Energy efficiency and emissions intensity standards*

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Abstract

We investigate the role of energy efficiency in rate-based emissions intensity standards, a particularly policy relevant consideration given the Environmental Protection Agency's Clean Power Plan allows crediting of electricity savings as a means of complying with state-specific emissions standards. We show that for perfectly inelastic energy services demand, crediting efficiency measures can recover the first-best allocation. This approach extends the output subsidy in a traditional intensity standard to energy efficiency, thereby eliminating the distortion that favors energy generation over energy efficiency. However, when demand for energy services exhibits some elasticity, crediting energy efficiency can no longer recover first-best. While crediting energy efficiency removes the relative distortion between energy generation and energy efficiency, it distorts the absolute level of both generation and efficiency via an energy services subsidy. Simulations calibrated to the electricity sector in Texas examine these issues numerically and explore the implications of alternative energy efficiency crediting schemes.

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1 Introduction

Emissions intensity standards have recently emerged as a policy tool of interest for curbing greenhouse gas emissions.[1] For example, California instituted a Low Carbon Fuel Standard (LCFS) for transportation fuels which sets declining limits for the average emissions per gallon of fuel consumed (Holland, Hughes, and Knittel 2009). Similarly, under the Environmental Protection Agency's (EPA) recently released Clean Power Plan (CPP), which sets rate-based emissions targets (in pounds of CO2 per megawatt-hour) for the electric sector in every state, an emissions intensity standard is identified as an option for achieving compliance with the rate-based targets (Palmer and Paul 2015).

A well-known consequence of emission intensity standards is that they encourage substitution towards less emissions-intensive sources but also subsidize energy output, and thus are considered by economists to be inferior to the first-best solution of a Pigovian tax or equivalent cap and trade system. However, this output subsidy effect, and intensity standards more generally, have been considered in frameworks that do not explicitly incorporate energy efficiency choices.[2] This omission is particularly noteworthy in the context of electricity, where energy efficiency has been considered an important channel of cost-minimizing

[1] Emissions intensity standards can be characterized simply as requiring the sum of emissions from all sources (the numerator) divided by total output (the denominator) to be less than some specified intensity target. Such standards are often referred to as "rate-based" policies, as opposed to "mass-based" policies that target total emission levels.

[2] Intensity standards, and more generally output-based policies, have been considered in many other contexts. For example, others have looked at intensity standards/output-based policies under imperfect competition (Gersbach and Requate 2004; Fischer 2011; Fowlie, Reguant, and Ryan 2016), with emissions leakage (Bernard, Fischer, and Fox 2007), with tax interactions (Fischer and Fox 2007; Holland 2012), under uncertainty (Newell and Pizer 2008; Branger and Quirion 2014; Meunier, Montero, and Ponssard 2016), and with political economy considerations (Sterner and Isaksson 2006).

emissions reductions. Indeed, to encourage energy efficiency measures for the electricity sector, crediting of energy efficiency as a means of complying with the intensity standard is identified as an option under the EPA's CPP. In this paper, we ask: Can emissions intensity standards recover the first-best solution when energy efficiency choices are considered, and under what conditions? How should regulators credit energy efficiency in an emissions intensity standard framework? What are the consequences of alternative crediting levels for the electricity sector?

The result that intensity standards cannot achieve a first-best outcome due to the implicit output subsidy has been well-established in the prior literature (Helfand 1991; Fullerton and Heutel 2010).[3] For example, in the context of the LCFS, Holland, Hughes, and Knittel (2009) show that the standard implicitly subsidizes all fuel sources (relative to first-best), such that overall emissions may perversely increase. Recognizing this source of inefficiency, prior studies have advocated the coupling of intensity standards with additional instruments such as a fuel tax (Holland, Hughes, and Knittel 2009) or consumption tax (Holland 2012), or adjusting the emissions ratings of each source (Lemoine 2016). While such approaches recover first-best (fuel/consumption tax), or improve on the second-best (emissions ratings), they also require the implementation of an additional instrument or complex manipulation of emission ratings. Furthermore, as energy efficiency measures are not considered in the above studies, it is unclear how decisions about energy efficiency are impacted by such standards. If some form of crediting energy efficiency within an intensity standard can recover first-

[3] If there are additional market failures above and beyond the emissions externality, an intensity standard is not necessarily inferior to an emissions tax. For example, Holland (2012) finds that an intensity standard may dominate an emissions tax in the presence of leakage to unregulated regions.

best outcomes, such an approach may be more appealing relative to the multiple-policy instrument options prescribed in previous works.

To examine the role of energy efficiency in intensity standards policies, with a particular application to electricity markets, we develop a parsimonious model of the electricity sector, where households meet their demand for energy services by purchasing electricity or energy efficiency from firms. Firms decide which types of electricity generators, each with differing emissions intensities, they will dispatch, as well as how much energy efficiency to produce.[4] We then consider outcomes under various forms of regulations, including energy efficiency crediting, regarding emissions and generation mixes.[5]

We show that if demand for energy services is perfectly inelastic, then the traditional intensity standard (no crediting) cannot achieve the first-best outcome. Relative to the first-best policy of an emission tax, due to the output subsidy effect there is too little investment in energy efficiency, and, similar to previous works on intensity standards, too much generation due to the output subsidy. However, optimally crediting energy efficiency can recover the first-best outcome. The intuition is that by crediting energy efficiency, the relative output subsidy distortion between generation and energy efficiency is eliminated. Importantly, this adjustment to the traditional intensity standard does not require the use of an additional

[4] As our model is static, we abstract from the dynamic considerations associated with the fact that energy efficiency in practice is a characteristic bundled within a durable good (e.g. an Energy Star refrigerator). Instead, households are assumed to be able to purchase an amount of energy efficiency at some cost.

[5] The distinction between energy demand and energy service demand is an important feature of this analysis. In the previous literature on standards, it is straightforward to show that if energy demand is perfectly inelastic, then the output subsidy is not problematic. By characterizing energy service demand as a function of both energy consumption and energy efficiency, we are able to provide a richer analysis of the response to intensity standards and examine how crediting affects the various margins of household response.

instrument or optimal adjustments to emissions ratings to achieve first-best.

However, when demand for energy services exhibits some elasticity, the intensity standard with energy efficiency crediting can no longer recover first-best, though it may still be more efficient than the traditional intensity standard offering no efficiency crediting. This occurs because the intensity standard with crediting replaces the output subsidy of the traditional intensity standard with an energy services subsidy, leading to excessive consumption of energy services (both generation and energy efficiency) relative to first-best. As such, a tradeoff in crediting emerges between removing the relative distortion between generation and energy efficiency, and creating a distortion in the absolute level of energy services consumed.

Finally, in a detailed numerical application calibrated to Electricity Reliability Corporation of Texas (ERCOT) region, we consider the relative efficiency of intensity standards versus emission tax policies under a range of energy efficiency crediting levels and under a variety of demand, market, and policy conditions. This simulation exercise highlights that the relatively simple theory model does well in predicting the general outcomes of a much more complicated electricity dispatch model with energy efficiency. The simulations also show policy-relevant outcomes from energy efficiency crediting in a wide range of settings, thereby providing guidance in setting appropriate energy efficiency crediting rates.

Our paper provides several contributions. First, it incorporates energy efficiency choices into the theoretical literature on intensity standards. Second, we show that in some cases, crediting energy efficiency can undo the adverse output subsidy effect created by intensity standards. Third, we incorporate energy efficiency in the simulation exercise in a theoretically-consistent manner. Finally, our results provide policymakers guidance in terms of designing policies, particularly with respect to the CPP and the tradeoffs associated with crediting energy efficiency.

2 Intensity standards and energy efficiency

Our theoretical model examines the role of energy efficiency in emissions intensity standards. We compare intensity standards with a first-best emissions tax under alternative crediting schemes for energy efficiency. While our exposition will focus on the electricity sector, the basic insights are relevant for other sectors where energy efficiency is relevant (e.g. fuel).

We first describe the common components of the theoretical exercise. We begin by assuming the representative household's preferences do not include energy consumption or energy efficiency directly, but rather households have preferences for energy services such as heating, lighting, recreation, refrigeration, etc. Energy services $ES(Q, \theta)$ are produced from both energy consumption Q and investments in energy efficiency θ, which is increasing in both arguments.[6] While we assume consumers are indifferent to the source of production for Q, the general formulation for energy services allows for energy consumption and energy efficiency to have varying degrees of productivity and substitutability in terms of generating energy services.

On the production side, we assume a representative firm produces both electricity Q and energy efficiency θ.[7] Total electricity production Q (MWh) is produced from N different

[6] Energy efficiency θ can be thought of as avoided electricity use (e.g. avoided megawatt-hours MWh). For example, in the case of lighting, a household could receive the same level of energy services from a cheap 60 watt bulb as they could from "investing" in a more expensive energy-efficient LED bulb that uses the equivalent of 9 watts. In that case, when using the LED bulb for one hour they are "consuming" 51 watt-hours of energy efficiency and consuming 9 watt-hours of electricity.

[7] Our treatment collapses the complicated electricity sector into a tractable setup that nonetheless captures the key decisions regarding efficiency. As a consequence, it abstracts

generation technologies, each indexed by i, with quantities of Q_i and emission rates of $\gamma_i \geq 0$ (tons per MWh), such that:[8]

$$Q = \sum_{i}^{N} Q_i. \tag{1}$$

The marginal cost of producing the q^{th} unit of electricity for each technology is given as $c_i(q_i)$ and is assumed to be weakly increasing in q_i. The cost of producing energy efficiency is given by $e(\theta)$ and is assumed to be increasing and convex.

Emissions are assumed to generate constant marginal external damages, and as such, the first-best policy is to set a tax τ equal to marginal external damage (in the absence of additional distortions (Goulder, Parry, Williams Iii, and Burtraw 1999)). The emissions intensity standard policy is modeled as:

$$I \geq \frac{\sum_i^N \gamma_i Q_i}{f(\theta) + Q}, \tag{2}$$

where $I > 0$ is the intensity standard target (emissions per unit output) and $f(\theta)$ describes how energy efficiency is credited for the purposes of the intensity standard. For example, if energy efficiency is not credited (the traditional intensity standard), then $f(\theta) = 0$, and if energy efficiency is credited one-for-one, then $f(\theta) = \theta$. As a practical example, suppose an energy efficiency firm goes into an office building using incandescent light bulbs and replaces them with LED light bulbs. Regulators may credit the avoided electricity θ, which can then be applied towards the intensity standard.

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from other important issues such as behaviorial responses by consumers to electricity and energy efficiency prices (Allcott and Greenstone 2012; Ito 2014).

[8] We assume that $\gamma_i > 0$ for at least some i, and that $\gamma_i \neq \gamma_j$ for some $i \neq j$.

2.1 Perfectly inelastic demand for energy services

We first consider the case where demand for energy services is assumed to be perfectly inelastic, such that $\overline{ES} = ES(Q, \theta)$. With perfectly inelastic demand for energy services, consumer surplus is undefined, and as such we focus on the firm's problem of meeting the fixed energy service demand $\overline{ES}$ at minimum cost. We first characterize the efficient allocation (i.e a first-best emissions tax), and then contrast that with the allocation that arises under an emissions intensity standard with crediting.

2.1.1 First-best emissions tax

Consider the problem of a representative firm subject to an emissions tax τ who is meeting the perfectly inelastic demand for energy services at a minimum cost. The firm's Lagrangian is given by:

$$L = \sum_i^N \int_0^{Q_i} c_i(q_i) dq_i + e(\theta) + \tau(\sum_i^N \gamma_i Q_i) + \lambda(\overline{ES} - ES(Q, \theta)), \tag{3}$$

where λ is the shadow cost of the fixed energy service constraint. The first-order conditions for this problem are:

$$\begin{aligned} \frac{\partial L}{\partial Q_i} =& c_i(Q_i) + \tau\gamma_i - \lambda \frac{\partial ES}{\partial Q} = 0, \quad \forall i \\ \frac{\partial L}{\partial \theta} =& \frac{de}{d\theta} - \lambda \frac{\partial ES}{\partial \theta} = 0. \end{aligned} \tag{4}$$

which can be rearranged as:

$$\frac{c_i(Q_i) + \tau\gamma_i}{\partial ES/\partial Q} = \frac{c_j(Q_j) + \tau\gamma_j}{\partial ES/\partial Q} = \frac{de/d\theta}{\partial ES/\partial\theta} \quad \forall i, j. \tag{5}$$

Consider first the laissez-faire solution ($\tau = 0$), in which case the firm equates the marginal cost of producing energy services across all generation technologies and energy efficiency.[9] However, because emissions are not priced, the resulting allocation is not first-best due to the standard externality problem.

Next, consider the standard Pigouvian prescription where the emissions tax τ is set equal to the marginal external damages. Relative to the case without regulation, the firm now must account for the additional cost associated with the tax on emissions, such that the marginal cost of energy services from each generation technology inclusive of emissions damages is equated across sources and with energy efficiency. Relative to the laissez-faire solution, the tax increases the costs of generation from high-emission sources relative to lower emission sources, and generation in general becomes more costly relative to energy efficiency.[10]

2.1.2 Emissions intensity standard with and without crediting

We next consider whether or not an emissions intensity standard can recover the above condition for first-best regulation of the emissions externality. In particular, we focus on the

[9] The denominator of equation 5 accounts for the transformation of generation or energy efficiency into energy services. An intuitive case to consider that aids exposition is where electricity and energy efficiency are perfect substitutes and each produce one unit of energy service ($\partial ES/\partial Q = \partial ES/\partial\theta = 1$). In that case, marginal costs are simply equated across all generators and energy efficiency.

[10] Note that the emissions tax does not directly affect the efficiency sector. Rather, by raising the marginal costs of generation, it induces a substitution to efficiency to meet the fixed energy services demand.

the role of crediting of energy efficiency, given by $f(\theta)$ in equation 2 describing the intensity standard. Given equation 2 as binding, the firm's Lagrangian problem is:

$$L = \sum_i^N \int_0^{Q_i} c_i(q_i)dq_i + e(\theta) + \mu(\sum_i^N \gamma_i Q_i - I(f(\theta) + \sum_i^N Q_i)) + \lambda(\overline{ES} - ES(Q,\theta)), \quad (6)$$

where μ is the shadow cost of the emissions intensity standard I. The first-order conditions of equation 6 are as follows:

$$\begin{aligned} \frac{\partial L}{\partial Q_i} &= c_i(Q_i) + \mu\gamma_i - \mu I - \lambda \frac{\partial ES}{\partial Q} = 0, \quad \forall i \\ \frac{\partial L}{\partial \theta} &= \frac{de}{d\theta} - \mu I f'(\theta) - \lambda \frac{\partial ES}{\partial \theta} = 0, \end{aligned} \quad (7)$$

which can rearranged as:

$$\frac{c_i(Q_i) + \mu\gamma_i - \mu I}{\partial ES/\partial Q} = \frac{c_j(Q_j) + \mu\gamma_j - \mu I}{\partial ES/\partial Q} = \frac{de/d\theta - \mu I f'(\theta)}{\partial ES/\partial\theta} \quad \forall i, j. \quad (8)$$

We first consider the "traditional" emissions intensity standard that does not credit energy efficiency, such that $f(\theta) = 0$. From equation 7, there are two key effects of the emissions intensity standard. First, it acts as an implicit tax of magnitude $\mu\gamma_i$ that penalizes higher-emitting sources. Second, it provides a (constant) subsidy to all forms of electricity generation via μI. For generation technologies with emission rates in excess of the standard $\gamma_i > I$ (e.g. coal), the standard is a net tax ($\mu(\gamma_i - I) > 0$) that is nonetheless smaller than the Pigouvian tax, while for technologies with emission rates less than the standard $\gamma_i < I$ but greater than zero (e.g. natural gas), the standard is effectively a net subsidy

$(\mu(\gamma_i - I) < 0)$.[11]

Now suppose the regulator credits energy efficiency in the denominator of equation 2 according to the rule $f(\theta)$. Per equation 7, the emissions intensity standard with efficiency crediting introduces a subsidy $\mu I f'(\theta)$ to the energy efficiency sector. In this case, both generation and energy efficiency are subsidized.

The analysis and discussion above leads to our first proposition (proofs in Appendix A):

Proposition 1. *Under perfectly inelastic demand for energy services,*

a) the emissions intensity standard without crediting $(f(\theta) = 0)$ *cannot recover the first-best allocation,*

b) if the emissions intensity standard I *is set such that* $\mu = \tau$*, then the emissions intensity standard without crediting* $(f(\theta) = 0)$ *yields an allocation equivalent to that achieved under a combined emissions tax and energy efficiency tax,*

c) the emissions intensity standard with crediting such that $f'(\theta) = \frac{\partial ES/\partial \theta}{\partial ES/\partial Q}$ *and* I *such that* $\mu = \tau$ *recovers the first-best allocation,*

d) the first-best emissions tax (and equivalent standard with crediting) increases energy efficiency θ *and decreases generation* Q *relative to the laissez-faire allocation,*

e) the emissions intensity standard without crediting and standard set such that $\mu = \tau$ *decreases energy efficiency* θ *and increases generation* Q *relative to first-best.*

[11] If coal is a high-emitting source and gas is a low-emitting source, then the emission intensity standard acts like an implicit tax on coal, inducing substitution out of coal, but it also generates an implicit subsidy to gas. This is obviously inefficient as gas generates emissions and should be taxed. The fact that all generators are subsidized by μI is the essence of the output subsidy effect noted by other authors, and indeed is one of the general criticism of the use of standards (Helfand 1991; Holland, Hughes, and Knittel 2009; Fullerton and Heutel 2010).

Proposition 1 yields a number of important insights regarding emissions intensity standards and energy efficiency crediting when demand for energy services is perfectly inelastic. First, in the absence of crediting, because all generators receive a subsidy μI, an emissions intensity standard cannot recover first-best even if the standard is set such that $\mu = \tau$. Furthermore, because all generators are subsidized by μI, there is too little investment in energy efficiency relative to first-best. While others have noted the inefficiency of standards in the energy sector due to μI, as Proposition 1 shows, the allocation under the traditional intensity standard is in fact equivalent to that under an emissions tax coupled with a tax on energy efficiency. That is, the constant subsidy to all generators (μI) coupled with fixed energy service demand ($\overline{ES}$) distorts relative incentives between generation and efficiency in the same way as a tax on energy efficiency. Given that increasing energy efficiency is thought to be an important component of the CPP, clearly a traditional emissions intensity standard is problematic.

While an additional instrument (in this case an electricity tax) could eliminate this output subsidy and recover first-best, per Proposition 1 setting crediting such that $f'(\theta) = \frac{\partial ES/\partial \theta}{\partial ES/\partial Q}$ and the standard such that $\mu = \tau$ also recovers the first-best allocation.[12] Intuitively, the subsidy to energy efficiency from crediting offsets the output subsidy to all forms of generation, removing the relative distortion between generation and energy efficiency. Thus, generators simply face the $\mu * \gamma_i$ implicit tax component of the intensity standard, ensuring the correct relative mix across generation sources. Furthermore, because $\overline{ES} = ES(Q, \theta)$, the resulting allocation from the emissions intensity standard with efficiency crediting is

[12] The ratio $\frac{\partial ES/\partial \theta}{\partial ES/\partial Q}$ is the marginal rate of technical substitution between energy efficiency and consumption in the household's production function for energy services.

equivalent to the first-best emissions tax.

Focusing further on the emissions crediting rule of $f'(\theta) = \frac{\partial ES/\partial \theta}{\partial ES/\partial Q}$, in the simple (and plausible) case where energy consumption and energy efficiency are perfect substitutes ($ES = Q + \theta$), then one-for-one crediting whereby $f(\theta) = \theta$ achieves first-best. If energy services are a more complicated non-linear function of generation and energy efficiency, the crediting rule becomes more complicated, but nonetheless a first-best crediting rule exists. Thus, rather than introduce an additional instrument to recover first-best, crediting energy efficiency in the denominator of the standard creates an implicit subsidy for output reduction, offsetting the output subsidy effect and achieving first-best outcomes.

2.2 Downward-sloping demand for energy services

Analyzing emissions intensity standards when demand for energy services is downward-sloping requires a few modifications to account for changes in consumer surplus due to changes in energy services. Denote the inverse demand for energy services as $P(ES(Q, \theta))$ such that $P' < 0$ with an elasticity given by ϵ. We also assume the energy services function exhibits constant-elasticity-of-substitution given by σ, and that demand for energy services is less elastic (in magnitude) than the elasticity of substitution, $|\epsilon| < \sigma$.[13]

We assume a representative household chooses energy consumption and energy efficiency to maximize the area under the demand curve net of expenditures. Similarly, a representative firm maximizes profits by choosing generation and energy efficiency. We assume the market

[13] While slightly restrictive, these assumptions are useful for the proofs below. Furthermore, given that demand for energy services is thought to be fairly inelastic, this assumption is not overly onerous.

is competitive and the analysis below is set up in terms of the social planner's problem.[14]

We again begin by characterizing the first-best allocation arising from an emissions tax τ equal to the marginal external damage of emissions. The objective function is given by:

$$\max_{Q_i,\theta} \int_0^{ES(Q,\theta)} P(q)dq - \sum_i^N \int_0^{Q_i} c_i(q_i)dq_i - e(\theta) - \tau(\sum_i^N \gamma_i Q_i). \tag{9}$$

Under downward-sloping energy services demand, the first-best allocation equates marginal private benefits of generation and energy efficiency with the marginal social costs.

$$\begin{aligned} P(ES(Q,\theta))\frac{\partial ES}{\partial Q} =& c_i(Q_i) + \tau\gamma_i \quad \forall i \\ P(ES(Q,\theta))\frac{\partial ES}{\partial \theta} =& \frac{de}{d\theta}. \end{aligned} \tag{10}$$

We now contrast the preceding optimal allocation with the allocation resulting from emissions intensity standards with crediting rule $f(\theta)$. The objective function is given by:

$$\max_{Q_i,\theta} \int_0^{ES(Q,\theta)} P(q)dq - \sum_i^N \int_0^{Q_i} c_i(q_i)dq_i - e(\theta) + \mu(I(f(\theta) + \sum_i^N Q_i) - \sum_i^N \gamma_i Q_i). \tag{11}$$

with first-order conditions given by:

$$\begin{aligned} P(ES(Q,\theta))\frac{\partial ES}{\partial Q} =& c_i(Q_i) + \mu\gamma_i - \mu I \quad \forall i \\ P(ES(Q,\theta))\frac{\partial ES}{\partial \theta} =& \frac{de}{d\theta} - \mu I f'(\theta). \end{aligned} \tag{12}$$

[14] If P_E represents the price of electricity and P_θ represents the price of energy efficiency, then price-taking households equate the marginal benefit of energy consumption and efficiency with those prices, while price-taking firms equate marginal costs with those prices.

As in the perfectly inelastic demand for energy services case, the intensity standard generates an implicit tax of $\mu\gamma_i$ and an implicit subsidy μI for all generators, while crediting provides a subsidy of $\mu I f'(\theta)$ to energy efficiency. However, the key distinction with the prior case is that now the level of energy services can vary, which leads to the following proposition:

Proposition 2. *Under downward-sloping demand for energy services,*

a) the emissions intensity standard cannot recover the first-best allocation for any crediting rule $f(\theta)$,

b) setting the standard such that $\mu = \tau$ and crediting at $f'(\theta) = \frac{\partial ES/\partial\theta}{\partial ES/\partial Q}$ offsets the output subsidy effect, but creates an energy services subsidy effect.

c) the first-best emissions tax increases energy efficiency θ and decreases generation Q relative to the laissez-faire allocation.

Recall that in the perfectly inelastic demand for energy services case, crediting energy efficiency via $f(\theta)$ in the denominator of the standard could recover first-best. However, per Proposition 2, when demand for energy services is downward sloping, crediting energy efficiency can no longer be first-best due to the demand response via $P(ES(Q,\theta))$. While crediting energy efficiency at $f'(\theta) = \frac{\partial ES/\partial\theta}{\partial ES/\partial Q}$ removes the relative distortion created by the output subsidy effect as all sectors receive the same subsidy per unit of energy service, it creates its own distortion - an energy services subsidy effect - that leads to too large of energy services consumed relative to first-best. This suggests there is a tradeoff to crediting energy efficiency in the sense that failing to credit leads to a relative distortion between generation and energy efficiency, while crediting increases the overall level of energy services as all sectors are now receiving an implicit subsidy. We return to this point analytically in the next section, and in the numerical application to follow.

2.3 Second-best emissions intensity standards and crediting

The above results indicate that selecting the crediting rule is an important regulatory consideration. For example, under downward-sloping demand for energy services, an important tradeoff emerges - while crediting energy efficiency offsets the relative distortion created by the output subsidy effect, it creates an absolute distortion in the level of energy services consumed. Similarly, prior work such as Holland, Hughes, and Knittel (2009) and Lemoine (2016) has noted that there are also important tradeoffs in selecting the second-best intensity standard. While we have shown that with downward-sloping demand for energy services an intensity standard cannot recover first-best, in the analysis below, we consider the second-best choice of the crediting rule and intensity standard.

Suppose a regulator were to implement the crediting rule $f(\theta) = \kappa\theta$, whereby energy efficiency is credited at some constant rate, such that $f'(\theta) = \kappa$. What crediting rule κ and intensity standard I should the regulator select, conditional on understanding how the decentralized market will respond?[15] Formally, the regulator solves:

$$\max_{\kappa,I} W = \int_0^{ES(Q(\kappa,I),\theta(\kappa,I))} P(q)dq - \sum_i^N \int_0^{Q_i(\kappa,I)} c_i(q_i)dq_i - e(\theta(\kappa,I)) - \tau(\sum_i^N \gamma_i Q_i(\kappa,I)), \tag{13}$$

where τ is the marginal external damage from emissions. First-order conditions for the

[15] While it is likely regulators will adopt either a no crediting ($\kappa = 0$) or a one-for-one ($\kappa = 1$) crediting rule, consideration of the second-best crediting rule may nonetheless provide some useful policy guidance in choosing between the two. As such, we consider a simple linear crediting here and in the numerical analysis to follow.

regulators problem (at the interior) are then:[16]

$$\frac{\partial W}{\partial \kappa} = (P(ES)\frac{\partial ES}{\partial \theta} - \frac{de}{d\theta})\frac{\partial \theta}{\partial \kappa} + \sum_i^N [(P(ES)\frac{\partial ES}{\partial Q} - c_i - \tau\gamma_i)\frac{\partial Q_i}{\partial \kappa}] = 0. \tag{14}$$

$$\frac{\partial W}{\partial I} = (P(ES)\frac{\partial ES}{\partial \theta} - \frac{de}{\theta})\frac{\partial \theta}{\partial I} + \sum_i^N [(P(ES)\frac{\partial ES}{\partial Q} - c_i - \tau\gamma_i)\frac{\partial Q_i}{\partial I}] = 0.$$

Substituting in the intensity standard first-order conditions from equation 12 yields the following condition governing the second-best choices of κ and I:

$$(\mu I \kappa)\frac{\partial \theta}{\partial \kappa} = \sum_i^N [(\mu(\gamma_i - I) - \tau\gamma_i)\frac{\partial Q_i}{\partial \kappa}] \tag{15}$$

$$(\mu I \kappa)\frac{\partial \theta}{\partial I} = \sum_i^N [(\mu(\gamma_i - I) - \tau\gamma_i)\frac{\partial Q_i}{\partial I}]$$

Similar to Holland, Hughes, and Knittel (2009) and Lemoine (2016), the change in welfare due to a change in the crediting rule or standard is equal to the wedge between marginal benefits and costs in the efficiency sector times the change in energy efficiency, plus the wedge between marginal benefits and social costs in all of the electricity generating sectors times the change in respective generation. Equation 14 can thus be interpreted as a series of marginal deadweight losses associated with changes in κ and I.

While the above is a useful representation of the conditions governing the second-best choice of κ and I, note that the efficiency and generation responses to κ and I are not arbitrary, but are governed by the fact that the intensity standard constraint $(I(\theta\kappa + \sum_i^N Q_i) - \sum_i^N \gamma_i Q_i = 0)$ must continue to hold. Differentiation of the constraint with respect to κ and

[16] Note that the terms in parenthesis are equivalent to the first-order conditions from the emission tax (equation 10).

I yields the following expression relating the shadow value of the intensity standard μ to the marginal external damages τ at the second-best levels of κ and I:

$$\frac{\mu}{\tau} = \frac{\sum_i^N \gamma_i \frac{\partial Q_i}{\partial \kappa}}{I\theta} = \frac{\sum_i^N \gamma_i \frac{\partial Q_i}{\partial I}}{\kappa\theta + \sum_i^N Q_i}. \tag{16}$$

Note that if I is set arbitrarily, the above still holds for the choice of κ, that is $\frac{\mu}{\tau} = \frac{\sum_i^N \gamma_i \frac{\partial Q_i}{\partial \kappa}}{I\theta}$, and similarly for arbitrary κ, $\frac{\mu}{\tau} = \frac{\sum_i^N \gamma_i \frac{\partial Q_i}{\partial I}}{\kappa\theta + \sum_i^N Q_i}$. This leads to our third proposition:

Proposition 3. *At the second-best interior solution for the crediting rule κ and intensity standard I,*

a) emissions are increasing in both κ and I, $\sum_i^N \gamma_i \frac{\partial Q_i}{\partial \kappa} > 0$ and $\sum_i^N \gamma_i \frac{\partial Q_i}{\partial \kappa} > 0$,

b) The shadow-value of the intensity standard constraint exceeds the marginal external damages from emissions, $\mu > \tau$ if and only if $\kappa \frac{\partial \theta}{\partial \kappa} + \sum_i^N \frac{\partial Q_i}{\partial \kappa} > 0$ and $\kappa \frac{\partial \theta}{\partial I} + \sum_i^N \frac{\partial Q_i}{\partial I} > 0$.

Proposition 3 makes a number of important points about the second-best crediting rule and intensity standard. First, an increase in crediting must increase emissions, and crediting occurs until the benefit from crediting energy efficiency $\mu I\theta$ equals the costs of increased emissions $\tau \sum_i^N \gamma_i \frac{\partial Q_i}{\partial \kappa} > 0$. Crediting encourages energy efficient investment (which per Proposition 2 is too low in the absence of regulation), but it also loosens the emissions constraint. Second, the value of μ will exceed the marginal external damages from emissions only when an increase in crediting or the standard increases the denominator of the standard $(\theta\kappa + \sum_i^N Q_i)$ given in equation 2.

The above results plus the findings in the preceding sections have important policy implications. While the second-best crediting rule implicitly defined in equation 16 generates the greatest welfare under an emissions intensity standard, from Section 2.2 that crediting rule does not provide an identical allocation to that under an emissions tax. As such, the relative abatement cost of the emissions intensity standard will be minimized at the second-best crediting rule, but because of the energy services demand response, the abatement cost of the emissions intensity standard will always exceed that under the emissions tax.

3 Numerical exercise

In this section, we develop a calibrated numerical model to further explore and extend the analytic results presented above. In particular, we examine emissions intensity standards under alternative energy efficiency crediting levels using a detailed electricity dispatch model. We compare the welfare outcomes under these standards to those from an emissions tax policy, given a fixed emissions target.[17]

This numerical exercise enhances our analysis in several key ways. First, even with specific functional forms for the energy service demand curve and production functions, a closed form solution to the second-best energy efficiency crediting rule is intractable. Therefore, numerical methods are useful in determining the second-best crediting rate, κ. Second, the lack of a tractable closed form solution for κ also means that one cannot easily derive comparative static results with respect to other key variables in the model. Examining our numerical model under a range of parameter settings helps us better understand the change in κ with respect to a variety of parameter values. Third, our numerical model also allows us to examine the extent of the welfare distortion relative to an emissions tax policy under

[17] Many of the modeling choices that follow are motivated by the features of the CPP. In particular, because states are given the option to adopt an equivalent mass-based policy (e.g. cap and trade or an emissions tax), understanding the relative efficiency of the rate-based emissions standard approach is important.

a range of energy efficiency crediting levels in a policy relevant setting.

The model is calibrated to represent the ERCOT region, chosen for several reasons. First, ERCOT has relatively small electricity import/export capacities, so modeling it as a closed system is not an egregious over-simplification as it may be for other regions. Second, the ERCOT region represents about 90 percent of the load in Texas. As the CPP sets state-level targets, calibrating the model to ERCOT effectively allows us to analyze a specific state's response to a CPP-like policy.

To analyze emission tax and intensity standard policies in a dispatch model that incorporates energy efficiency, we first must specify a demand for energy services (ES). We assume a constant-elasticity demand of the form:

$$ES_h(P_h) = \phi_h P_h^{\epsilon}, \tag{17}$$

where ES_h is the demand for energy services in time period (hour) h, P_h is the implied unit-cost of energy services, ϕ_h is a scale parameter, and ϵ is the elasticity of demand for energy services. The unit-cost formulation for energy services embeds the optimizing behavior by households and in CES form is given by:

$$P_h(P_{Eh}, P_{\theta h}) = (\alpha^{\sigma} P_{\theta h}^{1-\sigma} + (1-\alpha)^{\sigma} P_{Eh}^{1-\sigma})^{1/(1-\sigma)}, \tag{18}$$

where P_{Eh} is the price of electricity in hour h, $P_{\theta h}$ is the price of energy efficiency in hour h, α is the productivity of energy efficiency in the production of energy services and σ is the elasticity of substitution between electricity (Q) and energy efficiency (θ). Applying Shephard's Lemma on the expenditure function $ES_h(P_h) * P_h(P_{Eh}, P_{\theta h})$ yields the hourly demand functions for electricity, $Q_h(P_{Eh}, P_{\theta h})$, and energy efficiency, $\theta_h(P_{Eh}, P_{\theta h})$, as a function of prices P_{Eh} and $P_{\theta h}$ as:

$$Q_h(P_{Eh}, P_{\theta h}) = \phi_h P_{Eh}^{-\sigma}(1-\alpha)^{\sigma} \left(P_{\theta h}^{(1-\sigma)}\alpha^{\sigma} + P_{Eh}^{(1-\sigma)}(1-\alpha)^{\sigma}\right)^{\left(\frac{\epsilon+\sigma}{1-\sigma}\right)} \tag{19}$$

$$\theta_h(P_{Eh}, P_{\theta h}) = \phi_h P_{\theta h}^{-\sigma}\alpha^{\sigma} \left(P_{\theta h}^{(1-\sigma)}\alpha^{\sigma} + P_{Eh}^{(1-\sigma)}(1-\alpha)^{\sigma}\right)^{\left(\frac{\epsilon+\sigma}{1-\sigma}\right)}. \tag{20}$$

Note that these functional forms assume the energy efficiency market clears hourly and depends on hourly electricity prices. We chose this specification for our base policy comparison results because it is closer in spirit to the static analytical model developed above where electricity and energy efficiency markets clear contemporaneously for the given period. In reality, it is likely that energy efficiency would in part be the result of durable purchases and thus not necessarily respond to hourly fluctuations in electricity prices. That said, energy-efficiency providing durables would still provide time-varying energy savings (MWh's avoided), with more energy savings in high electricity demand periods and less in low demand periods.[18] In that respect, $\theta_h(P_{Eh}, P_{\theta h})$, would roughly approximate the market outcome as θ_h responds positively to increases in P_{Eh} and ϕ_h, both of which increase in periods of high electricity demand.

For other parameters of note, we assume constant values for α, σ, and ϵ (given in Table 1), though we also vary these in sensitivity analyses. We also assume a constant marginal

[18] For example, if energy efficiency is provided through more energy efficient air conditioning units, those units would provide more energy savings during hot time periods (i.e. high demand periods) than in hours of moderate temperature (i.e. low demand periods).

cost of energy efficiency, c_θ, and thus in the baseline case $c_\theta = P_{\theta h}\ \forall h$.[19] We then use these assumed values, along with observed 2013 hourly electricity prices and quantities for ERCOT to derive hourly values for the remaining parameter, ϕ_h.[20]

The final step in our numerical analysis is to form hourly electricity supply and demand curves to get hourly production quantities for each generator and hourly prices. Details of this process, and how it accounts for an emissions intensity standard and an emissions tax, are given in the Appendix B. In general though, to form the supply curves we simply order generators from least to highest costs. Given this hourly supply curve, we find the intersection with the hourly demand to determine the hourly price and production levels.

3.1 Policy Comparison

The goal of our policy comparison is to calculate the cost of achieving a given emissions level under an emissions standard regulation, with and without energy efficiency crediting, as compared to the cost of achieving the same emissions level under an emissions tax. That is, we set the standard, given the efficiency crediting rate, and the emissions tax to achieve

[19] The assumed marginal cost of energy efficiency is taken from Arimura et al. (2012). The constant marginal cost assumption is likely not limiting over a small range of energy efficiency levels, but may be more problematic if simulated energy efficiency levels differ considerably from current levels. We maintain a constant marginal cost assumption for this analysis as it dramatically reduces the complexity of deriving equilibrium values and also vary this constant value in our sensitivity analysis.

[20] Price and quantity data, as well as all other generator-specific and wind generation data, was downloaded from the data management firm ABB (formerly Ventyx), which collects and organizes publicly available data on the electricity sector. The underlying data is available from EIA-860 forms, EPA's Continuous Emissions Monitoring System, and ERCOT's website. Electricity prices and quantities were given for four sub-regions: South, West, North, Houston. We create a single load variable by summing each sub-region's hourly quantity and create a single quantity-weighted price for all of ERCOT to calculate the ϕ parameter.

the same level of emissions reduction relative to the "no policy" baseline.[21] In practice, emission standard compliance will be achieved via a "tradable performance standard" (TPS) system. Associated with this resulting TPS market is a price for the credits, represented as μ in the analytic modeling above.

The cost of meeting the target emissions level under a given policy j, with $j = [TPS, Tax]$, has several components and is given relative to the "no emissions policy" baseline. More specifically, we calculate the cost of complying with the target via policy j as:

$$C^j = \sum_{h=1}^{H} \left(\int_{ES_h^j}^{ES_h^0} P(ES_h) dES \right) - \sum_{i=1}^{N} \sum_{h=1}^{H} \left(c_i(Q_{ih}^0 - Q_{ih}^j) + \tau\gamma_i Q_{ih}^j \right) - \sum_{h=1}^{H} c_\theta(\theta_h^0 - \theta_h^j), \quad (21)$$

The costs are summed over all hours of production, $h = 1, ..., H$. The first term on the right hand side of (21) represents the change in total consumer surplus (area under the ES demand curve) given the policy-induced change in energy services, where ES_h^0 is the baseline energy services in hour h, ES_h^j is energy services under policy j, $P(ES_h)$ is the inverse demand for energy services. The second term gives the change in the cost of electricity generation for generators $i = 1, ..., N$ where $c_i(Q_{ih})$ is the cost for generator i producing Q_{ih} MWh's and $(Q_{ih}^0 - Q_{ih}^j)$ is the difference in hourly generation from generator i between the baseline and policy j. The term $\tau\gamma_i Q_{ih}^j$ represents the assumed lump sum transfer of any emission tax revenues where τ is the emissions tax and γ_i is the emissions intensity of generator i. The final term in (21) gives the change in cost associated with the

[21] Holding emissions constant across policies appears consistent with general decisions of policy makers (how does one choose among policies given an environmental objective) and the CPP also provides emission mass targets for each state. Additionally, by keeping the emissions reductions constant across policies we can then focus on the relative costs of the policies, as the benefits of carbon emission reductions will be constant across policies.

change in energy efficiency investment where $c_\theta(\theta_h)$ is the cost associated with θ_h MWh's avoided and $(\theta_h^0 - \theta_h^j)$ is the difference in energy efficiency under the baseline and policy j. As a more interpretable measure, we report the average annual cost per unit of emissions abated, $({}^{C}\!/\!{}_{A})^j = {}^{C^j}\!/\!{}_{(Emissions^0 - Emissions^j)}$, where $(Emissions^0 - Emissions^j)$ is the difference in annual emissions between the baseline case and those generated under policy j.

3.2 Simulation Results

Reference case parameter policy comparisons are given in Table 2. This table gives the results from a TPS and emissions tax policy aimed at reducing emissions 20 percent below the predicted "no policy" baseline of 2020 CO_2 emissions, a target in line with the CPP's goal for Texas.[22] For the TPS policy, we consider different energy efficiency crediting rates, κ, ranging from 0 to 1.2. The bottom two lines of Table 2 give the summary results from the tax and baseline runs. The remainder of the results are for the TPS outcomes.

Of primary importance from an efficiency standpoint are the "Cost Ratio" outcomes. This row gives the ratio of the TPS's to tax's average policy cost per unit of abatement (ratio of $({}^{C}\!/\!{}_{A})^{TPS}$ to $({}^{C}\!/\!{}_{A})^{Tax}$), and can thus be seen as a measure of relative efficiency. The relative inefficiency of the TPS to tax policies is U-shaped over the range of crediting rates explored, with the inefficiency minimized at a crediting rate near 0.8. Of course, this particular second-best crediting ratio is not a general result and will vary with assumed parameterizations as we show in more detail below.

Remaining results in Table 2 are largely as expected. With increasing energy efficiency

[22] Projected and target emissions for Texas under the CPP were taken from `http://www.epa.gov/airquality/cpptoolbox/texas.pdf`.

crediting, the standard, I, and related TPS credit price, μ, needed to meet the emissions target are falling. This is as expected because increasing the crediting rate subsidizes energy efficiency, increasing energy efficiency levels, θ^{TPS}, and increasing the denominator of the standard (equation 2). Consequently, increasing κ leads to a decrease in electricity consumption, Q^{TPS}, and correspondingly lower average electricity prices relative to the tax policy and even relative to the no-policy baseline results. However, as the analytic model predicts, crediting energy efficiency leads to an overall increase in energy service levels compared to the efficient levels generated by the emissions tax.

3.3 Sensitivity Analysis

To further explore how the chosen parameterization has affected our main results and to more fully describe the policy implications of energy efficiency crediting we conduct a variety of sensitivity analyses. In addition, as noted above, a tractable closed form solution for the second-best κ is not forthcoming, so our sensitivity analysis gives us insight into comparative static results of the second-best crediting rates.

We present a summary of these analyses by plotting the "Cost Ratio" under different parameter settings and energy efficiency crediting rates, κ. These plots are given in Figures 1 and 2.[23] Before discussing these sensitivity analyses, it is useful to recall that energy efficiency crediting can offset the production subsidy inefficiencies that arise in a typical rate-based standards policy. Specifically, subsidizing energy efficiency through crediting induces a substitution out of electricity consumption, and thus reduces some of the inefficiencies associated with the implicit electricity production subsidy. We can therefore think about

[23] More complete summaries of the sensitivity analyses are given in Appendix B.

how altering a given parameter impacts the relative cost of energy efficiency versus electricity production and therefore what level of energy efficiency crediting best reduces the electricity production subsidy.

The plots in Figure 1 summarize sensitivity results across three parameters in the CES unit cost function - α, σ, and ϵ.[24] With respect to higher values of α, the productivity of energy efficiency in creating energy services, second-best crediting is lower because relatively high productivity of energy efficiency reduces the need to subsidize it.[25] With respect to σ, the elasticity of substitution between electricity and energy efficiency, second-best crediting remains stable near 0.8 - 1.0. However, the relative cost savings from crediting decreases as σ decreases; a low elasticity of substitution restricts the ability to substitute out of electricity towards energy efficiency, and thus crediting energy efficiency will not elicit much of an increase in energy efficiency investment. Finally, with respect to ϵ, the elasticity of demand for energy services, the second-best κ decreases as ES demand becomes more elastic. With more elastic energy service demand ($\epsilon = -0.4$), increasing κ does un-do some of the production subsidies implicit in a TPS, but it also induces relatively too much energy efficiency investment implying a lower second-best credit rate.

[24] Note that for every parameter iteration considered the ϕ values are recalculated, again calibrated using observed 2013 electricity prices and quantities. All other parameters not mentioned as being changed remain the same as in the reference case. Also, for all sensitivity analyses, we have aggregated from the hourly frequency to the 12-hour frequency. We found this aggregation had little numerical impacts on the results and greatly reduced computation times. In addition, we explored numeric models that used even more aggregated time-periods (smaller H) and the central comparison of TPS and tax policies remains similar to the results shown here, giving us additional confidence that our hourly modeling construct for energy efficiency is not unduly influencing our results.

[25] For example, if light from an energy efficient bulb is viewed by consumers to be as good as or better than light from an incandescent bulb, α would be relatively high for that case. But, if the light from the energy efficient bulb is considered inferior then it would imply a relatively low α value.

The plots in Figure 2 explore the Cost Ratios under various market and policy conditions by varying c_θ, P_{NG}, and the level of emission reductions. For c_θ, the cost of a MWh avoided through energy efficiency, the second-best crediting rate κ declines with lower energy efficiency costs.[26] Lower energy efficiency costs will induce a significant amount of energy efficiency adoption regardless of crediting and therefore only a small level of crediting is needed to negate the electricity production subsidy. In varying P_{NG}, the price of natural gas, a lower second-best κ occurs for the high gas price scenario because higher gas prices lead to higher electricity prices, which incentivizes more investment in energy efficiency and reduces the need for energy efficiency crediting. Finally, when we alter the emissions reduction target we find that second-best κ remains around the same point.

Several other key points from the figures are worth mentioning. First, for low α and high emissions reductions, we see crediting energy efficiency does little to change the relative cost of the TPS compared to the emissions tax. For the low α scenario, energy efficiency is unproductive in creating energy services and thus subsidizing it does little to incentivize its adoption. For the high emissions reduction case, because electricity prices under such a scenario are already high, there is already significant incentive to invest in energy efficiency regardless of the crediting. Second, when emission reduction levels are low, natural gas prices are high, and demand for energy services is quite inelastic, we find the relative cost difference between the TPS and the tax is reduced dramatically when moving from the no-crediting case to the second-best crediting rule. This occurs for the low emission reduction case because with low electricity prices, crediting is needed to induce energy efficiency investment

[26] Though somewhat difficult to see from the figure at $c_\theta = \$35$ the second-best κ over the values explored is 0.6, while at $c_\theta = \$65$ it is at $\kappa = 1.2$.

to counteract the electricity production subsidy. For the case of high P_{NG}, substituting out of coal to gas-fired generation is expensive, so crediting energy efficiency provides a lower cost alternative to electricity consumption. With respect to the near perfectly inelastic energy services demand, the intuition mirrors the analytic section - the TPS without crediting leads to relatively too much electricity consumption and not enough energy efficiency. Crediting energy efficiency leads to substitution away from electricity toward energy efficiency at levels that are similar to those under the emissions tax.

4 Discussion

Under the EPA's CPP, both mass-based (cap and trade) and rate-based (emission intensity standards) policies can be used by states to achieve compliance with their targets.[27] Despite the fact that, from a national welfare perspective, rate-based policies may be a second-best alternative to optimal mass-based policies, many states may favor rate-based policies as an option for CPP compliance due to their reduced impacts on generation costs and electricity prices, and their potential to increase the incentive for investment in in-state generation capacity (Bushnell, Holland, Hughes, and Knittel 2014).[28] Given the likelihood of wide adoption of rate-based compliance approaches, it is crucial to understand the welfare implications of these alternative policies and how they will impact decision-making regarding

[27] States are also permitted to use a "state-measures" approach under which the state implements a suite of indirect emissions policies, such as energy efficiency resource standards, renewable portfolio standards, planned retirements of fossil capacity and addition of low or zero-carbon generation capacity, which in aggregate achieve emissions reductions sufficient to meet the CPP targets.

[28] Note that these same outcomes can be achieved through a mass-based policy if emissions allowances are freely allocated based on production (Palmer and Paul 2015)

consumption of energy efficiency and generation.

We have shown that crediting of electricity savings resulting from energy efficiency measures can yield first-best outcomes when demand for energy services is perfectly inelastic. Furthermore, we show that under conditions with perfectly inelastic demand for energy services, if energy efficiency (or more accurately the savings resulting from efficiency measures) is perfectly substitutable with electricity generation for producing energy services (i.e. 1 MWh saved yields the same amount of energy services as 1 MWh generated) then one-to-one crediting of efficiency savings achieves the first best outcome. This one-to-one crediting of electricity savings and generation is precisely the approach allowed under the EPA's CPP. Under the rate-based option for compliance with the CPP, savings resulting from energy efficiency measures create "emissions reduction credits (ERCs)" which can be added to the generation in the denominator of the intensity fraction. This approach effectively treats electricity savings as a form of zero-emissions generation, and thereby eliminates the distortion between generation and efficiency measures, yielding an allocation equivalent to that under an emissions tax. Furthermore, such a modification does not require an additional instrument to achieve first-best (Holland, Hughes, and Knittel 2009; Holland 2012), which may make it easier to implement in practice.

Importantly, however, the optimality of the emissions standard with crediting of efficiency savings breaks down when demand for energy services exhibits some elasticity. Crediting savings from efficiency measures can no longer recover first-best, and even if crediting improves the economic efficiency of the policy (relative to providing no credit for energy efficiency measures), adjustments to the crediting rate for efficiency savings may be required to maximize welfare. Thus, while crediting of efficiency savings eliminates the relative distortion between energy efficiency and generation, both generation and energy efficiency are still effectively subsidized, increasing overall energy services relative to first-best.

Given that demand for energy services in the real world likely exhibits some elasticity, the simplified one-to-one crediting approach suggested by EPA may not achieve the optimal outcomes. However, our numerical analysis demonstrates that under most conditions, crediting of efficiency measures under an emissions intensity standard reduces costs and increases welfare relative to a standard that does not credit efficiency. Although the optimal crediting rate for efficiency will ultimately depend on a range of factors, including the substitutability of electricity savings and electricity generation, the elasticity of demand for energy services, and the level of emissions reduction required by the policy, crediting at a rate of 1 (i.e. one-for-one crediting) may be in many relevant situations preferred over no crediting at all.

The equivalence of crediting energy efficiency and first-best regulation under perfectly inelastic demand for energy services holds under certainty. However, in reality, determining energy efficiency activities to be credited and determining the level of MWh's avoided may be very uncertain. More specifically, recent work by Fowlie, Greenstone, and Wolfram (2015) has called in to question engineering-based estimates of energy savings from various residential weatherization-related energy efficiency projects. Such measurement error issues may also be present in other forms of energy efficiency projects. Further research into whether this equivalency holds under various considerations of uncertainty may provide further useful guidance for policymakers.

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Table 1: Baseline Parameter Values

Parameter	Value	Description
α	0.4	Productivity of energy efficiency in the production of energy services
σ	2	Elasticity of substitution between electricity and energy efficiency
ϵ	-0.1	Energy services demand elasticity
c_θ	\$50/MWh	Marginal cost of energy efficiency
e_i^{NG}	116.9lbs/MMBtu	CO_2 Emissions intensity for natural gas
e_i^{C}	210.6lbs/MMBtu	CO_2 Emissions intensity for coal
P_{2020}^{NG}	\$5.17/MMBtu	Assumed price of natural gas in 2020
P_{2020}^{C}	\$2.22/MMBtu	Assumed price of coal in 2020
$reduction$	20%	Target emission levels are at this percent below 2020 baseline emissions

Table 2: Policy Analysis Results

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.412	1.265	1.160	1.122	1.083	1.089	1.116
$(C/A)^{TPS}$	15.59	13.97	12.81	12.39	11.96	12.02	12.32
μ	25.65	24.00	22.86	21.65	20.66	19.56	18.50
I	1001	1010	1013	1008	997	980	958
ES^{TPS}	190.5	191.0	191.4	191.8	192.2	192.5	192.7
Q^{TPS}	274.7	270.4	265.9	261.8	257.5	254.0	251.1
θ^{TPS}	102.5	106.8	111.4	116.0	120.6	124.5	127.8
Avg P_E^{TPS}	42.31	41.57	40.98	40.51	40.15	39.87	39.65
Tax: $(C/A)^{Tax} = 11.04$, $\tau = 18.31$, $ES = 188.6$, $Q = 250.8$, $\theta = 119.9$, Avg$P_E = 48.75$							
Baseline : $ES = 191.2$, $Q = 283.4$, $\theta = 97.8$, Avg$P_E = 40.15$, $CO_2 = 171.9$							

Notes: "Tax" and "Baseline" values are for the tax policy and baseline case with no policy, respectively, and are constant across all κ values. Remaining values are for the TPS policy with varying crediting ratios of κ. "Cost Ratio" gives the ratio of $(C/A)^{TPS}$ to $(C/A)^{Tax}$. μ and τ are in \$/tCO_2. ES values are in millions of ES units. Q and θ values are in million MWhs. Avg. P_E values give the quantity weighted average electricity prices in \$/MWh. In the "Baseline" row, "CO_2" gives emissions in million tCO_2 and the emissions of the policies are 20% below that value.

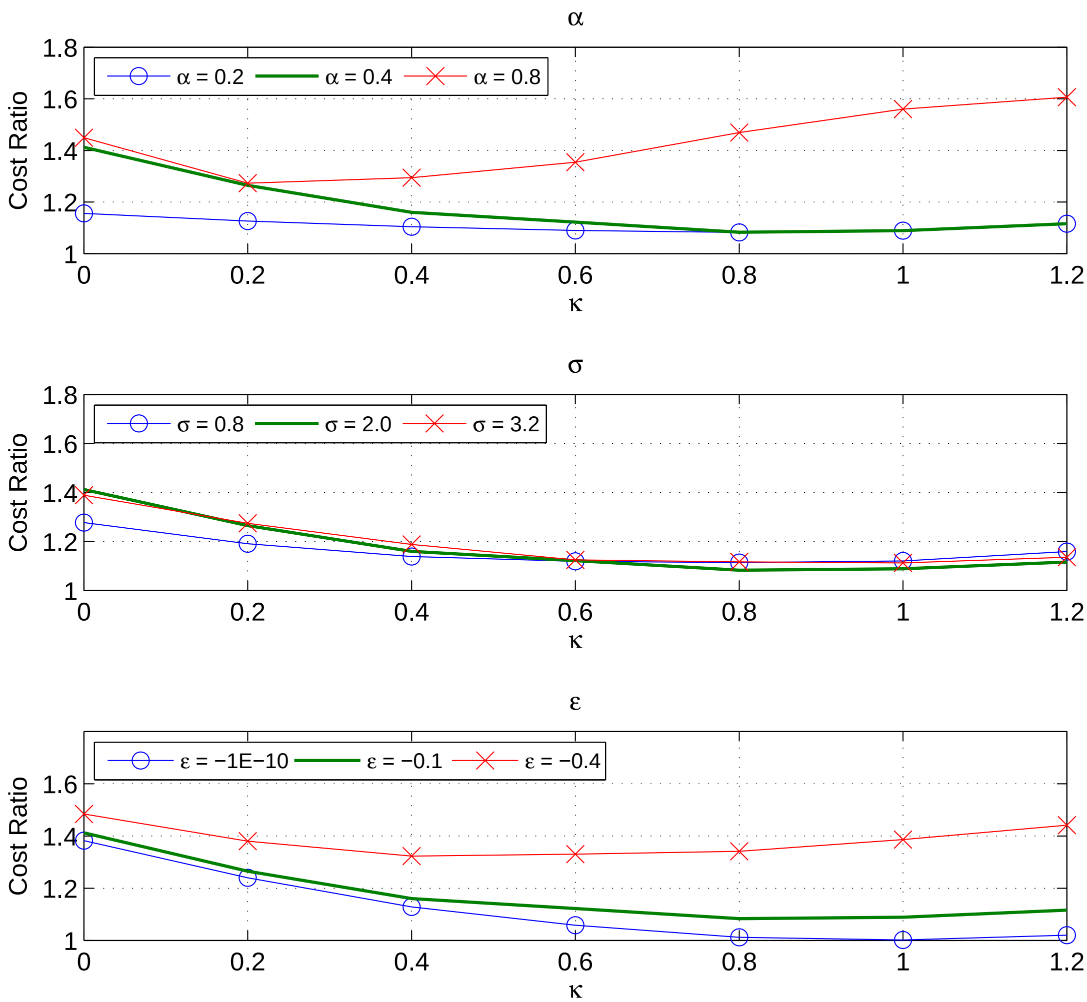

Figure 1: Sensitivity Analysis - Demand Parameters. Displays Cost Ratio (abatement cost of TPS versus emissions tax) for various crediting rules κ. The top panel varies the productivity of energy efficiency in the production of energy services (α), the middle panel varies the elasticity of substitution between electricity and energy efficiency (σ), and the bottom panel varies the elasticity of energy service demand (ϵ).

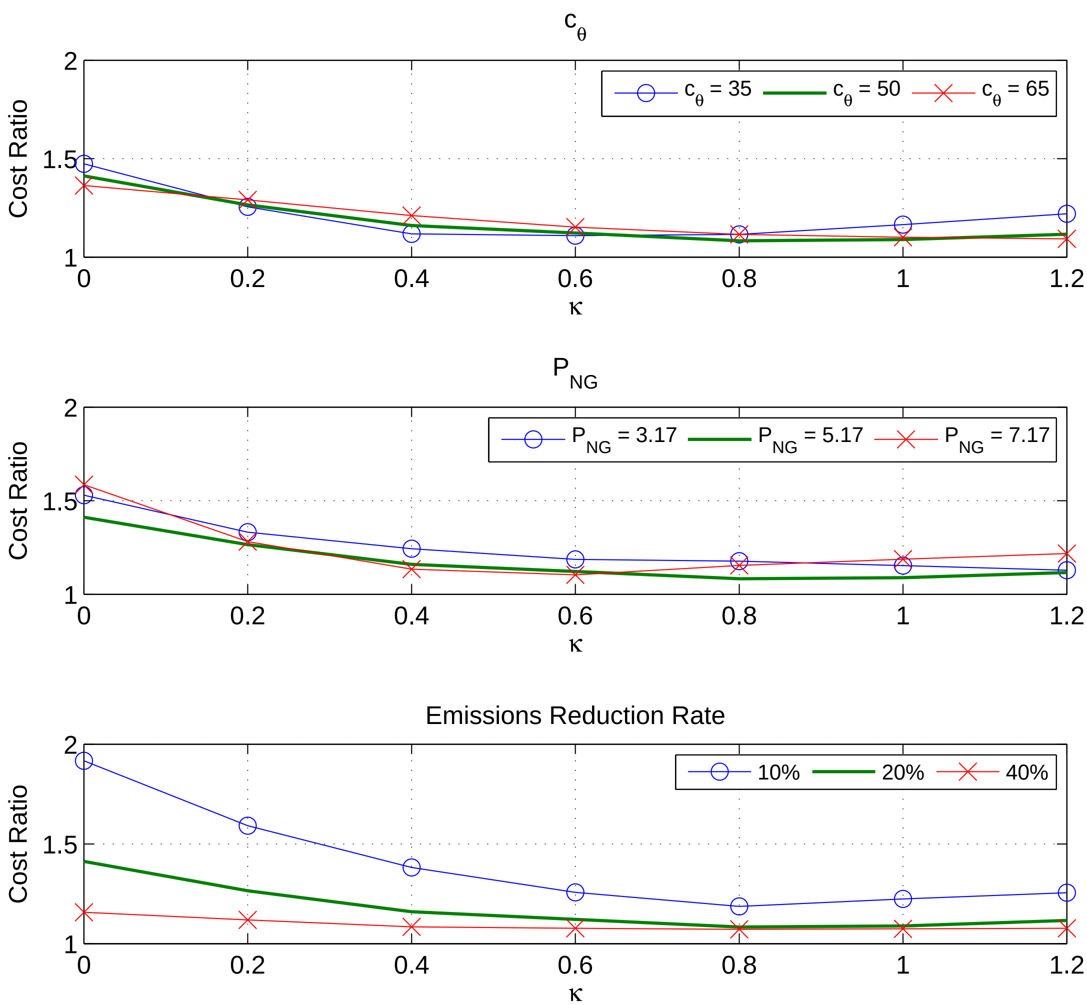

Figure 2: Sensitivity Analysis - Market and Policy Parameters. Displays Cost Ratio (abatement cost of TPS versus emissions tax) for various crediting rules κ. The top panel varies the marginal cost of energy efficiency (c_θ), the middle panel varies the price of natural gas (P_{NG}), and the bottom panel varies the emissions reduction rate of the policy.

A Analytical Proofs

A.1 Proof of Proposition 1

To establish the first part of Proposition 1, compare equation 7 with $f'(\theta) = 0$ to the optimal conditions established in 4. Optimality under the emissions intensity standard would require that $\tau\gamma_i = \mu(\gamma_i - I)\forall i$. However, if $\tau\gamma_i = \mu(\gamma_i - I)$, then $\mu = \frac{\tau\gamma_i}{\gamma_i - I}$, and thus $\tau\gamma_j = \frac{\tau\gamma_i}{\gamma_i - I}(\gamma_i - I)$. Rearranging, this requires $\frac{\gamma_i}{\gamma_j} = \frac{\gamma_i - I}{\gamma_j - I}$, or that either $\gamma_i = \gamma_j \forall i, j$ or $I = 0$, both of which have been ruled out by assumption. As such, emissions intensity standard with $f'(\theta) = 0$ cannot recover the first-best allocation.

To show the equivalence of the allocation under an emissions intensity standard with that under an emissions tax coupled with an energy efficiency tax, let δ represent a tax on energy efficiency θ. Then the firm's problem is to solve:

$$L = \sum_i^N \int_0^{Q_i} c_i(q_i)dq_i + e(\theta) + \tau(\sum_i^N \gamma_i Q_i) + \delta\theta + \lambda(\overline{ES} - ES(Q, \theta)), \tag{22}$$

with first-order conditions:

$$\begin{aligned} \frac{\partial L}{\partial Q_i} =& c_i(Q_i) + \tau\gamma_i - \lambda\frac{\partial ES}{\partial Q} = 0, \quad \forall i \\ \frac{\partial L}{\partial \theta} =& \frac{de}{d\theta} + \delta - \lambda\frac{\partial ES}{\partial \theta} = 0. \end{aligned} \tag{23}$$

Equating the emissions tax and the standard such that $\mu = \tau$ and setting the emission tax such that $\delta = \mu I \frac{\partial ES/\partial \theta}{\partial ES/\partial Q}$ yields the conditions:

$$\begin{aligned} \frac{\partial L}{\partial Q_i} =& c_i(Q_i) + \mu\gamma_i - \lambda\frac{\partial ES}{\partial Q} = 0, \quad \forall i \\ \frac{\partial L}{\partial \theta} =& \frac{de}{d\theta} + \mu I \frac{\partial ES/\partial \theta}{\partial ES/\partial Q} - \lambda\frac{\partial ES}{\partial \theta} = 0. \end{aligned} \tag{24}$$

Setting $f'(\theta) = 0$ and solving for λ in equation 7 and rearranging gives $c_i(Q_i)+\mu\gamma_i-\mu I - \frac{\frac{de}{d\theta}}{\frac{\partial ES}{\partial \theta}}\frac{\partial ES}{\partial Q} = 0, \quad \forall i$, while a similar manipulation of the above expressions yields $c_i(Q_i)+\mu\gamma_i - \frac{\frac{de}{d\theta}+\mu I\frac{\partial ES/\partial \theta}{\partial ES/\partial Q}}{\frac{\partial ES}{\partial \theta}}\frac{\partial ES}{\partial Q} = 0, \quad \forall i$. Cancelling terms shows that the allocation under an emissions and energy efficiency tax yields an identical allocation to the intensity standard.

To establish the third result that crediting can recover first-best, recall that crediting introduces an energy efficiency subsidy equal to $\mu I f'(\theta)$. If $f'(\theta)$ is set equal to the ratio of energy service production $\frac{\partial ES/\partial \theta}{\partial ES/\partial Q}$, then the μI terms disappear from equation 8, and if the standard is set such that $\mu = \tau$, then all terms are equivalent to the first-best solution in equation 5.

To establish that the fourth result that energy efficiency is always greater under an emissions tax relative to the unregulated case, compare equation 5 with $\tau = 0$ and $\tau > 0$. The emissions tax raises the marginal cost for at least some generator (since by assumption $\gamma_i > 0$ for some generator) relative to the unregulated case. Given that the demand for energy services is fixed, the firm substitutes towards providing more energy efficiency.

Formally, consider the case of two electricity generators - a high emission generator producing Q_h and a low emission generator producing Q_l. Totally differentiating the first-order conditions yields the following system of equations:

$$
\begin{aligned}
c_l' dQ_l - \lambda\frac{\partial^2 ES}{\partial Q^2}dQ_l - \lambda\frac{\partial^2 ES}{\partial Q^2}dQ_h - \lambda\frac{\partial^2 ES}{\partial Q \partial\theta}d\theta - \frac{\partial ES}{\partial Q}d\lambda &= -\gamma_l d\tau \\
c_h' dQ_h - \lambda\frac{\partial^2 ES}{\partial Q^2}dQ_l - \lambda\frac{\partial^2 ES}{\partial Q^2}dQ_h - \lambda\frac{\partial^2 ES}{\partial Q \partial\theta}d\theta - \frac{\partial ES}{\partial Q}d\lambda &= -\gamma_h d\tau \\
e'' d\theta - \lambda\frac{\partial^2 ES}{\partial Q \partial\theta}dQ_l - \lambda\frac{\partial^2 ES}{\partial Q \partial\theta}dQ_h - \lambda\frac{\partial^2 ES}{\partial \theta^2}d\theta - \frac{\partial ES}{\partial \theta}d\lambda &= 0 \\
-\frac{\partial ES}{\partial Q}dQ_l - \frac{\partial ES}{\partial Q}dQ_h - \frac{\partial ES}{\partial \theta}d\theta &= 0
\end{aligned}
\tag{25}
$$

Application of the implicit function theorem yields the following:

$$
\frac{\partial\theta}{\partial\tau} = \frac{-\frac{\partial ES}{\partial Q}\frac{\partial ES}{\partial\theta}(\gamma_h c_l' + \gamma_l c_h')}{c_h'(B\lambda - (\frac{\partial ES}{\partial Q})^2 e'') + c_l'(B\lambda - \frac{\partial^2 ES}{\partial\theta^2}c_h' - (\frac{\partial ES}{\partial Q})^2 e'')}
\tag{26}
$$

where $B = (-2\frac{\partial ES}{\partial Q}\frac{\partial ES}{\partial\theta}\frac{\partial^2 ES}{\partial Q\partial\theta} + \frac{\partial^2 ES}{\partial Q^2}(\frac{\partial ES}{\partial\theta})^2 + \frac{\partial^2 ES}{\partial\theta^2}(\frac{\partial ES}{\partial Q})^2)$. Because $ES(Q,\theta)$ is an increasing function and thus strictly quasiconcave, then $B < 0$ and the denominator of equation 26 is strictly negative (consistent with the sign of the bordered Hessian from the constrained minimization problem). The numerator of equation 26 is also strictly negative, which allows us to sign $\frac{\partial\theta}{\partial\tau} > 0$.

Similarly,

$$
\frac{\partial Q_l}{\partial\tau} + \frac{\partial Q_h}{\partial\tau} = \frac{(\frac{\partial ES}{\partial\theta})^2(\gamma_h c_l' + \gamma_l c_h')}{c_h'(B\lambda - (\frac{\partial ES}{\partial Q})^2 e'') + c_l'(B\lambda - \frac{\partial^2 ES}{\partial\theta^2}c_h' - (\frac{\partial ES}{\partial Q})^2 e'')}
\tag{27}
$$

whereby the numerator is strictly positive, and therefore $\frac{\partial Q}{\partial\tau} < 0$.

To prove the final result, note that the above establishes the relationship between the emission tax $\tau\gamma_i$ and energy consumption and energy efficiency, and thus the response of energy consumption and energy efficiency to the $\mu\gamma_i$ component of the intensity standard. To establish the effect of μI (effectively a lump-sum generation subsidy s) on those same decisions, we set the left-hand side of the first two equations in 31 equal to ds. Application of the implicit function theorem yields:

$$\frac{\partial\theta}{\partial s} = \frac{\frac{\partial ES}{\partial Q}\frac{\partial ES}{\partial \theta}(c_l' + c_h')}{c_h'(B\lambda - (\frac{\partial ES}{\partial Q})^2 e'') + c_l'(B\lambda - \frac{\partial^2 ES}{\partial \theta^2}c_h' - (\frac{\partial ES}{\partial Q})^2 e'')} \tag{28}$$

and

$$\frac{\partial Q_l}{\partial s} + \frac{\partial Q_h}{\partial s} = \frac{-(\frac{\partial ES}{\partial \theta})^2(c_l' + c_h')}{c_h'(B\lambda - (\frac{\partial ES}{\partial Q})^2 e'') + c_l'(B\lambda - \frac{\partial^2 ES}{\partial \theta^2}c_h' - (\frac{\partial ES}{\partial Q})^2 e'')} \tag{29}$$

Per the above discussion, $\frac{\partial Q}{\partial s} > 0$, and $\frac{\partial \theta}{\partial s} < 0$. Thus, the μI generation subsidy to all generators increases energy consumption and reduces energy efficiency relative to the emissions tax.

A.2 Proof of Proposition 2

To establish the first part of Proposition 2, note that in order for the intensity standard allocation to be identical to that under an emissions tax, the price of energy services $P(ES(Q,\theta))$ must be identical. Thus, the right-hand side of equation 10 must equal the corresponding right-hand side of equation 12. As above, this requires that $\tau\gamma_i = \mu(\gamma_i - I)\forall i$. However, if $\tau\gamma_i = \mu(\gamma_i - I)$, then $\mu = \frac{\tau\gamma_i}{\gamma_i - I}$, and thus $\tau\gamma_j = \frac{\tau\gamma_i}{\gamma_i - I}(\gamma_i - I)$. Rearranging, this requires $\frac{\gamma_i}{\gamma_j} = \frac{\gamma_i - I}{\gamma_j - I}$, or that either $\gamma_i = \gamma_j \forall i,j$ or $I = 0$, both of which have been ruled out by assumption.

To establish the second part of Proposition 2, setting $f'(\theta) = \frac{\partial ES/\partial\theta}{\partial ES/\partial Q}$, the standard such that $\mu = \tau$, and rearranging equation 12 yields the following relationship:

$$\frac{c_i(Q_i) + \tau\gamma_i}{\partial ES/\partial Q} = \frac{c_j(Q_j) + \tau\gamma_j}{\partial ES/\partial Q} = \frac{de/d\theta}{\partial ES/\partial\theta} \quad \forall i, j. \tag{30}$$

This is the same expression as obtained from rearranging 10, and as such the correct relative incentives exist across generators and between generation and emissions. However, returning to the first-order conditions, the presence of the subsidy $\tau * I$ for both sectors and the fact that $P(ES(Q, \theta))$ is downward-sloping implies a lower energy services price in equilibrium, and thus greater energy services consumed, under the intensity standard.

To establish the third part of Proposition 2, again consider the case of two electricity generators - a high emission generator producing Q_h and a low emission generator producing Q_l. Totally differentiating the first-order conditions for the emissions tax in 10 yields the following system of equations:

$$\begin{gathered}
(P\frac{\partial^2 ES}{\partial Q^2} + P'(\frac{\partial ES}{\partial Q})^2 - c_l')dQ_l + (P\frac{\partial^2 ES}{\partial Q^2} + P'(\frac{\partial ES}{\partial Q})^2)dQ_h + (P\frac{\partial^2 ES}{\partial Q\partial\theta} + P'\frac{\partial ES}{\partial Q}\frac{\partial ES}{\partial\theta})d\theta = \gamma_l d\tau \\
(P\frac{\partial^2 ES}{\partial Q^2} + P'(\frac{\partial ES}{\partial Q})^2)dQ_l + (P\frac{\partial^2 ES}{\partial Q^2} + P'(\frac{\partial ES}{\partial Q})^2 - c_h')dQ_h + (P\frac{\partial^2 ES}{\partial Q\partial\theta} + P'\frac{\partial ES}{\partial Q}\frac{\partial ES}{\partial\theta})d\theta = \gamma_h d\tau \\
(P\frac{\partial^2 ES}{\partial Q\partial\theta} + P'\frac{\partial ES}{\partial Q}\frac{\partial ES}{\partial\theta})dQ_l + (P\frac{\partial^2 ES}{\partial Q\partial\theta} + P'\frac{\partial ES}{\partial Q}\frac{\partial ES}{\partial\theta})dQ_h + (P\frac{\partial^2 ES}{\partial\theta^2} + P'(\frac{\partial ES}{\partial\theta})^2 - e'')d\theta = 0
\end{gathered} \tag{31}$$

Application of the implicit function theorem yields the following:

$$\frac{\partial\theta}{\partial\tau} = \frac{(\gamma_h c_l' + \gamma_l c_h')(P\frac{\partial^2 ES}{\partial Q\partial\theta} + P'\frac{\partial ES}{\partial Q}\frac{\partial ES}{\partial\theta})}{H} \tag{32}$$

where H is the determinant of the Hessian from the corresponding maximization problem and is strictly less than zero. If energy efficiency and energy consumption are substitutes ($\frac{\partial^2 ES}{\partial Q \partial \theta} < 0$) then the numerator is strictly negative and $\frac{\partial \theta}{\partial \tau} > 0$. If they are complements, then the necessary condition for $\frac{\partial \theta}{\partial \tau} > 0$ is that $\frac{\frac{-\partial^2 ES}{\partial Q \partial \theta}}{\frac{\partial ES}{\partial Q}\frac{\partial ES}{\partial \theta}} > \frac{P'}{P}$. Given our assumption that ES exhibits constant-elasticity-of-substitution, then the left-hand side simplifies to $\frac{-1}{\sigma * ES}$. Noting that $\frac{\frac{\partial ES}{\partial P}}{\frac{ES}{P}} = \epsilon$, then the condition is met as long as demand for energy services is less elastic in magnitude than the elasticity of substitution ($-\sigma < \epsilon < 0$). Note that if ES is Cobb-Douglas, then this simply requires that demand for energy services is relatively inelastic ($-1 < \epsilon < 0$). Per our assumptions then, $\frac{\partial \theta}{\partial \tau} > 0$

Similarly, for generation the implicit function theorem yields:

$$\frac{\partial Q_l}{\partial \tau} + \frac{\partial Q_h}{\partial \tau} = \frac{-(\gamma_h c_l' + \gamma_l c_h')(P\frac{\partial^2 ES}{\partial \theta^2} + P'(\frac{\partial ES}{\partial \theta})^2 - e'')}{H} \tag{33}$$

whereby the numerator is strictly positive, and therefore $\frac{\partial Q}{\partial \tau} < 0$.

A.3 Proof of Proposition 3

First, note that differentiation of the intensity standard ($I(\theta\kappa + \sum_i^N Q_i) - \sum_i^N \gamma_i Q_i = 0$) with respect to κ and I respectively yields:

$$\begin{aligned} \sum_i^N \gamma_i \frac{\partial Q_i}{\partial \kappa} &= \kappa I \frac{\partial \theta}{\partial \kappa} + I\theta + I \sum_i^N \gamma_i \frac{\partial Q_i}{\partial \kappa}, \\ \sum_i^N \gamma_i \frac{\partial Q_i}{\partial I} &= \kappa I \frac{\partial \theta}{\partial I} + \kappa\theta + \sum_i^N Q_i + I \sum_i^N \gamma_i \frac{\partial Q_i}{\partial I} \end{aligned} \tag{34}$$

Substitution into the first-order conditions in equation 15 yields equation 16, from which it is clear that emissions must be increasing at the second-best crediting rule and intensity standard.

To prove the second part, note that equation 15 can be rewritten as:

$$(\mu - \tau)\sum_i^N \gamma_i \frac{\partial Q_i}{\partial \kappa} = \mu I(\kappa\frac{\partial \theta}{\partial \kappa} + \sum_i^N \frac{\partial Q_i}{\partial \kappa}), \tag{35}$$
$$(\mu - \tau)\sum_i^N \gamma_i \frac{\partial Q_i}{\partial I} = \mu I(\kappa\frac{\partial \theta}{\partial I} + \sum_i^N \frac{\partial Q_i}{\partial I}).$$

Substitution of the differentiated constraints in equation 34 into this expression and canceling terms yields:

$$(\mu - \tau)I\theta = \tau I(\kappa\frac{\partial \theta}{\partial \kappa} + \sum_i^N \frac{\partial Q_i}{\partial \kappa}), \tag{36}$$
$$(\mu - \tau)(\kappa\theta + \sum_i^N Q_i) = \tau I(\kappa\frac{\partial \theta}{\partial I} + \sum_i^N \frac{\partial Q_i}{\partial I}).$$

Thus $\mu > \tau$ provided $\kappa\frac{\partial \theta}{\partial \kappa} + \sum_i^N \frac{\partial Q_i}{\partial \kappa} > 0$ and $\kappa\frac{\partial \theta}{\partial I} + \sum_i^N \frac{\partial Q_i}{\partial I} > 0$.

B Numeric Electricity Supply and Demand Model Details

To conduct our numerical analysis we must form hourly electricity supply curves (the dispatch curve) and an energy efficiency curve to solve the market equilibriums. The energy efficiency supply curve is formed via the assumed constant marginal cost for energy efficiency, c_θ. For the electricity supply curve, we begin by collecting data on heat rates (MMBtu of fuel burned per MWh of generation), non-fuel variable operation and maintenance costs (VOM, given in \$/MWh), capacity, scheduled outage rates, and forced outage rates for all non-renewable generating facilities in ERCOT in 2013. Using fuel prices for coal, natural gas, and uranium from the EIA's Annual Energy Outlook (AEO) 2014, along with heat rates and VOM's, we form a marginal generation cost for each generator.[29]

To account for the impacts of forced and scheduled outage rates, we effectively reduce the capacity of each non-renewable plant that is available for generation. The forced and scheduled outage rates are given as the percent of annual hours for which the plant is closed down. We follow the procedure of Fell and Linn (2013) to account for these outage rates. More specifically, we first assume that scheduled maintenance occurs in ERCOT's low-demand months: February - April and October - December. We then reduce the maximum possible capacity factors by a constant rate over these months, such that the average capacity factor across all hours of the year for each generator matches one minus the reported average scheduled outage rate. For the closures due to unscheduled maintenance on the nonrenewable generators, we assume that in each hour of the year, including those in the assumed scheduled maintenance period, the capacity factor is lowered by a constant rate such that the cumulative reduction in the capacity factor is equal to the average unscheduled maintenance rate. Multiplying these outage-rate adjusted maximum possible capacity factor by each plant's given capacity, we then have the effective capacity available to generate for each plant for each hour of the year.

Also, similar to Fell and Linn (2013), we assume coal and natural gas combined cycle

[29] For generator i, marginal cost is given as $c_i = hr_i P_i^f + VOM_i$ where hr_i is i's heat rate and P_i^f is its fuel price. For semi-nonrenewable generation plants, such as those fueled by landfill gases, we assume a fuel price of zero.

(NGCC) plants have limited ramping capabilities, which we model simplistically as a minimum "must-run" constraint. For coal plants we assume that they must run at a minimum of 40 percent of their given capacity and that NGCC plants must run at a minimum of 15 percent of their capacities.[30]

Finally, we collect data on hourly wind generation and effectively model wind generation as a single generator, treating it as a zero marginal cost generation source.[31] Combining this wind generation with the marginal costs of the non-renewable sources and their hourly effective capacity, we form the hourly supply curve by ordering generators from lowest to highest marginal costs. Given the hourly electricity supply curve, assumed constant marginal cost of energy efficiency and the demand equations 19 and 20, we can calculate the hourly market clearing conditions (prices and quantities) for electricity, energy efficiency, and energy services as a whole.[32]

For the cases where we consider an intensity-standard policy or an emissions tax, we must alter our supply curves slightly. To begin, we assume the policies take place in 2020 and use the EIA's AEO 2014 projected fuel prices for ERCOT for that year, though we do

[30] Fell and Linn (2013) use must-run limits of 40 and 30 percent of capacity for coal and NGCC plants, respectfully. Upon examination of the actual hourly generation data for 2013, the 30 percent must-run constraint appears too strict. We therefore reduced it to 15 percent, which is approximately the fifth percentile capacity factor among NGCC plants in ERCOT, conditioned on those plants having positive generation.

[31] Modeling all wind farms as a single generator abstracts from local concentrations of wind generation and resulting local transmission congestion - modeling transmission constraint issues is beyond the scope of this simulation exercise. Additionally, generation from solar plants are excluded as they make up a very small fraction of generation in ERCOT.

[32] The simulation technique used here does assume hourly energy efficiency decisions. This, in many instances, is a more flexible form of energy efficiency updating than is likely possible for many technologies. However, more restrictive energy efficiency updating forms also impose some assumptions that may not be relevant, so we opt for the most flexible form for our framework.

assume that generation capacity remains fixed.[33] We also assume that policies are designed to achieve a fixed percentage reduction relative to the baseline "no policy" case. That is the intensity standard and tax are set to achieve a common level of emissions reductions, which allows for a more apples-to-apples efficiency comparison.

For the standards model with energy efficiency crediting, we assume a simple linear crediting function such that $f(\theta) = \kappa\theta$ where $\kappa \geq 0$. Given this assumption about energy efficiency crediting the effective emissions rate is calculated:

$$I = \frac{\sum_{h=1}^{H} \sum_{i=1}^{N} \gamma_i Q_{ih}}{\sum_{h=1}^{H} \sum_{i=1}^{N} Q_{ih} + \sum_{h=1}^{H} \kappa\theta_h} = \frac{Emissions}{Q + \kappa\theta} \tag{37}$$

In practice, emission standard compliance will be achieved via a "tradable performance standard" (TPS) system, whereby generators with emission rates above the standard will purchase credits from generators with below-standard emission rates. Associated with this resulting TPS market is a price for the credits, represented as μ in the analytic modeling above. This price for credits affects the marginal costs of generators, such that $c_i = hr_i P_i^f + VOM_i + \mu(\gamma_i - I)$ and the effective price of energy efficiency such that $P_{\theta h}^{TPS} \equiv P_{\theta}^{TPS} = c_\theta - \kappa\mu I$.[34] To find the emissions standard that achieves the target emissions level, we use an iterative search process. The process begins by giving the dispatch with energy efficiency

[33] The first interim policy goals for the CPP take place between 2020 - 2030, so we opted for 2020 as the year the policy takes effect. AEO 2014 projections for the Texas region do show some expansion in renewable and NGCC generation capacity in a reference case that does not include the CPP. Capacity of the remaining generating sources remained relatively flat from 2013 - 2020. Given this and the added complexity, both computationally and in terms of interpreting results, we do not include a capacity expansion component to our model.

[34] We assume an emissions intensity for natural gas as 116.9 lbs/MMbtu and for coal of 210.6lbs/MMBtu based on EPA calculated averages given at `http://www.epa.gov/cleanenergy/energy-resources/refs.html`.

model a certain emissions standard. The model then searches for a TPS credit price, μ, that makes the standard just binding. The model then compares the emissions from the binding standard to the target level and continues to feed the model values of the standard until the difference between the binding-standard emissions meets that of the target.[35]

Finding the emissions tax, τ, that leads to an emissions level that hits the target is done in a similar, though somewhat simpler manner. The tax also alters the marginal cost of generators, such that $c_i = hr_i * P^f + VOM_i + \tau\gamma_i$.[36] The search is again set up as a minimization problem where the solver finds the tax rate that minimizes the difference between the resulting emissions under the tax and the target emission level.

C Sensitivity Analysis Results Summary

Below are the tables giving more details on the outputs from the sensitivity analyses. At the top of each table is the variable that was altered in the analysis. All other variables not listed otherwise are those given in Table 1. Note also that Figures 1 and 2 contain three plots for each parameter sensitivity analysis. The middle parameter value in each of these analyses is simply the reference case results. A summary of the outputs from the reference case is given in Table 2.

[35] This is operationalized as a minimization problem, minimizing the difference in emissions from the binding standard and the emissions target, in Matlab using the solver "fminunc". We use a similar process for the minimization problem to find the emissions tax rate.
[36] Note that the emissions tax also indirectly affects energy efficiency through the price of electricity.

Table C.1: α Sensitivity

$\alpha = 0.8$

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.449	1.273	1.294	1.354	1.469	1.560	1.606
$(C/A)^{TPS}$	6.40	5.63	5.72	5.98	6.49	6.89	7.10
μ	18.58	16.32	14.36	12.62	11.33	10.33	9.54
I	1060	1055	1027	987	944	902	862
ES^{TPS}	2201.5	2209.1	2214.6	2218.3	2220.9	2222.7	2224.0
Q^{TPS}	237.7	233.5	230.4	228.5	227.4	226.6	226.0
θ^{TPS}	3048.7	3063.3	3074.0	3081.1	3085.9	3089.4	3091.9
Avg P_E^{TPS}	39.46	38.54	37.87	37.42	37.09	36.86	36.68
Tax: $(C/A)^{Tax} = 4.42$, $\tau = 8.87$, $ES = 2201.1$, $Q = 226.4$, $\theta = 3057.7$, Avg$P_E = 40.46$							
Baseline : $ES = 2202.0$, $Q = 259.6$, $\theta = 3036.7$, Avg$P_E = 37.25$, $CO_2 = 157.5$							

$\alpha = 0.2$

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.156	1.126	1.104	1.090	1.082	1.089	1.116
$(C/A)^{TPS}$	20.09	19.57	19.19	18.94	18.80	18.92	19.40
μ	30.64	29.81	28.95	28.39	27.59	26.77	26.06
I	971	973	974	972	968	961	950
ES^{TPS}	213.6	213.8	214.1	214.3	214.5	214.6	214.8
Q^{TPS}	298.2	296.8	295.4	293.8	292.1	290.4	288.7
θ^{TPS}	15.8	17.4	19.0	21.0	23.0	25.2	27.6
Avg P_E^{TPS}	44.11	43.74	43.37	43.09	42.79	42.53	42.34
Tax: $(C/A)^{Tax} = 17.38$, $\tau = 25.07$, $ES = 209.4$, $Q = 285.3$, $\theta = 22.1$, Avg$P_E = 54.20$							
Baseline : $ES = 215.0$, $Q = 302.0$, $\theta = 14.4$, Avg$P_E = 41.37$, $CO_2 = 180.9$							

Notes: "Tax" and "Baseline" values are for the tax policy and baseline case with no policy, respectively, and are constant across all κ values. Remaining values are for the TPS policy. "Cost Ratio" gives the ratio of $(C/A)^{TPS}$ to $(C/A)^{Tax}$. μ and τ are in \$/tCO_2. ES values are in millions of ES units. Q and θ values are in million MWhs. Avg. P_E values give the quantity weighted average electricity prices in \$/MWh. In the "Baseline" row, "CO_2" gives emissions in million tCO_2 and the emissions of the policies are 20% below that value.

Table C.2: σ Sensitivity

$\sigma = 0.8$

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.277	1.191	1.139	1.119	1.114	1.121	1.159
$(C/A)^{TPS}$	16.78	15.65	14.97	14.71	14.64	14.73	15.23
μ	26.90	25.73	24.52	23.60	22.84	22.02	21.33
I	991	997	996	991	980	964	943
ES^{TPS}	231.6	232.3	233.0	233.5	234.1	234.5	234.9
Q^{TPS}	280.4	277.2	274.3	271.2	268.2	265.3	262.7
θ^{TPS}	177.0	180.8	184.6	188.5	192.5	196.2	199.7
Avg P_E^{TPS}	42.15	41.61	41.14	40.81	40.56	40.37	40.25
Tax: $(C/A)^{Tax} = 13.14$, $\tau = 21.01$, $ES = 229.3$, $Q = 261.2$, $\theta = 189.8$, Avg$P_E = 50.15$							
Baseline : $ES = 232.4$, $Q = 287.7$, $\theta = 173.3$, Avg$P_E = 39.83$, CO_2 =173.6							

$\sigma = 3.2$

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.389	1.274	1.188	1.125	1.117	1.113	1.136
$(C/A)^{TPS}$	17.10	15.68	14.62	13.84	13.75	13.70	13.99
μ	26.74	25.21	23.75	22.58	21.37	20.36	19.30
I	992	1001	1004	1000	988	970	947
ES^{TPS}	201.3	201.9	202.4	202.8	203.2	203.5	203.7
Q^{TPS}	282.5	278.4	274.0	269.2	264.9	260.4	256.7
θ^{TPS}	140.4	145.0	149.9	155.1	160.1	165.2	169.4
Avg P_E^{TPS}	43.13	42.35	41.69	41.19	40.80	40.52	40.33
Tax: $(C/A)^{Tax} = 12.31$, $\tau = 19.28$, $ES = 199.2$, $Q = 256.8$, $\theta = 159.3$, Avg$P_E = 50.01$							
Baseline : $ES = 202.1$, $Q = 289.5$, $\theta = 136.5$, Avg$P_E = 41.09$, $CO_2 = 175.2$							

Notes: "Tax" and "Baseline" values are for the tax policy and baseline case with no policy, respectively, and are constant across all κ values. Remaining values are for the TPS policy. "Cost Ratio" gives the ratio of $(C/A)^{TPS}$ to $(C/A)^{Tax}$. μ and τ are in \$/tCO_2. ES values are in millions of ES units. Q and θ values are in million MWhs. Avg. P_E values give the quantity weighted average electricity prices in \$/MWh. In the "Baseline" row, "CO_2" gives emissions in million tCO_2 and the emissions of the policies are 20% below that value.

Table C.3: ϵ Sensitivity

$\epsilon = -1.0\text{E}^{-10}$

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.382	1.240	1.128	1.058	1.012	1.002	1.020
$(C/A)^{TPS}$	16.15	14.49	13.18	12.37	11.83	11.71	11.92
μ	26.94	25.03	23.45	22.09	20.95	19.81	18.69
I	993	1003	1007	1005	996	981	961
ES^{TPS}	194.8	194.8	194.8	194.8	194.8	194.8	194.8
Q^{TPS}	279.1	274.4	269.6	264.9	260.4	256.6	253.5
θ^{TPS}	107.2	111.1	115.2	119.3	123.4	127.1	130.2
Avg P_E^{TPS}	42.69	41.82	41.12	40.57	40.12	39.78	39.52
Tax: $(C/A)^{Tax} = 11.69$, $\tau = 19.57$, $ES = 194.8$, $Q = 255.9$, $\theta = 127.6$, Avg$P_E = 49.60$							
Baseline : $ES = 194.8$, $Q = 289.6$, $\theta = 85.6$, Avg$P_E = 37.49$, $CO_2 = 173.2$							

$\epsilon = -0.4$

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.484	1.380	1.323	1.330	1.341	1.386	1.441
$(C/A)^{TPS}$	12.94	12.04	11.53	11.60	11.69	12.08	12.57
μ	23.75	22.83	21.82	21.00	20.03	19.04	18.16
I	1018	1023	1020	1008	989	965	937
ES^{TPS}	181.0	182.6	184.1	185.4	186.5	187.4	188.2
Q^{TPS}	263.3	260.3	257.1	253.9	250.9	248.2	245.8
θ^{TPS}	96.7	102.1	107.5	113.1	118.2	122.6	126.5
Avg P_E^{TPS}	41.54	41.06	40.65	40.35	40.10	39.92	39.78
Tax: $(C/A)^{Tax} = 8.72$, $\tau = 17.72$, $ES = 175.5$, $Q = 240.1$, $\theta = 106.9$, Avg$P_E = 46.34$							
Baseline : $ES = 184.0$, $Q = 275.5$, $\theta = 93.0$, Avg$P_E = 39.27$, $CO_2 = 167.6$							

Notes: "Tax" and "Baseline" values are for the tax policy and baseline case with no policy, respectively, and are constant across all κ values. Remaining values are for the TPS policy. "Cost Ratio" gives the ratio of $(C/A)^{TPS}$ to $(C/A)^{Tax}$. μ and τ are in \$/tCO_2. ES values are in millions of ES units. Q and θ values are in million MWhs. Avg. P_E values give the quantity weighted average electricity prices in \$/MWh. In the "Baseline" row, "CO_2" gives emissions in million tCO_2 and the emissions of the policies are 20% below that value.

Table C.4: c_θ Sensitivity

c_θ = \$35/MWh avoided

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.474	1.255	1.118	1.109	1.115	1.165	1.220
$(C/A)^{TPS}$	14.04	11.95	10.65	10.56	10.62	11.10	11.62
μ	24.41	22.43	20.61	18.71	17.10	15.90	14.83
I	1011	1023	1020	999	968	931	893
ES^{TPS}	232.8	233.7	234.6	235.2	235.6	236.0	236.3
Q^{TPS}	268.3	261.4	254.6	249.3	245.1	241.8	239.4
θ^{TPS}	203.2	213.4	223.6	232.1	238.9	244.5	248.6
Avg P_E^{TPS}	41.89	40.86	40.09	39.54	39.14	38.84	38.63
Tax: $(C/A)^{Tax} = 9.52$, $\tau = 16.64$, $ES = 231.0$, $Q = 244.0$, $\theta = 228.8$, Avg$P_E = 47.33$							
Baseline : $ES = 233.6$, $Q = 278.8$, $\theta = 195.0$, Avg$P_E = 39.72$, $CO_2 = 169.5$							

c_θ = \$65/MWh avoided

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.364	1.290	1.211	1.152	1.115	1.101	1.093
$(C/A)^{TPS}$	16.47	15.57	14.62	13.90	13.46	13.29	13.20
μ	26.27	25.28	24.16	23.37	22.55	21.75	21.04
I	995	1001	1005	1005	1001	994	983
ES^{TPS}	169.7	170.0	170.3	170.6	170.9	171.1	171.3
Q^{TPS}	279.2	276.3	273.3	270.2	267.1	264.1	261.2
θ^{TPS}	61.9	64.2	66.6	69.1	71.6	74.1	76.6
Avg P_E^{TPS}	42.58	42.06	41.57	41.18	40.84	40.57	40.34
Tax: $(C/A)^{Tax} = 12.07$, $\tau = 19.56$, $ES = 167.7$, $Q = 256.1$, $\theta = 74.5$, Avg$P_E = 49.75$							
Baseline : $ES = 170.46$, $Q = 286.8$, $\theta = 58.7$, Avg$P_E = 40.42$, $CO_2 = 175.6$							

Notes: "Tax" and "Baseline" values are for the tax policy and baseline case with no policy, respectively, and are constant across all κ values. Remaining values are for the TPS policy. "Cost Ratio" gives the ratio of $(C/A)^{TPS}$ to $(C/A)^{Tax}$. μ and τ are in \$/tCO_2. ES values are in millions of ES units. Q and θ values are in million MWhs. Avg. P_E values give the quantity weighted average electricity prices in \$/MWh. In the "Baseline" row, "CO_2" gives emissions in million tCO_2 and the emissions of the policies are 20% below that value.

Table C.5: P_{NG} Sensitivity

$P_{NG} = \$3.17$/MMBtu

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.529	1.332	1.244	1.187	1.177	1.153	1.129
$(C/A)^{TPS}$	6.82	5.94	5.55	5.30	5.25	5.14	5.04
μ	34.56	27.30	22.93	19.89	17.61	15.83	14.33
I	923	923	918	912	904	895	886
ES^{TPS}	193.8	194.4	194.8	195.2	195.4	195.6	195.8
Q^{TPS}	312.0	309.8	308.1	306.7	305.5	304.5	303.8
θ^{TPS}	82.5	84.4	86.0	87.2	88.3	89.1	89.7
Avg P_E^{TPS}	33.87	32.91	32.28	31.83	31.51	31.26	31.06
Tax: $(C/A)^{Tax} = 4.46$, $\tau = 11.65$, $ES = 192.8$, $Q = 301.4$, $\theta = 86.1$, Avg$P_E = 36.12$							
Baseline : $ES = 195.4$, $Q = 330.4$, $\theta = 71.8$, Avg$P_E = 30.38$, $CO_2 = 180.1$							

$P_{NG} = 7.17$/MMBtu

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.585	1.282	1.134	1.104	1.154	1.188	1.218
$(C/A)^{TPS}$	20.48	16.56	14.65	14.27	14.91	15.35	15.74
μ	41.54	38.00	34.55	30.55	27.17	24.41	22.28
I	1061	1075	1070	1047	1016	982	949
ES^{TPS}	187.9	188.9	189.7	190.3	190.8	191.2	191.5
Q^{TPS}	242.3	235.5	229.4	225.6	223.7	222.6	221.9
θ^{TPS}	127.2	136.3	145.0	151.0	154.9	157.3	159.0
Avg P_E^{TPS}	51.25	49.59	48.20	47.05	46.16	45.43	44.87
Tax: $(C/A)^{Tax} = 12.92$, $\tau = 23.86$, $ES = 186.5$, $Q = 223.7$, $\theta = 145.2$, Avg$P_E = 57.3$							
Baseline : $ES = 189.2$, $Q = 258.0$, $\theta = 118.4$, Avg$P_E = 46.56$, $CO_2 = 160.6$							

Notes: "Tax" and "Baseline" values are for the tax policy and baseline case with no policy, respectively, and are constant across all κ values. Remaining values are for the TPS policy. "Cost Ratio" gives the ratio of $(C/A)^{TPS}$ to $(C/A)^{Tax}$. μ and τ are in \$/tCO_2. ES values are in millions of ES units. Q and θ values are in million MWhs. Avg. P_E values give the quantity weighted average electricity prices in \$/MWh. In the "Baseline" row, "CO_2" gives emissions in million tCO_2 and the emissions of the policies are 20% below that value.

Table C.6: Emissions Reduction Sensitivity

Reduction = 10%

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.917	1.591	1.382	1.257	1.187	1.224	1.255
$(C/A)^{TPS}$	11.97	9.94	8.63	7.85	7.41	7.64	7.83
μ	19.60	18.32	17.11	16.09	15.09	13.98	12.91
I	1099	1109	1113	1111	1104	1091	1075
ES^{TPS}	191.4	191.8	192.2	192.5	192.8	193.0	193.2
Q^{TPS}	280.6	277.1	273.7	270.4	267.5	265.4	263.8
θ^{TPS}	100.8	104.3	107.8	111.2	114.2	116.7	118.5
Avg P_E^{TPS}	40.89	40.31	39.85	39.46	39.13	38.89	38.71
Tax: $(C/A)^{Tax} = 6.24$, $\tau = 12.04$, $ES = 190.0$, $Q = 263.2$, $\theta = 112.9$, Avg$P_E = 45.33$							
Baseline : $ES = 191.8$, $Q = 284.5$, $\theta = 99.4$, Avg$P_E = 39.96$, $CO_2 = 171.3$							

Reduction = 40%

κ	0	0.2	0.4	0.6	0.8	1.0	1.2
Cost Ratio	1.157	1.119	1.084	1.077	1.072	1.074	1.077
$(C/A)^{TPS}$	20.86	20.17	19.54	19.41	19.33	19.36	19.42
μ	307.28	147.83	76.90	54.20	43.05	36.94	33.16
I	895	855	821	787	756	726	696
ES^{TPS}	186.7	192.4	192.4	192.4	192.5	192.6	192.7
Q^{TPS}	219.0	229.3	228.5	227.9	227.3	226.4	225.1
θ^{TPS}	154.6	154.5	154.1	154.5	155.1	156.3	157.9
Avg P_E^{TPS}	58.65	42.92	43.21	43.21	43.16	43.02	42.87
Tax: $(C/A)^{Tax} = 18.03$, $\tau = 37.43$, $ES = 187.2$, $Q = 225.9$, $\theta = 144.7$, Avg$P_E = 56.52$							
Baseline : $ES = 191.8$, $Q = 284.5$, $\theta = 99.4$, Avg$P_E = 39.96$, $CO_2 = 171.3$							

Notes: "Tax" and "Baseline" values are for the tax policy and baseline case with no policy, respectively, and are constant across all κ values. Remaining values are for the TPS policy. "Cost Ratio" gives the ratio of $(C/A)^{TPS}$ to $(C/A)^{Tax}$. μ and τ are in \$/tCO_2. ES values are in millions of ES units. Q and θ values are in million MWhs. Avg. P_E values give the quantity weighted average electricity prices in \$/MWh. In the "Baseline" row, "CO_2" gives emissions in million tCO_2 and the emissions of the policies are 10% below that value for the "Reduction = 10%" case and 40% below that for the "Reduction = 40%" case.