COMBINED HEAT AND POWER:
AN ASSESSMENT OF WASHINGTON STATE POLICY

by

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ABSTRACT

Combined Heat and Power: A Washington State Policy Assessment

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There is a recognized potential for combined heat and power (CHP) to meet a substantial percentage of the nation's electricity needs—perhaps as much as 20%. CHP's well-established, low-cost technologies offer striking efficiency gains over traditional central generation. While CHP's high efficiency offers many economic, environmental, and societal benefits, its deployment falls far short of the acknowledged potential in the state of Washington and across the nation. Focusing on Washington, this paper provides a detailed examination of the state's various policies affecting CHP development, and places them in the context of best practices, as those have emerged and continue to evolve with the benefit of experience gained from state and federal efforts. The purpose is to promote a clearer understanding of the state's policies in aggregate and in relation to each other, as well as in relation to those of other states. Individually, many of Washington's policies show considerable room for improvement; in the aggregate they suffer from a lack of cohesiveness and coordination. In order to fully realize the benefits of CHP in a state with some of the lowest electricity prices in the nation, it is imperative to craft a harmonized set of policies that will nurture CHP and other forms of distributed generation. The lack of sustained, explicit legislative commitment is the most important deficiency to address.

Table of Contents

List of Figures

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Introduction

Combined Heat and Power, usually referred to as CHP or cogeneration, is the production of both electricity and useful thermal energy at the same time, from the same fuel source. Because it burns fuel only once for two purposes, the process is considerably more efficient than the separate generation of electricity and heat. The thermal energy is typically hot water or steam used for industrial processes or for space heating, but it can also be used for cooling, drying, dehumidification, and other purposes. CHP is a sub-category of distributed generation (DG), which comprises small, decentralized electricity production in all its forms, including wind, solar, geothermal, and others in addition to CHP. DG, in turn, can be included in an even broader category known as distributed energy resources (DER), which includes all of the above, as well as conservation, efficiency, and demand reduction strategies considered as a resource (Bloomquist, Nimmons, & Spurr, 2001, p 1).

While CHP's high efficiency offers many economic, environmental, and societal benefits, its deployment falls far short of the acknowledged potential in the state of Washington and across the nation. Focusing on Washington, this paper provides a detailed examination of the state's various policies affecting CHP development, and places them in the context of best practices, as those have emerged and continue to evolve with the benefit of experience gained from state and federal efforts. The purpose is to promote a clearer understanding of the state's policies in aggregate and in relation to each other, as well as in relation to those of other states. Individually, many of Washington's policies show room for improvement; in the aggregate they suffer from a

lack of cohesiveness and coordination. In order to fully exploit the benefits of CHP in a state with some of the lowest electricity prices in the nation, it is imperative to craft a harmonized set of policies that will nurture all forms of distributed generation. I will suggest that the lack of sustained, explicit legislative commitment is the most important deficiency to address.

Washington has a stated intention to become a leader in clean energy technologies, and has ambitious goals for renewable energy, energy efficiency and conservation, and greenhouse gas reduction. These goals, which are codified in statute, are in themselves sufficient reason to make concerted efforts to identify and eliminate every obstacle to the full development of CHP's underutilized, relatively low-cost efficiencies. But the regulatory, institutional, and economic barriers that slow the expansion of CHP often hinder renewable energy and other forms of distributed energy resources as well. This fact lends both urgency and further justification to the task.

A toolbox of policy options can be assembled which, if employed judiciously, can enable policy makers to improve the state's economy, reduce environmental impacts, and save money for businesses and ratepayers. However, experience shows that these tools work best in coordination, and when calibrated to local circumstances. Even then, optimum results will not automatically follow, underscoring the need for continuing legislative commitment to larger policy goals. Those goals are best served by a thorough understanding of the issues and obstacles; this paper represents a small step in that direction.

Many of the policy issues that will be considered here are at least partly the result of the independent, interlocking, and overlapping jurisdictions under whose authorities

the production of electricity is regulated and managed in the United States. The Federal Energy Regulatory Commission (FERC), the successor to the Federal Power Commission, has jurisdiction over nuclear power plants, most hydropower facilities, interstate transmission lines, and all generation that supplies wholesale power to the grid. State utility regulators—which in Washington means the Utilities and Transportation Commission (UTC)—generally control the activities of for-profit, investor-owned utilities (IOUs) selling retail power within their jurisdictions. Public utility commissions typically wield statutory authority under the auspices of state legislatures. Not-for-profit, consumer-owned utilities (COUs), including electric cooperatives and municipal utilities like Tacoma Power or Seattle City Light, are in principle largely independent and unregulated, subject of course to enabling legislation and other statutory limitations and guidance (Shirley, 2007, p 1). Historically, and in many cases even now, individual utilities have had wide latitude in setting the terms of business with their customers; this has been true of regulated power companies and municipals alike, especially in matters not directly related to rates.

Background

History

Combined heat and power is by no means a new idea. When the electric power industry was in its infancy, it was common—indeed necessary—for power plants to be located close to the consumers (DOE, 2007, p i). The earliest plants were direct current (DC) generators, and at that time, DC power could not be conveniently transmitted over long distances. Neither could heat, and power plants produce a great deal of that as well. Thus, a power plant sited near its customers could improve its efficiency and profitability by capturing waste heat and selling it for use by its neighbors.

Direct current, however, was not the only way to generate and transmit electricity. Alternating current (AC), while initially more complicated and challenging, had the advantage of being much more easily and inexpensively transmissible over long distances (Fenn, 1984, p 6). AC power allowed a utility to reach customers farther from the power plant. Obviously, this also meant that the power plant no longer needed to be located near the end users. This fact had its own set of advantages: plants could be built in isolated locations where there would be fewer complaints about smoke and soot, and they could be built close to existing transportation infrastructure or supplies of needed resources such as fuel and water, increasing convenience and reducing costs. Economies of scale were another important consideration favoring alternating current; once the distance obstacle was eliminated, a single massive power plant could serve a larger, more dispersed population.

These and other factors contributed to the rise of a system of large, centralized, and often remotely located generating stations, connected to each other (for greater reliability) and to their customers by an interstate network of transmission and distribution lines. The notion of localized plants making full and efficient use of their fuel resources by utilizing their waste heat or selling it to neighboring customers fell by the wayside. Such efficiencies were not imperative when fuel was abundant and cheap, air pollution unregulated and global climate change unheard of. CHP continued to be employed in a few industrial settings with high demand for both electricity and heat, such as paper mills, chemical plants and oil refineries (ORNL, 2008, p iv), but otherwise languished for decades. Indeed, at least until the 1960s, technological improvements and economies of scale resulted in falling electricity prices even as the overall energy efficiency of the industry was in decline (DOE, 2007, p 1/2; Fenn, 1984, p 26). In addition, for a number of reasons including the capital-intensive nature of the business, electric utilities had been treated as natural monopolies and often granted exclusive territorial franchises free of competition (Steinhurst, 2008, p 4). In such circumstances, neither utilities nor their customers had much reason to consider CHP or any other form of investment in energy efficiency.

In the 1960s, however, this golden age of electricity showed signs of coming to a close. The construction of ever-larger power plants became less and less desirable for a number of reasons. As manufacturers pushed the bounds of technology in the pursuit of higher efficiency and lower costs per unit of output, the increasing operating temperatures and steam pressures of these massive units began to cause more frequent breakdowns. Meanwhile the sheer size and complexity of the facilities made even

routine maintenance more time-consuming and costly. As a consequence of these factors, overall cost-effectiveness and operational efficiency suffered, effectively capping the benefits heretofore available from larger unit size. Electric utilities, like all heavy industry, also felt the growing burden imposed by the dawning era of environmental regulation. As costs increased, demand at last began to fall, after decades of growth so strong and steady that utility forecasters were once said to need no tools except a good ruler (Fenn, 1984, p 6); in contrast, by 1986 "an *Electrical World* editorialist called load forecasting 'a psychoanalytical crap-shoot'" (Hirsh, 1989, p 163).

Among the causes of all this uncertainty were the energy crises and oil price shocks of the 1970s, which brought fear of endlessly climbing oil and natural gas prices, and gave renewed currency to the concepts of efficiency and conservation. One of the results was the enactment by Congress, in 1978, of the Public Utilities Regulatory Policies Act (PURPA). PURPA not only promoted renewable energy sources such as wind and solar, it also included cogeneration which met certain standards. Electric utilities had almost exclusively been large, vertically integrated entities owning their own generation, transmission and distribution infrastructure. Now, for the first time, non-utility power producers were allowed—even encouraged—to export electricity into the utilities' systems, if only on a relatively small scale, and only on a wholesale basis. Producers that met statutory requirements could apply for status as a Qualifying Facility (QF), a new class of generating entity created specifically by PURPA. Utilities were required to purchase power from QFs at a price equal to what it would have cost the utilities to generate it themselves (the so-called avoided cost).

The avoided cost was expected to continue rising with the projected upward trend of oil and natural gas as power plant fuel. As long as this held true, PURPA provided a reliable, attractive rate of return for investors in CHP, stimulating the addition of as much as 44,000 megawatts (MW) of new cogeneration capacity in the twenty years after 1980 (ORNL, 2008, p iv). But fossil fuel prices began to fall in the mid-80s, gradually weakening the investment incentive. By 2001, a Washington State University CHP study said that because of evolving energy markets and low avoided cost payments, PURPA had become "a dead letter" in much of the country (Bloomquist et al., 2001, p 6).

Nonetheless, one of the effects of PURPA was to stimulate a new generation of renewable and high-efficiency distributed generation technology. The intervening years have also seen the development of innovative designs that make customized onsite generation available to utility customers (DOE, 2007, p ii). As a result, encouraging DG and CHP has become an increasingly important policy tool for improving energy efficiency, curbing air pollution, reducing reliance on imported fossil fuels, and making the nation more economically competitive. Currently, both the Department of Energy (DOE) and the Environmental Protection Agency (EPA) have programs encouraging combined heat and power development. The DOE promotes CHP and other forms of distributed energy through the Industrial Distributed Energy activities of its Industrial Technology Program, and by sponsoring partnerships involving government, academia and the private sector in its Clean Energy Application Centers, formerly called CHP Regional Application Centers (DOE, Industrial Distributed Energy webpage). And since 2001, the EPA has operated its own Combined Heat and Power Partnership to encourage public/private cooperation in CHP development (EPA, 2011).

The great value of combined heat and power, as mentioned at the outset, lies in its ability to make use of the tremendous amount of waste heat produced in power generation, which typical power plants simply reject to the environment—either to the air or an adjacent river. As one industry observer wrote in 1989, a company using cogeneration "reaps an energy bonanza" by utilizing 80% of the fuel's energy content, as opposed to a mere 35% conversion efficiency for central generation (Hirsh, 1989, p 165).

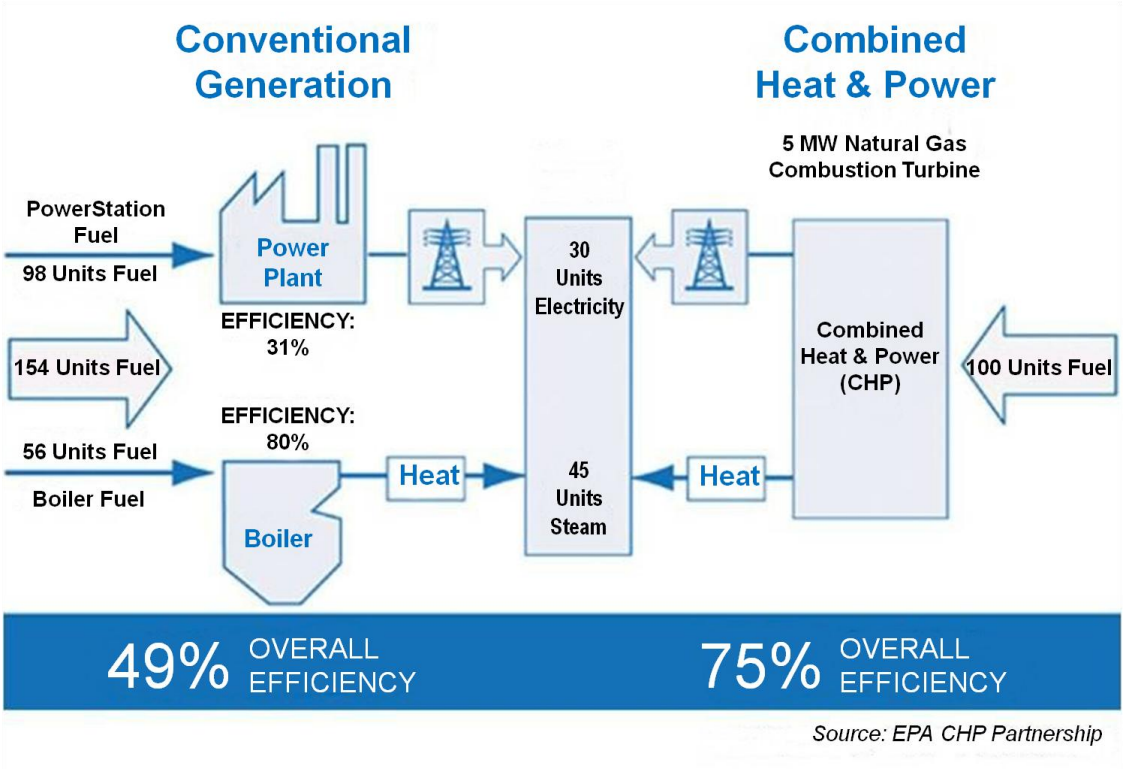


Figure 1: Comparative Efficiency, Central Generation vs. CHP

Those astonishing numbers are just as true today. During the typical process of converting fossil fuel to electricity, as much as two thirds of the fuel's latent energy ends up as waste heat, a constraint imposed by the laws of thermodynamics. Adding insult to injury, five percent of power generated is used by the plant itself, and about seven percent is lost in transmission and distribution, according to the Energy Information

Administration (EIA), making the overall efficiency of centrally generated power very low indeed (EIA, 2010, p 66).

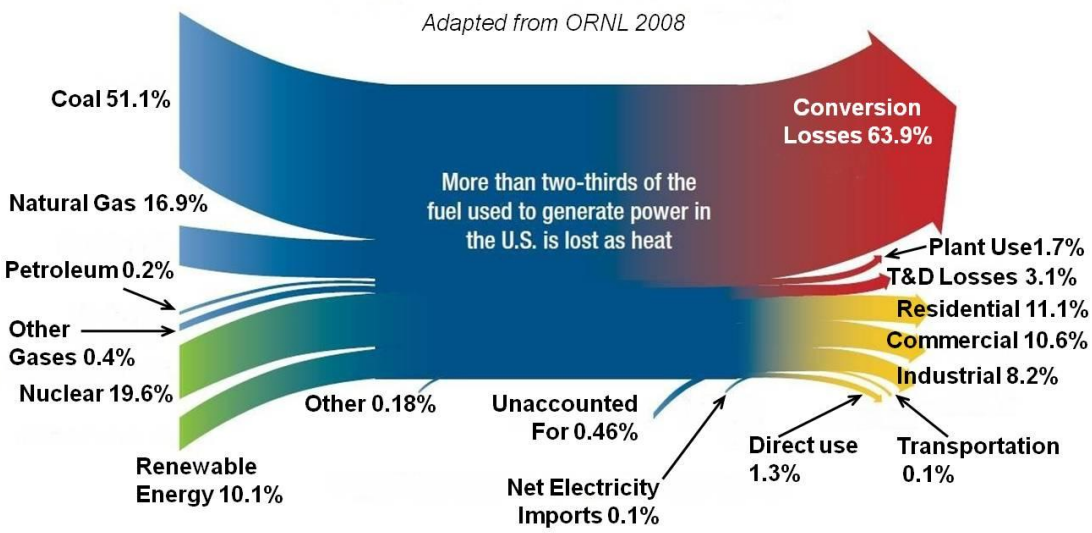


Figure 2: U.S. Electricity—Where It Comes From, Where It Goes

As also stated earlier, CHP accomplishes its feat of efficiency by producing both electricity and thermal energy from a single combustion process. CHP is not a technology in its own right, however, as much as a way of applying technology to derive maximum benefit from the primary energy source. The driver or prime mover may be an engine (reciprocating, Stirling, or Organic Rankine Cycle), gas turbine, boiler/steam turbine combination, or even a fuel cell (WGA, 2006, p 5). In modern applications the fuel is frequently natural gas, but depending on the application may be gasoline, diesel, biomass, coal, or virtually anything combustible.

The most common configuration generates electricity first, then employs waste heat for any purpose useful to the host site, including cooling and dehumidification. One method burns fuel in an engine or turbine, then uses the exhaust gases to heat water;

another burns fuel in a boiler to run a steam turbine for power generation, re-using the steam afterward at lower pressure and temperature for secondary purposes (see Figure 3).

Other arrangements are also possible. Waste heat from high-temperature industrial processes can sometimes be captured to create steam to run a generator. Large institutions such as colleges often generate high-pressure steam at a central location and

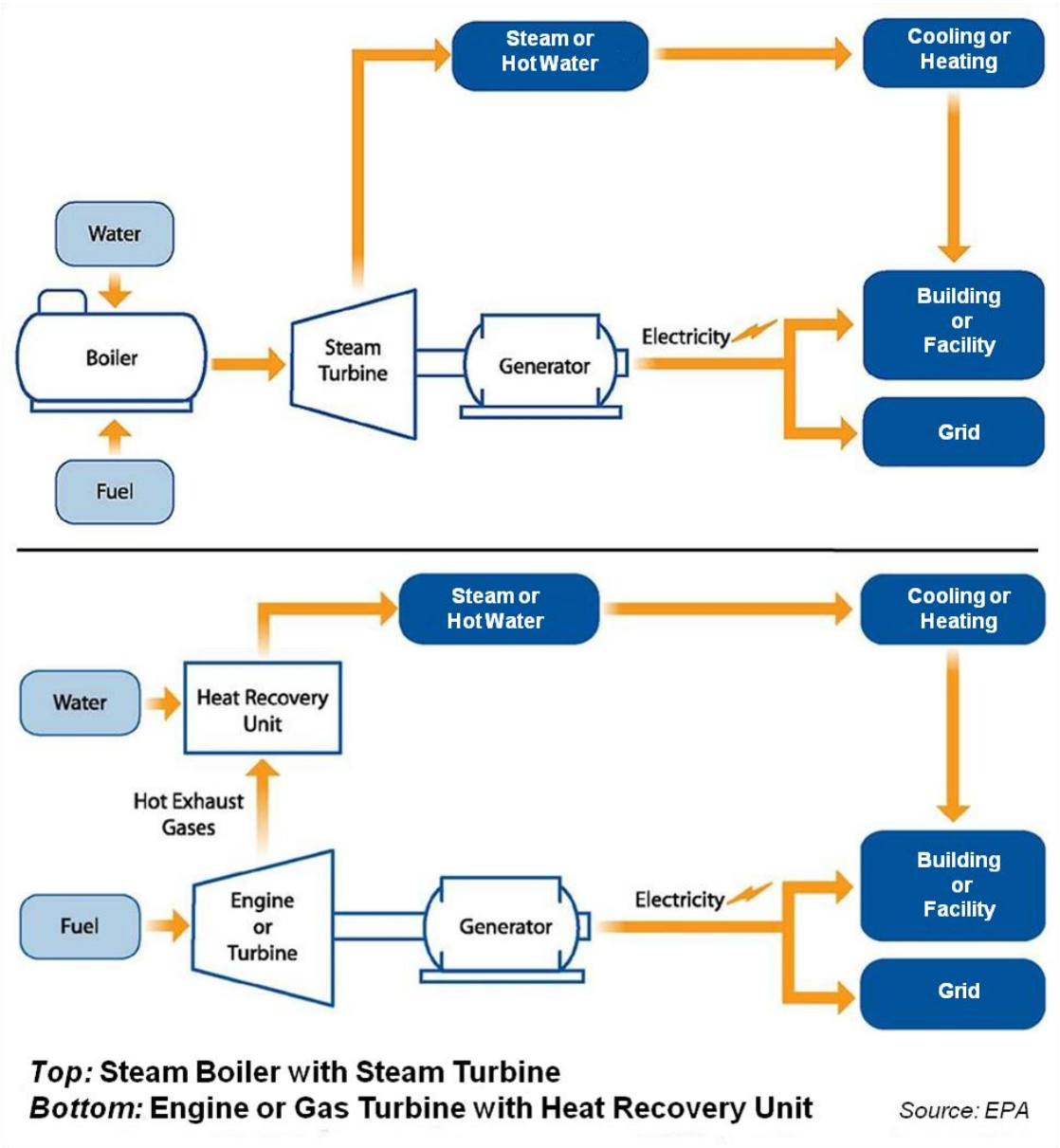


Figure 3: Typical CHP Configurations

distribute it to buildings throughout the campus, using valves to reduce the pressure to the levels required for specific applications. At such points, back-pressure steam turbines can be installed in place of pressure-reduction valves, generating electricity with little or no additional fuel burned (Casten, 2003a).

Other nations are well aware of the value of CHP, and of efficiency in general. Figures 4 and 5 portray the situation vividly. At least a dozen countries including China derive a greater portion of their power production from CHP than does the U.S., some of them three to five times as much. Partly as a consequence, U.S. economic output per unit of energy consumed also lags far behind the rest of the developed world, a fact that will loom larger and larger as fossil fuel supplies tighten and prices rise over the coming decades. The positive side of those unpleasant facts is that the nation has a great deal of untapped CHP potential, which if developed could provide numerous benefits for the

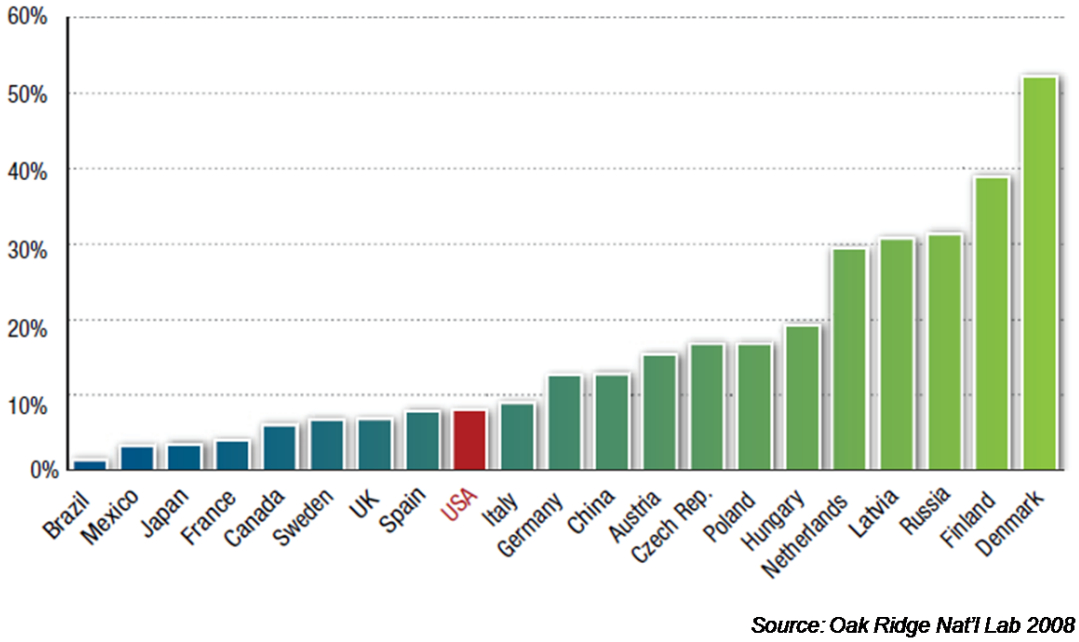


Figure 4: CHP Share of National Power Production

economy, the environment, and the public power supply system. In the state of Washington alone, DOE's Northwest Clean Energy Application Center finds there is technical potential for over 4,300 MW of new CHP (NW CEAC, 2010, p 3), equaling more than 14% of Washington's total 2009 generating capacity (EIA, 2011).

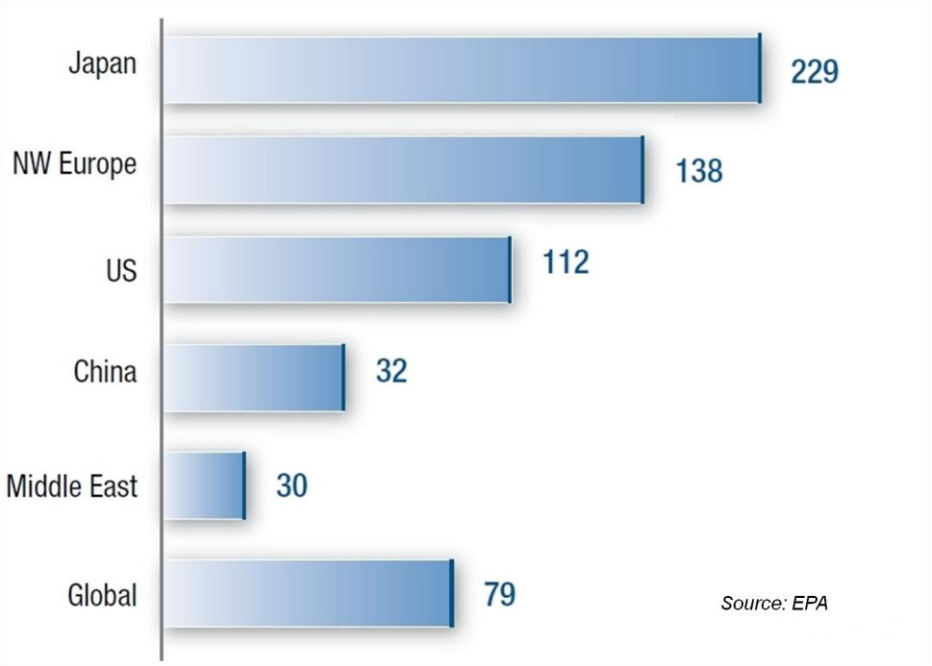


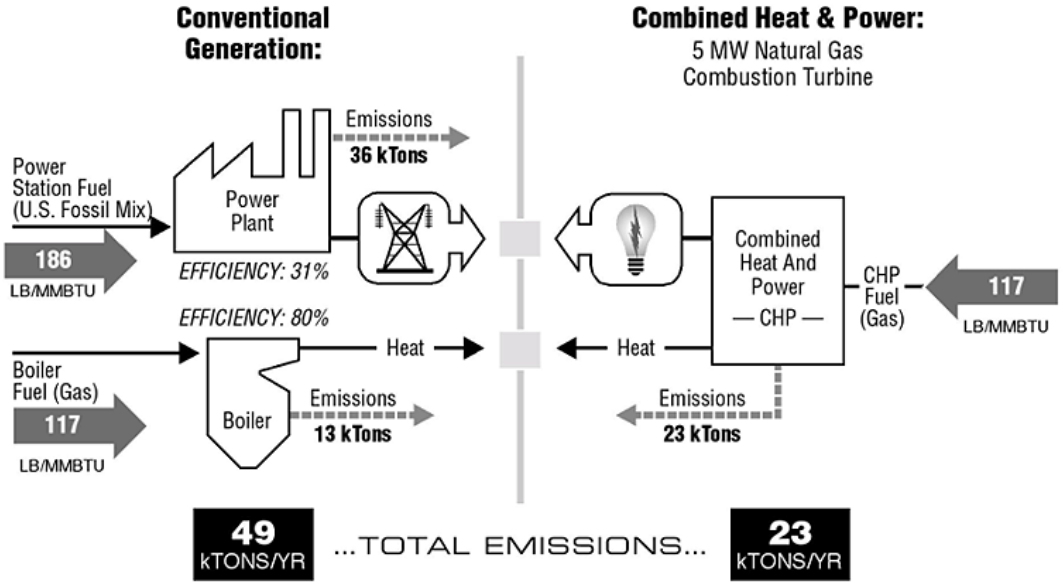
Figure 5: Global Energy Productivity (Billion Real $ GDP per Quad)

Benefits of CHP

While even the rough sketch just presented is enough to make fostering CHP a worthwhile policy goal, the benefits of cogeneration extend far beyond energy productivity and economic efficiency. Among them are: lower greenhouse gas emissions; reduced pollution from criteria pollutants such as mercury, sulfur dioxide, and particulates; relief for congested transmission and distribution (T&D) lines, including lower infrastructure costs due to deferring or eliminating the need for T&D construction; and greater system reliability.

Greenhouse gas emissions

It should be obvious that because CHP makes more productive use of primary energy inputs, overall emissions levels will be lower. This is true even in Washington; although a substantial majority of the electricity consumed in the state comes from emission-free hydropower, 17% comes from coal, and 13% from natural gas (WA Dept. of Commerce, 2010). According to a report prepared for the Western Governors' Association (WGA), CHP produces on average 49% less CO_2 than conventional generation (WGA, 2006, p 15). The main reason, of course, is that CHP onsite not only mitigates the host's need to purchase electricity from the grid, it also provides thermal energy that would otherwise be produced by separate conventional boilers (Figure 6). And by generating power at the point of use, the emissions associated with power lost in transmission and distribution are also prevented.



Source: EPA

Figure 6: CO_2 Emissions Benefits of CHP

Criteria pollutants

For the same reasons that cogeneration reduces greenhouse gas emissions, it has a similar impact on traditional regulated pollutants. The specific effect will vary according to the pollutant in question, the fuel and prime mover used in the CHP installation, and the type of central generation displaced. For instance, most cogeneration is natural gas, and in the timber-rich western states may also be wood waste or other "opportunity fuels" from the lumber and paper industries (WGA, 2006, p 15). Unlike coal, these fuels contain no mercury and will completely eliminate emissions of this dangerous pollutant associated with any coal-fired generation displaced. The impact of electricity production on environmental quality is succinctly highlighted in a report from the National Regulatory Research Institute (NRRI):

> Electricity production may affect air and water quality, greenhouse gas levels, radiation levels, land use, wildlife, crops, and human health. Electric generation accounts for about 40% of U.S. greenhouse gas emissions, as well as 67% of the nation's airborne mercury emissions, and large amounts of sulfur dioxide and nitrogen oxide emissions, mainly from coal. Transmission and distribution construction, too, have environmental effects through land clearing and herbicide application. The environmental effects of producing and delivering fuels for generators are also a concern, as well as the disposal of ash, nuclear waste, and other materials used or produced by generator operations. (Steinhurst, 2008, p 3)

CHP offers benefits in all these areas, improving efficiency and thereby reducing fuel consumption, and reducing the need for new infrastructure and its unavoidable impacts.

T&D congestion

With population growth and the inexorable long-term increase in demand for electricity, existing transmission and distribution infrastructure inevitably becomes overloaded, in need of upgrade or expansion. But because CHP produces power at or near the point of use, it can reduce the strain on existing capacity when sited in

constrained areas, and mitigate or eliminate the need for expensive new construction. This also helps avoid political battles over siting of new lines and facilities, and reduces capital investment costs as well. And regardless of location, CHP facilities in aggregate provide system benefits by reducing load growth and postponing the need for capital investment (WGA, 2006, p 8). In addition, T&D power losses are greatest when lines are overloaded during peak hours, in some cases rising to as much as 20%. Thus, by reducing demand, especially at peak, CHP can enable the entire system to operate more efficiently (ORNL, 2008, p 20).

System reliability

The two key aspects of power supply reliability—adequacy and security—can both be enhanced by CHP, for the host site and for the system as a whole (Schwartz, 2005, p 6). A utility customer that has its own generating capacity has protection against power outages, of course, which is why facilities like hospitals typically have backup generators. But by reducing system overloads associated with peak demand, CHP has the potential to improve the reliability of the entire system. In addition, if CHP and other forms of distributed generation become sufficiently widespread, they also reduce the grid's vulnerability to both accidental outages and deliberate sabotage, offering fewer large, attractive targets and strengthening the system's ability to provide continued service in the event of a successful attack. And because CHP tends to be located in commercial/industrial areas, equipment is less physically isolated than typical large power plants and inherently less subject to security concerns (WGA, 2006, p 14).

Barriers

Despite these and other advantages and benefits, CHP remains an underutilized resource. Part of the problem resides in trying to change a nationwide system that has for a century been geared toward monopoly control, massive central power plants, and a one-way flow of electricity from generator to end user. Like turning an aircraft carrier, it is a slow and ponderous process. But there are many obstacles of a more specific nature, most of them amenable to politically feasible policy solutions. They can be—and have been—variously enumerated and categorized, and no two methods are entirely alike. Some analyses examine a single state, region or group of states, while others take a wider view, looking at the picture nationwide or even on a global scale. Some focus on technical challenges, or specifically on barriers related to rates, though most attempt to cover all the bases. Issues may be lumped together in broad categories, or teased out and addressed in more detailed particulars. Finally, studies may encompass DG in general, or restrict their scope to CHP only, though areas of overlap are so extensive that what applies to one will often apply to the other.

The Oregon Public Utilities Commission, for example, found the major obstacles to be as follows (Schwartz, 2005, p 1):

- interconnection standards
- backup power rates
- outdated PURPA policies
- customers' inability to easily sell power they generate to the utility or other customers
- utility planning for T&D being done separately from capacity planning
- utility disincentives

In contrast, the Western Governors' Association White Paper characterizes CHP's barriers this way (WGA, 2006, p 22):

- financial bias of electric utilities
- false conflict between environmental and economic policies
- failure of retail-level grid management to acknowledge unregulated market participants
- conflict between electric utility shareholders and the public interest
- private sector capital allocation processes

As a last example, a 2008 report by Oak Ridge National Laboratory (ORNL) used a somewhat more concise breakdown (ORNL, 2008, p 22):

- regulated fees and tariffs
- interconnection issues
- environmental permitting
- tax treatment
- technical barriers

A few moments' study will uncover areas of both commonality and disagreement among the idiosyncrasies of terms and description found in the lists above. And of course, any arbitrary set of categories will be subject to overlap and ambiguity, with the result that there is no right or perfect way to dissect the problem. However, after consulting these and numerous other studies, the following categories seem most relevant to Washington state and will be used in the subsequent discussion:

- interconnection standards
- rates and tariffs
- siting and permitting
- utility disincentives
- policy support

Policies from around the nation will be examined to identify best practices, and compared with the current state of affairs in Washington.

Best Practices Defined

Before discussing best practices, it is important to define the term. Utility commissions have traditionally considered it their mission to ensure low rates and reliable service (Keeler, 2008, p 1), a tempting basis for definition. But a myopic focus on low rates in the present may perpetuate a system that tolerates or even encourages inefficiencies which the future may find unforgivable. Further, methods that have provided reliable service for nearly a century, by focusing almost exclusively on massive central generation, may no longer do so in changing circumstances. This discussion will take it as given that the world is increasingly constrained by shrinking supplies of readily available fossil fuels, even as global demand rises along with their costs and the environmental impacts of obtaining and burning them. In that context, it will be assumed that best practices are those that maximize energy efficiency and which promote, to that end, the greatest cost-effective market penetration of CHP technologies in appropriate circumstances where fossil fuels will continue to be used for the foreseeable future.

Even with such a specific and concise definition, however, best practices are not always easy to determine or to apply from one state or region to another. Each state has an economic and political landscape not quite like any other. But the welter of state, federal and municipal authorities described in the introduction means that each state also has its own statutory and regulatory environment. Regulatory differences are amplified by the fact that a number of states have undergone restructuring to introduce market competition to their electric power industries. Since the Enron debacle and the rolling blackouts and price spikes of the early 2000s, some states including California have suspended restructuring. Consequently, there are states with traditional regulation,

restructured states, and others somewhere in between, making it even more difficult to say with confidence that best practices in one place will translate well to another.

Interconnection Standards

Interconnection standards are the rules, regulations, and policies governing the connection of a customer generating facility to the utility's distribution system and the grid at large. Interconnection allows the customer to receive electricity from the utility if its generator is shut down or produces less than the customer needs, and to feed back into the grid any power generated in excess of the customer's consumption. Interconnection standards are among the most complex and yet pivotal areas of policy affecting the spread of distributed generation technologies of all types. They are complex because they reach across the spectrum from the practical to the political—from engineering details and business contracts to rate regulation and broad-scale public policy choices—and pivotal because very few customers are either willing or able to rely entirely upon their own generating capacity for all their needs at all times. Further, project economics often depend upon the ability to sell at least some portion of generated power to the utility or other customers.

Interconnection standards generally fall into two broad categories: technical standards, governing the means, methods, engineering requirements and equipment of the actual physical connection between the customer's generating apparatus and the power company's system; and business practices, including application processes, insurance requirements, design review procedures, equipment certification, etc. As with the broader topic of obstacles to CHP generally, the division is necessarily artificial. Others have also commented on the fluid nature of such descriptive categories, which are

reformulated by various researchers for convenience of analysis (Alderfer, Eldridge, & Starrs, 2000, p 5).

Technical Standards

When PURPA opened the door for non-utility power producers in the late 1970s, it also engendered a need for equipment and procedures for connecting those generators to the grid and managing their operations. The necessity grew as distributed generation became more common with the advent of customizable technologies. Technical standards became even more important when in the late 1990s, federal authorities began to experiment with restructuring electric utilities, creating competitive markets for wholesale power and encouraging new entrants to the field (Steinhurst, 2008, p 6). The Institute of Electrical and Electronics Engineers (IEEE) is one of a number of groups that creates standards for the electrical industry; to address the growing need for uniformity it drafted IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems," which addresses technical and hardware requirements for interconnection. This standard was adopted in 2003, and was cited as a reference standard by the Energy Policy Act of 2005 (EPAct), which encouraged (but did not require) states to use it as a basis for their interconnection rules (DOE, 2007, p 1/14).

Another important technical standard is UL 1741, "Inverters, Converters, and Controllers for Use in Independent Power Systems," devised by Underwriters Laboratories, the well-known testing organization. This standard implements the requirements of IEEE 1547 and includes additional product testing provisions (Sheehan, 2008, p 4). When adopted by utilities and regulators, these two technical standards can provide a measure of consistency and uniformity regarding the physical interconnection of small CHP and other forms of distributed generation.

Business Practices

Regulatory oversight notwithstanding, utilities have generally had considerable freedom in doing business with potential interconnection customers (Alderfer et al., 2000, p 15). This is due at least in part to the potential impact of DG projects on safety and reliability of service, matters for which the utility bears the primary responsibility. Unfortunately, such deference to industry expertise is partly responsible for the current situation, which prompted the observation, as recently as 2007, that there are no uniform interconnection standards in the U.S. (Shirley, 2007, p 1). But just as standardized engineering specifications help manufacturers, standardized paperwork and procedures help developers, as well as businesses considering investing in CHP, by introducing predictability and regularity to the process. The EPA, in its 2006 *Clean Energy-Environment Guide to Action*, recommends a streamlined application process with procedures and costs tiered in recognition of the increasing complexity of interconnecting larger generators. The agency also emphasizes the existence of extensive groundwork done in creating model interconnection rules by such organizations as the National Association of Regulatory Utility Commissioners (NARUC), the Interstate Renewable Energy Council (IREC), and the FERC, and urges state commissions, in the interest of fostering uniformity, to use these model rules as a basis for their regulations (EPA, 2006, p 5/49).

Best Practices

As of late 2010 thirty-five states had interconnection policies incorporating IEEE 1547 and UL 1741 (NNEC, 2010, p 106). There are also other standards that must be complied with by utilities, power producers and/or makers of electrical equipment. Some

are from the IEEE, and others are from such sources as the American National Standards Institute (ANSI), the National Electrical Code, (NEC), and the National Electrical Safety Code (NESC) (Shirley, 2007, p 6). However, for present purposes, IEEE 1547 and UL1741 provide a sufficient baseline for what constitutes best practices in regard to technical standards, though even here there is room for contention and inconsistency. For business practices, incorporation of major aspects of existing model rules will be the guideline, such as the use of standardized forms and procedures, mandatory timelines, and limited fees.

Washington's Practices

The Energy Policy Act of 2005 required states to consider whether to adopt interconnection standards and various other standards which the Act added to the existing Public Utility Regulatory Policies Act. Partly in response to that requirement, the Washington Utilities and Transportation Commission adopted revised and expanded rules in late 2007 (UTC, 2007, p 2). In a process that invited participation of stakeholders across the spectrum from utilities to federal agencies, from trade groups to interested private individuals, the UTC crafted regulations intended to cover all interconnection customers from the smallest home solar photovoltaic (PV) systems up to 20 MW facilities. The rules cover both the technical and procedural aspects of interconnection, including (among others) timelines, fees, insurance, and the conditions under which a utility may refuse an interconnection request. On the technical side, the new standards incorporate IEEE 1547 and UL 1741, along with a number of other relevant standards. For procedural matters, the rules lay out explicit guidelines for generators up to 300 kW in size. For larger facilities, the Commission refers to the FERC rules (UTC, 2007, p 11),

thereby incorporating key aspects of one of the important model rules. Thus the UTC's Order 545, "Relating to Electric Companies—Interconnection With Electric Generators," effective October 28, 2007, seems to place Washington in the ranks of states employing best interconnection practices. But a closer look is less encouraging.

Provisions for generators larger than 300 kW are particularly important for CHP, as most CHP applications in the state tend to be at least that large (Sjoding, 2007a, p 1). However, where the FERC rules include model forms for all utilities to use, Washington's rules require each utility to file, for the commission's approval, its own versions of the following forms: application; feasibility study agreement; system impact study agreement; facilities study agreement; construction agreement; interconnection agreement; and certificate of completion (State of Washington, 2007c, p 43). Unfortunately, this path leads away from the kind of consistent, predictable, and streamlined process that lowers costs and encourages development. Indeed, it can lead to precisely the opposite result. In mid-2007, as the UTC was nearing completion of its rulemaking, the DOE released a congressionally mandated study on DG's potential benefits and the obstacles impeding its growth. Referring to just this kind of utility-written, state commission-approved interconnection procedures, the study says that by stipulating the utility as arbiter of what is needed, such procedures allow the utility potentially discriminatory, anticompetitive influence over the customers' costs and therefore over investment decisions (DOE, 2007, p 8/26). In Washington, the utilities urged the commission not to require standardized procedures above 300 kW, because of the complexity of larger installations and the uniqueness of each utility's system (DeBoer, 2006, p 4). Regulators recognize that interconnection becomes more

complicated with increasing system size, yet in many states standard rules apply up to 2 MW (NNEC, 2010, p 30).

It must be noted that the UTC requires utilities to offer interconnection service essentially the same as that offered under tariffs approved by the FERC (State of Washington, 2007c, p 37). There is also provision for dispute resolution through both formal and informal complaint processes. However, allowing each power company to draft its own procedures, even within guidelines, appears contrary to the concept of "standards," and is a departure from what the FERC and many states have done. In comments on the proposed rule, Dave Sjoding of the NW CHP Application Center pointed out that CHP proponents were uneasy about this issue. He expressed concern that the situation could end up back where it started, and suggested that the interconnection issue was not yet fully resolved (Sjoding, 2007c).

During the rulemaking process, another stakeholder raised the same issue, arguing that allowing utilities to draft their own procedures was contrary to the notion of a statewide standard expressed by the EPAct amendments to PURPA. The commission responded that it could not enact a statewide standard because it had no authority over publicly owned utilities. The UTC made this statement despite having earlier explicitly invited and entertained proposals for statewide interconnection standards that might be used by all utilities, including those outside the commission's jurisdiction (UTC, 2007, pp 6 and 19). Such uncertainty and ambiguity of purpose can lead to policies of questionable effectiveness, which at times seem at odds with the purposes for which they were ostensibly crafted. The need for clarity in policymaking will be the subject of a later section, but the considerable efforts of the UTC in this rulemaking offer an early

object lesson, by producing a result less conducive to CHP/DG development than it might have been.

The outcome is ironic because the commission cited a thirty-year-old state law, RCW 80.28.025 (Revised Code of Washington, the compilation of state laws), whose title is "Encouragement of energy cogeneration, conservation, and production from renewable resources." The commission took note of the law's establishment of a general policy to encourage renewable energy, and of its intent to promote it by use of incentives. However, its reference did not mention cogeneration, which is explicit in the statute's title (UTC, 2007, p 2). RCW 80.28.025 contained specific incentives which expired long ago, but the statute clearly states that its scope is not limited to those provisions (State of Washington, 1980), and the law remains on the books and in the minds of the commissioners. But while the UTC was explicitly aware of the statute and its requirement for policies to encourage cogeneration, the resultant rule allows interconnection more than encourages it, and stopped short of providing the actual incentives its adoption order referred to. This is not surprising, given the commission's primary mission to ensure adequate, reliable, and fairly priced power (UTC, 2011). A CHP assessment for the Western Governors' Association observes that PUCs may not have the resources to give proper consideration to CHP policy amid the complex details of their busy schedules (WGA, 2006, p i). In such circumstances, clear and consistent legislative guidance could help the commission to accomplish larger policy purposes that might otherwise not be its first concern.

As a case in point, the new regulations allow power companies to charge the interconnection customer for a variety of additional equipment and studies if they are

deemed necessary. While the concept that the party which incurs the cost should pay the cost is familiar to regulators, so also is the notion that what benefits everyone should be paid for by all. The commission might have ruled that such costs would be paid by the utility and recovered from customers in its rate base, in recognition of the systemic value of encouraging all forms of distributed generation as noted by the statute. In fact, the state's net metering law, which will be discussed in detail later, prohibits utilities from assessing a variety of additional fees and charges. The only exception occurs if the commission determines, after public comment, that direct costs to the utility exceed any related benefits *and* that recovering such costs from the entire rate base is not in the best interests of public policy (State of Washington, 1998). The new rule inverts that principle for all other interconnections, stating that only if the utility demonstrates that benefits exceed costs will it be allowed to recover costs from all customers (State of Washington, 2007c, p 31). Below an arbitrary system size limit (itself a subject for later discussion), Washington's net metering law assumes public benefits unless proven otherwise; for all other systems, the UTC's interconnection rule assumes the opposite. Whatever the merits of either approach, the state would benefit from clear, cohesive, and consistent policies regarding distributed generation.

Washington's new regulations can also be compared to those in other states, using an established yearly assessment of nationwide policies on interconnection and net metering (an issue of particular concern for small distributed generation projects). *Freeing the Grid* is an annual publication of Network for New Energy Choices and the Interstate Renewable Energy Council; it scores each state's interconnection standards using a system based on the evolving national consensus (NNEC, 2010, p 8). The

emphasis is on PV systems, but the analysis is broadly applicable to CHP/DG concerns. The underlying data come from the online Database of State Incentives for Renewables and Efficiency (DSIRE), a collaborative interagency public/private effort managed by DOE's National Renewable Energy Lab (NREL). Fifteen different types of policy provision are scored, such as limitations on system size, favorability of charges and fees, dispute resolution procedures, etc.

Washington's new interconnection rules were adopted too late to be incorporated in *Freeing the Grid 2007*, which gave Washington an F. Only one state out of nearly three dozen with any form of interconnection standards received a lower score (Missouri scored a -2, compared with Washington's 0). By contrast, Washington's Pacific coast neighbors, Oregon and California, were both in the top ten with scores of 7 and 8.5, respectively (NNEC, 2007, p 73).

After the UTC issued its revised rules, Washington's score rose to 5, earning a grade of D. The number fell to 3 (still a D) in the 2010 iteration, apparently due to a re-evaluation of the state's policies rather than because of any substantive rule changes, which serves to highlight the subjective nature of such assessments. However, Oregon has now doubled its score to 14, moving from a C to an A, while California has improved to 11.5, rising from a C to a B while nonetheless falling out of the top ten, as a number of states in the East and Midwest rose in the rankings on the strength of improved policies (NNEC, 2010). To place these numbers in the context of changing policies across the nation, the highest score in *Freeing the Grid 2007* was 12.5. By 2010, there were ten states with scores higher than 12.5, of which the highest was 18 (NNEC, 2007, p 73; NNEC 2010, p 106).

Evaluation

Quibbles regarding the fairness and/or accuracy of the ratings aside, Washington has clearly not done well, compared to many other states, in the estimation of those interested in expanded deployment of DG and renewable energy. While a detailed analysis of every component of the state's score in *Freeing the Grid 2010* would be a substantial work in its own right, it is apparent that there is a great deal of difference between policies that *allow* interconnection and those that *encourage* it. It is not enough merely to have an interconnection standard. *Freeing the Grid* makes clear that many states are engaged in continual efforts to create a policy environment conducive to distributed generation. Washington can benefit from their examples and their experience.

Rates and Tariffs

Utility rate and tariff structures are another of the pervasive issues affecting the spread of CHP in Washington and throughout the U.S. From a certain perspective, it might be argued that most impediments to CHP, apart from the capital cost of the equipment itself, are in some way tied to rates and tariffs. The charges levied by the utility for service, and the payments made for excess electricity, are crucial to determining both the profitability of a project, and the length of time to recover the investment (the payback period). The cost of fuel for the generator's prime mover is also important, of course. But especially in the common case of natural gas, it is also a commodity whose rates are regulated and that may well be provided by the same utility that provides electricity. The interconnection issue (beyond its minimum technical requirements) is to a significant degree a question of charges by the power company as well—what items the utility can bill to the customer or require it to buy, and with what limitations. Indeed, the very structure of traditional utility rate regulation creates an incentive for the utility to avoid all forms of customer generation, because it reduces sales volume and therefore revenue. For the purposes of this section, however, standby rates and net metering provisions will be the focus of attention. Standby rates will receive the most detailed scrutiny, partly because they have been called the most frequently cited rate-related barrier (Alderfer et al., 2000, p iii), but also because Washington already has effective net metering policies in place, albeit with some inevitable room for improvement.

Standby Rates

Very few firms with an interest in or potential for utilizing CHP are likely to go completely off the grid, relying entirely on their own capacity to generate electricity. Most, in fact, will generate only a portion of the power they need, especially if their cogeneration facility is sized to fit their thermal load, which is the most energy efficient and cost-effective design (EPA, 2009, p 2). These customers will need the utility to cover the balance of their power needs (supplemental power); they will also need utility power for their entire load when their own generator is out of service, whether due to equipment failure or for scheduled maintenance (backup power). Such "partial requirements" customers, so called because the power company supplies only part of their electricity needs, create a different set of cost recovery circumstances for the utility which are often addressed under the general umbrella of standby rates.

There are several reasons why customers who generate some of their own power are typically charged differently than full requirements customers. Foremost among them is the fact that many of the utility's costs—for instance, capital investments in generating capacity and T&D infrastructure—do not vary with the amount of power sold, as do operating costs such as fuel (Schwartz, 2009, p 3). Most of those costs, however, are normally recovered in variable volumetric charges—the price per kilowatt-hour (kWh) paid by the customer. By purchasing less electricity from the utility, CHP customers may potentially pay less than their share of fixed costs. Another reason is that the utility must be ready to provide the customer's entire load, and do it on very short notice in case of an unplanned outage on the part of the CHP generator. If such an unscheduled demand should coincide with peak demand on the utility system, meeting that need could be

costly. This can be true whether the power company is covering the emergency demand with its own excess generating capacity or with power purchased on the spot market.

There are three basic components of typical standby charges: a customer charge, which tends to be small and covers administrative costs for billing, metering, etc.; demand charges, covering the utility's cost to provide and maintain capacity and delivery infrastructure to meet the customer's maximum load; and energy charges—the price of electricity actually consumed. The relative weight of each part of the tariff varies greatly from one utility to another, as does the overall cost of standby service. In addition, some utilities break the charges down further by purpose or time of use (supplemental or backup power, on- or off-peak usage, etc.), and use different terminology to describe the various elements (Goulding & Bahçeci, 2007, p 90).

Power companies and CHP proponents disagree sharply over how high standby charges need to be, how the rates should be structured, or even whether such charges should be allowed at all. Unsurprisingly, utilities in general defend the necessity for standby rates, while CHP developers and owners would like to see them reduced or eliminated. The disagreement is exacerbated by the fact that determining a CHP customer's contribution to utility infrastructure costs is complex, uncertain, and without a generally accepted formula. Consequently, there is little or no consistency in standby tariffs around the country or even from one utility to the next (Jackson, 2007, p 1897). In 2003, a microcosm of the ongoing dispute between utilities and DG advocates played out in the pages of *Electricity Journal*; a close examination will illuminate the various sides of the issue.

The CHP position

In the May issue, CHP developer and policy expert Sean Casten argued against rate components that weaken the relationship between power consumption and the size of the customer's bill (Casten, 2003b, p 58). He claimed that standby rates "are not only unnecessary, but actually stand in direct opposition to the public interest." As do most DG/CHP advocates, Casten highlighted the many benefits of distributed generation, and said that standby rates discourage its spread, thereby causing harm to the public interest. More than one study supports this view (DOE, 2007, p 8/1, Jackson, 2007, p 1897).

Another well-supported argument in Casten's paper is that the utility doesn't have to provide sufficient reserve to cover *all* the distributed generation capacity on its system, because the probability of all the DG going offline at once is very low, and the normal variability in demand means the power company will likely have enough capacity to meet the need, especially since most customer generation is small. A 2007 study notes that most CHP manufacturers report average downtimes of less than 10%, and since ordinary maintenance can be scheduled at times of least impact to the utility, no more than 10% of emergency outages should occur at times of peak demand when the utility might incur the greatest expense supplying it (Jackson, 2007, p 1903). This agrees with a 2006 report by the American Council for an Energy Efficient Economy (ACEEE), which found the concurrent failure of all CHP on a utility's system highly unlikely. The report further noted that the costs small CHP facilities impose on a utility system are well within the range of those attributable to normal load variation (Brooks, Elswick, & Elliot, 2006a, p 2). Finally, the Oregon PUC's 2005 study of distributed generation points out that FERC rules for QFs do not allow standby rates to be based on unsupported worst-case assumptions. The study also asserts that for systems under 1 MW, the load variation they

cause is invisible to the utility, and that such systems should not be subject to standby charges (Schwartz, 2005, p 22).

A third point in Casten's case against standby rates is that a DG owner is wholly responsible only for the small portion of wires and equipment that serve his facility exclusively, that all other infrastructure is shared with and amortized across a number of other customers that increases with upstream distance from the DG (Figure 7). Even this fractional infrastructure cost, he maintained, is never stranded or unrecoverable by the utility, because normal load growth means any such temporarily idled capacity will inevitably soon be needed by new customers. This invocation of load growth as a counter to stranded infrastructure costs is an argument not frequently seen in the literature. It has an intuitive appeal, and accords well with the standard observation that DG in general takes pressure off the T&D system and may delay or eliminate the need for costly upgrades. However, it ignores the fact that the power company is in fact providing an essential service to the customer who has his own generation, and that such service differs in significant ways from that provided to full requirements customers.

The utility position

The DG/CHP viewpoint was countered in the October 2003 issue of *Electricity Journal* by Jay Morrison, a representative of the National Rural Electric Cooperative Association (Morrison, 2003). His case relies on four points. First, all customers incur some level of utility costs to serve their needs. Second, since CHP customers consume less electricity, and most costs are recovered in volumetric rates, CHP owners pay less than their share of system costs unless standby rates are formulated to account for their different characteristics. Third, probabilistic calculations of outage risk are inapplicable to DG because there isn't enough of it on most utility systems to make a reliable

statistical analysis. Also, the utility's "obligation to serve" requires them to have enough capacity for a worst-case scenario no matter how unlikely. Fourth, benefits derived from CHP and other distributed generation are highly locational and situation-specific, and additionally dependent on how the customer chooses to operate its generator; not all DG provides benefits to society and/or the utility system, and abolishing standby rates would be an inefficient subsidy of the bad along with the good.

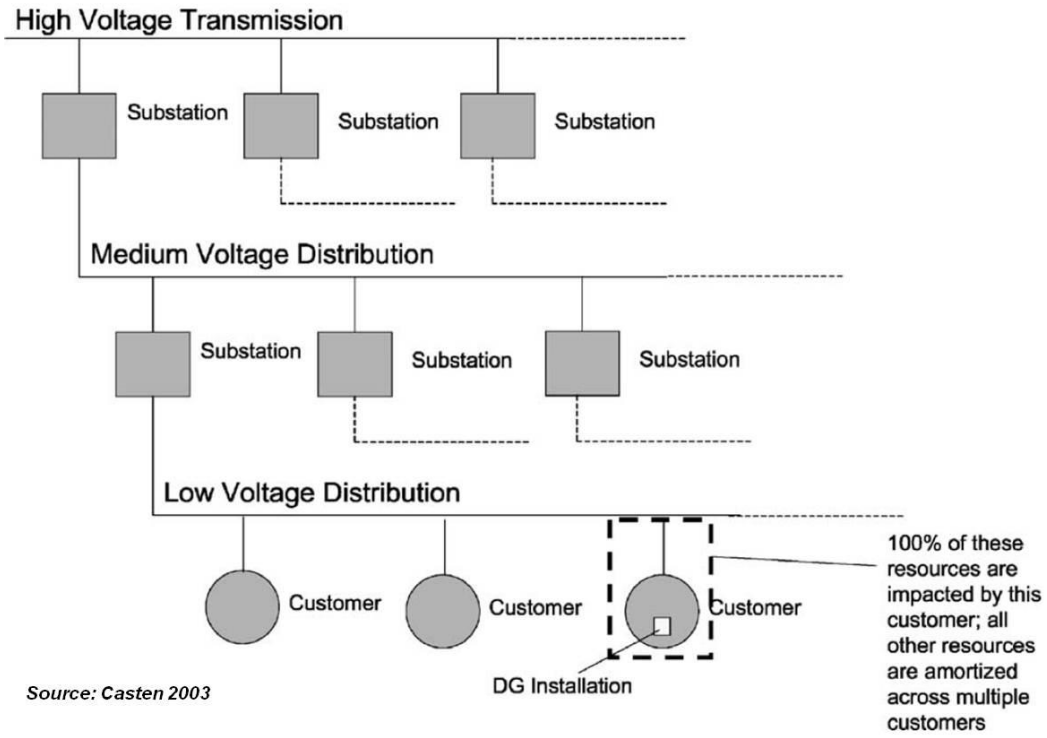


Figure 7: Utility Grid Schematic

Morrison's first point is axiomatic, made primarily to prepare the ground for his second, which is also true, at least to the extent that DG customers require a different set of services and therefore a different rate treatment. But it does not necessarily follow that standby rates as commonly applied are the correct way to price those services. As noted earlier, standby rates have been shown capable of discouraging CHP development. In a 2007 paper, the authors note that utilities have embedded incentives to resist distributed

generation, not only because reduced sales affect profitability, but because of the Averch-Johnson effect, which describes the tendency of regulated firms to over-capitalize so as to maximize profits when they are allowed a guaranteed return on capital investments. The expansion of DG reduces the need for new infrastructure investment and thus doubly threatens profits, causing utilities to favor rate structures that discourage distributed generation, even as they profess to be concerned solely with cost recovery and fairness (Goulding & Bahçeci, 2007, p 88).

Morrison's third point does not hold up under scrutiny, given the observations already made regarding outage probabilities and normal variability in demand for utility resources. However, Goulding and Bahçeci hold that probability analysis applies even in a worst-case scenario like the one Morrison invokes. They argue that standby rates shouldn't assume every generator will be offline at the same time, any more than regular rates assume that every light and appliance will be on at the same time (Goulding & Bahçeci, 2007, p 89).

Morrison's fourth point ignores the reams of evidence for CHP's benefits, especially the observation from the WGA study mentioned earlier, that CHP systems provide aggregate benefits regardless of location by deferring the need for investment in T&D infrastructure. He claims that most utilities don't have enough DG to derive any real benefits; in a rebuttal in the same journal issue, Casten accused him of trying to have it both ways: "If there isn't enough DG on the grid to recognize the system benefits, how can there be enough DG on the grid to impose stranded costs?" (Casten, 2003c, p 82). Goulding and Bahçeci meanwhile look askance at both the utility and DG positions, saying that both are inconsistent with basic economic principles, the DG position because

it denies real utility costs for valuable services, the utility view because it undervalues DG and assigns costs incorrectly, with the potential to be anticompetitive (Goulding & Bahçeci, 2007, p 88).

Goulding and Bahçeci offer an alternative view of standby service as insurance against failure of the customer's own generator. They propose an actuarially based, experience-adjusted system of rates, which they claim could give utilities a definite incentive to install more DG. They suggest that utilities could profitably exploit differences between the probability of outage for a single facility and the probability for an entire group of them, just as conventional insurance companies do. Goulding and Bahçeci also offer a parallel with options pricing in commodities markets as another alternative, though it seems less appropriate than the insurance model. This is an attempt to stimulate some creative thinking that might eventually lead the way to an acceptable consensus about standby services. The biggest objection to these proposals is that they fail to address the core difficulty of reliably, consistently and fairly determining exactly what the costs of providing the service really are. Standby tariffs, then, remain a vexed issue, and need to be carefully designed to recognize the legitimate costs of the utility while providing DG owners with fair and reasonable rates.

Best Practices in Standby Rates

It should be evident from the foregoing discussion that there is as yet no clear consensus regarding what constitutes best practice in standby rates. However, the EPA Combined Heat and Power Partnership published a report in late 2009, entitled "Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs." The report concedes the futility of finding a one-size-fits-all solution, given the

disparate realities of markets and regulatory structures. Instead, it attempts to identify the broad outlines of win-win scenarios, in which CHP owners can substantially reduce their electric bills while paying fairly for the services they receive (EPA, 2009, p 6).

The report provides a tool designed to determine the elements of a rate structure favorable to DG. Existing tariffs from selected utilities are analyzed for their effects on a hypothetical 5 MW CHP facility with specified operating characteristics. Because specific cost data was not available, the study relies on the presumption that costs will not be inappropriately shifted to other customers (EPA, 2009, p 2); it otherwise supplies a useful approximation of best practice.

Throughout the report, its authors emphasize that the economics of distributed generation rely on reduced electricity purchases, although they point out that CHP in particular has additional efficiency benefits to the owner (which are a separate issue not necessary to the analysis). The DG owner trades capital investment and operating and maintenance costs for lower electricity bills. The problem arises when grid power consumption declines but utility bills do not (EPA, 2009, p 5). This can result from a higher volumetric rate, but often involves demand charges that are set too high or contain a ratchet clause. (A ratchet is a mechanism that applies the peak demand from a given month for up to 12 months in the future unless a higher peak occurs, which increases the demand ratchet even further. Such a provision can cause a single major outage of the customer's generator to wipe out an entire year's electricity savings, and in the worst case can result in the customer paying more infrastructure costs than a similar full requirements customer.) In order to ensure that reduced electricity purchases result in lower utility bills and equitable cost assignment, the EPA recommends the following:

- Demand charges that are low relative to volumetric energy rates
- No ratchets, or no more than a month-to-month ratchet
- Tariffs that result in overall savings of at least 90% of the cost of equivalent full requirements service

While the report asserts that avoiding 90% of what the bill would have been in the absence of DG will usually provide enough savings to justify CHP (EPA, 2009, p 9), it does not explain how this figure was derived. Nor is there any assurance that a given utility could confidently recover its fixed costs with the remaining 10%, aside from the fact that the utilities offering the published tariffs examined in the study are presumed to do so.

The EPA also finds a need for regulators to make sure that standby rates capture the environmental and other benefits of DG, but opinions diverge on the issue of whether these tariffs should provide subsidies or incentives (see for instance Goulding & Bahçeci, 2007, and Parmesano, 2003). Those who disagree argue that rates which subsidize DG distort the market, and that governments can more appropriately use a wide array of existing tools such as tax credits, grants, and others. On the other hand, electric utilities are regulated entities; such regulation can and often does serve a variety of public purposes. This is especially relevant in these circumstances, where a power company that proposes a standby tariff may be in the position of effectively regulating its own competition. In any event, the EPA cautions that decisions about assignment of costs and benefits need to be based on accurate information about how distributed generators actually operate in real-world conditions (EPA, 2009, p B5).

Net Metering

The practice of encouraging small distributed generation, especially wind and solar, by crediting DG customers for the full retail price of every kilowatt of power they send into the grid, is known as net metering. In most cases, the meter is capable of running both forward and backward. The customer is thus billed only for the net amount of electricity metered during the month (hence the name); if more is produced than consumed, the excess is typically (though not always) credited toward the next month's bill. Naturally, net metering cannot occur unless the customer is interconnected with the grid. Net metering laws may address interconnection requirements and even standby charges, as either of them relates to the subset of DG to which the laws apply. However, interconnection and standby policies are typically considered separately from net metering, as they have been here; net metering will be evaluated largely for other program components.

Best Practices in Net Metering

Along with interconnection standards, *Freeing the Grid* includes a detailed yearly analysis of states' net metering rules. As it did earlier for interconnection of the smallest systems, *Freeing the Grid 2010* will provide a basis for evaluation. Net metering laws have a variety of provisions, describing which technologies and sizes of system are eligible, the disposition of excess generation at the end of a billing period, and other aspects of the relationship between customer and utility. Among the most important aspects are limits on the size of individual systems and on the aggregate amount of net metered generation a utility is required to accept. Both of these are especially important for CHP development because so many of its applications are in larger commercial or

industrial facilities. Which technologies are eligible is also crucial to CHP, as wind, solar and other renewables are sometimes exclusively targeted by the rules.

The ratings in *Freeing the Grid 2010* give more weight to system and aggregate capacity limits than any other feature except so-called "safe harbor" provisions, which prevent utilities from imposing added fees and requirements for additional equipment, insurance, etc. Restricting individual system size interferes with the customer's ability to match generating capacity to facility load, thus obstructing efficiency especially for CHP applications, for which the need for thermal output is a key parameter. As long as the system is designed primarily to meet the site's own requirements, power exported into the grid is likely to be limited and have minimal effect on the utility. Caps on total net-metered generation on a given utility, on the other hand, may hobble a state's ability to meet its own renewable energy targets. Intended to address utility concerns about lost revenue (which could instead be allayed with a lost-revenue adjustment mechanism), capacity caps may also hamper DG developers who can't be certain net metering will still be available when a planned installation finally gets off the drawing board (NNEC, 2010, p 23).

Washington's Practices

Standby Rates

Washington has no policy regarding standby tariffs, either at the legislative or utility commission levels (EPA, 2010). Tariffs are devised by individual utilities and (in the case of IOUs) approved by the UTC. According to the ACEEE State Energy Efficiency Policy Database (ACEEE, 2010), Puget Sound Energy has a tariff that is seen to be CHP-neutral, because it contains only a moderate monthly demand charge, and the

customer then contracts for actual energy usage on the open market. The relatively low demand charge accords well with EPA's benchmark, and the ability to buy power in a competitive market should also help keep overall costs down. Of the state's other two IOUs, one is not mentioned and the other is described as having an unfavorable standby rate.

Net Metering

The most recent issue of *Freeing the Grid* gives Washington a respectable grade for its policies, a score of 12.5 that translates as a solid B. In this regard, the state is in the middle of the pack, with twenty states scoring higher. For purposes of comparison, Colorado and Arizona lead the way with respective scores of 21 and 20.5; coastal neighbors Oregon and California are part of a four-way tie for third place with identical scores of 18.5 (NNEC, 2010, p 104). While CHP is an eligible technology in Washington (an important consideration), when compared to neighboring Oregon almost the entire difference between the two scores resides in Washington's restrictive limits on the size of both individual systems and aggregate capacity. System size is capped at 100 kW, while the total of all net metered systems cannot exceed 0.25% of the utility's 1996 peak demand, rising to 0.5% in 2014. Both of these could potentially have a negative impact on CHP as well as other forms of DG, and on the state's ability to meet its goals for renewable energy development, as noted above. In contrast, *Freeing the Grid* recommends a system size limit no lower than 2 MW, and an aggregate limit of at least 5% (NNEC, 2010, p 24). As an aside, it is interesting to observe that Washington gets high marks for its "safe harbor" provisions; state net metering law in most cases prohibits the kind of extraneous charges, equipment and other requirements that are allowed in the UTC's interconnection rules for non-net metered DG, and about which DG proponents

expressed concerns (DSIRE, 2010). In that context, it is noteworthy that the editors of *Freeing the Grid* give considerable weight to safe harbor provisions, highlighting their potential to support or discourage distributed generation.

Evaluation

Washington's net metering laws are good, as already stated, but have room for improvement in system and capacity limits. While utilities may object, raising the caps would be an excellent way to encourage further deployment of not only CHP but renewable energy. As it happens, a bill was introduced in the 2011 legislature that would have increased system limits to 5 MW and assigned ownership of any renewable energy credits[1] (RECs) to the DG owner (State of Washington, 2011a), although without raising the aggregate limit to 5% as recommended in public testimony on the proposed legislation (State of Washington, 2011c). The bill was still in committee as the regular session ended, the cap having been eroded from 5 MW to 199 kW, a doubling of current 100 kW limits but still well below the size of most CHP. Under the bill's revised terms, the RECs would now become the property of the utility (State of Washington, 2011b).

Standby tariffs are a more complicated matter and a much lower regulatory priority than net metering. Net metering has been specifically addressed by the legislature in statute; standby rates have not been made a priority by either the legislature or the UTC, despite their significance as an obstacle to CHP. While the impediment they represent could be addressed by the UTC with or without legislative impetus, a directive

[1]Renewable energy credits are tradable proof of electricity generated from renewable sources. Utilities that have not met their obligations to acquire renewable resources under Washington's RPS can make up the difference by purchasing RECs. Granting legal ownership of RECs to the power company, instead of to the customer responsible for their existence, may make utilities more agreeable to raising the limits on net metering, but it also reduces the value of distributed generation for the customer and dilutes the incentive to install it.

from lawmakers could bring about statewide changes. The commissioners have authority only over IOUs, as they pointed out during the interconnection rulemaking proceedings. In any case, a detailed cost of service study, as suggested by the EPA study, is likely to be necessary to enable informed, judicious decision making.

Siting and Permitting

The next major obstacle to the spread of CHP is rooted, not in the practices of power companies, nor in the rules of public utility commissions, but in the other government entities that are responsible for issuing permits to construct and operate the facility. Complicating matters, the authority responsible for siting is often different from the one responsible for air quality permits. Some states have state-level siting statutes that preempt local jurisdictions for energy facilities, but state authority often applies only above a considerable capacity threshold, leaving projects the size of typical CHP applications to negotiate a potential maze of city and county ordinances with little consistency or predictability (ORNL, 2004, p 14). State facility siting requirements designed for large power plants may be cumbersome and time-consuming, but they often have the benefit of providing a one-stop process. Smaller projects, on the other hand, can face a welter of local and regional permit and code requirements with different application and approval procedures (Arthur D. Little Co., 1999, p 22). According to one report, CHP developers were of the opinion that obtaining approval from local officials inexperienced with CHP was one of the two biggest factors slowing them down (WGA, 2006, p 8).

The treatment of CHP in emissions regulations is another aspect of the problem. Proponents complain that traditional regulation under the Clean Air Act does not acknowledge cogeneration's higher efficiency. The reason is that power plant and boiler emissions have typically been measured in terms of either exhaust concentration (the familiar parts per million) or fuel consumed (pounds of pollutant per million BTU input).

Both of these methods are indifferent to the productive output of the process (EPA, 2004, p 10). A CHP plant replaces two fires with one, burning fuel once to provide both thermal and electrical output, and thereby reducing overall emissions. But measured by traditional input means, its emissions may be as high as a less efficient central power plant—in some cases even higher.

Best Practices

Except in the most general terms, it is perhaps more difficult to identify specific best practices with respect to siting and permitting than any other major factor affecting the widespread adoption of CHP. Siting, for instance, might seem at first glance to be best handled by the dedicated expertise of a statewide authority. But such a superficial assessment ignores the importance of traditional local control of land-use decisions. As will be shown later, local authorities can display considerable hostility to the preemption of local prerogatives by distant central bureaucracies, which are sometimes perceived to be unfamiliar with—and uninterested in—the concerns of those who must live with the consequences of siting decisions. Meanwhile, emission levels (except for greenhouse gases) are regulated by the Clean Air Act, with its voluminous federal standards and varying state implementations delegated to a plethora of smaller authorities. Different locales and circumstances—such as attainment and non-attainment areas—invoke different standards and requirements, including New Source Review or Prevention of Significant Deterioration rules, and are controlled by numerous local and regional permitting agencies (Washington has at least ten). The multifarious complexities of the Clean Air Act are beyond the scope of this work, and no attempt will be made to discuss

either the federal law or Washington's implementation. For these reasons, discussion of best practices in siting and permitting will be limited to broad outlines.

Siting

This has been an important issue for decades, which may speak both to the difficulty of resolving it and to the lack of sustained and concerted effort to do so. Ten years ago, a study of issues facing CHP devoted significant space to the matter, and noted that even in the early 1990s, an annual survey by the National Conference of State Legislatures listed facility siting as "the number one-ranked energy/environmental problem" for several years running (Bloomquist et al., 2001, p 61). The problem has two aspects, both mentioned above: the patchwork of codes and permitting agencies, and the fact that local officials often lack experience with CHP.

As also mentioned above, a solution that immediately suggests itself is to place siting approval under a state-level authority. But states do not agree on the threshold at which preemption of local control should take place, or whether all siting of energy facilities should be handled by the state, or none. In Oregon, the threshold is 25 MW; in Washington 350MW; Idaho has no state siting statute at all; and Montana, whose preemption level was once 50 MW, raised it in 1997 to 250 MW. Siting laws may also provide exceptions and exemptions that vary from state to state (Bloomquist et al., 2001, p 58).

While many states have seen fit to take control of siting for at least the largest facilities, there are pitfalls as well, some of them vividly illustrated by a bill introduced in the Washington state legislature in early 2011. HB 1081, as it evolved over the course of the legislative session, was a bill intended to expedite alternative energy siting. It would

allow small alternative energy facilities[2] to bypass local permitting processes by applying to the state's Energy Facility Site Evaluation Council (EFSEC) for approval. The bill would only apply if the local authority had no appropriate ordinance, if that ordinance had not been updated in at least ten years, or if the local process took longer than six months. City and county governments were also encouraged to enter into cooperative agreements with the EFSEC to perform siting services on their behalf (State of Washington, 2011d).

It should be noted that alternative energy facilities of any size already have the right to opt in to the EFSEC process. The key alteration to be effected by this legislation is that it would exempt small facilities from EFSEC's formal hearing and stakeholder process, as well as from approval by the governor, both of which the normal EFSEC procedure requires (EFSEC). Instead, the Council would be allowed to delegate the site approval process to staff members, who could be authorized to issue permits.

The bill, which originated in the House, was not satisfactory to the Senate, which responded with an amended version. The Senate amendments struck the entire language of the House bill, and instead instructed the state's Department of Commerce to develop model siting ordinances for use by local governments. The Senate further instructed those authorities to enact their own from among those recommended, with suitable

[2]Relevant to CHP, the bill defined "small alternative energy facility" to mean any net metering facility. Under existing law, CHP does not qualify as an alternative energy technology eligible to opt in to the EFSEC process. By using the net metering definition, CHP would be included because of its eligibility for that program. On the other hand, net metering is restricted to only 100kW (smaller than most CHP), thus limiting the proposed law's usefulness for cogeneration and further confusing the regulatory picture by erecting yet another arbitrary size limit. The public testimony described herein also makes clear that the bill was intended to benefit small wind projects that were facing local opposition, emphasizing the problems of piecemeal policy that (effectively or not) attempts to promote DG, but helps CHP only as a secondary effect, if at all.

adaptations to local circumstance. At the time of this writing, the legislation was stalled, with neither chamber willing to modify its position.

The House bill hoped to streamline the process by putting it in the hands of experts; the Senate amendments would have left decision making in the hands of local authorities, with models provided to guide and inform their discretion. Public testimony for and against the two versions highlights their strengths and weaknesses. DG proponents were clearly frustrated by outdated or nonexistent local ordinances, and the lack of technological expertise. They appeared to seek access to officials who are familiar with the issues, ready and able to make timely permitting decisions. On the other side were the state associations of cities and counties, who strongly opposed usurpation of local control. Criticizing the bill as "a fundamental departure from the land use process," they called for technical and financial assistance to develop effective local ordinances as an alternative to a statewide mandate (State of Washington, 2011e, p 3; State of Washington, 2011d, p 5).

While to a certain extent these comments epitomize the traditional power struggle between cities, counties, states and the federal government, at a more practical level they point to narrow, conflicting interests that might have been brought together by an effective stakeholder consultation process. Matters of state and even national energy policy can be decisively affected by local decision making, and tradeoffs may be necessary to ensure that larger policy priorities are not derailed by ineffective local processes. Prudent guidance from above may be necessary, and simply offering an assortment of model ordinances may be inadequate. At the same time, many matters of planning, zoning and urban design rightfully belong in local hands, and should not be

heedlessly preempted. Putting permit decisions in the hands of those with the most expertise is one thing, but exempting the process from any stakeholder involvement whatsoever is another.

Bloomquist and his colleagues, in their analysis of CHP barriers for Washington State University's Extension Energy Program, included a discussion of the 1992 Keystone Model, a collaboratively designed process for developing siting statutes. While it was intended to provide a framework for state-level rules, and specifically for high-voltage transmission lines (which were then a particular object of contentious debate), the authors justifiably felt it offered an instructive example with broad applicability. Somewhat abridged for clarity, and with transmission-specific provisions removed, the Keystone Model provides the following framework:

- specify reasonable time frames for each major decision point
- clarify the criteria that will be used to make the siting decision
- provide for early involvement of all stakeholders
- address all concerns raised, including technical/professional assessments
- consolidate responsibility for all necessary permits in one agency, if possible

The WSU study further notes the importance of practicality and cost-effectiveness, pointing out that unwieldy, expensive processes benefit no one (Bloomquist et al., 2001, p 66). But the authors emphasize the importance of strengthening local processes, primarily with training and technical assistance, rather than simply imposing standards. This is in agreement with the public testimony of cities and counties regarding HB 1081. In the context of a balanced approach that recognizes the priority of larger public policy goals, these principles provide the outlines of useful siting practices.

Environmental Permitting

State-level siting processes may include air and water discharge permits under the same roof, but siting under local jurisdictions is unlikely to incorporate them. A study done by ORNL observed that environmental permitting is both a part of, and separate from, facility siting issues, because it is a different process involving different jurisdictional agencies (ORNL, 2004, p 16). Thus, while plumbing, electrical, zoning and construction permits might perhaps be gathered into a single process like that recommended by the Keystone Model, environmental permits will remain a separate hurdle. The ORNL study also pointed out that among Northwest states, Oregon and Washington have the most stringent emissions regulations, with no exemptions for CHP, which makes permitting all the more important to the prospects for cogeneration.

One solution is to create output-based emission standards, which avoid smokestack measurements entirely, and measure pollutants relative to energy output (lbs per MWh produced) rather than to energy input. When the thermal output is added to the electrical output, the advantage for CHP becomes obvious, as the calculation is no longer simply lbs/MWh, but rather lbs/($MWh_{electrical}$ + $MWh_{thermal}$). Output-based standards offer considerable benefits for conventional air pollution regulation. As the EPA says in its *Output-Based Regulations: A Handbook for Air Regulators*,

> The primary benefit of output-based regulations is that they encourage efficiency and pollution prevention. More efficient combustion technologies and low-emitting renewable energy…reduces fossil fuel use and leads to multi-media reductions in the environmental impacts of the production, processing, transportation, and combustion of fossil fuels. (EPA, 2004, p 11)

The *Handbook* goes on to note that the lower fuel consumption resulting from higher efficiency reduces all emission products instead of only the specific targets of regulation.

As long as the thermal output is properly credited, output-based regulations benefit CHP by recognizing its greater efficiency and overall emission reductions. There is one difficulty, however. Replacing two fires with one reduces total emissions, but CHP may increase emissions locally by burning more fuel onsite than the boiler it replaces, while the central power generation it eliminates may be distant and not contributing directly to local pollutant levels. The challenge is to craft regulations that give credit for overall benefits while safely managing local pollution levels.

Washington's Practices

Siting

As the earlier discussion revealed, Washington has a statute that gives control of facility siting to the Energy Facility Site Evaluation Council. However, the preemption threshold is 350 MW, putting the siting of all but major central generating plants under local control. The exception is DG projects of any size using entirely renewable resources, but only if the developer chooses to use the EFSEC process. CHP does not qualify, unless of course it is in the subset of renewably fueled cogeneration. Consequently, the EFSEC's one-stop siting process, which includes air and water permits, is generally unavailable to cogeneration developers. HB 1081 (explored in detail above) is an example of an attempt to address the problems presently inherent in local jurisdiction, but the effort seems doomed to failure, quite possibly because it tries to help one set of interests without fully considering others.

Environmental Permitting

Washington's Clean Air Act regulations were not examined for this study. However, among the literature reviewed in the course of this work, no mention was made of Washington among the states significant for their use of output-based regulation of

various air pollutants. In 2007, the state legislature passed ESSB 6001, a bill which established significant statewide greenhouse gas reduction goals. As part of that effort, the law set an emissions performance standard (EPS) for Washington's electric utilities, both investor- and consumer-owned (State of Washington, 2007b). Because it receives credit for its useful thermal output, most CHP facilities will meet the standard, making cogeneration a more attractive source of incremental generating capacity.

Evaluation

The EFSEC siting process is excellent for large facilities, but below the level of central generating plants, CHP development may continue to be hampered by inconsistency and lack of local familiarity. The Senate amendments to HB 1081 seemed to point in the right direction, calling for a state-level effort to craft model ordinances and requiring cities to use them. However, following the Keystone Model and the public comments of cities and counties asking for 'help, not preemption,' it would have been useful to provide training, expertise, and other assistance, rather than simply mandating updated ordinances that local jurisdictions might still have lacked the resources to effectively apply. But the bill did not pass; without the prod of a similar legislative mandate to adopt updated ordinances, and/or a legislative commitment to provide the kind of assistance that would enable local officials to make informed, effective decisions, local siting processes that facilitate CHP development are likely to be slow in coming.

Washington's power plant emissions performance standard recognizes the efficiency of CHP by giving full credit for its thermal output. Regardless of its effectiveness in curbing greenhouse gases, the EPS gives cogeneration the potential to compete on an equal footing with gas-fired generation for baseload purposes. This fact

might provide utilities with a small incentive to look for future opportunities to include industrial CHP in baseload procurement efforts, at least for smaller capacity increments.

Utility Disincentives

There are a variety of reasons why utilities may be less than enthusiastic about customer-owned and -operated generating facilities. One of them is rooted in the historical structure of the electrical distribution grid, with power flowing in one direction only, from central generating stations to final consumer, with the entire process under the power company's control (DOE, 2007, p 2/11). Siting generation at the consumer end of the network raises engineering concerns about safety and reliability; it also introduces uncertainty into utility planning and operation, especially when the utility may have no control over when the generator produces power. While all of these issues can be and have been resolved by technical, contractual, or regulatory means, there remains a certain amount of suspicion and unease on the part of utilities. Time and experience, however, are the surest means of overcoming these obstacles.

Another potential disincentive for power companies to welcome customer-owned CHP on their systems involves the way DG reduces the need for capital investment. In pointing out the possible influence of the Averch-Johnson effect on utility behavior, Goulding and Bahçeci observed that if new capital investments are an important source of earnings growth, the expansion of distributed generation could block the achievement of financial goals (Goulding & Bahçeci, 2007, p 88). This could conceivably be the case, if energy efficiency programs inhibit demand even as CHP or other DG deployment reduces the need for investment in generating capacity or T&D infrastructure. Other authors have made similar comments (Petrill et al., 2007, p 19).

There is, however, another view. David Moskovitz focuses on the difference between profits (in absolute terms) and profitability (earnings per share). He notes that more capital investment would not make a utility more profitable if costs increased more than revenues. He wrote that there would be no benefit in adding a million dollars to profits if the percentage rate of return fell because of the costs. In a footnote, he pointed out that profitability will only rise if the cost of capital is lower than the allowed rate of return, or profits on new investment are higher than expected average profits, and concludes by saying that for most utilities, neither condition applies (Moskovitz, 2000, p 13).

In either case, the largest and most obvious disincentive for power companies to welcome CHP lies elsewhere. It is a widely recognized fact that the structure of traditional electric utility rates creates a strong linkage between sales and profits, providing utilities with a powerful signal to avoid any activity that reduces sales volume. This is because a large portion of the utility's costs do not vary with sales in the short run, but the majority of those fixed costs are nonetheless recovered via the price per kilowatt-hour paid by the customer. Thus, if less electricity is sold, less revenue is collected and the bottom line suffers. The Regulatory Assistance Project[3] (RAP) emphasizes the magnitude of the incentive, saying that because the change in profits is disproportionately greater than the change in revenue, sales variations can have a profound impact on profits (RAP, 2008, p 5).

Because every CHP installation reduces electricity sales, customer-owned cogeneration carries a disproportionate threat to utility profits. Over ten years ago,

[3] The Regulatory Assistance Project is a non-profit organization of experienced former utility regulators, which has been providing guidance and information to governments and regulatory agencies on matters of gas and electric utility regulation for nearly 20 years (RAP, 2008, p 4).

Moskovitz made a similar observation. He pointed out the "overwhelmingly adverse financial impacts on utilities" from customer-owned generation, and went on to say that if the problem were not addressed, utilities would predictably obstruct distributed generation, its expansion would be slow, and old obstacles would persist while new ones appeared (Moskovitz, 2000, p 3). Yet Moskovitz also noted that an overwhelming majority of utility studies had shown that the system benefits of DG were even greater than the energy and capacity savings. Nonetheless, six years later another report declared, "Utility opposition to new CHP is a widespread national problem…" (Brooks, Elswick, & Elliot, 2006b, p 31).

Connecting the dots between utility resistance to CHP, the substantial benefits that CHP offers, and the tendency of traditional ratemaking to encourage utility behavior at cross purposes with the realization of those benefits, the National Association of Regulatory Utility Commissioners in 2008 issued its "Resolution to Encourage the Use of Combined Heat and Power, Including the Recycling of Waste Energy." Among other things, the resolution advised that PUCs should consider policies that would remove the barriers to CHP presented by traditional rate mechanisms (NARUC, 2008).

Breaking the link between sales volume and profits for utilities is important, not only because of CHP's many documented benefits, but because Washington's RPS (The Energy Independence Act, RCW 19.285, under which CHP is a qualifying resource) requires utilities to acquire all available cost-effective conservation (State of Washington, 2007a). According to Schwartz, creating an energy efficiency mandate in a state with traditional utility rates introduces a "structural conflict [that] is at best paradoxical. At worst, it makes utilities adversaries instead of motivated partners…" (2009, p 4). There

are a variety of approaches to solving the problem; they are described by such terms as decoupling, performance-based rates, and revenue adjustment mechanisms. The methods they describe often seem interchangeable, and can be used for purposes other than correcting utility disincentives for CHP.

Best Practices

As with standby charges, there is currently nothing resembling a broad consensus and little likelihood of a one-size-fits-all solution. One potential method is to provide distributed resources credits or create distributed resources development zones, but these are best suited to encouraging DG in specific areas where T&D congestion exists or where distribution costs are particularly high. Since utility costs are normally averaged to derive a rate that is applied to everyone in a customer class regardless of location, siting CHP in districts with high distribution costs would do little or no harm to utility profits (Moskovitz, 2000, p 25). While these methods may capture some of the system benefits of CHP, their impact on utility attitudes toward DG will be strictly locational.

A more broadly effective tool is to directly decouple revenue from sales volume. A number of states have implemented revenue decoupling for some or all of their electric utilities, among them California and Idaho (RAP, 2008, p 43); several more have considered it, including Minnesota, which has a legislative mandate to develop criteria and standards for decoupling, with the objective of overcoming utility disincentives to efficiency (Minnesota PUC, 2010, p 2).

Among the many ways to decouple utility revenue from sales, one possibility is a lost-revenue adjustment mechanism, a method that has been described as especially useful for CHP due to the relative simplicity of measuring the change in energy

consumption caused by customer generation (Brooks, Elswick, & Elliot, 2006a, p 6). The rate adjustment can be targeted to include only the revenue lost due to CHP and/or other desired forms of distributed generation. It has the advantage of working as a modifier within the existing rate structure.

The most commonly recommended solution is a rate decoupling mechanism based on a revenue cap. The effect is similar to lost revenue adjustment, but more broadly applied. Basically, a utility's revenue requirement is determined by public utility commissioners in the same manner as is currently done; revenue is capped at that level, and prices are periodically adjusted up or down as necessary to meet that requirement as real-world conditions change. In contrast, under traditional price-based regulation, prices are set by the commission and revenues rise or fall according to conditions until the next rate case hearing. With the traditional approach, since the volumetric price contains fixed costs that do not rise with sales volume, along with variable costs that do, utility profits rise with every kilowatt-hour sold above and beyond the projected volume on which the price is based. With revenue-cap decoupling, the only way to increase profits is to lower costs.

The problem of including fixed costs in variable rates can be solved by moving all fixed costs into the fixed customer charge, which is another way of ensuring revenue adequacy and insulating utility revenues from sales fluctuations. Unfortunately, this design, somewhat confusingly referred to as a straight fixed-variable rate, makes the customer's bill less responsive to changes in consumption, due to the dominance of fixed charges. This can have the perverse effect of stimulating higher usage, a problem which

must then be corrected in some fashion, and which may also have a disproportionate effect on low-income customers (Boonin, 2008, p 4).

Revenue caps, on the other hand, can also go astray in the absence of modifications to the fundamental concept. For instance, they are typically implemented on the basis of allowed revenue per customer, rather than total revenue, because growth in the customer base can cause the power company to incur costs that would not be recovered otherwise. But even the revenue-per-customer decoupling mechanism can have other undesirable results, and a number of variations on the theme have been introduced to deal with them. For one thing, decoupling as described makes a utility impervious to all changes in revenue, even those caused by its own business decisions (RAP, 2008, p 6). There are several adjustments designed to prevent decoupling from shielding utilities and/or their customers from appropriate risks, such as weather or economic changes. For the purposes of encouraging CHP, the revenue adjustment can be limited to cover only the changes in sales resulting from cogeneration or other stipulated DG and energy efficiency measures (Moody, 2009, p 13).

Some years ago, RAP published a primer on performance-based ratemaking which pointed out that since all regulation creates incentives, effective rules must be carefully designed with an understanding of what incentives will exist under a given scheme (RAP, 2000, p 3). In that context it is important to note that a rate regime which creates an incentive to lower costs may also create an incentive to cut corners on maintenance and customer service. While RAP views significant service deterioration as unlikely, they also recommend that such negative outcomes can be largely avoided by the

establishment—if they do not already exist—of specific, measurable service standards with explicit penalties for failure to uphold them (RAP, 2008, p 29).

Among regulated utilities, there is some disagreement about the desirability of decoupling or performance-based rates. Jay Morrison, regulatory counsel for the National Rural Electric Cooperative Association, argued that a cap would essentially function as a subsidy for distributed generators, which would be paid for by other customers while the utility was protected from loss (Morrison, 2003, p 76). While this is true as far as it goes, it avoids confronting the fact that *all* efficiency and conservation efforts reduce sales and have some effect on utility revenue recovery, a conflict which regulators must eventually address if they are to align utility interests with efficiency mandates and the need to reduce the impacts of endlessly spiraling consumption.

In a foreword to Moskovitz's paper on decoupling methods, a long-time utility executive said that revenue caps made him uneasy, and declared that all utilities find them unnatural (Moskovitz, 2000, p i). He might more accurately have said that *any* profit-driven business finds them so. In fact, even publicly owned utilities, with no profit motive and no shareholders to satisfy, worry about the potential loss of sales and revenue if efficiency programs are successful (Moody, 2009, p 14), a fear that applies equally to CHP development.

On the other hand, at least some utilities take a broader view. Pacific Gas and Electric (PG&E) told staff of the Oregon Public Utilities Commission that the utility was in favor of decoupling, acknowledging the existence of disincentives that the company described as contrary to sound public policy (Schwartz, 2005, p 33). In this PG&E is in agreement with such organizations as RAP and NARUC, and also (among others) the

authors of DG/CHP studies for the Oregon PUC and the Western Governors' Association (Schwartz, 2005, p 42; WGA, 2006, p 29).

A last point in regard to the value of various means of decoupling revenue from sales: such alternatives to traditional ratemaking procedures may mitigate or remove the utility disincentive to CHP, but fall short of providing a positive incentive. If such incentives prove desirable, in lieu of or in addition to any incentives targeted at developers and prospective owners of CHP, there are certainly options available. A number of studies propose an incentive that gives utilities a share of the savings created by system cost reductions resulting from customer-sited generation (Schwartz, 2005, p 34; Moskovitz, 2000, p 26; RAP, 2008, p 24). The Oregon PUC study also suggests that utilities be allowed to earn a return on investments in DG facilities they do not own, as they are with conservation/efficiency investments. The Electric Power Research Institute (EPRI), an industry group, has also pointed out the advantages of utility ownership of customer-sited generation in creating win-win situations for society, the customer and the utility (Petrill et al., 2007, p 34). Encouraging utility ownership would also address another impediment to CHP: the reluctance of businesses to invest large amounts of capital in non-core activities like power generation, which can cause them to seek extremely short payback periods or reject the self-generation option (EPRI, 2005, p xv). Over time, it would also facilitate utility expertise, familiarity, and comfort levels with distributed generation.

Washington's Practices

Washington has no explicit policy with respect to decoupling utility revenue from sales volume. In 2005, the UTC initiated proceedings to investigate revenue decoupling

for natural gas distribution companies, for the purpose of eliminating disincentives to conservation and efficiency (UTC, 2005, p 1). However, the commissioners decided that the wide variability in decoupling mechanisms made a generic rulemaking an inappropriate tool, and that decoupling should be handled in the context of individual utility rate proposals. Decoupling proposals from two natural gas providers have since been approved. In the early 1990s, the company now known as Puget Sound Energy employed a decoupling mechanism for electricity customers, but ended it after four years, apparently due to increasing resource costs (RAP, 2008, p 44). The rate structure capped revenue on a per-customer basis, with the objective of removing disincentives to conservation, a goal that (while it lasted) was apparently successfully achieved (EPA, 2006, p 6/32).

Evaluation

The foregoing discussion has made clear the importance of overcoming utility disincentives to CHP and other distributed generation. The need to decouple revenue from sales has been remarked upon by the National Association of Regulatory Utility Commissioners, the National Regulatory Research Institute, the Department of Energy, and a variety of other studies and industry experts, including at least some investor-owned utilities. Even publicly owned utilities have cause to be concerned about the effect of reduced sales on revenue sufficiency. Yet many states, including Washington, have legislation in place that puts pressure on utilities to find steadily increasing amounts of energy efficiency and conservation resources, prompting one RAP publication to remark on the contradiction inherent in creating a requirement to do one thing in the face of an existing incentive to do the opposite (Schwartz, 2009, p 1).

While some of the UTC's past actions indicate that the commission recognizes the value of decoupling, utility commissions are by nature cautious and conservative, important traits that are useful for preserving stability and consistency. The commission has demonstrated no inclination to take aggressive steps to provide advantages to CHP in the absence of legislative guidance. Nor (as repeatedly noted) can the UTC make rules for the publicly-owned utilities, which serve over half the state's customers. Only the state's lawmakers can provide the kind of direction that will result in definite changes to the regulatory landscape, changes affecting the entire state and not just regulated utilities. The state of Minnesota recognized this need in its 2007 decoupling law, and gave its PUC plenty of discretion in the establishment of criteria and standards. Washington might benefit from similar legislative action.

Policy Support

In a perfect world—or at least a perfect market—the many advantages and benefits of CHP would inevitably lead to its employment in every appropriate circumstance, and to the maximization of its operational efficiency wherever it was installed. As the cost of fossil fuels rose with increasing scarcity and growing awareness of their environmental impacts, CHP would simply become more and more attractive, and it would be very difficult to inhibit its expansion or stifle its popularity. The present reality does not accord well with such conceptions of the ideal, however, and in the absence of support from policy makers, CHP technologies are disadvantaged in a number of ways, many of them previously discussed.

Like most businesses, electric utilities naturally resist inroads into their market share by competitors. The capital-intensive nature of utilities, and the consequent importance of fixed costs for their revenue requirements, can cause even consumer-owned utilities with no profit motive to become concerned over the prospect of losing revenue to customer-sited generation. And the monopolistic nature of the power supply industry, especially in a traditionally regulated state like Washington, makes it relatively easy for utilities to erect barriers to CHP founded on legitimate concerns turned to anticompetitive purposes. These problems may require regulatory or legislative intervention to overcome.

Many of the benefits of CHP are public, such as reduced emissions, improved grid reliability, and system resilience in the face of outages or sabotage. But the costs are largely private, paid by the owner, absorbed by the utility or passed on to other customers

in the rate base. Public benefits deserve public support; without it, CHP and society in general can fall victim to a chicken-or-egg situation in which system or societal benefits aren't meaningful until a certain level of deployment is reached, but sufficient expansion won't occur without compensation for benefits that haven't yet been realized. This is because the private benefits also accrue slowly, in the form of energy cost savings over the life of the equipment, while the upfront cost is relatively high. The result is that most businesses require very short payback periods when investing scarce resources in self-generation options, and many projects never get implemented. The outcome can be so striking that an analysis of California CHP markets cited a *technical* potential of over 20,000 MW in existing and new facilities by 2020, but the base case *economic* potential was expected to be scarcely 10% of that amount (EPRI, 2005, p v). The Oregon study found that with incentives and falling technology costs, that state's economic potential could be nearly five times as high as in the base case. While such studies are often quite sensitive to changes in the underlying assumptions, the numbers make clear the potential value of policy support in the form of tax credits, grants, low-interest loans, and other financial incentives that defray some of the capital investment. The observation is only amplified by the fact that Washington consistently has some of the lowest electricity prices in the nation, making the short-run savings even smaller.

The many permutations of financial assistance can be crucial to achieving the sort of widespread adoption of CHP that produces measurable benefits and allows economies of mass production to make it competitive on its own. But financial incentives are not always effective, according to an ACEEE report on the role of incentives, and work best in combination with favorable regulations (Kaufman & Elliot, 2010, p 5/200). The work

is very recent, and the authors were admittedly cognizant of the scarcity of money for incentives in the present environment of chronic budget shortfalls. For this reason, the report recommends a focus on eliminating regulatory obstacles, with complementary incentives where feasible (Kaufman & Elliot, 2010, p 5/190). But there is no guarantee that any combination of carrots, sticks and statutes will have the desired effect. An EPRI paper on DG incentives says that distributed generation is still not a priority for California IOUs despite a favorable policy environment and a well-established decoupling regime (Petrill et al., 2007, p 22). Whether this says more about the structure of California's policies or about the difficulty of enabling the spread of CHP/DG is an open question.

But without the sort of legislative directive suggested earlier in regard to revenue decoupling, regulators may not provide sufficient movement. The Western Governors' Association CHP white paper pointed out that larger policy issues often take a back seat to a PUC's primary mission in a context of scarce resources and a busy agenda (WGA, 2006, p i). For obvious reasons the WGA study highlights the potential role of the executive branch in fostering regulatory change, but the ability of the legislature to enshrine policy in statute gives it a greater and longer-lasting influence. The EPA's *Clean Energy-Environment Guide to Action* notes the ability of legislatures to provide resources, political support for otherwise unpopular measures, and if necessary, stimulus to action when commissioners fail to take the initiative (EPA, 2006, p 6/35). In addition, the legislature's power of the purse bestows tremendous influence over incentive program choices and funding sources. Lastly, because PUCs generally have no authority over publicly owned entities like municipal utilities, rural electric cooperatives, and

public utility districts (PUDs), legislative action is often the only way to achieve statewide reach.

Best Practices

The availability of policy tools and incentive measures to minimize barriers and enable CHP development is essentially limited only by the creativity of policy makers. This is especially true when considering the endless variations enabled or necessitated by the specific statutory, regulatory, and economic environments of the several states. There are, however, rules of thumb worthy of consideration. The ACEEE, in the CHP division of its annual *State Energy Efficiency Scorecard* (Kaufman & Elliot, 2010, p 5/192), ranks policy in five categories:

1) The presence of an interconnection standard that explicitly applies to CHP systems
2) The nature of tariffs and standby rates imposed on CHP systems by large utilities
3) The presence of financial incentives for CHP
4) The presence of output-based emissions regulations
5) The eligibility of CHP in renewable portfolio standard

Since all of these have been addressed above except number 3, the discussion here will focus primarily on financial incentives, most of which can be categorized according to whether they target utilities or the CHP industry and its customers.

Tax credits/exemptions, rebates, grants, and loans

These are familiar tools aimed largely at prospective owners of cogeneration, and require little explanation. The ACEEE does, however, offer a couple of caveats. First, tax incentives provide no help for tax-exempt institutions, a group that unfortunately includes some of the best candidates for CHP because of their large thermal loads,

namely hospitals and colleges. Second, financial incentives in general are often targeted for energy efficiency and renewable energy, even if they also include CHP. Therefore, CHP may end up competing against other technologies for limited funds, with results that are not favorable to the spread of cogeneration (Kaufman & Elliot, 2010, p 5/191).

As an interesting policy option, the previously mentioned assessment of CHP in California, jointly sponsored by EPRI and the California Energy Commission (CEC), suggested an instructive modification to that state's existing Small Generator Incentive Program. The original incentive structure offered a straight payment per kilowatt of installed capacity, to help offset the considerable capital cost burden. The study proposed "unbundling" the incentive into a number of separate payments for different project attributes, any or all of which a given installation might qualify for: a minimum payment, plus adders for fuel conversion efficiency, location (i.e., in a T&D constrained area), on-peak availability, and ability to be dispatched by the local utility (EPRI, 2005, p H/1). A multi-part incentive like this could provide at least some support for all CHP, in recognition of its general higher efficiency and aggregate system value. At the same time, by providing incrementally higher subsidies for those projects that offer the most benefit to the utility and society at large, it addresses utility criticism of blanket subsidies for the good, the bad, and the ugly.

Fuel Rates

Natural gas is far and away the most common fuel in CHP installations, used in almost 70% of all systems (ORNL, 2008, p iii). Further, fuel costs are one of the three biggest cost-related obstacles mentioned by prospective CHP owners, along with upfront costs and onerous interconnection charges (EPRI, 2005, p 3/13). In 2006, the Western Governors' Association CHP White Paper explained that increasing gas prices over the

preceding two and a half years had caused several CHP projects to be cancelled, and a number of existing ones were shut down, giving some indication of the importance of fuel prices for CHP. There was considerable irony in the situation, as the paper noted studies showing that CHP's higher efficiency would actually cause gas prices to fall at sufficient levels of deployment (WGA, 2006, p 11). One of the cited studies found that a 50% increase in CHP capacity could reduce overall gas consumption by 6.4%, and referred to yet another study that showed a price decline of approximately 20% resulting from lowering consumption by 7.5% (USCHPA, 2003, p 15). These reports make it apparent that CHP provides efficiency benefits not just to the electrical grid, but to the natural gas distribution system as well.

With these observations in mind, it may be especially appropriate to create CHP incentives involving natural gas prices. This can be accomplished through the utilities commission since gas is a regulated commodity, through rebates funded by any mechanism the legislature chooses, or by fuel tax exemptions. However structured, this is one type of incentive that may have benefits beyond its intended target.

System Benefits Charge

Often called a public benefits fund, a system benefits charge (SBC) is not an incentive in itself, but a funding source which can be used to pay for incentive programs. Eighteen states and the District of Columbia currently have some form of SBC. They are usually paid for by a small surcharge on electricity, on the order of $0.002 per kWh. The fund can be used for almost any purpose a legislature wants to include, but energy efficiency, low-income assistance, and renewable energy are commonly among the eligible beneficiaries. At least four states include CHP (DSIRE, 2011). The advantage of a system benefits charge is that it provides a stable source of funding for purposes that

might otherwise be eliminated when economic conditions resemble those currently prevailing.

Shareholder incentives

In line with the observation (in regard to decoupling) that removing utility disincentives is still a step short of providing a genuine inducement, a number of reports and studies have proposed giving utilities a definite incentive to encourage CHP/DG on their systems (Schwartz, 2005, p 42; EPA, 2006, p 6/28; EPRI, 2005, p H/3). Suggestions include shared savings, in which the utility receives a portion of measurable reductions in T&D or other costs attributable to the customer's CHP; allowing utilities to earn a return on investment in co-owned or customer-owned generation in which they have invested; and paying a higher rate of return on qualifying investments, or higher earnings allowances. Performance could be monitored, and cost recovery disallowed for undesirable projects while the most beneficial receive higher levels of incentive. All of these ideas assume that profits and sales volume have already been decoupled, and recognize the importance of providing incentives to the stakeholders with the greatest motivation to obstruct CHP.

CHP barrier study

In 2002 the Oregon PUC made the identification and elimination of barriers to DG an explicit objective. Its staff undertook a comprehensive statewide study pursuant to that goal (Schwartz, 2005, p 1), and issued its report in early 2005. A similar inquiry has been suggested by various observers as a valuable first step in developing the full potential of cogeneration in Washington and elsewhere (Prindle et al., 2003, p 18; WGA, 2006, p ii; Sjoding, 2007c). It is important to understand the problem thoroughly before enacting measures to resolve it, and especially before committing significant financial

resources. The Northwest CEAC has just done a study of CHP's technical potential in Washington, and intends a complete assessment of the economic potential (NW CEAC, 2010, p 1), but the specific and unique obstacles to achieving it remain to be studied. This paper represents a step toward clarifying the picture, but it is no substitute for the kind of in-depth statewide analysis done in Oregon. Washington has sought, by both legislation and voter initiative, to position itself as a national leader in clean energy technologies (State of Washington, 2007a); a barrier study could lay the foundation for more cohesive, successful policies to promote that goal.

CHP Portfolio Standard

Among non-financial policy options, perhaps the most audacious and to the point is found in an appendix of the EPRI/CEC study of California CHP. In offering it, the report asserts baldly that little progress will occur without a hard target. A comparison is drawn with the auto industry, which resisted fuel efficiency improvements until they were mandated, and has continued to resist them ever since (EPRI, 2005, p H/9). Assuming for the sake of discussion the relevance of a comparison to the auto industry, the point is perhaps emphasized by the fact that fuel efficiency standards almost certainly have less of a direct impact on car company profits than CHP does on electric utility profits. Even if significant results can be obtained without a mandated target, it is certainly true that a portfolio standard for CHP would be one of the most direct and explicit statutory affirmations of the value of cogeneration imaginable, which brings up a similar option.

Explicit policy commitment

The value of legislative guidance has already been discussed in more than one context. State legislatures can give needed direction to regulatory commissioners whose

primary focus is ensuring an adequate power supply at fair and reasonable prices—interpreting and implementing policy rather than making it. Legislative mandates can legitimize and provide political impetus for PUC actions that might otherwise not be undertaken or pursued to successful completion. Ten years ago, Washington State University's Cooperative Extension Energy Program published a study of legal, institutional, and regulatory issues affecting CHP. In the context of promoting CHP in state facilities, the authors emphasized the need for unequivocal policy direction, saying that without it most institutions would avoid the risks inherent in taking the initiative (Bloomquist et al., 2001, p 73).

While the challenges, constraints and budgetary circumstances under which state-owned facilities operate are undoubtedly different from those in the rest of the economy, the advice can certainly be applied more broadly. The history of decades of limited success, untapped potential, and stakeholders working at cross purposes should be sufficient to establish the need for an overarching and explicit policy mandate that is more than an idealistic expression of hope for the future. The welter of jurisdictions that characterizes electric utility regulation in the United States only serves to underscore the necessity for a focal point of authority and will. Five years ago, an ACEEE report lamented the unlikelihood of action at the federal level. In its absence, the authors wrote, any progress was going to have to come from the states (Brooks, Elswick, & Elliot, 2006a, p iv). What better way to advance that progress than for the state itself to make it an unambiguous policy priority?

Washington's Practices

A number of legislative and regulatory actions have provided benefits or helped to remove barriers affecting combined heat and power. Most of them have already received attention in these pages:

- The UTC's interconnection rulemaking, completed in 2007, effected a certain amount of clarity and streamlining but did not receive high marks from DG proponents.
- The state's renewable portfolio standard allows renewably fueled CHP as an eligible technology. The standard, which further requires utilities to acquire all cost-effective energy efficiency, also allows CHP as an efficiency resource if the thermal output is utilized.
- Net metering is another policy that applies to CHP—it is limited to 100 kW, but must be offered by all utilities, including COUs.
- Finally, the state's laws contain one statute that expressly intends to promote cogeneration (RCW 80.20.025), enacted in 1980 and still in force, though a utility incentive provision has long since expired. Another law had been passed the year before, entitled "Cogeneration Facilities—Tax Credits," whose first section said in part, "It is the purpose and intent of the legislature to promote the growth of cogeneration in the state of Washington" (State of Washington, 1979, p 750). That law provided an excise tax rebate of up to 50% of the capital cost of new CHP plants initiated before the end of 1984, providing such facility cost no more than ten million dollars. The unexpired portions of the statute were repealed by the 2005 legislature in a cleanup of obsolete and unused incentives (State of Washington, 2005, p 1884).

On the other side of the coin, none of the above, with the exception of the two Carter-era laws just described, were specifically undertaken with the intent to promote and expand the deployment of CHP. However, no exhaustive search of legislative archives was undertaken for this study; it is entirely possible that there have been other laws over the years that benefited CHP, if not so explicitly. There are currently no financial incentives in place for which CHP can qualify (ACEEE), though they are the single most straightforward policy tool (Prindle et al., 2003, p 17). While noting the state's moderately favorable regulations, which earned three of a possible 5 points in the most recent *State Energy Efficiency Scorecard*, an ACEEE analysis also pointed out the state's record of meager incentives (Kaufman & Elliot, 2010, p 5/194). Oak Ridge National Laboratory, in a 2004 report on CHP potential in the Northwest, also commented on Washington's lack of support for CHP, despite the largest population and gross state product in the study area (ORNL, 2004, p v).

Evaluation

It seems clear that the first step should be a thorough study of barriers to CHP in the state. Many useful and quite possibly effective actions to improve the prospects for CHP can probably be taken without it, based on the accumulated insight and advice of the voluminous literature and the many available experts here and around the country. But given the unique character of each state's economic, political and regulatory landscape, it makes sense to conduct the kind of in-depth analysis that can harness the power of multiple stakeholders, facilitate consensus, identify local solutions, and locate and prioritize the most appropriate targets for incentive or regulatory reform.

Financial incentives have been widely remarked as a valuable tool for encouraging CHP development, especially when combined with effective policy and regulation. But ensuring a stable, consistent source of funding for incentives can be challenging, to say the least, under the kind of constrained fiscal conditions that currently exist and are likely to continue for a number of years. A system benefits charge could offer a way to fund needed incentives with a minimum of pain and political resistance. Among states in the region, California, Oregon, and Montana all have SBCs in place. Although there is always risk of diluting the power of the fund by applying it in too many places and spreading it too thin, such a fund can provide for a number of valuable public purposes in addition to CHP, thus building support for its implementation. With the potential to supply nearly 15% of the state's power needs, CHP could be a prime beneficiary of well-designed incentives financed by a future SBC.

As fundamental as a barrier study may be, and no matter how important the incentive targets and regulatory reforms that it identifies, or how valuable the SBC that could support them, it is entirely possible that none of these actions will take place without clear and unequivocal legislative guidance. CHP is not the sort of issue the voters are likely to champion, despite Washington's voter initiative culture. Legislative action is the only way to be certain of affecting all utilities (Sjoding, 2007b). The fact that so much potential remains untapped, after so many years of work and so many small victories, highlights the need for stronger, more focused efforts. That the UTC could officially reference (in its interconnection proceedings) an old state law explicitly encouraging CHP without even acknowledging that plainly stated purpose, only emphasizes the point further. The DOE's national study of barriers to distributed

generation recognized that encouraging sufficient DG to fully realize its potential benefits would require concerted and cooperative effort (DOE, 2007, p v). That effort needs to begin with the Washington State Legislature and a firm, unambiguous statutory declaration of policy intent.

Conclusions and Recommendations

The foregoing discussion has brought Washington's policy landscape into sharper focus, locating a number of inconsistencies and areas for improvement. However, it is also evident that existing policies lack cohesiveness. In some of the areas examined, Washington has no explicit policy at all. By examining individual policies in the context of the whole, it is easier to see that, for instance, an interconnection rule can either help or hinder the achievement of goals for energy efficiency or renewable energy.

The discussion of interconnection standards remarked upon the difference between policies that encourage CHP, and those that merely allow it, and showed early evidence of inconsistent policy. Even with the existence of a net metering law that prohibits most fees and requirements for extra equipment on the presumption of public benefit, and in the explicit knowledge of a law requiring the encouragement of CHP through incentives, the new rule leaves those costs to be paid by cogenerators on the opposite presumption of no public benefit.

In the chapter on rates and tariffs, the net metering law itself was shown to be adequate but unnecessarily restrictive. Low and arbitrary limits on system size and aggregate capacity serve only to constrain customers' ability to size their systems to meet their needs. Since the law requires that net metered systems be primarily intended to meet some or all of those needs, little power is likely to flow into the grid no matter what size the system. Meanwhile, neither the UTC nor the legislature has explicitly addressed the standby rate issue. Inequitable or poorly designed standby tariffs can significantly impact the likelihood of a CHP project's success or even implementation, by stripping

away the savings from reduced electricity purchases that are such an important part of project economics.

Siting regulations are a weakness in Washington as well, at least as they apply to CHP systems, which are ineligible for the EFSEC siting process unless they burn exclusively alternative fuels. As in a number of places throughout the paper, the need for high-level guidance can be seen, here to provide assistance to inexperienced and ill-equipped local authorities who nonetheless oppose centralized control. While action at the state level may be needed, policy direction supported by technical assistance and training might be better accepted and more successful than preemption.

Utility disincentives to encourage cogeneration on their systems are a crucial aspect of the continuing sluggishness of CHP expansion. As long as rate structures reward utilities with higher profits when they sell more power, they will be strongly disinclined to do—or to facilitate anyone else doing—anything that will reduce their sales volume. However, because there are a variety of laws and policies requiring power companies to invest in energy efficiency, renewable energy, and conservation, utilities are not likely to overtly oppose cogeneration. They can, however, obstruct it by raising ostensibly legitimate concerns with the effect of stifling development by making CHP more difficult, time-consuming, and expensive to install and operate.

Likewise with standby rates, and net metering as well. Utilities argue for substantial standby charges on grounds of cost recovery and revenue sufficiency, yet the EPA study was able to find several companies offering rates apparently adequate to their needs, which also allowed the partial requirements customer to save over 90% of equivalent full requirements costs. The power companies are also in favor of restrictive

limits on net metering, both individual system size and aggregate capacity. But the Oregon PUC study found that distributed generators up to 1 MW had no more impact on the utility than normal load fluctuation. The larger the customer's generator, however, the more sales the utility loses. And because nearly every CHP facility or other distributed generator will be interconnected with the utility distribution system, every such facility must have the assistance and cooperation of the local utility, which gives that company considerable potential to influence the process.

The utility is in business to make money for its shareholders; when an activity runs counter to that imperative, as distributed generation does under the traditional rate structures which prevail in Washington, the utility can be expected to resist. The same can even be true of not-for-profit utilities, because CHP can threaten their ability to recover costs without rate increases. In recognition of that fact, the task is then to craft regulations that align utility incentives with the public interest.

It is this which makes policy support the key to the CHP conundrum. There are countless ways to do it, from favorable interconnection rules and standby charges to generous net metering provisions, preferential gas rates, low-interest loans, outright grants, tax breaks, targeted incentives and even—perhaps most interesting of all for its refreshing and forthright audacity—CHP portfolio standards. What works will be to some extent a function of present resources and circumstances, but probably there is no single combination more effective than all the others, whether in Washington or anywhere else. The important thing is to fully consider all the barriers and all the stakeholders, in a sustained, consistent, and coordinated fashion. The following

recommendations are intended to offer a concise and reasonable set of actions to address key obstacles:

- *Do a study of CHP barriers*. The kind of in-depth, statewide examination done a few years ago in Oregon should be a mandatory requirement, to enable informed, effective action at every subsequent step.
- *Decouple revenue from sales*. The recent Minnesota law may or may not go far enough to be successful, but at a minimum it gives the utilities commission clear direction. If necessary, performance-based ratemaking can be mandated, leaving specific application to the commission.
- *Impose a System Benefits Charge*. Given the present chronic budget shortfalls, a stable source of funding for incentives could be invaluable. Financial incentives have been called the most direct way to encourage CHP, and an effective one-two punch when coupled with favorable regulations.
- *Provide incentives for utilities to want CHP*. EPRI observed that California utilities still weren't making CHP a priority, even in a state with favorable regulations and generous developer incentives; the Oregon study also noted that removing disincentives might not be enough, that utilities might need a positive inducement as well. There are many ways to go about it, from rate-of-return bonuses to production tax credits to allowing return on investment in customer-owned assets.
- *Enact a clear, unequivocal statewide policy supporting CHP*. Leadership is the linchpin. It takes a legislative mandate to provide sustained direction that reaches every corner of the state. The executive branch can be invaluable by initiating and facilitating the process, but executive orders don't have the power or longevity of statutory requirements, and the legislature can establish dedicated funding sources. The commitment should be comprehensive, programmatic and long-term; ten years may not be enough to reorient a century-old system.

A policy mandate may have been last on the list, but it is likely to be the first and most important thing that must be done. Even the obvious prerequisite of a state barrier study has not been done in Washington, though the UTC has no need of permission to authorize one. As others have noted, utility commissions often do not have the time or inclination to pursue larger questions of public policy unless specifically directed from above. Their job is to keep the state's utilities working smoothly and fairly for both consumers and regulated entities; nor are electric utilities by any means their only responsibility.

Equally important, the policy must represent a sustained and substantive commitment. It must not be haphazard or narrowly applied; it must have sufficient duration to provide certainty and consistency for investors, for whom a major project may take years to become a reality, and even longer to pay for. It should firmly intend the removal of all identified barriers, and should offer appropriate incentives to all stakeholders, consistent with the widespread societal benefits that accrue with higher levels of market penetration.

This is not a naïve prescription, though its enactment may seem unlikely. Clearly, the political will for this kind of long-term effort to change the electric utility landscape is not easy to come by. However, it need not be costly, and may in fact provide benefits in excess of its costs. Washington has declared its intention to be a leader in energy efficiency and renewable energy; the state already has a Renewable Portfolio Standard and a greenhouse gas Emissions Performance Standard for all utilities, and significant economy-wide greenhouse gas reduction goals for the coming decades. None of the above are likely to be achieved or maintained under business-as-usual conditions. The

Northwest CEAC found over 4000 MW of CHP potential in the state, equal to 14% of total state generating capacity. It is, of course, unlikely that all of that potential is ever going to be installed, even under ideal conditions. The decision to opt for onsite power generation is first and foremost a business decision, and most businesses base those choices on factors that have little to do with greenhouse gases, utility transmission and distribution problems, or even power reliability or electricity rates. What matters is how best to address the company's key business priorities. If the choices are being made by utilities that don't want CHP on their systems, and businesses that don't think of it as a high priority, those entities need to be given an incentive environment that will change those perceptions and calculations. As the DOE study of rate-related barriers observed,

> However, there will need to be a concerted and cooperative effort for the numerous benefits of DG to be realized and for more DG to be deployed on the grid. This effort may require cooperation among electric system planners, operators, and industry groups; Federal, State, and local government agencies; equipment manufacturers; electricity consumers; and academic, research, and public interest organizations. (DOE, 2007, p v)

That kind of effort will not occur without the kind of policy direction suggested here. Making it all the more certain are the absence of federal initiative and the fact of Washington's low, hydropower-driven electricity rates, which weaken any inherent incentive for businesses to install CHP.

There are many reasons why there remains so much untapped potential for CHP, both in Washington and across the nation. The list of obstacles examined herein is neither exhaustive nor comprehensive; the roster could have been expanded, conceptualized differently, discussed from a different perspective, or at greater or lesser levels of generality. The literature which informed this analysis is immense; the topic has

attracted attention from virtually every individual and group mentioned in the quote above. Yet for all their hard work—for all the time, energy and money invested—only about a quarter of Washington's potential has been tapped, a situation common in the rest of the nation as well.

It is now more than thirty years since Congress passed the Public Utilities Regulatory Policies Act, signaling its intention to open the electric power industry to small, independent generators. It is also more than thirty years since the Washington state legislature enacted RCW 82.35, with its hefty cogeneration tax credit, or RCW 80.28.025, which encouraged "energy cogeneration, conservation, and production from renewable resources." It is time for the commitment expressed in those laws to be renewed, strengthened, and given the advantage of complementary policies that are durable and thoughtfully crafted. Because the times are changing after all. The evidence for anthropogenic climate effects resulting from unrestrained burning of fossil fuels grows daily more compelling. Energy costs are on the rise, taking food and other prices with them; they would likely be even higher but for the reduced demand brought about by the global economic crisis. The state's ambitious goals for energy efficiency, renewable energy and greenhouse gas reduction will be very hard to meet without the kind of concerted effort the DOE called for. It will be up to legislators and policy makers, perhaps with impetus from the governor, to make it happen.

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Abbreviations and Acronyms

AC.....alternating current

ACEEE.....American Council for an Energy-Efficient Economy

BTU.....British thermal unit

CEAC.....Clean Energy Application Center

CEC.....California Energy Commission

CHP.....combined heat and power

COU.....consumer-owned utility

DC.....direct current

DER.....distributed energy resources

DG.....distributed generation

DOE.....Department of Energy

DSIRE.....Database of State Incentives for Renewables and Efficiency

EFSEC.....Energy Facility Site Evaluation Council

EIA.....Energy Information Administration

EPA.....Environmental Protection Agency

EPAct.....Energy Policy Act of 2005

EPRI.....Electric Power Research Institute

EPS.....emissions performance standard

FERC.....Federal Energy Regulatory Commission

IEEE.....Institute of Electrical and Electronics Engineers

IOU.....investor-owned utility

kW.....kilowatt

MW.....megawatt

MWh.....megawatt-hour

NARUC.....National Association of Regulatory Utility Commissioners

NREL.....National Renewable Energy Laboratory

NRRI.....National Regulatory Research Institute

ORNL.....Oak Ridge National Laboratory

PUC.....public utilities commission

PURPA.....Public Utility Regulatory Policies Act

PV.....photovoltaic

QF.....Qualifying Facility

RAP.....Regulatory Assistance Project

RCW.....Revised Code of Washington

REC.....renewable energy credit

RPS.....renewable portfolio standard

SBC.....system benefits charge

T&D.....transmission and distribution

UL.....Underwriters Laboratories

UTC.....Utilities and Transportation Commission

Quad.....one quadrillion BTUs

WGA.....Western Governors' Association