

THREE ESSAYS  
ON ADDRESSING NEW CHALLENGES FOR ENERGY POLICY

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The three papers in this dissertation all deal with new challenges for energy policy. The first paper deals with mitigation of market power in deregulated wholesale electricity markets, while the second and third papers deal with reduction of greenhouse gas emissions.

The first paper experimentally tests a novel mechanism used to suppress the exercise of market power in New York City and neighboring West Chester. We find that this mechanism can reduce market prices. However, if generation owners have enough market power even during periods without transmission-system congestion, as may be true in some parts of the world, the owners are able to gradually raise the market price well above short-run marginal cost in spite of the mechanism. If they are not able to do this, the mechanism keeps the market price of electricity too low during times of high demand to induce adequate investment in generation and energy conservation.

The second paper simulates the Regional Greenhouse Gas Initiative, which will impose a cap-and-trade program on the carbon dioxide emissions of the electric power sector in ten northeastern US states. Constraints in the power transmission system, an alternating-current system, affect the cost of the policy and the emission increases it will induce in neighboring states and provinces. To our knowledge, this is the first study that uses an alternating-current model to predict the effects of an environmental

policy. We find that there are important differences between our simulation's predictions and those of a direct-current approximation.

The third paper examines the possibility of time inconsistency in public decision-making. In time inconsistency, an individual's preferences over a set of outcomes change as a function of only his reference point in time relative to the outcomes. We show that time inconsistency in group decisions can lead to welfare losses. Through a simple experiment and historical examples, we produce evidence that time inconsistency may exist in public decision-making, particularly when males are involved. We also discuss implications for public policy and means of reducing time inconsistency.

## BIOGRAPHICAL SKETCH

Daniel Shawhan attended high school in Maryland and Ecuador. He attended college in Iowa and Nepal, receiving his Bachelor of Arts degree in Economics from Grinnell College. At Cornell, Daniel has been a doctoral student and instructor in the Department of Applied Economics and Management.

To Ena Maxine Burdine Shawhan, in gratitude for her dedication to all of us fortunate enough to call her our mother or grandmother.

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## INTRODUCTION

The three papers in this dissertation all deal with new challenges for energy policy. Two of the most important new realities of energy are wholesale electric industry deregulation and pressure to reduce greenhouse gas emissions. The first paper deals with electric deregulation, while the second and third papers deal with reduction of greenhouse gas emissions.

Though the deregulation of wholesale electricity prices was intended largely to reduce electricity prices, it creates the possibility that power plant owners may raise prices by exercising market power. One of the main proposed responses is “automatic mitigation procedures” that reduce the offer prices of generation owners if those prices violate both a “conduct screen” and an “impact screen.” So far, in the United States, automatic mitigation procedures have been adopted only in the part of New York State that includes New York City and neighboring West Chester. In chapter 1 of this dissertation, we test the rules used in this region. We test their effectiveness at reducing prices, at keeping prices close to marginal cost, and at allowing prices during times of high demand to be high enough to induce adequate generation investment and “peak-shaving” power conservation. We also test whether they affect the extent to which generation units with higher operating cost are sometimes used in place of units with lower operating cost.

Concern about the effects of greenhouse gas emissions poses a different sort of challenge. In order to decide what policies to adopt in response to this challenge, it is useful for policymakers to know what the effects of these policies are likely to be. Incentive-based regulatory mechanisms such as cap-and-trade programs and emission fees are being considered on a massive scale, such as in large regions of the United States and at the national level in the United States. In chapter 2, we examine the

effect of an incentive-based mechanism for regulating carbon dioxide emissions from the electric power industry, using northeastern North America as our region of study. Our analysis applies equally to a cap-and-trade program or an emission fee, since either puts a price on emissions. We predict the effect of an incentive-based mechanism, with four different levels of stringency, on emissions and on the cost of operating the electricity supply system.

We make these predictions under two different scenarios, the “uniform regulation scenario” and the “regulated subregion scenario.” In the uniform regulation scenario, the price on emissions applies in the entire modeled region. This simulates a continental policy or a national policy that includes provisions to prevent effects across national boundaries. In the regulated subregion scenario, the price on emissions applies only in a part of the region, a part that corresponds approximately to the ten states participating in The Regional Greenhouse Gas Initiative (RGGI). RGGI is a cap-and-trade program that will begin limiting the aggregate carbon dioxide emissions from power plants in ten US states, starting in 2009. US federal law governing inter-state commerce makes it difficult to prevent RGGI from resulting in increased imports of power to those ten states from neighboring states. As a result, carbon dioxide emissions in the neighboring states are likely to increase. This is known as “leakage” because some emissions are shifted out of the regulated region rather than being eliminated. In the regulated subregion scenario, we predict the effect of a regional incentive-based mechanism, specifically RGGI, on leakage as well as on the cost of operating the power supply system.

Ours is not the first analysis to estimate these effects. ICF (2007) estimated them in an analysis for the governments of the RGGI states. However, ICF used a model of the power system in which the northeast is divided into regions, there is a fixed flow constraint between each pair of adjacent regions, and power flows on the

shortest path from source to point of use. In reality, a much more complex set of constraints and flow equations governs the operation of the electric power system, which is an alternating-current system. One of the most important sets of constraints is voltage constraints: voltage must be maintained within acceptable limits and more expensive plants must often be operated in order to achieve this. Furthermore, rather than flowing on the shortest or least congested path from source to point of use, power flows along multiple lines, potentially including already-congested lines, in accordance with Kirchoff's Law. The resulting constraints and flow equations affect which set of generation units satisfies electricity demand at the lowest cost in each moment. Consequently, these constraints and flow equations also play a major role in determining the effects of a carbon-dioxide emission regulation on emissions, cost, prices, fuel use, and leakage.

To more realistically model these effects, we use an alternating-current model of the electric supply system, with all of the kinds of flow equations and constraints that govern the actual system. To our knowledge, we are the first to use an alternating-current model for the purpose of estimating the effects of an environmental regulation.

Chapter 3 deals with group decision-making when the options involve costs followed by benefits. Government policy decisions regarding education, infrastructure, environmental protection, health, and the military deal with such options. Increasingly, energy policy decisions deal with such options, for two reasons. First, epidemiological studies now indicate that fine particle, ground-level ozone, and mercury pollution from fuel combustion have long-term effects on the health of those exposed. Second, there is now widespread concern about negative effects of current carbon dioxide emissions from the energy sector on people and the environment for hundreds of years into the future. Consequently, energy policy decisions that reduce

emissions at some cost in the near term appear likely to produce benefits for decades or centuries to come.

The specific phenomenon we investigate in chapter 3 is known as time inconsistency. An individual exhibits time inconsistency if his preferences over a set of outcomes change as a function of only his reference point in time relative to the outcomes. As an illustration, suppose that we could ask a person either in January or in February whether he would like to spend less and invest more in February. If he would honestly answer yes in January but no in February, in spite of there being no unanticipated change in circumstances, then this would be a case of time inconsistency.

Previous experiments have established that individuals exhibit time inconsistency in making decisions that apply only to themselves individually, but no experiment has heretofore tested with real money whether they exhibit time inconsistency in making group, majority-rule decisions, and whether the tendency for time inconsistency is attenuated in such decisions. Chapter 3 reports on an experiment that tests these hypotheses, finding that the male participants in our experiment do indeed appear to exhibit time inconsistency in group decisions, while the female participants do not. As further evidence that time inconsistency may exist in group decisions, we describe past government decision sequences in which governments have first approved a policy with costs followed by benefits, then later rejected it closer to the time of potential implementation.

This finding may have important implications for public policymaking. As chapter 3 shows, time inconsistency in group decisions can result in a loss of social welfare. Furthermore, this is not an idle observation because, as chapter 3 explains, when decision-makers are time inconsistent, there may be measures that they or others

can take to either promote or prevent a decision in favor of a policy with costs followed by benefits.

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<http://www.awm.delaware.gov/Info/Regs/Documents/0c8105de9e594764b0f417a53239be85ICFDelawareRGGIpresentation111907.pdf>. Accessed July 26, 2008.

**CHAPTER ONE:  
AN EXPERIMENTAL TEST OF NEW YORK’S NOVEL REGULATIONS ON  
WHOLESALE ELECTRICITY PRICES<sup>1</sup>**

**1. Introduction**

New York State is one of many jurisdictions around the US and the world that have a “deregulated” electricity market. However, New York City and neighboring West Chester, in the southeastern part of New York State, have few generation owners and limited power import capacity. To prevent the high prices that could result from the exercise of market power, the New York Independent System Operator (NYISO) has imposed an unusual system of price regulations on the owners of generation units in this zone of the state, which we shall often refer to simply as “NYC,” bearing in mind that we mean New York City as well as West Chester. In the latest Environmental Protection Agency information about this zone, six companies owned 95% of the generation capacity, as shown in Table 1.1.

**Table 1.1: Top Six Owners of Generation Capacity in New York City and West Chester, 2004**

<b>Company</b>	<b>Share of generation capacity</b>
KeySpan	23%
Astoria Generating Co LP	20%
Entergy Nuclear	20%
NRG Energy	14%
Power Authority of State of NY	12%
Consolidated Edison Co-NY Inc	6%

Source: Environmental Protection Agency (2007)

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New York's basic electricity market is standard for a deregulated electricity market in the United States: it uses a type of statewide, last-accepted-offer auction. As in other regions with deregulated electricity markets, this auction is a "smart market" (McCabe, Rassenti, and Smith 1991) in the sense that the "locational marginal price" of electricity can vary from one location to another because transmission constraints and losses make the marginal cost of supplying electricity to some locations greater than the marginal cost of supplying electricity to others. Furthermore, as in other deregulated electricity markets, each unit able to operate must offer to do so, and must offer to do so at some price no greater than an offer cap of \$1000 per megawatt-hour (MWh). What is unusual is that the NYISO uses an automatic mitigation procedure for electricity asking prices or "offers." The offers submitted by the generation owners are subject to a "conduct screen" and an "impact screen." If at least one offer violates the conduct screen and the offers in the market collectively violate the impact screen, the system operator replaces all offers violating the conduct screen with their "reference offers." As will be explained later, the reference offer for a unit is often based on the average of recently accepted offers from that unit during time periods without transmission congestion into or within NYC. An offer fails the conduct screen if it exceeds its corresponding reference offer by more than a specified amount that we will call the "allowable margin." The offers collectively fail the impact screen if replacement of those offers failing the conduct screen would reduce the market-clearing price by more than the amount of the allowable margin.

It is difficult to assess the performance of NYC-style regulations theoretically, even with knowledge of the generation owners and the marginal cost of each of their generation units. Since the electricity market is repeated each day by the same participants, there is a wide range of Nash equilibria (Tirole 1988 pp. 246–247).

Empirical data about NYC-area electricity offers, costs, and prices could provide another means of assessing the performance of the NYC-style regulations. However, much of these data are confidential, and the cost data within them allow only estimates of marginal cost rather than exact knowledge of marginal costs. Furthermore, these data say little about how the NYC-style regulations would perform if adopted in a different jurisdiction.

We instead use an experiment to assess the performance of the regulations. We are able to vary the design parameters and to know the exact marginal costs of generation. We test a simplified version of the NYC-style regulations in two variants of a simplified, simulated electricity market with six sellers and fixed demand. In both variants, “off-peak” periods alternate with “on-peak” periods. On-peak periods simulate transmission-system congestion by dividing the six sellers into two smaller markets with three sellers each. The two variants differ only in off-peak demand. The variant with higher off-peak demand may be taken as an “acid test” of the NYC-style mechanism, examining its performance at times or places that have high demand relative to supply even during hours without transmission congestion. This may be the case in the many parts of the world with severe shortages of generation capacity. It may also apply where congestion does not coincide exactly with high demand.

In each of the two market variants, we compare the results under the NYC-style regulations to the results under a more lax system, common in US deregulated electricity markets. This more lax system, which we refer to as the system “without NYC-style regulations,” consists only of two rules: that each unit able to operate must offer to do so, and that each unit must offer to do so at some price no greater than an offer cap of \$1000 per MWh. These are in fact a strict subset of the NYC-style regulations. We also compare the results both with and without the NYC-style

regulations to the counterfactual results that would have occurred if all generation units had submitted offers equal to variable cost.

We conclude that the NYC-style regulations can lower the average market price of electricity. The NYC-style regulations did so in both the treatment with low off-peak demand and the treatment with high off-peak demand. However, if market power is sufficiently high even during periods without transmission congestion into or within the region subject to the regulations, in our case because of high off-peak demand, market prices can still be significantly higher under NYC-style price regulations than they would be if each unit's offer equaled its marginal cost.

By design, the NYC-style regulations may keep market prices close to the marginal cost of supply. Under these regulations, “peaker” units, which have high marginal cost and consequently operate little of the time, are unlikely to be able to recover their fixed costs. Similarly, “peak-shaving” measures for reducing demand during times of high demand are less likely to be worthwhile to those who could implement them. As a result, the NYC-style regulations may prevent adequate investment in peakers and peak-shaving measures. In the absence of some other intervention to ensure adequate peakers and peak-shaving measures<sup>2</sup>, the result will be blackouts, which are very costly in terms of lost productivity.

Kiesling and Wilson (2007) and Entriken and Wan (2005) also each test an automatic mitigation procedure (AMP), but the procedures they test lack an essential characteristic of New York's AMP, which is that the reference offers can move over time. In Kiesling and Wilson's test and in Entriken and Wan's test, the reference offers are fixed. Kiesling and Wilson's experiment is interesting because it examines the effect of a type of AMP on investment in new generation capacity. Entriken and

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<sup>2</sup> New York and some other jurisdictions have such an intervention, known as the “installed capacity market.” It provides an annual payment to generators for offering their generation into the electricity market, regardless of how often they actually operate.

Wan’s simulation is interesting because it tests another kind of AMP using computer agents instead of human experiment participants. However, neither is a test of New York’s AMP. In addition, neither examines whether the mechanism changes the extent to which higher-marginal-cost units are used in place of lower-marginal-cost units.

The rest of this paper is organized as follows: Section 2 describes the regulatory regime and power generation industry in New York City and West Chester. Section 3 describes our experiment. Section 4 presents the results. Section 5 concludes.

## **2. Price Regulations in NYC and in Our Experiment**

The price regulations we examine in this paper apply to the power generation units that are located in NYC and that sell electrical energy into the NYISO wholesale electricity market. We reproduced those regulations in the experiment,<sup>3</sup> with some modifications summarized in the description below.

In NYC as in our experiment, offers are subject to a conduct screen and an impact screen. The conduct screen applies to offers individually, while the impact screen applies to the offers in NYC collectively.

An offer fails the conduct screen if it exceeds what we call a “threshold.” The threshold for each unit, each hour, is the unit’s then-current “reference offer” plus the allowable margin that applies during that minute. The allowable margin depends on whether there is or is not currently transmission congestion into or within NYC. In minutes when there is, the NYISO sets the allowable margin at a number between \$3 and \$24, depending on the time of year. We use an allowable margin of \$13 during the on-peak rounds in our experiment, since they represent the market when there is

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<sup>3</sup> Materials available by emailing shawhd@rpi.edu.

congestion. In hours when there is not congestion, the allowable margin is the lesser of \$100 or three times the unit's reference offer. We simply use \$100 in the experiment.

In the NYISO wholesale electricity market, offers are hourly in the sense that a generation owner can submit a different offer for one hour than for the next. The reference offer for each unit is updated daily and is the mean of the "eligible" hourly offers from that unit in the preceding 90 days, provided there have been at least ten eligible hourly offers within those 90 days. In the experiment, to allow reference offers to change, we instead use the mean of the last *two* eligible offers, provided there have been at least two in the last 20 rounds.

To be eligible, an offer must have been accepted in the sense that the system operator chose to purchase electricity from that unit in that hour on the basis of that offer. In addition, there must not have been transmission congestion into or within NYC during that hour, and the offers in the market, collectively, must not have failed the impact screen<sup>4</sup> during that hour. In the experiment, the no-congestion requirement is represented by a requirement that the round must be an "off-peak" round, since the off-peak rounds in the experiment represent the hours in NYC with no congestion.

If, for a particular unit, there have been at least ten hours of eligible offers during the last 90 days, then the reference offer for that unit in the real New York mechanism equals the lesser of the mean and median of the unit's eligible offers from the last 90 days. If there have been fewer than ten during the last 90 days, the reference offer instead equals the NYISO's estimate of the unit's marginal cost of generation. To permit the NYISO to produce these estimates, unit owners are periodically required to submit an accounting of their expenditures for fuel and other

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<sup>4</sup> Failing the impact screen implies that the NYISO replaced at least one offer, and vice versa. We mention this here because in the experiment instructions, we explained this criterion for an "eligible" offer in terms of offer replacement rather than in terms of failing the impact screen.

determinants of marginal cost. In the experiment, the reference offer for a unit starts at the unit's marginal cost of generation. If there have been at least two eligible offers from a particular unit during the last 20 rounds (or since the experiment began if less than 20 rounds ago), then the reference offer for that unit equals the mean of the unit's last two eligible offers. If not, then the reference offer of the unit reverts to the unit's marginal cost.

The impact screen relies on the following process: The NYISO calculates the system-wide average locational marginal price (LMP) based on the offers submitted. Then it calculates what the system-wide average LMP would be if all offers failing the conduct screen were replaced with their respective reference offers. If the former exceeds the latter by more than the allowable margin (the same allowable margin used in the conduct screen and described four paragraphs above), the offers fail the impact screen. If the offers fail the impact screen, the NYISO replaces all offers failing the conduct screen with their respective reference offers.

In addition to the screens just described, there are at least two other constraints on the offer behavior of the generation units in NYC, as mentioned in the introduction. First, each must offer to produce power equal to or greater than its claimed capacity unless it has a problem that prevents that or it is undergoing approved maintenance. In other words, no unit can "withhold" its output. The NYISO has a branch, with 30 staff, tasked with promptly visiting any unit suspected of withholding, to ensure compliance with the no-withholding regulation. Second, as is common in other deregulated electricity markets in the US, the maximum allowable offer is \$1000.

### **3. Description of Experiment**

As discussed in the introduction, we designed the experiment to test of the type of price regulation system used in NYC. We simplified the market and the regulations

somewhat so that the participants could understand and complete the experiment in under two hours. However, we sought to retain the essential features of the regulations and of electricity markets.

In the experiment, Cornell students, primarily undergraduate economics and business students, played the role of owners of generation units (or simply “units”). Each unit had a capacity of 100 MW. It produced either 100 MW or nothing, depending on whether the owner successfully sold its output in that round. The participants had to submit an offer for each unit each round, and could choose any whole-number offer price greater than \$0 but no more than \$1,000.

The experiment alternated between “off-peak” and “on-peak” rounds. Demand in all rounds was perfectly inelastic<sup>5</sup>. Compared with an on-peak round, an off-peak round combined lower demand with more competitors per market (to simulate less transmission congestion) and fewer units available to operate (to simulate the higher rate of maintenance that occurs during weeks of low demand and to keep an appropriate relationship between supply and demand).

In off-peak rounds, there were six generation owners in each market. Each generation owner controlled three units, with marginal costs of \$30, \$50, and \$80 per MW per round, respectively. In on-peak rounds, each market of six generation owners split up into two separate submarkets with three generation owners in each submarket, to simulate the effect of transmission congestion into and within NYC. However, in these two submarkets, each generation owner controlled six units, two each with marginal costs of \$30, \$50, and \$80 per MW per round. This design creates more competition among generation owners during off-peak periods, to represent the fact that there tends to be less congestion and hence more competition among generation owners during off-peak periods. We grouped each participant with the same five other

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<sup>5</sup> In reality, demand in electricity markets is not perfectly inelastic, but it is highly inelastic in the short term because most customers face a price that changes no more frequently than monthly.

participants in every off-peak round and with the same two other participants in every on-peak round, though we did not reveal who was grouped with whom.

There were four treatments, with thirty participants in each. No individual participated more than once. Two treatments were “conventional demand treatments.” In them, the ratio of demand to generation capacity was 1:2 during each off-peak round and 5:6 during each on-peak round. The other two treatments were “high off-peak demand treatments.” In them, the ratio of demand to generation capacity was 5:6 during both off-peak and on-peak rounds. However, the off-peak rounds still featured more competition because there were six generation owners in each market, compared with three generation owners in each market during the on-peak rounds. Table 1.2 summarizes the types of rounds in both the conventional demand and high off-peak demand treatments.

**Table 1.2: Types of Rounds**

<b>Type of round</b>	<b>Units available to each generation owner (each unit has capacity of 100 MW)</b>	<b>Total generation capacity per group of 6 generation owners</b>	<b>Demand (perfectly inelastic)</b>
Off-peak rounds in conventional demand treatments	3 units, with marginal generation costs of \$30, \$50, and \$80, respectively	6 owners x 3 units x 100 MW = 1,800 MW	900 MW
Off-peak rounds in high off-peak demand treatments	Same as above	Same as above	1,500 MW
On-peak rounds in all treatments	6 units, 2 with each of the following marginal generation costs: \$30, \$50, \$80	2 submarkets x 3 owners x 6 units x 100 MW = 3,600 MW	3,000 MW

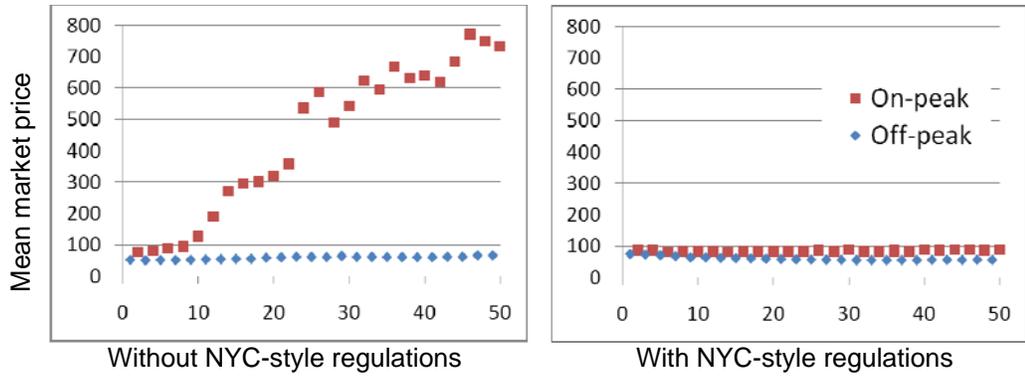
Aside from the off-peak demand, the other condition that varied between treatments was the presence or absence of NYC-style price regulations. One conventional demand treatment and one high off-peak demand treatment were “without NYC-style regulations” because the only price regulations were the rule against withholding and a \$1000 cap on offers. The other two treatments were “with NYC-style regulations” because the rest of the NYC-style price regulations, specifically AMP, also applied. In summary, we used a two-by-two design in which the two conditions we varied were off-peak demand and price regulations.

The participants earned a small fraction of a real dollar for each dollar of experimental earnings. We set the exchange rate for each treatment to equal our *a priori* guess at the exchange rate that would produce mean US dollar earnings of \$25 per participant in that treatment. Though we did not tell the participants until after the end of the fiftieth round, the experiment lasted 50 rounds.

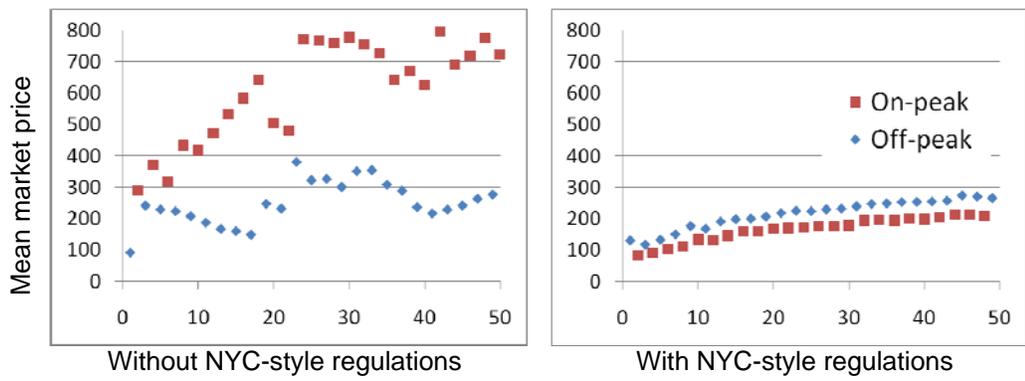
#### **4. Results**

We base our inferences on the mean market prices in rounds 31–49. As one can see from inspecting the plots in Figures 1.1 and 1.2, the market prices in some treatments had a trend. We submit that the results in the rounds toward the end of the experiment, such as rounds 31–49, are the best indicator we have of what the prices would be in a setting of indefinite repetition, as in real electricity markets.

For statistical testing, we use the round 31–49 means in each group of six participants, shown in Tables 1.3 and 1.4. We use one-tailed Wilcoxon rank sum tests. We use these non-parametric tests rather than t-tests because the group means may not be normally distributed.



**Figure 1.1: Mean Market Price by Round, Conventional Demand Treatments**



**Figure 1.2: Market Price by Round, High Off-Peak Demand Treatments**

**Table 1.3: Mean Price by Group, Rounds 31–49, Conventional Demand Treatments**

With NYC-style regulations			Without NYC-style regulations		
Group	Off-peak rounds	On-peak rounds	Group	Off-peak rounds	On-peak rounds
B9.1	50.3	87.1	A9.1	80.3	968.6
B9.2	50.0	82.1	A9.2	51.1	87.9
B9.3	53.4	80.5	A9.3	63.7	800.5
B9.4	78.3	92.4	A9.4	57.4	767.5
B9.5	50.5	89.7	A9.5	59.8	638.8
Mean	56.5	86.4	Mean	62.5	652.6

*Result 1: The NYC-style regulations reduced on-peak prices*

As Tables 1.3 and 1.4 show, the mean on-peak price with NYC-style price regulations is lower than the on-peak price without NYC-style price regulations. This is true in both the conventional demand treatments and the high off-peak demand treatments. The NYC-style regulations reduced the mean on-peak price from \$653 to \$86 in the conventional demand treatments and from \$714 to \$200 in the high off-peak demand treatments. Both differences are significant at better than the 95% confidence level. We conclude that the NYC-style regulations reduced the prices during on-peak rounds.

**Table 1.4: Mean Price by Group, Rounds 31–49, High Off-Peak Demand Treatments**

With NYC-style regulations			Without NYC-style regulations		
Group	Off-peak rounds	On-peak rounds	Group	Off-peak rounds	On-peak rounds
B15.1	166.8	129.1	A15.1	107.5	496.4
B15.2	574.4	484.0	A15.2	365.4	693.8
B15.3	344.9	209.4	A15.3	304.7	693.7
B15.4	115.7	98.3	A15.4	165.1	953.3
B15.5	80.5	81.3	A15.5	443.1	750.2
Mean	256.5	200.4	Mean	277.2	717.4

*Result 2: The NYC-style regulations did not significantly change off-peak prices*

There are reasons to believe that the NYC-style price regulations could raise or lower the mean prices in off-peak rounds. First, they could conceivably lower the mean prices. In the off-peak rounds, the NYC-style regulations prevent offers from being accepted if those offers are more than \$100 higher than the corresponding reference offers and if they also increase the market price by more than \$100 over the

market price that would prevail if all offers equaled their corresponding reference offers. As a result, the NYC-style regulations cap the rate of increase of off-peak prices and they limit the potential effect of high, speculative offers on the price in a given round.

Second, the NYC-style regulations could instead increase the mean prices in off-peak rounds. The maximum prices during *on*-peak rounds are limited by the reference offers, which in turn are based on the recent offers during off-peak rounds. To raise the maximum prices possible during on-peak rounds, participants must get higher offers accepted during off-peak periods. As a result, the desire for higher on-peak prices creates an incentive for raising offers during off-peak rounds.

Instead of significantly raising or lowering off-peak prices, the NYC-style regulations had no significant effect on the mean of off-peak prices. The mean off-peak price was slightly lower under the NYC-style price regulations in both the conventional demand treatments and the high off-peak demand treatments, but in neither case was the difference close to being statistically significant at conventional levels.

*Result 3: The NYC-style regulations may not keep prices close to marginal cost in some circumstances*

If every offer from every unit equaled the short-run marginal cost of generation from that unit, then the market prices would be \$50 in the off-peak rounds of the conventional load treatments, \$80 in the on-peak rounds of those treatments, and \$80 in both kinds of rounds in the high off-peak demand treatments. We will call these levels “marginal cost.” Under the conventional load treatments, the NYC-style price regulations kept the mean market price from rising more than \$6.50 above marginal cost in both the off-peak and on-peak rounds. However, in the high off-peak demand

treatments, the mean price was \$176.5 above marginal cost in the off-peak rounds and \$120.4 above marginal cost in the on-peak rounds.<sup>6</sup> These mean margins above marginal cost are larger than those under the conventional load treatments, with a confidence level greater than 95%. We conclude that if generation owners have enough market power during the periods when the reference prices are being set (off-peak rounds in the case of our experiment), they can raise prices well above the marginal cost of generation in spite of the NYC-style price regulations.

*Result 4: The NYC-style regulations may keep on-peak prices too low to incentivize the efficient quantity of peaker generation units and “peak-shaving” conservation*

Power generation units are costly to build and install. In order to recover its investment cost from sales of electricity, a generation unit must, when it operates, earn an average price that is higher by some margin than its short-run marginal cost. The higher the short-run marginal cost of generation at a particular unit, the less often the market price of electricity will be high enough to justify operating that unit. The less a unit is used, the greater is the average margin it must earn above its short-run marginal cost of generation. For example, a peaker may have a levelized capital cost of \$80,000 per MW per year at the owner’s cost of capital and a short-run marginal generation cost of \$60 per MWh (Mount, 2007). If this peaker operates 5% of the time (or 438 hours per year), it must earn an average of \$182 per MWh more than its short-run marginal generation cost. As a result, in order for all units be profitable based on energy sales, including the least-used units, the price must be far above marginal cost at least during times of extremely high demand, when even the least-

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<sup>6</sup> The higher price in off-peak than on-peak rounds can be explained by the higher allowable margin during off-peak rounds, combined with a desire by participants to raise their reference offers. If the experiment had been long enough for offer to stabilize, we would expect on-peak prices to be higher than off-peak prices, though not by much because of the small allowable margin that applies during on-peak rounds.

used units can profit from these extremely high scarcity prices. However, the NYC-style regulations cap the market price at the reference price of the marginal unit (when units are ranked from lowest to highest reference price) plus the allowable margin. During times of high demand, there tends to be congestion into or within New York City and West Chester. As mentioned earlier, when there is congestion, the allowable margin is between \$3 and \$24. For additional units that may be needed to prevent blackouts at times of high demand, this allowable margin is too small to enable the additional units to recoup their first costs if peakers are unable to raise their reference offers. In the absence of some other prospective earnings that appear likely to make building the units profitable, profit-seeking entities will not build the units. Similarly, fewer “peak-shaving” measures that reduce on-peak electricity demand will be profitable if the NYC-style price regulations suppress on-peak prices. As a result, the quantity of peakers and peak-shaving measures may be insufficient to prevent blackouts. It may also be below the socially optimal quantity. Alternatively, generation owners may be able to raise the reference offers of their peakers so that they are able to charge prices high enough to recover their first costs and so that a more extensive set of peak-shaving investments is profitable. Our experiment is one test of the extent to which generation owners are able to raise the reference offers of their peakers under NYC-style price regulations.

In the experiment, under the conventional load treatments, the participants earned a mean of only \$86.50 per MW sold during on-peak rounds. The highest mean in any group was \$92.40. Since the marginal cost of generation was \$80, this indicates that generation owners were able to raise the reference offers of their peakers very little under the conventional load treatments. We conclude that in the absence of some intervention to make the expected profits of peakers or peak-shaving

conservation profitable, the NYC-style regulations may lead to an inefficiently low quantity of both.

*Result 5: The NYC-style regulations did not significantly change the excess cost from out-of-merit-order use of generation units*

The peakers in the experiment were the units with an \$80 short-run marginal cost of generation. The NYC-style price regulations create an incentive for generation owners to get offers from peakers accepted during off-peak rounds. This is the only way to raise the peakers' reference offers, since those reference offers are based on offers accepted during off-peak rounds. As a result, the NYC-style price regulations could cause generation owners to sell power from peakers in place of power from lower-marginal-cost units. This is known as using generation units "out of merit order." It results in a loss of economic surplus, as a producer is incurring a higher cost than necessary to produce the good.

Table 1.5 shows the ratio of actual generation cost to minimum generation cost, by group. Using Wilcoxon rank sum tests, the NYC-style price regulations did not significantly change the excess cost from out-of-merit-order use of units in either the conventional demand treatment or the high off-peak demand treatment.

## **5. Conclusion**

Our experiment tests the effects of the wholesale electricity price regulations used in New York City and West Chester, an area with few generation owners and limited power import capacity. These regulations may be considered elsewhere, particularly in other areas subject to concerns about the influential exercise of market power by owners of power generation units.

**Table 1.5: Mean Cost of Generation, as a Ratio of Minimum Possible Cost, Rounds 31–48**

Conventional demand treatments				High off-peak demand treatments			
With NYC-style regulations		Without NYC-style regulations		With NYC-style regulations		Without NYC-style regulations	
Group	Cost	Group	Cost	Group	Cost	Group	Cost
B9.1	1.0100	A9.1	1.0772	B15.1	1.1106	A15.1	1.0484
B9.2	1.0038	A9.2	1.0282	B15.2	1.0916	A15.2	1.0622
B9.3	1.0245	A9.3	1.0477	B15.3	1.0952	A15.3	1.0514
B9.4	1.0527	A9.4	1.0276	B15.4	1.0617	A15.4	1.0607
B9.5	1.0358	A9.5	1.0314	B15.5	1.0093	A15.5	1.0782
Mean	<b>1.0254</b>	Mean	<b>1.0424</b>	Mean	<b>1.0737</b>	Mean	<b>1.0602</b>

Under a demand pattern designed represent a conventional pattern of electricity demand (i.e. in the “conventional demand treatments”), on-peak electricity prices were significantly lower under the NYC-style regulations than without them. The mean on-peak price during rounds 31–49 was 716% above marginal cost without the NYC-style regulations, but only 8% above marginal cost when the NYC-style regulations were in place. The NYC-style regulations did not have a statistically significant effect on *off*-peak prices, which were 25% above marginal cost without the NYC-style regulations and 13% above marginal cost with them.

The on-peak prices that prevailed under the NYC-style regulations have the potential to be too low in the sense that high on-peak prices may be necessary to induce adequate investment in generation capacity and “peak-shaving” energy conservation.

We also tested the NYC-style regulations under a different demand pattern (the “high off-peak demand treatments”), in which demand remains high relative to load

even during times without transmission-system congestion. In these treatments, the NYC-style regulations did significantly reduce the mean on-peak price in rounds 31–49, from \$717 without the regulations to \$200 with them. However, the NYC-style regulations did not keep electricity prices nearly as close to marginal cost as they did under the conventional demand treatments. The mean price was 221% above marginal cost in the off-peak rounds and 150% above marginal cost in the on-peak rounds. The high off-peak market power that produced these results may apply in the many parts of the world with severe shortages of generation capacity or with very few generation owners. It may also apply where congestion does not coincide exactly with high demand so that high demand occurs at times when reference offers are being set. Our result from these treatments indicates that in such places, the NYC-style regulations may not prevent the mean price of generation from rising well above marginal cost.

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**CHAPTER TWO:  
AN ECONOMIC AND ENGINEERING ANALYSIS OF THE IMPACT OF  
CARBON DIOXIDE REGULATION ON EMISSIONS AND COSTS FROM  
ELECTRIC POWER<sup>1</sup>**

**1. Introduction**

The purpose of this study is to analyze the impacts and outcomes of carbon dioxide (CO<sub>2</sub>) regulation on the electric power industry using an integrated economic and engineering approach that incorporates a full alternating current (AC) model of transmission for northeastern North America. The reason for conducting such an integrated analysis rather than using simplified assumptions about transmission is well illustrated by the California experience where markets were designed and introduced on the assumption that transmission constraints were relatively unimportant. In fact, transmission constraints proved fatal to that market design, making the market much less competitive than economists initially assumed. Another example is the Northeast power outage that occurred in August of 2003. Markets in Ohio (unlike the rest of the Northeast) were not designed to provide incentives for generators to assist in maintaining voltage (a public good). This design flaw, which resulted from a failure to consider the requirements of an AC network, proved to be a major factor in the collapse of the system. Simply put, in a contest between physics and economics, physics wins.

This chapter is organized as follows: The second section reviews current and proposed legislation at the national and regional level for regulation of CO<sub>2</sub>. The third section presents the optimization/simulation model and network used in the analysis. The fourth section presents results from the simulation model which allows analysis of

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the effects of various CO<sub>2</sub> prices either from a cap and trade program or a carbon tax on the cost of operating the system, emissions inside the regulated region, and emissions outside the regulated region. The study shows that outcomes depend critically not only on the transmission constraints in the system but also on whether the simulation uses a simplified linear approximation (called a DC approximation since flows can be modeled by linear equations in a direct current network) or the more realistic non-linear AC network that includes constraints on voltage. These additional more complex constraints that arise in AC modeling (DC modeling ignores the fact that voltage, a public good, must be kept within bounds or equipment damage results) become especially important when the network is operated in new ways such as will occur when CO<sub>2</sub> charges change the historic mix of generation and fuel type, no longer using what was the cheapest mix of power. The prior study of the emission and price effects of RGGI (see ICF 2007) used a simplified representation of transmission that just constrains flows between regions—a pipeline representation. In fact, electricity flows do not behave in a manner consistent with the point-to-point pipeline analogy. Instead, power from a particular source flows along multiple lines, potentially including already-congested lines, in accordance with Kirchoff's Law.

A major issue that arises in attempts by various regions to independently begin control of CO<sub>2</sub>, in the absence of a national program, is the possibility of “leakage.” That is, by increasing the price of electricity in the regions where it applies, CO<sub>2</sub> regulation may increase imports of electricity from unregulated to regulated regions, either reducing the effectiveness of regulation in reducing CO<sub>2</sub> or, in the worst case, increasing total CO<sub>2</sub> emissions. Clearly, an accurate model of transmission is needed to examine this issue. Additionally, issues of cost, elasticity of demand for permits, etc., also require accurate modeling of transmission. This study represents a first step in that analysis.

## 2. Current and Proposed Legislation

This section will first describe the leading contender for US national legislation, the Lieberman-Warner Climate Security Act (LWCSA). Then, the various regional initiatives will be identified and one, the Regional Greenhouse Gas Initiative, will be described in detail since it forms the basis for part of our case study that is able to contrast regional to national legislation.

The LWCSA proposes the following greenhouse gas (GHG) reductions over time:

- By 2012: reduce to 2005 levels
- By 2020, reduce to 10% below 2005 levels
- By 2030, reduce to 30% below 2005 levels
- By 2040, reduce to 50% below 2005 levels
- By 2050, reduce to 70% below 2005 levels

These reductions will be achieved through a cap and trade program. States can adopt any standard, cap, limitation, or prohibition relating to emissions but these must be at least as stringent. The auction is scheduled to start in 2012 and the use of offsets (credits earned from emission reduction activities outside the scope of the RGGI regulations, such as tree planting or reducing emissions from a facility in another country) is limited to 15%. Additional allowances can be released in the first 2 years if problems arise. Then, borrowing is allowed only as needed to avoid significant harm to the economy.

Several studies have shown that allocating pollution permits for free results in windfall gains to polluting industries. Free distribution of permits is limited in the LWCSA to 20%, declining to 0% by 2035, in each of the following sectors:

- Electric Power
- Industrial

- Transportation

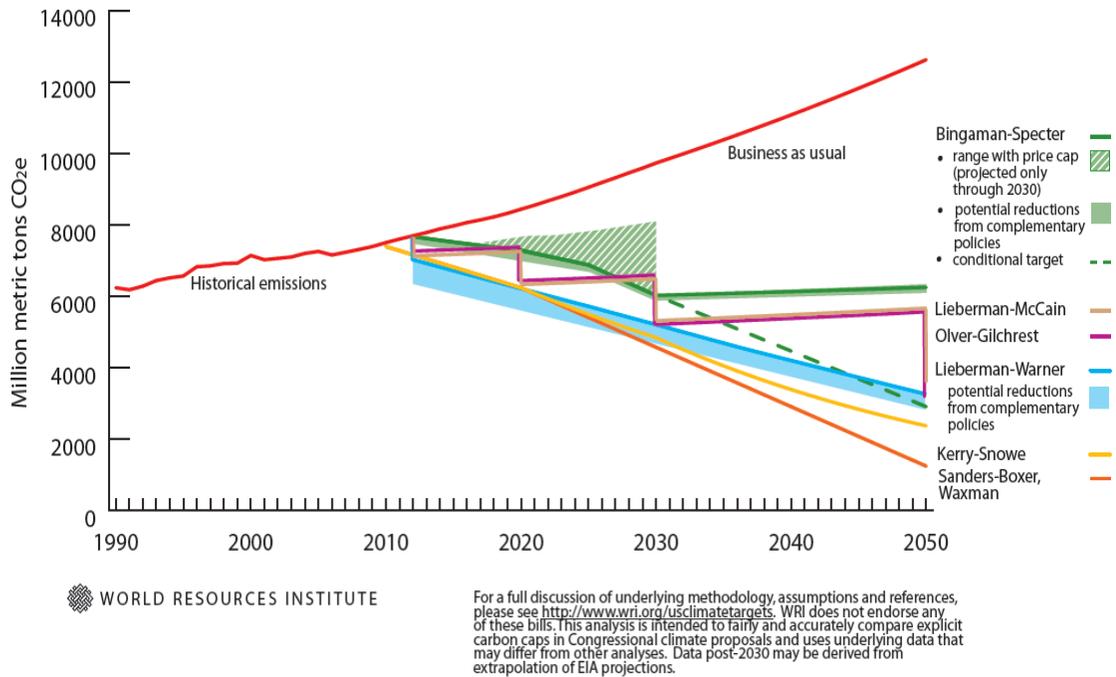
Free permits would be issued to others as follows:

- Utility distribution companies: 10%
- Regulated entities with early reductions 5% in 2012, down to 0% by 2017
- State governments: 5%

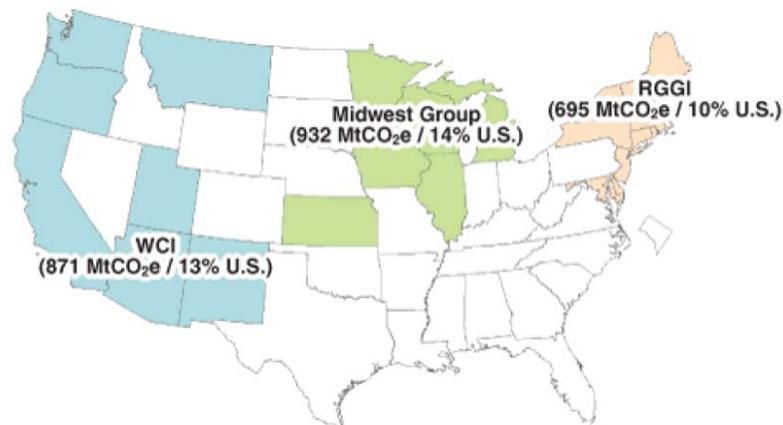
The LWCSA passed the Senate Environmental and Public Works Committee in December of 2007 on a vote of 11-8, and came to the Senate floor in June of 2008 but failed because there were insufficient votes to defeat a filibuster, falling 12 votes shy of cloture. There were also insufficient votes to defeat a threatened presidential veto. The bill is likely to be introduced again in 2009. Figure 2.1 shows how the LWCSA climate change targets compare to other proposed legislative initiatives.

In addition to this federal legislation, three regional cap and trade initiatives are underway as shown in Figure 2.2. Note that these three initiatives comprise 37 percent of US emissions. The states in the Regional Greenhouse Gas Initiative (RGGI) contain 16% of the US population (Grenfell, 2008) but emit only 10% of US GHG emissions, in part because of the RGGI region's electricity generation mix that uses relatively less coal than some other areas.

In this study we focus on the Regional Greenhouse Gas Initiative because of the availability of an existing network model that can explore many issues that have been raised concerning CO<sub>2</sub> regulation. RGGI has ten member states shown in Figure 2.3, importantly excluding Pennsylvania that has a substantial availability of coal fired generation. RGGI proposes to reduce power-sector CO<sub>2</sub> emissions 10% from the 2009 level, between 2009 and 2018. Note that it is significantly less stringent than the LWCSA.



**Figure 2.1: Comparison of Legislative Climate Change Targets in the 110th Congress, as of December 7, 2007. Source: Larsen and Heilmayr 2007.**



**RGGI = 10% of US total GHG emissions**  
**MW = 14%**  
**West = 13%**  
**TOTAL: 37%**

**Figure 2.2: Total GHG Emissions of States Participating in Prospective Regional GHG Cap and Trade Initiatives Source: Damassa, 2007. Notes from source: “GHG emission totals from Canadian Provinces participating in the Midwest Accord and WCI are not included here. MtCO<sub>2</sub>e is million metric tons of carbon dioxide equivalent per year. Percentages are of total U.S. emissions.”**



**Figure 2.3: Member States of the Regional Greenhouse Gas Initiative. Map from <http://www.awm.delaware.gov/Info/Regs/Pages/RGGI.aspx>. Accessed July 26, 2008.**

In the 2009–2014 interval, emissions will be capped at 2009 levels. From 2015–2019 the cap is reduced by 2.5% per year. Currently, 6 states plan to auction off 100% of their permits. The others are required to auction at least 25% of permits. Auction revenue will be used for consumer benefits including energy efficiency programs. A three-year compliance or “true up” period will be enforced unless the trigger price of \$10 is reached in which case this period can be extended. Offset usage is limited to 3.3% unless the trigger price reached, so that, if permits reach \$10/ton, there will be no limit on offset use.

As noted above, one of the main worries for all of the regional programs is “leakage.” As generators inside regulated areas are forced to pay for CO<sub>2</sub> permits, their prices will rise compared to the prices offered by generators outside of the

regulated region. Imports from cheaper coal fired power plants outside of RGGI states may cause emissions to increase outside of RGGI states more than emissions decrease in RGGI states. In what follows, we test this hypothesis as well as demonstrating what happens if all of the Northeastern states and provinces are regulated in a national program.

### **3. The Simulation Model and Network**

The usual approach for modeling transmission is to employ DC modeling (e.g. GE MAPS, PowerWorld, etc.) which provides a linear approximation to the actual behavior of the non-linear AC system used in the real world. There are several major deficiencies in this computationally simplified approach. First, voltage is ignored so there are no voltage constraints that must be in place for the system to operate. In managing day-to-day operation, proxy limits are employed to maintain voltage. These proxy limits are limits placed on the flow through lines in DC models that are not based on actual line capacity but are rather based on observed decreases in voltage that occur when too much flow is allowed through actual lines. This approach will not work for CO<sub>2</sub> regulation because permit prices or CO<sub>2</sub> taxes could easily alter operation of system sufficiently that existing proxy limits derived from real world experience may no longer approximate needed voltage constraints. A second factor is that the transmission prices derived from DC optimal power flows are always incorrect and may lead to mis-allocation of resources and inefficiency. In this study, MATPOWER, a full AC optimization/simulation framework developed at Cornell University, is used to study the Northeast power system's response to CO<sub>2</sub> regulation. Figure 2.4 shows the mathematical formulation of MATPOWER that is fully described at <http://www.pserc.cornell.edu/matpower/>.

The optimization problem can be expressed as follows:

$$\min_x \sum_i (f_{1i}(P_{gi}) + f_{2i}(Q_{gi}))$$

subject to

$$g_P(x) = P(\theta, V) - P_g + P_d = 0 \quad (\text{active power balance equations})$$

$$g_Q(x) = Q(\theta, V) - Q_g + Q_d = 0 \quad (\text{reactive power balance equations})$$

$$g_{S_f}(x) = |S_f(\theta, V)| - S_{\max} \leq 0 \quad (\text{apparent power flow limit of lines, from end})$$

$$g_{S_t}(x) = |S_t(\theta, V)| - S_{\max} \leq 0 \quad (\text{apparent power flow limit of lines, to end})$$

$$l \leq A \begin{bmatrix} x \\ z \end{bmatrix} \leq u \quad (\text{general linear constraints})$$

$$x_{\min} \leq x \leq x_{\max} \quad (\text{voltage and generation variable limits})$$

**Figure 2.4: The Formulation of MATPOWER**

MATPOWER minimizes the cost of operating the electric power system subject to the demands and availability of electricity at each node and the transmission capability of the lines in the system and voltage requirements. Costs of purchasing carbon permits or carbon taxes are incorporated in the optimization. The simulation works by using representative hours and solving the optimization with different CO<sub>2</sub> emission prices. The current study does not consider reliability so no contingencies are incorporated in the analysis at this stage and only existing generation is incorporated with no investment decisions at this stage of the analysis.

Figure 2.4 shows the mathematical formulation of MATPOWER. In that formulation, there are two groups of optimization variables, labeled  $x$  and  $z$ . The  $x$  variables are the optimal power flow variables, consisting of the voltage angles  $\theta$  and voltage magnitudes  $V$  at each “bus” or node in the network, and real and reactive generator injections  $P_g$  and  $Q_g$  at generators  $g = 1, 2, 3, \dots$

The transmission lines and nodes or “buses” of the physical network representation utilized in the study are shown in Figure 2.5. The network includes

only PJM-East (New Jersey, Delaware, Washington DC, and most of Pennsylvania and Maryland), New York, New England, Ontario, Quebec, and the Maritime Provinces. Allen, Lang, and Ilic (2008) developed this network representation as a simplified version of the northeast power grid, which has thousands of buses. Their simplified representation aggregates the thousands of actual buses in the Northeast into 36 buses, and specifies the electrical characteristics of those 36 buses and the aggregated lines that connect them. The simplified network is "...intended to be a test system for algorithms and software, as opposed to a study system of the Northeastern US bulk electric power system." However, it approximates thermal, voltage, and reactive power constraints of the real system and "...some of the major intra- and inter-area congestion patterns are preserved...." Ilic (2008) has reported that in comparisons between the simplified model and a detailed model of the same region, the simplified model produces results very similar to those of the detailed model. Given that no completed study of CO<sub>2</sub> regulation includes a network, with an AC or DC model, it is at least reasonable to examine the issues raised by CO<sub>2</sub> regulation using an available AC network model.

The optimization problem associated with determining the operation of an AC network has more constraints than a DC system and is non-linear and complex. Consequently, using a simplified representation of the network is necessary because it allows us to solve for the operation of the system.

Table 2.1 shows both the marginal costs and emissions characteristics of the generator types used in the pilot runs. Allen, Lang, and Ilic specify only the total quantity of gas fired generation. We assume that half of it is "efficient" and the other half "inefficient."

In what follows, results are based on a set of pilot runs that are simplistic in that only two levels of demand ("load") are considered, low and high. Demand is

assumed to be fixed, since few electricity customers face real-time electricity prices. We assume the low load two thirds of the time and the high load one third of the time. One purpose of the pilot is to see if model converges at high and low loads. The final runs, which will be presented in future publications, will have 20 or more representative load-availability combinations.

The CO<sub>2</sub> prices we consider are \$0, \$5, \$120, and \$250 per tonne. The \$120 and \$250 prices are much higher than the \$10 trigger price that allows firms to use offsets for any proportion of the RGGI emission reduction requirements, so we do not expect to see such high prices under RGGI. However, because we have not yet incorporated a detailed representation of the thousands of generators in the Northeast into the model, we do not yet have fine gradations of marginal costs and emission rates, so our model is not yet valid for estimating the effects of small changes in emission prices. Nonetheless, the use of such high emission prices still achieves most of the objectives of this study because it predicts the ceiling of emission reductions that can be expected from a change in operation of the existing Northeast power system under RGGI and provides a case study of the effect of AC versus DC modeling of environmental regulations applied to the power sector. Given the marginal costs and emission rates in Table 2.1, the \$120 price makes the short-run marginal cost of efficient gas fired generation lower than that of coal fired generation. The \$250 price makes short-run marginal cost of all gas fired generation lower than that of coal fired generation.



**Table 2.1: Marginal Costs and Emissions per MWh, Used in Our Simulation**

	<b>Marginal cost per MWh</b>	<b>Tonnes CO<sub>2</sub> per MWh</b>
Nuclear, hydro, wind, refuse	\$0	0
Coal	\$23.70	0.94
Efficient gas	\$54	0.43
Inefficient gas	\$81	0.65
Oil	\$96.30	0.93

#### **4. Simulation Results**

The right-most column of Table 2.2 shows the results of our alternating-current simulation of the effect of the Regional Greenhouse Gas Initiative on carbon dioxide emissions from the electric power sector in the modeled region. Each number in the table is a weighted average of the two representative hours that we model, one with high demand and one with low demand. At each of the three CO<sub>2</sub> emission prices we consider, \$5, \$120, and \$250, the policy reduces emissions inside the regulated region but increases emissions by a larger amount outside of the regulated region. The predicted effect of the cap-and-trade program in the RGGI CO<sub>2</sub> emission reduction policy is to actually increase CO<sub>2</sub> emissions. The policy does this by decreasing generation from natural gas inside the regulated region and increasing generation from coal outside the regulated region.

However, this analysis ignores two other components of the RGGI policy that should reduce CO<sub>2</sub> emissions. First, power plant owners in the RGGI region may satisfy some of the emission reduction requirements by purchasing offsets. Second, the states may use some of the revenues from the sale of RGGI emission permits to

fund programs that help energy customers to improve their energy efficiency and consequently to reduce their CO<sub>2</sub> emissions.

**Table 2.2: Change in Emissions as % of Emissions in RGGI, if No Charge on Imports**

CO <sub>2</sub> price		DC model	AC model
\$5	Inside RGGI	0%	-1.03%
	Outside RGGI	0%	1.07%
	Total	0%	0.04%
\$120	Inside RGGI	-13.2%	-10.9%
	Outside RGGI	23.9%	15.3%
	Total	10.7%	4.3%
\$250	Inside RGGI	-14.9%	-11.6%
	Outside RGGI	24.3%	15.5%
	Total	9.5%	3.9%

For comparison, we also present results of a simulation that is similar but uses a linear, direct-current model of the power system rather than the more realistic alternating-current model. This DC model predicts no change of emissions with a \$5 CO<sub>2</sub> price. With a \$120 or \$250 price, the DC model predicts total changes of CO<sub>2</sub> emissions that are more than twice as great as those predicted by the AC model. It appears that AC modeling can make an important difference in the results.

The voltage constraints in the AC model may be an important reason why its results differ from the results of using the DC model. In the solution in the AC simulation, the voltage constraints were binding at approximately half of the buses with low load and two thirds of the buses with high load.

Next, we predict the effect of a CO<sub>2</sub> emission tax or cap-and-trade program if it were applied to the entire region encompassed by the physical network in our simulation. Leakage is no longer possible because the entire power supply and

demand system modeled is now subject to the CO<sub>2</sub> price. As a result, this simulation is akin to a national CO<sub>2</sub> regulation, in which leakage is reduced by the imposition of a tax or a permit purchase requirement on imports from outside the country.<sup>2</sup>

Table 2.3 shows the results of our AC simulation. With a \$5 price on CO<sub>2</sub> emissions, there is a 0.5% reduction in CO<sub>2</sub> emissions, which comes at a cost of \$0.01 per tonne in terms of the cost of operating the power system. With a \$120 price, there is a 7.6% reduction in emissions, which comes at a cost of \$95 per tonne. Raising the CO<sub>2</sub> price from \$120 to \$250 has little additional effect on the predicted operation of the power system, and consequently has little additional effect on emissions or on the cost of power production.

**Table 2.3: Changes in Emissions if Regulation Applied to Whole Region, Predicted Using AC Model**

	CO <sub>2</sub> \$5	CO <sub>2</sub> \$120	CO <sub>2</sub> \$250
<b>Change in emissions</b>			
High load	-0.001%	-0.6%	-0.9%
Low load	-2%	-37%	-37%
Weighted average	-0.5%	-7.4%	-7.5%
<b>Cost of reductions (change in operating cost)</b>			
High load	\$3/tonne	\$66/tonne	\$98/tonne
Low load	\$.004/tonne	\$97/tonne	\$97/tonne
Weighted average	\$.01/tonne	\$95/tonne	\$97/tonne

Table 2.4 shows the predictions of the DC model as well as the AC model. In this case, the predicted effect of the policy on emissions is similar in the two models, but the estimated cost per tonne of CO<sub>2</sub> emissions differs by nearly a factor of two.

<sup>2</sup> The RGGI states may be prohibited by federal inter-state commerce laws from addressing leakage from other states in this way.

**Table 2.4: DC Model Versus AC Model: Predicted Emission Reductions with \$120 CO<sub>2</sub> Price and with Regulation in Whole Modeled Region**

	DC model	AC model
<b>Change in emissions</b>		
High load	-0.2%	-0.6%
Low load	-48%	-37%
Weighted average	-8%	-7.4%
<b>Cost of reductions (change in operating cost)</b>		
High load	\$118/tonne	\$66/tonne
Low load	\$50/tonne	\$97/tonne
Weighted average	\$52/tonne	\$95/tonne

Our results are sensitive to the assumed distribution of load. As mentioned above, we are assuming a very simple distribution of high load one third of the time and low load for the other two thirds of the time.

## 5. Conclusions and Future Research

Based on this pilot analysis, we draw some tentative conclusions. First, in the short run, emission reductions on the order of 7% may require permit prices and system operation cost increases well above the \$10-per-tonne “trigger price” in RGGI. Second, permit prices in a cap-and-trade program can vary greatly as a result of only a small change in required emission reductions. For example, to reduce emission reductions from 7.4% below business as usual to 7.5% below business as usual, our simulation predicts that the permit price would have to more than double, from \$120 per tonne of CO<sub>2</sub> to \$250. In contrast to a cap and trade program, a CO<sub>2</sub> tax would prevent volatility in the prices of CO<sub>2</sub> emissions. A more predictable emission price would reduce the risk associated with investments in CO<sub>2</sub> emission reductions, and therefore make them more appealing to risk-averse companies.

Third, AC results differ from DC results. Since the AC model is a more realistic representation of how the power supply system physically operates, we believe that this is a reason to consider using AC modeling.

To improve the simulation, the following parameter improvements are in progress:

- Detailed generator representation
- Predicted load and capacity by sub-region, 2009–2018
- Derating of generation capacity based on historical planned and unplanned outage rates
- Predicted fuel prices, 2009–2018
- Effect of RGGI on natural gas price
- Contingencies
- Geographically larger, more detailed, purpose-made reduction of eastern power system
- Improvement of solution algorithm

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**CHAPTER THREE:  
PUBLIC DECISION-MAKING AND TIME INCONSISTENCY:  
EXPERIMENTAL EVIDENCE AND SOCIAL CONSEQUENCES<sup>1</sup>**

**1. Introduction**

Governments often must decide when and if they should undertake actions involving up-front costs and delayed benefits. In many of these cases, they are criticized for excessively delaying or ultimately foregoing an action with apparent net social benefits. For example, the United States has a long history of delaying action to reduce known toxic threats, including cigarette smoke, lead, DDT, and mercury. Many governments have been slow to take action to reduce the spread of pandemics such as HIV/AIDS, which now infects a quarter of the population in some nations. Education and infrastructure also are chronically under-funded in many countries.

There are many possible explanations for the above delays and failures to act, one of which is time inconsistency. An individual exhibits time inconsistency if his preferences over a set of outcomes change as a function of only his reference point in time relative to the outcomes.<sup>2</sup> As an illustration, suppose that we could ask a person either in January or in February whether he would like to spend less and invest more in February. If he would honestly answer yes in January but no in February, in spite of there being no unanticipated change in circumstances, then this would be a case of time inconsistency. Prior experimental research has shown time inconsistency in decisions over individual outcomes (e.g., Green, Fristoe, and Myerson, 1994; see Henderson and Langford, 1998 and Frederick et al., 2002 for summaries). Further,

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<sup>2</sup> This notion of time inconsistency is based on ideas in the behavioral economics literature. In other economics literature, time inconsistency often refers to governments' inability to keep commitments to certain policies as time passes. However, the change in preferred policy over time is due to something more than just the passing of time in these instances. It is often due to induced behavior of constituents caused by the original policy.

prior theoretical research has shown this behavior can lead to excessive (even infinite) delays in performing desirable tasks – specifically those where costs are realized before benefits. These delays can ultimately result in significant welfare losses (O’Donoghue and Rabin, 1999).

While some behaviors manifest themselves similarly in individual and group decisions, others do not. For example, prior experimental research has found differences between individuals and groups in rationality and risk preference (see Bornstein and Yaniv, 1998, and Shupp and Williams, 2006).<sup>3</sup> As of this writing, very little research has examined whether or not time inconsistency extends to decisions over group outcomes, and there has been little discussion about the potential social welfare consequences if it does.<sup>4</sup> This is true in spite of the closing words in Strotz’s classic 1956 paper on individual time inconsistency:

We have here treated the problem of the intertemporal tussle only in the context of microeconomics. Similar issues may arise, however, in the aggregate case where a group of persons or an economy must decide the distribution of economic activity over time. Political decisions to eliminate a foreign trade deficit or to balance a budget not this year, but next may serve as illustrations.

In this paper, we show that time inconsistency in group decision-making can reduce social welfare. We then describe some of the patterns of behavior that may result from time inconsistency. Next, using an experiment with real-money incentives, we show that time inconsistency, as found for individual preferences, extends to preferences over group outcomes. We discuss implications for public policy and means of reducing time inconsistency. Finally, we present examples of

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<sup>3</sup> See Cox, 2002, Kerr, MacCoun and Kramer, 1996, Kocher and Sutter, 2005, and Bone, Hey, and Suckling, 1999 for several more individual vs. group comparisons.

<sup>4</sup> Cairns, 1994, and Lazaro et al., 2001 & 2002b, find evidence of declining discount rates for social outcomes. However, all three papers use hypothetical surveys, and none finds any direct evidence of time inconsistency.

government decision sequences in the past that may be explained by time inconsistency.

If time inconsistency does exist for group outcomes, the stakes can be high. Many future governmental decisions involve options with up-front costs and delayed benefits. For example, reductions in global-warming emissions may be costly in the near term and may provide benefits for hundreds of years into the future. Another important issue is the threat from weapons of mass destruction. Reducing this risk, for example by benevolence in foreign policy or by costly restrictions or actions to prevent the spread of dangerous technology, may involve costs in the near future and benefits in the more distant future. Meanwhile, with billions of people living in poverty, the arguments for more and better education, health care, and other poverty-alleviating investments remain. Delaying or forgoing investments such as these as a result of time inconsistency may be very costly in the long run. Our experimental findings suggest that time inconsistency, consequent welfare losses, and ways to reduce them are legitimate concerns for public policy.

## **2. Social Welfare Losses Due to Time Inconsistency**

### *2a. Social welfare losses from time inconsistency when borrowing is possible*

In this section, we show how time inconsistency, in the form of a decreasing proportion voting for an investment, can lead to social welfare losses. Assume there are three time periods, 0, 1, and 2. A group receives income  $Y_1$  in period 1 and  $Y_2$  in period 2. The group can invest amount  $I$  in period 1, in which case its income is reduced by  $I$  in period 1 but is increased by  $I(1+r)$  in period 2. In either period 0 or period 1, the group votes on whether to make the investment in period 1. If it votes in period 0, we say it makes the decision with a front-end delay. If it votes in period 1, we say it makes the decision with no front-end delay.

The group can also borrow any amount in period 1. Let  $c$  denote the amount of income the group chooses to borrow in period 1. Then the group's income in period 1 is increased by  $c$ , but its income in period 2 is reduced by  $c(1+s)$ .

If the group does not invest, but borrows  $c$  in period 1 and pays it back in period 2, then its income in period 1 is

$$Y_1 + c \tag{1}$$

and its income in period 2 is

$$Y_2 - c(1+s). \tag{2}$$

If the group does invest, it can achieve income in period 1 of  $Y_1 + c$ , the same as in (1), by borrowing  $I + c$ . In that case, its income in period 2 is

$$Y_2 + I(1+r) - (I+c)(1+s),$$

which simplifies to

$$Y_2 - c(1+s) + I(r-s). \tag{3}$$

A comparison of (3) versus (2) reveals that if  $r > s$ , investing produces an unambiguous increase in wealth, while if  $r < s$ , investing produces an unambiguous reduction in wealth. Whether social welfare increases with wealth depends on the distribution of wealth and on the social welfare function used. For example, if each individual's income in each period is a strictly increasing function of societal wealth and if social welfare is a strictly increasing function of each individual's income in each period, then social welfare is a strictly increasing function of societal wealth.

Assuming social welfare is a strictly increasing function of societal wealth, the group can make two kinds of mistakes. The first is to fail to invest when  $r > s$ . The second is to invest when  $s > r$ . Either of these mistakes produces a reduction in wealth and welfare compared with the alternative, as explained in the preceding paragraph.

Time inconsistency is not a necessary condition for a group to be capable of making such mistakes, but accompanied by some other assumptions, it is a sufficient

condition. Assume that the final vote on an investment could be taken either in time period 0 or in time period 1. Let  $t$  denote the time period in which the vote is taken. Let  $P(r-s,t)$  denote the proportion of voters who cast votes in favor of an investment. To allow  $P$  to be a continuous function for the sake of simplicity, assume that at least one person can cast a split vote, any portion of which is in favor of the investment, and the remainder of which is opposed to the investment. Assume  $P$  is a strictly increasing function of  $(r-s)$  and a strictly decreasing function of  $t$ . Further assume that for some values of  $(r-s)$ ,  $P(r-s,0) > 0.5$  and that for some values of  $(r-s)$ ,  $P(r-s,1) < 0.5$ . Then for some range of values of  $(r-s)$ , the proportion voting in favor of the investment will be a majority if the vote occurs in time period 0, but a minority if the vote occurs in time period 1. For any given value of  $(r-s)$  in this range, other than 0, one or the other of these decisions would be a mistake. Therefore, given the other assumptions in this paragraph, time inconsistency, in the form of a declining proportion of votes for an investment, is a sufficient condition for wealth-reducing mistakes to be possible. An implication is that, again given the assumptions in this paragraph, a time-inconsistent group will be capable of wealth-reducing mistakes regardless of the other characteristics of the group.

*2b. Behaviors that can result from time inconsistency in voting*

In majority-rule time inconsistency, the majority switches from voting in favor of investing to voting against investing, as a function of a change in the group's reference point in time relative to the possible investment. In our experiment, the proportion in favor of investing was lower when the amount of time between the vote and the potential investment was less. This points to the first behavior that may result from majority-rule time inconsistency: Preferring in advance to make some investment, then preferring less far in advance not to make that investment. As stated

above, if  $r > s$ , and if borrowing is possible, then failing to invest results in an unambiguous reduction of societal wealth.

If the investment can be made later, then the majority may prefer to make the investment later even as it votes not to make the investment at the earliest possible time. This can be called “delay.”

As time passes and the later potential investment time becomes the earliest possible investment time, the group may again prefer not to invest at that new earliest possible investment time, again preferring to delay the investment. This can be called “repeated delay.” In the extreme, delay can be repeated infinitely. If  $r > s$ , and if borrowing is possible, then each delay results in an unambiguous reduction of societal wealth.

The opportunity to make the investment later rather than sooner may even be the reason for delaying. That is, investing at the soonest possible investment time may be preferred to not investing at all, but may be passed over in favor of investing at the later investment time. If the group repeats this behavior, then it repeatedly passes up its preferred option, the option of investing.

### **3. The Experiment**

We have shown above that time inconsistency can lead to social welfare losses. It may be possible that phenomena such as other-regarding behavior could temper individuals’ time-inconsistency problems (that we know exist for personal decisions) when they are members of a group. For example, individuals could have time-inconsistent preferences about outcomes that apply only to them, but time-consistent preferences about outcomes that apply to others. In this section and the next, we present a test of this possibility.

We employed a between-subjects design, using 239 subjects recruited from an introductory business management class at Cornell University.<sup>5</sup> As the subjects entered the symmetrical room used for the experiment, we directed half to sit on the left side and half to sit on the right side, on an alternating basis. The instructions told each subject that she had been assigned to a group that included half of the class, but included nothing about a difference in treatments between the groups.

Those on one side of the room were in the “immediate payment group.” For them, the initial payment time was at the end of the experiment session, while the final payment time was three weeks after the session. Those on the other side of the room were in the “delayed payment group.” For them, the initial payment time was three weeks after the experiment session and the final payment time was six weeks after the session.

The instructions told the subjects that all payments would be in cash and that they would receive their future payments in their class. The instructions further explained that we would individually contact any student who failed to collect a future payment in class, in order to arrange payment in person or via certified mail or courier service.

Each subject was asked to make an “individual decision” and to vote on a “group decision.” To control for order effects, we randomized which question was listed first. The instructions explained that one of these two decisions, selected at random, would be implemented.

Since in the group decisions subjects make their choices via their votes and do not directly choose the outcome, we can assume that each has voted for her preferred group outcome only if voting is demand revealing. Prior work has shown that voting on a dichotomous choice between group real-money outcomes is both incentive-

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<sup>5</sup> Experiment materials are available at:  
[http://www.people.cornell.edu/pages/jtp35/index\\_files/OnlineApp2.pdf](http://www.people.cornell.edu/pages/jtp35/index_files/OnlineApp2.pdf)

compatible (i.e., participants have an incentive to reveal their true preference) and transparent (i.e., participants can easily see that it is incentive compatible).<sup>6</sup> In conjunction, these findings justify the assumption that voting is, in fact, demand revealing.

In the group decision, each subject had an initial balance of \$7, receivable at her initial payment time. Each subject had to vote for one of two payment streams, dubbed option A and option B. In option A, each subject would pay \$1 (out of her initial balance) at the initial payment time and receive \$3.50 at the final payment time. In option B, each subject would pay \$5 (out of her initial balance) at the initial payment time and receive \$8.50 at the final payment time. Table 3.1 shows these options. The instructions told each subject that the option receiving a majority of the votes cast by the members of her group would be applied to her entire group.

The individual decision facing each subject was identical to the group decision except that, as explained in the instructions, each subject's decision would apply only to her.

**Table 3.1: Schedule of Payment Options for Each Group**

<b>Group</b>	<b>Option</b>	<b>Receive today</b>	<b>Receive 3 weeks from today</b>	<b>Receive 6 weeks from today</b>
<b>Immediate payment group</b>	A	$\$7 - \$1 = \$6$	\$3.50	-
	B	$\$7 - \$5 = \$2$	\$8.50	-
<b>Delayed payment group</b>	A	-	$\$7 - \$1 = \$6$	\$3.50
	B	-	$\$7 - \$5 = \$2$	\$8.50

<sup>6</sup> See Plott and Levine (1978) and Farquharson (1969).

If our subjects generally are time consistent, we should observe similar choice patterns between options A and B across the immediate and delayed payment groups; otherwise, we view this as evidence of time inconsistency. We are particularly interested in whether there is a difference in voting patterns across the immediate and delayed payment groups for the group decision, and how this difference compares to that for the individual decision.

#### **4. Experiment Results**

In our results, the pattern that would reflect time inconsistency is a statistically significant difference in the percentage choosing option A in the immediate payment group and the percentage choosing option A in the delayed payment group, since the only difference between these two groups is their reference point in time relative to the available outcomes.

We present our “group decision” results in Table 3.2.<sup>7</sup> In the immediate payment group, 42 of the 119 subjects voted for option A. In the delayed payment group, 23 of the 115 subjects voted for option A. The difference is statistically significant at conventional levels using a simple binomial test of proportions ( $p < .01$ ). Consequently, we reject the null hypothesis of no time inconsistency. This yields our first conclusion: Individuals exhibit time inconsistency in group decisions. For comparison, we present the results for the “individual decision” in Table 3.3. In the immediate payment group, 48 out of 119 chose option A. In the delayed payment group, 20 out of 115 chose option A. We find time inconsistency for this decision as well ( $p < .01$ ).

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<sup>7</sup> We removed from the data set five students who had participated in a pilot version of the same experiment and one who failed to answer one of the questions.

**Table 3.2: Results for Group Decision**

	<b>Voted for option A</b>	<b>Voted for option B</b>	<b>Total subjects</b>
<b>Immediate payment group</b>	42 (35%)	77 (65%)	119
<b>Delayed payment group</b>	23 (20%)	92 (80%)	115

**Table 3.3: Results for Individual Decision**

	<b>Voted for option A</b>	<b>Voted for option B</b>	<b>Total subjects</b>
<b>Immediate payment group</b>	48 (40%)	71 (60%)	119
<b>Delayed payment group</b>	20 (17%)	95 (83%)	115

We wish to test whether there is a difference in rates of time inconsistency between the individual decision and the group decision. Table 3.4 shows the switching rates for the immediate and delayed payment group across the “individual decision” and the “group decision.” In it, we show the number who chose A in the individual decision and B in the group decision and the number who chose the reverse. In the immediate payment group, 11 of the 119 subjects chose option A only in the individual decision and 5 chose option A only in the group decision. This difference in switching rates is not statistically significant at conventional levels ( $p = 0.21$  using McNemar’s test). This yields our second conclusion: The participant behavior in the group decision did not differ significantly from the participant behavior in the individual decision. Of course, this does not definitively mean that there are no

differences in time inconsistency between individual and group decisions. Future experiments could test further for such differences.

**Table 3.4: Switching Rates**

	<b>Chose option A only in individual decision</b>	<b>Chose option A only in group decision</b>
<b>Immediate payment group (119 participants)</b>	11	5
<b>Delayed payment group (115 participants)</b>	4	7

The time inconsistency in both the group and individual decisions is overwhelmingly a male phenomenon. Table 3.5 shows the results for the group decisions. Thirteen percent of the males in the delayed payment group chose option A, while 42% of the males in the immediate payment group chose option A. This difference is highly significant ( $p < .01$ ). In contrast, the percentages of females choosing A were nearly identical in the delayed and immediate payment groups, 27% and 28%. The gender results for the individual decisions are qualitatively the same as those for the group decisions, as shown in Table 3.6.

There are two key aspects of the above experiment that we believe enhance the reliability of our results. First, the choices involve real money. Prior research (e.g., Bohm, 1994) has shown that humans sometimes choose differently in real-money decisions than they would in otherwise-similar hypothetical decisions. Second, our subjects were not confronted with a large number of decisions or options. Therefore, boredom and perceived irrelevance are likely not issues for the decision-makers because the incentives are sufficient for payoff dominance (Smith, 1982).

**Table 3.5: Number of Subjects, by Gender, Choosing Each Option in Group Decision**

<b>Gender</b>	<b>Group</b>	<b>Chose option A</b>	<b>Chose option B</b>	<b>Total</b>
<b>Male</b>	<b>Delayed payment group</b>	<b>7 (13%)</b>	<b>49 (87%)</b>	<b>56</b>
	<b>Immediate payment group</b>	<b>25 (42%)</b>	<b>34 (58%)</b>	<b>59</b>
<b>Female</b>	<b>Delayed payment group</b>	<b>16 (27%)</b>	<b>43 (73%)</b>	<b>59</b>
	<b>Immediate payment group</b>	<b>17 (28%)</b>	<b>43 (72%)</b>	<b>60</b>

**Table 3.6: Number of Subjects, by Gender, Choosing Each Option in Individual Decision**

<b>Gender</b>	<b>Group</b>	<b>Chose option A</b>	<b>Chose option B</b>	<b>Total</b>
<b>Male</b>	<b>Delayed payment group</b>	<b>5 (9%)</b>	<b>51 (91%)</b>	<b>56</b>
	<b>Immediate payment group</b>	<b>31 (53%)</b>	<b>28 (47%)</b>	<b>59</b>
<b>Female</b>	<b>Delayed payment group</b>	<b>15 (25%)</b>	<b>44 (75%)</b>	<b>59</b>
	<b>Immediate payment group</b>	<b>17 (28%)</b>	<b>43 (72%)</b>	<b>60</b>

## **5. Discussion**

Our experimental results provide evidence that time inconsistency extends to group choice over some outcomes, at least among males.

When the front-end delay is shortened, in our case from 21 to zero days, time inconsistency could result in either an increase or a decrease in the proportion of voters voting for option A, the lower-up-front-cost, lower-delayed-benefit option. In

our experiment, it resulted in an increase. This could result from some of the voters, specifically some of the male voters, discounting future costs and benefits “hyperbolically.” In hyperbolic discounting, the per-period discount rate decreases if the front-end delay between decision and prospective investment increases.

Group decisions frequently are made by families, boards of directors, government officials (e.g. members of a legislature), and the general population (e.g. in the case of referenda). Even if elected representatives do not have time-inconsistent preferences themselves, they may feel compelled to vote in a time-inconsistent manner if their constituents have such preferences. In this section, we discuss implications and possible historical examples of time inconsistency in group decision-making, as well as limitations of our findings.

### *5.1. Implications for public decision-making*

Many public policy decisions concerning infrastructure, health, the environment, science, and the military involve two or more options with varying up-front costs and delayed, expected benefits. The options in our experiment were designed to be as analogous to these types of decisions as possible. For example, option A could be considered analogous to low spending on education, while option B could be considered analogous to higher education spending and concomitantly higher future benefits from a more educated populace.

For the remainder of this subsection, we focus on two approaches that could eliminate or at least mitigate some of the problems resulting from time inconsistency in public decision-making. The first approach is awareness. Time-inconsistent decision-makers may be unaware of their time inconsistency problem. If those who are unaware are made aware of their time inconsistency, some of the delays symptomatic of decisions with up-front costs and delayed benefits could be avoided

(O'Donoghue and Rabin, 1999). In addition, group members could choose to delegate some decisions to people or subgroups with known time consistency.

Our results suggest that women may be a time-consistent subgroup, at least for the type of decision in our experiment. Gender differences in time consistency, and in inter-temporal discounting more generally, have implications for public policy. The prevalence of men in government and corporate decision-making roles may have systematic effects on decisions. For example, the historical instances of government policy reversals that will be described in subsection 5.2 might not have occurred if women rather than men had predominated in the government bodies that made those policies.

The second approach is to manipulate the front-end delay in decisions in order to change decision outcomes. If the proportion of group members supporting an investment increases with front-end delay, as in our experiment results, then increasing the front-end delay may change a group's decision about a particular investment from disapproval to approval. For example, school boards that repeatedly fail to win referenda for investing in physical improvements to schools could try increasing the front-end delay, i.e. proposing that the physical improvements occur two or more years in the future instead of one.<sup>8</sup>

### *5.2. Possible Historical Evidence of Time Inconsistency in Governmental Decisions*

In this subsection, we present some historical examples suggestive of time inconsistency in public policy. One example may be the pattern of foreign aid goals set, then later missed. Several times since 1970, the world's higher-income nations have espoused the goal of each giving 0.7% of national income as aid to developing

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<sup>8</sup> In the United States, most school construction is funded by bonds, so the "pain," in the form of tax increases or reductions in other spending, is already likely to be spread over multiple future years. However, voters might still perceive the date of the physical improvements as an important indicator of when they will experience the pain.

countries (United Nations 1970, UNICEF 1996, Beattie 2005, Ortiz 2005, Sachs 2005). However, only six of the countries have met that goal (WDM 2004). In 2004, the aggregate percentage given by the 30 wealthy nations that constitute the Organization for Economic Cooperation and Development was 0.25% (Beattie 2005).

In the last several years, the governments of some individual countries have set deadlines for themselves to reach certain percentages by certain dates. However, in a pattern consistent with time inconsistency, most of these deadlines have been missed or have been postponed as they have approached. Finland missed its 2000 deadline to give 0.4%, giving 0.31% that year (OECD 1998, OECD 2003a). In 2000, the government of Ireland set and publicized a 2002 deadline to give 0.45% and a 2007 deadline to give 0.7%. Ireland missed the 2002 deadline, but the 2007 deadline still enjoyed widespread support in 2003 (Trocaire 2004, Taoiseach 2003). However, in 2005 the same government and prime minister that had set the 2007 deadline postponed it to 2012 (*The Mirror* 2005). Norway and Luxembourg missed their 2005 deadline to give 1%, respectively giving 0.93% and 0.87% that year (OECD 2003b, OECD 2004, OECD 2006). In Luxembourg as in Ireland, the shortfall occurred in spite of widespread support for increased aid (OECD 2003b) and no change in prime minister. Outside of the six countries that have met the UN target of 0.7%, the only instances we have found of aid percentage targets reached are a UK target of 0.33%, set when the UK was at 0.32%, and a US target of at least 0.15%, set when the US was at 0.17%.

Another possible past instance of time inconsistency has to do with dams on the Paute River in Ecuador. The Congress of Ecuador decided to have two hydroelectric dams built on the Paute River. The downstream dam was built first and provides approximately one third of the country's electric power. The upstream dam, though smaller, was necessary to reduce the country's chronic shortage-induced power

outages and to prevent silt from severely shortening the life of the downstream dam. However, consistent with time inconsistency, the Congress repeatedly failed to appropriate funds for the upstream dam until 20 years after the downstream dam had been built. As a result, the country suffered increased power outages and, in spite of costly remedial dredging, the downstream dam's reservoir accumulated the amount of silt it was designed to accumulate in the dam's intended 50-year operating life.

(*Mercurio* 2003, *Hidropaute* 2005, *Malo* 2005)

Another possible instance of time inconsistency could be the behavior of the United States Congress regarding completion of levees designed to protect New Orleans from hurricane storm surges. In the three years prior to the flooding of New Orleans by Hurricane Katrina, Congress cut funding for levee construction along Lakes Pontchartrian and Borgne, bringing construction nearly to a standstill and preventing the scheduled heightening of levee segments that were two to four feet below their design heights (Mittala 2005, Grissett 2004). The inadequacy of New Orleans' levees had very costly consequences when Hurricane Katrina flooded the city in August of 2005.

The above are but a few of many examples. While we cannot claim that any one of them is direct evidence of time inconsistency in public decision-making, the large number of such incidents combined with our experimental results suggests that time inconsistency likely has played a role in some public decisions.

### 5.3. *Limitations*

The above examples suggest that our experimental findings extend to actual public decisions; however, we recognize there are several limitations in this regard. First, our time scale is relatively small (six weeks maximum). Most public policy decisions involve costs and benefits over a much longer period of time than our

experiment. However, if per-period or instantaneous discounting is in fact strictly decreasing over these longer periods, or if political costs are immediate and significant, time inconsistency could still result.

Second, the group to which our subjects belonged was anonymous. It could be that they would have voted differently if they had known who else comprised their group. However, the seating arrangement (with a clear divide down the middle of the room) suggested to which group each belonged.

Finally, the costs and benefits in our experiment were relatively small in magnitude. It may be the case that time inconsistency declines as the size of the costs and benefits increases.

## **6. Conclusion**

In this paper, using a simple model, we have shown that time inconsistency can lead to welfare losses and to characteristic patterns of behavior. Through a simple experiment and historical examples, we have shown evidence that time inconsistency may exist in public decision-making, particularly when males are involved. We have also discussed implications for public policy and means of reducing time inconsistency.

For future work, our findings suggest the need for field experiments and econometric studies to further explore and identify the prevalence of time inconsistency in public decision-making. To the extent that time inconsistency indeed applies in public decisions, further research could test the effectiveness of approaches to dealing with it.

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## CONCLUSION

The first paper experimentally tests a novel mechanism used to suppress the exercise of market power in New York City and neighboring West Chester. We find that this mechanism can reduce market prices. However, if generation owners have enough market power even during periods without transmission-system congestion, as may be true in some parts of the world, the owners are able to gradually raise the market price well above short-run marginal cost in spite of the mechanism. If they are not able to do this, the mechanism keeps the market price of electricity too low during times of high demand to induce adequate investment in generation and energy conservation.

A future step in the research on this mechanism is to vary its parameters to determine how this affects its performance. For example, would the mechanism still work if the allowable margin were increased during times of very high demand? Another future step is to compare the performance of this mechanism with that of other mechanisms for addressing market power in wholesale electricity markets.

The second paper simulates the Regional Greenhouse Gas Initiative, which will impose a cap-and-trade program on the carbon dioxide emissions of the electric power sector in ten northeastern US states. Constraints in the power transmission system, an alternating-current system, affect the cost of the policy and the emission increases it will induce in neighboring states and provinces. To our knowledge, this is the first study that uses an alternating-current model to predict the effects of an environmental policy. We find that there are important differences between our simulation's predictions and those of a direct-current approximation.

Our next step in this area will be to make the analysis more detailed, incorporating the thousands of generation units in the Northeast, with their varied

marginal costs and emission rates. Another future step will be to combine our power system model with an air quality fate and transport model to guide efficient regulation of other pollutants.

The third paper examines the possibility of time inconsistency in public decision-making. In time inconsistency, an individual's preferences over a set of outcomes change as a function of only his reference point in time relative to the outcomes. We show that time inconsistency in group decisions can lead to welfare losses. Through a simple experiment and historical examples, we produce evidence that time inconsistency may exist in public decision-making, particularly when males are involved. We also discuss implications for public policy and means of reducing time inconsistency. Future research in this area could examine the prevalence of time inconsistent decision-making in various group decision contexts, and the effectiveness of various possible means of improving intertemporal group decision-making.