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What Happens When California Goes It Alone? Regulating GHG Emissions in an Imperfect World

Political commitment to reducing greenhouse gas (GHG) emissions varies considerably across nations and states. Regional initiatives, such as those recently instituted by the European Union, a coalition of Northeastern U.S. states, and California, are emerging in response to gridlock and policy inaction at higher levels of governance. The global nature of the climate change problem creates challenges for these regional initiatives. In particular, emissions "leakage" has become a defining issue in the design and implementation of regional climate policy.

Meredith Fowlie, an assistant professor of economics at the University of Michigan, explores the impacts of emissions leakage in her paper "Incomplete Environmental Regulation, Imperfect Competition, and Emissions Leakage" (CSEM WP 175). Environmental regulation is said to be "incomplete" when only a subset of emitters are subject to regulatory constraints. "Leakage" refers to increases in production and associated emissions among unregulated producers that occur as a direct result of incomplete environmental regulation.

Regulation passed in California in 2006 mandates a 25 percent reduction in state-wide GHG emissions by 2020. Ideally, California would regulate all electricity producers supplying the California market. However, constitutional law and jurisdictional limitations make this impossible. California policy analysts anticipate that the leakage associated with a conventional, generation-based emissions trading program for in-state producers would be substantial. Given California's heavy reliance on imported electricity, emissions leakage has the potential to significantly undermine the effectiveness of California's climate change policies as they pertain to the electricity sector. Fowlie analyzes the potential for leakage in California's wholesale electricity market.

Fowlie's paper develops a theoretical framework for analyzing emissions leakage in an incompletely regulated and imperfectly competitive industry – such as electricity – and then uses California data to assess the consequences of California-only GHG regulation. The emphasis is on understanding how incomplete market-based regulation affects firm behavior in the short run. The theoretical model shows that if the regulated firms are cleaner than their unregulated counterparts (and unregulated production can be easily substituted for regulated production), industry

CONTINUED ON PAGE 7

IN THIS ISSUE

CAN ONE POWER PLANT OPERATOR MAKE A DIFFERENCE? PAGE 2

CAN NATURAL GAS UTILITIES BE TOO CAUTIOUS ABOUT AVOIDING SERVICE FAILURES? PAGE 3

THE ECONOMICS OF SOLAR PV PAGE 4

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Can One Power Plant Operator Make a Difference? The Impact of Labor Practices in Fuel Efficiency

Jim Bushnell and Catherine Wolfram (UC Energy Institute and UC Berkeley Haas School of Business) explore the impact of labor policies on the operations of electric power plants in their paper "The Guy at the Controls: Labor Quality and Power Plant Efficiency" (CSEM WP 168). At first glance, it might seem that workers should have little scope to influence the performance of the electricity industry and that this should be particularly true of the generation sector, where costs are dominated by the capital required to build plants and the fuel required to operate them. Yet, in extensive interviews with plant managers and utility executives in the U.S. and Europe, Bushnell and Wolfram found that most expressed the belief that the individual skill and effort of key personnel could make a significant difference in the performance of the generating plant. While previous work has focused on measuring the impacts of the workers' environments (e.g., teams, compensation schemes, co-workers), the authors focus on the size of the difference in productivity across workers at "the same firm.

In the U.S., total electricity sales in 2004 were nearly $300 billion per year and in 2006 more than half of the employees in the electricity industry worked in generation. Even given the large number of employees in the generation sector, labor expenses are less than 10% of total generation costs while fuel accounts for the bulk of the expenses. For fossil-fired steam generation units, fuel accounted for about 75% of power plant operating costs in 2003. Since fuel is the dominant input into this production process, even small improvements in the efficiency at which fuel is converted into electricity can result in significant cost savings. There is widespread belief in the industry that the quality of the workforce can have a non-trivial impact on performance. In particular, the decisions of one key employee, the plant operator, can affect the efficiency with which the plant converts fuel into electricity.

The plant operator is primarily responsible for monitoring and controlling the combustion process. At more complex plants, such as coal facilities, an operator controls a number of factors that can influence fuel efficiency and emissions. Bushnell and Wolfram use data from the U.S. Environmental Protection Agency (EPA) to obtain an hourly measure of the fuel efficiency of each generation unit. A plant's heat rate (the ratio of the heat content of the fuel used per unit of electricity output) is a measure of the plant's fuel efficiency. When less fuel is needed to produce electricity, the plant's heat rate decreases which means the plant is running

TABLE 1: CHARACTERISTICS OF UNITS ANALYZED

	Plant A	Plant B	Plant C	Plant D	Plant E
Units under Operator's Control	1	2	2	7	1
Unit(s) Characteristics					
Size (MW)	950	700	700	2000	250
Primary Fuel	Coal	Gas	Gas	Gas & Oil	Gas
Year Installed	1975	1965	1965	1955-1970	1965
Operating Statistics					
Average Capacity Factor (%)	90	56	43	43	45
Starts/year	14	26	31	42	6
Efficiency (MMBtu/MWh)					
Average	8.9	10.2	10.5	11.4	10.4
Std. Dev. .	0.5	1.0	3.7	3.8	1.3
Positive Output (MW)					
Average	826	181	144	184	92
Std. Dev.	110	82	93	163	60
Outputt/Outputt-1					
Average	1.02	1.05	1.08	1.06	1.02
Std. Dev.	.85	.78	1.00	.73	.27
Combustion Optimization In Use ?	No In later periods		In-house version		
Shift Schedule Information					
Source	Operator logs	Bi-weekly schedule		Annual schedule	
Period covered	2003	2001-2003		2002-2003	
Shift length	8 hour	12 hour		12 hour	
Total operators	12 individuals	11 individuals		4 teams	
N	7,578	33,490	18,003	28,790	15,339

Note: Unit size rounded to 50MW increments, and unit installation years rounded to half-decade.

CONTINUED ON PAGE 6

Can Natural Gas Utilities Be Too Cautious About Avoiding Service Failures?

When a sudden winter cold snap spikes demand for natural gas, it isn't always easy for utilities to meet the increased demand. This is in part because the amount of natural gas that can be imported into a particular demand region is limited by the pipeline capacity in the region. New research by Severin Borenstein (UC Energy Institute and UC Berkeley Haas School of Business), Meghan Busse (UC Energy Institute and UC Berkeley Haas School of Business), and Ryan Kellogg (UC Energy Institute and UC Berkeley Agricultural and Resource Economics Department) suggests that the regulatory incentives faced by natural gas utilities may exacerbate the problem.

Incentive systems often use implicit rewards and punishments in addition to or in place of explicit outcome-based mechanisms. In such systems, the rewards depend not only on quantifiable outcomes, but also on what can be inferred about an actor or decision-maker as a result of those outcomes. One example is executives who are promoted on the basis of job evaluations. Their quantifiable accomplishments matter, but so does what their boss thinks of them on the basis of their accomplishments. In the context of regulated utilities, prudency review is an example of this sort of incentives: regulators care not only about what the outcome of a particular decision was, but they also try to infer whether the utility was prudent in making the decision. Borenstein, Busse, and Kellogg argue in their paper "Principal-agent incentives, excess caution, and market inefficiency: Evidence from utility regulation" (CSEM WP 174) that implicit incentives faced by natural gas utilities exacerbate the difficulty of obtaining gas in the forward (month-ahead) market during high demand times.

One of the chief concerns of regulators and natural gas utilities is to ensure "security of supply." Because regulated prices do not vary with market conditions – certainly not with day-to-day demand fluctuations - there is little scope for demand response during high demand periods. Further, capacity constrained pipelines mean that, on short notice, the gas that is potentially available to a utility in a particular area is limited to what it and other utilities in the area have already in storage, or have scheduled to be delivered in the near term. In the event of a short term shock to demand, such as a severe cold snap, local gas spot markets do not always succeed in allocating these limited gas supplies to those utilities with the greatest needs: transactions are impeded by physical bottlenecks and the difficulty of coordinating gas supply and transportation within a short timeframe. Utilities, with the blessing of regulators, therefore try to arrange for nearly all of their natural gas needs using the forward market.

In the forward market for gas, one would expect prices of natural gas to be high during periods when demand is expected to be high. Normally, one would anticipate that the opportunity to earn high prices would elicit offers to sell gas by those who wished to benefit from those opportunities. In the natural gas market, however, selling forward in a high demand period carries some risk: if the utility turns out to need the gas, there may not be a way to get replacement gas in the spot market, and the only alternative may be curtailment. A curtailment is something regulators – and utilities – want to avoid, both because of economic costs (such as business disruption for industrial customers) and political costs (arising from inconvenienced and cold customers complaining to elected political leaders who then demand accountability from regulatory bodies). Moreover, the harshness of regulators' treatment of the utility is likely to depend on what inference the regulator draws about why a curtailment happened. In particular, a curtailment that occurred despite a utility's best efforts to procure additional supplies would presumably incur less severe consequences than a curtailment that was more directly attributable to a mistake or misjudgment on the utility's part.

Borenstein, Busse, and Kellogg refer to attempts to avoid situations that will lead regulators to conclude that utilities made mistakes they should not have as "excess caution." They distinguish between normal caution, which would lead utilities to take the precautions against curtailment that the regulator would want, and "excess caution" which are additional precautions the utility takes that are more costly than they are worth.

In this particular context, Borenstein, Busse, and Kellogg argue that "excess caution" will make utilities reluctant to sell natural gas on the forward market when demand is high, and there is a risk that they might need the gas and be unable to re-obtain it. The reason is that having had gas and sold it and then needed it will almost certainly make them blameworthy in the regulator's

CONTINUED ON PAGE 5

The Economics of Solar PV: Do You Know How Much You Really Pay for Electricity?

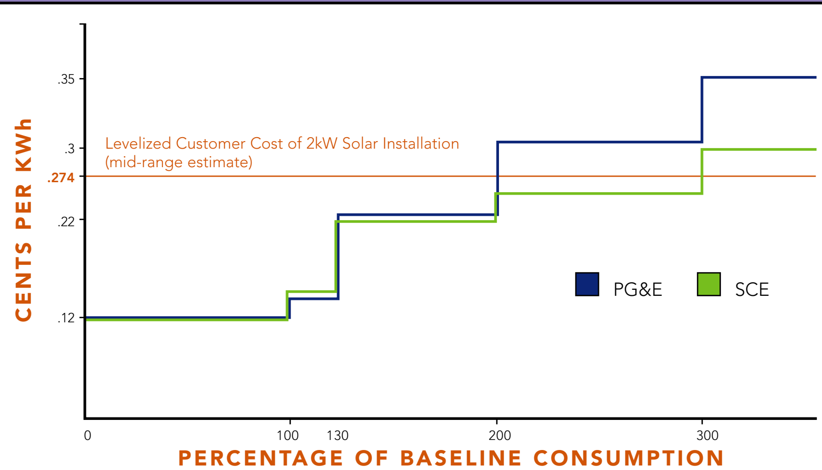
Homeowners who are thinking of installing solar photovoltaic panels on their roofs are probably thinking about the environment, but also hoping to save money. Many customers focus on the cost of installing the panels, tax credits, state rebates, and how much electricity they will generate. In CSEM working paper #172, "Electricity Rate Structures and the Economics of Solar PV," Severin Borenstein argues that one of the most important determinants of the financial return a customer will get from solar PV is the retail electricity tariff the customer faces.

The critical role of the retail tariff was highlighted in May 2007 when a Los Angeles Times newspaper article reported that the California Solar Initiative (CSI), commonly called the "million solar roofs" program, was being hobbled by a requirement that recipients of the solar PV subsidies go on time-of-use (TOU) rates. TOU rates charge higher prices for electricity at peak demand times (primarily weekday summer afternoons in California) and lower prices at off-peak times than the flat-rate tariff, which imposes the same price for a kilowatt-hour (kWh) of electricity at all times. Most small commercial and virtually all residential customers in California are on flat-rate tariffs.

The TOU tariff was thought by many to be a benefit to customers installing solar PV, because the output from the solar systems is greater during the times that rates are high under the TOU plan. But the newspaper article, and some installers of solar PV, argued that many customers were being deterred from adopting the panels because they believed that the TOU pricing would actually reduce the financial benefits they got from the solar installation.

To study the effect of TOU versus flat-rate pricing on the incentives to install solar PV, Borenstein examined the hourly household consumption from a sample of 274 medium- to high-use residential customers of Pacific Gas & Electric (PG&E) and Southern California Edison (SCE). In constructing actual and hypothetical bills for these customers under different retail tariffs, however, it became apparent that the TOU effect was being confounded with the multi-tiered (also known as "increasing-block") retail price structures that the utilities use. Under their standard residential rates, the utilities charge a comparatively low price for a "baseline" level of consumption during a billing period. If a customer consumes more than the baseline level, additional kilowatt-hours are charged at a higher price. PG&E and SCE each have 5-tier structures, with the price for incremental power consumption going up as the customer consumes more during the billing period. The change in rates is quite significant: under its most recently filed tariff, PG&E charges about 12 cents per kWh for consumption on the lowest tier, and about 35 cents for consumption on the highest tier (which covers all consumption more than three times baseline level).

PG&E AND SCE RESIDENTIAL ELECTRICITY RATES AS OF JANUARY 1, 2008



Clearly, Borenstein argues, the household's financial benefit to installing solar PV will depend upon the price of the power that is being replaced by electricity from the solar panels. If the customer was consuming a lot of electricity, then his marginal price might be as high as 35 cents. The economic gain to replacing that with power from solar panels will be substantially higher than if the household consumes very little electricity and faces an electricity price of only 12 or 13 cents per kwh.
The comparison of rates is further complicated by the fact that the tiering may be applied differently to different retail tariffs. For instance, PG&E has a five-tier rate structure for both its standard residential tariff and for the TOU tariff that was used by customers installing solar PV. SCE,

CONTINUED ON PAGE 5

however, uses a five-tier rate structure for its standard residential tariff, but no tiering at all for its TOU tariff.

Borenstein calculates bills for each customer in the sample under the standard residential tariff and the alternative TOU tariff, both assuming that the customer has no solar PV installation and assuming a typical 2kW installation. He concludes that about 95% of the PG&E customers in the sample would be better off under a TOU tariff than under a flat-rate tariff after installing the solar PV system.

For SCE customers, however, he finds that the share is much greater: over half of the customers studied would be worse off on one of SCE's TOU tariffs than under its residential flat rate. But the reason has less to do with the time-varying property of the TOU tariff than with the fact that SCE's standard residential rate has a five-tier structure, but its TOU rate does not. Its TOU rate varies by peak and off-peak periods, but it does not increase as a customer consumes more within a billing period. As a result, most high-use SCE customers would reduce their bills by going on the TOU tariff regardless of whether they install solar PV, and most lower-use customers would see their bills increase with a switch to TOU, with or without a solar PV system. Imposition of a TOU rate for customers who install solar PV does not make solar PV uneconomic for most customers.

Having calculated the potential bill savings from installing solar PV under each of the tariff options, Borenstein then analyzes the economic costs and benefits for these customers, accounting for tax credits and rebates, as well as the timing of expenditures and savings. Estimates of savings depend crucially on assumptions about the future level and structure of retail electricity prices. On the assumption that rates and rate structures remain at current inflation-adjusted levels, he finds that roughly one-quarter to one-half of the PG&E customers in the sample would benefit financially from installing solar PV. Under the same assumption, however, none of the SCE customers in the sample would benefit. At current electricity rates, solar PV is not cost effective for SCE customers.

Borenstein then argues that even high-use PG&E customers installing solar PV — the customers he calculates are most likely to save money — are placing a bet that the steeply tiered rate structure currently in place will continue, so that the power the solar panels produce will be replacing power for which the customer would otherwise have had to pay 30 cents or more. If the utilities were to return to a much less steeply tiered rate schedule, similar to the structure that it had prior to the 2000-01 California electricity crisis, the solar panels would be replacing power that would otherwise cost the customer 16-18 cents and the customer would end up losing money on the investment.

Given the complexity of the utilities' electricity rate structures, most ratepayers probably don't really understand what they are actually paying for their electricity. But understanding their current electricity costs is a crucial component in calculating whether installing solar panels can save you money. Borenstein's research suggests that only a small subset of California ratepayers could benefit economically from installing solar PV and even those ratepayers are counting on the continuance of the steep rate structure that exists today.

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CAN NATURAL GAS UTILITIES BE TOO CAUTIOUS ABOUT AVOIDING SERVICE FAILURES?

CONTINUED FROM PAGE 3

eyes. Utility executives confided to the authors that they prefer to avoid a situation in which they had sold gas reserves that could have been used later to avert or mitigate a curtailment. Not only would these circumstances appear to the ratepaying public as (at best) a lack of foresight or (at worst) profiteering, but it virtually guarantees that the regulator will not infer that the utility was doing its best to avert the disaster.

Borenstein, Busse, and Kellogg show that this excess caution distorts forward markets for gas. First, forward prices for natural gas exceed spot prices for natural gas when spot markets are expected to be tight, but not during other time periods. Second, the volume of transactions in the forward market shrinks during high demand periods. Both of these effects result from the reluctance of potential sellers of natural gas to actually sell their reserves in forward markets, despite the fact that they could sell it at high prices.

In addition to better understanding prices in natural gas markets, there is a larger implication of the study. It is during high demand periods that trade has the potential to be the most valuable, because potential buyers want to buy in order to prevent curtailments. In contrast, buying during low demand periods is more likely to be for reasons (such as restocking shortage) for which failure to buy will have much less costly consequences. The authors show is that the market dries up at precisely the time when access to the market would be most valuable. Sellers are unwilling to sell during the times when buyers desperately need to find a seller, an unintended market inefficiency brought about by implicit regulatory incentives.

CSEMRR

CAN ONE POWER PLANT OPERATOR MAKE A DIFFERENCE?

CONTINUED FROM PAGE 2

more efficiently with respect to fuel. They combine these data with information on workers' shifts provided by several power companies. The key characteristics of the plants are described in Table 1. Although by no means a comprehensive sample of U.S. generation technology, the plants do represent some of the standard technologies in use in the U.S. today.

Bushnell and Wolfram's efficiency estimates for Plant A, a large coal plant in the South, suggest that the best operator achieved an average heat rate that was more then 3% lower than the average heat rate achieved by the worst operator. To gain perspective on the magnitudes of the estimated effects, consider that if every operator were able to achieve the same average heat rate as the best operator, the unit would save approximately $3.5 million in fuel costs each year. These savings are no doubt considerably larger than the annual payroll costs for operators. Plant B, a gas plant with two units in the West, had a smaller range of operator effects than Plant A. At Plant B, the most efficient operator was only 1.9% better than the least efficient operator. The authors spoke with engineers from both coal and gas plants who suggested that operator decisions are likely to have more impact on efficiency at coal plants than at other fossil-fired plants.

Estimates from Plants C, D and E were small and not significant. Plants C and E only have natural gas-fired units, while Plant D is a large plant with seven natural gas or oil-fired units. Overall, the results suggest that there were no discernable differences between the four shifts at any of these plants. One factor may be that the plants were operating an in-house software program that automated many of the decisions made by the plant operators. Also, the authors received much less precise information on shifts for these plants.

Aggregate employment statistics suggest a pronounced reduction in power plant employment throughout the U.S. over the last 10-15 years. These reductions are most pronounced in areas actively pursuing some form of deregulation. The largest reductions overall seem to be plants divested from regulated utilities to non-utility operators. The reduction in employment has coincided, at least in restructured states, with a declining influence of unions and increasingly flexible work rules. According to managers at some plants, wage levels have in many cases risen as the number of employees has been reduced and responsibilities expanded. Despite these broad trends that indicate increasing productivity at power plants in liberalized electricity markets, Bushnell and Wolfram found little management focus on the quality of specific employees.

Bushnell and Wolfram did learn of some efforts to link bonuses to plant performance and one specific effort to link employee pay to the efficiency of the plant. Unfortunately, the one attempt turned counter-productive. The incentive scheme was based upon the relative performance of shifts and operators quickly discovered that degrading the performance of other shifts could be as rewarding as an increase in their own efficiency. It appeared that there were more and easier options for sabotaging other shifts than for improving their own performance.

There is a more recent trend though to adopt automated combustion optimization software and systems. In theory such systems should reduce the disparities between operator's performances. However, the goal of these systems appears to be aimed more at reducing emissions rather than improving fuel efficiency.

It is worth noting that market incentives have only recently been introduced into the industry. The process of regulatory restructuring is less than a decade old in most of the world, and this is a relatively short time in an historically slow-moving industry. It remains to be seen whether firms facing more exposure to market incentives will prove to be more adept at taking advantage of operator effects, or whether such effects are an immutable characteristic of the power generation business.

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WHAT HAPPENS WHEN CALIFONIA GOES IT ALONE?

CONTINUED FROM FRONT PAGE

emissions will exceed the emissions that would have occurred under complete regulation. Conversely, if regulated firms are dirtier than their unregulated rivals, industry emissions could be lower under incomplete regulation as compared to complete regulation. Furthermore, the more competitive the industry, the greater the effect of incomplete participation on industry emissions.

The net impact on society of incomplete regulation depends not only on the extent to which emissions leakage occurs, but also on how incomplete regulation reallocates production among different electricity producers. If the regulated firms are less efficient in producing electricity than the exempt firms, then incomplete environmental regulation could mitigate the pre-existing production inefficiencies by allocating more electricity production to the more efficient unregulated firms.

Using detailed data from California and surrounding states (Arizona, Nevada, New Mexico, Oregon, Utah and Washington), Fowlie analyzes three regulatory scenarios: 1) No regulation of GHG emissions (the baseline case), 2) All generators - California and the surrounding states - must purchase permits to offset emissions (the complete regulation case), and 3) Only California generators must purchase permits (the incomplete regulation case). She compares the results to actual 2004 emissions levels and wholesale electricity prices. The benchmark model that incorporates a forward contract market closely replicates observed prices and emissions in 2004 although it, like the other models, over predicts the level of emissions from out-of-state producers. Table 1 gives a summary of the simulation results under each of these three scenarios and under two different permit prices - $10 and $25 per ton of CO2 emissions. A permit price of $10/ton is associated with emissions reductions on the order of 4 percent under complete regulation and only 1.5 percent under incomplete regulation. If the permit price is $25 per ton of CO2, then complete regulation delivers emissions reduction of roughly 9 percent and incomplete regulation of only 3 percent. In both scenarios incomplete regulation results in fewer emissions reductions relative to complete regulation. In addition, the introduction of environmental regulation increases the costs of meeting California's electricity demand (net of environmental compliance costs); the market share of the relatively high cost producers increases under regulation.

TABLE 1: SUMMARY OF EQUILIBRIUM PRICES AND EMISSIONS: TWO-STAGE MODEL (price standard deviations in parentheses)

SIMULATION RESULTS	Observed	No Regulation	Complete Regulation	Incomplete Regulation
PERMIT PRICE = $10/ton				
Average California Electricity Price ($/MWh)	$46.71 ($7.12)	$45.80 ($8.61)	$59.47 ($10.05)	$55.17 ($11.18)
Emissions from generation located in California (millions of tons)	55.2*	54.6	59.2	43.4
Emissions from generation serving California load (millions of tons)	118.7**	123.5 1	116.9	120.7
Total emissions (million tons CO2)	206.4*	226.5	218.2	223.7
Leakage (million tons CO2)				8.4
Leakage as a percentage of reductions at regulated facilities				75%
PERMIT PRICE = $25/ton				
Average California Electricity Price ($/MWh)	$46.71 ($7.12)	$45.80 ($8.61)	$68.11 ($10.80)	$65.78 ($10.81)
Emissions from generation located in California (millions of tons)	55.2*	54.6	58.5	35.8
Emissions from generation serving California load (millions of tons)	118.7**	123.5	110.8	116.9
Total emissions (million tons CO2)	206.4*	226.5	205.8	220.0
Leakage (million tons CO2)				12.3
Leakage as a percentage of reductions at regulated facilities				65%

* These estimates are taken from the Energy Information Administration state profiles for 2004.
** This estimate is taken from the Inventory of California Greenhouse Gas Emission and Sinks: 1990 to 2004 (California Energy Commission, Oct. 2006). The report estimates that CO2 emissions from instate generation in 2004 were 51.85 million tons. GHG emissions from electricity imports are estimated to be approximately 66.8 million tons. Note that the CEC estimate of California's emissions is substantially less than the EIA estimate.

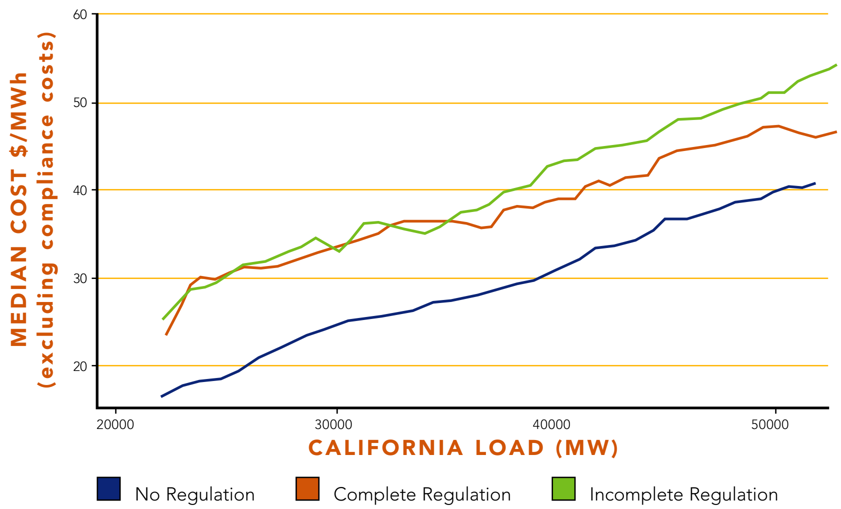
Finally, simulated costs and emission can be used to calculate the implicit cost per ton of CO2 reduced. Average costs per ton of abatement increase by almost three times under incomplete regulation compared to no regulation. Figure 1 plots the median simulated hourly operating costs of supplying California load (not including the costs of complying with the CO2 regulation) as a function of California load. This figure illustrates how the introduction of environmental regulation unambiguously increases median operating costs.

CONTINUED ON PAGE 8

WHAT HAPPENS WHEN CALIFONIA GOES IT ALONE?

CONTINUED FROM PAGE 7

FIGURE 1: PRODUCTION COSTS/MWh (Net of Compliance Costs) AS A FUNCTION OF CALIFORNIA LOAD



These three median spline functions plot median hourly operating costs (not including the costs of complying with CO2 regulations) among strategic ?rms as a function of California load.

Fowlie's results suggest that incomplete regulation exempting all out-of-state producers would achieve approximately a third of the emissions reductions achieved under complete regulation and at almost three times the cost per ton of emissions abated.

Because Fowlie's analysis is limited to simulating the short-run impacts of introducing a cap-and-trade program on production and emissions at existing facilities, it cannot address long run capital turnover decisions that are expected to deliver substantial reductions in industrial GHG emissions. However, understanding how incomplete climate change mitigation policies will affect prices and asset utilization rates in the short run is an essential first step in understanding how regulatory incentives can affect investment patterns and accelerate asset replacement decisions in the longer term. **CSEMRR**