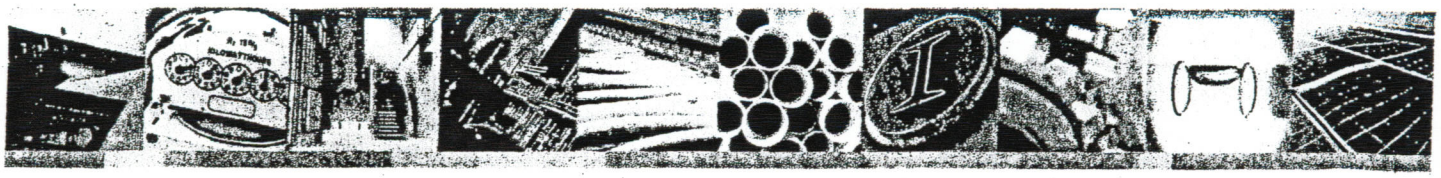
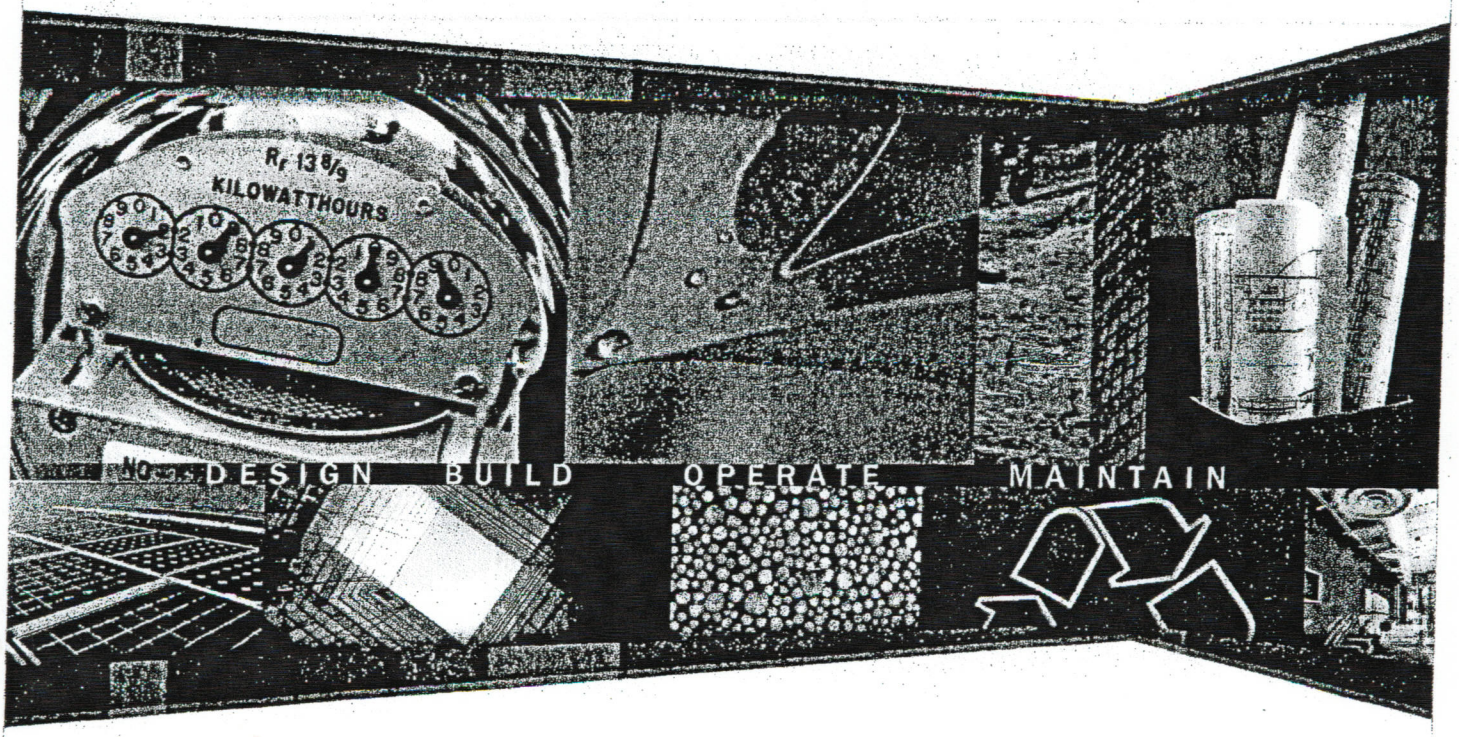


Shoshone County

Renewable Energy Feasibility Study

Shoshone County, Idaho



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Prepared by McKinstry
Prepared for Shoshone County

McKinstry
For The Life Of Your Building

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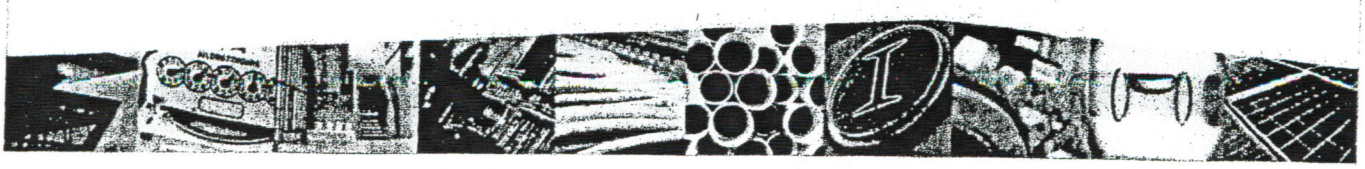

Section 1 Executive Summary

A. INTRODUCTION

In conjunction with Shoshone County, McKinstry has completed a feasibility study of a renewable energy generation facility (REF), to be located within Shoshone County. The purpose and intent of the feasibility study was to determine if there are any technical, contractual, economic, financial or political hurdles that would render the project impossible, and also to outline the next steps required in order to successfully design, build, and operate a REF.

Fuel supply is the paramount issue to be resolved in future development efforts, and has driven the conclusion of the three most likely options listed below. Other than Alaska, Idaho is unique as compared to other biomass-rich states, in that virtually all of the woody biomass resource available for feed stock resides on Federal lands. This is particularly true in northern Idaho. Washington, Oregon and Montana have large tracks of private forest lands from which dependable volumes of fuel can be obtained. Unfortunately, in Idaho the limited fiber resources that reside on private and state lands are already allocated for multiple competing industry channels. Fiber from the Idaho State Department of Land's (IDL) southern locations are too distant to be of practical use. Idaho has not adopted a biomass transportation tax credit, so geographic proximity of fiber is critical.

McKinstry has stated as a matter of public record, that we are not interested in competing for existing fiber supply chains. This would distress existing businesses and cause greater competitive price escalation. McKinstry is only interested in developing woody biomass projects that utilize newly developed and sustainable sources of fiber. This policy will ensure that fuel costs remain competitively low by confirming an adequate supply of new fuel. Unfortunately, any significant increase in woody biomass supply will have to come from Federal lands.

Based on information gathered to date, there appear to be three distinct options for proceeding with a project that have a good likelihood of becoming a reality. These options are:

1. A woody biomass facility sized between 15 and 20 megawatts that is financially viable
2. A woody biomass facility sized between 3 and 6 megawatts that is financially dependent on Federal and State incentives
3. A municipal solid waste to energy facility sized between 2 and 3 megawatts that is also financially dependent on Federal and State incentives.

Refer to the cover letter for a description of the Benefits, Challenges and Next Steps associated with each of these three recommended options.

While the technology is presently available to design, permit, install, operate, and maintain each of the three recommendations, the most important component to the success of the entire project is a sustained fuel supply, and the associated cost per btu of that fuel supply. Also, the fuel supply available for the REF will determine the magnitude of electric generation (2MW-20MW) and also what types of industry, commerce, or other waste heat users that can co-locate with the facility. Co-locating a waste heat user with the REF will increase overall efficiency of the process, improve financial performance of the REF, as well as provide an immediate increased economic impact to the County in the form of increased job creation and diversifying the industrial base of the County.

The feasibility study and this report have been separated into the following categories: Site Assessment, Fuel Supply/Ash Disposal, Utility Interconnection and Power Purchase, Emissions and Permitting, Preliminary Scope Development, and Preliminary Project Financials. This report details the work completed for each major category of the feasibility study.

B. HISTORY OF SILVER VALLEY ECONOMIC AND ENVIRONMENTAL ISSUES

Economic:
The economy and heritage of the Silver Valley have been dominated by mining activities which started in the 1880's and lasted until the 1980's, when operations were severely curtailed. In fact, the Silver Valley is among the top ten mining districts in world history and has produced silver, zinc, and lead with a total value of over $6 billion. With the restriction of most mining activities, the Silver Valley has experienced a massive loss of jobs and population, and is still reeling financially from the loss of a stable industrial backbone. The County is also saddled with significant environmental challenges resulting from mining activities, and the federal government has been active in the Superfund "box" for several decades. Federal activity carries on today as the "box" continues to move west.

Tree Planting:
During the 1970's and into the early 1980's, Bunker Hill Mining Company began a rigorous tree planting campaign to repopulate the Silver Valley hillsides with native trees. In all, over 2.8 million trees were planted over thousands of acres. Due to the high levels of zinc found in the soils around the mines and smelters it was believed that 25% or less of the planted trees would survive, and then the acidic soils would cause more attrition every year. To date, the survival rate of the planted trees is approximately 96%. Unfortunately the high survival rate of the planted trees means they were planted too close together, creating unhealthy competition for sunlight and nutrients. This competition has led to a detrimental condition in the forests whereby trees are becoming stagnate, are dying in place, and are not resistant to insect infestations and disease. Equally as harmful, the trees are not able to sequester as much carbon from the atmosphere as they should be and the high volume of trees per acre has created a significant fire hazard and has limited plant and brush food supply for native wildlife such as deer and elk.

Fire Hazard in the Idaho Panhandle National Forest:
According to some estimates, there is somewhere between one and three times the fire hazard present today in the Idaho Panhandle National Forest as there was just before the catastrophic 1910 fire. The 1910 fire was the largest forest fire in American history, and possibly the largest forest fire in world history. Scientists have determined that the firestorm lasted two days and burned three million acres. The fires were known to go on runs of more than 50,000 acres, and throw fire brands, that would often start new fires, 10 miles in front of the main fire. The fires of 1910 caused drastic changes in the policy that the Unites States Forest Service (USFS) had, because so much forest had burned. They turned to a complete fire suppression mode, and put out any fire they could. This fire suppression philosophy was followed by dramatic opposition from environmental groups, which further limited the activity of the USFS in the forests. These factors have led to our present state of fire danger.

C. RENEWABLE ENERGY FACILITY BENEFITS

The proposed REF is being planned and structured in a way to aid in addressing the issues noted above, as well as many other environmental, political, and economic issues. It is the belief of Shoshone County and McKinstry that the proposed REF needs to be a win-win solution for the forests, wildlife, watersheds, air quality, the Silver Valley residents, local economy, as well as the investors and businesses that would partner with the REF. The main source of fuel for the REF will likely be slash piles and pulp wood from ongoing forest and logging activities conducted by the Idaho Department of Lands, BLM and the USFS, stewardship contract slash piles and pulp wood, City and County fire mitigation efforts, and slash and pulp wood from various private timber and land management activities. These fuel sources are not presently marketed in the region because they have little commercial value, and use of these materials would not interfere with or compete with existing forest based industry. One more possible feed stock is to capture the mill waste that the local mills are presently paying to dispose of. Much of this material is transported to Montana and could be redirected to the REF, which would positively impact the financial results of the local mills by reducing a costly operating expense.

Air Quality:
This facility would positively impact air quality in the Silver Valley because slash piles from logging activities would be burnt efficiently and with emissions control at the REF, rather than at the trail head. Efficient burning at a central location allows for emissions abatement, complete combustion, and ongoing monitoring at the REF which would dramatically decrease the amount of emissions released into the atmosphere. At present, the most economical means available to dispose of slash piles is to burn them on designated days throughout the year. The result is that air quality suffers dramatically throughout the Silver Valley on these days. The figure below demonstrates the effects of the natural inversion layer in the Silver Valley and shows that on any given day, whether burning is occurring or not, the amount of airborne particulate in Pinehurst is several times higher than in other areas in North Idaho. The figure below is taken from the Idaho Department of Environmental Quality report titled 'North Idaho Air Quality Summary – October 2009'.

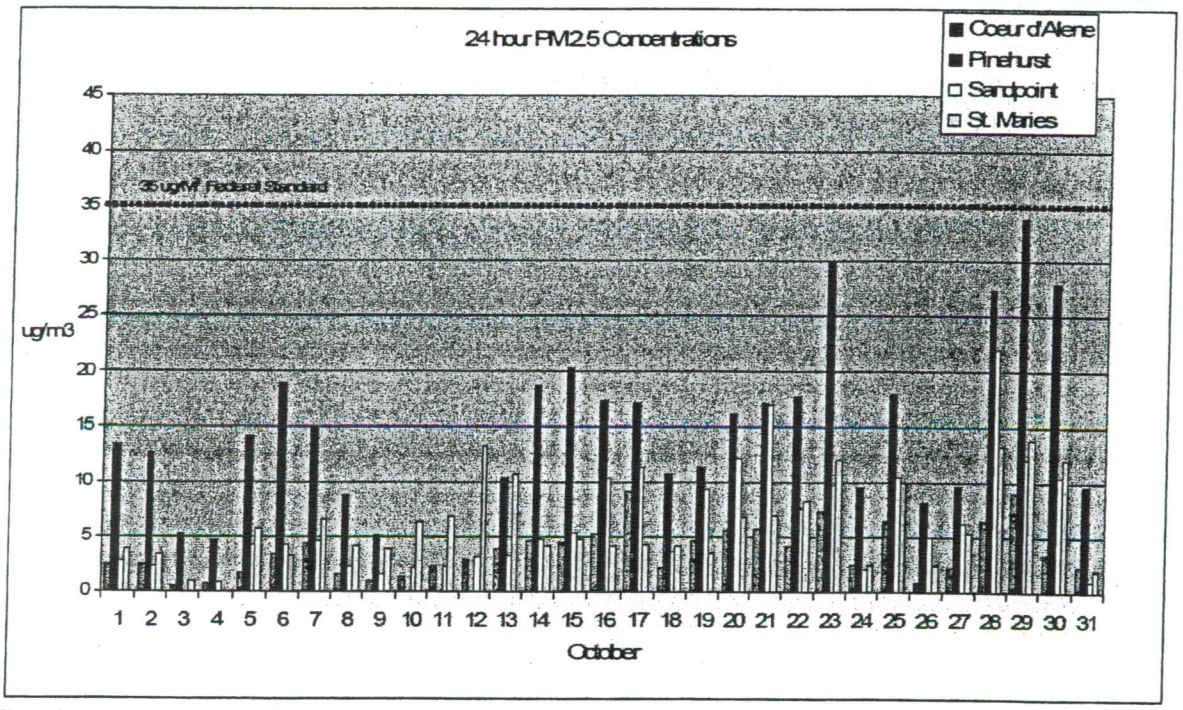

Figure 1: North Idaho Air Quality Summary – October 2009

Wildlife:
Healthy forest logging activities would increase the food supply for elk and other wildlife by allowing sunlight to strike the forest floor, which creates an environment that brush can grow and thrive. The present density of forested lands prohibits vegetation growth on the forest floor, which has created a scarcity of food and cover for elk and deer.

Forest Health and Fire Mitigation:
Removing slash piles, dead and dying trees, diseased and infested trees, and pulp wood from the forest has the benefit of increasing forest health, increased carbon sequestration of the forest, reduced forest fire potential by removing unnatural levels of fuel, and the economic stimulus of the REF can be used as a platform to implement long term forest management practices. For reference, forest health and fire mitigation logging activities associated with the proposed REF would not include clear cutting or removing trees that have intrinsic value to the environment.

Economic:
Economically, this facility would create sustainable jobs based on local renewable resources at the REF itself, through the fuel supply chain, and possibly through a co-located waste heat user such as a pellet plant or a Job Corps campus. The REF would also generate long term revenue sources for the County and State via income taxes, land leases, business taxes, and would serve as a springboard for a variety of economic development opportunities for Shoshone County.

Watershed Preservation:
Shoshone County crosses nine watersheds, each one unique and vital to the ongoing health of the human and wildlife populations within them. In Shoshone County the watersheds have tremendous intrinsic value and need to be protected and preserved. Among other things they provide water to support wildlife, drinking water for humans, wildlife habitat and space, commercial and industrial uses, recreation, and beautiful scenery.

It is the belief of Shoshone County, McKinstry and the Collaboration Group that any forest activities associated with the REF need to be structured in a way to minimize impact to the watersheds. To meet this goal, a watershed approach will be developed for public lands and used to address various concerns because land-use decisions are made in one area of a watershed, which will inevitably affect another part of the watershed. Since Shoshone County crosses 9 watersheds, this approach will require cooperative efforts among a variety of entities.

Stewardship Contracting/Collaboration Group:
In 1999 Congress mandated that the Forest Service start using a new "tool": stewardship contracting. Stewardship contracting is a way of integrating both timber sale work and service work in one contract and it uses best value contracting. This type of contracting also allows the Forest Service Districts to retain the receipts from the sale of timber and to be able to use that money on the local forests to directly make improvements through restoration projects. Normally, timber sale receipts are sent to Washington, D.C. and then appropriated to Forests for specific activities. Stewardship contracts are only awarded if the interested party (Shoshone County in this case) completes the federally mandated NEPA process. The NEPA process is a lengthy procedure that begins with a Collaboration effort, then filing the NEPA paperwork, culminating with a NEPA process review and a in some cases an awarded Stewardship Contract. Stewardship contracts are generally awarded in existing roaded forest areas or Wildland Urban Interfaces (WUI's) which are in and around communities, and for a contract duration of between five and ten years.

The collaboration effort can be quite time consuming, depending on whether or not the parties within the Collaboration group are willing to work together to reach a common goal, or if members of the group want to stifle the process. The main goal of Collaboration is to define a set of criterion by which stewardship contracting activities must abide by. For example, fire line construction, road maintenance, tree planting, road obliterations, road realignment and trail construction may trump common concerns such as fire mitigation, forest health, and wildlife population. Whatever the final set of stewardship contracting criterion is determined to be, is summarized and used as the basis for the NEPA application.

Municipal Solid Waste:
One other possible benefit of the REF to the global environment and Shoshone County in particular is the potential of solving some of the ongoing issues associated with Shoshone County's Municipal Solid Waste stream. Presently Shoshone County transports their garbage to a landfill at Missoula, MT, at a cost of roughly $65 per ton, where it will slowly decay and release harmful greenhouse gasses to the environment over an extended period of time. Other consequences associated with land filling garbage is that the County has long term financial liability associated with future shut down and clean up efforts that may be required at the Missoula landfill. See the Fuel Supply Section of this report for more details regarding the environmental benefits of

D. CONCLUSION

Should the REF be built, Shoshone County would become a showcase example of rural, forest-based communities utilizing their local renewable energy resources to provide sustainable energy, infrastructure, and economic development solutions through successful public/private partnerships. There are very few rural communities in the US that have addressed large scale environmental, political, and economic challenges, and Shoshone County would be a model that other communities would follow. The proposed REF would be a long term and sustainable solution to the various challenges that the Silver Valley is faced with, and would go a long way towards reversing the impact mining and other activities have had on the land.

Through this mutual effort with Shoshone County, McKinstry has developed a report detailing the actions taken to date that demonstrates basic feasibility of the proposed REF. This report demonstrates the REF has cleared many of the major hurdles which would hinder the project impossible, and outlines the next steps required to successfully structure the project in a fashion that the REF can ultimately be designed and built.

Section 2 Site Assessment

A. OVERVIEW

As part of the feasibility study, McKinstry worked with the County Commissioners and the County Planner to identify as many potential sites as possible with the ability to house the renewable energy facility (REF). The general search criteria used to locate sites was the following: each site needed to be equal to or greater than ten acres, relatively flat, and relatively close to the I-90 corridor. Based on these search parameters only five sites were identified as suitable in the entire County, one of which is next to a school in Osburn. The site in Osburn is planned for use by the school for a future bus garage. This particular site's proximity to a school, coupled with the school's desire to utilize the site in the future, led the team to a unanimous decision to remove this site from the list.

The four remaining sites in Shoshone County were all visited by the McKinstry development team and Shoshone County, with the intent to gather information to determine viability of each site to house the renewable energy facility. In all, each of the four sites were scored based on relative ranking of twenty five discrete evaluation points including topography, water rights, utility access, zoning, and ownership. The table below details the complete list of evaluation points.

Of the four sites, the site that had the overall best ranking (lowest score) is the Government Gulch site in Kellogg, ID. This site is already zoned for the intended use, has a water rights claim associated with the property, has great ingress and egress access, is not located in a densely populated residential area, is in general a great site for a major construction project, and to house a REF. The largest "red flag" associated with the site is that it is located at ground zero of the EPA superfund site and issues associated with disturbing the soil have not yet been vetted. The contaminated soils may in fact be a mixed blessing because there is a potential for grants and other subsidies which may offset the cost of handling this material. Also, the Idaho State DEQ has ownership of this site and there is a set process that must be followed in order for the County to obtain ownership of the land. The 9-page land transfer policy has been included in this section of the report for reference. There are no guarantees the County will be able to obtain ownership of the proposed site from DEQ, however if obtaining ownership of this land is not possible, two of the other sites studied appear capable of housing the REF.

B. RANKING OF SITES

Evaluation Point	Description	Gov't Gulch Mining	Shoshone County	Government Gulch	Burke Canyon
1.00	Soil	4	2	1	3
1.01	Type	3	1	2	4
1.02	Strength	2	1	3	4
1.03	Contamination	2	1	3	4
2.00	Slope	3	1	4	2
3.00	Ground Water	4	3	2	1
4.00	Streams/Lakes Ponds	4	3	2	1
5.00	Air Quality	4	3	2	1
6.00	Utilities				
6.01	Potable Water	4	3	1	2
6.02	Storm Drain	4	3	1	2
6.03	Sanitary Sewer	1	2	3	4
6.04	Telephone	2	1	3	4
6.05	Natural Gas	3	2	1	4
6.06	Electricity	4	3	1	2
7.00	Fire Protection	4	3	1	2
8.00	Aesthetics	3	4	1	2
9.00	SD Detention Capabilities	4	3	1	2
10.00	Acreage	2	4	1	3
11.00	Ingress/Egress	2	1	3	4
12.00	Existing Structures	1	3	4	2
12.01	Demolition	1	3	4	2

12.02	Re-Usable	1	3	4	2
13.00	Zoning	4	3	1	2
14.00	Ownership	4	3	1	2
Overall Score		68	58	47	57
Overall Ranking		4	3	1	2

B. MAPS OF SITES

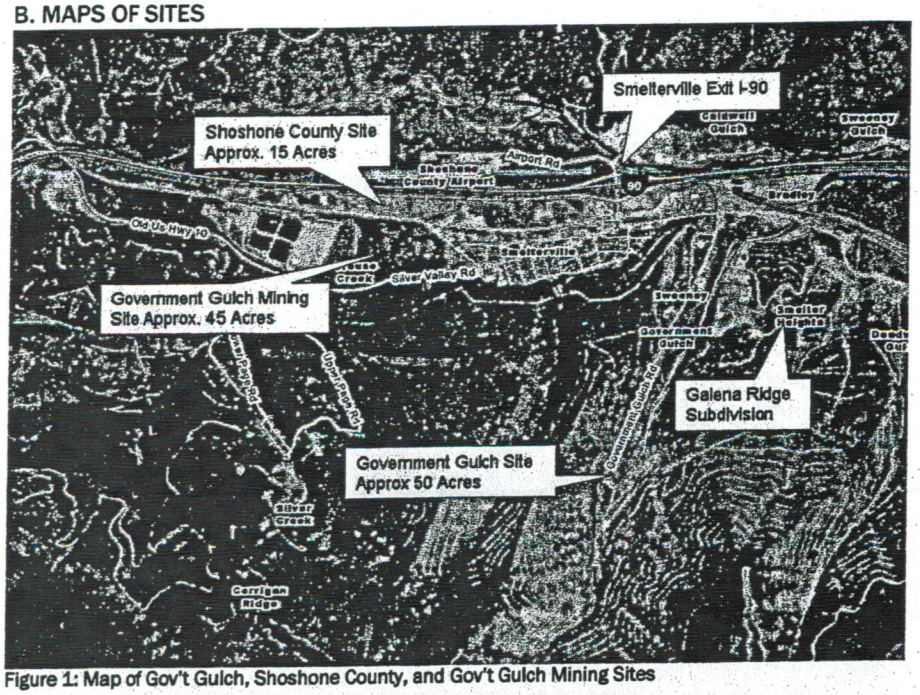

Figure 1: Map of Gov't Gulch, Shoshone County, and Gov't Gulch Mining Sites

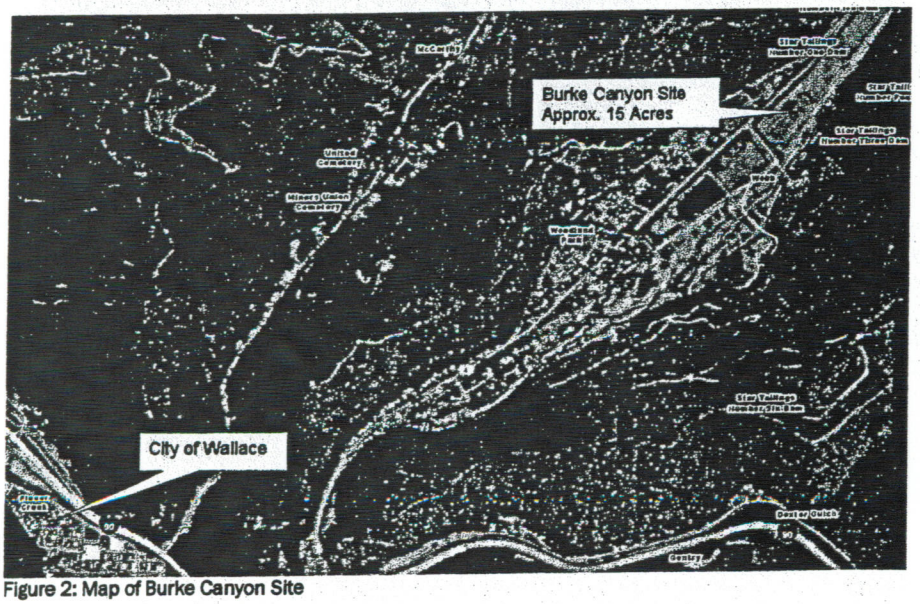

Figure 2: Map of Burke Canyon Site

The appendix of this report contains the detailed site evaluation reports for each of the sites evaluated. In order, the site reports are Government Gulch, Shoshone County owned site, Government Gulch Mining owned site, and Burke Canyon.

C. CONCLUSIONS AND NEXT STEPS

Next Steps to complete under the Site Evaluation category will include a detailed plan for obtaining surface and sub-surface rights to the Government Gulch site, ensuring access to all or a significant portion of the water rights associated with the site, verifying the interconnection point to Avista's grid, and coordination with Silver Mountain to ensure their concerns are addressed. Project development next steps will include a preliminary geotechnical report with a review of soil contamination, a review of potential costs and subsidies associated with the soils on the Government Gulch site, and a detailed water quality analysis to aid with the decision to use air or water cooling in the electricity generation process.

GOV'T GULCH FLOODPLAIN

0 1,000 2,000 4,000 6,000 Feet

Legend

- Parcels
- ShoshoneCountyRoads
- s_bfe
- s_firm_pan

s_fld_haz_ar

- <all other values>

FLD_ZONE, FLOODWAY

- 0.2 PCT ANNUAL CHANCE FLOOD HAZARD,
- A,
- AE,
- AE, FLOODWAY
- AH,
- AO,
- X,

O

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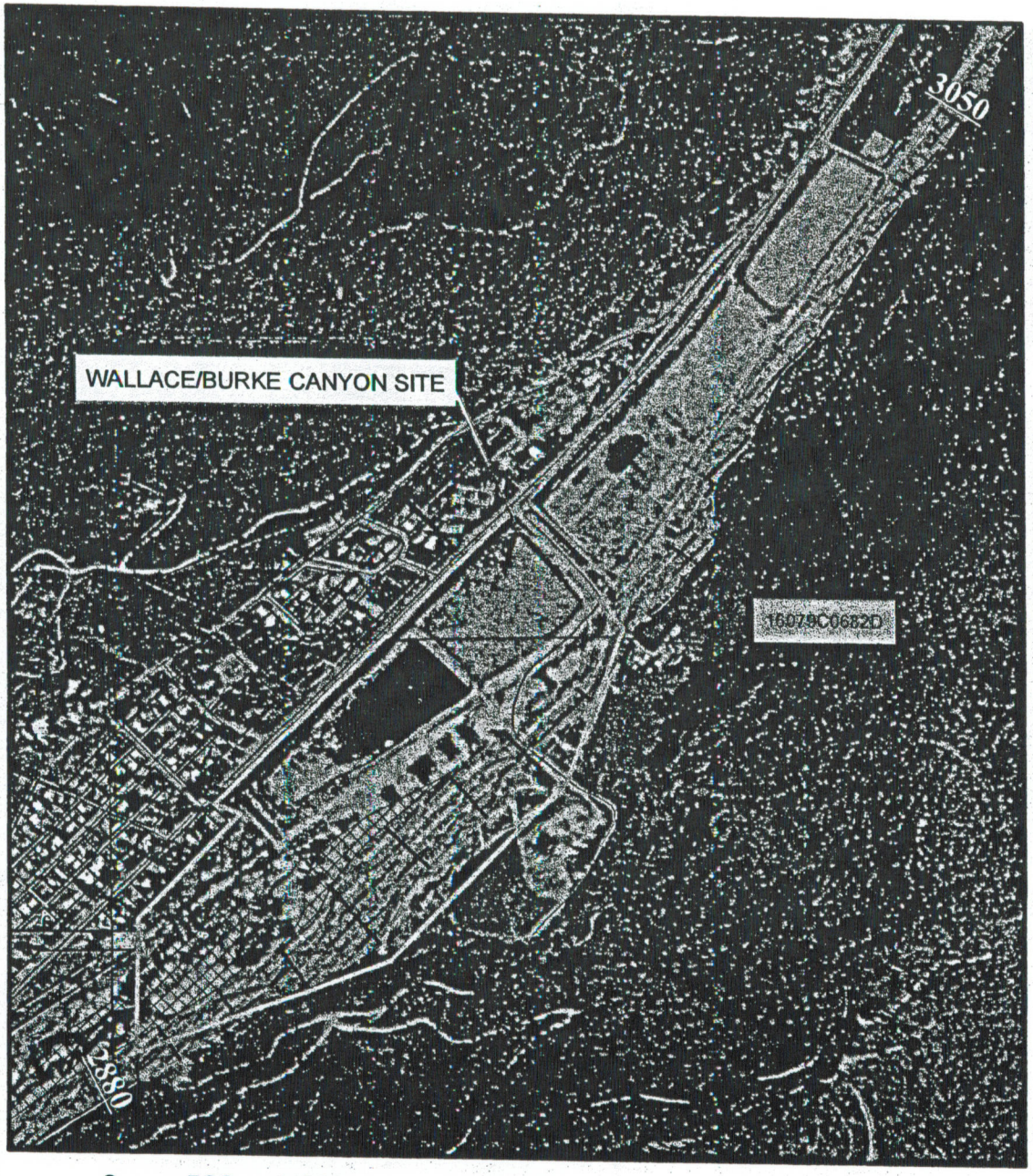
WALLACE/BURKE CANYON SITE FLOODPLAIN



0 500 1,000 2,000 Feet

Legend

- Parcels
- ShoshoneCountyRoads
- s_bfe
- s_firm_pan

s_fld_haz_ar

- <all other values>

FLD_ZONE, FLOODWAY

- 0.2 PCT ANNUAL CHANCE FLOOD HAZARD,
- A,
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- AE, FLOODWAY
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- AO,
- X,

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STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

1410 North Hilton • Boise, ID 83706-1255 • (208) 373-0502

C. L. "Butch" Otter, Governor
Toni Hardesty, Director

DEQ POLICY MEMORANDUM
PM08-01

POLICY FOR LAND TRANSFER

PURPOSE:
The purpose of this policy is to provide guidance for transferring or leasing DEQ property to other parties at the Bunker Hill Superfund Site.

BACKGROUND
DEQ currently owns real estate parcels and, in the future, will acquire other real estate parcels within the Bunker Hill Superfund Site via transfers from EPA. EPA acquired these parcels for the purpose of remediation under CERCLA (also known as Superfund) through bankruptcy proceedings of Potentially Responsible Parties (PRPs). CERCLA requires EPA to transfer such real property to the State upon completion of remedial actions.

DEQ has statutory authority to acquire, manage, lease and dispose of this real property pursuant to Idaho Code Section 39-107A as provided below:

> TITLE 39, HEALTH AND SAFETY, CHAPTER 1 ENVIRONMENTAL QUALITY -- HEALTH
> 39-107A. REAL PROPERTY IN BUNKER HILL CLEANUP SITE. Notwithstanding any other provision of law to the contrary, the department may accept transfer from the United States of any real property or interest in real property acquired by the United States for remediation purposes concerning the Bunker Hill Superfund Site pursuant to 42 U.S.C. section 9604(j). The state of Idaho shall incur no liability nor be subject to any claims related to the existence, release or threatened release of any hazardous substance or contaminant or pollutant on, or from, any such real property. The department may, in its sole discretion, manage, lease or dispose of such property for the purpose of facilitating appropriate operation and maintenance activities, encouraging economic development of the Silver Valley or assisting local governmental entities. The management, lease or disposal of such property shall not be subject to chapter 3, title 58, Idaho Code. Any receipts from the management, lease or disposal of such property shall be deposited in the Bunker Hill Cleanup Trust Fund established by the Trust Fund Declaration of the state of Idaho dated May 2, 1994 (Attachment M, Consent Decree, United States of America v. Asarco, Inc. No. CV-94-0206-N-HLR (D. Idaho)) for the purpose of funding institutional control or operation and maintenance activities regarding the site.

In 2001, Governor Kempthorne provided three guideline priorities for the disposition of this real property as follows:

> First, the property will be used to leverage job producing and property tax paying enterprises.
>
> Second, the property will be used to give local units of government the opportunity to accept and utilize such property for public service facilities and purposes, or for transfers and trades for existing publicly owned property that could be more appropriately used for economic development.
>
> Third, the property will be used to provide opportunities for additional recreational and tourism activities.

These authorities and guidance are consistent with the State of Idaho's longstanding advocacy of healthy local economies and communities as critical components of a successful and sustainable cleanup. Closure of the smelter and several of the local mines left the Silver Valley economy near collapse in the 1980's and through the early 2000's. Local communities were plagued with high unemployment and inadequate local tax revenues to maintain infrastructure and other public services. State statutes and policies allow DEQ to manage Bunker Hill real property in a manner that improves the local economy and tax revenues for local governments, schools, and utility districts or otherwise supports local communities.

In 2001 a DEQ Land Transfer Team was established to guide DEQ's management of its Bunker Hill real property. Current participants include:

Jerry Cobb, Panhandle Health District
Rob Hanson, DEQ Mine Waste Program Manager
Curt Fransen, Deputy Attorney General
Freeman Duncan, Real Estate Attorney under contract to the AG's Office
Gale Allen, Planner under contract to PHD
Tom Bourque, Civil Engineer under contract to DEQ

Participants may change over time and are selected by the DEQ Director based on appropriate agency and community representation and necessary legal and real estate expertise.

LAND TRANSFER ACTIVITIES TO DATE

Idaho DEQ has transferred four parcels of land in four separate transactions:

1. The former Bunker Hill mine engineering building was transferred to the City of Kellogg to support city administration.

2. A small parcel of property was transferred to the South Fork of the Coeur d'Alene River Sewer District for location of a lift station for the Page Ponds facility.

3. Significant acreage located south of McKinley Avenue was transferred to Eagle Crest Idaho, LLC. now known as Galena Ridge, LLC, for development of a golf course and associated commercial and residential properties.

4. The zinc plant building and associated real property in Government Gulch was sold to Galena Ridge to support the golf course.

In addition, DEQ leased a small parcel in Government Gulch to Shoshone County for use as a public shooting range.

With the exception of the zinc plant sale, these transactions were not premised on the establishment or payment of fair market value. However, DEQ did negotiate, under the direction of former Director Steve Allred, contributions to the Bunker Hill Cleanup Trust Fund. The purpose of such contributions was to assist DEQ in meeting its ongoing and future obligations at the Site regarding operation and maintenance (O&M) and the Institutional Control Program. The Sewer District and the County transactions did not include negotiated contributions given the limited value and development potential of the small parcels concerned and the overall general benefit to the local community.

CURRENT ECONOMIC SITUATION AND NEEDS IN THE VALLEY

The State's goal of improving the local economy through its management and disposition of the Bunker Hill real estate has largely been accomplished through the transfer of significant acreage to Eagle Crest and its related efforts and success in developing its properties. The completion of remedial work, the success of the ICP and the general real estate market have also been important contributing factors in reversing the economic stagnation in the Kellogg area. Local real estate prices have increased dramatically and DEQ's remaining real properties have significant value. Continued below market value disposition of such properties no longer appears necessary to spur the local economy and could be detrimental to the extent such transactions could distort the market. Use of the properties to provide adequate funding and support for O&M and ICP activities remains important to the long term success of cleanup actions and the future health of the local economy. In addition, local governmental entities have expressed ongoing interest in obtaining or using some properties for public purposes such as support of school transportation, road maintenance and affordable housing for teachers, health care workers, policeman, etc.

DEMANDS ON THE GOVERNOR'S TRUST FUND FOR CLEANUP

The Governor's Trust Fund was established after the 1995 Consent Decree with the Upstream Mining Group (UMG). The Fund holds settlement money from the site PRPs (UMG, Stauffer, and UPRR) for the purposes outlined in the consent decree such as blood lead testing and funding the Institutional Controls Program (ICP) and for activities in support of the Box cleanup such as O&M of the remedial action and land management and transfer costs. Receipts from land transfers has also gone into this Fund as required in the legislation. Costs for O&M in the Box will increase as remedial action moves into Phase II water quality improvements. Additionally, ICP costs are likely to increase due to soil disposal issues. Money from this Fund could also be directed to the Basin (EPA OU3) cleanup where it is expected that the state will have a match and operation and maintenance (O&M) shortfall to complete the work outlined in the EPA OU3 ROD.

LAND TRANSFER POLICIES

1. Except for the limited exceptions in items 2 and 3 below, DEQ Bunker Hill real property will be sold or leased at market value to augment the Governor's Trust Fund for the purpose of funding O&M and ICP activities to ensure the long term success of the cleanup and support the health of the local economy. DEQ will lease rather than sell properties which require long term control by IDEQ to manage significant O&M risks such as the Central Impoundment Area (CIA). The CIA has a synthetic liner cap that must be maintained to prevent water infiltration. Leasing such properties will allow the State to control activities and uses to ensure the remedy is protected and O&M costs are controlled.
2. DEQ may retain, lease, or transfer property to another party or governmental entity that will use the land for the sole or primary purpose of supporting the O&M or ICP activities or other direct support or protection of the cleanup. The need of Panhandle Health District (PHD) for property for ICP purposes is an example.
3. DEQ may transfer, sell or lease limited portions of the Bunker Hill real property to local governmental or tax supported entities at less than fair market value. Such transactions may be made to entities that have made past requests or proposals to the Transfer Team and shall be based on demonstrated benefits to the general public. Pending requests or proposals include those from Shoshone County, the City of Kellogg and School District 391. In addition the Land Transfer Team has been advised that Shoshone Medical Center has an interest in acquiring property for work force housing. The Medical Center is also working with other entities including local police and fire agencies to identify property for work force housing in Shoshone County.

THE LAND TRANSFER PROCESS

In the past, land transfers have generally been initiated by prospective purchasers. Land values were low and DEQ was looking for opportunities to jumpstart the local economy helping local tax collections and creating jobs. Recent development activities by Eagle Crest and others as well as the completion of cleanups and the general real estate market have dramatically improved real estate values in the Kellogg Area. As indicated, DEQ will seek market value for its properties with limited exceptions for tax supported entities as listed above. DEQ may place land on the market utilizing a local real estate sales professional.

DEQ is currently evaluating its property base and assessing its present and potential market values. This initial evaluation will be used to identify basic marketing and development strategies that could enhance and recover these values and also address community needs. DEQ will then select and implement development and marketing plans to sell, lease, transfer or retain properties. The following separate processes and requirements will be applicable to transactions concerning tax supported entities for public purposes and private entities for fair market value:

Transactions with Tax Supported Entities for Public Purposes:

- DEQ will consider existing requests or proposals which shall include those made as of June 1, 2007. Any future requests or proposals for non-fair market value transfers will not be considered

except upon a demonstration of exceptional, significant, and immediate benefits to the public and a minimal impact on the recovery of fair market value.

- The DEQ Land Transfer Team will recommend to the DEQ Director whether each request should be accepted, accepted with modifications, or rejected. The DEQ Director will make the final decision.
- All requests that have not been processed must complete the Land Transaction Proposal Form that provides information about the property desired, why it is needed, how the need is being met now, and the proposed transfer, sale or lease terms.
- Tax supported entities will be required to survey the requested property and bear the cost of any necessary improvements or other costs incurred by DEQ prior to completion of any transaction
- Tax supported entities will be required to work with the appropriate local jurisdictions to address any land use requirements.
- DEQ O&M obligations relating to vegetative cover and barrier protection will be transferred with the property. DEQ O&M obligations related to drainage control will be retained by DEQ except the new owner/lessee will assume O&M obligations for any drainage control features modified by the new owner/lessee. Such modification will require the advance approval of DEQ.
- DEQ will retain access rights for itself and any appropriate designee, including PHD or EPA, for O&M or ICP purposes and evaluation of water quality and remedy effectiveness
- DEQ will require a demonstration of financial capability and development milestones where significant development of the property is necessary for the intended public purpose.
- DEQ will retain reversionary interests to ensure properties are utilized consistent with the public benefit purpose of the transfer.
- The Land Transaction Proposal Form will be completed by the initiator of the land transfer to provide DEQ the information it needs to make a decision on the transfer. DEQ may ask for additional information if determined necessary to facilitate the transfer.

Transactions with Private Entities for Fair Market Value:

- The DEQ will develop and implement a marketing plan to sell or lease properties to private parties for fair market value.
- Parties offering to purchase or lease the DEQ owned properties will be required to complete the Land Transaction Form. Information from the form will be used to assess the qualifications of the applicant and the overall benefit of the project to the community and environmental protection.
- DEQ will enter into a land transaction negotiation with the party that has placed a bid that meets fair market value based on an open competitive process, demonstrates ability to implement the project, and meets the basic criteria of community benefit and environmental protection.
- DEQ O&M obligations relating to vegetative cover and barrier protection will be transferred with the property. DEQ O&M obligations related to drainage control will be retained by DEQ except the new owner/leasee will assume O&M obligations for any drainage control features modified by the new owner/leasee. Such modification will require the advance approval of DEQ.
- DEQ will retain access rights for itself and any appropriate designee, including PHD and EPA, for ICP and O&M purposes and evaluation of water quality and remedy effectiveness.
- DEQ may require a demonstration of financial capability and development milestones where significant development of the property is a factor or consideration in the sale or lease of any large parcel(s). The purpose of such requirements is to ensure that the local economy and communities realize the benefits of development in a timely manner and to avoid speculative purchases/leases.

- DEQ may retain reversionary interests to ensure properties are timely developed.

IMPLEMENTATION

This policy shall be effective immediately.
Dated this 13 day of February, 2008.

TONI HARDESTY
DIRECTOR

Land Transaction Proposal Form

Initiator: _____

Mailing Address: _____

_____

Contact Person: _____

_____

Phone number: _____

FAX: _____

E-Mail: _____

Land Description: Please describe the parcel or parcels of land owned by the Idaho Department of Environmental Quality (DEQ) that you propose to acquire:
Section _____, Township _____, Range _____.

_____
_____
_____
_____

Parcel size requested. _____

Project Description: Please describe your intended use of the land:

_____
_____
_____
_____

Please answer the following questions with reference to your proposed use of the land. Do not limit your answers to the space provided. It is important that you be as thorough as possible. Your answers will affect the ranking of your proposal with other proposals.

Benefits of the Proposal:

(1) Describe how your proposed use of the land will compliment and enhance environmental protection in the Silver Valley and is compatible with the Superfund remedy and the State's O&M obligations. Need explanation for remedy and O&M?

_____
_____

(2) Will your proposed use of the land increase recreational opportunities and the quality of life in the Silver Valley. If so, how?

(3) Will your proposed use of the land contribute to the economic development of the Silver Valley (Be specific as to job creation, payroll and benefits)? If so, how?

(4) Will your proposed use of the land increase the value and utility of adjoining properties? If so, how?

(5) Will your proposed use of the land enhance the operation of local government entities in the Silver Valley? If so, how?

(6) Describe any special attributes that your proposed use of the land adds to the Silver Valley that does not already exist:

Transaction Description:

(1) Please identify the participants in your proposal (please include contact information).

(2) Identify your development experience. Please provide information on projects similar to your current proposal.

_____

_____

_____

_____

(3) Describe your financial capability to implement and complete the project.

_____

_____

_____

_____

(4) Please identify your desired timeline for your proposed acquisition and project completion.

_____

_____

_____

_____

By signing this proposal, the Initiator acknowledges that the information contained herein will be used by DEQ staff to study the proposal and that under Idaho's Public Records Act, may be considered to be a public document.

Date: _____

Initiator: _____
Signature

Section 3 Fuel Supply/Ash Disposal

A. OVERVIEW

Two main fuel sources have been analyzed for the renewable energy facility; forest based woody biomass and municipal solid waste (MSW). While literally hundreds of materials fall under the category "biomass", forest based woody biomass was a logical biomass choice for fuel supply, because Shoshone County is a heavily forested area. MSW from Shoshone County and surrounding Counties has also been examined as a possible fuel source as part of this feasibility study because of long standing environmental and financial burdens the County has historically borne with MSW disposal. Shoshone County endures a tremendous expense in disposing of their waste in Missoula, and is in fact carrying a potential long term liability associated with future closure and cleanup efforts at the landfill. Key motivators for the renewable energy facility have been to reduce the annual cost of MSW disposal to the County rate payers, and also to limit Shoshone County's liability associated with the Missoula landfill.

It is important to note the common misconception that burning municipal solid waste to make energy is an environmentally unhealthy practice. While the Waste-To-Energy process may seem like a deviation from "renewable" or "sustainable" practices, this process has been proven across the United States, and also the world, as a way to reduce greenhouse gas emissions, reduce carbon footprint, and is a preferred renewable source of electricity for much of Europe that promotes re-using, recycling and composting of the MSW. Much more detail regarding the environmental benefits of Waste-To-Energy is included in below.

Forest based woody biomass is also a great choice of fuel supply for a renewable energy facility located in Shoshone County because the local supply on Federal lands is abundant, and removing certain types of biomass from the forests would be a tremendous benefit to the environment. Many of the forested acres in the County and surrounding areas are unhealthy for a variety of reasons including insect infestations, overgrown tree stands causing unhealthy competition for sunlight and nutrients, trees at or beyond their life cycle, etc. (see Executive Summary, section B for more details). It is the intent of Shoshone County and McKinstry to structure the proposed renewable energy facility in a manner that does the most good for the local forests, wildlife, watersheds, fire mitigation programs, and air quality, not to clear cut acres of forest or old growth trees for the sole benefit of the local economy.

B. FUEL REQUIREMENTS OF RENEWABLE ENERGY FACILITY

Based on preliminary engineering completed to date, the renewable energy facility will require approximately 130,000 green tons of material per year to fuel a 10MW plant. Obviously, variations in electrical output and waste heat users may dictate a different fuel requirement. For example, a 20MW facility co-located with a 100,000 ton per year pellet plant waste heat user would require approximately 360,000 green tons per year. On the other end of the spectrum, a 6MW facility with no waste heat user would require approximately 65,000 green tons per year.

C. FUEL SUPPLY- FOREST BASED WOODY BIOMASS

The renewable energy facility (REF) will likely be located in Smelterville, ID due to the Government Gulch site being identified as the best location in Shoshone County for the facility. The following tables are simple breakdowns of land ownership and forest type within a twenty mile radius of Smelterville. As can be seen from the first Table, the USFS is the largest landowner, followed by Private ownership. As such, efforts to secure fuel supply for the REF should be primarily focused on these two ownership groups.

Land Owner	Acres
USFS	368,925 (59%)
Private	176,234 (28%)
BLM	48,310 (8%)
State	33,013 (5%)
Indian Res.	3,123 (<1%)
TOTAL	629,605

Table 1: Land Ownership around Smelterville

Forest Type	Acres	%
Grand Fir	124,432	35%
Douglas Fir	106,255	30%
Western Hemlock	48,409	14%
Lodgepole Pine	15,106	4%
Western White Pine	14,507	4%
Spruce/Subalpine fir	10,162	3%
Mt. Hemlock/SAF	9,939	3%
Western Larch	9,309	3%
Western Red Cedar	8,229	2%

Table 2: Forest Type around Smelterville

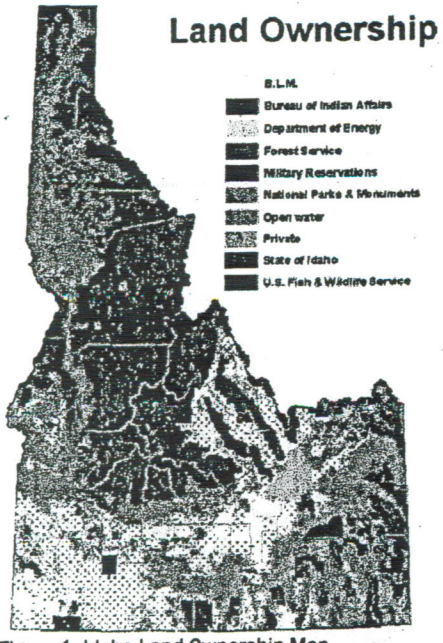


Figure 1: Idaho Land Ownership Map

United States Forest Service (USFS)

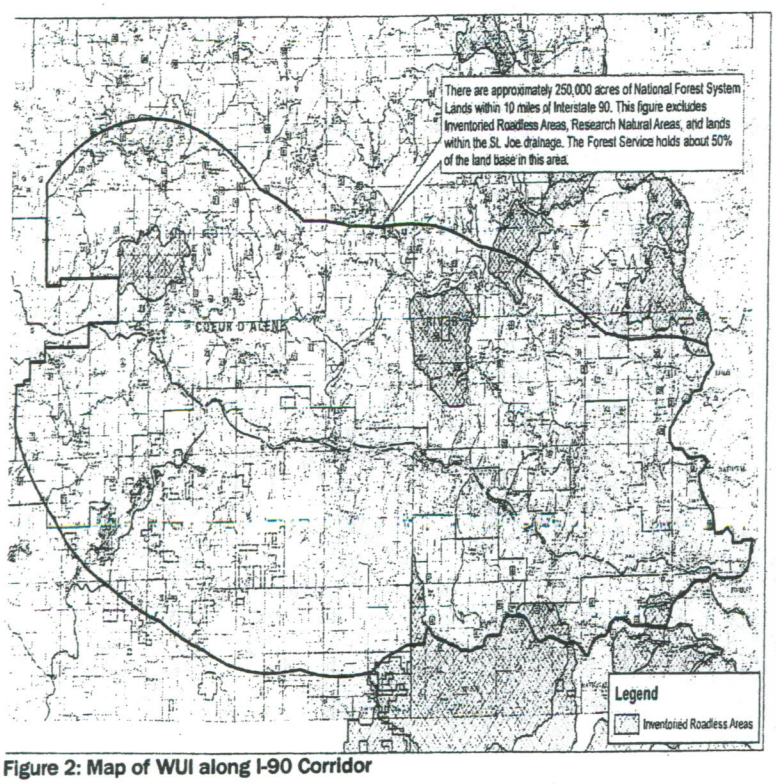
The USFS owns approximately 14.5 million acres in Idaho and manages the vast majority of the land in the Idaho Panhandle National Forest. Because of various internal and external influences including environmental opposition, federal funding cuts, loss of employees, and fear of litigation, the local USFS division has undermanaged their forests. In the Idaho National Panhandle Forest alone, 400 million board feet of timber grows each year, between 50 and 100 million board feet is harvested for beneficial use, and 200 million board feet is reported to die and decay in place. As more timber grows each year than is removed from the forest, between 300 and 350 million board feet, a significant fire load has been created.

Many scientists agree that there is more fire hazard present in the Idaho Panhandle National Forest today in 2009, than there was before the catastrophic 1910 fire. The 1910 fire was the largest forest fire in American history, and possibly the largest forest fire in world history. Because of their magnitude and the severity of the devastation caused, the fires of 1910 caused drastic changes in Forest Service forest policy, because so much forest had burned. The USFS turned to a complete fire suppression mode, and put out all fires, as soon as

possible. This long standing fire suppression philosophy was followed by dramatic opposition from environmental groups, which further limited the activity of the USFS in the forests.

Today, the Coeur d'Alene River Ranger District current program levels associated with small/large log harvest are to treat 1200 to 1500 acres per year, and to focus in the WUI along the I-90 corridor. The USFS owns approximately 250,000 acres in the WUI, so the percentage of USFS lands that are actively managed is around 0.6%. In the acres that the Forest Service is managing, they are finding that residual slash from the small/large log harvest associated with their multiple resource sales is averaging between 10-20 green tons per acre at the landing piles. At present levels of forest management, the USFS produces approximately 20,000 tons per year of biomass, which equates to roughly 15% of the feed stock requirement of a 10 MW renewable energy facility.

While the USFS owns approximately 250,000 acres in the WUI, for the purposes of this report it is assumed that a potential 10-year stewardship contract with the USFS would comprise of approximately 100,000 acres, or about one-third of their holdings. Assuming a sustainable and healthy yield for the duration of the stewardship contract is 10 tons per acre and 10,000 treated acres per year, the annual fuel yield from the WUI to the renewable energy facility would be 100,000 tons per year. It is believed that the 10 tons per acre yield is a very conservative value because many of the tree stands in the WUI are in desperate need of fire mitigation and healthy forest activities, so a more realistic average of residual biomass per ton may approach 20 tons per acre.



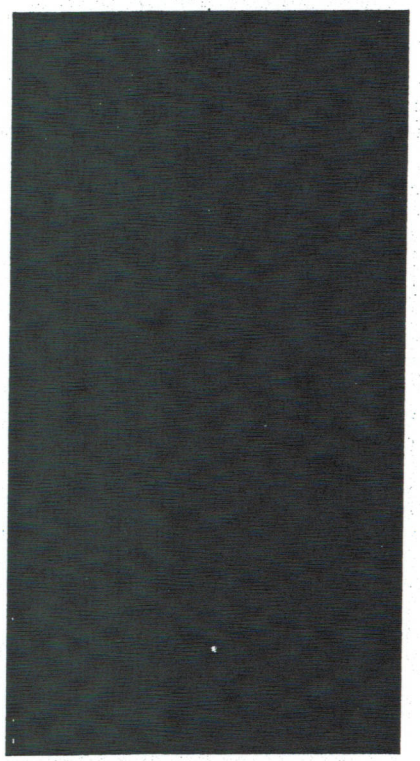


Figure 2: Map of WUI along I-90 Corridor

One example of a local stewardship contract is the stewardship being conducted on the West side of Priest Lake by the Priest Community Forest Connection. While collaboration efforts began in 2000, the stewardship contract was not awarded until February, 2002 and on-the-ground implementation began in May 2002. Completed activities as of June 2007 (five years into the contract) included nearly 1300 acres of harvesting, over 250 acres of hand piling of fuels, nearly 1300 acres of slashing and grapple piling of fuels, 100 acres of slashing for broadcast burning, 560 chains of fire line construction, hundreds of thousands of dollars in road maintenance, 58 acres of white pine pruning, planting of 47,064 trees, 4.5 miles of road obliterations, installing a recreation shelter and toilet at a historic camp, and road realignment and trail construction on an old roadbed. This example demonstrates the complexity of a stewardship contract with the USFS and the level of collaboration

required, as well as the diversity of environmental issues that can be addressed as part of a stewardship contract. The potential stewardship contract in the Shoshone County WUI would undoubtedly need to address many similar concerns, as well as treating thousands of acres for fire mitigation.

Bureau of Land Management (BLM)

While the BLM holds 11.7 million acres in Idaho, they hold less than 70,000 acres along the I-90 corridor in North Idaho, and these acres are spread over a large land area. The BLM also does a good job of actively managing their lands for forest health, and the possibility of a meaningful stewardship contract to support a renewable energy facility is unlikely. According to the local BLM representative out of Coeur D'Alene, the BLM would work with a renewable energy facility and gear their timber sales in a manner to provide the renewable facility with an opportunity to purchase residual slash in a competitive atmosphere. While this mechanism of procuring biomass for the renewable facility is real and would provide a source of biomass, the amount of slash generated would be small in comparison to the total feed stock required. The amount of feed stock generated in this manner from the BLM would be varying each year depending on funding, revisions to their forest management plan, and changes in the timber market.

Idaho Department of Lands (IDL)

The Idaho Department of Lands manages approximately 2.5 million acres of endowment lands in the State of Idaho. These lands have been granted to the State of Idaho, and the State constitution outlines the process by which these lands must be managed to support public schools and institutions over time. Historically, the IDL generates between $50 million and $80 million annually for public schools, colleges and universities, and public buildings through revenue generating timber sales.

Of the 2.5 million acres owned by the IDL, 800,000 acres are primary forest land, and 200,000 acres are secondary forest land. On this roughly 1 million acres, the IDL holds between 60 and 100 timber sales annually across the State, and in 2007 the timber sales generated approximately 212 MMBF. The IDL plans to increase this yield to 247 MMBF in the future. As every MMBF of merchantable timber produces about 2,000 tons of biomass, 212 MMBF equates to 414,000 tons of recoverable biomass in the form of slash piles. These 414,000 tons of recoverable biomass is a theoretical maximum assuming perfect conditions, and equates to about two 20MW renewable energy facilities. Further, the 414,000 tons does not include much of the pulp wood or dead, dying and diseased trees that could be included in timber sales across the State if there was a renewable energy facility or other use of this material to create a market for it.

The IDL has published their 'Fiscal Year 2009 Sales Plan' which estimates biomass tonnage potentially available Statewide on endowment lands at about 180,000 tons. Actual quantities of biomass that are sold from active sales and direct sale follow-up projects are only 6,615 tons (3.6% of total). This percentage is low primarily due to the economics of burning slash piles in the forest vs. transporting them to existing biomass facilities. See Figure 3 below for the location of biomass facilities in the State of Idaho.

The IDL timber sales in the Silver Valley, or Cataldo District, are managed out of the local office in Kingston, ID and are planned based on sustainable forestry practices, i.e. the maximum volume of timber that can be sold by the IDL in a given year is equivalent to the volume in board feet that grows each year. In addition to their own timber sales, the local IDL office is responsible for the permitting process for private logging activities. Based on the last five years worth of historical records, it appears that approximately 24 million board feet of timber is sold each year in the Cataldo district, which yields approximately 48,000 tons of residual slash. While this data is very preliminary in nature, it appears that the average of annual private and IDL timber sales yields a significant amount of biomass that could be utilized in the renewable energy plant. Also, a market for lodge pole and pulp chips would be created where none exists now, and unhealthy and overgrown lodge pole stands could be profitably removed and included as part of the Idaho Department of Lands timber sales and private logging.

Private Landowners:

Besides the USFS, private land owners are the largest land owners in a 20 mile radius around the possible REF location in Smelterville. While there are only a few private land owners in all of Idaho that have enough land and

potential feed stock on that land to support a REF, an interesting opportunity exists to create a private land owner co-op, which could be similar in structure to the many agricultural co-ops in the region. This co-op could be comprised of small and large land owners, and all acres in the co-op could be managed for the best long term return on investment using sustainable forestry practices.

Existing Private Biomass Market:
It is estimated that approximately 70,000 tons per year of biomass are transported along the I-90 corridor between Coeur D'Alene and Montana each year. This material is generated by local producers including small sawmills, and is handled by local biomass brokers and truckers. While this existing market is relatively small and the renewable energy facility is structured to not compete with existing local industries, further investigation is warranted to understand this market and determine what level of feed stock is available for a renewable energy facility.

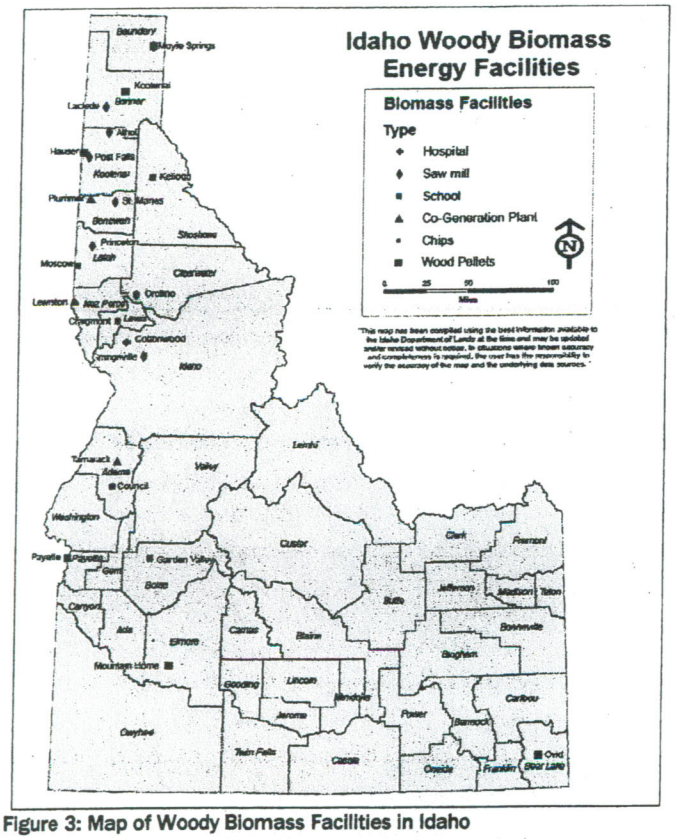


Figure 3: Map of Woody Biomass Facilities in Idaho

One-Time Fuel Sources:
There are many one-time fuel sources that would comprise a portion of the renewable energy facility feed stock, however, these fuel sources will not assist in the effort to secure financing for the REF as they are not a sustained, year after year type of feed stock. These one-time fuel sources include insurance company and County green zone/fire suppression efforts, utility company power line extensions, commercial/industrial construction activities, etc.

D. THE CASE FOR WASTE-TO-ENERGY

Waste-To-Energy (WTE), or Energy Recovery, is the process of Incineration of solid waste to convert it to thermal energy to generate steam that drives turbines for electricity generation. WTE is a significant source of renewable energy that substantially reduces GHG emissions by displacing (a) electric power generation from fossil fuels and (b) landfill disposal of municipal waste. Benefits of the WTE process:

- WTE facilities provide a clean, base load energy source with very low emissions.

- WTE facilities recover 10 times the energy (electric power) from a ton of waste in comparison to landfill methane recovery-reuse.
- WTE facilities are also "distributed" generation, i.e., energy is used where it is generated, which reduces the environmental impact and cost of transporting both waste and energy.
- Research indicates that WTE complements recycling programs rather than competing with recycling, in fact WTE communities have some of the highest recycling rates in the US.
- WTE offsets the need for fossil fuels.
- And WTE is an underutilized energy resource.

Category	Emissions (tons CO_2 eq/MWe-hr)
Landfill (with energy recovery)	3.7
Coal-Fired Power Plant	1.1
WTE Facility	0.7

Figure 4: Greenhouse Gas Emissions Per MWh

Background Information on Waste-To-Energy (WTE)

- Waste-To-Energy (WTE), or Energy Recovery, present status as a renewable energy resource (i.e., an energy resource that is replaced rapidly by recurring processes) is well established: WTE is widely recognized as renewable at both state and federal levels: e.g., Department of Energy, EPA, Biomass Research and Development Act of 2000, Energy Policy Act of 2005, Public Utility Regulatory Policy Act, and laws and regulations in nearly 25 states.
- The World Economic Forum's report (January 2009), Green Investing – Towards a Clean Energy Infrastructure, recognizes WTE as one of eight "key renewable energy sectors" and "particularly promising in terms of . . . abatement potential" for carbon emissions.
- A largely untapped resource in the U.S., WTE has far greater use in a number of other nations that are at least equally conscientious stewards of the environment.
- Only 6.9% of the municipal waste stream in the U.S. is directed to WTE, while 64.5% is land filled.
- Reflecting state and federal requirements for the most advanced emissions control technology, WTE emissions have plummeted since the late 1980's (e.g., annual WTE emissions of dioxin have decreased by a factor of 1,000 to less than 12 grams), and WTE emissions are lower than landfill emissions for 9 of 10 major air pollutants. As a result, USEPA recognizes WTE as a renewable energy source that "produce[s] 2800 megawatts of electricity with less environmental impact than almost any other source of electricity."
- EPA's hierarchy for "integrated waste management" recommends waste combustion with energy recovery over land filling (as does the European Union) because WTE recovers approximately 600 kWh of electricity per ton of waste, which is approximately 10 times the electric energy recoverable from a ton of land filled waste.
- WTE is the paradigm example of "distributed generation" that serves nearby load without the need for new long-distance transmission lines (unlike other renewables). WTE is also base-load generation, available 24/7 and unaffected by days that are cloudy or calm (in contrast to sources such as solar and wind power).
- The Nature Conservancy ranks WTE as one of the most environmentally protective alternative energy sources.

- As is often the case with environmentally preferred alternatives, WTE can cost more (at least on a short-term and intermediate basis) – And our communities accept the higher cost precisely because the result is better for the environment.

WTE's role in reducing greenhouse gas emissions (GHG) is widely recognized: As shown by EPA's Municipal Solid Waste Decision Support Tool, WTE reduces GHG emissions in three ways by:

- generating electricity and/or steam which reduces GHG emissions from fossil fuel sources,
- avoiding the potential methane emissions that would result if the same waste was land filled,
- recovering ferrous and nonferrous metals which avoids the additional energy consumption that would be required if the same metals were produced from virgin ores.

GHG emissions from WTE are primarily of biogenic origin (approximately 67%). These emissions are already part of the natural carbon cycle because the biogenic carbon that comprises paper, food and other biomass in municipal waste is removed from the atmosphere as part of the plant growth-natural carbon cycle. The remaining petrochemical-based material (approximately 33%) can also be considered renewable (it's generated year after year), but if relegated to land filling rather than combustion with energy recovery that material would represent the loss of a vast amount of valuable energy – WTE recovers from each ton of MSW the energy equivalent of one barrel of oil.

Scientific studies show that WTE reduces GHG emissions by 0.5 - 1.3 tons of CO2 equivalents per ton of MSW combusted rather than land filled (the low end of that range assumes a modern landfill with landfill gas recovery-reuse). WTE's mitigation of GHG is expressly recognized by the Intergovernmental Panel on Climate Change (IPCC), a leading forum of independent scientific experts on climate change. The IPCC emphasizes WTE's dual benefits of offsetting fossil fuel combustion and avoided landfill methane emissions

Similarly, the Kyoto Protocol's Clean Development Mechanism approves WTE as a source of tradable GHG emission reduction credits that displaces electricity from fossil fuels and avoids landfill methane emissions from waste. In addition, the Feb. 20, 2007 joint statement of Columbia University's-Earth Institute Global Roundtable on Climate Change (GROCC) identifies WTE as an important means to reduce carbon emissions from fossil fuel-based electricity and methane emissions from landfills.

WTE ENCOURAGES RECYCLING

WTE is also entirely compatible with recycling and WTE communities' recycling rates outperform non-WTE communities: WTE communities typically have recycling rates at least 5 percentage points above the national average and in some cases lead the Nation in recycling.

- A recent (June 2009) national survey shows that WTE communities have a 33.3% recycling rate, which exceeds the national rate and is conservatively calculated (the WTE communities' recycling rate omits several recyclables that the national rate includes, and the national rate is a composite that includes WTE communities – the more accurate comparison would exclude WTE communities in calculating the national rate).

E. FUEL SUPPLY - MUNICIPAL SOLID WASTE (MSW)

In addition to forest based biomass, municipal solid waste (MSW) is a potential feed stock for a renewable energy facility. The Table below shows the volume of MSW that is available from Shoshone County and surrounding Counties, and equates each County to a percentage of total feed stock required for a 10 MW renewable energy facility. Kootenai County is not represented in the Table below because they are pursuing a methane gas recapture system, which would effectively lock up their MSW stream for the duration of the development contract, the term of which would likely be between 10 and 20 years.

County	Annual tons	% of Feed Stock 10MW
Shoshone	9,284	7.1%
Benewah	7,825	6.0%
Bonner	27,970	21.5%
Boundary	4,333	3.3%
Total	49,412	37.9%

Table 3: Shoshone and Adjacent County MSW Volume (Non Inert)

Assuming the four Counties in Table 3 would contribute all their non inert MSW streams to a renewable energy facility, it appears that 37.9% of the annual feed stock requirement for a 10 MW plant could come from MSW. Presently each of the four Counties transports their garbage to regional landfills where it will slowly decay and release harmful greenhouse gasses to the environment over an extended period of time. It appears possible for the renewable energy facility to use this garbage as a portion of the total fuel source and dramatically reduce greenhouse gasses released to the environment. This will also provide an economic benefit to Shoshone County residents by fixing their costs of garbage disposal, rather than being dependant on the cost of foreign oil, creating revenue through tipping fees charged to the other Counties, and by reducing Shoshone County's long term legal and financial liability associated with the landfill.

While MSW is a proven, reliable and renewable fuel source, adding municipal solid waste to the fuel supply dramatically increases first cost of the renewable energy facility as well as operational expenses ranging from number of employees to annual operational and maintenance budgets, to various consumables for emissions abatement and ash quenching. As such, further investigation is required to develop detailed first cost and ongoing operational expenses. (See Project Financials).

E. ASH DISPOSAL

It is presently estimated that the renewable energy facility will generate around 6,000 tons of ash per year, which will need to be used or disposed of in some manner. In a 100% forest biomass facility the ash would all be an inert white fly ash which can be used as an additive for road beds, concrete, fertilizer, slurries, and many other marketable uses. If the plant moves forward with a biomass/MSW mixture, it will be necessary to determine if the ash contains enough heavy metals to be designated anything other than inert. If the ash is not inert, it will be necessary to find a use for this ash or begin negotiations on a long term disposal contract. These activities will be conducted during later phases of project development.

For reference, the waste to energy facility located in Spokane County is a 100% garbage, or MSW, fired system and the ash generated from the process is considered Hazardous by the Washington Department of Ecology. The ash generated from this plant is trucked to a landfill in Roosevelt, WA. The ash is land filled in a double composite lined mono-fill at an aggregate cost to the solid waste system of $49 per ton. While the ash disposal process and cost to the taxpayers of Spokane county may seem excessive, there are four landfills in Spokane county that are on the superfund list, with a total estimated cost of over $100 million in remediation efforts. As Spokane County now incinerates most of their garbage, they have limited their long term liability associated with their garbage generated (approximately 10% bypass and the land filled ash) since the plant became operational.

F. NEXT STEPS

Next Steps to complete under the Fuel Supply category will include detailed fuel supply agreements for both forest based biomass and MSW with the appropriate Federal/State/County/Private entities, verifying real-time and long-term cost per ton of fuel with local loggers and entrepreneurs, and developing a fuel specification based on equipment selections and fuel source.

Next Steps to complete under the Ash Disposal category will include a detailed analysis of the ash generated from both a biomass and a biomass/MSW fuel mixture, with a definitive ruling on whether the ash is considered inert, hazardous or some other designation. Once the ash is classified, it will be possible to determine various methods of re-use or disposal, and the associated costs or revenue potential of the ash.

Section 4 Utility Interconnect/Power Purchase

A. OVERVIEW

As the Government Gulch site was selected as the most favorable location for the renewable energy facility, further study regarding interconnection to the local utility grid was studied at this site only. The Government Gulch site used to house a zinc smelter with an electrical load of approximately 60MW. The original power poles and lines have been abandoned in place and are now overgrown with vegetation; however they appear to be in serviceable condition. As the proposed renewable energy facility is anticipated to generate between 2MW and 20MW, the relative cost of electrical infrastructure required to connect to Avista's grid is small. It appears that a few modifications and upgrades are required at the substation, the cost of which may be shared by Avista as routine maintenance activities.

McKinstry has started communications with Avista on two separate fronts, with the transmission group and also with the power purchase group. Both groups within Avista are vitally important to the success of the renewable energy facility. To date, McKinstry has contracted with the transmission group to perform an Interconnection Feasibility Study, which is now complete and included in the section of the feasibility report for reference.

McKinstry has also conducted preliminary conversations with the Avista power purchase group to verify the general parameters of the renewable energy facility, and also to ensure the power purchase agreement associated with the facility is consistent with what the Idaho PUC recently published for non-fueled power producers. The simplest option to sell electricity would be to sign a long term power sales agreement with Avista that is in compliance with the Idaho PUC published rates. However, this may not be the most financially lucrative power sales option available to the County.

As such, McKinstry coordinated with a local energy marketer, and has started to define the requirements and possibilities around selling the electricity and renewable energy credits (REC's or green tags) in the California market. Selling electricity and REC's in California is an extremely attractive option for new renewable energy facilities across the county because of the high cost of electricity in California, plus the market that the California Energy Commission has created for REC's with the statewide adoption of their Renewable Portfolio Standards (RPS).

Selling electricity and REC's in California is obviously more complicated that signing a direct contract with Avista and preliminary estimates show a range of sold electricity in California to also carry a burden of approximately $7-$10 per MWh, due to transmission losses and wheeling charges of the various entities between Smelterville and California. There are two options for transmission of the power to California, the California-Oregon-Border (COB) and the Nevada-Oregon-Border (NOB). The COB, or John-Day transmission line, appears to be the best option as the local energy marketer has transmission rights within this line for the next 30 years.

Other options for marketing the electricity generated by the renewable energy facility include the "spot market". Entering this market typically requires selling power in 25MW blocks at a minimum to receive the best market price for the day, month, or year that is being traded and sold. While the proposed REF is not this large, the potential market price for sold electricity may not be favorable, plus the energy spot market is the most volatile market in the world by orders of magnitude and McKinstry does not recommend that Shoshone County take on this risk.

B. AVISTA INTERCONNECTION STUDY

No matter which power sales option the County and REF opt to pursue, an interconnection with Avista is still required. As such, McKinstry contracted with Avista to provide an Interconnection Feasibility Study for a nominal 10MW-20MW electricity producing plant at the Government Gulch site. The results of their feasibility study show that interconnection to Avista's grid is relatively simple and cost effective, when compared to almost any other

interconnection request they have in their queue. As was stated earlier, there is an existing abandoned transmission line in place that can be re-energized and utilized, which negates the cost of new transmission lines. Also, the past de-energized 60MW load of the zinc smelter means the infrastructure in the transfer station is more than adequate to serve up to a 20MW generation load, with very minimal effects on Avista's grid or infrastructure required in their substation.

While the overall scope of work required to connect to Avista's grid is relatively small, they still estimate a $2.1 million capital cost required as part of the overall construction cost of the REF. This $2.1 million includes the cost a new electrical substation at the REF, the work required at Avista's substation, all metering and other miscellaneous expenses, and an allowance of $150,000 for clearing of trees under the transmission lines. Avista is excited about the potential of allowing the REF to clear the trees from the existing lines, and would gladly credit back the $150,000.

The entire Interconnection Study Report is included in this section of the report for reference.

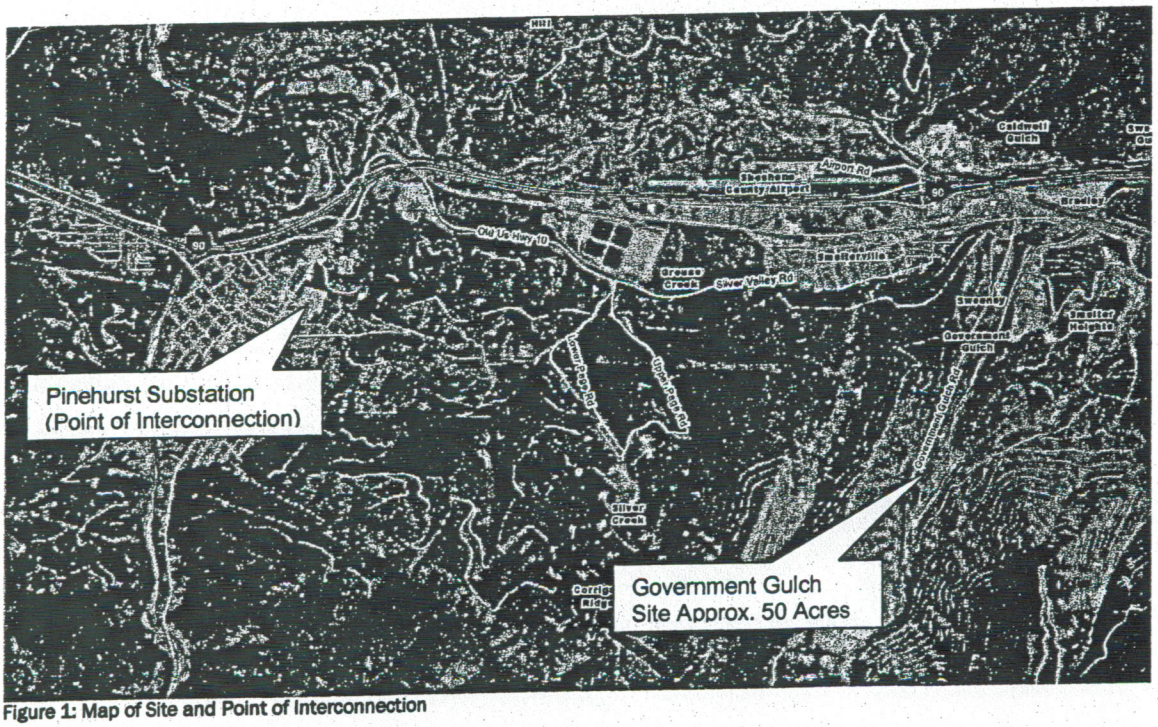


Figure 1: Map of Site and Point of Interconnection

C. POWER PURCHASE CONTRACTS AND AGREEMENTS

As stated earlier, Shoshone County and the REF have two clear options for power sales. First is a power sales agreement to Avista, in line with the Idaho PUC published rates as provided below. The second option is to market the power to California and have the opportunity to market two products, the electricity produced by a green source and the associated REC's. While this option carries with it a $7-$10 per MWh sold due to transmission losses and charges, the potential for greater revenue generation from power sales exists. As the power sales option to California requires further study and direct negotiation with various utilities governed by the CEC, this section of the report focuses primarily on the Idaho PUC published rates.

In 2004, Idaho passed a bill (I.C. §31-869) that provided explicit authorization for Counties to sell electricity produced by renewable (biomass, solar and geothermal) energy plants (up to 25MW) for the principal purpose of providing revenue for the municipality. This coupled with the revised PURPA agreements, provided a way for

communities to consider leveraging local renewable energy resources as a means to generate sustainable economic development and long-term revenue, rather than relying solely on property taxes.

McKinstry has verified through the Idaho Public Utilities Commission that Biomass and Municipal Solid Waste (MSW) qualify for the renewable and/or "Non Fueled" power purchase rate of $93 per MW/h (assuming the plant comes on-line in 2011). While MSW may or may not qualify for carbon credits, grants and other subsidies, the power purchase agreement will remain unaffected by the composition of the fuel source, as long as the renewable energy facility is not dependent on fossil fuels.

Federal Energy Regulatory Commission (FERC) & Public Utility Regulatory Act (PURPA) regulate the purchase of power generated via small-scale (up to 10 MW) generation plants through a cost-avoided calculation process. Generally, this is approximately $74 MW/hr.; however, in Idaho, Avista and Idaho Power are paying a premium for renewable or "green" power based on renewable power portfolio requirements. For this project both biomass and MSW qualify for the "Non-Fueled" premium of $93 MW/hr. Please note that we will use somewhere between $93 and $98MW/hr rate purchase option in the preliminary financial model as the renewable energy facility will be able to sell REC's, or green tags, at a market value of around $5 per MWh in the Northwest.

The following is an example of the Non-Levelized and Levelized 20-year power purchase contracts and power purchase agreements. The complete IPUC Order No. 30744 text is included later in this section of the report for reference.

PURPA - Firm Contracts (qualifying for Published Avoided Costs)

Non-Levelized Contract	Levelized Contract
Energy Price Published Avoided Cost - Annually changing rates set at contract inception	Energy Price Published Avoided Cost - Single rate set at contract inception
Term Maximum of 20 years	Term Maximum of 20 years
Monthly Generation commitment 90 - 110 %. energy delivery = Full contract payment Less then 90 % = Energy price adjusted to reflect energy deliveries Excess over 110 % = Energy price based upon Market rates	Monthly Generation commitment 90 - 110 % energy delivery = Full contract payment Less then 90 % = Energy price adjusted to reflect energy deliveries Excess over 110 % = Energy price based upon Market rates
Insurance General Liability Insurance	Insurance General Liability Insurance All Risk Property Boiler, Machinery Insurance Earthquake and Flood (catastrophic Perils) Business Interruption
	Escrow Requirements Debt Reserve Maintenance Reserve
	Securitization 2nd Lien required with Idaho Power as lien holder
Early contract termination penalties Damages	Early contract termination penalties Damages Overpayment liability
Idaho Public Utilities Commission approval required	Idaho Public Utilities Commission approval required

Figure 2: Outline of PURPA Contract Options

As much of the design, equipment, capital, and construction costs are somewhat constant, regardless of the generation capacity; in most cases it is financially preferable to design a plant of no less than 6MW. 10MW is the largest amount of power that can be sold from a site and qualify for standard PURPA rates under the simplified 1-20 year power purchase agreement. Designing the system for a nominal generation capacity of 10-13MW (assuming fuel, etc.) is optimal depending on whether it makes financial sense for the plant to purchase or produce the parasitic load from the local utility. Ultimately, the plant capacity may be largely determined by the amount of available fuel that can be guaranteed to an investment-grade standard.

AVISTA
AVOIDED COST RATES FOR NON-FUELED PROJECTS
SMALLER THAN TEN MEGAWATTS
March 16, 2009
$/MWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2009	2010	2011	2012	2013	2014		
1	76.47	75.56	77.68	79.96	81.86	83.81	2009	76.47
2	76.04	76.58	78.78	80.88	82.80	84.77	2010	75.56
3	76.54	77.62	79.72	81.78	83.72	85.75	2011	77.68
4	77.30	78.55	80.62	82.67	84.66	86.70	2012	79.96
5	78.07	79.44	81.50	83.56	85.57	87.64	2013	81.86
6	78.84	80.30	82.37	84.43	86.47	88.57	2014	83.81
7	79.61	81.15	83.22	85.30	87.36	89.47	2015	85.81
8	80.38	81.97	84.06	86.15	88.23	90.36	2016	87.96
9	81.14	82.78	84.88	86.99	89.08	91.23	2017	90.04
10	81.90	83.57	85.68	87.80	89.91	92.08	2018	92.30
11	82.64	84.35	86.47	88.60	90.73	92.91	2019	94.50
12	83.36	85.10	87.23	89.38	91.53	93.73	2020	96.74
13	84.07	85.84	87.98	90.15	92.31	94.55	2021	99.05
14	84.76	86.56	88.72	90.89	93.10	95.38	2022	101.41
15	85.44	87.26	89.43	91.64	93.88	96.20	2023	103.84
16	86.10	87.95	90.15	92.39	94.66	97.01	2024	106.32
17	86.75	88.63	90.86	93.13	95.44	97.82	2025	108.86
18	87.39	89.31	91.56	93.87	96.20	98.60	2026	111.97
19	88.03	89.98	92.26	94.59	96.94	99.36	2027	115.16
20	88.67	90.64	92.95	95.29	97.66	100.10	2028	118.46
							2029	121.86
							2030	125.36
							2031	128.19
							2032	131.63
							2033	135.17
							2034	138.81

Figure 3: Idaho PUC Published Avoided Cost Rates

D. NEXT STEPS

Next steps in the Utility Interconnect/Power Purchase category include further definition of possible energy marketing strategies, power sales options and associated transmission charges, ensuring the proposed REF complies with CEC guidelines and is in compliance with the California RPS standards, market value of REC's in the Northwest and California, direct negotiations with various utilities including Avista and PG&E, verification of transmission capacity of the John-Day line, and negotiations with Avista regarding costs associated with interconnection.

Office of the Secretary
Service Date
March 17, 2009

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE FUEL-COST-RELATED ADJUSTMENT TO PUBLISHED IDAHO AVOIDED COST RATES FOR IDAHO POWER COMPANY, PACIFICORP DBA ROCKY MOUNTAIN POWER, AND AVISTA CORPORATION DBA AVISTA UTILITIES.	)	**CASE NO. GNR-E-09-01** **ERRATA TO ORDER NO. 30744**

On March 12, 2009, IPUC Order No. 30744 was issued by this Commission. An error was found in the avoided cost rates for fueled projects. Attached to this Erratum are the new avoided cost rates for fueled projects. Also included for ease of reference are the avoided cost rates for non-fueled projects.

DATED at Boise, Idaho this 16th day of March 2009.

Jean D. Jewell
Commission Secretary

bls/O:GNR-E-09-01_Errata

AVISTA
AVOIDED COST RATES FOR NON-FUELED PROJECTS
SMALLER THAN TEN MEGAWATTS
March 16, 2009
$/MWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2009	2010	2011	2012	2013	2014		
1	76.47	75.56	77.68	79.96	81.86	83.81	2009	76.47
2	76.04	76.58	78.78	80.88	82.80	84.77	2010	75.56
3	76.54	77.62	79.72	81.78	83.72	85.75	2011	77.68
4	77.30	78.55	80.62	82.67	84.66	86.70	2012	79.96
5	78.07	79.44	81.50	83.56	85.57	87.64	2013	81.86
6	78.84	80.30	82.37	84.43	86.47	88.57	2014	83.81
7	79.61	81.15	83.22	85.30	87.36	89.47	2015	85.81
8	80.38	81.97	84.06	86.15	88.23	90.36	2016	87.96
9	81.14	82.78	84.88	86.99	89.08	91.23	2017	90.04
10	81.90	83.57	85.68	87.80	89.91	92.08	2018	92.30
11	82.64	84.35	86.47	88.60	90.73	92.91	2019	94.50
12	83.36	85.10	87.23	89.38	91.53	93.73	2020	96.74
13	84.07	85.84	87.98	90.15	92.31	94.55	2021	99.05
14	84.76	86.56	88.72	90.89	93.10	95.38	2022	101.41
15	85.44	87.26	89.43	91.64	93.88	96.20	2023	103.84
16	86.10	87.95	90.15	92.39	94.66	97.01	2024	106.32
17	86.75	88.63	90.86	93.13	95.44	97.82	2025	108.86
18	87.39	89.31	91.56	93.87	96.20	98.60	2026	111.97
19	88.03	89.98	92.26	94.59	96.94	99.36	2027	115.16
20	88.67	90.64	92.95	95.29	97.66	100.10	2028	118.46
							2029	121.86
							2030	125.36
							2031	128.19
							2032	131.63
							2033	135.17
							2034	138.81

Note: The rates shown in this table have been computed using the Northwest Power and Conservation Council's December 29, 2008 Fuel Price Forecast. (See Order No. 30480).

AVISTA
AVOIDED COST RATES FOR FUELED PROJECTS
SMALLER THAN TEN MEGAWATTS
March 16, 2009
$/MWh

LEVELIZED

CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2009	2010	2011	2012	2013	2014
1	21.26	21.58	21.91	22.23	22.57	22.91
2	21.41	21.74	22.06	22.40	22.73	23.08
3	21.56	21.89	22.22	22.55	22.89	23.24
4	21.71	22.04	22.37	22.71	23.05	23.40
5	21.86	22.19	22.52	22.86	23.20	23.55
6	22.00	22.33	22.67	23.01	23.35	23.71
7	22.14	22.47	22.81	23.15	23.50	23.86
8	22.27	22.61	22.95	23.30	23.65	24.00
9	22.41	22.74	23.09	23.43	23.79	24.15
10	22.54	22.88	23.22	23.57	23.93	24.29
11	22.66	23.00	23.35	23.70	24.06	24.42
12	22.79	23.13	23.48	23.83	24.19	24.56
13	22.91	23.25	23.60	23.96	24.32	24.68
14	23.02	23.37	23.72	24.08	24.44	24.81
15	23.14	23.48	23.84	24.20	24.56	24.93
16	23.25	23.60	23.95	24.31	24.68	25.05
17	23.35	23.70	24.06	24.43	24.79	25.17
18	23.46	23.81	24.17	24.53	24.90	25.28
19	23.56	23.91	24.27	24.64	25.01	25.39
20	23.66	24.01	24.37	24.74	25.12	25.49

NON-LEVELIZED

CONTRACT YEAR	NON-LEVELIZED RATES
2009	21.26
2010	21.58
2011	21.91
2012	22.23
2013	22.57
2014	22.91
2015	23.25
2016	23.61
2017	23.96
2018	24.32
2019	24.69
2020	25.06
2021	25.44
2022	25.82
2023	26.22
2024	26.61
2025	27.01
2026	27.42
2027	27.84
2028	28.26
2029	28.69
2030	29.12
2031	29.56
2032	30.01
2033	30.47
2034	30.93

EFFECTIVE DATE	ADJUSTABLE COMPONENT
3/16/2009	55.21

The total avoided cost rate in each year is the sum of the adjustable component and the fixed component from either of the tables above.

Example 1. A 20-year levelized contract with a 2009 on-line date would receive the following rates:

Years	Rate
1	23.66 + 55.21
2-20	23.66 + Adjustable component in each year

Example 2. A 4-year non-levelized contract with a 2009 on-line date would receive the following rates:

Years	Rate
1	21.26 + 55.21
2	21.58 + Adjustable component in year 2010
3	21.91 + Adjustable component in year 2011
4	22.23 + Adjustable component in year 2012

Note: The rates shown in this table have been computed using the Northwest Power and Conservation Council's December 29, 2008 Fuel Price Forecast. (See Order No. 30480).

IDAHO POWER COMPANY
AVOIDED COST RATES FOR NON-FUELED PROJECTS
SMALLER THAN TEN MEGAWATTS
March 16, 2009
$/MWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2009	2010	2011	2012	2013	2014		
1	76.56	75.65	77.77	80.05	81.95	83.90	2009	76.56
2	76.12	76.67	78.86	80.96	82.89	84.86	2010	75.65
3	76.63	77.71	79.81	81.87	83.82	85.84	2011	77.77
4	77.38	78.65	80.72	82.76	84.75	86.79	2012	80.05
5	78.16	79.54	81.60	83.66	85.67	87.75	2013	81.95
6	78.94	80.40	82.47	84.54	86.58	88.67	2014	83.90
7	79.72	81.26	83.33	85.41	87.47	89.59	2015	85.90
8	80.49	82.08	84.18	86.27	88.35	90.48	2016	88.05
9	81.26	82.90	85.00	87.11	89.21	91.36	2017	90.14
10	82.02	83.70	85.81	87.94	90.05	92.22	2018	92.40
11	82.77	84.49	86.61	88.74	90.88	93.06	2019	94.59
12	83.50	85.25	87.38	89.54	91.69	93.89	2020	96.84
13	84.22	86.00	88.15	90.31	92.48	94.73	2021	99.15
14	84.93	86.73	88.89	91.07	93.28	95.56	2022	101.51
15	85.62	87.44	89.62	91.84	94.08	96.40	2023	103.94
16	86.29	88.14	90.35	92.60	94.87	97.23	2024	106.42
17	86.96	88.84	91.08	93.35	95.66	98.05	2025	108.97
18	87.61	89.53	91.80	94.10	96.45	98.85	2026	112.07
19	88.27	90.22	92.51	94.85	97.20	99.63	2027	115.27
20	88.92	90.90	93.22	95.56	97.94	100.39	2028	118.57
							2029	121.97
							2030	125.47
							2031	128.31
							2032	131.75
							2033	135.29
							2034	138.93

Note: The rates shown in this table have been computed using the Northwest Power and Conservation Council's December 29, 2008 Fuel Price Forecast. (See Order No. 30480). These rates also reflect a change in Idaho Power's weighted cost of capital as a result of Order No. 30722 in the Company's recent general rate case.

IDAHO POWER COMPANY
AVOIDED COST RATES FOR FUELED PROJECTS
SMALLER THAN TEN MEGAWATTS
March 16, 2009
$/MWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2009	2010	2011	2012	2013	2014		
1	21.34	21.67	21.99	22.32	22.66	23.00	2009	21.34
2	21.50	21.82	22.15	22.48	22.82	23.17	2010	21.67
3	21.65	21.98	22.31	22.64	22.98	23.33	2011	21.99
4	21.80	22.13	22.46	22.80	23.14	23.49	2012	22.32
5	21.94	22.28	22.61	22.95	23.30	23.65	2013	22.66
6	22.09	22.42	22.76	23.10	23.45	23.80	2014	23.00
7	22.23	22.56	22.90	23.25	23.60	23.95	2015	23.35
8	22.37	22.70	23.04	23.39	23.74	24.10	2016	23.70
9	22.50	22.84	23.18	23.53	23.89	24.25	2017	24.06
10	22.63	22.97	23.32	23.67	24.03	24.39	2018	24.42
11	22.76	23.10	23.45	23.80	24.16	24.53	2019	24.79
12	22.88	23.23	23.58	23.93	24.30	24.66	2020	25.16
13	23.01	23.35	23.71	24.06	24.43	24.79	2021	25.54
14	23.13	23.47	23.83	24.19	24.55	24.92	2022	25.93
15	23.24	23.59	23.95	24.31	24.67	25.05	2023	26.32
16	23.35	23.71	24.06	24.43	24.79	25.17	2024	26.71
17	23.46	23.82	24.18	24.54	24.91	25.29	2025	27.12
18	23.57	23.93	24.29	24.65	25.02	25.40	2026	27.53
19	23.67	24.03	24.39	24.76	25.14	25.51	2027	27.94
20	23.77	24.13	24.50	24.87	25.24	25.62	2028	28.37
							2029	28.80
							2030	29.23
							2031	29.68
							2032	30.13
							2033	30.58
							2034	31.05

EFFECTIVE DATE	ADJUSTABLE COMPONENT
3/16/2009	55.21

The total avoided cost rate in each year is the sum of the adjustable component and the fixed component from either of the tables above.

Example 1. A 20-year levelized contract with a 2009 on-line date would receive the following rates:

Years	Rate
1	23.77 + 55.21
2-20	23.77 + Adjustable component in each year

Example 2. A 4-year non-levelized contract with a 2009 on-line date would receive the following rates:

Years	Rate
1	21.34 + 55.21
2	21.67 + Adjustable component in year 2010
3	21.99 + Adjustable component in year 2011
4	22.32 + Adjustable component in year 2012

Note: The rates shown in this table have been computed using the Northwest Power and Conservation Council's December 29, 2008 Fuel Price Forecast. (See Order No. 30480). These rates also reflect a change in Idaho Power's weighted cost of capital as a result of Order No. 30722 in the Company's recent general rate case.

PACIFICORP
AVOIDED COST RATES FOR NON-FUELED PROJECTS
SMALLER THAN TEN MEGAWATTS
March 16, 2009
$/MWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2009	2010	2011	2012	2013	2014		
1	76.73	75.83	77.95	80.24	82.14	84.09	2009	76.73
2	76.30	76.85	79.05	81.15	83.08	85.05	2010	75.83
3	76.81	77.89	80.00	82.05	84.00	86.03	2011	77.95
4	77.56	78.83	80.90	82.95	84.94	86.99	2012	80.24
5	78.34	79.72	81.78	83.85	85.86	87.94	2013	82.14
6	79.12	80.58	82.66	84.72	86.77	88.87	2014	84.09
7	79.89	81.44	83.51	85.60	87.66	89.78	2015	86.09
8	80.67	82.26	84.36	86.46	88.54	90.67	2016	88.25
9	81.44	83.08	85.18	87.30	89.39	91.54	2017	90.34
10	82.20	83.88	85.99	88.12	90.23	92.40	2018	92.60
11	82.94	84.66	86.78	88.92	91.06	93.25	2019	94.80
12	83.68	85.42	87.56	89.71	91.87	94.07	2020	97.05
13	84.39	86.17	88.32	90.49	92.66	94.91	2021	99.36
14	85.09	86.90	89.06	91.24	93.45	95.74	2022	101.73
15	85.78	87.61	89.79	92.00	94.25	96.57	2023	104.15
16	86.45	88.30	90.51	92.76	95.04	97.40	2024	106.64
17	87.11	89.00	91.23	93.51	95.83	98.22	2025	109.19
18	87.77	89.69	91.95	94.26	96.60	99.01	2026	112.30
19	88.42	90.37	92.66	95.00	97.35	99.78	2027	115.50
20	89.06	91.05	93.36	95.71	98.09	100.54	2028	118.80
							2029	122.20
							2030	125.71
							2031	128.55
							2032	131.99
							2033	135.54
							2034	139.18

Notes: (1) The rates shown in this table have been computed using the Northwest Power and Conservation Council's December 29, 2008 Fuel Price Forecast. (See Order No. 30480). (2) The rates shown in this table have been computed using the weighted average cost of capital from PacifiCorp's most recent general rate case. (See Order No. 30482).

PACIFICORP
AVOIDED COST RATES FOR FUELED PROJECTS
SMALLER THAN TEN MEGAWATTS
March 16, 2009
$/MWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2009	2010	2011	2012	2013	2014		
1	21.52	21.85	22.17	22.51	22.85	23.19	2009	21.52
2	21.68	22.00	22.33	22.67	23.01	23.36	2010	21.85
3	21.83	22.16	22.49	22.83	23.17	23.52	2011	22.17
4	21.98	22.31	22.65	22.99	23.33	23.68	2012	22.51
5	22.13	22.46	22.80	23.14	23.49	23.84	2013	22.85
6	22.27	22.61	22.95	23.29	23.64	24.00	2014	23.19
7	22.41	22.75	23.09	23.44	23.79	24.15	2015	23.54
8	22.55	22.89	23.23	23.58	23.94	24.30	2016	23.89
9	22.68	23.03	23.37	23.72	24.08	24.44	2017	24.25
10	22.82	23.16	23.51	23.86	24.22	24.59	2018	24.62
11	22.94	23.29	23.64	24.00	24.36	24.73	2019	24.99
12	23.07	23.42	23.77	24.13	24.49	24.86	2020	25.37
13	23.19	23.54	23.90	24.26	24.62	24.99	2021	25.75
14	23.31	23.66	24.02	24.38	24.75	25.12	2022	26.14
15	23.43	23.78	24.14	24.50	24.87	25.25	2023	26.53
16	23.54	23.90	24.26	24.62	24.99	25.37	2024	26.93
17	23.65	24.01	24.37	24.74	25.11	25.49	2025	27.34
18	23.76	24.12	24.48	24.85	25.22	25.60	2026	27.75
19	23.86	24.22	24.59	24.96	25.33	25.72	2027	28.17
20	23.96	24.32	24.69	25.06	25.44	25.82	2028	28.60
							2029	29.03
							2030	29.47
							2031	29.92
							2032	30.37
							2033	30.83
							2034	31.30

EFFECTIVE DATE	ADJUSTABLE COMPONENT
3/16/2009	55.21

The total avoided cost rate in each year is the sum of the adjustable component and the fixed component from either of the tables above.

Example 1. A 20-year levelized contract with a 2009 on-line date would receive the following rates:

Years	Rate
1	23.96 + 55.21
2-20	23.96 + Adjustable component in each year

Example 2. A 4-year non-levelized contract with a 2009 on-line date would receive the following rates:

Years	Rate
1	21.52 + 55.21
2	21.85 + Adjustable component in year 2009
3	22.17 + Adjustable component in year 2010
4	22.51 + Adjustable component in year 2011

Notes: (1) The rates shown in this table have been computed using the Northwest Power and Conservation Council's December 29, 2008 Fuel Price Forecast. (See Order No. 30480). (2) The rates shown in this table have been computed using the weighted average cost of capital from PacifiCorp's most recent general rate case. (See Order No. 30482).

Office of the Secretary
Service Date
March 12, 2009

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE FUEL-COST-RELATED ADJUSTMENT TO PUBLISHED IDAHO AVOIDED COST RATES FOR IDAHO POWER COMPANY, PACIFICORP DBA ROCKY MOUNTAIN POWER, AND AVISTA CORPORATION DBA AVISTA UTILITIES.	)	**CASE NO. GNR-E-09-01**
	)	**ORDER NO. 30744**

Pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA) and the implementing regulations of the Federal Energy Regulatory Commission (FERC), the Idaho Public Utilities Commission (Commission) has approved a Surrogate Avoided Resource (SAR) methodology for calculation of the avoided cost rates paid to PURPA qualifying cogeneration and small power production facilities (QFs) by Idaho Power Company, Avista Corporation and PacifiCorp. Avoided cost rates are the purchase price paid to QFs for purchases of QF capacity and energy.

Three recent events have triggered a revision and updated calculation of new PURPA avoided cost rates, i.e., the conclusion of a general rate case for Idaho Power (Case No. IPC-E-08-10), the Commission's approval of a Stipulation proposing changes to non-fuel variable components of avoided cost rates (Case No. GNR-E-08-02), and the release of a new natural gas price forecast by the Northwest Power and Conservation Council (NPCC; Council).

The conclusion of a general rate case affects avoided cost rates because cost of capital figures are used in avoided cost computations in accordance with the approved methodology. The appropriate time to incorporate new cost of capital figures is following a general rate case. A final Order in Idaho Power's general rate case was issued on January 30, 2009 in Order No. 30722.

Pursuant to Commission-approved avoided cost methodology (Order No. 29124) natural gas prices are to be updated when a new forecast becomes available from the Council or the Council's general advisory committees. Fuel costs are a component in both the fueled rates and non-fueled rates available to QFs. A new Council natural gas price forecast was released on December 29, 2008. Commission Staff provided Idaho Power, Avista and PacifiCorp with worksheets on February 9, 2009 for review and comment showing the computation of the revised avoided cost rates. The proposed changes are made in accordance with existing Commission

Orders and approved methodology. The resultant change in avoided cost rates is a simple arithmetic calculation. The new forecast includes a new starting gas price and fuel escalation rate.

Idaho Power and Avista accept Staff's avoided cost calculations as accurately incorporating the Council's December 29, 2008, revised natural gas price forecasts and as consistent with the Commission's approved SAR methodology.

PacifiCorp in its comments believes that the Council's medium natural gas price curve yields a price that is too high, and is not a true reflection of current gas costs. The Council's price forecast includes five different levels to capture a range of possible outcomes (low, medium-low, medium, medium-high, and high). Citing the Council's description of its low case forecasts, current market "sign posts," and current market forwards, PacifiCorp believes that the Council's low and medium-low price forecasts are a better indicator of current market conditions than the medium case.

PacifiCorp requests that a technical conference be conducted to allow the parties to revisit the existing avoided cost methodology and come up with a solution in light of the current economic forecast. PacifiCorp suggests that the Commission consider updating the price forecast after conditions have become more stable. At a minimum, PacifiCorp requests that the Commission postpone approval of the gas curve component of published avoided cost rates until the Council's draft fuel prices become final.

PacifiCorp states it has received six wind QF project requests totaling 235 MW since January 26, 2009. All of these projects are off-system QFs with scheduled deliveries into an already transmission-constrained area. PacifiCorp reminds the Commission that based on the multi-state Revised Protocol agreement, costs associated with new QF contracts which exceed the costs PacifiCorp would have otherwise incurred acquiring comparable resources will be assigned directly to the state approving those contracts. Case No. PAC-E-02-3, Order No. 29708.

Commission Findings

The Commission has reviewed the filings of record in Case No. GNR-E-09-01 including the comments and recommendations of Idaho Power, PacifiCorp and Avista. We have also reviewed and considered the related comments of Black Canyon LLC and Idaho Windfarms

LLC recommending approval, the underlying Idaho SAR avoided cost methodology, and the Council's December 29, 2008, natural gas price forecast for its Sixth Power Plan.

Presented in this case for Commission approval under existing methodology are revised published avoided cost rates incorporating the Council's December 29, 2008 medium case (east-side delivered) natural gas price forecast (Draft Fuel Prices for the Sixth Power Plan). PacifiCorp contends that use of the Council's medium natural gas price curves results in avoided prices that are too high. PacifiCorp recommends that a technical conference be held to determine the continued reasonableness of the published rate avoided cost methodology. Under the present methodology, rates are changed when the Council issues a new gas price forecast. The calculation of the fuel cost adjustment to published avoided cost rates is arithmetic. PacifiCorp recommends that there be no change until the Council's draft fuel prices become final.

A contemporaneous avoided cost filing before the Commission is Case No. GNR-E-08-02, a Petition seeking Commission approval of a Stipulation proposing changes in generic non-fuel-related Surrogate Avoided Resource (SAR) variables. Petitioners in that case recommended that the generic non-fuel-related values of published rates be implemented at the same time the Commission approves new fuel-related avoided cost components based on the Council's median forecast of natural gas prices. In Order No. 30738 we approved changes in the generic non-fuel cost variables to the SAR methodology. We incorporate those changes in our calculation of the resultant rates in this case. Also incorporated in the revised rates is a utility-specific change in Idaho Power's weighted cost of capital as a result of Order No. 30722 in Idaho Power's recent general rate case.

We addressed PacifiCorp's procedural recommendations in Case No. GNR-E-08-02, Order No. 30738. In that case we denied the relief requested by PacifiCorp stating:

> The question as to reasonableness of rates needs to be based on a foundation and supported by evidence. A single point in time 12-year price strip from the New York Mercantile Exchange (NYMEX) for Henry Hub is not justification for the relief requested by PacifiCorp nor reason to find that published rates for 20-year contracts calculated under our approved methodology no longer represent the utility's avoided costs. The record in this case, we find, does not support the changes in the SAR avoided cost methodology or published rate eligibility cap recommended by PacifiCorp. Nor does PacifiCorp present a persuasive and compelling reason to defer Commission decision regarding a change in the published rates until a record can be built. The uncertainty that would result from granting the relief requested by PacifiCorp is justification

> and reason to proceed in a prudent and judicious manner and to require a greater offering of proof than anecdotal evidence.

Order No. 30738, p. 6.

Our reasoning in Case No. GNR-E-08-02 carries forward into this case where PacifiCorp presents the same arguments. Regarding potential QF projects and scheduled deliveries to PacifiCorp into transmission-constrained areas, we note that this is not an entirely novel issue of the "first impression." Reference Case No. IPC-E-06-21, Order No. 30414. Also meriting mention, in Case No. GNR-E-08-02, the Commission apprised both utilities and QFs that under the Commission's Rules of Procedure, should any party believe that a prima facie case can be made that the existing SAR methodology no longer produces reasonable avoided cost rates, a petition could be filed by such party proposing a change.

The Commission in this case finds it reasonable to approve a change in the fuel-cost component of published rates under the existing SAR methodology. We find the resultant change in avoided cost rates to be a simple arithmetic calculation. At the same time, we find it reasonable to adjust the published rate for changes in the generic non-fuel variables approved in Order No. 30738[1] and the change in Idaho Power's weighted cost of capital from 7.852% to 8.180% approved in Order No. 30722. The Commission has reviewed the revised and updated calculation of the avoided cost rates as set forth in the appendices to this Order and finds that they correctly incorporate the identified changes. See Order No. 30744, Appendices A, B, and C. We find it reasonable to approve the avoided cost rates approved in this Order for QF contracts executed on or subsequent to March 16, 2009.

We take notice of the draft nature of the Council's planning assumptions and fuel forecast and have reasonable confidence that the numbers and values will be used by the Council in its Sixth Power Plan. However, should the numbers and values change appreciably in the Council's final Sixth Power Plan document we will adjust rates accordingly for prospective QF contracts.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over Idaho Power Company, PacifiCorp dba Rocky Mountain Power and Avista Corporation dba Avista Utilities, electric

[1] i.e., Heat Rate 7,100; Equivalent Availability Factor 90%; Capital Cost $1,313 per kW; Variable O&M $1.77 per MWh; Fixed O&M $14.57 per kW; O&M Escalation Rate 2.0%; SAR Escalation Rate 1.4%; and General Inflation Rate 2.0%.

utilities, pursuant to the authority and power granted it under Title 61 of the Idaho Code and the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Commission has authority under PURPA Sections 201 and 210 and the implementing regulations of the Federal Energy Regulatory Commission (FERC), 18 C.F.R. § 292, to set avoided costs, to order electric utilities to enter into fixed-term obligations for the purchase of energy from qualified facilities and to implement FERC rules.

ORDER

In consideration of the foregoing and as more particularly described above IT IS HEREBY ORDERED and the Commission hereby approves changes in the published avoided cost rates incorporating (1) the Northwest Power and Conservation Council's December 29, 2008 medium case (east-side delivered) natural gas price forecast (Draft Fuel Prices for the Sixth Power Plan), (2) the generic non-fuel variable changes approved in Case No. GNR-E-08-02, Order No. 30738, and (3) the change in Idaho Power's weighted cost of capital approved in Order No. 30722. A schedule of new rates accompanies this Order for an authorized effective date of March 16, 2009.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 12th day of March 2009.

MACK A. REDFORD, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

JIM D. KEMPTON, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

bls/O:GNR-E-09-01_sw

FEASIBILITY STUDY REPORT FOR PROJECT #21

October 20, 2009

Tracy Rolstad
Avista System Planning Engineer

Randy Spacek
Avista System Protection Manager

Sharon Vore
Avista Transmission System Forester

Avista Project Account # 77705146

Executive Summary

On September 8, 2009 the Project #21 Developer (Interconnection Customer) entered into a Feasibility Study Agreement with Avista Corporation (Avista) for a proposed 13 MW (maximum output) biomass generating facility, located near Kellogg, Idaho. This project has a projected earliest possible operating date of the summer of 2011.

The Interconnection Feasibility Study Agreement states that Avista will study the possible interconnection of Project #21 at Avista's Pine Creek Substation via the presently de-energized 115 kV line from Government Gulch to Pine Creek. No alternative point of interconnection (POI) was considered.

The goal of this study was to determine interconnection impacts and a cost estimate associated with the integration of Project #21. A power flow study was conducted by Avista's System Planning Group to determine transmission needs. Dynamic studies (i.e. transient stability simulations) were not performed. A short circuit analysis study was completed by the System Protection Group to determine if the existing equipment is adequate for the proposed Project #21 interconnection.

This study evaluated a single option for interconnection:

- Option 1 – Existing Transmission System with re-energization of the existing Government Gulch-Pine Creek 115 kV line (require addition of a single line position at the Pine Creek 115 kV bus).

A summary of total estimated costs is given in Table 1.

Responsibility	Project Requirements	Cost ($)
Interconnection Customer	Government Gulch station (115/13.8 kV-20 MVA xfmr)	$1.5 million
Avista	Re-breaker Pine Creek (add 115 kV breaker)	$300 K
Avista	Perform line clearing on de-energized line	$150 K
Avista	Drop line, clear line, and re-install line	$150 K
Total Estimated Integration Cost (+/- 50%)		$2.1 million

Table 1: Estimated Total Cost of Integration

This project is deemed feasible by Avista provided that the existing Government Gulch-Pine Creek 115 kV is cleared of vegetation and the empty line position (for the Government Gulch line) at Pine Creek is placed back into service (this requires a single 115 kV circuit breaker and attendant equipment).

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Introduction

General

On September 8, 2009 the Project #21 Developer entered into a Feasibility Study Agreement with Avista for a proposed 13 MW biomass generating facility, located near Kellogg, Idaho. Project #21 proposes to interconnect at the terminus of the de-energized (i.e. no longer in service) Avista owned Government Gulch-Pine Creek 115 kV line. A presumed interconnection date of summer 2011 was used for the purposes of this feasibility study. No alternative point of interconnection (POI) was specified in the feasibility study agreement.

This study evaluated one possible option for interconnection:

- Option 1 – Interconnect to the Government Gulch terminus of the Government Gulch-Pine Creek 115 kV line.

Scope of Feasibility Study

This study will evaluate the impact of the proposed interconnection on the reliability of the Transmission System and will consist of a power flow analysis and a short circuit analysis. The study will consider all existing generating facilities, pending higher queued interconnection requests in Avista's queue (including associated identified network upgrades) and interconnection requests on neighboring transmission systems that may have an impact on the studied interconnection request.

The resulting Interconnection Feasibility Study report will include the following information:

- Identification of potential thermal overload or voltage limit violations resulting from the interconnection.
- Identification of any circuit breaker or equipment short circuit capability limits exceeded as a result of the interconnection.
- Initial review of grounding requirements and electric system protection.
- Description and non-binding, good faith estimated cost of facilities required to interconnect the project to the Transmission System and to address the identified power flow and short circuit issues.

All construction costs are in 2009-year dollars and are based on engineering judgment only with +/- 50% error. Neighboring systems were not contacted or involved with this study work. The report provides estimated costs to integrate the plant onto Avista's Transmission System with an assumed cost associated with the station providing the point of interconnection.

Point of Interconnection

The feasibility study agreement states that Avista will study the possible interconnection of Project #21 at the Government Gulch end of Avista's Government Gulch-Pine Creek 115 kV line.

This line is presently de-energized, although it is still owned by Avista. The Government Gulch-Pine Creek 115 kV line historically served a metal smelter load of about 60 MWs. The smelter was demolished in the early 1990's, the Government Gulch load was subsequently lost, and Avista removed the circuit breaker at Pine Creek that served the Government Gulch 115 kV line. The Government Gulch station serving the smelter was removed at the same time the smelter was removed. The Government Gulch-Pine Creek 115 kV line appears to be structurally sound, but it is heavily encumbered with vegetation and will require aggressive line clearing prior to being placed back into service.

Figure 1 depicts the local transmission system for the area surrounding the Point of Interconnection (POI). This is the only interconnection option studied to determine the effects on the local transmission system.

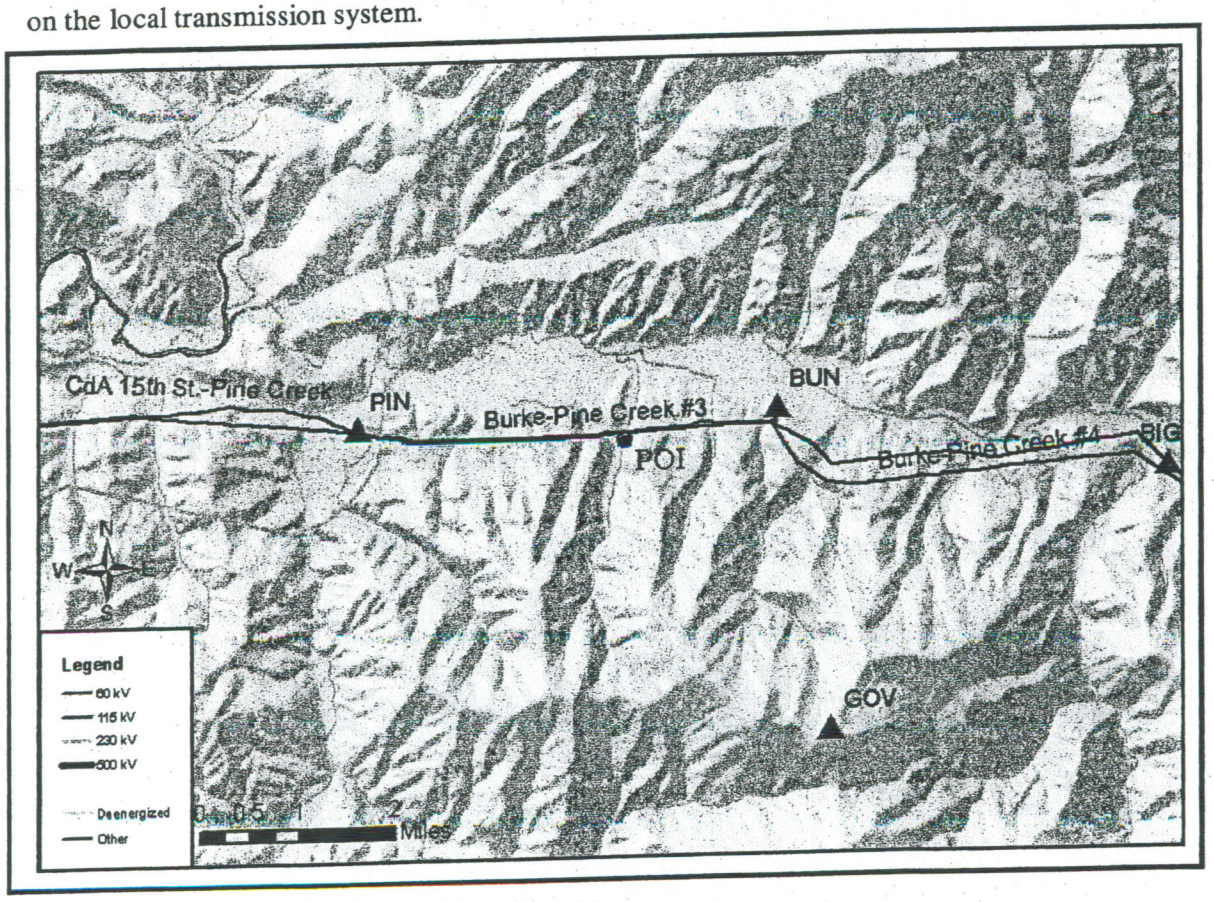


Figure 1: LGIR #21 Area of Interconnection

Figure 2 (from hand-held photography) clearly shows that the line is over grown and will require substantial clearing before the line can be placed back into service.

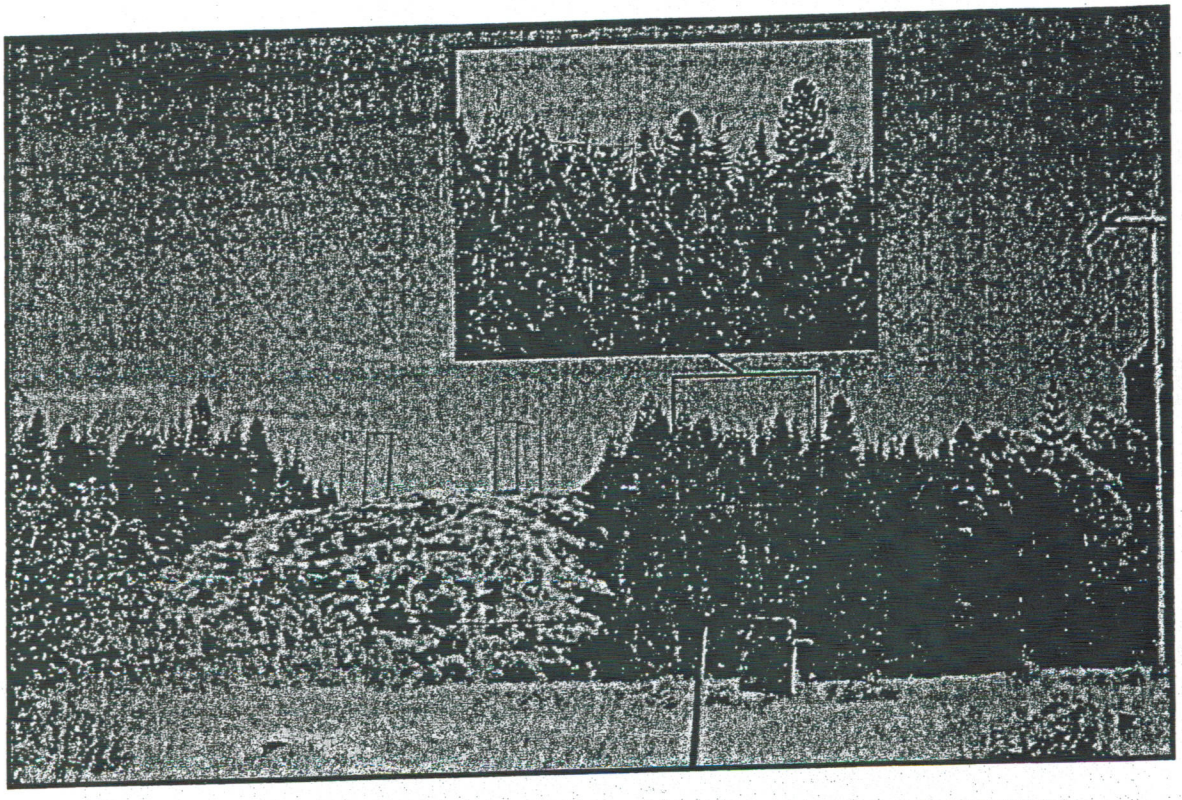


Figure 2: Vegetation Impairment of Government Gulch—Pine Creek 115 kV Line

Note the inset (see Figure #2) which depicts the amount of vegetation that has grown into the H-frame cross arm. The two 115 kV lines located to the left of the Government Gulch-Pine Creek 115 kV line represent the typical appearance of a cleared, in-service transmission line.

Option 1

Interconnect Project #21 at the Government Gulch end of the existing, de-energized Government Gulch-Pine Creek 115 kV line as shown in Figure 3. This option will require Avista to install a 115 kV circuit breaker in the empty line position bay in the Pine Creek. Additionally, Avista will need to perform aggressive and detailed line clearing of the Government Gulch-Creek 115 kV line. Interconnection requirements at the Government Gulch substation (to be supplied by the project developer) are estimated to be $1.5 million. Avista costs for line clearing and breaker installation (at Pine Creek) are estimated to be $600 K. The total estimated cost for Option 1 is $2.1 million (in CY 2009 dollars with a variance of +/- 50%).

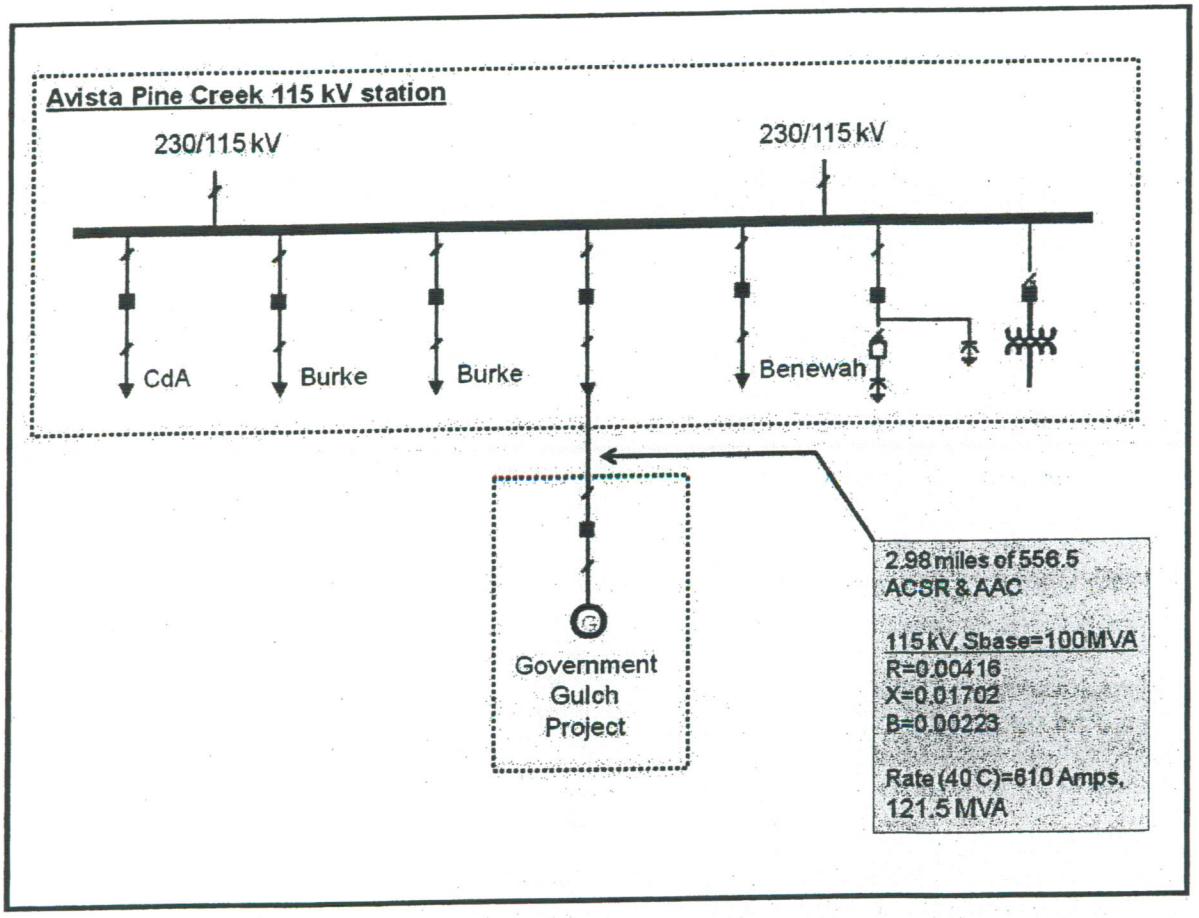


Figure 3: Option 1 – Re-energization of Government Gulch-Pine Creek 115 kV line.

Power Flow Analysis

Procedure

Steady-state power flow simulations were performed to identify any possible thermal or voltage violations as a result of connecting Project #21 to the transmission system with all facilities in service. Preliminary contingency analysis was also performed to identify thermal and voltage violations under N-1 conditions. Results of the analysis were evaluated with the NERC/WECC planning standards under an N-0 and N-1 situation. Additionally, a sensitivity analysis was conducted to provide the customer with information regarding what other parties might be affected by the project interconnection.

This study primarily focuses on the impacts of this interconnection request and solely on the affected transmission line or other interconnection requests that directly impact these results. Note that there are large transmission projects currently being studied both by Avista and by the region as a whole, which may have an impact on the study results and the transmission availability. Since the Western Electricity Coordinating Council (WECC) Regional Planning Process for these proposed transmission network projects are in the preliminary study stages, any of these projects may be further modified to accommodate regional needs. The transmission additions simulated in the study cases, which are necessary to provide Interconnection Service, were based on the best information available at the time the study was initiated. Therefore it is likely that the actual plan of service will differ from the plan of service studied, and Avista reserves the right to restudy this request if necessary.

Transmission impacts identified by this Interconnection Feasibility Study Report are provided for informational purposes only. A complete analysis of the impacts of transmission of Project #21 and the facilities needed to mitigate the impacts would be identified through a transmission System Impact Study and a Facilities Study.

Study Case Development and Description

Case Selection

Historical power flows (from telemetered SCADA analogs) at the Pine Creek substation were analyzed in order to determine what particular loading scenario should be studied for the purposes on integrating Project #21. The general flow pattern is shown in Figure #4. An inspection of the flows across the two 230/115 kV transformers at the Pine Creek station indicates that power flows in both direction; that is power flows ***from*** the 230 kV to the 115 kV system during heavier loading conditions and ***to*** the 230 kV system from the 115 kV during light loading conditions. Considering the small size of proposed generator (i.e. 13 MW) it is clear that generator ***reduces*** loading for flows from the 230 kV to 115 kV system. The generator ***increases*** loading for flows from the 115 kV to 230 kV system. Accordingly, Avista selected a single loading condition as relevant for studying the interconnection of Project #21. The case deemed relevant was the Light Summer loading scenario.

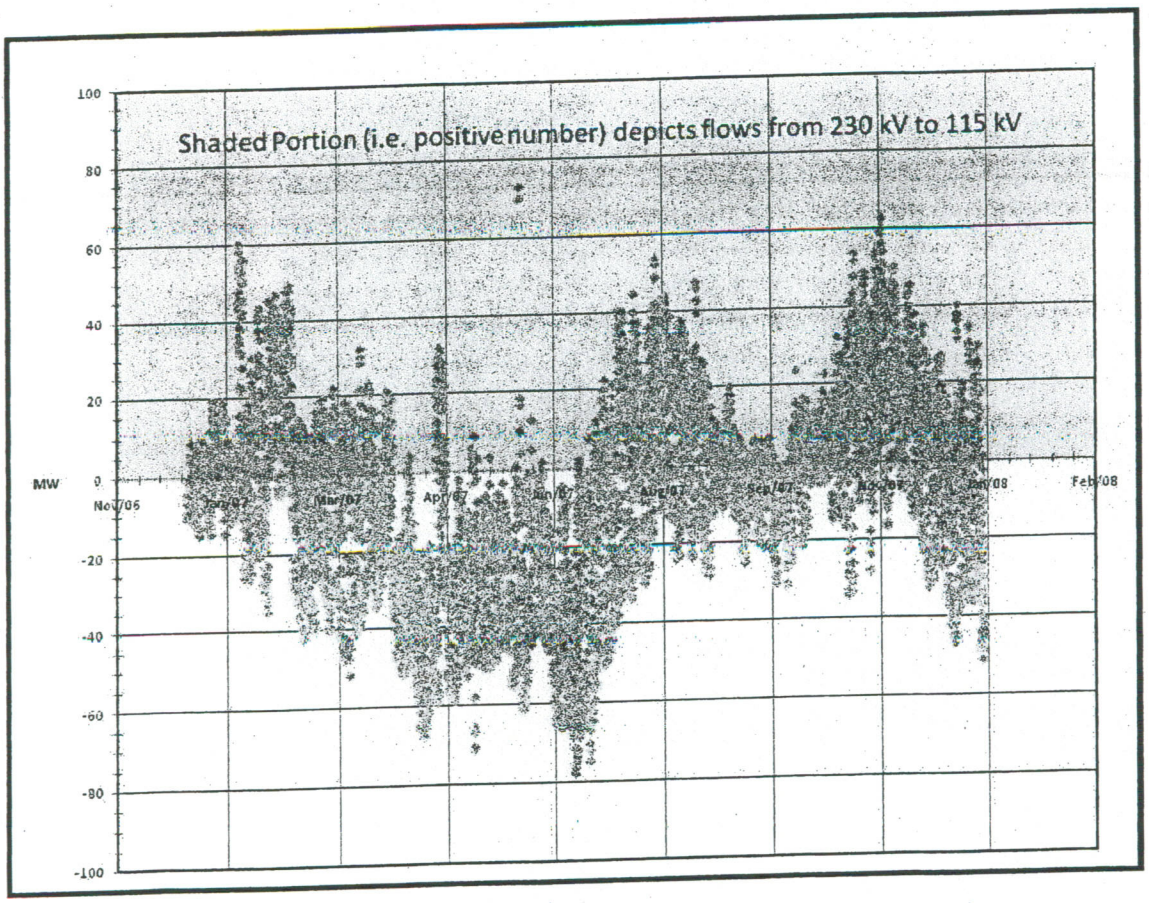


Figure 4: Historical Flows (total) across Pine Creek 230/115 kV transformers.

2009 Light Summer with High West of Hatwai Flows (Light Summer Case)

During light summer (night time loading), high western Montana hydro and high Montana thermal generation, the WECC rated path "West of Hatwai" (WECC Path #6) reaches its heaviest loading. During this scenario, elements of the transmission system are nearing their stability limits. These limits define some of the operating constraints for the region and also establish some of the trigger points for local Remedial Action Schemes (RAS). This case is also limited by the summer normal and emergency thermal limits on all transmission equipment, which helps to indicate where the system is near capacity in normal and contingency operation. Higher queued generation was modeled only if Project #21 was sensitive to the superior queue position generation. A summary of the case MW flows is shown in Table 2.

The WECC approved light summer case **09ls1a** was used with the following modifications:

- Avista Balancing Area loads were set at 50% of 2009 summer peak, 1047 MW
- Adjusted path flows for high West of Hatwai flows, per Avista guideline
- Added Project #21 biomass facility, set at 100% capacity, adding 13 MW

Western Montana Hydro	1670.7
Noxon Rapids (562MW)	520.5 MW
Cabinet Gorge (265MW)	230.2 MW
Libby (605MW)	540.0 MW
Hungry Horse (430MW)	380.0 MW
Colstrip Total	
Colstrip 1 (330MW)	330.0 MW
Colstrip 2 (330MW)	330.0 MW
Colstrip 3 (823MW)	823.0 MW
Colstrip 4 (823MW)	823.0 MW
Rathdrum Thermal (175MW)	0.0 MW
Lancaster Thermal (270MW)	223.7 MW
Spokane River Hydro	182.2 MW
Boundary Hydro (1040MW)	980.0 MW
Lower Snake/N.F. Clearwater	
Dworshak (458MW)	387.9 MW
Lower Granite (930MW)	113.7 MW
Little Goose (930MW)	112.7 MW
Lower Monumental (930MW)	127.7 MW
Coulee Generation	
Coulee 500 kV	1228.0
Coulee 230 kV	394.9 MW
SE Washington Wind	0.0 MW
NE Oregon Wind	30.0 MW

West of Hatwai (Path 6)	3763.3
Lolo-Oxbow 230kV	155.5 MW
Dry Creek-Walla Walla 230kV	126.9 MW
West of Cabinet	3190.9
Montana-Northwest (Path 8)	1839.0
Idaho-Northwest (Path 14)	678.1 MW
Midpoint-Summer Lake (Path	744.6 MW
Idaho-Montana (Path 18)	-175.8
South of Boundary	979.1 MW
North of John Day (Path 73)	4882.5
TOT 4A (Path 37)	215.3 MW
Miles City DC	136.0 MW
Path C (Path 20)	146.5 MW
Borah West (Path 17)	1400.4
Bridger West (Path 19)	2017.4
Pacific AC Intertie (Path 66)	2902.6
Pacific DC Intertie (Path 65)	1999.7
Northwest Load	17563.5
Avista Load	975.1 MW
Avista Native Load	829.2 MW
Avista Control Area Load	1066.9
Clearwater Load	60.2 MW
Idaho Load	2565.5
Montana Load	1373.0

Table 2: Light Summer Case loadings.

Power Flow Analysis Results

Option 1

The Light Summer Case was modified through generation re-dispatch to accommodate the additional 13 MW of Project #21's generation output. The decremented generation was a composite injection group that included all of Avista's "internal" generation (this precluded decrementing Colstrip, Coyote Springs II, or Avista's contractual share of the Mid-Columbia).

Note that given the very small size of Project #21 no individual Avista generator moved more than 1 MW, in fact, all of the generation moved substantially less than 1 MW. The full gamut of Avista contingencies was simulated and no adverse impacts due to Project #21 were noted.

The only point of concern associated with integrating Project #21 is that the presence of Project #21 increases loading on an operationally significant "star point." The star point is the normally open Benewah-Pine Creek 115 kV line. This line is normally open at the Ogara substation as part of Avista's "Star Network" program. The use of star networks allows sectionalizing of Avista's 115 kV network in various strategic locations in order to minimize losses and prevent the through flow of power in the 115 kV system.

Avista requires operational flexibility such that these open star points can be closed by Avista's System Operators as needed. The difference in loading across the open star point at Ogara can be seen by comparing Figures 5, 6, & 7. The increased loading across the Ogara star point is ~2% (91% to 93%). The generator at Government Gulch causes the loading on the closed-in star point to go from 279.2 Amps/55.8 MVA (i.e. 91%) to 287.5Amps/57.5 MVA (i.e. 93%). The loading is presently acceptable, but may be of concern in the future. The 115 kV line from Benewah to Pine Creek serves Plummer, Ogara, and St. Maries Idaho. The limiting conductor type is 7#7 Cu and 2/0 CU 7S with the newer portions of this line using 556.5 AAC and 556.5 ACSR.

Avista deems Project #21 feasible at its proposed maximum generation output of 13 MW.

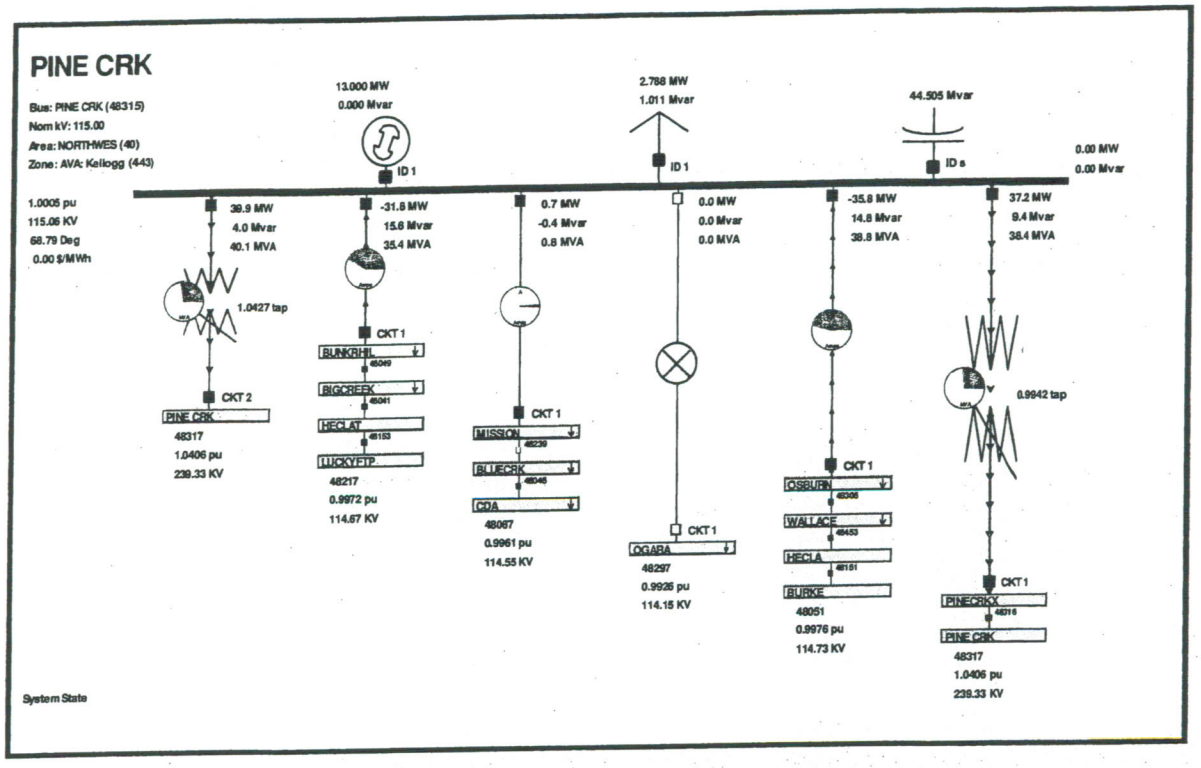


Figure 5: Open Star Point, Generation at Maximum

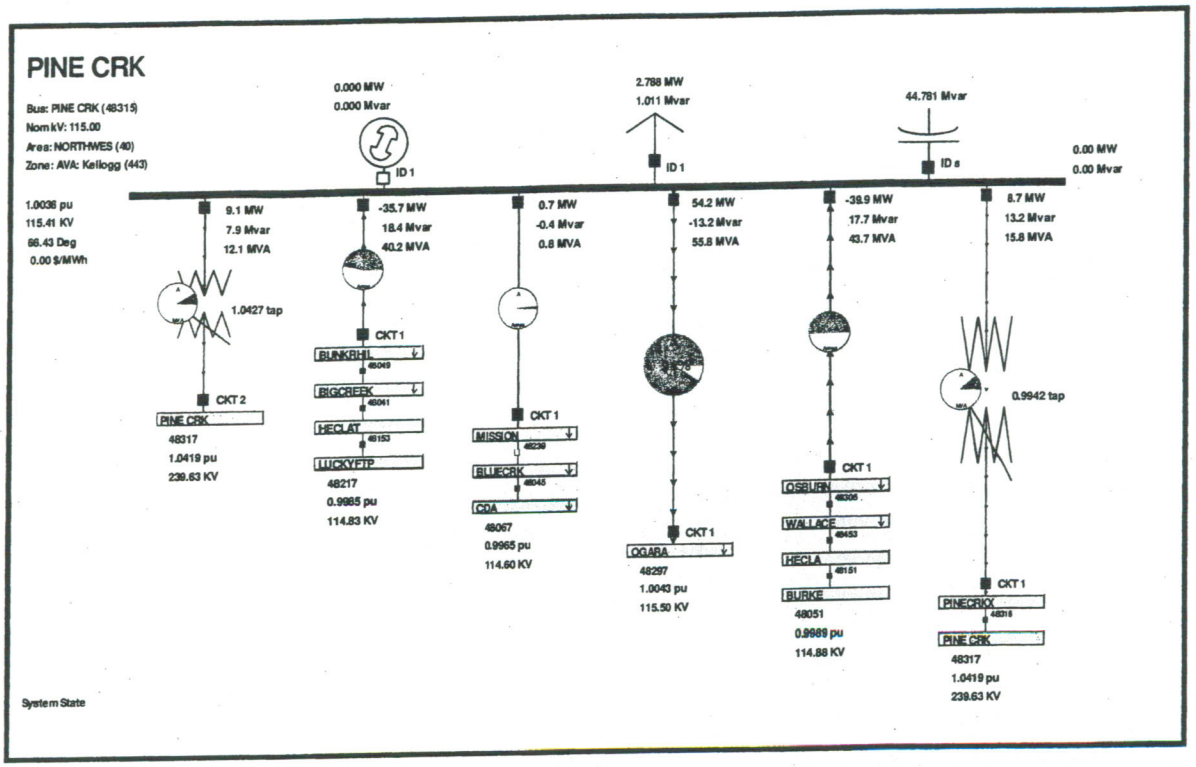


Figure 6: Closed Star Point, Generation Off

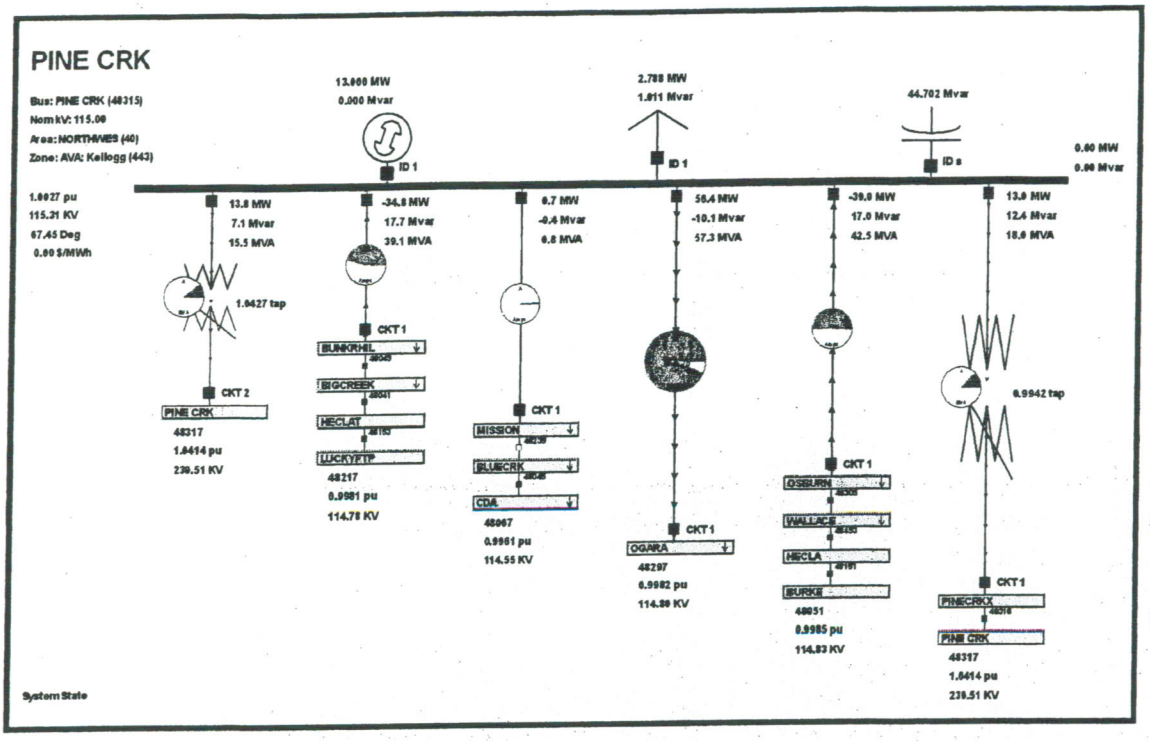


Figure 7: Closed Star Point, Generation at Maximum

Contingency Violation Summary

No contingencies were noted as being sensitive to Project #21.

Impacted Transmission Facilities

Sensitivity analysis was performed in order to determine the various affected transmission facilities and WECC monitored paths for the proposed Project #21 interconnection. This analysis was completed through the use of the Power Transfer Distribution Factor (PTDF) tool within PowerWorld Simulator.

This tool provides the change in power flow on the transmission lines for an incremental increase in generation at a specified point of receipt while a second specified point of delivery absorbs such an increment. The method of calculating these sensitivities is based purely on the system topology and not a specific operating condition. The POR modeled was the proposed generation facility and the POD was all Avista loads (without a transmission agreement for POD or balancing, this sensitivity analysis best identifies impacted parties). A review of the results indicates that the affected parties that should be informed of the Project #21 interconnection process include the following:

- Avista Corporation (conducted the Feasibility Study - deemed as informed),

Short Circuit Analysis

General

Project #21 is a proposed 13 MW biomass steam turbine in Shoshone County Idaho (near Government Gulch) approximately 3 miles from the Pine Creek Station. An existing de-energized 115 kV line from Pine Creek to Government Gulch will be utilized for the POI. For the purposes of the System Protection Feasibility Study, the generation POI will be the Pine Creek 115 kV breaker position. The assumptions for the Project #21 model are:

1. The facility topology is single generator with a generator breaker, a station GSU transformer with a 115 kV breaker and station service from the low voltage bus.

2. 1 - 20 MVA delta-wye step up 2 winding transformer 13.8/115 kV with 7 to 10% impedance and an X/R ratio in the range of 30 to 50.

3. 1 – 13 Megawatt synchronous generator.

ASPEN Model Development

Station Transformer

The 115/13.8 kV 20 MVA transformer connected wye-delta impedance percentages were based on Spokane Waste to Energy Plant of 25 MVA transformer (which represents a deployed, reasonable proxy for Project #13). The impedances are as follows:

- Z1 = 0.01556 + j0.46667

- Z0 = 0.0154 + j0.462

Generator

The 13 MVA generator impedance percentages were based on Spokane's Waste to Energy Plant of a single 30 MVA generator. Equating the 13 MVA generator impedances to the 30 MVA base a multiplying factor of 30/13 is used. The impedances are as follows:

- Z1 = 2.3(0.02708 + j 0.4333) = 0.062284 + j0.99659
-

All reactance values were set equal except the Z0 which was set to infinity representing a high impedance ground.

Fault Analysis Study

A short circuit analysis study was performed to determine if Avista's installed equipment is adequate for the proposed Project #21 POI. ***All star points around the Pine Creek Station were closed to provide the maximum fault duty expected***. The following analysis was performed:

1. Perform 3LG close in faults on each line terminal breaker at affected buses by the interconnection.

2. Perform 3LG at each 115 kV bus at affected substations.

3. Compare resulting fault duties to breaker or power fuse interrupt ratings.

Fault Duty Comparisons

The changes in fault duties due to addition of the Project #21 generation networked to Pine Creek are shown below in Table 3.

System Location	3LG w/out Generation	3LG with Generation	Percent Change	1LG w/out Generation	1LG with Generation	Percent Change
Pine Creek 115kV Bus	11441	11724	2.5	12248	12443	2.4
BEN-PIN 115kV Line	9726	9979	2.3	10617	10761	1.4
BUR-PIN #3 Line	10161	10428	2.6	11332	11499	1.5
BUR-PIN #4 Line	10183	10450	2.6	11294	11460	1.5
CDA-PIN 115kV Line	9204	9476	2.9	10863	11018	1.4

Table 3: Fault Duties

Station Breaker/Device Ratings

The Pine Creek 115 kV station breaker interrupting ratings are 40 kA symmetrical.

Short Circuit Analysis Summary

The results show integrating Project #21 generation onto Avista's 115 kV system at the Pine Creek Station increased fault duties an average of 2.5%. All fault duties are under the interrupting rating of the existing breakers expected to clear the faults.

Conclusion

Project #21 is a feasible project based on the analysis performed. The power flow and short circuit analysis considered a single option with the point of interconnection at the terminus of the Government Gulch-Pine Creek 115 kV line.

A total estimate of costs is given in Table 4. .

Responsibility	Project Requirements	Cost ($)
Interconnection Customer	Government Gulch station (115/13.8 kV-20 MVA xfmr)	$1.5 million
Avista	Re-breaker Pine Creek (add 115 kV breaker)	$300 K
Avista	Perform line clearing on de-energized line	$150 K
Avista	Drop line, clear line, and re-install line	$150K
Total Estimated Integration Cost (+/- 50%)		$2.1 million

Table 4: Option summary.

All construction costs are in 2009-year dollars and are based on engineering judgment only with +/- 50% error. These cost estimates assume that the Project #21 owners are responsible for the cost of building a 115 kV substation at Government Gulch. Detailed cost figures will be determined during future studies.

Section 5 Emissions/Permitting

A. OVERVIEW

The process for obtaining the required air and land permits for a renewable energy facility can be complicated, difficult and time consuming. In general the steps required to obtain these permits require a defined fuel source, an accurate emissions model including fugitive emissions from the site, coordinating with and meeting the requirements of the various entities involved, namely the DEQ and EPA, and stepping through the appropriate procedures to comply with the Clean Air Act permitting process. If the renewable energy facility has a garbage component to the fuel supply, the emissions model will become much more complicated, and the DEQ may require meteorological data to be collected from the site for one full year. Also, if any garbage is going to be stored on site it may be necessary to obtain a land permit, which is an entirely separate process.

Fortunately for this project, all four of the potential project sites are not located in "nonattainment areas", see Figure 1 below. The Clean Air Act and Amendments of 1990 define a nonattainment area as a locality where air pollution levels persistently exceed National Ambient Air Quality Standards or that contributes to ambient air quality in a nearby area that fails to meet standards. Designating an area as nonattainment is a formal rulemaking process, and EPA normally takes this action only after air quality standards have been exceeded for several consecutive years. Nonattainment areas are given a classification based on the severity of the violation and the type of air quality standard they exceed. EPA designations of nonattainment areas are only based on violations of national air quality standards for carbon monoxide, lead, ozone (1-hour), particulate matter (PM-10), and sulfur dioxide. EPA has not yet designated areas based on the newer 8-hour ozone or PM 2.5 standards. For reference, there are four non attainment areas in Idaho and all four areas exceed the PM-10 particulate air quality standards.

Even though the renewable energy facility will not be located in a nonattainment area, the entire Silver Valley is subject to a massive inversion layer which limits dispersion of particulates and emissions. The emissions model that will be developed during later stages of project development will address this complexity and develop a series of solutions so air quality in the Silver Valley is improved over existing conditions, where slash piles are burned throughout the year and the Silver Valley becomes choked with smoke.

Whether the REF has a 100% biomass feed stock, or a combination of biomass and MSW, the REF will be a single point emitter of various items including particulate, CO2, and various other items. It will be extremely important to develop a fact sheet that explains the emissions potential from the REF, as well as the overall carbon cycle of existing slash burning and land filling to garner as much public support as possible. While emissions studies are a very scientific process, public opposition can and probably will assert itself in the absence of fact and the perception of "pollution" at the REF.

In order to define the "worst case" emissions potential of the REF, McKinstry completed a preliminary emissions process study that evaluated the various processes as set forth by the EPA and Idaho DEQ, and this study is included in the appendix for reference. This study is based on MSW comprising 100% of the feed stock.

Idaho Nonattainment Areas

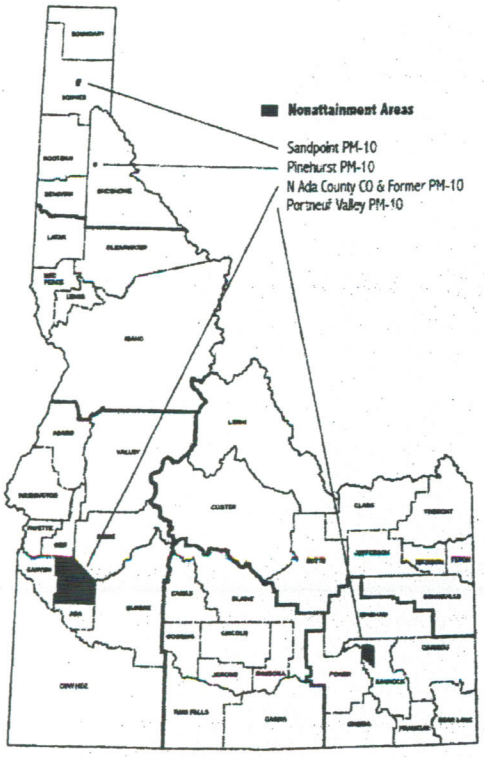


Figure 1: Idaho Nonattainment Map

B. NEXT STEPS

Next steps for the emissions category can only be completed after the fuel supply for the renewable energy facility is defined. Once this is known, if the feed stock is biomass or a combination of MSW and biomass, it will then be possible to define the permits required (air, land, etc), the entire permitting process, coordinating with appropriate Idaho DEQ and EPA personnel. As well as the lead time associated with the required permits, and the abatement equipment and processes required.

Section 6 Preliminary Scope Development

A. OVERVIEW

McKinstry has worked diligently to provide basic preliminary scope development services as part of this feasibility study. Scope development actions taken to date can be broken into the following categories: preliminary process flow diagram, preliminary boiler analysis, emissions process review, waste heat user analysis, preliminary site layout, and Avista Interconnection.

Preliminary Process Flow Diagram: Thomas Engineering Company (TEC) has prepared a steam driven, electricity generation process flow diagram specifically for the Shoshone County project that shows estimated mass flows for the various cycles of the renewable energy facility. While these mass flow quantities are estimated, they do provide a ballpark estimate and will aid with future scoping discussions, equipment selection, and cost estimating. This mass flow diagram is included in this section of the report.

Preliminary Boiler Analysis: Energy Products of Idaho (EPI) has prepared a preliminary boiler analysis that details fuel requirements for a wood and garbage mixture, consumables required for emissions abatement and ash quenching, a basis of design for the boiler, a process description, and a few other key items such as schedule, preliminary cost, and other equipment required. EPI has requested that their report stay confidential, so it is not included in this report, however it is available upon request.

Emissions Process Review: McKinstry completed a preliminary emissions process study that evaluated the various processes as set forth by the EPA and Idaho DEQ, and this study is included in the appendix for reference. This study is based on MSW comprising 100% of the feed stock, which serves as a "worst case"; however, this study does provide some guidelines for future consideration.

Waste Heat User Analysis: Based on EPI's above mentioned report, McKinstry was able to estimate the amount of energy available from the stack gasses for an industrial process, such as a pellet manufacturer. Preliminary estimates show the stack gasses, after the economizer, can support a pellet plant that produces 40,000 tons of pellets per year and would provide a cost advantage to the pellet manufacturer of approximately $16 per ton, while generating approximately $625,000 annually for the renewable energy facility.

Preliminary Site Layout: the Government Gulch site is relatively long and has existing road access along the entire length of one side of the parcel, which would facilitate access for the renewable energy facility truck traffic as well as traffic from a co-located industrial and/or commercial entity. While no formal site layout has been prepared for this feasibility study report, the overall size, orientation and road access contribute to the site being well suited for the intended use.

Utility Interconnection: McKinstry has coordinated with Avista on two separate fronts, with the transmission group and also with the power purchase group. To date, McKinstry has contracted with the transmission group to perform an Interconnection Feasibility Study, which will is complete and included in section 4 of this report. McKinstry has also held conversations with Avista's power purchase to group to verify the general parameters of the renewable energy facility, and also to ensure the power purchase agreement associated with the facility is consistent with what the Idaho PUC recently published for non-fueled power producers.

B. PELLET MANUFACTURER ANLAYSIS

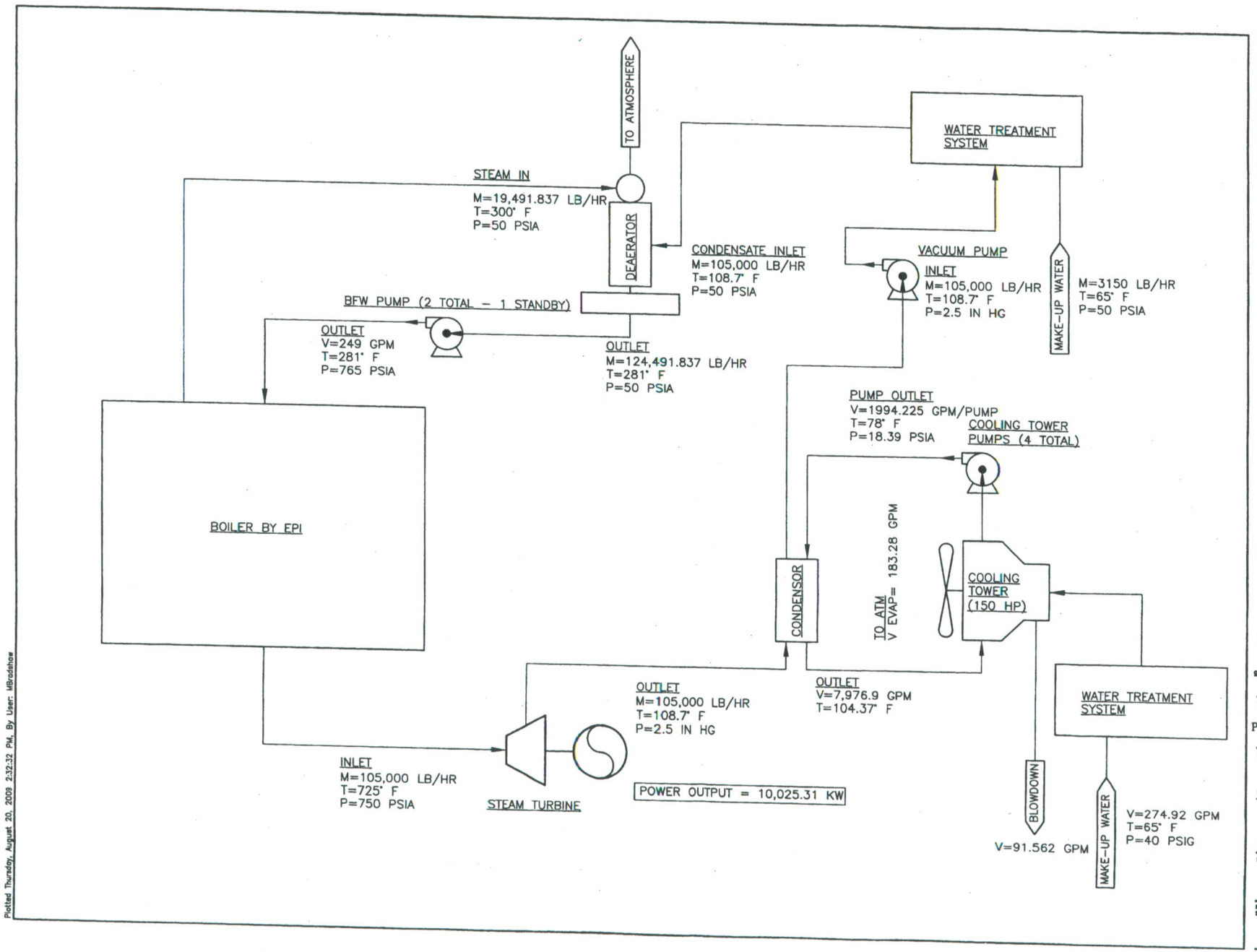
All pellet manufactures must dry their material before processing to about 10% moisture content. There are a couple of ways to accomplish the drying including a natural gas heated drum, or heating the drum with wood that could used for pellets. For the purposes of this analysis it is assumed that the drum dryer would be heated with either waste heat from the stack or with steam from the REF, and that the green wood delivered to the pellet

plant has 40% moisture content. If the pellet plant is purchasing wood at $60 per green ton and paying the REF $625,000 per year for steam or waste heat, preliminary estimates show that the pellet plant can afford to sell pellets at a discount of $16.38 per ton. This provides the pellet manufacturer with a competitive advantage and an incentive to co-locate with the REF.

A few items to note are that a larger pellet plant can be co-located with the REF, however stack heat will be insufficient to heat the drum dryer. Further analysis is required to determine the optimal pellet plant size because if waste heat can be diverted before the cooling towers, overall cycle efficiency of the REF will greatly improve, creating a cogeneration cycle instead of a condensing cycle. As has been stated before, the amount of feed stock available will ultimately be the deciding factor in the electricity generation capacity of the REF and the size and type of the co-located industry or commercial entity.

C. NEXT STEPS

Next steps for the Scope Development can be completed once the type and quantity of feed stock is verified. Future activities include process/technology selection, identifying equipment and lead times, developing design documents, designing infrastructure for steam connection to a co-located heat user, and finalizing a site plan. This engineering will happen in later phases of project development and will serve as the backbone of the future business plan for the renewable energy facility.



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brent_t@thomasengr.com

REVISIONS:

△	24.4.09	
△ FLOW DIAGRAM W/O PRESSURE LOADS	20.07.09	
△		
△		
△		

STAMP:

CLIENT:
MCKINSTRY ESSENTION INC.
9 S. WASHINGTON STREET, STE 605
SPOKANE, WA
509-747-3389

PROJECT:
STEAM GENERATOR PROCESS FLOW DIAGRAM

ISSUE:
PRELIMINARY LAYOUT

DATE: JULY 24 2009

DRAWN BY:
CHECKED BY:
DATE:
DRAWING SCALE:

SHEET NAME:

PROJECT NO:
SHEET NO: 09014

Plotted Thursday, August 20, 2009 2:32:32 PM, By User: MBradshaw

Section 7 Project Financials

A. OVERVIEW

The current economic recession presents specific challenges for funding supply-side energy projects in today's financial lending markets. However, funding for this project will be specifically engineered to take advantage of a public/private partnership between Shoshone County and McKinstry, inclusive of other potential equity partners, and possibly the City of Kellogg. Whereas wholly private projects are particularly difficult to fund, public/private partnerships that provide for a tax-exempt municipal funding mechanism, for example industrial revenue bonds, are a preferred option in today's capital lending market.

It is assumed that this project will likely be funded by some form of tax-exempt municipal revenue bond. Unlike General Obligation Bonds, Revenue Bonds do not obligate local taxpayers for project funding. Although they do not obligate local taxpayers, revenue bonds may still require a super-majority vote of the public to approve funding, although pending Idaho State legislation may remove this requirement.

Whereas the current PURPA (Public Utility Regulatory Policies Act) & FERC (Federal Energy Regulatory Commission) provide for a cost-avoided power purchase agreements for up to 20 years, biomass fuel project funding will require significant guarantees for the delivery of fuel necessary to meet the contractual requirements for electric generation. Therefore, prior to funding, fuel resources, contract terms, and performance guarantees must be in place to insure that power generation disruption does not occur. Final technical and financial analysis may also determine an optimum project production capacity of greater than 10 megawatts, but less than 20 megawatts and the best capital to revenue ratio. Whatever the final plant capacity, fuel verification and guarantees will be a critical component to securing financing.

B. AVAILABLE SUBSIDIES AND GRANTS

Shoshone County's biomass generation project must ideally stand on its own financial legs, without the necessity for grants or financing subsidies to make it financially feasible over a 10-20 year period. However, grants, financing subsidies, REC's, carbon credits, etc. do result in significantly improved return on investment (ROI). The more financial leverage this project can include using grants and subsidies, the easier it will be to secure financing/funding due to the decreased risks against performance shortfalls.

The financing approach will be designed to take advantage of as many of the following incentives and financing options as possible: Renewable Energy Credits ($5 per MWh in the Northwest, potentially higher in California), Federal Tax Credit (10% of project total capitalized in lieu of multi-year tax credits), Carbon Credits (est. $500K - $1M per 10MW biomass plant), Federal Stimulus Funding Matching Grants for biomass generation, Fuel transportation tax credits, Federal CREBs – Clean Renewable Energy Bonds – 0% financing, USDA Rural Development Loan Guarantee Funds, USDA Rural Development Grants, Business Energy Tax Credits (potential Idaho legislation), Tax Exempt Municipal Revenue Bonds, Private Equity Investment Partners.

Tax structure incentives that presently exist to support the fuel supply chain for a biomass REF include tax subsides for landowners through counting gains or losses from timber sales as capital gains instead of income, allowing for depreciation of equipment and maintenance costs to be accounted for as expenses, and the Reforestation Amortization and Tax Credit allows for itemized deduction of various expenses related to reforestation.

Federal direct spending programs that presently exist are Biomass Crop Assistance Program through the Farm Service Agency, which is a dollar for dollar match per bone dry ton of delivered biomass, grants through the USFS made possible by the Recovery Act of 2009, the following link details a list of projects per state, http://fs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb5098109.pdf, and the Fuels for Schools program through the Forest Service and IDL.

Pending legislation that have the potential to make more federal dollars available for biomass renewable energy facilities include the National Forest Insect and Disease Emergency Act of 2009, and the Waxman-Markey climate and energy bill—aka the American Clean Energy and Security Act.

C. REVENUE SOURCES AND OPERATIONAL EXPENSES

Immediately following the language in this section of the report are seven preliminary financial models, one for each of the operational scenarios that McKinstry has identified as most probable to be implemented. The preliminary financial models, or simplified cash flows, are a simplified snap shot of the projected financial performance of the renewable energy facility under various operational scenarios. As can be seen by the list below, there are many inputs to the preliminary financial models, and McKinstry has worked diligently to determine a reasonable value for each input. Please note that the explanation for each of the revenue sources and operational expenses below are in relation to a 10MW woody biomass facility.

Revenue Sources:

Electricity Sales bundled With REC's: at $98 per MWhr ($93 in electricity sales, $5 in REC's), a rated output of 10MW, and 340 days per year of 24 hour operation, the total revenue potential of electricity sales is approximately $7.98 million annually. This will increase substantially if a capacity greater than 10MW can be sustained through fuel procurement and resources, even though the power sales rate per MWh would decrease.

Carbon Credits: there is potential for the renewable energy facility to market carbon credits, even if the fuel supply contains garbage. As federal legislation on this topic is ever-changing, this potential revenue source will require further definition in future phases of project development. Currently carbon offset credits have a value of approximately $7 per metric ton of offset carbon. These are typically purchased in 15 year offset volumes. However, it is likely that the value of the carbon offsets will increase substantially; if the US adopts a carbon policy or tax of some kind. Therefore, it may be preferred to keep and "bank" the carbon offsets. For the purposes of this analysis, $500,000 in carbon credits has been included in the cash flow.

Tipping Fees: if the fuel supply of the renewable energy facility contains garbage, it will be possible to charge a tipping fee of Shoshone County (and possibly other sources as well). This tipping fee is negotiable however preliminary estimates show revenue potential around $540k annually, if the REF only accepts MSW from Shoshone County. Revenue potential jumps dramatically if adjacent County MSW is accepted.

Waste Heat: it may be possible to co-locate a separate business entity with the renewable energy facility and sell this entity process heat at a rate less than the cost of natural gas. There are many potential entities to co-locate, include a wood pellet facility that could utilize waste heat from the stack to produce approximately 40,000 tons of densified wood pellets each year. This would allow for synergies between the plant of reducing the pellet manufacturer's production costs and generating a revenue source for the renewable energy facility of approximately $625,000 annually.

Tax Credits/Grants/Other Subsidies: while McKinstry and Shoshone County are actively pursuing each of these avenues, estimates for each category of outside capital combined have only been developed at a very high level of 30% of the first cost of construction in the form of grants, Other items that can dramatically improve the financial performance of the renewable energy facility are federal tax credits and pending legislation regarding biomass transportation subsidies, business energy tax credits and new grant programs designed to promote renewable energy facilities. McKinstry has included a summary of American Reinvestment and Recovery Act (ARRA) Appropriated Bonds in this section of the report for reference.

Operational Expenses:

Debt Service: preliminary estimates show an initial capital cost of approximately $3 million per MW, or $30 million for a 10 MW facility. Assuming total grant value equal to 30% of the initial cost, debt service on the remaining $21 million over 20 years is approximately $2.06 million annually at an assumed interest rate of 9%. The actual cost of the facility may be less if used, but fully-warranted equipment is located and purchased at a significant discount.

Woody Biomass: based on the preliminary cash flows, the allowable cost of delivered biomass to the renewable energy facility would range between $30 and $39 per dry ton, which equates to roughly $46 to $60 per green ton. This estimate of delivered cost per green ton is known to be highly variable because presently there is not a

large market for biomass wood chips in Shoshone County and there is no market for pulp logs, slash piles, dead trees, etc. After the renewable energy facility is constructed, both markets will be created, and the cost per green ton may be driven down dramatically, based on economies of scale. Preliminary engineering estimates show a total use of approximately 85,000 dry tons of biomass per year, for a fuel cost of approximately $2.7 million annually at $32 per dry ton, or $49 per green ton at 35% moisture content. For the purposes of this analysis it is assumed that the delivered cost of biomass would escalate 3% annually.

Employees: With a fuel supply of 100% biomass, preliminary estimates show a full time workforce of approximately 15 people to operate all aspects of the renewable energy facility for 24x7 operations. Assuming an average salary of $40,000 per year with 42% burden; the total cost of the labor force at the facility would be $850,000 annually.

Maintenance and Repairs: preliminary estimates show an operational and repair allowance of $4.00 per MWh of electricity produced. For the renewable energy facility this equates to approximately $326,000 annually.

Consumables: the renewable energy facility will consume various resources including natural gas, water, and lime. The rate that these resources will be consumed varies depending on whether the fuel stream includes garbage or not, as garbage requires more resources to abate emissions and quench the ash. Preliminary cost estimates for consumables for a 100% biomass plant are approximately $84,000 annually.

Ash Disposal: the renewable energy facility will generate a significant amount of ash that will need to be disposed of or used in some manner in another process. If the fuel source is 100% biomass, the ash is an inert material that has a variety of industrial, commercial and agricultural uses. If the fuel source contains garbage, the ash may have significant levels of heavy metals which may classify the ash as something other than inert and increase the cost of disposal. Based on the fuel supply being 100% biomass, preliminary cost estimates for ash disposal are $42,500 annually.

Taxes and Land Lease: the level of taxation on the renewable energy facility will depend on the level of revenue generated and also the overall financial performance of the facility. Also, the cost of land lease will vary depending on the amount of land the renewable energy facility requires. At this point, McKinstry is assuming the land lease will be fixed at $200k per year and the use and sales taxes on total electricity sales will be deferred during the debt period.

D. NEXT STEPS

Next steps in the project financials category can be accomplished once the fuel supply type and quantity is validated. It appears that the fuel supply will be comprised of residual slash from timber and resource sales, adding lodge pole stands to these timber sales, residual slash from fire mitigation efforts, and unhealthy, dead or dying trees that would be cleared as part of IDL, BLM, and USFS timber sales, as well as City and County land management and fire mitigation efforts, private land management, one time projects that create biomass material such as power line extensions, and possibly a stewardship contract with the USFS.

Once the fuel supply is vetted, it will be possible to complete engineering and financial modeling of the renewable energy facility that includes specific amounts associated with the various incentives listed above. For example, it will be possible to determine electricity production capacity, and also if there is enough fuel available for a waste heat user that requires wood as a feedstock, or only a waste heat user that will purchase heat to condition a building or feed a process. These two examples of waste heat users would have a vastly different impact on the financial model, because an industrial pellet manufacturer would be able to purchase much more heat, and generate much more revenue for the renewable energy facility, than a large commercial campus which would only be interested in heating/cooling buildings.

While McKinstry and our lending partners are still developing the benchmarks that define a bankable financial model, six of the seven operational scenarios have a positive NPV after 20 years, with the 100% biomass, cogeneration, and used equipment options being the best performers. Now that it is known that the project appears to be financially feasible, further analysis to more accurately define financial performance of the renewable energy facility is justified and necessary to successfully design and install the REF.

Scenario 1: 10MW, Condensing, New Equipment, PURPA, 100% Biomass

Summary

income :	$9,249,464	per year
expenses :	($4,024,779)	per year
net :	**$5,224,685**	per year

Operating Hours

continuous, less oil ops :	8,147	per year
	7% downtime	

Rates

avoided cost, elec :	$98.0000	per MWh
forest biomass :	$32.0000	per dry ton
purchased n gas :	$7.0000	per mmBTU
water, treated :	$5.0000	per kgal
aq ammonia :	$90.0000	per ton
limestone, ground :	$30.0000	per ton
hydrated lime :	$80.0000	per ton

Escalation

electricity sold :	0.0000	per year
biomass :	0.0200	per year
purchased n gas/kwh :	0.0300	per year
tipping fees :	0.0000	per year
disposal :	0.0300	per year
water :	0.0300	per year
additives :	0.0200	per year
ops expenses :	0.0250	per year

Y1 Income, details

	units	dollars
electrical sales :	81,468	$7,983,864
tipping fees, MSW :	765,600	$765,600
Carbon Credits :	500,000	$500,000

Y1 Ops Expenses

	units	dollars
salaries, FTEs :	15	($852,000)
op and maint :	81,468	($325,872)

Y1 Material Expenses

	units	dollars
biomass :	85,000	($2,720,000)
disposal :	4,250	($42,500)
natural gas :	2,080	($14,560)
water :	9,741	($48,706)
aq ammonia :	0	$0
limestone, ground :	705	($21,141)
hydrated lime :	0	$0
auxiliary power :		$0

Project Cost

	percent	dollars
Construction :		$25,000,000
(as a % of Cons) Permits :	0.0350	$875,000
Design :	0.0300	$750,000
Bid Period :	0.0020	$50,000
CM/CA :	0.0250	$625,000
Start-up / training :	0.0075	$187,500
Cx Support :	0.0100	$250,000
subtotal :	**0.1095**	**$27,737,500**
ISST (on Cons only) :	0.0600	$1,500,000
total		**$29,237,500**

Financial

		dollars
total project cost :		$29,237,500
client capital :		$0
rebate/grants :	0.3000	$8,771,250
amount financed :		$20,466,250
finance period :	20	years
interest rate :	0.0900	
payments :	1	per year
annual payments :	($2,056,886)	
client discount rate :	0.0600	
NSP (gross) :	5.60	years
NSP (net) :	3.92	years

Output

net electrical output :	10.0	MW
annual output :	81,468	MWh

Steam (instantaneous)

to DA :	20,313	lb/hr
to turbine :	131,000	lb/hr
total :	151,313	lb/hr

Other Revenue Sources

Waste Heat User :	$0
Tipping Fees :	$0

Ops costs

average salary, burdened :	$56,800	per year
op&maint :	$4.0000	per MWh

Steam (annual)

to DA :	165,483	klb/yr
to turbine :	1,067,231	klb/yr
total :	1,232,713	klb/yr

Annual Taxes and Land Lease

Sales/Use Taxes :	$0	County may impose
Land Lease :	($200,000)	
1st Year Tax Credit :	$0	

Fuel Flow

annual input heat

MSW:	0	tons			
WW:	0	tons			
biomass:	85,000	bone dry tons		ash, tons:	4,250
nat gas	32	hrs	65	mmBTU/hr	2,080

Biomass

req:	85,000	tons/yr	avail:	30	ton/acre	
req:	2,833	acre/yr	regrow:	15	yrs	
			to be sustainable, acres required:			42,500
depth of stor:	25	ft	storage:	21,250	tons	pile size: 2.6 acres

Trucks

max load:	22.5	ton/load	loads in per day, 24/7:	10.4
trucks in:	3,778	loads/yr	load in per day, weekdays only:	15.1
ash trucks out:	378	loads/yr		

Cash Flow

Income and Expenses, escalated, $1,000 — **NPV: $16,646,346**

yr	elec sold	Other Revenue	Cost of Biomass	Taxes & Land Lease	Anunal ops	Disposal & Consumible:	debt service	total
1	7,983.9	500.0	(2,720.0)	(200.0)	(1,177.9)	(126.9)	(2,057)	$2,202,199
2	7,983.9	500.0	(2,774.4)	(200.0)	(1,207.3)	(130.5)	(2,057)	$2,114,756
3	7,983.9	500.0	(2,829.9)	(200.0)	(1,237.5)	(134.2)	(2,057)	$2,025,386
4	7,983.9	500.0	(2,886.5)	(200.0)	(1,268.4)	(138.0)	(2,057)	$1,934,044
5	7,983.9	500.0	(2,944.2)	(200.0)	(1,300.2)	(141.9)	(2,057)	$1,840,688
6	7,983.9	500.0	(3,003.1)	(200.0)	(1,332.7)	(146.0)	(2,057)	$1,745,271
7	7,983.9	500.0	(3,063.2)	(200.0)	(1,366.0)	(150.1)	(2,057)	$1,647,747
8	7,983.9	500.0	(3,124.4)	(200.0)	(1,400.1)	(154.4)	(2,057)	$1,548,070
9	7,983.9	500.0	(3,186.9)	(200.0)	(1,435.1)	(158.8)	(2,057)	$1,446,190
10	7,983.9	500.0	(3,250.7)	(200.0)	(1,471.0)	(163.3)	(2,057)	$1,342,059
11	7,983.9	500.0	(3,315.7)	(200.0)	(1,507.8)	(167.9)	(2,057)	$1,235,626
12	7,983.9	500.0	(3,382.0)	(200.0)	(1,545.5)	(172.7)	(2,057)	$1,126,838
13	7,983.9	500.0	(3,449.6)	(200.0)	(1,584.1)	(177.6)	(2,057)	$1,015,644
14	7,983.9	500.0	(3,518.6)	(200.0)	(1,623.7)	(182.7)	(2,057)	$901,989
15	7,983.9	500.0	(3,589.0)	(200.0)	(1,664.3)	(187.9)	(2,057)	$785,817
16	7,983.9	500.0	(3,660.8)	(200.0)	(1,705.9)	(193.2)	(2,057)	$667,073
17	7,983.9	500.0	(3,734.0)	(200.0)	(1,748.6)	(198.7)	(2,057)	$545,697
18	7,983.9	500.0	(3,808.7)	(200.0)	(1,792.3)	(204.4)	(2,057)	$421,632
19	7,983.9	500.0	(3,884.8)	(200.0)	(1,837.1)	(210.3)	(2,057)	$294,815
20	7,983.9	500.0	(3,962.5)	(200.0)	(1,883.0)	(216.3)	(2,057)	$165,186

Scenario 2: 10MW, Condensing, Used Equipment, PURPA, 100% Biomass

Summary

income :	$9,249,464	per year
expenses :	($4,279,779)	per year
net :	**$4,969,685**	per year

Operating Hours

continuous, less oil ops :	8,147	per year
	7% downtime	

Rates

avoided cost, elec :	$98.0000	per MWh
forest biomass :	$35.0000	per dry ton
purchased n gas :	$7.0000	per mmBTU
water, treated :	$5.0000	per kgal
aq ammonia :	$90.0000	per ton
limestone, ground :	$30.0000	per ton
hydrated lime :	$80.0000	per ton

Escalation

electricity sold :	0.0000	per year
biomass :	0.0200	per year
purchased n gas/kwh :	0.0300	per year
tipping fees :	0.0000	per year
disposal :	0.0300	per year
water :	0.0300	per year
additives :	0.0200	per year
ops expenses :	0.0250	per year

Y1 Income, details

	units	dollars
electrical sales :	81,468	$7,983,864
tipping fees, MSW :	765,600	$765,600
Carbon Credits :	500,000	$500,000

Y1 Ops Expenses

	units	dollars
salaries, FTEs :	15	($852,000)
op and maint :	81,468	($325,872)

Output

net electrical output :	10.0	MW
annual output :	81,468	MWh

Steam (instantaneous)

to DA :	20,313	lb/hr
to turbine :	131,000	lb/hr
total :	151,313	lb/hr

Other Revenue Sources

Waste Heat User :	$0
Tipping Fees :	$0

Y1 Material Expenses

	units	dollars
biomass :	85,000	($2,975,000)
disposal :	4,250	($42,500)
natural gas :	2,080	($14,560)
water :	9,741	($48,706)
aq ammonia :	0	$0
limestone, ground :	705	($21,141)
hydrated lime :	0	$0
auxiliary power :		$0

Project Cost

	percent	dollars
Construction :		$21,000,000
(as a % of Cons) Permits :	0.0350	$735,000
Design :	0.0300	$630,000
Bid Period :	0.0020	$42,000
CM/CA :	0.0250	$525,000
Start-up / training :	0.0075	$157,500
Cx Support :	0.0100	$210,000
subtotal :	**0.1095**	**$23,299,500**
ISST (on Cons only) :	0.0600	$1,260,000
total		**$24,559,500**

Financial

		dollars
total project cost :		$24,559,500
client capital :		$0
rebate/grants :	0.3000	$7,367,850
amount financed :		$17,191,650
finance period :	20	years
interest rate :	0.0900	
payments :	1	per year
annual payments :	($1,727,784)	
client discount rate :	0.0600	
NSP (gross) :	4.94	years
NSP (net) :	3.46	years

Ops costs

average salary, burdened :	$56,800	per year
op&maint :	$4.0000	per MWh

Steam (annual)

to DA :	165,483	klb/yr
to turbine :	1,067,231	klb/yr
total :	1,232,713	klb/yr

Annual Taxes and Land Lease

Sales/Use Taxes :	$0	County may impose
Land Lease :	($200,000)	
1st Year Tax Credit :	$0	

Fuel Flow

annual input heat

MSW:	0	tons			
WW:	0	tons			
biomass:	85,000	bone dry tons	ash, tons:		4,250
nat gas	32	hrs	65	mmBTU/hr	2,080

Biomass

req:	85,000	tons/yr	avail:	30	ton/acre	
req:	2,833	acre/yr	regrow:	15	yrs	
			to be sustainable, acres required:			42,500
depth of stor:	25	ft	storage:	21,250	tons	pile size: 2.6 acres

Trucks

max load:	22.5	ton/load	loads in per day, 24/7:	10.4
trucks in:	3,778	loads/yr	load in per day, weekdays only:	15.1
ash trucks out:	378	loads/yr		

Cash Flow

Income and Expenses, escalated, $1,000 — **NPV: $16,999,816**

yr	elec sold	Other Revenue	Cost of Biomass	Taxes & Land Lease	Anunal ops	Disposal & Consumible:	debt service	total
1	7,983.9	500.0	(2,975.0)	(200.0)	(1,177.9)	(126.9)	(1,728)	$2,276,301
2	7,983.9	500.0	(3,034.5)	(200.0)	(1,207.3)	(130.5)	(1,728)	$2,183,758
3	7,983.9	500.0	(3,095.2)	(200.0)	(1,237.5)	(134.2)	(1,728)	$2,089,185
4	7,983.9	500.0	(3,157.1)	(200.0)	(1,268.4)	(138.0)	(1,728)	$1,992,538
5	7,983.9	500.0	(3,220.2)	(200.0)	(1,300.2)	(141.9)	(1,728)	$1,893,769
6	7,983.9	500.0	(3,284.6)	(200.0)	(1,332.7)	(146.0)	(1,728)	$1,792,832
7	7,983.9	500.0	(3,350.3)	(200.0)	(1,366.0)	(150.1)	(1,728)	$1,689,678
8	7,983.9	500.0	(3,417.3)	(200.0)	(1,400.1)	(154.4)	(1,728)	$1,584,257
9	7,983.9	500.0	(3,485.7)	(200.0)	(1,435.1)	(158.8)	(1,728)	$1,476,519
10	7,983.9	500.0	(3,555.4)	(200.0)	(1,471.0)	(163.3)	(1,728)	$1,366,412
11	7,983.9	500.0	(3,626.5)	(200.0)	(1,507.8)	(167.9)	(1,728)	$1,253,884
12	7,983.9	500.0	(3,699.0)	(200.0)	(1,545.5)	(172.7)	(1,728)	$1,138,880
13	7,983.9	500.0	(3,773.0)	(200.0)	(1,584.1)	(177.6)	(1,728)	$1,021,344
14	7,983.9	500.0	(3,848.5)	(200.0)	(1,623.7)	(182.7)	(1,728)	$901,221
15	7,983.9	500.0	(3,925.4)	(200.0)	(1,664.3)	(187.9)	(1,728)	$778,452
16	7,983.9	500.0	(4,004.0)	(200.0)	(1,705.9)	(193.2)	(1,728)	$652,978
17	7,983.9	500.0	(4,084.0)	(200.0)	(1,748.6)	(198.7)	(1,728)	$524,739
18	7,983.9	500.0	(4,165.7)	(200.0)	(1,792.3)	(204.4)	(1,728)	$393,672
19	7,983.9	500.0	(4,249.0)	(200.0)	(1,837.1)	(210.3)	(1,728)	$259,714
20	7,983.9	500.0	(4,334.0)	(200.0)	(1,883.0)	(216.3)	(1,728)	$122,801

Scenario 3: 15MW, Condensing, New Equipment, Non PURPA, 100% Biomass

Summary

income :	$12,024,972	per year
expenses :	($5,834,536)	per year
net :	**$6,190,436**	per year

Operating Hours

continuous, less oil ops :	8,147	per year
	7% downtime	

Rates

avoided cost, elec :	$86.0000	per MWh
forest biomass :	$34.0000	per dry ton
purchased n gas :	$7.0000	per mmBTU
water, treated :	$5.0000	per kgal
aq ammonia :	$90.0000	per ton
limestone, ground :	$30.0000	per ton
hydrated lime :	$80.0000	per ton

Escalation

electricity sold :	0.0000	per year
biomass :	0.0150	per year
purchased n gas/kwh :	0.0300	per year
tipping fees :	0.0000	per year
disposal :	0.0300	per year
water :	0.0300	per year
additives :	0.0200	per year
ops expenses :	0.0250	per year

Y1 Income, details

	units	dollars
electrical sales :	122,202	$10,509,372
tipping fees, MSW :	765,600	$765,600
Carbon Credits :	750,000	$750,000

Y1 Ops Expenses

	units	dollars
salaries, FTEs :	15	($852,000)
op and maint :	122,202	($488,808)

Y1 Material Expenses

	units	dollars
biomass :	127,500	($4,335,000)
disposal :	6,375	($63,750)
natural gas :	2,080	($14,560)
water :	9,741	($48,706)
aq ammonia :	0	$0
limestone, ground :	1,057	($31,711)
hydrated lime :	0	$0
auxiliary power :		$0

Project Cost

	percent	dollars
Construction :		$35,000,000
(as a % of Cons) Permits :	0.0350	$1,225,000
Design :	0.0300	$1,050,000
Bid Period :	0.0020	$70,000
CM/CA :	0.0250	$875,000
Start-up / training :	0.0075	$262,500
Cx Support :	0.0100	$350,000
subtotal :	**0.1095**	**$38,832,500**
ISST (on Cons only) :	0.0600	$2,100,000
total		**$40,932,500**

Financial

		dollars
total project cost :		$40,932,500
client capital :		$0
rebate/grants :	0.3000	$12,279,750
amount financed :		$28,652,750
finance period :	20	years
interest rate :	0.0900	
payments :	1	per year
annual payments :	($2,879,640)	
client discount rate :	0.0600	
NSP (gross) :	6.61	years
NSP (net) :	4.63	years

Output

net electrical output :	15.0	MW
annual output :	122,202	MWh

Steam (instantaneous)

to DA :	20,313	lb/hr
to turbine :	131,000	lb/hr
total :	151,313	lb/hr

Other Revenue Sources

Waste Heat User :	$0
Tipping Fees :	$0

Ops costs

average salary, burdened :	$56,800	per year
op&maint :	$4.0000	per MWh

Steam (annual)

to DA :	165,483	klb/yr
to turbine :	1,067,231	klb/yr
total :	1,232,713	klb/yr

Annual Taxes and Land Lease

Sales/Use Taxes :	$0	County may impose
Land Lease :	($200,000)	
1st Year Tax Credit :	$0	

Fuel Flow

annual input heat

MSW:	0	tons			
WW:	0	tons			
biomass:	127,500	bone dry tons		ash, tons:	6,375
nat gas	32	hrs	65	mmBTU/hr	2,080

Biomass

req:	127,500	tons/yr	avail:	30	ton/acre	
req:	4,250	acre/yr	regrow:	15	yrs	
			to be sustainable, acres required:			63,750
depth of stor:	25	ft	storage:	31,875	tons	pile size: 3.9 acres

Trucks

max load:	22.5	ton/load	loads in per day, 24/7:	15.5
trucks in:	5,667	loads/yr	load in per day, weekdays only:	22.7
ash trucks out:	567	loads/yr		

Cash Flow

Income and Expenses, escalated, $1,000 — **NPV: $16,932,515**

yr	elec sold	Other Revenue	Cost of Biomass	Taxes & Land Lease	Anunal ops	Disposal & Consumible:	debt service	total
1	10,509.4	750.0	(4,335.0)	(200.0)	(1,340.8)	(158.7)	(2,880)	$2,345,196
2	10,509.4	750.0	(4,400.0)	(200.0)	(1,374.3)	(163.2)	(2,880)	$2,242,206
3	10,509.4	750.0	(4,466.0)	(200.0)	(1,408.7)	(167.7)	(2,880)	$2,137,276
4	10,509.4	750.0	(4,533.0)	(200.0)	(1,443.9)	(172.4)	(2,880)	$2,030,366
5	10,509.4	750.0	(4,601.0)	(200.0)	(1,480.0)	(177.3)	(2,880)	$1,921,436
6	10,509.4	750.0	(4,670.0)	(200.0)	(1,517.0)	(182.3)	(2,880)	$1,810,446
7	10,509.4	750.0	(4,740.1)	(200.0)	(1,554.9)	(187.4)	(2,880)	$1,697,353
8	10,509.4	750.0	(4,811.2)	(200.0)	(1,593.8)	(192.6)	(2,880)	$1,582,114
9	10,509.4	750.0	(4,883.3)	(200.0)	(1,633.6)	(198.1)	(2,880)	$1,464,687
10	10,509.4	750.0	(4,956.6)	(200.0)	(1,674.5)	(203.6)	(2,880)	$1,345,025
11	10,509.4	750.0	(5,030.9)	(200.0)	(1,716.3)	(209.4)	(2,880)	$1,223,084
12	10,509.4	750.0	(5,106.4)	(200.0)	(1,759.3)	(215.2)	(2,880)	$1,098,817
13	10,509.4	750.0	(5,183.0)	(200.0)	(1,803.2)	(221.3)	(2,880)	$972,177
14	10,509.4	750.0	(5,260.7)	(200.0)	(1,848.3)	(227.6)	(2,880)	$843,113
15	10,509.4	750.0	(5,339.7)	(200.0)	(1,894.5)	(234.0)	(2,880)	$711,578
16	10,509.4	750.0	(5,419.8)	(200.0)	(1,941.9)	(240.6)	(2,880)	$577,519
17	10,509.4	750.0	(5,501.1)	(200.0)	(1,990.4)	(247.4)	(2,880)	$440,885
18	10,509.4	750.0	(5,583.6)	(200.0)	(2,040.2)	(254.3)	(2,880)	$301,623
19	10,509.4	750.0	(5,667.3)	(200.0)	(2,091.2)	(261.5)	(2,880)	$159,679
20	10,509.4	750.0	(5,752.3)	(200.0)	(2,143.5)	(268.9)	(2,880)	$14,996

Scenario 4: 15MW, Condensing, Used Equipment, Non PURPA, 100% Biomass

Summary

income :	$12,024,972	per year
expenses :	($6,089,536)	per year
net :	$5,935,436	per year

Operating Hours

continuous, less oil ops :	8,147	per year
	7% downtime	

Rates

avoided cost, elec :	$86.0000	per MWh
forest biomass :	$36.0000	per dry ton
purchased n gas :	$7.0000	per mmBTU
water, treated :	$5.0000	per kgal
aq ammonia :	$90.0000	per ton
limestone, ground :	$30.0000	per ton
hydrated lime :	$80.0000	per ton

Escalation

electricity sold :	0.0000	per year
biomass :	0.0150	per year
purchased n gas/kwh :	0.0300	per year
tipping fees :	0.0000	per year
disposal :	0.0300	per year
water :	0.0300	per year
additives :	0.0200	per year
ops expenses :	0.0250	per year

Y1 Income, details

	units	dollars
electrical sales :	122,202	$10,509,372
tipping fees, MSW :	765,600	$765,600
Carbon Credits :	750,000	$750,000

Y1 Ops Expenses

	units	dollars
salaries, FTEs :	15	($852,000)
op and maint :	122,202	($488,808)

Y1 Material Expenses

	units	dollars
biomass :	127,500	($4,590,000)
disposal :	6,375	($63,750)
natural gas :	2,080	($14,560)
water :	9,741	($48,706)
aq ammonia :	0	$0
limestone, ground :	1,057	($31,711)
hydrated lime :	0	$0
auxiliary power :		$0

Project Cost

	percent	dollars
Construction :		$30,000,000
(as a % of Cons) Permits :	0.0350	$1,050,000
Design :	0.0300	$900,000
Bid Period :	0.0020	$60,000
CM/CA :	0.0250	$750,000
Start-up / training :	0.0075	$225,000
Cx Support :	0.0100	$300,000
subtotal :	**0.1095**	**$33,285,000**
ISST (on Cons only) :	0.0600	$1,800,000
total		**$35,085,000**

Financial

		dollars
total project cost :		$35,085,000
client capital :		$0
rebate/grants :	0.3000	$10,525,500
amount financed :		$24,559,500
finance period :	20	years
interest rate :	0.0900	
payments :	1	per year
annual payments :	($2,468,263)	
client discount rate :	0.0600	
NSP (gross) :	5.91	years
NSP (net) :	4.14	years

Output

net electrical output :	15.0	MW
annual output :	122,202	MWh

Steam (instantaneous)

to DA :	20,313	lb/hr
to turbine :	131,000	lb/hr
total :	151,313	lb/hr

Other Revenue Sources

Waste Heat User :	$0
Tipping Fees :	$0

Ops costs

average salary, burdened :	$56,800	per year
op&maint :	$4.0000	per MWh

Steam (annual)

to DA :	165,483	klb/yr
to turbine :	1,067,231	klb/yr
total :	1,232,713	klb/yr

Annual Taxes and Land Lease

Sales/Use Taxes :	$0	County may impose
Land Lease :	($200,000)	
1st Year Tax Credit :	$0	

Fuel Flow

annual input heat

MSW:	0	tons			
WW:	0	tons			
biomass:	127,500	bone dry tons	ash, tons:		6,375
nat gas	32	hrs	65	mmBTU/hr	2,080

Biomass

req:	127,500	tons/yr	avail:	30	ton/acre	
req:	4,250	acre/yr	regrow:	15	yrs	
			to be sustainable, acres required:			63,750
depth of stor:	25	ft	storage:	31,875	tons	pile size: 3.9 acres

Trucks

max load:	22.5	ton/load	loads in per day, 24/7:	15.5
trucks in:	5,667	loads/yr	load in per day, weekdays only:	22.7
ash trucks out:	567	loads/yr		

Cash Flow

Income and Expenses, escalated, $1,000 — NPV: $18,364,061

yr	elec sold	Other Revenue	Cost of Biomass	Taxes & Land Lease	Anunal ops	Disposal & Consumible	debt service	total
1	10,509.4	750.0	(4,590.0)	(200.0)	(1,340.8)	(158.7)	(2,468)	$2,501,573
2	10,509.4	750.0	(4,658.9)	(200.0)	(1,374.3)	(163.2)	(2,468)	$2,394,758
3	10,509.4	750.0	(4,728.7)	(200.0)	(1,408.7)	(167.7)	(2,468)	$2,285,946
4	10,509.4	750.0	(4,799.7)	(200.0)	(1,443.9)	(172.4)	(2,468)	$2,175,095
5	10,509.4	750.0	(4,871.7)	(200.0)	(1,480.0)	(177.3)	(2,468)	$2,062,166
6	10,509.4	750.0	(4,944.7)	(200.0)	(1,517.0)	(182.3)	(2,468)	$1,947,115
7	10,509.4	750.0	(5,018.9)	(200.0)	(1,554.9)	(187.4)	(2,468)	$1,829,902
8	10,509.4	750.0	(5,094.2)	(200.0)	(1,593.8)	(192.6)	(2,468)	$1,710,481
9	10,509.4	750.0	(5,170.6)	(200.0)	(1,633.6)	(198.1)	(2,468)	$1,588,808
10	10,509.4	750.0	(5,248.2)	(200.0)	(1,674.5)	(203.6)	(2,468)	$1,464,838
11	10,509.4	750.0	(5,326.9)	(200.0)	(1,716.3)	(209.4)	(2,468)	$1,338,524
12	10,509.4	750.0	(5,406.8)	(200.0)	(1,759.3)	(215.2)	(2,468)	$1,209,818
13	10,509.4	750.0	(5,487.9)	(200.0)	(1,803.2)	(221.3)	(2,468)	$1,078,671
14	10,509.4	750.0	(5,570.2)	(200.0)	(1,848.3)	(227.6)	(2,468)	$945,035
15	10,509.4	750.0	(5,653.8)	(200.0)	(1,894.5)	(234.0)	(2,468)	$808,857
16	10,509.4	750.0	(5,738.6)	(200.0)	(1,941.9)	(240.6)	(2,468)	$670,087
17	10,509.4	750.0	(5,824.6)	(200.0)	(1,990.4)	(247.4)	(2,468)	$528,671
18	10,509.4	750.0	(5,912.0)	(200.0)	(2,040.2)	(254.3)	(2,468)	$384,555
19	10,509.4	750.0	(6,000.7)	(200.0)	(2,091.2)	(261.5)	(2,468)	$237,684
20	10,509.4	750.0	(6,090.7)	(200.0)	(2,143.5)	(268.9)	(2,468)	$88,001

Scenario 5: 20MW, Condensing, Used Equipment, Non PURPA, 100% Biomass

Summary

income :	$15,778,096	per year
expenses :	($8,267,892)	per year
net :	**$7,510,204**	per year

Operating Hours

continuous, less oil ops :	8,147	per year
	7% downtime	

Rates

avoided cost, elec :	$86.0000	per MWh
forest biomass :	$38.0000	per dry ton
purchased n gas :	$7.0000	per mmBTU
water, treated :	$5.0000	per kgal
aq ammonia :	$90.0000	per ton
limestone, ground :	$30.0000	per ton
hydrated lime :	$80.0000	per ton

Escalation

electricity sold :	0.0000	per year
biomass :	0.0150	per year
purchased n gas/kwh :	0.0300	per year
tipping fees :	0.0000	per year
disposal :	0.0300	per year
water :	0.0300	per year
additives :	0.0200	per year
ops expenses :	0.0250	per year

Y1 Income, details

	units	dollars
electrical sales :	162,936	$14,012,496
tipping fees, MSW :	765,600	$765,600
Carbon Credits :	1,000,000	$1,000,000

Y1 Ops Expenses

	units	dollars
salaries, FTEs :	17	($965,600)
op and maint :	162,936	($651,744)

Y1 Material Expenses

	units	dollars
biomass :	170,000	($6,460,000)
disposal :	8,500	($85,000)
natural gas :	2,080	($14,560)
water :	9,741	($48,706)
aq ammonia :	0	$0
limestone, ground :	1,409	($42,282)
hydrated lime :	0	$0
auxiliary power :		$0

Project Cost

		percent	dollars
	Construction :		$39,500,000
(as a % of Cons)	Permits :	0.0350	$1,382,500
	Design :	0.0300	$1,185,000
	Bid Period :	0.0020	$79,000
	CM/CA :	0.0250	$987,500
	Start-up / training :	0.0075	$296,250
	Cx Support :	0.0100	$395,000
	subtotal :	**0.1095**	**$43,825,250**
	ISST (on Cons only) :	0.0600	$2,370,000
	total		**$46,195,250**

Financial

		dollars
total project cost :		$46,195,250
client capital :		$0
rebate/grants :	0.3000	$13,858,575
amount financed :		$32,336,675
finance period :	20	years
interest rate :	0.0900	
payments :	1	per year
annual payments :	($3,249,880)	
client discount rate :	0.0600	
NSP (gross) :	6.15	years
NSP (net) :	4.31	years

Output

net electrical output :	20.0	MW
annual output :	162,936	MWh

Steam (instantaneous)

to DA :	20,313	lb/hr
to turbine :	131,000	lb/hr
total :	151,313	lb/hr

Other Revenue Sources

Waste Heat User :	$0
Tipping Fees :	$0

Ops costs

average salary, burdened :	$56,800	per year
op&maint :	$4.0000	per MWh

Steam (annual)

to DA :	165,483	klb/yr
to turbine :	1,067,231	klb/yr
total :	1,232,713	klb/yr

Annual Taxes and Land Lease

Sales/Use Taxes :	$0	County may impose
Land Lease :	($200,000)	
1st Year Tax Credit :	$0	

Fuel Flow

annual input heat

MSW:	0	tons			
WW:	0	tons			
biomass:	170,000	bone dry tons		ash, tons:	8,500
nat gas	32	hrs	65	mmBTU/hr	2,080

Biomass

req:	170,000	tons/yr	avail:	30	ton/acre	
req:	5,667	acre/yr	regrow:	15	yrs	
			to be sustainable, acres required:			85,000
depth of stor:	25	ft	storage:	42,500	tons	pile size: 5.2 acres

Trucks

max load:	22.5	ton/load	loads in per day, 24/7:	20.7
trucks in:	7,556	loads/yr	load in per day, weekdays only:	30.2
ash trucks out:	756	loads/yr		

Cash Flow

Income and Expenses, escalated, $1,000 — **NPV: $24,027,532**

yr	elec sold	Other Revenue	Cost of Biomass	Taxes & Land Lease	Anunal ops	Disposal & Consumible:	debt service	total
1	14,012.5	1,000.0	(6,460.0)	(200.0)	(1,617.3)	(190.5)	(3,250)	$3,294,724
2	14,012.5	1,000.0	(6,556.9)	(200.0)	(1,657.8)	(195.8)	(3,250)	$3,152,097
3	14,012.5	1,000.0	(6,655.3)	(200.0)	(1,699.2)	(201.3)	(3,250)	$3,006,855
4	14,012.5	1,000.0	(6,755.1)	(200.0)	(1,741.7)	(206.9)	(3,250)	$2,858,947
5	14,012.5	1,000.0	(6,856.4)	(200.0)	(1,785.2)	(212.6)	(3,250)	$2,708,320
6	14,012.5	1,000.0	(6,959.3)	(200.0)	(1,829.9)	(218.6)	(3,250)	$2,554,921
7	14,012.5	1,000.0	(7,063.6)	(200.0)	(1,875.6)	(224.7)	(3,250)	$2,398,696
8	14,012.5	1,000.0	(7,169.6)	(200.0)	(1,922.5)	(230.9)	(3,250)	$2,239,587
9	14,012.5	1,000.0	(7,277.1)	(200.0)	(1,970.6)	(237.4)	(3,250)	$2,077,538
10	14,012.5	1,000.0	(7,386.3)	(200.0)	(2,019.8)	(244.0)	(3,250)	$1,912,491
11	14,012.5	1,000.0	(7,497.1)	(200.0)	(2,070.3)	(250.8)	(3,250)	$1,744,387
12	14,012.5	1,000.0	(7,609.6)	(200.0)	(2,122.1)	(257.8)	(3,250)	$1,573,163
13	14,012.5	1,000.0	(7,723.7)	(200.0)	(2,175.1)	(265.0)	(3,250)	$1,398,759
14	14,012.5	1,000.0	(7,839.5)	(200.0)	(2,229.5)	(272.4)	(3,250)	$1,221,111
15	14,012.5	1,000.0	(7,957.1)	(200.0)	(2,285.3)	(280.1)	(3,250)	$1,040,153
16	14,012.5	1,000.0	(8,076.5)	(200.0)	(2,342.4)	(287.9)	(3,250)	$855,821
17	14,012.5	1,000.0	(8,197.6)	(200.0)	(2,401.0)	(296.0)	(3,250)	$668,045
18	14,012.5	1,000.0	(8,320.6)	(200.0)	(2,461.0)	(304.3)	(3,250)	$476,758
19	14,012.5	1,000.0	(8,445.4)	(200.0)	(2,522.5)	(312.8)	(3,250)	$281,889
20	14,012.5	1,000.0	(8,572.1)	(200.0)	(2,585.6)	(321.6)	(3,250)	$83,364

Scenario 6: 10MW, Cogen - Pellet, Used Equipment, PURPA, 100% Biomass

Summary

income :	$9,249,464	per year
expenses :	($4,733,379)	per year
net :	**$4,516,085**	per year

Operating Hours

continuous, less oil ops :	8,147	per year
	7% downtime	

Rates

avoided cost, elec :	$98.0000	per MWh
forest biomass :	$39.0000	per dry ton
purchased n gas :	$7.0000	per mmBTU
water, treated :	$5.0000	per kgal
aq ammonia :	$90.0000	per ton
limestone, ground :	$30.0000	per ton
hydrated lime :	$80.0000	per ton

Escalation

electricity sold :	0.0000	per year
biomass :	0.0200	per year
purchased n gas/kwh :	0.0300	per year
tipping fees :	0.0000	per year
disposal :	0.0300	per year
water :	0.0300	per year
additives :	0.0200	per year
ops expenses :	0.0250	per year

Y1 Income, details

	units	dollars
electrical sales :	81,468	$7,983,864
tipping fees, MSW :	765,600	$765,600
Carbon Credits :	500,000	$500,000

Y1 Ops Expenses

	units	dollars
salaries, FTEs :	17	($965,600)
op and maint :	81,468	($325,872)

Y1 Material Expenses

	units	dollars
biomass :	85,000	($3,315,000)
disposal :	4,250	($42,500)
natural gas :	2,080	($14,560)
water :	9,741	($48,706)
aq ammonia :	0	$0
limestone, ground :	705	($21,141)
hydrated lime :	0	$0
auxiliary power :		$0

Project Cost

	percent	dollars
Construction :		$21,000,000
(as a % of Cons) Permits :	0.0350	$735,000
Design :	0.0300	$630,000
Bid Period :	0.0020	$42,000
CM/CA :	0.0250	$525,000
Start-up / training :	0.0075	$157,500
Cx Support :	0.0100	$210,000
subtotal :	**0.1095**	**$23,299,500**
ISST (on Cons only) :	0.0600	$1,260,000
total		**$24,559,500**

Financial

		dollars
total project cost :		$24,559,500
client capital :		$0
rebate/grants :	0.3000	$7,367,850
amount financed :		$17,191,650
finance period :	20	years
interest rate :	0.0900	
payments :	1	per year
annual payments :	($1,727,784)	
client discount rate :	0.0600	
NSP (gross) :	5.44	years
NSP (net) :	3.81	years

Output

net electrical output :	10.0	MW
annual output :	81,468	MWh

Steam (instantaneous)

to DA :	20,313	lb/hr
to turbine :	131,000	lb/hr
total :	151,313	lb/hr

Other Revenue Sources

Waste Heat User :	$625,000	
	40,000 ton/yr pellet plant	
Tipping Fees :	$0	

Ops costs

average salary, burdened :	$56,800	per year
op&maint :	$4.0000	per MWh

Steam (annual)

to DA :	165,483	klb/yr
to turbine :	1,067,231	klb/yr
total :	1,232,713	klb/yr

Annual Taxes and Land Lease

Sales/Use Taxes :	$0	County may impose
Land Lease :	($200,000)	
1st Year Tax Credit :	$0	

Fuel Flow

annual input heat

MSW:	0	tons			
WW:	0	tons			
biomass:	85,000	bone dry tons		ash, tons:	4,250
nat gas	32	hrs	65	mmBTU/hr	2,080

Biomass

req:	85,000	tons/yr	avail:	30	ton/acre	
req:	2,833	acre/yr	regrow:	15	yrs	
			to be sustainable, acres required:			42,500
depth of stor:	25	ft	storage:	21,250	tons	pile size: 2.6 acres

Trucks

max load:	22.5	ton/load	loads in per day, 24/7:	10.4
trucks in:	3,778	loads/yr	load in per day, weekdays only:	15.1
ash trucks out:	378	loads/yr		

Cash Flow

Income and Expenses, escalated, $1,000

NPV: $18,019,396

yr	elec sold	Other Revenue	Cost of Biomass	Taxes & Land Lease	Anunal ops	Disposal & Consumible:	debt service	total
1	7,983.9	1,125.0	(3,315.0)	(200.0)	(1,291.5)	(126.9)	(1,728)	$2,447,701
2	7,983.9	1,125.0	(3,381.3)	(200.0)	(1,323.8)	(130.5)	(1,728)	$2,345,518
3	7,983.9	1,125.0	(3,448.9)	(200.0)	(1,356.9)	(134.2)	(1,728)	$2,241,098
4	7,983.9	1,125.0	(3,517.9)	(200.0)	(1,390.8)	(138.0)	(1,728)	$2,134,393
5	7,983.9	1,125.0	(3,588.3)	(200.0)	(1,425.5)	(141.9)	(1,728)	$2,025,349
6	7,983.9	1,125.0	(3,660.0)	(200.0)	(1,461.2)	(146.0)	(1,728)	$1,913,916
7	7,983.9	1,125.0	(3,733.2)	(200.0)	(1,497.7)	(150.1)	(1,728)	$1,800,041
8	7,983.9	1,125.0	(3,807.9)	(200.0)	(1,535.2)	(154.4)	(1,728)	$1,683,669
9	7,983.9	1,125.0	(3,884.1)	(200.0)	(1,573.5)	(158.8)	(1,728)	$1,564,744
10	7,983.9	1,125.0	(3,961.7)	(200.0)	(1,612.9)	(163.3)	(1,728)	$1,443,210
11	7,983.9	1,125.0	(4,041.0)	(200.0)	(1,653.2)	(167.9)	(1,728)	$1,319,008
12	7,983.9	1,125.0	(4,121.8)	(200.0)	(1,694.5)	(172.7)	(1,728)	$1,192,079
13	7,983.9	1,125.0	(4,204.2)	(200.0)	(1,736.9)	(177.6)	(1,728)	$1,062,363
14	7,983.9	1,125.0	(4,288.3)	(200.0)	(1,780.3)	(182.7)	(1,728)	$929,796
15	7,983.9	1,125.0	(4,374.1)	(200.0)	(1,824.8)	(187.9)	(1,728)	$794,315
16	7,983.9	1,125.0	(4,461.6)	(200.0)	(1,870.4)	(193.2)	(1,728)	$655,856
17	7,983.9	1,125.0	(4,550.8)	(200.0)	(1,917.2)	(198.7)	(1,728)	$514,352
18	7,983.9	1,125.0	(4,641.8)	(200.0)	(1,965.1)	(204.4)	(1,728)	$369,734
19	7,983.9	1,125.0	(4,734.6)	(200.0)	(2,014.3)	(210.3)	(1,728)	$221,933
20	7,983.9	1,125.0	(4,829.3)	(200.0)	(2,064.6)	(216.3)	(1,728)	$70,878

Scenario 7: 10MW, Cogen - Pellet, Used Equipment, PURPA, 90% Biomass, 10% MSW

Summary

income :	$8,991,920	per year
expenses :	($4,414,871)	per year
net :	**$4,577,049**	per year

Operating Hours

continuous, less oil ops :	7,884	per year
	10% downtime	

Rates

avoided cost, elec :	$98.0000	per MWh
forest biomass :	$30.0000	per dry ton
purchased n gas :	$7.0000	per mmBTU
water, treated :	$5.0000	per kgal
aq ammonia :	$90.0000	per ton
limestone, ground :	$30.0000	per ton
hydrated lime :	$80.0000	per ton

Escalation

electricity sold :	0.0000	per year
biomass :	0.0200	per year
purchased n gas/kwh :	0.0300	per year
tipping fees :	0.0000	per year
disposal :	0.0300	per year
water :	0.0300	per year
additives :	0.0200	per year
ops expenses :	0.0250	per year

Y1 Income, details

	units	dollars
electrical sales :	78,840	$7,726,320
tipping fees, MSW :	765,600	$765,600
Carbon Credits :	500,000	$500,000

Y1 Ops Expenses

	units	dollars
salaries, FTEs :	22	($1,249,600)
op and maint :	78,840	($433,620)

Y1 Material Expenses

	units	dollars
biomass :	76,500	($2,295,000)
disposal :	6,225	($305,025)
natural gas :	2,080	($14,560)
water :	9,427	($47,135)
aq ammonia :	233	($20,932)
limestone, ground :	792	($23,770)
hydrated lime :	315	($25,229)
auxiliary power :		$0

Project Cost

	percent	dollars
Construction :		$40,000,000
(as a % of Cons) Permits :	0.0500	$2,000,000
Design :	0.0450	$1,800,000
Bid Period :	0.0040	$160,000
CM/CA :	0.0375	$1,500,000
Start-up / training :	0.0075	$300,000
Cx Support :	0.0100	$400,000
subtotal :	**0.1540**	**$46,160,000**
ISST (on Cons only) :	0.0600	$2,400,000
total		**$48,560,000**

Financial

		dollars
total project cost :		$48,560,000
client capital :		$0
rebate/grants :	0.3000	$14,568,000
amount financed :		$33,992,000
finance period :	20	years
interest rate :	0.0900	
payments :	1	per year
annual payments :	($3,416,242)	
client discount rate :	0.0600	
NSP (gross) :	10.61	years
NSP (net) :	7.43	years

Output

net electrical output :	10.0	MW
annual output :	78,840	MWh

Steam (instantaneous)

to DA :	20,313	lb/hr
to turbine :	131,000	lb/hr
total :	151,313	lb/hr

Other Revenue Sources

Waste Heat User :	$625,000	
	40,000 ton/yr pellet plant	
Tipping Fees :	$540,000	
	Shoshone County MSW Only	

Ops costs

average salary, burdened :	$56,800	per year
op&maint :	$5.5000	per MWh

Steam (annual)

to DA :	160,145	klb/yr
to turbine :	1,032,804	klb/yr
total :	1,192,949	klb/yr

Annual Taxes and Land Lease

Sales/Use Taxes :	$0	County may impose
Land Lease :	($200,000)	
1st Year Tax Credit :	$0	

Fuel Flow

annual input heat

MSW:	0	tons			
WW:	0	tons			
biomass:	76,500	bone dry tons	ash, tons:		6,225
nat gas	32	hrs	65	mmBTU/hr	2,080

Biomass

req:	76,500	tons/yr	avail:	30	ton/acre	
req:	2,550	acre/yr	regrow:	15	yrs	
			to be sustainable, acres required:			38,250
depth of stor:	25	ft	storage:	19,125	tons	pile size: 2.3 acres

Trucks

max load:	22.5	ton/load	loads in per day, 24/7:	9.3
trucks in:	3,400	loads/yr	load in per day, weekdays only:	13.6
ash trucks out:	553	loads/yr		

Cash Flow

Income and Expenses, escalated, $1,000

NPV: $5,649,287

yr	elec sold	Other Revenue	Cost of Biomass	Taxes & Land Lease	Anunal ops	Disposal & Consumible:	debt service	total
1	7,726.3	1,665.0	(2,295.0)	(200.0)	(1,683.2)	(436.7)	(3,416)	$1,360,207
2	7,726.3	1,665.0	(2,340.9)	(200.0)	(1,725.3)	(449.1)	(3,416)	$1,259,826
3	7,726.3	1,665.0	(2,387.7)	(200.0)	(1,768.4)	(461.8)	(3,416)	$1,157,117
4	7,726.3	1,665.0	(2,435.5)	(200.0)	(1,812.6)	(474.9)	(3,416)	$1,052,025
5	7,726.3	1,665.0	(2,484.2)	(200.0)	(1,858.0)	(488.4)	(3,416)	$944,494
6	7,726.3	1,665.0	(2,533.9)	(200.0)	(1,904.4)	(502.3)	(3,416)	$834,465
7	7,726.3	1,665.0	(2,584.5)	(200.0)	(1,952.0)	(516.6)	(3,416)	$721,879
8	7,726.3	1,665.0	(2,636.2)	(200.0)	(2,000.8)	(531.3)	(3,416)	$606,676
9	7,726.3	1,665.0	(2,689.0)	(200.0)	(2,050.8)	(546.5)	(3,416)	$488,794
10	7,726.3	1,665.0	(2,742.7)	(200.0)	(2,102.1)	(562.1)	(3,416)	$368,169
11	7,726.3	1,665.0	(2,797.6)	(200.0)	(2,154.7)	(578.1)	(3,416)	$244,735
12	7,726.3	1,665.0	(2,853.5)	(200.0)	(2,208.5)	(594.6)	(3,416)	$118,426
13	7,726.3	1,665.0	(2,910.6)	(200.0)	(2,263.7)	(611.5)	(3,416)	($10,826)
14	7,726.3	1,665.0	(2,968.8)	(200.0)	(2,320.3)	(629.0)	(3,416)	($143,091)
15	7,726.3	1,665.0	(3,028.2)	(200.0)	(2,378.3)	(647.0)	(3,416)	($278,441)
16	7,726.3	1,665.0	(3,088.8)	(200.0)	(2,437.8)	(665.5)	(3,416)	($416,951)
17	7,726.3	1,665.0	(3,150.5)	(200.0)	(2,498.7)	(684.5)	(3,416)	($558,693)
18	7,726.3	1,665.0	(3,213.6)	(200.0)	(2,561.2)	(704.1)	(3,416)	($703,747)
19	7,726.3	1,665.0	(3,277.8)	(200.0)	(2,625.2)	(724.2)	(3,416)	($852,191)
20	7,726.3	1,665.0	(3,343.4)	(200.0)	(2,690.9)	(744.9)	(3,416)	($1,004,106)