

Barriers to the expansion of electrical co-generation by the wood products industry in the United States

Irene Kowalczyk¹

Summary. Cogeneration is a very efficient way to produce useful heat and electric power. Although use of this technology proliferated with the passage of PURPA, since the mid 1990s with the establishment of regional transmission organizations, a trend has developed which has stifled growth of cogeneration facilities. The FERC contributed to this treatment of cogeneration with the deference provided to the regional transmission organizations in the design of the market rules which strive to treat cogenerators similar to merchant power plants. These rules, for the most part, do not recognize the substantial differences between cogeneration and merchant plant facilities, nor do they consider the additional societal value cogeneration facilities bring to our nation. In addition, the FERC's interpretation of the EPCRA of 2005 reform of the mandatory buy obligation in Section 210 of PURPA requires cogenerators in some regions of the country to follow the same processes and rules that merchant facilities must abide by to become interconnected and to obtain equal compensation for their power output. These developments have caused significant hurdles for CHP facilities to overcome and have stifled the further growth in use of this technology. This paper includes a review of the many new regulatory and other barriers which have developed over the years and makes recommendations to overcome them.

Keywords: *Cogeneration, combined heat and power (CHP), Public Utility Regulatory Policy Act (PURPA), Energy Policy Act (EPCRA) of 2005, qualified facilities, Open Access Transmission Tariff (OATT), interconnected generators, distributed generators, "deliverability" standard, minimum interconnection standard, "gross load" pricing, output-based allowance, Clean Energy Standard Offer Program (CESOP), feed-in tariffs, exit fees*

Introduction

Cogeneration, also known as combined heat and power (CHP), is a common practice in the US pulp and paper industry. The industry's need for thermal heat to "cook" wood chips to break wood down and then dry the wood fiber when it is reconstituted as paper coupled with its need for electrical power to run large paper machine drives makes the industry a natural fit for application of CHP technologies. For example, MWV's three domestic mills co-generated 1.86 million megawatt hours of power in 2007 which represents almost 70 percent of these mills' total power requirements. Use of CHP saves millions of dollars in energy costs annually and reduces our carbon dioxide emissions significantly compared to purchasing all of our power from the local utility. In addition, since most of the fuel used in our cogeneration facilities is biomass-based, our carbon dioxide emission reductions are further enhanced.

Since 1972, American Forest and Paper Association (AF&PA) member pulp and paper mills have decreased the use of fossil fuels and purchased energy per ton of product by 56%. From 2004 to 2006, they reduced their use of fossil fuels and purchased energy per ton of production by 9%. This was mostly achieved by extensive use of CHP technologies. In 2006, AF&PA member pulp

¹ Irene Kowalczyk is the Director of Energy Policy and Supply for MeadWestvaco Corp.

and paper mills generated 64% of the energy they used from carbon-neutral biomass, and in 2005, the forest products industry accounted for 82% of biomass energy generated by all industries, producing more than 28.5 million megawatt hours of electricity. In 2005, 98% of the electricity generated at pulp and paper mills was co-generated.

CHP in the United States today avoids more than 1.9 Quadrillion Btu of fuel consumption and 248 million metric tons of CO₂ emissions compared to traditional separate production of electricity and heat. This CO₂ reduction is the equivalent of removing more than 45 million cars from the road. (DOE 2008)

CHP is an energy efficient method to produce electric power, as energy is effectively used twice as compared to a stand alone power plant which includes a single pass through condensing turbine that dissipates unrecovered energy as waste to the atmosphere. This highly efficient use of energy is believed to be one of the more cost effective ways to reduce greenhouse gas emissions and other pollutants. The federal government recognized this value and passed the Public Utility Regulatory Policy Act (PURPA) in 1978 to foster increased use of CHP and power generation from renewable energy sources. For twenty years the law did exactly that as cogeneration and small power production from renewable resources increased from 4% (Casten 1998) of US power generation to nearly 9% (DOE EIA 2009) by 1998.

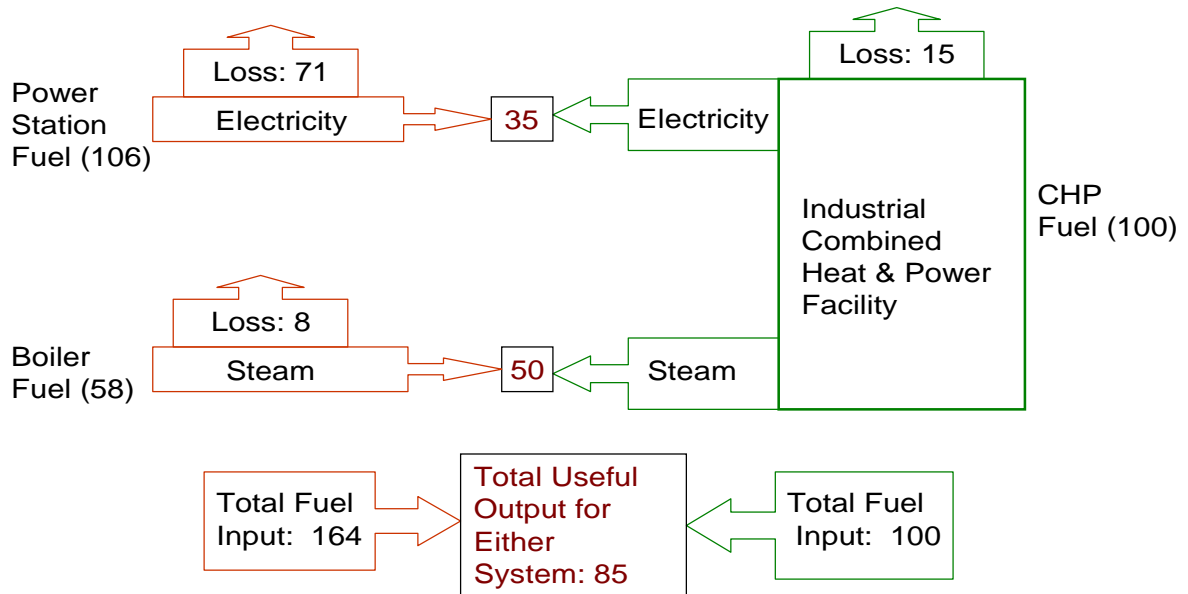
The EIA estimates that the potential exists to produce 18% of US power needs from CHP systems. (DOE EIA 2000) If CHP were to supply up to 20% of U.S. electricity generating capacity by 2030, the projected increases in CO₂ emissions would be cut by 60%. (DOE ITP 2008). However, relatively recent regulatory barriers, often in the name of improving the reliability of the nation's power grid, virtually negated the incentives that PURPA provided. The growth in CHP has stagnated and it was less than 8% of US power generation in 2007. (DOE EIA 2009). This paper outlines some of those regulatory barriers to increased use of CHP and makes recommendations to overcome them to put CHP back on track to meet its potential.

Background

Cogeneration, or combined heat and power (CHP) is the process of sequential generation of electricity, useful heat or steam and sometimes mechanical energy. It is generally twice as efficient as traditional fossil fuel fired utility generation and is made possible at its basic level because of an industrial or commercial business' need for the non-electrical energy output.

Power production by cogenerators results in benefits to the environment. These environmental benefits come from the efficiency gained by producing electric energy and useful heat in a single sequential process rather than through independent and separate processes. The following schematic illustrates the benefits of CHP as compared to separate standalone processes for the production of steam and power.

Comparative Efficiencies: Industrial Boiler and Thermal Power Plant v. Industrial CHP Plant



CHP Results in 40% Less CO₂ For Same Useful Output

Source: Northwest Pulp and Paper Association

The need for steam in the paper making process at CHP facilities in the pulp and paper industry enables these mills to utilize the low pressure steam that is extracted from the turbine as part of the power generation process. This differs from utilities which condense the low pressure steam resulting in heat being lost to the atmosphere when the cooling water from the condenser runs through the cooling tower. Because CHP systems use less fuel, they produce fewer emissions to the air; so there is also less particulate, CO₂, SO_x, NO_x and other pollution emitted than in utility systems using the same fuels (DOE 2008).

CHP systems have other environmental and efficiency benefits as well. Condensing steam in utility power plants requires makeup water due to evaporation losses. CHP systems typically do not include condensers so they use virtually no makeup water for cooling purposes, eliminating thermal pollution as well as conserving energy. Adding CHP power generation units widely dispersed throughout the electrical grid also improves system reliability in that the electrical system is less dependent upon any single generation unit. Since the power which is cogenerated is typically used locally, electric transmission and distribution line losses (often as much as 7%) are also reduced (AF&PA 2003).

Despite these well known environmental and energy efficiency advantages of CHP the growth rate of new CHP installations has been quite low over the past five to ten years. This is because significant barriers have been raised in both the legislative and regulatory environments.

Legislative History and Resultant Regulatory Barriers to Increased Large CHP

PURPA Created Incentives for Combined Heat and Power

The PURPA law of 1978 encouraged greater utilization of CHP and effectively created a market for these resources. PURPA recognized the stagnant technology in the utility industry and sought to encourage innovation by non-utility entities. The key intention of PURPA was to promote the increased development of cogeneration and small power production. PURPA streamlined regulations to enable sales of electricity by non-utility owned power generation facilities, thereby encouraging the development of a competitive market in wholesale sales of electricity.

PURPA sought to encourage cogeneration and small power production by protecting non-utility owned producers from monopolistic market abuses by utilities. PURPA guaranteed that they would not be discriminated against when connecting to the electrical grid. Another protection afforded by PURPA is the guarantee that non-utility owned power generation facilities could get supplemental, back-up and maintenance power at just and reasonable rates.² It was recognized that if utilities charged exorbitant rates to recover revenues lost because of CHP self-generation when the CHP was down for maintenance or for unscheduled outages, few CHP facilities would be installed.

Under PURPA, utilities were required to purchase power from facilities that met PURPA qualifications at the cost the utilities avoided from either building additional power plants or purchasing power from the wholesale market. The basic tenet of PURPA was to pay the CHP facilities what the utility would pay if it installed the unit itself or purchased the power from other sources.

Under PURPA, the installation of CHP facilities flourished for about twenty years from 1978 to 1998 through most parts of the country. The FERC delegated to the states the responsibility for determining the methodology to be used for determining utilities' avoided costs. In some parts of the country, particularly in the Southeast, utilities and their state public utility commissions were reluctant to embrace the federal law. As a result, policies were put in place which continued to provide preferential treatment for utilities' power plant build options. For example, in some jurisdictions there were no provisions for competitive bidding, utilities' true avoided costs were not transparent and the tariffs established by the state regulator for PURPA qualified facilities to sell power to the local utility did not provide the assurances needed to secure financing for CHP facilities. Developers which asserted their legal PURPA rights incurred real barriers to entry and significant litigation costs. They ultimately gave up and developed their projects in more CHP friendly jurisdictions.

In other states the Public Service Commissions required purchased power agreements with PURPA qualified facilities to flow through the fuel factor at cost. Since the utilities involved

² Specifically, Federal Energy Regulatory Commission (FERC) regulations prohibited designing or charging stand-by and back-up rates under the unrealistic assumption that all non-utility owned power generation facilities will be off line simultaneously during the system peak period.

were not afforded an opportunity to earn a rate of return on equity on the capacity component of these purchase power agreements, they naturally resisted entering into PURPA based purchased power agreements. This regulatory treatment created a bias against CHP. There was also a genuine mistrust of the ability of CHP facilities to reliably provide power to the utility.

PURPA Incentives for Combined Heat and Power Recently Rolled Back

The passage of the Energy Policy Act (EPA) of 2005 substantially reformed PURPA and stifled the continued development of CHP.³ Under the Federal Energy Regulation Commission's (FERC) interpretation of this law,⁴ utilities were not required to demonstrate that their markets were functionally competitive before being relieved of the mandatory purchase obligation. This ruling applied, even though the market monitor from (PJM)⁵ stated that the capacity market in many parts its territory was not workably competitive. This FERC interpretation also placed the burden on qualified facilities to prove discrimination in the implementation of an Open Access Transmission Tariff (OATT). Under the FERC OATT, all non utility users of the grid are to be afforded access under the same terms and conditions as utility users. In practice given the utilities' rights to preserve transmission capacity for future native load, non utility users have not received nondiscriminatory access to the grid as was intended by the FERC.

These interpretations are important because they effectively end the purchase obligations for utilities in a large part of the nation. Existing contracts were not affected but any qualified facility seeking to renew a contract or seeking a new arrangement for expanded or additional capacity may find itself with little leverage in negotiating with utilities. Qualified facilities in these areas have to be large enough⁶ to afford the costly regulatory interconnection process or rely on the goodwill of utilities to obtain reasonable deals for sale of their power.⁷

³ PURPA reform included a new Section 210(m) which provides that a public utility may file an application for relief from the mandatory purchase obligation on a service territory wide basis. The FERC in its order (Order 688 issued 10/20/06) on implementation of the law, effectively removed the mandatory purchase obligation under Section 210 in situations where cogenerators supposedly have competitive markets into which they can sell their output. The FERC ordered that all utilities located in Independent System Operators (ISO) or Regional Transmission Organizations (RTO) could be relieved of their Section 210 "must buy" obligation after making a ministerial compliance filing stating which RTO or ISO they belong to and that they provide service under an Open Access Transmission Tariff (OATT).

⁴ The FERC's order on rehearing (Order 688-A issued 6/22/07) reaffirmed many of the objectionable findings which are described below.

1. Utilities Who Are Members of New York ISO, New England ISO, PJM and Mid-West ISO are Automatically Exempt From The Purchase Requirements under 210(m). Although the FERC claims that its findings that these markets are competitive are "rebuttable presumptions", the FERC order does not permit qualified facilities to submit any evidence regarding the competitiveness of the markets to rebut the claims.

2. Any Utility That Has an Open Access Transmission Tariff (OATT) is Presumed to Provide Non-Discriminatory Access to Any Markets That do Exist.

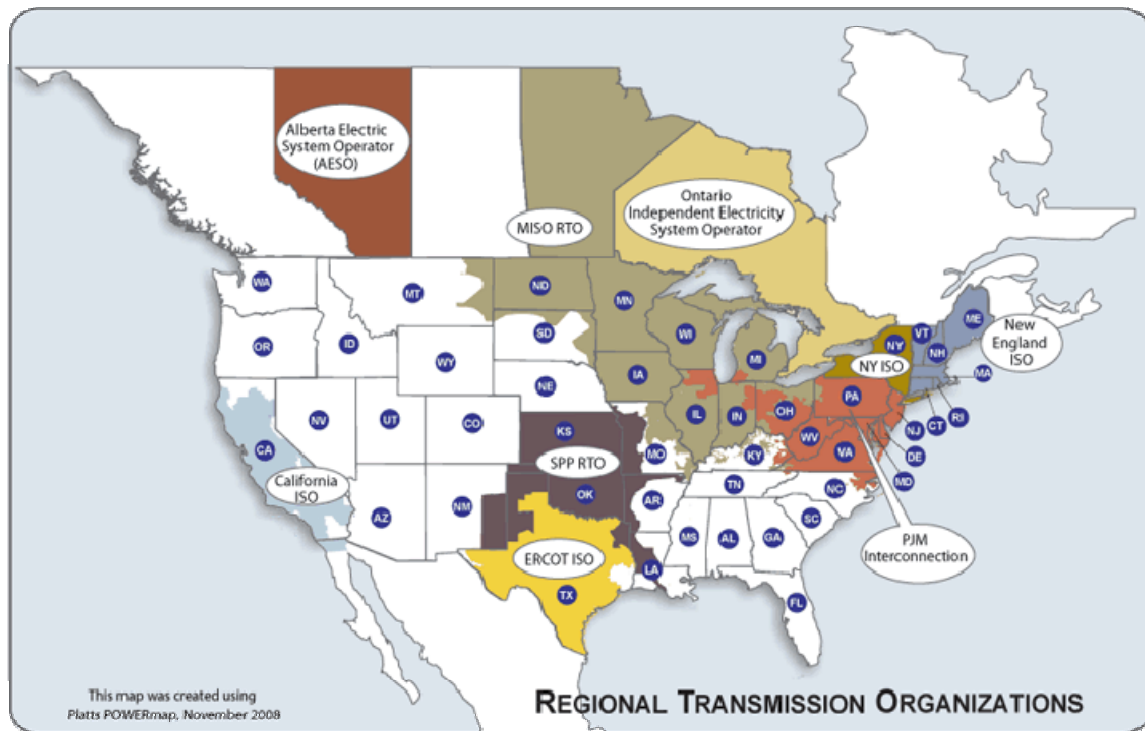
⁵ PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

⁶ Only the largest and most sophisticated qualified facilities can afford to undergo the expense of pursuing the interconnection process.

RTO and ISO⁸ Rules to Improve Reliability Create Additional CHP Disincentives

Operational Challenges Faced by CHP in an RTO Environment

CHP facilities like those operated by the pulp and paper industry are different than power plants that only have one purpose (merchant generators), producing electricity for sale to the grid. While a CHP may elect to sell power into an electrical transmission grid, its primary function is to support the host facility by providing electric power and steam or other useful thermal energy for the manufacturing process. The FERC program to standardize the use of the grid through the development of ISOs and RTOs fails to recognize this important difference (AF&PA 2007).



Generally the operating rules developed by these entities (RTOs and ISOs) fail to recognize the significant operational differences between cogenerators and merchant generators. This is the case even though the FERC has acknowledged in a California case where the issue was specifically addressed that qualified CHP facilities differ in purpose and operation from traditional generators and that reducing the host facility's control over the curtailment and

⁷ Due to the potential financial ramifications of this FERC order, it was appealed to the U.S. Court of Appeals for the District of Columbia Circuit (No. 07-1328) by the American Forest & Paper Association. However on Dec 18, 2008 the District Court affirmed the FERC decision and let the Order stand.

⁸In 1996 and 1999 FERC created rules to establish regional transmission organizations (RTO) and independent system operators (ISO) to coordinate the movement of wholesale electricity in a designated area.

dispatch of their power could lead to process, safety and health problem for the host facility (AF&PA 2003).

RTOs and ISOs often require that interconnected generators, including onsite CHP, be under their control, even if the generator is not making sales to the market. This requirement allows an RTO to dispatch a CHP's entire power production capability to other uses based on the needs of the electrical transmission grid, irrespective of the needs of the CHP's primary business. This requirement is a significant disincentive for any industrial CHP facility seeking access to the grid (AF&PA 2003, 2007).

Another deterrent for CHP interconnection can be found in the EPAct of 2005 in the establishment of the Electric Reliability Organization (ERO)⁹ to ensure the reliability of the electric power transmission grid. All interconnected generators, including qualified CHP facilities must become members of their regional electric reliability organization and submit to extensive reporting and other requirements imposed by that reliability organization. Compliance with these new mandatory requirements is time consuming and expensive and poses another barrier to CHP connecting to the grid.

Interconnection Standards Remain a Deterrent to CHP Entry

Interconnection policy has broad implications for competitive entry of distributed generators¹⁰ and for the future development of CHP. FERC has recently finalized new generation interconnection rules for both small facilities with capacity less than 20 MW and for larger generators with capacity greater than 20 MW. These new rules represent a substantial improvement in many areas of interconnection policy. Unfortunately, these improved FERC interconnection standards are the default only if the ISO or RTO has not set its own unique standard so they are only applicable in a few regions.

A significant barrier to entry for distributed generators is a concept called "deliverability."¹¹ The deliverability concept is generally incompatible with competitive entry into ISO/RTO markets for generators. The FERC rule defines a dual approach with two new types of interconnection services based upon the PJM model of interconnection: "Energy Only Service" and "Network Resource Service." Facilities that qualify as a Network Resource Service are guaranteed a much higher price for their electric power than Energy Only Service. To obtain Network Resource Service status in PJM for example, facilities must go through an expensive three prong interconnection process and pay the cost of upgrading the transmission system if the studies show

⁹ The FERC selected the North American Electric Reliability Council (NERC) as the ERO and the historic NERC sub regions also became part of the ERO.

¹⁰ Distributed generators is a term used for non-utility power sources that provide power to the grid. These generators can use any fuel source including solar and wind and are usually much smaller than utility power plants.

¹¹ Deliverability is a requirement that new applicants for interconnection to the grid must pay a fee towards the grid's transmission upgrade needs. Often this fee is well out of proportion to the power the new facility will sell to the grid especially in congested areas (like New Jersey) where the need for new power and new generation is acute. Deliverability fees are generally set to favor large generation facilities where the fee can be spread amortized over large amount of power sold to the grid.

that this is needed for the power to be “deliverable”. Even though this money is refunded with interest over time in bill credits for transmission service, facilities seeking to interconnect must nonetheless put up this money upfront to fulfill the interconnection requirements. Facilities can only participate in the auctions to receive a capacity payment from the PJM administered capacity market if they go through this process (AF&PA 2007).

The “deliverability” standard provides for the reduced price paid to “Energy Only Service” providers which do not become “Network Resource Service” providers. This is because during the interconnection process these new entrants are treated as the “marginal unit” which must be worked into the mix and be capable of running simultaneously without disturbing the incumbents units’ “right” sanctioned by the RTO to run. This preference of Network Resource Service units over Energy Only Service units is used even when the Energy Only Service units can provide power at a lower price than Network Resource Service units. Under FERC’s dual Energy/Network interconnection standard, the concept of “deliverability” limits competition from new entrants who wish to displace higher cost incumbents from the transmission system. It does so by creating obstacles through the burdensome interconnection process that only the most sophisticated entities can navigate. (AF&PA 2007)

Another aspect of meeting the “deliverability” standard for CHP facilities in some RTOs is they must demonstrate that their power output is “deliverable” to the market. In the impact study phase of the interconnection process the RTO assesses what upgrades are necessary to deliver power from the CHP to the market without the industrial load being present. It is virtually impossible for the CHP to be able to deliver this power if the industrial site to which it is intrinsically tied is assumed to not exist. Furthermore, CHP facilities cannot be sited to minimize interconnection costs posed by the deliverability standard as CHP must co-locate at the already existing industrial site. As a result, CHP plants oftentimes limit themselves to making sales into the non-firm energy market (Energy Service Only – lower price) only in order to avoid the burden imposed by the deliverability standard.

The “deliverability” standard does not need to be so onerous. This is evidenced by the approach taken by the New York RTO and the New England ISO that adopted a non-discriminatory standard as a regional variation to FERC’s rule. This standard known as the Minimum Interconnection Standard maximizes competitive entry to the grid. In these RTOs, any unit which is interconnected to the grid in a fashion which preserves the reliability stability and existing transfer capacity of the grid (without expanding the grid) is entitled to compete in both the capacity and energy markets. If there is not enough transmission infrastructure to “deliver” the output from both the new and existing units, then the units are forced to compete on the basis of price to determine which unit gets dispatched (AF&PA 2007).

Potential Discriminatory Treatment of Behind the Meter¹² CHP

RTOs and ISOs have repeatedly attempted to interfere with CHP in the area of “Behind the Meter” pricing. The RTOs and ISOs have attempted to charge customers who supply their own

¹² When the all of electric power output of CHP facilities is used internally, they are deemed to be “Behind the Meter” CHP facilities.

needs with “Behind the Meter” generation as if they had taken their entire power supply from the ISO - controlled grid. They try to charge for transmission, ancillary services and administrative fees based upon the total electrical consumption of a manufacturing facility, rather than the “net” amount actually taken from the grid. This cost allocation scheme, known as “Gross Load” pricing.¹³ (AF&PA 2007)

Gross load pricing failed in the PJM RTO and an equitable settlement was reached between PJM and Behind the Meter generators, most of which were owners of CHP installations. However this issue is now being raised in the MISO RTO in the context of a resource adequacy case (Dkt. ER08-394-001) where the FERC agreed to a rehearing request to consider disallowing the netting of Behind the Meter generation from gross load. Although it is anticipated that the Behind the Meter ruling will stand upon rehearing, this illustrates that owners of Behind the Meter CHP facilities must remain continually vigilant in their advocacy efforts on this issue as the challenges to the appropriate treatment of Behind the Meter generation is a reoccurring problem.

General Deterrents to CHP

CHP projects with power sales to RTOs are much harder to finance than sales under long term contracts with utilities at avoided cost under PURPA. This is because power sales agreements with utilities under PURPA would typically establish a capacity payment for a 20 year term. Under the new RTO rules, sales contracts to RTOs have price certainty for capacity payments (only in RTOs where capacity markets exist) for only a 3 year maximum period. The lack of long term price certainty, which was afforded by PURPA’s mandatory purchase obligation, is a major deterrent to financing the installation of new CHP.

Back in 1996, the Code of Alabama (37-4-30) was amended to allow electric utilities to impose exit fees on industrial customers who seek to serve their power requirements through third party CHP facilities. The argument used to gain acceptance of this practice was made in the context of the “stranded costs” supposedly incurred by the utility due to the industrial seeking more energy efficient options for their steam and power supply. The utilities argued that recovering these “stranded costs” through an exit fee on those who seek to obtain power from such CHP facilities and who leave the utility system is justified since it protects those customers who remain on the system, as if there was never going to be any load growth on the system or the utility was unable to sell excess power to neighboring utilities. Many third party CHP facilities which should have been built in Alabama to serve industrial load since 1996 were not built because the threat of an exit fee significantly affected the economics of the project. This law, which protects the utility’s franchise, continues to sanction a highly discriminatory practice and prolongs inefficiency in the generation of power, as it has not yet been repealed.

¹³ An example of this discriminatory practice is described as follows. Back in 2005, the PJM RTO claimed to have a reliability concern because of “Behind the Meter” generation. PJM stated that although Resource Adequacy risk is concentrated in a relatively small number of days of the year, (90% in 10 Coincident Peak days), a Behind the Meter facility that has a power failure requiring it to pull additional power from the grid during those days poses a risk that its Behind the Meter load will “Lean” on the system. PJM failed to recognize that a customer with Behind the Meter Generation CHP is nothing more than a customer with a poor load factor.

Other utilities throughout the country have included life of contract demand ratchets in their large industrial rate tariffs. These serve as a deterrent to increased installation of CHP as well since the industrial customer must pay up to 75% of the demand listed in their contract regardless of whether they take the power or not. Many customers faced with the cost of this potential demand ratchet wait to install their CHP facilities until after the initial term of their contract has expired. The contract is then cancelled during an annual rollover period to minimize costs incurred from the demand ratchet.

The lengthy and extensive process to secure environmental permitting for CHP is a real barrier to entry. Expedited and streamlined permitting procedures for CHP facilities, which will increase the energy efficiency of an industrial operation, are greatly needed. In addition, major new emission sources are required to meet New Source Review (NSR) requirements to obtain operating and construction permits. NSR sets emission rates for criteria pollutants and requires installation of the best available control technology. (ACEEE 2003) New sources are also required to offset existing emissions in non-attainment areas. The emissions standards are usually based on fuel input, an approach that does not recognize the fuel efficiency of CHP technologies. As a result of these environmental deterrents, CHP facilities are often times not installed because they may represent marginal improvements but do not achieve BACT or sufficient offsets are not available in these non-attainment areas for the new facility to get built.

Another potential deterrent to the expansion of CHP looming on the horizon is in the area of allocation of allowances under a greenhouse gas reduction program. The most commonly discussed methodologies allocate allowances based on historic direct emissions (not including purchased power). The problem with this approach is that it does not consider the superior energy efficiency attributes of existing CHP and treats such facilities similarly to utility plant. These approaches to GHG mitigation impose a cost on polluters but provide no incentive to clean energy sources such as CHP (clean by virtue of using at least 1/3 less fuel). Going forward, industrials will be hesitant to install new CHP because they will have to secure allowances to emit from the new facility while not receiving any credit for the reduced power consumption.

An alternative “output-based allowance”¹⁴ (OBA) allocation scheme relates emissions to the productive output of a process. OBAs encourage all actions that lower greenhouse gas emissions per unit of useful output, and penalize above average pollution per unit of output, thereby

¹⁴ Under this methodology each electric producer including the CHP facility is awarded with initial allowances of 0.62 metric tons of CO₂ emissions per delivered megawatt-hour of electricity (MWh_E). Also provide each thermal energy producer with initial allowances of 0.44 metric tons of CO₂ emissions per delivered megawatt-hour of thermal energy (MWh_T). These allowances levels reflect the 2007 average national emissions for electric and thermal. The next step requires every plant that generates heat and/or power to obtain total allowances equal to its CO₂ emissions. Dirty plants purchase extra allowances from clean plants at market prices. Since costs for allowance purchases equal revenue from allowance sales, the economy feels no increase in the average cost of producing heat and power, but clean plants win and dirty plants lose. Schedule these allowances – for each pollutant per unit of output – to drop every year and correct for increased output in order to insure total emission reductions.

unleashing innovation and creativity (Munson et al 2008). This market-based approach encourages heat and power producers to lower GHG and other emissions without increasing overall energy costs. An OBA system, encourages efficiency, which lowers GHG and criteria pollutant emissions, saves fossil fuel, and reduces heat and power costs. OBAs stimulate investment in high efficiency while lowering all pollutant emissions.

Recommendations

The RTOs and ISOs should not mandate that CHP facilities comply with all the operational rules developed for merchant generators listed in their generic tariff provisions and mandated by execution of their operating agreements, but instead should allow for the refinement of contract terms to accommodate any particular needs and concerns with respect to the curtailment and dispatch of CHP. The RTO cannot accommodate the dynamic requirements of CHP's industrial processes when dispatching facilities as the first priority of a CHP is the provision of steam or heat to the industrial host. This accommodation of CHP needs is warranted in light of the economic and environmental benefits that accrue from CHP operations.

It should not be the responsibility of the new entrant offering a lower price designed to displace the incumbent's facility for the benefit of consumers to build transmission facilities in order to compete for the same load. In a purely physical sense, any unit connected reliably to the electric grid and capable of delivering energy to any load is "deliverable" to that load. This physical idea of deliverability is not applied under the FERC Network Resource Standard where the generator seeking to interconnect must fund transmission upgrades to become "deliverable". This concept of "deliverability" as implemented in the FERC interconnection standards and by PJM should be abandoned. The Minimum Interconnection Standard used in the New York RTO and New England ISO should be adopted by the FERC and all the RTOs and ISOs in the nation.

Targets should be set for CHP and recycled energy that increase capacity installation and operation. In particular, CHP and recycled energy should be declared acceptable to meet at least half of the requirements in any adopted policy requiring a percentage of power purchased for resale by utilities to come from renewable or energy-efficient sources of electric generation.

Since utilities are guaranteed returns for building expensive new central power projects, there is a reluctance to buy power from CHP and other independent generators unless there is a mandate requiring them to do so. One potential legislative solution to this problem is to adopt the Clean Energy Standard Offer Program (CESOP) as national policy. Under CESOP, state regulators determine the cost of delivering electricity from the best new, electric only power plant that meets environmental standards and then offers long term contracts for clean energy at 80% of that cost. (RED 2008). Two different CESOP rate structures are proposed depending on whether the power is generated from industrial waste energy or from new CHP that meets the annual efficiency tests. Both structures would ensure that the state obtains clean energy at a cost below what it would pay for power from new coal fired centralized facilities. (TVA 2008) The contract term of 20 years would remove the financing problem mentioned above.

Incentives should be provided for states that adopt, for jurisdictional utilities, a gas delivery tariff that provides gas delivery to CHP facilities at rates for transmission and distribution service no less advantageous than the rate at which gas is delivered to any other gas-fired electric generator. This has already been implemented in much of New York State.

A complementary approach, used in the European Union as part of their cogeneration directive, is to provide feed-in tariffs to encourage the development of CHP resources. A feed-in tariff is an agreement between an electricity generator and a utility whereby the former is paid an agreed-upon rate (could be the CESOP rate or another rate set by the regulator) for electricity that is fed back onto the grid (DOE 2008). This kind of arrangement can be used to deliver all of the CHP production to the utility particularly if the CHP is renewable or it can be used to deliver the excess electricity produced. The overarching principle is that it allows for optimization of the CHP facility to ensure maximum efficiency.

If a cap and trade program is established, special provisions will need to be made for CHP systems as current cap and trade approaches provide no credit for the energy efficiency provided by existing CHP systems. Emissions based approaches also do not provide an incentive mechanism as its basic construct for the nation to become as energy efficient as possible through CHP and distributed generation resources (Munson et al 2008). This is a major deterrent to new CHP being developed. The output based approach discussed above should be seriously considered as an alternative to the emissions based approach for allocation of allowances. However, should an emissions based approach be ultimately adopted, an alternative albeit less elegant solution to removing the deterrent to increased CHP would be to establish a mechanism for transferring emissions allocations from a utility, which would reduce emissions, to a CHP system, which would increase emissions.

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