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Otter Tail Ag Enterprises, LLC
Evaluation of Alternative Technology Proposals

B&V Project 892008
27 October 2008

Attn: Kelly Longtin
Otter Tail Ag Enterprises, LLC
24096 170th Avenue
Fergus Falls, MN 56537

Subject: Final Report Submittal

Dear Mr. Longtin:

Black & Veatch is pleased to submit this Final Report to Otter Tail Ag Enterprises, LLC for the Evaluation of Alternative Technology Proposals. We thank you for the opportunity to work on this important evaluation.

We trust that this submittal meets your expectations and needs. Should you have any comments, please feel free to contact me at (913) 458-2293.

Very truly yours,

BLACK & VEATCH

Jon Erickson, PE
Project Manager

RMK
Enclosure[s]

Otter Tail Ag Enterprises, LLC

Evaluation of Alternative Technology Proposals

FINAL REPORT
B&V Project Number: 892008.1156

October 2008

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1.0 Executive Summary

Otter Tail Ag Enterprises (OTAE) has retained Black & Veatch to prepare an independent evaluation of alternative technology proposals for potential application at their 55 million gallon per year ethanol plant near Fergus Falls, Minnesota. The OTAE plant currently burns natural gas to generate process steam and to dry distillers wet grain (DWG) and syrup for animal feed. Proposals were received from vendors offering technology solutions which would utilize ethanol plant co-products as fuels to replace expensive natural gas or as feedstocks to derive valuable and marketable components from those co-products. This study evaluates the technical and economic merits of the submitted proposals.

After the cost of feedstock, utilities are the largest component of the cost of producing ethanol. Based on current pricing, OTAE will consume over 135,000 million British thermal units (MMBtu) of natural gas monthly, costing the plant over $1.6 million per month. Burning syrup and wet cake to generate steam from the plant’s byproducts instead of natural gas is one viable alternative. Creating an alternative fuel through anaerobic digestion of thin stillage and thereby reducing the drying load is another. Finally, extraction of valuable minerals used in fertilizers worldwide prior to anaerobic digestion could potentially create another revenue stream. Key findings of the evaluation are summarized in this Executive Summary.

1.1 Technology Options Overview

This section provides an overview of the proposed processes as submitted to OTAE for evaluation.

1.1.1 Fluidized Bed Combustion of Syrup and Wet Cake Producing Steam

Combustion is the complete oxidation of a fuel resulting in generation of heat. This heat can be used either directly, such as in a drying process, or indirectly by transferring it to a “working fluid” such as steam. If the heat is transferred to steam, it is generally accomplished in a boiler. The steam produced by the boiler may be sent directly to process end users or may be used to spin a steam turbine generator to generate electricity.

Combustion of biomass in fluidized bed boilers has been practiced for several decades. In bubbling fluidized bed boilers, fuel feeders discharge either to chutes that drop the fuel into the bed or to fuel conveyors that distribute the fuel to feed points around the boiler. The speed of the feeders is modulated to maintain output when fuel conditions or loads change. The materials resident in the boiler at any given time take on a fluid appearance when air is driven through them from below. These materials form the bed and typically consist of fuel, ash from the fuel, inert material (e.g., sand), and possibly a sorbent (e.g., limestone) to reduce sulfur emissions. Bubbling fluidized beds are fuel flexible and are capable of burning both wet cake and syrup. Since the sulfur content for wet cake and syrup is somewhat higher than other types of biomass, sorbent injection may be necessary.

The air to the fluidized bed is introduced through a grid for even distribution. The amount of air is just sufficient to cause the bed material to lift and separate. In this manner, circulation patterns occur causing fuel discharged on top of the bed to mix throughout the bed. Because of the turbulent mixing, heat transfer rates are very high and combustion efficiency is good. Consequently, combustion temperatures can be kept low compared to other conventional fossil fuel burning boilers. The bed may also be operated in a sub-stoichiometric mode with additional air added in the secondary combustion chamber (freeboard) to complete combustion. Low bed temperatures and air staging reduces NO_x formation. Low temperature is also an advantage with biomass fuels because these fuels may have relatively low ash fusion temperatures. Low ash fusion temperatures can lead to excessive boiler slagging.

Because of the low combustion temperatures, NO_x emissions from a bubbling fluidized bed boiler burning biomass will generally be less than 0.20 lb/MMBtu. In addition, the operating temperature of a bubbling fluidized bed is usually within the temperature range that allows a selective non-catalytic reduction (SNCR) system to be effective if NO_x control is warranted or becomes so at a later time.

Both wet cake and syrup are relatively high moisture fuels. If the combined moisture content is above 67 percent, combustion may not be self-sustaining and will require supplemental fuel such as natural gas.

High moisture content fuel can also severely limit boiler performance resulting in decreased efficiency, poor load-following ability, and increased carbon monoxide emissions. Such conditions will be aggravated if the fuel properties vary significantly. OTAE may want to consider alternatives to improve performance which could include:

- Improved ethanol process performance (centrifuge and evaporators) resulting in lower moisture content syrup
- Supplemental firing with natural gas
- Supplemental firing with lower moisture content biomass fuels

1.1.2 Anaerobic Digestion of Thin Stillage

Anaerobic digestion is the naturally occurring process that occurs when bacteria decompose organic materials in the absence of oxygen. The byproduct gas typically contains a significant amount of methane. The most common applications of anaerobic digestion are for treating industrial wastewater, animal manure, or human sewage. The primary economic drivers for anaerobic digestion projects are increasingly stringent agricultural manure and sewage sludge management regulations, with power production being a secondary consideration. Anaerobic digestion of stillage can be employed at ethanol plants, though few plants exist that have installed digesters.

The digester is placed between the plant's primary centrifuges and the evaporators. The thin stillage is piped from the thin stillage storage tank to the anaerobic digester tanks. Biogas is produced and piped to a biogas scrubber prior to utilization in the plant's combustion systems. In this proposed arrangement, chemicals are added to the digester effluent stream to precipitate the struvite in solution. Centrifuges remove the precipitated struvite along with any residual solids from the effluent. The centrate then enters the evaporators for dewatering. The process results in a biogas stream with approximately 55-70 percent methane. Condensate from the evaporators is returned to the ethanol plant process.

Biogas produced by anaerobic digestion can be used for power generation, direct heat applications, or steam generation. In an ethanol plant, the volatile solids reduction through anaerobic digestion tends to improve water quality within the ethanol production process. The energy from digester gas production offsets natural gas requirements for distillation and drying and can insulate the facility from volatile natural gas prices. Doing so, however, will require adjustments or retrofits to existing boiler and/or dryer combustion equipment so that the lower quality fuel may be utilized.

1.1.3 Anaerobic Digestion of Thin Stillage with Struvite Extraction

The anaerobic digestion and struvite extraction processes are based on independently proven technologies; however, they have not been combined for application to thin stillage. By precipitating struvite upstream of an anaerobic digestion process, the vendor claims several potential operational problems, such as scaling in the digesters, mixing equipment, pumps, discharge and piping may be reduced or eliminated. Struvite removal also reduces the concentration of phosphorus in the digested solids, reducing the possibility of over-applying phosphorus to the land when utilizing the biosolids as a fertilizer.

The precipitated struvite is a renewable inorganic fertilizer. The vendor of the struvite precipitation equipment, Ostara Nutrient Recovery Technologies, offers several options for contracting with their company. In each case, Ostara maintains the right to purchase all struvite produced at the plant by their process. Depending on the final financial arrangement with Ostara, struvite production by the plant may produce an additional revenue stream for the facility.

The combination of struvite precipitation and anaerobic digestion applied to any byproduct from an ethanol facility is a patent pending process.

1.2 Economic Analysis Results

To determine the financial viability of the proposed options, Black & Veatch developed a pro forma economic model for potential operating scenarios based primarily on values provided in vendor proposals and coupled with the assumptions outlined in this section. This economic model calculates the revenues and costs associated with the project (relative to the current ethanol production process). The model also establishes the owner’s internal rate of return (IRR) under the specified conditions.

The financial model consists of a spreadsheet-based, 20-year annual cash flow (pro forma) model. The model takes into account the project’s capital and operating costs, performance characteristics (e.g., capacity factor), added or lost product sales (e.g., DDGS), offset natural gas consumption, financing terms, and other income streams to calculate the amount of revenue available each year to service the debt and cover operating expenses. The primary revenue streams are the offset cost of natural gas and, in one anaerobic digestion case, the sale of struvite. With consideration of these factors, the model calculates the equity investors’ IRR. The model presumes that the project owner has no out-of-pocket tax liability.

Although the economic model depends on many high-level and preliminary assumptions, the results of the analysis should be sufficient to indicate general project viability, to differentiate between the various options, and to evaluate which project parameters have significant influence over the economic results. If the project proceeds, it is recommended that an exhaustive financial model be constructed.

1.3 Pro Forma Baseline Assumptions

Several sets of assumptions were established to form the bases for pro forma calculations. Defining these assumptions was necessary in order to develop reasonable estimates that were applicable to the project. At this stage of review, however, there is uncertainty in some parameters. Therefore, the model construction, assumptions and results should be viewed as the initial iteration in an ongoing process.

1.3.1 Existing Ethanol Plant Operational Assumptions

Existing plant operational assumptions are summarized in Table 1-1.

Table 1-1. Business As Usual Ethanol Plant Assumptions.

Ethanol Production (MMGPY, undenatured)	55.0
Annual Corn Grind (million bu)	19.84
DDGS (10% moisture content)	
DDGS Yield (lb/bu)	18.53
DDGS Production (tons/day)	525
Syrup production (60% moisture content)	
Syrup Production (tons/day)	523
Syrup Production (MMBtu/hr)	148.1
Wet Cake Production (65% moisture content)	
Wet Cake Production (tons/day)	752
Wet Cake Production (MMBtu/hr)	207.0
Thin Stillage Production (92-94% moisture content)	
Thin Stillage Production (gallons/day)	538,000
Thin Stillage Production (MMBtu/hr)	149.8
Natural Gas Price ($/MMBtu)	$11.75
Elec. Purchase Price ($/MWh)	$50.00

1.3.2 Scenario Specific Assumptions

Assumptions associated with specific proposals are summarized in Table 1-2.

Table 1-2. Scenario Specific Assumptions.

	Bubbling Fluidized Bed Combustion	Anaerobic Digestion	Anaerobic Digestion with Struvite Extraction
Design Conditions			
Main Steam Flow Rate (lb/hr)	120,074	n/a	n/a
Main Steam Pressure (psig)	80	n/a	n/a
Natural Gas Burn Rate (MMBtu/hr)	148.3	148.3	148.3
Syrup Utilization Rate (ton/day)	523	n/a	n/a
Wet Cake Utilization Rate (ton/day)	142	n/a	n/a
Thin Stillage Utilization Rate (gpd)	n/a	538,000	538,000
Operational Assumptions			
Operating Hours per Year	8400	8400	8400
Ash Generation (wt% of input)	2.7%	n/a	n/a
Economic Assumptions			
Capital Cost ($000)	23,950	26,450	35,550
Fixed O&M Cost ($000/yr)	193	240	302
Variable O&M Cost ($000/yr)	2,026	1,877	3,661

1.3.3 Financial Assumptions

Financial assumptions are summarized in Table 1-3. Renewable Energy Credits and Carbon Credits were not included in the economic analysis, though it is noted that such credits would make the scenarios more economical.

Table 1-3. Financial Assumptions (2008$).

Debt to Equity Ratio	80 : 20
Debt Term (years)	10
Debt Interest Rate (%)	7.00%
Financing Fee (% of issuance)	1.50%
Minimum DSCR, average annual	1.40
Debt Service Reserve Fund (years)	0.5
Equity IRR Hurdle Rate	15.0%
Income Tax Rate	n/a
Depreciation	n/a
Annual Inflation Rate	2.50%
DDGS Escalation Rate	2.50%

1.3.4 Product Value Assumptions

- The **Distillers Dry Grain with Solubles (DDGS)** sales price was set at $160/ton based on a value provided by OTAE. The price (and lost DDGS sales) was assumed to be inflated by a rate of 2.50% per year over the life of the project.
- The **Natural Gas Price** was assumed to be $11.75/MMBtu, which was considered the reasonable near-term market price for natural gas. In the calculations, the natural gas cost escalates with inflation.
- The **Sludge** sales price was calculated to be $25.17/ton based on the sludge mineral content provided by ADI Systems and fertilizer values provided by OTAE. The sludge sales price was determined to be negligible for the struvite extraction scenario since most of these key minerals are removed. The assumption was made that any value of the low-mineral sludge would only offset its disposal, as was also assumed in the Rein proposal.
- The **Ash Value** associated with the syrup and wet cake combustion process was assumed to be $150/ton based on actual reports by Corn Plus Ethanol in Winnebago, MN. Corn Plus Ethanol is now investigating pelleting the ash to increase its market value to $300/ton.
- The **Struvite Price** was based on a value of $1,500/ton, a price provided by Rein and Associates. Though used in the calculations, the price was not confirmed with any outside sources. The market price is expected to be lower.

- The **Biogas Price** was based on a value of $11.75/MMBtu, equal to the value of natural gas being offset.
- The **Electricity Purchase Price**, the price paid by the ethanol plant for electricity, was assumed to be $50/MWh (2008$). This price was based on OTAE data.

1.4 Base Case Results

The results for the base case model are shown in Table 1-4. A copy of the pro forma model output and year-by-year cash flow calculation for each scenario are included in Section 7 of this report.

Table 1-4. Base Case Economic Analysis Results.

	Bubbling Fluidized Bed Combustion	Anaerobic Digestion	Anaerobic Digestion with Struvite Extraction
Average Debt Service Coverage Ratio	1.03	0.99	1.18
Minimum Debt Service Coverage Ratio	0.58	0.51	0.86
After-Tax Internal Rate of Return on Equity	3.9%	1.8%	12.5%

The three scenarios produced very different economic results with the assigned base case assumptions. Internal rate of return (IRR) values ranged from 1.8 percent for an aerobic digestion to 12.5 percent for anaerobic digestion with struvite extraction. None of the scenarios exceeded the minimum IRR hurdle rate of 15 percent assuming base case values. As well, none of the scenarios met the minimum DSCR of 1.40.

It was determined that if the value of DDGS drops even by as little as $16 per ton (to $144 per ton), with all other variables remaining constant, all scenarios would achieve the minimum IRR target. Similarly, if the cost of natural gas increases $0.98/MMBtu (to $12.73/MMBtu), all scenarios would achieve the hurdle rate. The impact of variations in such key project variables is explored further in the next section.

1.5 Sensitivity Analysis

The figures following this section show a graphical representation of the sensitivity of the project results to moderate changes in input assumptions for the major project variables. The sensitivity results of the Fluidized Bed Combustion scenario are shown in Figure 1-1, the Anaerobic Digestion scenario in Figure 1-2, and the Anaerobic Digestion with Struvite Extraction scenario in Figure 1-3.

The center point of each diagram represents the base case results for the specified scenario. Each input variable is represented by a line on the chart. As the variables are increased or decreased independently of other variables, the corresponding IRR impact is shown on the chart. Sensitivity to a particular input is indicated by the slope of the line. A steep slope means that variable impacts the IRR greater than a variable with a shallow sloping line.

1.5.1 Sensitivity Analysis – Fluidized Bed Combustion and Steam Generation

Based on the sensitivity analysis for the fluidized bed boiler scenario, the project is highly sensitive to changes primarily in DDGS value and natural gas price, and lesser so to moderate fluctuations in capital cost, O&M costs, and ash value. If the DDGS price increases beyond $160/ton, the IRR decreases rapidly. Conversely, when the DDGS price decreases, the IRR increases substantially. At $80/ton, the IRR is off the chart at 148%. Though not having as great an impact on the economics, a $50/ton gate price for ash would add three percentage points to the IRR. As stated before, Corn Plus Ethanol in Winnebago currently sells their bubbling fluidized boiler ash for $150/ton.

1.5.2 Sensitivity Analysis – Anaerobic Digestion

The IRR for the anaerobic digestion scenario is also highly sensitive to changes in DDGS value. A drop in DDGS price of about $16/ton (10%) brings the IRR up to approximately 15%. At $80/ton, the IRR would be 98%. While the value of sludge is affected by many factors (i.e. location, mineral content, water content, transportation), it does add some value to the process. However, since it is doubtful that a year-round market for the product would exist, some additional processing costs (i.e. drying, pelleting) as well as storage costs would also need to be evaluated. For the analysis, sludge value was varied between $19 and $38/ton, a range which Black & Veatch believes to be reasonable.

1.5.3 Sensitivity Analysis – Anaerobic Digestion with Struvite Extraction

The sensitivity analysis for this scenario also revealed a high sensitivity to changes in DDGS value. In this scenario, a drop in DDGS value of less than 10% results in an IRR above the hurdle rate. The base case IRR was higher than that of the anaerobic digestion only scenario due to the use of a high value for struvite ($1,500 per lb). Neither the Ostara or the Rein proposal documents provide substantiation for this value. Further market research is warranted. While struvite value to the plant was not well defined in the proposal documents, the analysis demonstrates that an increase of 20% in the struvite value above the base value of $1,500/ton would result in a 20% IRR. Conversely, a 20% decrease in struvite value would result in an IRR of under 5%.

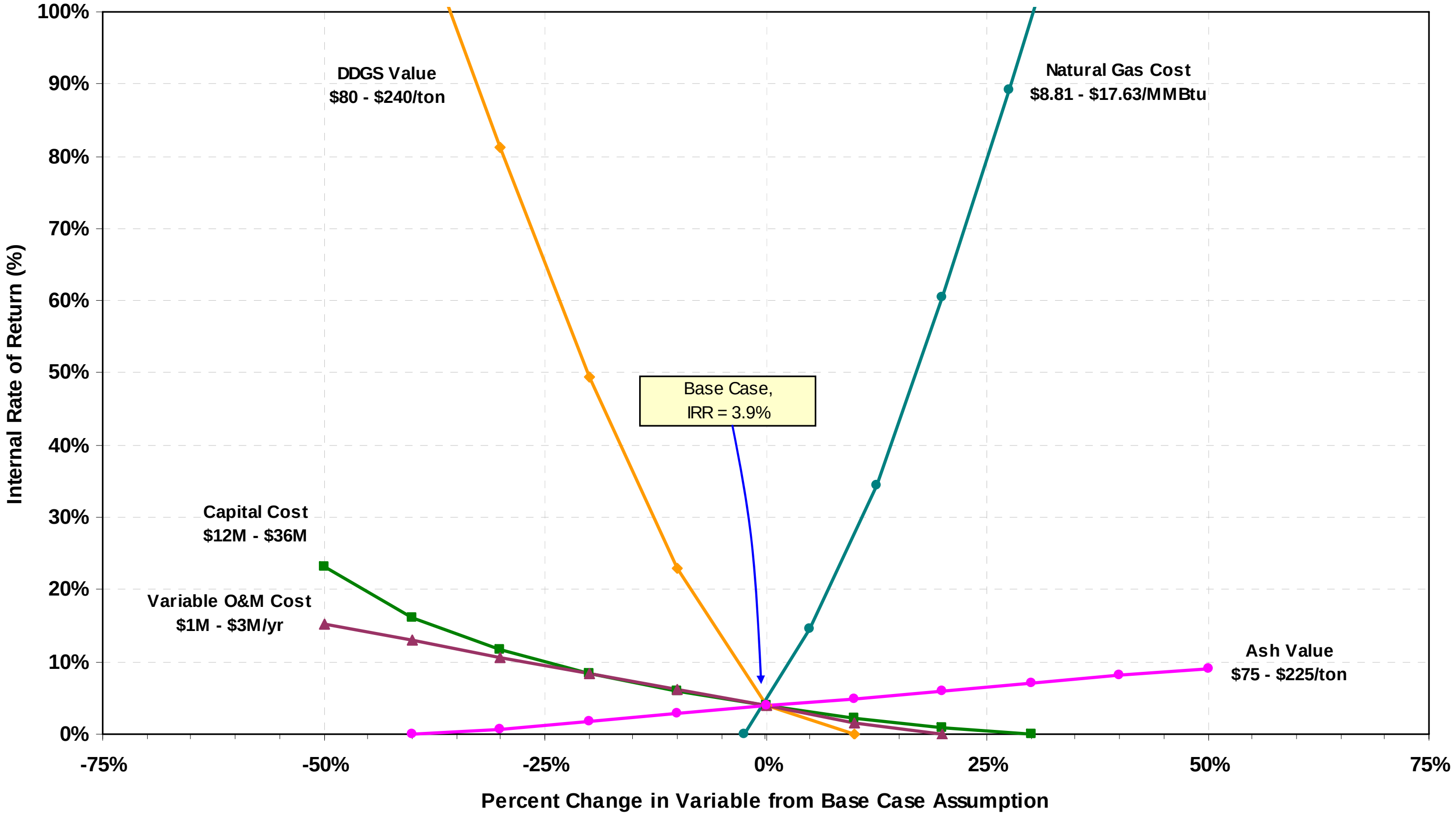


Figure 1-1. Sensitivity of Project IRR to Changes in Input Assumptions – Fluidized Bed Combustion

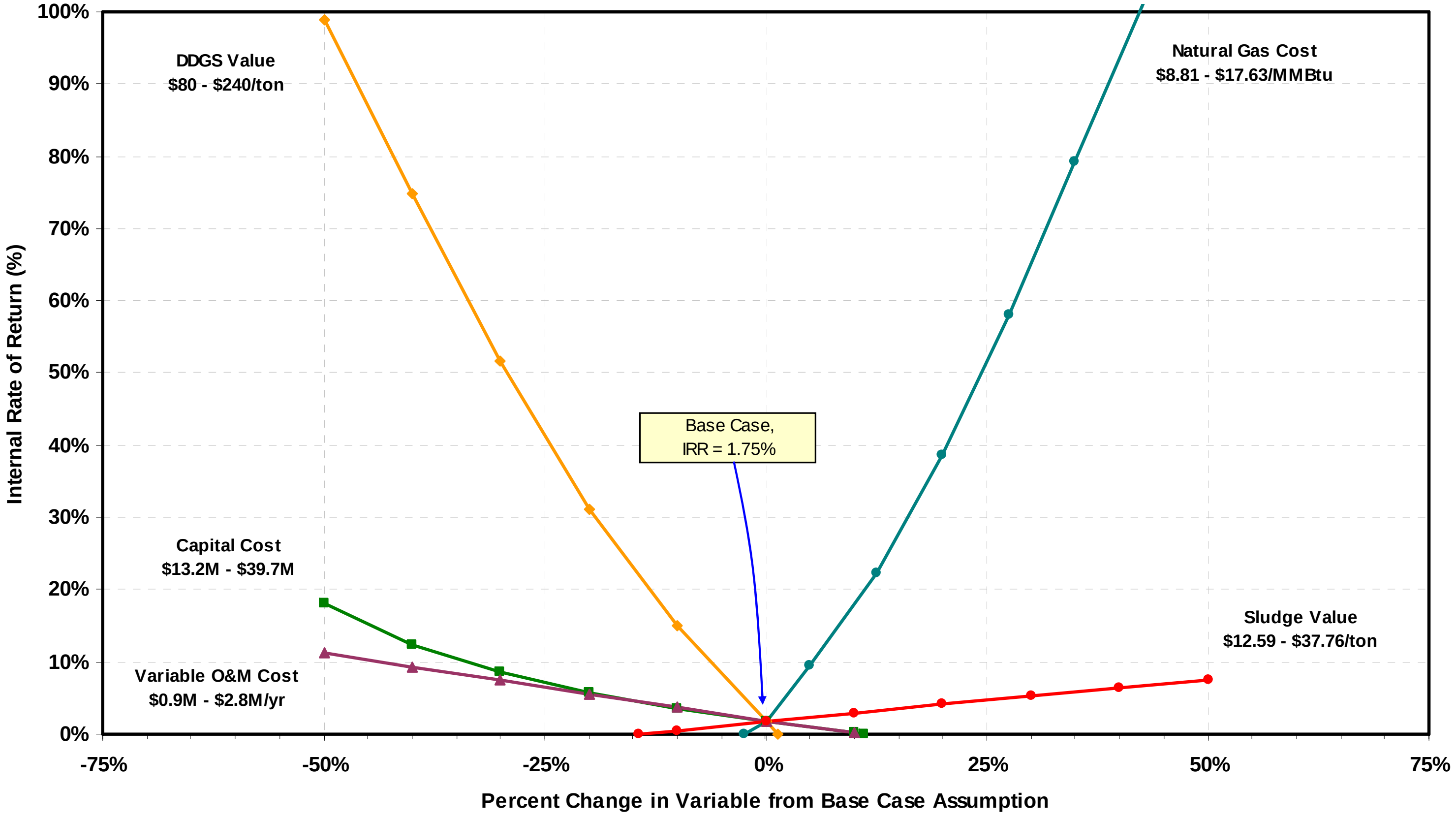


Figure 1-2. Sensitivity of Project IRR to Changes in Input Assumptions – Anaerobic Digestion

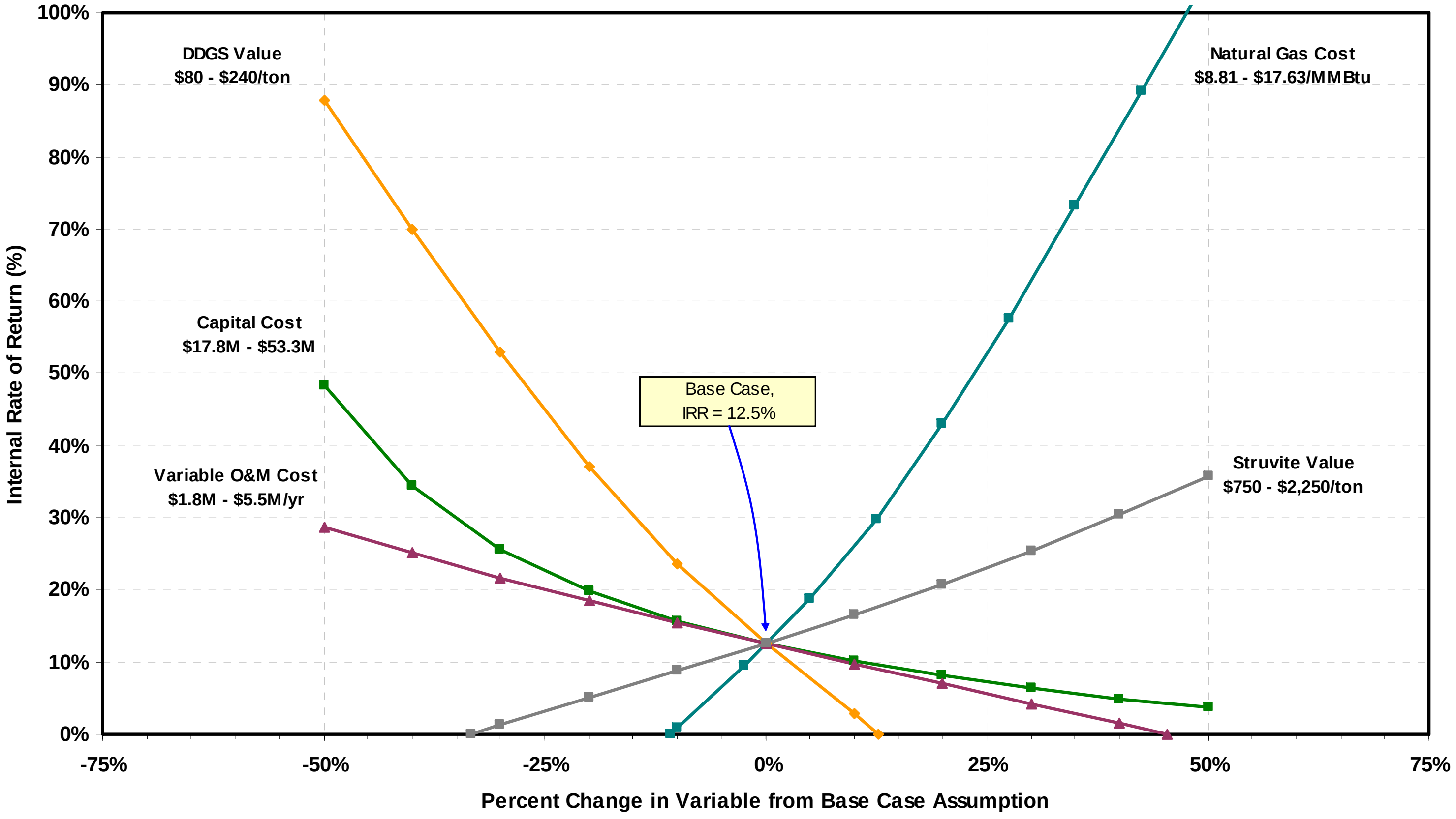


Figure 1-3. Sensitivity of Project IRR to Changes in Input Assumptions – Anaerobic Digestion with Struvite Extraction

2.0 Introduction

Otter Tail Ag Enterprises, LLC (OTAE) has retained Black & Veatch to perform an independent evaluation of three proposals for the application of alternative technologies at their ethanol plant near Fergus Falls, Minnesota. Proposals were received from Harris Mechanical of St. Paul, Minnesota representing AE&E Von Roll technology, ADI Systems Inc. of Salem, New Hampshire, and Rein and Associates of Moorhead, Minnesota.

The OTAE plant currently burns natural gas to produce steam for manufacturing ethanol and to dry distillers' wet grains with solubles for animal feed. As the cost of natural gas increases, the economics for the ethanol plant become less attractive. This study investigates the technical and economic merits of proposals which would use the plant's co-products as fuels or fuel generating feedstocks to replace expensive natural gas. Also evaluated is a proposal to produce struvite, a valuable fertilizer.

2.1 Background

Otter Tail Ag Enterprises operates a nominal 55 million gallon per year ethanol plant near Fergus Falls, Minnesota. The plant construction was completed in mid-April 2008 and has been operating at approximately nameplate capacity. It is a conventional dry-mill ethanol plant that produces ethanol by fermentation of corn. A large stream of mash byproducts made up of all the fermentation ingredients other than ethanol is also produced. The plant sells approximately 20% of the mash byproducts as wet distillers grains (WDG). The plant dries and sells approximately 80% of the mash byproducts as distillers' dried grains with solubles (DDGS). The plant also sells about 1,000 tons of syrup per month. Syrup, WDG and DDGS are consumed by livestock such as cattle, swine and poultry.

After the cost of the corn feedstock, utilities such as natural gas and electricity are the largest component of the cost of producing ethanol. The plant currently burns natural gas to produce steam for the ethanol process and to create heat for a direct-fired rotary drum dryer to produce DDGS. At a current cost of around $11.75/MMBtu, this amounts to a monthly cost of over $1.6 million. The plant also consumes a substantial amount of electricity, with an estimated cost of around $2.5 million per year.

The recent volatility and high price of natural gas have placed increased emphasis on reducing natural gas consumption. OTAE is considering the economic feasibility of alternative approaches for reducing their natural gas expense.

2.2 Objective

The objective of this study is to provide a high-level technical and economic evaluation of three proposed technology alternatives so OTAE can make an informed decision about whether to advance with one of the proposed solutions. This study also attempts to identify notable considerations in the technology solutions that might cause undue risk to the plant.

The following proposed options have been evaluated:

- Fluidized Bed Combustion of Syrup and Wet Cake for Steam Generation submitted by Harris Mechanical/AE&E Von Roll
- Anaerobic Digestion of Thin Stillage for Production of Biogas submitted by ADI Systems Inc.
- Anaerobic Digestion of Thin Stillage for Production of Biogas and Struvite submitted by Rein and Associates

The scope of work as outlined below is based on Black & Veatch's understanding of the project requirements. If one or more of the proposed technology options is found to be viable, it is anticipated that additional study, permitting, engineering and other analyses would need to be undertaken prior to project construction.

2.3 Scope of Work

Black & Veatch was retained to perform the following study tasks for OTAE:

- Obtain proposals and supplemental information from the suppliers and OTAE
- Review data and request additional information if needed
- Perform a technical assessment
    - Review supplier energy and mass balances
    - Incorporate supplier processes into OTAE process flow diagram
    - Review water mass balance
    - Evaluate water recycling opportunities
- Estimate preliminary capital and operation & maintenance costs
- Evaluate OTAE pro forma economic analysis (or develop a simplified one)
- Produce a report of findings

3.0 Dry Mill Ethanol Process Overview

Dry mill ethanol processing plants dominate the ethanol production industry in the United States. This section provides an overview of a typical corn dry mill ethanol plant process.

Among dry mill ethanol plants, corn is the most common feedstock. These processing plants use enzymes and a fermentation process to convert starch in kernels of corn into ethanol. Several other byproducts and coproducts are produced at the same time. Most dry mill ethanol plants utilize natural gas combustion to produce the steam that drives many of the chemical conversion processes, and in natural gas fired dryers that dry one of the key coproducts, distillers dried grains with solubles. Figure 3-1 shows a typical diagram of a dry mill ethanol process.

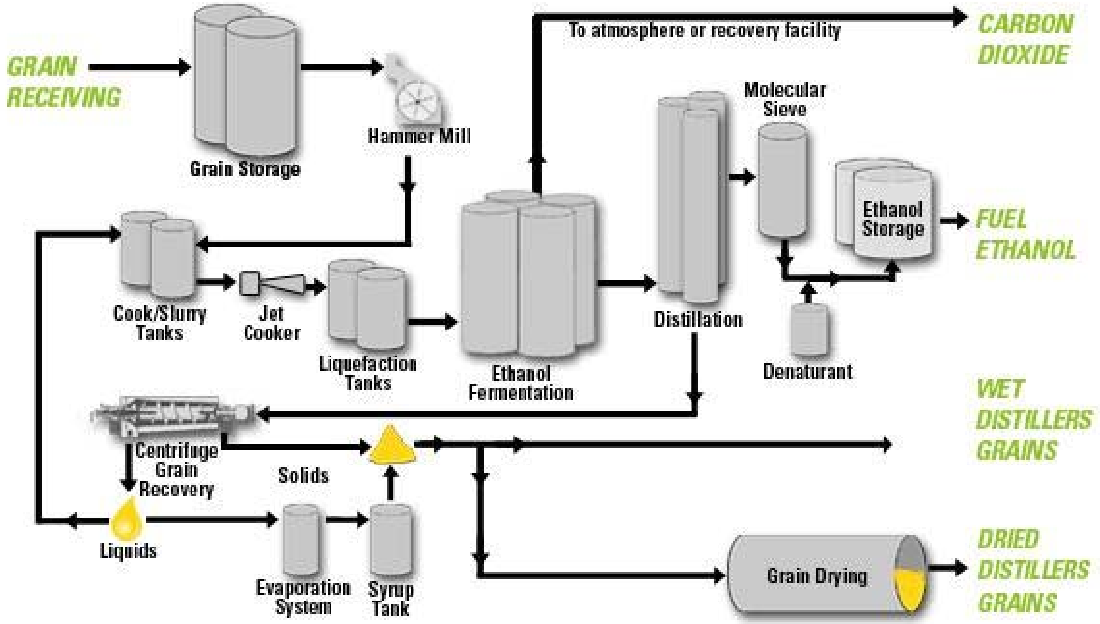


Figure 3-1. Typical Dry Mill Ethanol Process (Source: icminc.com)

3.1 Dry Mill Ethanol Process

In most conventional dry mill ethanol plants, the entire corn kernel or other starchy grain is first ground into meal and processed without separating out the various component parts of the grain (i.e. fiber, germ, etc.). The meal is mixed with fresh and recycled water to form a liquefied mash. Enzymes are added to the mash to convert the starch to dextrose, a simple sugar. Ammonia is added for pH control and as a nutrient to the yeast.

The mash is heated in a cooker to reduce bacteria levels ahead of fermentation. It is then cooled and transferred to a fermenter where yeast is added to metabolically convert the sugar to ethanol and carbon dioxide (CO_2).

Typically, complete fermentation can take from 40 to 60 hours. During this part of the process, the mash is agitated and kept cool to facilitate yeast activity. After fermentation, the resulting product (i.e. beer) is transferred to a distillation process where the ethanol is stripped away from the remaining stillage. The ethanol is concentrated to 190 proof using additional distillation processes and is then dehydrated to approximately 200 proof using a molecular sieve system.

The ethanol is blended with approximately 3 to 5% denaturant (such as unleaded gasoline) to render it undrinkable. It is then ready for shipment to gasoline terminals or retailers.

Carbon dioxide (CO_2) released during fermentation is sometimes captured and sold for use in carbonating soft drinks and beverages and the manufacture of dry ice. More typically, it is vented to atmosphere.

The water and all solids (protein, fat, and fiber) are collected from the base of the distillation column. This material is called whole stillage. The whole stillage is pumped into a centrifuge that separates the coarse solids from the liquid, or centrate. The coarse solids collected from the centrifuge are called wet cake, and the centrate is called thin stillage. A portion of the thin stillage is recycled to the beginning of the process and is called backset. The balance of the thin stillage is typically concentrated in an evaporator to become condensed distillers solubles (CDS) or "syrup."

The wet cake and syrup are blended and sold as a wet livestock feed, or dried to produce distillers dried grains with solubles (DDGS).

3.2 Dry Mill Byproducts and Coproducts

Wet cake is a relatively high moisture ethanol process byproduct which has value in both wet and dried forms; it is also known as spent grain or, if wet, distillers wet grain (DWG). Wet cake contains liquid water, yeast, proteins, oils, and fibrous carbohydrates. Depending on centrifuge settings, it typically has a moisture content of about 68 percent and a higher heating value of approximately 3,000 Btu/lb. Wet cake is either sold as-is to local animal feed markets or dried, which allows longer-term storage and transport to more distant feed markets. Drying the DWG requires substantial energy input, most commonly in the form of natural gas.

Syrup is concentrated thin stillage produced from evaporators. Most ethanol facilities add the syrup back to the wet cake, and the combination is dried to make distillers dried grain with solubles, or DDGS. Syrup typically has a moisture content of over 62 percent and a higher heating value of about 3,200 Btu/lb.

Due to their heating value and the cost required for drying these co-products, a number of dry mill ethanol plant managers have investigated combusting them to produce steam. Corn Plus Ethanol, a dry mill ethanol plant in Winnebago, Minnesota, burns syrup in a fluidized bed boiler to reduce natural gas consumption. They also dry the remaining DWG and sell it without the solubles being reapplied.

A substantial number of dry mill ethanol plants are adding various corn fractionation technologies ahead of the ethanol process or are extracting valuable oily residue streams from the stillage, both of which add value to the plant's operation. Neither of these processes were proposed or evaluated as a part of this study, though Black & Veatch has performed similar evaluations of such opportunities. These alternative technologies warrant further study and consideration in light of the results of the present evaluation.

4.0 Technology Options Overview

This section provides an overview of the proposed processes as submitted to OTAE for evaluation.

4.1 Fluidized Bed Combustion of Syrup and Steam Generation

Combustion is the complete oxidation of a fuel resulting in generation of heat. It may be characterized by the following simplified equation:

$$\text{Fuel} + \text{Oxygen} \rightarrow \text{Heat}$$

The above reaction is an overly-simplified representation of the actual combustion process, which consists of many steps. Nevertheless, heat is the primary product of the combustion process. This heat can be used either directly, such as in a drying process, or indirectly by transferring it to a "working fluid" such as steam. If the heat is transferred to steam, it is generally accomplished in a boiler. The steam produced by the boiler may be sent directly to process end users or may be used to spin a steam turbine generator to generate electricity.

Figure 4-1 shows a typical block flow diagram for the combustion process.

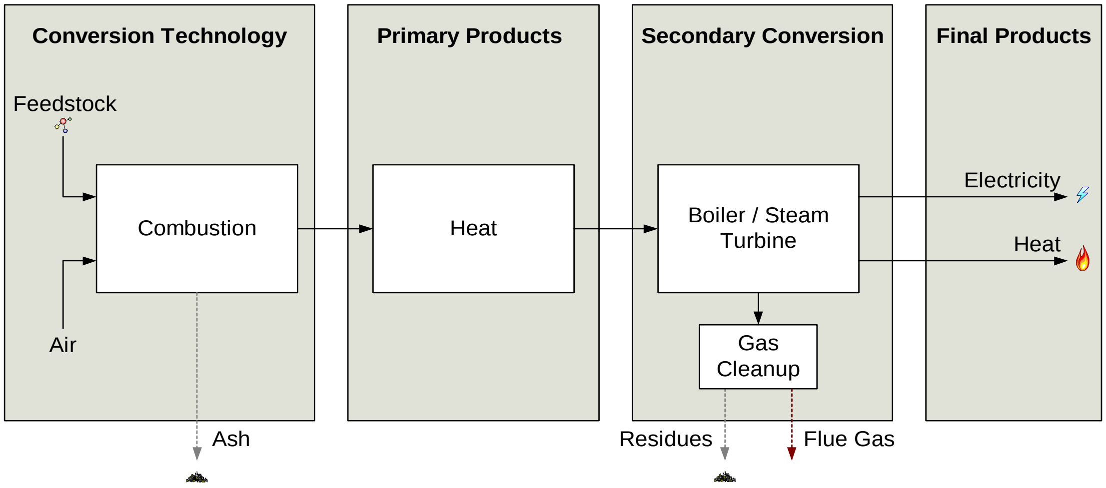


Figure 4-1. Combustion Process Flow Diagram

Combustion of biomass in fluidized bed boilers has been practiced for several decades. Figure 4-2 illustrates a typical model. In bubbling fluidized bed boilers, fuel feeders discharge either to chutes that drop the fuel into the bed or to fuel conveyors that distribute the fuel to feed points around the boiler. The speed of the feeders is modulated to maintain output when fuel conditions or loads change. The materials resident in the boiler at any given time take on a fluid appearance when air is driven through them from below. These materials form the bed and typically consist of fuel, ash from the fuel, inert material (e.g., sand), and possibly a sorbent (e.g., limestone) to reduce sulfur emissions. In most biomass fired applications, the fuel typically has no or very little sulfur, thus limestone sorbent is not always required and a sand bed is typically utilized. Bubbling fluidized beds are fuel flexible and are capable of burning both wet cake and syrup. Since the sulfur content for wet cake and syrup is somewhat higher than other types of biomass, sorbent injection may be necessary.

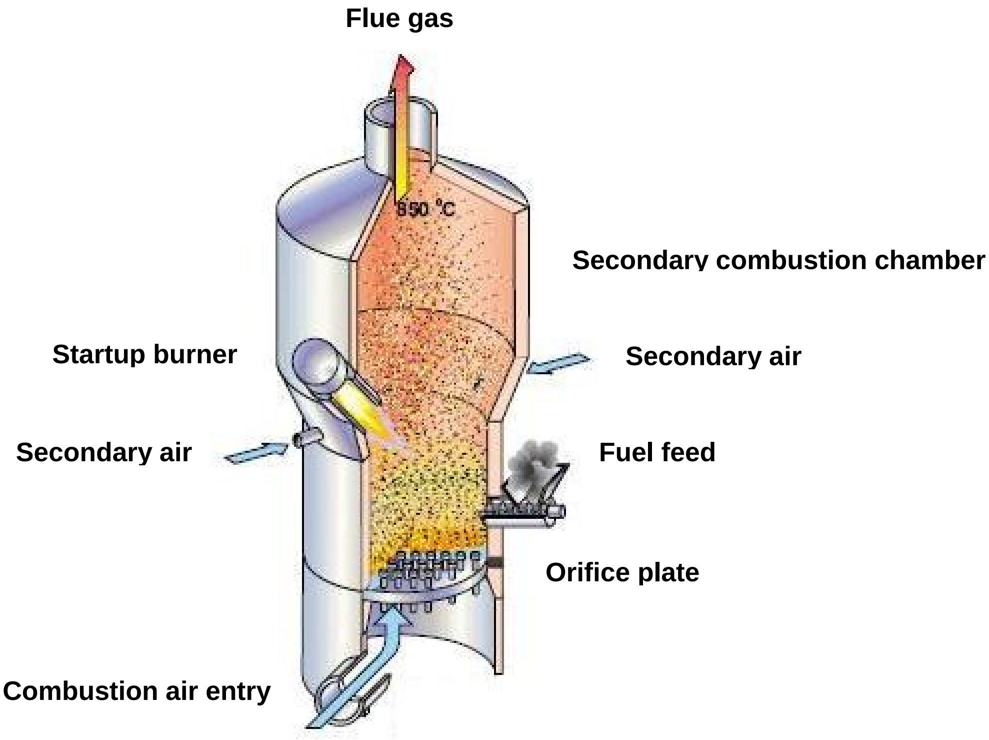


Figure 4-2. Typical Bubbling Fluidized Bed (source: AE&E – Von Roll).

As stated before, the fluidized state of the bed is maintained by hot primary air flowing upward through the bed. The air is introduced through a grid to evenly distribute the air. The amount of air is just sufficient to cause the bed material to lift and separate. In this manner, circulation patterns occur causing fuel discharged on top of the bed to mix throughout the bed. Because of the turbulent mixing, heat transfer rates are very high and combustion efficiency is good. Consequently, combustion temperatures can be kept low compared to other conventional fossil fuel burning boilers. The bed may also be operated in a sub-stoichiometric mode with additional air added in the secondary combustion chamber (freeboard) to complete combustion. Low bed temperatures and air staging reduces NO_x formation. Low temperature is also an advantage with biomass fuels because these fuels may have relatively low ash fusion temperatures. Low ash fusion temperatures can lead to excessive boiler slagging.

A bubbling fluidized bed boiler is generally designed to have gas velocities through the bed of less than 10 feet per second. This low velocity minimizes the amount of large solid material entrained in the flue gas stream. Management of tramp material and agglomerates in the bed is very important for long term, reliable operation. For example, in the AE&E-Von Roll bubbling fluidized bed boiler, there is a bed recycle system that withdraws material from the bottom of the fluidized bed. The removed bed material is screened to separate the tramp materials (dirt, and other noncombustibles) from the inert bed material, and the reclaimed inert material is recycled back to the bed.

In the bed, the fuel rapidly devolatilizes. This results in 55 to 60 percent of the combustion occurring in the bed and 40 to 45 percent occurring above the bed. Overfire air is required to ensure complete combustion of the fuel.

Because of the low combustion temperatures, NO_x emissions from a bubbling fluidized bed boiler burning biomass will generally be less than 0.20 lb/MMBtu. In addition, the operating temperature of a bubbling fluidized bed is usually within the temperature range that allows a selective non-catalytic reduction (SNCR) system to be effective if NO_x control is warranted or becomes so at a later time.

An assessment of fouling and slagging potential due to alkali material can be made by examining biomass ash properties. Detailed ash composition data was not provided for this study. However, ash composition analysis is certainly warranted since some studies have shown syrup and DWG ash to be relatively high in oxides of sodium and potassium. Keeping combustion temperatures low, adding limestone or other sorbents, utilizing boiler tube screens and providing adequate sootblower capacity may be necessary to prevent slagging and fouling in the boiler and downstream components.

Both wet cake and syrup are relatively high moisture fuels. If the combined moisture content is above 67 percent, combustion may not be self-sustaining and will require supplemental fuel such as natural gas.

High moisture content fuel can also severely limit boiler performance resulting in decreased efficiency, poor load-following ability, and increased carbon monoxide emissions. Such conditions will be aggravated if the fuel properties vary significantly. OTAE may want to consider alternatives to improve performance which could include:

- Improved ethanol process performance (centrifuge and evaporators) resulting in lower moisture content syrup
- Supplemental firing with natural gas
- Supplemental firing with lower moisture content biomass fuels

4.2 Anaerobic Digestion of Thin Stillage

Anaerobic digestion is the naturally occurring process that occurs when bacteria decompose organic materials in the absence of oxygen. The byproduct gas typically contains a significant amount of methane. The most common applications of anaerobic digestion are for treating industrial wastewater, animal manure, or human sewage. The primary economic drivers for anaerobic digestion projects are increasingly stringent agricultural manure and sewage sludge management regulations, with power production being a secondary consideration. Anaerobic digestion of stillage can be employed at ethanol plants, though few plants exist that have installed digesters.

The digester is placed between the plant's primary centrifuges and the evaporators. The thin stillage is piped from the thin stillage storage tank to the anaerobic digester tanks. Biogas is produced and piped to a biogas scrubber prior to utilization in the plant's combustion systems. In this proposed arrangement, chemicals are added to the digester effluent stream to precipitate the struvite in solution. Centrifuges remove the precipitated struvite along with any residual solids from the effluent. The centrate then enters the evaporators for dewatering. The process results in a biogas stream with approximately 55-70 percent methane. Condensate from the evaporators is returned to the ethanol plant process.

Biogas produced by anaerobic digestion can be used for power generation, direct heat applications, or steam generation. In an ethanol plant, the volatile solids reduction through anaerobic digestion tends to improve water quality within the ethanol production process. The energy from digester gas production offsets natural gas requirements for distillation and drying and can insulate the facility from volatile natural gas prices. Doing so, however, will require adjustments or retrofits to existing boiler and/or dryer combustion equipment so that the lower quality fuel may be utilized.

4.3 Anaerobic Digestion of Thin Stillage with Struvite Extraction

The anaerobic digestion and struvite extraction processes are based on independently proven technologies; however, they have not been combined for application to thin stillage. By precipitating struvite upstream of an anaerobic digestion process, the vendor claims several potential operational problems, such as scaling in the digesters, mixing equipment, pumps, discharge and piping may be reduced or eliminated. Struvite removal also reduces the concentration of phosphorus in the digested solids, reducing the possibility of over-applying phosphorus to the land when utilizing the biosolids as a soil amendment.

The precipitated struvite is a renewable inorganic fertilizer. The vendor of the struvite precipitation equipment, Ostara Nutrient Recovery Technologies, offers several options for contracting with their company. In each case, Ostara maintains the right to purchase all struvite produced at the plant by their process. Depending on the final financial arrangement with Ostara, struvite production by the plant may produce an additional revenue stream for the facility.

Struvite (magnesium ammonium phosphate, $MgNH_4PO_4 \cdot 6H_2O$) is a crystalline material consisting of equimolar concentrations of magnesium, ammonium, and phosphorus. Struvite precipitates when available concentrations of the three constituents exceed the struvite solubility limit. The solubility limit varies depending on the pH, temperature, and ionization of the solution and is defined by the solubility product (K_{sp}), which ranges from $10^{-12.6}$ to $10^{-13.26}$, depending on the ionic strength of the solution. When the concentration product $[Mg^{2+}][NH_4^+][PO_4^{3-}]$ is less than the K_{sp}, the solution is considered undersaturated for struvite precipitation, while solutions with concentration products that are greater than the K_{sp} are oversaturated and will precipitate struvite. As pH and temperature increase, the struvite precipitation potential increases.

The anaerobic digestion process solubilizes particulate phosphorus and nitrogen, increasing the dissolved concentrations of PO_4^{3-} and NH_4^+. When the digested solids are pumped or dewatered, the turbulence created by these operations strips carbon dioxide from the liquid, increasing pH. The combination of the increase in dissolved constituent concentrations and the elevated pH results in conditions favorable for struvite formation. The vendor of the struvite precipitation option asserts that the pH of untreated digester influent is such that struvite will be precipitated resulting in negative consequences to the digester and downstream equipment. No conclusive data was provided that irrefutably confirmed this claim.

The combination of struvite precipitation and anaerobic digestion applied to any byproduct from an ethanol facility is a patent pending process.

5.0 Technical Assessment of Technology Options

This section summarizes Black & Veatch's technical assessment of the proposed processes. It includes discussion of potential project options, performance assumptions, conceptual process flow diagrams, and basic heat and mass balances.

5.1 Project Configurations

Three proposed project configurations were evaluated. All of these options are based on the use of ethanol plant co-products (syrup or thin stillage) as feedstocks for the intermediate processes.

Each of the proposed solutions can substantially reduce the amount of natural gas consumed by the ethanol plant. In the fluidized bed boiler case it is assumed that the plant's existing natural gas boilers will remain as backup if the fluidized bed combustion system is not available due to maintenance or forced shutdowns. Biogas produced by either anaerobic digestion scenario would be used in the plant's existing boilers in place of natural gas.

A description of the proposed configuration options follows.

5.1.1 Fluidized Bed Combustion of Syrup and Steam Generation

A bubbling fluidized bed biomass steam generator would burn all the plant's syrup and approximately 19% of the wet cake in order to produce process steam for the ethanol process. The unburned wet cake and any unused syrup would be dried in the natural gas-fired dryer, and the resulting DDG would be sold. The plant currently has an average DDGS production capability of approximately 525 tons per day. Under this scenario, about 237 tons of DDG would be produced. When operating, the biomass combustion process would offset all of the natural gas used for steam generation, and about 55 percent used for drying. If necessary based on operational characteristics (i.e. fuel moisture content), the combustor may require co-firing with natural gas. Selling ash as a soil amendment also has merit.

5.1.2 Anaerobic Digestion of Thin Stillage

Thin stillage from the ethanol plant is to be anaerobically digested to produce biogas. The biogas produced is scrubbed and compressed for final use by the plant off-setting the use of natural gas. A precipitation tank downstream of the digesters will precipitate struvite from the digester effluent. The struvite-laden solids will be separated from the liquid using dewatering centrifuges. The separated solids containing the precipitated struvite will be sold as a fertilizer. Centrate will be returned to the ethanol plant process via the evaporators.

5.1.3 Anaerobic Digestion of Thin Stillage with Struvite Extraction

In the third scenario, anaerobic digestion is preceded by a patented and commercially available struvite precipitation process to create a value-added co-product and reduce wear on downstream operations. Struvite is a renewable inorganic fertilizer and is expected to generate revenue for the facility. The supernatant from the struvite precipitator will be anaerobically digested to extract energy in the form of biogas, which will be used by the plant, off-setting the use of natural gas. The digested solids will be dewatered using belt filter presses and the separated solids will be hauled away presumably as a soil amendment. Centrate will be returned to the ethanol plant process via the evaporators.

5.2 Technical Description

This section describes the major systems and equipment that are proposed for each technology option. Included are any major associated systems required to define a complete project which were not included in the vendor's proposed scope of supply.

5.2.1 Fluidized Bed Combustion of Syrup and Steam Generation

The proposed steam generator is a syrup-fueled, bubbling fluidized bed boiler of proven design, nominally rated to produce 120,074 lbs/hr at 80 psig and 324°F. Feedwater for the boiler will be supplied from a deaerator and will enter the boilers at a temperature of 230°F.

The proposed boiler is provided with all of the following equipment and subsystems:

- Fluidizing air fan, secondary air fan, flue gas recirculation fan, and induced draft fan, including motor drives, expansion joints, and flow control dampers and actuators, couplings and guards, bearing temperature indicators, and inlet filters.
- Fluidized bed reactor, including field erection of the vessel proper, sight glass, flanged instrument nozzles as required, freeboard and windbox access doors, flanged connections for combustion air, syrup feed, spray water, and in-bed natural gas lances.
- Fluidized bed reactor refractory, materials, and installation, including supervision of dry-out and curing.
- Overbed burner start-up system, including skid mounted pipe rack.

- In-bed natural gas lances.
- Limestone storage silo, including fill stations, feeder, instruments and controls.
- Sodium bicarbonate storage and delivery system.
- Sand storage silo with coned bottom and rotary air lock will be provided to feed sand to the reactor. The silo will have sufficient capacity for one bed charge.
- Feed material mixing (syrup plus limestone) tank, including propeller-type, motor-driven mixer. Access ladder will be provided to top of tank.
- Mixed material feed to fluidized bed reactor, including feed conveyor, controls, and instruments.
- Waste heat boiler system with trim and feedwater controls. Boiler will be supplied with refractory-lined ash hoppers and trim shipped separately. Support steel and service platforms provided for access to soot blowers and boiler roof.
- Baghouse with inlet and outlet manifolds, ash hoppers, support steel, duct expansion joints, control dampers, stair tower, service platforms, control panel, insulation and lagging, and instruments.
- Bed material, water-cooled screw, including instruments and controls.
- Boiler and baghouse ash removal system, consisting of drag conveyors discharging to a pneumatic ash handling system for transport of ash to storage silo.
- Free-standing stack with test ports and platforms.
- Electrical motor drives.
- Process instruments and controls.
- Field mounted instrumentation, including thermocouples and pressure gauges.

The proposed boiler will be inside a vendor-supplied building enclosing the unit for appearance and noise attenuation purposes.

The ash content of the syrup is approximately 2.7 percent on a wet mass basis. Ash is collected from the boiler, waste heat boiler, economizer, and the fabric filter. Fly ash will be either pneumatically or mechanically drawn out of the fabric filter and boiler back pass hoppers and transported to an ash silo. Bottom ash leaving the fluid bed will be cooled and conveyed to the ash silo. The ash would either be hauled off site for disposal or reused as fertilizer. As a fertilizer, the ash market appears to be improving as other fertilizers increase in cost.

The boiler is designed to utilize syrup, wet cake and natural gas as fuels, though the primary fuel is intended to be syrup and secondarily, wet cake. The syrup would be transferred directly from the ethanol process to a small holding tank and then to the combustor using pumps.. DWG would be fed to the combustor from a small bin using water-cooled screw conveyors.

Because the syrup and DWG have relatively high moisture content which can vary considerably, natural gas may be needed occasionally to supplement the heat input to the boiler. Piping for natural gas is included in the vendor’s scope of supply.

It is proposed to modify and use the plant’s existing distributed control system (DCS) to control the boiler system and the balance of plant equipment. The DCS would then serve as the main operator interface to the plant equipment with user interface stations located in the plant control room.

Typically, the boiler system package would be provided with the following balance of plant equipment. However, the proposed system will tie into the existing steam, boiler feedwater, condensate, and instrument air systems.

- Condensate Pumps (2x100 percent)
- Deaerator
- Boiler Feedwater Pumps (2 x 100 percent)
- Air Compressor (2 x 100 percent - Oil Free)
- Dual-tower Desiccant Air Dryer
- Steam & Water Sampling and Analysis Panel
- Boiler Chemical Feed Systems
- RO Demineralizer
- Waste Water Blowdown Sump and Plant Waste Sump
- Thermal Insulation and Lagging
- Cathodic Protection System
- Elevator (Rack and Pinion Type)

5.2.2 Anaerobic Digestion of Thin Stillage

The anaerobic digestion facilities proposed for implementation are based on proven design and operational and pilot experience. In this application they include two 12-million gallon (MG) digesters. Effluent from the anaerobic digesters will flow by gravity to a precipitation tank for struvite precipitation. Chemicals will be added to the precipitation tank to promote struvite crystallization. The precipitated struvite will be retained in the solids and will be separated from the liquid stream in the subsequent dewatering step using centrifuges. This prevents the struvite from creating downstream issues. The struvite-rich solids have some value as a soil amendment. The solids content of this stream is approximately 25% so additional dewatering/drying, if required, would add expense.

The two 12-MG digesters will provide a retention time of approximately 45 days based on a thin stillage flow of 538,000 gallons per day (gpd). At an influent chemical oxygen demand (COD) load of 619,200 pounds per day (ppd), the digester loading will be approximately 3.1 grams COD per liter of digester volume per day (g COD/L/d), which is slightly lower than the literature values of 4.5 to 12 g COD/L/d (*Wilkie et al., 2000; Schaefer and Sung, 2008*). The conceptual design criteria for the digestion facilities are summarized in Table 5-1.

Table 5-1. Conceptual Design Criteria for Anaerobic Digestion-Only Facilities

Parameters	Quantities
Flow to Digesters, *gpd*	538,000
No. of Digesters	2
Volume per Digester, *MG*	12
Total Volume, *MG*	24
Retention Time, *days*	45
Operating Temperature, °*F*	95
Total COD in Digester Feed, *mg/L*	138,000
COD Loading, *g COD/L/day*	3.1

Based on the information obtained from ADI Systems Inc., the modified ADI-BVF® digesters will be equipped with membrane covers. The digester contents will be mixed continuously using submersible mechanical mixers to reduce stratification of suspended material in the digesters and ensure better contact. The digesters are not equipped with heat exchangers since thin stillage is available at a temperature of 165°F. However, an additional cooling step is required to lower the influent temperature to the mesophilic range of 95 to 100°F. The supplier indicated that there is provision to add steam directly to the stillage for heating the reactors during startup and emergencies. The effluent from the centrifuges will also require reheating to the evaporator inlet temperature of 165°F.

The digester gas from the two digesters will be collected through a common header. Digester gas is composed primarily of methane and carbon dioxide, but can also contain impurities that include sediments and hydrogen sulfide (H_2S). The gas will also be saturated with moisture at the operating temperature of the digesters. If left untreated, these contaminants can increase the maintenance requirements of the equipment fueled by the gas and reduce equipment life. The digester gas collection and handling system provided by the supplier includes a scrubber system to remove H_2S and compressors for boosting the gas pressure for final use in the plant's combustion systems.

The gas cleaning system includes scrubbing and regeneration vessels. The chemicals used in the scrubbers include caustic soda, iron EDTA solution, and tetrasodium EDTA. Relatively pure sulfur is recovered from the regeneration process in a slurry form, which is then dewatered to 85 percent solids using a plate and frame system. Any surplus gas will be combusted in a flare supplied by the vendor.

5.2.3 Anaerobic Digestion of Thin Stillage with Struvite Extraction

Anaerobic digestion with struvite extraction is a two-step process. The first step involves recovery of nutrients. Ostara Nutrient Recovery Technologies' (Ostara) patented nutrient recovery technology will be used for removal of magnesium, phosphorus, and nitrogen from thin stillage prior to anaerobic digestion. The Ostara system includes five 64-inch liquid fluidized bed reactors with chemical handling equipment, pumps, dewatering, drying and bagging equipment. (Utilities to the system such as water, electricity, process water, and instrument air are by others). Additional facility requirements include a stillage equalization and storage basin and a 9,200 square foot finished building is to be provided by others.

The anaerobic digestion facilities proposed for implementation as part of this process scheme are similar to those discussed in the previous section. At an influent COD load of 619,200 ppd, the digester loading will be approximately 3.1 g COD/L/d. The conceptual design criteria for the digestion facilities are summarized in Table 5-2.

Table 5-2. Conceptual Design Criteria for Anaerobic Digestion & Struvite Removal Facilities

Parameters	Quantities
Flow to Digesters[1], gpd	579,500
No. of Digesters	2
Volume per Digester, MG	12
Total Volume, MG	24
Retention Time, days	41
Operating Temperature, °F	95
Total COD in Digester Feed, mg/L	138,000
COD Loading, g COD/L/day	3.1

[1] *Includes NaOH and polymer.*

The stabilized solids from the anaerobic digesters will be dewatered using belt filter presses. These dewatered solids may have value as a soil amendment. The solids content of this stream is less than 20% so additional dewatering/drying, if required, would add expense.

Digester gas collected from the anaerobic digestion process will be cleaned to remove contaminants, compressed and piped to the plant's combustion systems.

5.3 Performance Assumptions

Table 5-3 summarizes the criteria used for estimating the performance of the two anaerobic digestion options.

Table 5-3. Process Performance of Anaerobic Digestion Options

	Anaerobic Digestion	Anaerobic Digestion w/ Struvite Precipitation
Flow to Digesters	538,000 *gpd*	579,500 *gpd*
Digester Feed COD	138,000 *mg/L*	138,000 *mg/L*
COD Reduction in Digesters	90%	90%
Estimated Biogas Production[1]	4,804,900 *cf/d*	4,804,900 *cf/d*
Gross Energy from Biogas[2]	2,885 *MMBtu/d*	2,885 *MMBtu/d*
Biosolids Production (wet)	132 tpd	159 tpd
Struvite Precipitation	n/a	19,000 *ppd*

[1] *Based on 0.35 L CH_4/g COD destroyed (Speece, 1996) and 65% CH_4 content*

[2] *Based on a heating value of 600 Btu/scf of digester gas*

Biogas production was estimated for the two processing schemes based on the standard 0.35 liters of methane per gram of COD destroyed in the digesters (*Speece, 1996*). The gross energy available from digester gas was estimated using a heating value of 600 British thermal units per standard cubic feet (Btu/scf) of biogas. Based on literature values, the biogas can contain 55 to 65 percent methane. ADI indicated the methane production would be 65 percent. Rein indicated a higher value. For the purposes of the evaluation, 65 percent was used.

For the anaerobic digestion option with struvite precipitation, the concentrations of magnesium (Mg), phosphorus (P), and nitrogen (N) in the influent stream to the precipitator seem adequate to precipitate the estimated 28,000 ppd of struvite. Struvite [$(NH_4)MgPO_4 \cdot 6(H_2O)$] contains approximately 9.8 percent by weight of magnesium (Mg), 12.7 percent by weight of phosphorus (P), and 5.7 percent by weight of nitrogen

(N). However, the effectiveness of the struvite precipitation process is also dependent on other process parameters, such as pH, solubility etc. It was assumed that the required process parameters would be maintained at optimal levels to facilitate struvite precipitation.

Even though the anaerobic digestion-only scheme also incorporates a precipitation step following anaerobic digestion, information is lacking for estimating the struvite precipitation potential. Nevertheless, the precipitated solids have been identified as a revenue stream in the proposal.

5.4 Heat and Mass Balances

Black & Veatch has prepared performance estimates for all three scenarios. These are shown in the tables and figures on the following pages.

5.4.1 Fluidized Bed Combustion of Syrup and Steam Generation

AE&E Von Roll Inc. provided a preliminary process flow diagram with a material and energy balance, a copy of which is included in Appendix A to this report. The balance was found to be sufficiently complete and to be accurate. A simplified block flow diagram is shown in Figure 5-1 below.

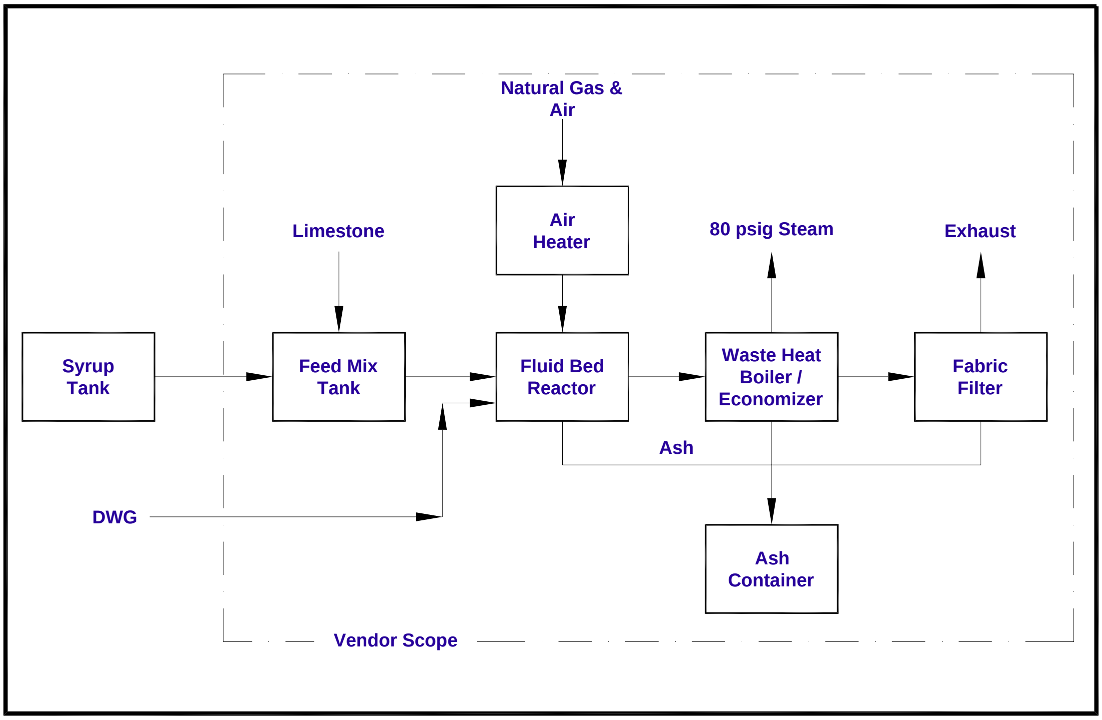
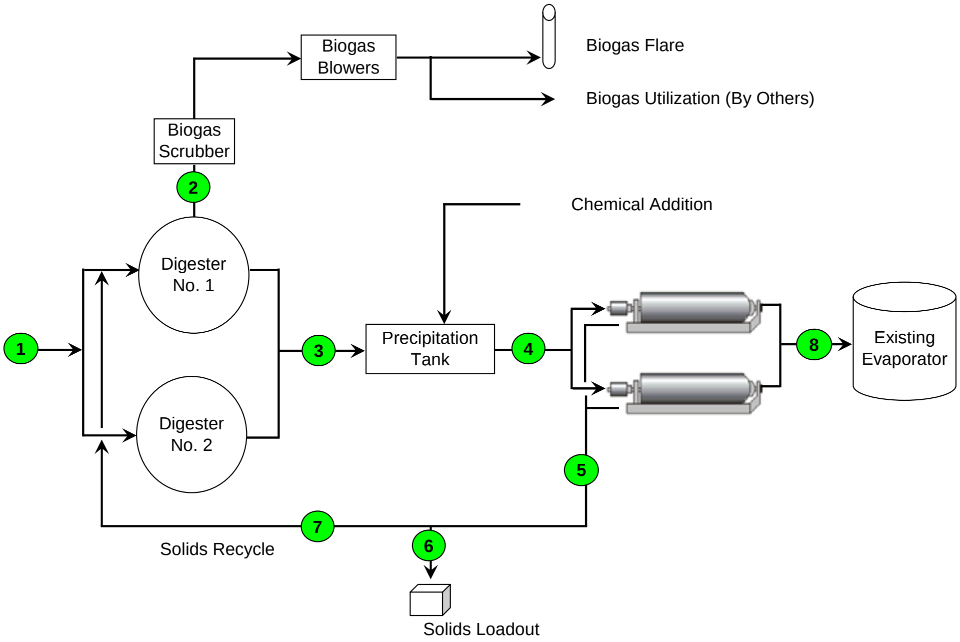


Figure 5-1. Block Flow Diagram of Bubbling Fluidized Bed Boiler System

5.4.2 Anaerobic Digestion of Thin Stillage

Figure 5-2 illustrates the solids and liquid balance evaluations performed for the anaerobic digestion scenario based on the information provided. The stream numbers in the heat and mass balance table correspond to the stream numbers on the diagram.

The information provided for the anaerobic digestion scenario was not adequate to evaluate flows and loads through the entire system. The COD and total suspended solids (TSS) concentrations in the digester feed and the centrate stream from dewatering were provided by the supplier. This information was used to develop an approximate solids-liquid balance through the system and estimate potential biogas production.



Parameter	Units	1	2	3	4	5	6	7	8	Destruction	
		Thin Stillage	Digester Gas	Digested Solids[A]	Precipitator Effluent	Dewatered Solids[B]	Solids Loadout	Solids Recycle	Centrate to Evaporator	Digester	Overall
Flow	gpd	538,000		538,000	538,000	32,600	31,700	900	505,400		
Total Suspended Solids	mg/L	36,900		12,500	17,000	250,000	250,000	250,000	1,969		
	%	3.7%		1.3%	1.7%	25.0%	25.0%	25.0%	0.2%		
	ppd	165,600		56,100	76,300	68,000	66,000	1,900	8,300	66%	95%
Total COD	mg/L	138,000		13,700	14,000	153,400	153,400	153,400	5,000		
	ppd	619,200		61,500	62,800	41,700	40,500	1,200	21,100	90%	97%

[A] Estimated based on Rein Proposal

[B] Based on 89% capture in centrifuges

Figure 5-2. Mass and Flow Analysis for Anaerobic Digestion Option

Based on the COD and TSS information and assuming identical digester performance as the digestion scenario with struvite precipitation, the system achieves a COD reduction of approximately 90 percent through the digestion process.

5.4.3 Anaerobic Digestion of Thin Stillage with Struvite Extraction

Figure 5-3 is a block flow diagram of the proposed process. Figure 5-4 contains a data table for the solids and liquid balance evaluations performed for the anaerobic digestion–struvite precipitation scenario. The stream numbers in the heat and mass balance table correspond to the stream numbers on the figures.

Some of the concentration and load numbers in the Rein proposal do not add up properly. The differences are not very significant and could possibly be rounding errors.

Based on the projected digester performance, approximately 90 percent of the total influent COD would be converted to biogas through the digestion process. The overall COD and TSS removals through the entire system (based on raw influent and belt filter press filtrate COD and TSS concentrations) average 96 percent. These COD and TSS reduction values concur with published values from literature.

Energy balances were developed for the two digestion scenarios to determine additional energy needs to maintain digestion process temperatures. Based on information obtained from the supplier, raw thin stillage from the plant would be available for digestion at approximately 165°F. Approximately 12 MMBtu/hr of heat must be recovered from the influent stream to drop the feed temperature to the 95-100°F range required for mesophilic digestion. The proposal indicates that heat recovery operations are to be performed by others and the equipment required for heat recovery is not included in the scope. The digesters are not equipped with heat exchangers, but the supplier indicated that there is provision to add steam directly to the stillage for heating the reactors during startup and emergencies. However, if steam were to be used for process heating, a portion of the biogas generated from the digesters would have to be used as the energy source for steam generation, which would decrease revenues from the operation.

A cursory evaluation of digester heat losses indicated potential average transmission losses of up to 1.2 MMBtu/h for the two scenarios. Since the information provided by the suppliers did not include any information on digester construction and/or configuration, heat loss estimates were developed based on the following digester configuration:

- Two cylindrical tanks, each 200 feet in diameter by 51 feet in height
- Concrete construction with geo-membrane covers
- One-third of the tank below-grade
- Tank walls and cover insulated (Insulation R-value of 5)

An additional steam requirement of approximately 1,200 pounds per hour was estimated to maintain mesophilic process temperatures based on a heat content of 1,000

Btu per pound of steam. These numbers can be confirmed when detailed drawings of the proposed digestion facility become available.

The final temperature of the effluent from the dewatering centrifuges can range from 85 to 90°F. Since the thin stillage was originally at 165°F, additional energy would be required to raise this effluent stream temperature to the evaporator inlet temperature. It is expected that this would require an additional 15 MMBtu/hr (based on 85°F) which equates to approximately 15,000 lb/hr of steam.

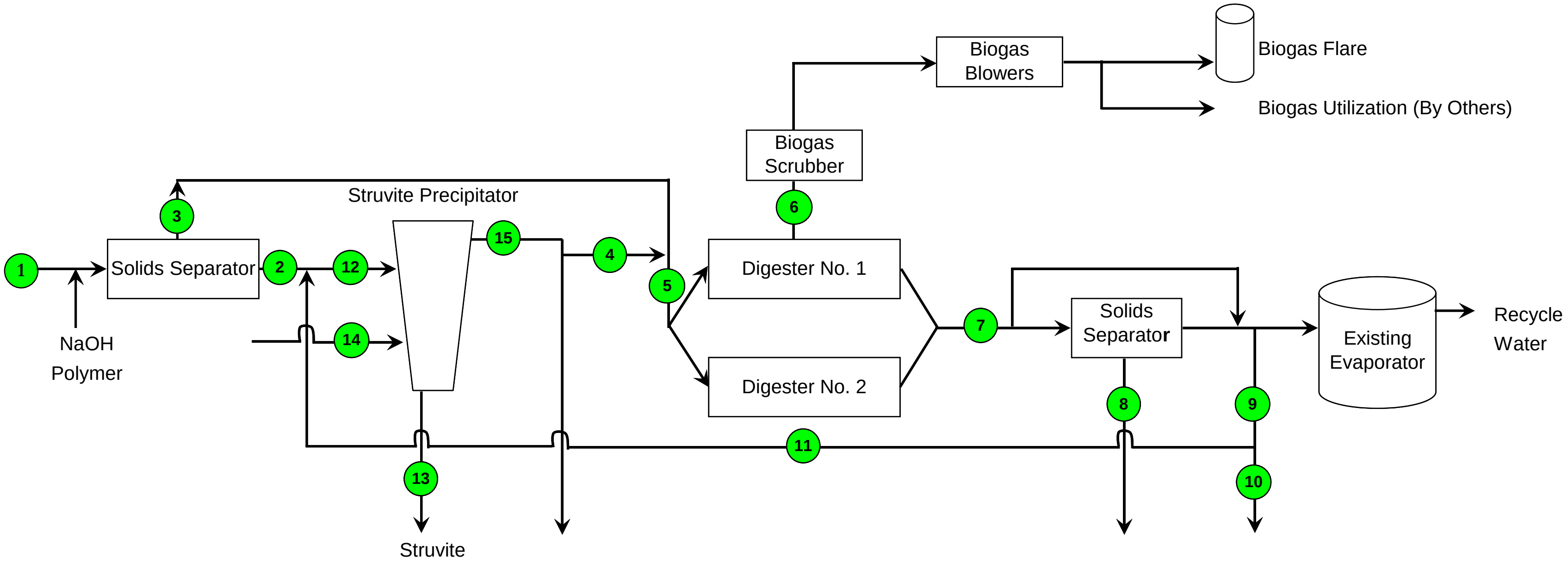


Figure 5-3. Block Flow Diagram for Anaerobic Digestion-Struvite Precipitation Option.

Parameter	Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	estruction/Remova	
		Thin Stillage & Chemicals[1]	Liquid to Precipitator	Solids to Digestion	Precipitator Supernatan	Digester Feed	Digester Gas	Digester Effluent[2]	Dewatered Solids	Liquid from Separator[3]	Recyclable Water	Return Stream	Precipitator Influent	Struvite	NaOH & Nutrients	Liquid from Precipitator	Digester	Overall
Flow	*gpd*	**579,900**	**528,100**	**51,800**	**527,700**	**579,500**		**580,000**	**38,100**	**570,900**	**570,900**	**0**	**528,100**	**6,700**	**6,300**	**527,700**		
Total Suspended Solids	*mg/L*	34,200	800	385,000	1,100	35,400		12,000	162,000	1,910	1,910	1,910	800	673,200		1,100		
	%	3.4%	0.1%	38.5%	0.1%	3.5%		1.2%	16.2%	0.2%		0.2%	0.1%	67.3%		0.1%		
	ppd	153,500	3,500	166,300	4,800	171,100		58,000	51,500	9,100		0	3,500	37,600		4,800	**66%**	**94%**
Total Dissolved Solids	*mg/L*	31,600	30,800	30,800	33,100	32,900		17,100	16,300	16,300	16,300	16,300	30,800	30,500		33,100		
	%	3.2%	3.1%	3.1%	3.3%	3.3%		1.7%	1.6%	1.6%		1.6%	3.1%	3.1%		3.3%		
	ppd	141,800	135,700	13,300	145,700	159,000		82,700	5,200	77,600		0	135,700	1,700		145,700		
Total Solids	*mg/L*	65,800	31,600	415,800	34,200	68,300		29,100	178,300	18,210	18,210	18,210	31,600	703,700		34,200		
	%	6.6%	3.2%	41.6%	3.4%	6.8%		2.9%	17.8%	1.8%		1.8%	3.2%	70.4%		3.4%		
	ppd	**295,200**	**139,200**	**179,600**	**150,500**	**330,100**		**140,800**	**56,700**	**86,700**		**0**	**139,200**	**39,300**		**150,500**	**57%**	**71%**
Volatile Suspended Solids	*mg/L*	30,500	700	335,100	500	30,400		6,900	88,700	1000	1,000	1,000	700	10,600		500		
	%	3.1%	0.1%	33.5%	0.1%	3.0%		0.7%	8.9%	0.1%		0.1%	0.1%	1.1%		0.1%		
	ppd	136,900	3,100	144,800	2,200	146,900		33,400	28,200	4,800		0	3,100	600		2,200	**77%**	**96%**
Volatile Dissolved Solids	*mg/L*	31,600	30,800	30,800	33,100	32,900		17,100	16,300	16,300	16,300	16,300	30,800	30,500	0	33,100		
	%	3.2%	3.1%	3.1%	3.3%	3.3%		1.7%	1.6%	1.6%		1.6%	3.1%	3.1%		3.3%		
	ppd	130,700	135,700	13,300	145,700	159,000		82,700	5,200	77,600		0	135,700	1,700		145,700		
Total Volatile Solids	*mg/L*	62,100	31,500	365,900	33,600	63,300		24,000	105,000	17,300	17,300	17,300	31,500	41,100		33,600		
	%	6.2%	3.2%	36.6%	3.4%	6.3%		2.4%	10.5%	1.7%		1.7%	3.2%	4.1%		3.4%		
	% of TSS	94.4%	99.7%	88.0%	98.2%	92.7%		82.5%	58.9%	95.0%		95.0%	99.7%	5.8%		98.2%		
	ppd	**278,600**	**138,700**	**158,100**	**147,900**	**305,900**		**116,100**	**33,400**	**82,400**		**0**	**138,700**	**2,300**		**147,900**	**62%**	**70%**
Total COD	*mg/L*	138,000	66,300	757,400	65,300	138,000		13,800	128,000	4,500	4,500	4,500	66,200	0		65,300		
	ppd	**619,200**	**292,000**	**327,200**	**287,400**	**619,200**		**62,000**	**40,700**	**21,400**		**0**	**291,600**	**0**		**287,400**	**90%**	**97%**
Particulate COD	*mg/L*	63,100	1,400	693,000	1,100	62,900		9,400	121,800	1,400	1,400	1,400	1,400	0		1,100		
	ppd	283,100	6,200	299,400	4,800	304,000		45,500	38,700	6,700		0	6,200	0		4,800		
Dissolved COD	*mg/L*	74,900	64,900	64,400	64,200	75,100		4,400	6,200	3,100	3,100	3,100	64,800	0		64,200		
	ppd	336,100	285,800	27,800	282,500	363,000		21,300	2,000	14,800		0	285,400	0		282,500		
Dissolved Mg	*mg/L*	670	530	530	50	95		95	90	90	90	90	530	52		50		
	ppd	**3,010**	**2,330**	**230**	**220**	**460**		**460**	**30**	**430**		**0**	**2,330**	**0**		**220**		
Dissolved Ortho-P	*mg/L*	630	440	440	70	100		230	100	100	100	100	440	70		70		
	ppd	**2,830**	**1,940**	**190**	**310**	**480**		**1,110**	**30**	**480**		**0**	**1,940**	**0**		**310**		
Dissolved NH_4-N	*mg/L*	90	90	90	30	40		560	540	540	540	540	90	30		30		
	ppd	**400**	**400**	**40**	**130**	**190**		**2,710**	**170**	**2,570**		**0**	**400**	**0**		**130**		

[1] *Includes 41,900 gpd chemicals (NaOH, Polymer) added to the solids separator*

[2] *Includes 510 gpd $FeCl_3$ fed to the digesters*

[3] *Includes 29,000 gpd polymer added to the centrifuges*

Figure 5-4. Mass and Flow Analysis for Anaerobic Digestion-Struvite Precipitation Option.

5.5 Vendor-Supplied Performance Information

Performance estimates and other supporting data from vendors are included in Appendix A of this report.

6.0 Preliminary Project Costs

This section provides information on the estimates for capital and operating and maintenance costs prepared by Black & Veatch. These estimates have been prepared to identify promising project configurations and eliminate unviable options from the solutions proposed. They should not be considered definitive cost estimates, which will need to be developed in later stages of site specific project development.

6.1 Capital Costs

These cost estimates include estimated costs for equipment and materials, construction labor, engineering services, construction management, indirect and other costs. The estimated cost of materials and equipment for the project is based primarily on the vendor's proposals with Black & Veatch experience and estimation capability providing the balance of costs. Table 6-1 presents a summary of the total project cost estimates for the different options. The estimates include direct costs and owner's costs. Cost estimates for the balance of work not covered by the scope of the vendor's proposal were determined using in-house estimates. All costs in this report are in 2008$ unless otherwise stated.

Table 6-1. Estimated Project Capital Costs (2008$).

	Fluidized Bed Combustion	Anaerobic Digestion	Anaerobic Digestion with Struvite Extraction
Direct Costs	23,500,000	26,000,000	32,300,000
Balance of Work	150,000	150,000	2,800,000
Owner's Soft Costs	300,000	300,000	450,000
Total Project Cost	23,950,000	26,450,000	35,550,000

Balance of work costs were set at $150,000 for the fluidized bed combustion and anaerobic digestion-only options; these proposals contained nearly all scope items. The proposal for anaerobic digestion with struvite recovery was not a fixed fee offer and excluded a significant number of scope areas that have been accounted for in the $2,800,000 figure.

Likewise, a fixed value of $300,000 was assigned to Owner's Soft Costs in the first two scenarios and $450,000 for the third scenario. Table 6-2 provides a listing of possible Owner's "soft" costs that should be considered by the project developer in order to determine the total project cost. Their applicability varies with specific project requirements.

Table 6-2. Owner's "Soft" Costs.

Project Development:
- Road modifications / upgrades
- Demolition
- Environmental permitting / offsets
- Public relations / community development

Utility Interconnections:
- Gas system upgrades (if applicable)
- Electrical transmission
- Supply water
- Waste water / sewer (if applicable)

Spare Parts and Plant Equipment:
- AQCS materials, supplies, and parts
- Boiler materials, supplies, and parts
- BOP equipment / tools
- Rolling stock
- Plant furnishings and supplies

Owner's Project Management:
- Provide personnel for construction management
- Perform engineering due diligence
- Prepare bid documents and selection of contractor(s) and suppliers
- Provide project management

Plant Start-up / Construction Support:
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals / reagents
- Consumables
- Auxiliary power purchase
- Construction risk insurance

Taxes / Advisory Fees / Legal:
- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - Contract-procurement and construction
  - Property transfer

Financing:
- Loan administration and commitment fees
- Interest during construction
- Financial advisor, lender's legal, market analyst, and engineer
- Debt service reserve fund

Owner's Contingency:
- Owner's uncertainty and costs pending final negotiation:
  - Unidentified project scope increases
  - Unidentified project requirements
  - Costs pending final agreement

This report presents information that is believed to be consistent with current market conditions. It should not be construed as an offer by Black & Veatch to perform the work or provide equipment and materials at the values presented herein.

6.2 Operating and Maintenance Costs

Operating and maintenance (O&M) costs are defined as all production related expenses associated with the specific technology option. O&M costs typically include production and maintenance labor, chemical costs, water costs, ash disposal costs, maintenance parts and materials, and various other expenses associated with plant operation and maintenance. Not included in O&M costs are items such as fixed charges on capital investment which consist of return on investment, depreciation, and income taxes. Operating and maintenance costs are typically split into fixed and variable components.

- **Fixed Operating and Maintenance Costs** are O&M costs associated with a facility that do not vary with the output of the facility. Such costs typically include staffing, insurance, property taxes, etc. Fixed O&M estimates were determined based on staff and labor cost estimates provided in vendor proposals plus one-half percent of the total capital cost.
- **Variable Operating and Maintenance Costs** are those O&M costs that vary according to the of plant output, and include consumables such as limestone and sodium bicarbonate as well as spare equipment parts and materials. Estimates for the variable O&M for the project were obtained from a cost build-up based upon Black & Veatch’s experience with similarly sized systems or from the vendors’ proposals. Variable O&M estimates are shown with fixed O&M estimates in Table 6-3.

Table 6-3. Annual Operation and Maintenance Cost Assumptions (2008$).

	Fluidized Bed Combustion	**Anaerobic Digestion**	**Anaerobic Digestion with Struvite Extraction**
Fixed O&M			
Labor	75,000	110,000	140,000
Other Fixed O&M	117,500	130,000	161,500
Total Fixed O&M, $/yr	**$192,500**	**$240,000**	**$301,500**
Variable O&M[a]			
Limestone	700,000	0	0
Calcium Bicarbonate[b]	600,000	0	0
Ash Disposal[c]	0	0	0
Sand Disposal	1,440	0	0
Chemical NaOH	0	134,750	1,482,000
Chemical Na_3PO_4	0	0	153,720
Chemical $MgCl_2$	0	318,500	0
Polymer	0	300,300	882,000
Biogas Scrubber Chemicals	0	120,000	120,000
Fabric Filter Replacement	36,000	0	0
Maintenance Parts and Materials	500,000	500,000	500,000
Auxiliary Electricity	189,000	503,770	523,000
Total Variable O&M, $/yr	**$2,026,440**	**$1,877,320**	**$3,660,720**
Total Annual O&M, $/yr[a]	**$2,218,940**	**$2,117,320**	**$3,962,220**

Notes:

[a] Assuming 8400 operating hours for the purposes of making annual calculations.

[b] Used for air quality control.

[c] Assumes revenues from ash sales as fertilizer offset disposal costs.

7.0 Economic Analysis

To determine the financial viability of the proposed options, Black & Veatch developed a pro forma economic model for potential operating scenarios based primarily on values provided in vendor proposals and coupled with the assumptions outlined in this section. This economic model calculates the revenues and costs associated with the project (relative to the current ethanol production process). The model also establishes the owner’s internal rate of return (IRR) under the specified conditions. This section provides an overview of the pro forma economic model, the base case economic assumptions, analysis results, sensitivity investigations, and economic analysis conclusions. All values in this section are provided in 2008$ unless otherwise stated.

7.1 Economic Model Overview

The financial model consists of a spreadsheet-based, 20-year annual cash flow (pro forma) model. The model takes into account the project’s capital and operating costs, performance characteristics (e.g., capacity factor), added or lost product sales (struvite, DDGS, ash), offset natural gas consumption, financing terms, and other income streams to calculate the amount of revenue available each year to service the debt and cover operating expenses. The primary revenue streams are the offset cost of natural gas and, in one anaerobic digestion case, the sale of struvite. With consideration of these factors, the model calculates the equity investors’ IRR. The model presumes that the project owner has no out-of-pocket tax liability.

The results are driven by many high-level and preliminary assumptions made regarding project capital costs, operating costs, financing, revenues, incentives and escalation of costs and revenues. Although the economic model is not exhaustive, the results of the analysis should be sufficient to indicate general project viability, to differentiate between the various options, and to evaluate which project parameters have significant influence over the economic results. If the project proceeds, it is recommended that an exhaustive financial model be constructed to more accurately reflect the intricacies of project structure, periodic maintenance expenditures, debt service reserve funds, degradation, capital outlays during construction, and other economic parameters. In particular, firm proposals with definitive capital costs, operating cost, and project performance guarantees should be received and evaluated.

7.2 Pro Forma Baseline Assumptions

Several sets of assumptions were established to form the bases for pro forma calculations. These include Existing Ethanol Plant Operational Assumptions, Scenario

Specific Assumptions, Financial Assumptions, and Product Value Assumptions. Defining these assumptions was necessary in order to develop reasonable estimates that were applicable to the project. At this stage of review, however, there is uncertainty in some parameters. Therefore, the model construction, assumptions and results should be viewed as the initial iteration in an ongoing process.

7.2.1 Existing Ethanol Plant Operational Assumptions

The "business-as-usual" operational assumptions associated with the existing ethanol plant are summarized in Table 7-1. They include:

- **Wet Cake Production** and **Syrup Production** were estimated based on review of operational data for 2008 and cross referenced with the ethanol plant process designer's design information. The combined production is estimated to be 1,275 wet tons per day on average. This is sufficient to provide an estimated 148 MMBtu/hr of energy from the syrup alone and an additional 207 MMBtu/hr from the wet cake.
- **Thin Stillage Production** was estimated based on vendor data, though the volume rate differed from the ethanol plant process designer's rate by approximately 2.5%. A volume flow of 538,000 gallons per day was assumed to be available for anaerobic digestion. For the purpose of calculating lost DDGS sales it was assumed that all of the solids in the syrup production stream would be consumed in the digester.
- **Potential DDGS Production** was estimated to determine revenues that would be lost once the syrup is used for fuel. It was assumed that the average DDGS moisture content is 10 percent. The potential DDGS production was calculated to be 525 tons/day on average, or 184,000 tons per year. It was also assumed that all wet cake and all syrup are normally dried and sold as DDGS rather than at separate, discounted rates.
- Annual **Potential Natural Gas Consumption** of the ethanol plant in its current configuration was estimated to be 1,648,500 MMBtu based on typical results for dry mill plants. The **Natural Gas Price** was assumed to be $11.75/MMBtu based on owner input. The cost of drying wet cake and syrup was assumed to be 1,300 Btu/lb of evaporated water based on B&V's extensive experience with drying.
- **Potential Electricity Consumption** was estimated to be 42,390 MWh of electricity per year based on electricity bills for a three-month period as provided by OTAE. The **Electricity Purchase Price** was assumed to be $50/MWh based on Owner's input.

Table 7-1. Business As Usual Ethanol Plant Assumptions.

Ethanol Production (MMGPY, undenatured)	55.0
Annual Corn Grind (million bu)	19.84
DDGS (10% moisture content)	
DDGS Yield (lb/bu)	18.53
DDGS Production (tons/year)	183,795
DDGS Production (tons/day)	525
Syrup production (60% moisture content)	
Syrup Production (tons/year)	183,208
Syrup Production (tons/day)	523
Syrup Production (MMBtu/hr)	148.1
Wet Cake Production (65% moisture content)	
Wet Cake Production (tons/year)	263,140
Wet Cake Production (tons/day)	752
Wet Cake Production (MMBtu/hr)	207.0
Thin Stillage Production (92-94% moisture content)	
Thin Stillage Production (gallons/day)	538,000
Thin Stillage Production (MMBtu/hr)	149.8
Natural Gas Consumed (MMBtu/yr)	1,648,500
Natural Gas Price ($/MMBtu)	$11.75
Electricity Consumption (MWh)	42,390
Elec. Purchase Price ($/MWh)	$50.00

7.2.2 Scenario Specific Assumptions

Assumptions associated with the defined scenarios are shown in Table 7-2 and include:

- The **Main Steam Flow Rate** requirement for the plant was assumed to be approximately 120,000 lb/hr with a **Main Steam Pressure** requirement of 80 psig for Scenario 1 based on data received from the plant.
- **Net Capacity Factor** is a measure of the fraction of time the plant effectively operates at full load. The operating hours per day was set at 24 for 350 days per year and a capacity factor of 100 percent was assumed for all scenarios.
- The **Ash Generation** was calculated based on ultimate analysis data obtained from a report from the American Society of Agricultural and Biological Engineers

(ASABE). The report contained data from a survey of five dry mill ethanol plants. A copy of the relevant parts of the report are included in Appendix A.

- **Capital Cost** and **O&M Costs** are also provided in the table. Their development is described in Section 6 of this report.

Table 7-2. Scenario Specific Assumptions.

	Scenario 1 Bubbling Fluidized Bed Combustion	Scenario 2 Anaerobic Digestion	Scenario 3 Anaerobic Digestion with Struvite Extraction
Design Conditions			
Main Steam Flow Rate (lb/hr)	120,074	n/a	n/a
Main Steam Pressure (psig)	80	n/a	n/a
Natural Gas Burn Rate (MMBtu/hr)	148.3	148.3	148.3
Syrup Utilization Rate (ton/day)	523	n/a	n/a
Wet Cake Utilization Rate (ton/day)	142	n/a	n/a
Thin Stillage Utilization Rate (gpd)	n/a	538,000	538,000
Operational Assumptions			
Operating Hours per Year	8400	8400	8400
Ash Generation (wt% of input)	2.7%	n/a	n/a
Economic Assumptions			
Capital Cost ($000)	23,950	26,450	35,550
Fixed O&M Cost ($000/yr)	193	240	302
Variable O&M Cost ($000/yr)	2,026	1,877	3,661

7.2.3 Financial Assumptions

Financial and incentive assumptions are summarized in Table 7-3 and include:

- The **Debt to Equity Ratio** was assumed to be 80:20. The debt term was assumed to be 10 years at 7 percent interest.
- The **Equity IRR Hurdle Rate** was assumed to be 15 percent.
- The **Income Tax Rate** was assumed to not apply.
- The **Accelerated depreciation** would normally be assumed to be 7-year, double-declining balance, applied to 80 percent of the total project cost. Costs for land, land development, permitting, financing fees, etc. are not depreciable. Since income taxes were taken to be zero, depreciation does not apply.

- A **Production Tax Credit (PTC)** was assumed to not be applicable.
- **Renewable Energy Credits** and **Carbon Credits** were not included in the economic analysis, though it is noted that such credits would make the scenarios more economical.

Table 7-3. Financial Assumptions (2008$).

Debt to Equity Ratio	80 : 20
Debt Term (years)	10
Debt Interest Rate (%)	7.00%
Financing Fee (% of issuance)	1.50%
Minimum DSCR, average annual	1.40
Debt Service Reserve Fund (years)	0.5
Equity IRR Hurdle Rate	15.0%
Income Tax Rate	n/a
Depreciation	n/a
Annual Inflation Rate	2.50%
DDGS Escalation Rate	2.50%

7.2.4 Product Value Assumptions

- The **Distillers Dry Grain with Solubles (DDGS)** sales price was set at $160/ton based on a value provided by OTAE. The price (and lost DDGS sales) was assumed to be inflated by a rate of 2.50% per year over the life of the project.
- The **Natural Gas Price** was assumed to be $11.75/MMBtu, which was considered the reasonable near-term market price for natural gas. In the calculations, the natural gas cost escalates with inflation.
- The **Sludge** sales price was calculated to be $25.17/ton based on the sludge mineral content provided by ADI Systems and fertilizer values provided by OTAE. The sludge sales price was determined to be negligible for the struvite extraction scenario since most of these key minerals are removed. The assumption was made that any value of the low-mineral sludge would only offset its disposal, as was also assumed in the Rein proposal.
- The **Ash Value** associated with the syrup and wet cake combustion process was assumed to be $150/ton based on actual sales reports by Corn Plus Ethanol in Winnebago, MN. It is worth noting that Corn Plus is investigating pelleting the ash to increase its market value to $300/ton.

- The **Struvite Price** was based on a value of $1,500/ton, a price provided by Rein and Associates. Though used in the calculations, the price was not confirmed with any outside sources. The market price is expected to be lower.
- The **Biogas Price** was based on a value of $11.75/MMBtu, equal to the value of natural gas being offset.
- The **Electricity Purchase Price**, the price paid by the ethanol plant for electricity, was assumed to be $50/MWh (2008$). This price was based on OTAE data.

7.3 Base Case Results

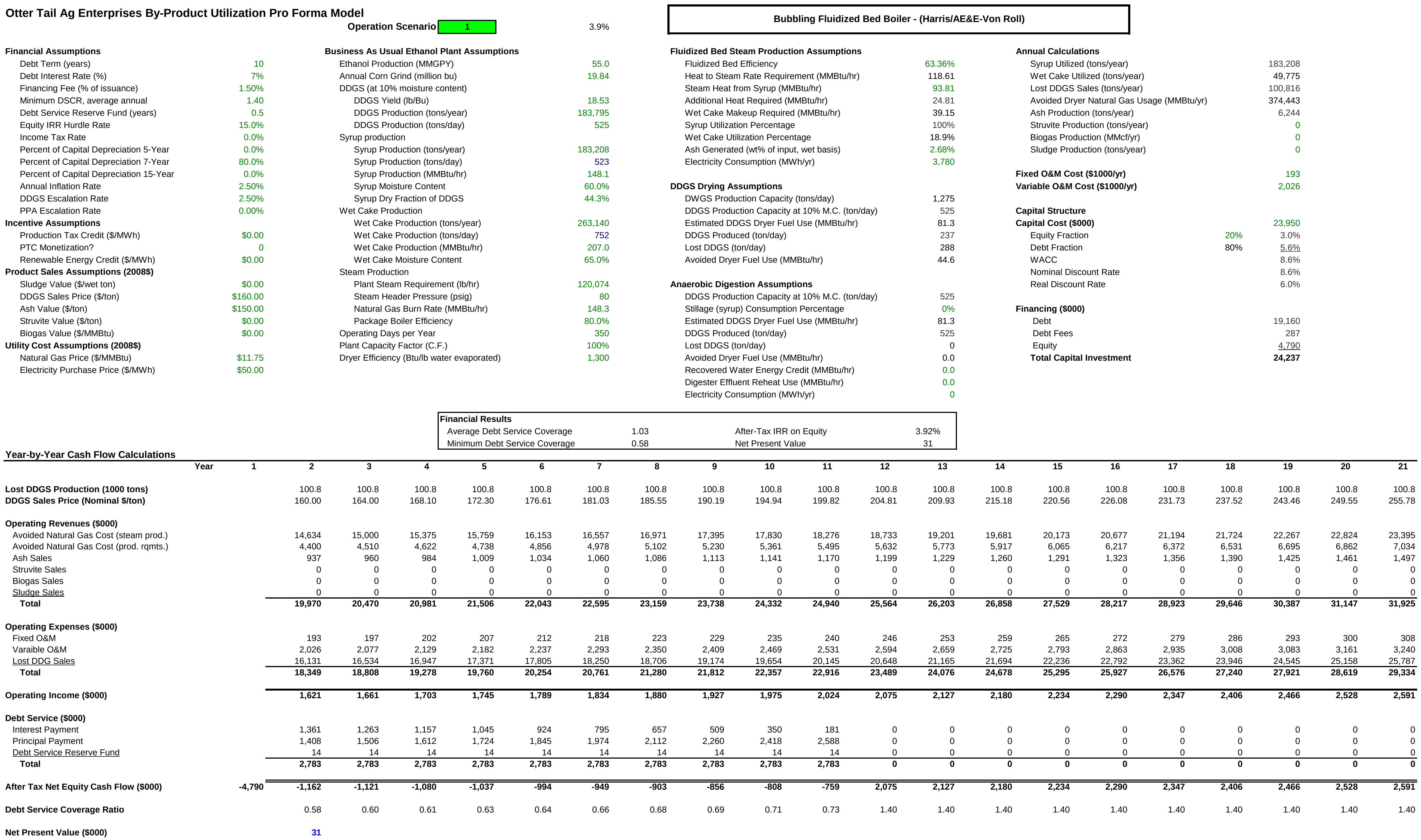
The results for the base case model are shown in Table 7-4. A copy of the pro forma model output and year-by-year cash flow calculation for each scenario are included in Figures 7-1 through 7-3 on the following pages.

Table 7-4. Base Case Economic Analysis Results.

	Bubbling Fluidized Bed Combustion	Anaerobic Digestion	Anaerobic Digestion with Struvite Extraction
Average Debt Service Coverage Ratio	1.03	0.99	1.18
Minimum Debt Service Coverage Ratio	0.58	0.51	0.86
After-Tax Internal Rate of Return on Equity	3.9%	1.8%	12.5%

The three scenarios produced very different economic results with the assigned base case assumptions. Internal rate of return (IRR) values ranged from 1.8 percent for the anaerobic digestion scenario to 12.5 percent for anaerobic digestion with struvite extraction. None of the scenarios exceeded the minimum IRR hurdle rate of 15 percent assuming base case values. As well, none of the scenarios met the minimum DSCR of 1.40.

It was found that if the value of DDGS drops even by as little as $16 per ton, with all other variables remaining constant, all scenarios would achieve the minimum IRR target. Similarly, if the cost of natural gas increases $0.98/MMBtu, all scenarios would achieve the hurdle rate. The impact of variations in such key project variables is explored further in the next section.



Otter Tail Ag Enterprises By-Product Utilization Pro Forma Model

Operation Scenario 1 3.9%

Bubbling Fluidized Bed Boiler - (Harris/AE&E-Von Roll)

Financial Assumptions	
Debt Term (years)	10
Debt Interest Rate (%)	7%
Financing Fee (% of issuance)	1.50%
Minimum DSCR, average annual	1.40
Debt Service Reserve Fund (years)	0.5
Equity IRR Hurdle Rate	15.0%
Income Tax Rate	0.0%
Percent of Capital Depreciation 5-Year	0.0%
Percent of Capital Depreciation 7-Year	80.0%
Percent of Capital Depreciation 15-Year	0.0%
Annual Inflation Rate	2.50%
DDGS Escalation Rate	2.50%
PPA Escalation Rate	0.00%
Incentive Assumptions	
Production Tax Credit ($/MWh)	$0.00
PTC Monetization?	0
Renewable Energy Credit ($/MWh)	$0.00
Product Sales Assumptions (2008$)	
Sludge Value ($/wet ton)	$0.00
DDGS Sales Price ($/ton)	$160.00
Ash Value ($/ton)	$150.00
Struvite Value ($/ton)	$0.00
Biogas Value ($/MMBtu)	$0.00
Utility Cost Assumptions (2008$)	
Natural Gas Price ($/MMBtu)	$11.75
Electricity Purchase Price ($/MWh)	$50.00

Business As Usual Ethanol Plant Assumptions	
Ethanol Production (MMGPY)	55.0
Annual Corn Grind (million bu)	19.84
DDGS (at 10% moisture content)	
DDGS Yield (lb/Bu)	18.53
DDGS Production (tons/year)	183,795
DDGS Production (tons/day)	525
Syrup production	
Syrup Production (tons/year)	183,208
Syrup Production (tons/day)	523
Syrup Production (MMBtu/hr)	148.1
Syrup Moisture Content	60.0%
Syrup Dry Fraction of DDGS	44.3%
Wet Cake Production	
Wet Cake Production (tons/year)	263,140
Wet Cake Production (tons/day)	752
Wet Cake Production (MMBtu/hr)	207.0
Wet Cake Moisture Content	65.0%
Steam Production	
Plant Steam Requirement (lb/hr)	120,074
Steam Header Pressure (psig)	80
Natural Gas Burn Rate (MMBtu/hr)	148.3
Package Boiler Efficiency	80.0%
Operating Days per Year	350
Plant Capacity Factor (C.F.)	100%
Dryer Efficiency (Btu/lb water evaporated)	1,300

Fluidized Bed Steam Production Assumptions	
Fluidized Bed Efficiency	63.36%
Heat to Steam Rate Requirement (MMBtu/hr)	118.61
Steam Heat from Syrup (MMBtu/hr)	93.81
Additional Heat Required (MMBtu/hr)	24.81
Wet Cake Makeup Required (MMBtu/hr)	39.15
Syrup Utilization Percentage	100%
Wet Cake Utilization Percentage	18.9%
Ash Generated (wt% of input, wet basis)	2.68%
Electricity Consumption (MWh/yr)	3,780
DDGS Drying Assumptions	
DWGS Production Capacity (tons/day)	1,275
DDGS Production Capacity at 10% M.C. (ton/day)	525
Estimated DDGS Dryer Fuel Use (MMBtu/hr)	81.3
DDGS Produced (ton/day)	237
Lost DDGS (ton/day)	288
Avoided Dryer Fuel Use (MMBtu/hr)	44.6
Anaerobic Digestion Assumptions	
DDGS Production Capacity at 10% M.C. (ton/day)	525
Stillage (syrup) Consumption Percentage	0%
Estimated DDGS Dryer Fuel Use (MMBtu/hr)	81.3
DDGS Produced (ton/day)	525
Lost DDGS (ton/day)	0
Avoided Dryer Fuel Use (MMBtu/hr)	0.0
Recovered Water Energy Credit (MMBtu/hr)	0.0
Digester Effluent Reheat Use (MMBtu/hr)	0.0
Electricity Consumption (MWh/yr)	0

Annual Calculations		
Syrup Utilized (tons/year)		183,208
Wet Cake Utilized (tons/year)		49,775
Lost DDGS Sales (tons/year)		100,816
Avoided Dryer Natural Gas Usage (MMBtu/yr)		374,443
Ash Production (tons/year)		6,244
Struvite Production (tons/year)		0
Biogas Production (MMcf/yr)		0
Sludge Production (tons/year)		0
Fixed O&M Cost ($1000/yr)		193
Variable O&M Cost ($1000/yr)		2,026
Capital Structure		
Capital Cost ($000)		23,950
Equity Fraction	20%	3.0%
Debt Fraction	80%	5.6%
WACC		8.6%
Nominal Discount Rate		8.6%
Real Discount Rate		6.0%
Financing ($000)		
Debt		19,160
Debt Fees		287
Equity		4,790
Total Capital Investment		**24,237**

Financial Results			
Average Debt Service Coverage	1.03	After-Tax IRR on Equity	3.92%
Minimum Debt Service Coverage	0.58	Net Present Value	31

Year-by-Year Cash Flow Calculations

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Lost DDGS Production (1000 tons)		100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8	100.8
DDGS Sales Price (Nominal $/ton)		160.00	164.00	168.10	172.30	176.61	181.03	185.55	190.19	194.94	199.82	204.81	209.93	215.18	220.56	226.08	231.73	237.52	243.46	249.55	255.78
Operating Revenues ($000)																					
Avoided Natural Gas Cost (steam prod.)		14,634	15,000	15,375	15,759	16,153	16,557	16,971	17,395	17,830	18,276	18,733	19,201	19,681	20,173	20,677	21,194	21,724	22,267	22,824	23,395
Avoided Natural Gas Cost (prod. rqmts.)		4,400	4,510	4,622	4,738	4,856	4,978	5,102	5,230	5,361	5,495	5,632	5,773	5,917	6,065	6,217	6,372	6,531	6,695	6,862	7,034
Ash Sales		937	960	984	1,009	1,034	1,060	1,086	1,113	1,141	1,170	1,199	1,229	1,260	1,291	1,323	1,356	1,390	1,425	1,461	1,497
Struvite Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biogas Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sludge Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		**19,970**	**20,470**	**20,981**	**21,506**	**22,043**	**22,595**	**23,159**	**23,738**	**24,332**	**24,940**	**25,564**	**26,203**	**26,858**	**27,529**	**28,217**	**28,923**	**29,646**	**30,387**	**31,147**	**31,925**
Operating Expenses ($000)																					
Fixed O&M		193	197	202	207	212	218	223	229	235	240	246	253	259	265	272	279	286	293	300	308
Varaible O&M		2,026	2,077	2,129	2,182	2,237	2,293	2,350	2,409	2,469	2,531	2,594	2,659	2,725	2,793	2,863	2,935	3,008	3,083	3,161	3,240
Lost DDG Sales		16,131	16,534	16,947	17,371	17,805	18,250	18,706	19,174	19,654	20,145	20,648	21,165	21,694	22,236	22,792	23,362	23,946	24,545	25,158	25,787
Total		**18,349**	**18,808**	**19,278**	**19,760**	**20,254**	**20,761**	**21,280**	**21,812**	**22,357**	**22,916**	**23,489**	**24,076**	**24,678**	**25,295**	**25,927**	**26,576**	**27,240**	**27,921**	**28,619**	**29,334**
Operating Income ($000)		**1,621**	**1,661**	**1,703**	**1,745**	**1,789**	**1,834**	**1,880**	**1,927**	**1,975**	**2,024**	**2,075**	**2,127**	**2,180**	**2,234**	**2,290**	**2,347**	**2,406**	**2,466**	**2,528**	**2,591**
Debt Service ($000)																					
Interest Payment		1,361	1,263	1,157	1,045	924	795	657	509	350	181	0	0	0	0	0	0	0	0	0	0
Principal Payment		1,408	1,506	1,612	1,724	1,845	1,974	2,112	2,260	2,418	2,588	0	0	0	0	0	0	0	0	0	0
Debt Service Reserve Fund		14	14	14	14	14	14	14	14	14	14	0	0	0	0	0	0	0	0	0	0
Total		**2,783**	**2,783**	**2,783**	**2,783**	**2,783**	**2,783**	**2,783**	**2,783**	**2,783**	**2,783**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
After Tax Net Equity Cash Flow ($000)	**-4,790**	**-1,162**	**-1,121**	**-1,080**	**-1,037**	**-994**	**-949**	**-903**	**-856**	**-808**	**-759**	**2,075**	**2,127**	**2,180**	**2,234**	**2,290**	**2,347**	**2,406**	**2,466**	**2,528**	**2,591**
Debt Service Coverage Ratio		0.58	0.60	0.61	0.63	0.64	0.66	0.68	0.69	0.71	0.73	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Net Present Value ($000)		31																			

Figure 7-1. Pro Forma Model – Fluidized Bed Combustion

Otter Tail Ag Enterprises By-Product Utilization Pro Forma Model

Operation Scenario 2 1.8%

Anaerobic Digestion - (ADI)

Financial Assumptions	
Debt Term (years)	10
Debt Interest Rate (%)	7%
Financing Fee (% of issuance)	1.50%
Minimum DSCR, average annual	1.40
Debt Service Reserve Fund (years)	0.5
Equity IRR Hurdle Rate	15.0%
Income Tax Rate	0.0%
Percent of Capital Depreciation 5-Year	0.0%
Percent of Capital Depreciation 7-Year	80.0%
Percent of Capital Depreciation 15-Year	0.0%
Annual Inflation Rate	2.50%
DDGS Escalation Rate	2.50%
PPA Escalation Rate	0.00%
Incentive Assumptions	
Production Tax Credit ($/MWh)	$0.00
PTC Monetization?	0
Renewable Energy Credit ($/MWh)	$0.00
Product Sales Assumptions (2008$)	
Sludge Value ($/wet ton)	$25.17
DDGS Sales Price ($/ton)	$160.00
Ash Value ($/ton)	$0.00
Struvite Value ($/ton)	$0.00
Biogas Value ($/MMBtu)	$11.75
Utility Cost Assumptions (2008$)	
Natural Gas Price ($/MMBtu)	$11.75
Electricity Purchase Price ($/MWh)	$50.00

Business As Usual Ethanol Plant Assumptions	
Ethanol Production (MMGPY)	55.0
Annual Corn Grind (million bu)	19.84
DDGS (at 10% moisture content)	
DDGS Yield (lb/Bu)	18.53
DDGS Production (tons/year)	183,795
DDGS Production (tons/day)	525
Syrup production	
Syrup Production (tons/year)	183,208
Syrup Production (tons/day)	523
Syrup Production (MMBtu/hr)	148.1
Syrup Moisture Content	60.0%
Syrup Dry Fraction of DDGS	44.3%
Wet Cake Production	
Wet Cake Production (tons/year)	263,140
Wet Cake Production (tons/day)	752
Wet Cake Production (MMBtu/hr)	207.0
Wet Cake Moisture Content	65.0%
Steam Production	
Plant Steam Requirement (lb/hr)	120,074
Steam Header Pressure (psig)	80
Natural Gas Burn Rate (MMBtu/hr)	148.3
Package Boiler Efficiency	80.0%
Operating Days per Year	350
Plant Capacity Factor (C.F.)	100%
Dryer Efficiency (Btu/lb water evaporated)	1,300

Fluidized Bed Steam Production Assumptions	
Fluidized Bed Efficiency	63.36%
Heat to Steam Rate Requirement (MMBtu/hr)	118.61
Steam Heat from Syrup (MMBtu/hr)	0.00
Additional Heat Required (MMBtu/hr)	118.61
Wet Cake Makeup Required (MMBtu/hr)	0.00
Syrup Utilization Percentage	0%
Wet Cake Utilization Percentage	0.0%
Ash Generated (wt% of input, wet basis)	0.00%
Electricity Consumption (MWh/yr)	0

DDGS Drying Assumptions	
DWGS Production Capacity (tons/day)	1,275
DDGS Production Capacity at 10% M.C. (ton/day)	525
Estimated DDGS Dryer Fuel Use (MMBtu/hr)	81.3
DDGS Produced (ton/day)	525
Lost DDGS (ton/day)	0
Avoided Dryer Fuel Use (MMBtu/hr)	0.0

Anaerobic Digestion Assumptions	
DDGS Production Capacity at 10% M.C. (ton/day)	525
Stillage (syrup) Consumption Percentage	100%
Estimated DDGS Dryer Fuel Use (MMBtu/hr)	81.3
DDGS Produced (ton/day)	292
Lost DDGS (ton/day)	233
Avoided Dryer Fuel Use (MMBtu/hr)	36.0
Recovered Water Energy Credit (MMBtu/hr)	6.5
Digester Effluent Reheat Use (MMBtu/hr)	15.0
Electricity Consumption (MWh/yr)	10,075

Annual Calculations		
Syrup Utilized (tons/year)		183,208
Wet Cake Utilized (tons/year)		0
Lost DDGS Sales (tons/year)		81,458
Avoided Dryer Natural Gas Usage (MMBtu/yr)		231,523
Ash Production (tons/year)		0
Struvite Production (tons/year)		0
Biogas Production (MMcf/yr)		1,682
Sludge Production (tons/year)		46,200
Fixed O&M Cost ($1000/yr)		240
Variable O&M Cost ($1000/yr)		1,877
Capital Structure		
Capital Cost ($000)		26,450
Equity Fraction	20%	3.0%
Debt Fraction	80%	5.6%
WACC		8.6%
Nominal Discount Rate		8.6%
Real Discount Rate		6.0%
Financing ($000)		
Debt		21,160
Debt Fees		317
Equity		5,290
Total Capital Investment		**26,767**

Financial Results			
Average Debt Service Coverage	0.99	After-Tax IRR on Equity	1.75%
Minimum Debt Service Coverage	0.51	Net Present Value	-2360

Year-by-Year Cash Flow Calculations

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Lost DDGS Production (1000 tons)		81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5
DDGS Sales Price (Nominal $/ton)		160.00	164.00	168.10	172.30	176.61	181.03	185.55	190.19	194.94	199.82	204.81	209.93	215.18	220.56	226.08	231.73	237.52	243.46	249.55	255.78
Operating Revenues ($000)																					
Avoided Natural Gas Cost (steam prod.)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Natural Gas Cost (prod. rqmts.)		2,720	2,788	2,858	2,930	3,003	3,078	3,155	3,234	3,315	3,397	3,482	3,569	3,659	3,750	3,844	3,940	4,038	4,139	4,243	4,349
Ash Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Struvite Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biogas Sales		12,844	13,165	13,494	13,832	14,177	14,532	14,895	15,268	15,649	16,041	16,442	16,853	17,274	17,706	18,148	18,602	19,067	19,544	20,032	20,533
Sludge Sales		1,163	1,192	1,222	1,252	1,284	1,316	1,349	1,382	1,417	1,452	1,489	1,526	1,564	1,603	1,643	1,684	1,726	1,769	1,814	1,859
Total		**16,727**	**17,146**	**17,574**	**18,014**	**18,464**	**18,925**	**19,399**	**19,884**	**20,381**	**20,890**	**21,412**	**21,948**	**22,496**	**23,059**	**23,635**	**24,226**	**24,832**	**25,453**	**26,089**	**26,741**
Operating Expenses ($000)																					
Fixed O&M		240	246	252	258	265	272	278	285	292	300	307	315	323	331	339	348	356	365	374	384
Varaible O&M		1,877	1,924	1,972	2,022	2,072	2,124	2,177	2,232	2,287	2,345	2,403	2,463	2,525	2,588	2,653	2,719	2,787	2,857	2,928	3,001
Lost DDG Sales		13,033	13,359	13,693	14,035	14,386	14,746	15,115	15,492	15,880	16,277	16,684	17,101	17,528	17,966	18,416	18,876	19,348	19,832	20,327	20,836
Total		**15,151**	**15,529**	**15,918**	**16,316**	**16,723**	**17,141**	**17,570**	**18,009**	**18,460**	**18,921**	**19,394**	**19,879**	**20,376**	**20,885**	**21,407**	**21,943**	**22,491**	**23,053**	**23,630**	**24,220**
Operating Income ($000)		**1,577**	**1,616**	**1,657**	**1,698**	**1,740**	**1,784**	**1,829**	**1,874**	**1,921**	**1,969**	**2,018**	**2,069**	**2,121**	**2,174**	**2,228**	**2,284**	**2,341**	**2,399**	**2,459**	**2,521**
Debt Service ($000)																					
Interest Payment		1,503	1,395	1,278	1,154	1,020	878	725	562	387	200	0	0	0	0	0	0	0	0	0	0
Principal Payment		1,554	1,663	1,780	1,904	2,038	2,180	2,333	2,496	2,671	2,858	0	0	0	0	0	0	0	0	0	0
Debt Service Reserve Fund		15	15	15	15	15	15	15	15	15	15	0	0	0	0	0	0	0	0	0	0
Total		**3,073**	**3,073**	**3,073**	**3,073**	**3,073**	**3,073**	**3,073**	**3,073**	**3,073**	**3,073**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
After Tax Net Equity Cash Flow ($000)	**-5,290**	**-1,496**	**-1,457**	**-1,417**	**-1,375**	**-1,333**	**-1,289**	**-1,245**	**-1,199**	**-1,152**	**-1,104**	**2,018**	**2,069**	**2,121**	**2,174**	**2,228**	**2,284**	**2,341**	**2,399**	**2,459**	**2,521**
Debt Service Coverage Ratio		0.51	0.53	0.54	0.55	0.57	0.58	0.60	0.61	0.63	0.64	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Net Present Value ($000)		**-2,360**																			

Figure 7-2. Pro Forma Model – Anaerobic Digestion

Otter Tail Ag Enterprises By-Product Utilization Pro Forma Model

Operation Scenario 3 12.5%

Anaerobic Digestion w/ Struvite Capture - (Rein and Associates)

Financial Assumptions	
Debt Term (years)	10
Debt Interest Rate (%)	7%
Financing Fee (% of issuance)	1.50%
Minimum DSCR, average annual	1.40
Debt Service Reserve Fund (years)	0.5
Equity IRR Hurdle Rate	15.0%
Income Tax Rate	0.0%
Percent of Capital Depreciation 5-Year	0.0%
Percent of Capital Depreciation 7-Year	80.0%
Percent of Capital Depreciation 15-Year	0.0%
Annual Inflation Rate	2.50%
DDGS Escalation Rate	2.50%
PPA Escalation Rate	0.00%
Incentive Assumptions	
Production Tax Credit ($/MWh)	$0.00
PTC Monetization?	0
Renewable Energy Credit ($/MWh)	$0.00
Product Sales Assumptions (2008$)	
Sludge Value ($/wet ton)	$0.00
DDGS Sales Price ($/ton)	$160.00
Ash Value ($/ton)	$0.00
Struvite Value ($/ton)	$1,500.00
Biogas Value ($/MMBtu)	$11.75
Utility Cost Assumptions (2008$)	
Natural Gas Price ($/MMBtu)	$11.75
Electricity Purchase Price ($/MWh)	$50.00

Business As Usual Ethanol Plant Assumptions	
Ethanol Production (MMGPY)	55.0
Annual Corn Grind (million bu)	19.84
DDGS (at 10% moisture content)	
DDGS Yield (lb/Bu)	18.53
DDGS Production (tons/year)	183,795
DDGS Production (tons/day)	525
Syrup production	
Syrup Production (tons/year)	183,208
Syrup Production (tons/day)	523
Syrup Production (MMBtu/hr)	148.1
Syrup Moisture Content	60.0%
Syrup Dry Fraction of DDGS	44.3%
Wet Cake Production	
Wet Cake Production (tons/year)	263,140
Wet Cake Production (tons/day)	752
Wet Cake Production (MMBtu/hr)	207.0
Wet Cake Moisture Content	65.0%
Steam Production	
Plant Steam Requirement (lb/hr)	120,074
Steam Header Pressure (psig)	80
Natural Gas Burn Rate (MMBtu/hr)	148.3
Package Boiler Efficiency	80.0%
Operating Days per Year	350
Plant Capacity Factor (C.F.)	100%
Dryer Efficiency (Btu/lb water evaporated)	1,300

Fluidized Bed Steam Production Assumptions	
Fluidized Bed Efficiency	63.36%
Heat to Steam Rate Requirement (MMBtu/hr)	118.61
Steam Heat from Syrup (MMBtu/hr)	0.00
Additional Heat Required (MMBtu/hr)	118.61
Wet Cake Makeup Required (MMBtu/hr)	0.00
Syrup Utilization Percentage	0%
Wet Cake Utilization Percentage	0.0%
Ash Generated (wt% of input, wet basis)	0.00%
Electricity Consumption (MWh/yr)	0

DDGS Drying Assumptions	
DWGS Production Capacity (tons/day)	1,275
DDGS Production Capacity at 10% M.C. (ton/day)	525
Estimated DDGS Dryer Fuel Use (MMBtu/hr)	81.3
DDGS Produced (ton/day)	525
Lost DDGS (ton/day)	0
Avoided Dryer Fuel Use (MMBtu/hr)	0.0

Anaerobic Digestion Assumptions	
DDGS Production Capacity at 10% M.C. (ton/day)	525
Stillage (syrup) Consumption Percentage	100%
Estimated DDGS Dryer Fuel Use (MMBtu/hr)	81.3
DDGS Produced (ton/day)	292
Lost DDGS (ton/day)	233
Avoided Dryer Fuel Use (MMBtu/hr)	36.0
Recovered Water Energy Credit (MMBtu/hr)	6.5
Digester Effluent Reheat Use (MMBtu/hr)	15.0
Electricity Consumption (MWh/yr)	10,460

Annual Calculations		
Syrup Utilized (tons/year)		183,208
Wet Cake Utilized (tons/year)		0
Lost DDGS Sales (tons/year)		81,458
Avoided Dryer Natural Gas Usage (MMBtu/yr)		231,523
Ash Production (tons/year)		0
Struvite Production (tons/year)		3,325
Biogas Production (MMcf/yr)		1,681
Sludge Production (tons/year)		55,744
Fixed O&M Cost ($1000/yr)		302
Variable O&M Cost ($1000/yr)		3,661
Capital Structure		
Capital Cost ($000)		35,550
Equity Fraction	20%	3.0%
Debt Fraction	80%	5.6%
WACC		8.6%
Nominal Discount Rate		8.6%
Real Discount Rate		6.0%
Financing ($000)		
Debt		28,440
Debt Fees		427
Equity		7,110
Total Capital Investment		**35,977**

Financial Results			
Average Debt Service Coverage	1.18	After-Tax IRR on Equity	12.54%
Minimum Debt Service Coverage	0.86	Net Present Value	12948

Year-by-Year Cash Flow Calculations

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Lost DDGS Production (1000 tons)		81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5
DDGS Sales Price (Nominal $/ton)		160.00	164.00	168.10	172.30	176.61	181.03	185.55	190.19	194.94	199.82	204.81	209.93	215.18	220.56	226.08	231.73	237.52	243.46	249.55	255.78
Operating Revenues ($000)																					
Avoided Natural Gas Cost (steam prod.)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Avoided Natural Gas Cost (prod. rqmts.)		2,720	2,788	2,858	2,930	3,003	3,078	3,155	3,234	3,315	3,397	3,482	3,569	3,659	3,750	3,844	3,940	4,038	4,139	4,243	4,349
Ash Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Struvite Sales		4,988	5,112	5,240	5,371	5,505	5,643	5,784	5,929	6,077	6,229	6,384	6,544	6,708	6,875	7,047	7,223	7,404	7,589	7,779	7,973
Biogas Sales		12,842	13,163	13,492	13,829	14,175	14,529	14,892	15,265	15,646	16,038	16,438	16,849	17,271	17,702	18,145	18,599	19,064	19,540	20,029	20,529
Sludge Sales		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		**20,550**	**21,063**	**21,590**	**22,130**	**22,683**	**23,250**	**23,831**	**24,427**	**25,038**	**25,664**	**26,305**	**26,963**	**27,637**	**28,328**	**29,036**	**29,762**	**30,506**	**31,269**	**32,050**	**32,852**
Operating Expenses ($000)																					
Fixed O&M		302	309	317	325	333	341	350	358	367	377	386	396	405	416	426	437	448	459	470	482
Varaible O&M		3,661	3,752	3,846	3,942	4,041	4,142	4,245	4,351	4,460	4,572	4,686	4,803	4,923	5,046	5,173	5,302	5,434	5,570	5,709	5,852
Lost DDG Sales		13,033	13,359	13,693	14,035	14,386	14,746	15,115	15,492	15,880	16,277	16,684	17,101	17,528	17,966	18,416	18,876	19,348	19,832	20,327	20,836
Total		**16,995**	**17,420**	**17,856**	**18,302**	**18,760**	**19,229**	**19,710**	**20,202**	**20,707**	**21,225**	**21,756**	**22,300**	**22,857**	**23,428**	**24,014**	**24,615**	**25,230**	**25,861**	**26,507**	**27,170**
Operating Income ($000)		**3,554**	**3,643**	**3,734**	**3,827**	**3,923**	**4,021**	**4,122**	**4,225**	**4,330**	**4,439**	**4,550**	**4,663**	**4,780**	**4,899**	**5,022**	**5,147**	**5,276**	**5,408**	**5,543**	**5,682**
Debt Service ($000)																					
Interest Payment		2,021	1,874	1,718	1,550	1,371	1,180	974	755	520	269	0	0	0	0	0	0	0	0	0	0
Principal Payment		2,089	2,236	2,392	2,559	2,739	2,930	3,135	3,355	3,590	3,841	0	0	0	0	0	0	0	0	0	0
Debt Service Reserve Fund		21	21	21	21	21	21	21	21	21	21	0	0	0	0	0	0	0	0	0	0
Total		**4,131**	**4,131**	**4,131**	**4,131**	**4,131**	**4,131**	**4,131**	**4,131**	**4,131**	**4,131**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
After Tax Net Equity Cash Flow ($000)	**-7,110**	**-576**	**-488**	**-396**	**-303**	**-207**	**-109**	**-9**	**94**	**200**	**308**	**4,550**	**4,663**	**4,780**	**4,899**	**5,022**	**5,147**	**5,276**	**5,408**	**5,543**	**5,682**
Debt Service Coverage Ratio		0.86	0.88	0.90	0.93	0.95	0.97	1.00	1.02	1.05	1.07	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
Net Present Value ($000)		**12,948**																			

Figure 7-3. Pro Forma Model – Anaerobic Digestion with Struvite Extraction

7.4 Sensitivity Analysis

The figures following this section show a graphical representation of the sensitivity of the project results to moderate changes in input assumptions for the major project variables. The sensitivity results of the Fluidized Bed Combustion scenario are shown in Figure 7-4, the Anaerobic Digestion scenario in Figure 7-5, and the Anaerobic Digestion with Struvite Extraction scenario in Figure 7-6.

The center point of each diagram represents the base case results for the specified scenario. Each input variable is represented by a line on the chart. As the variables are increased or decreased independently of other variables, the corresponding IRR impact is shown on the chart. Sensitivity to a particular input is indicated by the slope of the line. A steep slope means that variable impacts the IRR greater than a variable with a shallow sloping line.

7.4.1 Sensitivity Analysis – Fluidized Bed Combustion and Steam Generation

Based on the sensitivity analysis for the fluidized bed boiler scenario, the project is highly sensitive to changes primarily in DDGS value and natural gas price, and lesser so to moderate fluctuations in capital cost, O&M costs, and ash value. If the DDGS value increases beyond $160/ton, the IRR decreases rapidly. Conversely, when the DDGS value decreases, the IRR increases substantially. At $80/ton, the IRR is off the chart at 148%.

A natural gas price increase of 5.0% to $12.34/MMBtu results in an 11% improvement in IRR. However, on the other side of the curve, a twenty-one cent drop in the gas price would drop the 3.9% base case IRR to zero.

Ash value does not affect the economics greatly, though a $150/ton gate price for ash adds approximately four percentage points to the IRR. As stated before, Corn Plus Ethanol in Winnebago currently sells their bubbling fluidized boiler ash for $150/ton.

7.4.2 Sensitivity Analysis – Anaerobic Digestion

The IRR for the anaerobic digestion scenario is also highly sensitive to changes in DDGS value and natural gas price. A drop in DDGS value of about $16/ton (10%) brings the IRR up to approximately 15%. At $80/ton, the IRR would be 98%.

On the other hand, if the price of natural gas drops to $10.50/MMBtu, the IRR goes to zero.

While the value of sludge is affected by many factors (i.e. location, mineral content, water content, transportation), it does add some value to the process. However, since it is doubtful that a year-round market for the product would exist, some additional processing costs (i.e. drying, pelleting) as well as storage costs would also need to be evaluated. For the analysis, sludge value was varied between $12 and $38/ton, a range which Black & Veatch believes to be reasonable.

7.4.3 Sensitivity Analysis – Anaerobic Digestion with Struvite Extraction

The sensitivity analysis for this scenario also revealed a high sensitivity to changes in DDGS value. In this scenario, an IRR above the hurdle rate will be achieved when the DDGS value is less than $155/ton. This presumes that the base case assumptions are correct.

This case is almost as sensitive to natural gas price fluctuations as is the digester case without struvite removal. Like the former case, a $1.25/MMBtu drop in the price of natural gas would result in an IRR equal to zero.

The base case IRR was higher than that of the anaerobic digestion-only scenario due to the use of a high value for struvite. Neither the Ostara or the Rein proposal documents provide substantiation for this value. Further market research is warranted. While struvite value to the plant was not well defined in the proposal documents, the analysis demonstrates that an increase of 20% in the struvite value above the base value of $1,500/ton would result in a 20% IRR. Conversely, a 20% decrease in struvite value would result in an IRR of under 5%.

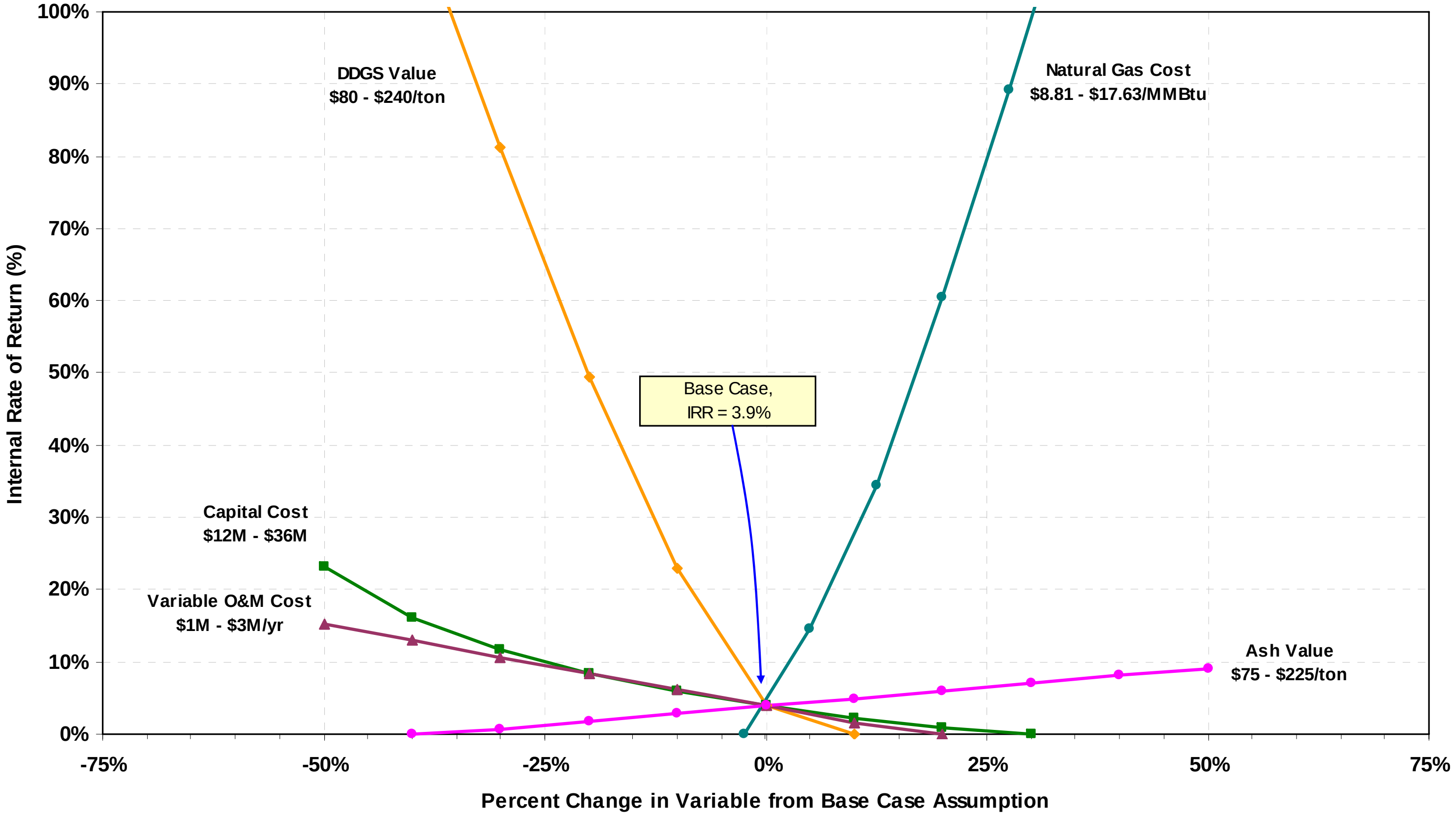


Figure 7-4. Sensitivity of Project IRR to Changes in Input Assumptions – Fluidized Bed Combustion

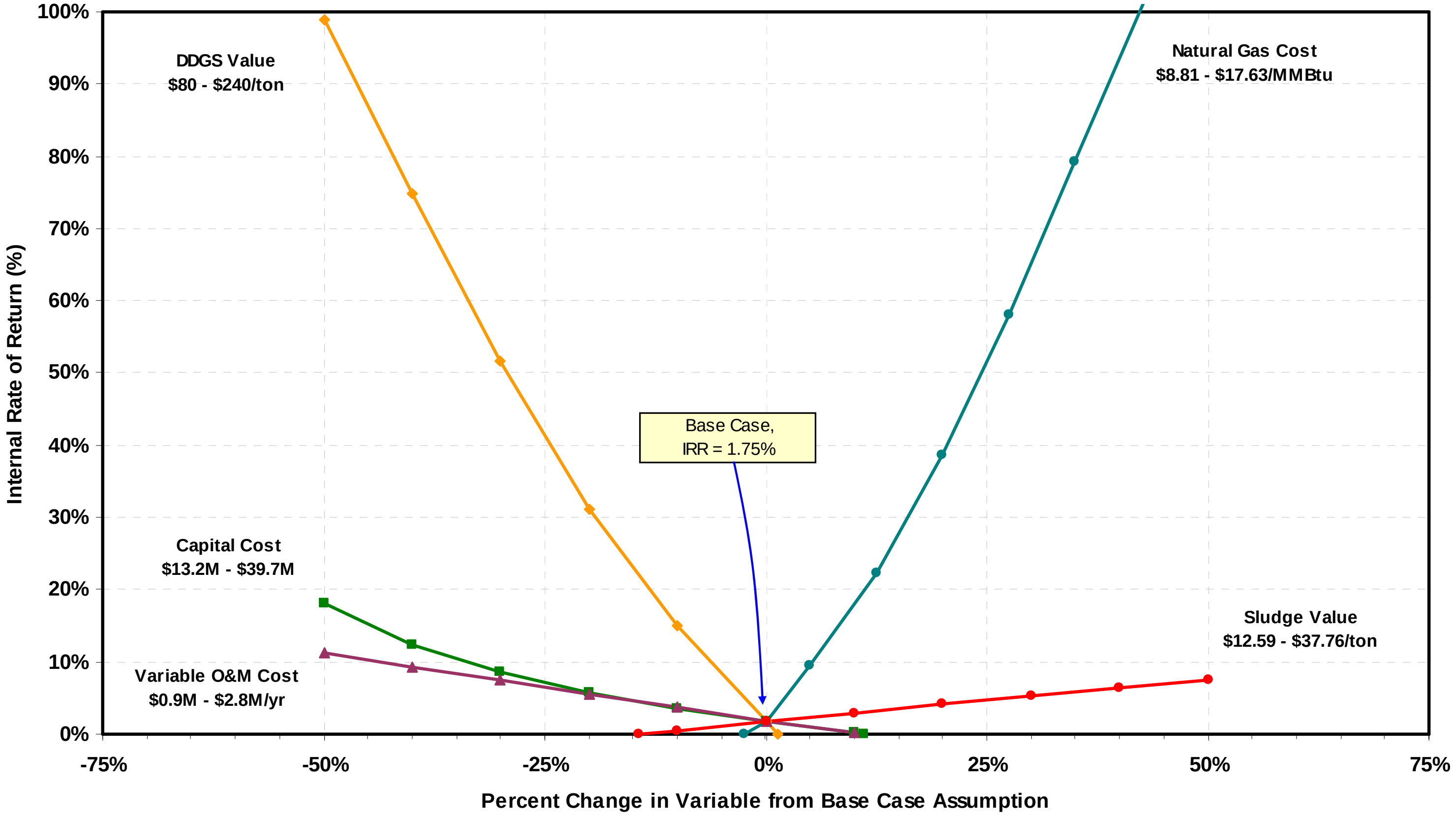


Figure 7-5. Sensitivity of Project IRR to Changes in Input Assumptions – Anaerobic Digestion

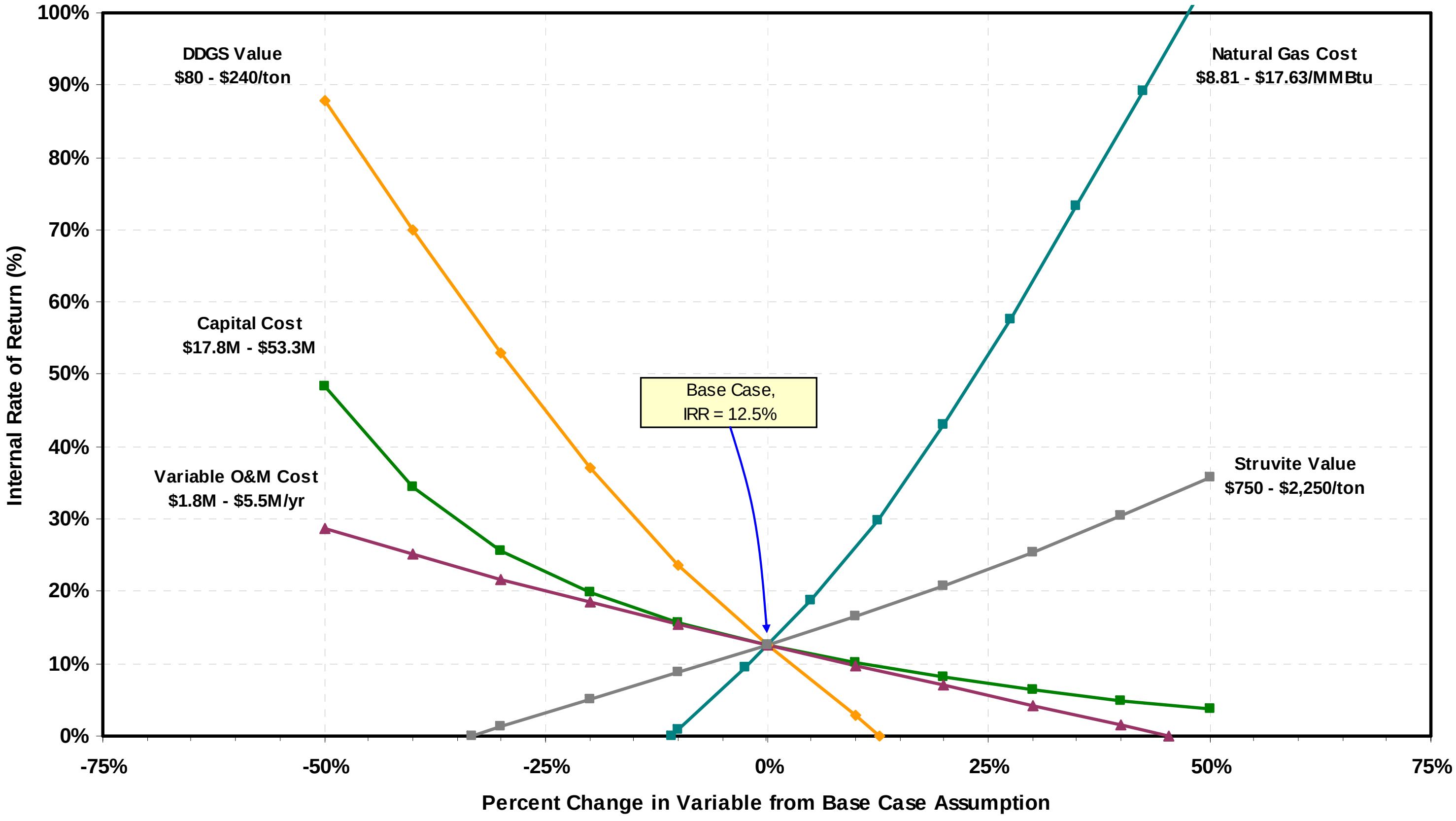


Figure 7-6. Sensitivity of Project IRR to Changes in Input Assumptions – Anaerobic Digestion with Struvite Extraction

Appendix A. Vendor Information - CONFIDENTIAL

Ethanol Plant Process
Delta-T Corporation

Ethanol Plant Operations
Otter Tail Ag Enterprises

Boilers
Harris / AE&E Von Roll

Struvite Recovery
Ostara

Ash Content
ASABE Report