVE

Travel Time Zone	Source Category	Within Zone Bone Dry Tons	Within Zone Delivered Cost ($/BDT)	Cumulative Bone Dry Tons	Cumulative Delivered Cost ($/BDT)
0 - 10	Phase III	147,100	75.41	147,100	75.41
10 - 20	Phase III	531,100	81.41	678,200	80.11
20 - 30	Phase III	1,422,100	87.41	2,100,300	85.05
30 - 40	Phase III	858,100	93.41	2,958,400	87.48
40 - 50	Phase III	164,400	100.91	3,122,800	88.18
0 - 10	Phase II	87,200	108.95	3,210,000	88.75
10 - 20	Phase II	313,100	114.95	3,523,100	91.08
20 - 30	Phase II	837,900	120.95	4,361,000	96.82
30 - 40	Phase II	506,400	126.95	4,867,400	99.95
40 - 50	Phase II	96,900	134.45	4,964,300	100.62
0 - 10	Phase I	22,300	150.72	4,986,600	100.85
10 - 20	Phase I	80,600	156.72	5,067,200	101.74
20 - 30	Phase I	215,800	162.72	5,283,000	104.23
30 - 40	Phase I	130,200	168.72	5,413,200	105.78
40 - 50	Phase I	24,900	176.22	5,438,100	106.10
Total		**5,438,100**			

TABLE 15: PONY SPRINGS SUPPLY COST CURVE

Travel Time Zone	Source Category	Within Zone Bone Dry Tons	Within Zone Delivered Cost ($/BDT)	Cumulative Bone Dry Tons	Cumulative Delivered Cost ($/BDT)
0 - 10	Phase III	320,100	75.41	320,100	75.41
10 - 20	Phase III	733,500	81.41	1,053,600	79.59
20 - 30	Phase III	527,700	87.41	1,581,300	82.20
30 - 40	Phase III	496,500	93.41	2,077,800	84.88
40 - 50	Phase III	690,300	100.91	2,768,100	88.88
0 - 10	Phase II	188,200	108.95	2,956,300	90.15
10 - 20	Phase II	432,000	114.95	3,388,300	93.31
20 - 30	Phase II	311,100	120.95	3,699,400	95.64
30 - 40	Phase II	292,700	126.95	3,992,100	97.93
40 - 50	Phase II	407,000	134.45	4,399,100	101.31
0 - 10	Phase I	48,600	150.72	4,447,700	101.85
10 - 20	Phase I	111,300	156.72	4,559,000	103.19
20 - 30	Phase I	80,100	162.72	4,639,100	104.22
30 - 40	Phase I	75,300	168.72	4,714,400	105.25
40 - 50	Phase I	104,700	176.22	4,819,100	106.79
Total		**4,399,100**			

Given the information shown in both of the preceding supply cost curves, it is apparent that from the perspective of minimizing cost, the best approach would be to treat only Phase III acres. However, based on discussions with BLM staff, it would also be preferable to treat some Phase I acres each year to prevent those acres converting to woodland from the more preferable sagebrush.

While the Ely RMP identifies objectives for vegetative treatments of P-J forests, it does not identify specific acres planned for harvests, nor does it account for the competing factors of minimizing delivered cost and treating acres in multiple phase classifications. Given this ambiguity, BECK has consulted with BLM staff and calculated an overall average delivered cost, assuming that 10 percent of the fuel will come from Phase I acres, 40 percent from Phase II acres, and 50 percent from Phase III acres. **Therefore, the all inclusive delivered cost of the fuel is calculated to be $96.36 per bone dry ton, as shown in Table 16.**

TABLE 16: ESTIMATED AVERAGE DELIVERED FUEL COST – YEAR 1 ($/BDT)

Phase Classification	Percent of Fuel from Phase Type	Total Fuel Volume Needed (BDT)	Fuel Volume from Phase Type (BDT)	Delivered Fuel Cost ($/BDT)
Phase I	10	67,300	6,730	150.72
Phase II	40	67,300	26,920	108.95
Phase III	50	67,300	33,650	75.41
Totals	**100**		**67,300**	
Weighted Average				**96.36**

In addition to identifying the weighted average delivered cost, the information shown in Table 16 can also be used to identify the number of acres treated per year in each Phase type and the average volume removed per acre. This is illustrated in Table 17.

TABLE 17: WEIGHTED AVERAGE YIELD PER ACRE AND ACRES TREATED PER YEAR

Phase Classification	Yield (BDT per acre)	Area treated per year (acres)
Phase I	2.6	2,600
Phase II	5.1	5,300
Phase III	17.3	1,900
Weighted Average/Total	6.9	9,800

CHAPTER 6 – REVIEW OF POTENTIAL PLANT SITES

As will be discussed in further detail in Chapter 8, the LCPD transmission system has as it's backbone a radial, 69 KV line that extends north to Pioche from the Tortoise Substation near Moapa. The line terminates at Pony Springs, north of Pioche. There is also a 69 KV line branching off the backbone line that serves the Caliente area. LCPD has preliminarily estimated that the existing 69 KV system can support the interconnection of a 10MW or smaller biomass project. LCPD has also indicated the existing lines may support a slightly larger project, but that is unknown without conducting more detailed engineering studies. The total LCPD system peak load is currently 18MW, so the upside for interconnection on the existing system is likely to be only modestly beyond 10MW, and almost certainly not beyond the system peak load..

Discussions with LCPD indicate they have evaluated possible interconnection at both the Prince and Pony Springs Substations, which are both 69/24.9 KV. LCPD believes that interconnection at either location is feasible up to 10MW. Prince is the main distribution substation in LCPD's northern area and contains a 15 MVA 69 KV/24.9 KV main transformer. Pony Springs is a smaller rural substation with a 3 MVA, 69 KV/24.9 KV main transformer.

Generators in the size range anticipated for the Lincoln County project, typically generate power at either 12.47 KV or 13.8 KV. In some cases, such generators generate power at as low as 4.16 KV. However, in all cases, it would be necessary to transform the biomass project's output to 24.9 KV, which is low voltage needed for connection to LCPD's 69 KV substations at Prince, Pony Springs and Caliente. A generator with an output voltage of 24.9 KV could be purchased to eliminate the need to transform the biomass project's power. However, doing so would leave the project vulnerable to limited ability to find a replacement in the event of a generator failure, as the universe of potential replacement units would be much smaller.

Thus, in BECK's judgment, it appears that the prudent business decision would be to purchase a 13.8 KV/24.9 KV or a 13.8 KV/69 KV transformer for the project site to allow the project to tie into LCPD's system on either the low voltage side of the substations or the 69 KV system directly. The 69 KV/24.9 KV transformer at Pony Springs, at 3 MVA, is too small to accept the output of the 10MW plant and so would need to be replaced regardless.

It would appear, prior to further study by LCPD, that a 10MW or smaller project could tie onto LCPD's 69 KV system at numerous locations, provided an appropriately sized 13.8 KV/69 KV transformer is provided (along with the appropriate breakers, switches, relays and communications equipment). This means the project would have some siting flexibility, provided it does not venture far from LCPD's existing 69 KV system.

The siting decision then becomes one based on permitting issues, potential heat customers and minimization of fuel haul costs. This study has been unable to identify a substantial heat user that would provide a compelling case for siting the project adjacent. All of eastern Nevada is in compliance with ambient air quality standards, so no area of Lincoln County is off limits to air quality permitting with the possible exception of narrow canyons. The three main population centers in the Lincoln County P-J area are Pioche, Panaca and Caliente, and each vary little in fuel haul costs from the resource concentration.

The best balance of the above filters in this preliminary evaluation would appear to be siting near LCPD's Prince Substation in Caselton, northwest of Pioche, adjacent to LCPD's headquarters. This location should allow for all necessary permits, is at the strongest portion of LCPD's system and has access to what modest water services the project will require. In addition, this location should allow the largest plant that LCPD's system can support to be located, though that potential size is still to be determined. The Prince site will form the basis of the project economics to be developed in Chapter 14, the Financial Analysis section.

An additional siting option that came to light late in the study was a location adjacent to LCPD's Antelope Canyon substation at the north end of Caliente. This substation is another 69 KV/24.9 KV substation and currently contains a 7.5MVa step-down transformer. This substation is adjacent to Perlite, a manufacturing plant that operates a "popping plant" that expands the perlite mineral through the application of heat so that it can be used in the potting soil industry. The plant currently uses propane to accomplish the heating. Despite several calls to the company, it has not been possible to obtain information as of this date regarding the magnitude of fossil fuel use in the facility. This process may represent a thermal energy user for the proposed project.

This site is also very near the Caliente Youth Center, which operates two relatively small boilers, again run off of propane. These boilers supply both the kitchen and the space heating needs of the campus. Again, this represents a potential small scale heat customer.

Thus, this site is relatively centrally located within LCPD's system, could accept a minimum of 10MW of output, and has two potential heat customers. It could also have city services available. The problems with this site is that it is at the mouth of a very narrow canyon with little available real estate, except right on Highway 93. It is more urban than the other options, meaning that traffic to and from the site will more heavily scrutinized. Also, it is not known at this time what impact the "canyon" location would have on plant permitting, particularly air quality permitting. The site also has not had a fuel supply study done for it to know the availability of fuel within the 50 mile radius, but is not likely to be as favorable as Prince and Pony Springs because of its location further to the south. At this point, this site will not become the base case for this study based on these unknowns, but should be further studied if a decision is made to go ahead with the project.

CHAPTER 7 – REVIEW OF THERMAL ENERGY USERS

7.1 COGENERATION APPLICATIONS IN LINCOLN COUNTY

One of biomass energy's advantages over other renewable technologies is that it can be moved (within reason) to a site where the combustion can simultaneously produce electricity and heat for a process or space heating use. If the process use is large, and has the correct characteristics, this co-location can dramatically increase the overall thermal efficiency and economics of the process.

The ideal characteristics of the thermal host are the following:

1. The user is large, consuming 10 percent or more of the residual heat from the power facility.

2. The user uses low pressure/temperature steam or hot water in order to maximize power generation efficiency.

3. There are only limited variations in demand due to seasonality, days of week and time of day.

4. The user is in a stable business that will be there for the life of the power contract or, even better, is growing.

There are several reasons that thermal host sites need to have the above characteristics:

1. Even a low pressure/temperature steam user detracts from the power generation process. Steam extracted for process use at 50 psig lowers power generation from that increment by about 50 percent, while steam as low as 5 psig still lowers power generation by one-third.

2. The inclusion of an automatic extraction port for a thermal user lowers overall turbine-generator (T-G) efficiency even if no heat is removed. T-G literature indicates that overall T-G efficiency drops as much as 4 percent with a single extraction point.

3. The inclusion of an extra extraction point and piping to serve a thermal user is expensive, especially if that user is seasonal.

4. Moving the project next to a thermal user often complicates permitting and utility interconnection, and may increase fuel haulage and site costs if the user is within an urbanized area.

A survey of potential industrial/institutional heat users in Lincoln County was performed by the University of Nevada Reno in 2005. More recently, BECK inquired (through the Nevada State Boiler Inspectors office in Henderson) about permitted boilers in Lincoln County. In neither the University of Nevada Reno nor the current study was there a single (or even a combination of) user(s) in Lincoln County identified that rises to a level to be considered a viable host for a 10MW biomass facility. At most, the existing potential users would consume less than one-half of 1 percent of the thermal energy available from turbine extraction or exhaust. Consequently, this study will not attempt to co-locate the project at a thermal host, but will instead focus on those locations that minimize fuel haul and interconnection costs.

One concept that is gaining popularity in the United States and is common in Europe is to anchor a new industrial park with a biomass combined heat and power facility as an inducement for businesses seeking "green" sources of energy. If the plant is designed so that potential users could be satisfied with steam similar to the quality of that serving the project deaerator (1-5 psig) or with hot water exiting the air cooled condenser (approx. 125 F), then there is virtually no penalty to pay in T-G performance prior to the time a heat user might be identified and developed. The new Meadow Valley Industrial Park at the south end of Caliente might be such a location so long as this site does not complicate air permitting qualifications or increase fuel haul distances and times. All other siting consideration being equal, an industrial park setting preserves the option for a heat customer.

CHAPTER 8 – TRANSMISSION INFRASTRUCTURE

8.1 LINCOLN COUNTY POWER DISTRICT NO. 1

The electrical utility serving all of Lincoln County is Lincoln County Power District No. 1 (LCPD), whose headquarters are located in Caselton. LCPD is a not-for-profit political subdivision of the state of Nevada formed to bring electrical power to Lincoln County. LCPD has an allocation of power from the federal hydroelectric system on the Colorado River that is sufficient to supply the district under normal circumstances. At times of extended drought or during unusual load conditions, LCPD has also made short term purchases from NV Energy or others. LCPD has no generating resources of its own, nor are there other generating resources located within its service territory at this time.

LCPD operates as a radial 69 KV system, meaning that all power flows are from supply points in the south and flow to consumers further north within the county. The LCPD lines do not connect with those of other utilities north of Lincoln County. . No realistic opportunities exist to "loop" the system with utilities further north.

LPCD receives its bulk power at the Reid Gardner Substation of NV Energy, located in Moapa in Clark County. LCPD jointly owns and operates the Tortoise Substation about two miles north of Reid Gardner with Overton Power District. There is a 138 KV line connecting these two substations. From the Tortoise substation, a 69 KV LPCD line parallels state highway 138 northwest to the junction with US Highway 93. At that junction, there is an alternate power delivery point from NV Energy, which is typically not utilized.

The 69 KV backbone system then continues north along the east side of Highway 93 to a point just south of the town of Alamo. At that point, the line heads northeast away from the highway and across a series of dry lake beds to cross Highway 93 several miles west of Oak Springs Summit. North of the highway, a switch serves a 69 KV circuit to the town of Caliente, terminating at the Antelope Canyon substation mentioned in the previous section.. The main backbone system continues northeast to the town of Caselton where the Prince Substation is located adjacent to LCPD's headquarters. The Prince Substation contains a 15MVa 69/24.9 KV transformer. Separate 24.9 KV circuits continue east and south to the towns of Pioche and Panaca.

The 69 KV backbone system again crosses highway 93 north of Pioche and continues north along the east side of the highway. The 69 KV system terminates at the Pony Springs Substation, located approximately 30 miles north of Pioche and north of the spur road to Mt. Wilson. The Pony Springs Substation contains a 3MVa 69/24.9 KV transformer.

LCPD's peak system load is about 18MW and is roughly the same both summer and winter, peaking in the southern portion of the county in the summer and in the northern portion in the winter. LCPD has preliminarily analyzed the addition of a biomass fueled power project to its system and has determined that it may be possible to add at least a 10MW project to its system, at least at either the Prince or Pony Springs Substation. Additional interconnection points, and slightly larger projects, may be possible, but will require additional study and potentially new infrastructure.

A radial system, such as that operated by LCPD is characterized by substantial losses of power in the transmission and distribution (9-10 percent in this case), and by the necessity to provide voltage stabilization equipment at various points in the system. An appropriately sized generating resource located at certain points within the system could serve as a benefit to the system, lowering overall losses of power and providing voltage control. This is true so long as the resource added is not so large as to require a complete upgrading or rebuilding of the 69 KV system. With the proper equipment to resynchronize LPCD's system to the main power grid, it would also be possible to utilize the proposed plant to provide additional reliability within LPCD's system during disturbances that would otherwise result in a systemwide outage. It would appear that a 10MW addition, or perhaps slightly more, would meet the criteria of being a beneficial addition.

8.2 TRANSMISSION OUTSIDE LCPD

It is assumed for purposes of this investigation that a minimum of 10MW could be delivered by LCPD to the power grid at Reid Gardner on a cost of service basis. At Reid Gardner, the power is now part of the western power grid administered by the Western Electricity Coordinating Council (WECC). The WECC system serves the entire U.S. West to the eastern edges of Montana, Wyoming, Colorado and New Mexico, and includes the Canadian Provinces of British Columbia and Alberta and a small portion of northern Baja Peninsula, Mexico. As part of the WECC, NV Energy is required to "wheel" power for others on the basis of a filed Open Access Transmission Tariff (OATT). That tariff allows NV Energy to recover the cost of operating its transmission system (and the losses of power in that transmission) from those using the system, including its own native load customers, on a nondiscriminatory basis.

NV Energy has interconnections with various public, government and investor owned utilities that represent potential customers for a project in Lincoln County. Many of these interconnections occur in the greater Las Vegas area as various entities have transmission rights that reach hydroelectric and coal fired facilities that are located east and north of Las Vegas, but primarily serve customer loads in southern California. The Las Vegas area is a veritable multilane freeway of transmission circuits with various substations (Mead, Marketplace, and McCullough) that serve as trading hubs for power transactions between entities. This is a very positive situation for a potential power project in Lincoln County.

If the purchaser of the project output is NV Energy in order to meet its RPS obligation, then the transaction can take place at the Reid Gardner Substation of NV Energy, with only LCPD providing wheeling services. If, however, the purchaser of the power is another entity having transmission rights to one of the main Las Vegas area substations, then the power must also cross a portion of NV Energy's system and an additional payment must be made.

The principle of paying investor owned utilities for transmission wheeling service is the concept of the "postage stamp rate". Like a postage stamp, the cost is the same regardless of the distance the letter (or power) is moved. Since it is simply too complicated to calculate the cost and losses associated with each of thousands of transactions daily, NV Energy simply adds up the total annual cost of transmission and the total annual losses and allocates them equally to each MWh of power moved across the system. In the case of NV Energy's OATT, the cost of transmission services and losses amounts to approximately $6/MWh of power wheeled from a baseload facility such as a biomass power facility. Thus, if the power sale is to another entity at one of the Las Vegas area substations, the purchase price would need to be discounted by this $6/MWh cost to arrive at a net price at the Reid Gardner Substation. If the sale, however, is to NV Energy at Reid Gardner, this $6/MWh is avoided.

In the universe of biomass power facilities, which invariably occur in rural locations due to fuel availability, Lincoln County represents a reasonably good transmission situation. In the case of LCPD, the project, if sized correctly, can represent a positive development, and so the wheeling cost can be low to deliver the power to Reid Gardner. At Reid Gardner, the power connects directly to a utility with a strong RPS requirement, NV Energy. Within the greater Las Vegas area, there are numerous utilities, primarily from California, having transmission rights while also being subject to a strong RPS requirement. Thus, the power from a Lincoln County biomass project is likely to attract a fairly high price within the Las Vegas area from either NV Energy or another purchaser.

8.3 ONE NEVADA TRANSMISSION LINE

The new One Nevada transmission line of NV Energy will also traverse Lincoln County. The line will cross the county from north to south along the western side. This 500 KV line will begin in the north at the new Robinson Summit Substation west of Ely and terminate at the Reid Gardner power station. This line will connect the northern and southern halves of NV Energy's system for the first time. Ground was recently broken for the line, with completion expected to be in 2012.

Theoretically, this line will allow a Lincoln County project to connect directly to NV Energy, thereby eliminating the need for wheeling service from LCPD. However, no substations are planned along the line through the county, and a small individual project would not be able to pay the cost of an interconnection to a 500 KV line, which would likely run in excess of $10 million. Thus, while the line construction is interesting, it does not offer any realistic new options for a small biomass project, and so wheeling by LCPD to Reid Gardner remains the most likely scenario.

CHAPTER 9 – MARKETS FOR RENEWABLE POWER

9.1 RENEWABLE POWER BACKGROUND INFORMATION

PURPA, the Public Utilities Regulatory Policies Act of 1978, established the principles governing the sale of power from small renewable power facilities to utilities. That act required regulates utilities to purchase power from facilities meeting certain criteria (Qualifying Facilities, or QFs) at the utility's "avoided cost". The avoided cost is the cost that the utility would have incurred to produce the same power but for the existence of the small independent producer. The calculation of avoided cost and inclusion of that rate in a contract was left to each state to interpret. In Nevada, the law is implemented by the Public Utilities Commission (PUC).

Subsequent Federal laws and regulations required the regulated utilities and power marketing agencies to "wheel" this power across their systems to other buyers if requested and established mechanisms to value that service. This "open access" transmission principle often allows renewable producers to move their power from low valued markets to higher valued markets in other states. Projects greater than 20MW using this wheeling service, as opposed to selling to the local utility at avoided costs, register with the Federal Energy Regulatory Commission (FERC) as an Exempt Wholesale Generator (EWG) as opposed to a QF.

9.2 RENEWABLE POWER IN NEVADA

The value of renewable power in a given state is governed by a combination of the utility's inherent avoided cost, by regulatory policies adopted by the state PUC, and by the existence of an Energy or Renewable Portfolio Standard (RPS) within a given state. The RPS is a statute that requires certain utilities within the state to acquire a certain percentage of their total energy requirements from renewable sources by dates certain. Nevada has such a statute, passed in 1997 and revised in 2009, that requires investor owned utilities (NV Energy), competitive electricity suppliers and certain large mining interests to obtain 15 percent of their power from renewable resources during 2011 – 2012, 18 percent during the period 2013 – 2014, 20 percent during the period 2015 – 2019, 22 percent during the period 2020 – 2024 and 25 percent in 2025 and thereafter. A certain portion of the above amounts must be from solar energy and a certain amount may be from efficiency measures. The state did not require publicly owned utilities, such as Lincoln Power District No 1, to meet this standard.

Nevada's law allows the utilities, primarily NV Energy, to meet the standard by the purchase or production of renewable energy directly, by the purchase of Renewable Energy Credits (RECs) separately from the underlying energy, or by a combination of the two. The RECs can be purchased from throughout the west to meet this standard. There is a maximum limit on what the utility must pay above existing costs to meet the standard, or it may instead pay a penalty of $10/MWh for any shortfall in the program.

Often, the rate of increase in a utility's renewable energy requirements due to an RPS cannot be satisfied by purchasing at avoided cost, particularly when fossil fuel prices are low, as they are currently. There are simply not enough renewable power facilities that can be developed at the fossil fuel derived avoided cost. In this case the utility will often seek authority from the regulatory commission to issue a Request for Proposals (RFP) for specific amounts of renewable power, with only qualified renewable power plants being allowed to bid into the subsequent auction. A very recent ruling by FERC, however, allows states with an RPS requirement to use the cost of renewable power in determining avoided cost rather than relying exclusively on fossil fuel avoided cost determinations. It is unknown if the Nevada PUC will adopt this method in the future, or whether NV Energy will continue to rely on renewable RFPs to fill their RPS requirement.

NV Energy has generally kept pace with its requirement to acquire increasing amounts of renewable energy by conducting such auctions for renewable energy projects and offering contracts to the winning bidders. Winning bidders have involved projects utilizing solar, geothermal, wind and landfill gas energy. NV Energy has previously purchased biomass energy from projects in Loyalton, CA and Carson City, NV, but those projects are currently closed. Unlike most state renewable auction results, NV Energy has been forced to make public the power cost of the recent winning bidders. For non-solar projects, the recent first year prices vary from $81 – 98/MWh with a 1 percent annual escalation, and for solar projects, the prices are $132 – 135/MWh with the same 1 percent escalator.

9.2.1 Sale to Federal Facilities

Another potential opportunity is to sell the biomass power to a federal agency, which are all under a mandate to purchase at least 7.5 percent of their power from renewable sources, with a preference going to projects developed at federal facilities. This renewable mandate can be met through the purchase of renewable power directly or through the purchase of RECs disassociated from the power. Often, federal facilities opt to purchase RECs while continuing to buy power from the local utility as it simplifies their compliance.

9.2.2 Sale Outside the State

Within the larger Western Electricity Coordinating Council (WECC) grid, there are numerous states with RPS requirements, including Nevada. The largest market in the west is, of course, California, which has a 20 percent by 2010 mandate. The major investor owned utilities will not reach this goal, or the recently established requirement, by the California Air Resources Board, of 33 percent by 2020. This 33 percent by 2020 requirement applies not only to investor owned utilities (70 percent of total state load), but to all municipal utilities as well.

To reach these markets, transmission service must be purchased from each of the intervening transmission owners. This "pancaking" of transmission rates often eliminates all of the benefits of selling to a more vibrant market outside the state. In addition, since high voltage transmission is essentially a "common carrier" function, all of the rights may have already been sold to others. This will be covered in more detail in Section 9.3 .

Another concept is to sell the power locally without RECs attached and sell the RECs into another market separately. In the case of a project located within the service territory of Lincoln County Power District, this may at first seem to be a logical thing to do since Lincoln has no RPS obligation that it is required to meet and so cannot value the RECs. On the other hand, LCPD is a very small system with very low bulk power prices of well under $40/MWh ($0.04/KWh). Therefore, a sale to LCPD at a price that would support the project investment would be an unreasonable expectation and would unduly raise retail rates for LCPD customers. On the other hand, Lincoln County may still be a good location for the facility since the project could provide valuable system electrical services to LCPD and LCPD could take on the plant auxiliary power load as a new customer, allowing the facility to sell its full gross output to parties elsewhere.

In looking at western RPS markets, however, you quickly find that REC pricing is currently very low, typically under $10/MWh. This market is established primarily by the voluntary purchasers, people and businesses who agree to pay extra for "green" power, and the utility then procures RECs on behalf of those customers. Since most western RPS standards do not ratchet to significant levels prior to 2015, this leaves Nevada and California as the markets that have significant requirements between 2010 and 2015.

California does not currently allow the use of tradable RECs (or TRECs as they are known in California) for RPS compliance. Power must be brought into the state "bundled", though in certain limited circumstances the bundling can be a REC bundled with fossil power. For the 5 years prior to the current recession, California had been unable to increase the percentage of renewable power in the state, with the proportion stuck at 12 – 13 percent, despite Herculean efforts and hundreds of signed contracts. Load drops associated with the current recession has made compliance easier, however, and so the major utilities expect to deliver perhaps 15 – 18 percent renewable power by the end of 2010.

The California PUC now has before it proposals to allow the use of TRECs for 25 to 40 percent of the total utility requirement, which happens to be about the amount the major utilities are currently short on their 2010 obligations. Knowledgeable observers expect that some version of the current proposals will pass, creating an instant market for TRECs from throughout the WECC, including eastern Nevada. What is not known, however, is how quickly the market structure will develop to support bankable long term transactions that could be used in support of a project's financing.

9.3 POWER PRICE FOR A LINCOLN COUNTY PROJECT

Arriving, in advance, at a power/REC sales combination that will support a project financial model is absolutely critical to preparing a viable financial model and to subsequently moving forward with any biomass power or CHP development in Lincoln County. Based on the interconnection/transmission discussion in Section 9.2.2 , plus this section's discussion of markets, it is possible to reasonably project the value of power to a Lincoln County project at the point it enters the larger western grid. The two most viable opportunities are to sell to NV Energy as part of its next renewable RFP. Based on the most recent published prices for non-solar renewable power, a reasonable price for power would be $92 – 97/MWh at project startup for power delivered to Reid Gardner, plus a 1 percent annual escalator.

Since California utilities, both public and investor owned, have transmission assets in the Las Vegas area and are constantly issuing their own RFPs, it is instructive to look at the prices these entities are paying for power currently. Though most contract prices are not released publicly in California, it is possible to make projections based on the relationship of the contract price to the Market Price Referent (MPR), California's version of the avoided cost calculation. All contracts signed with California investor owned utilities must indicate whether the contract is at, below or above the MPR. Also, many publicly owned utilities choose to release power price information publicly.

In general, prices delivered to California utilities tend to be between $105 – 110/MWh at startup for non-solar projects, but with no or minimal escalation over the contract life. If the contract price is to escalate on some fixed basis, the starting price will be slightly lower, say $100 – 105/MWh. A recent example is an RFP released by the Southern California Public Power Authority (SCPPA) for renewable resources delivered to their members, which lists a maximum price for biomass power of $100/MWh at startup, escalating at 1.5 percent annually. One of the delivery points under this RFP is listed as Marketplace, NV, a substation in the Las Vegas area. Thus, after paying NV Energy the roughly $6/MWh charge to move the power from Reid Gardner to Marketplace, the net sales price for a Lincoln County project delivered to Reid Gardner is again likely in the range of $92 – 97/MWh at startup, with a low escalator of 1 – 1.5 percent annually.

For purposes of the financial model of the project in Lincoln County, a busbar[10] power price of $95/MWh at project startup is chosen, escalating at 1.5 percent annually. The wheeling charges from LCPD will be charged separately within the project Operation and Maintenance costs and no energy losses to Reid Gardner are assumed as the project is actually lowering flows north on the 69 KV system and thus saving losses.

[10] A busbar is an electrical conducter that connects two or more circuits. It is commonly used to define the point at which power is transferred from a generator to the utility.

CHAPTER 10 – FACILITY SCALE ASSESSMENT

Biomass power is distinct among baseload power technologies in that fuel becomes more expensive as transportation distances increase. This means that the "economy of scale" only works up to a certain plant size, which is distinct for each application depending primarily on delivered fuel costs. In contrast, at a gas-fired or coal plant, the cost of power keeps getting cheaper as plant size increases. In other words, fuel cost is constant, or may even decrease slightly, with larger plant size.

Biomass power price components react differently to size changes. Like gas and coal, as plant size goes up, both capital and non-fuel operating cost go down quickly. But unlike gas or coal, every size increase brings an increase in fuel price as the average haul distance increases. At the margin, in a biomass plant, you have an ever increasing fuel price.

In a Lincoln County context, this fuel situation is present because as size increases the plant must dig deeper into the fuel supply from the next fuel radius out from the chosen plant site. At some point, there are no longer enough acres of P-J to restore to support a larger plant over the time period of the debt, an absolute requirement to obtaining financing.

In addition, the LCPD 69 KV grid will only support a certain size plant without very expensive upgrading. It is uncertain at what size this will occur. However, preliminary studies indicate that at least 10MW can be supported. Thus, that size serves as the base case model used in the financial analysis section of this report.

Despite the limitations of the existing 69 KV grid, it is instructive to analyze how project economics shift with changing plant size. In the following analysis, financial models for three different size plants in Lincoln County were developed. The plants considered were:

1. A 60,000 pound per hour boiler and 7MW T-G
2. A 90,000 pound per hour boiler and 10MW T-G (the base case scenario)
3. A 150,000 pound per hour boiler and a 17MW T-G

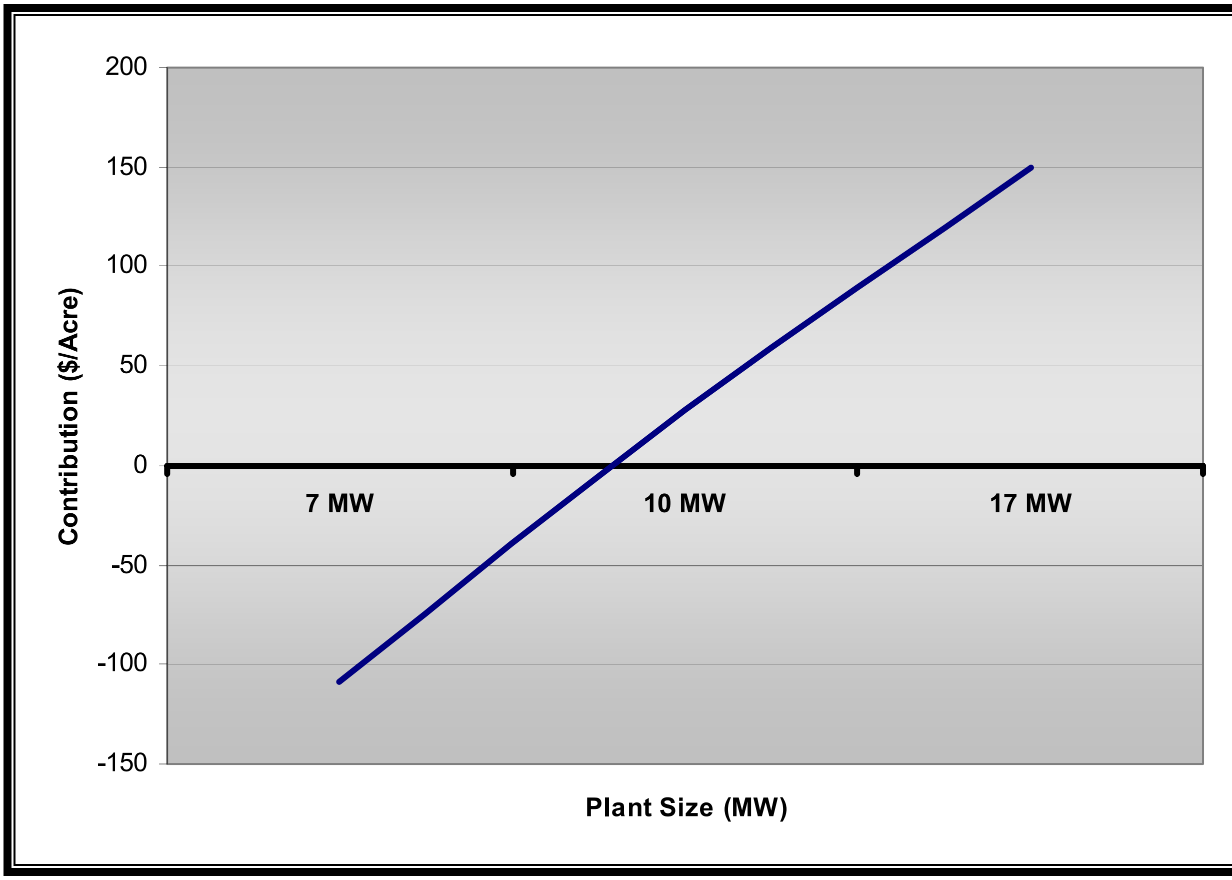
Table 18 shows the plant size and associated capital, operating and fuel costs. With respect to fuel costs, the total maximum allowable fuel cost column is the fuel cost that will provide a minimum target return for each plant size. The fuel chipping and delivery costs are subtracted from that amount to identify the amount (if any) a prospective power plant can contribute to management treatment costs (i.e., tree harvesting and skidding).

TABLE 18: PLANT SIZE IMPACT ON A PROJECT'S CONTRIBUTION TOWARD MANAGEMENT TREATMENT COSTS

Plant Size	Capital Cost ($1000s/Gross MW)	Non-Fuel O&M Cost ($/MWh)	Total Maximum "allowable" Fuel Cost ($/BDT)	Fuel Chipping & Delivery Cost ($/BDT)	Contribution to Management Treatment Cost ($/BDT	Contribution to Management Treatment Cost ($/acre)
60K/7MW	5,630	41.30	5.50	21.20	-16.00	-108.00
90K/10MW	4,755	34.38	27.00	23.00	4.00	28.00
150K/17MW	3,475	26.77	47.85	26.20	22.00	149.00

The same information shown in Table 18 is presented graphically in Figure 3. As can be seen, the smallest plant requires further subsidy, while larger plants begin to return an ever increasing amount to the restoration effort.

FIGURE 3: PLANT SIZE IMPACT ON CONTRIBUTION TOWARD MANAGEMENT TREATMENT COSTS



CHAPTER 11 – ENVIRONMENTAL PERMITTING & REGULATORY REQUIREMENTS

11.1 PERMITTING AND REGULATORY BACKGROUND

Except for Clark and Washoe Counties, all environmental permitting in Nevada, with the exception of local land use issues, is handled by the Nevada Division of Environmental Protection (NDEP), which is headquartered in Carson City. In the case of Renewable Energy Resources, the NDEP has also developed a streamlined permitting process for such resources, applicable to permitting for air emissions, wastewater discharge and solid waste management. The specific permitting that must be done for a biomass power project in Nevada is as follows:

11.1.1 Land Use Permit

Lincoln County will be the lead agency in permitting a project for local land use issues. The permit process, which takes the form of a Special Use Permit, will involve, among other issues, zoning, building/stack heights, access, traffic, fire safety, noise, aesthetics, fugitive emissions, utilities, hours of operation, etc. This process will require a minimum of two months, and is greatly simplified if the land on which the power facility is located is already zoned for the proposed purpose. The county permit process is the primary vehicle under which local residents have an opportunity to shape the outcome.

11.1.2 Air Emissions Permit

The air emissions permit for a biomass power facility is typically the most complex and time consuming permit process. In Nevada, the NDEP Bureau of Air Pollution Control (BAPC) manages the process.

Nevada has a tiered permitting system that begins at Class III for the smallest emission sources of less than 5 tons per year (TPY) of any regulated pollutant, through Class II for sources of 5 – 100 TPY of any pollutant, to Class I, which are major sources of greater than 100 TPY of any pollutant or more than 25 TPY of total hazardous air pollutants (HAPs) or more than 10 TPY of any one HAP.

A 10MW biomass power project in Lincoln County combusting P-J would likely consist of a 90,000 lb. steam/hour boiler equipped with a multiclone collector for coarse particulate control, an electrostatic precipitator for fine particulate control and heated combustion air and multiple levels of overfire air for control of both carbon monoxide (CO) and nitrogen oxides (NO_x). With that configuration, the likely guaranteed emissions from the facility are shown in Table 19.

TABLE 19: LIKELY GUARANTEED AIR EMISSIONS

Pollutant	Emission Rate (Lb./Million BTU)	Annual Emission (Tons/Year)
Particulate (PM-10)	0.025	15
Nitrogen Oxides	0.20	118
Carbon Monoxide	0.22	129
Volatile Organic Compounds	0.005	3

The basis for the figures in Table 19 is a heat input of 144 million BTU/hour and 8,200 hours of operation per year, both as shown on the project heat balance in Figure 5 on page 69.

As can be seen in Table 19, two of the pollutants, CO and NO_x, are in excess of the 100 TPY cutoff for a Class II Permit. This means that the project will likely require a Class I Permit. It is possible that further refinement of emissions based on fuel quality information and vendor discussions could result in vendor guarantees below 100 TPY for each of CO and NO_x. If such guarantees could be obtained, it would likely result in the ability to obtain a Class II Permit. However, for this analysis, a Class I Permit requirement is assumed. This distinction is important because the streamlined permitting process for renewable energy sources assumed biomass facilities would require only a Class II or III Permit. Consequently, the compressed timelines for a streamlined permit will not be used in this discussion.

The major source (Class I) designation also means that the project will be analyzed by BAPC against Prevention of Significant Deterioration (PSD) guidelines from the Federal Environmental Protection Agency (EPA). Neither evaluation requires an Environmental Impact Statement (EIS), so none is assumed here.

The Class I Permit process is triggered by the submission of a permit application and a proposed protocol for air quality modeling. BAPC has 30 days to respond to the modeling protocol and 60 days to declare the air permit application complete. Once complete, the BAPC has one year to either issue or deny a permit for the project. Factoring in time for permit application and modeling to occur, the total timeline to a Class I Permit is approximately 18 months, provided credible meteorological data is available that is representative of the proposed site. This timeline is contrasted with the streamlined process for a Class II Permit, which is estimated by BAPC to be 75 days.

The existing ambient air quality in Eastern Nevada is excellent, which greatly simplifies permitting. There are simply no areas in Eastern Nevada that are out of compliance with ambient air quality standards for any criteria pollutant. In establishing these standards, Nevada follows the federal standards, except in the Tahoe Basin, where more stringent standards are in place.

Nevada BAPC also publishes a map of PSD trigger areas in the state, meaning areas of special concern regarding potential air quality deterioration. In the case of Lincoln County, the only PSD trigger areas are in the Lower Meadow Wash and Virgin River Valley areas in the far Southern end of the county. No such areas are close to the proposed project location in the Pioche/Panaca/Caliente area. Very little ambient air quality monitoring is done by BAPC in Eastern Nevada (outside Clark County). Particulate only monitoring is done just at McGill and Baker, both in White Pine County. Both sites show very low ambient particulate concentrations.

The air quality modeling that is part of a Class I application must rely on meteorological data that is gathered over a long period of time and is representative of the site. The locations in Eastern Nevada that gather such data (temperature profiles, wind direction, wind speed, air mixing, etc.) are in Ely, Las Vegas and at Desert Rock on the Nevada test site. The Desert Rock site is the only one monitoring upper air data as well as surface data and so would likely be the source of the 5 years of data preferred by the BAPC. BAPC has stated that, due to the lack of substantial meteorological data in rural Nevada, they will look at each application separately rather than make a blanket requirement. It is likely that the small size of the project and low existing ambient concentration will allow use of the Desert Rock data unless the site chosen is in a canyon, for instance, where the data might not be representative. If no representative data is found, the application will require one full year of onsite meteorological data, further delaying the permit process.

As can be seen from the previous discussion, the air quality permit will consume the bulk of the permitting effort. However, the location and size of the facility will likely produce a positive outcome without exceptional air emission reduction requirements.

11.1.3 Water Use Permit

Because of the arid conditions in Lincoln County, this project is being analyzed, for the base case, with an air cooled condenser as opposed to a more standard and cheaper wet mechanical draft cooling tower. This change will drop total water consumptive use by over 90 percent to approximately 9 gallons/minute (13.6 acre-ft./yr.). There may be locations in Lincoln County that could support wet cooling (approx.180 acre-ft./yr.), and this situation would improve project economics provided the water cost was reasonable.

With this low base case usage, it is expected that the water will be purchased from the local water agency in the vicinity of the project or from a party holding existing water rights, and thus no state permitting process will be required.

11.1.4 Wastewater Disposal Permit

Of the 9 gallons/minute makeup water mentioned in the previous section, only about 3 gallons/minute will require disposal. That amount is the blowdown from the boiler required to maintain mineral concentrations and is actually fairly high quality water by Eastern Nevada surface water standards. Choices for the disposal of that water include disposal to a public sewer system, if available, or reuse in the plant for wetting of ash prior to disposal and for humidification of air prior to the air cooled condenser to increase heat transfer efficiency.

The NDEP Bureau of Water Quality Planning (BWQP) governs such wastewater disposal. As in air quality permitting, the BWQP has a streamlined process for renewable energy resources. Because of the small quantity, high quality and reuse options available to the project, the wastewater permit issue is considered a minor permit issue.

11.1.5 Solid Waste Permit

In addition to a small amount of typical commercial/industrial trash which will be disposed of through normal channels, the project produces ash from the combustion of wood, which is estimated to total about 2,400 tons annually. This ash consists of bottom ash from under the boiler grates and fly ash collected downstream of the combustion process in pollution control equipment. A typical split is 50 percent each of bottom and fly ash.

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

The fly ash portion is much finer and contains a certain percentage of unburned carbon. It is typically high in pH. This material is often utilized in agricultural operations as a soil amendment. The material has excellent moisture retention capabilities, is often used as a "liming" agent on low pH soils, and possesses certain beneficial trace minerals. With the high pH typical of soils in eastern NV, agricultural spreading opportunities may be few, though application on the alfalfa and potato field in the Pioche, Panaca, Caliente areas should be investigated. The material can also be used as a cover material at landfills, incorporated into commercial soil amendments or simply be returned to the land from which the fuel originated.

In areas with high concentrations of biomass projects, such as California, Best Management Practices have been developed for these various uses. It is expected that uses will be found for all of the ash components. This activity is regulated by the NDEP Bureau of Waste Management (BWM), which, again, has a streamlined process for permitting for renewable energy resources. Because of reuse options available locally and in Las Vegas, it is expected that solid waste permitting will be a minor permit activity.

11.1.6 Summary

The permitting process for a biomass power facility in Lincoln County will likely revolve around local land use and state air quality permit issues. All other permits are considered minor in comparison. The state air quality permit process will likely establish the project timeline critical path. If project sizing, pollution control equipment or vendor guarantees allow the project to obtain a Class II air quality permit, the timeline can be shortened by over one year. The permitting required for a Lincoln County project is expected to be straightforward and without any special circumstances.

CHAPTER 12 – TECHNOLOGY ASSESSMENT

This section describes the biomass power technology considered in this assessment and how technology choices affect the design of a power plant.

The findings from this analysis are that a boiler with a moving-grate, air-swept stoker system is appropriate for combusting woody P-J biomass of varying moisture contents and particle sizes. In addition, a standard direct connected steam turbine-generator is the proper prime mover for converting the steam energy into electrical energy. The turbine portion will feature a steam extraction port at an appropriate point to support a process steam use if a viable steam customer can be found. To be conservative, it is assumed that the project will have little water available to it and thus an air cooled condenser will be the exhaust steam cooling technology of choice.

The conclusions that can be drawn from these findings are that:

- The technology of combusting biomass to fire a boiler is mature. The reliability of the technology considered for the biomass fueled power plant modeled in this study has been proven many times over.
- The design of the boiler and balance of plant equipment would allow a power plant to comply with a Nevada BACT determination and produce emissions at levels that comply with NDEP standards.
- The lack of water in Lincoln County may force the choice of an air cooled condenser, which will raise capital cost and lower plant efficiency, but is available and proven technology. This more severe option is the base case modeled in the financial analysis section.

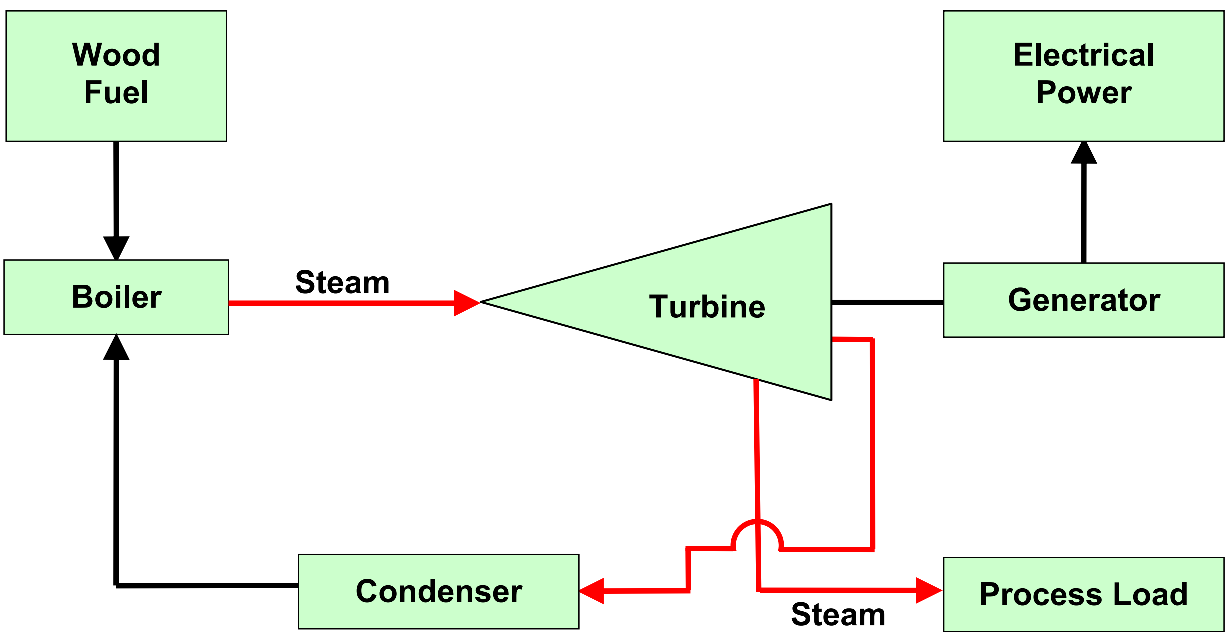
12.1 PROJECT DESIGN AND TECHNOLOGY

The technology underlying the power plant being considered as part of this study is mature. For example, biomass fuel has been successfully combusted in industrial and power generation applications for many decades. The following section describes the design and technology of the power facilities considered in this study.

As shown in Figure 4, a simplified diagram of a wood-fired power system, the process begins when wood fuel is combusted in a furnace whose walls consist of water filled pipe. The high pressure water in the pipe boils to steam; the steam is then heated to a higher temperature before exiting to the turbine generator (T-G). The T-G is a multistage bladed rotor that turns within a series of bladed fixed diaphragms. The passage of steam through the unit drops steam temperature and pressure at each stage as thermal energy is converted into mechanical energy. The mechanical energy of the rotating turbine is converted into electrical energy in a direct or gearbox connected generator which uses a magnetic spinning rotor to induce electrical current in the windings of the fixed stator that surrounds it.

Part way down the T-G, a portion of the steam may be extracted for use by a process steam customer, should one be found for the particular application. The extracted amount is automatically controlled by the demand of the process load. Further down the T-G (but not shown in the diagram), a second lower pressure extraction supplies the deaerator, a device that removes entrained oxygen from the feedwater as it goes back to the boiler. The steam not needed for kilns or deaerator exits the back end of the turbine to the condenser to be turned back into water at a pressure far below atmospheric pressure in order to maximize T-G efficiency. The condenser is supplied either with water from a wet mechanical draft cooling tower, which evaporates a portion of the water as it cools it for the return trip to the condenser, or with large volumes of air if sufficient water is not available.

FIGURE 4: SIMPLIFIED DIAGRAM OF WOOD-FIRED COMBINED HEAT AND POWER SYSTEM



12.1.1 Boiler Technology

The primary choice to be made in plant design is the selection of the boiler technology. The large majority of biomass boilers burn the wood on a grate containing holes so that primary combustion air can be introduced below the grate. The fuel is spread across the grate by an air swept stoker. The grate itself can be fixed, vibrating, traveling, reciprocating or rotating. The purpose of a moving grate is to automatically remove ash and to provide a space for fresh fuel.

Another boiler design is a fluidized bed, which comes in either a bubbling bed or circulating bed version. In both designs, a large bed of sand and fuel is kept "fluidized" by large volumes of air introduced below the bed. There is no grate in this design.

A third option, though much less common in boilers of this size range, is to gasify the fuel in a separate vessel. This occurs through heating the fuel in an oxygen starved condition. The gases produced as part of this process are introduced to the boiler proper where combustion is completed.

The pros and cons of various designs are debated endlessly, but some of the advantages and disadvantages of each are as follows. The grate designs are proven, efficient, rugged and reliable. The fluidized beds are newer in design; they operate at a lower temperature, which means that some pollutants (e.g., NO_x and CO) are minimized. However, they require additional auxiliary power for the fluidizing process. Gasification offers advantages when fuels with very low ash melting points are used because gasification can prevent boiler conditions that might otherwise foul boiler tube surfaces. For example, combustion of agricultural residues sometimes relies on gasification. The downside of gasification is that the systems are more complex, not proven at larger scale, and offer no thermal efficiency advantage so long as the resulting gas is simply burned in a standard boiler.

In this study, the fuel quality is known (chipped or ground forest residue) and varies only by particle size and moisture content. There will be no combustion of high moisture sludges such as might be encountered in a pulp and paper industry application and which could require fluidized bed combustion. These projects do not anticipate combusting agricultural residues that might point to a gasification process. For these reasons, the choice for costing and efficiency calculations in this study is a moving grate system fed by an air swept stoker.

The moving grate/air swept stoker system gives the widest choice of vendors and has a relatively low capital cost and auxiliary power use. Since the location chosen is in an air quality attainment area, the stoker grate will be able to comply with a Nevada BACT determination when equipped with an electrostatic precipitator for particulate control and multiple levels of heated overfire air for CO, NOx and VOC control. These pollution control technologies are proven in performance in dozens of biomass fueled applications, and commercial performance guarantees are available. This design system forms the basis of the financial model used in Chapter 14, the Financial Analysis section of this report.

12.1.2 Balance of Plant Equipment

There are several vendors of T-Gs in this size range that should ensure competitive bids for the project. One unique feature of this project, necessitated by the uncertainty of obtaining a large volume water supply for the project, is an air cooled condenser. Since the potential project is at a very preliminary state, it cannot be assumed that the final site chosen will have the requisite water supply needed for a standard wet cooling tower due to the arid conditions in eastern Nevada.

An air cooled condenser is basically a very large radiator, mounted horizontally, into which the turbine exhaust steam enters to be condensed back into water. That condensing is done by passing large volumes of air over the outside of the tubes containing the steam. The air is forced through the condenser by large fans mounted on either the top or bottom of the air cooled condenser. While this technology is proven in hundreds of applications around the world, it is typically only chosen for applications such as this as it both raises the capital cost of the project and lowers the efficiency of the electrical generation process. Even though there may be locations in Lincoln County that have the available water to support the project with a standard wet cooling tower, the conservative choice is to include in the design an air cooled condenser to eliminate over 95 percent of traditional water use.

It would indeed be fortuitous for the project to obtain water rights to allow use of a standard two cell wet cooling tower in this application. This substitution would lower capital cost by roughly 10 percent, and allow 5.7 percent more power to be obtained from the same fuel supply quantity. This benefit would, of course, have to be balanced against the cost to obtain the nearly 180 acre-feet per year of water required for this method of cooling.

CHAPTER 13 – INCENTIVE PROGRAMS

The following sections describe various incentive programs and financing structures, both of which very often determine the success or failure of a proposed biomass development. With biomass power, particularly when the primary fuel source is a relatively high cost material from thinning operations, these programs are crucial to lowering the cost of power to an acceptable level for a utility purchaser.

13.1 STATE INCENTIVES

Nevada has a solid package of incentives for renewable energy producers, with clearly the most important being the Energy Portfolio Standard (EPS) discussed in Chapter 9, Markets for Renewable Power section. In addition to the EPS, Nevada offers other incentives, which are discussed below.

13.1.1 Renewable Energy Sales and Use Tax Abatement

Renewable energy systems of 10MW and larger are entitled to sales and use tax abatement such that the total sales and use tax paid is just 2.25 percent (after 6/30/11). In order to qualify for the abatement, the project must also:

- Employ a certain number of full-time employees during construction, a percentage of whom must be Nevada residents.
- Ensure that the hourly wage paid to the facility's employees and construction workers is a certain percentage higher than the average statewide hourly wage.
- Make a capital investment of a specified amount in the state of Nevada.
- Provide the construction workers with health insurance, which includes coverage for each worker's dependents.

13.1.2 Renewable Energy Property Tax Abatement

Renewable energy systems of 10MW and larger can receive a property tax abatement of up to 55 percent of taxes otherwise due on both real and personal property for up to 20 years. In order to qualify for this abatement, the project must also:

- Employ a certain number of full-time employees during construction, a percentage of whom must be Nevada residents.
- Ensure that the hourly wage paid to the facility's employees and construction workers is a certain percentage higher than the average statewide hourly wage.

- Make a capital investment of a specified amount in the state of Nevada.
- Provide the construction workers with health insurance, which includes coverage for each worker's dependents.

13.1.3 Portfolio Energy Credits

A somewhat more complicated incentive, the Portfolio Energy Credit (PEC) law, allows those generating their own electricity to earn PECs (1 PEC/KWh) that can then be sold to NV Energy to assist them in meeting their Energy Portfolio Standard requirements. In the case of a Lincoln County project, it was assumed that the PECs were sold along with the electricity in a "bundled" transaction.

Interestingly, the law also allows, at least for solar thermal applications, the generation of PECs for the thermal use of renewable energy (1 PEC for 3,412 BTU of thermal energy). Though not currently applicable to biomass thermal applications, the inclusion alongside solar thermal systems would dramatically boost the prospects for biomass combined heat and power systems, including a potential Lincoln County project.

13.2 FEDERAL INCENTIVES

Over the last five years, a substantial package of federal incentives has been assembled for biomass, particularly for combined heat and power projects such as the one anticipated by this study. This accelerated recently with the passage of the American Recovery and Reinvestment Act of 2009 (Stimulus Bill).

13.2.1 Investment Tax Credit/Production Tax Credit Election

Since 2005, biomass projects have been able to claim a Section 45 Production Tax Credit (PTC) of 1.1 cents/KWh against federal income tax liability for the first 10 years of a project's life, with the 1.1 cent amount escalating with general inflation. That credit could be used in a consolidated return and carried forward for up to 20 years. The Stimulus Bill added an election in Section 48 to take instead a 30 percent of qualifying total capital cost Investment Tax Credit (ITC) in the first year of operation against federal income tax liability. In other words, a developer could choose either the PTC or the ITC.

The ITC can be further traded for a grant of an equivalent amount (30 percent of eligible project costs) from the U.S. Treasury at startup. In order to qualify for the ITC election, a project must be under construction by the end of 2010 and be completed by the end of 2013. Grants cannot be applied for after October 1, 2011. Grants lower the depreciable asset base of the project by one half of the grant amount, but are not taxable for federal income tax purposes. Legislation has been introduced in Congress to extend the grant feature for start of construction dates through the end of 2011, but this legislation must now pass in the lame duck session, is not at all certain, and has not been included in the financial analysis.

The grant feature was added in response to the loss of many “tax equity partners” as a result of the current financial crisis. Previously, many projects would bring in a partner with a high tax liability (financial institution) who would invest substantial equity in the project in order to collect nearly all the early year tax advantages. That partner would exit the project when its target return was reached. This was a way for the original developer to receive the value of the tax credits that the project would not otherwise have the tax liability to monetize. This new ITC/PTC election/grant is a powerful incentive for projects that can be placed under construction quickly, but will not be used in the following financial analysis because of its uncertain future.

13.2.2 Combined Heat & Power Tax Credit (CHP)

Also in Section 48 of the tax code is a CHP ITC of up to 10 percent of project cost for projects that use steam sequentially for both power production and process heat. In order to qualify, at least 20 percent of the net heat must be used for each of power generation and process heat.

The CHP credit also has an efficiency and a size test. The full 10 percent ITC can only be claimed if the project has an overall thermal efficiency of 60 percent (power plus steam), a difficult standard for a biomass project. A prorated amount is awarded for lower efficiencies. Also, the full credit is also available only up to 15 MW of capacity, with reductions for larger projects and a full phase out at 50MW. Any project must be in service by 2016 to qualify.

With the recent passage of the previous PTC/ITC election, also in Section 48, changes were made to the program so that a project cannot collect both the PTC/grant and the CHP ITC. This credit is not included in the financial analysis of this project.

13.2.3 Accelerated Depreciation

The Lincoln County project would qualify for the Modified Accelerated Cost Recovery System (MACRS) depreciation tax treatment. For the boiler and fuel handling portion of the project, which typically represents 55 percent or more of total project cost, the depreciation time period is over just 5 years. The MACRS depreciation schedules are used in this analysis.

Also, the Stimulus Bill extended “bonus depreciation” for projects such as this through 2010. The bonus depreciation allows 50 percent of the total project cost to be depreciated in the first year of service in addition to the typical first year depreciation on the remainder. Though it would appear likely that bonus depreciation would be extended again, and bills have been introduced in Congress to do just that, the benefits of that treatment are not included in the analysis.

13.2.4 USDA Grants

The U.S. Dept. of Agriculture has numerous small grant and loan guarantee programs for rural biomass projects such as this. A typical grant for such a project is $¼ to ½ million. Federal loan guarantees can also be obtained for up to $10 million, with new program changes pushing that amount to $25 million in certain circumstances.

These aforementioned programs have been supplemented by the new Stimulus Bill, as billions of additional dollars have been appropriated by this bill towards expanding these programs. No grant funds from this source have been assumed in the analysis.

13.3 PROJECT FINANCING

In the world of renewable power – post financial crisis – obtaining project financing, particularly construction financing, has become extremely difficult, frustrating, and time consuming. Lenders require extreme quality in terms of fuel supply, technology choice, power purchase agreements and steam host credit (if applicable) in order to move forward with a project. Governments, both state and federal, have responded by putting in place, or reviving, loan and loan guarantee programs that transfer some of the risk to the government entity.

For the last 15 years or so, the business development model for renewable projects was to find a tax equity partner who would fund the equity portion of the project development costs in exchange for the early tax benefits that the project would produce. The partner might receive 99 percent of the benefits in the early years and then "flip" to a 1 percent ownership position when his equity interest was repaid, with the original developer becoming the 99 percent owner. Since the onset of the financial crisis, these types of arrangements are almost nonexistent.

Today, projects seeking financing often need the federal grant, described in section 13.2.2, that replaced temporarily the tax credit driven project development scenario described above. That grant is typically pledged as equity towards a long term financing package that may include loan guarantees from a relevant federal agency. Most lenders will require additional equity beyond the federal grant to assure that the developer has "skin in the game" throughout. If the grant is indeed not extended, the tax equity partnership must be revived.

Were it not for the ongoing financial crisis, the switch to a federal grant system versus a federal income tax credit would be seen as a simplification of the whole process. You simply get a check for nearly 30 percent of the total cost of the project, walk down the street to the bank and plunk it down for the equity that you need, get the loan, and go build the project. The big problem with the above scenario is a dual timing problem.

The first is that you cannot file to get preapproval of the federal grant until you are "under construction". To get to the point of being under construction you need to complete interconnection/transmission studies, permitting for long lead time permits, securing of property, term sheet for sale of power, financial modeling, preliminary engineering, equipment contracting, etc. The developer may have well over $1 – 2 million invested before he can even apply for qualification for the federal grant. Secondly, even if you are prequalified, you still need to complete construction and startup before you can certify expenditures and apply for the check. In other words, a developer has to spend a substantial amount of money before getting an indication that the project qualifies for the grant, and all of the money before he is reimbursed the 30 percent that becomes the equity for long term financing..

The topic of project finance is highly complex and transitional at this point in time. Things have definitely improved from the depths of the financial crisis, but are a long way from normal. Various programs are being put in place to help, but these are highly project and site specific, with applicability being determined by such things as the poverty level of the community or who the power purchaser is. Examples of current financing vehicles or assistance are discussed in the following sections.

13.3.1 New Market Tax Credits

This is a federal program whereby the project debt lender can claim a federal tax credit of up to 38 percent of the value of the loan to the project over 7 years. This program is only applicable in communities with a high poverty level or low income relative to state averages, and requires a third party who has an existing allocation of credits to apply. At the project level, the net effect is both a reduction in long term debt interest rates of 1 - 2 percent plus a cash infusion with no payback requirement from the lender. Unfortunately, the Lincoln County area does not qualify for this program.

13.3.2 Rural Utilities Service (RUS) Loan Program

This is a new federal loan program available to generators who sell their project output to a rural electric cooperative or cooperative buying group. In that case, the borrower can obtain up to 75 percent of the project cost as debt financing for up to 20 years at an interest rate of 3.5 – 4 percent. The debt is not available for construction and can only be put in place at startup. Since Lincoln Power District is not a Rural Electric Cooperative, this program may also not be available.

13.3.3 Local Revenue Bonds

In Nevada, cities and counties are able to issue tax exempt bonds to support development of private renewable energy facilities. The bonds are repaid by the project, with no recourse to the public entity. There is a limit on the amount of bonds that can be outstanding at any point in time within the state.

The value of these bonds, beyond the low interest rate, is that they can be issued at project initiation and thus provide construction financing, as well as long term debt.

13.3.4 U.S. Department of Agriculture Loan Guarantee

The USDA has a longstanding loan guarantee program that can provide a federal guarantee of loans for up to 75 percent of the project cost on a long term basis. This is a competitive process, and Congress provides the USDA with the ceilings on the amount of loans that can be guaranteed. The USDA can guarantee up to $25 million in loans to an individual project, and the net effect of the guarantee is to lower interest rates in the market by 1 – 2 percent and certainly make credit more available to a project.

13.3.5 U.S. Department of Energy Loan Guarantee

This is a new loan guarantee program put in place by the ARRA. It is designed to guarantee loans for innovative technology and biomass projects qualify under the program. Again, Congress provides the total loan ceiling, and the process is competitive. The program does not appear to have the same individual project ceilings as the USDA program, and the net effect on interest rates is the same.

13.3.6 Partnership with Purchasing Utility

Many renewable Requests for Proposals (RFPs) that have gone out recently in the West have included options of a partnership with the purchasing utility or sale of the project to the utility in the future. This potentially brings the utility's capital raising strength and a lower interest rate into a project. A guaranteed sale, for example, after development and 5 years of operation, would give lenders the comfort they would need to fund the construction. The 5 year hold period prior to sale is the amount of time required to extinguish any repayment obligation under the federal Section 1603 ITC grant program described in Section 13.2.2 , should that remain applicable. If the partner is a tax paying entity, the 5 year hold period would not be necessary.

13.3.7 Prepayment for Power

When the power purchaser is a public entity, such as a city or a public utility district, it may be allowed by law to issue low interest bonds for the pre-purchase of power from the proposed project. This mechanism allows the developer to tap lower interest financing not otherwise available to them and to do so earlier in the project so that the funds can be used for construction. Deals such as this are often talked about, are very complex, and are not often completed.

Typically, only a portion of the above list of financing options will be able in a given location. The project owner must decide the ownership structure and level of risk that is acceptable. The first point of contact should likely be with the bank with which the owner has an established banking arrangement. The bank, if it participates at all in the financing, will do so as part of a syndicate of banks in order to lower the risk to any one bank. Equity requirements will be high during both construction and operation, often 30 percent or more of total project cost, and the equity portion will be expensive if acquired from independent investors or investment groups. Fortunately, the 30 percent federal grant allows equity substitution at startup, so outside equity investors may only be in place for a limited period of time.

In today's risk averse world of finance, the owner will not be able to employ unproven new technology, despite its promise, and manufacturer guarantees must be ironclad and backed with a strong balance sheet. The developer will likely have to accept all future environmental costs, with no pass through to the utility, in order to obtain an acceptable power contract. Likewise, fuel risk will be on the developer, though this risk can be mitigated by the contract structure. The availability of fuel over the life of the power contract and financing must be almost absolute.

Though the above list is daunting, there are quality biomass projects that are finding their way through this maze and entering construction today. A quality project by a quality company can be successfully financed and developed.

CHAPTER 14 – FINANCIAL ANALYSIS

In this section of the report, BECK provides a financial analysis of the prospective biomass fueled power plant. As described in the Chapter 5, the Biomass Fuel Supply Assessment section, there is little difference between Pony Springs and Prince in terms of fuel supply. However, from a transmission and interconnection perspective, the Prince location is preferable. Therefore, the financial analysis has been conducted using Prince as the site and using the fuel and capital investment costs associated with the Prince location.

Note that the financial analysis is structured in such a way that the financial model returns the fuel cost at which the plant will provide the project's investors a 15 percent net present value after tax return on their equity.

The key assumptions associated with the financial analysis are described as follows:

14.1 ESTIMATED BIOMASS FUEL REQUIREMENT AND COST

As described previously, BECK has estimated that approximately 5.43 million bone dry tons of fuel are available within a 50 mile radius of the Prince Substation. The power plant modeled here will consume 67,300 bone dry tons of fuel annually. Thus, BECK has concluded there is ample fuel available to supply a power plant.

As shown in the fuel supply analysis, BECK has estimated that fuel could be supplied to the facility for an all cost inclusive delivered price of $96.36 per bone dry ton (includes costs for harvesting, chipping, and transport, rehabilitation, and administrative costs incurred by the BLM).

14.2 PLANT SIZE

Based on the fuel volumes and costs listed above and based on the capacity of the existing LCPD transmission lines, the project team identified an appropriately sized power plant with the following specifications:

- A 90,000 pound per hour steam 900 psig/900 degree Fahrenheit wood-fired stoker rotating grate boiler and a 10 MW nameplate extraction/condensing turbine-generator with an output voltage of 13.8 KV.
- The turbine will have only an uncontrolled extraction point for steam to the deaerator, with steam for soot-blowing and steam jet air ejection being supplied from the 900 psig system through a pressure reducing station. Exhaust steam from the turbine will be condensed in an air cooled condenser (ACC) to minimize

water usage, with the ACC producing an annual average condensing pressure of 4 in. Hg absolute.

- The power plant will operate 8,200 hours per year. On this operating schedule, and at this size, the plant will consume 67,346 BDT per year, assuming the fuel has an aggregate annual moisture content of 40 percent.

14.3 TECHNOLOGY AND PROJECT EXECUTION

Standard stoker grate technology was chosen for the boiler and a standard multistage steam T-G for the turbine. The required cooling was provided by an air cooled condenser as water was assumed not to be available to utilize standard wet cooling technology. As described in the Technology Assessment in Chapter 12, all of these technologies are proven many times over.

Budgetary quotations were obtained from Wellons, Inc. for the supply of the required equipment. The quotations from Wellons were for delivering the project on a turnkey basis. The turnkey approach to developing a power plant minimizes the owner's risk of the plant not operating as designed since the vendor provides performance, completion, and environmental guarantees. Wellons is a leading supplier of such equipment to the forest products industry on such a contractual basis, and so the cost estimates supplied are considered to have a high level of credibility.

The design and method of delivery is such that the project can be completed in a timely manner, is designed to combust the available fuels successfully, and interconnect with the utility, will be financeable within the current financial environment, and can meet the requirements of NDEP.

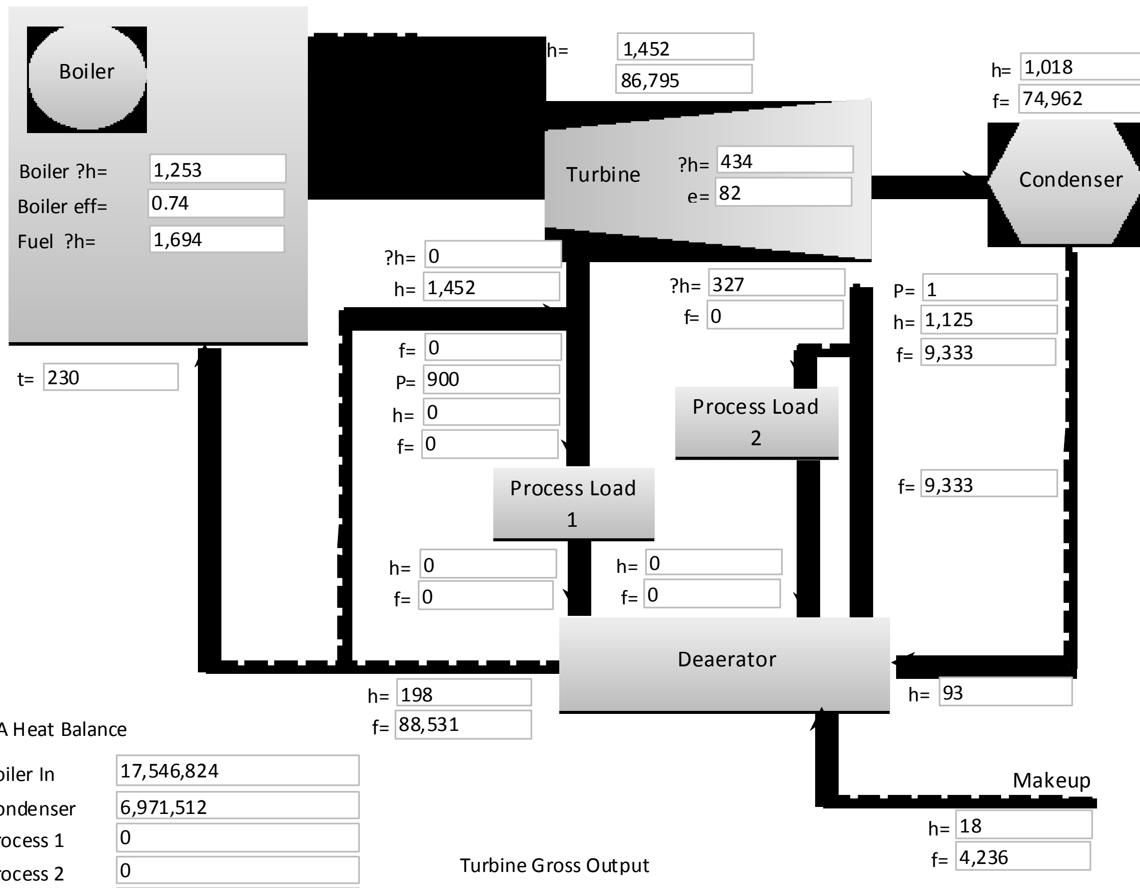
For the purposes of the study, the power plant boiler was assumed to be equipped with the following air pollution control equipment:

- A three field electrostatic precipitator and a multi-clone mechanical collector for particulate control.
- Multiple levels of controlled, heated over-fire air for control of CO and VOCs.
- A complete set of continuous emission monitoring devices for NOx, CO, CO_2, O_2 and opacity, with an automatic data acquisition system.

A complete heat balance for the power plant is included as shown in Figure 5.

FIGURE 5: COMPLETE POWER PLANT HEAT BALANCE

Client:	Lincoln County
Project:	Pioche 10MW Power Project
Boiler Pressure / Temperature:	



DA Heat Balance

Boiler In	17,546,824
Condenser	6,971,512
Process 1	0
Process 2	0
Makeup	76,246
Net	10,499,066
DA Steam	9,333

Turbine Gross Output

Extraction 1	0
Extraction 2	857
Condensing	9,143
Total	10,000

Fuel Required

Fuel Heating Value	17,900,000
Hours of Operation	8,200
Annual Fuel Required	67,346

Makeup Water

Wastewater

Note the following key inputs from Figure 5.

- Boiler Efficiency – 74 percent (based on 40 percent average moisture content)
- Turbine Efficiency – 82 percent
- Annual Hours of Operation – 8,200
- Fuel Heating Value – 17,900,000 BTU/BDT (8,950 BTU/pound dry)
- Annual Fuel Usage – 67,346 BDT
- Average Boiler Output – 86,795 pounds per hour
- Steam Conditions – 900 psig/900°F
- Generator Output – 10,000 KW

The two ash streams: bottom ash from beneath the grates and fly ash from the pollution control devices, will be collected separately because of their different characteristics. The bottom ash will be shipped to a sand and gravel operation as aggregate material, while the fly ash will be shipped to a mulch preparation yard for incorporation into landscaping products, used on fields or pastures as a soil conditioner, or land filled. The cost of hauling and disposal is included in the financial model.

14.4 BUDGETARY CAPITAL COST

As previously described, a budgetary estimate was obtained from Wellons, Inc. of Vancouver, WA for the turnkey engineering, procurement and construction (EPC) of the project. Wellons is a leading supplier of biomass power projects in this size range to the forest products industry. Wellons provides in house engineering of their entire scope, plus manufacturing of boilers, ductwork, pollution control equipment, water treatment equipment and plant control systems. Major purchased equipment includes turbine-generator, air cooled condenser and main power transformer.

Wellons scope extends, on the boiler path, from the fuel storage silos through the boiler stack. On the turbine-generator path, the scope extends from the steam outlet of the boiler through the interconnection substation with the utility, including a 12.5 MVA 13.8 KV/69 KV main transformer. The fuel receiving, processing and storage facilities are handled outside of the Wellons scope. Likewise, the costs of interconnecting to the utility beyond the onsite substation are beyond the scope of Wellons, but are included separately in the financial model. Working capital consists of the cost of spare parts, initial chemical purchases, an initial 3 months of fuel supply and the cost of the first month Operating and Maintenance expense.The price for the Wellons scope, including startup and training is $37,750,000 (See Table 20).

In addition, the project will require nearly $10 million for project management, permitting, site preparation, working capital, interconnection costs, fuel system, sales tax and interest during construction, all as shown on the financial model, making the total installed capital cost $47,547,000. These additional expenditures were estimated based on a combination of the project team's experience and actual costs for similar items in recently completed or currently under construction projects. This amount is for a project that will be completed in 2013; using proven technology; with guarantees of completion, plant performance and environmental performance; and with an initial 3 month fuel inventory on site.

TABLE 20: BUDGETARY CAPITAL COST ESTIMATE ($ 000s)

Capital Cost Item	Cost
Equipment, Engineering, and Construction Costs	37,750
Project Management/Permitting/Engineering	400
Site Prep/Roads/Fencing	400
Working Capital	850
Utility Interconnection	800
Fuel Receiving/Processing	3,000
Interest During Construction	2,394
Issuance Costs	978
Total Capital Cost	**47,547**
Capital Cost per net MW	**4,755**

14.5 ADDITIONAL ASSUMPTIONS

- The power would be sold for $95 per megawatt hour and will escalate at 1.5 percent per year.
- Power wheeling costs were assumed to be a flat $50,000 per year.
- Corporate ownership overheads were assumed to be $80,000 per year.
- The plant would operate 8,200 hours per year. After accounting for scheduled downtime and station service (power generated and consumed by the turbine portion of the plant), the plant would generate 82,000 MWh of power annually.
- Auxiliary Power – 1000 KW of plant power purchased from LCPD at $0.04 per KWh.
- All power and RECs generated at the plant would be sold to the power grid.
- The plant would require 12 full time employees. Wage rates and fringe benefits typical of other Nevada manufacturing businesses were used for the hourly labor.

- The routine and major maintenance costs are based on costs experienced at similar operations. The major maintenance costs are based on an annual accrual payment into an account for a major turbine overhaul every seven years and for periodic replacement of the boiler refractory and superheater.
- Construction financing assumes 100 percent would be borrowed at 6 percent interest.
- Project financing assumes 30 percent equity and 70 percent long-term debt.
- The interest rate on the long term debt was assumed to be 4.0 percent.
- The MACRS depreciation schedule was used for calculating depreciation costs, but without including bonus depreciation.
- Federal taxes are included as 35 percent of income.
- Sales Tax Reduction to 2.25 percent and Property Tax Reduction of 55 percent for 20 years were assumed.
- Water was assumed to be purchased from the local municipality, and wastewater was assumed to be consumed on site.
- The production tax credit is applied at a rate of $0.012 cents per KWh beginning in 2013 for the first 10 years of the project. The tax credit escalates at 3 percent annually.
- The Corporate Owner/Tax Equity Partner was assumed to fully utilize tax credits depreciation, and tax losses.
- All expenses are assumed to rise by 3 percent annually due to inflation, with power revenue rising only 1.5 percent annually.
- The owner was assumed to require a 15 percent rate of return on equity supplied to the project.

14.6 PRO FORMA INCOME STATEMENT

As shown in the following Year One pro forma income statement (Table 21), the power plant generates the following revenues and expenses. Note that the fuel cost associated with this pro forma income statement is the $27.00 per bone dry ton required for the owner to obtain the target rate of return. If the all inclusive estimated delivered fuel costs were input into the financial model, the total cash flow benefit would change from the $3.17 million shown in Table 21 to $155,000 in Year One and would drop into negative total cash flows during later years – ranging between negative $0.6 and $5.6 million.

TABLE 21: POWER PLANT YEAR ONE PRO FORMA INCOME STATEMENT

REVENUE/EXPENSE LINE ITEM	($ 000s)
Electric Sales	7,790
Steam Sales	0
Total Revenues:	**7,790**
O&M	2,768
Fuel	1,845
Ash Disposal	24
Total Expenses:	**4,638**
OPERATING INCOME:	**3,152**
– Interest	1,331
– Depreciation	2,377
PRETAX INCOME:	**(557)**
– Taxes	**(1,485)**
NET INCOME (book)	**928**
PROJECT CASH FLOWS & BENEFITS	
PRETAX INCOME:	(557)
+ Book Depreciation	2,377
– Loan Principal	(1,118)
PRETAX CASH FLOW	703
TAXES/CREDITS	
State Taxes/Credits	0
Federal Taxes	(1,485)
Federal (Production Tax Credit)	(984)
NET TAXES	**(2,469)**
NET CASH FLOWS	
Operating Pretax Cash Flow	703
State Credits/Grants	0
Federal Credits/Grants	2,469
Total Cash Flow Benefit	**3,172**

As shown in the preceding pro forma income statement, the project generates a Year One revenue stream of nearly $7.79 million, of which $1.85 million is used to procure fuel and $2.77 million is used to pay operation and maintenance expenses. This leaves a net operating income of $3.15 million prior to application of depreciation, payment of long-term debt, and taxes. The total after tax cash flow benefit is $3.17 million in Year One. A 20 year pro forma is included in Appendix 3.

Given the preceding assumptions and analysis, the project requires a delivered fuel price of about $27.00 per bone dry ton, escalating at 3 percent annually, in order to provide the project owner with a 15 percent net present value after tax rate of return on their equity.

The $27.00 per bone dry ton fuel price required to meet the minimum return is nearly $70.00 per bone dry ton lower than the all inclusive $96.30 per bone dry ton cost estimated by BECK. **This means that in order to provide the investor with the desired return, the plant's fuel cost would have to be less by approximately $4.71 million annually ($70.00 per bone dry ton x 67,300 bone dry tons) that the full cost incurred producing the fuel from P-J restoration efforts.**

14.7 DISCUSSION

The $27.00 per BDT fuel price returned by the financial model is substantially less than the cost to cut and remove excess P-J, skid that material to roadside, chip it, and deliver it to the plant. The $27/BDT amount is greater, however, than the cost of chipping and transporting the material from the landing area to the plant. For the first year, the chipping and transport costs have been projected to be about $23.00/BDT. Thus the existence of a power plant leaves a landowner in need of P-J vegetative treatment in a slightly better financial position. This is because, the plant owner can contribute about $4.00 per BDT ($27 minus $23) towards the cost of P-J harvesting and skidding to roadside.

As modeled in this study, a 10 MW facility would require the treatment of about 9,800 acres per year and would have an average removal of 6.9 bone dry tons per acre (based on treating 10 percent Phase I, 40 percent Phase II, and 50 percent Phase III). **This means that the biomass plant could contribute on average about $28 per acre toward the cost of harvesting and skidding biomass ($4/BDT x 6.9 BDT/Acre).**

14.8 SENSITIVITY

As stated previously, the base case modeling effort attempted to be realistic, but slightly conservative in terms of capital, operation and maintenance costs. This included assumed qualification for existing state and federal programs, some that currently require project completion and startup by December 31, 2013. Perhaps the most problematic assumption in terms of limiting project feasibility is that of long term financing for 20 years at 4 percent and a 30 percent equity requirement.

Therefore, the project team also modeled a "best case" scenario in which assumptions about the following key factors were changed:

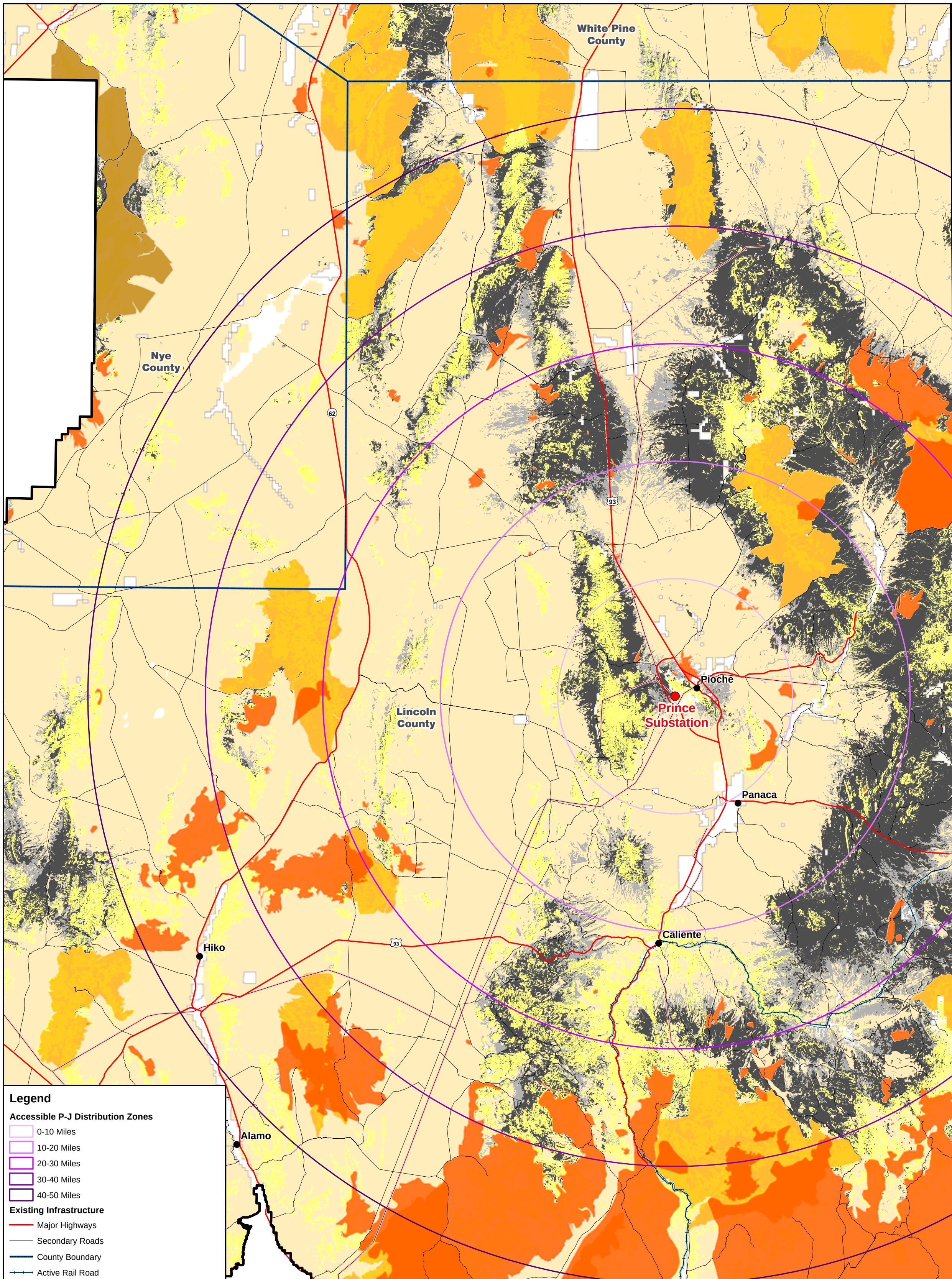
- Wet cooling was assumed instead of dry cooling. This reduced the capital cost by 10 percent and increased the T-G efficiency by 5.7 percent.

- Interest on construction financing was assumed to be 2 percent instead of the 6 percent assumed in the base case scenario.
- Interest on long-term debt was assumed to be 2 percent instead of the 4 percent assumed in the base case scenario.
- The owner's equity in the project was assumed to be 20 percent instead of the 30 percent assumed in the base case scenario.
- The project developer would require a 10 percent return on equity instead of the 15 percent assumed in the base case scenario.

Given the preceding list of changes in key assumptions, the "best case" scenario changes the "allowable" fuel cost to $52.00 per bone dry ton as opposed to the $27.00 per bone dry ton finding in the base case scenario. Thus, the changes allow for a higher allowable fuel cost, but the "allowable" cost in the best case scenario still falls about $44.00 per bone dry ton short of the estimated all-inclusive delivered fuel cost of $96.30 per bone dry ton.

In the "best case" scenario, the contribution of the power plant to treatment costs (harvesting, skidding, and rehabilitation) after accounting for chipping and transport is about $31 per bone dry ton ($52/BDT - $21/BDT). This means that the power plant project could contribute about $214 per acre to treatment costs in the best case scenario. There were other scenarios investigated, such as a slightly larger plant, continuation of federal grant program, etc. that yielded results between the base and best case results, but the reults are bracketed by these two results.

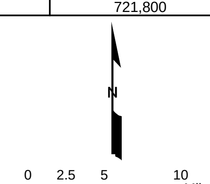
It should be mentioned in conclusion that neither the base case nor best case scenario are possible without a long term (15 – 20 year) stewardship contract of a size to provide sufficient acreage that would yield the necessary to fuel the facility. The project simply cannot be financed, under any terms, without the assurance of fuel quantity and price.



**Accessible Pinyon-Juniper Near Prince Substation, Lincoln County, Nevada

Zone (Miles from Prince SS)	0-30% Canopy Cover (Zone Acreage)	30-60% Canopy Cover (Zone Acreage)	0-30% Canopy Cover (Cumulative Acreage)	30-60% Canopy Cover (Cumulative Acreage)	Combined Canopy (Cumulative Acreage)
0-10	8,900	25,200	8,900	25,200	34,000
10-20	26,300	96,400	35,200	121,600	156,800
20-30	68,600	260,000	103,800	381,600	485,400
30-40	46,900	151,600	150,700	533,200	683,900
40-50	12,100	25,800	162,800	559,000	721,800

Appendix 1
**Accessible Pinyon-Juniper within 50 Miles of Prince Substation



Data Source:
* BLM Ely District Office
**Based on P-J Distribution, less wilderness area, less fire area, less slopes>30%

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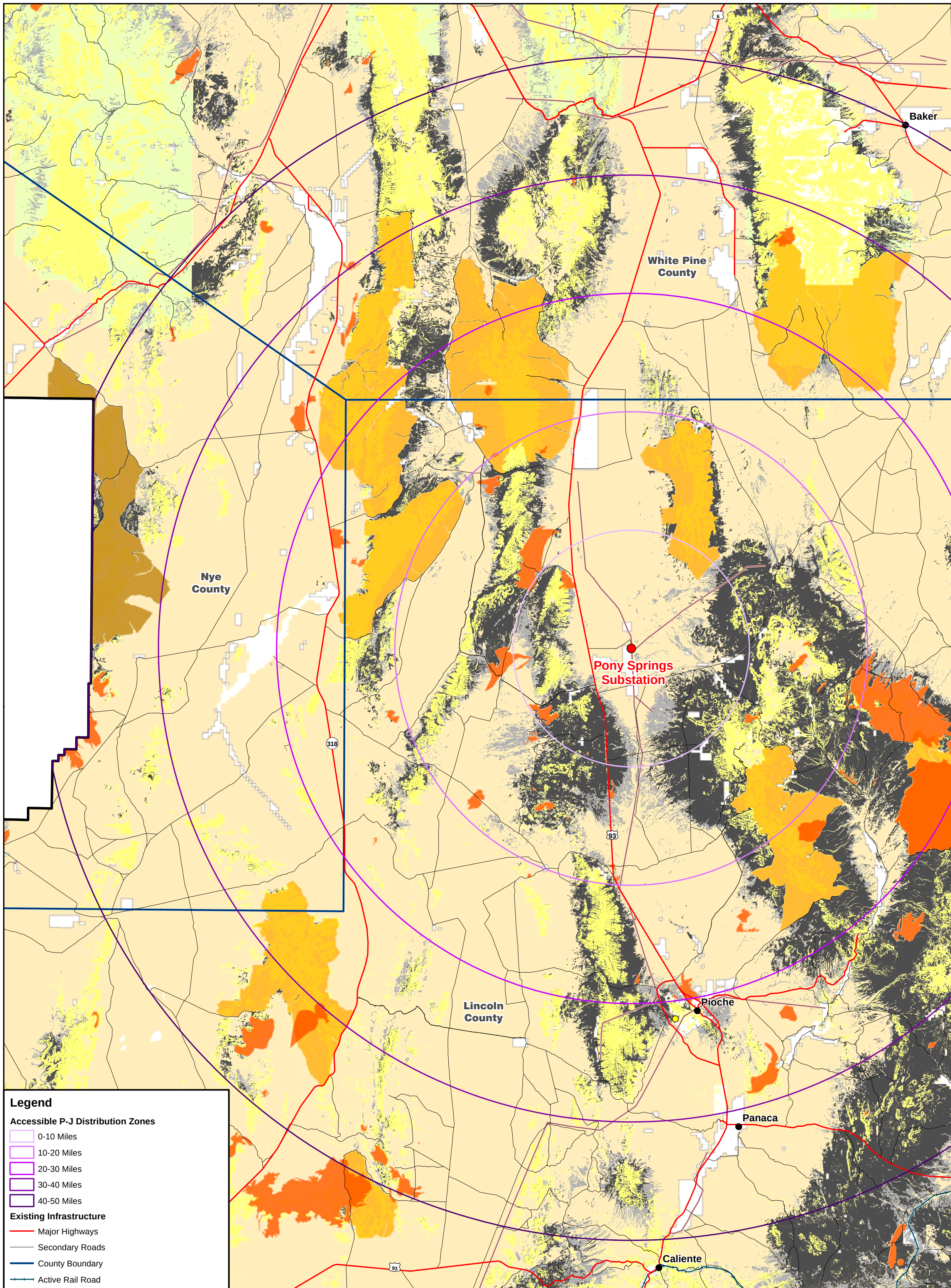

Data Source:
* BLM Ely District Office
**Based on P-J Distribution, less wilderness area, less fire area, less slopes>30%

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****Accessible Pinyon-Juniper Near Pony Springs Substation, Lincoln County, Nevada**

Zone (Miles from Pony Springs SS)	0-30% Canopy Cover (Zone Acreage)	30-60% Canopy Cover (Zone Acreage)	0-30% Canopy Cover (Cumulative Acreage)	30-60% Canopy Cover (Cumulative Acreage)	Combined Canopy (Cumulative Acreage)
0-10	19,200	54,600	19,200	54,600	73,800
10-20	33,800	135,600	53,000	190,100	243,000
20-30	26,700	95,300	79,700	285,500	365,100
30-40	18,200	96,600	97,900	382,000	479,900
40-50	40,500	119,000	138,400	501,000	639,400

Appendix 2

**Accessible Pinyon-Juniper within 50 Miles of Pony Springs Substation

N

0 2.5 5 10 Miles

APPPENDIX 3

10 MW Base Case Power Plant - Pro Forma Income Statement (20 years)

	Year 0	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
REVENUE																						
Electric Sales		7,790	7,907	8,025	8,146	8,268	8,392	8,518	8,646	8,775	8,907	9,041	9,176	9,314	9,454	9,595	9,739	9,885	10,034	10,184	10,337	180,133
Steam Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue		**7,790**	**7,907**	**8,025**	**8,146**	**8,268**	**8,392**	**8,518**	**8,646**	**8,775**	**8,907**	**9,041**	**9,176**	**9,314**	**9,454**	**9,595**	**9,739**	**9,885**	**10,034**	**10,184**	**10,337**	**180,133**
EXPENSES																						
Operating & Maintenance		2,768	2,799	2,805	2,837	2,887	2,939	3,006	3,086	3,169	3,255	3,344	3,435	3,530	3,628	3,729	3,833	3,941	4,052	4,168	4,287	67,497
Purchased Steam		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel		1,845	1,901	1,958	2,016	2,077	2,139	2,203	2,269	2,338	2,408	2,480	2,554	2,631	2,710	2,791	2,875	2,961	3,050	3,141	3,236	49,583
Ash Disposal		24	25	26	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	43	651
Total Operating Expenses		**4,638**	**4,725**	**4,788**	**4,880**	**4,991**	**5,107**	**5,238**	**5,385**	**5,537**	**5,694**	**5,856**	**6,023**	**6,195**	**6,373**	**6,556**	**6,745**	**6,941**	**7,142**	**7,351**	**7,565**	**117,732**
OPERATING INCOME		**3,152**	**3,182**	**3,237**	**3,266**	**3,277**	**3,285**	**3,280**	**3,261**	**3,238**	**3,213**	**3,184**	**3,153**	**3,118**	**3,080**	**3,039**	**2,994**	**2,945**	**2,891**	**2,834**	**2,772**	**62,402**
INTEREST		1,331	1,287	1,240	1,192	1,141	1,089	1,035	978	919	858	795	728	660	588	514	436	356	272	185	94	15,697
																						0
DEPRECIATION		2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	47,547
																						0
PRETAX INCOME		**(557)**	**(482)**	**(380)**	**(303)**	**(242)**	**(181)**	**(132)**	**(95)**	**(59)**	**(23)**	**13**	**47**	**81**	**115**	**148**	**181**	**212**	**242**	**271**	**300**	**(843)**
TAXES		(1,485)	(2,825)	(1,574)	(804)	(745)	(162)	411	449	465	478	490	503	514	526	538	574	609	620	630	640	(147)
NET INCOME - BOOK		**928**	**2,343**	**1,194**	**500**	**503**	**(19)**	**(544)**	**(544)**	**(524)**	**(501)**	**(478)**	**(455)**	**(433)**	**(411)**	**(390)**	**(393)**	**(397)**	**(378)**	**(359)**	**(340)**	**(697)**
TAX INCOME STATEMENT																						
PRETAX INCOME		(557)	(482)	(380)	(303)	(242)	(181)	(132)	(95)	(59)	(23)	13	47	81	115	148	181	212	242	271	300	(843)
PLUS: Book Depreciation		2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	2,377	47,547
LESS: Loan Principal		(1,118)	(1,162)	(1,209)	(1,257)	(1,308)	(1,360)	(1,414)	(1,471)	(1,530)	(1,591)	(1,654)	(1,721)	(1,789)	(1,861)	(1,936)	(2,013)	(2,093)	(2,177)	(2,264)	(2,355)	(33,283)
PRETAX CASH FLOW		**703**	**733**	**788**	**817**	**828**	**836**	**831**	**812**	**789**	**764**	**735**	**704**	**669**	**631**	**590**	**545**	**496**	**442**	**385**	**323**	**13,421**
State Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
less: State credits		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Federal Taxes		(1,485)	(2,825)	(1,574)	(804)	(745)	(162)	411	449	465	478	490	503	514	526	538	574	609	620	630	640	(147)
less: Federal credits		(984)	(1,014)	(1,044)	(1,075)	(1,108)	(1,141)	(1,175)	(1,210)	(1,247)	(1,284)	0	0	0	0	0	0	0	0	0	0	(11,280)
NET TAXES		(2,469)	(3,839)	(2,618)	(1,879)	(1,852)	(1,303)	(764)	(761)	(781)	(806)	490	503	514	526	538	574	609	620	630	640	(11,427)
NET CASH FLOW																						
CAPITAL INVESTMENT	(47,547)																					(47,547)
AMOUNT TO FINANCE	33,283																					33,283
OPERATING PRETAX CASH FLOWS		703	733	788	817	828	836	831	812	789	764	735	704	669	631	590	545	496	442	385	323	13,421
STATE CREDITS / TAXES	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FEDERAL CREDITS / TAXES	0	2,469	3,839	2,618	1,879	1,852	1,303	764	761	781	806	(490)	(503)	(514)	(526)	(538)	(574)	(609)	(620)	(630)	(640)	11,427
TOTAL CASH FLOW BENEFITS	**(14,264)**	**3,172**	**4,572**	**3,406**	**2,696**	**2,680**	**2,139**	**1,594**	**1,573**	**1,570**	**1,570**	**245**	**201**	**155**	**105**	**52**	**(29)**	**(113)**	**(178)**	**(245)**	**(317)**	**10,584**
Cumulative Pretax Cash Flow		703	1,436	2,224	3,041	3,869	4,705	5,536	6,348	7,137	7,901	8,636	9,340	10,009	10,641	11,231	11,776	12,272	12,714	13,098	13,421	
Cumulative After Tax Cash Flow		3,172	7,743	11,149	13,845	16,525	18,665	20,259	21,832	23,402	24,972	25,217	25,419	25,573	25,679	25,731	25,702	25,589	25,411	25,166	24,848	