

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 13 – Electric Generation Considerations

This chapter outlines the opportunities and challenges of generating electricity and selling it to the grid. It was primarily prepared by project participants at LLS Resources LLC and RMT Inc.

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RD56: Generating Electricity with Biomass Fuels at Ethanol Plants “Electric Generation Considerations,” Part of Report for Task 13, “Electricity Production Estimates and Development of a Conceptual Model Plant”

Introduction

The generation, transmission, distribution, and sale of electricity are heavily regulated at both the federal and state levels, and may also be subject to requirements of the utility generating the electricity and to local and regional electricity transmission and distribution organizations. The generation of electricity by nonutility sources (such as ethanol plants), and the connection of these sources to the electricity grid for purposes of buying electricity from the grid and selling electricity to the grid, add another tier of regulatory complexity. Still more regulatory complexity is added if the fuel for the electricity generation is a renewable fuel, such as ethanol plant co-products. This regulatory complexity has significant potential impact on the economic, technical, and operational success of the ethanol plant. However, new regulations have also removed some of the barriers and improved price incentives.

In this section, these complex regulatory considerations will be examined, and their economic, technical, and operational impacts on ethanol plants will be discussed. Other sections of this report also bear on the impact on ethanol plants of the complex electricity regulatory framework.

Section 1. Regulatory Aspects of On-Site Electricity Generation

1.1 Federal and State Regulations

Both federal and state regulations and programs have been put in place to encourage the generation of electricity from biomass and other renewable energy sources. The mechanisms used to encourage this generation include the creation of renewable energy markets, favorable tax treatments, and favorable regulatory status. The major applicable regulations and programs are discussed below.

1.1.1 Public Utility Regulatory Policies Act (PURPA)

Under PURPA, facilities generating their own electricity and meeting certain fuel and efficiency standards (a “Qualified Facility” or QF) are accorded special regulatory qualifications. As initially approved, PURPA required that the local utility purchase all energy sold by the owner of a QF at its avoided cost and provide standby, backup, and maintenance power to the QF. However, EPACT '05 amended PURPA, such that where the Federal Energy Regulatory Commission (FERC) determines that competitive conditions exist, such as areas that participate in regional transmission markets, a utility is no longer required to buy power from renewable energy and combined heat and power (CHP, or cogeneration) plants, even when such plants can generate power less expensively than the utility, and even when such plants would otherwise meet PURPA standards.

The revised PURPA standards do provide an exception for generating units rated 20 MW or less. Before being relieved of their purchase obligation from units rated 20 MW or less, the local utility must provide a showing that the units have access to competitive power markets. Smaller generating units, such as those at ethanol plant sites and generating only the plant load, are typically connected at distribution voltage and therefore do not have transmission access to the Regional Transmission Organization (RTO) markets, in this case the Midwest Independent System Operator's (MISO's) markets. To receive the full benefit of those parts of PURPA that still apply, a DG facility that cogenerates should be formally registered by the owner as a QF under the PURPA self-certification process. Despite any changes in federal regulations, the states of Minnesota and Wisconsin actively encourage the development of distributed generation, as discussed below.

1.1.2 Renewable Energy Credits

Customers who generate their own electricity utilizing qualified renewable fuels, such as ethanol co-products, can sell Renewable Energy Credits (RECs) into national and state markets, where such markets exist, even when the electricity is all utilized on-site. However, once sold, the RECs remain with the property of the buyer, who can further trade the RECs. The current market for RECs are small and regional, though evolving, with transactions via over-the-counter trades or bilateral deals.

1.1.3 Production Tax Credits

Under the Energy Policy Act of 2005 (EPACT '05), wholesale generators of electricity from biomass that is sold for use by others are eligible for a production tax credit (PTC), for the first 10 years of such electricity production. The PTC for 2006 for "open-loop" biomass is about one half of the \$0.019/ kWh credit for other renewable energy technologies, with an annual adjustment for inflation. To be eligible for a PTC under the current law, the electricity-generating equipment must be on-line before January 1, 2008. Among other eligibility requirements for the PTCs, the regulations restrict the use of coal in the fuel-to-flame initialization and stabilization, and facilities that use the renewable energy to serve any on-site needs are ineligible. The energy associated with natural gas used in the production of electricity is not eligible for production tax credits, and any electricity produced by "co-mingling" natural gas and renewable fuels would need to be sorted by fuel type.

Similar to PTCs, renewable generation assets owned by tax exempt state and municipal utilities are eligible for renewable energy production incentive (REPI) payments from the federal government.

1.2 Distributed Generation and Utility Regulations

Action has been initiated at both state and federal levels to encourage development of smaller, dispersed generating facilities, called Distributed Generation Facilities (DGs), that supply electricity to the customer owning the generation, and/or supply electricity directly to the utility without the customer taking any of the energy (a wholesale generator). The actions at both levels of government have been aimed at removing barriers typically erected by utility organizations against DGs. DGs can

provide benefits of increased grid reliability, reduced investment in transmission facilities, reduced grid system losses, and increased efficiency of energy conversion.

The definition of a DG varies by state and federal jurisdiction. Also, regulations for the interconnection of these facilities with the electricity grid may vary by electric utility. The amount paid by the utility to the DG is stipulated under various rate schedules (tariffs) approved for investor-owned utilities by the state Public Service Commission. (Electric Cooperatives and municipal electric utilities set their policies via their Board of Directors who must comply with state and federal mandates.) The electricity buyback rates may vary based on several factors, including the reliability of the DG supply and the amount of electricity delivered by the DG. DGs with capacities above certain thresholds often have the opportunity to negotiate special buyback rates outside of the tariff.

Units exceeding the state DG size threshold or PURPA applicability threshold would be subject to more lengthy and costly connection and application procedures, as outlined in the RTO or local utility connection rules. These procedures are less precise and may require extensive negotiations after utility completion of special interconnection and transmission access studies. However, if generating units at ethanol plant sites are sized to meet only the plant electric load plus steam requirements, then these units are likely to fall within the DG or PURPA applicability standard.

1.2.1 Minnesota Distributed Generation Rules

In Minnesota, distributed generation is defined as electricity-producing facilities burning clean fuels and rated 10 MW or less and operating at 35 kV or less. The electricity buyback rates offered by Northern States Power (NSP) change annually, and are based on NSP's expected marginal monthly on-peak and off-peak energy costs. The price paid by NSP for its purchase of firm capacity from DGs (the capacity buyback rate) also changes annually, based on NSP's cost of capital and the remaining life of the DG equipment and NSP's need to otherwise install its own generating facilities.

The State of Minnesota has developed a document entitled "Distributed Generation Connection Requirements," which, in addition to specifying the setting of relays and other physical aspects of interconnection, describes the technical requirements for metering, monitoring, and controlling generation. The document has been appended to NSP's Distributed Generation tariffs (Section 10, Sheets 135 through 159.6, found at www.xcelenergy.com/docs/corpcomm/Me_Section_10.pdf). The State of Minnesota has also adopted a net metering standard for very small DGs.

1.2.2 Wisconsin Distributed Generation Rules

In Wisconsin, uniform DG rules apply under PSC 119, Wisconsin Administrative Code, to all investor-owned utilities, and to all customer-owned DGs. DGs are defined as electricity-producing facilities up to 15 MW in size, operating in parallel with the utility. As a practical matter, some utility tariffs only consider DGs of 12 MWs and under, and somewhat different rules apply for DGs less than 1 MW. For generation under 20 kW, net electricity billing applies, where the customer meter is bi-directional, and runs in the reverse direction when power flows out instead of in, resulting in a net invoice to the customer showing a credit amount for the electricity sold to the utility.

A document produced by the Wisconsin Distributed Resources Collaborative, entitled "Wisconsin Distributed Generation Interconnection Guidelines," provides the technical and procedural requirements involved in interconnecting DG facilities to the grid (found at www.wisconsin.gov/library/PSC/WI_InterconnectionGuidelines.pdf). A standard interconnection agreement, which must be signed by both the applicant and the utility before parallel operation can commence, is available through the Public Service Commission of Wisconsin (found at psc.wi.gov/utilityinfo/electric/distributedGeneration/electricgenerationForms.htm).

1.2.3 Federal Distributed Generation Rules

Federal regulations promulgating DG standards have been initiated by the Federal Energy Regulatory Commission (FERC) and are stated in FERC Order No. 2006-B which became effective on August 26, 2006. The regulations will apply to generating units rated 20 MW or less. However, the definition of lower nameplate capacity for DGs by the various states (generally 10 to 15 MW) is currently the operative definition in those states. FERC regulations regarding transmission access and facility interconnection are effective nationwide.

1.2.4 Non-DG Units

In certain cases, the availability of byproduct fuel will allow the installation of generating units with capacity ratings far in excess of the amount required to operate the plant. Although such units would be too large to qualify for DG or PURPA benefits and would require transmission access, they would meet classification as Independent Power Producers (IPPs) and could register as Exempt Wholesale Generators (EWGs). Registration as an EWG means that they are exempt from conventional utility regulation as long as they do not have majority ownership by an electric utility. An EWG also has the right of access to the transmission grid for purposes of wholesale transactions.

EWGs in Minnesota and Wisconsin must make application via the Midwest Independent System Operator (MISO) to interconnect with the transmission system and to reserve transmission capability required to transmit the output. This is done by following a complicated application procedure accompanied by substantial study funding (to be paid by the EWG) under the MISO Open Access Transmission and Energy Markets Tariff. The MISO study results provide the EWG with an interconnection configuration, along with the amount of investment the EWG must make in the transmission grid.

Prices paid for energy to the EWG are based either on MISO market prices (if the EWG becomes a market participant) or on individually negotiated bilateral contracts. EWGs are eligible for the federal PTC.

1.3 Utility Interconnection Requirements and Approvals

Customer on-site generation may be sized to meet some of the plant needs while continuing to purchase remaining plant requirements (such as during peak electricity demand) from the local utility under standard tariffs, meeting all of the plant needs and selling excess power (produced by the DG when its electricity usage is less than its peak usage) off-site, or meeting all of the plant needs and

continuously generating excess electricity to the grid, even during peak plant demand. Unless electricity is to be sold off-site to a wholesale entity other than the local utility, connections to the local electrical distribution system are under the rules set by the local utility. If generating facilities at ethanol plants are sized to be under the state standard, approval will be under local utility requirements conforming to state DG standards.

Regulations regarding connecting DG facilities to a utility system vary by generator size and interconnection voltage. Details within the regulations include relaying standards, circuit breaker ratings, switch ratings, approved devices, etc. Utilities cannot make interconnection requirements more stringent than the new uniform state and federal regulations without an approved reason.

1.3.1 Applicable Utility Tariffs

When a DG's electricity is utilized on-site, and the DG remains connected to the utility, provisions related to standby, backup, and maintenance power apply. The price for each of these services is stated in the utility tariffs. The applicable Northern States Power (Xcel Energy, Minnesota) and Wisconsin Power & Light (Alliant Energy, Wisconsin) rates for these services, as well as pricing for the energy and capacity purchased from the customer-owned generation are discussed below.

Standby power costs are almost always a major cost component for an industrial user, and are currently priced at \$2 (WP&L) to \$3 (NSP) per kW-month. Backup generators at a customer's site may reduce or eliminate standby power costs, in addition to avoiding brownouts or blackouts, and allowing the industrial user to consider the use of interruptible rates from the utility. However, backup generators entail costs and environmental complications, which must be balanced against their advantages.

Buyback rates for energy sold to the grid vary by utility. The current NSP pricing for DG is \$0.03/kWh to \$0.125/kWh, depending on time of day and season, plus capacity credits that change annually depending on NSP's cost of capital and the value of the capacity on the NSP system. The current WP&L pricing for DG is \$.06/kWh on-peak and \$0.025/kWh off-peak. Additional credits may be available from the utility for the supply of energy from renewable fuels.

1.3.2 Metering, Insurance, Applications, etc.

DG regulations also state metering requirements, minimum insurance requirements, application procedures and costs, approval procedures and costs, timelines, contract formats and many other details associated with DG installations. These requirements should be reviewed and taken into account in evaluating the advisability of installing a DG facility.

In Wisconsin, DGs larger than 20 kW must have a minimum commercial liability insurance coverage starting at \$1 million per occurrence. Similar insurance requirements are in effect in Minnesota for units larger than 100 kW.

1.3.3 Interconnection Studies

An engineering study by the host utility may be required for DGs that plan to produce electricity for sale onto the local electric distribution and transmission network (“grid”). The studies can vary in cost, depending on the amount of DG capacity sold to the utility. The study will determine what additional electric infrastructure is required by the utility to accommodate the output of the DG facility, including any upgrades to existing equipment. If the amount of capacity sold does not exceed the expected load of the local substation that is feeding the plant, then the DG may be considered as not affecting the transmission system, and the interconnection procedures of the local utility apply. For DG capacity sold that is greater than the load of the local substation, the procedures of the Midwest Independent System Operator (MISO) and Regional Transmission Operator (RTO) apply.

1.3.4 Generating Unit Accreditation

Capacity accreditation by the Mid-Continent Area Power Pool (MAPP), the organization responsible for ensuring adequate regional electric system reliability, or its successor organization, the Midwest Reliability Organization, may be a means of reducing utility standby charges and/or receiving capacity credits for customer-owned generation. Capacity credits are utilized by the local utility to help meet its total capacity requirements, typically equal to peak load plus 15 percent reserve. The MAPP Generation Reserve Sharing Handbook describes the accreditation process (found at www.mapp.org/assets/pdf/GRSP_Handbook_20050311.pdf). Variable capacity unit accreditation is applicable to combined heat and power units for which the amount of power available to the grid may vary and is not dispatchable by the local utility.

1.4 Regulations Summary

Table EPE 1 below provides a summary of the regulations pertaining to the generation of electricity from biomass fuels.

**Table EPE 1
Summary of Regulations Pertaining to Renewable Energy Electric Generation**

REGULATION	DESCRIPTION
Federal Production Tax Credit	Payment in the form of a tax credit per kWh produced and sold to the grid.
Renewable Energy Credits	Where market exists, payment by marketers for green energy sales to end-users
PURPA	Gives standards for regulation of cogeneration facilities, which states may adopt.
State Distributed Generation Rules	Define interconnection requirements by the size of the generating unit. Address insurance, application, and approval issues.
Federal Distributed Generation Rules	Provide for uniform regulations from which states cannot be more stringent.
Utility Tariffs	Rate schedules

Table EPE 1 (continued)
Summary of Regulations Pertaining to Renewable Energy Electric Generation

REGULATION	DESCRIPTION
Standby capacity service	Fee for contracted amount of reserve backup capacity.
Supplemental energy	Standby, maintenance, or supplemental energy are usually supplied under the normal tariff for which the customer qualifies.
Buyback rates	Payment by a utility to a DG for energy sold to that utility. May be at utility avoided cost (NSP) with premium for renewable energy or at a flat rate (WP&L).
Interconnection requirement	Addresses voltage, relaying, frequency, devices, metering, monitoring, control of generation, and other technical issues.
Interconnection study	Electrical engineering study of the effect of supplying additional capacity onto the local electric distribution and transmission network.
Generating unit accreditation	Recognition of capacity benefit of generation units to the regional electric system network. May help to reduce standby capacity charges.