Feasibility Study for Small-Scale Ethanol Production in Minnesota

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NOTICE

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I. EXECUTIVE SUMMARY

The Agricultural Utilization Research Institute (AURI) has retained BBI International to assess both the economic and technical feasibility of small-scale ethanol production. The purpose of the project will be to evaluate the financial performance of a small-scale ethanol plant in the range of 100,000 to 2 million gallons of annual capacity. Additionally, the availability of technology and equipment for the aforementioned scales will be evaluated. This study includes a conceptual plant design and layout, a major equipment list, anticipated capital and operating costs, market analysis, financial performance at three small-scale sizes. Regulatory, safety and transportation issues are also addressed.

Background

AURI is a non-profit agency committed to the mission of rural economic development in Minnesota. It seeks to identify new uses and markets for the mass quantity of agricultural commodities and products. AURI assists business owners throughout the entire product development process. There are three offices in different areas of the state. AURI also operates several laboratories for testing a variety of agricultural products.

Regulatory and Compliance

The small scale of the proposed projects will somewhat reduce the scope of some permitting structures as compared to a standard 50-mmgy corn dry-mill ethanol plant. Overall, however, the permitting process will not deviate significantly from the traditional ethanol plant permitting process.

The proposed facility will emit pollutants into U.S. air and water resources, and will therefore require permits requisite to the Clean Air Act and Clean Water Act. The facility will handle distilled spirits and hazardous substances, requiring compliance and permits with the Alcohol and Tobacco Tax and Trade Bureau (TTB) and Comprehensive Environmental Response Compensation and Liability Act & Community Right to Know Act (CERCLA/EPCRA) regulations. A Federal Air Emissions Permit will NOT be required for the ethanol plant scales' evaluated in this study. A Minnesota Air Permit is required.

Transportation and Safety

The proper training of plant personnel in safety procedures is not only important, it is required by OSHA. The ethanol industry has an enviable safety record, even though there are numerous safety hazards that can pose significant risk. While state and federal law set certain requirements, it is important for management to go beyond these base regulations by placing a strong company emphasis on plant safety. An important first step is to either develop a safety manual internally or hire an experienced safety consultant to develop one. This manual will serve as the guide to implementing an effective safety program that will minimize on-the-job injuries.

Safety considerations for truck and rail shipping are clearly established for all plant scales, from a 100,000-gpy plant to a 100-mmgy plant scale. The design, engineering, and equipment at loadin and load-out areas of the plant are required to adhere to these regulations. Permits and regulations described in Section III will cover the majority of the safety considerations for these transfer areas, and local regulators will oversee the remaining construction and operations matters. It is more likely that a small-scale ethanol plant will ship by truck due to presumably lower pricing and also due to low volumes taking considerable time to produce enough ethanol to fill rail cars.

Ethanol and Co-products Market Analysis

The recently updated Renewable Fuels Standard ensures a long term U.S. market for biofuels. Voluntary blending is expected to occur at an increasing rate as long as the price of ethanol remains less than or equal to gasoline plus the blender's tax credit—making blending economically attractive. At this time, some ethanol plants are struggling due to continued higher than average corn prices and lower ethanol prices as they still correlate to oil prices which have dipped significantly in the 4^{th} quarter of 2008 and continuing on into 2009. Plants that are efficiently run have cash on hand and solid risk management should be able to make it through this difficult financial performance period.

Ethanol production capacity is just over one billion gallons in Minnesota. Minnesota gasoline use is approximately 2.6 billion gallons per year. Minnesota produces far more ethanol than it can use based on the EPA blending rule of 10% and small markets for E85. Despite this level of production, it is assumed that a small-scale producer could sell all output to a local or regional blender. In fact, this is an essential element of a small-scale producer since shipping ethanol long distances with not be economically feasible.

The ethanol price is set to the one year average futures price from CME Group of $1.57 per gallon increasing at a rate of 2% per year in the economic model. Shipping costs are estimated at $0.05 per gallon. It is assumed that all ethanol is shipped by truck.
All distillers grains will be sold in the wet form. Production of DWG is as follows: 771 tons from the 100,000 gallon scenario; 7,710 tons from the 1-mmgy scenario; and 15,420 tons from the 2-mmgy scenario. The price is set to 80% the price of corn on a dry weight basis ($45.53 per ton based on one year future corn price of $3.87 per bushel-CME Group).

Small-Scale Technology

There are few companies designing small-scale ethanol plants. This is presumably due to the challenging economics and interest in such plants.

ICM has 101 plants in North America that utilize their process design, the smallest of which is 10-mmgy. They are currently working on a re-design of the 10-mmgy plant to modularize it, and are confident that it could be easily scaled down to the 1- to 2-mmgy range.

Additionally, BBI contacted two small-scale ethanol technology providers, Easy Automation and Diversified Ethanol but neither company responded to telephone inquiries.

Financial Feasibility

BBI prepared three financial scenarios to evaluate the performance of small-scale ethanol production at three scales. The three scales are 100,000 gallons, 1,000,000 gallons and 2,000,000 gallons of ethanol production per year. Additionally, a fourth scenario was created to observe if there was a benefit to producing 1,000,000 per year but for only half the year—this involves building a 2,000,000 gallon plant and operating it half the time.

The key model inputs include product and co-product yields, product and raw material pricing, shipping costs, labor costs, energy consumption and pricing, capital costs including engineering, procurement and construction of the ethanol plant and all supporting facilities and systems, project development costs, financing costs, start-up costs, working capital and inventory costs.

The BBI model produces a ten-year operating forecast for the project including a balance sheet, income statement, and cash flow statement. The complete 11-year proforma for the dry mill ethanol plants for all three scenarios are included in the appendices. The impact of critical project variables will be determined and the viability of the project with regard to each will be evaluated.

Table 1 – Financial Modeling Results, Pre-tax

AURI Ethanol Project	100,000-gy	1-mmgy	2-mmgy
11-year Average Annual ROI	-81.4%	-46.4%	-34.0%
Internal Rate of Return	N/A	N/A	N/A
EBITDA	($237,021)	($118,430)	$49,373
Average Annual Income	($641,000)	($907,000)	($959,000)
Installed Capital Cost ($/gal)	$26.24	$6.52	$4.70
Plant Capital Cost	$2,160,000	$5,676,000	$8,254,500
Owner's Costs	$463,890	$844,140	$1,146,420
Total Project Investment	$2,623,890	$6,520,140	$9,400,920
30% Equity	$787,167	$1,956,042	$2,820,276

As evidenced in Table 1, all three of the small-scale ethanol scenarios yield negative financial results. This is due to the current and forecasted low ethanol prices that make profits challenging for existing large-scale plants with no debt. The projects also suffer because they must install much of the same infrastructure as larger plants and cannot achieve economies of scale. BBI also looked at producing 1 million gallons at a plant operating for only half the year and the ROI was -47%, which is worse than operating either the 1-mmgy or 2-mmgy plant over an entire year. Additionally, the capital costs are high per installed gallon when compared with the costs of building a new large-scale ethanol plant. For comparison, a new 50-mmgy using the same corn and ethanol prices results in a -3.8% ROI.

Recommendations

Based on the assumptions used, small-scale ethanol production is not economically viable at or below two million gallons of production. This is due primarily to current and future ethanol and corn pricing. Each of the evaluated scenarios provided a negative return on investment. BBI recommends that projects development for proposed plants achieving a hurdle of at least +25% ROI. Even if corn prices were lower and ethanol prices were higher, it is still clear that these small-scale plants would be troubled to weather any economic downturns. The current industry—largely composed of large-scale plants—is struggling with 33 plants idle as of March 2009. It is not advisable to build a small-scale ethanol plant at this time or in the near future.

If financial conditions change and corn prices return to historical averages and ethanol prices rise, small-scale production would be more feasible. The designs and equipment are available to produce ethanol at the scales evaluated.

BBI would like to thank AURI for the opportunity to work on this feasibility study.

II. PROJECT OVERVIEW

Purpose of Study

AURI is assessing the technical and economic feasibility of small-scale ethanol production. These plants would likely be sited on farms or in other rural settings near corn production. This study includes a technology review of small-scale ethanol design companies as well as plant designs and layouts prepared by BBI at three scales (100,00; 1,000,000 and 2,000,000 gallons per year). Regulatory and permitting issues are reviewed as well as safety concerns. Plant and operating costs are evaluated at the small-scale as well as costs to transport ethanol to the market. This report will highlight the most feasible size of small-scale production based on the scenarios evaluated.

BBI is an independent consulting firm with no stake in the proposed project. The information detailed in this report reflects to the best of our ability, a true and accurate evaluation of the current ethanol industry, applicable markets, and the feasibility of the project.

Scope of Work

This feasibility evaluates three small-scale capacities for ethanol production. This full feasibility study makes an evaluation of the following areas:

- Regulatory and Compliance Issues
  - TTB
  - Permitting
- Transportation and Safety
  - Safety
  - Transportation logistics
- Ethanol and Co-Product Market Analysis
  - Ethanol Markets and Pricing
  - Co-Products Market and Pricing
    - Distillers Grains
    - Carbon Dioxide
- Small-scale Technology Providers
- Plant Design and Layout
- Plant Costs
- Operation Costs
- Financial Analysis and Revenue Outlook
  - Sensitivity Analysis
- Summary and Recommendations

III. PERMITTING AND REGULATORY COMPLIANCE

This section details the permitting and regulatory requirements for constructing and operating an ethanol production facility. The following permits are normally required for an ethanol project. However, the size and design of the ethanol plant, the method of steam and power generation, and local permitting requirements ultimately affect the actual permits required. Without knowing the emissions characteristics of the final production facility, it cannot be determined which permits and regulatory obligations will need to be met. The following is meant for guidance only.

Below are estimated emissions profiles for the proposed facilities at all three plant scales. The figures are calculated based on existing facilities and emissions. The air emissions are based on Land O' Lakes' Melrose Dairy Proteins facility in Melrose, MN. The wastewater discharge figures are based on internal figures resulting from BBI's extensive ethanol plant modeling history.

Table 2 – Air Emissions from Proposed Facilities

Pollutant	PM	PM10	SO2	NOx	VOCs	CO	Lead
Emissions Scenario	tons per year						
2-mmgy Facility (estimated)	4.07	2.13	19.00	12.40	6.93	53.33	0.00013
1-mmgy Facility (estimated)	2.03	1.07	9.50	6.20	3.47	26.67	0.00007
100,000-gpy Facility (estimates)	0.20	0.11	0.95	0.62	0.35	2.66	0.00001
Permitted Emissions (3mmgy)*	**6.10**	**3.20**	**28.50**	**18.60**	**10.40**	**80.00**	**0.00020**

* Based on emissions characteristics of MPCA Permit No. 14500003-06

Table 3 – Wastewater Discharge from Proposed Facilities

Parameter	100,000-yr	1-mmgy	2-mmgy
Water (gallons/yr)	668,000	6,777,000	13,554,000
Wastewater (gallons/yr)	57,000	570,000	1,140,000

The small scale of the proposed projects will somewhat reduce the scope of some permitting structures as compared to a standard 50-mmgy corn dry-mill ethanol plant. Overall, however, the permitting process will not deviate significantly from the traditional ethanol plant permitting process.

The following permitting guidelines were created with the special input of Mergent, a Minneapolis-based environmental compliance consulting firm. It is recommended that a qualified environmental consulting firm be hired to assist with the facility permitting process.

Federal Regulations

The proposed facility will emit pollutants into U.S. air and water resources, and will therefore require permits requisite to the Clean Air Act and Clean Water Act. The facility will handle distilled spirits and hazardous substances, requiring compliance with the Alcohol and Tobacco Tax and Trade Bureau (TTB) and Comprehensive Environmental Response Compensation and Liability Act & Community Right to Know Act (CERCLA/EPCRA) regulations. Below are general regulatory guidelines for each of the federal permits and compliances required of large-scale ethanol plants, and their applicability to the proposed plant scales.

Clean Air Act

Title V Operating Permit of the Clean Air Act Amendments of 1990

Also known as Part 70 Permit, this applies to the largest air emissions facilities in the country.

Implications for proposed facilities: All three plant scales will NOT be required to apply for a federal air emissions permit if emissions levels are at or below projected levels. However, a state air permit will be required. Air emissions permitting is managed by the Minnesota Pollution Control Agency.

Prevention of Significant Deterioration (PSD) and Construction Permits:

PSD permit required for facilities that emit any criteria pollutant expected to be greater than 100 tons per year after the use of control equipment, or 250 tons per year aggregate all criteria pollutants.

Implications for proposed facilities: All three plant scales will NOT be required to apply if emissions levels are at or below projected levels.

Applicable Federal New Source Performance Standards (NSPS):

Sets pollution control standards for Clean Air Act and Clean Water Act permitted facilities.

Implications for proposed facilities: May apply to boilers; otherwise air and water permits will contain applicable pollution control standards.

National Emission Standards for Hazardous Air Pollutants (NESHAPS:)

Regulates extensive list of Hazardous Air Pollutants.

Implications for proposed facilities: The proposed facilities will likely not emit hazardous air pollutants and regulation will not be required. However, testing and monitoring of emissions as a function of air permitting requirements is recommended.

Clean Water Act

National Pollutant Discharge Elimination System (NPDES)

Under the NPDES Program, all facilities which discharge pollutants from any point source into waters of the United States are required to obtain an NPDES permit. The level of permitting will vary based on the volume of discharge and concentration of pollutants.

Implications for proposed facilities: All three plant scales will need to acquire NPDES permitting coverage if waters are discharged. Permitting is managed by the Minnesota Pollution Control Agency.

Oil Spill Prevention and Control Countermeasures (SPCC) Plan

Required for all facilities storing over 1,320 gallons of oil total at the facility.

Implications for proposed facilities: Proposed facilities will likely NOT have to fill out an SPCC plan unless use of a generator or other petroleum-based fuel equipment requires fuel storage in excess of 1,320 gallons.

Other Federal Agencies and Regulations

Alcohol and Tobacco Tax and Trade Bureau (TTB)

Producers of distilled spirits for fuel use need to apply for an Alcohol Fuel Permit (AFP) and post bond. Distilleries below 10,000 'proof gallons' (gallon of 100 proof alcohol) are 'eligible' or 'small' distilleries and do not require bonding. 10,000-500,000 proof gallons produced annually categorizes a facility as a medium distillery, and more than that is a large distillery.

Implications for proposed facilities: The 100,000 gpy facility is labeled a medium distillery and is subject to reduced bonding and requirements. The 1mmgy and 2mmgy plant scales are large distilleries. All facilities will need to apply for an AFP.

Comprehensive Environmental Response Compensation and Liability Act & Community Right to Know Act (CERCLA/EPCRA),
EPCRA Section 313 and 304 and CERCLA Section 103:

Commonly known as the Superfund law; tracks use and release of regulated substances above threshold and/or designated quantities annually. Any release of a Hazardous Substance above that substance's reportable quantity (RQ) is subject to reporting to the National Response Center. Releases to both air and water are subject to the regulations. Federal Tier II forms must be filed for all hazardous materials stored in excess of the Threshold Planning Quantity (TPQ) which is 500lbs for most substances.

Implications for proposed facilities: All three plant scales will be required to submit annual Tier II forms for storage of hazardous substances. All facilities with reportable release must report.

OSHA Process Safety Management of Highly Hazardous Chemicals standard (29 CFR 1910.119)

Occupational Safety and Health Administration (OSHA) Management Plan required for all facilities handling over 10,000 lbs of flammable liquid/vapor in a process (100 proof ethanol and higher, denatured ethanol, denaturant), or over 10,000 lbs of anhydrous ammonia, or over 15,000 lbs of aqueous ammonia (>44% concentration).

Implications for proposed facilities: All three plant scales will likely store over 10,000lbs of ethanol and other flammable materials, and will need to comply with the guidelines set forth in the standard.

EPA Risk Management Plan:

EPA's Risk Management Plan (RMP) standard is tripped when a facility has over 10,000 lbs of anhydrous ammonia or 20,000 lbs of aqueous ammonia (>20%) in a process. Ethanol facilities also commonly trip RMP when the denaturant used contains pentane in excess of 10,000 lbs.

Department of Transportation Security Plan:

DOT's Security Plan requirement is usually tripped at ethanol facilities when hazardous material in bulk packaging (bulk sulfuric acid, ammonia, ethanol, etc.) is transported (sent or received) in quantities greater than 3,500 gallons.

Implications for proposed facilities: All three plant scales will all likely trip this requirement, as a standard tanker truck exceeds the 3,500 gallon threshold.

Minnesota State Regulations

Minnesota Pollution Control Agency (MPCA)

Air Quality Permits

MPCA oversees state and federal air pollution monitoring and compliance efforts. All facilities must receive an air permit.

Implications for proposed facilities: All facilities are required to apply for air emissions permit, likely synthetic minor air permits. The facilities could potentially remain a natural minor source or qualify for a Registration permit if the facility emissions are below applicability thresholds. Additional details on the process and controls would be needed to determine the appropriate permit for each option. Also note, the MPCA has the authority to request a dispersion modeling analysis verifying that the proposed facility meets both State and National Ambient Air Quality Standards.

Air Emissions Risk Analysis and Environmental Assessment Worksheet

An Environmental Assessment Worksheet (EAW) and Air Emissions Risk Analysis (AERA) are required for ethanol facilities increasing production by 5mmgy or with air emissions of any criteria pollutant expected to be greater than 100 tons per year after the use of control equipment (MN Rules Ch. 4410). An EAW is also required for a facility capable of storing 1mm gallons or more of hazardous material (denatured ethanol and denaturant are included).

Implications for proposed facilities: All three plant scales will likely be underneath threshold limits for air emissions. Ethanol and other materials storage for the largest plant scale may trip EAW requirements. Please note that if an EAW is deemed necessary, an Air Emissions Risk Analysis (AERA) evaluation would likely need to be completed.

Water Quality Permits

MPCA oversees state and federal water discharge monitoring and compliance efforts, under the authority of the federal NPDES program. Separate permits are required for process wastewater and non-contact process water, unless the two are blended prior to discharge.

Implications for proposed facilities: All facilities require an NPDES/SDS permit to discharge industrial process/non-contact cooling water. The specific type of permit would depend on the facility's discharge plans—whether the facility would like to discharge to surface water or land-apply the water. Use of a sanitary sewer for industrial wastewater would require pretreatment, the approval of the local wastewater treatment authority and application for a pretreatment permit. The facility's anticipated SIC code (2869—Industrial Organic Chemicals) would require that the facility also obtain stormwater coverage for industrial activities (operation stage). In Minnesota, stormwater discharges are most often authorized in the facility's NPDES/SDS permit.

Stormwater Permit

A permit separate from the wastewater discharge permit is required for water falling onto the facility site and leaving the premises as surface water. Construction stormwater permits are required as the facility is being built if more than 1 acre is disturbed and an industrial facility permit after commission. Note that the MPCA can still require that permit coverage is necessary if a facility disturbs less than 1 acre but may pose a risk to water resources. Permits involve developing an effective Stormwater Pollution Prevention Plan (SWPPP) which contains your Stormwater Control Measures, described as Best Management Practices (BMPs).

Implications for proposed facilities: All facilities are required to apply for applicable stormwater permits unless a 'condition of No Exposure' can be certified. The operations stormwater permit will be contained within the facility's NPDES/SDS permit.

Wetlands

Any facilities that will impact wetlands through water discharges or construction filling require a U.S. Army Corps of Engineers 401 permit to do so. MPCA oversees these activities.

Implications for proposed facilities: Permitting will be required if facility site impacts wetlands.

Minnesota Department of Natural Resources (MNDNR)

Water Appropriation Permit

MNDNR requires water appropriation permits for uses of surface or groundwater that exceed 10,000 gallons per day or 1mmgy.

Implications for proposed facilities: The 100,000gpy ethanol plant will not need a state water appropriations permit. The facility could potentially be exempt from permitting requirements if it drew its water from a municipal water system. The two larger plant sizes will require permits.

Additional State and Local Permits and Regulations

Storage Tank Permits
Local Building Code Regulations
State Liquor License
State Department of Motor Fuels Permit
State Department of Transportation
- **Highway Access Permit**
- **Possible Easement rights**

State Department of Public Service
- **Boiler License**

IV. TRANSPORTATION AND SAFETY CONCERNS

The proper training of plant personnel in safety procedures is not only important, it is required by OSHA. The ethanol industry has an enviable safety record, even though there are numerous safety hazards that can pose significant risk. While state and federal laws set certain requirements, it is important for management to go beyond these base regulations by placing a strong company emphasis on plant safety. No matter what the size of the plant, a Safety Director, responsible for encouraging and enforcing safety procedures, needs to be appointed.

An important first step is to either develop a safety manual internally or hire an experienced safety consultant to develop one. This manual will serve as the guide to implementing an effective safety program that will minimize on-the-job injuries. In addition, a well-developed safety manual will also reduce the number of OSHA violations by pointing out problem areas in advance. It is important to establish an environment of "safety first" right from the start.

Safety Recommendations

The plant safety manual should cover basic safety expectations, enforcement provisions and other critical operational procedures, including:

- Lockout/Tagout
- Confined space entry
- Use of personal protective equipment
- Emergency response
- Hazard communication (employee right-to-know)
- Hot works
- Respiratory protection
- Fall protection
- Other related management issues affecting the facility

Train employees at the time of initial employment about the safety program, safety expectations and how employees will be held accountable for the implementation of the plant's safety program.

All personnel should have an understanding of hazardous materials present in the plant. This includes training them on how to work with those hazardous materials safely (prior to use) and the use of any appropriate personal protective equipment.

Points to Consider:

- Bring a safety professional on board in the earliest possible stages of plant construction to not only begin program development, but also to consult on safety deficiencies with plant and equipment design and installation. This can often avoid costly changes or retrofits after construction is completed.

- Conduct a wall-to-wall inspection of the facility with an eye to all of the OSHA regulations. Quite often, only the most obvious regulations are implemented early on, leaving lesser regulations to be brought up to speed at a later date. OSHA requires that all regulations be complied with from the start.
- A strong show of commitment by plant management is paramount in establishing buy-in at the grass roots level. This commitment can be shown by support of the program by all levels of management, and by consistent insistence on adherence to established safety rules – no exceptions.
- Encourage employee participation in the safety process to the furthest extent possible. This helps establish "ownership" of the safety program by the employees, making the safety program "our" safety program.

Process Safety Management

The Process Safety Management (PSM) standard is very specific in what must be in place to comply with the standard. There are 13 elements that clearly state what is expected.

- Process Safety Information
- Process Hazard Analysis
- Pre-startup Safety Review
- Employee Participation
- Standard Operating Procedures
- Employee Training
- Contractor Management
- Special Permits and Practices
- Mechanical Integrity
- Management of Change
- Incident Investigation
- Emergency Planning and Response
- Compliance Audits

Due to the in-depth nature of each of these elements, it is usually necessary to employ a consultant, at least in the early stages, to assist in developing the PSM program. Also, since each facility generally has conditions and hazards unique to that facility, a good PSM program is not "one-size-fits-all" in nature. Care should be taken in the selection of a consultant to ensure that they have experience not only with PSM, but also with the ethanol industry.

Transportation Safety and Considerations

Safety considerations for truck and rail shipping are clearly established for all plant scales, from a 100,000-gpy plant to a 100-mmgy plant scale. The design, engineering, and equipment at loadin and load-out areas of the plant are required to adhere to these regulations. Permits and regulations described in Section III will cover the majority of the safety considerations for these transfer areas, and local regulators will oversee the remaining construction and operations matters.

The major variations in design and safety will be whether the facility utilizes truck and/or rail infrastructure for acquiring raw materials and selling finished products. At the initial impression, the transportation logistics will likely be truck-based for all three proposed ethanol plant scales. Under the right circumstances, the 2-mmgy and possibly the 1-mmgy plant scales can benefit from rail shipping of materials into and out of the facility. Both the cost of equipment construction and the potential for additional sales revenue will factor into the final decision.

The primary markets for ethanol and distillers grains from any of the proposed plant scales will be local, and likely easily accessible by truck. The entire ethanol output of the proposed plants can be easily absorbed by the nearest fuel distribution rack with the ability to blend ethanol, and it will not take many grain distributors to accept the plant's distillers grains production. As Table 4 indicates, the 100,000-gpy plant scale will only produce 2,000 gallons of ethanol per week, or roughly one tanker truck per month. It would take this plant scale nearly four months to fill one rail car for shipment. At the smallest scale for the proposed plant, truck-based loading and unloading is the only viable option.

Table 4 – Ethanol Shipment Analysis

Shipping Stats	100,000-gpy	1-mmgy	2-mmgy
Annual ethanol production, gal	100,000	1,000,000	2,000,000
Production days per year	**353**		
Weekly ethanol production, gal	2,000	20,000	40,000
Tanker truck capacity, gal	**8,000**		
Tankers per WEEK	0.25	2.5	5.3
Tankers per MONTH	1	10	21
Rail car capacity, gal	**30,000**		
Rail cars per MONTH	0.26	2.6	5.3

The larger two plant scale scales may benefit from access to railroad shipping in addition to truck-based shipping. The ability to access broader markets allowed by rail-based shipping may be worth building at a site with existing rail access. However, the cost of building new rail switches and spurs, and the challenges working a deal with the large rail interests, are likely too high to justify new construction at any of the three proposed plant scales. The 2-mmgy scale is the most likely to profit from rail access; the plant will fill a rail car with less than a week's worth of production. If rail access is determined to be viable, it will still be secondary to truck transport with the small volumes of materials that will be going in and out of the plants.

Shipping cost is not as significant of a factor as the capital cost of rail access construction. Shipping single rail car loads of fuel does not save much as compared to local truck delivery, especially if a long-term contract for the truck shipping can be reached. As well, rail car shipping will likely access the more distant markets, increasing the shipping charge.

V. ETHANOL AND CO-PRODUCTION MARKET ANALYSIS

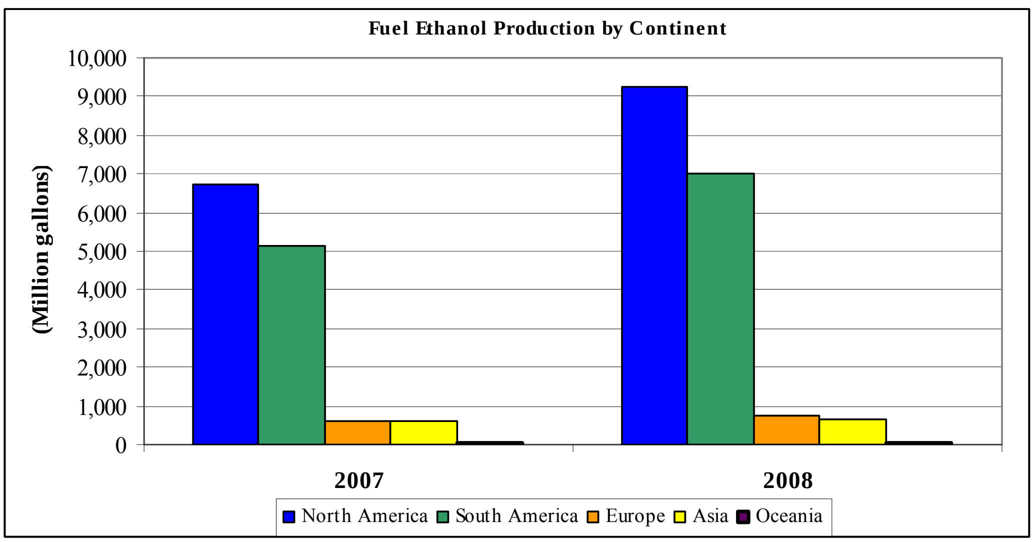
World ethanol markets are comprised of three distinct segments: fuel, industrial, and beverage (in decreasing order of production and use). At present, world economics as well as environmental and oil dependency concerns are providing enormous opportunities for world fuel ethanol growth while population growth will offer modest growth opportunities for the much smaller industrial and beverage segments. Worldwide fuel ethanol production reached approximately 17.3 billion gallons in 2008. That is four billion gallons above worldwide production in 2007.

Of the world's total ethanol production, approximately 80% is now fuel ethanol. Even though the bulk of the world's fuel ethanol production still comes from Brazil and the U.S., there are significant developments in other countries as well. Some of these could result in the establishment of new production centers in addition to the traditional ones in the western hemisphere.

International Markets

Brazil had long been the world's number one fuel alcohol producer, making three to five billion gallons of anhydrous alcohol each year. The United States began challenging this prominence with bipartisan support for the alcohol fuel industry and the phase out of MTBE as a fuel oxygenate. U.S. ethanol production first exceeded Brazilian production in 2005. Figure 1 shows fuel ethanol production by continent.

Figure 1 – Worldwide Ethanol Production by Continent



(Source: Renewable Fuels Association)

North and South America are the world's leading ethanol production regions, with no indication of change in the near future. Total production in the Americas in 2008 reached 16 billion gallons, or about 93% of the world ethanol output. Total U.S. ethanol production in 2008 was 9 billion gallons.

Renewable Fuel Standard

The 2007 Energy Bill was signed into law on December 19, 2007. The legislation included a revised Renewable Fuels Standard. The bill established a 36 billion gallon renewable fuels standard (RFS), headlining several important provisions for biofuels. H.R. 6 will take effect on January 1, 2009 – with the exception of the 9.0 billion gallon requirement for the current RFS program that will take effect in 2008.

The 36 billion gallon RFS has several different provisions for assorted types of biofuels. They are conventional biofuels, advanced biofuels, cellulosic biofuels, and biomass-based diesel. H.R. 6 defines these categories as follows:

> Conventional biofuels is ethanol derived from corn starch. Conventional ethanol facilities that commence construction after the date of enactment must achieve a 20 percent greenhouse gas (GHG) emissions reduction compared to baseline lifecycle GHG emissions. The 20 percent GHG emissions reduction requirement may be adjusted to a lower percentage (but not less than 10 percent) by the U.S. Environmental Protection Agency (EPA) Administrator if it is determined the requirement is not feasible for conventional biofuels.
>
> Advanced biofuels is a renewable fuel other than ethanol derived from corn starch, which is derived from renewable biomass, and achieves a 50 percent GHG emissions reduction requirement. The definition – and the schedule – of advanced biofuels include cellulosic biofuels and biomass-based diesel. The 50 percent GHG emissions reduction requirement may be adjusted to a lower percentage (but not less than 40 percent) by the Administrator if it is determined the requirement is not feasible for advanced biofuels. (Cellulosic biofuels that do not meet the 60 percent threshold, but do meet the 50 percent threshold, may qualify as an advanced biofuel.)
>
> Cellulosic biofuels is renewable fuel derived from any cellulose, hemicellulose, or lignin that is derived from renewable biomass, and achieves a 60 percent GHG emission reduction requirement. The 60 percent GHG emissions reduction requirement may be adjusted to a lower percentage (but not less than 50 percent) by the Administrator if it is determined the requirement is not feasible for cellulosic biofuels. The feedstocks under consideration in this study fall under this category of advanced biofuels.
>
> Biomass-based diesel is renewable fuel that is biodiesel as defined in section 312(f) of the Energy Policy Act of 1992 (42 U.S.C. 13220(f)) and achieves a 50 percent GHG emission reduction requirement. Notwithstanding the preceding sentence, renewable fuel derived from co-processing biomass with a petroleum feedstock is considered an advanced biofuel if it meets advanced biofuel requirements, but is not biomass-based diesel.

H.R. 6 sets the following targets for each of these biofuel types. The following table shows RFS volumes from 2008 to 2022.

Table 5 – Renewable Fuels Standard Volumes (Billions of Gallons)

Year	Conventional Biofuel	Advanced Biofuels			Total RFS
		Cellulosic	Biomass-based Diesel	Undifferentiated	
2008	9.0	---	---	---	9.00
2009	10.5	---	0.50	0.10	11.10
2010	12.0	0.10	0.65	0.20	12.95
2011	12.6	0.25	0.80	0.30	13.95
2012	13.2	0.50	1.00	0.50	15.20
2013	13.8	1.00	1.00	0.75	16.55
2014	14.4	1.75	1.00	1.00	18.15
2015	15.0	3.00	1.00	1.50	20.50
2016	15.0	4.25	1.00	2.00	22.25
2017	15.0	5.50	1.00	2.50	24.00
2018	15.0	7.00	1.00	3.00	26.00
2019	15.0	8.50	1.00	3.50	28.00
2020	15.0	10.50	1.00	3.50	30.00
2021	15.0	13.50	1.00	3.50	33.00
2022	15.0	16.00	1.00	4.00	36.00

In addition to the 36 billion gallon RFS, the bill authorizes $500 million annually for FY2008 to FY2015 for the production of advanced biofuels that have at least an 80 percent reduction in lifecycle greenhouse gas (GHG) emissions relative to current fuels. It also authorizes $25 million annually for FY2008 to FY2010 for R&D and commercial application of biofuels production in states with low rates of ethanol and cellulosic ethanol production; and a $200 million grant program for FY2008 to FY2014 for the installation of refueling infrastructure for E-85.

The bill also includes appropriations for waivers to be granted based on various environmental, economical, and/or production scenarios. It authorizes the EPA Administrator, one or more States, or a refiner/blender to petition for a waiver of the renewable fuels mandate. The Administrator is authorized to waive the renewable fuels mandate if they determine that implementing the requirement would severely harm the economy or the environment, or that there is inadequate domestic supply to meet the requirement. There is a separate waiver provision for cellulosic biofuels if the minimum volume requirement is not met. The Administrator is authorized to reduce the applicable volume of required cellulosic biofuels, and make available for sale a cellulosic biofuels credit at the higher of $0.25 per gallon or the amount by which $3.00 per gallon exceeds the average wholesale price of a gallon of gasoline (in the U.S.). Finally, beginning in 2017, if the EPA Administrator waives at least 20 percent of the mandate for two consecutive years, or waives 50 percent of the mandate for a single year, the Administrator is authorized to modify the volume requirement for the remaining years of the renewable fuels mandate.

Farm Bill Provisions

The 2008 Farm Bill extended the current small producer tax credit but lowered the Volumetric Ethanol Excise Tax Credit (VEETC) blender's credit from 51¢/gal to 45¢/gal in January 2009. This reduction has not appeared to impact ethanol pricing.

The recent stimulus package includes $800 million for the Biomass Program of the Department of Energy Office of Energy Efficiency and Renewable Energy. Biofuels spending will be increased by an additional $500 million although specifics on what the money will be used for are not yet known.

Current Industry

In the U.S., ethanol's primary purpose is to serve as an octane enhancer for gasoline, a clean air additive in the form of an oxygenate, and as an aid in reducing dependence on imported oil – thereby reducing the balance of trade. In order to accomplish these tasks in the face of resistance from the oil industry, Congress established an incentive in the form of a tax credit during the mid-1970s to encourage the oil industry to blend ethanol. The tax incentive is still in place, but set to expire in 2010.

New restrictions on automobile emissions, reductions in carbon monoxide, smog mitigation programs in major cities, and a general trend toward the reduction of greenhouse gas emissions, continue to drive the demand for ethanol.

Ethanol plays a key role in helping refiners extend their product by as much as 10%. The slightest upset in refining capacity (fire, shutdown, closure) sends gasoline prices soaring. U.S. refining capacity operates extremely close to capacity.

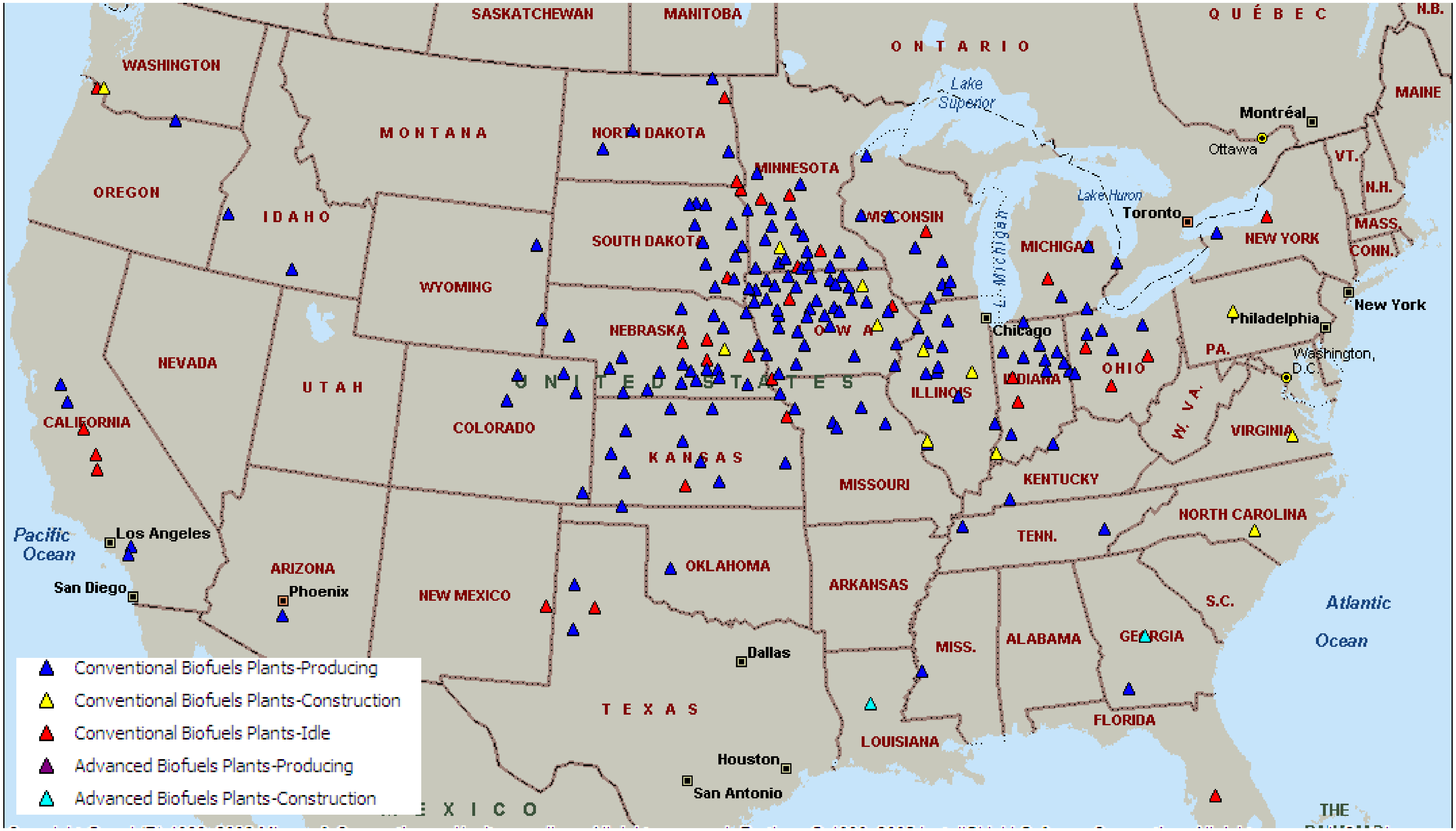
Corn is not the sole provider, but it accounts for 95% of U.S. fuel ethanol and it follows that the majority of production capacity and use of fuel ethanol is in the Midwest Corn Belt. Every state uses ethanol-blended fuel; 50% of U.S. gasoline use in 2007 was ethanol-blended fuel. While corn has been the primary feedstock for fuel ethanol in the U.S., other feedstocks including wheat, milo and various waste starch and sugar streams are also used. Grain-based ethanol will likely continue to be the major contributor to ethanol production in the years ahead.

The industry has entered a period of consolidation driven by tight margins and the desire for some early-stage investors to exit the sector. The recent volatility in corn and ethanol prices has also exposed risk management shortcomings at many plants and some companies need additional capital to maintain liquidity. As of December 2008, most publicly traded ethanol companies had enterprise valuations that were lower than the construction price for a new project in today's dollars, and some even traded below the price it originally took to construct the plant. Additionally, some plants may be in an "upside down" position—locked into old ethanol contracts at low prices with expiring corn contracts which could lead to such plants going idle until corn prices decline. There are 28 idle plants with capacity of 1.8 billion gallons. Nearly half the idle plants are the result of the VeraSun bankruptcy which was primarily a result of locking into corn contracts well above current corn prices.

There are currently 171 commercial fermentation ethanol production facilities in operation in the U.S. with a combined production capacity of about 10.6 billion gallons per year (Figure 2). Verenium Biofuels is the only small-scale commercial cellulosic producer. There are 15 new plants under construction, adding about 1.5 billion gallons of annual production capacity. At this time, 33 plants are idle largely due to high corn prices, low ethanol prices and other risk management issues. These plants represent over 2 billion gallons of capacity.

There are 17 operating plants with capacities of less than 12-mmgy. Of plants with less than 5-mmgy of capacity, only three use corn as the feedstock. These three small-scale plants using corn as a feedstock are idle.

Figure 2 – Fuel Ethanol Plants in the U.S. (2/22/09)



Several factors have and will continue driving the U.S. fuel ethanol industry's growth. They are:

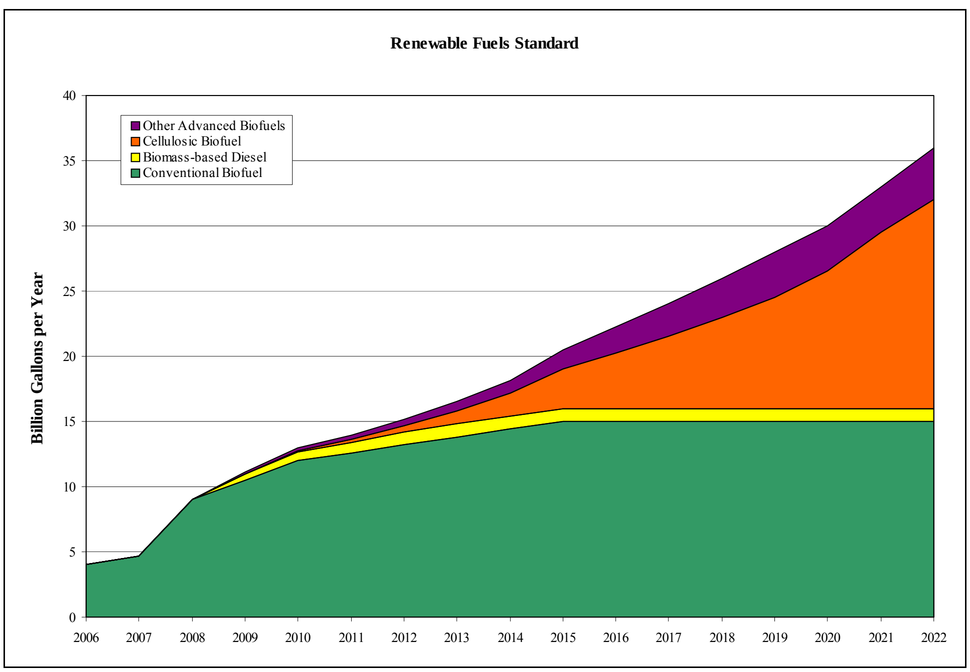
- Federal Renewable Fuels Standard
- Ethanol price relative to crude oil (or gasoline)
- Clean octane
- Oxygenate for RFG program
- Gasoline extender (refinery capacity)
- Local economic development

Following is a brief discussion of each of these drivers and their potential impacts.

Federal Renewable Fuels Standard

The RFS established a market floor of 36 billion gallons for 2022, which should provide some comfort to ethanol producers, investors, and lenders. Ethanol production above the minimum RFS is not viable unless sold at prices that are attractive to gasoline blenders i.e., rack unleaded price plus a portion of the 45¢ per gallon Volumetric Ethanol Excise Tax Credit. Otherwise, voluntary blending above the level required by the RFS will decline until ethanol prices fall to the point where voluntary blending becomes profitable. Under this scenario, wholesale gasoline prices determine ethanol demand above the RFS level. H.R. 6 enacts the following RFS volumes:

Figure 3 – H.R. 6 RFS Volumes by Year



Ethanol Price Relative to Crude Oil or Gasoline

Regardless of any potential RFS, any ethanol production in excess has to be competitive with gasoline. Voluntary blending of ethanol is profitable when the price of ethanol is less than or equal to the price of gasoline plus the VEETC, which is a blender's tax credit. This means that with the current 45¢ per gallon VEETC, if a blender can sell a gallon of gasoline for $2.00, they will pay up to $2.45 per gallon for ethanol.

Clean Octane

Octane is a measurement of gasoline's auto-ignition resistance. The octane number gives the percentage by volume of iso-octane in a mixture of iso-octane and n-heptane that has the same anti-knocking characteristics as the fuel under consideration. For example, gasoline with a 90 octane rating has the same ignition characteristics as a mixture of 90% iso-octane and 10% heptane.

Table 6 shows the octane rating of several compounds in pure form. Frequently referred to as "Dirty Octane," Benzene, Toluene, and Xylene, have toxic human and environmental effects; in many cases, they have been strictly limited in the amount allowed in fuels.

Table 6 – Octane Ratings of Various Compounds

Compound	Octane Rating
n-heptane	0
iso-octane	100
Benzene	101
Methanol	113
Toluene	114
Ethanol	116
Xylene	117

This leaves ethanol as the highest-octane compound that does not have negative human or environmental effects. It is a great source for "Clean Octane" and this provides another incentive for its use in transportation fuels.

Oxygenate For RFG Program & MTBE Phase-out

In 2006, the EPA eliminated the 2.0% oxygen by weight requirement from the Reformulated Gasoline (RFG) program. The interesting part here is that MTBE was a very popular oxygenate, but also an extremely serious environmental and human health problem. Regardless, it was widely used because of the oxygenate requirement. The most current EIA data (from 2003) indicates that 17 states should have MTBE bans by now; even so, the EPA regulation change effectively eliminated its use.

It is true that not all areas use RFG fuel, but it is required in non-attainment areas like Denver, most of California, and New England. Even with the oxygenate requirement gone, RFG fuels still must meet certain VOC control requirements, and the easiest way to do this is with an oxygenate.

This provides as excellent market area for ethanol, although the MTBE oxygenate replacement is nearly complete, and any future growth in this sector is most likely dependent on population growth.

Gasoline Extender (Refinery Capacity)

There is some potential for ethanol, or any fuel-blending agent, to extend the supply of transportation fuels. Simply put, if someone uses 10 gallons of gasoline with no blended agents, they use 10 gallons of gasoline; however, if they use 10 gallons of gasoline blended at 10% ethanol to do the same work, they only consume 9 gallons of gasoline. Multiply this by billions of gallons, and the savings are appreciable.

Local Economic Development

An ethanol plant can re-invigorate a rural community. A typical 50-mmgy dry mill facility creates about 36 new direct jobs, the majority of them being skilled positions requiring special training or education. Repeatedly, near-ghost town communities have re-grown thanks to the new plant in town. In addition to the jobs working at the plant, a new ethanol plant creates hundreds of indirect jobs.

In 2008, the ethanol industry contributed the following to the U.S. economy:[1]

- The industry spent $22 billion on raw materials, other inputs and goods and services
- Combination of spending for operations, ethanol transportation capital for new plants and R&D added $65.6 billion GDP
- Supported the creation of 494,000 jobs in all sectors of the economy, including nearly 46,000 jobs in the manufacturing sector;
- Put an additional $19.9 billion into the pockets of American consumers; and
- Added $11.9 billion (federal subsidies were $4.7 billion) in new tax revenue for the federal government and $9 billion for state and local governments

BBI Projected Ethanol Demand

BBI has projected the demand for ethanol in the U.S. using the following assumptions:

- Ethanol production in the U.S. will not exceed demand less the full import allowance under the Caribbean Basin Initiative (CBI);
- Complete oxygenate demand is met using ethanol;
- Displacement/discretionary blending will create demand up to 9.5% of the total gasoline demand;
- E85 use accounts for all of the ethanol demand beyond the oxygenate and 9.5% blend demands; and

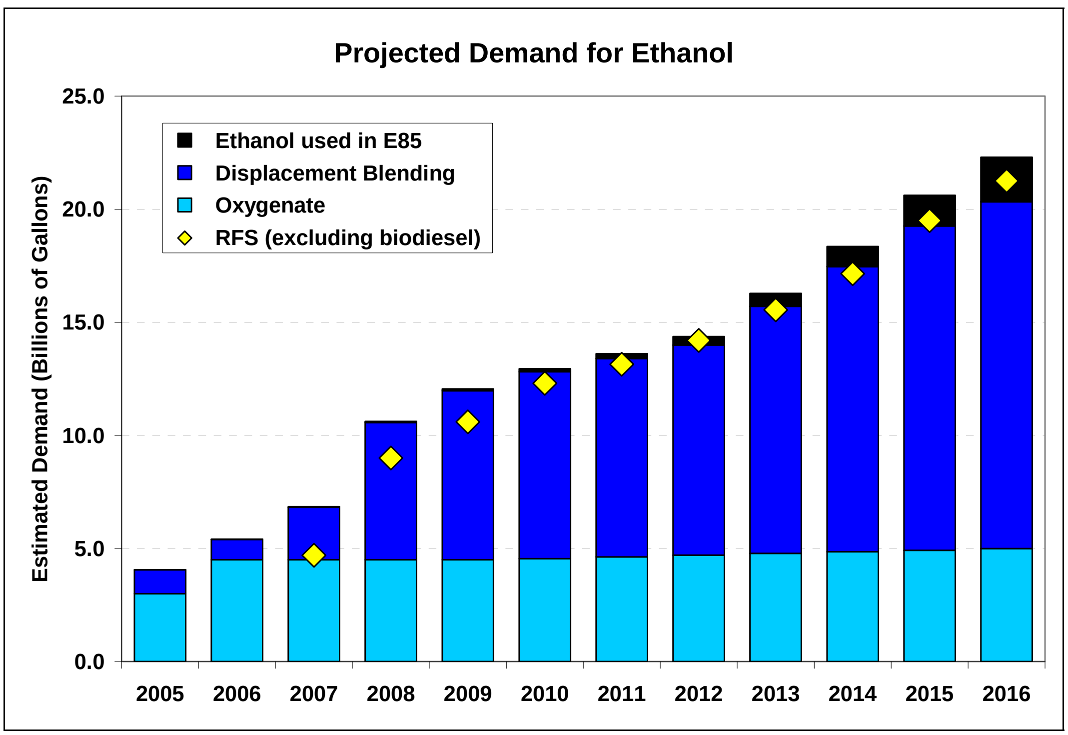
[1] From: "Contribution of the Ethanol Industry to the Economy of the United States," LECG, LLC, February 2009

- Adequate infrastructure – beyond plant production capacity (i.e. with blenders and distributors, E85 pumps) – exists or will exist to meet the demand.
- There is also an assumption that the EPA will allow blending rates above E10 in the future

Figure 4 shows BBI's projections for ethanol demand by use category. By the end of 2006 the 4.5 billion gallon oxygenate market in the U.S. was essentially served, with the only increases in this market due to changes in gasoline demand.

One assumption here is that the EPA designates no new Ozone/Air Quality Non-Attainment areas during the projected period. This may be a moot point though as the displacement blending projections increase to nearly 9.5% of gasoline demand by 2012. Displacement blending is an estimate of how much discretional blending will occur. Finally, E85 demand comes from Renewable Fuels Association (RFA) projections for number of E85 vehicles and their potential demand, factored by BBI estimates on the market penetration and accessibility that these vehicles will have. The most important note is that BBI assumes no infrastructure limits on demand, such as refiners/blenders capacity to store/use ethanol or distribution of the blended product.

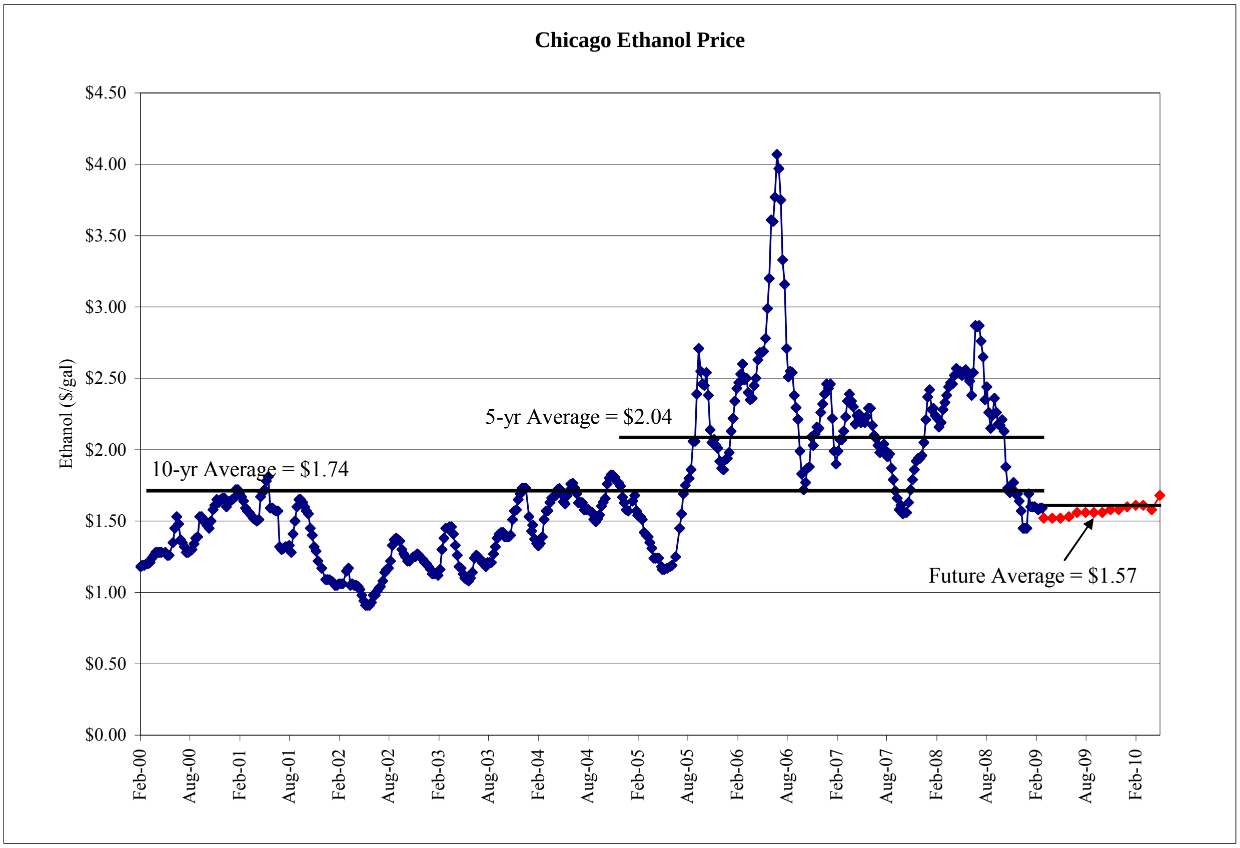
Figure 4 – BBI Projected Ethanol Demand by Use



Ethanol Pricing

The ethanol price has experienced many fluctuations over the past ten years. Figure 5 shows the 10-year historical average price on the Chicago spot price (OPIS) and future pricing (CME Group). Spot prices tend to be slightly higher than contract prices. The average future price for March 2009 through May 2010 is $1.57 per gallon.

Figure 5 – Historical Chicago Ethanol Pricing

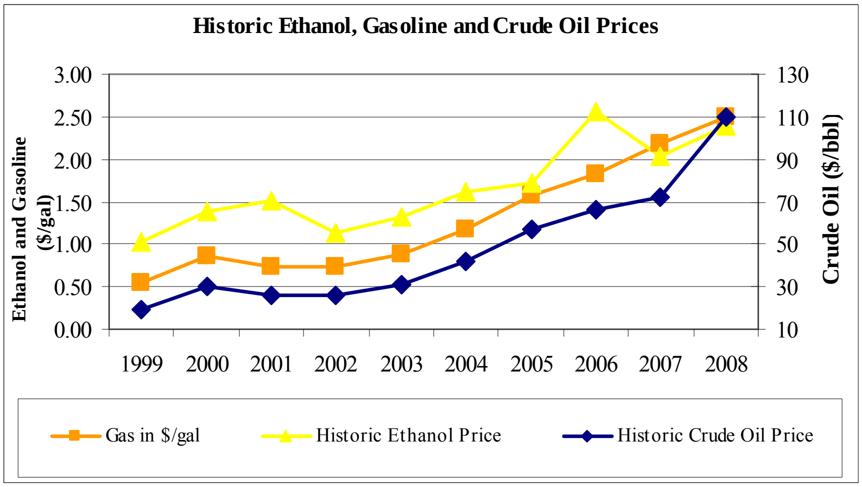


(Source – OPIS, CME Group)

Ethanol Price as it relates to Crude Oil and Gasoline and Corn

Over the past 10 years, the spot prices of fuel ethanol, crude oil and gasoline have similar, upward trends (Figure 6). The price of crude oil has a significant effect on the price of gasoline; there is a correlation coefficient of 0.996 for the average annual spot market prices of crude oil and gasoline. Similarly, although not as direct, there is also a correlation between ethanol and crude oil pricing. Consequently, estimating future ethanol prices based on projections for the price of crude oil is possible. This analysis uses spot ethanol prices for Chicago as reported by OPIS. As evidenced in Figure 6, ethanol has previously traded at a higher value than gasoline presumably due to the 45¢/gallon VEETC. In the past year, the prices of ethanol and gasoline are closer indicating an over supply of ethanol as plants come online faster than the infrastructure to blend and sell ethanol to retail customers.

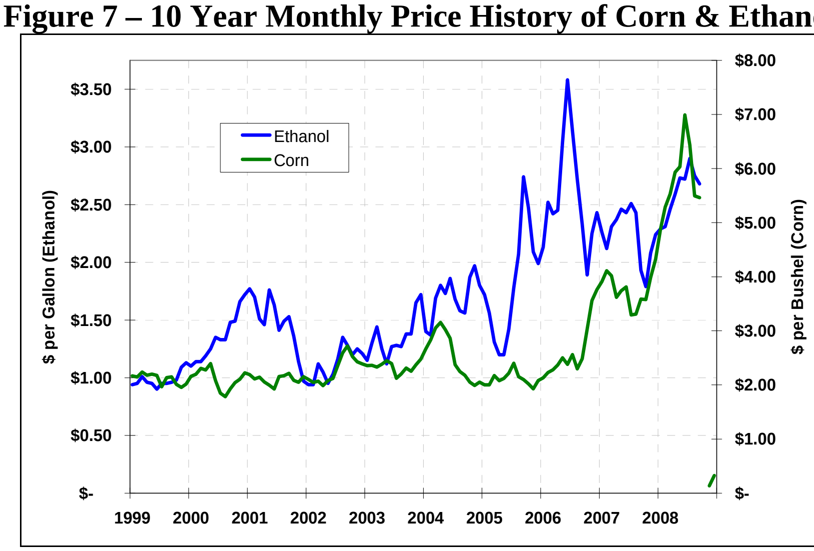
Figure 6 – Historic Relationship between Prices of Oil, Gas, and Ethanol (USD)



(Source – OPIS, US DOE Energy Information Administration)

One of the major risks to an ethanol plant has traditionally been the lack of correlation between ethanol and corn prices. Prior to 2007, ethanol and corn prices were generally uncorrelated with each other (Figure 7). As the prices of the two commodities moved independent of one another, plants could realize large profits or be forced to shut down. In the past three years, ethanol's demand for corn has increased from under 15 percent of the total U.S. consumption to an expected level of 32 percent for the 2008-09 marketing year. This shift in demand has been accompanied with increased correlation between the prices of ethanol and corn. Since October 2007, ethanol and corn prices have moved almost in tandem with correlation of 0.94 between the daily nearby CME prices for the two commodities. While prices in most commodities have moved in sync over the past few years, such high degree of correlation may reflect a new operating environment for ethanol plants. The increased consumption of corn in the biofuels sector may change the pricing environment for the crop to new patterns not previously considered.

Figure 7 – 10 Year Monthly Price History of Corn & Ethanol



(Source: USDA, OPIS)

Small-Scale Ethanol Sales

Ethanol production capacity is just over one billion gallons in Minnesota. This includes three plants that are idle (137-mmgy combined) and one plant under construction (55-mmgy). Minnesota gasoline use is approximately 2.6 billion gallons per year. Minnesota produces far more ethanol than it can use based on the EPA blending rule of 10% and small markets for E85. Despite this level of production, it is assumed that a small-scale producer could sell all output to a local or regional blender. In fact, this is an essential element of a small-scale producer since shipping ethanol long distances with not be economically feasible.

It is assumed that a small-scale ethanol producer can enter into a long term supply contract with an area blender and therefore avoid marketing fees—typically 1% of ethanol sales price for large plants. The economic model uses an estimated shipping cost of $0.05 per gallon. It is assumed that all ethanol is shipped by truck.

Co-Products

Distillers Grains

Distillers grains are the residues that remain after high quality cereal grains have been fermented by yeast. In the fermentation process, nearly all of the starch in the grain is converted to ethanol and carbon dioxide, while the remaining nutrients (proteins, fats, minerals, and vitamins) undergo a three-fold concentration in the beer, which after distillation and centrifugation of the still bottoms, yields DWG and "thin stillage." Distillers Wet Grain (DWG) is the wet cake that comes directly from the centrifuge. It has approximately 65% moisture. The syrup that is centrifuged out is evaporated and returned back into the wet cake.

The primary market for DWG is local dairy and beef cattle. Cattle perceive DWG as sweet and readily eat it without any added sweeteners. Wet distillers grain is nutritionally superior compared to dry distillers grain (drying reduces digestibility). An ethanol plant produces 46.3 pounds per bushel of corn processed.

Distillers grain market price is determined through a number of factors that include the market value of local feed grain, the market value of soybean meal and other competitive protein ingredients, the performance or value of distillers grain in a particular feed formulation, the supply and demand within the market, and, most importantly, acceptance by animal producers. While pricing is localized, DWG generally sell for 80% the price of corn on a dry weight basis. This results in a price of $45.53 per ton (based on one year future corn price of $3.87 per bushel-CME Group).

DWG are collected by area cattle and dairy farmers so there are no marketing or transportation fees. Minnesota law requires DWG to be sold within three days of it being produced.

Carbon Dioxide

Dry ice and liquid carbon dioxide (CO_2) are principally used as expendable refrigerants in the food industry. Carbon dioxide, whether solid, liquid, or gaseous, is recognized as safe for use in foods. Food applications include:

- Beef, pork, and poultry slaughter operations
- Frozen food storage and transportation
- Supplemental cooling for refrigerated products
- Meat, sausage and bakery processing
- Airline catering
- Gift food packaging
- Carbonation of beverages

Non-food applications include:

- Various chemical processes
- Oil extraction via CO_2 injection
- Dermatologists
- Blood banks
- Pharmaceutical manufacturing
- pH control

Currently in the U.S. about 20% of the CO_2 produced by ethanol plants is captured and the rest vented to the atmosphere. In most cases, the carbon dioxide captured is from very large ethanol plants. Capture of CO_2 from medium sized and smaller plants is usually not justified unless special market conditions are present. If justified, the ethanol plant can easily capture raw carbon dioxide. However, further processing is necessary if it is to be used for commercial purposes. At most, the revenue potential from the sale of CO_2 is approximately 3% of total plant revenues.

Typically, a CO_2 processing company will construct a processing facility next to the ethanol plant. The raw CO_2 is piped to the processing facility for finishing. In order for the processing facility to be economically viable, there must be a close market for the finished CO_2. If all the produced CO_2 is sold, it can add about 3% to revenues. Due to the low production levels of carbon dioxide from small-scale ethanol plants, it is unlikely that it will be captured and sold. Carbon dioxide sales are not included in the economic model.

Ethanol and Co-Product Market Summary

The recently updated Renewable Fuels Standard ensures a long term U.S. market for biofuels. Voluntary blending is expected to occur at an increasing rate as long as the price of ethanol remains less than or equal to gasoline plus the blender's tax credit—making blending economically attractive. At this time, some ethanol plants are struggling due to continued higher than average corn prices and lower ethanol prices as they still correlate to oil prices which have dipped significantly in the 4th quarter of 2008 and continuing on into 2009. Plants that are efficiently run, have no debt and have a solid risk management strategy should be able to make it through this difficult financial period.

Ethanol production capacity is just over one billion gallons in Minnesota. Minnesota gasoline use is approximately 2.6 billion gallons per year. Minnesota produces far more ethanol than it can use based on the EPA blending rule of 10% and small markets for E85. Despite this level of production, it is assumed that a small-scale producer could sell all output to a local or regional blender. In fact, this is an essential element of a small-scale producer since shipping ethanol long distances with not be economically feasible.

The ethanol price is set to the one year average futures price from CME Group of $1.57 per gallon increasing at a rate of 2% per year in the economic model. Shipping costs are estimated at $0.05 per gallon. It is assumed that all ethanol is shipped by truck.

All distillers grains will be sold in the wet form. Production of DWG is as follows: 771 tons from the 100,000 gallon scenario; 7,710 tons from the 1-mmgy scenario; and 15,420 tons from the 2-mmgy scenario. The price is set to 80% the price of corn on a dry weight basis ($45.53 per ton based on one year future corn price of $3.87 per bushel-CME Group).

VI. SMALL-SCALE TECHNOLOGY PROVIDERS

The project sponsor should ensure that reputable design and construction firms are engaged throughout the development, design, and construction of the project. The construction firm should guarantee the completion of the project within a fixed budget and time schedule and must warrant all workmanship for a period of not less than a year following startup. The firm should be capable of posting performance, materials, and labor bonds and should be willing and financially able to accept liquidated damages provisions in their contract, if it is required by the sources of debt financing for the project.

The supplier of the ethanol process technology and the designer of the process should be experienced and well regarded, to guarantee the performance of the plant so long as the construction firm builds it to the designer's specifications. This guarantee should include a minimum yield requirement, and specific quality requirements of products. The guarantee should also include quality and quantity requirements of feedstock (usually a bushel of #2 yellow dent corn). Requirements for energy and utility consumption for the use of chemicals and enzymes, and for the process water, with respect to consumption, should be stated in the process guarantee. The volume and characteristics of wastewater should also be addressed in this guarantee, and all requirements should be presented on a per bushel basis. The guarantee is normally considered satisfied if a successful performances test of several days duration is completed after plant startup.

In some cases, the same firm may be both the designer and the constructor. In such cases, the General Constructor (GC) will provide the performance guarantees and the process designer will act as a subcontractor to the GC. In cases where separate contracts are held for both the designer and the construction contractor, the process and construction guarantees would be in separate documents. BBI recommends that there be a single "turnkey" contract providing the strongest possible financial resources to back the design and construction scope of work.

What follows is a list and short description of firms that BBI knows to be successful and reliable in the ethanol industry.

Fagen, Inc. (Granite Falls, MN)

Fagen Inc. has been the design-build contractor, E.P.C. contractor, general contractor, or subcontractor for at least 77 ethanol plant projects, both new construction and expansion jobs, and claims more ethanol industry experience than any other U.S. firm during the past decade. With the addition of Fagen Engineering LLC and Fagen Management LLC, Fagen now performs the civil, structural, mechanical, and electrical engineering aspects for ethanol projects and provides management services after construction and startup. They typically utilize the ethanol process design of ICM, Inc.

Fagen, Inc. is located at 501 West Highway 212, Granite Falls, MN 56241
Telephone (320) 564-3324. Web address: http://www.fageninc.com/

ICM, Inc. (Colwich, KS)

ICM, Inc. of Colwich, KS, serves the agricultural industry by developing and implementing innovative and practical processing solutions. ICM, Inc. employs people in all aspects of ethanol project development and operation including cash and commodity trading of corn, marketing of ethanol and distillers grain, process consulting, engineering, equipment fabrication, field installation, and plant start-up. The former technology leader of High Plains Corporation formed ICM. High Plains operates plants in Nebraska, Kansas, and New Mexico. ICM does own and operate a facility in Russell, Kansas, which acts as both a training and research facility for their technology. Six of the latest ethanol plants in the United States have utilized ICM technology.

ICM has 101 plants in North America that utilize their process design, the smallest of which is 10-mmgy. They are currently working on a re-design of the 10-mmgy plant to modularize it, and are confident that it could be easily scaled down to the 1- to 2-mmgy range.

ICM Inc. is located at 310 N. First Street, Colwich, KS 67030
Telephone (316) 796-0900. Web address: http://www.icminc.com/

There are several other ethanol technology providers that have contributed to the current industry, including: POET, Katzen, Lurgi, Vogelbusch, although it is unclear as to their involvement in currently providing small-scale ethanol technology. Attempts to reach these firms were unsuccessful.

Additionally, BBI contacted two small-scale ethanol technology providers, Easy Automation (800-397-9736) and Diversified Ethanol (800-689-3544) but neither company responded to telephone inquiries.

VII. PLANT DESIGN, LAYOUT AND COSTS

The production of ethanol or ethyl alcohol from starch or sugar-based feedstocks has been practiced for thousands of years. While the basic process steps remain the same, the process has been considerably refined in recent years, leading to a highly efficient process that now yields more energy in the ethanol and co-products than is required to make the products.

Process Description

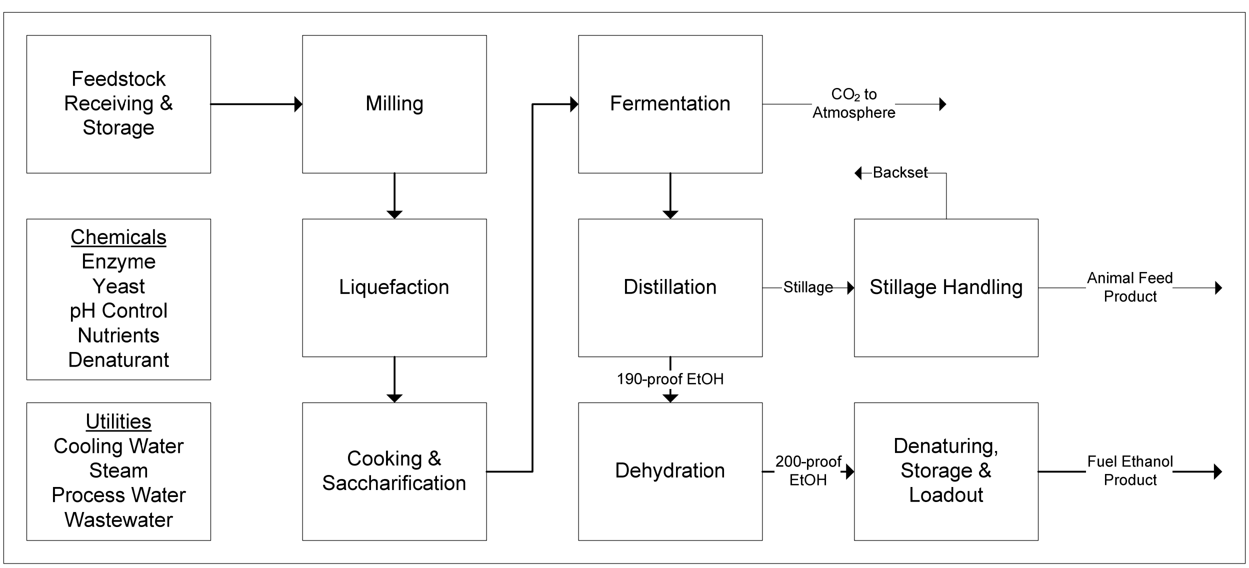
In the small-scale dry milling process, corn is ground into meal and slurried with water to form a mash. Enzymes are added to the mash to convert the starch to glucose. Ammonia is added for pH control and as a nutrient for the yeast. The mash is processed through a high temperature cook step, which reduces bacteria levels prior to fermentation. The mash is cooled and transferred to the fermenters where yeast is added and the conversion of sugar to ethanol and carbon dioxide (CO_2) begins.

After fermentation, the resulting beer goes to distillation where the ethanol is separated from the mixture; this step also produces a high solids stillage stream. The ethanol is concentrated to 190-proof via conventional distillation and then is dehydrated to approximately 200-proof in a molecular sieve system. The anhydrous ethanol is blended with about 5% denaturant (usually gasoline) and is ready for use.

The stillage is separated into a coarse grain fraction and a soluble fraction by centrifugation. Some of the soluble fraction is recycled to the front of the process, and the remainder is blended with the solids to produce a modified wet distiller's grain (WDG) product that is about 30% solids.

A block diagram of this small scale process is shown in Figure 8.

Figure 8 – Flow Diagram for Small Scale Dry Mill Ethanol Plant



The most apparent difference between this conceptual design and that of a typical dry mill is that the small-scale plant will not have evaporators or a dryer for the stillage handling steps. This exclusion is made because of the small amount of feed product and its use in the local area. Even a larger dry mill will forgo installing the drying systems if there is the opportunity to serve a local market.

Design Basis

All three scenarios share the same design basis. Following is a detailed description of the operational parameters of the plants.

Feedstock is delivered by truck and stored on site in silos (TNK-0001) that have a seven day capacity. From the silos (TNK-0001) corn feeds into the hammer mill (MLB-0001) where it is ground to 1/16th inch flour. The flour travels down a weigh belt (CVT-0001) that measure the amount of flour going into the wet mixing conveyor (CVS-0001) where the flour is combined with backset and makeup water to achieve 33% solids and goes into the Liquefaction Tank (TAK-0001). Enzymes are also added to start breaking down starch and lower the viscosity of the mixture. The tank has a 10 minute residence time to ensure adequate slurrying of the material. From here it is pumped (PMC-0002) through a steam heater (PIP-001) with a 10 minute retention time to sterilize the stream. Because this results in increased pressure the mash passes through an atmospheric flash drum (FLA-0001) to bring pressure back down before getting pumped (PMC-0003) into the Saccharification Tank (TAC-0001), and additional enzymes are added.

There are two Saccharification Tanks (TAC-001) each with a 12 hour residence time. This allows for enough material to be built up prior to fermentation. During saccharification the material is pumped (PMC-004) through a heat exchanger (HTX-0001) to maintain the appropriate temperature conditions.

Fermentation is operated as a batch process, with each tank (TAK-0002) containing 12 hours of material. The whole process, of loading, fermentation, unloading, and cleaning each tank takes 48 hours. There are four tanks (TAK-0002), pumps (PMC-0005), and heat exchangers (HTX-0002) that allow fermentation to operate at a semi-continuous process as far as the rest of the process is concerned. At the end of fermentation, the stream is loaded into the Beer Well (TAK-0004), which acts as a buffer between the batch fermentation operations and the continuous distillation and back-end of the plant. It has the capacity to hold 18 hours of material. From here, material is pumped (PMC-0008) to distillation.

Carbon dioxide is generated during fermentation. It contains trace amounts of ethanol and other VOCs, and so it is collected from each fermentation tank and the beer well and sent to a scrubber (ABS-0001) where it is cleaned to allow atmospheric venting. The liquid material coming out of the bottom is pumped (PMC-0009) back into the beer well (TAK-0004).

Distillation is used to separate the ethanol from the broth. It generates a 190-proof vapor stream, which is condensed against the incoming beer (HTX-0004) and pumped (PMC-0010) through a chiller (HTX-0008) to ensure full condensation and is stored for up to 7 days in a tank (TNK-

0012). From this tank it is pumped (PMC-0013) through another heat recovery exchanger (HTX-0009), fully reboiled (TNC-0003), and sent through dehydration (SPC-0001). The dehydration units generate a 200-proof ethanol vapor stream. This stream is condensed (HTX-0010) and pumped (PMC-0014) to a 7-day storage tank (TNK-0013). From here the anhydrous ethanol is pumped (PMC-0015) through a mixer (MIX-0006) that meters in denaturant before entering the final storage tank (TNK-0014). This tank is equipped with a pump (PMC-0016) for loadout.

The residual material from the bottom of the distillation unit is pumped (PMC-0012) through centrifuge (CED-0001) to separate the suspended solids. The centrate is pumped (PMC-0017) to a holding tank (TNK-0015) and up to 85% is recycled (PMC-0018) to the front of the process, with the remainder being remixed with the solids (CVS-0002), and stored in a short-term storage tank (TNK-0017) before being unloaded (CVS-0003) for use a animal feed.

The plant runs a closed-loop cooling water system (TWC-0001) requiring makeup water only for blowdown and evaporative losses. A single pump (PMC-0019) services the plant. It also generates its own steam via a package natural gas boiler (STB-0001). The plant has a process water tank (TNK-0018) which holds 7 days of water.

Material Balance

In order to generate a capital cost estimate, BBI prepared a mass balance for each scenario. The following assumptions were used in the modeling:

- 80% starch conversion;
- 90% fermentation efficiency;
- Yeast direct-pitched to fermenters at 2 lb/1,000 gal;
- 0.5% ethanol loss through scrubber;
- Denaturant addition to 3% v/v;
- Maximum backset recycle 85%; and
- DWG product max 30% solids.

The following table shows the corn composition used for the modeling.

Table 7 – Corn Compositional Analysis

	Dry Basis (%)	As Received (%)
Starch	74	62.9
Protein	8	6.8
Fiber	10	8.5
Fat/Oil	4	3.4
Ash	1	0.85
Other	3	2.55
TOTAL DRY	**100**	**---**
Moisture	---	15
TOTAL	**---**	**100**

Using this information, BBI developed the material balance using Metsim process modeling software. Process flow diagrams (PFDs) from Metsim are presented in APPENDIX D. The material balance is shown for each scenario in the table below.

Table 8 – Overall Mass Balance

Case	100mgy	1mmgy	2mmgy
Stream	(ton/day)	(ton/day)	(ton/day)
Corn	2.88	28.84	57.68
Cooling Tower Makeup Water	6.46	64.57	129.15
Cooling Tower Air	100.54	1,005.44	2,010.87
Boiler Makeup Water	0.5	5.01	10.03
Process Water	1.03	10.27	20.54
Denaturant	0.01	0.11	0.21
Yeast	0	0.02	0.04
Enzyme	0.01	0.09	0.18
Nutrients	0	0.04	0.08
Total Input	**111.44**	**1,114.39**	**2,228.78**
CO_2	0.99	9.91	19.82
Fuel Ethanol	0.94	9.36	18.71
DWG	2.43	24.32	48.64
Cooling Tower Air	105.71	1,057.09	2,114.19
Condensate Flash	0.05	0.49	0.97
Wastewater	1.32	13.22	26.44
Total Output	**111.44**	**1,114.39**	**2,228.78**

In addition to the overall material balance, the modeling determined utility usage for each scenario. BBI uses a financial model that is based on inputs in usage per gallon of ethanol produced or per bushel of feedstock processed. The following table presents the financial model utility inputs based on the process modeling output.

Table 9 – Utility Usage for Financial Model

Utility	Unit	Value
Makeup Water	1,000 gal/bushel	0.019
Wastewater	1,000 gal/bushel	0.003
Thermal Energy	BTU/denatured gallon	21,190
Electricity	kWh/bushel	0.75

Equipment List

The process modeling also generates an equipment list for the plant. Each scenario run for this study has the same equipment, so the following equipment list is valid for all scenarios.

Table 10 – Major Equipment List

Name	Type	Qty
CO2 Scrubber	Packed Column	1
Whole Stillage Centrifuge	Centrifuge	1
Delivery Elevator	Conveyor	1
Wet Mixing Conveyor	Conveyor	1
DWG Mix/Transfer Auger	Conveyor	1
DWG Unloading Auger	Conveyor	1
Milled Grain Conveyor	Conveyor	1
Mash Flash Vessel	Process Tank	1
Condensate Rtn Flash	Process Tank	1
Saccharification Cooler	Heat Exchanger	2
FM Broth Coolers	Heat Exchanger	4
Distillation Preheater	Heat Exchanger	1
190-proof Chiller	Heat Exchanger	1
Ethanol/Ethanol Exchanger	Heat Exchanger	1
200-proof Chiller	Heat Exchanger	1
Denaturant Mixer	In-Line Mixer	1
Hammer Mill	Mill	1
Steam Heater	Process Tank	1
Denaturant Pump	Pump	1
Liquefaction Unload Pump	Pump	1
Flash Pump	Pump	1
Saccharification Tank Pump	Pump	2
Fermentation Transfer Pumps	Pump	4
Beer Well Unloading Pump	Pump	1
Scrubber Water Pump	Pump	1
190-pf Pump	Pump	1
Stillage Pump	Pump	1
190-proof Pump	Pump	1
200-proof Transfer Pump	Pump	1
200-proof Unloading Pump	Pump	1
Fuel Ethanol Unloading Pump	Pump	1
Thin Stillage Pump	Pump	1

Name	Type	Qty
Backset Transfer Pump	Pump	1
CWS Pump	Pump	1
Condensate Pump	Pump	1
Process Water Pump	Pump	1
Dehydration Unit	Molecular Sieve	1
Boiler	Steam Boiler	1
Saccharification Tank	Process Tank	2
Liquefaction Tank	Process Tank	1
Fermentation Tanks	Process Tank	4
Beer Well	Process Tank	1
190-proof Reboiler	Heat Exchanger	1
Storage Silos	Silo	1
Denaturant Tank	Process Tank	1
Distillation Package	Distillation Columns	1
190-proof Storage Tank	Process Tank	1
200-proof Storage Tank	Process Tank	1
Fuel Ethanol Storage Tank	Process Tank	1
Backset Storage Tank	Process Tank	1
DWG Storage	Process Tank	1
Process Water Tank	Process Tank	1
Cooling Tower	Cooling Tower	1

The centrifuge, distillation, and dehydration equipment is the longest lead time equipment, though wait times may be shorter than for similar equipment for a larger 100-mmgy plant. This list does not include electrical equipment like transformers, which if required have lead times of about 12 to 18 months. However, much of this equipment may be available from projects that have been canceled, though such equipment would be much larger than required for a small scale plant. Also, recent project cancellations (not only relating to ethanol projects) may have freed production capacity and could result in shorter lead times.

Capital Equipment Cost

Using the equipment list for each scenario, BBI estimated the cost of the installed plant. This cost is for the plant construction only, and does not include any potential site work or infrastructure improvements that may be needed.

Table 11 – Plant Capital Costs

Scenario	Total Installed Cost	$/gal
2-mmgy Plant	$7,492,000	3.75
1-mmgy Plant	$5,064,000	5.06
100-mgy Plant	$1,799,000	17.99

VIII. PROJECT STATISTICS

The project statistics shown in the following tables are general guidelines only and may change with the specific plant design and other project variables. Refer to the Appendices for specific statistics.

Ethanol Plant Statistics

The following table shows the project statistics for each scenario. In the case of 100,000 gallon per year plant, it is likely that smaller fuel trucks will be used in order to ship the product to market more quickly.

Table 12 – Ethanol Plant Statistics

Plant Parameters	100,000-yr	1-mmgy	2-mmgy
Plant Inputs			
Corn (Bu/yr)	35,670	356,697	713,394
Water (Gal/yr)	668,000	6,777,000	13,554,000
Electricity (kWh/yr)	75,000	750,000	1,500,000
Thermal Energy (MMBTU/yr)	2,071	20,710	41,420
Plant Outputs			
Denatured Ethanol (GPY)	100,000	1,000,000	2,000,000
DWG (Tons/yr)	825	8,250	16,500
CO_2 (Tons/yr)	314	3,140	6,280
Wastewater (Gal/yr)	57,000	570,000	1,140,000
Transportation (truckloads)			
Grain	40	400	800
Ethanol	13	130	260
DWG	51	512	1,024

Personnel Requirements

The personnel requirements used in the feasibility study are listed in Table 13. The positions and salaries shown are typical of the industry. Labor is a far more significant operating cost for a small-scale plant when compared to a typical 50-mmgy plant. BBI believes this is the bare minimum of employees for these sizes of plants and will require long work hours. It is assumed that the plant operates 24 hours per day; otherwise, there is stranded capital in equipment not being used. Operators of small-scale ethanol plants will need to be creative in their labor allocation.

Table 13 – Personnel Requirements for Plants

Position	100,000-yr	1-mmgy	2-mmgy	Annual Salary
Administration/Management				
Plant Manager	1	1	1	60,000
Controller	0	1	1	55,000
Production Labor				
Lab Technician	1	1	1	29,700
Shift Team Leader	1	1	1	43,600
Shift Operator	1	1	1	36,600
Yard/Commodities Labor	0	0	1	26,700
Total Number of Employees	4	5	6	

IX. REVENUE OUTLOOK AND FINANCIAL ANALYSIS

BBI prepared three financial scenarios to evaluate the performance of small-scale ethanol production at three scales. The three scales are 100,000 gallons, 1,000,000 gallons and 2,000,000 gallons of ethanol production per year. Additionally, a fourth scenario was created to observe if there was a benefit to producing 1,000,000 per year but for only half the year—this involves building a 2,000,000 gallon plant and operating it half the time.

The key model inputs include product and co-product yields, product and raw material pricing, shipping costs, labor costs, energy consumption and pricing, capital costs including engineering, procurement and construction of the ethanol plant and all supporting facilities and systems, project development costs, financing costs, start-up costs, working capital and inventory costs.

The BBI model produces a ten-year operating forecast for the project including a balance sheet, income statement, and cash flow statement. The complete 11-year proforma for the dry mill ethanol plants for all three scenarios are included in the appendices. The impact of critical project variables will be determined and the viability of the project with regard to each will be evaluated.

Assumptions Used in the Financial Forecast

The major variables for the financial analysis are ethanol price, feedstock price, distillers grains price, and energy costs. In addition to these issues, various financial model input sensitivities were analyzed and are described below. The assumptions used in the financial forecasts that have the greatest impact on the project risk and return are:

- *Ethanol Price*. The ethanol price used in the financial forecast is $1.57 per gallon of denatured ethanol. This price is based on one year average forward ethanol pricing from CME Group. Shipping costs are 5¢/gallon.

- *Ethanol Yield.* The ethanol yield is an important variable for profitable ethanol production. The ethanol yield is set at 2.67 gallons of anhydrous ethanol for each 56-pound bushel of #2 yellow corn (at 15% moisture or less) processed.

- *Feedstock Price*. Corn is priced at $3.87 per bushel based on one year future corn pricing from the CME Group.

- *Wet Distillers Grains*. The selling price for DWG is set at 80% of the price of corn on a dry weight basis resulting in a price of $45.53/ton.

- *Electricity Price.* The electric rate is 5.5¢ per kWh based on average EIA Minnesota industrial rate.

- *Water Usage.* 19.0 gallons per bushel.

- *Natural Gas Price*. The natural gas price is set at $5.65 per MMBTU based on future NYMEX pricing at Henry Hub plus an additional 70 cent/MMBTU to cover delivery and associated fees.

- *Incentive Payments*. The financial forecast does not include any state tax credits or ethanol incentive payments. The Federal Small Producer Tax Credit (60-mmgy and below) is included in the analysis.

- *Financing*. Senior debt data was included in the base model. For the fractionation and biomass scenarios financing is assumed at 30% equity and 70% debt at 8.0% interest amortized over 10 years.

Table 14 shows the key project assumptions discussed above plus additional assumptions used in the financial projections.

Table 14 – Assumptions Used In the Financial Forecast

AURI Ethanol Project	100,000-gy	1-mmgy	2-mmgy
Nameplate Ethanol Production (gal/year)	**100,000**	**1,000,000**	**2,000,000**
Anhydrous Ethanol Production (gal/year)	95,238	952,381	1,904,762
Product Values			
Conversion Rate (anhydrous gal/bushel)	2.67	2.67	2.67
Grain ($/Bu)	3.87	3.87	3.87
Ethanol ($/gal)	1.57	1.57	1.57
Ethanol Sales Commission (%)	0.00%	0.00%	0.00%
Ethanol Shipping Cost ($/gal)	0.050	0.050	0.050
DWG ($/ton)	45.53	45.53	45.53
Denaturant ($/gal)	1.57	1.57	1.57
Thermal Energy ($/MMBTU)	5.65	5.65	5.65
Electricity ($/kWh)	0.055	0.055	0.055
Makeup Water ($/1000 gal)	0.50	0.50	0.50
Wastewater ($/1000 gal)	0.50	0.50	0.50

Project and Capital Costs

The costs to build a small-scale plant are higher on a per gallon basis. This is primarily due to needing most of the same equipment as a large-scale plant but in smaller volumes. The process designs of these plants generated the following capital costs for plant construction only on a per gallon basis: $17.99 per gallon for the 100,000 gallon plant; $5.06 per gallon for the 1-mmgy plant; $3.75 per gallon for the 2-mmgy plant.

Table 15 – Small-Scale Average Capital Cost Estimate

AURI Ethanol Project	100,000-gy	1-mmgy	2-mmgy
Nameplate Ethanol Production (gal/year)	**100,000**	**1,000,000**	**2,000,000**
Anhydrous Ethanol Production (gal/year)	**95,238**	**952,381**	**1,904,762**
Project Engineering & Construction Costs			
EPC Contract	$1,799,000	$5,064,000	$7,492,000
Site Development	$261,000	$412,000	$462,500
Rail	$0	$0	$0
Contingency	$100,000	$200,000	$300,000
Total Engineering and Construction Cost	**$2,160,000**	**$5,676,000**	**$8,254,500**
Owners Costs			
Inventory - Feedstock	$4,000	$40,000	$79,000
Inventory - Chemicals, Yeast, Denaturant	$400	$4,000	$8,000
Inventory - Spare Parts	$1,000	$10,000	$15,000
Start-up Costs	$115,990	$200,640	$239,920
Land	$0	$0	$0
Fire Protection & Potable Water	$17,000	$30,000	$35,000
Administration Building & Office Equipment	$145,000	$147,000	$147,000
Insurance & Performance Bond	$25,000	$45,000	$55,000
Rolling Stock & Shop Equipment	$0	$0	$0
Organizational Costs & Permits	$89,000	$101,000	$106,000
Capitalized Interest & Financing Costs	$34,500	$66,500	$78,500
Working Capital/Risk Management	$32,000	$199,000	$382,000
Total Owners Costs	**$463,890**	**$843,140**	**$1,145,420**
Total Project Capital Cost	**$2,623,890**	**$6,519,140**	**$9,399,920**

Economic Modeling Results

Pre-tax average annual Return on Investment (ROI) was used to measure the projected profitability of the project. The results are summarized in Table 16. The ROI is the average of the return for the 11 years of the financial forecast including the construction year. Results that are more detailed are shown on the following pages and the complete 11-year economic forecast for the project is included in the appendices.

Table 16 – Financial Modeling Results—Fractionation

AURI Ethanol Project	100,000-gy	1-mmgy	2-mmgy
11-year Average Annual ROI	-81.4%	-46.4%	-34.0%
Internal Rate of Return	N/A	N/A	N/A
EBITDA	($237,021)	($118,430)	$49,373
Average Annual Income	($641,000)	($907,000)	($959,000)
Installed Capital Cost ($/gal)	$26.24	$6.52	$4.70
Plant Capital Cost	$2,160,000	$5,676,000	$8,254,500
Owner's Costs	$463,890	$844,140	$1,146,420
Total Project Investment	$2,623,890	$6,520,140	$9,400,920
30% Equity	$787,167	$1,956,042	$2,820,276

As evidenced in Table 16, all three of the small-scale ethanol scenarios yield negative financial results. This is due to the current and forecasted low ethanol prices that make profits challenging for existing large-scale plants with no debt. The projects also suffer because they must install much of the same infrastructure as larger plants and cannot achieve economies of scale. Additionally, the capital costs are high when compared with the costs of building a new large-scale ethanol plant. BBI also looked at producing 1 million gallons at a plant operating for only half the year and the ROI was -47% so that is worse than operating either the 1-mmgy or 2-mmgy plant over an entire year. Table 17 through Table 19 show sensitivities for corn price and ethanol price that highlight the conditions where a small-scale plant would be profitable.

For comparison, BBI ran a model for a new 50-mmgy plant with the same corn and ethanol prices and the results are still negative with an estimated ROI of -3.8%. Again, the primary reason is the low ethanol price.

Sensitivity and Breakeven Analysis

The variables that have the greatest impact on the project's profitability are the delivered price for corn and the ethanol selling price. A series of sensitivity analyses were run to examine the effect of critical parameters on the projected 11-year Average Annual Income. The parameters analyzed include:

- Feedstock Price
- Ethanol Price
- Thermal Energy Price
- Electricity Price
- DWG Price
- Capital Cost

The results of these parameter studies are shown in the graphs that follow. Each of the sensitivity figures that follows assumes that only one variable is changing and that all others are constant as listed in the financial assumptions towards the beginning of this chapter. As expected, the projected profitability as measured by the ROI is very sensitive to corn and ethanol prices; moderately sensitive to the DWG price and capital costs; and relatively insensitive to the electricity price and natural gas price.

Figure 9 – Effect of Corn Price on 11-year Average Annual Income

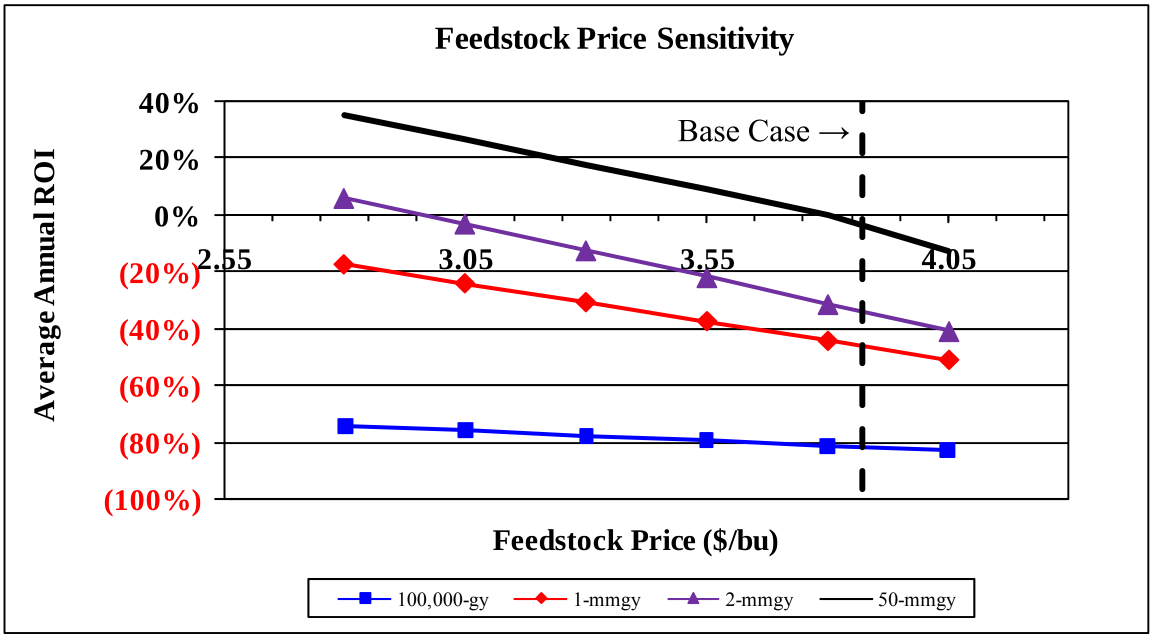


Figure 10 – Effect of Ethanol Price on 11-year Average Annual Income

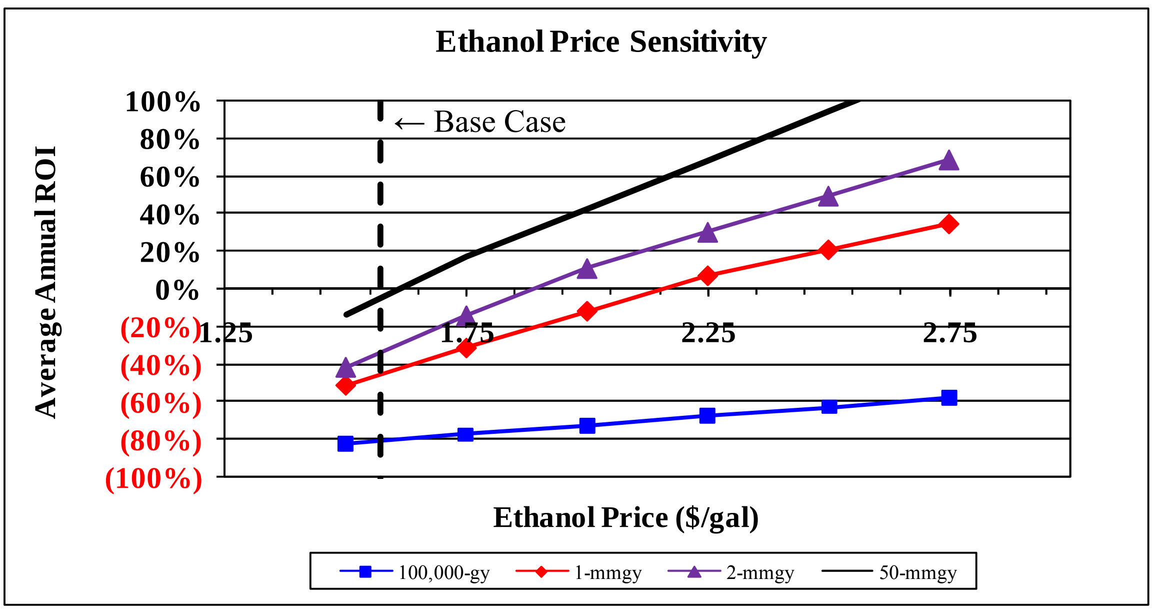


Figure 11 – Effect of DWG Price on 11-year Average Annual Income

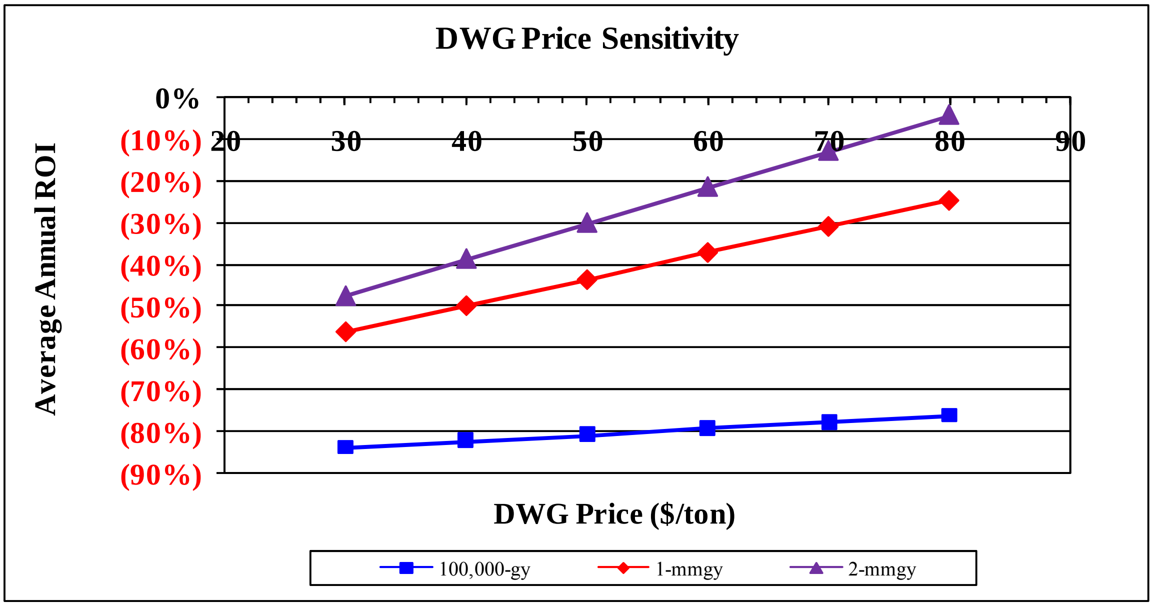


Figure 12 – Effect of Natural Gas Price on 11-year Average Annual Income

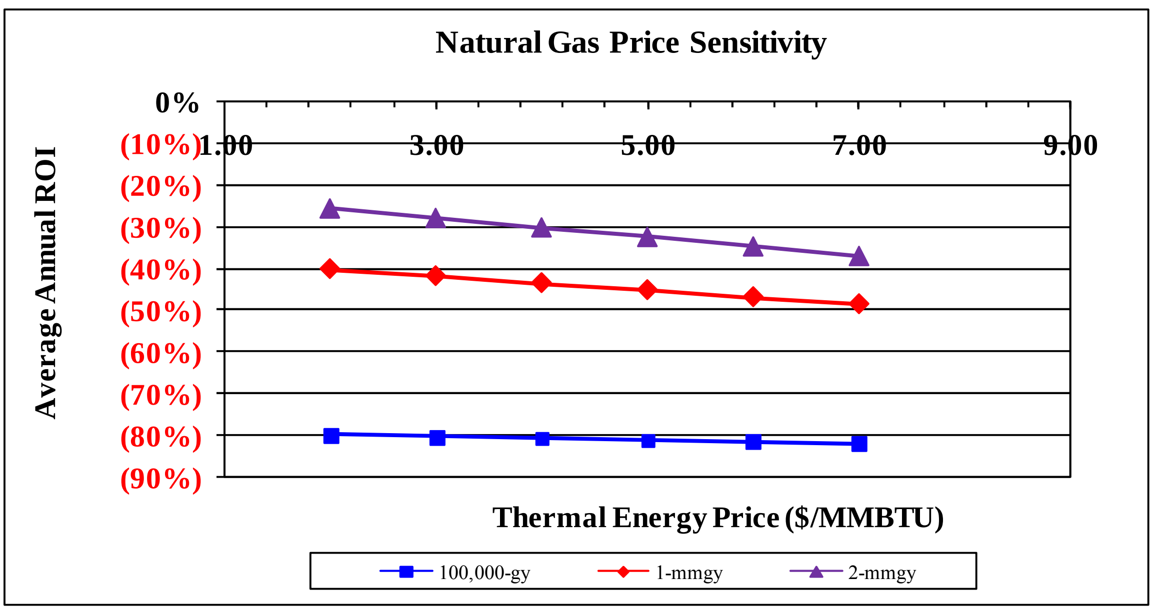


Figure 13 – Effect of Electricity Price on 11-year Average Annual Income

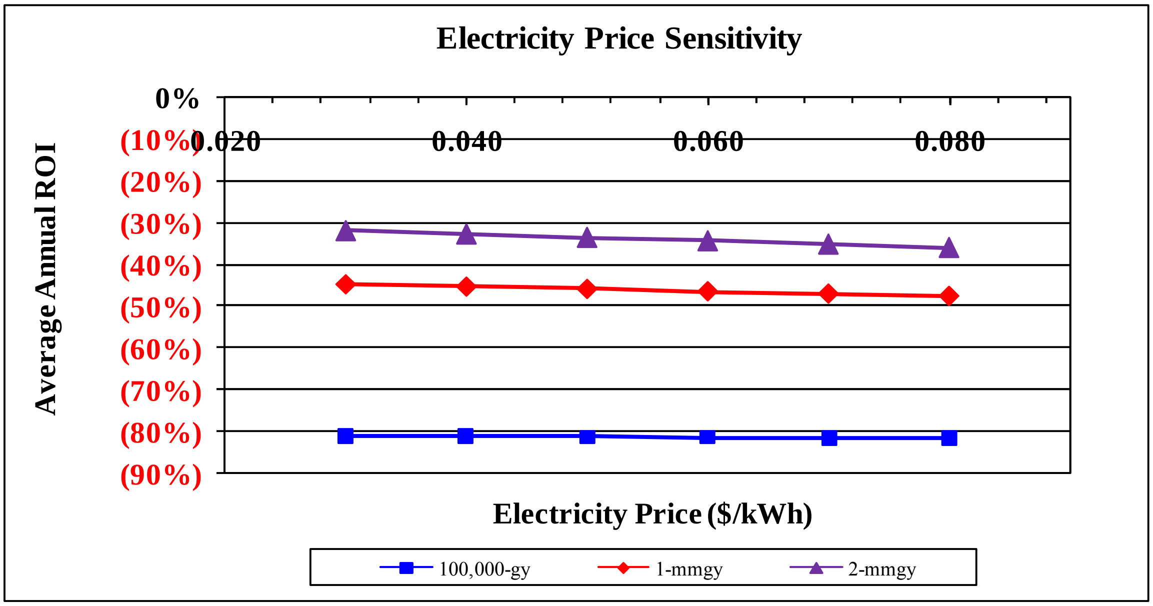
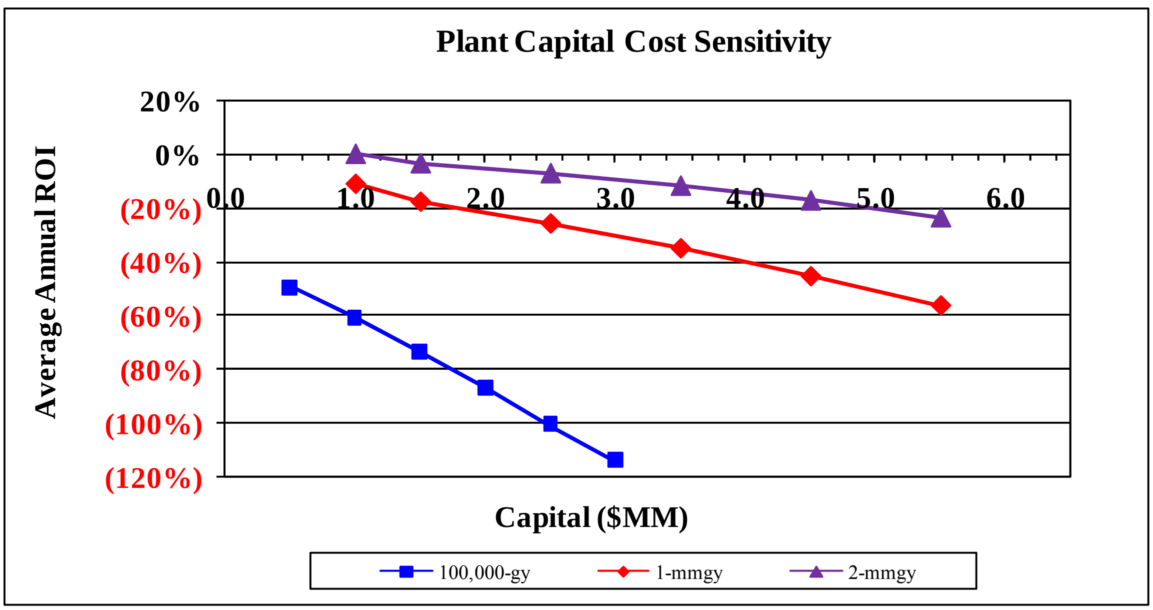


Figure 14 – Effect of Capital Costs on 11-year Average Annual Income



The following table shows the change in the projected average annual ROI for the project for changes in both ethanol and corn price.

Table 17 – Sensitivity and Breakeven Analysis for 100,000 Plant

Feedstock and Ethanol Price Sensitivity
11-Year Average Annual Return on Investment
AURI Ethanol Project - 100000
0.1 MMGPY Plant

Feedstock ($/bushel)	Ethanol ($/gallon) 0.57	1.07	1.57	2.07	2.57	3.07	3.57	4.07
0.37	-77.3%	-67.6%	-57.8%	-48.1%	-38.3%	-28.6%	-18.5%	-8.9%
0.87	-80.7%	-70.9%	-61.2%	-51.4%	-41.7%	-31.9%	-21.9%	-12.2%
1.37	-84.1%	-74.3%	-64.6%	-54.8%	-45.0%	-35.3%	-25.3%	-15.5%
1.87	-87.4%	-77.7%	-67.9%	-58.2%	-48.4%	-38.7%	-28.9%	-18.9%
2.37	-90.8%	-81.0%	-71.3%	-61.5%	-51.8%	-42.0%	-32.3%	-22.2%
2.87	-94.2%	-84.4%	-74.7%	-64.9%	-55.1%	-45.4%	-35.6%	-25.9%
3.37	-97.5%	-87.8%	-78.0%	-68.3%	-58.5%	-48.8%	-39.0%	-29.3%
3.87	-100.9%	-91.2%	-81.4%	-71.6%	-61.9%	-52.1%	-42.4%	-32.6%
4.37	-104.3%	-94.5%	-84.8%	-75.0%	-65.2%	-55.5%	-45.7%	-36.0%
4.87	-107.6%	-97.9%	-88.1%	-78.4%	-68.6%	-58.9%	-49.1%	-39.3%
5.37	-111.0%	-101.3%	-91.5%	-81.7%	-72.0%	-62.2%	-52.5%	-42.7%
5.87	-114.4%	-104.6%	-94.9%	-85.1%	-75.4%	-65.6%	-55.8%	-46.1%
6.37	-117.7%	-108.0%	-98.2%	-88.5%	-78.7%	-69.0%	-59.2%	-49.4%
6.87	-121.1%	-111.4%	-101.6%	-91.8%	-82.1%	-72.3%	-62.6%	-52.8%
7.37	-124.5%	-114.7%	-105.0%	-95.2%	-85.5%	-75.7%	-65.9%	-56.2%
7.87	-127.8%	-118.1%	-108.3%	-98.6%	-88.8%	-79.1%	-69.3%	-59.6%

Table 18 – Sensitivity and Breakeven Analysis for 1-mmgy Plant

Feedstock and Ethanol Price Sensitivity
11-Year Average Annual Return on Investment
AURI Ethanol Project - 1-mmgy
1 MMGPY Plant

Feedstock ($/bushel)	Ethanol ($/gallon) 0.57	1.07	1.57	2.07	2.57	3.07	3.57	4.07
0.37	-29.8%	7.3%	35.0%	62.6%	90.2%	117.9%	145.5%	173.1%
0.87	-43.6%	-4.2%	25.5%	53.2%	80.8%	108.4%	136.1%	163.7%
1.37	-57.1%	-17.6%	16.1%	43.7%	71.4%	99.0%	126.6%	154.3%
1.87	-70.7%	-31.2%	6.7%	34.3%	61.9%	89.6%	117.2%	144.9%
2.37	-84.2%	-45.0%	-5.5%	24.9%	52.5%	80.1%	107.8%	135.4%
2.87	-97.8%	-58.5%	-19.0%	15.4%	43.1%	70.7%	98.4%	126.0%
3.37	-111.3%	-72.1%	-32.6%	6.0%	33.6%	61.3%	88.9%	116.6%
3.87	-124.9%	-85.6%	-46.4%	-6.9%	24.2%	51.8%	79.5%	107.1%
4.37	-138.5%	-99.2%	-59.9%	-20.4%	14.8%	42.4%	70.1%	97.7%
4.87	-152.0%	-112.7%	-73.5%	-33.9%	5.1%	33.0%	60.6%	88.3%
5.37	-165.6%	-126.3%	-87.0%	-47.8%	-8.3%	23.6%	51.2%	78.8%
5.87	-179.1%	-139.8%	-100.6%	-61.3%	-21.8%	14.1%	41.8%	69.4%
6.37	-192.7%	-153.4%	-114.1%	-74.9%	-35.6%	3.9%	32.3%	60.0%
6.87	-206.2%	-167.0%	-127.7%	-88.4%	-49.2%	-9.6%	22.9%	50.5%
7.37	-219.8%	-180.5%	-141.2%	-102.0%	-62.7%	-23.2%	13.5%	41.1%
7.87	-233.3%	-194.1%	-154.8%	-115.5%	-76.3%	-37.0%	2.5%	31.7%

Table 19 – Sensitivity and Breakeven Analysis for 2-mmgy Plant

Feedstock and Ethanol Price Sensitivity
11-Year Average Annual Return on Investment
AURI Ethanol Project - 2-mmgy
2 MMGPY Plant

Feedstock ($/bushel) \ Ethanol ($/gallon)	0.57	1.07	1.57	2.07	2.57	3.07	3.57	4.07
0.37	-11.5%	30.9%	69.2%	107.6%	145.9%	184.2%	222.6%	260.9%
0.87	-30.2%	17.8%	56.1%	94.5%	132.8%	171.1%	209.5%	247.8%
1.37	-49.2%	4.7%	43.1%	81.4%	119.7%	158.1%	196.4%	234.7%
1.87	-68.0%	-13.3%	30.0%	68.3%	106.6%	145.0%	183.3%	221.7%
2.37	-86.8%	-32.1%	16.9%	55.2%	93.6%	131.9%	170.2%	208.6%
2.87	-105.6%	-51.1%	3.4%	42.1%	80.5%	118.8%	157.2%	195.5%
3.37	-124.4%	-69.9%	-15.2%	29.1%	67.4%	105.7%	144.1%	182.4%
3.87	-143.2%	-88.7%	-34.0%	16.0%	54.3%	92.6%	131.0%	169.3%
4.37	-162.0%	-107.5%	-53.1%	1.6%	41.2%	79.6%	117.9%	156.2%
4.87	-180.8%	-126.3%	-71.9%	-17.2%	28.1%	66.5%	104.8%	143.2%
5.37	-199.6%	-145.1%	-90.7%	-36.0%	15.1%	53.4%	91.7%	130.1%
5.87	-218.4%	-163.9%	-109.5%	-55.0%	-0.3%	40.3%	78.7%	117.0%
6.37	-237.2%	-182.7%	-128.3%	-73.8%	-19.1%	27.2%	65.6%	103.9%
6.87	-256.0%	-201.5%	-147.1%	-92.6%	-37.9%	14.1%	52.5%	90.8%
7.37	-274.8%	-220.3%	-165.9%	-111.4%	-56.9%	-2.2%	39.4%	77.7%
7.87	-293.6%	-239.1%	-184.7%	-130.2%	-75.7%	-21.0%	26.3%	64.7%

Financial Summary

Based on the assumptions used, small-scale ethanol production is not economically viable at or below two million gallons of production. This is due primarily to current and future ethanol and corn pricing. Each of the evaluated scenarios provided a negative return on investment. BBI recommends that projects development for proposed plants achieving a hurdle of at least +25% ROI. Even if corn prices were lower and ethanol prices were higher, it is still clear that these small-scale plants would be hard-pressed to weather any economic downturns. The current industry—mostly large-scale plants—is struggling with 33 plants idle as of March 2009. It is not advisable to build a small-scale ethanol plant at this time or in the near future.

X. SUMMARY OF FEASIBILITY ASSESSMENT

There are no technical issues or barriers to building a small-scale ethanol plant. There is, however, a significant economic barrier to building a small-scale plant. The process requires a certain amount of equipment to process corn into ethanol and economies of scale cannot be reached at small plants as they still need much of the same infrastructure as larger plants. There are very few examples of existing operating small-scale plants. Most of the small-scale plants are idle due to current economic conditions of high corn and low ethanol prices. At this time, it is not advisable to build a small-scale plant and it is certainly not a project a bank would consider financing. If conditions change and corn returns to historical levels and ethanol prices increase, then it may be possible for a small-scale plant of at least 1-mmgy to be financially viable. There does not appear to be a situation whereby a 100,000 gallon plant can be financially successful.

APPENDIX A: FINANCIAL FORECAST 100,000 GALLONS PLANT

AURI Ethanol Project - 100000
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	100,000
Anhydrous Ethanol Production (gal/year)	95,238
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Previous Year	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	97,714	105,000	110,250	110,250	110,250	110,250	110,250	110,250	110,250	110,250	
Ethanol Price ($/gal)	$1.5700	$1.6014	$1.6334	$1.6661	$1.6994	$1.7334	$1.7681	$1.8034	$1.8395	$1.8763	2.00%
Ethanol Sales Commission (% of Ethanol Price)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%
Ethanol Transportation ($/gal)	$0.0500	$0.0510	$0.0520	$0.0531	$0.0541	$0.0552	$0.0563	$0.0574	$0.0586	$0.0598	2.00%
Delivered Feedstock Price ($/bu)	$3.8700	$3.9087	$3.9478	$3.9873	$4.0271	$4.0674	$4.1081	$4.1492	$4.1907	$4.2326	1.00%
Feedstock Procurement Fees ($/bu)	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	0.00%
Feedstock Usage (bu/year)	35,670	37,453	39,326	39,326	39,326	39,326	39,326	39,326	39,326	39,326	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
Available DWG (ton/yr)	825	867	910	910	910	910	910	910	910	910	
% Available DWG Sold	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	825	867	910	910	910	910	910	910	910	910	
DWG Price, FOB ($/ton)	$45.529	$45.985	$46.445	$46.909	$47.378	$47.852	$48.330	$48.814	$49.302	$49.795	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	0.00%
CO_2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO_2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO_2 Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
CO_2 Price ($/ton)	$6.000	$6.060	$6.121	$6.182	$6.244	$6.306	$6.369	$6.433	$6.497	$6.562	1.00%

AURI Ethanol Project - 100000
Production Assumptions, continued

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Electricity Use (kWh/bu)	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	
Annual Electricity Use (million kWh/year)	0.071	0.075	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	
Electricity Price ($/kWh)	$0.0550	$0.0561	$0.0572	$0.0584	$0.0595	$0.0607	$0.0619	$0.0632	$0.0644	$0.0657	2.00%
Thermal Energy Use (BTU/gal)	21,190	21,190	21,190	21,190	21,190	21,190	21,190	21,190	21,190	21,190	
Annual Thermal Energy Use (MMBTU/year)	2,071	2,225	2,336	2,336	2,336	2,336	2,336	2,336	2,336	2,336	
Thermal Energy Price ($/MMBTU)	$5.6500	$5.7630	$5.8783	$5.9958	$6.1157	$6.2381	$6.3628	$6.4901	$6.6199	$6.7523	2.00%
Fresh Water Use (1000 gal/bu)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	
Annual Fresh Water Use (1000 gal/year)	678	712	747	747	747	747	747	747	747	747	711,610
Fresh Water Price ($/1000 gal)	$0.5000	$0.5050	$0.5101	$0.5152	$0.5203	$0.5255	$0.5308	$0.5361	$0.5414	$0.5468	1.00%
Effluent Water Disposal (1000 gal/bu)	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	
Annual Effluent Water Disposal (1000 gal/year)	136	142	149	149	149	149	149	149	149	149	142,322
Effluent Water Disposal Price ($/1000 gal)	$0.5000	$0.5050	$0.5101	$0.5152	$0.5203	$0.5255	$0.5308	$0.5361	$0.5414	$0.5468	1.00%
Denaturant Use (% of ethanol sold)	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	
Annual Denaturant Use (gal/year)	4,762	5,000	5,250	5,250	5,250	5,250	5,250	5,250	5,250	5,250	
Denaturant Price ($/gal)	$1.5700	$1.6014	$1.6334	$1.6661	$1.6994	$1.7334	$1.7681	$1.8034	$1.8395	$1.8763	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Number of Employees	4	4	4	4	4	4	4	4	4	4	
Average Salary Including Benefits	$53,094	$54,421	$55,782	$57,176	$58,606	$60,071	$61,572	$63,112	$64,690	$66,307	2.50%
Maintenance Materials & Services (% of Capital Equipm	2.500%	2.538%	2.576%	2.614%	2.653%	2.693%	2.734%	2.775%	2.816%	2.858%	1.50%
Property Tax & Insurance (% of Depreciated Property, Pl	2.000%	2.060%	2.122%	2.185%	2.251%	2.319%	2.388%	2.460%	2.534%	2.610%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

Financial Assumptions

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$1,799,000
Site Development	$261,000
Rail	$0
Barge Unloading	$0
Additional Grain Storage	$0
Contingency	$100,000
Total Engineering and Construction Cost	$2,160,000
Development and Start-up Costs	
Inventory - Feedstock	$4,000
Inventory - Chemicals, Yeast, Denaturant	$400
Inventory - Spare Parts	$1,000
Start-up Costs	$115,990
Land	$0
Fire Protection & Potable Water	$17,000
Administration Building & Office Equipment	$145,000
Insurance & Performance Bond	$25,000
Rolling Stock & Shop Equipment	$0
Organizational Costs & Permits	$89,000
Capitalized Interest & Financing Costs	$34,500
Working Capital/Risk Management	$32,000
Total Development Costs	$463,890
TOTAL USES	**$2,623,890**

SOURCE OF FUNDS:		
Senior Debt		
Principal	$1,836,723	70.00%
Interest Rate	8.00%	fixed
Lender and Misc. Fees	$18,367	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	
Subordinate Debt		
Principal	$0	0.00%
Interest Rate	9.00%	interest only
Lender Fees	$0	0.000%
Placement Fees	$0	1.500%
Amortization Period	10	years
Equity Investment		
Total Equity Amount	$787,167	30.00%
Placement Fees	$0	0.000%
Common Equity	$787,167	100.000%
Preferred Equity	$0	0.000%
Grants		
Amount	$0	0.00%
TOTAL SOURCES	**$2,623,890**	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	8.00%
State Producer Payment	
Producer payment, $/gal	$0.000
Estimated annual payment	$0
Incentive duration, years	5
Other Incentive Payments	
Small Producer Tax Credit	Yes
% of CCC Payment	0%

Plant Operating Rate

Month	% of Nameplate
13	100.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol & Biodiesel	14		8
Distillers Grain	14		8
Denaturants		10	15
Chemicals & Enzymes		15	20
Feedstock		10	10
Utilities		15	

AURI Ethanol Project - 100000
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	0	0	0	0	0	0	0	0	0	0
Accounts Receivable - Trade	0	7,373	8,106	8,665	8,821	8,981	9,143	9,308	9,477	9,649	9,824
Inventories											
Feedstock	0	3,975	4,215	4,469	4,514	4,559	4,604	4,650	4,696	4,742	4,789
Chemicals, Enzymes & Yeast	0	400	385	389	392	396	400	404	408	413	417
Denaturant	0	320	327	333	340	347	354	361	368	375	383
Finished Product Inventory	0	6,479	7,334	7,669	7,801	7,936	8,073	8,214	8,357	8,503	8,652
Spare Parts	0	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Total Inventories	0	12,174	13,260	13,861	14,048	14,238	14,431	14,628	14,829	15,033	15,241
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	19,547	21,366	22,525	22,869	23,218	23,574	23,937	24,306	24,682	25,065
Land	0	0	0	0	0	0	0	0	0	0	0
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	1,950,480	2,425,990	2,440,990	2,455,990	2,470,990	2,485,990	2,500,990	2,515,990	2,530,990	2,545,990	2,560,990
Less Accumulated Depreciation & Amortization	0	83,821	249,883	414,077	576,413	737,273	897,386	1,056,534	1,214,525	1,372,026	1,529,189
Net Property, Plant & Equipment	1,950,480	2,342,169	2,191,107	2,041,913	1,894,577	1,748,717	1,603,604	1,459,456	1,316,465	1,173,964	1,031,801
Capitalized Fees & Interest	60,119	134,543	121,089	107,634	94,180	80,726	67,271	53,817	40,363	26,909	13,454
Total Assets	2,010,599	2,496,259	2,333,562	2,172,072	2,011,626	1,852,661	1,694,450	1,537,210	1,381,133	1,225,554	1,070,320
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	5,005	5,495	5,837	5,905	5,975	6,045	6,116	6,188	6,260	6,334
Notes Payable	0	323,141	870,914	1,461,818	2,100,859	2,792,393	3,540,564	4,349,827	5,224,995	6,171,267	7,194,235
Current Maturities of Senior Debt (incl. sweeps)	0	130,395	141,143	152,778	165,372	179,004	193,759	209,731	227,020	245,734	130,362
Current Maturities of Sub Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	458,541	1,017,553	1,620,433	2,272,136	2,977,371	3,740,368	4,565,674	5,458,203	6,423,261	7,330,931
Senior Debt (excluding current maturities)	1,253,274	1,644,904	1,503,760	1,350,982	1,185,610	1,006,607	812,847	603,116	376,096	130,362	0
Subordincated Debt (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	1,253,274	2,103,444	2,521,313	2,971,415	3,457,747	3,983,978	4,553,215	5,168,790	5,834,299	6,553,623	7,330,931
Capital Units & Equities											
Common Equity	787,167	787,167	787,167	787,167	787,167	787,167	787,167	787,167	787,167	787,167	787,167
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants (capital improvements)	0	0	0	0	0	0	0	0	0	0	0
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(29,842)	(394,352)	(974,918)	(1,586,510)	(2,233,288)	(2,918,484)	(3,645,933)	(4,418,747)	(5,240,332)	(6,115,236)	(7,047,778)
Total Capital Shares & Equities	757,325	392,815	(187,751)	(799,343)	(1,446,121)	(2,131,317)	(2,858,766)	(3,631,580)	(4,453,165)	(5,328,069)	(6,260,611)
Total Liabilities & Equities	2,010,599	2,496,259	2,333,562	2,172,072	2,011,626	1,852,661	1,694,450	1,537,210	1,381,133	1,225,554	1,070,320

AURI Ethanol Project - 100000
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	148,526	162,792	174,350	177,837	181,394	185,022	188,722	192,497	196,347	200,274
DWG	0	36,018	39,858	42,270	42,692	43,119	43,551	43,986	44,426	44,870	45,319
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	0	0	0	0	0	0	0	0	0	0
Federal Small Producer Tax Credit	0	9,283	9,975	10,474	10,474	10,474	10,474	10,474	10,474	10,474	10,474
Total Revenue	0	193,827	212,625	227,094	231,003	234,987	239,046	243,182	247,396	251,691	256,066
Production & Operating Expenses											
Feedstocks	0	139,112	147,517	156,430	157,982	159,550	161,134	162,734	164,349	165,981	167,629
Chemicals, Enzymes & Yeast	0	6,667	7,070	7,498	7,573	7,648	7,725	7,802	7,880	7,959	8,039
Thermal Energy	0	11,402	12,822	13,733	14,007	14,288	14,573	14,865	15,162	15,465	15,775
Electricity	0	3,929	4,208	4,506	4,596	4,688	4,782	4,878	4,975	5,075	5,176
Denaturants	0	7,476	8,007	8,575	8,747	8,922	9,100	9,282	9,468	9,657	9,851
Makeup Water	0	339	359	381	385	389	393	397	401	405	409
Wastewater Disposal	0	68	72	76	77	78	79	79	80	81	82
Direct Labor & Benefits	0	114,479	140,809	144,330	147,938	151,636	155,427	159,313	163,296	167,378	171,563
Total Production Costs	0	283,471	320,864	335,529	341,306	347,199	353,213	359,349	365,611	372,001	378,522
Gross Profit	0	(89,644)	(108,239)	(108,435)	(110,302)	(112,212)	(114,167)	(116,167)	(118,215)	(120,310)	(122,455)
Administrative & Operating Expenses											
Maintenance Materials & Services	0	44,975	45,650	46,334	47,029	47,735	48,451	49,178	49,915	50,664	51,424
Repairs & Maintenance - Wages & Benefits	0	0	0	0	0	0	0	0	0	0	0
Consulting, Management and Bank Fees	0	10,000	10,200	10,404	10,612	10,824	11,041	11,262	11,487	11,717	11,951
Property Taxes & Insurance	7,802	39,010	48,249	46,491	44,625	42,647	40,545	38,296	35,899	33,353	30,635
Admin. Salaries, Wages & Benefits	0	0	0	0	0	0	0	0	0	0	0
Legal & Accounting/Community Affairs	12,000	12,000	12,240	12,485	12,734	12,989	13,249	13,514	13,784	14,060	14,341
Office/Lab Supplies & Expenses	5,040	7,200	7,344	7,491	7,641	7,794	7,949	8,108	8,271	8,436	8,605
Travel, Training & Miscellaneous	5,000	5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Total Administrative & Operating Expenses	29,842	118,185	128,782	128,407	127,948	127,401	126,755	125,988	125,099	124,088	122,931
EBITDA	(29,842)	(207,829)	(237,021)	(236,842)	(238,250)	(239,614)	(240,922)	(242,155)	(243,314)	(244,398)	(245,387)
Less:											
Interest - Operating Line of Credit	0	0	25,851	69,673	116,945	168,069	223,391	283,245	347,986	418,000	493,701
Interest - Senior Debt	0	72,861	138,177	127,428	115,793	103,199	89,567	74,812	58,840	41,551	22,837
Interest - Sub Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	83,821	179,516	177,649	175,789	174,315	173,567	172,602	171,446	170,955	170,617
Pre-Tax Income	(29,842)	(364,510)	(580,566)	(611,592)	(646,778)	(685,196)	(727,448)	(772,814)	(821,586)	(874,904)	(932,542)
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(29,842)	(364,510)	(580,566)	(611,592)	(646,778)	(685,196)	(727,448)	(772,814)	(821,586)	(874,904)	(932,542)
Pre-Tax Return on Investment	-3.8%	-46.3%	-73.8%	-77.7%	-82.2%	-87.0%	-92.4%	-98.2%	-104.4%	-111.1%	-118.5%
11-Year Average Annual Pre-Tax ROI	-81.4%										

AURI Ethanol Project - 100000
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(29,842)	(364,510)	(580,566)	(611,592)	(646,778)	(685,196)	(727,448)	(772,814)	(821,586)	(874,904)	(932,542)
Non cash charges to operations											
Depreciation & Amortization	0	83,821	179,516	177,649	175,789	174,315	173,567	172,602	171,446	170,955	170,617
	(29,842)	(280,690)	(401,049)	(433,943)	(470,988)	(510,882)	(553,881)	(600,212)	(650,140)	(703,949)	(761,925)
Changes in non-cash working capital balances											
Accounts Receivable	0	7,373	733	559	156	159	162	165	169	172	175
Inventories	0	12,174	1,086	600	187	190	194	197	201	204	208
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(5,005)	(489)	(342)	(68)	(69)	(70)	(71)	(72)	(73)	(74)
	0	14,542	1,330	817	275	280	286	291	297	303	309
Investing Activities											
Land Purchase	0	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	1,950,480	475,510	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Capitalized Fees & Interest	60,119	74,424	0	0	0	0	0	0	0	0	0
	2,010,599	549,934	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Financing Activities											
Senior Debt Advances	1,253,274	583,449	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(61,425)	(130,395)	(141,143)	(152,778)	(165,372)	(179,004)	(193,759)	(209,731)	(227,020)	(245,734)
Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	787,167	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	(323,141)	(547,774)	(590,903)	(639,041)	(691,534)	(748,171)	(809,263)	(875,168)	(946,272)	(1,022,968)
Cash (Indebtedness), Beginning of Year	0	0	(323,141)	(870,914)	(1,461,818)	(2,100,859)	(2,792,393)	(3,540,564)	(4,349,827)	(5,224,995)	(6,171,267)
Cash (Bank Indebtedness), End of Year	0	(323,141)	(870,914)	(1,461,818)	(2,100,859)	(2,792,393)	(3,540,564)	(4,349,827)	(5,224,995)	(6,171,267)	(7,194,235)
IRR	N/A										

AURI Ethanol Project - 100000

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		(207,829)	(237,021)	(236,842)	(238,250)	(239,614)	(240,922)	(242,155)	(243,314)	(244,398)	(245,387)
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(14,542)	(1,330)	(817)	(275)	(280)	(286)	(291)	(297)	(303)	(309)
Investing Activities (Capital Expenditures)		(549,934)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)
Senior Debt Advances		583,449	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		(188,855)	(253,351)	(252,659)	(253,525)	(254,894)	(256,208)	(257,447)	(258,611)	(259,701)	(260,696)
Senior Debt P&I Payment		134,286	268,571	268,571	268,571	268,571	268,571	268,571	268,571	268,571	268,571
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		(1.41)	(0.94)	(0.94)	(0.94)	(0.95)	(0.95)	(0.96)	(0.96)	(0.97)	(0.97)
10-year Average Debt Coverage Ratio	**(1.00)**										

Note: the '1st Year Operations' consists of 0 months of construction and startup, plus 12 months of commercial operation

Depreciation Schedules

	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	15 year SLN	50,000	100,001	100,001	100,001	100,001	100,001	100,001	100,001	100,001	100,001
Minor process equipment	15 year SLN	11,030	22,059	22,059	22,059	22,059	22,059	22,059	22,059	22,059	22,059
Process buildings	30 year DDB	13,158	25,439	23,743	22,160	20,683	19,304	18,017	16,816	15,695	14,648
Vehicles	5 year DDB	0	0	0	0	0	0	0	0	0	0
Office building	30 year DDB	3,333	6,444	6,015	5,614	5,240	4,890	4,564	4,260	3,976	3,711
Office equipment	5 year DDB	500	1,100	960	576	346	630	500	0	0	0
Start-up cost	20 year DDB	5,800	11,019	9,917	8,925	8,033	7,230	6,507	5,856	5,270	4,743
Annual capital expenditures	10 year SLN	0	0	1,500	3,000	4,500	6,000	7,500	9,000	10,500	12,000
Total Depreciation		83,821	166,062	164,195	162,335	160,861	160,113	159,148	157,992	157,501	157,162

Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)

Note 2: Only 50% of the "1st Year Operations" depreciation shown in the above table is claimed

APPENDIX B: FINANCIAL FORECAST 1-MMGY PLANT

AURI Ethanol Project - 1-mmgy
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	1,000,000
Anhydrous Ethanol Production (gal/year)	952,381
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Previous Year	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	977,143	1,050,000	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500	1,102,500	
Ethanol Price ($/gal)	$1.5700	$1.6014	$1.6334	$1.6661	$1.6994	$1.7334	$1.7681	$1.8034	$1.8395	$1.8763	2.00%
Ethanol Sales Commission (% of Ethanol Price)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%
Ethanol Transportation ($/gal)	$0.0500	$0.0510	$0.0520	$0.0531	$0.0541	$0.0552	$0.0563	$0.0574	$0.0586	$0.0598	2.00%
Delivered Feedstock Price ($/bu)	$3.8700	$3.9087	$3.9478	$3.9873	$4.0271	$4.0674	$4.1081	$4.1492	$4.1907	$4.2326	1.00%
Feedstock Procurement Fees ($/bu)	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	0.00%
Feedstock Usage (bu/year)	356,697	374,532	393,258	393,258	393,258	393,258	393,258	393,258	393,258	393,258	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
Available DWG (ton/yr)	8,255	8,668	9,101	9,101	9,101	9,101	9,101	9,101	9,101	9,101	
% Available DWG Sold	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	8,255	8,668	9,101	9,101	9,101	9,101	9,101	9,101	9,101	9,101	
DWG Price, FOB ($/ton)	$45.529	$45.985	$46.445	$46.909	$47.378	$47.852	$48.330	$48.814	$49.302	$49.795	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
CO2 Price ($/ton)	$6.000	$6.060	$6.121	$6.182	$6.244	$6.306	$6.369	$6.433	$6.497	$6.562	1.00%

AURI Ethanol Project - 1-mmgy
Production Assumptions, continued

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Electricity Use (kWh/bu)	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	
Annual Electricity Use (million kWh/year)	0.714	0.750	0.788	0.788	0.788	0.788	0.788	0.788	0.788	0.788	
Electricity Price ($/kWh)	$0.0550	$0.0561	$0.0572	$0.0584	$0.0595	$0.0607	$0.0619	$0.0632	$0.0644	$0.0657	2.00%
Thermal Energy Use (BTU/gal)	21,190	21,190	21,190	21,190	21,190	21,190	21,190	21,190	21,190	21,190	
Annual Thermal Energy Use (MMBTU/year)	20,706	22,250	23,362	23,362	23,362	23,362	23,362	23,362	23,362	23,362	
Thermal Energy Price ($/MMBTU)	$5.6500	$5.7630	$5.8783	$5.9958	$6.1157	$6.2381	$6.3628	$6.4901	$6.6199	$6.7523	2.00%
Fresh Water Use (1000 gal/bu)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	
Annual Fresh Water Use (1000 gal/year)	6,777	7,116	7,472	7,472	7,472	7,472	7,472	7,472	7,472	7,472	7,116,105
Fresh Water Price ($/1000 gal)	$0.5000	$0.5050	$0.5101	$0.5152	$0.5203	$0.5255	$0.5308	$0.5361	$0.5414	$0.5468	1.00%
Effluent Water Disposal (1000 gal/bu)	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	
Annual Effluent Water Disposal (1000 gal/year)	1,355	1,423	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,423,221
Effluent Water Disposal Price ($/1000 gal)	$0.5000	$0.5050	$0.5101	$0.5152	$0.5203	$0.5255	$0.5308	$0.5361	$0.5414	$0.5468	1.00%
Denaturant Use (% of ethanol sold)	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	
Annual Denaturant Use (gal/year)	47,619	50,000	52,500	52,500	52,500	52,500	52,500	52,500	52,500	52,500	
Denaturant Price ($/gal)	$1.5700	$1.6014	$1.6334	$1.6661	$1.6994	$1.7334	$1.7681	$1.8034	$1.8395	$1.8763	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Number of Employees	5	5	5	5	5	5	5	5	5	5	
Average Salary Including Benefits	$56,225	$57,631	$59,071	$60,548	$62,062	$63,613	$65,204	$66,834	$68,505	$70,217	2.50%
Maintenance Materials & Services (% of Capital Equipm	2.500%	2.538%	2.576%	2.614%	2.653%	2.693%	2.734%	2.775%	2.816%	2.858%	1.50%
Property Tax & Insurance (% of Depreciated Property, Pl	2.000%	2.060%	2.122%	2.185%	2.251%	2.319%	2.388%	2.460%	2.534%	2.610%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

Financial Assumptions

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$5,064,000
Site Development	$412,000
Rail	$0
Barge Unloading	$0
Additional Grain Storage	$0
Contingency	$200,000
Total Engineering and Construction Cost	$5,676,000
Development and Start-up Costs	
Inventory - Feedstock	$40,000
Inventory - Chemicals, Yeast, Denaturant	$4,000
Inventory - Spare Parts	$10,000
Start-up Costs	$200,640
Land	$0
Fire Protection & Potable Water	$30,000
Administration Building & Office Equipment	$147,000
Insurance & Performance Bond	$45,000
Rolling Stock & Shop Equipment	$0
Organizational Costs & Permits	$101,000
Capitalized Interest & Financing Costs	$66,500
Working Capital/Risk Management	$200,000
Total Development Costs	$844,140
TOTAL USES	**$6,520,140**

SOURCE OF FUNDS:		
Senior Debt		
Principal	$4,564,098	70.00%
Interest Rate	8.00%	fixed
Lender and Misc. Fees	$45,641	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	
Subordinate Debt		
Principal	$0	0.00%
Interest Rate	9.00%	interest only
Lender Fees	$0	0.000%
Placement Fees	$0	1.500%
Amortization Period	10	years
Equity Investment		
Total Equity Amount	$1,956,042	30.00%
Placement Fees	$0	0.000%
Common Equity	$1,956,042	100.000%
Preferred Equity	$0	0.000%
Grants		
Amount	$0	0.00%
TOTAL SOURCES	**$6,520,140**	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	8.00%
State Producer Payment	
Producer payment, $/gal	$0.000
Estimated annual payment	$0
Incentive duration, years	5
Other Incentive Payments	
Small Producer Tax Credit	Yes
% of CCC Payment	0%

Plant Operating Rate

Month	% of Nameplate
13	100.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol & Biodiesel	14		8
Distillers Grain	14		8
Denaturants		10	15
Chemicals & Enzymes		15	20
Feedstock		10	10
Utilities		15	

AURI Ethanol Project - 1-mmgy
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	0	0	0	0	0	0	0	0	0	0
Accounts Receivable - Trade	0	73,727	81,060	86,648	88,212	89,805	91,429	93,083	94,769	96,487	98,237
Inventories											
Feedstock	0	39,746	42,148	44,694	45,138	45,586	46,038	46,495	46,957	47,423	47,894
Chemicals, Enzymes & Yeast	0	4,000	3,848	3,886	3,925	3,964	4,004	4,044	4,084	4,125	4,166
Denaturant	0	3,204	3,268	3,334	3,400	3,468	3,538	3,608	3,680	3,754	3,829
Finished Product Inventory	0	41,243	44,374	47,002	47,580	48,166	48,761	49,364	49,976	50,597	51,226
Spare Parts	0	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Total Inventories	0	98,194	103,637	108,916	110,043	111,184	112,341	113,512	114,698	115,899	117,116
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	171,921	184,698	195,564	198,255	200,990	203,770	206,595	209,467	212,386	215,353
Land	0	0	0	0	0	0	0	0	0	0	0
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	4,916,520	6,043,640	6,093,640	6,143,640	6,193,640	6,243,640	6,293,640	6,343,640	6,393,640	6,443,640	6,493,640
Less Accumulated Depreciation & Amortization	0	201,069	599,909	996,944	1,392,334	1,786,760	2,181,369	2,575,976	2,970,425	3,365,752	3,762,264
Net Property, Plant & Equipment	4,916,520	5,842,571	5,493,731	5,146,696	4,801,306	4,456,880	4,112,271	3,767,664	3,423,215	3,077,888	2,731,376
Capitalized Fees & Interest	139,376	310,427	279,384	248,341	217,299	186,256	155,213	124,171	93,128	62,085	31,043
Total Assets	5,055,896	6,324,919	5,957,812	5,590,601	5,216,859	4,844,126	4,471,254	4,098,430	3,725,810	3,352,360	2,977,771
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	50,054	54,949	58,370	59,053	59,745	60,446	61,156	61,876	62,604	63,343
Notes Payable	0	492,689	1,375,791	2,298,611	3,274,995	4,314,059	5,420,140	6,597,872	7,852,236	9,188,590	10,612,664
Current Maturities of Senior Debt (incl. sweeps)	0	324,019	350,729	379,640	410,935	444,809	481,476	521,165	564,125	610,627	323,938
Current Maturities of Sub Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	866,762	1,781,469	2,736,621	3,744,983	4,818,613	5,962,062	7,180,193	8,478,237	9,861,822	10,999,945
Senior Debt (excluding current maturities)	3,158,600	4,087,443	3,736,715	3,357,074	2,946,140	2,501,331	2,019,855	1,498,691	934,565	323,938	0
Subordincated Debt (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	3,158,600	4,954,205	5,518,183	6,093,696	6,691,122	7,319,944	7,981,917	8,678,883	9,412,803	10,185,760	10,999,945
Capital Units & Equities											
Common Equity	1,956,042	1,956,042	1,956,042	1,956,042	1,956,042	1,956,042	1,956,042	1,956,042	1,956,042	1,956,042	1,956,042
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants (capital improvements)	0	0	0	0	0	0	0	0	0	0	0
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(58,746)	(585,328)	(1,516,413)	(2,459,137)	(3,430,305)	(4,431,860)	(5,466,704)	(6,536,495)	(7,643,035)	(8,789,442)	(9,978,215)
Total Capital Shares & Equities	1,897,296	1,370,714	439,629	(503,095)	(1,474,263)	(2,475,818)	(3,510,662)	(4,580,453)	(5,686,993)	(6,833,400)	(8,022,173)
Total Liabilities & Equities	5,055,896	6,324,919	5,957,812	5,590,601	5,216,859	4,844,126	4,471,254	4,098,430	3,725,810	3,352,360	2,977,771

AURI Ethanol Project - 1-mmgy
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	1,485,257	1,627,920	1,743,502	1,778,372	1,813,940	1,850,219	1,887,223	1,924,967	1,963,467	2,002,736
DWG	0	360,185	398,583	422,698	426,925	431,194	435,506	439,861	444,259	448,702	453,189
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	0	0	0	0	0	0	0	0	0	0
Federal Small Producer Tax Credit	0	92,829	99,750	104,738	104,738	104,738	104,738	104,738	104,738	104,738	104,738
Total Revenue	0	1,938,270	2,126,253	2,270,937	2,310,034	2,349,871	2,390,462	2,431,821	2,473,964	2,516,906	2,560,663
Production & Operating Expenses											
Feedstocks	0	1,391,118	1,475,169	1,564,298	1,579,823	1,595,504	1,611,341	1,627,336	1,643,491	1,659,808	1,676,288
Chemicals, Enzymes & Yeast	0	66,667	70,700	74,977	75,727	76,484	77,249	78,022	78,802	79,590	80,386
Thermal Energy	0	114,022	128,224	137,328	140,074	142,876	145,733	148,648	151,621	154,653	157,746
Electricity	0	39,286	42,075	45,062	45,964	46,883	47,820	48,777	49,752	50,747	51,762
Denaturants	0	74,762	80,070	85,755	87,470	89,219	91,004	92,824	94,680	96,574	98,506
Makeup Water	0	3,389	3,594	3,811	3,849	3,888	3,927	3,966	4,005	4,046	4,086
Wastewater Disposal	0	678	719	762	770	778	785	793	801	809	817
Direct Labor & Benefits	0	114,479	140,809	144,330	147,938	151,636	155,427	159,313	163,296	167,378	171,563
Total Production Costs	0	1,804,400	1,941,359	2,056,324	2,081,615	2,107,268	2,133,287	2,159,678	2,186,449	2,213,606	2,241,154
Gross Profit	0	133,870	184,894	214,614	228,419	242,604	257,175	272,143	287,515	303,300	319,508
Administrative & Operating Expenses											
Maintenance Materials & Services	0	126,600	128,499	130,426	132,383	134,369	136,384	138,430	140,506	142,614	144,753
Repairs & Maintenance - Wages & Benefits	0	0	0	0	0	0	0	0	0	0	0
Consulting, Management and Bank Fees	0	10,000	10,200	10,404	10,612	10,824	11,041	11,262	11,487	11,717	11,951
Property Taxes & Insurance	19,666	98,330	120,357	116,566	112,479	108,078	103,335	98,205	92,675	86,729	80,319
Admin. Salaries, Wages & Benefits	0	0	0	0	0	0	0	0	0	0	0
Legal & Accounting/Community Affairs	24,000	24,000	24,480	24,970	25,469	25,978	26,498	27,028	27,568	28,120	28,682
Office/Lab Supplies & Expenses	10,080	14,400	14,688	14,982	15,281	15,587	15,899	16,217	16,541	16,872	17,209
Travel, Training & Miscellaneous	5,000	5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Total Administrative & Operating Expenses	58,746	278,330	303,324	302,550	301,530	300,249	298,677	296,772	294,521	291,909	288,890
EBITDA	(58,746)	(144,461)	(118,430)	(87,936)	(73,111)	(57,645)	(41,502)	(24,629)	(7,006)	11,391	30,618
Less:											
Interest - Operating Line of Credit	0	0	39,415	110,063	183,889	262,000	345,125	433,611	527,830	628,179	735,087
Interest - Senior Debt	0	181,053	343,357	316,647	287,736	256,441	222,567	185,901	146,211	103,251	56,749
Interest - Sub Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	201,069	429,883	428,077	426,433	425,468	425,652	425,650	425,492	426,369	427,555
Pre-Tax Income	(58,746)	(526,582)	(931,085)	(942,723)	(971,169)	(1,001,554)	(1,034,845)	(1,069,791)	(1,106,540)	(1,146,408)	(1,188,773)
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(58,746)	(526,582)	(931,085)	(942,723)	(971,169)	(1,001,554)	(1,034,845)	(1,069,791)	(1,106,540)	(1,146,408)	(1,188,773)
Pre-Tax Return on Investment	-3.0%	-26.9%	-47.6%	-48.2%	-49.6%	-51.2%	-52.9%	-54.7%	-56.6%	-58.6%	-60.8%
11-Year Average Annual Pre-Tax ROI	-46.4%										

AURI Ethanol Project - 1-mmgy
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(58,746)	(526,582)	(931,085)	(942,723)	(971,169)	(1,001,554)	(1,034,845)	(1,069,791)	(1,106,540)	(1,146,408)	(1,188,773)
Non cash charges to operations											
Depreciation & Amortization	0	201,069	429,883	428,077	426,433	425,468	425,652	425,650	425,492	426,369	427,555
	(58,746)	(325,513)	(501,202)	(514,646)	(544,736)	(576,086)	(609,193)	(644,141)	(681,047)	(720,038)	(761,218)
Changes in non-cash working capital balances											
Accounts Receivable	0	73,727	7,333	5,588	1,564	1,593	1,624	1,654	1,686	1,718	1,750
Inventories	0	98,194	5,444	5,278	1,127	1,142	1,156	1,171	1,186	1,201	1,217
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(50,054)	(4,895)	(3,422)	(683)	(692)	(701)	(710)	(719)	(729)	(738)
	0	121,867	7,882	7,444	2,008	2,043	2,079	2,115	2,152	2,190	2,229
Investing Activities											
Land Purchase	0	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	4,916,520	1,127,120	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Capitalized Fees & Interest	139,376	171,051	0	0	0	0	0	0	0	0	0
	5,055,896	1,298,171	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Financing Activities											
Senior Debt Advances	3,158,600	1,405,498	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(152,635)	(324,019)	(350,729)	(379,640)	(410,935)	(444,809)	(481,476)	(521,165)	(564,125)	(610,627)
Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	1,956,042	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	(492,689)	(883,103)	(922,820)	(976,384)	(1,039,064)	(1,106,081)	(1,177,732)	(1,254,365)	(1,336,354)	(1,424,074)
Cash (Indebtedness), Beginning of Year	0	0	(492,689)	(1,375,791)	(2,298,611)	(3,274,995)	(4,314,059)	(5,420,140)	(6,597,872)	(7,852,236)	(9,188,590)
Cash (Bank Indebtedness), End of Year	0	(492,689)	(1,375,791)	(2,298,611)	(3,274,995)	(4,314,059)	(5,420,140)	(6,597,872)	(7,852,236)	(9,188,590)	(10,612,664)
IRR	N/A										

AURI Ethanol Project - 1-mmgy

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		(144,461)	(118,430)	(87,936)	(73,111)	(57,645)	(41,502)	(24,629)	(7,006)	11,391	30,618
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(121,867)	(7,882)	(7,444)	(2,008)	(2,043)	(2,079)	(2,115)	(2,152)	(2,190)	(2,229)
Investing Activities (Capital Expenditures)		(1,298,171)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)	(50,000)
Senior Debt Advances		1,405,498	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		(159,001)	(176,311)	(145,380)	(125,119)	(109,688)	(93,581)	(76,745)	(59,159)	(40,799)	(21,611)
Senior Debt P&I Payment		333,688	667,376	667,376	667,376	667,376	667,376	667,376	667,376	667,376	667,376
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		(0.48)	(0.26)	(0.22)	(0.19)	(0.16)	(0.14)	(0.11)	(0.09)	(0.06)	(0.03)
10-year Average Debt Coverage Ratio	**(0.17)**										

Note: the '1st Year Operations' consists of 0 months of construction and startup, plus 12 months of commercial operation

Depreciation Schedules

	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	15 year SLN	126,035	252,069	252,069	252,069	252,069	252,069	252,069	252,069	252,069	252,069
Minor process equipment	15 year SLN	27,802	55,604	55,604	55,604	55,604	55,604	55,604	55,604	55,604	55,604
Process buildings	30 year DDB	33,167	64,123	59,848	55,858	52,134	48,659	45,415	42,387	39,561	36,924
Vehicles	5 year DDB	0	0	0	0	0	0	0	0	0	0
Office building	30 year DDB	3,333	6,444	6,015	5,614	5,240	4,890	4,564	4,260	3,976	3,711
Office equipment	5 year DDB	700	1,540	1,344	806	484	881	700	0	0	0
Start-up cost	20 year DDB	10,032	19,061	17,155	15,439	13,895	12,506	11,255	10,130	9,117	8,205
Annual capital expenditures	10 year SLN	0	0	5,000	10,000	15,000	20,000	25,000	30,000	35,000	40,000
Total Depreciation		201,069	398,841	397,034	395,390	394,426	394,609	394,607	394,449	395,327	396,513

Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)

Note 2: Only 50% of the "1st Year Operations" depreciation shown in the above table is claimed

APPENDIX C: FINANCIAL FORECAST 2-MMGY PLANT

AURI Ethanol Project - 2-mmgy
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	2,000,000
Anhydrous Ethanol Production (gal/year)	1,904,762
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Previous Year	0%	5%	5%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	1,954,286	2,100,000	2,205,000	2,205,000	2,205,000	2,205,000	2,205,000	2,205,000	2,205,000	2,205,000	
Ethanol Price ($/gal)	$1.5700	$1.6014	$1.6334	$1.6661	$1.6994	$1.7334	$1.7681	$1.8034	$1.8395	$1.8763	2.00%
Ethanol Sales Commission (% of Ethanol Price)	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%
Ethanol Transportation ($/gal)	$0.0500	$0.0510	$0.0520	$0.0531	$0.0541	$0.0552	$0.0563	$0.0574	$0.0586	$0.0598	2.00%
Delivered Feedstock Price ($/bu)	$3.8700	$3.9087	$3.9478	$3.9873	$4.0271	$4.0674	$4.1081	$4.1492	$4.1907	$4.2326	1.00%
Feedstock Procurement Fees ($/bu)	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	0.00%
Feedstock Usage (bu/year)	713,394	749,064	786,517	786,517	786,517	786,517	786,517	786,517	786,517	786,517	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
Available DWG (ton/yr)	16,510	17,335	18,202	18,202	18,202	18,202	18,202	18,202	18,202	18,202	
% Available DWG Sold	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	16,510	17,335	18,202	18,202	18,202	18,202	18,202	18,202	18,202	18,202	
DWG Price, FOB ($/ton)	$45.529	$45.985	$46.445	$46.909	$47.378	$47.852	$48.330	$48.814	$49.302	$49.795	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
CO2 Price ($/ton)	$6.000	$6.060	$6.121	$6.182	$6.244	$6.306	$6.369	$6.433	$6.497	$6.562	1.00%

AURI Ethanol Project - 2-mmgy
Production Assumptions, continued

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Electricity Use (kWh/bu)	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	
Annual Electricity Use (million kWh/year)	1.429	1.500	1.575	1.575	1.575	1.575	1.575	1.575	1.575	1.575	
Electricity Price ($/kWh)	$0.0550	$0.0561	$0.0572	$0.0584	$0.0595	$0.0607	$0.0619	$0.0632	$0.0644	$0.0657	2.00%
Thermal Energy Use (BTU/gal)	21,190	21,190	21,190	21,190	21,190	21,190	21,190	21,190	21,190	21,190	
Annual Thermal Energy Use (MMBTU/year)	41,411	44,499	46,724	46,724	46,724	46,724	46,724	46,724	46,724	46,724	
Thermal Energy Price ($/MMBTU)	$5.6500	$5.7630	$5.8783	$5.9958	$6.1157	$6.2381	$6.3628	$6.4901	$6.6199	$6.7523	2.00%
Fresh Water Use (1000 gal/bu)	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	
Annual Fresh Water Use (1000 gal/year)	13,554	14,232	14,944	14,944	14,944	14,944	14,944	14,944	14,944	14,944	14,232,210
Fresh Water Price ($/1000 gal)	$0.5000	$0.5050	$0.5101	$0.5152	$0.5203	$0.5255	$0.5308	$0.5361	$0.5414	$0.5468	1.00%
Effluent Water Disposal (1000 gal/bu)	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	
Annual Effluent Water Disposal (1000 gal/year)	2,711	2,846	2,989	2,989	2,989	2,989	2,989	2,989	2,989	2,989	2,846,442
Effluent Water Disposal Price ($/1000 gal)	$0.5000	$0.5050	$0.5101	$0.5152	$0.5203	$0.5255	$0.5308	$0.5361	$0.5414	$0.5468	1.00%
Denaturant Use (% of ethanol sold)	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	
Annual Denaturant Use (gal/year)	95,238	100,000	105,000	105,000	105,000	105,000	105,000	105,000	105,000	105,000	
Denaturant Price ($/gal)	$1.5700	$1.6014	$1.6334	$1.6661	$1.6994	$1.7334	$1.7681	$1.8034	$1.8395	$1.8763	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Number of Employees	6	6	6	6	6	6	6	6	6	6	
Average Salary Including Benefits	$52,417	$53,727	$55,070	$56,447	$57,858	$59,305	$60,787	$62,307	$63,865	$65,461	2.50%
Maintenance Materials & Services (% of Capital Equipm	2.500%	2.538%	2.576%	2.614%	2.653%	2.693%	2.734%	2.775%	2.816%	2.858%	1.50%
Property Tax & Insurance (% of Depreciated Property, Pl	2.000%	2.060%	2.122%	2.185%	2.251%	2.319%	2.388%	2.460%	2.534%	2.610%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

Financial Assumptions

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$7,492,000
Site Development	$462,500
Rail	$0
Barge Unloading	$0
Additional Grain Storage	$0
Contingency	$300,000
Total Engineering and Construction Cost	$8,254,500
Development and Start-up Costs	
Inventory - Feedstock	$79,000
Inventory - Chemicals, Yeast, Denaturant	$8,000
Inventory - Spare Parts	$15,000
Start-up Costs	$239,920
Land	$0
Fire Protection & Potable Water	$35,000
Administration Building & Office Equipment	$147,000
Insurance & Performance Bond	$55,000
Rolling Stock & Shop Equipment	$0
Organizational Costs & Permits	$106,000
Capitalized Interest & Financing Costs	$78,500
Working Capital/Risk Management	$383,000
Total Development Costs	$1,146,420
TOTAL USES	**$9,400,920**

SOURCE OF FUNDS:		
Senior Debt		
Principal	$6,580,644	70.00%
Interest Rate	8.00%	fixed
Lender and Misc. Fees	$65,806	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	
Subordinate Debt		
Principal	$0	0.00%
Interest Rate	9.00%	interest only
Lender Fees	$0	0.000%
Placement Fees	$0	1.500%
Amortization Period	10	years
Equity Investment		
Total Equity Amount	$2,820,276	30.00%
Placement Fees	$0	0.000%
Common Equity	$2,820,276	100.000%
Preferred Equity	$0	0.000%
Grants		
Amount	$0	0.00%
TOTAL SOURCES	**$9,400,920**	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	8.00%
State Producer Payment	
Producer payment, $/gal	$0.000
Estimated annual payment	$0
Incentive duration, years	5
Other Incentive Payments	
Small Producer Tax Credit	Yes
% of CCC Payment	0%

Plant Operating Rate

Month	% of Nameplate
13	100.0%
14	100.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol & Biodiesel	14		8
Distillers Grain	14		8
Denaturants		10	15
Chemicals & Enzymes		15	20
Feedstock		10	10
Utilities		15	

AURI Ethanol Project - 2-mmgy
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	0	0	0	0	0	0	0	0	0	0
Accounts Receivable - Trade	0	147,455	162,120	173,296	176,424	179,611	182,858	186,167	189,538	192,974	196,474
Inventories											
Feedstock	0	79,492	84,295	89,388	90,276	91,172	92,077	92,991	93,914	94,846	95,788
Chemicals, Enzymes & Yeast	0	8,000	7,695	7,772	7,850	7,928	8,008	8,088	8,169	8,250	8,333
Denaturant	0	6,408	6,536	6,667	6,800	6,936	7,075	7,217	7,361	7,508	7,658
Finished Product Inventory	0	80,506	86,311	91,506	92,600	93,708	94,832	95,971	97,126	98,297	99,484
Spare Parts	0	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Total Inventories	0	189,407	199,838	210,334	212,526	214,745	216,992	219,266	221,570	223,902	226,263
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	336,861	361,958	383,630	388,949	394,355	399,850	405,433	411,108	416,875	422,737
Land	0	0	0	0	0	0	0	0	0	0	0
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	7,086,660	8,666,420	8,736,420	8,806,420	8,876,420	8,946,420	9,016,420	9,086,420	9,156,420	9,226,420	9,296,420
Less Accumulated Depreciation & Amortization	0	285,576	852,258	1,416,873	1,979,748	2,541,712	3,104,052	3,666,715	4,229,663	4,794,043	5,360,266
Net Property, Plant & Equipment	7,086,660	8,380,844	7,884,162	7,389,547	6,896,672	6,404,708	5,912,368	5,419,705	4,926,757	4,432,377	3,936,154
Capitalized Fees & Interest	196,473	393,130	353,817	314,504	275,191	235,878	196,565	157,252	117,939	78,626	39,313
Total Assets	7,283,133	9,110,836	8,599,938	8,087,681	7,560,813	7,034,942	6,508,782	5,982,390	5,455,804	4,927,879	4,398,205
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	100,108	109,897	116,741	118,107	119,491	120,892	122,312	123,751	125,209	126,685
Notes Payable	0	490,078	1,527,460	2,584,025	3,682,314	4,835,391	6,046,368	7,318,532	8,655,391	10,060,687	11,538,383
Current Maturities of Senior Debt (incl. sweeps)	0	467,180	505,691	547,376	592,497	641,338	694,205	751,430	813,372	880,420	467,063
Current Maturities of Sub Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	1,057,366	2,143,048	3,248,142	4,392,918	5,596,220	6,861,465	8,192,274	9,592,514	11,066,315	12,132,131
Senior Debt (excluding current maturities)	4,538,804	5,893,390	5,387,699	4,840,324	4,247,826	3,606,488	2,912,284	2,160,854	1,347,482	467,063	0
Subordincated Debt (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	4,538,804	6,950,756	7,530,747	8,088,466	8,640,745	9,202,708	9,773,749	10,353,128	10,939,996	11,533,378	12,132,131
Capital Units & Equities											
Common Equity	2,820,276	2,820,276	2,820,276	2,820,276	2,820,276	2,820,276	2,820,276	2,820,276	2,820,276	2,820,276	2,820,276
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants (capital improvements)	0	0	0	0	0	0	0	0	0	0	0
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(75,947)	(660,196)	(1,751,085)	(2,821,061)	(3,900,208)	(4,988,042)	(6,085,243)	(7,191,014)	(8,304,468)	(9,425,775)	(10,554,202)
Total Capital Shares & Equities	2,744,329	2,160,080	1,069,191	(785)	(1,079,932)	(2,167,766)	(3,264,967)	(4,370,738)	(5,484,192)	(6,605,499)	(7,733,926)
Total Liabilities & Equities	7,283,133	9,110,836	8,599,938	8,087,681	7,560,813	7,034,942	6,508,782	5,982,390	5,455,804	4,927,879	4,398,205

AURI Ethanol Project - 2-mmgy
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	2,970,514	3,255,840	3,487,005	3,556,745	3,627,880	3,700,437	3,774,446	3,849,935	3,926,934	4,005,472
DWG	0	720,369	797,167	845,395	853,849	862,388	871,012	879,722	888,519	897,404	906,378
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	0	0	0	0	0	0	0	0	0	0
Federal Small Producer Tax Credit	0	185,657	199,500	209,475	209,475	209,475	209,475	209,475	209,475	209,475	209,475
Total Revenue	0	3,876,540	4,252,507	4,541,875	4,620,069	4,699,742	4,780,924	4,863,643	4,947,929	5,033,813	5,121,325
Production & Operating Expenses											
Feedstocks	0	2,782,236	2,950,337	3,128,597	3,159,647	3,191,007	3,222,681	3,254,672	3,286,983	3,319,617	3,352,577
Chemicals, Enzymes & Yeast	0	133,333	141,400	149,955	151,454	152,969	154,498	156,043	157,604	159,180	160,772
Thermal Energy	0	228,045	256,448	274,656	280,149	285,752	291,467	297,296	303,242	309,307	315,493
Electricity	0	78,571	84,150	90,125	91,927	93,766	95,641	97,554	99,505	101,495	103,525
Denaturants	0	149,524	160,140	171,510	174,940	178,439	182,008	185,648	189,361	193,148	197,011
Makeup Water	0	6,777	7,187	7,622	7,698	7,775	7,853	7,932	8,011	8,091	8,172
Wastewater Disposal	0	1,355	1,437	1,524	1,540	1,555	1,571	1,586	1,602	1,618	1,634
Direct Labor & Benefits	0	142,292	175,019	179,394	183,879	188,476	193,188	198,018	202,968	208,042	213,243
Total Production Costs	0	3,522,134	3,776,118	4,003,382	4,051,234	4,099,738	4,148,907	4,198,749	4,249,275	4,300,498	4,352,427
Gross Profit	0	354,406	476,388	538,493	568,835	600,004	632,017	664,894	698,653	733,315	768,898
Administrative & Operating Expenses											
Maintenance Materials & Services	0	187,300	190,110	192,961	195,856	198,793	201,775	204,802	207,874	210,992	214,157
Repairs & Maintenance - Wages & Benefits	0	0	0	0	0	0	0	0	0	0	0
Consulting, Management and Bank Fees	0	10,000	10,200	10,404	10,612	10,824	11,041	11,262	11,487	11,717	11,951
Property Taxes & Insurance	28,347	141,733	172,645	167,286	161,495	155,245	148,496	141,194	133,311	124,821	115,665
Admin. Salaries, Wages & Benefits	0	0	0	0	0	0	0	0	0	0	0
Legal & Accounting/Community Affairs	30,000	30,000	30,600	31,212	31,836	32,473	33,122	33,785	34,461	35,150	35,853
Office/Lab Supplies & Expenses	12,600	18,000	18,360	18,727	19,102	19,484	19,873	20,271	20,676	21,090	21,512
Travel, Training & Miscellaneous	5,000	5,000	5,100	5,202	5,306	5,412	5,520	5,631	5,743	5,858	5,975
Total Administrative & Operating Expenses	75,947	392,033	427,015	425,793	424,207	422,232	419,829	416,944	413,552	409,628	405,113
EBITDA	(75,947)	(37,627)	49,373	112,700	144,628	177,772	212,189	247,950	285,101	323,687	363,786
Less:											
Interest - Operating Line of Credit	0	0	39,206	122,197	206,722	294,585	386,831	483,709	585,483	692,431	804,855
Interest - Senior Debt	0	261,047	495,061	456,551	414,866	369,744	320,903	268,037	210,812	148,870	81,822
Interest - Sub Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	285,576	605,995	603,928	602,188	601,277	601,654	601,975	602,261	603,693	605,536
Pre-Tax Income	(75,947)	(584,249)	(1,090,889)	(1,069,976)	(1,079,147)	(1,087,834)	(1,097,200)	(1,105,771)	(1,113,454)	(1,121,307)	(1,128,427)
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(75,947)	(584,249)	(1,090,889)	(1,069,976)	(1,079,147)	(1,087,834)	(1,097,200)	(1,105,771)	(1,113,454)	(1,121,307)	(1,128,427)
Pre-Tax Return on Investment	-2.7%	-20.7%	-38.7%	-37.9%	-38.3%	-38.6%	-38.9%	-39.2%	-39.5%	-39.8%	-40.0%
11-Year Average Annual Pre-Tax ROI	-34.0%										

AURI Ethanol Project - 2-mmgy
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(75,947)	(584,249)	(1,090,889)	(1,069,976)	(1,079,147)	(1,087,834)	(1,097,200)	(1,105,771)	(1,113,454)	(1,121,307)	(1,128,427)
Non cash charges to operations											
Depreciation & Amortization	0	285,576	605,995	603,928	602,188	601,277	601,654	601,975	602,261	603,693	605,536
	(75,947)	(298,674)	(484,894)	(466,047)	(476,959)	(486,558)	(495,546)	(503,796)	(511,193)	(517,614)	(522,891)
Changes in non-cash working capital balances											
Accounts Receivable	0	147,455	14,666	11,176	3,128	3,187	3,247	3,309	3,371	3,435	3,501
Inventories	0	189,407	10,432	10,495	2,192	2,219	2,247	2,275	2,303	2,332	2,361
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(100,108)	(9,790)	(6,843)	(1,366)	(1,384)	(1,402)	(1,420)	(1,439)	(1,457)	(1,477)
	0	236,753	15,308	14,828	3,954	4,022	4,092	4,164	4,236	4,310	4,385
Investing Activities											
Land Purchase	0	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	7,086,660	1,579,760	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Capitalized Fees & Interest	196,473	196,657	0	0	0	0	0	0	0	0	0
	7,283,133	1,776,417	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Financing Activities											
Senior Debt Advances	4,538,804	2,041,840	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(220,074)	(467,180)	(505,691)	(547,376)	(592,497)	(641,338)	(694,205)	(751,430)	(813,372)	(880,420)
Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	2,820,276	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	(490,078)	(1,037,382)	(1,056,566)	(1,098,289)	(1,153,077)	(1,210,977)	(1,272,164)	(1,336,859)	(1,405,296)	(1,477,696)
Cash (Indebtedness), Beginning of Year	0	0	(490,078)	(1,527,460)	(2,584,025)	(3,682,314)	(4,835,391)	(6,046,368)	(7,318,532)	(8,655,391)	(10,060,687)
Cash (Bank Indebtedness), End of Year	0	(490,078)	(1,527,460)	(2,584,025)	(3,682,314)	(4,835,391)	(6,046,368)	(7,318,532)	(8,655,391)	(10,060,687)	(11,538,383)
IRR	N/A										

AURI Ethanol Project - 2-mmgy

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		(37,627)	49,373	112,700	144,628	177,772	212,189	247,950	285,101	323,687	363,786
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(236,753)	(15,308)	(14,828)	(3,954)	(4,022)	(4,092)	(4,164)	(4,236)	(4,310)	(4,385)
Investing Activities (Capital Expenditures)		(1,776,417)	(70,000)	(70,000)	(70,000)	(70,000)	(70,000)	(70,000)	(70,000)	(70,000)	(70,000)
Senior Debt Advances		2,041,840	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		(8,957)	(35,934)	27,873	70,675	103,750	138,096	173,787	210,865	249,377	289,400
Senior Debt P&I Payment		481,121	962,241	962,241	962,241	962,241	962,241	962,241	962,241	962,241	962,241
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		(0.02)	(0.04)	0.03	0.07	0.11	0.14	0.18	0.22	0.26	0.30
10-year Average Debt Coverage Ratio	**0.13**										

Note: the '1st Year Operations' consists of 0 months of construction and startup, plus 12 months of commercial operation

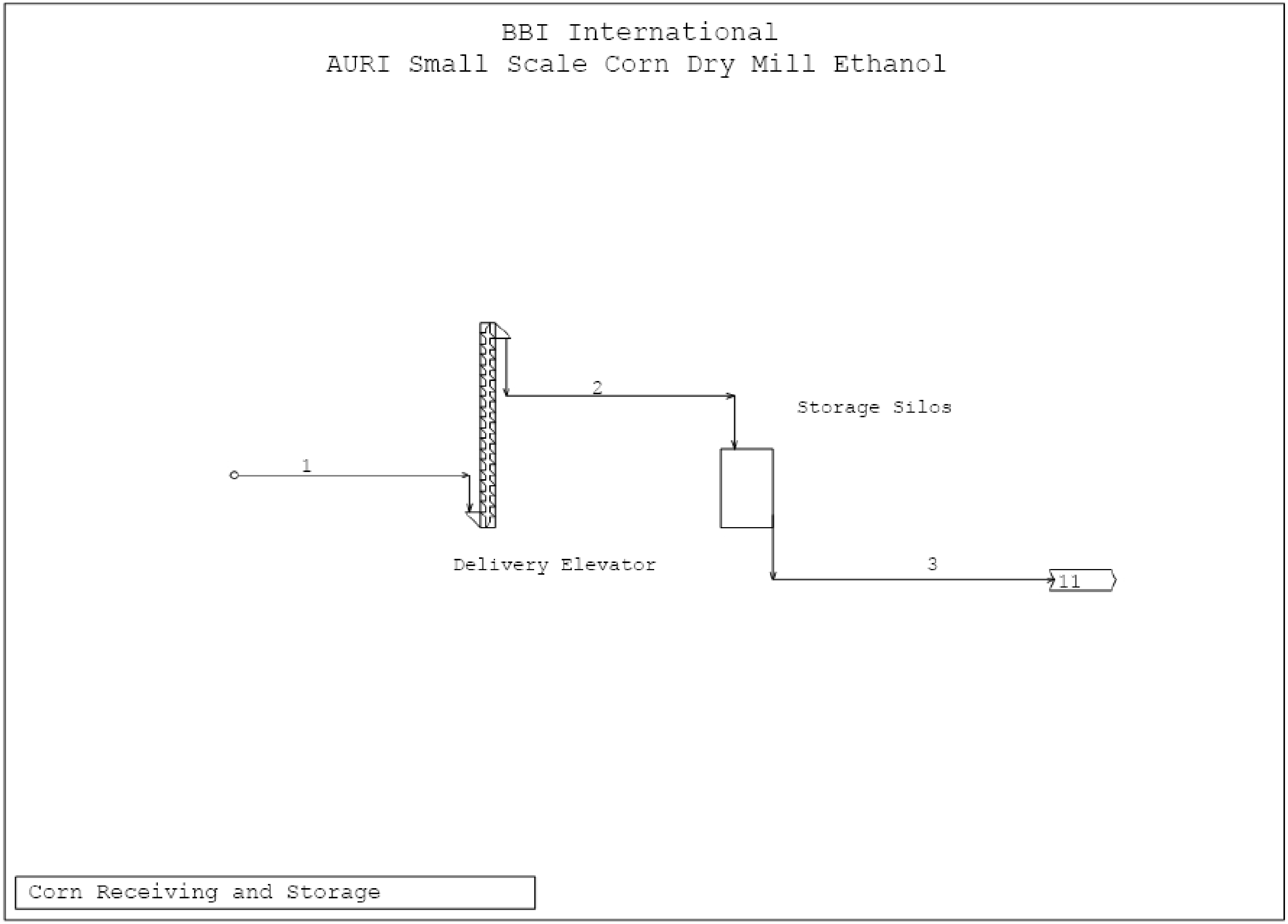
Depreciation Schedules

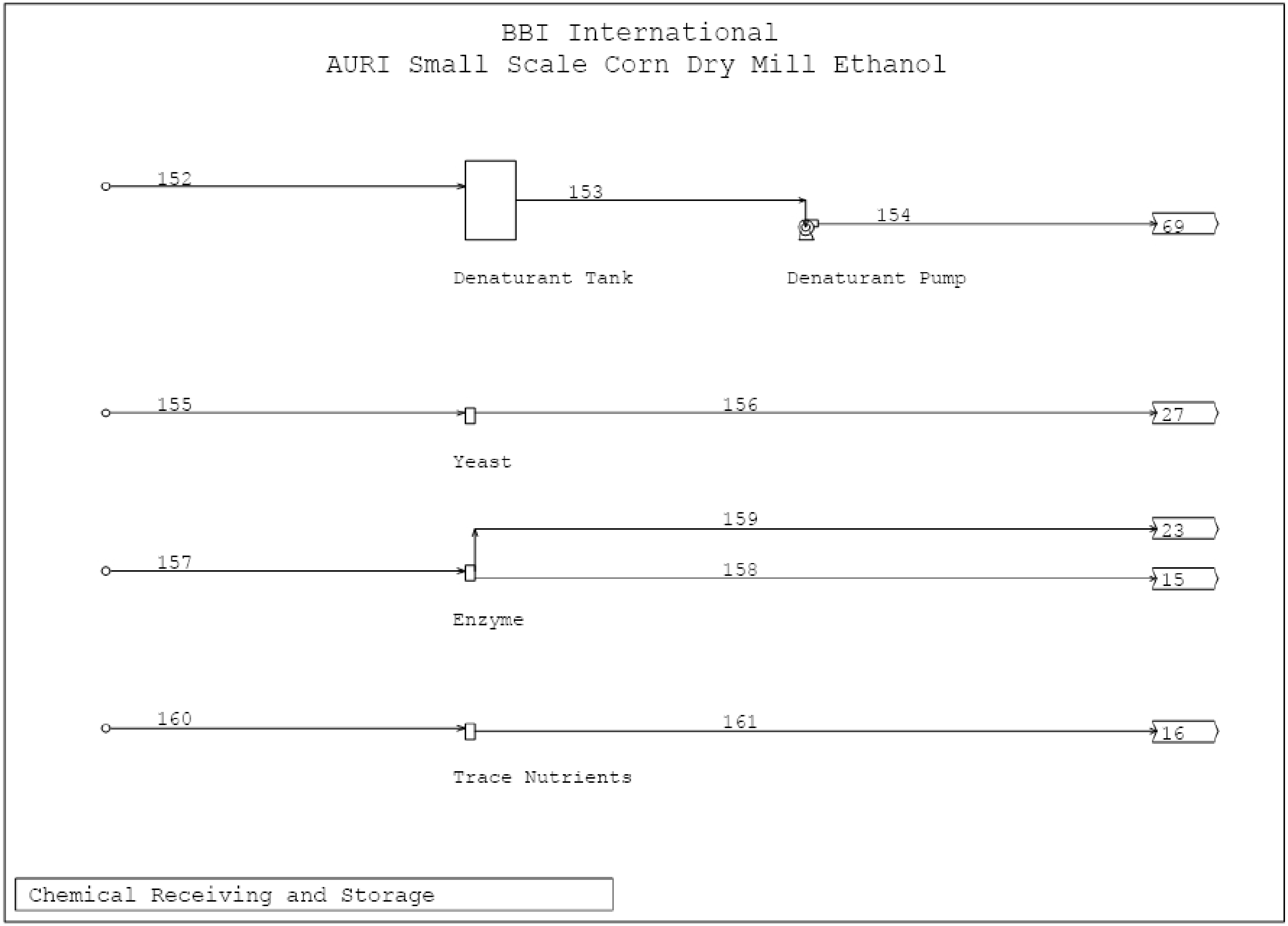
	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	15 year SLN	181,666	363,332	363,332	363,332	363,332	363,332	363,332	363,332	363,332	363,332
Minor process equipment	15 year SLN	40,073	80,147	80,147	80,147	80,147	80,147	80,147	80,147	80,147	80,147
Process buildings	30 year DDB	47,807	92,427	86,265	80,514	75,146	70,136	65,461	61,097	57,024	53,222
Vehicles	5 year DDB	0	0	0	0	0	0	0	0	0	0
Office building	30 year DDB	3,333	6,444	6,015	5,614	5,240	4,890	4,564	4,260	3,976	3,711
Office equipment	5 year DDB	700	1,540	1,344	806	484	881	700	0	0	0
Start-up cost	20 year DDB	11,996	22,792	20,513	18,462	16,616	14,954	13,459	12,113	10,902	9,811
Annual capital expenditures	10 year SLN	0	0	7,000	14,000	21,000	28,000	35,000	42,000	49,000	56,000
Total Depreciation		285,576	566,682	564,615	562,875	561,964	562,341	562,662	562,948	564,380	566,223

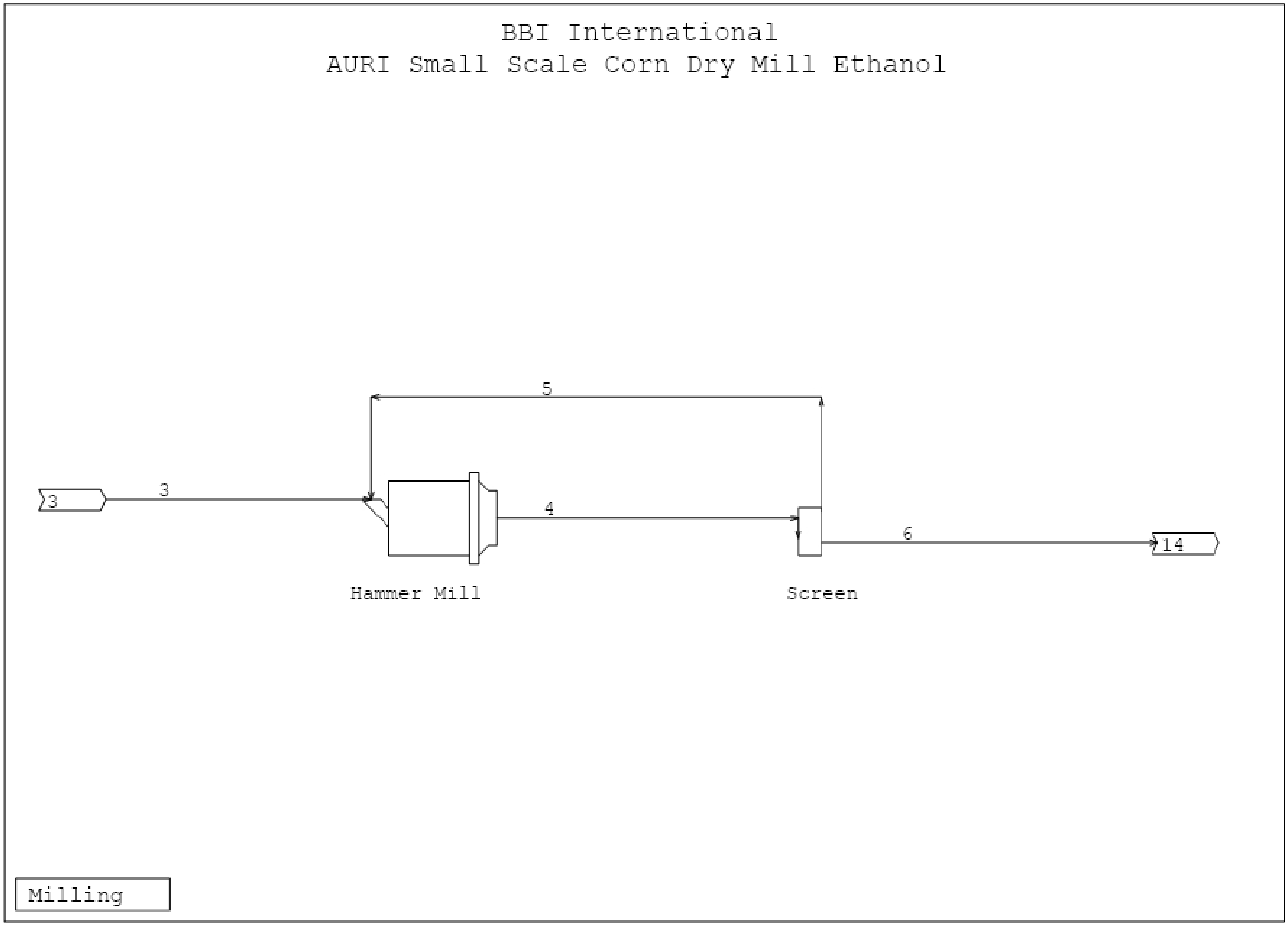
Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)

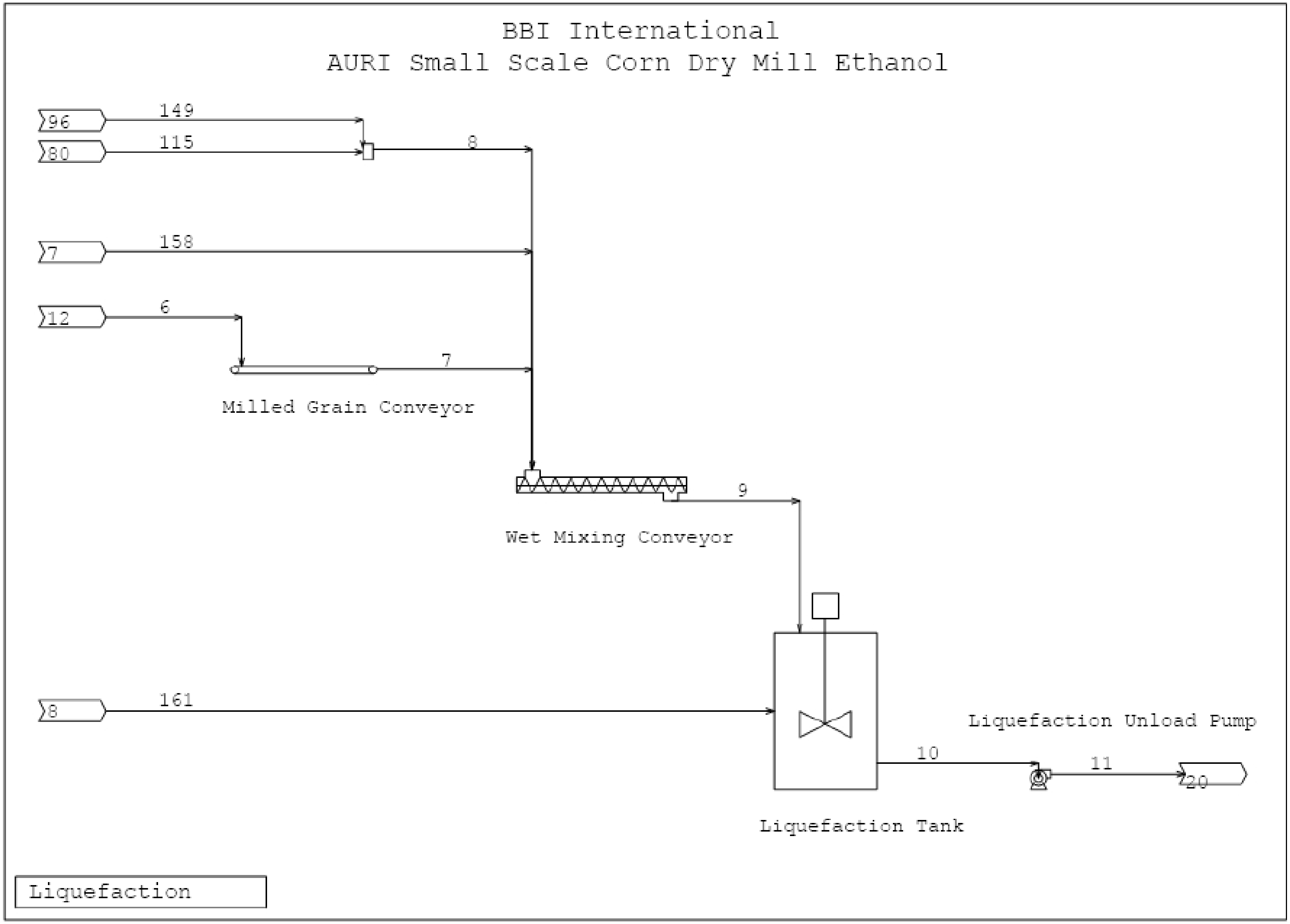
Note 2: Only 50% of the "1st Year Operations" depreciation shown in the above table is claimed

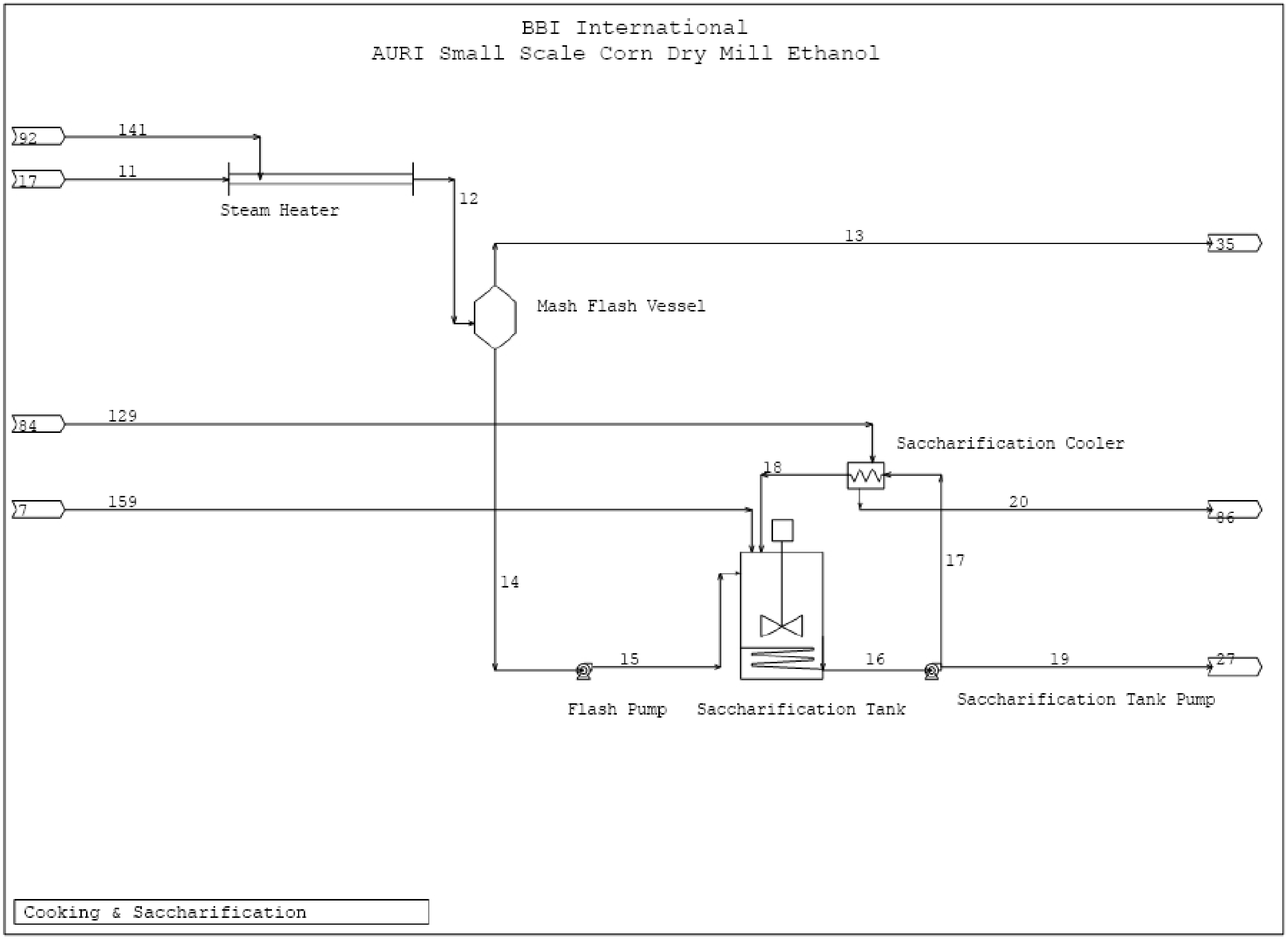
APPENDIX D: DESIGN PFD

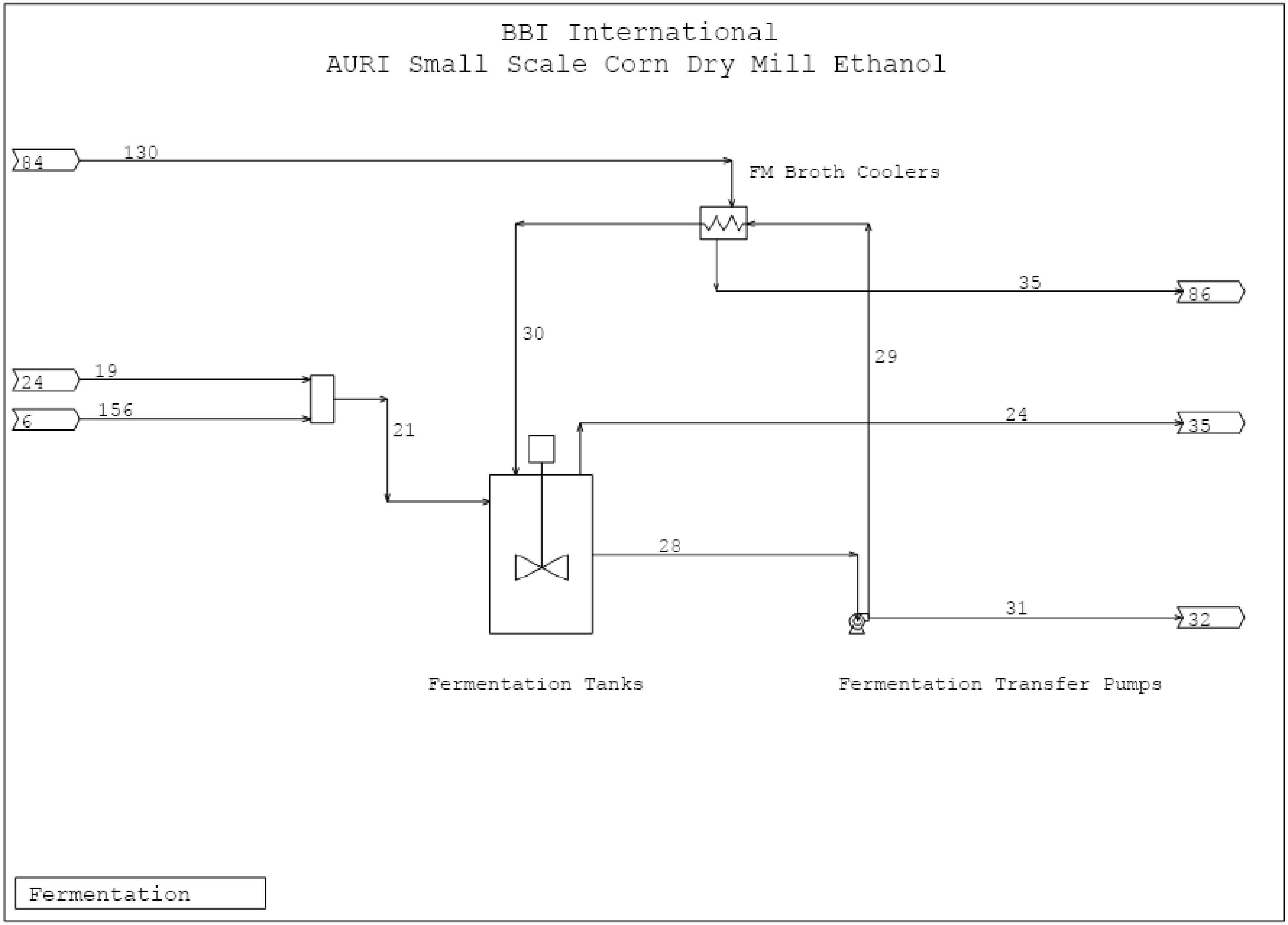

BBI International
AURI Small Scale Corn Dry Mill Ethanol
1
2
3
11
Storage Silos
Delivery Elevator
Corn Receiving and Storage

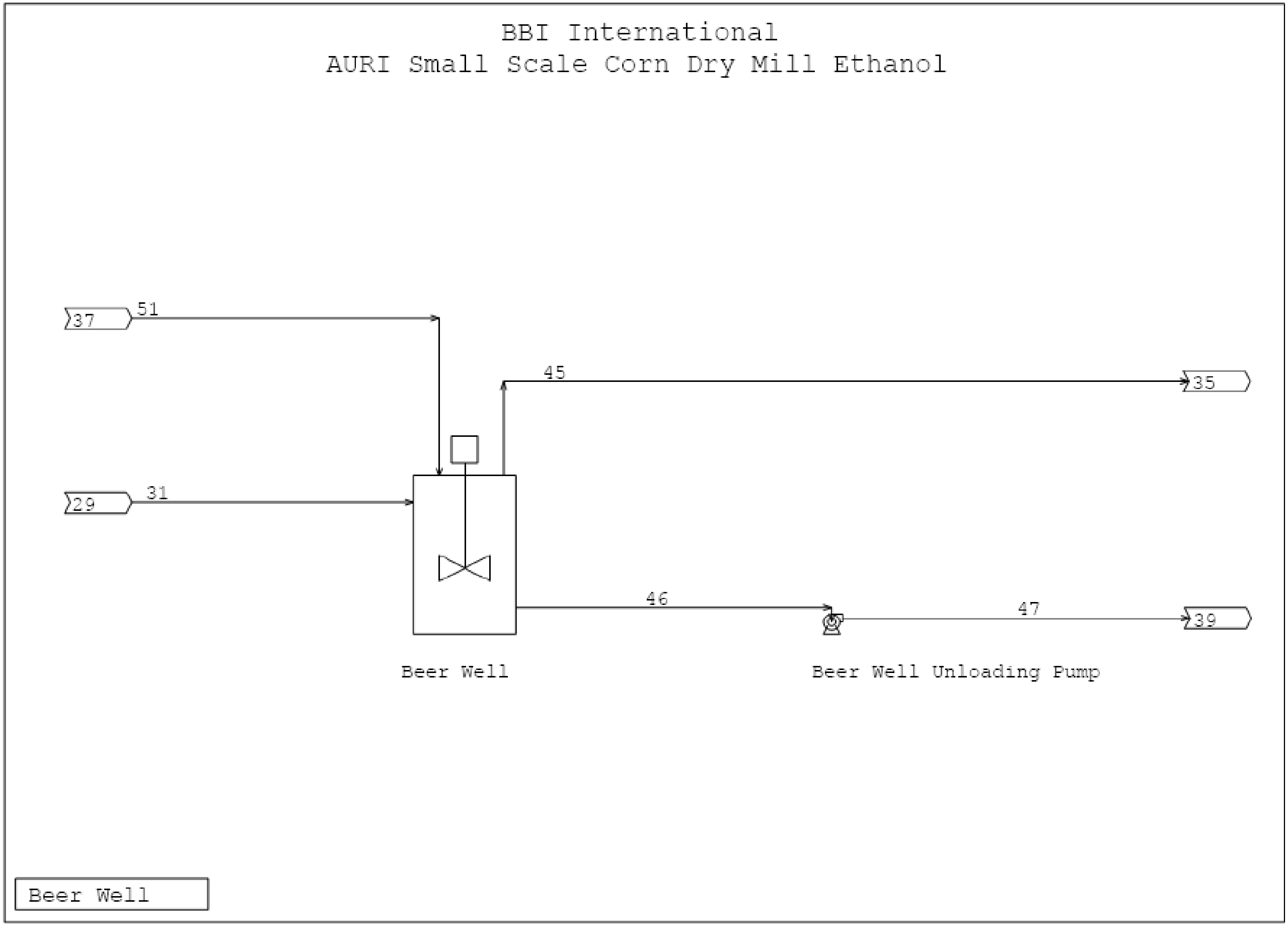

BBI International
AURI Small Scale Corn Dry Mill Ethanol
152
153
154
69
Denaturant Tank
Denaturant Pump
155
156
27
Yeast
159
23
157
158
15
Enzyme
160
161
16
Trace Nutrients
Chemical Receiving and Storage

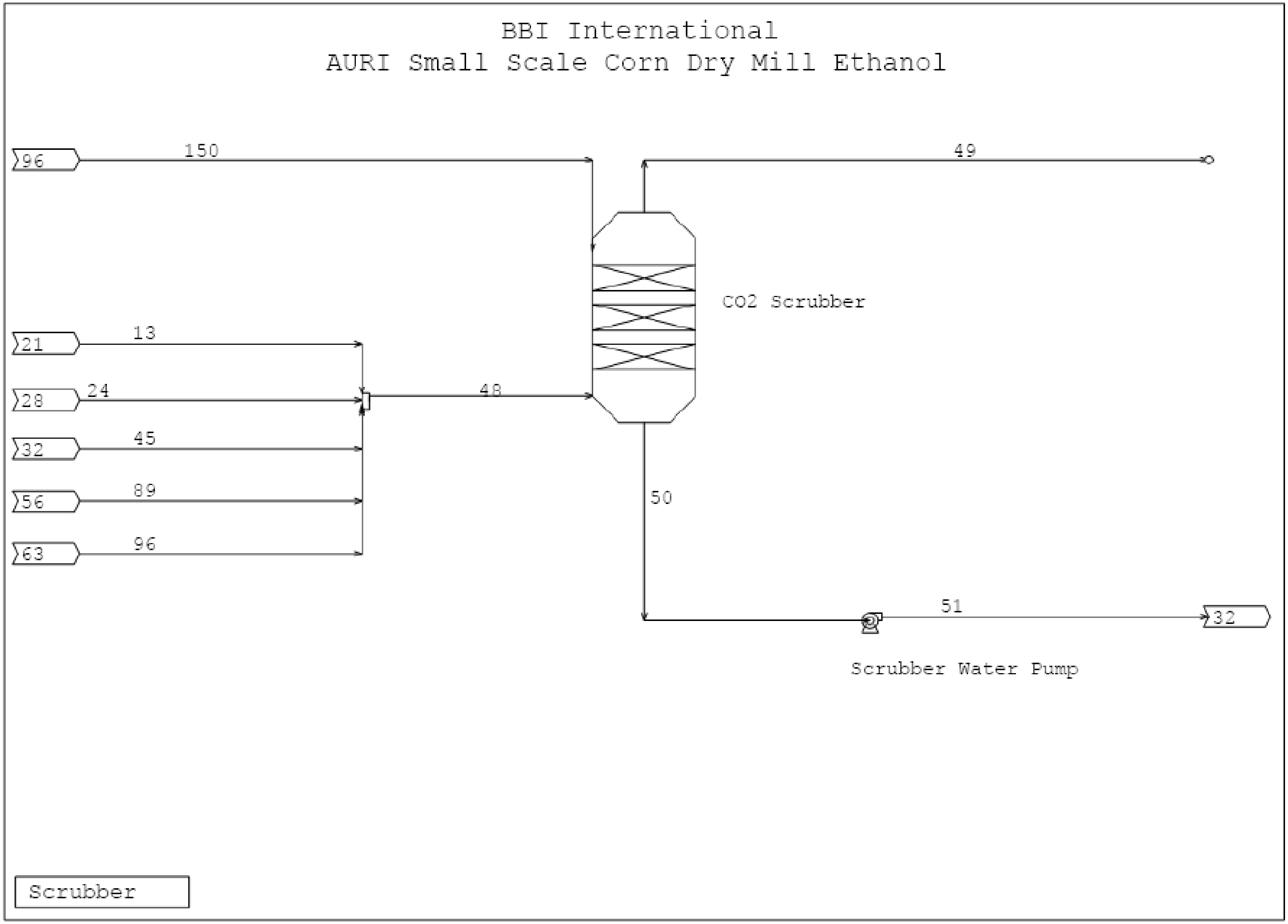

BBI International
AURI Small Scale Corn Dry Mill Ethanol
3
3
5
4
6
14
Hammer Mill
Screen
Milling

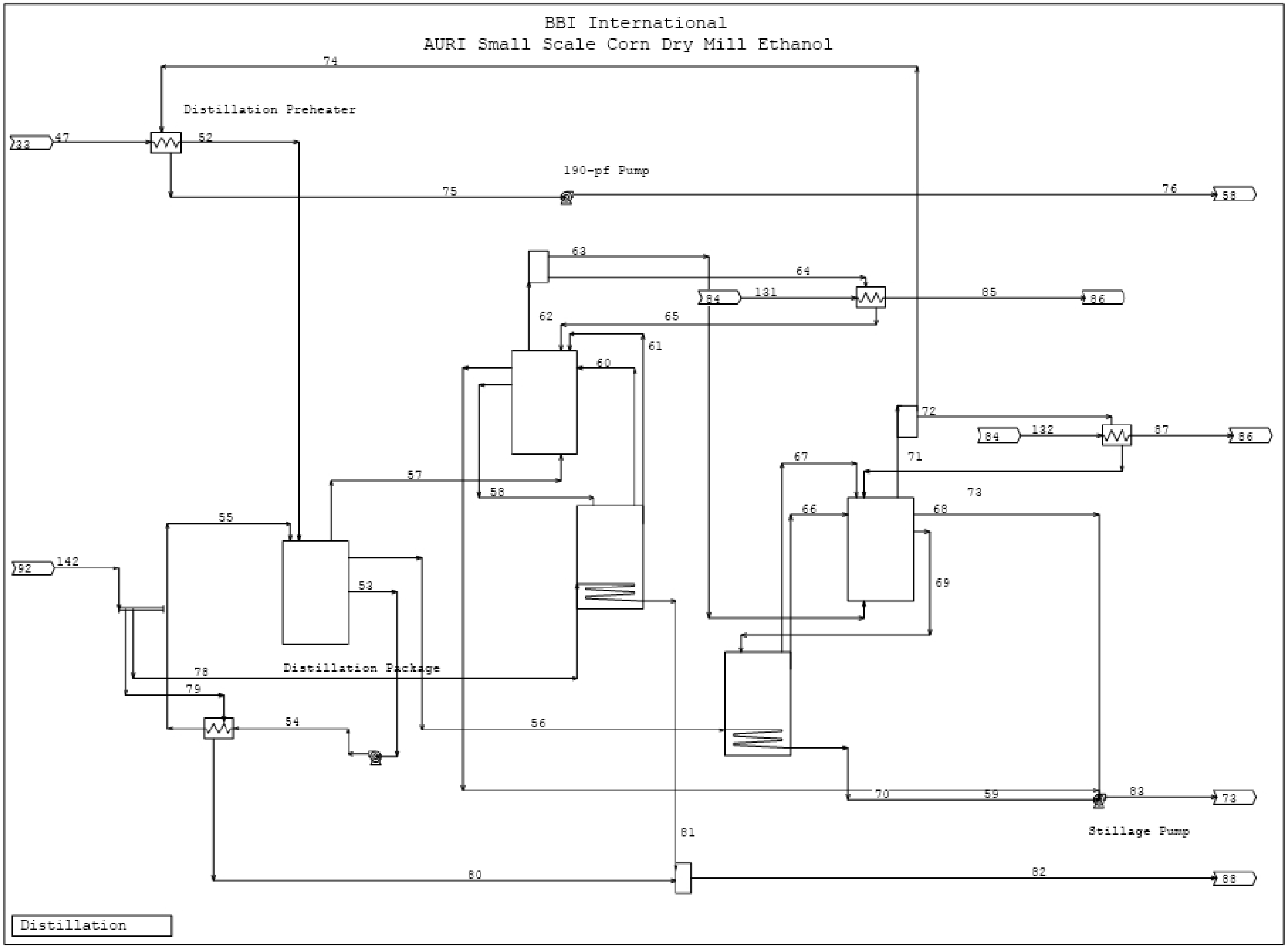

BBI International
AURI Small Scale Corn Dry Mill Ethanol
96
149
80
115
8
7
158
12
6
7
Milled Grain Conveyor
9
Wet Mixing Conveyor
8
161
Liquefaction Unload Pump
10
11
20
Liquefaction Tank
Liquefaction

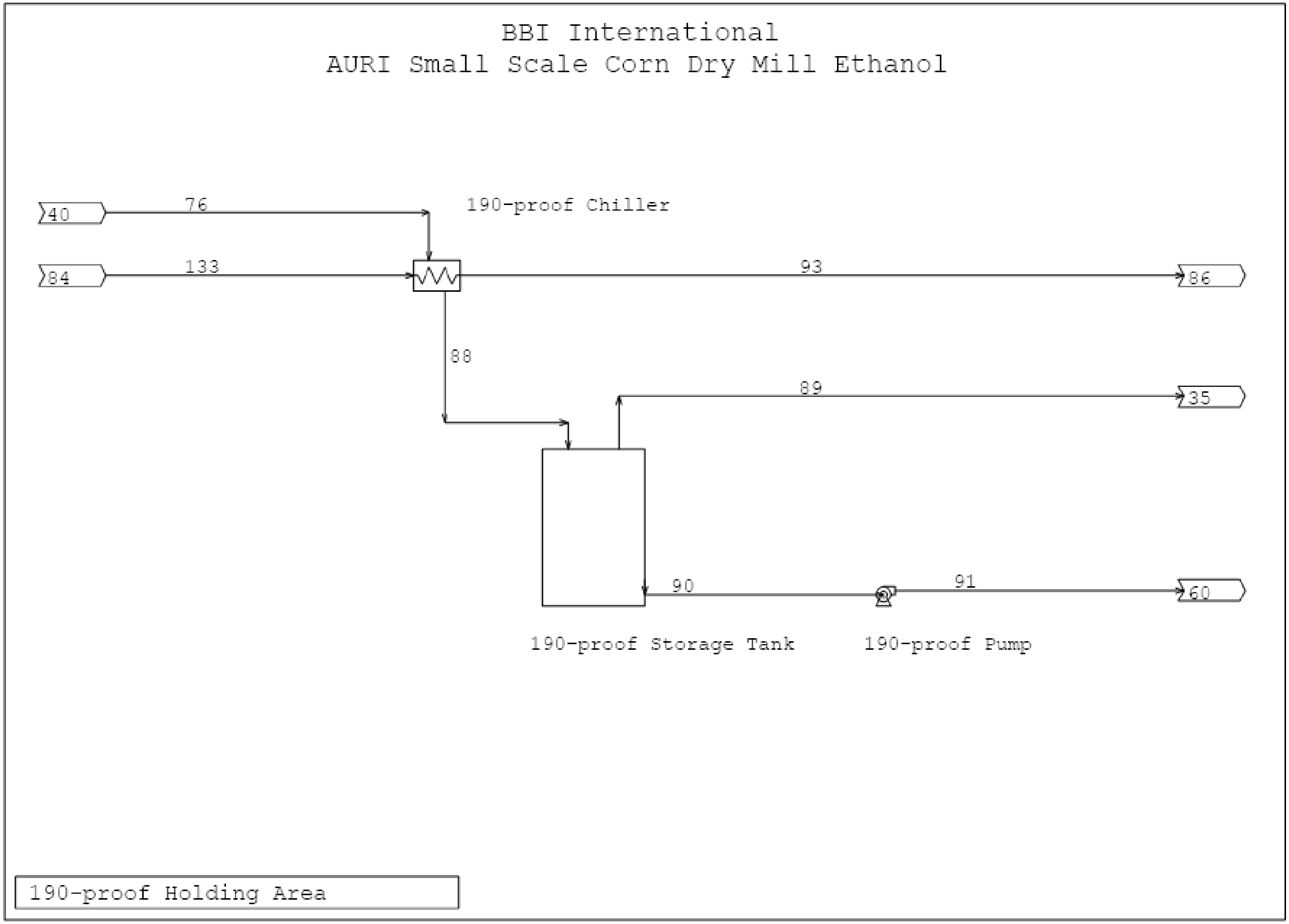

BBI International
AURI Small Scale Corn Dry Mill Ethanol
92
141
17
11
Steam Heater
12
13
35
Mash Flash Vessel
84
129
Saccharification Cooler
18
7
159
20
86
17
14
15
16
19
27
Flash Pump
Saccharification Tank
Saccharification Tank Pump
Cooking & Saccharification

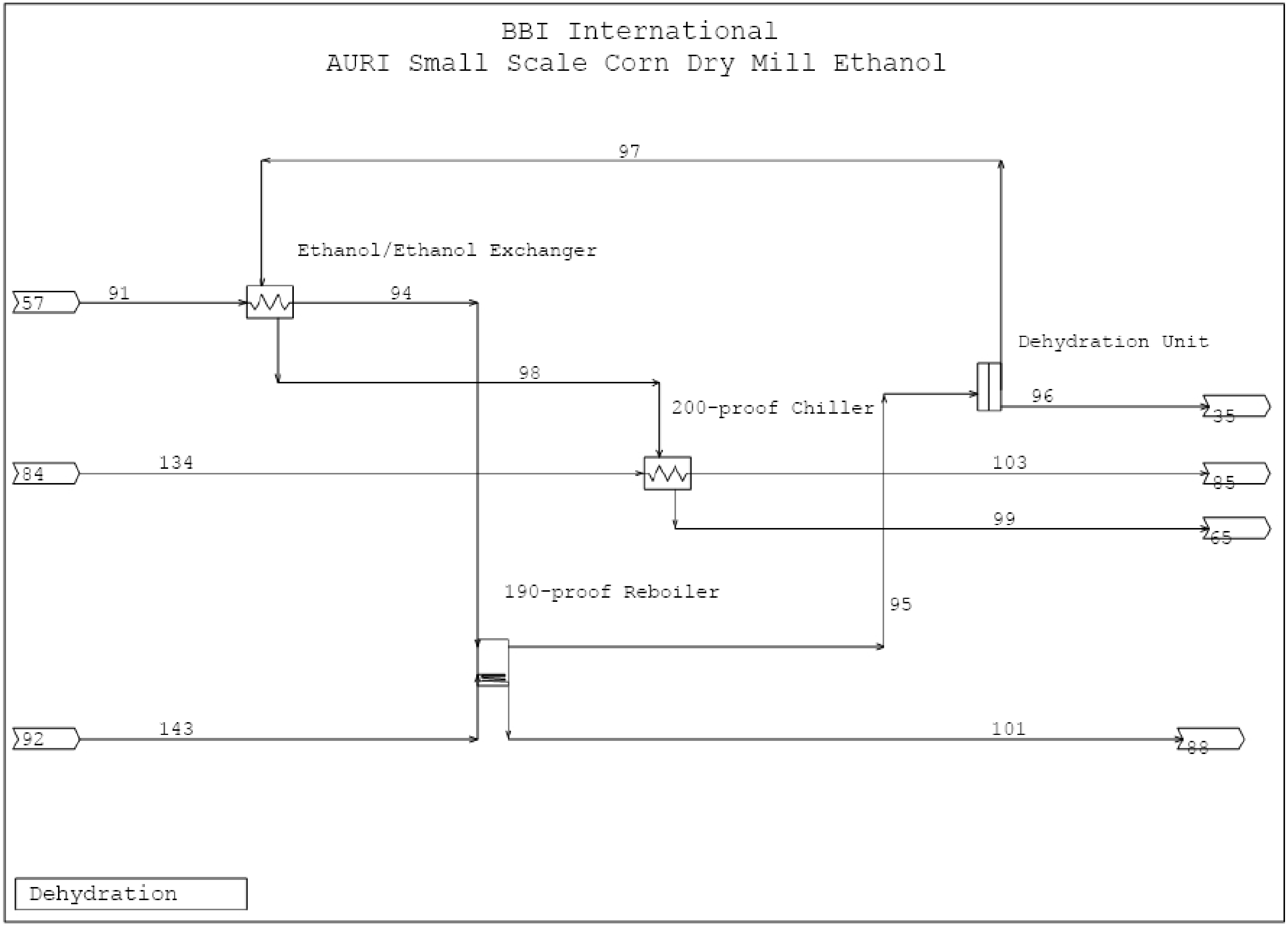

BBI International
AURI Small Scale Corn Dry Mill Ethanol
84
130
FM Broth Coolers
35
86
30
29
24
19
6
156
21
24
35
28
31
32
Fermentation Tanks
Fermentation Transfer Pumps
Fermentation

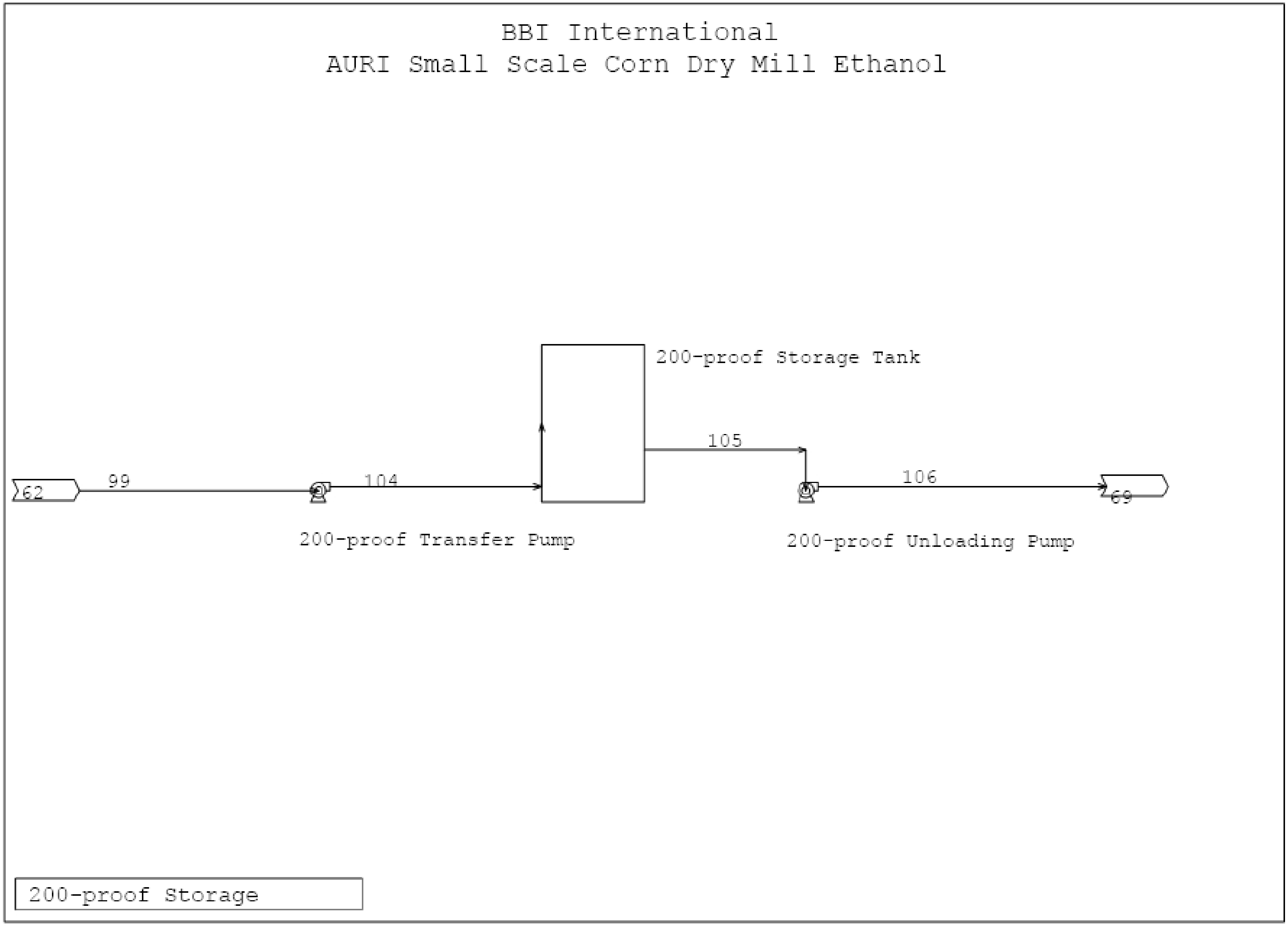

BBI International
AURI Small Scale Corn Dry Mill Ethanol
37
51
45
35
29
31
46
47
39
Beer Well
Beer Well Unloading Pump
Beer Well

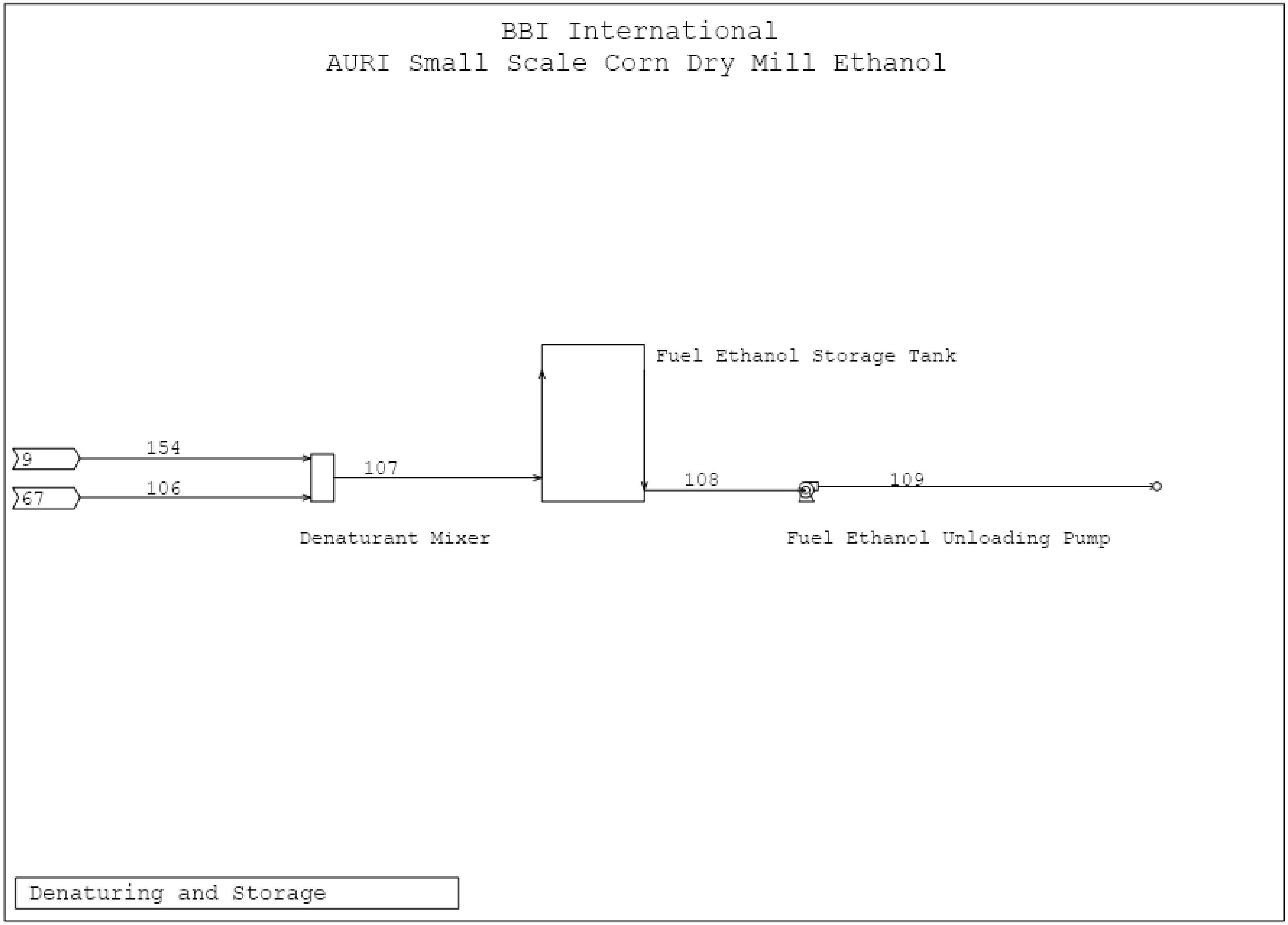

BBI International
AURI Small Scale Corn Dry Mill Ethanol
96
150
49
CO2 Scrubber
21
13
28
24
48
32
45
56
89
50
63
96
51
32
Scrubber Water Pump
Scrubber

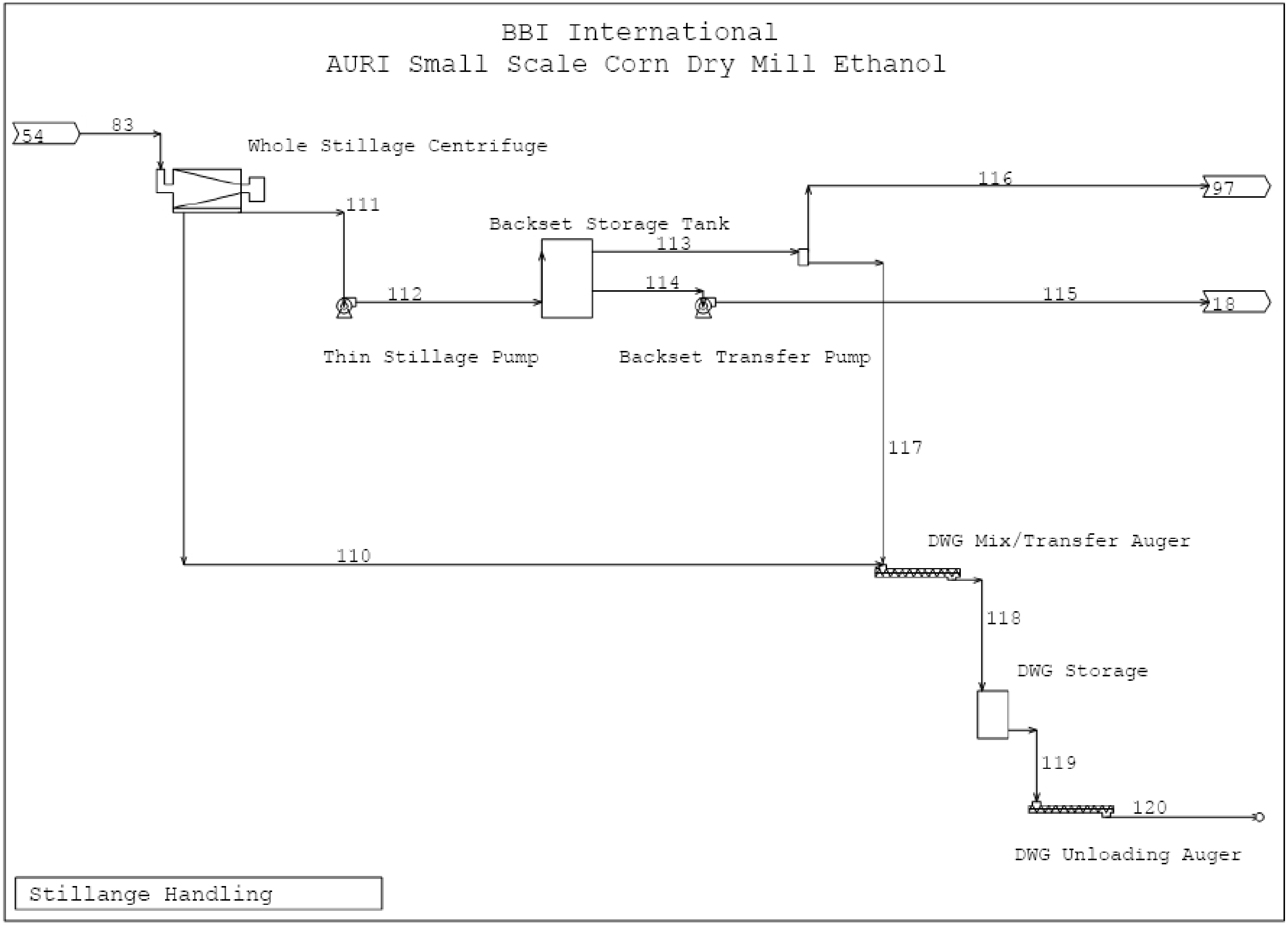

BBI International
AURI Small Scale Corn Dry Mill Ethanol
Distillation Preheater
190-pf Pump
Distillation Package
Stillage Pump
Distillation
74
47
52
75
76
63
64
131
85
62
65
61
60
72
132
87
57
58
67
71
73
55
66
68
142
53
69
78
79
54
56
70
59
83
81
80
82
33
58
84
86
92
73
88

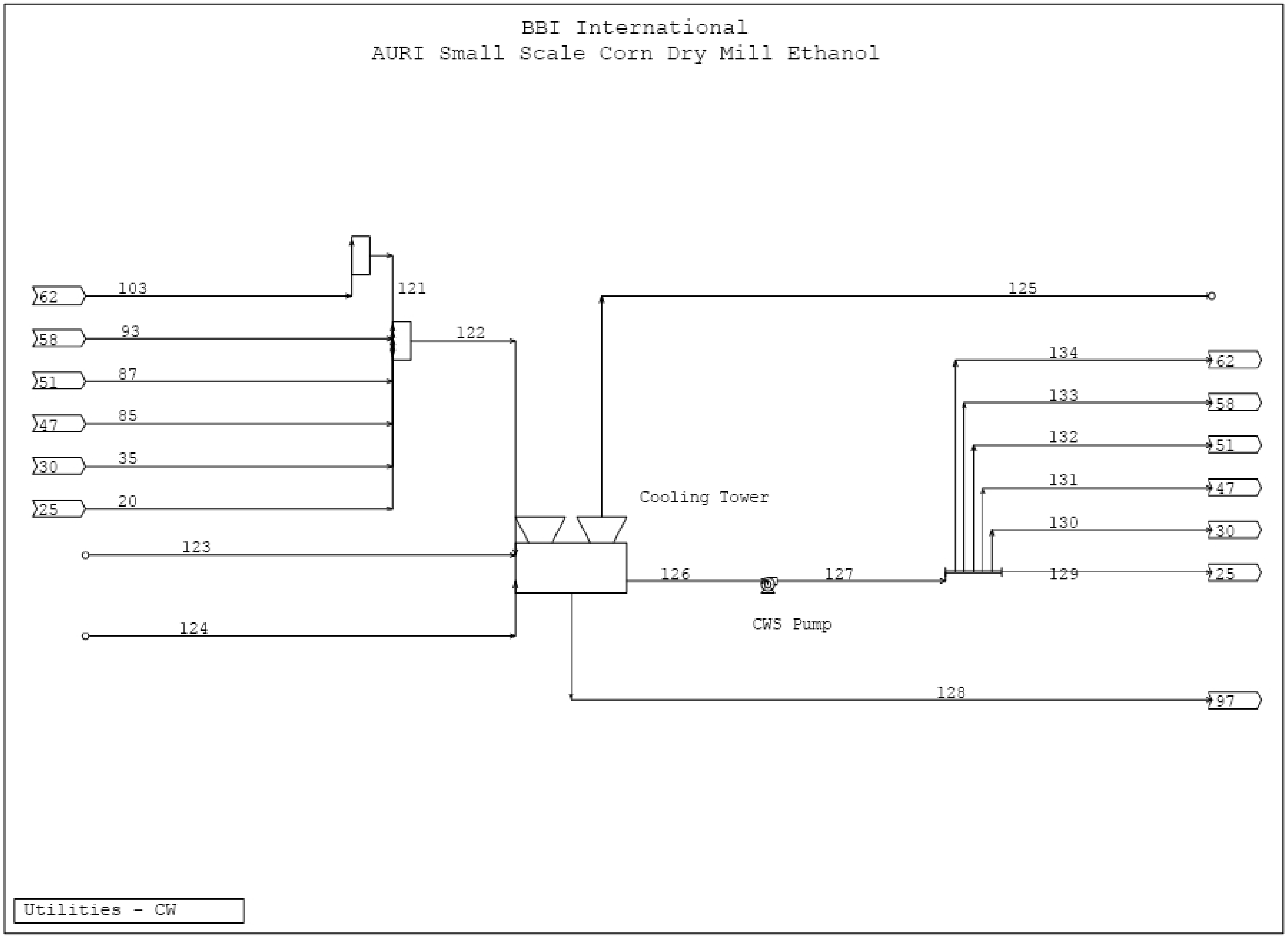

BBI International
AURI Small Scale Corn Dry Mill Ethanol
40
76
190-proof Chiller
84
133
93
86
88
89
35
90
91
60
190-proof Storage Tank
190-proof Pump
190-proof Holding Area

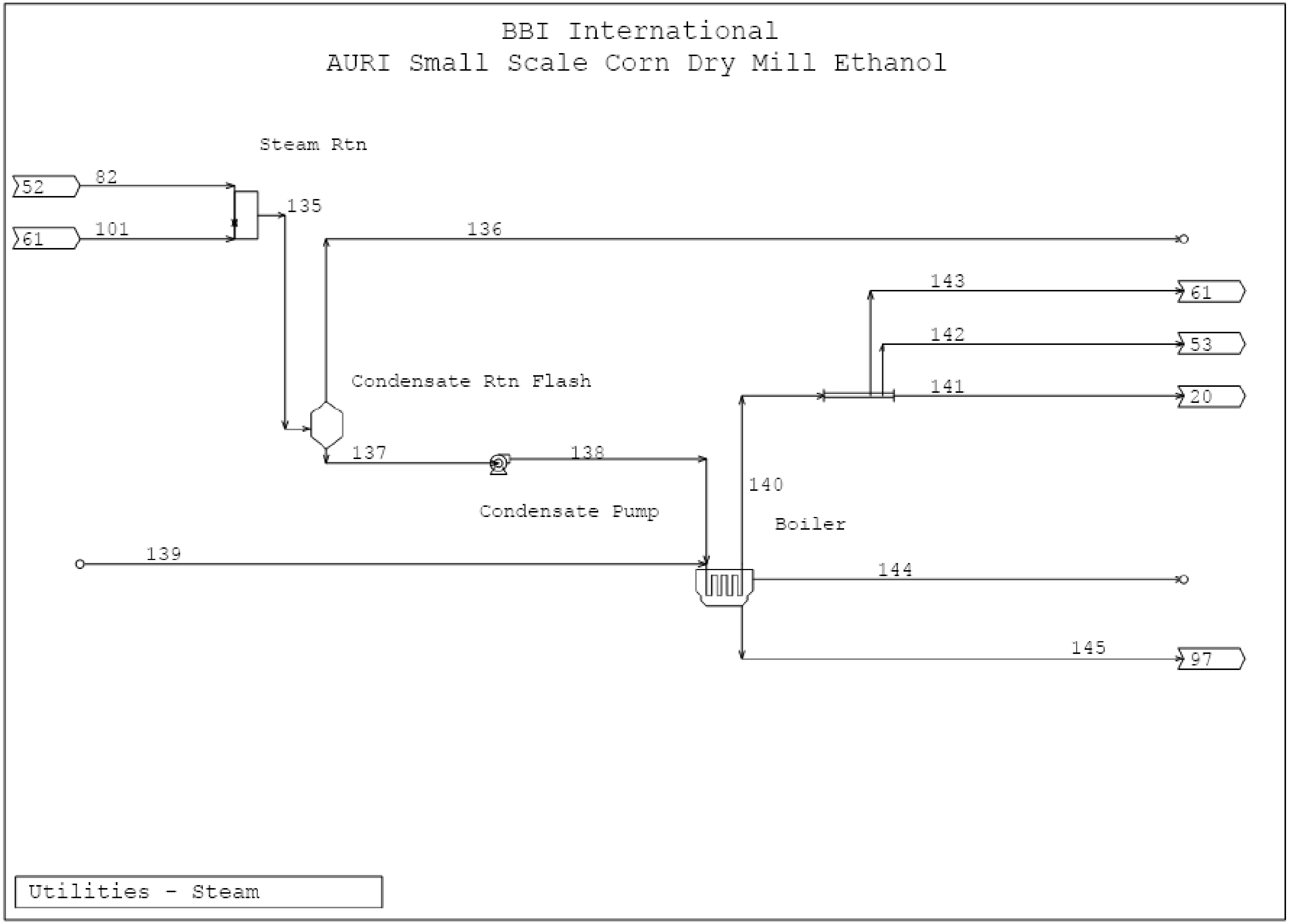

BBI International
AURI Small Scale Corn Dry Mill Ethanol
97
Ethanol/Ethanol Exchanger
57
91
94
Dehydration Unit
98
96
35
200-proof Chiller
84
134
103
85
99
65
190-proof Reboiler
95
92
143
101
88
Dehydration

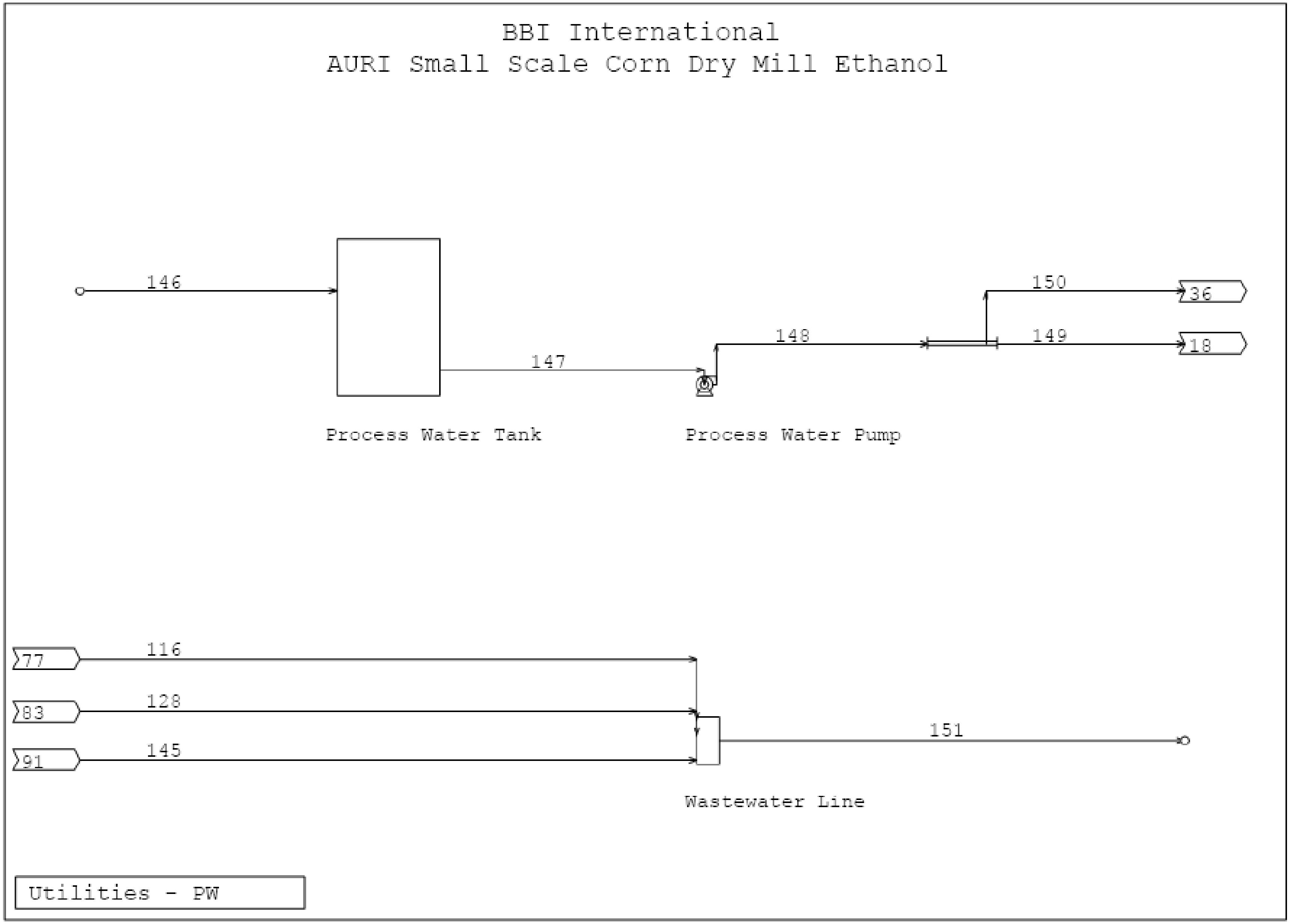

BBI International
AURI Small Scale Corn Dry Mill Ethanol
200-proof Storage Tank
105
62
99
104
106
69
200-proof Transfer Pump
200-proof Unloading Pump
200-proof Storage


BBI International
AURI Small Scale Corn Dry Mill Ethanol
Fuel Ethanol Storage Tank
9
154
67
106
107
108
109
Denaturant Mixer
Fuel Ethanol Unloading Pump
Denaturing and Storage


BBI International
AURI Small Scale Corn Dry Mill Ethanol
54
83
Whole Stillage Centrifuge
116
97
111
Backset Storage Tank
113
114
112
115
18
Thin Stillage Pump
Backset Transfer Pump
117
DWG Mix/Transfer Auger
110
118
DWG Storage
119
120
DWG Unloading Auger
Stillange Handling


BBI International
AURI Small Scale Corn Dry Mill Ethanol
62
58
51
47
30
25
103
93
87
85
35
20
121
122
123
124
125
Cooling Tower
126
CWS Pump
127
134
133
132
131
130
129
128
62
58
51
47
30
25
97
Utilities - CW


BBI International
AURI Small Scale Corn Dry Mill Ethanol
Steam Rtn
52
82
61
101
135
136
143
61
142
53
Condensate Rtn Flash
141
20
137
138
140
Condensate Pump
Boiler
139
144
145
97
Utilities - Steam


BBI International
AURI Small Scale Corn Dry Mill Ethanol
146
147
148
150
149
36
18
Process Water Tank
Process Water Pump
77
116
83
128
91
145
151
Wastewater Line
Utilities - PW