

NO GOOD DEED GOES UNPUNISHED: The End of IRP and the Role of Market-Based Environmental Regulation in a Restructured Electric Industry

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INTRODUCTION

Looking back, Integrated Resource Planning (IRP) was the knockout punch for the vertically integrated electric industry. Environmentally motivated initiatives promoting demand-side management (DSM), renewables, and independent power producers (IPPs) resulted in front-loaded contracts and increased rates, and the call for rate relief from businesses and fixed income ratepayers. At the same time it promoted competitive bidding and a better understanding of the spot market for electricity. The regulatory overhead has been immense. Therefore, it is not surprising that those states that led the charge to implement integrated resource planning are now those furthest down the road to retail competition. Were the goals of IRP unwarranted? And if not, how do we maintain long-term perspectives related to fuel and resource diversity, load forecasting, and technology development in a restructured electric industry?

Market-based environmental regulation holds the key to establishing a balanced competitive market of independent system operators, generators, brokers and aggregators, and distributors. Environmental performance constraints, such as “cap and trade” systems for SO₂ and NO_x, are well suited to a market of disaggregated but highly coordinated actors, and helps identify the relative costs of alternate resource portfolios. It has been shown that fuel and technological diversification can have greater significance in managing emissions performance than cost performance¹, and where those resource alternatives reduce multiple emissions, portfolio managers can mitigate their market risks as well as signal technology developers of their long-term resource needs. However, the current industry environment—driven by the market uncertainties of competitive restructuring—seeks to minimize cost exposure, additional capital cost exposure in particular. Even so, 1990 Clean Air Act Amendment (CAAA) provisions will require capital additions prior to the resolution of the restructuring dockets. With SO₂, NO_x and air toxics reductions (as yet undefined) already called for by the CAAA, further initiatives to reduce emissions of ultrafine particulates and carbon dioxide are highly likely in the forthcoming years. How can CAAA targets be met with a minimum of both cost *and* capital exposure? “Cap and trade” approaches to emissions reductions offer much greater flexibility than traditional “command and control” methods. The technical manifestations of such market-based trading systems allow both hardware and operational modifications to achieve reductions. Furthermore, such responses can be designed to reduce several emissions simultaneously, further enhancing cost-effectiveness.

This paper summarizes recent work performed by M.I.T.’s ANALYSIS GROUP FOR REGIONAL ELECTRICITY ALTERNATIVES (AGREA) regarding the cost and emissions performance of alternate resource portfolios for the New England electric industry. Using demand and technological inputs from the NEW ENGLAND POWER POOL and its member utilities, the New England regional system is transformed over a twenty year period (1995-2014) following a series of alternate technological paths designed to first meet anticipated regional

NO_x reduction requirements. Then the “best” of these strategies is extended further by adding additional levels of conservation and renewables (windpower). The performance of these strategies are then evaluated across natural gas cost uncertainties, and their larger implications discussed with respect to restructuring and environmental regulation.

THE NO_x/OZONE PROBLEM

For New England, utility NO_x reductions are currently the primary CAAA challenge. For a region with a peak load of approximately 20 GW, and installed capacity of around 26 GW, New England has a very heterogeneous generation mix. Baseload nuclear accounts for 24% of nameplate capacity, with baseload coal accounting for 10%. Oil, natural gas and wood fired intermediate and base loaded generation accounts for 42% of capacity, some of which—like coal—are becoming quite old. Peaking units (combustion turbines, diesels and pumped storage) account for an additional 11% of the generation mix, with the remaining 13% comprised of hydropower and extra-regional power contracts.² Since coal is such a small component of New England’s generation mix, Title IV provisions of the CAAA calling for reductions in SO₂ have been met by shifting to lower sulfur fuels in existing fossil power plants. Within Title I of the CAAA regarding ground-level ozone, NO_x is the primary electric utility emission contributing to smog.

Utility requirements to reduce NO_x began in 1995 with the installation of Reasonably Available Control Technologies (RACT), primarily combustion modifications to existing utility boilers. However, as described in the Fall 1994 Memorandum of Understanding (MOU) among the Northeast states’ environmental regulators, additional retrofits are called for by 1999, and possibly 2003 if the airsheds within the Ozone Transport Region (OTR) have not achieved compliance.³ While the MOU was couched in command and control language, with further reductions in NO_x emissions rates specified for existing utility boilers, it recommended that market-based trading systems for NO_x and other ozone precursors be applied where appropriate. Furthermore it differentiated regions within the OTR with respect to the severity of the ozone problem, and the associated levels of Phase II (1999) and possibly Phase III (2003) target reductions. Discussions have further promoted a seasonal strategy with respect to NO_x control, with May through September reductions taking precedence over year round reductions.

With these targets in mind, AGREA has modeled what accounts for an effective “cap and trade” constraint system for NO_x emissions from New England generators. Beginning in 1999, the constraint defies a summertime “NO_x season,” and within that season sets an emissions reduction target of 80% from 1990 utility NO_x emissions in Southern New England (Connecticut, Rhode Island, and Massachusetts). Northern New England (Vermont, New Hampshire and Maine) are left unconstrained with the 1995 NO_x RACT measures in place. Allowing some room for NO_x stack emissions from future generators, this “Southern Seasonal” NO_x constraint is just below 14,000 tons of NO_x.⁴

Resource strategies responding to this Southern Seasonal cap are a combination of additional retrofits, primarily flue gas treatments for NO_x, SCRs (Selective Catalytic Reduction), with some SNCRs (Selective Non-Catalytic Reduction). While AGREA modeled five levels of NO_x retrofits beyond 1995 NO_x RACT, only the two most cost-effective retrofit levels are reported here, a “Strict” and “Relaxed” Phase II 1999 level of retrofits. Table One shows the basic components of the first four of these illustrative NO_x reduction strategies. The first strategy “Phase I–RACT” provides the “do nothing” baseline for cost and emissions performance. This strategy is followed by the “Phase II–Strict” strategy which *does not* employ the Southern New England Seasonal (Sou. Seas. or SS) NO_x constraint. The final two strategies in Table One employ the Relaxed Phase II level of NO_x retrofits with the SS NO_x constraint applied.⁵ All choose natural gas fired generation to meet new generation requirements, and have DSM activities set at utilities’ proposed 1995 levels. This level of DSM results in just under a 10% reduction in cumulative GWh demand from the No Utility DSM baseline. Dual fueled gas and distillate oil-fired combined-cycle units were used as baseload/intermediate plants, with gas-fired combustion turbines used for new peaking capacity.⁶ The fourth strategy presumes 1,400 MWs of wind generated in Northern Maine, Western Massachusetts and Southern Vermont, sized to offset 2% of 2010 system CO₂ emissions.⁷ Due to the modest load growth uncertainty incorporated into this analysis, no new gas generation is added prior to 2003, with almost half of the 7,140 MWs going to replace 3,170 MWs of nuclear decommissioned beginning in 2008.

TABLE ONE: Characteristics of NO_x Reduction Strategies

NO _x Reduction Strategies	Ph.II NO _x Retrofits	New Generation		DSM Impacts		
		Nat. Gas	Wind	Peak Gr.	Demand Gr	Dem. Red.
Ph. I-RACT	0	7,140	0	1.06	1.25	-9.9
Ph. II-Strict	9,146	7,140	0	1.06	1.29	-9.7
Ph. II-Relaxed/SS	7,357	7,140	0	1.06	1.29	-9.7
Ph. II-Relaxed/SS & Wind	7,357	7,140	1,417	1.09	1.32	-8.3
(SS-Sou. Seas. NO _x)	(MW-1999)	(MW-2014)		(%/yr.)	(% from No)	

PERFORMANCE OF NO_x REDUCTION STRATEGIES

Figure One on the following page shows the annual emissions and relative cost performance of the four NO_x reduction strategies. The first graph shows how well each of the four strategies performs relative to the Southern Seasonal NO_x constraint. Phase I-RACT emissions are well above the reduction target; so high in fact that they are outside the range of all operational controls. Therefore, additional NO_x retrofits beyond 1995 RACT will be required. The straight retrofit strategy, Phase II-Strict, achieves the target reduction easily but has slightly higher than desired SS NO_x emissions in later years. Both Phase II-Relaxed/SS strategies achieve the NO_x target easily. Dispatch modifications to achieve a desired NO_x reduction work well when there are units of dissimilar emissions characteristics in the intermediate-load range. In the intermediate range, relatively large shifts in hours of operation between units can be achieved with only a modest incremental costs. With new generation units still required to install Best Available (NO_x) Control Technologies (BACT), heterogeneity of NO_x emissions increases as new generation is introduced, particularly if overzealous NO_x retrofits to existing generation can be avoided. This gives such dispatch approaches more “room to work.” Note that the Phase II-Relaxed/SS & Wind strategy has nearly identical SS NO_x emissions as its non-wind counterpart. This is due primarily to the fact that annual wind, and therefore wind generation in New England is skewed towards the winter months and contributes little to summertime NO_x reductions.

The second and third graphs in Figure One show annual SO₂ and CO₂ emissions respectively. As mentioned previously SO₂ emissions are not an important CAAA consideration at this time in New England. The SO₂ allowance allocation line in the background of the second graph shows that intra New England banking of allowances should easily offset later increases in SO₂ emissions. In the SO₂ graph we also see the SO₂/fossil generation displacement provided by windpower. This is also evident in the CO₂ graph. Unfortunately, CO₂ emissions rises substantially over the long-term as the compounding effects of 1.3%/yr. growth in electricity demand are acerbated by the expiration of a Hydro Quebec power contract in 2001, and the decommissioning of nuclear units in 2008, 2009, 2012 and 2013. This 80% increase in CO₂ by 2014 (over 1990 levels) is particularly troubling in that it comes primarily from the introduction of new gas combined-cycle generation to meet growing demand and to replace the lost nuclear.

The fourth graph in Figure One shows the percentage change in total regional revenue requirements resulting from the addition of future NO_x retrofits, the Southern Seasonal NO_x constraint, and introducing windpower. In 2010, the Phase II-Relaxed/SS strategy is 2.0% more expensive than the Phase I-RACT strategy, while the Phase II-Strict is 2.4% more expensive. This 20% cost differential however only buys an additional 0.8% decrease in Southern Seasonal NO_x (2010). Fortunately, much of the overall cost increase comes from the Variable O&M, not the capital cost of SCRs and SNCRs. If environmental regulators are progressive enough to allow power plant owners to turn off high-end NO_x control equipment outside the summer NO_x season, the cost impact of NO_x retrofits can be substantially reduced. Table Two defines the attributes which measure strategies’ twenty-year performance. The two cost and four emissions performance attributes are then tabulated for the four NO_x reduction strategies in Table Three. As can be seen, the one and a half to two percent increase in twenty-year costs does achieve an additional 40% decrease in summertime NO_x. However, this large dollar expenditure does little or nothing to address SO₂ or CO₂ concerns.

Figure One: Annual Performance of NOx Reduction Strategies

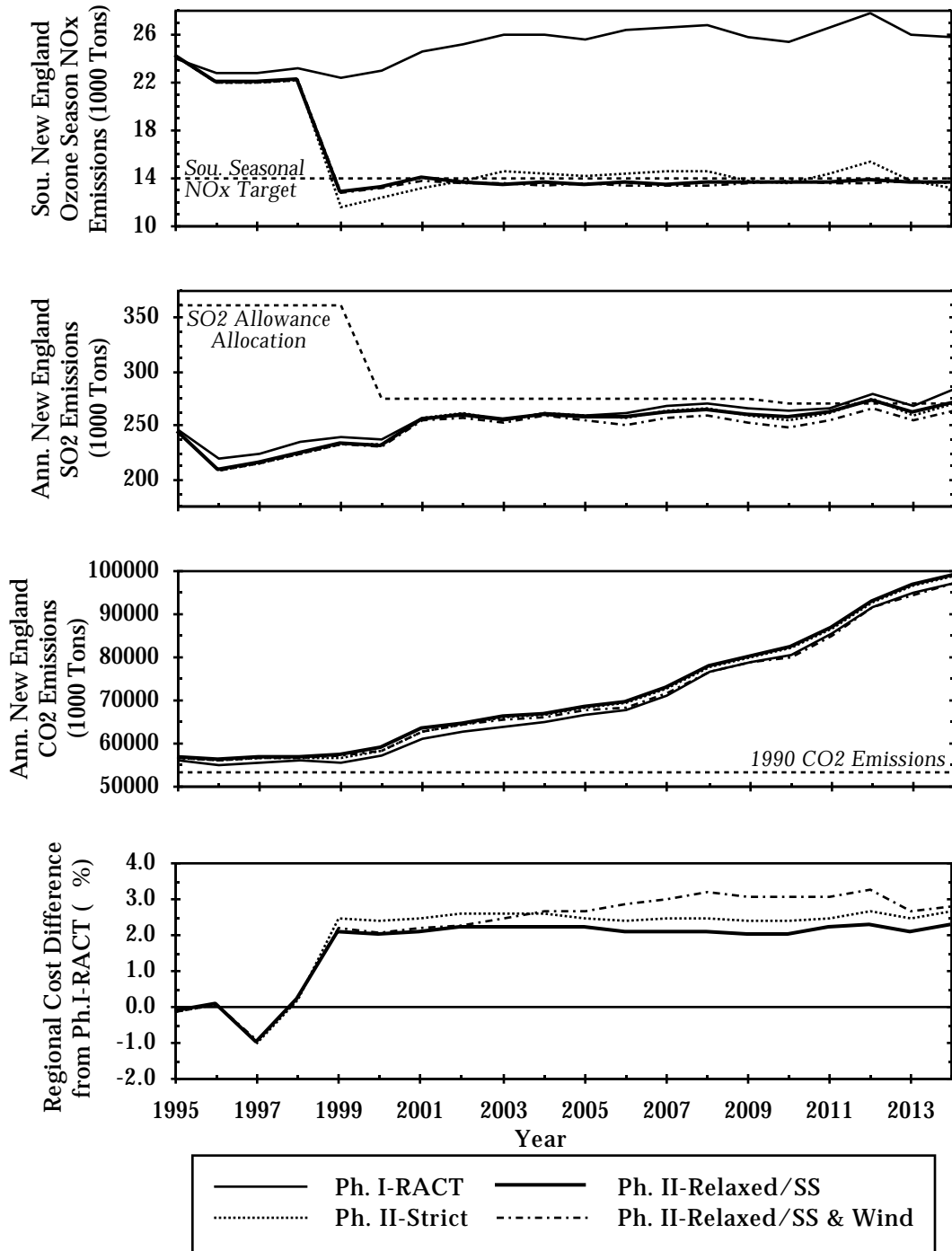


TABLE TWO: Definition of Cost and Emissions Performance Attributes

COST ATTRIBUTES	
<ul style="list-style-type: none"> • <u>NPV Direct Costs/Regional Direct</u> (1994\$B, PV@10%) – Standard “Revenue Requirement” calculation applied to ALL of the region’s direct costs over the twenty year study period, including participant contributions to DSM. Employs utility cost of capital as the discount rate. • <u>NPV Direct Costs/Electric Industry Direct</u> (1994\$B, PV@10%) – Same as above, but does not include DSM program “out of pocket” costs by participants Represents industry cash flow that must be collected via rates. 	
AIR EMISSIONS ATTRIBUTES	
<ul style="list-style-type: none"> • <u>Cumulative New England Nitrogen Oxides Emissions</u> (Million Tons, 1994-2014) – Used as a performance measure relative to issue of ozone formation and smog. Simple sum of all NO_x stack emissions from generators producing electricity for consumption in New England. NO_x offsets from new units’ residual emissions are not subtracted from the total. 1990 utility NO_x emissions totaled 159.6 thousand tons. • <u>Cumulative Southern New England Seasonal Nitrogen Oxides Emissions</u> (Million Tons, 1994-2014) – Same as above but summed only for Southern N.E. generators during the Summer Ozone season. The annual Southern Seasonal NO_x constraint was set at 13.95 thousand tons. • <u>Cumulative Sulfur Dioxide Emissions</u> (Million Tons, 1994-2014) – Used as a performance measure relative to issue of Acid Deposition. Simple sum of all SO₂ emissions from generators producing electricity for consumption in New England. 1990 New England Utility SO₂ emissions totaled 373 thousand tons. • <u>Cumulative Carbon Dioxide Emissions</u> (Million Tons, 1994-2014) – Used as a performance measure relative to issue of Global Climate Change. Simple sum of all CO₂ emissions from generators producing electricity for consumption in New England. CO₂ emissions from biomass generation have been subtracted out. 1990 New England Utility CO₂ emissions totaled 53,587 thousand tons. 	

TABLE THREE: Cumulative Performance of NO_x Reduction Strategies

<u>NOx Reduction Strategies</u>	<u>NPV Direct Costs</u>		<u>Cumulative Electric Sector Air Emissions</u>			
	<u>Regional Direct</u>	<u>Elec. Ind. Direct</u>	<u>New Eng. NOx</u>	<u>Sou. Seas. NOx</u>	<u>New Eng. SO2</u>	<u>New Eng. CO2</u>
Ph. I-RACT	134.0	132.8	2.32	0.504	5.13	1402
Ph. II-Strict	136.3	135.1	1.70	0.313	5.03	1429
Ph. II-Relaxed/SS	136.0	134.8	1.81	0.308	5.02	1430
Ph. II-Relaxed/SS & Wind	136.5	135.3	1.80	0.307	4.95	1414
(Ref. Utility DSM)	(PV-1994\$B, r=10%)		(Million Tons, 1995-2014)			
<u>% from Ph. I-RACT</u>						
Ph. II-Strict	1.7	1.8	-26.9	-37.8	-2.0	2.0
Ph. II-Relaxed/SS	1.5	1.5	-22.1	-38.9	-2.3	2.0
Ph. II-Relaxed/SS & Wind	1.8	1.9	-22.3	-39.0	-3.5	0.8
	(%)		(%)			

PERFORMANCE OF MULTIPLE EMISSIONS REDUCTION STRATEGIES

As we saw in the previous section, significant NO_x reductions can be achieved by coupling dispatch modifications with modest levels of retrofit technologies. Such costs can be substantially less if high variable cost NO_x reduction technologies such as SCRs are turned off outside the “NO_x Season.” Nevertheless, a 1% increase year in twenty-year revenue requirements for the reduction of a single summertime pollutant appears expensive. What alternatives exist to leverage those costs across several emissions? Table Four briefly describes three additional “multiple emissions reduction” strategies, which build upon the Phase II-Relaxed/SS strategy discussed above. The alternatives double then triple the level of conservation presented previously, and then add wind.⁸ As can be seen, demand growth is substantially depressed with increased levels of hypothetical DSM. Since 3,170 MWs of nuclear is decommissioned over the twenty-year time horizon, the triple DSM strategies result in a net reduction of available capacity.

TABLE FOUR: Characteristics of Multiple Emissions Reduction Strategies

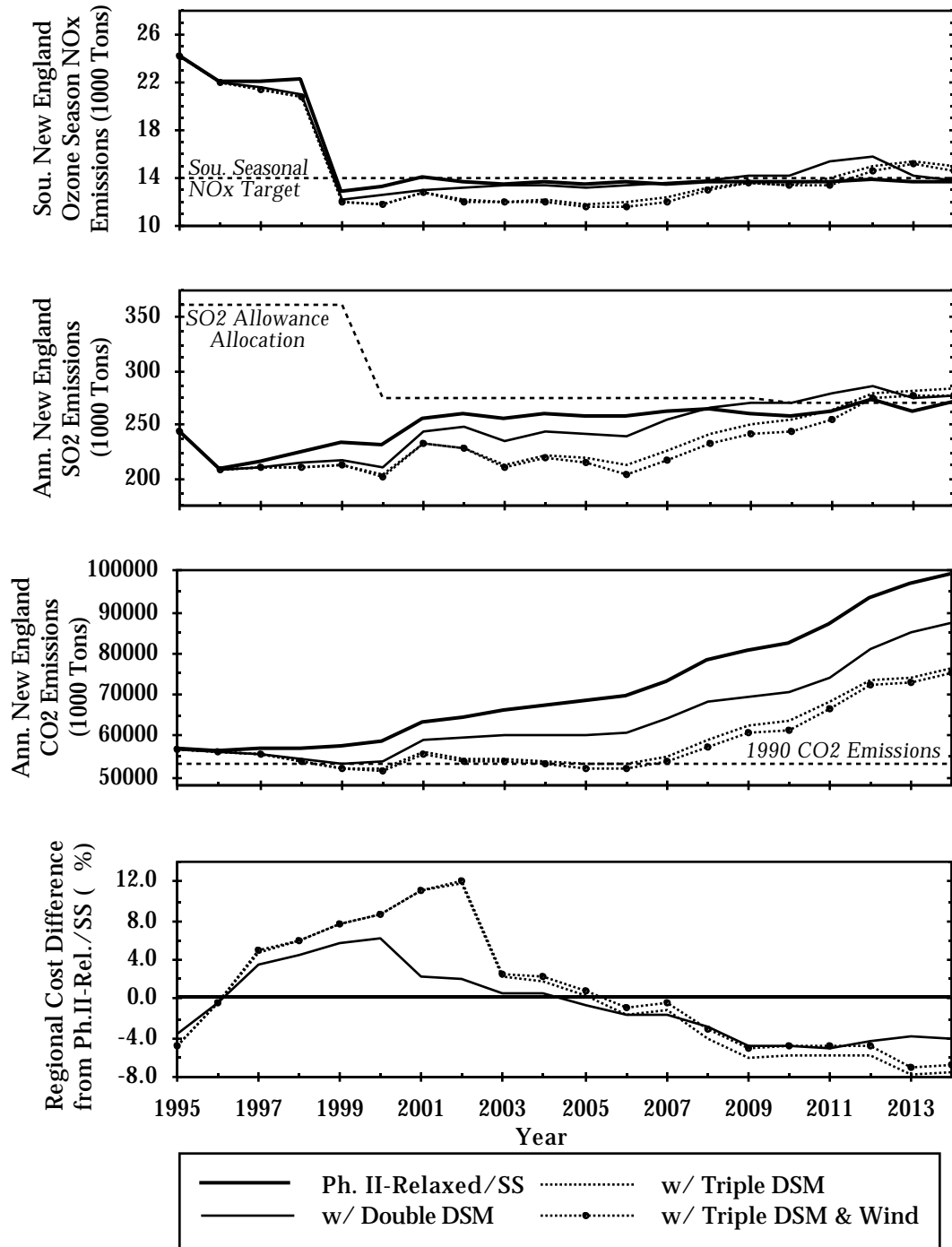
Multiple Reduction Strategies	Ph.II NO _x Retrofits	New Generation		DSM Impacts		
		Nat. Gas	Wind	Peak Gr.	Demand Gr	Dem. Red.
Ph. II-Relaxed/SS	7,357	7,140	0	1.06	1.29	-9.7
w/ Double DSM	7,357	3,540	0	0.46	0.57	-16.6
w/ Triple DSM	7,357	520	0	-0.08	-0.16	-21.2
w/ Triple DSM & Wind	7,357	520	1,417	-0.06	-0.09	-19.9
(SS-Sou. Seas. NO _x)	(MW-1999)	(MW-2014)		(%/yr.)	(% from No)	

Figure Two shows the annual performance of these multiple emissions reduction strategies for Southern Seasonal NO_x, and annual SO₂, CO₂ and relative regional cost. As can be seen, additional DSM/conservation further reduces SS NO_x. Here the additional DSM effectively “disables” use of the NO_x dispatch constraint until 2009. While not modeled here, with sufficient verification of DSM’s NO_x reduction potential, a “Super Relaxed” level of NO_x retrofits could be pursued, rather than a forestalling of the “cap and trade” option. Even though the hypothetical Double and Triple DSM options are dominated by conservation rather than peak load reduction programs, substantial reductions in peak load do occur. By postponing the introduction of new/additional generation capacity, the NO_x and SO₂ emissions savings characteristics of the aggressive DSM options are eventually eroded by the increasing capacity factor of existing, aging fossil generation. Beginning in 2009 for the Double DSM strategy, and 2012 for the Triple DSM strategies, the emissions reduction benefits are eclipsed by the increased utilization of fossil (again acerbated by the decommissioning of nuclear). The story is a bit different for CO₂. Triple DSM in particular keeps CO₂ at roughly 1990 levels until 2008 when is the programs effectively end. CO₂ emissions, although still substantially lower than the Reference and Double DSM levels, begin to rise rapidly and are 43% above 1990 levels by 2014, 40% over 1990 if the wind option is included. With the international FRAMEWORK CONVENTION ON CLIMATE CHANGE (resulting from the RIO TREATY) considering proposals that call for *reductions* of ten to twenty percent from 1990 levels, these results should raise real concerns about how the industry can seriously develop and implement cost-effective CO₂ emissions reduction strategies under a competitive regulatory structure.

TABLE FIVE: Cumulative Performance of Integrated Multiple Emissions Reduction Strategies

Multiple Reduction Strategies	NPV Direct Costs		Cumulative Electric Sector Air Emissions			
	Regional Direct	Elec. Ind. Direct	New Eng. NO _x	Sou. Seas. NO _x	New Eng. SO ₂	New Eng. CO ₂
Ph. II-Strict	136.3	135.1	1.70	0.313	5.03	1429
Ph. II-Relaxed/SS	136.0	134.8	1.81	0.308	5.02	1430
w/ Double DSM	136.1	133.0	1.77	0.309	4.95	1291
w/ Triple DSM	137.6	132.5	1.67	0.298	4.71	1184
w/ Triple DSM & Wind	138.1	133.0	1.66	0.295	4.63	1167
	(PV-1994\$B, r=10%)		(Million Tons, 1995-2014)			
<u>% from Ph. II-Strict</u>						
Ph. II-Relaxed/SS	-0.3	-0.3	6.6	-1.7	-0.3	0.0
w/ Double DSM	-0.2	-1.6	4.4	-1.4	-1.5	-9.7
w/ Triple DSM	0.9	-1.9	-1.6	-5.0	-6.3	-17.2
w/ Triple DSM & Wind	1.3	-1.6	-2.3	-5.9	-8.0	-18.3
	(%)		(%)			

FIGURE TWO: Annual Performance of Multiple Emissions Reduction Strategies



The cost premium for implementing aggressive DSM options appears rather high, particularly given the current industry climate. Alternate financing schemes could mitigate these cost impacts by extending cost recovery into later years when the aggressive DSM strategies show a relative cost savings. This has some implications regarding customers' long-term relationships with DSM and electric service providers under competition. Table Five above shows the cumulative cost and emissions impacts of the multiple emissions reduction strategies compared to the Phase II-Strict strategy. Due to DSM cost recovery assumptions which have recipients of DSM measures paying a greater share of their cost, the regional "bill" for electric service (Regional Direct Cost) goes up while the regional "rate" (Electric Industry Direct Cost) drops.

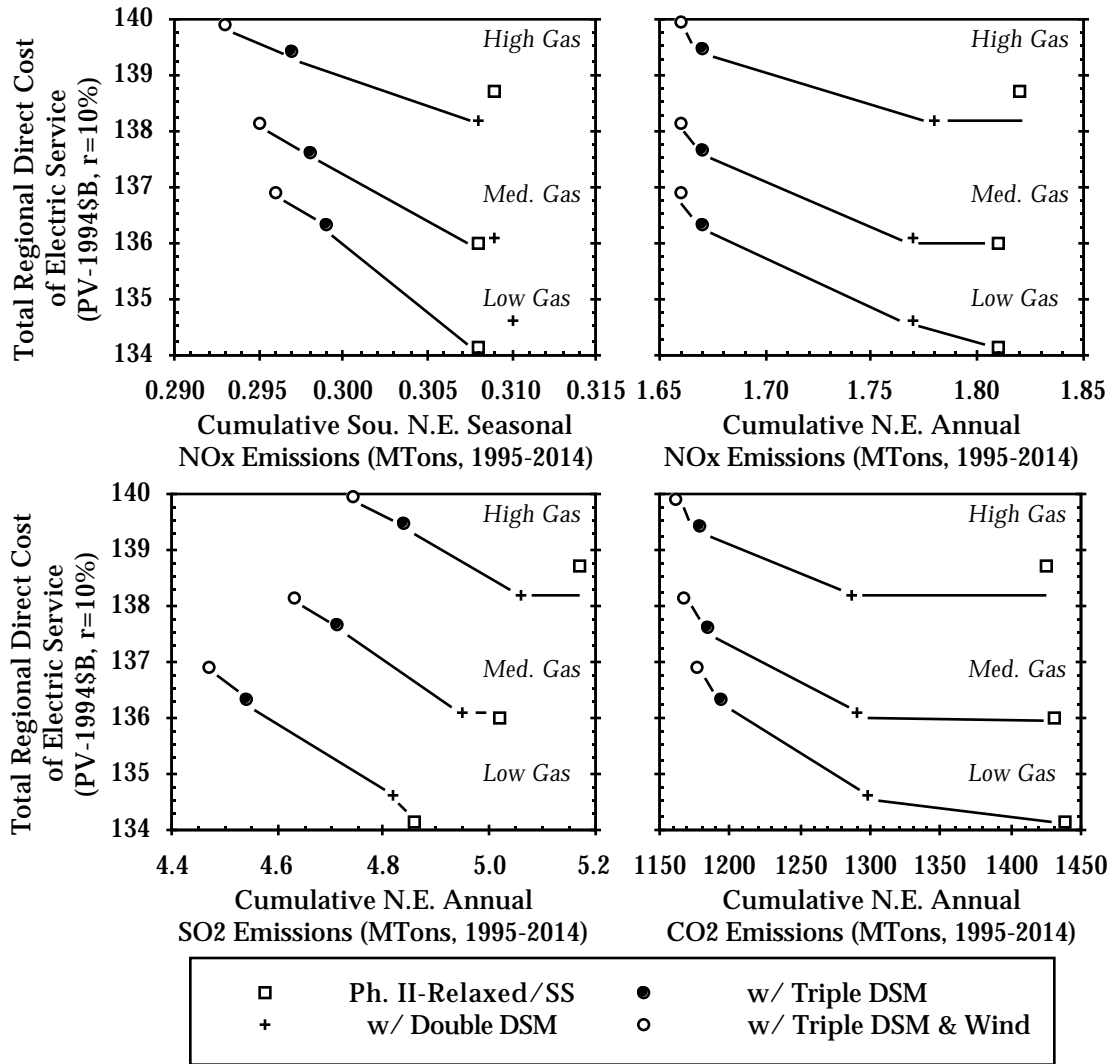
RISK MITIGATION ASPECTS OF MULTIPLE EMISSIONS REDUCTION STRATEGIES

When compared with the Phase II-Strict strategy, the multiple emissions reduction strategies offer substantially better emissions performance for a roughly equivalent cost. For the 1% increase in cost incurred by the Double DSM strategy an additional 5% reduction in Ozone Season NO_x is attained, along with an additional 6% reduction in SO₂ and 17% reduction in twenty-year CO₂ emissions. If the concerns regarding air toxics, the detrimental soil productivity impacts of long-term acid deposition (SO₂ and NO_x emissions), and the health effects of ultrafine particulates (also related to sulfate aerosols) prove warranted these multiple emissions strategies may be well positioned to meet future environmental requirements. Characteristic of "pollution prevention," versus "end of pipe" emissions reduction strategies, is their ability to avoid *all* combustion-related emissions.

Environmental risk mitigation comes in a number of forms. The above mentioned environmental *regulatory* risk mitigation is complemented by the "emissions diversity" (analogous to fuel diversity) benefits of integrated technological strategies. In New England, like elsewhere in the United States, natural gas has become the preferred fuel of not only new generation, but for existing generation, buildings, industry and as an alternate fuel for vehicles. Although cost forecasts and reserve estimates for natural gas are encouraging, delivery into New England may be a problem in the long-term. The high utilization of pipelines from the Gulf Coast and Canada to storage in the Mid-Atlantic states, coupled with siting difficulties faced by pipelines and natural gas storage facilities, point to possible delivery—and therefore cost—risk for New England. Figure Three shows the cost and emissions variability of the four multiple emissions reduction strategies presented above. In each tradeoff plot, strategy performance is plotted for low, medium and high natural gas cost uncertainties. For the low gas cost uncertainty, natural gas is presumed to be roughly equivalent in cost to low sulfur residual oil (on an \$/MMBtu basis). For the medium gas case, natural gas costs a little more than residual oil. The high gas cost uncertainty assumes a supply constraint arises in 2000 which drives the cost of natural gas up to levels equivalent to distillate oil.

As can be seen in the top two plots in Figure Three, NO_x emissions are relatively insensitive to natural gas costs. For cumulative Annual NO_x emissions each strategy's NO_x emissions are effectively unchanged, while for cumulative Sou. Seas. NO_x the Triple DSM strategies' emissions actually drop slightly with higher gas costs. The reason for this seemingly odd phenomena relates to the distribution of SCR retrofits among existing units fueled with oil versus gas, and the fact that so little new gas combined-cycle generation is built over the twenty years. In previous studies with higher load growths, high natural gas costs shifted generation away from ultra-clean gas combined-cycle units to older existing units with higher NO_x emissions. In this analysis, generation is shifted from existing units fired with gas, to existing oil fired units—some of which have been retrofitted with SCRs. Note that for the two NO_x versus cost plots, the cost range along the y-axis is 4.5%, while the NO_x range along the cumulative Southern Seasonal and Annual NO_x emissions axes are 8.6% and 12% respectively. For SO₂, the range is 18%, and the range for CO₂ is 26%. We can see that SO₂ emissions are more sensitive to natural gas cost, but CO₂ surprisingly is not. This may be due to the fact that since so little new gas generation is built, most of the shift between existing gas and oil fired generation is occurring in the low capacity factor intermediate load range. Focusing on the relative cost of strategies, we see that the Phase II-Relaxed/SS (Reference DSM) strategy moves off the "efficient" tradeoff frontier as gas costs go from low to high. We see that while Triple DSM and Wind "buys down" SS NO_x, SO₂ and CO₂ reduces emissions an average of 4.4%, 8.1% and 18.4% respectively, the cost differential from the Reference DSM strategy to the Triple DSM and Wind strategy drops from 2.1 to 0.9%.

FIGURE THREE: Natural Gas Cost Uncertainty Performance of Multiple Emissions Reduction Strategies



DISCUSSION AND CONCLUSIONS

Were the goals of Integrated Resource Planning unwarranted? The above analysis indicates that as an analytic tool *strategic resource planning* can uncover synergies among various technological and operational approaches, and supply and demand resources as well. In this paper we saw that through the use of NO_x emissions constraints and dispatch modifications target NO_x reductions could be met without excessive reliance on NO_x control technologies. Summer oriented DSM initiatives can further reduce the need for additional NO_x retrofits, while substantially reducing all other combustion related emissions. Windpower—while not effective for reducing summertime NO_x—was effective at reducing a broad range of emissions. Such highly integrated strategies have the additional benefit of reducing broader environmental, market and regulatory risks.

Are current restructuring debates considering the dynamic benefits of such integrated strategies, or are they preoccupied with important, but transitional issues such as stranded assets and divestiture? Will new competitive rules promote the development and deployment of such integrated efforts? If *real* CO₂ reductions are called for in the future, then radically innovative and integrated strategies will be required. How does a competitive, coordinated, yet disaggregated, industry prepare for such tasks? And who is responsible (if anyone) for ensuring that such options have seen the light of day when the need arises?

Competitive markets work well when they respond to known rules and constraints. The authors believe that market-based environmental regulations play an essential role in establishing an environmentally responsible restructured electric industry. Simultaneous market-based environmental regulations provide the necessary constraints and signals to market players to develop and deploy integrated energy solutions. Judging by the apparent cost of reducing just summertime NO_x, only several “cap and trade” type markets may be necessary for competitors to seek more innovative and integrated emissions reduction strategies. Furthermore, even though only several emissions may be targeted via market-based environmental regulations, the full range of pollutants—SO₂, NO_x, air toxics, ultrafine particulates and CO₂ emissions (not to mention soil, water, solid waste issues)—are likely to be affected.

The inherent flexibility of “cap and trade” type environmental regulations should help competing energy service and other companies respond in cost-effective ways which recognize the uncertainties of the marketplace. “Cap and trade” regulations are themselves flexible—as demonstrated by the seasonal and geographic specificity incorporated into the OTR NO_x debate—thus enabling adaptation of the constraint (not the technological specification) in response to new and better information regarding the environment. The sophistication of a vibrant energy services market at the customer level, as opposed commodity based wholesale competition alone, will only further the development and deployment of innovative strategies. Failure to implement such regulatory initiatives risks the loss of control over a broad range of performance criteria, as well as a “dumbing down” of the technology-based electric infrastructure.

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- ¹ Connors, Stephen R. “Informing decision makers and identifying niche opportunities for windpower: Use of multi-attribute trade off analysis to evaluate non-dispatchable resources.” in *Energy Policy*, Vol. 24, No. 2, pp 165-176, 1996.
 - ² New England Power Planning. NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 1996-2011. NEPOOL. Holyoke, MA. April 1, 1996.
 - ³ OTC Stationary/Area Source Committee. Draft Proposed Regional NO_x Strategy for Stationary Sources in Support of 1994 State Implementation Plans. September 27, 1994.
 - ⁴ For a complete description of the NO_x constraint calculations, Phase II & III levels of retrofit controls and other detailed inputs and results of the analysis, see O’Neill, Erin T. Cost-Effective Strategies for Nitrogen Oxides Reduction: Ozone Attainment Policy for New England. Masters Thesis in Technology and Policy. May 1996.
 - ⁵ Costs assumptions for NO_x retrofits are; for SCR – \$45/kW, \$1/kW-yr, and \$4/MWh (1994), and for SNCR—\$25/kW, \$0.2/kW-yr, and \$0.76/MWh for capital costs, fixed O&M and variable O&M respectively. NO_x retrofits are modeled as operating year-round.
 - ⁶ Total power plant costs ranged from \$630 to \$740/kW (1994) for combined-cycle, and \$440 to \$680/kW for combustion turbines depending on plant size. Windfarm costs were assumed to start at \$1000/kW before transmission system upgrades. Analysis showed that winter-dominated wind generation did little to provide annual peak power during summer months. As such, wind generation was modeled as an energy only resource with no capacity credit.
 - ⁷ The hypothetical wind resource option, while high by today’s level of wind industry activity, is within estimates the available wind resource. Additional costs and transmission losses associated with “remote” power have been included.
 - ⁸ These hypothetical DSM alternatives are simple multiples of the savings observed in utilities’ 1995 DSM portfolios. While such levels are believed to be within the bounds of DSM “technical potential” and include the savings of increased standards, their feasibility with respect to implementation is not implied. To reduce rate impacts, increased levels of DSM are phased in over longer time horizons. The cost of conserved energy for DSM was assumed to be 2.5¢/kWh for commercial and industrial applications, and 5¢/kWh for residential (\$1994).