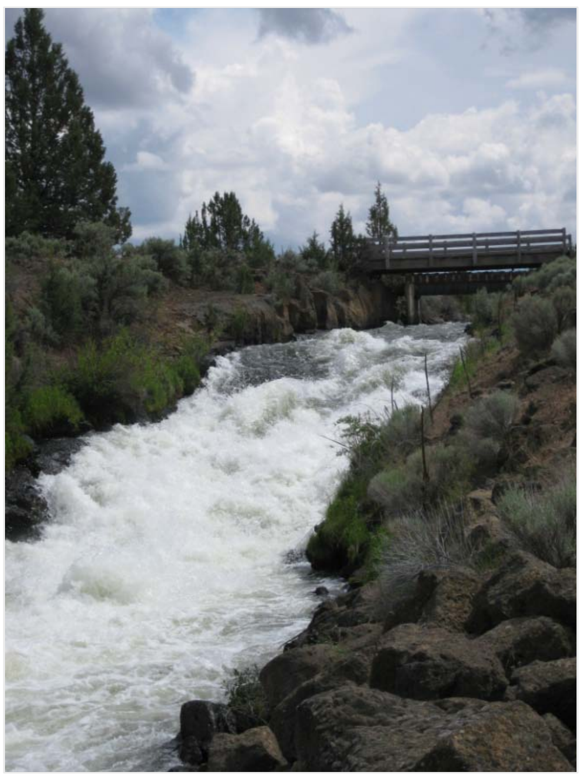
FEASIBILITY REPORT
to
NORTH UNIT IRRIGATION DISTRICT
August, 2009

FEASIBILITY STUDY ON FIVE POTENTIAL HYDROELECTRIC POWER GENERATION LOCATIONS IN THE NORTH UNIT IRRIGATION DISTRICT



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I. EXECUTIVE SUMMARY

Each of the five projects were evaluated similarly. Gross and net head were developed either based upon field survey data or based upon lateral project design information (58-9, 58-11). Flow information was developed using District measurements and/or Stage Gauge data with the exception of the 58-9 lateral that was developed based upon pre-existing design information, expected peak flow rates, and interpolation from 58-11 data. Grant and other funding source information for each project was included based upon current knowledge of commonly accessed programs and funding sources for Central Oregon hydropower projects. Utility interconnect information was based upon field locations of nearest facilities and current understanding of utility interconnect policies.

Once the power generation estimates were developed for each site, expected utility rates were defined and a table of expected revenue over the next 14 years was developed. Next, a cost estimate range was developed proving a low to high cost range for each project. Significant cost variability exists in the marketplace for turbine and generator systems. Additionally, utility interconnect costs have been found to range significantly.

Lastly, the project revenues and costs were compared based upon first year benefit v. cost of revenue versus amortized loan and simple payback periods. The final ranking and results for the various projects are as follows with "Low" indicating low end of cost range and "High" indicating high end of cost range:

North Unit Irrigation District
Feasibility Level
Ranking of Five Potential Hydropower Production sites
Black Rock Consulting
August, 2009

Project Location	Rank	BC/NG Low	High	BC/WG Low	High	SP/NG Low	High	SP/WG Low	High
Haystack Reservoir	1	0.83	0.45	1.40	0.71	12	23	8	14
58-11	2	0.79	0.35	1.18	0.52	14	23	9	22
Brinson Blvd.	3	0.59	0.33	1.02	0.54	17	30	10	18
58-9	4	0.50	0.21	0.75	0.31	22	55	15	37
Smith Rock Drop	5	0.27	0.18	0.47	0.27	26	60	18	36

BC/NG=Benefit v. Cost with No Grant
BC/WG=Benefit v. Cost with Grants
SP/NG=Simple Payback Period with No Grant
Sp/WG=Simple Payback Period with Grants

It should be noted that soft costs such as the cost of financing has not been included in this study or cost analysis as such costs are very project specific and unknown at the time of this study.

Based upon the above results, the District may choose to move forward with the Haystack Reservoir project, the Brinson Blvd. Project and the 58-11 lateral project, however the 58-9 and Smith Rock Drop projects do not appear to be financially attractive given the long payback periods estimated.

It is recommended that any project further considered by the District for action be conceptually designed and then re-costed to insure that the project continues to be viable once more project detail and field information is gathered and incorporated.

II. BACKGROUND

The intent of this Feasibility Report is to evaluate and present the technical, financial, and permitting feasibility of 5 potential hydroelectric power generation sites in the North Unit Irrigation District, Madras, Oregon. The sites included in this study are identified as:

- Brinson Boulevard
- Smith Rock Drop
- Haystack Reservoir
- 58-11 Lateral
- 58-9 Lateral

These sites are generally located as indicated on Figure 1, below.

Black Rock Consulting of Bend, Oregon was authorized by agreement (dated June 10, 2009) with the North Unit Irrigation District to perform these services. Funding for the Study is from North Unit Irrigation District funds and grant funds from the Oregon Department of Energy.

The primary objectives of this Feasibility Study and associated data development were as follows:

1) Review any available historical project information provided by NUID.
2) Establish project limits based upon canal specifics (elevation differential, existing houses or structures in vicinity, location of existing utility facilities, etc.) for each project site.
3) Develop a feasibility-level gross head assessment for each site.
4) Develop an aerial site plan (Google Earth aerials) for each site.
5) Research and verify probable annual average flow rates (minimum/average/peak) at each site. Data to be gathered from NUID offices.
6) Identify permits and agreements that must be completed with the US Bureau of Reclamation, Oregon Water Resources Department, and Interconnect Utility
7) Size probable penstock pipe size and material for each site.
8) Evaluate project head-loss for each site and develop estimated net head at the turbine for each site.
9) Size a feasibility level turbine and generator for each site.
10) Request equipment cost estimates from reputable manufacturers.
11) Evaluate financing options for the facilities.
12) Develop feasibility level cost estimates for each site.
13) Develop feasibility level energy production estimates for each site.
14) Develop revenue expectations given a typical power purchase agreement contract.
15) Develop benefit/cost comparisons for each site.
16) Compile the above information for the five sites and providing recommendations for each site.

III. GENERAL PROJECT LOCATIONS

The five projects are located throughout the North Unit Irrigation District. The following aerial exhibit provides the general locations of the five sites.

IV.BRINSON BOULEVARD SITE

A. Historical Information Review

Although there were past evaluations such as “Reconnaissance Study on Potential Hydroelectric Projects” by Tudor Engineering dated Jan., 1981 there were no real substantive calculations or information provided other than the District should further evaluate this site.

B. Aerial Site Plan

The Brinson Boulevard Site is located on the NUID main canal where it parallels the Central Oregon Irrigation District Pilot Butte Canal approximately 2 miles downstream of the canal diversion off of the Deschutes River. Figure 1, below provides and aerial view of the proposed Brinson Boulevard Site. The site is located at approximate Lat/Long 44°04’55 N and 121°17’ W. The street location is: from Bend Parkway turn right on Empire Blvd, right on Boyd Acres and left on Brinson. The site sits 0.6 miles due east of the Bend Parkway.

As may be seen in Figure 1, below, the site is located in close proximity to residential housing and lies in the City limits of the City of Bend, Oregon.

Figure 1: Combined NUID and COI canals at the Brinson Boulevard Site.

C. Summary Feasibility Project Details

The canal in this area is typical of most Central Oregon irrigation canals in that it is basaltic lava material in the canal bottom and rocky soil berm material in the banks (typically sidecast/placed during original canal construction) with the exception that the bed and banks were recently lined by the NUID with roller compacted concrete and shotcrete. A geotechnical investigation would be required to confirm the depth of the lava flow(s), materials and depth of materials, and/or any characteristics necessary for construction. For the purposes of this report, it is assumed that basaltic lava exists to the full depth of any necessary construction.

As shown in the figure above, the NUID project would include a forebay structure and trash rack, an approximate 1,100-LF penstock pipeline, a single francis or axial type turbine and energy dissipation system in a powerhouse, a tailrace structure and re-entry point for water into the NUID canal. The forebay structure would be constructed within the existing canal and would be a reinforced concrete structure with headwall, sidewalls, trash rack and access walk. An estimated 108-IN diameter penstock (assumed HDPE Weholite material) would connect to the headwall be constructed in trench at the northerly bank of the existing canal to the powerhouse. The powerhouse structure and site area would include the turbine, generator, energy dissipation valve (cone type or baffle structure probable) controls, substation and intertie yard for interconnection that would be shared with the Central Oregon Irrigation District. The tailrace structure would be a concrete structure that would receive water from the turbine draft tube and energy dissipation bypass valve and return flows to the NUID main canal.

D. Profile/Probable Gross Head

On Friday, June 12, 2009 a field elevation survey was performed at the site. The survey involved measuring the canal water surface elevation at the probable powerhouse site(s) and at the top of the drop. Additionally, the adjacent COID canal was surveyed to determine if a combined project may provide the NUID any savings.

There are two hydraulic drops within the study area. The first is immediately below the main fall as seen on Figure 1 above.   The gross head at this drop was measured to be approximately 23-FT. The second drop is approximately 1,100-LF downstream near where the probable powerhouse location is shown. The gross head from above the main fall to below the second one is approximately 35.5-FT.

E. Historical Flow Data

The flow data and total operational days from 2001 through the mid season of 2008 was obtained from NUID for the site. The data is measured upstream of the project site approximately 2 miles at the State Gauge. The NUID collates the data and averages it on a monthly basis. This information is provided in tabular form below.

		Op. Days	Min CFS	Ave CFS	Peak CFS			Op. Days	MIN CFS	Ave CFS	Peak CFS
	April	26.00	330.20	381.54	497.40		April	27.00	210.20	333.37	496.00
	May	31.00	474.50	622.21	753.80		May	31.00	73.00	257.78	666.80
	June	30.00	323.20	479.77	710.00		June	30.00	423.00	503.90	669.50
2001	July	31.00	166.90	354.38	538.10	**2005**	July	31.00	403.50	485.02	592.60
	August	31.00	189.40	338.92	449.90		August	31.00	445.00	486.34	540.70
	September	30.00	179.00	282.37	381.90		September	30.00	316.20	426.07	525.40
	October	11.00	187.30	326.31	454.90		October	7.00	195.70	318.96	482.40
	WT'D AVERAGES>>	190.00	270.88	406.08	551.00		WT'D AVERAGES>>	187.00	309.03	413.03	579.78
		Op. Days	**MIN CFS**	**Ave CFS**	**Peak CFS**			**Op. Days**	**MIN CFS**	**Ave CFS**	**Peak CFS**
	April	23.00	302.00	382.80	535.60		April	12.00	275.00	360.92	587.40
	May	31.00	398.70	545.60	680.30		May	31.00	249.00	593.67	762.00
	June	30.00	386.40	524.55	645.40		June	30.00	344.10	467.77	650.70
2002	July	31.00	323.20	514.34	595.20	**2006**	July	31.00	380.00	473.52	624.00
	August	31.00	295.70	461.94	561.30		August	31.00	429.00	482.84	575.00
	September	30.00	295.70	389.08	484.90		September	30.00	228.00	411.23	555.00
	October	11.00	257.70	304.67	353.40		October	19.00	210.00	340.10	410.00
	WT'D AVERAGES>>	187.00	330.42	463.87	572.49		WT'D AVERAGES>>	184.00	311.15	463.12	607.61
		Op. Days	**MIN CFS**	**Ave CFS**	**Peak CFS**			**Op. Days**	**MIN CFS**	**Ave CFS**	**Peak CFS**
	April	11.00	273.20	305.16	390.30		April	29.00	354.00	459.14	682.00
	May	31.00	266.50	489.13	715.40		May	31.00	533.00	650.48	698.00
	June	30.00	291.20	519.06	642.70		June	30.00	221.00	498.90	677.00
2003	July	31.00	370.00	499.01	590.00	**2007**	July	31.00	318.00	514.26	663.00
	August	31.00	257.70	362.09	467.40		August	31.00	363.00	448.81	546.00
	September	30.00	233.80	328.50	452.40		September	30.00	251.00	390.23	463.00
	October	7.00	284.50	382.35	452.40		October	17.00	140.00	298.33	350.00
	WT'D AVERAGES>>	171.00	283.43	428.76	557.13		WT'D AVERAGES>>	199.00	323.82	477.79	598.22
		Op. Days	**MIN CFS**	**Ave CFS**	**Peak CFS**			**Op. Days**	**MIN CFS**	**Ave CFS**	**Peak CFS**
	April	19.00	200.00	404.02	520.30		April	23.00	389.00	454.51	585.00
	May	31.00	367.60	482.73	764.80		May	31.00	295.00	590.84	810.00
	June	30.00	355.80	531.75	699.20		June	30.00	249.00	515.83	703.00
2004	July	31.00	418.10	514.15	696.40	**2008**	July	31.00	307.00	573.99	733.00
	August	31.00	316.20	443.95	507.50		August	31.00			
	September	30.00	222.90	358.85	447.50		September	30.00			
	October	13.00	218.70	346.61	477.20		October	22.00			
	WT'D AVERAGES>>	185.00	314.39	451.71	602.81		WT'D AVERAGES>>	198.00	177.17	313.33	416.05

F. Permitting/Utility Interconnect

Expected permitting for the project will include applying for and obtaining:

1) Federal Energy Regulatory Commission (FERC) conduit exemption. This site appears eligible for a FERC conduit exemption in that it involves waters already diverted into a delivery system, and that it is a project less than 15MW. Another criteria is that the real property interests for the project have been obtained. Although the ability of the District to pipe the canal has been addressed favorably in Federal court, the real property ownership beneath the powerhouse should be addressed by the District.
2) City of Bend building permit and zoning clearance for the powerhouse,
3) US Army Corps of Engineers maintenance exemption,
4) Oregon Water Resources Department issued water right for use of the canal water for hydropower production,
5) If Federal funding is involved in the project, the National Environmental Policy Act (NEPA) process must be followed for environmental clearance related to the project,

Depending upon the final design characteristics of the powerhouse and final findings by the District and the USBOR, additional easement and/or fee ownership of the land beneath the powerhouse may be required and a land use approval by the City of Bend may also be required.

Depending upon the funding sources involved in the project, other necessary processing may include Oregon Department of Energy bond/loan application, ODOE Business Energy Tax Credit application, Energy Trust grant application, Oregon Watershed Enhancement Board, Deschutes River Conservancy, ARRA or other funding requirements.

Interconnection with a utility requires an agreement for power purchase as well as an agreement for interconnection. The power purchase agreement will provide guidance on the term and rate for power purchase. The interconnection agreement will provide the technical terms and costs for the interconnection from the proposed plant into the utility grid.

In the case of this project, the nearest powerlines are owned by PacifiCorp and are located in Brinson Boulevard approximately 750-LF from the potential powerhouse site. There are no known reasons at the time of this study that a power purchase agreement and an interconnect agreement may not be obtained. It should be noted that for the purposes of this report the current published PUC power purchase rates (Schedule 37 peak/off-peak) will be used to develop revenue estimates for the project. These rates are subject to change. In fact, an adjustment to these rates is already under consideration and may be adopted after August, 2009. Additionally, for the purposes of this report, an estimated interconnect cost has been developed based upon recent experience in Central Oregon. It should be noted that the cost of interconnect is subject to the final utility requirements and these may not be obtained until a facility interconnect study is requested and funded and the cost of interconnect may vary significantly from what has been estimated herein.

G. Penstock Sizing, Length, and Net Head Development

We evaluated two alternatives for this site. First, a powerhouse located just downstream of the main fall. Second, a powerhouse located just below the second drop as shown on Figure 1. The powerhouse location just below the second drop was selected to optimize the benefit/cost ration for the project by increasing total project net head and combining the project with COI. Due to ground elevation differential, the combined powerhouse did not work as well at the base of the main fall.

For the purposes of this study, we used 1,100-LF of pipe and assume an additional 50-FT long forebay section to develop limited storage and pool to operate the plant. As the system will be low head, there are several pipe material alternatives that are available including HDPE Weholite pipe, reinforced concrete low-head pipe, steel pipe, and fiberglass pipe. For the purposes of this study, we have assumed that fully welded Weholite HDPE pipe will be used.

Based upon a Hazen-Williams coefficient of C=135 for the pipe, 1,100-LF of length and a flow range from 200 CFS to 775 CFS, we have selected a diameter of 108-IN for this project. The associated head loss through the pipe will be approximately 3-FT at 764 CFS which was the second maximal flow over the last 8 years of records at the site. At the average flow of approximately 450 CFS, the head loss through the pipe will be approximately 1.2-FT.

When including minor head losses through the powerhouse entrance reducer and butterfly valve, we estimate a total of approximately 5.0-FT of head loss for the entire system at maximum flow. The net head for the project is therefore 35.5-FT (gross) – 5.0-FT (losses) = 30.5-FT. Based upon the actual design for the project, this net head may require adjustment during design. Such adjustment will affect the revenue estimates for the project.

H. Turbine and Generator

There are options available for the procurement of the mechanical and electrical generating equipment for this project. Not only are there domestic and international supplier options but there are likely two options for the type of turbine manufactured including axial and francis versions. For the purposes of this report, we have provided a range of costs that include domestic and international manufacture as some funding sources (such as stimulus dollars) may limit the purchase to a domestic manufacturing source, only.

The international manufacturer recommended an axial flow turbine/generator setup for this site, operating at 360 RPM, 6300 volts and 84% efficiency through the generator (i.e turbine and generator losses included). The rated output being 968 KW at 440 CFS rated flow.

One domestic manufacturer recommended an axial flow (Kaplan type) turbine for this site rated for 1,250 KW at 600 CFS design flow.

The pricing for international (Chinese manufactured) turbines is significantly less than domestic manufacture. The cost estimate presented later in this section provides a low and high range that includes the Chinese turbine/generator and controls in the low end and the domestic system in the high end of the cost estimate.

I. Energy/Revenue Production Estimate

Three steps were taken to determine the feasibility level revenue estimate for the project. First, the expected power production was calculated on a composite average basis, then the expected utility revenue that would apply per kilowatt hour of production, then revenue was calculated on an annual basis based upon the expected utility rates over the period from 2010 to 2023 (as published).

The expected power production was determined based upon the net head for the project as estimated in Section F. above, the expected flow rates based upon the monthly average data provided over the 8 year sample period, and an overall feasibility level plant efficiency of 80%. This data yielded the information provided in the Power Production table included in the appendix at this end of this tab section.

This data was then averaged on a monthly basis to determine the average monthly production for the period from 2001 to 2008 as follows.

	2001-08 Ave kWH
April	**456,794.14**
May	**813,919.73**
June	**752,135.58**
July	**755,503.22**
August	**664,801.97**
September	**550,080.45**
October	**220,860.14**

PacifiCorp Schedule 37 provides the published rates that the utility will pay the hydroelectric power producing interconnection customer. These are known as avoided cost purchases and they apply to production of 10MW or less. The table below provides the published rates for on-peak and off-peak in cents paid per kilowatt hour. On-peak hours are 16 hours each day of the week except for Sundays. Holidays and Sundays are off-peak. For the period that NUID operates its system, we calculated the composite rate per kilowatt hour as indicated.

Year	On Peak	Off Peak	Composite Price ¢/kWh	$/kWh
2010	7.21	5.59	6.498658	0.06498658
2011	7.16	5.42	6.395966	0.06395966
2012	7.68	5.86	6.880838	0.06880838
2013	7.72	5.86	6.903274	0.06903274
2014	7.95	6.06	7.120101	0.07120101
2015	8.25	6.32	7.402537	0.07402537
2016	8.4	6.44	7.539364	0.07539364
2017	8.55	6.55	7.6718	0.076718
2018	8.69	6.66	7.798627	0.07798627
2019	8.86	6.78	7.946672	0.07946672
2020	9.03	6.91	8.099108	0.08099108
2021	9.01	6.86	8.065935	0.08065935
2022	9.03	6.83	8.06398	0.0806398
2023	9.06	6.82	8.076416	0.08076416

Given the composite rate paid per kilowatt hour per year and the average composite kilowatt hour monthly production estimated at the facility, the following feasibility level revenue estimates were calculated.

	Composite kWH 2001-2008	2010	2011	2012	2013	2014	2015	2016
April	456,794	29,685	29,216	31,431	31,534	32,524	33,814	34,439
May	813,919	52,894	52,058	56,004	56,187	57,952	60,251	61,364
June	752,136	48,879	48,106	51,753	51,922	53,553	55,677	56,706
July	755,503	49,098	48,322	51,985	52,154	53,793	55,926	56,960
August	664,802	43,203	42,521	45,744	45,893	47,335	49,212	50,122
September	550,080	35,748	35,183	37,850	37,974	39,166	40,720	41,473
October	220,860	14,353	14,126	15,197	15,247	15,725	16,349	16,651
Yearly Revenue		**$273,860**	**$269,532**	**$289,965**	**$290,910**	**$300,048**	**$311,950**	**$317,716**

	Composite kWH 2001-2008	2017	2018	2019	2020	2021	2022	2023
April	456,794	35,044	35,624	36,300	36,996	36,845	36,836	36,893
May	813,919	62,442	63,475	64,679	65,920	65,650	65,634	65,735
June	752,136	57,702	58,656	59,770	60,916	60,667	60,652	60,746
July	755,503	57,961	58,919	60,037	61,189	60,938	60,924	61,018
August	664,802	51,002	51,845	52,830	53,843	53,622	53,610	53,692
September	550,080	42,201	42,899	43,713	44,552	44,369	44,358	44,427
October	220,860	16,944	17,224	17,551	17,888	17,814	17,810	17,838
Yearly Revenue		**$323,297**	**$328,641**	**$334,880**	**$341,304**	**$339,906**	**$339,824**	**$340,348**

J. Discussion of NUID/COI Combined Project

Flows in the NUID canal at the Brinson Boulevard site vary from approximately 200 CFS to 800 CFS throughout the irrigation season annually. Similarly, the COID canal fluctuates from approximately 200 CFS to approximately 600 CFS. Although each District operates on similar seasons, the start and end date for the Districts is set by the Board of each District and does not necessarily coincide between the Districts. Additionally, certain factors within each District can affect its delivery volume from time to time. Based upon these flow rates, the combined flows of the Districts could range from 200 CFS if one District, only, were operating, to over 1,400 CFS at peak season with both operating. This wide range of potential flow rates does not lend itself to sizing one turbine to address the full range of flows. There is also the issue of combining the flows and then splitting them with relative accuracy. For these reasons, and to optimize the benefit versus cost of the project, combining the flows through a single turbine has not been pursued further.

The real benefit of combining District efforts at this site involve developing a hydropower plant building and interconnection that may be shared by the Districts. Additionally, it may be possible to share a generator between the turbines to reduce overall project costs. This possibility should be evaluated in design to determine if this approach could save additional dollars on the overall project.

For the purposes of this study, a dedicated penstock and forebay have been assumed for NUID. A single powerhouse for both Districts, a separate turbine and generator for each District, combined electrical components and interconnect, and wall separated tailrace structure have also been assumed.

K. Feasibility Level Cost Estimate for Project

The following cost estimate provides feasibility level cost estimating for the proposed project. As indicated above, combining efforts with the COI has been assumed and the associated costs reflect such cost saving measures.

Feasibility Level Cost Estimate						
ITEM	QTY	UNITS	COST/UNIT LOW	COST/UNIT HIGH	SUBTOTAL LOW	SUBTOTAL HIGH
Forebay	1	LS	$150,000	$175,000	$150,000	$175,000
Penstock Pipe	1100	LF	$900	$1,100	$990,000	$1,210,000
Energy Dissipation	1	LS	$250,000	$375,000	$250,000	$375,000
Outlet Structure	1	LS	$100,000	$175,000	$100,000	$175,000
Turb./Gen/Switchgear	1	LS	$900,000	$1,900,000	$900,000	$1,900,000
Install system	1	LS	$250,000	$400,000	$250,000	$400,000
Building	2500	SF	$150	$350	$375,000	$875,000
Excavation/Sitework	1	LS	$75,000	$175,000	$75,000	$175,000
Permits/Processing	1	LS	$50,000	$150,000	$50,000	$150,000
Electrical Service	1	LS	$650,000	$1,000,000	$650,000	$1,000,000
Electrical Interconnect	1	LS	$500,000	$1,100,000	$500,000	$1,100,000
Contingency	15%				$643,500	$1,130,250
Design/Legal/C.M.	10%				$429,000	$753,500
				TOTAL	**$5,362,500**	**$9,418,750**

L. Financing and/or Grant Options

The Oregon Department of Energy administers the Business Energy Tax Credit Program. For a municipal organization such as NUID, the program follows a pass-through process to allow the District to pass on credits to a private entity with an Oregon tax burden. To facilitate this process, an incentive is credited to the private business utilizing the tax credits. This net grant opportunity to the District is approximately 33% of the project cost.

The Energy Trust of Oregon provides incentive funds for hydropower projects that are marginally viable or non-viable in the absence of such incentive funds. The Energy Trust evaluates projects on a case by case basis and based upon the proposed production and marginality of the project makes a determination at what level, if any, they will participate financially. One limitation of this funding source is that they will only provide construction related funds for project interconnecting with PacifiCorp or Portland General Electric.

Typically, water conservation funds are also available for projects that conserve seepage water and are willing to transfer conserved water in-stream. At the Brinson Boulevard location, the District has already implemented a water conservation project therefore the propose project will not result in any substantial water savings.

Green Tag renewable energy credits a will be generated by the project. Should Energy Trust funds be used, the Energy Trust will be interested in retaining all or a portion of these credits. Credits are currently worth approximately $24/KW of generation.

Although water conservation may not be a key element on the project, alternative energy production is a priority of the State and Nation. The United States Bureau of Reclamation, Oregon Watershed Enhancement Board, and Natural Resources Conservation Service should be approached regarding the long term benefits of the project and on-going grants available.

M. Simple Payback/Benefit vs. Cost of Project

The following table provides a simple cost benefit analysis for year one of the completed project (2010) based upon assuming the full project debt and then assuming BETC and energy Trust participation.

Benefit versus Cost	Low	High
Project Cost Without Financial Assistance	$5,362,500	$9,418,750
Ammortization Given 20 Year Term and 6% Int.	$467,527	$821,169
Revenue Year 2010	$273,860	$273,860
Benefit/Cost Ratio	**0.585763**	**0.3335002**
Probable BETC 33%	$1,769,625	$3,108,188
Possible ET Participation	$500,000	$500,000
Net Project Debt.	$3,092,875	$5,810,563
Ammortization Give 20 Year Term and 6% Int.	$269,650	$506,591
Benefit/Cost Ratio	**1.0156128**	**0.5405939**

The simple payback period for the project with no grants applied ranges from 17 to 30 years depending upon true project cost. The simple payback period for the project with BETC and ET participation as indicated ranges from 10 to 18 years depending upon true project cost.

The results indicate that the most viable project would be a project that is designed and constructed with the lowest cost in mind, with international equipment, and assumes approval of BETC and Energy Trust of Oregon for tax credits and grant funding.

APPENDIX TO TAB 1 – ENERGY PRODUCTION ESTIMATES

	Month	Op. Days	Ave CFS	Net Head (Ft.)	Eff.	Ave MW	Annual kWH
2001	April	26	381.54	30.5	80%	0.79	492,303.00
	May	31	622.21	30.5	80%	1.29	957,233.17
	June	30	479.77	30.5	80%	0.99	714,288.08
	July	31	354.38	30.5	80%	0.73	545,192.61
	August	31	338.92	30.5	80%	0.70	521,408.31
	September	30	282.37	30.5	80%	0.58	420,396.28
	October	11	326.31	30.5	80%	0.67	178,132.08
	WT'D AVERAGES>>	190	406.0761	30.5	80%	0.84	3,828,953.54
2002	Month	Op. Days	Ave CFS	Net Head (Ft.)	Eff.	Ave MW	Annual kWH
	April	23	382.8	30.5	80%	0.79	436,937.00
	May	31	545.6	30.5	80%	1.13	839,373.23
	June	30	524.55	30.5	80%	1.08	780,957.15
	July	31	514.34	30.5	80%	1.06	791,281.58
	August	31	461.94	30.5	80%	0.96	710,667.29
	September	30	389.08	30.5	80%	0.80	579,267.58
	October	11	304.67	30.5	80%	0.63	166,318.84
	WT'D AVERAGES>>	187	463.866	30.5	80%	0.96	4,304,802.67
2003	Month	Op. Days	Ave CFS	Net Head (Ft.)	Eff.	Ave MW	Annual kWH
	April	11	305.16	30.5	80%	0.63	166,586.33
	May	31	489.13	30.5	80%	1.01	752,497.49

	Month	Op. Days	Ave CFS	Net Head (Ft.)	Eff.	Ave MW	Annual kWH
	June	30	519.06	30.5	80%	1.07	772,783.57
	July	31	499.01	30.5	80%	1.03	767,697.28
	August	31	362.09	30.5	80%	0.75	557,053.99
	September	30	328.5	30.5	80%	0.68	489,075.25
	October	7	382.35	30.5	80%	0.79	132,824.50
	WT'D AVERAGES>>	171	428.7552	30.5	80%	0.89	3,638,518.41
2004	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	19	404.02	30.5	80%	0.84	380,956.62
	May	31	482.73	30.5	80%	1.00	742,651.47
	June	30	531.75	30.5	80%	1.10	791,676.61
	July	31	514.15	30.5	80%	1.06	790,989.27
	August	31	443.95	30.5	80%	0.92	682,990.74
	September	30	358.85	30.5	80%	0.74	534,260.75
	October	13	346.61	30.5	80%	0.72	223,616.32
	WT'D AVERAGES>>	185	451.7083	30.5	80%	0.93	4,147,141.78
2005	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	27	333.37	30.5	80%	0.69	446,693.20
	May	31	257.78	30.5	80%	0.53	396,579.24
	June	30	503.9	30.5	80%	1.04	750,213.15
	July	31	485.02	30.5	80%	1.00	746,174.50
	August	31	486.34	30.5	80%	1.01	748,205.24
	September	30	426.07	30.5	80%	0.88	634,338.79
	October	7	318.96	30.5	80%	0.66	110,803.46

	WT'D AVERAGES>>	187	413.0275	30.5	80%	0.85	3,833,007.58
2006	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	12	360.92	30.5	80%	0.75	214,937.04
	May	31	593.67	30.5	80%	1.23	913,326.08
	June	30	467.77	30.5	80%	0.97	696,422.32
	July	31	473.52	30.5	80%	0.98	728,482.43
	August	31	482.84	30.5	80%	1.00	742,820.70
	September	30	411.23	30.5	80%	0.85	612,244.80
	October	19	340.1	30.5	80%	0.70	320,685.48
	WT'D AVERAGES>>	184	463.1189	30.5	80%	0.96	4,228,918.84
2007	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	29	459.14	30.5	80%	0.95	660,788.06
	May	31	650.48	30.5	80%	1.35	1,000,724.89
	June	30	498.9	30.5	80%	1.03	742,769.08
	July	31	514.26	30.5	80%	1.06	791,158.50
	August	31	448.81	30.5	80%	0.93	690,467.56
	September	30	390.23	30.5	80%	0.81	580,979.72
	October	17	298.33	30.5	80%	0.62	251,689.39
	WT'D AVERAGES>>	199	477.7921	30.5	80%	0.99	4,718,577.21
2008	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	23	454.51	30.5	80%	0.94	518,788.50
	May	31	590.84	30.5	80%	1.22	908,972.29

	June	30	515.83	30.5	80%	1.07	767,974.70
	July	31	573.99	30.5	80%	1.19	883,049.56
	WT'D AVERAGES>>	198	313.3251	30.5	80%	0.65	3,078,785.05

V. SMITH ROCK DROP SITE

A. Historical Information Review

No historical information was provided for review on this site.

B. Aerial Site Plan (See Figure 2, below) and Site Characteristics

The Smith Rock Drop site is located on the NUID Main Canal at approximate LAT/LONG 44° 20' 52 N 121° 06' 54 W near the Smith Rocks State Park just 3 miles to the east of Terrebonne, Oregon. The drop is at the approximate 25-mile point along the canal (i.e. 25 miles below the diversion into the canal in Bend, Oregon. Smith Rock Way is a County Road that runs west to east immediately adjacent to the proposed powerhouse site. A Central Electric Cooperative powerline runs immediately adjacent to the site in Smith Rock Way on the south side of the road.

The canal in this area is typical of most Central Oregon irrigation canals in that it is basaltic lava material in the canal bottom and rocky soil berm material in the banks (typically sidecast/placed during original canal construction). A geotechnical investigation would be required to confirm the depth of the lava flow(s), materials and depth of materials, and/or any characteristics necessary for construction. For the purposes of this report, it is assumed that basaltic lava exists to the full depth of any necessary construction.

The site is located in a rural farming area with no structures or houses immediately adjacent to the site. As may be seen in Figure 2, below, the nearest farm house is located approximately 400 feet from the project site to the West.

Figure 2: Smith Rock Drop

C. Summary Feasibility Project Details

The canal in this area is typical of most Central Oregon irrigation canals in that it is basaltic lava material in the canal bottom and rocky soil berm material in the banks (typically sidecast/placed during original canal construction) with the exception that the bed and banks were recently lined by the NUID with roller compacted concrete and shotcrete. A geotechnical investigation would be required to confirm the depth of the lava flow(s), materials and depth of materials, and/or any characteristics necessary for construction. For the purposes of this report, it is assumed that basaltic lava exists to the full depth of any necessary construction.

As shown in the figure above, the NUID project would include a forebay structure and trash rack, an approximate 600-LF penstock pipeline, a single axial type turbine and energy dissipation system in a powerhouse, a tailrace structure and re-entry point for water into the NUID canal. The forebay structure would be constructed within the existing canal and would be a reinforced concrete structure with headwall, sidewalls, trash rack and access walk. An estimated 108-IN diameter penstock (assumed HDPE Weholite material) would connect to the headwall be constructed in trench at the westerly bank of the existing canal to the powerhouse. The powerhouse structure and site area would include the turbine, generator, energy dissipation (concrete baffles), controls, substation and intertie yard for interconnection. The tailrace structure would be a concrete structure that would receive water from the turbine draft tube and energy dissipation baffle system and return flows to the NUID main canal.

D. Profile/Probable Gross Head

On Friday, June 12, 2009 a field elevation survey was performed at the site. The survey involved measuring the canal water surface elevation at the probable powerhouse site and at the top of the drop. The gross elevation difference in the 500-FT canal length was found to be approximately 18.5-FT. Elevation was also determined at the top of a riffle approximately 200-FT further upstream from the main drop and an additional 1.1-FT of head could be gained for a total of 19.6-FT of gross head in 700-FT. The water surface elevations shown for the top and bottom of the drop and the alternative upstream location are also shown on Figure 2, above.

E. Historical Flow Data

The NUID operates a weir measurement device on its Main Canal upstream from the Smith Rock Drop Site. This weir is known as the 25/75 Discharge. This data represents the approximate flow rates that would be passed through the proposed powerhouse facility.

		Op. Days	MIN CFS	Ave CFS	Peak CFS			Op. Days	MIN CFS	Ave CFS	Peak CFS
2001	**April**	26	276.00	335.64	408.20	**2005**	**April**	27	194.70	277.58	355.90
	May	31	400.70	552.75	683.00		**May**	31	64.00	223.11	589.10
	June	30	287.10	431.93	662.00		**June**	30	369.60	442.03	599.90
	July	31	134.90	313.80	480.10		**July**	31	271.60	396.42	505.50
	August	31	170.90	296.59	400.70		**August**	31	371.90	409.05	482.00
	September	30	162.90	247.99	327.10		**September**	30	265.60	361.91	428.00

	October	11	169.30	289.80	395.80		**October**	7	161.30	271.85	398.20
	WT'D AVERAGES>>	190	233.89	359.84	490.09		**WT'D AVERAGES>>**	187	253.34	349.74	492.56
		Op. Days	**MIN CFS**	**Ave CFS**	**Peak CFS**			**Op. Days**	**MIN CFS**	**Ave CFS**	**Peak CFS**
	April	23	271.60	345.66	462.70		**April**	12	204.20	297.26	513.50
	May	31	349.30	487.08	616.10		**May**	31	206.10	520.80	674.00
	June	30	335.90	461.37	572.90		**June**	30	5284.90	399.77	572.90
2002	**July**	31	276.00	450.80	527.00	**2006**	**July**	31	335.90	416.03	581.00
	August	31	257.60	407.14	518.90		**August**	31	376.50	425.89	497.90
	September	30	261.60	351.39	440.40		**September**	30	179.50	360.35	495.30
	October	11	232.70	268.31	291.50		**October**	19	167.70	298.90	355.90
	WT'D AVERAGES>>	187	289.31	411.66	512.14		**WT'D AVERAGES>>**	184	1076.32	403.77	539.73
		Op. Days	**MIN CFS**	**Ave CFS**	**Peak CFS**			**Op. Days**	**MIN CFS**	**Ave CFS**	**Peak CFS**
	April	11	232.70	262.80	296.00		**April**	29	282.70	398.06	599.90
	May	31	223.20	424.68	656.00		**May**	31	475.10	592.64	638.40
	June	30	263.60	456.08	574.90		**June**	30	171.60	445.93	616.10
2003	**July**	31	302.60	426.63	518.90	**2007**	**July**	31	276.00	464.42	608.00
	August	31	230.80	331.20	433.00		**August**	31	327.50	405.95	492.80
	September	30	96.00	300.81	433.00		**September**	30	208.00	359.60	423.00
	October	7	309.30	359.94	423.00		**October**	17	105.70	259.67	316.00
	WT'D AVERAGES>>	171	227.88	378.80	504.67		**WT'D AVERAGES>>**	199	275.48	429.53	542.00
		Op. Days	**MIN CFS**	**Ave CFS**	**Peak CFS**			**Op. Days**	**MIN CFS**	**Ave CFS**	**Peak CFS**
	April	19	204.20	388.68	475.10		**April**	23	347.00	421.70	556.70
	May	31	324.80	437.83	674.00		**May**	31	271.60	556.91	801.00
	June	30	307.10	457.18	602.60		**June**	30	228.90	486.97	686.00
2004	**July**	31	353.70	438.20	610.20	**2008**	**July**	31	278.20	554.43	710.00
	August	31	261.60	379.04	651.20		**August**	31			
	September	30	198.50	311.02	378.80		**September**	30			
	October	13	194.70	315.48	433.00		**October**	22			
	WT'D AVERAGES>>	185	274.17	396.97	562.68		**WT'D AVERAGES>>**	198	161.07	296.77	405.18

F. Permitting/Utility Interconnect

Expected permitting for the project will include applying for and obtaining:

1) Federal Energy Regulatory Commission (FERC) conduit exemption. This site appears eligible for a FERC conduit exemption in that it involves waters already diverted into a delivery system, and that it is a project less than 15MW. Another criteria is that the real property interests for the project have been obtained. Although the ability of the District to

pipe the canal has been addressed favorably in Federal court, the real property ownership beneath the powerhouse should be addressed by the District.

2) Crook County building permit and zoning clearance for the powerhouse,
3) US Army Corps of Engineers maintenance exemption,
4) Oregon Water Resources Department issued water right for use of the canal water for hydropower production,
5) If Federal funding is involved in the project, the National Environmental Policy Act (NEPA) process must be followed for environmental clearance related to the project,

Depending upon the final design characteristics of the powerhouse and final findings by the District and the USBOR, additional easement and/or fee ownership of the land beneath the powerhouse may be required and a land use approval by Crook County may also be required.

Depending upon the funding sources involved in the project, other necessary processing may include Oregon Department of Energy bond/loan application, ODOE Business Energy Tax Credit application, Oregon Watershed Enhancement Board, Deschutes River Conservancy, ARRA or other funding requirements.

Interconnection with a utility requires an agreement for power purchase as well as an agreement for interconnection. The power purchase agreement will provide guidance on the term and rate for power purchase. The interconnection agreement will provide the technical terms and costs for the interconnection from the proposed plant into the utility grid.

In the case of this project, the nearest powerlines are owned by the Central Electric Cooperative and are located in Smith Rock Way adjacent to the proposed powerhouse sire. There are no known reasons at the time of this study that a power purchase agreement and an interconnect agreement may not be obtained. It should be noted that for the purposes of this report the current published PacfiCorp power purchase rates (Schedule 37 peak/off-peak) will be used to develop revenue estimates for the project. Other rates may be negotiated with CEC. Such negotiations are outside of the scope of this study. These rates used are subject to change. In fact, an adjustment to these rates is already under consideration and may be adopted after August, 2009. Additionally, for the purposes of this report, an estimated interconnect cost has been developed based upon recent experience in Central Oregon. It should be noted that the cost of interconnect is subject to the final utility requirements and these may not be obtained until a facility interconnect study is requested and funded and the cost of interconnect may vary significantly from what has been estimated herein.

G. Penstock Sizing, Length, and Net Head Development

For the purposes of this study, we used 600-LF of pipe and assume an additional 150-FT long forebay section to develop limited storage and pool to operate the plant. As the system will be low head, there are several pipe material alternatives that are available including HDPE Weholite pipe, reinforced concrete low-head pipe, steel pipe, and fiberglass pipe. For the purposes of this study, we have assumed that fully welded Weholite HDPE pipe will be used.

Based upon a Hazen-Williams coefficient of C=135 for the pipe, 600-LF of length and a flow range from 100 CFS to 800 CFS, we have selected a diameter of 108-IN for this project. The associated head loss through the pipe will be approximately 1-FT at 683 CFS which was the second maximal flow over the last 8 years of records at the site.

When including minor head losses through the powerhouse entrance reducer and butterfly valve, we estimate a total of approximately 3.5-FT of head loss for the entire system at maximum flow. The net head for the project is therefore 19.6-FT (gross) – 3.5-FT (losses) = 16.1-FT. Based upon the actual design for the project, this net head may require adjustment during design. Such adjustment will affect the revenue estimates for the project.

H. Turbine and Generator

There are options available for the procurement of the mechanical and electrical generating equipment for this project. Not only are there domestic and international supplier options but there are likely two options for the type of turbine manufactured including axial and francis versions. For the purposes of this report, we have provided a range of costs that include domestic and international manufacture as some funding sources (such as stimulus dollars) may limit the purchase to a domestic manufacturing source, only.

The international manufacturer recommended an axial flow turbine/generator setup for this site, operating at 225 RPM, 6300 volts and 83% efficiency through the generator (i.e. turbine and generator efficiencies combined). At 400 CFS average flow rate, the rated output would be 444 KW.

One domestic manufacturer recommended an axial flow (Kaplan type) turbine for this site. At 600 CFS design flow rate, the rated output would be 610 KW.

The pricing for international (Chinese manufactured) turbines is significantly less than domestic manufacture. The cost estimate presented later in this section provides a low and high range that includes the Chinese turbine/generator and controls in the low end and the domestic system in the high end of the cost estimate.

I. Energy/Revenue Production Estimate

Three steps were taken to determine the feasibility level revenue estimate for the project. First, the expected power production was calculated on a composite average basis, then the expected utility revenue that would apply per kilowatt hour of production, then revenue was calculated on an annual basis based upon the expected utility rates over the period from 2010 to 2023 (as published in Schedule 37).

The expected power production was determined based upon the net head for the project as estimated in Section F. above, the expected flow rates based upon the monthly average data provided over the 8 year sample period, and an overall feasibility level plant efficiency of 80%. This data yielded the information provided in the Power Production appendix at the end of this section.

This data was then averaged on a monthly basis to determine the average monthly production for the period from 2001 to 2008 as follows.

	2001-08 Ave kWH
April	**212,079.50**

May	**382,925.45**
June	**349,628.09**
July	**349,123.13**
August	**306,086.72**
September	**255,846.65**
October	**102,528.43**

For study purposes, PacifiCorp Schedule 37 published rates have been used to evaluate the potential revenue from the project. Negotiations with CEC will determine the actual final pricing. The following rates are known as avoided cost purchases and they apply to production of 10MW or less. The table below provides the published rates for on-peak and off-peak in cents paid per kilowatt hour. On-peak hours are 16 hours each day of the week except for Sundays. Holidays and Sundays are off-peak. For the period that NUID operates its system, we calculated the composite rate per kilowatt hour as indicated.

Year	On Peak	Off Peak	Composite Price ¢/kWh	$/kWh
2010	7.21	5.59	6.498658	0.06498658
2011	7.16	5.42	6.395966	0.06395966
2012	7.68	5.86	6.880838	0.06880838
2013	7.72	5.86	6.903274	0.06903274
2014	7.95	6.06	7.120101	0.07120101
2015	8.25	6.32	7.402537	0.07402537
2016	8.4	6.44	7.539364	0.07539364
2017	8.55	6.55	7.6718	0.076718
2018	8.69	6.66	7.798627	0.07798627
2019	8.86	6.78	7.946672	0.07946672
2020	9.03	6.91	8.099108	0.08099108
2021	9.01	6.86	8.065935	0.08065935
2022	9.03	6.83	8.06398	0.0806398
2023	9.06	6.82	8.076416	0.08076416

Given the composite rate paid per kilowatt hour per year and the average composite kilowatt hour monthly production estimated at the facility, the following feasibility level revenue estimates were calculated.

	Composite kWH 2001-2008	2010	2011	2012	2013	2014	2015	2016
April	212,080	13,782	13,565	14,593	14,640	15,100	15,699	15,989
May	382,926	24,885	24,492	26,349	26,434	27,265	28,346	28,870
June	349,628	22,721	22,362	24,057	24,136	24,894	25,881	26,360
July	349,123	22,688	22,330	24,023	24,101	24,858	25,844	26,322
August	306,087	19,892	19,577	21,061	21,130	21,794	22,658	23,077
September	255,847	16,627	16,364	17,604	17,662	18,217	18,939	19,289
October	102,529	6,663	6,558	7,055	7,078	7,300	7,590	7,730
Yearly Revenue		**$127,258**	**$125,247**	**$134,742**	**$135,181**	**$139,427**	**$144,958**	**$147,637**

	Composite kWH 2001-2008	2017	2018	2019	2020	2021	2022	2023
April	212,080	16,270	16,539	16,853	17,177	17,106	17,102	17,128
May	382,926	29,377	29,863	30,430	31,014	30,887	30,879	30,927
June	349,628	26,823	27,266	27,784	28,317	28,201	28,194	28,237
July	349,123	26,784	27,227	27,744	28,276	28,160	28,153	28,197
August	306,087	23,482	23,871	24,324	24,790	24,689	24,683	24,721
September	255,847	19,628	19,953	20,331	20,721	20,636	20,631	20,663
October	102,529	7,866	7,996	8,148	8,304	8,270	8,268	8,281
Yearly Revenue		**$150,231**	**$152,714**	**$155,613**	**$158,598**	**$157,949**	**$157,910**	**$158,154**

J. Feasibility Level Cost Estimate for Project

The following cost estimate provides feasibility level cost estimating for the proposed project.

Feasibility Level Cost Estimate						
ITEM	QTY	UNITS	COST/UNIT LOW	COST/UNIT HIGH	SUBTOTAL LOW	SUBTOTAL HIGH
Forebay	1	LS	$150,000	$175,000	$150,000	$175,000
Penstock Pipe	600	LF	$900	$1,100	$540,000	$660,000
Energy Dissipation	1	LS	$250,000	$375,000	$250,000	$375,000
Outlet Structure	1	LS	$125,000	$175,000	$125,000	$175,000
Turb./Gen/Switchgear	1	LS	$625,000	$1,900,000	$625,000	$1,900,000
Install system	1	LS	$250,000	$400,000	$250,000	$400,000
Building	1800	SF	$250	$450	$450,000	$810,000
Excavation/Sitework	1	LS	$100,000	$250,000	$100,000	$250,000
Permits/Processing	1	LS	$50,000	$150,000	$50,000	$150,000
Electrical Service	1	LS	$450,000	$750,000	$450,000	$750,000

Electrical Interconnect	1	LS	$300,000	$800,000	$200,000	$800,000
Contingency	15%				$478,500	$966,750
Design/Legal/C.M.	10%				$319,000	$644,500
				TOTAL	**$3,987,500**	**$8,056,250**

K. Financing and/or Grant Options

The Oregon Department of Energy administers the Business Energy Tax Credit Program. For a municipal organization such as NUID, the program follows a pass-through process to allow the District to pass on credits to a private entity with an Oregon tax burden. To facilitate this process, an incentive is credited to the private business utilizing the tax credits. This net grant opportunity to the District is approximately 33% of the project cost.

The Energy Trust of Oregon only works with projects in the PacifiCorp or PGE territories therefore ET funds will not be an option for this project.

Typically, water conservation funds are also available for projects that conserve seepage water and are willing to transfer conserved water in-stream. At the Smith Rock Drop location seepage may be estimated and an associated water conservation grant pursued. Grant programs are available for water conservation through the Deschutes River Conservancy, the USBR, Oregon Watershed Enhancement Board, the Natural Resources Conservation Service and potentially the Crooked River Watershed Council.

Renewable energy credit (REC) marketplace may also be a potential for this project although minimal revenue would be generated from RECs.

L. Simple Payback/Benefit vs. Cost of Project

The following table provides a simple cost benefit analysis for year one of the completed project (2010) based upon assuming the full project debt and then assuming BETC participation.

Benefit versus Cost	Low	High
Project Cost Without Financial Assistance	$3,987,500	$8,056,250
Ammortization Given 20 Year Term and 6% Int.	$467,527	$702,380
Revenue Year 2010	$127,258	$127,258
Benefit/Cost Ratio	**0.2721939**	**0.1811811**
Probable BETC 33%	$1,315,875	$2,658,563
Possible ET Participation	$0	$0
Net Project Debt.	$2,671,625	$5,397,688
Ammortization Given 20 Year Term and 6% Int.	$269,650	$470,595
Benefit/Cost Ratio	**0.4719377**	**0.2704194**

The simple payback period for the project with no grants applied ranges from 26 to well over 50 years depending upon true project cost. The simple payback period for the project with BETC and ET participation as indicated ranges from 18 to 36 years depending upon true project cost.

With a best-case benefit versus cost of 0.47 for the first year of operation and a best case simple payback period of 18 years, the results indicate that the project does not appear financially feasible.

APPENDIX TO TAB 2 – ENERGY PRODUCTION ESTIMATE

	Month	Op. Days	Ave CFS	Net Head (Ft.)	Eff.	Ave MW	Annual kWH
2001	April	26	335.64	16.00	80%	0.36	227,188.46
	May	31	552.75	16.00	80%	0.60	446,097.36
	June	30	431.93	16.00	80%	0.47	337,344.65
	July	31	313.80	16.00	80%	0.34	253,252.56
	August	31	296.59	16.00	80%	0.32	239,363.21
	September	30	247.99	16.00	80%	0.27	193,684.39
	October	11	289.80	16.00	80%	0.31	82,990.86
	WT'D AVERAGES>>	190	359.84	16.00	80%	0.39	1,779,921.49
2002	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	23	345.66	16.00	80%	0.37	206,974.18
	May	31	487.08	16.00	80%	0.53	393,098.33
	June	30	461.37	16.00	80%	0.50	360,337.79
	July	31	450.80	16.00	80%	0.49	363,818.52
	August	31	407.14	16.00	80%	0.44	328,582.68
	September	30	351.39	16.00	80%	0.38	274,441.55
	October	11	268.31	16.00	80%	0.29	76,836.71
	WT'D AVERAGES>>	187	411.66	16.00	80%	0.45	2,004,089.75
2003	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	11	262.80	16.00	80%	0.29	75,258.79
	May	31	424.68	16.00	80%	0.46	342,738.35
	June	30	456.08	16.00	80%	0.49	356,206.21

	Month	Op. Days	Ave CFS	Net Head (Ft.)	Eff.	Ave MW	Annual kWH
	July	31	426.63	16.00	80%	0.46	344,312.10
	August	31	331.20	16.00	80%	0.36	267,295.24
	September	30	300.81	16.00	80%	0.33	234,937.71
	October	7	359.94	16.00	80%	0.39	65,594.49
	WT'D AVERAGES>>	171	378.80	16.00	80%	0.41	1,686,342.90
2004	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	19	388.68	16.00	80%	0.42	192,258.26
	May	31	437.83	16.00	80%	0.47	353,351.07
	June	30	457.18	16.00	80%	0.50	357,065.33
	July	31	438.20	16.00	80%	0.48	353,649.68
	August	31	379.04	16.00	80%	0.41	305,904.55
	September	30	311.02	16.00	80%	0.34	242,911.89
	October	13	315.48	16.00	80%	0.34	106,771.27
	WT'D AVERAGES>>	185	396.97	16.00	80%	0.43	1,911,912.05
2005	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	27	277.58	16.00	80%	0.30	195,115.22
	May	31	223.11	16.00	80%	0.24	180,061.11
	June	30	442.03	16.00	80%	0.48	345,232.92
	July	31	396.42	16.00	80%	0.43	319,931.10
	August	31	409.05	16.00	80%	0.44	330,124.15
	September	30	361.91	16.00	80%	0.39	282,657.84
	October	7	271.85	16.00	80%	0.29	49,541.21
	WT'D AVERAGES>>	187	349.74	16.00	80%	0.38	

							1,702,663.55
2006	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	12	297.26	16.00	80%	0.32	92,866.04
	May	31	520.80	16.00	80%	0.56	420,312.08
	June	30	399.77	16.00	80%	0.43	312,227.15
	July	31	416.03	16.00	80%	0.45	335,757.36
	August	31	425.89	16.00	80%	0.46	343,714.89
	September	30	360.35	16.00	80%	0.39	281,439.46
	October	19	298.90	16.00	80%	0.32	147,849.11
	WT'D AVERAGES>>	184	403.77	16.00	80%	0.44	1,934,166.09
2007	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	29	398.06	16.00	80%	0.43	300,528.55
	May	31	592.64	16.00	80%	0.64	478,290.61
	June	30	445.93	16.00	80%	0.48	348,278.89
	July	31	464.42	16.00	80%	0.50	374,810.55
	August	31	405.95	16.00	80%	0.44	327,622.29
	September	30	359.60	16.00	80%	0.39	280,853.69
	October	17	259.67	16.00	80%	0.28	114,923.78
	WT'D AVERAGES>>	199	429.53	16.00	80%	0.47	2,225,308.38
2008	**Month**	**Op. Days**	**Ave CFS**	**Net Head (Ft.)**	**Eff.**	**Ave MW**	**Annual kWH**
	April	23	421.70	16.00	80%	0.46	252,505.38
	May	31	556.91	16.00	80%	0.60	449,454.69

	June	30	486.97	16.00	80%	0.53	380,331.82
	July	31	554.43	16.00	80%	0.60	447,453.20
	WT'D AVERAGES>>	198		16.00	80%	0.00	-

VI. HAYSTACK RESERVOIR SITE

A. Historical Information Review

The project site has been evaluated several times over the years. The most compelling evaluation was performed by Tudor Engineering in a report dated March 1982 and entitled "FEASIBILITY REPORT ON THE POTENTIAL HYDROELECTRIC DEVELOPMENT – NORTH UNIT CANAL POWER PROJECTS". This report focused on the Haystack, Mile 45 and Mile 51 power projects. This document was used as a reference in evaluating the Haystack site for current power production potential.

B. Aerial Site Plan

The Haystack Reservoir site is located approximately 37 miles north of Bend, Oregon at approximate Lat/Long 44° 30' N 121° 09' W just to the east of Highway 97. The property beneath and around the reservoir is owned by the United States Bureau of Reclamation and includes a Reclamation Boundary that encompasses the site. The North Unit Main canal was completed in 1948. At that time there was no Haystack Dam or associated reservoir. Haystack Dam was added in 1958, along with a feeder canal to carry water to the reservoir and outlet canal to release water back to the main canal. From a hydraulics standpoint, Haystack Dam is in parallel to the existing chute that is now termed the "Bypass Chute" by the NUID.

The site is located in a rural farming area with no structures or houses immediately adjacent to the site. As may be seen in Figure 3, below, the nearest farm house is located approximately 300 feet from the project site to the West.

PacifiCorp has an existing power pole facility located at the intersection of SW Jericho Lane and SW Bear Drive.

Figure 3: Haystack Reservoir Bypass Canal Alternative

C. Summary Feasibility Project Details

Figure 3 indicates the proposed project at the Haystack Reservoir site. It involves intercepting the incoming flows from the main canal and passing them through the proposed powerhouse site back to the main canal. Excess flows over the rated capacity of the plant would be passed into the Haystack Reservoir to maintain. Haystack would continue its purpose as a storage reservoir that may be called upon by the district to regulate system flows.

The penstock excavation would parallel the existing Bypass Chute to the east of it. The ground in this area is typical of most Central Oregon ground in that it is basaltic lava material. A geotechnical investigation would be required to confirm the depth of the lava flow(s), materials and depth of materials, and/or any characteristics necessary for construction. For the purposes of this report, it is assumed that basaltic lava exists to the full depth of any necessary construction.

As shown in the Figure 3, the NUID project would include a forebay structure and trash rack, an approximate 1,600-LF penstock pipeline, a single francis or axial type turbine and energy dissipation system in a powerhouse, a tailrace structure and re-entry point for water into the NUID canal. The forebay structure would be constructed within the existing canal and would be a reinforced concrete structure with headwall, sidewalls, trash rack and access walk. An estimated 90-IN diameter penstock (assumed coated and lined steel material) would connect to the headwall and would be constructed in trench offset to the east of the existing bypass chute. The penstock would enter the powerhouse located near the main canal downstream of the existing Haystack Reservoir outlet structure. The powerhouse structure and site area would include the turbine, generator, energy dissipation (potentially a cone valve), controls, substation and intertie yard for interconnection. The tailrace structure would be a concrete structure that would receive water from the turbine draft tube and energy dissipation system and return flows to the NUID main canal.

D. Profile/Probable Gross Head

Three alternatives were reviewed on a feasibility level basis. The first was a direct connection to the control gates within the dam and a powerhouse located near the existing dam outlet structure. The second was a forebay off of the feeder canal near the dam and a penstock that parallels the dam to a powerhouse site just below the dam outlet structure. The final alternative and the one selected was that as shown on Figure 3 above.

In summary, the issue with connection to the internal dam control gates is the physical connection, the age of the facilities, the expected high head loss through the existing facilities, agency processing timing, and the fact that the head in the reservoir fluctuates annually and provides the least head for the proposed project overall. The issue with the connection to the feeder canal paralleling the dam face is the excavation adjacent to the dam toe or alternative concrete saddle system for the piping, and that the normal flows passed through the bypass chute throughout the season would not pass through the power plant. These bypass chute flows create more than enough revenue to pay for the additional length of pipe to support the selected alternative.

Based upon a 90-IN steel penstock approximately 1,600-LF in length, the expected headwater level will be at approximate elevation 2848 at the forebay and tailwater will be at approximate elevation 2762, although this will fluctuate depending upon flows. Gross head is approximately 90-FT for the site and net head is approximately 85-FT to 86-FT.

E. Historical Flow Data

The NUID operates a weir/staff gauge measurement device on its Main Canal at the Haystack discharge. This data only accounts for reservoir releases. Additionally, the District took measurements at its bypass chute historically. The minimum, average and peak flows reported below indicate measurements taken at the reservoir discharge. The "Spill CFS" column were developed using monthly average bypass chute flows measured in the 1970s added to the average flows from the reservoir to develop a composite total expected flow rate to the powerhouse.

Month	**Op. Days**	**Min CFS**	**Ave CFS**	**Spill CFS**	**Peak CFS**
April	26	100	218	**264**	290
May	31	170	286	**318**	385
June	30	210	306	**396**	390
July	31	195	251	**344**	330
August	31	200	255	**255**	305
September	30	160	215	**215**	245
October	11	200	224	**224**	240
WT'D AVERAGES>>	190	175.868421	254.284211		320.2631579
Month	**Op. Days**	**Min CFS**	**Ave CFS**	**Spill CFS**	**Peak CFS**
April	23	125	264.13	**310**	335
May	31	172	316.03	**348**	400
June	30	208	293.1	**383**	375
July	31	195	267.1	**360**	295
August	31	265	297.58	**298**	320
September	30	215	257.83	**258**	320
October	11	185	204.09	**204**	235
WT'D AVERAGES>>	187	198.887701	278.876417		334.7860963
Month	**Op. Days**	**Min CFS**	**Ave CFS**	**Spill CFS**	**Peak CFS**
April	11	125	176.36	**222**	235
May	31	185	299.68	**332**	375
June	30	145	275.33	**365**	375

July	31	75	220.65	**313**	320
August	31	210	262.26	**262**	315
September	30	185	237.67	**238**	305
October	7	250	262.86	**263**	295
WT'D AVERAGES>>	171	161.374269	253.978187		329.5906433

Month	Op. Days	Min CFS	Ave CFS	Spill CFS	Peak CFS
April	19	150	268.95	**315**	360
May	31	110	213.55	**246**	400
June	30	100	257.5	**347**	410
July	31	20	230.81	**324**	300
August	31	165	261.13	**261**	315
September	30	160	228	**228**	290
October	13	190	240	**240**	290
WT'D AVERAGES>>	185	120.351351	241.43373		340.9459459

Month	Op. Days	Min CFS	Ave CFS	Spill CFS	Peak CFS
April	27	115	203.89	**250**	300
May	31	85	170.97	**203**	365
June	30	25	297.67	**388**	365
July	31	100	272.58	**365**	330
August	31	235	270.48	**270**	310
September	30	195	235.17	**235**	295
October	7	155	175.71	**176**	230
WT'D AVERAGES>>	187	127.326203	239.867005		324.4117647

Month	Op. Days	Min CFS	Ave CFS	Spill CFS	Peak CFS
April	12	100	225.42	**271**	360
May	31	20	271.94	**304**	650
June	30	182	279.09	**369**	374
July	31	69	276.84	**370**	307
August	31	36	279.9	**280**	318
September	30	42	236.13	**236**	316
October	19	162	196.65	**197**	247
WT'D AVERAGES>>	184	80.8315217	258.62538		376.2934783

Month	Op. Days	Min CFS	Ave CFS	Spill CFS	Peak CFS
April	29	145	243.9	**290**	337
May	31	235	306	**338**	410
June	30	87	258.6	**349**	389
July	31	130	226	**319**	290
August	31	59	272	**272**	325
September	30	162	235.3	**235**	292
October	17	46	153	**153**	196
WT'D AVERAGES>>	199	128.648241	248.317085		328.1909548
Month	**Op. Days**	**Min CFS**	**Ave CFS**	**Spill CFS**	**Peak CFS**
April	23	108	175.52	**221**	295
May	31	17	220.55	**253**	360
June	30	150	274.9	**365**	369
July	31	92	207.35	**300**	289
August	31	89	218.17	**218**	302
September	30	207	263.8	**264**	309
October	22	135	168	**168**	238
WT'D AVERAGES>>	198	112.636364	221.828939		312.3333333

F. Permitting

Expected permitting for the project will include applying for and obtaining:

1) Federal Energy Regulatory Commission (FERC) license. To move forward with the project as shown on Figure 3 it is necessary that a full FERC license be processed. Projects that are constructed on lands owned by the Federal Government are not exempt from Part I of the Federal Power Act, therefore are subject to the complete FERC licensing process. Should the District determine that it would rather proceed with a potentially exempt project, then the concept would have to change such that all facilities were located off of Federal lands. In reviewing the USBR ownership in at the site, this is possible but would add length to the penstock and additional cost to the construction of the project.
2) Jefferson County building permit and zoning clearance for the powerhouse,
3) US Army Corps of Engineers permit for the project,
4) Oregon Water Resources Department issued water right for use of the canal water for hydropower production,
5) National Environmental Policy Act (NEPA) process must be followed for environmental clearance related to the project. In the case of a full FERC license, it is likely that an Environmental Assessment will be required.

Depending upon the final design characteristics of the powerhouse and final findings by the District and the USBOR, additional easement and/or fee ownership of the land beneath the powerhouse may be required and a land use approval by Jefferson County may also be required.

Depending upon the funding sources involved in the project, other necessary processing may include Oregon Department of Energy bond/loan application, ODOE Business Energy Tax Credit application, Energy Trust grant application, Oregon Watershed Enhancement Board, Deschutes River Conservancy, ARRA or other funding requirements.

Interconnection with a utility requires an agreement for power purchase as well as an agreement for interconnection. The power purchase agreement will provide guidance on the term and rate for power purchase. The interconnection agreement will provide the technical terms and costs for the interconnection from the proposed plant into the utility grid.

In the case of this project, the nearest powerlines are owned by PacifiCorp and are located at the intersection of SW Jericho Lane and SW Bear Drive approximately 1,200 LF from the potential powerhouse site. There are no known reasons at the time of this study that a power purchase agreement and an interconnect agreement may not be obtained. It should be noted that for the purposes of this report the current published PacifiCorp power purchase rates (Schedule 37 peak/off-peak) will be used to develop revenue estimates for the project. These rates are subject to change. In fact, an adjustment to these rates is already under consideration and may be adopted after August, 2009. Additionally, for the purposes of this report, an estimated interconnect cost has been developed based upon recent experience in Central Oregon. It should be noted that the cost of interconnect is subject to the final utility requirements and these may not be obtained until a facility interconnect study is requested and funded and the cost of interconnect may vary significantly from what has been estimated herein.

G. Penstock Sizing, Length, and Net Head Development

The penstock length for the selected alternative was measured to be approximately 1,600-LF. The proposed forebay would be constructed at the top of the bypass chute and will provide for emergency flows to bypass the proposed forebay structure and pass down the existing bypass chute in the event of an overflow event for whatever reason. As the system will be medium head, the pipe material alternatives that are available are steel pipe and fiberglass pipe. For the purposes of this study, we have assumed that lined and coated spiral wound welded steel pipe will be used.

Based upon a Hazen-Williams coefficient of C=125 for the pipe, 1,600-LF of length and a flow range from 120 CFS to 580 CFS, we have selected a diameter of 90-IN for this project. The associated head loss through the pipe will be approximately 3.5-FT at 400 CFS which is the approximate high averaged monthly flow condition.

The Gross project is approximately 90-FT although some increased adjustment to this may be possible in design, therefore a net head of 85-FT is assumed for the project.

H. Turbine and Generator

There are options available for the procurement of the mechanical and electrical generating equipment for this project. There are both domestic and international supplier options. The turbine type will be a Francis type or axial type (Kaplan). For the purposes of this report, we have provided a range of costs that include domestic and international manufacture as some funding sources (such as stimulus dollars) may limit the purchase to a domestic manufacturing source, only.

The international manufacturer recommended an axial flow turbine/generator setup for this site, operating at 360 RPM, 6300 volts and 87% efficiency through the generator (i.e turbine and generator losses included). At an average flow rate of 280 CFS, the rated output would be 1,809KW.

One domestic manufacturer recommended an axial flow (Kaplan type) turbine for this site. The output for this system given an average flow rate of 280 CFS would be approximately 1,670 KW. The expected peak output at 525 CFS would be approximately 3,200 KW.

The pricing for international (Chinese manufactured) turbines is significantly less than domestic manufacture. The cost estimate presented later in this section provides a low and high range that includes the Chinese turbine/generator and controls in the low end and the domestic system in the high end of the cost estimate.

I. Energy/Revenue Production Estimate

Three steps were taken to determine the feasibility level revenue estimate for the project. First, the expected power production was calculated on a composite average basis, then the expected utility revenue that would apply per kilowatt hour of production, then revenue was calculated on an annual basis based upon the expected utility rates over the period from 2010 to 2023 (as published).

The expected power production was determined based upon the net head for the project as estimated in Section F. above, the expected flow rates based upon the monthly average data provided over the 8 year sample period, and an overall feasibility level plant efficiency of 80%. This data yielded the information provided in the Power Production in the appendix to this section.

This data was then averaged on a monthly basis to determine the average monthly production for the period from 2001 to 2009 as follows.

	2001-09 Ave kWH
April	**843,623**
May	**1,232,800**
June	**1,491,984**
July	**1,443,880**
August	**1,134,311**
September	**990,040**
October	**401,173**

PacifiCorp Schedule 37 provides the published rates that the utility will pay the hydroelectric power producing interconnection customer. These are known as avoided cost purchases and they apply to production of 10MW or less. The table below provides the published rates for on-peak and off-peak in cents paid per kilowatt hour. On-peak hours are 16 hours each day of the week except for Sundays. Holidays and Sundays are off-peak. For the period that NUID operates its system, we calculated the composite rate per kilowatt hour as indicated.

Year	On Peak	Off Peak	Composite Price ¢/kWh	$/kWh
2010	7.21	5.59	6.498658	0.06498658
2011	7.16	5.42	6.395966	0.06395966
2012	7.68	5.86	6.880838	0.06880838
2013	7.72	5.86	6.903274	0.06903274
2014	7.95	6.06	7.120101	0.07120101
2015	8.25	6.32	7.402537	0.07402537
2016	8.4	6.44	7.539364	0.07539364
2017	8.55	6.55	7.6718	0.076718
2018	8.69	6.66	7.798627	0.07798627
2019	8.86	6.78	7.946672	0.07946672
2020	9.03	6.91	8.099108	0.08099108
2021	9.01	6.86	8.065935	0.08065935
2022	9.03	6.83	8.06398	0.0806398
2023	9.06	6.82	8.076416	0.08076416

Given the composite rate paid per kilowatt hour per year and the average composite kilowatt hour monthly production estimated at the facility, the following feasibility level revenue estimates were calculated.

	Composite kWH 2001-2008	2010	2011	2012	2013	2014	2015	2016
April	843,623	54,824	53,958	58,048	58,238	60,067	62,450	63,604
May	1,232,800	80,115	78,849	84,827	85,104	87,777	91,258	92,945
June	1,491,984	96,959	95,427	102,661	102,996	106,231	110,445	112,486
July	1,443,880	93,833	92,350	99,351	99,675	102,806	106,884	108,859
August	1,134,311	73,715	72,550	78,050	78,305	80,764	83,968	85,520
September	990,040	64,339	63,323	68,123	68,345	70,492	73,288	74,643
October	401,173	26,071	25,659	27,604	27,694	28,564	29,697	30,246
Yearly Revenue		**$489,857**	**$482,116**	**$518,665**	**$520,356**	**$536,700**	**$557,989**	**$568,303**

	Composite kWH 2001-2008	2017	2018	2019	2020	2021	2022	2023
April	843,623	64,721	65,791	67,040	68,326	68,046	68,030	68,135

May	1,232,800	94,578	96,141	97,967	99,846	99,437	99,413	99,566
June	1,491,984	114,462	116,354	118,563	120,837	120,342	120,313	120,499
July	1,443,880	110,772	112,603	114,740	116,941	116,462	116,434	116,614
August	1,134,311	87,022	88,461	90,140	91,869	91,493	91,471	91,612
September	990,040	75,954	77,210	78,675	80,184	79,856	79,837	79,960
October	401,173	30,777	31,286	31,880	32,491	32,358	32,351	32,400
Yearly Revenue		**$578,286**	**$587,846**	**$599,005**	**$610,495**	**$607,995**	**$607,848**	**$608,785**

J. Feasibility Level Cost Estimate for Project

Feasibility Level Cost Estimate						
ITEM	QTY	UNITS	COST/UNIT LOW	COST/UNIT HIGH	SUBTOTAL LOW	SUBTOTAL HIGH
Forebay	1	LS	$175,000	$350,000	$175,000	$350,000
Penstock Pipe	1600	LF	$900	$1,100	$1,440,000	$1,760,000
Energy Dissipation	1	LS	$250,000	$375,000	$250,000	$375,000
Outlet Structure	1	LS	$125,000	$175,000	$125,000	$175,000
Turb./Gen/Switchgear	1	LS	$900,000	$2,500,000	$900,000	$2,500,000
Install system	1	LS	$250,000	$400,000	$250,000	$400,000
Building	2000	SF	$250	$450	$500,000	$900,000
Excavation/Sitework	1	LS	$150,000	$300,000	$150,000	$300,000
Permits/Processing	1	LS	$100,000	$250,000	$100,000	$250,000
Electrical Service	1	LS	$800,000	$1,500,000	$800,000	$1,500,000
Electrical Interconnect	1	LS	$700,000	$1,500,000	$700,000	$1,500,000
Contingency	15%				$808,500	$1,501,500
Design/Legal/C.M.	10%				$539,000	$1,001,000
				TOTAL	**$6,737,500**	**$12,512,500**

K. Financing and/or Grant Options

The Oregon Department of Energy administers the Business Energy Tax Credit Program. For a municipal organization such as NUID, the program follows a pass-through process to allow the District to pass on credits to a private entity with an Oregon tax burden. To facilitate this process, an incentive is credited to the private business utilizing the tax credits. This net grant opportunity to the District is approximately 33% of the project cost.

The Energy Trust of Oregon provides incentive funds for hydropower projects that are marginally viable or non-viable in the absence of such incentive funds. The Energy Trust evaluates projects on a case by case basis and based upon the proposed production and marginality of the project makes a determination at what level, if any, they will participate financially. One limitation of this funding source is that they will only provide construction related funds for project interconnecting with PacifiCorp or Portland General Electric.

Typically, water conservation funds are also available for projects that conserve seepage water and are willing to transfer conserved water in-stream. The Haystack project, as proposed, will not conserve water due to canal seepage as the existing Bypass Chute is lined and the proposed penstock will be constructed off to the side in existing ground.

Green Tag renewable energy credits a will be generated by the project. Should Energy Trust funds be used, the Energy Trust will be interested in retaining all or a portion of these credits. Credits are currently worth approximately $24/KW of generation.

Although water conservation may not be a key element on the project, alternative energy production is a priority of the State and Nation. The United States Bureau of Reclamation, Oregon Watershed Enhancement Board, and Natural Resources Conservation Service should be approached regarding the long term benefits of the project and on-going grants available.

L. Simple Payback/Benefit vs. Cost of Project

The following table provides a simple cost benefit analysis for year one of the completed project (2010) based upon assuming the full project debt and then assuming BETC and Energy Trust of Oregon participation.

Benefit versus Cost	Low	High
Project Cost Without Financial Assistance	$6,737,500	$12,512,500
Ammortization Given 20 Year Term and 6% Int.	$587,405	$1,090,896
Revenue Year 2010	$489,857	$489,857
Benefit/Cost Ratio	**0.833934**	**0.449040972**
Probable BETC 33%	$2,223,375	$4,129,125
Possible ET Participation	$500,000	$500,000
Net Project Debt.	$4,014,125	$7,883,375
Ammortization Given 20 Year Term and 6% Int.	$349,969	$687,309
Benefit/Cost Ratio	**1.3997154**	**0.712717279**

The simple payback period for the project in a absence of grants ranges from 12 to 23 years depending upon the final project cost. The simple payback period for the project assuming grant funding as indicated ranges from 8 to 14 years depending upon the final project cost.

Without grant participation, the project is marginal at the lowest cost level. With grant funding and moderate cost control the project yields a positive benefit versus cost ratio starting at year 1 and pays back within 8 to 14 years on a simple basis and becomes a viable and attractive project.

APPENDIX TO TAB 3 – ENERGY PRODUCTION ESTIMATE

Year		Op. Days	Spill CFS	Net Head (Ft.)	Eff.	Max MW	Average Annual kWH
2001	**April**	26	**264**	85	0.80	1.52	948,671.64
	May	31	**318**	85	0.80	1.83	1,364,577.71
	June	30	**396**	85	0.80	2.28	1,642,686.83
	July	31	**344**	85	0.80	1.98	1,473,714.95
	August	31	**255**	85	0.80	1.47	1,093,301.69
	September	30	**215**	85	0.80	1.24	892,067.80
	October	11	**224**	85	0.80	1.29	340,783.73
	WT'D AVERAGES>>	190		85	0.80	1.66	7,755,804.36
2002		**Op. Days**	**Spill CFS**	**Net Head (Ft.)**	**Eff.**	**Max MW**	**Average Annual kWH**
	April	23	**310**	85	80%	1.79	985,949.84
	May	31	**348**	85	80%	2.01	1,493,330.07
	June	30	**383**	85	80%	2.21	1,589,162.77
	July	31	**360**	85	80%	2.07	1,542,743.02
	August	31	**298**	85	80%	1.71	1,275,861.64
	September	30	**258**	85	80%	1.49	1,069,776.00
	October	11	**204**	85	80%	1.18	310,493.53

		Op. Days	Spill CFS	Net Head (Ft.)	Eff.	Max MW	Average Annual kWH
	WT'D AVERAGES>>	187		85	80%	1.78	8,267,316.86
2003		**Op. Days**	**Spill CFS**	**Net Head (Ft.)**	**Eff.**	**Max MW**	**Average Annual kWH**
	April	11	**222**	85	80%	1.28	338,011.82
	May	31	**332**	85	80%	1.91	1,423,230.13
	June	30	**365**	85	80%	2.10	1,515,432.33
	July	31	**313**	85	80%	1.81	1,343,590.61
	August	31	**262**	85	80%	1.51	1,124,428.64
	September	30	**238**	85	80%	1.37	986,129.08
	October	7	**263**	85	80%	1.51	254,484.12
	WT'D AVERAGES>>	171		85	80%	1.64	6,985,306.73
2004		**Op. Days**	**Spill CFS**	**Net Head (Ft.)**	**Eff.**	**Max MW**	**Average Annual kWH**
	April	19	**315**	85	80%	1.81	827,146.28
	May	31	**246**	85	80%	1.42	1,053,951.41
	June	30	**347**	85	80%	2.00	1,441,452.94
	July	31	**324**	85	80%	1.86	1,387,151.18
	August	31	**261**	85	80%	1.50	1,119,583.81
	September	30	**228**	85	80%	1.31	946,006.78
	October	13	**240**	85	80%	1.38	431,511.86
	WT'D AVERAGES>>	185		85	80%	1.61	7,206,804.26
2005		**Op. Days**	**Spill CFS**	**Net Head (Ft.)**	**Eff.**	**Max MW**	**Average Annual kWH**
	April	27	**250**	85	80%	1.44	932,468.92
	May	31	**203**	85	80%	1.17	

							871,391.46
	June	30	**388**	85	80%	2.23	1,608,124.39
	July	31	**365**	85	80%	2.11	1,566,238.28
	August	31	**270**	85	80%	1.56	1,159,671.54
	September	30	**235**	85	80%	1.36	975,756.20
	October	7	**176**	85	80%	1.01	170,111.11
	WT'D AVERAGES>>	187		85	80%	1.55	7,283,761.91
2006		**Op. Days**	**Spill CFS**	**Net Head (Ft.)**	**Eff.**	**Max MW**	**Average Annual kWH**
	April	12	**271**	85	80%	1.56	450,163.13
	May	31	**304**	85	80%	1.75	1,304,296.06
	June	30	**369**	85	80%	2.13	1,531,033.14
	July	31	**370**	85	80%	2.13	1,584,502.85
	August	31	**280**	85	80%	1.61	1,200,059.39
	September	30	**236**	85	80%	1.36	979,739.39
	October	19	**197**	85	80%	1.13	516,756.20
	WT'D AVERAGES>>	184		85	80%	1.67	7,566,550.17
2007		**Op. Days**	**Spill CFS**	**Net Head (Ft.)**	**Eff.**	**Max MW**	**Average Annual kWH**
	April	29	**290**	85	80%	1.67	1,162,014.70
	May	31	**338**	85	80%	1.95	1,450,326.87
	June	30	**349**	85	80%	2.01	1,446,017.00
	July	31	**319**	85	80%	1.84	1,366,528.51
	August	31	**272**	85	80%	1.57	1,166,188.47
	September	30	**235**	85	80%	1.36	

							976,295.59
	October	17	**153**	85	80%	0.88	359,731.53
	WT'D AVERAGES>>	199		85	80%	1.61	7,927,102.67
2008		**Op. Days**	**Spill CFS**	**Net Head (Ft.)**	**Eff.**	**Max MW**	**Average Annual kWH**
	April	23	**221**	85	80%	1.28	704,079.93
	May	31	**253**	85	80%	1.46	1,083,963.61
	June	30	**365**	85	80%	2.10	1,513,648.19
	July	31	**300**	85	80%	1.73	1,286,567.42
	August	31	**218**	85	80%	1.26	935,394.63
	September	30	**264**	85	80%	1.52	1,094,546.44
	October	22	**168**	85	80%	0.97	511,175.59
	WT'D AVERAGES>>	198		85	80%	1.47	7,129,375.82
2009		**Op. Days**	**Spill CFS**	**Net Head (Ft.)**	**Eff.**	**Max MW**	**Average Annual kWH**
	April	18	**253**	85	80%	1.46	630,782.38
	May	29	**259**	85	80%	1.49	1,037,534.04
	Thru June 10th	10	**316**	85	80%	1.82	436,918.21
	WT'D AVERAGES>>	**57**	**220**	85	80%	1.59	2,105,234.64

VII. 58-11 LATERAL SITE

A. Historical Information Review

There was no historical information provided for this project.

B. Aerial Site Plan

As indicated on Figure 4 below, the 58-11 site is located north of Madras Oregon approximately ¾ mile southwest of the intersection of NE Rex Drive and NE McFarland Drive.

The 58-11 hydropower plant would generate power from the proposed 58-11 lateral pipeline currently under design .

The site is located in a rural farming area with no structures or houses immediately adjacent to the site.

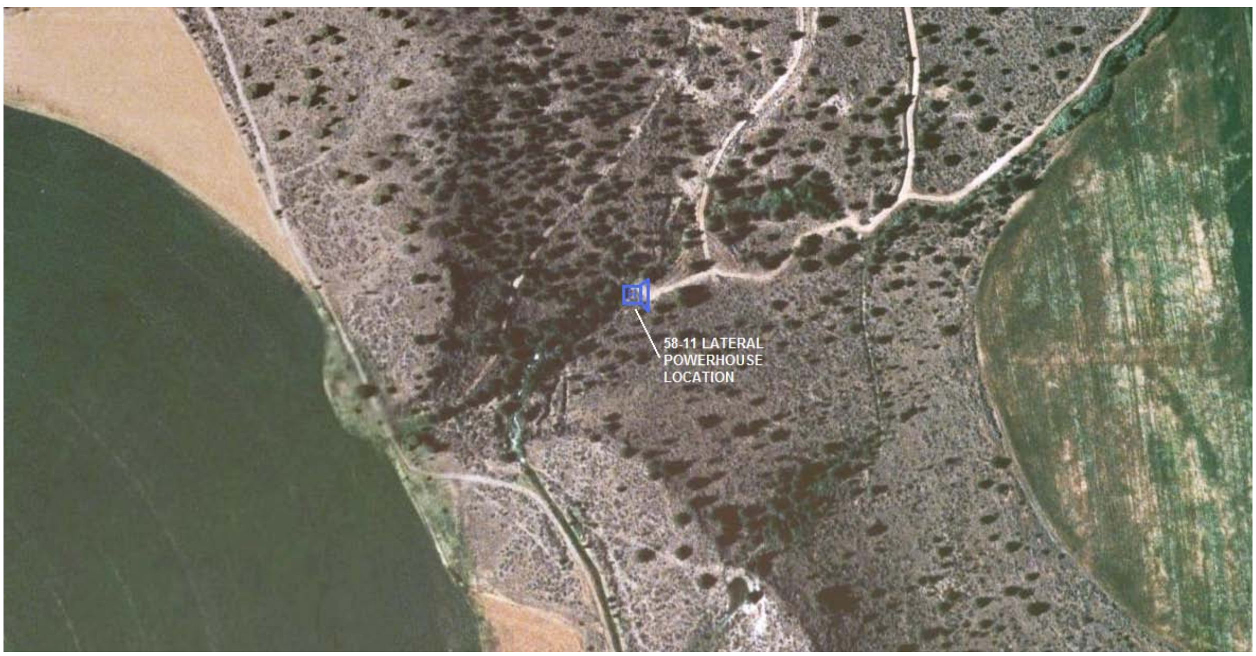

Figure 4: 58-11 Site

C. Profile/Probable Gross Head

Based upon the 30% design documents produced by Black Rock Consulting and the associated hydraulic analysis developed, the gross static head at the site is 128 PSI.

D. Historical Flow Data

The NUID monitors the flow rates for its many laterals using staff gauge and weir systems. The District has kept flow records for flows passing down the 58-11 lateral including deliveries and carry water required. For the piped system, the delivery calls are the most important data as those will drive the actual flow rates within the 58-11 system. The following date provides the min/max/ave flow data for the 58-11 lateral and the associated interpolated flow data available at the proposed hydro site given upstream deliveries predicted based upon irrigated acreage. Data is indicated in cubic feet per second.

58-11				**58-11 Hydro Site**			
2005	**Min**	**Max**	**Ave**	**2005**	**Min**	**Max**	**Ave**
April	1.9	35.4	19.5		0.5	8.5	4.7
May	2.0	41.9	16.4		0.5	10.1	3.9
June	23.8	49.4	36.8		5.7	11.8	8.8
July	27.4	48.4	36.6		6.6	11.6	8.8
August	25.4	42.4	35.5		6.1	10.2	8.5
Sept	24.8	37.9	31.0		6.0	9.1	7.4
Oct	10.8	26.4	19.5		2.6	6.3	4.7

E. Permitting

Expected permitting for the project will include applying for and obtaining:

1) Federal Energy Regulatory Commission (FERC) conduit exemption. This site appears eligible for a FERC conduit exemption in that it involves waters already diverted into a delivery system, and that it is a project less than 15MW. Another criteria is that the real property interests for the project have been obtained. Although the ability of the District to pipe the canal has been addressed favorably in Federal court, the real property ownership beneath the powerhouse should be addressed by the District.
2) Jefferson County building permit and zoning clearance for the small powerhouse,
3) Oregon Water Resources Department issued water right for use of the canal water for hydropower production,
4) If Federal funding is involved in the project, the National Environmental Policy Act (NEPA) process must be followed for environmental clearance related to the project,

Depending upon the final design characteristics of the powerhouse and final findings by the District and the USBOR, additional easement and/or fee ownership of the land beneath the powerhouse may be required and a land use approval by Jefferson County may also be required.

Depending upon the funding sources involved in the project, other necessary processing may include Oregon Department of Energy bond/loan application, ODOE Business Energy Tax Credit application, Oregon Watershed Enhancement Board, Deschutes River Conservancy, ARRA or other funding requirements.

Interconnection with a utility requires an agreement for power purchase as well as an agreement for interconnection. The power purchase agreement will provide guidance on the term and rate for power purchase. The interconnection agreement will provide the technical terms and costs for the interconnection from the proposed plant into the utility grid.

In the case of this project, the nearest powerlines are owned by the Central Electric Cooperative. There are no known reasons at the time of this study that a power purchase agreement and an interconnect agreement may not be obtained. It should be noted that for the purposes of this report the current published PacfiCorp power purchase rates (Schedule 37 peak/off-peak) will be used to develop revenue estimates for the project. Other rates may be negotiated with CEC. Such negotiations are outside of the scope of this study. These rates used are subject to change. In fact, an adjustment to these rates is already under consideration and may be adopted after August, 2009. Additionally, for the purposes of this report, an estimated interconnect cost has been developed based upon recent experience in Central Oregon. It should be noted that the cost of interconnect is subject to the final utility requirements and these may not be obtained until a facility interconnect study is requested and funded and the cost of interconnect may vary significantly from what has been estimated herein.

F. Penstock Sizing, Length, and Net Head Development

The penstock is the proposed pipeline under design to pipe the entire 58-11 lateral. Based upon the 30% design work performed by Black Rock Consulting, the expected net head at the powerhouse location under full lateral flow conditions is 247-FT (107 PSI).

G. Turbine and Generator

Although a francis type or pelton type turbine would work at the site, such custom turbine systems would be the most costly. The most viable cost alternative is a Cornell Pump Company turbine system which is a standard centrifugal pump run backwards with a generator connected to it. This type of system is approximately ½ the price of the Chinese pelton turbine option.

A Cornell Turbine (6TR2) was sized for this application at a constant set point of 8.8 CFS at 240-Ft of head for feasibility purposes. At 240-FT of head and 8.8 CFS, the rated output would be approximately 145KW.

The undesirable aspect of the Cornell turbine option is that it must run along a set operating curve. To run at a higher flow rate, a higher head must be produced. At lower flow rates, lower head must be produced. This is accomplished through an automated throttling valve that is included in the programming logic for the system.

H. Energy/Revenue Production Estimate

From the above data, energy production estimates were produced based upon 240-FT of net head. The results were as follows for one sample year (2005).

	2005 kWH
April	**34,872**
May	**47,212**
June	**103,094**

July	**106,530**
August	**102,899**
September	**86,693**
October	**12,848**

For study purposes, PacifiCorp Schedule 37 published rates have been used to evaluate the potential revenue from the project. Negotiations with CEC will determine the actual final pricing. The following rates are known as avoided cost purchases and they apply to production of 10MW or less. The table below provides the published rates for on-peak and off-peak in cents paid per kilowatt hour. On-peak hours are 16 hours each day of the week except for Sundays. Holidays and Sundays are off-peak. For the period that NUID operates its system, we calculated the composite rate per kilowatt hour as indicated

Year	On Peak	Off Peak	Composite Price ¢/kWh	$/kWh
2010	7.21	5.59	6.498658	0.06498658
2011	7.16	5.42	6.395966	0.06395966
2012	7.68	5.86	6.880838	0.06880838
2013	7.72	5.86	6.903274	0.06903274
2014	7.95	6.06	7.120101	0.07120101
2015	8.25	6.32	7.402537	0.07402537
2016	8.4	6.44	7.539364	0.07539364
2017	8.55	6.55	7.6718	0.076718
2018	8.69	6.66	7.798627	0.07798627
2019	8.86	6.78	7.946672	0.07946672
2020	9.03	6.91	8.099108	0.08099108
2021	9.01	6.86	8.065935	0.08065935
2022	9.03	6.83	8.06398	0.0806398
2023	9.06	6.82	8.076416	0.08076416

Based upon these 2010 rates and the 2005 energy production data, the maximum predicted power revenue would be approximately $32,119. However, with the requirement that the turbine curve be followed when operating the Cornell Turbine, the expected revenue would likely be more in the $25K-$28K range annually.

I. Feasibility Level Cost Estimate for Project

Feasibility Level Cost Estimate						
ITEM	QTY	UNITS	COST/UNIT LOW	COST/UNIT HIGH	SUBTOTAL LOW	SUBTOTAL HIGH
Turb./Gen/Switchgear	1	LS	$100,000	$250,000	$100,000	$250,000

Install system	1	LS	$50,000	$100,000	$50,000	$100,000
Building	40	SF	$500	$800	$20,000	$32,000
Excavation/Sitework	1	LS	$5,000	$10,000	$5,000	$10,000
Permits/Processing	1	LS	$10,000	$50,000	$10,000	$50,000
Electrical Service	1	LS	$5,000	$15,000	$5,000	$15,000
Electrical Interconnect	1	LS	$100,000	$200,000	$100,000	$200,000
Contingency	15%				$43,500	$98,550
Design/Legal/C.M.	10%				$29,000	$65,700
				TOTAL	**$362,500**	**$821,250**

J. Financing and/or Grant Options

The Oregon Department of Energy administers the Business Energy Tax Credit Program. For a municipal organization such as NUID, the program follows a pass-through process to allow the District to pass on credits to a private entity with an Oregon tax burden. To facilitate this process, an incentive is credited to the private business utilizing the tax credits. This net grant opportunity to the District is approximately 33% of the project cost.

Green Tag renewable energy credits a will be generated by the project. Should Energy Trust funds be used, the Energy Trust will be interested in retaining all or a portion of these credits. Credits are currently worth approximately $24/KW of generation.

Although water conservation may not be a key element on the project, alternative energy production is a priority of the State and Nation. The United States Bureau of Reclamation, Oregon Watershed Enhancement Board, and Natural Resources Conservation Service should be approached regarding the long term benefits of the project and on-going grants available.

K. Benefit vs. Cost of Project

The following table provides a simple cost benefit analysis for year one of the completed project (2010) based upon assuming the full project debt and then assuming BETC and Energy Trust of Oregon participation.

Benefit versus Cost	Low	High
Project Cost Without Financial Assistance	$362,500	$821,250
Ammortization Given 20 Year Term and 6% Int.	$31,604	$71,600
Revenue Year 2010	$25,000	$25,000
Benefit/Cost Ratio	**0.7910391**	**0.349162**
Probable BETC 33%	$119,625	$271,013

Possible ET Participation	$0	$0
Net Project Debt.	$242,875	$550,238
Ammortization Given 20 Year Term and 6% Int.	$21,174	$47,972
Benefit/Cost Ratio	**1.1806933**	**0.5211373**

The simple payback for the project ranges from 14 to 32 years without grants depending upon final project cost. The simple payback period for the project ranges from 9 to 22 years with grant funding depending upon final project cost.

Without grant participation, the project does not appear financially viable. Given moderate cost control during design and implementation of the project, the project yields a positive benefit versus cost ratio and an acceptable simple payback period.

VIII. 58-9 LATERAL SITE

A. Historical Information Review

There was no historical information provided for this project.

B. Aerial Site Plan

As indicated on Figure 5 below, the 58-9 site is located north of Madras Oregon approximately ¾ mile southeast of the intersection of NE Quaale Road and NE Emmerson Road just above the location known as the tri-wye.

The 58-9 hydropower plant would generate power from the proposed 58-9 lateral pipeline currently under phased construction.

The site is located in a rural farming area with no structures or houses immediately adjacent to the site.

Figure 4: 58-9 Site

C. Profile/Probable Gross Head

Based upon the 58-9 design report prepared by H&R Engineering of Redmond, Oregon, the total gross static head from the top of the 58-9 lateral to the tri-wye is 328.1-FT (142 PSI).

D. Flow Data

As the fully piped system will operate differently than the unlined open canal system, the H&R design manual for the 58-9 lateral has been used to estimate the fully piped flow at the proposed hydropower site. Based upon the report, an approximate peak flow of 7.05 GPM/acre has been estimated at peak flow in the system. The peak flow remaining in the system at the hydro site is 4,585 GPM (10.2 CFS). The seasonal flow ramping schedule is similar to that of the 58-11 as indicated under Tab 4 above, section D. This ramping schedule has been used to predict the flow range for the 58-9 hydro site as follows:

58-9 Hydro Site			
	Min	**Max**	**Ave**
April	0.4	7.4	4.1
May	0.4	8.7	3.4
June	4.9	10.2	7.6
July	5.7	10.0	7.6
August	5.3	8.8	7.4
Sept	5.1	7.9	6.4
Oct	2.2	5.5	4.0

E. Permitting

Expected permitting for the project will include applying for and obtaining:

5) Federal Energy Regulatory Commission (FERC) conduit exemption. This site appears eligible for a FERC conduit exemption in that it involves waters already diverted into a delivery system, and that it is a project less than 15MW. Another criteria is that the real property interests for the project have been obtained. Although the ability of the District to pipe the canal has been addressed favorably in Federal court, the real property ownership beneath the powerhouse should be addressed by the District.
6) Jefferson County building permit and zoning clearance for the small powerhouse,
7) Oregon Water Resources Department issued water right for use of the canal water for hydropower production,
8) If Federal funding is involved in the project, the National Environmental Policy Act (NEPA) process must be followed for environmental clearance related to the project,

Depending upon the final design characteristics of the powerhouse and final findings by the District and the USBOR, additional easement and/or fee ownership of the land beneath the powerhouse may be required and a land use approval by Jefferson County may also be required.

Depending upon the funding sources involved in the project, other necessary processing may include Oregon Department of Energy bond/loan application, ODOE Business Energy Tax Credit application, Oregon Watershed Enhancement Board, Deschutes River Conservancy, ARRA or other funding requirements.

Interconnection with a utility requires an agreement for power purchase as well as an agreement for interconnection. The power purchase agreement will provide guidance on the term and rate for power purchase. The interconnection agreement will provide the technical terms and costs for the interconnection from the proposed plant into the utility grid.

In the case of this project, the nearest powerlines are owned by the Central Electric Cooperative, located in NE Quaale Road approximately 800-LF to the west of the proposed site. There are no known reasons at the time of this study that a power purchase agreement and an interconnect agreement may not be obtained. It should be noted that for the purposes of this report the current published PacfiCorp power purchase rates (Schedule 37 peak/off-peak) will be used to develop revenue estimates for the project. Other rates may be negotiated with CEC. Such negotiations are outside of the scope of this study. These rates used are subject to change. In fact, an adjustment to these rates is already under consideration and may be adopted after August, 2009. Additionally, for the purposes of this report, an estimated interconnect cost has been developed based upon recent experience in Central Oregon. It should be noted that the cost of interconnect is subject to the final utility requirements and these may not be obtained until a facility interconnect study is requested and funded and the cost of interconnect may vary significantly from what has been estimated herein.

F. Penstock Sizing, Length, and Net Head Development

The penstock is the proposed pipeline under phased construction to pipe the entire 58-9 lateral. Based upon the design report prepared by H&R Engineering, the planned head to be extracted from the available head at this location is 65 PSI (150.2-FT).

G. Turbine and Generator

Although a francis type or pelton type turbine would work at the site, such custom turbine systems would be the most costly. The most viable cost alternative is a Cornell Pump Company turbine system which is a standard centrifugal pump run backwards with a generator connected to it. This type of system is approximately ½ the price of the Chinese pelton turbine option.

A Cornell Turbine (8TR3 at 1,200 RPM) was sized for this application at a constant set point of 9 CFS at 150-FT of head for feasibility purposes.

The undesirable aspect of the Cornell turbine option is that it must run along a set operating curve. To run at a higher flow rate, a higher head must be produced. At lower flow rates, lower head must be produced. This is accomplished through an automated throttling valve that is included in the programming logic for the system.

H. Energy/Revenue Production Estimate

From the above data, energy production estimates were produced based upon 150-FT of net head.

	kWH
April	**19,012**
May	**25,724**
June	**55,648**
July	**57,502**
August	**55,989**
September	**46,861**
October	**6,833**

For study purposes, PacifiCorp Schedule 37 published rates have been used to evaluate the potential revenue from the project. Negotiations with CEC will determine the actual final pricing. The following rates are known as avoided cost purchases and they apply to production of 10MW or less. The table below provides the published rates for on-peak and off-peak in cents paid per kilowatt hour. On-peak hours are 16 hours each day of the week except for Sundays. Holidays and Sundays are off-peak. For the period that NUID operates its system, we calculated the composite rate per kilowatt hour as indicated

Year	On Peak	Off Peak	Composite Price ¢/kWh	$/kWh
2010	7.21	5.59	6.498658	0.06498658
2011	7.16	5.42	6.395966	0.06395966
2012	7.68	5.86	6.880838	0.06880838
2013	7.72	5.86	6.903274	0.06903274
2014	7.95	6.06	7.120101	0.07120101
2015	8.25	6.32	7.402537	0.07402537
2016	8.4	6.44	7.539364	0.07539364
2017	8.55	6.55	7.6718	0.076718
2018	8.69	6.66	7.798627	0.07798627
2019	8.86	6.78	7.946672	0.07946672
2020	9.03	6.91	8.099108	0.08099108
2021	9.01	6.86	8.065935	0.08065935
2022	9.03	6.83	8.06398	0.0806398
2023	9.06	6.82	8.076416	0.08076416

Based upon the 2010 rates and the energy production data, the maximum predicted power revenue would be approximately $17,400. However, with the requirement that the turbine curve be followed when operating the Cornell Turbine, the expected revenue would likely be more in the $14K range annually.

I. Feasibility Level Cost Estimate for Project

Feasibility Level Cost Estimate						
ITEM	QTY	UNITS	COST/UNIT LOW	COST/UNIT HIGH	SUBTOTAL LOW	SUBTOTAL HIGH
Turb./Gen/Switchgear	1	LS	$80,000	$250,000	$80,000	$250,000
Install system	1	LS	$40,000	$75,000	$40,000	$75,000
Building	30	SF	$500	$800	$15,000	$24,000
Excavation/Sitework	1	LS	$5,000	$10,000	$5,000	$10,000
Permits/Processing	1	LS	$10,000	$50,000	$10,000	$50,000
Electrical Service	1	LS	$5,000	$15,000	$5,000	$15,000
Electrical Interconnect	1	LS	$100,000	$200,000	$100,000	$200,000
Contingency	15%				$38,250	$93,600
Design/Legal/C.M.	10%				$25,500	$62,400
				TOTAL	**$318,750**	**$780,000**

J. Financing and/or Grant Options

The Oregon Department of Energy administers the Business Energy Tax Credit Program. For a municipal organization such as NUID, the program follows a pass-through process to allow the District to pass on credits to a private entity with an Oregon tax burden. To facilitate this process, an incentive is credited to the private business utilizing the tax credits. This net grant opportunity to the District is approximately 33% of the project cost.

Green Tag renewable energy credits a will be generated by the project. Should Energy Trust funds be used, the Energy Trust will be interested in retaining all or a portion of these credits. Credits are currently worth approximately $24/KW of generation.

Although water conservation may not be a key element on the project, alternative energy production is a priority of the State and Nation. The United States Bureau of Reclamation, Oregon Watershed Enhancement Board, and Natural Resources Conservation Service should be approached regarding the long term benefits of the project and on-going grants available.

K. Simple Payback/Benefit vs. Cost of Project

The following table provides a simple cost benefit analysis for year one of the completed project (2010) based upon assuming the full project debt and then assuming BETC and Energy Trust of Oregon participation.

Benefit versus Cost	Low	High
Project Cost Without Financial Assistance	$318,750	$780,000
Ammortization Given 20 Year Term and 6% Int.	$27,790	$68,004
Revenue Year 2010	$14,000	$14,000
Benefit/Cost Ratio	**0.5037783**	**0.2058702**
Probable BETC 33%	$105,188	$257,400
Possible ET Participation	$0	$0
Net Project Debt.	$213,563	$522,600
Ammortization Given 20 Year Term and 6% Int.	$18,619	$45,563
Benefit/Cost Ratio	**0.7519201**	**0.3072669**

The simple payback period for the project ranges from 22 to 55 years without grants to 15 to 37 years with grants.

Without additional grant participation over and above that shown, the project does not appear financially viable. The first year break-even point is at a net project debt after grants of less than $160,000.