Utility-Owned Combined Heat and Power: Improving Reliability and Lessening Environmental Impact

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Abstract

Problem definition: Combined heat and power (CHP) plants generate electricity and useful heat at the same time, reaching high efficiencies. There are many benefits to utilities of having CHP plants in their portfolio, including increasing power reliability, reducing transmission losses, and meeting environmental regulations. Despite these benefits, only 3% of all CHP capacity in the U.S. is utility owned. We study the economics of utility ownership of CHP plants and examine the impact of regulatory policies on such investments.

Academic / Practical Relevance: There is little research on the economics of utility ownership of CHP. Given the low CHP adoption rate in the U.S., particularly by utilities, it is of general interest to understand the economics of CHP and how policies affect CHP adoption.

Methodology: We solve for the optimal form of investment and dispatch decisions using analytic economic modeling. Following this, we present a numerical study calibrated with real data from three different utilities in the U.S., including their existing generation portfolio, uncertainties in demand and fuel prices, granular renewable intermittency, and grid reliability.

Results: A utility's investment in different generating technologies follows an Invest/Stay Put/Disinvest (ISD) policy for a given siting decision of CHP plants. Numerically, we find investment in many CHP plants to be attractive to utilities, even without regulatory policy intervention. A low to moderate emissions tax makes CHP even more attractive for utilities.

Managerial Implications: There is significant interest in energy sustainability in the industrial and academic communities. We shed light on a technology that is well known to practitioners but less explored in academia and demonstrate its benefits rigorously. We show that utilities should seriously consider adopting CHP in their generation portfolios, and our model framework can aid such decisions.

1. Introduction

Combined heat and power (CHP, also known as cogeneration) plants generate electricity and useful heat by burning fuels such as natural gas, diesel, and biomass. This heat, which most power generation plants treat as waste and vent to the environment, can be used by on-site firms for space, water, and process heating. CHP plants are located on the sites of firms with large, stable thermal loads, such as industrial plants, hospitals, hotels, and universities. With their dual thermal and electrical outputs, CHP plants typically reach 65-85% efficiency, a great improvement over the 40-50% efficiency of natural gas combined cycle generation or the 30-35% efficiency of coal-fired generation (U.S. Department of Energy 2012). More efficient fuel use leads to lower combined emissions from fossil fuel use (EPA 2016, Athawale and Felder 2014). Indeed, some argue that CHP could help bridge the divide between today's electricity generation, which relies heavily on fossil fuels, and a clean energy future, as cogeneration is an effective way to reduce carbon emissions quickly and on a large scale (Ayres and Ayres 2009). In addition to providing heat, CHP plants offer higher quality power and improve system reliability in the face of severe weather events (Hampson et al. 2013). This is because CHP plants can be connected to the electrical grid but configured to run independently of it, so an on-site firm will only experience a power outage when both the electrical grid and the CHP plant are not functioning, a very rare occurrence. Our paper investigates the inclusion of CHP plants in the generation portfolio of regulated utilities in the United States. We strive both to understand the relationship of CHP to other generation types in investment and dispatch decisions and to test which regulatory policies are effective at encouraging CHP adoption.

The United States has approximately 85 gigawatts (GW) of CHP generation installed, accounting for 8% of total electricity generated. This lags behind other large economies, including 11% for G8+5 countries and 31% for Russia, in particular (IEA 2018). Over 240 GW of technical CHP potential has been identified (U.S. Department of Energy 2016a), and an executive order from President Obama in 2012 called for a goal of deploying 40 GW of new CHP by the end of 2020 (White House 2012). Suggestions for increasing CHP installations make up two of the first three chapters of the National Association for Clean Air Agencies' recommendations for implementing the 2014 Clean Power Plan (National Association of Clean Air Agencies 2015).

CHP plants can offer a myriad of benefits to utilities. CHP reduces transmission and distribution losses by generating electricity on site. When electricity is generated centrally, 7% of it is lost to transmission and distribution losses on average, and losses can be 2-3 times higher during peak demand (Chittum 2013). In contrast to privately-owned CHP plants, utility-owned CHP plants may be used to satisfy electricity demand on the grid when on-site firms are not operational. The utility can also provide electricity and heat to multiple nearby firms, for example in a business park, in a way that would be impractical or illegal for a privately-owned CHP plant (Ayres and Ayres 2009). Installed CHP can aid in compliance with environmental regulations. Renewable portfolio standards (RPS) require utilities to produce a minimum proportion of their electricity from renewable sources, and 20 states in the U.S. specifically call out CHP as eligible to count toward their RPS (EPA 2016). CHP plants could be sited at overloaded points on the grid to reduce network strain and forgo future infrastructure additions (Chittum 2013). Perhaps most importantly, utilities use a portfolio approach to optimize investments in power plants and have subject matter expertise in managing power plants which may be lacking at privately-owned plants.

Given these benefits, utility investment in CHP could represent a way to increase CHP installations. Utilities in the U.S., however, have been laggards with respect to CHP generation. Only 3% (2.4 GW) of existing CHP capacity is owned by utilities (U.S. Department of Energy 2012). Regulators and utilites have recently made privately-owned CHP more attractive through redesign of reservation fees and demand charges (Scripps 2019), but more consideration of utility-owned CHP is needed. In other parts of the globe, utility-owned CHP is more common, illustrating the potential for adoption. For example, in regions with cold climates and high heating needs, CHP is frequently owned by utilities to provide power and district heating (Di Lucia and Ericsson 2014).

Considering the societal benefits of CHP, we study the economics of utility ownership of CHP plants and examine the effect of regulatory policies, such as emissions taxes or renewable portfolio standards, on utility investment in CHP plants. Starting from an existing generation portfolio, we model a regulated utility's investment decision in additional electricity generation capacity, with the goal of minimizing the sum of upfront capacity adjustment costs and expected discounted operating costs as the utility satisfies exogenous customer demand. Such a cost-minimization would be relevant to a public utility commission, which has the responsibility of verifying the assumptions in a utility's integrated resources plan and approving capacity investments. While regulated utilities are not always rewarded for minimizing costs, the public utility commission's job is to minimize the costs experienced by the utility's captive customers. Investment options typically include inflexible generators, such as nuclear power, renewable generators, such as wind turbines, and flexible generators, such as natural gas combined cycle. To these options, we add CHP, which can be sized in a huge range, from tens of kilowatts to hundreds of megawatts.

Our analytical results detail the structure of the optimal investment decision and the optimal capacity dispatch decisions in the face of realized demand. We find that investments in inflexible, renewable, and flexible central generators follow a modified Invest/Stay Put/Disinvest (ISD) Policy. Typical ISD policies compare the marginal benefit of more capacity against adjustment costs, investing in additional capacity only if the benefit outweighs the cost and salvaging capacity only if the benefit is less than the salvage value. For a *given* siting decision of CHP plants, where the utility decides to build at certain potential sites and not others, the central generators follow such an ISD policy. As the CHP siting decision changes, however, interactions not typically seen in a standard ISD policy can arise. For instance, the utility may be in a "Stay Put" region for all central generators when no CHP plants are built. However, a different siting decision with multiple CHP plants may actually be optimal, and the utility can minimize costs by simultaneously installing CHP and salvaging some central generation. As such, we add the "modified" qualifier to our policy, with the "stay put" region of the ISD policy being modified by the CHP siting decision.

In addition to the utility cost-minimization, we also consider a societal cost-minimization. The societal decision maker includes the monetized impact of emissions from electricity generation, as well as heat and outage costs at on-site firms, in its optimization. Should CHP installations be optimal for society but not installed by the utility, it may be possible to institute regulatory policies, such as emissions taxes and RPS, to induce desired actions at the utility.

To study the utility investment decision in a realistic setting, we conduct a numerical study based on three regulated utilities: Georgia Power, Rocky Mountain Power, and Indianapolis Power & Light. We model their legacy generation portfolio, granular renewable intermittency, and various uncertainties, such as electricity demand, natural gas and coal prices, and outages at the firm, grid, and CHP. We find that even without regulatory changes, some CHP plants are present in the cost-minimizing utility portfolio. As such, utilities should be considering CHP more often in their integrated resource plans. To encourage CHP adoption, we find a low to moderate emission tax to be most effective. As emission taxes increase, the costs imposed by CHP plants on utilities follow a U-shaped curve. At low to moderate tax levels, the utility saves money by installing CHP instead of relying on coal-fired generators and natural gas combined cycle, as CHP plants have lower emissions. However, at high levels of the emission tax, all fossil-fuel based generators, including CHP, become more costly to own and operate than carbon-free nuclear power, wind turbines, or solar panels. As some states count CHP generation toward their RPS, we find that RPS policies may be effective if the standard is carefully specified.

Our numerical study confirms that utility ownership of CHP represents a promising path forward. Utilities should expend effort to identify customers with high thermal loads that would benefit from "no outage" electricity. By building CHP plants at these customers, the utility can simultaneously increase revenue, craft a more efficient generation portfolio, decrease costs at the on-site firm, and decrease overall emissions. These customers, who value the extra reliability of the CHP, would be less likely to defect from the grid in order to generate their own electricity on-site, thereby securing future utility revenue. Our paper provides a framework to value potential CHP contributions to U.S. regulated utilities.

2. Literature Review

Utility Generation Portfolio. There is a large literature on utility portfolio optimization and integrated resource planning that we extend to include CHP as an option. During resource planning, a utility strives to create a portfolio of generation assets that can effectively meet electricity demand in the future. We focus on regulated utilities, as electric distribution utilities are generally prohibited from owning generation assets, including CHP plants, in deregulated U.S. states. Aflaki and Netessine (2017) consider the effect of intermittency on the choice between installing renewable and nonrenewable generation. Rajagopalan et al. (1998) determine the optimal capacity expansion in situations where future technological breakthroughs are expected. While renewable generation is likely to become cheaper and more efficient in the future, CHP is a mature technology, thus allowing for a decision maker to be comfortable installing it immediately. Banal-Estañol and Micola (2009) examine how the composition of the generation portfolio affects market power and price setting in a wholesale electricity setting. Malguarnera and Razban (2015) look at utility ownership of CHP plants, but do not consider the full utility portfolio into which CHP will enter.

The two papers closest to our modeling approach are Kök et al. (2016) and Wang et al. (2013). Kök et al. (2016) examine a utility investing in inflexible, renewable, and flexible central generation, finding that renewable and flexible generation are complements. Our paper differs from Kök et al. (2016) in that we add CHP as a generation option, and we consider an adjustment to an existing generation portfolio, as opposed to crafting an optimal portfolio from scratch. In a different context, Wang et al. (2013) examine the problem of incrementally acquiring two types of capacity. They find that an ISD policy is optimal. In our context, we show that all central generation options follow a similar modified ISD structure.

Electricity Reliability. CHP plants can be configured to run independently of the electric grid, thereby continuing to provide power to on-site firms in the face of a grid outage. In the U.S., grid outages are relatively common, caused chiefly by distribution problems, such as a downed power line. Saviva Research (2013) reports that U.S. utility customers experience about four hours of outages per year, on average. This is a much higher outage rate than most of the developed world. Each outage can be very costly to customers. Heavy industry tends to be hit the hardest by minor grid outages; even momentary disruptions can ruin chips and circuits of machinery (Saviva Research 2013). LaCommare and Eto (2006) estimates the economic cost of power interruptions to U.S. electricity consumers to be $79 billion annually. Kleindorfer and Fernando (1993) partitions outage costs into rationing costs, disruption costs, and surplus losses due to unsatisfied demand.

Hampson et al. (2013) notes that CHP plants can improve the resiliency of critical infrastructure due to their ability to provide uninterrupted service in the event of a blackout. The authors also note that, due to its daily use, a CHP system is much more likely to be properly maintained and functional than a backup generator that is only used during emergencies. Many facilities continued to operate during the August 2003 Northeast Blackout because they had on-site CHP configured to operate independently of the electric grid (Carlson and Berry 2004).

Combined Heat and Power Operation. Before turning to the question of utility ownership of CHP, which is currently uncommon in the U.S., we briefly describe the larger literature related to private ownership and operation of CHP plants. Joskow and Jones (1983) introduce how to economically size a CHP plant. Fine temporal renderings of heat and electricity demand are necessary to properly size a CHP plant, especially for smaller plants with fluctuating needs (Hawkes and Leach 2005, Hu et al. 2015). Lahdelma and Hakonen (2003) create an efficient linear program to determine the optimal operation of a CHP plant, given heat and electricity needs. Mueller (2006) examines the relatively low adoption of CHP and determines that regulatory uncertainty plays a large role among private owners. We examine the causes for low adoption among utilities.

In colder climates, utilities often add CHP to their portfolios to provide district heating to consumers (Di Lucia and Ericsson 2014). Kwun and Baughman (1991) analyze the system level benefits of introducing a CHP plant using a deterministic mathematical program. Weber and Woll (2006) analyze the value of adding CHP to a utility's portfolio when it can also buy electricity in uncertain spot markets; however, they do not model the entire generation portfolio nor consider the impact of regulatory policies as we do.

Policies to Encourage Emission Reductions. It may be necessary to institute regulatory policies or incentives to encourage CHP adoption. Regulatory policies fall into three broad categories: policies that are specific to CHP plants, policies to reduce emissions from electricity generation, and policies to create standards for the utility's portfolio of generation assets. In the first category, Zhang et al. (2016) study the effect of rebates, tax credits, low tax loans, and utility credits on shortening the payback period for investment in CHP, finding that many current policies are not effective. Athawale and Felder (2014) argue that policies to insure against operational risk and to decrease the upfront cost of CHP may promote more investment. Sundberg and Henning (2002) look at the effect of fuel prices and subsidies on CHP operation. In the second category, Drake et al. (2016) examine the effect of cap and trade and carbon taxes on generation portfolios, where CHP is not explicitly considered. Another way to lower emissions is to capture and sequester carbon emissions from natural gas plants, as examined in İşlegen and Reichelstein (2011). We find that an emission tax can indeed benefit CHP adoption, but only at low to moderate levels. In the third category, a renewable portfolio standard (RPS) can increase CHP adoption. As previously discussed, 20 states call out CHP as eligible towards a utility's RPS. Ritzenhofen et al. (2016) simulate the market effectiveness and robustness of RPS and feed-in-tariffs on investment in renewables. We study RPS as a policy lever to increase CHP adoption.

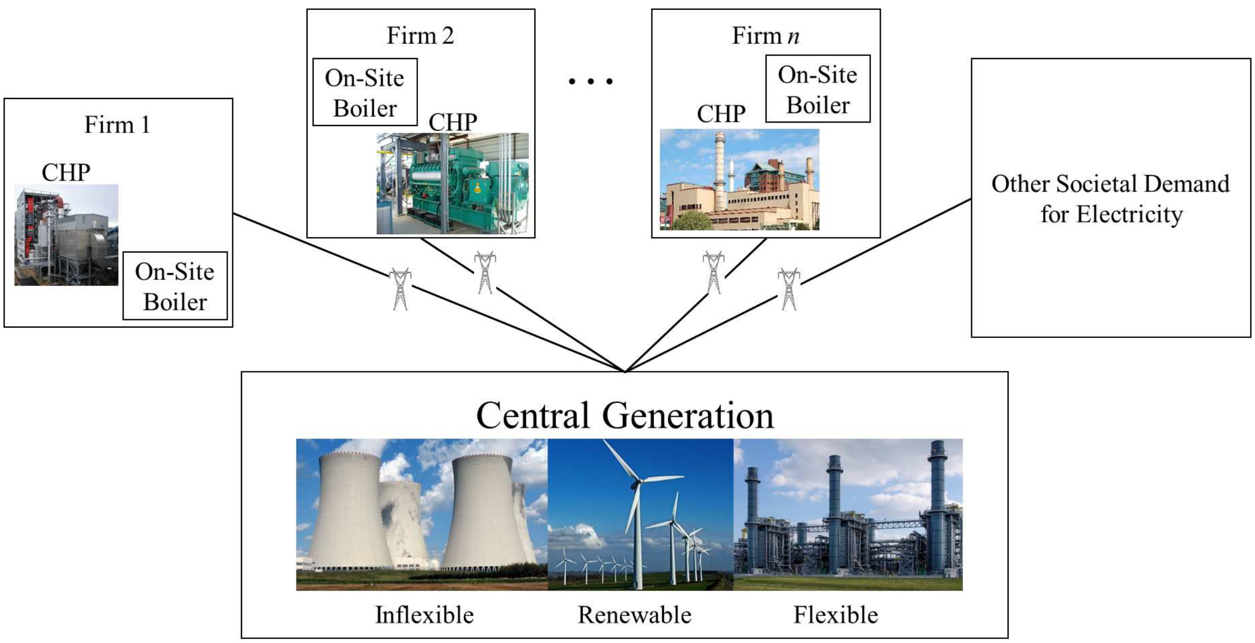
3. Model

We consider an investment decision in new electricity generation capacity from two different perspectives. The first perspective considers a public utility commission (PUC) that oversees investments in generation capacity by a regulated electric utility. Utilities often earn a fixed profit margin on their assets under management or investment costs, so utilities may not have ample incentive to invest in a cost-efficient manner. However, the PUC is appointed to protect the public's interests in the face of the monopoly granted to the electric utility. When considering utility investment decisions, the PUC can work to ensure that the utility is creating a generation portfolio that minimizes the sum of upfront installation costs and discounted future operating costs, so as to minimize the total cost to captive utility customers. The second perspective is of a societal decision maker that, in addition to caring about the monetary costs of building and operating generators, also cares about the environmental impacts and externalities of energy generation.

There are four main types of generation capacity: (centralized) inflexible generators, (centralized) renewable generators, (centralized) flexible generators, and (decentralized) CHP generators. Inflexible capacity, such as nuclear power, has a low marginal cost of generation, but the output level cannot be varied based on current demand. As such, inflexible generators produce according to their available capacity. Renewable capacity, as provided by wind turbines or solar panels, is characterized by negligible generation costs and intermittent generation. Flexible capacity includes generators that can ramp quickly to match demand changes, such as natural gas combined cycle.

At the central generators, electricity is generated remotely. When transmitting to distant customers, a portion of the generated electricity is lost to resistance in the transmission line and to energy conversions in the distribution process. CHP plants can be located at the site of a firm with large electricity and thermal needs, and hence line losses are eliminated when the electricity is used locally. If the CHP produces electricity in excess of firm demand, the excess may be sent to the grid, but it is subject to line losses. CHP plants are flexible in that their power output can be ramped up and down quickly. The heat produced at the CHP is used by the on-site firm, and it reduces or eliminates the need for heat from legacy boilers. We consider CHP plants that are configured to run independently of the grid. The CHP would continue to provide power to the firm in the event of a grid outage. To provide this reliability benefit, the CHP must be running when the firm is operating, so that there is no interruption in power if the grid fails.

Figure 1: Hub and spoke network



It may be useful to visualize this as a hub-and-spoke network, with the central generation options occupying the hub of the network. See Figure 1. Each potential CHP site is a spoke of the network, and there is another spoke that represents all other societal demand. If electricity and heat demand are not satisfied by an on-site CHP unit, then electricity must be transmitted from other utility generators and heat must be produced at an on-site boiler.

3.1 CHP and the On-Site Firm

The utility works with its large customers to identify possible CHP sites, indexed by the subscript $i \in \{1, 2, ..., n\}$. For a utility-owned CHP to be built on-site, the site owner and utility must work out a mutually beneficial agreement. This agreement will identify the electrical and thermal capacity at the CHP. It will often be optimal to size the CHP to satisfy the firm's thermal demand

(Joskow and Jones 1983, Chittum and Farley 2013, Darrow et al. 2017). For the potential CHP at site i, let μ_i be its electrical capacity (in MW) and let h_i be its thermal capacity (in MMBtu per period). The utility would be responsible for costs related to construction, grid connection, and operation of the CHP. The site owner would allow adequate land and site access for the utility to build and operate the CHP. The site owner will enter into a power purchase agreement with the utility to buy the electricity and heat, typically for 20-30 years, during which it will have "first call" on the CHP facility's electricity output. Let $z_i \in \{0, \mu_i\}$ be the installed MW at firm i after the utility has made its installation decision. Model notation is summarized in Table 1 of §3.4.

We take the electrical and thermal capacity, μ_i and h_i, of each possible CHP plant as given in order to focus on the question of whether CHP plants are a beneficial addition to a utility's portfolio. There is literature related to the sizing of CHP plants (e.g., Joskow and Jones 1983), and it is outside the scope of this paper to solve for CHP sizing. The agreed upon electrical capacity, μ_i, must be sufficient to allow the firm to continue operating in the face of a grid outage. Otherwise, there would be no reliability benefit to the firm. Generally speaking, the utility would not want to under-size the CHP as this reliability benefit would be threatened and would not want to over-size the CHP as the excess heat produced would be wasted.

For a firm to allow the utility to build a CHP plant on-site, the total costs to the firm must be lower with the CHP than without it. In other words, we consider the status quo in which those firms that find it advantageous to own private CHP plants have already built them. If a CHP is built, the firm would pay a surcharge, $r_i \geq 0$ per MW-period provided by the CHP, to compensate the utility for the provided heat as well as the reduced likelihood of outages. In the absence of the CHP, the firm would have to produce an extra h_i MMBtu of heat from legacy boilers at the cost of C_{Ht} per MMBtu in period t, where C_{Ht} typically depends on the cost of natural gas. We assume the firm needs heat even if there is an electrical outage.

If there is an electrical outage in a period in which firm i is trying to operate, firm i experiences an outage cost, ψ_i, due to lost productivity and process interruption, where ψ_i also accounts for savings from foregone electricity consumption. In period t, let $\mathbb{1}_{it}^G$ be an indicator that is one if the electrical grid at firm i is operational and zero otherwise. When the firm is operating, the outage costs in the absence of an on-site CHP are thus $(1 - \mathbb{1}_{it}^G)\psi_i$. As a CHP built on-site could run independently of the grid in "island" mode, the firm would only experience an outage when the CHP is non-operational and there is a grid failure. Let $\mathbb{1}_{it}^c$ be an indicator that is one if the CHP at firm i is operational in period t and zero if it is undergoing routine or unscheduled maintenance. The outage costs are thus $(1 - \mathbb{1}_{it}^G)(1 - \mathbb{1}_{it}^c)\psi_i$ when the firm is operating and a CHP is built on-site.

If the on-site firm experiences lower combined costs once a CHP is built on-site, we say that the CHP is incentive-compatible for the on-site firm. Let $\mathbb{1}^f_{it}$ be an indicator that is one if firm i is operating in period t and zero otherwise. The CHP is incentive-compatible if

$$\mathbb{E}\Big[\sum_{t=1}^{T}\delta_i^t \mathbb{1}^f_{it}\big(\mathbb{1}^c_{it}\mu_i r_i + (1-\mathbb{1}^c_{it})h_i C_{Ht} + (1-\mathbb{1}^c_{it})(1-\mathbb{1}^G_{it})\psi_i\big)\Big]$$
$$< \mathbb{E}\Big[\sum_{t=1}^{T}\delta_i^t \mathbb{1}^f_{it}\big(h_i C_{Ht} + (1-\mathbb{1}^G_{it})\psi_i\big)\Big], \qquad (1)$$

where δ_i is the per-period discount factor used at firm i. On the left side of the inequality are the expected costs at the firm if the CHP is built: surcharge when the CHP is operational + heat generation costs when the CHP is down + outage costs when both the CHP and grid are down. On the right side are the expected costs if the CHP is not built: heat generation costs + outage costs when the grid is down. Note that the firm's energy cost also includes the payment to the utility for electricity consumption. Since this cost is the same regardless of whether CHP is installed, it does not appear in (1). Costs to the firm are assumed to be zero when the firm is not operating. Inequality 1 can be simplified to

$$r_i\mu_i < h_i\bar{c}_H + (1-\bar{\mathbb{1}}^G_i)\psi_i, \qquad (2)$$

where $\bar{c}_H = \frac{\sum_{t=1}^{T}\delta_i^t \mathbb{E}[\mathbb{1}^f_{it}C_{Ht}]}{\sum_{t=1}^{T}\delta_i^t \mathbb{E}[\mathbb{1}^f_{it}]}$ is a measure of the expected cost per MMBtu produced via the legacy boiler and $\bar{\mathbb{1}}^G_i$ is the probability of the grid being operational at firm i. Inequality 2 suggests the firm is indifferent to the availability of the CHP, $\mathbb{1}^c_{it}$. The CHP is incentive-compatible as long as its heat and reliability surcharge is less than the combined heat and outage costs in the absence of the CHP. This indifference to CHP up-time is due to the fact that the firm does not pay the setup or maintenance costs of the CHP. The utility, which does pay those costs, is more sensitive to up-time.

3.2 Time-Varying Electricity Demand

We assume that the societal demand for electricity from the utility's customers is exogenous and has two components: demand at the n possible CHP sites, and demand at all other utility customers. In period t, the latter demand, in MW, is denoted χ_t. For the demand at the n firms, let the desired power draw of firm i in period t be $\mathbb{1}^f_{it}(\mu_i + \epsilon_{it})$, with $\epsilon_{it} \geq 0$. If a CHP is built on-site ($z_i = \mu_i$) and operational in period t ($\mathbb{1}^c_{it} = 1$), the CHP will cover μ_i MW of the firm's demand. If the grid is operational, any demand at the firm that is not met by the on-site CHP will be met by the utility's other generators. This unmet demand at firm i that is met by other generators is

$\mathbb{1}_{it}^{f}\mathbb{1}_{it}^{G}(\mu_i + \epsilon_{it} - \mathbb{1}_{it}^{c}z_i)$ in period t. As a result, the total demand, D_t, that the utility faces in period t after operational CHP plants have covered on-site demand is

$$D_t = \chi_t + \sum_{i=1}^{n} \mathbb{1}_{it}^{f}\mathbb{1}_{it}^{G}(\mu_i + \epsilon_{it} - \mathbb{1}_{it}^{c}z_i). \tag{3}$$

3.3 Installation Costs and Salvage Value

At the beginning of the planning horizon, the utility faces the option of altering its generation portfolio in order to more cost-effectively meet time-varying electricity demand. The utility may invest in more central generation, where the cost to install one MW is k_I for inflexible generation, k_R for renewable generation, and k_F for flexible generation. The per MW cost is linear in MW for centralized capacity because inflexible and flexible generators typically inhabit a range of sizes in which all available economies of scale have been exhausted and the per MW cost for additional generation is roughly constant (Christensen and Greene 1976). For utility-scale renewable generation, there are rarely significant economies of scale, as increasing the capacity of renewable generation typically entails installing more wind turbines or solar panels, each of which is relatively modular. Should the utility wish to reduce capacity, the salvage value from removing one MW is s_I for inflexible generation, s_R for renewable generation, and s_F for flexible generation, with $s_I < k_I$, $s_R < k_R$, and $s_F < k_F$. s_I, s_R, and s_F may take negative values if it is costly to decommission capacity.

Let k_i be the per-MW cost to install a μ_i MW CHP at firm i. CHP plants do exhibit economies of scale, and larger installations typically have lower install costs per MW. As we are interested in situations where a utility adds CHP to their generation portfolio, we assume that there are no CHP plants initially installed, thus obviating the need to specify a salvage value for CHP plants.

Let x_I, x_R, and x_F be the initial installed capacity (in MW) of inflexible generation, renewable generation, and flexible generation, respectively, prior to any adjustments. The utility may install or salvage capacity to have y_I, y_R, and y_F MW of installed capacity after adjustment. The utility specifies the CHP capacity, $z_i \in \{0, \mu_i\}$, at each of the n firms. Let $\mathbf{x} = [x_I, x_R, x_F]$, $\mathbf{y} = [y_I, y_R, y_F]$, and $\mathbf{z} = [z_1, z_2, ..., z_n]$. The total install/salvage costs are

$$\begin{aligned} V(\mathbf{x},\mathbf{y},\mathbf{z}) =& k_I(y_I - x_I)^+ + k_R(y_R - x_R)^+ + k_F(y_F - x_F)^+ + \sum_{i=1}^{n} k_i z_i \\ & - s_I(x_I - y_I)^+ - s_R(x_R - y_R)^+ - s_F(x_F - y_F)^+. \end{aligned} \tag{4}$$

Table 1: Notation table. A variable with a t subscript signifies the variable value in period t. Subscript g indicates central generation technology: $g = I$ for inflexible generators, $g = R$ for renewable generators, and $g = F$ for flexible generators. The subscript $i \in \{1, 2, ..., n\}$ denotes the index of the on-site firm at which a CHP plant could be built.

Decision Variables			
y_g	Installed MW capacity	z_i	Installed CHP capacity at firm i
q_{gt}	Capacity dispatched (MW)	q_{it}	MW dispatched to societal demand
Random Variables			
Φ_t	System state (encompasses other R.V.)	$\mathbb{1}_{it}^G$	Indicator grid is connected to firm
C_{gt}	Operating cost per MW-period	C_{it}	Operating cost per MW-period
χ_t	Societal demand away from n firms	$\mathbb{1}_{it}^f$	Indicator firm is operating
D_t	Total demand unmet by on-site CHPs	ϵ_{it}	Excess firm demand above μ_i
θ_{gt}	Proportion of capacity available	$\mathbb{1}_{it}^c$	Indicator CHP is available
Central Generation Parameters			
k_g	Install cost per MW	s_g	Salvage value per MW
x_g	MW capacity before adjustment	m_g	Maintenance cost per MW-period
ζ	Shortage cost per MW-period	η	Overage cost per MW-period
λ	Line loss proportion	e_g	Emission cost per MW-period
δ_U	Utility discount factor	δ_S	Societal discount factor
CHP and On-site Firm Parameters			
k_i	Install cost per MW	m_i	Maintenance cost per MW-period
μ_i	MW capacity	h_i	MMBtu heat capacity per period
ψ_i	Outage cost at firm per period	r_i	Surcharge for CHP heat/reliability
e_i	Emission cost per MW-period	δ_i	Firm discount factor
Cost Functions			
$\pi_U(\cdot)$	One-period costs to utility	$\pi_S(\cdot)$	One-period costs to society
$\nu_U(\cdot)$	Expected discounted costs to utility	$\nu_S(\cdot)$	Expected discounted costs to society
$V(\cdot)$	Capacity adjustment costs		

3.4 Costs in a Single Period

After the final capacity decision has been made, the utility operates and maintains the generators to meet demand in future periods. In this section, we detail the costs incurred in each period by the utility and by society. Let $\pi_U(\mathbf{y}, \mathbf{z}, \Phi_t)$ be the one period costs experienced by the utility if the capacity decision is $\mathbf{y}$ for central generation and $\mathbf{z}$ for CHP generation and the random state of the system is depicted by Φ_t. We expand upon what is included in Φ_t below. Similarly, let $\pi_S(\mathbf{y}, \mathbf{z}, \Phi_t)$ be the one period costs imposed on society.

Installed capacity may not always be available to dispatch. Renewable power is typically intermittent due to weather conditions, and its availability is exogenously determined. Inflexible and flexible generators may be unavailable due to maintenance issues, both scheduled and unscheduled. Let $\theta_{It} \in [0, 1]$, $\theta_{Rt} \in [0, 1]$, and $\theta_{Ft} \in [0, 1]$ be the proportion of the installed inflexible, renewable, and flexible capacity that is available in period t.

From the available capacity, a certain proportion is dispatched to meet societal demand. All available inflexible capacity must be dispatched, as the output level cannot be varied based on current demand. Let q_{Rt} and q_{Ft} be the amount of renewable and flexible generation that is dispatched in period t, in MW, subject to availability constraints. The CHP at firm i must run if it is operational and the firm is operating, in order to provide the reliability benefit. If the CHP is operational ($\mathbb{1}_{it}^c = 1$) and the firm is not operating ($\mathbb{1}_{it}^f = 0$), the CHP can be dispatched to meet other demand. Thus, let $q_{it} \in [0, (1 - \mathbb{1}_{it}^f)\mathbb{1}_{it}^c z_i]$ be the MW dispatched from CHP i to the grid.

Central generators face line losses in transmitting and distributing to customers. Let λ be the proportion of transmitted power that is lost to line losses. Electricity generated by CHP plants for on-site use is not subject to line losses. CHP plants may operate as grid resources when their on-site firms are idle and send power to other customers, but such transmissions would be subject to line losses.

Maintenance Costs. Whether the generators are operating or not, a maintenance cost (m_I, m_R, m_F, and m_i for inflexible generators, renewable generators, flexible generators, and CHP plant i, respectively) is charged each period per MW installed.

Operating Costs. Let C_{It}, C_{Rt}, and C_{Ft} be per MW-period operating costs for inflexible, renewable, and flexible generators, respectively, in period t. Let C_{it} be the per MW-period operating cost of CHP plant i in period t. These costs may vary from period to period based on fuel costs. Because the operating cost of solar and wind generation is negligible, we set $C_{Rt} = 0$. While costs vary from period to period, we assume the following hierarchy: $0 = C_{Rt} < C_{It} < C_{Ft} < C_{it}\ \forall\ i, t$.

Customers at the n on-site firms receive heat and reliability benefits if a CHP is built on-site. Outside of these n on-site firms, however, utility customers do not receive extra non-electrical benefits from CHP units. As such, it is prudent to account for the compensation the on-site firms provide to the utility for these benefits and only consider the *net* cost inclusive of these payments, of the CHP to utility customers as a whole. Firm i pays a surcharge of r_i per MW-period provided by the on-site CHP. Thus, when both firm i and CHP i are operating, the net cost to the utility of running CHP i is $C_{it} - r_i$ per MW-period.

Shortage and Overage Costs. If the amount of electricity dispatched is not enough to meet total demand, the utility faces a shortage penalty of ζ per MW-period. The shortage cost represents either the penalty to the utility for loss of load or the cost of importing electricity into the region from an external power pool. We assume the shortage penalty is more expensive per MW-period than all utility-owned generation options ($\zeta > C_{it} \forall\ i, t$). The shortage penalty in period

t is $\zeta\Big(D_t - (1-\lambda)(\theta_{It}y_I + q_{Rt} + q_{Ft} + \sum_{i=1}^n q_{it})\Big)^+$. Similarly, if the utility dispatches too much electricity, an overage charge of η per MW-period is applied. This represents the costs related to handling the energy imbalance on the system. The overage penalty in period t is $\eta\Big((1-\lambda)(\theta_{It}y_I + q_{Rt} + q_{Ft} + \sum_{i=1}^n q_{it}) - D_t\Big)^+$.

One Period Costs to Utility. The state of the system, Φ_t in period t, includes information about which firms are operating ($\mathbb{1}_{it}^f$) and their variations above their base demand (ϵ_{it}), the availability of generation capacity (θ_{gt} for $g \in \{I, R, F\}$ and $\mathbb{1}_{it}^c$ for $i \in \{1, 2, ..., n\}$), the status of the distribution grid at each of the n firms ($\mathbb{1}_{it}^G$), the societal demand not at the n firms (χ_t), and the operating costs (C_{gt} and C_{it}). We can now write the one-period costs to the utility, based on the utility's dispatch choices, $\mathbf{q_t} = [q_{Rt}, q_{Ft}, q_{it}]$, and the state of the system, Φ_t:

$$\pi_U(\mathbf{y}, \mathbf{z}, \Phi_t, \mathbf{q_t}) = m_I y_I + m_R y_R + m_F y_F + C_{It}\theta_{It}y_I + \sum_{i=1}^n \Big(m_i z_i + (C_{it} - r_i)\mathbb{1}_{it}^f \mathbb{1}_{it}^c z_i\Big)$$
$$+ C_{Ft}q_{Ft} + \sum_{i=1}^n C_{it}q_{it} + \zeta\Big(D_t - (1-\lambda)(\theta_{It}y_I + q_{Rt} + q_{Ft} + \sum_{i=1}^n q_{it})\Big)^+$$
$$+ \eta\Big((1-\lambda)(\theta_{It}y_I + q_{Rt} + q_{Ft} + \sum_{i=1}^n q_{it}) - D_t\Big)^+. \tag{5}$$

The first line in (5) includes all costs that are fixed for the utility: maintenance costs, operating costs of dispatching all available inflexible generation, and net operating costs of running CHP units for on-site firms that are currently operating. The second line includes operating costs for dispatched flexible generation and CHP generation that is sent to other customers when the on-site firm is not operational. Recall that dispatched renewable generation incurs zero operating costs. The last term on the second line represents shortage costs, and the third line has the overage costs.

Let Q_t be the space of possible dispatch choices in period t. $\mathbf{q_t} \in Q_t$ if $0 \le q_{Rt} \le \theta_{Rt}y_R$, $0 \le q_{Ft} \le \theta_{Ft}y_F$, and $0 \le q_{it} \le (1 - \mathbb{1}_{it}^f)\mathbb{1}_{it}^c z_i \forall\ i$.

Additional Costs to Society. A societal decision maker would be interested in overall societal welfare as it relates to energy use, including both the monetary costs and the environmental impacts of electricity generation. Monetary transfers, such as CHP surcharge revenue, are not pertinent to the societal decision maker, as such transfers cancel out when considering the entirety of society.

As the presence of a CHP plant affects heat generation and outage costs at the on-site firm, such costs will be considered by the societal decision maker. If the CHP is not built or not operational (indicated by $1 - \mathbb{1}_{it}^c \frac{z_i}{\mu_i}$), the firm will have to generate h_i MMBtu of heat via legacy boilers and will experience an outage, at cost ψ_i, if, in addition, the grid experiences a distributional failure.

Let e_I, e_F, and e_i be the environmental costs imposed on society per MW-period produced at inflexible plants, flexible plants, and CHP plant i, respectively. Let e_H be the environmental costs per MMBtu of heat produced at a firm's legacy boilers. If electricity is imported from external sources, let e_ζ be the environmental cost per MW-period imported.

The decision space for the dispatch decision, Q_t, is the same for the societal decision as the utility decision. $\pi_S(\mathbf{y}, \mathbf{z}, \Phi_t, \mathbf{q_t})$ gives the one-period costs to society, based on society's dispatch choices and the state of the system:

$$
\begin{aligned}
\pi_S(\mathbf{y}, \mathbf{z}, &\Phi_t, \mathbf{q_t}) = m_I y_I + m_R y_R + m_F y_F + (C_{It} + e_I)\theta_{It} y_I \\
&+ \sum_{i=1}^{n} \left(m_i z_i + (C_{it} + e_i)\mathbb{1}_{it}^{f}\mathbb{1}_{it}^{c} z_i + \mathbb{1}_{it}^{f}\Big(1 - \mathbb{1}_{it}^{c}\frac{z_i}{\mu_i}\Big)\Big((C_{Ht} + e_H)h_i + (1 - \mathbb{1}_{it}^{G})\psi_i\Big)\right) \\
&+ (C_{Ft} + e_F)q_{Ft} + \sum_{i=1}^{n}(C_{it} + e_{it})q_{it} + (\zeta + e_\zeta)\Big(D_t - (1-\lambda)(\theta_{It} y_I + q_{Rt} + q_{Ft} + \sum_{i=1}^{n} q_{it})\Big)^{+} \\
&+ \eta\Big((1-\lambda)(\theta_{It} y_I + q_{Rt} + q_{Ft} + \sum_{i=1}^{n} q_{it}) - D_t\Big)^{+}. \qquad (6)
\end{aligned}
$$

The first line in (6) includes maintenance costs and operating and environmental costs of inflexible generation. The second line includes maintenance costs of CHP units, operating and environmental costs for running CHP units for on-site power, heating costs via the legacy boiler when there is no on-site CHP available, and outage costs when neither the on-site CHP nor the grid can deliver power to the firm. The third lines includes operating and environmental costs of flexible generation and CHP generation that is sent away from the on-site firm, as well as shortage costs. The fourth line includes overage costs.

4. Optimal Investment in Generation

The public utility commission (PUC) wishes to alter generation capacity to minimize the initial capacity adjustment costs (4) plus expected discounted costs in future periods (5). Thus, the PUC, with per-period discount factor δ_U, solves the following two-stage problem:

$$\min_{\mathbf{y},\mathbf{z}} V(\mathbf{x}, \mathbf{y}, \mathbf{z}) + \sum_{t=1}^{T} \delta_U^t \mathbb{E}_{\Phi_t}\Big[\min_{\mathbf{q_t} \in Q_t} \{\pi_U(\mathbf{y}, \mathbf{z}, \Phi_t, \mathbf{q_t})\}\Big], \qquad (7)$$

$$\text{such that } \mathbf{y} \geq 0, \qquad (8)$$

$$z_i \in \{0, \mu_i\} \forall\ i. \qquad (9)$$

The expectation on costs in future periods is taken over Φ_t. The time horizon is T periods.

The societal decision maker solves a similar two stage problem as (7), with societal discount factor δ_S substituting for δ_U and $\pi_S(\mathbf{y}, \mathbf{z}, \Phi_t, \mathbf{q_t})$, given in (6), substituting for $\pi_U(\mathbf{y}, \mathbf{z}, \Phi_t, \mathbf{q_t})$. The constraints remain the same. It is likely that $\delta_S > \delta_U$, as the societal decision maker cares about the effect of emissions, which may have long-lasting impacts on the environment, while the utility and the PUC are only focused on monetary costs.

We first solve for the optimal dispatch amount, $\mathbf{q_t^U}$ for the utility and $\mathbf{q_t^S}$ for society, for every $\mathbf{y}/\mathbf{z}/\Phi_t$ combination. We then return to the first-stage minimization to determine the optimal capacity investment strategy.

4.1 Dispatch Decision

At the n firms identified for possible on-site CHP, the CHP units must run if they are built and operational and the firm is operating, in order to provide the heat and reliability benefits. Inflexible central generation has been pre-committed to run at its maximum available capacity ($\theta_{It}y_I$). Each period, the dispatch decision, $\mathbf{q_t^U} \in Q_t$, must be made of how much renewable, flexible, and CHP capacity to dispatch to minimize the utility's one-period costs in (5), based on system state, Φ_t. With the utility dispatching capacity in order of increasing operating cost per MW-period, the following proposition gives the optimal dispatch levels. All proofs are in the appendix.

Proposition 1 (Final Dispatch for Utility) *Consider the utility's one period costs in* (5)*. Let* (i) *denote the index of the CHP with the* i^{th} *lowest operating cost, ordering by* C_{it}*. To minimize one period costs, the following dispatch quantities should be used:*

$$q_{Rt}^U = \min\Big\{\theta_{Rt}y_R, \Big(\frac{D_t}{1-\lambda} - \theta_{It}y_I\Big)^+\Big\}, \tag{10}$$

$$q_{Ft}^U = \min\Big\{\theta_{Ft}y_F, \Big(\frac{D_t}{1-\lambda} - \theta_{It}y_I - \theta_{Rt}y_R\Big)^+\Big\}, \tag{11}$$

$$\begin{aligned} q_{(i)t}^U = \min\Big\{&\mathbb{1}_{(i)t}^G(1-\mathbb{1}_{(i)t}^f)\mathbb{1}_{(i)t}^c z_{(i)}, \\ &\Big(\frac{D_t}{1-\lambda} - \theta_{It}y_I - \theta_{Rt}y_R - \theta_{Ft}y_F - \sum_{j=1}^{i-1}(\mathbb{1}_{(j)t}^G(1-\mathbb{1}_{(j)t}^f)\mathbb{1}_{(j)t}^c z_{(j)})\Big)^+\Big\}. \end{aligned} \tag{12}$$

As $C_{Rt} < C_{Ft} < C_{it} < \zeta$, available renewable power will be dispatched to meet remaining demand first, followed by flexible power. Non-committed CHP generation is then dispatched, in order of increasing operational cost per MW-period. The utility must pay a shortage penalty for any remaining unsatisfied demand. The amount of shortage will be

$$q_{\zeta t}^U = \left(D_t - (1-\lambda)\Big(\theta_{It}y_I + \theta_{Rt}y_R + \theta_{Ft}y_F + \sum_{i=1}^{n}\mathbb{1}_{it}^G(1-\mathbb{1}_{it}^f)\mathbb{1}_{it}^c z_i\Big)\right)^+. \tag{13}$$

An overage is only experienced if there is too much inflexible power available. The amount of overage is

$$q^U_{\eta t} = \Big((1-\lambda)\theta_{It} y_I - D_t\Big)^+. \tag{14}$$

The minimal one period costs are obtained by setting the dispatch quantities to their optimal level, so henceforth we use the simplified notation:

$$\pi_U(\mathbf{y}, \mathbf{z}, \Phi_t) = \pi_U(\mathbf{y}, \mathbf{z}, \Phi_t, \mathbf{q_t^U}). \tag{15}$$

Recall that the societal decision maker faces a different one period cost structure, as shown in (6). The following proposition gives the dispatch levels that are optimal for society:

Proposition 2 (Final Dispatch for Society) *Consider the societal one period costs in* (6)*. The dispatch level for renewable generation, q^S_{Rt}, matches the value for q^U_{Rt} given in Proposition 1. Let (i) denote the index of the CHP plant or flexible generation with the i^{th} cheapest operating cost, ordered by $C_{it} + e_{it}$, where flexible generation takes index 0. Let $\mathbb{1}^G_{0t} = 1$, $\mathbb{1}^f_{0t} = 0$, $\mathbb{1}^c_{0t} = \theta_{Ft}$, and $z_0 = y_F$. Assume that $\zeta + e_\zeta > C_{it} + e_{it} \forall\ i, t$, so it is never optimal to intentionally leave a generator idle when facing remaining unmet demand. The following equation gives the dispatch amounts of flexible and CHP generation:*

$$q^S_{(i)t} = \min\Big\{\mathbb{1}^G_{it}(1-\mathbb{1}^f_{it})\mathbb{1}^c_{it} z_i, \Big(\frac{D_t}{1-\lambda} - \theta_{It} y_I - \theta_{Rt} y_R - \sum_{j=1}^{i-1}(\mathbb{1}^G_{(j)t}(1-\mathbb{1}^f_{(j)t})\mathbb{1}^c_{(j)t} z_{(j)})\Big)^+\Big\} \tag{16}$$

The societal decision maker includes the emission costs when determining the merit order by which generators should be dispatched. If including the emission costs does not change the order of the operating costs for the flexible and CHP generators, then the societal dispatch will exactly match the utility dispatch. Otherwise, there may be differences in the flexible and CHP dispatch. The amount of shortage and overage are unchanged from (13) and (14).

Similar to (15), simplify societal one period costs as

$$\pi_S(\mathbf{y}, \mathbf{z}, \Phi_t) = \pi_S(\mathbf{y}, \mathbf{z}, \Phi_t, \mathbf{q_t^S}). \tag{17}$$

We state the following result on the convexity of $\pi_U(\mathbf{y}, \mathbf{z}, \Phi_t)$ and $\pi_S(\mathbf{y}, \mathbf{z}, \Phi_t)$, which will be useful when solving for the optimal change in central generation capacity.

Theorem 1 *$\pi_U(\boldsymbol{y}, \boldsymbol{z}, \Phi_t)$ is convex in $\boldsymbol{y}$ for all possible $\boldsymbol{z}$ and Φ_t combinations. Similarly, $\pi_S(\boldsymbol{y}, \boldsymbol{z}, \Phi_t)$ is convex in $\boldsymbol{y}$ for all possible $\boldsymbol{z}$ and Φ_t combinations.*

Define the expected discounted costs to the utility and to society as

$$\nu_U(\mathbf{y},\mathbf{z}) = \sum_{t=1}^{T} \delta_U^t \mathbb{E}_{\Phi_t}[\pi_U(\mathbf{y},\mathbf{z},\Phi_t)] \tag{18}$$

$$\text{and} \quad \nu_S(\mathbf{y},\mathbf{z}) = \sum_{t=1}^{T} \delta_S^t \mathbb{E}_{\Phi_t}[\pi_S(\mathbf{y},\mathbf{z},\Phi_t)]. \tag{19}$$

$\nu_U(\mathbf{y},\mathbf{z})$ and $\nu_S(\mathbf{y},\mathbf{z})$ are each convex in $\mathbf{y}$ due to Theorem 1 and convexity preservation across positive weighted sums, including expectation and discounting.

4.2 Installation Decision for Central Generation

We now solve for the amount of central generation $\mathbf{y}$ and CHP generation $\mathbf{z}$ that minimize upfront capacity adjustment costs plus expected discounted costs in future periods. The presence of $\mathbf{z}$ as a decision variable complicates the solution for the optimal capacity decision, as the decision to install a CHP plant is binary, and a convex optimization is not possible. This is in contrast to the central generation options, where the capacity amounts are continuous decision variables. As such, we first solve for the optimal central generation capacity, $\mathbf{y}$, taking $\mathbf{z} = \hat{\mathbf{z}}$ as given. We re-write the PUC's investment problem in (7) as

$$\min_{\mathbf{y}\geq 0} V(\mathbf{x},\mathbf{y},\hat{\mathbf{z}}) + \nu_U(\mathbf{y},\hat{\mathbf{z}}). \tag{20}$$

The societal decision maker's problem is analogous, with $\nu_S(\cdot)$ substituting for $\nu_U(\cdot)$.

First, consider the PUC's decision. Installing more capacity of generation type $g \in \{I, R, F\}$ costs k_g per MW, while salvaging 1 MW of type g capacity yields s_g, with $s_g < k_g$. So capacity adjustment costs are piecewise linear and convex in $\mathbf{y}$. $\nu_U(\mathbf{y},\hat{\mathbf{z}})$ is also convex in $\mathbf{y}$, as noted in §4.1. Thus, $-\partial\nu_U/\partial y_g$ can be interpreted as the marginal benefit (via cost savings) of increasing the capacity of central generation type g. The PUC should have the utility increase the capacity of central generation type g until the marginal benefit no longer exceeds the installation cost k_g. Similarly, it would be beneficial to salvage capacity so long as the marginal benefit is less than the salvage value s_g. The optimal capacity choice y_g^U satisfies

$$s_g \leq -\frac{\partial \nu_U}{\partial y_g}\bigg|_{y_g = y_g^U} \leq k_g \quad \text{for } g \in \{I, R, F\}. \tag{21}$$

If setting $y_g = x_g$ satisfies (21), it is in the interest of the PUC to not alter that type of central generation. Otherwise, the capacity should be adjusted to the closest boundary point defined by the control policy in (21). This type of investment policy is called an ISD (invest/stay put/disinvest) policy. We adapt the following definition from Eberly and Van Mieghem (1997).

Definition 1 *A capacity adjustment policy is an ISD policy if, for each generation type* $g \in \{I, R, F\}$*, there exist two functions* $\alpha(\hat{\mathbf{z}}, \mathbf{x_{-g}}) \leq \omega(\hat{\mathbf{z}}, \mathbf{x_{-g}})$ *such that capacity type* g *is altered in the following way:*

$$y_g = \begin{cases} \alpha_g(\hat{\mathbf{z}}, \mathbf{x_{-g}}) & \text{if } x_g < \alpha_g(\hat{\mathbf{z}}, \mathbf{x_{-g}}) \\ x_g & \text{if } \alpha_g(\hat{\mathbf{z}}, \mathbf{x_{-g}}) \leq x_g \leq \omega_g(\hat{\mathbf{z}}, \mathbf{x_{-g}}) \\ \omega_g(\hat{\mathbf{z}}, \mathbf{x_{-g}}) & \text{if } \omega_g(\hat{\mathbf{z}}, \mathbf{x_{-g}}) < x_g \end{cases} \tag{22}$$

Here, $\mathbf{x_{-g}}$ *is the vector* $\mathbf{x}$ *with the entry for generation type* g *removed, signifying that functions* $\alpha(\hat{\mathbf{z}}, \mathbf{x_{-g}})$ *and* $\omega(\hat{\mathbf{z}}, \mathbf{x_{-g}})$ *depend on the initial capacities of other types of generation, but not on* x_g*.*

We now formalize that the investment in central generation capacity follows an ISD policy.

Theorem 2 *Given* $\mathbf{z} = \hat{\mathbf{z}}$*, if the PUC's solution to* $\min_{\mathbf{y} \geq 0}\{V(\mathbf{x}, \mathbf{y}, \hat{\mathbf{z}}) + \nu_U(\mathbf{y}, \hat{\mathbf{z}})\}$ *is unique, then it follows an ISD policy. Similarly, if the societal solution to* $\min_{\mathbf{y} \geq 0}\{V(\mathbf{x}, \mathbf{y}, \hat{\mathbf{z}}) + \nu_S(\mathbf{y}, \hat{\mathbf{z}})\}$ *is unique, then it follows an ISD policy.*

We have shown that the utility objective in (20) and the analogous societal objective are both convex in $\mathbf{y}$. If these objective functions are strictly convex, then the solutions are unique, and there is a unique optimal ISD policy for each decision maker.

4.3 Installation Decision for CHP Units

Using convexity, we solved for the optimal levels of centralized inflexible, renewable, and flexible generators, given the CHP siting decision. However, convexity cannot help us solve for the optimal CHP siting decision. It is necessary for the PUC and the societal decision maker to numerically test each possible siting decision, to determine which has the lowest expected cost.

Looking at Equations 5 and 6, one can see that the presence of a CHP significantly alters the one-period costs. For the utility, the surcharge revenue from on-site CHP use may be significant. For the societal decision maker, which considers the benefits to the on-site firms, the decreased outages and decreased reliance on legacy boilers could bring a large reduction in costs. As such, there are many circumstances in which CHP units may be built at the expense of central generation.

Remark: Suppose, in the absence of CHP options, it is optimal to maintain the status quo in central generation. In other words, inflexible, renewable, and flexible central generation are all in the "stay put" region. It may still be possible to lower costs by both installing CHP at specific sites and salvaging central generation.

Based on this remark, we call this a "Modified ISD" policy, in which the "stay put" region of the ISD control policy is modified by the option to build CHP plants.

In the next section, we comment on differences in the installation decisions between the PUC and the societal decision maker. We also investigate possible policies and regulations to nudge the installation decisions at the utility in a direction that is beneficial to society.

4.4 Aligning Installation Decisions Between the Utility and Society

Both the PUC and societal decision maker face the same capacity alteration costs, $V(\mathbf{x}, \mathbf{y}, \mathbf{z})$. The discounted costs, $\nu_U(\mathbf{y}, \mathbf{z})$ to the utility and $\nu_S(\mathbf{y}, \mathbf{z})$ to society, differ in three distinct ways:

1. The societal decision maker cares about environmental impacts and imposes environmental costs (e_I, e_F, e_i, e_ζ, and e_H) on energy generation. The utility and PUC only care about monetary costs, so there is no equivalent to these costs in $\nu_U(\mathbf{y}, \mathbf{z})$. These costs may lead to different dispatch orders for flexible and CHP generation.

2. The benefits of running a CHP to provide heat, power, and reliability to an on-site firm differ between the utility and society. The utility receives the contracted surcharge payment, $r_i\mu_i$, per period the CHP is running. The societal decision maker experiences lower heat and outage costs when the CHP is running. In the absence of a running CHP, these costs amount to $C_{Ht}h_i + (1 - \mathbb{1}_{it}^G)\psi_i$. From incentive-compatibility constraint (1), we know that the payment to the utility must be less than the expected heat and outage costs in the absence of the CHP in order for the firm to allow the CHP to be built on-site. So the reduction in costs to the societal decision maker from building a CHP on-site are larger than the revenue payments to the utility from the same CHP.

3. Each future period is discounted by a factor of δ_U for the utility and δ_S for society. Generally speaking, the societal decision maker discounts the future less than the utility ($\delta_S > \delta_U$).

We consider the societal decision maker's installation decision to be the "first best" decision for society, as it minimizes combined environmental, monetary, and outage costs. Any of the above differences could cause the public utility commission to deviate from this installation choice. The following policies and incentives could help align the PUC's incentives with societal interests.

Emission Tax. Difference 1 above indicates that while the utility cares about monetary costs, a full accounting of the impacts of energy generation on society will also include a measure of environmental impact. An emission tax would impose an additional cost on the utility for electricity generation. If this tax is aligned with the emission costs incurred by society, Difference 1 could be eliminated. An emission tax policy has the largest potential to bring the PUC into alignment with the societal decision maker.

Renewable Portfolio Standards (RPS). RPS require utilities to produce a minimum proportion of electricity from renewable sources. As of March 2016, 39 states and the District of Columbia have some form of RPS, with 20 states counting CHP as eligible toward their RPS (EPA 2016). RPS have at least two disadvantages. First, the threshold must be set carefully: it is trivial to surpass if it is too low, while it is impossible to attain if it is too high. Second, it may be difficult to calibrate the policy to induce the desired mix of renewables and CHP.

Energy Efficiency Resource Standards. Energy efficiency resource standards (EERS) require utilities to achieve a minimum amount of energy efficiency savings, with 27 U.S. states having some form of EERS. Typically, these savings are found by installing demand-side energy efficiency measures at customers. However, certain states count efforts to increase the efficiency of energy generation in their EERS, and 11 of them count CHP installations toward the threshold goal (EPA 2016). Our model focuses on capacity choices for generation, taking demand as exogenous. We cannot accurately model demand-side interventions to increase energy efficiency.

Investment Rebate. An investment rebate would reimburse the utility a certain percentage of the installation costs for specific types of generation. By subsidizing the installation costs for new CHP plants, the government could make CHP more attractive. However, the capacity adjustment costs, $V(\mathbf{x}, \mathbf{y}, \mathbf{z})$, are aligned between the utility and society. Changing the utility adjustment cost structure is not a direct approach to aligning the utility and societal cost structures.

Production Credit. A production credit, in which the government provides a subsidy per MWh produced at the CHP, would be equivalent, from the utility's perspective, to an increase in the heat and reliability surcharge paid by the on-site firm. A production credit could close the gap created by Difference 2 above.

5. Numerical Study

To explore the adoption of CHP plants under realistic conditions, we create numerical examples based on three U.S. utilities. The regulated utilities under study are Georgia Power, which serves approximately 2.5 million customers in the state of Georgia, Rocky Mountain Power, which serves approximately 1.1 million customers in Idaho, Utah, and Wyoming, and Indianapolis Power & Light, which serves approximately 500,000 customers in central Indiana. In each, the generation portfolio that minimizes upfront costs plus discounted expected future costs is chosen. We compute expected costs by modeling price and outage uncertainty. The effects of two regulatory policies, emission taxes and RPS, are also examined.

5.1 Data and Calibration

Generation Characteristics. Table 2 provides a description of the legacy power generation portfolio, $\mathbf{x}$, and yearly electricity demand at each of the utilities under consideration. Nuclear power is treated as inflexible. Natural gas combined cycle (NGCC) and coal generation (with 30% carbon sequestration) are both treated as flexible options, with the cheaper option being dispatched first; we describe the joint probability distribution of natural gas and coal prices below. Solar and wind power are both intermittent renewable options. Each utility has the option of installing or salvaging central generators, though we assume that Georgia Power is not in a position to build wind power and that Rocky Mountain Power and Indianapolis Power & Light will not opt for nuclear power, given that these generation options are absent in the legacy portfolios. The flexibility and reliability of hydropower generation varies significantly, and it could be considered inflexible, renewable, or flexible in our model, depending on the location. Without knowing the specific hydropower operating conditions at these utilities, we instead model legacy hydropower generation as solar power for Georgia Power and as a mix of solar and wind power for Rocky Mountain Power. Other forms of generation, present in much smaller amounts, such as geothermal, are ignored for the purpose of this study. In this section, all measures of electricity use are reported in megawatt-hours (MWh). The planning horizon is 30 years, with a 0.95 yearly discount factor.

Utility	Nuclear	Coal	NGCC	Solar	Wind	Yearly MWh Load
Georgia Power	1959.9	5799.6	6297.9	1216.6	0	89,700,000
Rocky Mountain Power	0	5919.0	2734.0	1584.1	3174.9	60,061,400
Indianapolis Power & Light	0	1729.0	1799.0	96.0	300.0	14,471,000

Table 2: Legacy central generation portfolio (in MW) and yearly electricity demand load for the three utilities of interest. Information for Georgia Power comes from the company's "Facts and Financials" webpage and the company's 2016 Annual Report. For Rocky Mountain Power, the information comes from the company's 2017 Integrated Resources Plan. For Indianapolis Power & Light, the information comes from the company's 2016 Integrated Resource Plan. Generation that is contracted through power purchase agreements is included in the table.

To model CHP options, we assume that two new firms are moving into each utility's service area. Each firm operates 6000 hours per year ($\mathbb{P}\{\mathbb{1}_{1t}^{f} = 1\} = \mathbb{P}\{\mathbb{1}_{2t}^{f} = 1\} = \frac{6000}{8760}$), with the first firm's electricity and heat needs being closely matched to a 9.341 MW reciprocating engine (denoted CHP 1 in the rest of this section) that yields 76.7 MMBtu/hr of heat. The second firm is larger and is well covered by a 44.488 MW gas turbine (CHP 2) that yields 422.1 MMBtu/hr of heat. The

CHP performance characteristics are taken from Darrow et al. (2017). Each utility has the option of building these CHP units on-site, as the firms have opted not to build their own private CHP units. The reliability and heat surcharges, r_1 and r_2, are specified as a parameter in each numerical example. The outage costs are $\psi_1 = \$100,000$ per outage and $\psi_2 = \$250,000$ per outage. The grid averages four hours of outages per year ($\mathbb{1}^G = .9995$).

Table 3 reports the operating characteristics of the utility's generation options: initial capital investment cost (k_g), yearly maintenance cost, and variable operating and maintenance costs (O&M) per MWh. The costs for the central generation options are taken from EIA (2018a). Variable O&M costs per MWh include all variable costs except fuel costs. For illustration purposes, Table 3 also shows values for Simple Levelized Cost of Energy (LCOE) based on average capacity factors. LCOE is a measure of the net present value of capital costs, operating and maintenance costs, and fuel costs per MWh of energy obtained from the generation asset over its lifetime. The lower the LCOE, the more cost effective the generator at this time. For the plants running on fossil fuels, the LCOE shown is specific to the Indianapolis Power & Light example, whose fuel costs fall between Rocky Mountain Power (on the low side) and Georgia Power (on the high side). The LCOE of the CHP units does not assign any value to its useful heat output.

Generation Type	**Installation Costs (\$/MW)**	**Maintenance Costs (\$/MW/year)**	**O&M Costs (\$/MWh)**	**Average Capacity Factor**	**LCOE (\$/MWh)**
CHP 1	1,433,000	-	8.5	0.98	59
CHP 2	1,248,000	-	9.2	0.93	65
Nuclear	5,946,000	101,280	2.32	0.90	72
Coal	5,089,000	70,700	7.17	0.85	86
NGCC	1,108,000	10,100	2.02	0.85	43
Solar	2,105,000	22,020	0	0.18	101
Wind	1,657,000	47,470	0	0.35	51

Table 3: Characteristics of all generation options. Values shown are in U.S. Dollars. The yearly maintenance at the CHP units is built into their O&M costs per MWh.

For each utility, we build a joint empirical distributions of coal and natural gas fuel costs based on monthly data from January 2008 to December 2017. Delivered coal costs vary by state and are taken from EIA (2017a). Data for delivered natural gas price to each state is not available every month. Thus, we estimate the natural gas cost to each utility by scaling the average U.S. natural gas price, which is available every month. Using data from EIA (2018b), we estimate that the natural gas price for Indianapolis Power & Light is 0.97 times the national average, for Georgia Power is 1.01 times the national average, and for Rocky Mountain Power is 0.85 times the national average. The required MMBtu to generate 1 MWh of electricity (known as the heat rate) is 9.75 for coal and 6.3 for NGCC (EIA 2018a), as well as 8.207 for CHP 1 and 9.488 for CHP 2 (Darrow et al. 2017). Figure 2 displays the fuel cost per MWh generated over the 10 years under consideration. To these fuel costs, one adds variable O&M costs from Table 3, yielding 120 observations for C_{Ft} and C_{it}. This creates a joint empirical distribution of coal and natural gas prices per MWh for each utility. Fuel costs for nuclear power are assumed constant at \$7.48 per MWh generated (EIA 2017b), and to that one adds the variable O&M cost of \$2.32 per MWh from Table 3, yielding $C_{It} = \$9.80$ per MWh. The renewable options have no fuel or O&M costs per MWh. The fuel cost distributions are stationary during the numerical study's planning horizon.

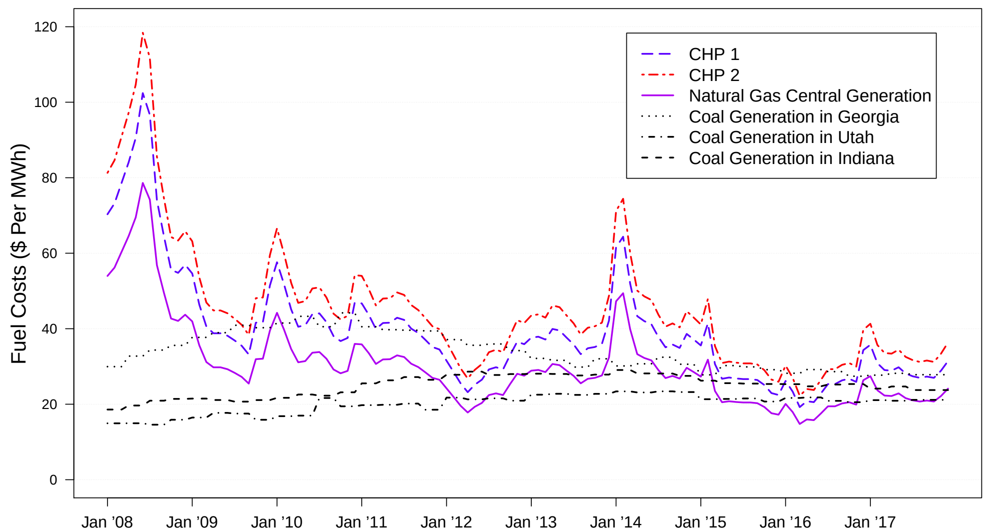


Figure 2: Fuel costs per MWh generated. For the CHP and natural gas, the prices shown are estimates of the costs experienced by Indianapolis Power & Light.

The line loss for central generators, λ, is 0.07. Without detailed utility disinvestment data, we assume the salvage value, s_g, of all central generators is \$100,000 per MW. To determine the proportional availability of nuclear, coal, and natural gas generators in a given period, we assume there are ten generators of each type, and that each is operational with probability given by the average capacity factors given in Table 3. If the available generation cannot meet society's demand for electricity, the shortage penalty ζ is \$200 per MWh, with the assumption that coal-generated power is imported from an external power pool during shortages. A large overage penalty of \$2000 per MWh prevents an oversupply of electricity.

Variations in Demand and Renewable Availability. To model the variations in electricity demand and renewable availability, a joint empirical distribution of societal demand, solar output, and wind output over one year of data is created. Observations are binned along these three dimensions, with forty possible bins in each dimension, totaling 64,000 bins in the joint distribution, though many bins have a probability of zero. The authors do not have access to granular actual demand from the three utilities of interest. However, the New England Independent Service Operator makes past demand information available on their website. Their demand data, with 30-minute granularity, from October 2, 2016 to October 1, 2017 is scaled for each utility so that the total MWh demanded matches the annual load reported in Table 2.

The societal demand is then paired with granular data from the National Solar Radiation Database (National Renewable Energy Laboratory 2019). To approximate output at each utility's solar panels, the solar radiation across the five largest cities in the utility's footprint are averaged for each 30-minute interval. This is then converted to the equivalent output that would be achieved at a fixed-tilt solar array. For wind energy, we use the wind speeds reported in the same database, adjusted as follows. Wind farms tend to be located at ideal locations for wind, such as on hills or ridges, so the wind speed reported in the database for nearby locations need to be scaled upward to ensure the wind farm's capacity factor approximates 0.35 when the turbine technology at the farm is considered. Indianapolis Power & Light draws power from a single wind farm in Minnesota via a power purchase agreement. Rocky Mountain Power draws wind energy from a number of farms, but we will consider just the two largest farms. Georgia Power does not have any legacy wind generation. This joint distribution of (demand, solar output, wind output) is assumed to be stationary in our numerical example.

Considering that all probability distributions are stationary, all periods in the planning horizon are equivalent in a probabilistic sense. As such, to compute future expected discounted costs, one simply takes, for each state Φ_t, the product of its cost and its probability, adds across all states, and discounts the result appropriately. A state Φ_t would include a realization of (demand, solar output, wind output), a realization of (natural gas price, coal price), and operating status for each of the resources (each generation type, each CHP, each firm, and the grid). The cost for each state is computed using the appropriate dispatch order. Since the granularity used for the joint distribution of (demand, solar output, wind output) is half an hour, one can think of a "period" in this study as half an hour.

5.2 Results: No Regulations

We first test the economic viability of CHP plants in the absence of regulatory actions. Depending on the heat and reliability surcharge paid by the on-site firm, the utility may or may not include the CHP plant in its portfolio. To facilitate comparisons, the surcharge payment will be shown as a percentage of the monetary value of the heat provided by the CHP. Recall CHP 1 yields 76.7 MMBtu/hr of heat, which would require 95.9 MMBtu/hr of natural gas to produce at a legacy boiler with 80% efficiency. If the surcharge is 100% of the heat value, then the firm would pay the utility 100% of the cost of 95.9 MMBtu of natural gas, which is the amount they would have spent to produce the heat with their legacy boiler. If the surcharge is 50%, the firm pays half as much.

Based on incentive-compatibility constraint (1), firm 1 could agree to any surcharge that is less than 113% of the value of the heat provided, as the CHP also protects against outages; the value is lower for firm 2 at 106%. Hence, the protection against outages is worth 13% of the value of the provided heat for firm 1 and 6% for firm 2. Firm 2 places a lower value on power reliability than firm 1 (6% vs. 13%) because its outage cost of $250,000 is lower relative to its electric load (44.49 MW), or $5.62/kW; for firm 1 these values are $100,000, 9.34 MW, and $10.71/kW, respectively. If the CHP enters the utility's optimal portfolio at a surcharge less than 113% for firm 1 and 106% for firm 2, then there is room for the firm and utility to strike a deal to build the CHP.

We study the minimum surcharge at which the utility builds each CHP in its cost minimizing portfolio. The minimum surcharge for CHP 1 to be economically viable is 75% for Georgia Power, 90% for Rocky Mountain Power, and 105% for Indianapolis Power & Light. As such, it is possible for an agreement to be made to build CHP 1 at each utility. Such an agreement would lower overall costs at both the utility and firm 1. CHP 2 requires a minimum surcharge of 95% for Georgia Power, 115% for Rocky Mountain Power, and 125% for Indianapolis Power & Light. Thus, a deal is possible for CHP 2 to be built only at Georgia Power. These results can be seen in Figure 3 at the emission tax level of $0.

5.3 Results: Emission Tax

To encourage the adoption of CHP 2, regulatory actions may be necessary. As discussed in §4.4, the societal decision maker cares about the environmental impact of emissions from power generation. We focus on greenhouse gas emissions, and report the cost or tax per ton of carbon dioxide equivalent (tCO2e). Estimates of the social cost of carbon vary considerably (Havranek et al. 2015), and we consider cost and/or tax in the range of $0 to $225 per tCO2e. Burning natural gas leads to 0.45 tCO2e per MWh, and burning coal leads to 0.74 tCO2e per MWh (accounting for 30% carbon sequestration) (U.S. Department of Energy 2016b). By instituting an emission tax, the emission costs experienced by society can be imposed on the utility. We only tax the net fuel use at CHP units, which includes the MMBtu burned for electricity generation in excess of what would have to be burned to produce the on-site heat for the firm. This appropriately accounts for the utility's

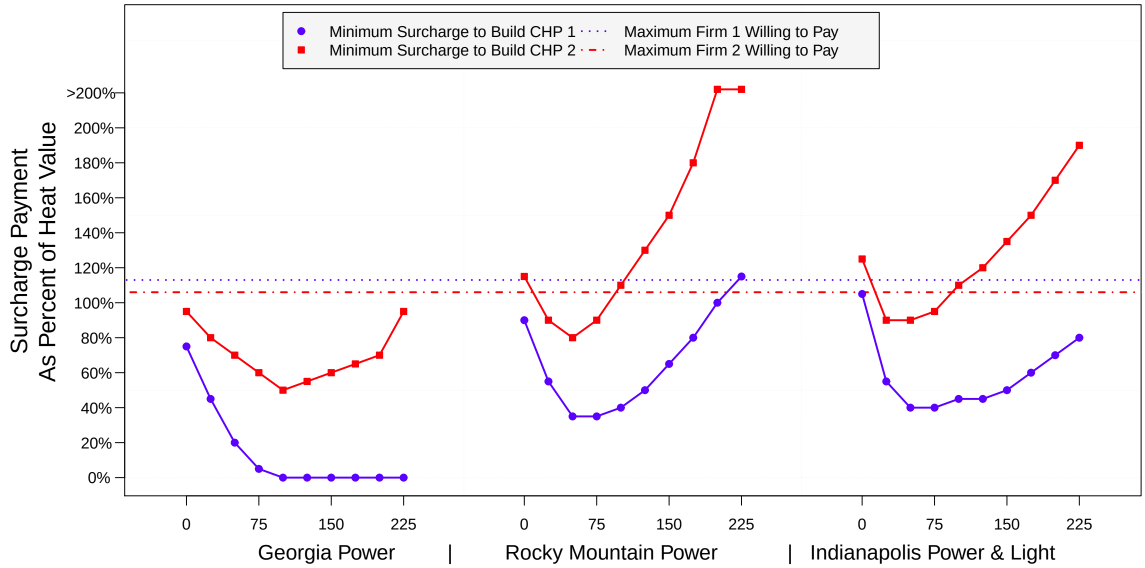


Figure 3: The effect of an emission tax on the economic viability of CHP units. The horizontal axis is split into three regions, one for each utility, with the numerical values representing the tax per ton of carbon dioxide equivalent emissions.

share of the emissions.

Figure 3 shows the minimum surcharge needed to build each of the CHP units as the emission tax varies. Note the U-shape of the utility's minimum surcharge payment with respect to the emission tax. Initially, the tax makes CHP units more economically viable relative to coal and natural gas central generators, in that they require less surcharge revenue to be included in the optimal portfolio. For Georgia Power, there are even points at which CHP 1 requires no surcharge revenue whatsoever to be included in the optimal generation portfolio. At higher emission tax levels, however, the effect typically reverses and the CHP units begin to become less economically viable. While CHP units are more efficient than natural gas combined cycle or coal-fired generation, they do still run on fossil fuels. As such, a high emission tax will begin to upset the case for CHP, and favor clean central generation, as we see next.

Indeed, the effect of an emission tax on capacity change for central generators tell a similar story, as shown in Figure 4. Coal-fired generation is quickly discarded; at tax levels of $175 per tCO2e and higher, all three utilities divest all coal generation. Natural gas combined cycle, like CHP, replaces coal-fired generation at low levels of emission tax before becoming less viable at high levels of tax. At high levels of tax, the clean options become dominant. Georgia Power opts for new nuclear and solar generation, while Rocky Mountain Power and Indianapolis Power & Light install wind generation. Recall that we assume that Georgia Power will not build wind generation

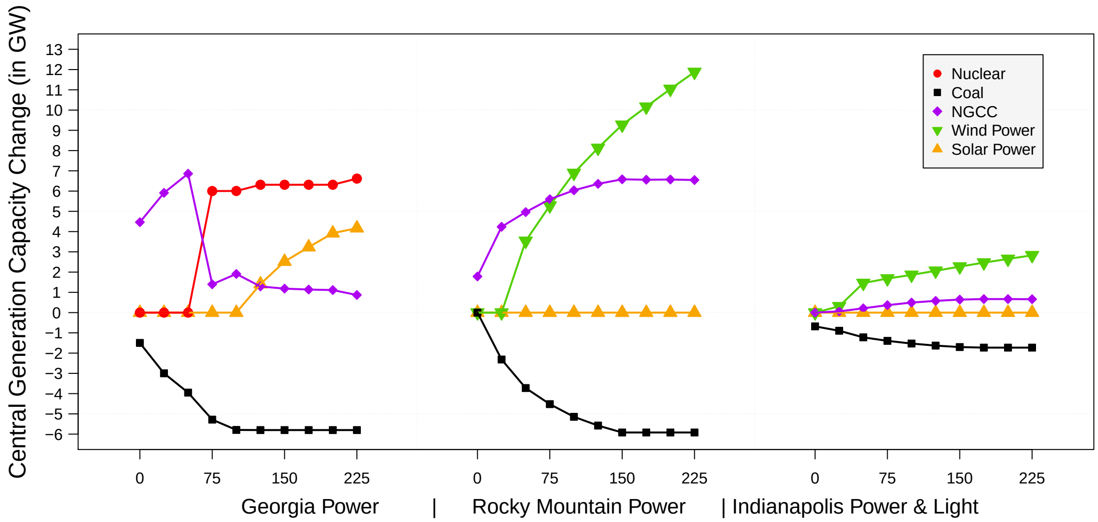


Figure 4: The effect of an emission tax, in dollars per ton of carbon dioxide equivalent emissions on the horizonal axis, on the change in central generation capacity at each utility. The CHP units installed include those CHP units which would be viable for the utility at an 80% surcharge payment, as a percentage of the heat value provided (see Figure 3).

and the other two utilities will not build nuclear power.

5.4 Results: Renewable Portfolio Standard

As mentioned in §4.4, many RPS policies count CHP generation toward the required proportion of electricity that comes from clean generators. Here, we study the effect of an RPS threshold ranging from 0% to 50% at the three utilities. Should a utility not have enough clean generation to meet the RPS threshold, they will be charged a penalty of $25 per MWh that they fall short of the threshold. No other regulations are in effect.

Figure 5 shows the effect of the RPS policy. The change in solar power is not shown, as no utility opts to alter its solar capacity. RPS policies are effective if the threshold is between 0% and 10% for Georgia Power, between 15% and 40% for Rocky Mountain Power, and between 5% and 40% for Indianapolis Power & Light. Outside these ranges, changes in the threshold do not alter the optimal capacity portfolio of the utility. Higher penalties will widen the effective range. As such, RPS policies promise some level of effectiveness in cleaning up the utility's generation portfolio, but only if the policy maker can effectively set the RPS threshold.

6. Conclusion

We have modeled a regulated utility's investment decision in new electricity generation capacity, with the goal of minimizing the sum of upfront capacity adjustment costs and expected discounted

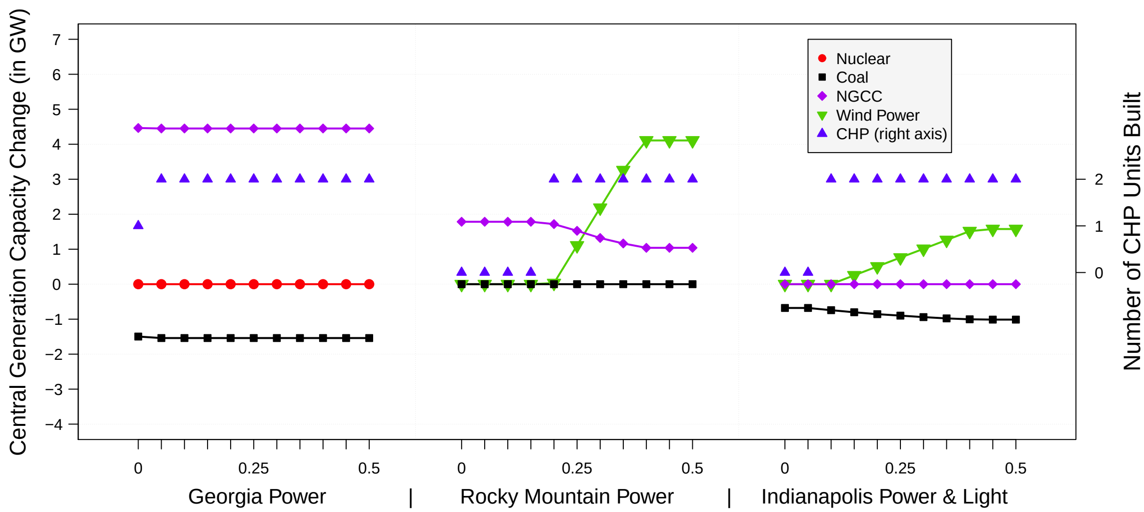


Figure 5: The effect of a renewable portfolio standard on the change in generation capacity at each utility. The horizontal axis shows the proportion of power that must be produced via wind turbines, solar panels, and CHP generation. The vertical axes shows the change in capacity for central generation (left) and the number of CHP units installed out of two possible sites (right) when the CHP surcharge is 80% of the heat value provided.

operating costs. Our analytical results prove investments in central generators should follow a modified Invest/Stay Put/Disinvest Policy, but numerical tests are necessary to examine the viability of combined heat and power (CHP) plants. A numerical examination of three U.S. utilities indicates that CHP is more economically viable than recent utility actions would indicate. While U.S. utilities operate less than 3 gigawatts of CHP generation, we find certain CHP plants to be economically attractive options to utilities without any regulatory incentives. For a societal decision maker that benefits from CHP generation, regulatory policies such as emission taxes or renewable portfolio standards can induce construction of more CHP plants. In particular, a low to moderate tax on carbon emissions is very effective at encouraging CHP adoption.

Our model and numerical examples are subject to a few limitations. First, we use a copper plate model of electricity supply and demand, in which only the total demand and total supply matter and local transmission constraints are ignored. This approximation may actually underestimate the value of CHP, as CHP could be strategically sited to relieve grid congestion. Second, our numerical examples make approximations with respect to utility demand. Scaling demand from the New England Independent System Operator region to approximate the demand in Georgia, Utah, or Indiana will not be accurate if electricity use patterns in these different geographies vary significantly. Third, we also approximate the characteristics of the generation portfolio at the utilities of interest. We model legacy hydropower as either solar or wind power, as hydropower characteristics are very site dependent and difficult to model. We also treat nuclear as totally inflexible and coal as totally flexible in the numerical example, when, in reality, both types of generation have some ability to vary their output, but they cannot change output levels quickly. A more accurate accounting of slow-varying generation would require our model to handle dependencies between periods.

Utility ownership of CHP represents a promising way to increase the reliability of the power supply and to decrease the environmental impact of electricity generation. Utilities should strive to identify those firms in their coverage area that have a high thermal load and that place a premium on "no outage" electricity service. Building CHP plants at these sites can simultaneously help the on-site firm, the utility, and the environment. Utility ownership, as opposed to private ownership, of CHP provides further benefits in terms of subject matter expertise, proper sizing of the CHP unit, and reduced transmission line losses.

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Appendix: Proofs

Proof of Proposition 1: After considering inflexible generation and on-site CHP units which are servicing on-site demand, the remaining societal demand is $(D_t - (1-\lambda)\theta_{It}y_I)^+$ MW. As 1 MW dispatched from generators satisfies just $(1-\lambda)$ MW of societal demand due to line losses, $(\frac{D_t}{1-\lambda} - \theta_{It}y_I)^+$ must be dispatched to meet this demand. Equation 10 suggests that renewables should be dispatched as much as possible, up to the amount necessary to meet demand. Suppose this were not the case and that $w > 0$ MW of flexible or CHP generation were dispatched instead of w MW of available renewable generation. This would lead to additional costs in the period (equal to $w(C_{Ft} - C_{Rt}) = wC_{Ft}$ if flexible substituted for renewable) above the amount that would be possible if (10) were followed, so the amount in (10) must minimize costs in (5). As $C_{Ft} < C_{it} \forall\, i, t$, a similar argument can be made to justify (11). Similarly, CHP units must then be dispatched in increasing order of C_{it}, up to their available capacity, $\mathbb{1}^G_{it}(1 - \mathbb{1}^f_{it})\mathbb{1}^c_{it}z_i$, or the amount necessary to satisfy remaining demand. Equation 12 follows. ∎

Proof of Proposition 2: For the societal decision maker, the cost of dispatching one MW of generation type g is $C_{gt} + e_g$. A similar argument as the one given in the proof of Proposition 1 will show that generators should dispatched in increasing order of $C_{gt} + e_g$. The renewable generation is again dispatched first, followed in increasing order of dispatch cost by the flexible and CHP generators. ∎

Proof of Theorem 1: First, show $\pi_U(\mathbf{y}, \mathbf{z}, \Phi_t)$ is convex in y_I.

$$\begin{aligned}\frac{\partial \pi_U(\mathbf{y}, \mathbf{z}, \Phi_t)}{\partial y_I} =& m_I + \theta_{It}C_{It} + \theta_{It}\eta\mathbb{1}\left\{\frac{D_t}{1-\lambda} < \theta_{It}y_I\right\} \\ & - \theta_{It}C_{Ft}\mathbb{1}\left\{\theta_{It}y_I + \theta_{Rt}y_R < \frac{D_t}{1-\lambda} \le \theta_{It}y_I + \theta_{Rt}y_R + \theta_{Ft}y_F\right\} \\ & - \sum_{j=1}^{n}\theta_{It}C_{(j)t}\mathbb{1}\left\{\theta_{It}y_I + \theta_{Rt}y_R + \theta_{Ft}y_F + \sum_{k=1}^{j-1}\mathbb{1}^G_{(k)t}(1-\mathbb{1}^f_{(k)t})\mathbb{1}^c_{(k)t}z_{(k)}\right. \\ & \left. < \frac{D_t}{1-\lambda} \le \theta_{It}y_I + \theta_{Rt}y_R + \theta_{Ft}y_F + \sum_{k=1}^{j}\mathbb{1}^G_{(k)t}(1-\mathbb{1}^f_{(k)t})\mathbb{1}^c_{(k)t}z_{(k)}\right\} \\ & - \theta_{It}\zeta\mathbb{1}\left\{\theta_{It}y_I + \theta_{Rt}y_R + \theta_{Ft}y_F + \sum_{i=1}^{n}\mathbb{1}^G_{it}(1-\mathbb{1}^f_{it})\mathbb{1}^c_{it}z_i < \frac{D_t}{1-\lambda}\right\}\end{aligned} \tag{23}$$

$\pi_U(\mathbf{y}, \mathbf{z}, \Phi_t)$ is piece-wise linear in y_I with non-decreasing slopes as y_I increases, as $C_{Ft} < C_{it} < \zeta$ and $\eta > 0$. Thus, $\pi_U(\mathbf{y}, \mathbf{z}, \Phi_t)$ is convex in y_I.

A similar calculation will show that $\pi_U(\mathbf{y}, \mathbf{z}, \Phi_t)$ is convex in y_F and y_R and that $\pi_S(\mathbf{y}, \mathbf{z}, \Phi_t)$ is convex in y_I, y_F, and y_R. ∎

Proof of Theorem 2: We alter the proof of Theorem 2 in Eberly and Van Mieghem (1997). Let $g \in \{I, R, F\}$ be a subscript denoting one of the three types of central generation. Let $\mathbf{y_{-g}}$ and $\mathbf{x_{-g}}$ be the 2-dimensional vectors obtained by deleting y_g from $\mathbf{y}$ and x_g from $\mathbf{x}$, respectively.

Consider first the PUC's problem. We will show that there exist two functions $\alpha_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}}) < \omega_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}})$ in which the optimal choice of central generation capacity, y_g^U, is of the following form:

$$y_g^U = \begin{cases} \alpha_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}}) & \text{if } x_g < \alpha_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}}) \\ x_g & \text{if } \alpha_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}}) \leq x_g \leq \omega_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}}) \\ \omega_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}}) & \text{if } \omega_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}}) < x_g \end{cases} \tag{24}$$

Define the following function $H_U(\mathbf{x_{-g}}, y_g, \hat{\mathbf{z}})$:

$$H_U(\mathbf{x_{-g}}, y_g, \hat{\mathbf{z}}) = \inf_{\mathbf{y_{-g}} \geq 0} \Big\{ \sum_{j \in \{I,R,F\}, j \neq g} (k_j(y_j - x_j)^+ - s_j(x_j - y_j)^+) + \nu_U(\mathbf{y}, \hat{\mathbf{z}}) \Big\}. \tag{25}$$

Using this notation, we must solve the following problem:

$$\inf_{y_g \geq 0} k_g(y_g - x_g)^+ - s_g(x_g - y_g)^+ + H_U(\mathbf{x_{-g}}, y_g, \hat{\mathbf{z}}). \tag{26}$$

$H_U(\mathbf{x_{-g}}, y_g, \hat{\mathbf{z}})$ is convex due to Theorem 1 and the piecewise linear investment cost in which installations cost more than divestments. First order (sub)differential conditions are sufficient.

For $x_g = 0$, an optimal value for y_g is

$$\alpha_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}}) = \sup\{\{0\} \cup \{y_g : \nabla_{y_g} H_U(\mathbf{x_{-g}}, y_g, \hat{\mathbf{z}}) \geq k_g\}\}. \tag{27}$$

Convexity yields that this invest-up-to level, $\alpha_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}})$, is optimal for all $x_g < \alpha_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}})$. For arbitrarily large x_g, an optimal value for y_g is

$$\omega_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}}) = \inf\{\{\infty\} \cup \{y_g : \nabla_{y_g} H_U(\mathbf{x_{-g}}, y_g, \hat{\mathbf{z}}) \leq s_g\}\}, \tag{28}$$

which is also optimal for all $x_g > \omega_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}})$. Convexity yields that it is optimal to "stay put" whenever $\alpha_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}}) \leq x_g \leq \omega_g^U(\hat{\mathbf{z}}, \mathbf{x_{-g}})$. Thus, for each factor g, there exists an optimal policy that is ISD for generation type g, where the investment decision follows (24). As the solution to the optimization problem is unique, all solutions found by the inflexible, renewable, and flexible ISD policies described above lead to the same optimal point. This unique policy is ISD with respect to each of the central generation options. Replicating the above steps with the societal decision will yield similar results. ∎