RUNNING IN PLACE:
RENEWABLE PORTFOLIO STANDARDS AND CLIMATE CHANGE

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ABSTRACT

Renewable portfolio standards ("RPS") have spread widely as states have made an effort to promote electricity production from renewable energy sources, granting privileged market access to eligible technologies and resources. One prominent public policy objective driving their rapid adoption and expansion in recent years has been the desire to mitigate greenhouse gas emissions from the power sector. Eighty percent of power sector CO_2, and thus one third of all U.S. CO_2, comes from 620 conventional coal-fired power plants. Any one of the range of recent proposals to mitigate U.S. GHG emissions will require dramatic reductions in the CO_2 emissions from these plants. This constitutes the essential challenge of power sector GHG policy – in a very real sense, nothing else matters.

With this in mind, I have reviewed four state RPS programs – Connecticut, Minnesota, Colorado and California. I offer a thorough analysis of the available data regarding the experience to date in each of these states as well as indications of future compliance activity. My key finding is that the dominant policy approach imposes three key constraints on the RPS market space – targets expressed only in units of bulk energy, aggressive quantities and timelines, and restrictive program cost limits – resulting in the over-stimulation of terrestrial wind at the expense of other renewable technologies often far better suited to displacing coal and far more likely to experience dramatic improvements in cost and performance.

In order to enhance the efficacy of these programs as climate policies, the following reforms are recommended: (1) create bands based on technological maturity and strongly favor promising early-stage technologies; (2) express targets in metrics more appropriate to replacing the grid's reliance on coal-fired plants; (3); establish compliance guidelines allowing market participants to select higher-cost, early-stage technologies that promise a wider range of services befitting their system requirements; (4) express cost constraints in terms of overall program cost rather than per-unit price caps; (5) skew compliance schedules to smaller quantities from targeted early-stage technologies at the front end, ramping up more rapidly at the back end; and (6) optimize program costs and benefits by allowing some portion of compliance through geographically unrestricted purchase of renewable energy credits, with the balance mandated through purchases from strategic local resources.

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Biographical Note

Michael Hogan was awarded a Bachelor of Science degree in Aerospace and Aeronautical Engineering and in a Bachelor of Arts degree in Philosophy from the University of Notre Dame in 1980. He was awarded a Master of Business Administration degree by the Harvard Business School in 1988. His professional career began at General Electric in 1980, where he was trained in and subsequently practiced the marketing of large power systems. Following Harvard Business School he embarked on an eighteen-year career developing, financing and managing large, privately-owned power generation and gas exploration and production businesses. He was responsible for the development of over $8 billion in assets in seven countries on four continents, and he built and directed two large regional organizations to oversee the resulting business operations.

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Introduction

Renewable portfolio standards ("RPS") are public policies requiring that a minimum quantity of the wholesale electric portfolio in a given jurisdiction be derived from eligible technologies utilizing eligible primary energy sources.[1] Lists of what qualify as RPS programs can vary depending on what one sets as threshold criteria, but for the purposes of this paper I am defining a renewable portfolio *standard* as a statute that mandates compliance at certain levels by certain dates (for example, statutes in Vermont and Virginia would not qualify, since their objectives currently exist only as voluntary goals). As of this writing, RPS statutes have been enacted by twenty-five states and the District of Columbia, but efforts to pass a Federal RPS have so far failed despite numerous attempts since 1997.

The technologies that are eligible to participate under the RPS statutes enacted to date vary somewhat from one state to the next, with a core set of technologies common to nearly every program (e.g., wind turbines) and others eligible in only a few (e.g., municipal solid waste incinerators). The primary energy sources that can be used by these technologies also vary from one state to the next, and in some cases the statutes designate as "eligible" primary energy sources that not everyone would agree are renewable (e.g. waste coal). Indeed in some cases the primary energy source is undeniably *not* renewable (an example is the eligibility of natural gas fuel cells in Connecticut), but those cases are the exceptions. Hydroelectricity receives notably varied (and generally unfavorable) treatment. Only Ohio and Texas grant unconditional eligibility to hydroelectric facilities. All other programs impose various restrictions on size and configuration, and in a few cases date of construction, with most programs disqualifying all but small run-of-river hydro facilities.

[1] Some jurisdictions call them renewables portfolio standards, renewable energy standards, renewable electricity standards, alternative energy standards and other variations on the same basic idea.

Standards can be applied to the production of wholesale electricity or as sourcing obligations applicable to the sale of electricity to end-users. All of the current statutes operate by placing minimum wholesale sourcing obligations on at least the regulated private-sector providers of retail electricity (investor-owned utilities or "IOUs") and where applicable on competitive retail power marketers; in a few cases the obligations extend to all retailers, including co-ops and municipals (all commonly referred to collectively as load-serving entities or "LSEs"). The standard could be expressed in any one of a number of relevant metrics, such as the number of megawatts ("MW") of installed capacity, the percentage of a generating company's installed generating capacity, the percentage of electric energy produced or the percentage of electric energy sold at retail. The great majority of the current statutes express the standards in terms of a percentage of electricity sold at retail, though two states (Texas and Iowa) have standards expressed in the number of MW installed. There are numerous other features of these statutes that can vary from one to the next, and Appendix A presents a tabular summary of the key features of each program.

The topic of this paper – the relationship between renewable portfolio standards and the battle against climate change – is often discussed, but one of the more thoughtful, robust and balanced treatments of the topic is a 2003 study conducted for Resources for the Future.[2] The report presented the results of a theoretical analysis of the likely impact of a national RPS at various levels, based on a digital model of the U.S. electric power system and compared to the theoretical impact of a production tax credit mechanism and a carbon cap-and-trade mechanism. What the authors could not easily have done was to analyze these questions based on actual experience with real RPS policies, since (as they noted at page 6 of the report) the population and

[2] Palmer, Karen and Dallas Burtraw. "Electricity, Renewables and Climate Change: Searching for a Cost Effective Policy," prepared for Resources for the Future, May 2004

reach of such policies in 2003 was relatively limited, and of those policies that were in place very few had been operating long enough to produce a meaningful amount of useful data. In the five years since they conducted their study the population of state-level RPS statutes has grown by over 2.5 times. While it is still early days for many of these programs, most of which extend out to or beyond 2020, there is now a considerable amount of data available from many of the more ambitious RPS programs, and that data provides the basis for the analysis presented in this paper. It is not my intention to test Palmer and Burtraw's conclusions or to update their analysis, but I do hope to expand on several of the themes touched on in their study, and to see if five additional years of data and a much larger population of statutes can tell us anything new about some of the issues they raised.

The thesis of this paper can be summarized as follows:

1) That the various state-level renewable portfolio standards have been enacted not to promote investment in renewables *per se*, but through the promotion of investment in renewables to achieve certain public policy goals;

2) That the public understanding of the goals established for these statutes is set both through the letter of the statute and through the public dialogue that takes place in and around the legislative process by which they are enacted into law;

3) That the principal public goods driving the adoption of these policies (and their predecessors) have evolved over time, and that playing a leading role in reducing power sector greenhouse gas emissions is a primary, in many cases the primary, public policy objective put forward in recent years to justify their enactment and/or expansion;

4) That it is possible, based on mainstream sources, to frame what would be considered a meaningful contribution by the power generation sector to U.S. climate change objectives and a timeline on which that contribution must be made;

5) That current RPS programs as designed are likely to play at best a very marginal role at an unnecessarily high cost in delivering the necessary reductions in power sector greenhouse gases, with little in the way of long-term technological development benefits to be expected, and are thus unlikely to achieve one of the primary public policy objectives put forward to justify their rapid expansion in recent years; and

6) That it is possible, through a reasonable package of refinements to the prevailing policy model, to substantially improve the likelihood that they will achieve those objectives.

The structure of the paper is straightforward and data-driven. In Chapter One I present an overview of the shifting public policy agendas that have shaped the development of the dominant policy model we see today. I trace the origins of the renewable portfolio standard back to the energy conservation legislation of the late nineteen-seventies, and I place the punctuated development of renewable electricity policies within the non-rational "policy entrepreneurship" model, developed by political scientist John Kingdon, describing how government policy and in particular government science policy is made. Finally, I provide some pertinent overall statistics on the actual impact of RPS policies to date, including two general insights that will become especially important later in the paper.

Chapter Two provides an overall framework within which I propose to define what would be a meaningful contribution by the power sector to U.S. climate policy and a meaningful timeline for that contribution. I do not claim that the reference scenario postulated here is in any way definitive, but at the same time I believe it is entirely credible and fully within the mainstream of public discussion on prospective U.S. actions to address climate change. It is against this reference scenario that I propose to evaluate the materiality of the contribution likely to be made by RPS programs as they are currently designed and operating.

Chapter Three provides a set of screening criteria for the selection of a sample of state programs for more detailed analysis. Based on those criteria four state programs are selected: Connecticut, Minnesota, Colorado and California. The market context, legislative evolution and structure of each program are then analyzed in detail, and an assessment is provided of the renewable resource potential accessible for compliance with each state's program.

In Chapter Four I provide a detailed analysis of the historical data for each state showing actual trends in renewables development, both in-state and regionally, and I analyze publicly available sources that give some indication in each case of prospective in-state and regional developments. An analysis is presented of power sector CO_2 emissions trends for each state since the passage of their respective RPS statutes. Finally, a detailed analysis is provided of the state-by-state market drivers likely to be shaping the industry responses characterized earlier.

Chapter Five is a summary the findings across the four state case studies, synthesizing those findings into an integrated package of six recommendations for reform of the policies. It is my hope that this final chapter presents some useful insights into how one might evaluate RPS policies going forward.

Chapter One

The Evolving Public Policy Agenda

Since they first appeared on the scene in the mid nineteen-nineties, renewable portfolio standards have spread quickly across a large and diverse array of U.S. state electricity markets. States in every region of the country have jumped on the bandwagon, and the pace of new programs and amendments to existing programs remains strong. This year has seen the addition of Ohio to the list of RPS states following the addition of four states in 2007 (New Hampshire, Oregon, North Carolina and Illinois). Eight existing state programs were substantially expanded in 2007, and a major expansion of the Massachusetts RPS (one of the earliest programs) was signed into law in July 2008. A critical question posed in this thesis is "Why?" What public policy objectives were behind the initial interest in these policies, and how have those objectives evolved to support the recent strong level of interest?

Renewable portfolio standards emerged in two distinct waves over the past fifteen years.[3] The first wave occurred between 1994 and the 1999, coinciding with the wave of state electricity restructuring. Indeed every RPS enacted during this period except for Minnesota's was embedded in electricity restructuring legislation, and as we shall see, even the Minnesota RPS was part of a larger regulatory give-and-take. Nine states enacted RPS programs during this first phase. The popularity of electric restructuring declined precipitously from 2000 onward, and with it, seemingly, went the impetus for RPS policies. Only one new RPS policy was enacted between 2000 and 2004 (California in 2002, which was arguably not actually new[4]), but beginning in 2004 the phenomenon burst back onto the scene. In the four years since 2004

[3] Though not thought of as a renewable portfolio at the time, Iowa enacted a law in 1983 requiring utilities to install 105 MW of wind generation by 1999

[4] In 2002 California revived the RPS that had been considered in 1995, because the approach chosen the first time around – a public benefits charge on customers' bills to support renewables – was having little impact

fifteen states and the District of Columbia have implemented RPS policies, and many of the earlier policies have been strengthened and/or substantially expanded. Remarkably, while every one of the nine first-wave programs was embedded in some form of omnibus utility legislation, all but three of the sixteen second-wave programs were enacted as stand-alone legislation (Illinois, Ohio and North Carolina being the exceptions), including the only two examples to date of successful RPS ballot initiatives (Colorado and Washington).

Renewables before the RPS - The Urge to Conserve

While the first RPS policies were implemented in the mid nineteen-nineties, their origins can be traced back much further to the energy crises of the nineteen-seventies.[5] The first major public policy initiative promoting the development of renewable electricity was the Public Utility Regulatory Policies Act ("PURPA"), which was passed into law by Congress in 1978. PURPA was part of the National Energy Act of 1978 ("NEA"), one of a number of responses to the oil and gas shortages that erupted during that decade, and its primary purpose was to promote the conservation of domestic fossil fuel reserves. Another component of the NEA was the National Energy Conservation Policy Act of 1978, which is often thought to have inaugurated the era of policy support for efficiency and demand-side management ("DSM") programs in the U.S. electric industry, though there had been state-level policy initiatives in California and Wisconsin as early as 1975.[6] DSM programs spread rapidly largely in parallel with but independent of the evolution of renewable energy under PURPA, a trend that continues today with some exceptions (for an example of RPS programs that combine renewables with efficiency see the discussion of

[5] See e.g. Guey-Lee, Louise, "Renewable Electricity Purchases: History and Recent Developments," *Renewable Energy 1998: Issues and Trends*, U.S. Department of Energy, Energy Information Agency, March 1999, pp. 1-44
[6] For a good introductory reference to research on the history of efficiency and DSM programs in the U.S. electric industry, see Loughran, David S. and Jonathan Kulick, "Demand-Side Management and Energy Efficiency in the United States," *The Energy Journal*, 2004, Vol. 25, Issue 1, pp 19-43

Connecticut's RPS statute in Chapter Three). By 1993, 447 utilities were spending $3.2 billion (1.7% of total revenues) on DSM annually over and above their expenditures for renewables.[7]

The primary beneficiaries of PURPA were cogeneration plants (as specifically defined) and renewables, both of which were expected to reduce the need to consume finite fossil fuel reserves in the production of electricity and thermal energy.[8] Thus while the environmental benefits of producing electricity using renewable primary energy sources did not go unnoticed, the dominant public policy objective driving the adoption of the first legislated support for renewable electricity production was conservation, more specifically the conservation of domestic fossil fuel reserves and in particular natural gas. As summarized by the Federal Energy Regulatory Commission in 1996,

> "In enacting PURPA, Congress recognized that the rising costs and decreasing efficiencies of utility-owned generating facilities were increasing rates and harming the economy as a whole. To lessen dependence on expensive foreign oil, avoid repetition of the 1977 natural gas shortage, and control consumer costs, Congress sought to encourage electric utilities to conserve oil and natural gas. In particular, Congress sanctioned the development of alternative generation sources designated as "qualifying facilities" (QFs) as a means of reducing the demand for traditional fossil fuels. PURPA required utilities to purchase power from QFs at a price not to exceed the utility's avoided costs and to sell backup power to QFs."[9]

Greenhouse gases and the theory of global warming were at that time little discussed outside of the climatology fraternity and were not particularly relevant to the Act's passage.

By the late nineteen eighties oil and natural gas shortages were becoming a distant memory. Both the oil shortage and the natural gas shortage had been artificially induced, in the case of natural gas by years of stringent price caps that had stifled exploration and production,

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[7] *Ibid*, pg. 19

[8] Cogeneration and combined heat and power ("CHP") are used interchangeably to refer to the re-use of thermal energy that otherwise would have been wasted; the "waste heat" can be the result either of primary power generation or of a thermal process, and the waste heat is used either for electricity production or for useful thermal applications

[9] FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," final order issued 24 April 1996, pp 22-23

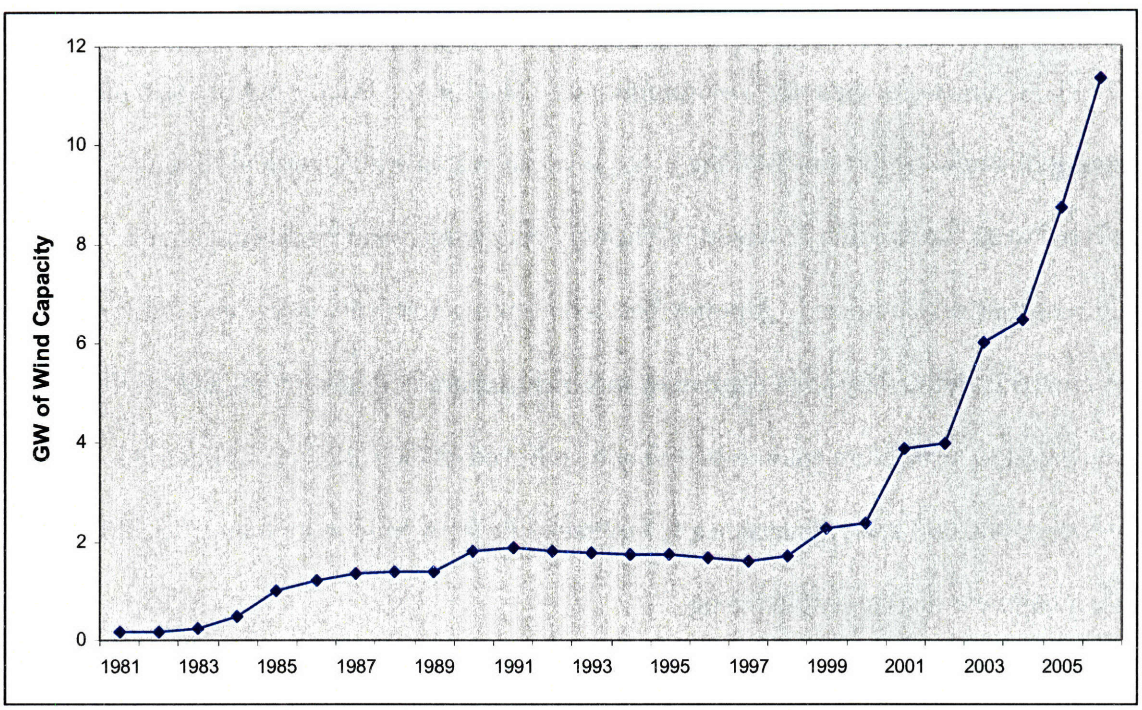
and in both cases supplies had once again become plentiful and cheap. But PURPA was on the books and the pace of development gained momentum throughout the eighties, as a number of states had mandated lucrative standard-offer contracts for PURPA-qualified facilities. In the case of renewables, the main action was in California. Of the states to mandate standard-offer PURPA contracts California was the only one aggressively to promote its renewables potential, and by 1991 California was home to over 80% of the world's installed wind capacity.[10]

PURPA's reign effectively came to an end in the early nineteen-nineties. Dire predictions for fossil fuel prices that had shaped most standard-offer PURPA contract rate structures had failed to materialize, and those contracts had proved to be quite expensive, even helping to drive some utilities into or close to insolvency. The urge to conserve had long passed, and market-based reforms of formerly government-dominated economic sectors were all the rage.[11] The U.S. electricity industry was not immune. The Energy Policy Act of 1992 marked the beginning of a new era for much of the U.S. power sector, in which vertical disaggregation (often referred to as "unbundling") would be strongly encouraged and market-regulated wholesale power prices embraced. A policy based on forcing vertically integrated utilities to enter into contracts defined by state regulators was inconsonant with this trend, and utilities and states that agreed to restructure could effectively be relieved of their PURPA obligations. Virtually every state that had enthusiastically embraced PURPA little more than a decade earlier eventually underwent market restructuring.

[10] It is worth noting that PURPA functioned in essentially the same fashion as the feed-in tariff mechanism adopted in many European countries to promote renewables beginning in the mid 1990s; states mandated purchase prices based on an administratively determined "avoided cost" for conventional utility-produced power and relied on the market to determine the quantity of resources that could be developed in response to those prices

[11] See Yergin, Daniel and Joseph Stanislaw, *The Commanding Heights: The Battle between Government and the Marketplace That Is Remaking the Modern World*, 1998

With PURPA (and conservation) no longer an effective driver, development of renewable power projects in the U.S. ground to a halt. Figure 1.1 below shows the trend in cumulative installed wind capacity in the U.S. since 1981. Figure 1.2 indicates that while some non-wind development continued beyond 1990 (primarily small hydro), it too had ceased by 1995. The Federal production tax credit ("PTC") for wind was enacted in 1992, but without a replacement for the guaranteed market access provided by PURPA the PTC seems to have had little or no immediate effect. The surge of PURPA-driven growth faltered in the early nineteen-nineties as utilities, regulators and developers anticipated the onset of a new paradigm for wholesale power generation.



Source data: U.S. Dept. of Energy, Energy Information Agency ("EIA")

Figure 1.1 – Cumulative U.S. installed wind capacity, 1981-2006

Renewable Portfolio Standards Arrive – As a Response to Electric Industry Restructuring

Renewables advocates, particularly the American Wind Energy Association ("AWEA," formed in 1974 in the wake of the 1973 OPEC Oil Embargo), began actively promoting new policy ideas that would revive the fortunes of renewables in the face of the coming wholesale competition while still claiming to be consistent with the rising market-driven ethos.[12] In response, renewable portfolio standards emerged as a leading policy innovation. The first serious debate over what would today be recognized as a typical RPS took place in California in 1995 during that state's restructuring deliberations, but the first RPS actually implemented was a solar portfolio standard enacted by the Arizona legislature in 1996.[13]

While the subject of global warming had by this time entered the wider public domain and become a fixture in the renewables advocacy literature, it was not strongly evident in the legislative and public discussions taking place at that time around the adoption of these new policies. Nor was there any urgency around conservation. And while acid rain and other power plant-related air quality concerns were certainly touted by renewables advocates and on the public agenda in the early nineteen-nineties, the main policy thrust on those issues was around SO_2 cap-and-trade and NO_x emission limits.[14] Instead, the overwhelming sense of the RPS debate at the time was of the demand in some quarters for a *quid pro quo* in return for granting at least tacit support for the move to market-based regulation of wholesale power prices and the

[12] For the definitive advocacy piece from this period, see Nancy A. Rader (writing as a consultant to AWEA) and Richard B. Norgaard, "Efficiency and Sustainability in Restructured Electricity Markets: The Renewables Portfolio Standard," *The Electricity Journal*, July 1996, pp. 37-49

[13] Iowa in 1983 mandated a small amount of wind generation and Minnesota enacted its proto-RPS in 1994, but Arizona's was the first standard expressed as a minimum percentage of energy sold at retail – it was subsequently withdrawn and replaced with the current policy in 2000

[14] See Judith A. Layzer. 2006. "Market-Based Solutions: Acid Rain and the Clean Air Act Amendments of 1990," *The Environmental Case: Translating Values Into Policy*, 2nd ed. (CQ Press), 375-403. While reduced emissions of NOx and SO_2 are indeed potential benefits of renewable power production, they differ from CO_2 in at least one essential feature – there exist proven means to control them at source that are currently more cost-effective than alternative production technologies specifically as a mitigant for these pollutants

neutering of PURPA. Sacred cows were at risk and must be safeguarded. Renewables were not the only candidate put forward for this purpose (legacy energy efficiency and low-income energy assistance programs were also in the mix), but renewables had gained a foothold under PURPA and were the environmental *cause célèbre* most directly threatened by wholesale competition.

As is evident from the data presented in Figure 1.1, this was a time when renewable energy advocates in the U.S. were very much on the back foot, with renewables development badly stalled and advocates of market-regulated wholesale electricity very much in the ascendancy. It was during this time that RPS policies evolved their focus on bulk energy produced and sold at retail, rather than installed production *capacity* or other pertinent industry metrics. This aspect of the RPS phenomenon will become an important topic of discussion later in the paper, but it would appear that there was an open question during this phase of policy advocacy whether it was best that the standards be expressed in installed MW of capacity, percentage of total kWh of energy sold at retail, or some other critical metric.[15] Iowa, Minnesota and Texas opted to express their standards in installed MW of production capacity, but every other program enacted in that first wave, and every program since, has opted for a standard expressed as a percentage of kWh sold at retail (including Minnesota, which converted its RPS to an energy-only metric in 2007).

The bias among advocates toward an energy-based metric seems to have been rooted in the assumption that the best way to ensure that the expected benefits are delivered is to measure the raw quantity of non-eligible electricity production that is displaced by eligible electricity production. In line with the times, there is a hint in the literature that this bias was driven as much by mistrust of the regulated LSEs as it was by a thorough analysis of the actual

[15] See e.g. Rader, Nancy and Scott Hempling, "The Renewables Portfolio Standard: A Practical Guide," report prepared for the National Association of Regulatory Utility Commissioners, February 2001, pg. xi

mechanisms by which the expected benefits would be best delivered, but I would maintain that either line of reasoning was flawed. In Chapters Four and Five I will address at length the disadvantages of an energy-only metric as a mechanism for delivering the expected benefits. As for the concern that the desired quantities of renewable energy would actually be produced, any mistrust that may have driven the energy-only bias were perhaps understandable but in retrospect were most likely unjustified, particularly in those markets that have subsequently come under the management of Federally chartered independent system operators. (See Chapter Three for more information.) As will be covered later, Minnesota's initial capacity-denominated standard was at least as successful as any other RPS programs of that period, and the marked success of the Texas program (still capacity-denominated) continues to reinforce that view. Nonetheless we have today a suite of state RPS programs overwhelmingly expressed in terms of bulk energy sold at retail, a fact the implications of which I will address in this paper.

As noted earlier, the dramatic downturn in electric industry restructuring at the start of this decade seemed to spell the end of the RPS phenomenon, with the last truly new first-wave RPS being enacted in mid 1999. With no new state electricity restructurings to tame, and with new renewables activity stirring once again (see Figure 1.1 above), what Kingdon[16] described as a "policy window" that had been so productive for renewables policy advocates appeared to close. Five years would pass before the enactment of the next new state RPS policy.

The March Resumes – A Policy Response to Climate Change and Energy Independence

The RPS phenomenon underwent a dramatic revival beginning in 2004. After five years during which the spread of the RPS policy model had all but ceased, the year 2004 saw seven states enact new RPS legislation. Over the next three and a half years eight more states and the

[16] Kingdon, John W., *Agendas, Alternatives and Public Policies, Second Edition*, 1995, Univ. of Michigan, Ch. 8

District of Columbia enacted new RPS policies, and a number of first-wave programs were dramatically expanded. What had changed?

While the package of benefits touted by proponents remained relatively constant, the crucial changes in the menu of urgent public policy issues between 1999 and 2004 appear to have been the emergence of climate change and energy independence as political hot-buttons. As noted earlier, global warming/climate change had long been part of the RPS sales pitch, but its newfound value as a "hook" in promoting adoption of RPS policies is borne out in the prominence of the issue in legislative, electoral and media discussions that have taken place around these proposals since 2004. What had been simply one piece of the argument in the nineteen-nineties, and one that went unmentioned in any of the nine legislative packages passed at that time, now featured prominently in RPS deliberations in every new state, and it was the central issue in many of those debates. Indeed Pennsylvania's inclusion of integrated coal-gasification combined cycle plants as an eligible technology (even with no carbon capture and sequestration) under its 2004 RPS statute has been justified on the basis that the primary goal of an RPS is CO_2 mitigation rather than the promotion of renewables *per se*, and that IGCC is a gateway technology to low-carbon coal-fired generation.[17] Climate change remained (and remains) a deeply divisive political topic capable of eliciting a visceral reaction from opponents, and as such it was still not explicitly referenced in most states' legislation. But for the first time it was explicitly referenced in the language of three of the new state RPS laws. As Richard Cowart, chairman of the Vermont Public Service Board from 1986 to 1999, wrote in May 2006:

> "The tide is finally turning on global warming policy in the US power sector. During the 1980's and 90's a number of regulatory policies and market reforms aimed at lowering power bills and environmental impacts, but they rarely focused on an explicit objective to lower the greenhouse gas emissions of the electric industry. Least-cost planning, DSM, renewables policies, and restructuring have all had impacts on the carbon profile of the

[17] See Dobesova, Apt and Lave, "Are Renewable Portfolio Standards Cost-Effective Abatement Policy?"

> electric sector – but their climate impacts (positive or negative) were always downplayed. During most of the 1990's, even mentioning that there were greenhouse benefits to policy options like renewable portfolio standards or efficiency programs was often seen as a political detriment."[18]

The newfound potency of the issue is also reflected in the changing emphasis found in advocacy material. AWEA's October 1997 fact sheet on RPS, for example, had focused almost entirely on its virtues as a market-based mechanism that promoted renewables without impeding the march of competition. Reducing greenhouse gas emissions warranted only a brief mention, well down the list as but one of many benefits. In May 2007, by contrast, AWEA sponsored an open letter from an impressive litany of U.S. corporations to Congressional leaders in support of Senator Jeff Bingaman's proposed Federal RPS. The first two benefits touted in that statement were national energy security and greenhouse gas reduction. Regarding climate change, the letter stated prominently that an RPS "...is one of the most important and readily available approaches to reducing greenhouse gases from the electricity generation sector." Climate change had really arrived and, along with energy independence, opened a new policy window for RPS advocates.

Renewables Advocacy as Successful Policy Entrepreneurship

The history of public policy support for renewables in the power industry can be seen as a good example of the policy formation model described by University of Michigan political scientist John W. Kingdon in his 1995 book *Agendas, Alternatives and Public Policies.* Kingdon co-opted an earlier theory dubbed "The Garbage Can Model of Organizational Choice,"[19] modifying it for use in his empirical analysis of federal policy decision-making. Kingdon

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[18] Presented at the American Council for an Energy Efficient Economy's *Conference on Energy Efficiency as a Resource*, May 2006

[19] See Kingdon, John W., Agendas, Alternatives and Public Policies (1995), in which he references Cohen, Michael, James March and Johan Olsen, "The Garbage Can Model of Organizational Choice," Administrative Science Quarterly 17 (March 1972): 1-25

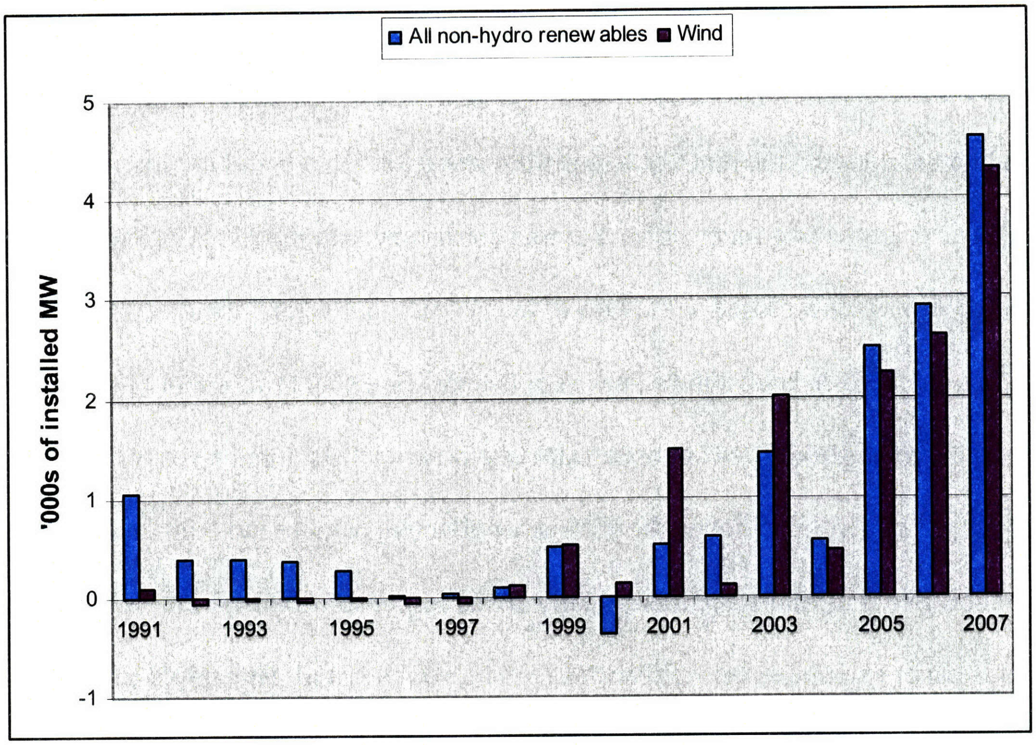
described three "streams" – (1) problem recognition, (2) the formation and refining of policy proposals, and (3) politics – each of which develops and operates independently of the other two. The opportunity for policies to become enacted into law occurs when what Kingdon calls a "policy window" opens. Such an opening appears with the coincidence of a particular problem gaining currency among government decision-makers as something worth addressing; the availability of prospective policy prescriptions seen as capable of addressing some aspect of the problem; and a shift in the political *Zeitgeist* that lends the problem a sufficient level of public urgency. Essential to the movement of a policy prescription through this process is what Kingdon called a "policy entrepreneur," an advocate able to identify a policy window and, in response, to define a given policy proposal as a viable solution to a given problem in a way that is compelling to policymakers (what Kingdon refers to as "coupling"), all within the unknowable timeframe during which the policy window will remain open.

Renewables advocates, most notably AWEA, have been remarkably effective over the past thirty years as policy entrepreneurs (with the notable exception of the Federal RPS). The package of benefits claimed for renewable power generation technologies (conservation of finite energy sources, economic development, pollution abatement, energy independence) has remained largely unchanged since the late nineteen-seventies (with the addition of global warming in the nineteen-eighties). The relative efficacy of the measures promoted has progressed as some of the technologies have matured, but the basic package of solutions hasn't really changed all that much. But the emphasis has shifted over the years in response to prevailing political winds and the dominant public policy agenda. When a policy window opened in the late nineteen-seventies for policy prescriptions aimed at fossil fuel conservation, renewables advocates were there with their contribution to PURPA. When PURPA faded in the nineteen-nineties, and as the feed-in tariff approach that characterized PURPA lost favor politically, renewables advocates successfully reformulated the same basic package of measures into a policy prescription – the renewable portfolio standard – that could be said to be a market-based approach to protecting renewables that was consistent with the rising political ethos of the time. That policy window closed at the turn of the century, but when global warming and energy independence emerged as hot-button issues over the past five years (importantly, each of the two issues appealing most strongly to opposite sides of a polarized electorate), renewables advocates once again successfully repositioned the RPS as an effective response to both concerns. How effective renewable portfolio standards actually are as responses to these various issues can be debated (this paper examines their efficacy as climate policies, and Appendix I presents a brief discussion of claims regarding energy independence and economic development), but Kingdon's key finding was that efficacy is not the primary consideration in the adoption or rejection of a given policy prescription. Opportunity, availability and expediency are the primary considerations, along with the essential role of the policy entrepreneur in "joining the streams." Renewables policy entrepreneurs have successfully joined the streams at key junctures over the course of several decades.

Meanwhile, Back at the Ranch...

As of mid 2008 the twenty-six renewable portfolio standards that have been enacted apply to 48% of all electricity sold at retail in the United States.[20] Given the impressive (bimodal) expansion of the RPS as an instrument of power industry regulatory policy, how much actual investment renewables has taken place, and where?

[20] A simple tally of the sales for each state in which an RPS has been enacted would yield a higher number, but the coverage rate stated here reflects excluded sales within each state based on the terms of the respective statutes

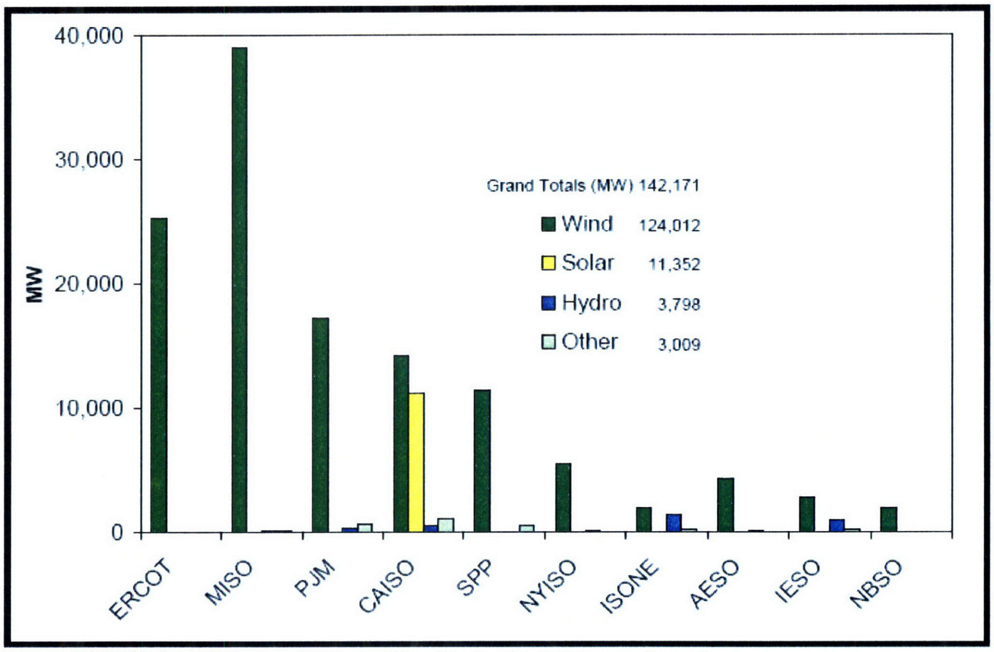


Source data: EIA

Figure 1.2 – New additions of non-hydroelectric renewable capacity in the U.S.

Figure 1.2 presents a picture of strong growth since the dawn of the RPS era. The first observation one might make is that wind has strongly dominated investment in renewable power generation since the first RPS statutes were passed. Over the past five years 97% of all new renewable generating capacity installed in the U.S. was wind generation. The ISO/RTO Council[21] noted in October 2007 that 87% of all the renewable generation in interconnection queues across the country was wind generation. (See Figure 1.3 below) I will address the important implications of this phenomenon at length in the following chapters.

[21] "ISO/RTO" stands, respectively, for Independent System Operator and Regional Transmission Organization, which will be described in Chapter Three

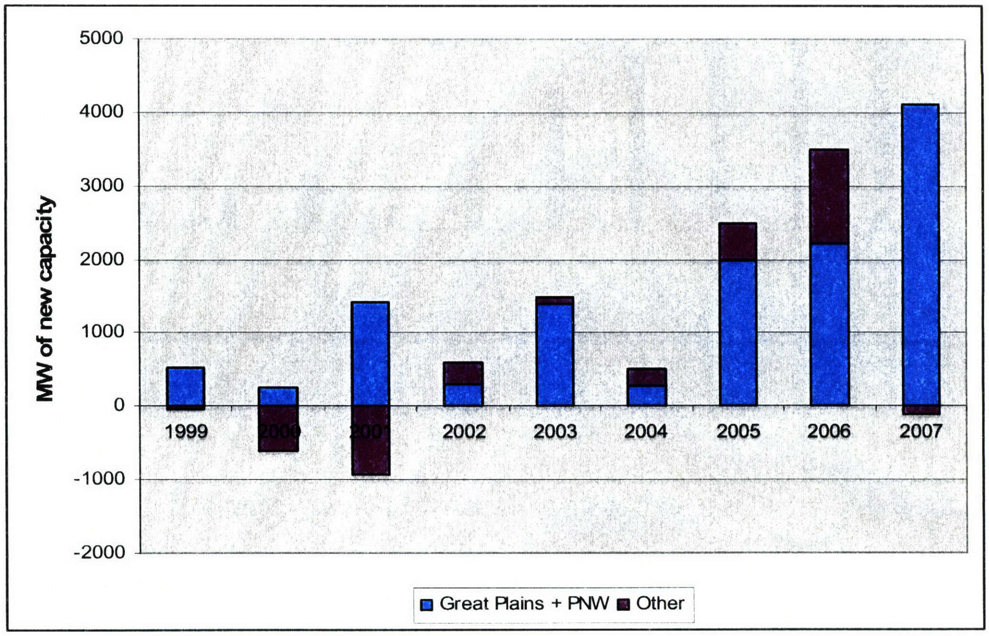


Source: ISO/RTO Council, *Increasing Renewables*, October 16, 2007, pg. 6, figure 2

Figure 1.3 – ISO/RTO Council graph of renewables in interconnection queues

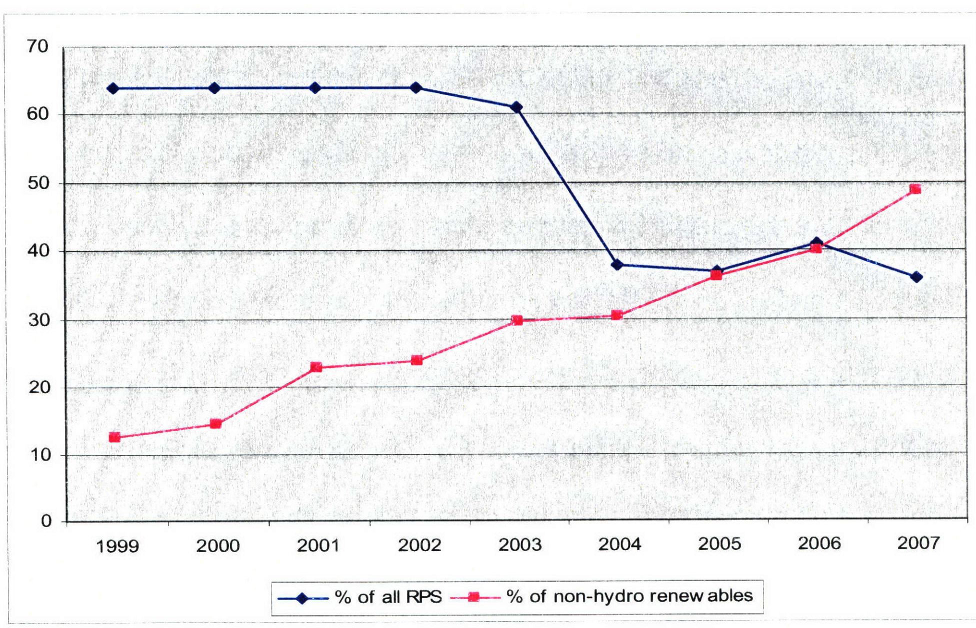
While the overall trend is one of sustained growth, a closer examination reveals a recurring and potentially troubling pattern. I noted earlier that the enactment of the Federal PTC in 1992 had little effect on renewables development until the advent of state-level RPS programs. Conversely, the PTC has three times during the RPS era expired without immediately being renewed – end of 1999, end of 2001 and end of 2003 – and each time it was belatedly reinstated about a year later. The result each time has been a notable pullback in the pace of renewables development. A strikingly coincidental pattern of interrupted progress is evident in the data presented in Figures 1.1 and 1.2. The PTC is currently set to expire at the end of 2008, and Congress has so far refused to extend it. As worrying for wind advocates, the leading proposal to renew the credit would extend the PTC for wind only through the end of 2009.

A final observation I would make here has to do with the geographic distribution of renewables investment. As shown in Figures 1.4 and 1.5 below, the rapid growth in new renewables is taking place predominantly in states with access to the Great Plains wind resource, and to a lesser extent Washington and Oregon, a trend that has persisted strongly in spite of the fact that total of the retail electricity sales subject to the RPS in those states has steadily declined as a percentage of all retail electricity sales subject to RPS statutes. Again, I will be addressing the potential implications of this phenomenon in the following chapters.



Source data: EIA

Figure 1.4 – Non-hydro renewables investment, Great Plains/PNW states vs. all others



Source data: EIA

Figure 1.5 – Great Plains/PNW as proportion of all RPS vs. proportion of non-hydro renewable capacity

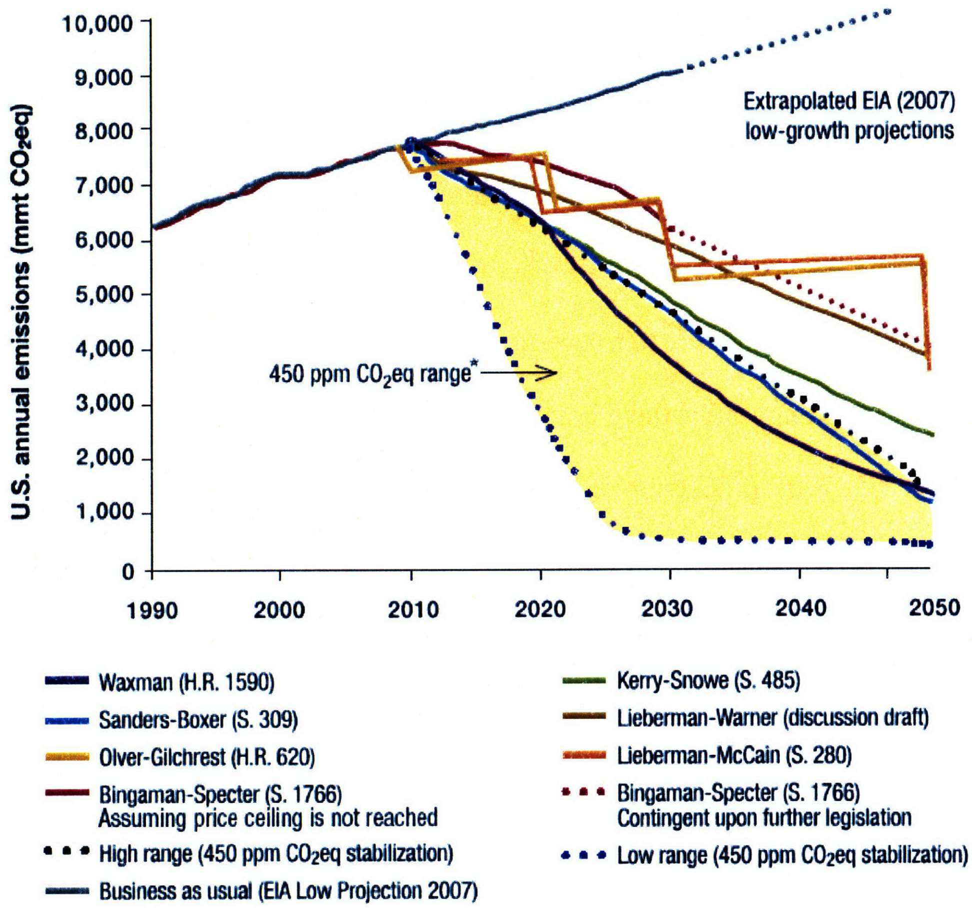
Chapter Two

Renewable Electricity Production and the Response to Climate Change

There is clearly a wide range of views regarding what should be done to reduce the net production of greenhouse gases ("GHG") from human activities and the time frame over which it should be done. It is not my intent in this paper to debate the science of climate change. This paper rather takes as its premise that there is a significant threat of dangerous climate change; that anthropogenic GHG (the production of greenhouse gases as a result of human activity) is a leading contributing factor to that threat; and that the mitigation of anthropogenic GHG to some specified level within some specified period of time is likely to stabilize the concentration of GHG in the atmosphere at a level that is likely to avert some but not all of the most adverse consequences. Put much more simply, this paper takes as its premise that we face a risk, most likely man-made, of unacceptable proportions, and that there are feasible risk mitigation measures that can, and therefore should be taken in response.

How High Is the Mountain?

Given this premise, a representative picture of the climate change "task" can be drawn from relatively conventional sources. Perhaps the most conventional source, or at least the one that most credibly bounds the prescription that may actually be enacted, can be found in the range of Congressional climate change proposals recently under consideration. These proposals are presented graphically in Figure 4.1 below.



Source: Union of Concerned Scientists

Figure 2.1 – Congressional climate change proposals

The range runs from a 50% to an 80% reduction from 1990 levels by 2050. Both presumptive Presidential candidates have endorsed targets that fall within this range, with Senator McCain having endorsed a target of 60% and Senator Obama supporting a target of 80% below 1990 levels by 2050. Focusing on a horizon more relevant to the time period covered by state-level RPS programs, most of these proposals require a return to 1990 levels by 2020 as a precursor to achieving their ultimate objectives. It is this interim objective – a return to 1990 levels by 2020 – that I will use as a benchmark in assessing the role to be played by the power generation sector.

Like nearly everything else about the electricity industry, the scale of its contribution to total greenhouse gas emissions is enormous. In fact, power generation as a category is the leading source of anthropogenic GHG. Of the 5.983 metric gigatons of CO_2 emitted in the United States in 2006, 41% or roughly 2.46 gigatons were emitted as a direct result of the production of electricity (transportation was second at 31% or 1.856 gigatons). [EIA data] For an industry that makes such a massive contribution to such a complex and contentious problem, the structure of its contribution is deceptively simple. Of the CO_2 emissions attributable directly to power production in 2006, roughly 80% or 1.974 gigatons were produced by the burning of coal in 620 power plants. These 620 plants were thus responsible for one third of all anthropogenic CO_2 in the U.S. in 2006. Unfortunately, that constituent simplicity masks the scale of the challenge – in 2006 coal accounted for 313 GW or roughly 32% of installed U.S. generating capacity and 49% of all of the electricity produced. The replacement value of those 620 coal plants is on the order of $500-750 billion.[22] To replace their productive capacity with nuclear plants would cost at least twice that much.[23] To replace the firm capacity provided by these plants with an equivalent amount of firm capacity from wind power plants could cost $4.5 trillion or more.[24]

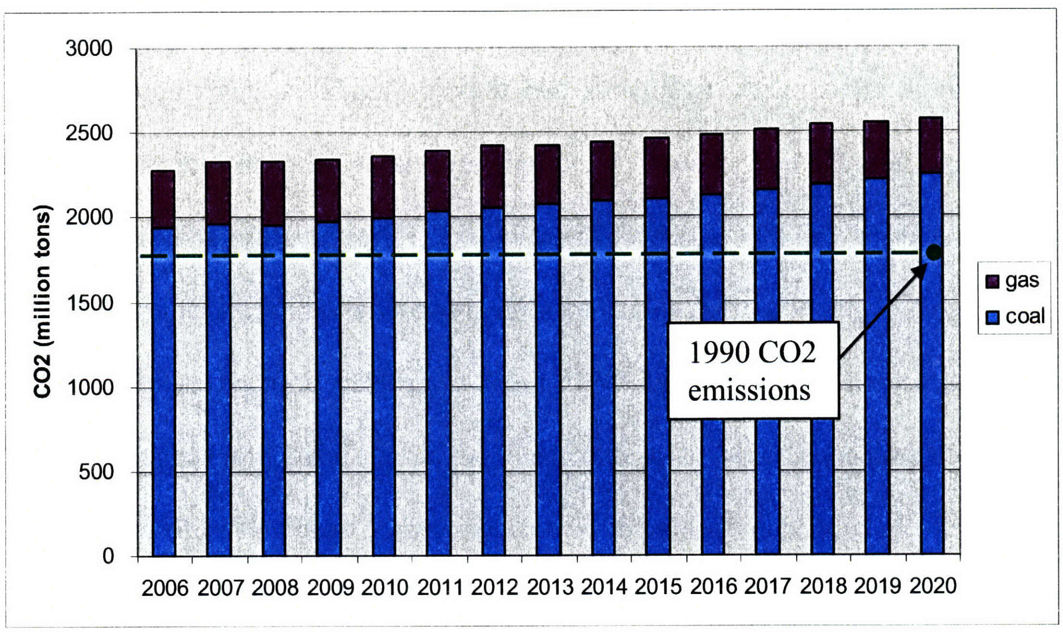
Yet replace them we must, or in some other way drastically reduce their CO_2 contribution, if the U.S. is to stand any chance of reaching the overall GHG reduction objectives I've postulated as a reference scenario. Given the size of power generation's contribution and the fact that 80% of it can be traced to only 620 facilities, it is inconceivable that the power

[22] Assumes a national average total cost for a new 1,000 MW pulverized coal plant, including interest during construction, of approximately $2,000-2,500/kW

[23] Assumes a national average total cost for a new 1,000 MW nuclear plant, including interest during construction, of approximately $5,000/kW, based on comments by Thomas Christopher, CEO of Areva, Inc., at the 2008 MIT Energy Conference; one can find lower estimates, but most recently cited estimates are at or above this level

[24] Assumes that the existing coal fleet has a firm capacity value of 90% of nameplate, that the replacement wind capacity will have an average firm capacity value equal to 10% of nameplate, and that wind will cost approximate $1,500/kW to construct, including interest during construction

sector will not be tasked with at least a *pro rata* share of any U.S. commitment to reduce GHG emissions. Using the EIA's 2008 Reference Case for power sector CO_2 emissions, and assuming the sector bears merely a *pro rata* share of the targeted reductions in GHG, the green line on Figure 4.2 below illustrates the CO_2 emission reductions that would be required of the power sector in order for the U.S. to reach the stipulated 2020 objective (an 80% reduction below 1990 levels by 2050 would equate to CO_2 emissions in 2050 of approximately 360 million tons).



Source data: U.S. Energy Information Agency

Figure 2.2 – CO_2 reductions from EIA 2008 Reference Case

With Figure 4.2 above as context, it is useful to consider one illustrative scenario. A fact sheet issued by the Union of Concerned Scientists in April 2007 calculated the total CO_2 emission reductions in 2020 attributable to renewable generation installed between 1997 and 2020, assuming that all then-current state RPS objectives for 2020 were met. The UCS analysis projected that nearly all of the growth in renewables would come from wind power. Based on that analysis, and taking account of the growth in renewables already built into the June 2008 EIA Reference Case (again, nearly all from wind), the incremental reduction in 2020 CO_2 emissions from the Reference Case would only come to approximately 70 million tons.[25] This small incremental impact is due in part to the fact that the RPS targets included in that analysis represented less than 10% of all electric production, but it is also attributable to the fact that nearly all of the production displaced by the projected wind energy would be natural gas-fired, a phenomenon that will be discussed in great detail in Chapters Four and Five.

To make the point in yet a different way, it is informative to look at the relative effectiveness of displacing a marginal kWh of electricity from conventional coal plants and a marginal kWh of electricity from comparable gas-fired plants (natural gas is the second largest source of U.S. power generation at 20%). Displacing a kWh of conventional coal-fired electricity eliminates approximately 2.45 times as much carbon in CO_2 as does displacing a kWh of electricity produced by a typical gas-fired combined cycle plant,[26] implying that a renewable technology capable of replacing coal-fired plants on the grid can be up to 2.45 times as expensive as a competing technology likely to displace primarily gas-fired plants and still be a more cost-effective approach reducing power sector GHG emissions. This comparison is a bit simplistic – it is unlikely that any mix of renewables added to the grid would displace *only* coal or *only* natural gas – but it is directionally useful.

In short, the mountain facing the power sector is the highest peak in the range, and it's made out of coal. It is highly unlikely that any policy that promotes substitution primarily of natural gas-fired or other types of non-coal-fired generation, regardless of how effective it is in doing so, stands any chance on its own of achieving these objectives.

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[25] EIA Annual Energy Outlook 2008, Table 15

[26] Assuming 35% thermal efficiency for the coal plant and 48% thermal efficiency for the combined cycle plant

The Interplay between RPS and Other Climate-Driven Policies in the Power Sector

Of course RPS policies are not intended to stand alone in dealing with this challenge.[27] Other prominent categories of policy initiatives motivated at least in part by a desire to reduce GHG emissions from the power sector include policies intended to:

1) Increase end-use efficiency;
2) Subsidize directly the cost of producing and delivering electricity from renewable sources (for example, through favorable tax treatment);
3) Establish a mandatory price for GHG emissions sufficient to drive the power sector to switch from today's commercial fossil-fueled technologies to lower-carbon technologies;
4) Develop technology and related infrastructure (such as pipelines to transport liquefied CO_2) to remove and sequester CO_2 from power generation, particularly from plants that rely on coal as the primary fuel; and
5) Support the construction of new nuclear power plants.

Each of these categories of policies interacts with RPS-style policies in importantly different ways.

Increased end-use efficiency - Policies designed to increase investment in end-use efficiency are intended to reduce the need to produce electricity from any source. As such they are largely complementary to RPS policies, though they compete with renewable generation policies to the extent that there is either an explicit or implicit limit on the public resources available to promote both efficiency and renewables, as has generally been the case. Much work has been done to

[27] A direct alternative to RPS policies is a feed-in tariff, or FIT, which is employed in a number of European markets and is under consideration in some U.S. states. While RPS fixes the quantity and lets the market determine the price, a FIT fixes the price and lets the market determine the quantity. Because the two approaches constitute variations on the same theme, I have not addressed FIT separately here.

quantify the scope available to increase end-use efficiency and the associated cost, and while there is a range of specific conclusions available from these studies, there is broad agreement that substantial improvements in end-use efficiency can be achieved at costs that are well below the total costs of the major renewable generation technologies, particularly in cost per ton of carbon avoided.[28] On the assumption that these efficiency gains can actually be realized and sustained, it would be straightforward to conclude strictly on a cost basis that our first priority should be to ensure that such opportunities are funded to the maximum extent before devoting resources to other, less cost-effective initiatives such as renewables. Yet it is also clear that reductions in end-use alone cannot be expected to deliver all of the GHG reductions posited in the reference scenario without radical adjustments to standards of living. New low-carbon production will also be required, and many of the most promising low-carbon technologies will likely need many years if not decades to reach commercial viability without some external assistance, time we do not have if the reference scenario is to be achieved. Thus the most compelling argument for investing public resources in the development of renewable technologies, even if doing so diverts limited public resources away from potentially more cost-effective efficiency measures, is that doing so is necessary in order to accelerate their journey down the learning curve on the required timescale.[29]

Direct subsidies to renewable producers – Like RPS programs, direct subsidies to renewable producers, such as the Federal production tax credit, are intended to accelerate the commercialization of the targeted technologies.[30] In this sense, the simultaneous application of

[28] See e.g. "Rhode Island Greenhouse Gas Action Plan," July 15, 2002, report of the Rhode Island Greenhouse Gas Stakeholder Process, pg. 17, Table 3b

[29] See e.g. Palmer, Karen and Dallas Burtraw, "Electricity, Renewables and Climate Change: Searching for a Cost-Effective Policy," May 2004, pp 16-17

[30] As with many other programs directed at renewables, these subsidies are also justified as economic development initiatives, but the new-industry aspect and the GHG agenda differentiate them from run-of-the-mill jobs programs.

an RPS with policies like the PTC can be seen as doubling down on those technologies that are targeted by both. A leading rationale for both approaches is a desire to compensate for the fact that certain perceived environmental and social externalities are not currently reflected in the cost of conventionally produced electricity. One would assume that a carbon tax or a cap-and-trade driven carbon price would thus be seen to obviate the need for direct, technology-specific subsidies like the PTC. Such subsidies typically must be renewed periodically, and this is a rationale that is sure to be marshaled against their continued renewal if and when a carbon pricing regime is implemented. The terms of most RPS policies, by contrast, extend well beyond the expiration dates of the related subsidy programs and, in many cases, the obligations have no sunset provisions once the final targets have been reached.

Another key difference between direct subsidy programs and an RPS is that, by using taxpayer money to reduce the cost to produce electricity they act as a net disincentive to increase efficiency. An RPS, by contrast, increases overall wholesale electricity costs and thus complements programs to promote end-use efficiency.[31] Even accounting for this differential impact on end-use efficiency, however, these approaches tend to mutually reinforce each other in important ways, as I will discuss in more detail in Chapter Four. As noted in Figure 1.1, the introduction of the PTC in 1992 appeared to have little impact on the development of renewable generation until the advent of RPS policies, and conversely the RPS policies alone appeared to be inadequate to maintain the pace of new investment during those periods when the PTC had been allowed to expire.

Carbon pricing policies – As discussed above, from an RPS perspective these can be seen as a prospective, non-technology-specific replacement for direct subsidy programs. Instead of promoting certain RPS-eligible technologies by making them less expensive, "carbon" (or GHG)

[31] See Palmer and Burtraw, 2004

pricing policies do so by making competing fossil-fueled technologies more expensive. A key difference between the two approaches is that, as shall become clear in Chapters Three and Four, policymakers in many, perhaps most states that have implemented RPS programs have relied on the Federal subsidy programs to contain the retail price impact of RPS compliance. A carbon pricing policy will arguably diminish or eliminate that concern, albeit by making electricity prices higher generally, a political barrier and a distributional equity issue that will have to be dealt with in designing any future carbon pricing policy.

More generally, while carbon pricing by virtue of its reach may be a more complex policy to design and implement, it is intuitively the purest and potentially most efficient approach to reducing GHG emissions from any sector, and that advantage is arguably most apparent in the power sector with its extensive reliance on coal combustion. Carbon pricing policies do not attempt to pick winning technologies, instead advantaging technologies indiscriminately in inverse proportion to the level of GHG emissions they produce. By internalizing to some degree the externalities associated with GHG emissions, they increase the price of electricity thus reinforcing policies designed to increase end-use efficiency. And, unlike most RPS programs, they are not specific to the production of any one product or service for the grid, instead driving up the cost of GHG-emitting sources for all products and services.

As a result, the interaction of carbon pricing policy with RPS policies is likely to be more complex than in the case of efficiency or direct subsidy programs. While a carbon price will tend to disadvantage all fossil-fuel-based generating technologies, it specifically disadvantages coal and in so doing raises the cost of all services provided to the grid by coal-fired power plants. In this sense it focuses economic resources most efficiently on one of the essential targets of climate policy, but it is agnostic as to what technology replaces the services conventional coal-fired power plants provide. If renewable technologies (or for that matter low-carbon coal or nuclear technologies, which will be addressed below) capable of providing some or all of these services are not ready to compete with advanced natural gas-fired generation, the immediate consequence of a carbon price would likely be the replacement of coal with natural gas rather than with renewables, or at best with a combination of renewables and natural gas. While the resulting increase in demand for natural gas[32] would inevitably drive the price to levels that would make non-fossil or low-carbon coal alternatives competitive, the risk of economic and social disruption that could ensue from an extended period of dramatically higher energy prices (and the possibility of increased reliance on imported LNG) makes such an approach problematic. Doubtless the development of renewable sources in general would benefit from the imposition of a carbon price. Indeed a carbon price would mitigate the need for RPS policies, in the case of certain technologies in certain areas obviating the need for an RPS altogether. But to the extent that RPS policies, intentionally or otherwise, favor renewable technologies that are (i) ill-suited to replacing the grid services provided by conventional coal plants; (ii) unable to compete with advanced natural gas-fired generation in doing so except at extraordinarily high gas prices; or (iii) able to do so only in combination with increased reliance on natural gas, they will be ineffective in easing a carbon-price-driven transition away from conventional coal technologies to renewables.

"Low-carbon coal"[33] technology development and new nuclear construction – I've lumped these two categories together because each bears a similar relationship to RPS policies. Both

[32] It is commonly observed that, in many areas, the expansion of intermittent sources like wind will initially reduce reliance on natural gas, though not on gas-fired generators; the discussion here goes beyond this initial, marginal impact to examine what if anything would challenge conventional coal under a meaningful carbon price.

[33] By "low-carbon coal" I mean technologies to capture and sequester the CO_2 produced by the combustion of coal ("CCS"), or other approaches to substantially reducing the atmospheric release of CO_2 from coal-fueled electricity production; I will use "conventional coal" to refer to any coal-fired power technology that does not specifically control CO_2 emissions – this would include technologies, such as ultra-supercritical pulverized coal power plants, that aim to improve conversion efficiency but otherwise do not control the resulting CO_2 emissions

aim to utilize public resources to promote investments in low-carbon technologies capable of expanding the supply of firm generating capacity as well as mitigating and/or replacing the current fleet of conventional coal-fired power plants. Neither of these technologies is likely to be commercially competitive with existing technologies in the foreseeable future without a very material price on carbon. As suggested by the foregoing discussion, in a world of meaningful carbon pricing these policies are intended to position low-carbon coal and nuclear to compete with natural gas and certain renewable technologies/strategies[34] to replace the energy and grid services provided by conventional coal-fired plants. Once again, the relevance of RPS policies in this process will depend on their design. RPS policies designed to advance technologies best capable of replicating those functions, particularly those able to do so without a reliance on complementary gas-fired generation, would compete directly with policies promoting low-carbon coal and nuclear in the race to replace conventional coal. RPS policies not so designed are likely to abdicate to natural gas, nuclear and/or low-carbon coal the role of replacing our reliance on conventional coal, without some other means to accelerate the commercialization of firm, dispatchable renewable technologies.

Ranking Renewables as Targets of a Climate-Driven RPS Policy

As the foregoing discussion makes clear, RPS policies, to the extent that they are intended to play a central role in achieving the required reductions in GHG emission from the power sector, operate alongside and/or in conjunction with other current and prospective policy approaches. The ways in which they interact with those alternative policy approaches, and thus

[34] There is a case to be made for eventual replacement of the current grid architecture with a "smart grid" approach that would combine intermittent renewables with high-voltage direct current transmission, firm renewables, distributed renewables, low-carbon conventional generation and dynamic grid management technology, obviating the need to replicate the grid services provided by conventional coal plants in the current architecture. However this paper assumes that those grid services will continue to be required to a material degree for the foreseeable future.

their likely effectiveness in achieving the desired outcomes, are importantly dependent on the design features of the RPS. More specifically, the effectiveness of RPS policies in achieving the stipulated GHG objectives for the power sector will depend on how they interact with other, related policies to promote not just the expansion of renewable generation technologies in general, but the expansion of certain classes of renewable technologies in particular. In broad terms, RPS programs that promote the following classes of renewable generation technologies are likely to be most effective in achieving the stipulated power sector GHG reductions:

1) Technologies capable of providing the grid services currently supplied by conventional coal plants; and
2) Promising technologies in an early stage of development that are expected to show dramatic improvements in price and performance as a result of the privileged market access that RPS programs provide.

Effectiveness is measured not only in quantity of GHG reduced, of course, but also in the cost per ton of emissions eliminated. For each measure discussed above, assessing either the quantity of reductions, or the cost, or both is to varying degrees a subjective exercise. In the seemingly straightforward case of carbon pricing, for instance, a carbon tax fixes the value of emissions but gives no definitive information about the quantity of reductions that will be delivered, while a cap-and-trade approach fixes the quantity of reductions to be delivered but gives no definitive information about the cost to do so. Ranking the cost-effectiveness of RPS-eligible technologies is arguably even more difficult. It is possible to model the mix of technologies likely to emerge based, *inter alia*, on assumptions about the cost to install them, their marginal costs of production and their operating characteristics, and from that information to estimate the marginal impact on GHG emissions and the related cost per ton. But each of these assumptions can be highly subjective, particularly for those technologies with which there is still little or no commercial experience, and especially in those cases the answers can be expected to change dramatically as the technologies are more widely deployed. In short, a definitive cost-effectiveness ranking of the GHG reduction measures discussed above is impossible. Nonetheless, it is possible to draw some broad ranking observations from the recent literature.

Perhaps the least contentious observation is that there is considerable scope for gains in end-use efficiency at a cost per ton of avoided emissions lower than that of any of the major classes of eligible renewables. A recent study sponsored by the Swedish utility Vattenfall and conducted by consultants McKinsey & Co.[35] has generated controversy over some of its conclusions, and I do not mean to imply that I concur with those conclusions by referencing the study here, but its quantification of the possibilities for GHG reduction through gains in efficiency and its *relative* ranking of the cost-effectiveness of those opportunities against other measures have not been seriously challenged. The study identifies various categories of energy consumption from which it maintains that savings of 1.3 gigatons per year by 2030, or over 20% of the current U.S. total, can be realized at no net cost to society. This specific conclusion can be and is being hotly debated, but it is possible to disagree with this and many other aspects of the study while still concurring that there is ample scope for GHG reductions through investments in efficiency at a cost per ton well below that for renewables.

The next most cost-effective approach to reducing GHG emissions is almost certainly a carbon pricing policy.[36] Yet while this contention is true in theory, it must be tempered by the dynamic relationship that should exist between a carbon pricing policy and other, related

[35] "Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost?" U.S. Greenhouse Gas Abatement Mapping Initiative Executive Report, December 2007, page 20
[36] Palmer and Burtraw, 2004, in particular Chapter 7, pp 61-62

policies, as I discussed briefly in the previous section. A carbon pricing policy, for instance, is only likely to be effective if implemented in combination with other policies designed to promote the timely availability of viable low-carbon alternatives. Failure to do so could result in the intended costs being incurred without achieving the targeted emission reductions, or in the need to set the price of carbon at a politically untenable level to achieve the targeted reductions.

The remaining policy categories are all intended to bring forward various specific technologies. The contention that these are less effective than a carbon pricing policy is driven not by the assumptions made about specific low-carbon alternatives, but by the expectation that a government policy designed to "pick winners" is likely to produce a suboptimal resource mix, whereas a well-designed carbon pricing policy should create the conditions under which the market can determine the most cost-effective resource mix. Yet I have also argued that a carbon pricing policy is only likely to be effective when combined with policies designed to accelerate the development of viable alternatives. Thus it is not so much that these policies are less effective than a carbon pricing policy, as it is that they are a necessary complement to carbon pricing and would not otherwise be as effective on a stand-alone basis.

Of these, RPS policies in particular operate by granting privileged market access to eligible technologies. Such policies cannot be justified on the basis of cost-effectiveness alone – few if any of the eligible renewable technologies are likely (today or in the near future) to be as cost-effective as a broad range of untapped opportunities to invest in increased end-use efficiency. By extension, it is difficult to justify extending them to mature technologies – granting such privileged market access to mature technologies does not promote cost-effectiveness but instead creates a dependency on public assistance that is likely to persist indefinitely, and it can unintentionally crowd out the development of earlier stage technologies, as will be discussed later. Rather, they are justified to the extent that the privileged market access they provide leads to the accelerated commercialization of appropriate technologies. (This is a crucial point and one that will be central to the discussion of my conclusions and recommendations in Chapter Five.) Appropriate renewable technologies, in turn, are those early-stage technologies that can most cost-effectively facilitate the transition from a supply portfolio built around conventional coal to a low-carbon supply portfolio. To do so they must replace, either alone or on close coordination with other renewable and/or non-renewable sources, not only the energy that coal plants produce but the full range of essential services coal plants deliver to most regional power grids.

Nearly all power plants connected to a power grid are expected to deliver some quantity of energy to the grid during the course of a year. But delivering energy is only one of many services performed by power plants in order to maintain a reliable, affordable supply of electricity. In the U.S. as in most of the world's power grids, coal-fired plants are the primary source of many of the most important non-energy services, including firm capacity for resource adequacy, spinning reserve and capacity that can economically provide reactive power and frequency regulation. (Appendix B provides a brief explanation of these and other ancillary grid services) Other conventional technologies are also capable of providing some or all of these services, most prominently gas-fired combined cycle plants and certain large hydro-electric facilities,[37] but none of these has been able historically to claim the unique combination of low marginal cost of production, wide geographic spread, operational responsiveness and the ability to stockpile fuel locally that coal-fired power plants have been able to offer.

Among the renewable technologies qualified under the various RPS programs, each has its own strengths and shortcomings as a substitute for the functions that coal-fired plants perform

[37] Nuclear is the next largest source of firm, baseload energy in the U.S. after coal, but because of its extremely low marginal cost of production and inherent lack of operational flexibility, nuclear is generally treated as "must-run" capacity and is typically not a major source of ancillary grid services.

for the grid, and each is in a somewhat different position to benefit from the privileged market access provided by an RPS. Extrapolating from the foregoing discussion, Table 2.1 below suggests a ranking of renewable or renewable-related technologies to be targeted by a well-conceived RPS policy, on the basis that such a policy must be viewed as a complement to end-use efficiency measures and carbon pricing in any integrated approach to achieving the stipulated reductions in power sector GHG emissions.

The first four columns posit a grade (on a scale of 0-4) for each category of technology against some of the key attributes that must be replicated, with a 0 indicating that the technology has little or no capability in that area and a 4 indicating a very strong capability. The grading in these columns is this author's judgment based on a broad review of the available literature. Column 5 shows the sum of the values in Columns 1-4 for each technology, and it can be thought of as the aggregate score for ability to replicate the services provided by coal-fired plants. The sixth column is intended to grade each technology on the learning curve progress that might be realized as a result of the privileged market access provided by an RPS policy. This can also be thought of as a rating of the technology's maturity, with a low score indicating a mature technology and a high score indicating an early-stage technology. The assessments included in the sixth column are consistent with an analysis by the EIA in their *Assumptions to the Annual Energy Outlook 2008*.

The ranking in Column 7 is based on the sum of the values in Columns 5 and 6, and as such it is a simple aggregation of the two key scores – ability to replace conventional coal and ability to benefit from privileged market access. A slightly more sophisticated methodology is used in Column 8. In this column I have averaged the scores in Columns 1-4 and added the result to Column 6. The two ranking methodologies do not produce dramatically different results

Table 2.1 – Ranking of Renewable Technologies by Likely Effectiveness as RPS Targets

	1	2	3	4	5	6	7	8
Technology	Potential scale	Firm capacity value	Dispatch	Load-following	Ability to replace coal (sum 1-4)	Learning opportunity	Rank (sum 5+6)	Rank (alternate)
Terrestrial wind	4	1	1	0	6	0	11	11
Wave	1	1	1	0	3	4	10	8
Tidal	1	3	1	0	5	4	9	5
Solar thermal	4	2	1	0	7	2	8	10
Solar PV	4	2	1	0	7	3	7	7
Offshore wind	4	3	1	0	8	3	6	6
Anaerobic MSW conversion	1	3	3	3	10	2	5	9
Biomass	2	4	4	4	14	2	4	4
Thermal storage (w/solar thermal)	4	4	3	3	14	3	3	3
Engineered geothermal	3	4	3	3	13	4	2	2
Electric storage (w/wind or PV)	4	4	3	3	14	4	1	1

Note: Eligible technologies not ranked include co-firing, conventional geothermal, small hydro, landfill gas and CHP – I have assumed that these technologies are commercially viable with or without an RPS.

The intended interpretation of this table for the policymaker considering an RPS is that the appropriate targets are those technologies in the middle range of the table – early enough in their development and promising enough in their attributes to adequately reward the grant of privileged market access, but not so early that they are unlikely to become relevant within the time horizon contemplated in the policy.[38]

The next two chapters present a detailed analysis of four state RPS programs. With that analysis in hand, I will revisit in the final chapter the framework illustrated in Table 2.1 as one basis upon which to evaluate the effectiveness of these programs, and to formulate recommendations for strengthening RPS as a weapon in the battle against climate change.

[38] Scientific discoveries can lead to abrupt changes in a given technology's prospects – see e.g. the recent breakthrough by MIT's Daniel Nocera in the oxidation of the water molecule, which may lead to new technologies in the storage of energy produced as electricity by photovoltaic cells – but this table reflects the current state of play.

Chapter Three

A Closer Look at Four State RPS Programs

A. Selection Criteria

In order to place these important questions in the context of actual RPS programs, I have selected four state programs for closer examination. The criteria utilized to select these programs are intended to identify a subset of programs that are likely to produce the best results the current crop of state-level RPS programs can be expected to deliver. By "best" I mean those results that most nearly match the shifting mix of public expectations that have been established for RPS-style policies, as discussed in Chapter One above.

I have already touched upon the highly idiosyncratic nature of these state-by-state programs. The manifest and florid variety of features found among these programs, as illustrated in Appendix A, makes it challenging to delineate clear subcategories of any analytical significance. Nonetheless, I have attempted to break these twenty-six programs down roughly along several useful dimensions, accepting that there will inevitably be a lack of categorical purity. These analytical categories are shown in Table 3.1 below.

Table 3.1 – Key characteristics of existing RPS programs

	State	Geography restricted? [1]	Region	Banded? [2]	Compliance std.? [3]	Targets [4]
Phase 1						
	CT	No	NEPOOL	Y (26%+ η, etc)	Moderate	Strong
	ME	No	NEPOOL	No	Weak	Weak
	MA**	No	NEPOOL	No	Moderate	Weak/Avg
	NJ	No	Mid-Atlantic	Y (10% solar)	Strong	Strong
	MN	No	Midwest	≥83.3% wind	Strong	Strong
	TX	Yes	Midwest	Y (10% unspecified)	Strong	Weak
	WI	No	Midwest	No	Strong	Weak
	AZ	Yes	Southwest	Yes (30%	Strong	Weak

				DG)		
	NV	Yes	Southwest	Yes (solar, η)	Moderate	Strong
Phase 2						
	NH	No	NEPOOL	No	Moderate	Weak
	RI	No	NEPOOL	No	Moderate	Avg/Weak
	DE	No	Mid-Atlantic	Y (10% solar by '19)	Weak	Average
	DC	No	Mid-Atlantic	No	Weak	Weak
	MD	No	Mid-Atlantic	No*	Weak	Weak
	NY	Yes	Mid-Atlantic	No	Strong	Weak
	NC	Yes	Mid-Atlantic	Y (ag waste, solar, η)	Moderate	Weak
	PA	Yes	Mid-Atlantic	Y (many incl non-RE)	Weak	Weak
	IL	Yes	Midwest	≥75% wind	Moderate	Strong
	OH	Yes	Midwest	No	Moderate	Weak
	CO	Yes/No [5]	Mountain	No*	Strong	Average
	MT	Yes	Mountain	No	Weak	Avg/Weak
	OR	No	PNW	No	Mod/Weak	Moderate
	WA	Yes	PNW	No*	Moderate	Avg/Weak
	CA	No	Pacific	No	Mod/Weak	Strong
	HI	Yes	Pacific	No	Moderate	Average
	NM	Yes	Southwest	No*	Weak	Average
Other						
	IA	Yes	Midwest	No	Strong	Weak

* These states offer disproportionate incentives for non-wind renewable resources
** MA substantially amended, and presumably strengthened, its RPS in July 2008

[1] Yes: The program requires in-state resources or direct connection to state, or has significant in-state incentives
No: The program has no restrictions or allows resources and/or deliverability anywhere within a RTO or a large region

[2] Yes: Program features a significant (>10%) carve-out for solar, efficiency or other non-wind resources

[3] Weak compliance standard has multiple escape options and/or unusually low ACP-style buyouts
Moderate compliance standard has "typical" safety valves and/or ACP-style buyouts
Strong compliance standard has no clear escape options and/or unusually high barriers to avoidance

[4] Strong: Final target > 20%, final date ≤ 2020, >90% of retail included
Average: Final target 15-20%, final date 2015-2020, 70-90% of retail included
Weak: Final target < 15%, final date > 2020, <70% of retail included

[5] Colorado is the only state with no geographic restrictions but grants a significant advantage to in-state resources

First Screening Criterion

My *first screening criterion* was to select two programs each from the first wave and the second wave of RPS programs, as described in Chapter One above. While the formally articulated rationales for the first wave of programs may have differed somewhat from those articulated for the second wave, that was not a significant consideration in setting this first criterion, in part because it is my contention, as developed previously, that a relatively narrow set of rationales has emerged to justify all of these programs. The significance of selecting two programs each from the two distinct waves of programs is rather to afford a comparison between promising but more recent programs with limited history (i.e. those from the second wave) on the one hand, and similarly promising programs with a longer history of actual implementation (i.e. those from the first wave) on the other. Most of the programs from the first wave have been in place for at least eight years and in some cases over ten years, many having proceeded through one or more rounds of revision and refinement, and as such they should offer a certain amount of valuable insight into how the industry responds to such policies.

Second Screening Criterion

My intent is to analyze only strong programs. Despite the highly individualistic nature of these programs, upon closer examination it becomes apparent that there is some clustering of attributes that complicates the task of isolating independent variables. As illustrated in Table 3.1, a disproportionate number of the programs with both strong targets and strong compliance regimes are first-wave programs. There are at least two possible reasons for this: (i) these programs have been in existence longer and may have been "tightened up" over time; and (ii) as noted in Chapter One, all but one of the first-wave programs originated as an integral part of market-based restructurings of the state electricity sectors. Thus the first-wave programs arguably emerged from jurisdictions in which entrenched utility interests wield relatively less political power, or are relatively more progressive, than those in which the second-wave programs were enacted, most of which are states where market-based reforms have been successfully suppressed or subverted by local utility interests. This difference between the two sets of programs may diminish over time as the second-wave programs mature. Nonetheless, I have designed my *second screening criterion* to mitigate as much as possible any related consequences for the purposes of this paper. Thus I have selected only programs from each wave that feature "moderately strong" or "strong" targets and compliance standards (which of course quickly truncated my choice of programs from the second wave).

Third Screening Criterion

A second pattern that differentiates the first wave from the second wave is the extent to which they feature explicit set-asides or "bands" for specific resource categories. Over half of the first-wave programs (five of nine) feature banding, whereas less than 20% of the second-wave programs (three of sixteen) feature such bands, and one of those that does (Pennsylvania) is so unique, and so compromised by the eligibility of non-renewable resources as to be of little relevance here. It is, however, also true that four of the remaining second-wave programs feature bonus multipliers to be applied to renewable energy credits obtained from specific types of resources, a feature not found in any of the first-wave programs; as a result, I have assumed that there is broad similarity between the two waves of programs in the extent to which they feature special set-asides for specific types of resources. The relative prevalence of banding *per se* among the first wave of programs is therefore not expected to undermine materially the value of information gained from experience with the first wave of programs in forecasting industry response to the more recent second-wave programs. Also, as suggested in the foregoing paragraph, second-wave programs may well evolve by amendment in the direction of the first-wave programs.

Yet the impact of technology banding on these programs remains of interest for at least two reasons. First, any difference in industry response indicated by first-wave experience with banding may be significant in evaluating likely future developments, whether in response to banding or to premium credits attributable to specific types of resources. Second, if experience to date indicates that current approaches to banding produce significantly different industry responses, that information may prove useful in considering other forms of banding, as I will do later in this paper. Thus, in an attempt to draw out material consequences of banding, my *third screening criterion* was that one of the programs selected from the first wave would feature explicit technology bands and the other would not.[39]

Fourth Screening Criterion

The *final selection criterion* I deployed was geographic diversity.[40] There are two reasons for doing so. The first was to isolate any potential impacts that might be evident owing to differences in indigenous renewable resources available in each region of the country. Thus if a consistent industry response is to be expected despite material differences in the types and quality of indigenous renewable resources available, such a phenomenon may be observable in the sample. Conversely, it may become apparent that industry response follows differences in

[39] In selecting programs with banding, I am looking specifically at banding for non-wind technologies. Nearly all states that have included technology bands have done so exclusively for non-wind technologies, presumably based on the concern that wind would capture a disproportionately large share of the hoped-for market at the expense of other promising technologies. The two exceptions (IL and MN) actually feature *minimum* requirements for wind. I treated these programs as being non-banded, since the market share of wind to date among renewable technologies in all states, and particularly in states like IL and MN with relatively strong wind resources, exceeds the minimums established in these two programs.

[40] Two factors I did not use as screening criteria are nonetheless worth mentioning. The first is whether or not the state is part of a vibrant competitive wholesale power market. While this may be significant in the selection of all new resources (though that remains to be seen), the RPS policies are universally designed to create a market (albeit a protected market) specifically for renewable resources, and as such I have assumed that the industry responses within these artificial markets will be largely the same regardless of the level of wholesale competition in the wider market. Furthermore, as the discussion notes, there is some degree of correlation between the use of market-based pricing and whether or not the state was in the first or second wave of RPS implementation, so that the first screening criteria to some degree serves as a proxy for market structure. The second factor is geographic limitations on eligibility. While there is quite a wide variability among the states in how they approach this issue, all of them contain geographic limitations of some kind (Colorado does not limit eligibility but grants a 25% premium to in-state resources), and every program but Colorado requires at least that renewable energy be physically deliverable into the state or into the immediate transmission control area in which the state resides. Paradoxically, or perhaps understandably, the smallest jurisdiction with a RPS (District of Columbia) recognizes the widest geographical boundaries, accepting renewable credits from states as distant as Missouri, Wisconsin and Alabama.

indigenous resource availability. The second reason I selected for geographic diversity was to illustrate the impact of these programs in the context of materially different mixes of existing generation resources. Thus the consequences of adding 500 MW of wind generation in, for instance, New England (with its disproportionately large amount of gas-fired combined-cycle production) could well be quite different from the consequences of doing so in the Midwest (with its disproportionately large amount of coal-fired production). By selecting programs from different regions, I wanted to create the opportunity for such differences to emerge.

Conclusion

In summary, I have utilized four screening criteria in selecting state programs for further study: (1) four programs have been selected, two from the first wave of programs and two from the second wave of programs; (2) all programs selected feature "moderately strong" or "strong" targets and compliance standards; (3) of the two programs selected from the first wave of programs, one features banding and the other does not; and (4) geographic diversity.

Four screening criteria might seem excessive, however as the foregoing discussion suggests, each criterion emerges naturally to some extent from the other criteria chosen. After applying these criteria to all twenty-six programs I arrived at a set of four programs for further study: Connecticut, Minnesota, Colorado and California.[41] (See Table 3.2 below)

Table 3.2 – Characteristics of selected state RPS programs

	State	Region	Banded?	Compliance standard	Targets
Phase 1					
	CT	New England	Y (efficiency, CHP)	Moderate	Strong

[41] For an independent confirmation of the strength of the RPS programs in the four selected states, see Environment America's *American Clean Energy Stars: State Actions Leading America to a New Energy Future* (Nov. 2007), which gives all four states' RPS programs it's highest rating.

	MN	Midwest	≥83.3% wind	Strong	Strong
Phase 2					
	CO	Mountain	No*	Strong	Average
	CA	Pacific	No	Moderate	Strong

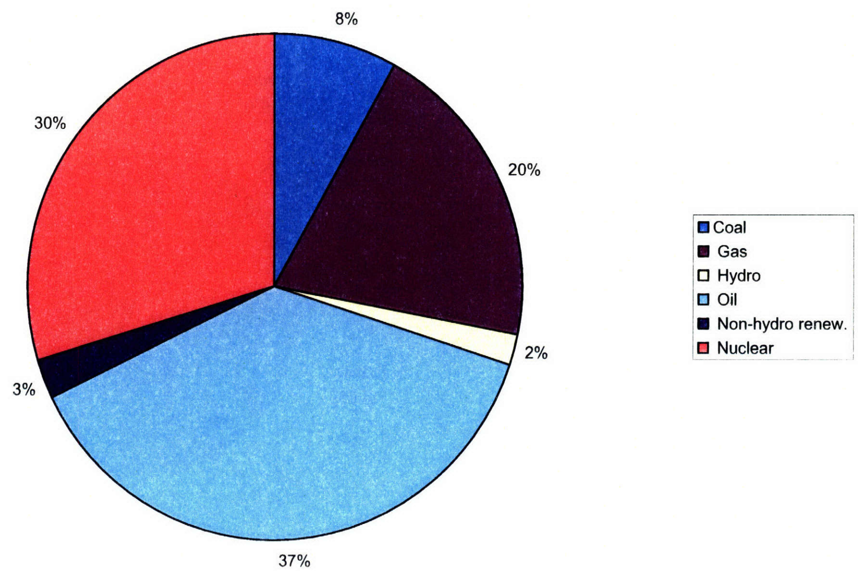
*Miniscule solar set-aside; significant incentives for in-state and "community-based" resources

B. Connecticut

Context

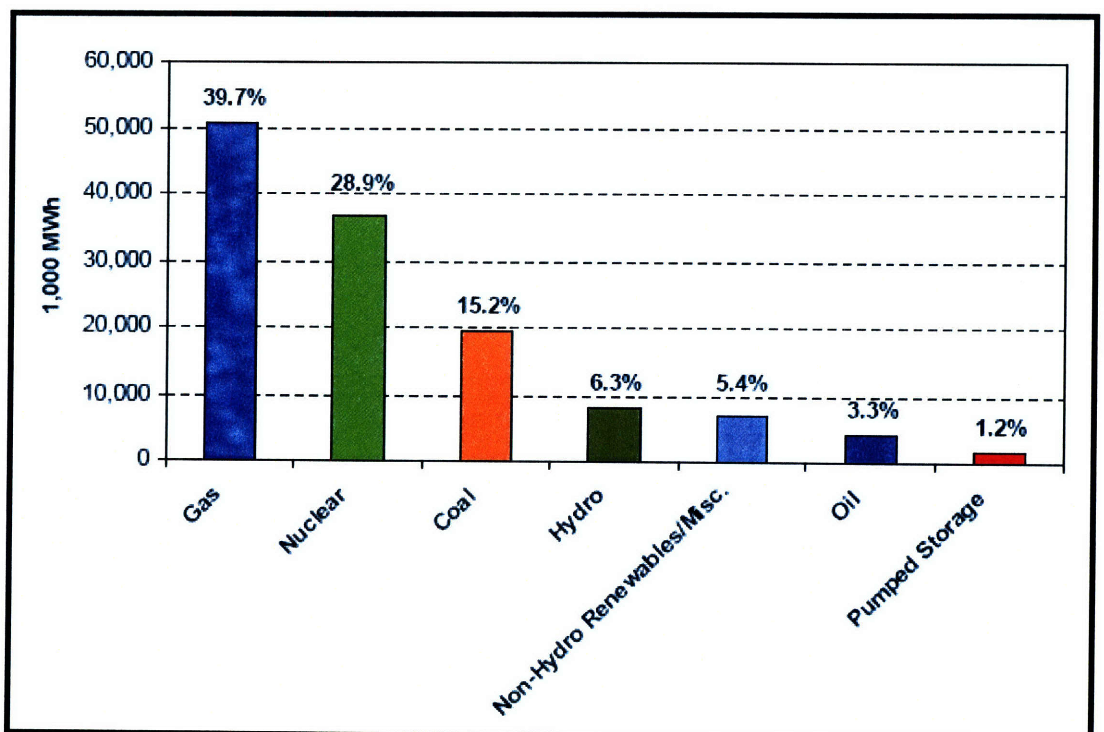
Connecticut restructured its electric utility industry in 1998, so that virtually 100% of the state's generation resources are owned by non-utility independents. Connecticut is part of the regional power market operated by the Independent System Operator of New England ("ISO New England" or "ISO-NE"), a federally-chartered Regional Transmission Operator ("RTO"). As such, the mix of generating resources available to the state is essentially the mix of resources available to all six states in the ISO-NE control area, which in addition to Connecticut includes Maine, New Hampshire, Vermont, Massachusetts and Rhode Island.[42] Of the six member states, only Vermont has yet to establish a mandatory RPS. Figure 3.1 below shows Connecticut's existing mix of generating resources (those designated by ISO-NE as contributing to Connecticut's obligation to meet its Local Sourcing Requirement); Figure 3.2 shows the sources of electricity produced in ISO-NE in 2006; Figure 3.3 shows the mix of generating capacity in ISO-NE in 2007; and Figure 3.4 shows the load duration curve for ISO-NE for 2006.

[42] New England is part of the Northeast Power Coordinating Council ("NPCC"), a cross-border reliability organization that was formed by the U.S. and Canada following the Great Northeast Blackout of 1965 to improve regional system reliability. In addition to the six New England states, NPCC includes New York State, Ontario, Quebec and the Canadian Maritime provinces. The New England states formed the New England Power Pool ("NEPOOL") in 1971 to coordinate region-wide least-cost dispatch operations, and NEPOOL subsequently provided the basis for the formation of ISO-NE when the region embarked on market restructuring in the late 1990s. As such, ISO-NE continues to coordinate operations with, and has a certain limited amount of interconnection with the surrounding NPCC regions of New York State, Ontario, Quebec and the Canadian Maritimes. In the late 1990s FERC embarked on an initiative to promote competitive wholesale power markets based in large part around these existing regional transmission compacts, and as a result ISO-NE became one of the first federally-chartered RTOs.



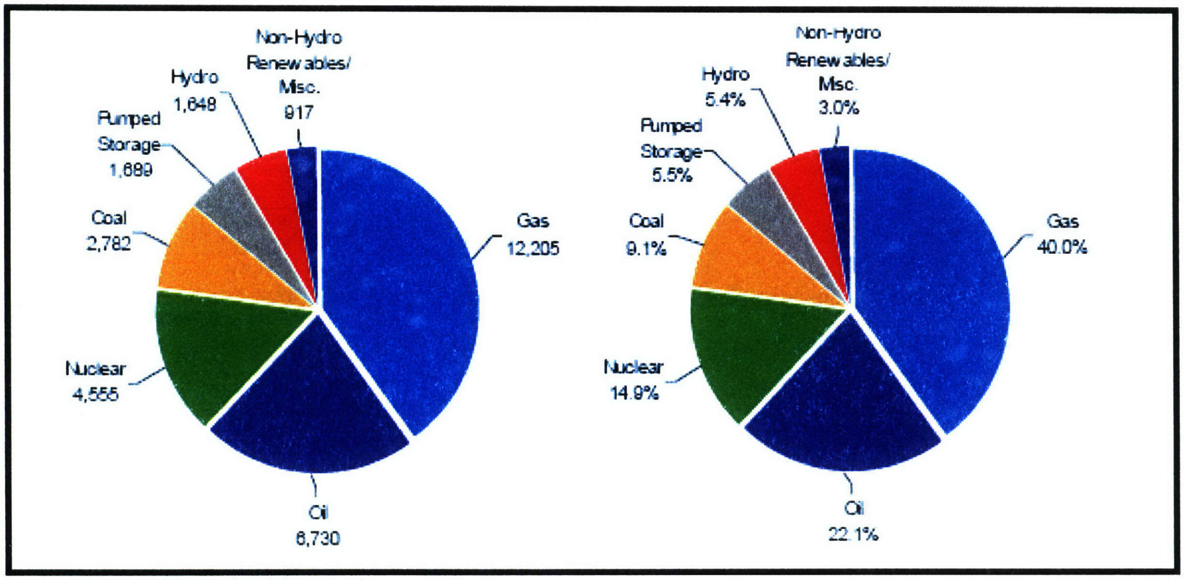
Source data: 2007 Energy Plan for Connecticut, Connecticut Energy Advisory Board, Feb. 2007, pp. 17-18

Fig. 3.1 – Connecticut 2007 installed capacity, by fuel (100% = 6,824 MW)



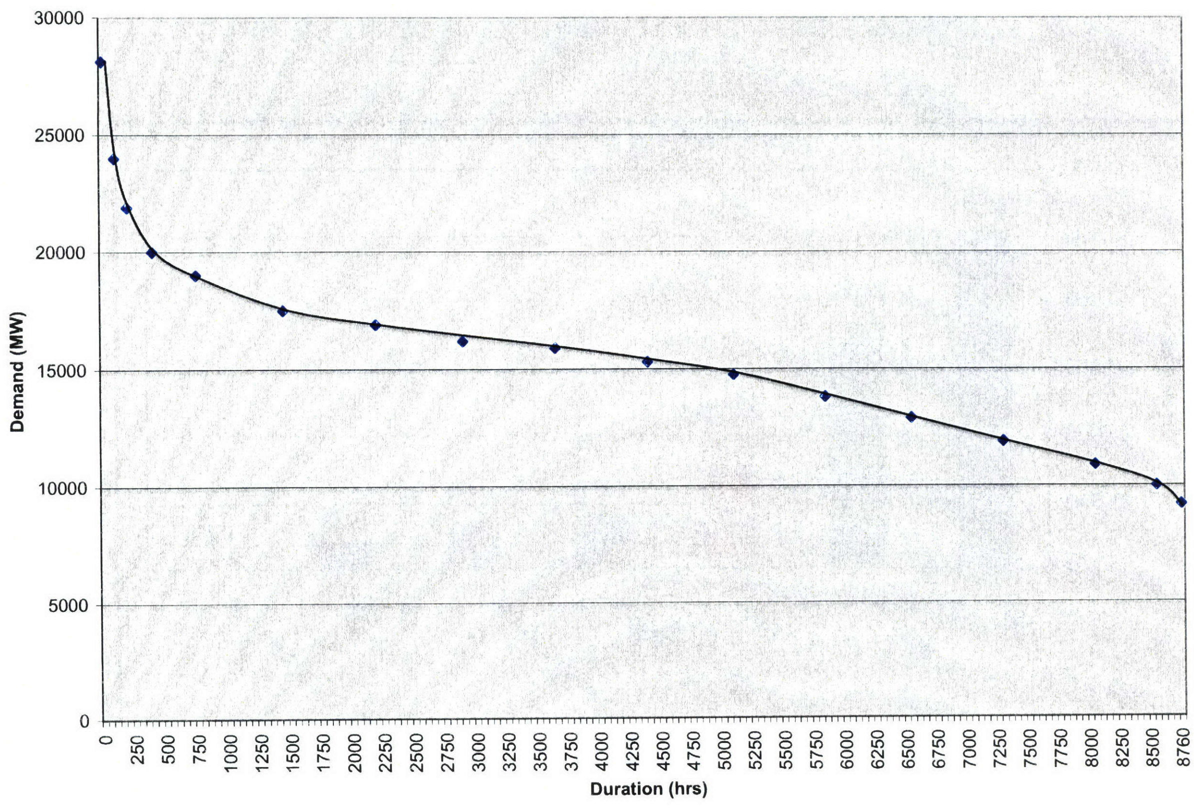
Source: ISO-NE 2007 Regional System Plan, page 49

Fig. 3.2 – 2006 ISO-NE production, by fuel type



Source: ISO-NE 2007 Regional System Plan, page 50

Fig. 3.3 – 2007 ISO-NE installed generating capacity, by fuel type (MW and %)



Source data: Presentation by Clifton Below, Commissioner, NHPUC, March 20, 2007 at the ACEEE Market Transformation Forum, Washington, D.C.

Figure 3.4 – ISO-NE Load Duration Curve

The combined nuclear, coal-fired and hydro-electric capacity of approximately 8,985 MW in ISO-NE is less than the minimum load of 9,200 MW shown in Figure 3.4, which means that even when all of the region's traditional baseload resources are operating at full load they are on the margin only a very small number of hours in the year. This explains why gas- or oil-fired generation sets the wholesale price for electricity in New England over 90% of the time.

RPS Evolution

Connecticut's RPS mandate was first established by legislation in April, 1998. Like all nine of the first wave programs, it constituted a part of a broader package of electricity-related legislation; like all but one of the first wave programs it was embedded in the state's electric restructuring law (Public Act 98-28, An Act Concerning Electric Restructuring). The original RPS required that 6% of retail sales come from eligible renewable sources by 2000, ramping up to 13% in 2009. It has been legislatively revised six times since originally enacted. Important revisions included the removal of the effective exemption for standard offer service customers, who constitute nearly all retail load in the state (P.A. 03-135 in 2003); the creation of a third resource class to promote cogeneration and energy efficiency as eligible resources (P.A. 05-01 in 2005); and a requirement that renewable portfolio standards be developed for the state's municipal-owned electric companies (P.A. 07-242 in 2007). The 2003 legislation substantially relaxed the original targets; the 2007 legislation (specifically Sections 40-44) kept the existing schedule but created additional, higher targets over a longer period of time. The current standard is discussed in detail below.

The original legislation included no language regarding the legislature's intentions in creating an RPS. Furthermore there was very little discussion of the RPS provision (Section 25) during extensive debate on the House and Senate floors, where Section 25 and a related provision (Section 44) establishing a Renewable Energy Investment Fund ("REIF") were described as being intended to "reduce dependence on fossil, nuclear and other more polluting forms of generation."[43] The only (very brief) debate in the House was not about Section 25 at all but rather over the cost and advisability of the REIF.[44] Section 25 did attract a brief exchange in the Senate, but the debate revolved around ratepayer impacts and the advisability of embedding such a major initiative in a larger piece of legislation. Intent was not a topic of discussion.

More recently, Governor M. Jodi Rell's 2005 Climate Change Action Plan set out a Renewable Energy Strategy,[45] calling on the legislature to "promote the development of renewable energy in Connecticut and in the region as a long-term GHG emissions reduction strategy and encourage the renewable industry in Connecticut." The Plan went on to recommend a substantial expansion of the RPS as the cornerstone of this Renewable Energy Strategy (the proposed new targets were largely reflected in the subsequent 2007 legislation). The Plan listed a handful of "co-benefits" from an expanded RPS (reduced air pollution; fuel cost savings; increased energy diversity and security; and economic development), but climate change was the central theme.

Targets and Eligibility

The current RPS has three classes of eligible resources. Class I includes solar; wind; new sustainable biomass; landfill gas; fuel cells (including those using natural gas as fuel); ocean

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[43] See Connecticut General Assembly, Session Transcripts for the House and the Senate for 15 April, 1998; the bill was overwhelmingly approved in both chambers that day and signed into law by Governor Rell on 29 April, 1998
[44] The REIF was to support renewable technology R&D and was to be funded through a system benefits charge added to customer bills – starting at a half mill in 2000 (approx. $15 million) and rising to one mill over four years.
[45] Governor's Steering Committee on Climate Change, "Connecticut Climate Change Action Plan," 15 February 2005, pg 169 ff *Electricity Sector*

thermal, wave and tidal power; low-emission advanced renewable energy conversion technologies; run-of-river hydro of no more than 5 MW capacity commissioned after 2003; and Class I-eligible distributed generation installations. Class II includes trash-to-energy facilities (including incinerators), certain other biomass not included in Class I and pre-2003 hydro facilities of no more than 5 MW. Class III includes new cogeneration facilities with at least 50% thermal efficiency; energy savings from conservation and load management; and commercial and industrial heat recovery systems. The RPS requirements ramp up as follows:

- On and after 1/1/06: 2.0% Class I + 3% Class I or II
- On and after 1/1/07: 3.5% Class I + 3% Class I or II + 1% Class III
- On and after 1/1/08: 5.0% Class I + 3% Class I or II + 2% Class III
- On and after 1/1/09: 6.0% Class I + 3% Class I or II + 3% Class III
- On and after 1/1/10: 7.0% Class I + 3% Class I or II + 4% Class III
- On and after 1/1/11: 8.0% Class I + 3% Class I or II + 4% Class III
- On and after 1/1/12: 9.0% Class I + 3% Class I or II + 4% Class III
- On and after 1/1/13: 10.0% Class I + 3% Class I or II + 4% Class III
- On and after 1/1/14: 11.0% Class I + 3% Class I or II + 4% Class III
- On and after 1/1/15: 12.5% Class I + 3% Class I or II + 4% Class III
- On and after 1/1/16: 14.0% Class I + 3% Class I or II + 4% Class III
- On and after 1/1/17: 15.5% Class I + 3% Class I or II + 4% Class III
- On and after 1/1/18: 17.0% Class I + 3% Class I or II + 4% Class III
- On and after 1/1/19: 18.5% Class I + 3% Class I or II + 4% Class III
- On and after 1/1/20: 20.0% Class I + 3% Class I or II + 4% Class III

While existing resources are eligible for compliance with most Class I and Class II technology categories, there were not a significant number of eligible resources pre-existing the RPS, making the 27% requirement by 2020 one of the most aggressive in the nation. Geographic eligibility is fairly broad - all five ISO-NE state programs allow retailers to purchase unbundled RECs from any qualified resource[46] located in or capable of delivering energy to NEPOOL.

[46] RECs in ISO-NE are tracked by the New England Generation Information System ("NE-GIS"), a regional database operated by NEPOOL that accounts for the generation attributes of electricity consumed within NEPOOL.

The inclusion of an "efficiency" tier makes Connecticut one of only six states that include efficiency as an RPS-eligible resource. The 2007 legislation that amended the RPS also imposed an obligation that "[r]esource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible." Not technically part of the RPS, this new requirement nonetheless effectively means that Connecticut electricity retailers are required to go well beyond the 4% Class III requirement for energy efficiency while the Class I and Class II requirements under the RPS remain unchanged.[47]

Compliance

Compliance standards under Connecticut's program are comparable to, though a bit less stringent than those in the other four New England programs. All five ISO-NE programs employ a form of alternative compliance payment ("ACP") as a way effectively to cap the rate impact of the RPS. Such a provision is sometimes referred to as a "safety valve,", and in this respect the New England programs are fairly typical nationally. As in all but the Maine RPS, Connecticut's program provides no other avenue to avoid compliance, a relatively strong feature of the New England compliance standards.

Uniquely in ISO-NE, Connecticut's ACP (actually referred to in the legislation as a "penalty") is set at a fixed $55 for each MWh by which a retail supplier falls short of the required volume of qualified RECs. While this level of buy-down payments puts Connecticut in the middle of the pack nationally (see Appendix A), it is today slightly below the ACP level in the rest of ISO-NE and, unless modified, that discrepancy will only grow wider. The other four

[47] All six ISO-NE states have joined the Regional Greenhouse Gas Initiative ("RGGI"), the first regional program in the U.S. to seek enforceable greenhouse gas emission limits; while Connecticut's RPS pre-dated RGGI and is thus not directly grounded in that initiative, each of the five states with RPS programs has promoted the RPS as a central policy feature of their plans to comply with their obligations under RGGI

state programs have harmonized their ACP mechanisms – they reached $57.12/MWh in 2007 and are indexed to inflation. In a tight market RECs can be expected to trade at prices close to but not above the ACP level, and it is of course always possible that there will simply not be enough RECs available, forcing LSEs to incur the ACP for some or all of their obligations (as has already occurred in Connecticut and Massachusetts) without directly creating new qualified sources of supply.[48] A unique risk for Connecticut LSEs is that the effective cap for REC prices in ISO-NE will be set by the higher ACP levels in the other member states. The implications will be discussed at more length in Chapter Four, but if left unchanged this could leave Connecticut LSEs priced out of an otherwise active ISO-NE REC market.

Access to Eligible Resources

Connecticut is not well endowed with indigenous renewable resources. While its RPS law and its membership in ISO-NE enables Connecticut to look to the renewable resources indigenous to the entire region, the situation there is not a great deal more encouraging. (See Appendix C for a regional map of available renewable resources) Limited land-based wind opportunities exist in the northwest quadrant of the state (a seminal 1991 study of U.S. wind potential by Pacific Northwest National Laboratory[49] estimated the state's land-based resource to be 571 MW, or enough to supply about 15% of the State's 2006 consumption, but a more recent study[50] estimated the total potential to be no more than 43 MW). Much more extensive

[48] As in most states with similar buy-down provisions, the funds collected by the state are placed in a fund (in the case of Connecticut, along with other funding sources) to be used for the promotion of related technologies or projects; it must be noted, however, that the legislature in Connecticut has since 2002 raided the fund to the tune of over $100 million to meet general revenue shortfalls and other unrelated uses. The Governor has pledged to restore the funds in the spring of 2008.
[49] "An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States," Elliott, D.L., L.L. Wendell and G.L. Gower, Pacific Northwest National Laboratory, August, 1991
[50] "Technical Assessment of Terrestrial and Offshore Wind Generation Potential in New England," Levitan and Associates, May 1, 2007, Table 8 (accessed via CL&P 2007 Integrated Resource Plan, page E-14)

terrestrial wind resources exist elsewhere in New England (primarily in northern Maine), but development of those resources has been hindered by significant siting and transmission access challenges. The region is blessed with good offshore wind resources, but development of those resources has been similarly plagued by issues of siting (amply demonstrated by the Cape Wind experience) and (in many but not all cases) remoteness, as well as by concerns with cost and technological maturity.

Among the more "conventional" renewable technologies, biomass for power generation (using wood and wood waste) is the only other resource indigenous to New England in any significant quantity and quality. Nearly every state in the region except for Rhode Island possesses some quantity of high-quality biomass resource, but once again, most of the best resource is concentrated in the northern reaches of the region, in Maine and northern New Hampshire. Biomass development in southern New England has been hampered by issues of scale and fragmentation among feedstock suppliers as well as local siting opposition, and while northern New England has ample supply and a good installed base of biomass generation, incremental development has been constrained by transmission access issues.

New England is one of the more promising regions for the development of tidal and wave energy, but those technologies are still in their infancy, and the most promising sites are along remote coastal areas of northern Maine and thus suffer from the same transmission access issues as do most of the region's best wind sites. Connecticut's coastal waters are not notable either for offshore wind potential or for wave/tidal opportunities.

Recognizing these regional resource limitations, Connecticut has turned to potential resources that, while closer to home, are not universally considered "renewable" and are thus not common to all RPS programs. Most notably, Connecticut is one of only eight states that grant unqualified eligibility to waste-to-energy incinerators, a controversial but potentially valuable source of RPS credits. Connecticut is one of only seven states nationally to make fuel cells using natural gas an eligible RPS resource, a provision designed to encourage development of a nascent in-state fuel cell industry. More progressively, Connecticut's RPS is one of a small number that have included energy efficiency and cogeneration as qualified resources, and in fact the 2007 legislation established a separate compliance tier for these resources. This is a feature that may well be expanded in Connecticut and copied in other states with concentrated urban and industrial centers and limited access to more commonly recognized renewable resources.[51]

C. Minnesota

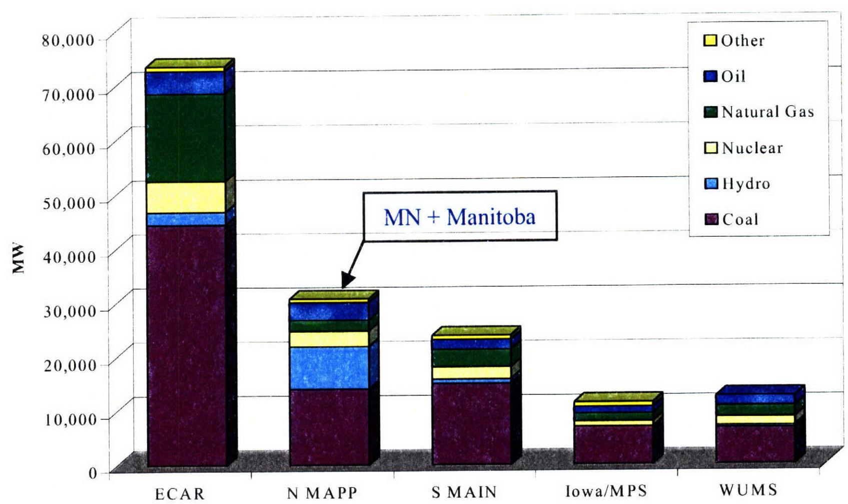
Context

All of the Minnesota grid (except for a small enclave on the Canadian border) is part of the Midwest Independent System Operator ("MISO"), a RTO that operates a wholesale power market and oversees system reliability in all or part of fifteen Midwestern states plus the Canadian province of Manitoba. Yet while Minnesota's power grid, like Connecticut's, is part of a regionally operated wholesale power market, Minnesota's electricity industry has never undergone restructuring, giving Minnesota a hybrid structure shared by many of the states in the MISO control area. Thus the great majority of Minnesota's installed generation is still owned and operated by vertically integrated electric utilities, of which by far the largest is Northern States Power, a wholly-owned subsidiary of Xcel Energy.[52] In addition, the electric utility sector is unusually fragmented, with a high percentage of retail electricity provided by a large number

[51] Ohio, the newest member of the RPS Club as of May 2008, established very aggressive targets for both efficiency and cogeneration alongside its more modest renewable energy targets

[52] According to the EIA's 2007 State Electricity Profile for Minnesota, 83% of installed capacity in 2006 was utility-owned, and 88% of electricity in 2006 was utility-generated.

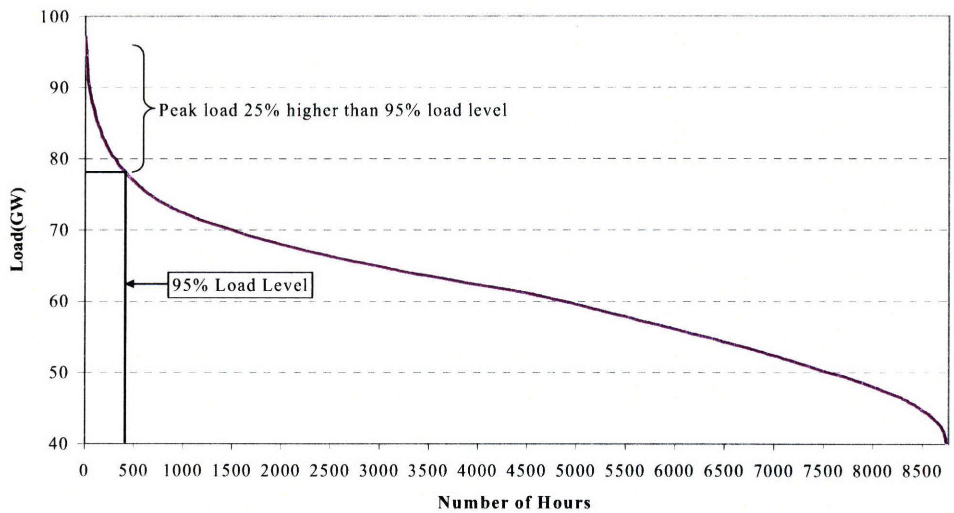
of co-operatives and public power districts.[53] As a result, while membership in MISO gives Minnesota LSEs access to all regional resources and the RPS allows them to satisfy their obligations with RECs from anywhere in MISO, the state's utility resource planning process continues to reflect less of a regional focus and more of a traditional focus on the development of in-state resources.[54]



Source: Midwest ISO 2003 Annual Report, April 2004

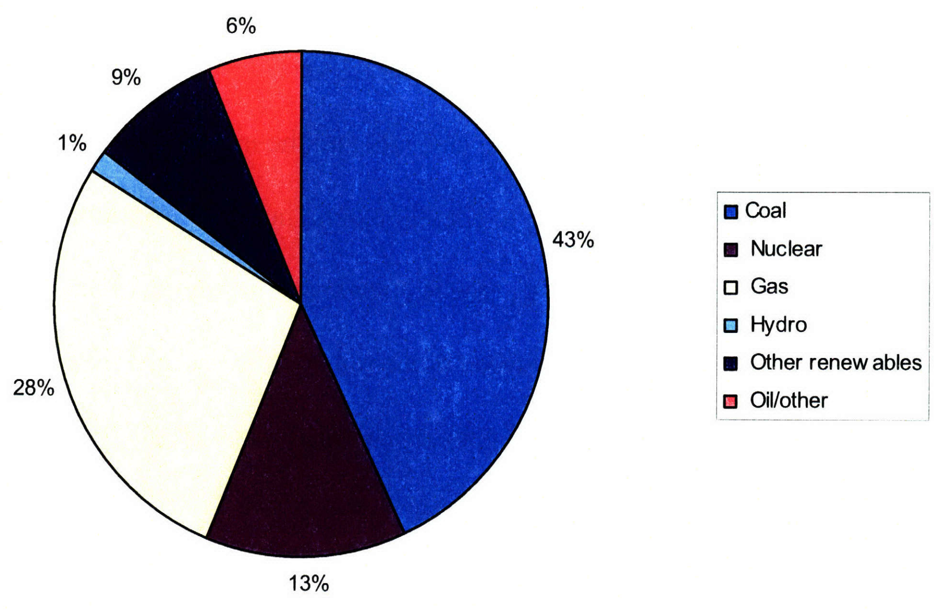
Fig. 3.5 – MISO installed generating capacity, by fuel type (by NERC region)

[53] *Ibid.* – IOUs supplied only 64% of retail electricity in 2006, with the balance supplied by 125 PPDs and 46 co-ops; NSP/Xcel alone supplied 48%.
[54] See, for example, pages 4-22 and 4-23 or Xcel Energy's 2007 Integrated Resource Plan.



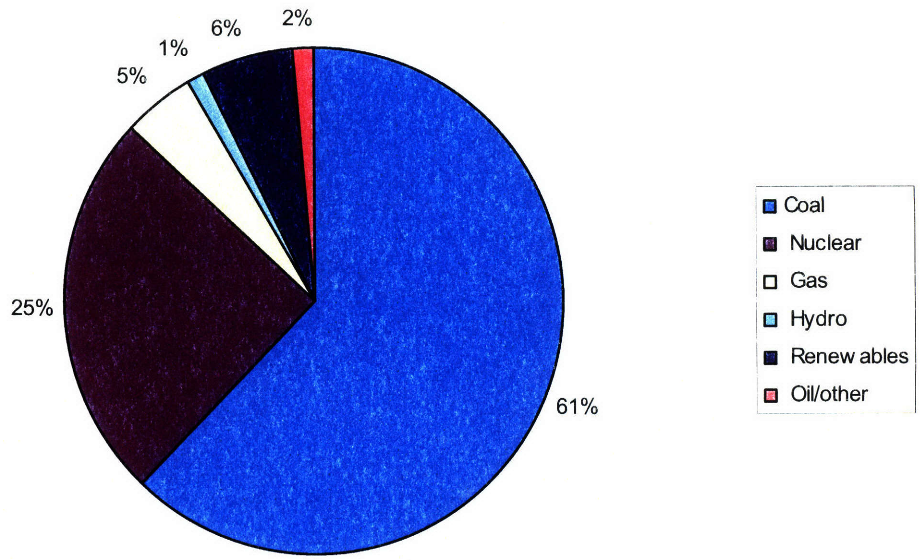
Source: Midwest ISO 2003 Annual Report, April 2004

Figure 3.6 – MISO load duration curve



Source data: EIA 2007 Minnesota State Energy Profile, Table 4

Figure 3.7 – Minnesota installed capacity, by fuel (100% = 12,651 MW)



Source data: EIA 2007 Minnesota State Energy Profile, Table 5

Figure 3.8 – Minnesota generation (MWh), by fuel (100% = 53.2 TWh)

As can be deduced from Figures 3.5 and 3.6, MISO is very generously supplied with production capacity. Given the amount of surplus capacity and the installed mix of technologies, generation in MISO is dominated by coal and, to a lesser extent, nuclear generation, and Minnesota's in-state resources very much reflect the regional mix (Figures 3.7 and 3.8). Load-following coal units are on the margin in the region in the range of 90% of the time, with hydro-electric and oil-fired generation used for needle-peaking service and gas-fired generation used increasingly to firm up intermittent renewable production.

RPS Evolution

The roots of Minnesota's current RPS program are unique. Like all first-wave RPS programs, Minnesota's was initiated as part of a larger electricity-related legislation package. In

Minnesota's case it was not restructuring, but rather the disposition of nuclear waste that gave rise to the initial renewable energy mandate. The state legislature in 1994 passed the Radioactive Waste Management Facility Authorization Law, which required Xcel to build or contract for 425 MW of wind and 125 MW of biomass generation by 2002 in exchange for the right to build a temporary dry-cask storage facility for spent fuel from their Prairie Island nuclear plant. The 1994 legislation was twice amended, in each case ratcheting up Xcel's renewable energy obligations (in 2001 increasing the mandated wind capacity to 825 MW by 2006, and in 2003 adding an incremental obligation of 10% of retail sales by 2015) while also placing a "good faith" renewable energy obligation on other Minnesota LSEs.

In February 2007 the legislature enacted stand-alone, wide-ranging RPS legislation (S.F. 4). The new law replaced all previous objectives with energy-only, retail sales-based obligations, ratcheting up Xcel's obligation yet again and placing binding obligations on all retail suppliers in the state. It also provided for compliance through the use of tradable credits, which must be certified by the Midwest Renewable Energy Tracking System ("M-RETS").

The intent of the original renewable obligation in the 1994 law was not stated explicitly in the legislation, though it seems clear that it was meant as a *quid pro quo* for allowing continued local storage of spent nuclear fuel.[55] Nor was there an explicit statement of intent in any of the subsequent legislation, including the sweeping 2007 RPS law.[56] The bill was the

[55] "Of far greater importance…is a unique 'quid pro quo' law regarding storage of spent nuclear fuel. A law passed in 1994 allows Northern States Power…to store nuclear waste in dry caskets near one of its nuclear power plants in exchange for a commitment to develop new wind capacity." *EIA Renewable Energy 2000: Issues and Trends*, "Forces Behind Wind Power," Louise Guey-Lee, pg. 100

[56] Numerous public statements by legislators, advocates and Governor Tim Pawlenty surrounding passage of the 2007 legislation consistently cited three primary expected benefits: reduced national and regional reliance on imported energy, local economic development, and reduced greenhouse gas emissions to combat climate change. For example, "'Together we believe that [the February RES law and a May energy efficiency bill] will reduce greenhouse gas emissions from electricity in Minnesota by over 40 percent,' says Sen. Ellen Anderson, DFL-St. Paul and a co-author of the energy efficiency bill." (Minnesota Public Radio, May 23, 2007); see also "'Right now,

subject of an extended debate on the floor of the Minnesota Senate on February 7, 2007, during which it was noted by the sponsors that the bill was the result of "100 to 200 hours" of stakeholder deliberations, including utilities, environmental groups and the Chamber of Commerce, among others.[57] The reasons stated in support of the legislation were (i) the need for Minnesota to "resume" leadership in the development of clean energy; (ii) to address climate change; (iii) other air and water pollution benefits; (iv) in-state economic benefits from the development of a renewable energy industry; and (v) a perceived need to make Minnesota less dependent on other states and other countries for its energy supplies. While a number of concerns were raised in debate regarding unquantified costs (direct rate impacts, the need to build more conventional plants to support intermittent wind power, other poorly understood consequences), unquantified benefits (CO_2 reduction, jobs) and the potential negative impacts on the development of energy-intensive industries in the northern part of the state, the bill was recommended for passage by a vote of 61-4. The debate clarified the particular emphasis placed on wind in the legislation – while Minnesota has very good wind resources, it would appear that the more important underlying motivation was the economic boost that an in-state wind industry would give to farmers in the southern tier of the state. This possibility appeared to trump any concerns expressed by the energy-intensive mining and industrial interests in the state's northern tier. It was also apparent during the debate that the then-recent loss of a wind turbine manufacturing facility to Pennsylvania was a prominent concern among some proponents.[58]

Minnesota imports more electricity than any other state. We need to keep more of our money at home,' said [RES law] sponsor, Rep. Aaron Peterson, DFL-Appleton." (Minneapolis-St. Paul Star Tribune, February 19, 2007).

[57] Source: video of Minnesota state senate proceedings for February 7th, 2007, accessed on the Senate's web site. The bill was formally passed by acclamation by the senate the following day, February 8th.

[58] Gamesa, a Spanish wind turbine manufacturer, had recently announced a decision choose Pennsylvania over Minnesota as the location for it's first North American wind manufacturing facility, citing the lack of a mandatory RPS in Minnesota as compared to the RPS that Pennsylvania had recently enacted.

Targets and Eligibility

Xcel continues to attract special consideration with the most stringent requirements, but the targets for all suppliers are among the most aggressive of any state in the nation:

Table 3.3 – Minnesota's current RPS targets

Year	Xcel Energy	All other LSEs
[2006	950MW]	
2010	15%	7%
2012	18%	12%
2016	25%	17%
2020	30%	20%
2025	30%	25%

The legislation further specifies that for Xcel alone, of the 30% obligation in 2020 at least 5/6ths of it (or 25% of the total) must come from wind. Xcel makes up about 48% of 2006 state retail sales,[59] thus holding Xcel's share of retail sales constant, the 2025 statewide target would equate to 27.4% of retail sales, of which at least 11.9% must come from wind. Existing resources are eligible under the RPS, and most of the existing biomass generation pre-existed the 1994 proto-RPS. But non-hydro renewables constituted only 5.7% of all generation in 2006, and since the great majority of that was developed after enactment of the proto-RPS legislative mandate in 1994, it is still fair to say that Minnesota's RPS targets are among the nation's most aggressive.

Wind and biomass were the only originally qualified resources, but the 2007 legislation expanded eligibility to include other "conventional" renewables (solar PV; solar thermal; landfill gas; anaerobic digestion; "low-impact" hydro; and fuel cells using renewably-derived hydrogen) and some less conventional options (combustion of municipal solid waste; co-firing of biomass with coal; mid-sized hydro; and fuel cells using non-renewably sourced hydrogen).[60] Eligible

[59] Source: EIA 2007 Minnesota State Energy Profile, Table 5

[60] Fuel cells using fossil-derived hydrogen are eligible only until December 31, 2010; hydro-electric facilities of up to 100 MW capacity are eligible, a somewhat higher limit than in other RPS programs.

resources must be qualified under M-RETS, which effectively means that they can be located anywhere within or be deliverable to the MISO control area.

Compliance

Minnesota's RPS provides no specific mechanism for alternative compliance, nor does it provide specified penalties for non-compliance, providing instead that the Public Utility Commission is authorized to compel utilities to comply or to pay a penalty based on an imputed cost to comply. With no specific bases upon which LSEs can be excused from their obligations under the RPS and no explicit provisions for alternative compliance, Minnesota's program could be said to be one of the strictest state policies. However the lack of specific penalties for non-compliance, coupled with the broad authority granted to the PUC to modify or delay the obligations under vaguely defined circumstances,[61] introduces a degree of uncertainty as to just how robust compliance will be over time.

Access to Eligible Resources

Minnesota has one predominant indigenous renewable resource – wind. (See Appendix D for a renewable resource map of the state) The western tier, and in particular the southwestern quadrant lie within the eastern edge of the massive wind resource that blankets the North Central Plains region. The 1991 PNNL study referenced previously estimated the in-state wind resource potential at 657 TWh, nearly ten times the state's 2006 electricity consumption of 66.77 TWh. The State also possesses a good biomass resource, located primarily in the northeastern quadrant

[61] The PUC is empowered to modify or delay the obligation to comply based on a number of considerations, including, *inter alia,* "significant" rate impacts, transmission limitations or reliability impacts "beyond the control of the utility." The legislation does not attempt to quantify what would be considered significant, and the sponsors declined to offer any guidance during final debate on the bill on the legislative intent behind the usage of the term.

known as the Iron Range. The exploitation of these resources has been well supported to date – farming interests dominate the western and southwestern parts of the state and have so far been welcoming of the economic rent available from wind farm development, and the paper mill and mining industries in the Iron Range historically have exploited local biomass and hydro resources where commercially feasible to do so. Outside of the industrial loads located in the Iron Range, electricity demand is concentrated in the Minneapolis-St. Paul metropolitan area in the east-central part of the state, and the existing electric infrastructure has developed around those two load centers. The western and southwestern concentration of the primary resources available to satisfy the RPS obligations will necessitate considerable new investment in high-voltage transmission facilities.[62]

D. Colorado

Context

Colorado is the only one of the four selected states that is not part of a RTO.[63] The state's grid operates within the Western Electricity Coordinating Council ("WECC"),[64] but it is operated by the state's vertically integrated utilities as a regulated cost-of-service monopoly, much as it has been since the first half of the last century.[65] While the grid is interconnected to and synchronized with the WECC system, its resource planning and deployment centers on the

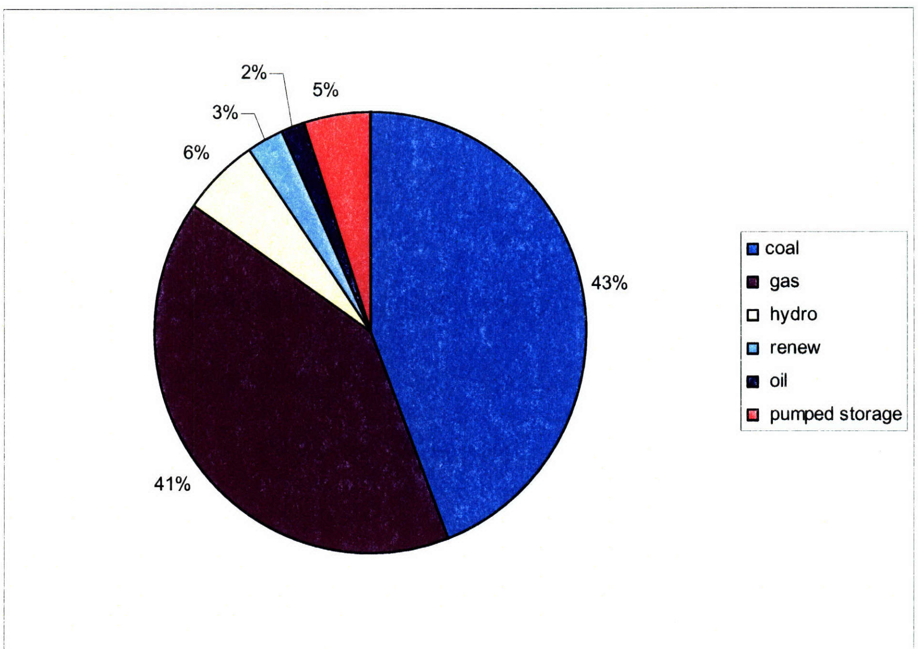
[62] See "Final Report - 2006 Minnesota Wind Integration Study," Appendix A dated November 30, 2006 (prepared by EnerNex in collaboration with MISO)

[63] Public Service of Colorado and thirteen other transmission-owning utilities in WECC participate in WestConnect, which was originally formed as a candidate to become the RTO for much of the WECC region; when FERC retreated from its push for wholesale markets the WestConnect members suspended formation of an RTO, but WestConnect continues to function as a sort of informal wholesale market.

[64] WECC is the Regional Reliability Organization that, pursuant to the Energy Policy Act of 2005, oversees system reliability for virtually all of the Mountain West and Pacific regions of the U.S., along with the Canadian provinces of Alberta and British Columbia.

[65] State law requires that new resources be procured through open competitive tender, but the process is tightly controlled by the vertically integrated utilities, which exercise considerable market power – in 2006, regulated utilities owned 72% of the state's generation capacity and produced 83% of the state's electricity.

vertically integrated in-state utilities over which the Colorado Public Utilities Commission exercises regulatory control. Colorado and Eastern Wyoming essentially comprise the Rocky Mountain Power Area, a transmission-delimited sub-region within WECC. In 2005, installed capacity in WECC was 156,815 MW, of which 11,088 MW was located in RMPA.[66] (See Appendix E for a schematic of the resource mixes in each of the WECC sub-regions) The RMPA market is dominated by Public Service Company of Colorado ("PSCo,"owned by Xcel Energy, also the largest LSE in Minnesota). In 2006 PSCo supplied 55% of all retail electricity in Colorado, with the balance provided by one other investor-owned utility and 58 public power companies and rural electric co-operatives.[67]

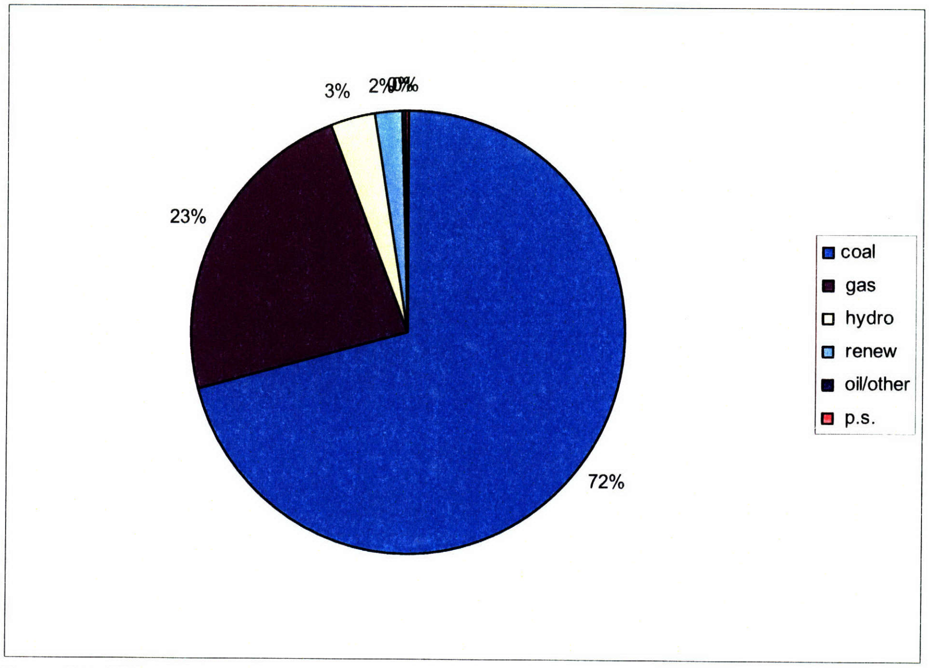


Source data: EIA

Fig. 3.9 – Colorado installed capacity, by fuel (100% = 11,156 MW)

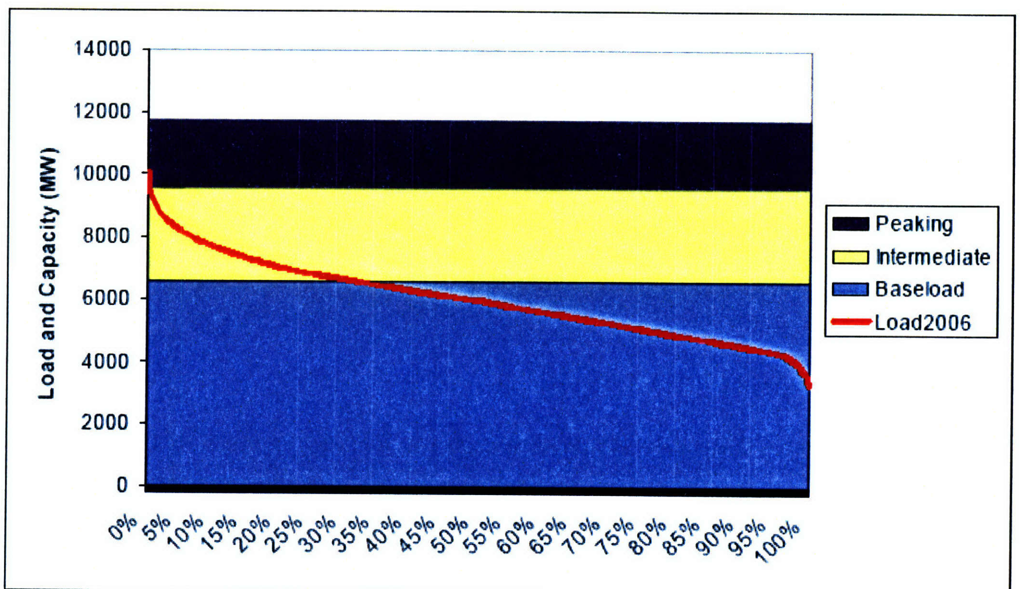
[66] WECC Summary of Estimated Loads and Resources, January 1, 2006

[67] "State Electricity Profiles 2006," EIA, November 21, 2007



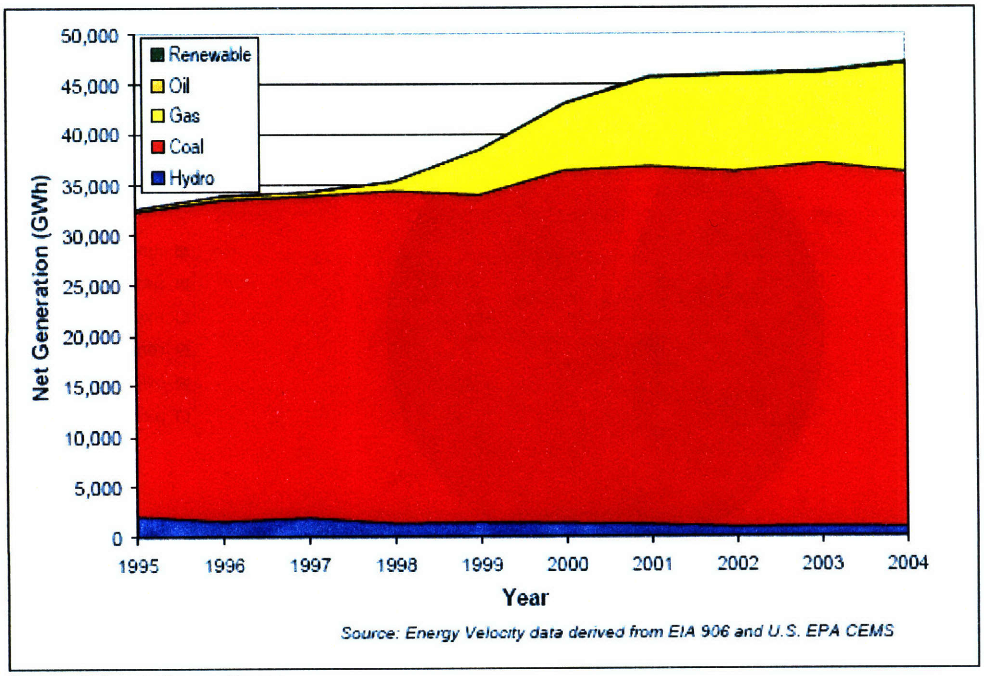
Source data: EIA

Fig. 3.10 – Colorado generation, by fuel (100% = 50.7 TWh)



Source: Colorado Energy Forum

Figure 3.11 – 2006 load duration curve



Source: Colorado Energy Forum

Figure 3.12 – Historical fuel mix by net generation

As can be derived from Figures 3.9 through 3.12, base-load coal is the marginal generation in Colorado (and the rest of the RMPA) approximately 70% of the time, with intermediate-load gas generation dominating the remaining hours.

RPS Evolution

Colorado is one of only two states in which the RPS program was first established through a ballot initiative (the other being Washington). Colorado voters passed Amendment 37 in November 2004 by a vote of 53.4% to 46.6%, requiring investor-owned utilities to derive 3% of their energy from qualifying renewable sources by 2007, rising to 10% by 2015. The initiative also imposed a limit of 2% on any resulting increase in residential electricity bills. In 2007 the legislature passed H.B. 1281, *An Act Concerning Increased Renewable Energy Standards*, which expanded the RPS requirement for IOUs and imposed a lesser requirement on all co-ops and those municipals with more than 40,000 customers. The effect was to expand the coverage of the RPS from roughly 58% to 94% of retail electricity sales in the state. The ballot initiative included utility rebates for customer installation of distributed generation, which the 2007 legislation retained.

The legislation's stated intent was "...to save consumers and businesses money, attract new businesses and jobs, promote development of rural economies, minimize water use for electricity generation, diversify Colorado's energy resources, reduce the impact of volatile fuel prices, and improve the natural environment of the state...."[68] This largely reflects the arguments for the original RPS articulated in the 2004 ballot initiative, though that language was more explicit in referencing CO_2 emissions reduction.[69] The 2007 expansion of the RPS was considered a centerpiece of "The New Energy Economy" touted by Governor Bill Ritter during and after his successful 2006 campaign.[70] The press release issued by the Governor's office upon signing of the legislation stated that it would "improve our economic security, our environmental security and our national security...breathe new economic life into rural Colorado...create new jobs, and...say to the rest of the world, 'Colorado is open for business in what will be one of the most important industries of the 21st Century.'" While these references imply that energy security and economic development figured more prominently than climate change in the evolution of Colorado's RPS than it had done in Connecticut and Minnesota, the 2007 RPS legislation also featured prominently in the Governor's November, 2007 *Climate Action Plan: A Strategy to Address Global Warming.*

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[68] *Analysis of the 2004 Ballot Proposals*, Legislative Council of the Colorado General Assembly, Research Publication No. 571-1, pg. 39

[69] *Ibid.*, pp. 15-16

[70] See, *e.g.*, the lead editorial "Key issues left for the legislature" in the March 19, 2007 *Denver Post.*

Targets and Eligibility

Colorado's RPS is has a number of unique features. It is the only state program with no geographic limitations whatsoever on resource eligibility, though it includes a number of features designed to promote compliance through the development of in-state and, in particular, customer-sited resources. Specifically, credits produced by in-state resources receive a 125% multiplier, and a 150% multiplier applies to credits from community-based resources of 30 MW or less. The legislation allows for tradability of credits but does not specify any established REC tracking organization or mechanism.

Table 3.4 – Schedule of Colorado REC purchase obligations

	IOUs*	Co-ops, Munis (munis w/>40k customers)
2007	3%	0%
2008	5%	1%
2011	10%	3%
2015	15%	6%
2020	20%	10%

*4% of the renewable energy procured by IOUs must be from solar, half of which must be customer-sited facilities

Eligible resources include solar (PV and thermal), wind and geothermal; low-impact hydro; landfill gas, biomass and co-firing of biomass with coal; fuel cells using renewably-produced fuel; and "recycled energy," which as defined is effectively CHP. The legislation also allows compliance using "verified generation savings" obtained under contract from energy efficiency measures. For co-ops and munis only, a 300% multiplier applies to RECs from solar facilities commencing operation prior to July 1, 2015. The RPS does allow compliance using existing resources, but prior to 2005 only 0.5% of generation in the state was from non-hydro renewable sources, and of the 2.5% of the state's supplies that come from hydro production, less than a third (27%) comes from RPS-eligible facilities.[71]

Compliance

Colorado's RPS compliance regime is among the most stringent in the nation. No provisions are made for alternative compliance payments, and failure to comply due to circumstances "beyond the control of the retail utility" is excusable only prior to 2010. The PUC is empowered to assess penalties for non-compliance, in the form of customer bill credits equal to an imputed cost that would have been incurred to comply, and further penalties may be assessed as well. These strict compliance rules must be considered in light of the legislation's provisions limiting rate impacts resulting from compliance with the RPS. Increases in residential electric bills are limited to 2% for IOU customers and 1% for co-op and muni customers. While such safety-valve mechanisms are common among the state RPS programs, there is some evidence (as will be reviewed in Chapter Four) that it represents less of a constraint on renewables development in Colorado than is the case in other state programs with similar provisions.

Access to Eligible Resources

Colorado's renewable resource potential is substantial (see Appendix F). The eastern half of the state lies in the western edge of the Plains wind resource – the 1991 PNNL study estimated in-state wind potential at 481 TWh, a bit less than ten times the state's 2006 consumption of 49.8 TWh, and *The Renewable Energy Atlas of the West* estimates the wind

[71] EIA Existing Capacity by Energy Source, Existing Generating Units in the United States by State, Company and Plant, 2004

potential to be 601 TWh.[72] The southern tier of the state contains good solar and geothermal potential (though the geothermal potential is largely undevelopable using current technology), and there is reasonable biomass potential particularly in the northeastern quadrant. *The Renewable Energy Atlas of the West* estimates Colorado's solar potential at 83 TWh, or roughly one and two thirds times the state's total 2006 consumption. There is also an appreciable amount of unexploited low-impact hydro potential scattered throughout the central and western parts of the state.

In December, 2007 a task force established by the Colorado State Senate issued a report[73] identifying Renewable Resource Generation Development Areas (GDAs), defined as "a concentration of renewable resources within a specific geographic region that provides a minimum of 1000 MW of developable electric generating capacity that could connect to an existing or new high voltage transmission line." The task force identified eight wind and two solar GDAs. Considering only these more concentrated resource sub-regions, the wind GDAs are estimated to contain 96 GW of developable potential (compared to Colorado's peak demand of 11 GW), while the estimate of concentrating solar power (CSP) potential identified in the two solar GDAs ranged from 26 GW to at least 275 GW. The task force did not identify sufficient concentrations of small hydro, biomass or geothermal potential to be able to establish GDAs for those technologies, but its report mapped extensive local opportunities for development of each of these sources. While other states may surpass Colorado in absolute potential in each category of renewable resources, the aggregate indigenous renewable energy potential is unusually diverse and equal to many times Colorado's current and forecasted electricity requirements.

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[72] Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential. Western Resource Advocates *et al.*, 2002

[73] See *Connecting Colorado's Renewable Resources to the Markets: Report of the Colorado Senate Bill 07-091 Renewable Resource Generation Development Area Task Force,* December 21, 2007

E. California

Context

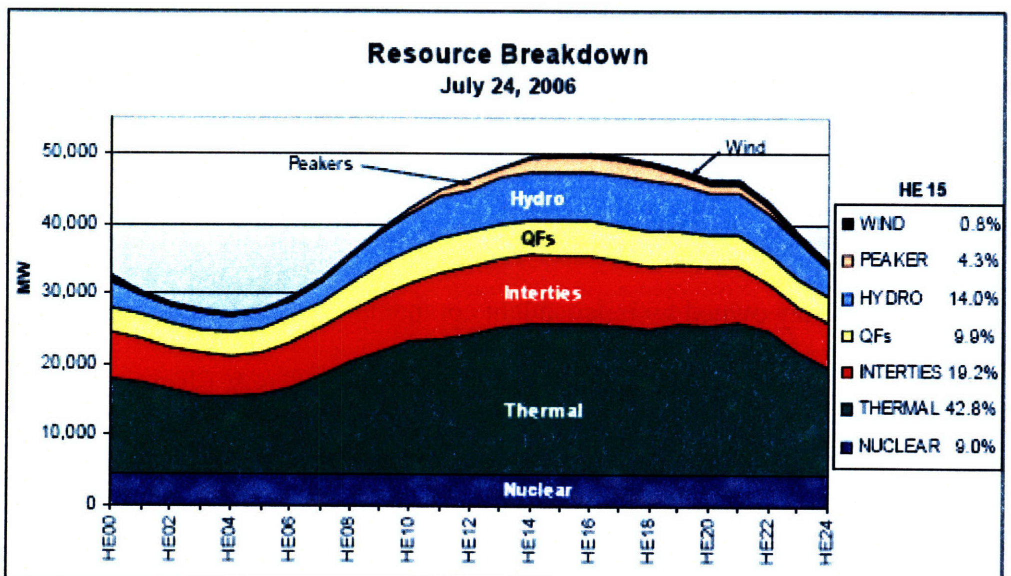
California is one of only two jurisdictions in the WECC that operate a wholesale electricity market (the Canadian province of Alberta being the other). Most of the State's grid is operated by the California Independent System Operator ("CAISO"), a federally-chartered wholesale market operator that operates entirely within the boundaries of the State of California (CAISO's control area covers over 80% of the load and 86% of the generating capacity in California). The balance of the state's grid is operated by a collection of municipal-owned utilities, public power districts and rural electric co-operatives. Over five years have passed since the nightmarish period when California became synonymous with wholesale electricity market failure, and while various state agencies and the ISO continue to work through legacy issues the market has been relatively stable over that period.

The California market was restructured in 1998. While several of the publicly-owned utilities own generation and some generation was retained by the IOUs under the restructuring, most generation in the state is today owned by independent companies.[74] Five LSEs account for approximately 80% of all retail sales, divided among three IOUs (Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric, all three of which are members of CAISO) and two municipals (Los Angeles Department of Water & Power and Sacramento Municipal Utility District, neither of which are members of CAISO).

California has historically relied upon significant amounts of out-of-state generation to meet demand, from other sub-regions of the WECC with a much different mix of resources (see

[74] In 2006, independents owned 58.3% of installed capacity and generated 53.7% of the electricity produced; Los Angeles Department of Water & Power is a vertically-integrated, municipally-owned utility that owns substantial amounts of generating capacity.

Appendix E). The combination of these two features makes California's wholesale power situation unique. While the state has very little indigenous coal-fired generation and no plans to develop any more, a significant percentage of the State's baseload requirements are met by large coal-fired plants located to the east and north of the State. In addition, major high-voltage DC and AC interties operate between California and the Pacific Northwest, arbitraging seasonal differences in demand between the two regions. These interties bring large amounts of hydroelectric energy south during Southern California's summer peak and send surplus fossil, nuclear and hydro generation north during the Pacific Northwest's winter peak. (See Appendix H) Figure 3.13 below shows the breakdown of resources available to meet CAISO demand on the 2006 summer peak day. Imports accounted for at least 20% of peak day supply in 2006, and coal and large hydro accounted for nearly 60% of total imported energy in that same period.[75]

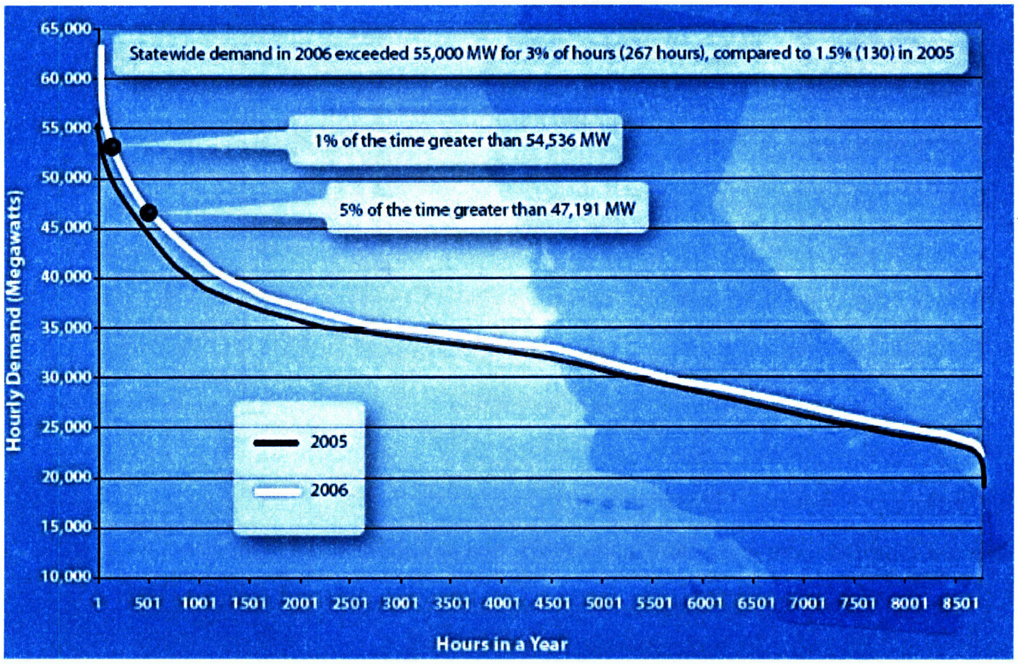


Source: CAISO *2007 Summer Loads and Resources Operations Assessment*, March 8, 2007

Fig. 3.13 – CAISO resources available to meet 2006 summer peak day demand

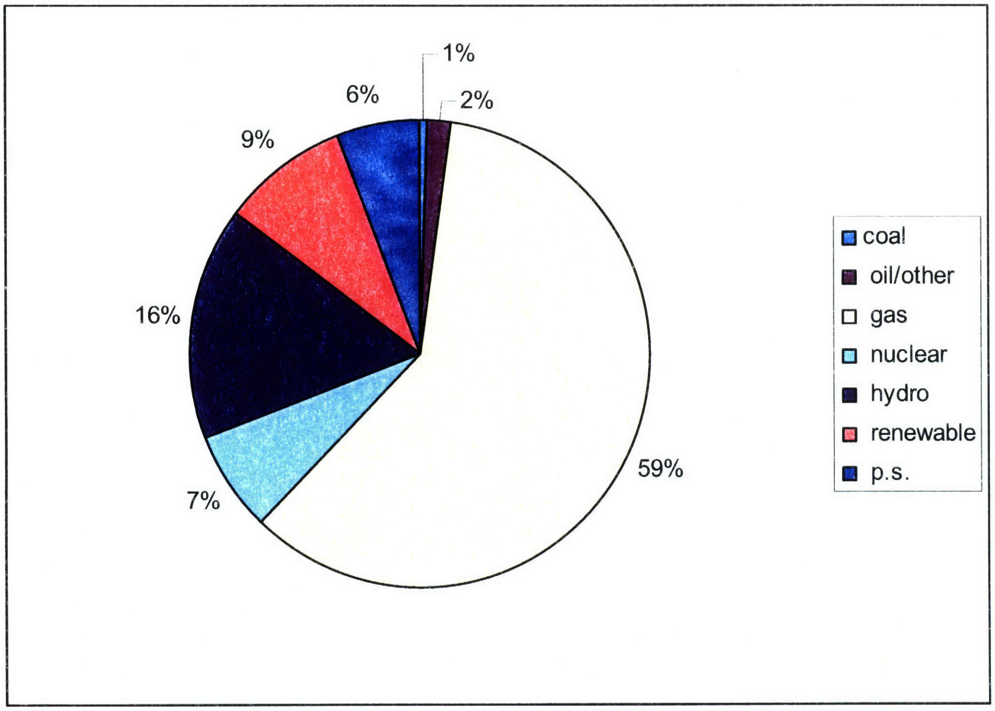
[75] California Energy Commission, *2006 Net System Power Report,* page 3, Table 1

Figures 3.14 through 3.17 below show the California Energy Commission's best estimate of the mix of generating resources available to California in 2006, based on their assessment of the likely mix of resources imported over the state's interties with the rest of the WECC.



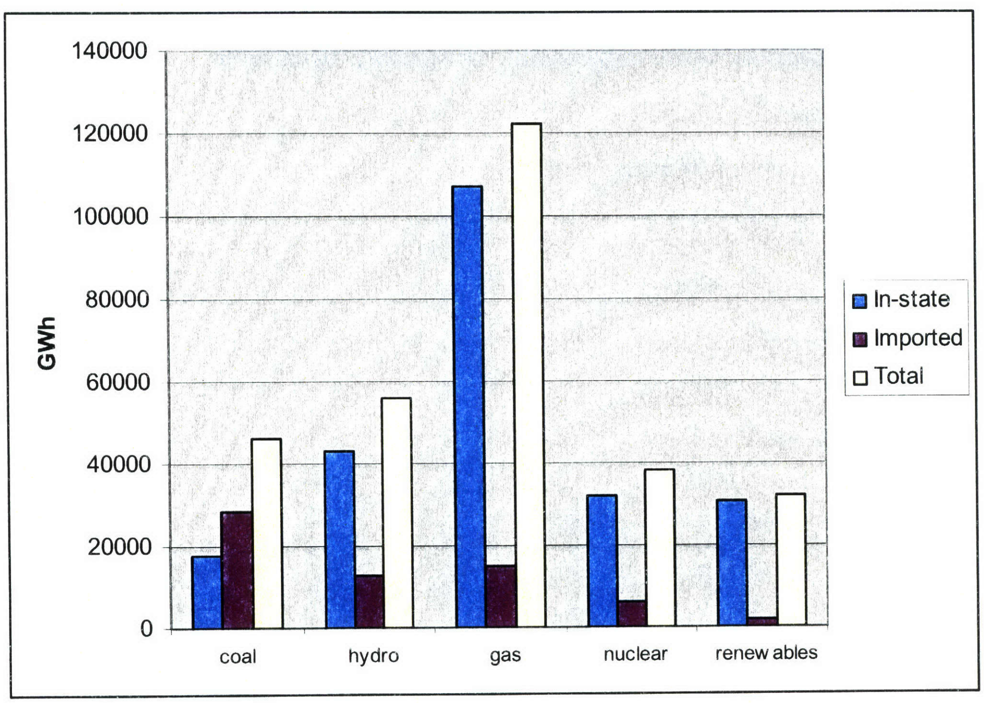
Source: CEC 2007 Integrated Energy Policy Report

Figure 3.14 – 2006 California load duration curve



Source data: EIA

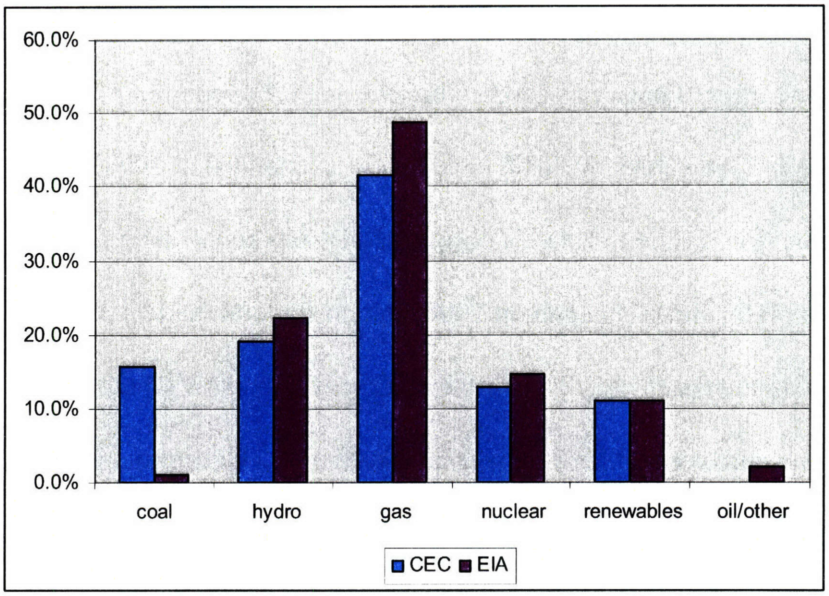
Fig. 3.15 - Installed capacity in 2006, by fuel type[76] (100% = 63,212 MW)



Source data: CA Energy Commission

Fig. 3.16 – Gross 2006 power production, including imports

[76] Note that the EIA data indicates 389 MW of coal-fired capacity installed in CA in 2006; this does not comport with CEC data showing over 17,000 GWh of coal-generated energy. The difference may due to be on-site facilities.



Source data: EIA and CA Energy Commission

Fig. 3.17 – 2006 production, comparing CEC data (including imports) with EIA data (in-state only)

These data show that while natural gas fired generation is on the margin in California nearly all of the time, the system is far more reliant on coal than would be indicated by looking only at the in-state resource mix.

Evolution of the RPS

The concept of an RPS as we know it today arguably originated in California during the state's restructuring debate in the mid 1990s.[77] This early experience with the design of post-restructuring renewable energy policy was reviewed in detail by Wiser, Pickle and Goldman,[78] but suffice it to say that the California PUC (in their 1996 restructuring order) rejected the RPS concept, choosing instead to promote renewables with funds raised through a distribution surcharge.

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[77] Wiser *et al.*, "The Experience with Renewable Portfolio Standards in the United States," *Electricity Journal,* May, 2007, pg. 8; also Wiser, Ryan, Steven Pickle and Charles Goldman, "California Renewable Energy Policy and Implementation Issues: An Overview of Recent Regulatory and Legislative Action" (1996)

[78] Wiser *et al.*, "Renewable Energy Policy and Electricity Restructuring: A California Case Study," *Energy Policy,* May, 1998, pp.465-475

The California legislature revisited renewable electricity policy in 2002, enacting a stand-alone RPS law (S.B.1078) that took effect January 1, 2003. This original RPS required applicable LSEs to source 20% from renewables by 2017. The law was amended in 2003, primarily to ease compliance obligations while the state's crippled IOUs worked to stabilize their financial condition. It was substantially amended again in 2006, also in stand-alone legislation (S.B.107), substantially accelerating the timetable. This last amendment also clarified the eligibility to include out-of-state resources capable of delivering electricity to California, and it established the right to trade RECs under the auspices of the Western Renewable Energy Generation Information System ("WREGIS").

California's 2002 legislation was the first of the stand-alone RPS laws enacted. The language of the legislation sets out a rather encyclopedic list of benefits as constituting the legislature's intent – diversity of energy sources; increased supply reliability; stable electricity prices; improved public health; cleaner air; improved environmental quality; sustainable economic development; new employment opportunities; reduced reliance on imported energy; and reduced reliance on fossil fuels are all listed as expected benefits.[79] Notably, climate change mitigation was not explicitly mentioned. A somewhat different sense of the motivations behind California's pioneering adoption of stand-alone RPS legislation can be gleaned from a review of the state's leading newspapers during the eighteen months leading up to passage of S.B.1078. California was struggling to emerge from the crippling energy crisis that had unfolded in the state beginning in 2000, and a concerted push to develop renewable supplies was promoted by renewables advocates as one way to ensure that the emergency would not be repeated. While the 1996 restructuring law provided funding to promote development of renewables, advocates were

[79] Article 16 (commencing with Section 399.11) of Division 1, Part 1, Chapter 2.3 of the Public Utilities Code, as added by S. B. 1078, Ch. 516, September 12, 2006

frustrated that progress had been negligible owing to the lack of any mandatory purchase obligation on the state's LSEs.[80] The San Francisco Chronicle editorialized aggressively in support of the legislation on April 27, 2002 and again on July 20, 2002, in both cases citing (1) the need to reduce the state's reliance on imported natural gas and (2) the need to reduce CO_2 emissions as the main reasons why the legislation should be enacted.

The dramatic acceleration of the RPS in S.B.107 contained no new language regarding intent, but by 2006 the issue of climate change had become a far more prominent driver of the RPS phenomenon. Upon signing S.B.107 into law, Governor Arnold Schwarzenegger's September 26, 2006 press release referred only to climate change to justify its expansion the RPS targets. The signing, along with two other pieces of legislation dealing with carbon capture and sequestration, was timed to take place during the same week as the signing of California's landmark greenhouse gas law. And in a lengthy front-page article in the same week,[81] the San Francisco Chronicle referred to the legislation as "a key component of California's push to reduce greenhouse gas emissions," with no reference to any of the long list of goals included in 2002's S.B.1078. More recently the California Energy Commission's *2007 Integrated Energy Policy Report* (page 102) states that the two policy goals driving renewable energy development are "reducing greenhouse gas emissions and managing cost and risk to ratepayers."

Targets and Eligibility

While the administrative details of the California RPS are famously complex (the October 2007 ISO/RTO Council report *Increasing Renewable Resources,* at page 31, stated that

[80] See, *e.g.*, "Without the requirement for the utilities to buy renewable power, we are not optimistic that the Governor's goals can be met...The Energy Commission's plan provides incentives to producers, but the problem we're facing is that there are no buyers for renewable power." Matt Freeman, staff attorney for The Utility Reform Network (a leading advocacy group) quoted in the July 28, 2001 *S.F. Chronicle*, pg. A2..
[81] "State red tape trips up green energy efforts," *S.F. Chronicle,* September 26, 2006, pg. A1

"California has perhaps the most complex Renewable Portfolio Standard in the nation"), the compliance targets are quite simple, perhaps overly so. The 2002 law mandated that LSEs source 20% of their wholesale electricity from eligible renewable sources by 2017, with no interim milestones established. The accelerated target established in 2006 mandates that LSEs increase the amount of wholesale power purchased from renewables each year by at least 1% from the level in 2001, such that the final target of 20% from renewables is met by 2010 (the jurisdictional LSEs purchased approximately 10% of their power from eligible renewable sources in 2001). Again, no interim milestones were set, though they would admittedly have been somewhat superfluous given the extraordinarily compressed timeframe between the enactment of the law and the final milestone date. On signing the bill, Governor Schwarzenegger set a further goal of 33% from renewables by 2020, a target that is currently non-binding but that state agencies are treating with some seriousness.[82]

Eligible sources include all of the conventionally recognized technologies, plus wave/tidal power, geothermal and non-combustion conversion of municipal solid waste. Eligibility is monitored by WREGIS, which was developed largely at the behest of the California Energy Commission and began operating in June 2007. Resources anywhere in the WECC are eligible as long as their power is deliverable into California, though interestingly renewable resources outside of CAISO must be firm, not intermittent. Efficiency and CHP, which are otherwise aggressively promoted in California, are not eligible resources under the RPS.

One completely unique aspect of California's RPS program (at least among the state programs in the U.S.) is the "least cost/best fit" criteria that is mandated by the 2002

[82] See e.g. "Feasibility of 33 Percent by 2020," *California Energy Commission 2007 Energy Report*,", pg 109; the 33%-by-2020 goal had originally been proposed by the CEC in their *2004 Integrated Energy Policy Report*.

legislation.[83] I will discuss the potential significance of this feature at more length in Chapters Four and Five, but it is worth noting here that California is the only state that not only allows, but requires that the LSEs rank-order proposed renewable resources not only according to cost but also according to the degree to which their specific attributes fit with the individual LSE's system requirements. The primary attributes to which this criterion applies include (1) the dispatchability and firm capacity value offered by the resource and (2) the investment in transmission that will be required to integrate the resource. The potential implications of such a requirement, when considered alongside the import prohibition on intermittent resources, and the degree to which these are already affecting renewable development, will be matters of interest later in the paper.

One weakness of the California program is the percentage of retail sales covered. The mandate applies to IOUs as well as several classes of competitive retail power marketers, but municipal utilities and public power districts are only encouraged to develop their own standards. The net effect is that the mandatory standard applies only to about 64% of 2004 retail sales.[84]

Compliance

The California compliance regime is not its strongest feature. On the positive side, no provisions are made for alternative compliance payments, and the CPUC is empowered to administer penalties for non-compliance. Yet no specific penalties are prescribed, nor are they mandated. The CPUC in June of 2003 set a non-compliance penalty of $50/MWh, capped at $25 million per utility per year and not indexed to inflation. Also, LSEs are excused from

[83] Div. 1, Part 1, Chapter 2.3, Section 399.14(B) of the Public Utility Code; see "Renewable Resources Development Report" (CEC, November 2003) page 121 for a good description of the requirement
[84] Source: The Union of Concerned Scientists' Renewable Electricity Standards Toolkit, California Renewable Portfolio Standard Summary: http://www.ucsusa.org/assets/documents/clean_energy/California.pdf

compliance if they are not creditworthy, a vestige from the dark days of the energy crisis and less of a factor today.

A further weakness of the compliance regime, and another unique feature of the California RPS, is that utilities are allowed to recover from customers renewable procurement costs only up to the cost of a proxy plant, called a Market Price Referent ("MPR"). The MPR's economics are established by the CPUC in consultation with stakeholders. The most recent MPR was set in December, 2006 (CPUC Resolution E-4049) and reflects a gas-fired combined-cycle plant. To the extent that the LSEs are required to pay a price above the MPR to obtain renewable supply, they are eligible to receive Supplemental Energy Payments ("SEP") from the state's System Benefits Charge fund to cover such above-market costs.[85] Most resources offered to date have been priced above the MPR, and it is not at all clear that there will be sufficient funds available to compensate the LSEs for the costs they will incur to meet the 2010 milestone. A further concern expressed by some is that the CPUC's process for allocating SBC funds is overly complex and an obstacle to progress.[86] Additionally, there is ongoing debate over whether or not the MPR's economics have been determined appropriately, including questions about the extent to which they fairly reflect applicable transmission costs, fuel price volatility and whether or not they should include prices for environmental externalities. Taken together, the MPR/SEP structure introduces a unique and material level of administrative complexity, and therefore uncertainty, into California's otherwise extremely aggressive RPS program.

[85] Through 2012 the program is to be funded at $135 million per year through a charge on customers' bills, at least 51.5% of which is to be made available to reimburse LSEs for above-market costs for renewable supplies.
[86] "Does It Have To Be This Hard? Implementing the Nation's Most Complex Renewables Portfolio Standard," R. Wiser, K. Porter, M. Bollinger, H. Raitt, *The Electricity Journal* ,October, 2005

Access to Eligible Resources

Like Colorado, California possesses a diverse wealth of indigenous renewable resources. (See Appendix G – see also the California Energy Commission's November 2003 "Renewable Resources Development Report") The southeastern quadrant of the state is home to some of the nation's richest solar resources, with enough exploitable solar potential alone to supply several times the state's 2006 consumption of 263 TWh. Much of the state, with the exception of the Central Valley and the far northwestern corner, offers good geothermal potential, and while a great deal of the conventional geothermal potential has already been developed, the incremental potential for advanced geothermal technologies is substantial. California's coastal waters possess some of the highest offshore wind potential in North America, particularly along the far northern coast, as well as some of the continent's best wave power potential. Ironically, while land-based wind has a long history of development in California, the state's terrestrial wind potential is modest compared to the best interior regions. The 1991 PNNL study estimated terrestrial wind potential at 59 TWh, a little more than 20% of the state's 2006 total consumption. The best terrestrial resources are concentrated in the mountain passes to the north and west of Los Angeles, many of which have already been extensively developed.

Chapter Four

Evaluating the Efficacy of RPS Policies

A. Framing the question

At the risk of stating the obvious, the answer to the question of whether or not RPS policies are succeeding depends critically on how one defines success. While it might be quite easy to define success for the policy entrepreneurs who promote these policies in order to encourage the adoption of specific technologies, it is not their definition of success that is of interest. It is true but uninteresting to say that increased investment in one or more renewable electricity generation technologies is an indicator of success for a renewable portfolio standard. The question I wish to answer is whether or not the programs are succeeding in achieving the public goods that drive public support for the rapidly spreading adoption and continued expansion of these programs.

I have discussed in general the rationales given for RPS programs across the various states in which they have been created, and I have reviewed in detail the rationales behind the creation of and ongoing support for RPS programs in four selected states. While the form and substance of the various state programs has varied widely, nearly all of these programs have been justified officially (through the relevant legislative, ballot or regulatory language and the formal legislative debates, if any, preceding their adoption) and unofficially (through public statements by the elected officials and non-governmental organizations promoting them) on the basis of one or more public policy goals drawn from a reasonably consistent menu of options. As is apparent from the public debate surrounding specific projects and programs that have been proposed in response to these policies, certain rationales and their proponents have been more effective than others in shaping the public expectations for what the policies will achieve. The rationales for many of the programs have evolved over time and in so doing, have informed amendments (in some cases multiple amendments) to the original policies. While one set of policy goals may have been most influential in the origins of the earliest RPS programs, it is the current mix of pressing problems on the energy and environmental policy agendas, and the success of various interest groups in coupling RPS-style policies with the policy windows thus created, that are today driving the rapid advance and continued evolution of such policies at the state level.

I reviewed in Chapter Two the evolution of the policy agenda toward the current mix of three high priority goals – combating climate change, capturing green jobs and investment, and promoting energy independence – and I have argued that combating climate change has become the most prominent among these in recent public debates around the expansion of these policies. How do we evaluate the past effectiveness and likely future effectiveness of RPS-style policies in meeting the expectations that have been created for them?

B. Establishing the criteria

I have shown that there are three leading policy goals that are being used to drive continued support for and public expectations of state-level RPS policies:

1) *Green jobs and economic development* – that promoting investment in electricity production using renewable resources will result in a positive net impact on local (that is, in-state) job creation and economic growth;

2) *Energy security* – that promoting investment in electricity production using renewable resources will reduce dependence on imported energy (nationally) and/or reliance on volatile

energy sources not under local control (state by state), and that in so doing it will result in lower and/or more stable energy prices; and

3) *Global climate change* – that promoting investment in electricity production using renewable resources is a timely and essential component of a cost-effective program to mitigate the risk of dangerous anthropogenic climate change; indeed it is consistently cited as the central feature, at least in the near term, of our response to this issue in the power production sector.

While the principal subject of this paper is the effectiveness of RPS policies in achieving the goal of combating climate change, it is important to recognize that the first two goals continue to feature prominently in many official pronouncements and public statements made in support of RPS policies and of the projects and programs promoted in response to them. Indeed, it is almost certainly the case that some of those supporting these policies and programs do so solely out of an interest in promoting job creation and/or energy independence and are not at all motivated by climate change. No critique of RPS-style policies would be complete without acknowledging this. For that reason I have included in Appendix I a brief and admittedly subjective discussion of the likelihood that these policies have had or will have any significant beneficial impact in the areas of incremental local jobs creation, national energy security or regional control over energy supplies. A more thorough treatment of these questions is beyond the scope of this paper. But as I demonstrated in Chapter One, the adoption of renewable portfolio standards is increasingly being promoted as the primary near-term means for reducing GHG emissions from the production of electricity. In Chapter Two I presented a brief analysis of the nature and magnitude of the GHG challenge in the electricity sector against which a given measure must be gauged as being material or effective. As currently structured, how effective have the various state RPS policies been, and how effective are they likely to be?

To help answer that question, this Chapter will explore the following questions:

1) How much and what types of new renewable electricity supplies have been and are projected to be developed in response to the current crop of RPS policies?

2) What progress on CO_2 emissions is discernable from progress to date?

3) What market factors might be shaping the industry responses to these policies?

C. <u>How much and what types of renewables are being developed?</u>

To determine the nature and extent of historical market activity in response to the four selected programs, I have extracted data from a number of public sources regarding the growth in eligible renewable resources roughly from the onset of the RPS phenomenon up to the present. These sources were primarily reports published by the U.S. Department of Energy's Energy Information Agency, reports and presentations from the relevant regulatory agencies in the respective states, and data published by the applicable ISO/RTOs. The data has been assembled in a manner consistent with the market definitions that emerge from the analyses presented in Chapter Three.

Forecasting what will be built in the future is obviously a far more speculative undertaking. An examination of the integrated resource plans ("IRP") for investor-owned utilities in each of the four states examined in Chapter Three provides one source of information about what is expected to be developed going forward. I have reviewed the most recent plans filed by one or more key IOUs in each state and extracted what information they provide regarding expected future renewable electricity resources. In addition, some of the relevant ISO/RTOs have published resource plans that identify renewable resources that they believe, based on their database of interconnection requests, will be developed to satisfy the demand for eligible RECs. Regulatory agencies in some states also publish analyses projecting future renewable resource additions, and I have incorporated that data where available.

Beyond published data on actual and proposed activity, prevailing market prices as determined by the market profiles summarized in Chapter Three should also help to explain developments to date and to illuminate what might be developed in the future. While an RPS by its nature establishes a protected market for the eligible technologies, virtually every RPS to date has included some form of stated or implied constraint on the social costs of compliance. For each state, therefore, I have looked at how the indigenous resource characteristics, any specified resource preferences, and the various forms of price ceilings might be interacting with local market prices to drive what quantity and what types of renewable resources are being developed.

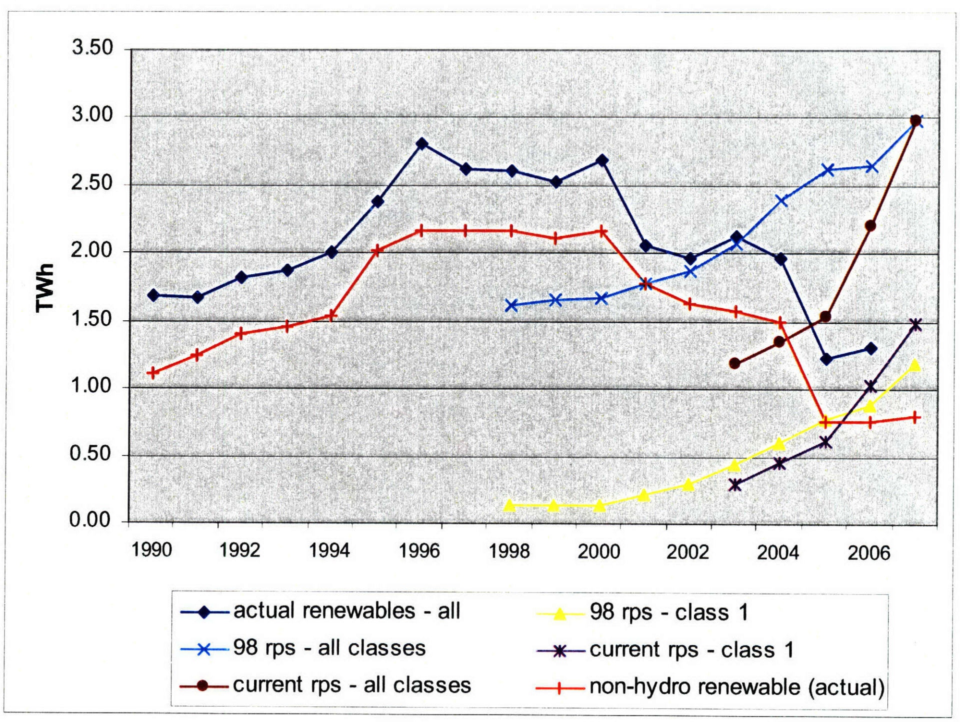
Finally, the experience to date with the first-wave RPS programs in Connecticut and Minnesota provides some insight not only into what might be expected in those states going forward, but it may also afford some insight into what to expect from the second-wave programs in, respectively, California and Colorado. I have attempted to extrapolate some trends for future activity from the activity to date in response to the two first-wave programs in my sample.

Connecticut - Experience to date

Connecticut has now passed the first three annual compliance milestones under the current RPS. According to the DPUC's final 2005 compliance report,[87] all LSEs in the state succeeded in acquiring sufficient RECs from qualified sources to meet the 1/1/06 requirement. The 2006 compliance report[88] shows that both of the largest LSEs in the state met the 1/1/07

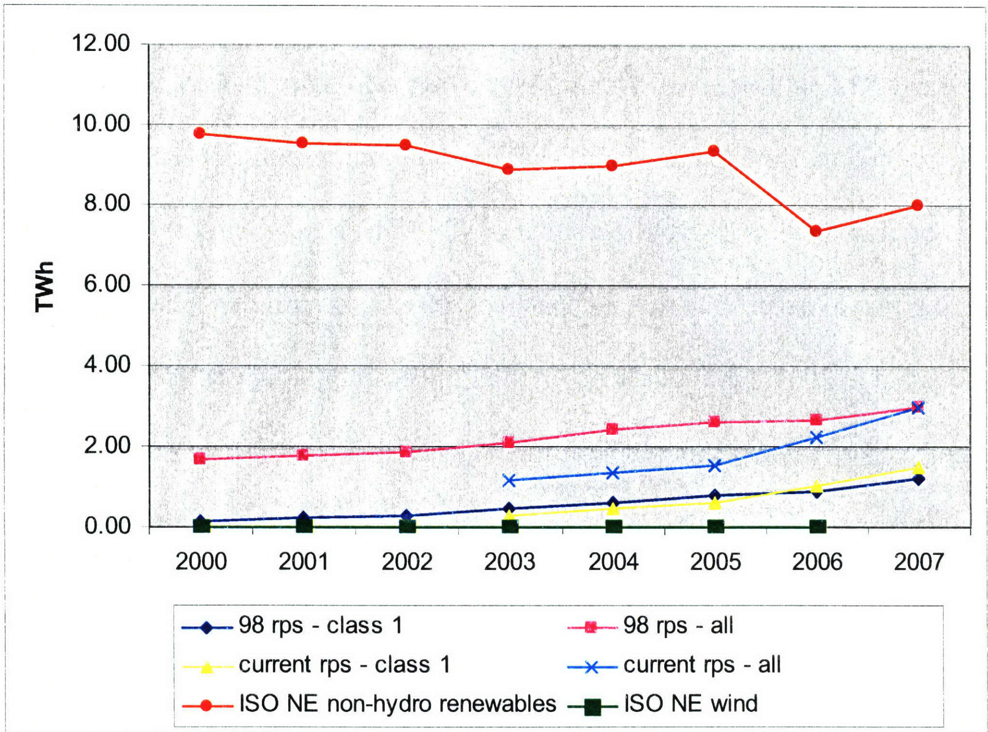
[87] "DPUC Investigation into Renewable Portfolio Standards Compliance for 2005," Connecticut Department of Public Utility Control Docket No. 06-09-17, July 25, 2007
[88] "DPUC Investigation into Renewable Portfolio Standards Compliance for 2006," Connecticut DPUC Docket No. 07-09-14, April 2, 2008

requirement for Class II credits but fell short of the required Class I credits, resulting in penalty payments of nearly $3.5 million. Data for 2007 is not yet available, however the data in Figures 4.1, 4.2 and 4.3 would indicate that no significant new eligible resources became available either in Connecticut or elsewhere in ISO-NE during 2007 (33 MW of new wind entered service in Maine), implying that a market that was incapable of delivering sufficient Class I RECs in 2006 failed to do so again in 2007, particularly given the significantly higher target set for 1/1/07. More importantly, these figures show little or no evidence of a market response in the form of new eligible resources, in Connecticut or elsewhere in New England, since the establishment of Connecticut's RPS in 1998. The DPUC's compliance reports make it clear that virtually all RECs procured by Connecticut LSEs to date have been from existing facilities (primarily landfill gas, municipal solid waste, biomass and small hydro), though some credits were created as a result of upgrades to existing facilities.



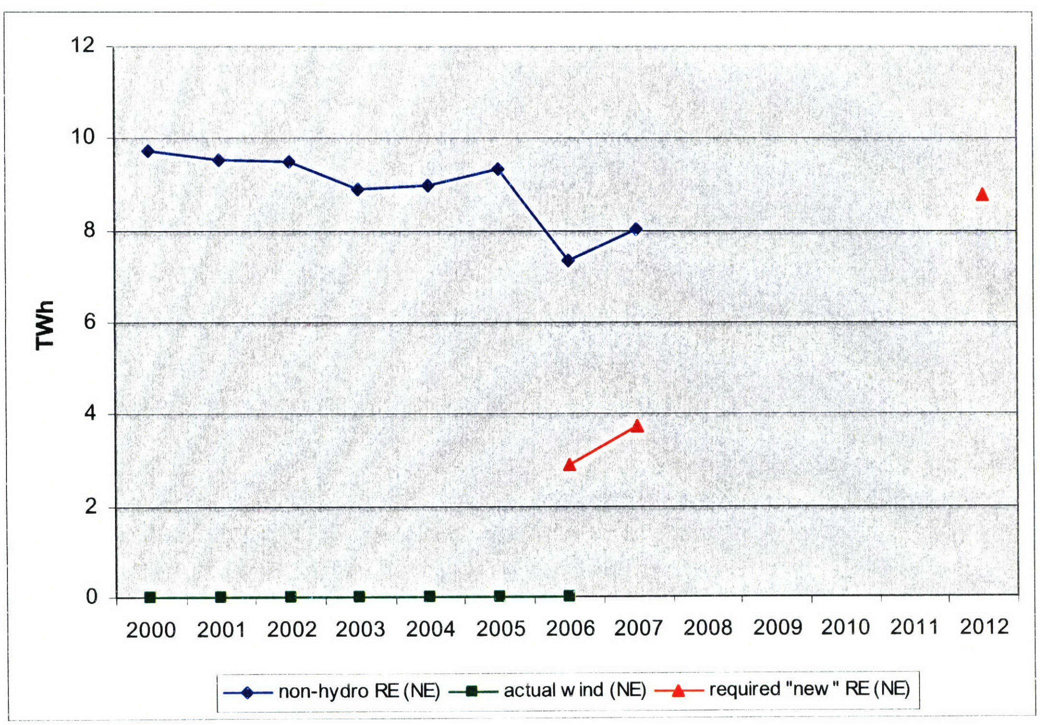
Source data: EIA

Fig. 4.1 - Connecticut RPS targets vs. Connecticut renewable resource trends



Source data: EIA

Fig. 4.2 - Connecticut RPS targets vs. ISO-NE renewable resource trends



Source data: ISO-NE 2007 Regional System Plan, Table 8.3, pg. 69

Fig. 4.3 - ISO-NE non-hydro renewable resources vs. new renewable requirements

Recognizing the challenges facing developers of new in-state renewable resources, the legislature created Project 100 in 2003, which required the state's two investor-owned utilities to enter into long-term contracts with 100 MW of new renewable projects in the state by 2008 (that requirement was subsequently expanded to 150 MW by 2010). The hope was that the availability of long-term contracts with incumbent LSEs would provide sufficient impetus to spur successful projects. Two rounds of solicitations have been conducted under Project 100, resulting in 124 MW of eligible projects being awarded contracts, yet recent publicly available information indicates that these projects are not progressing as expected (see below for more details).[89] Growth in on-site solar photovoltaic installations, which qualify as Class I resources, has been one of the few encouraging areas of new activity, growing steadily from zero in 2001 to a projected 9.5MW by the end of 2007.[90] In general, however, new renewable resources have so far largely failed to materialize in ISO-NE despite the fact that the demand for RECs created by the very aggressive RPS obligations on Connecticut LSEs, as well as the less onerous requirements in Massachusetts and Maine, has been visible to the market for at least five years.[91]

Connecticut – Projected development

Connecticut's two large IOUs, Connecticut Light & Power and United Illuminating, submitted a joint IRP in January, 2008. While the IRP (at its Appendix E) presents a general discussion of local and regional resource availability, it defers to the Connecticut Department of Public Utility Control's docket regarding Round 2 of Project 100 for specific in-state resource

[89] Connecticut Light & Power/United Illuminating Co. 2008 Integrated Resource Plan for Connecticut, January 1, 2008, pp. E-2 through E-4
[90] 2007 Energy Plan for Connecticut, Connecticut Energy Advisory Board State Energy Plan, February 6, 2007
[91] The aggressive targets in Connecticut's 1998 RPS gained real teeth only when the obligation was expanded in 2003 to cover Standard Offer Service retail sales.

projections and to ISO-New England's 2007 Regional System Plan for regional resource projections.

The DPUC's Docket No. 07-04-27, published January 30, 2008, documents the results of the second round of bids under Project 100 (Round 1, in 2006, produced a single 15 MW wood/wood waste fired project which has been delayed until at least 2010). Eleven projects were bid with a total of approximately 175 MW of capacity. Of these, three projects totaling approximately 70 MW proposed using wood/wood waste/agricultural waste as fuel, one was a proposed 30 MW landfill gas project, and the remaining seven projects were fuel cell or fuel cell/CHP projects totaling approximately 74 MW. The DPUC selected the three wood/agricultural waste projects, the landfill gas project and all but three of the fuel cell projects, for a total of 109 MW of capacity, which combined with the 15 MW of (delayed) capacity selected in Round 1 leaves 26 MW of capacity to be awarded in Round 3 to reach the mandated 150 MW. The selected project sponsors proposed on-line dates ranging from July, 2008 to October, 2009, implying that most if not all of the projects should be well along in development and/or construction at this date. Yet the CL&P/UI IRP notes that the fuel cell projects will not likely be viable at REC prices at or below the effective cap set by the penalty payment provision in the state's RPS law, and (according to the ISO-NE Generator Interconnection Queue) as of May 31, 2008, two of the wood/agricultural waste projects have pushed their on-line dates back to 2010, and neither the third wood/ag waste project nor the landfill gas project have yet filed an interconnection application. In short, currently available information paints a rather discouraging picture of the prospects for new renewable resources coming on-line in Connecticut in the foreseeable future. Those that are foreseen are comprised exclusively of natural gas fuel cells and various forms of waste biomass.

Looking to the ISO-NE 2007 Regional Resource Plan,[92] the picture is a bit more encouraging. Table 8-5 of the Plan (page 71) identifies the following resources with active applications in the Generator Interconnection Queue:

Table 4.1 – ISO-NE Generator Interconnection Queue (October 2007)

Type (no.)	Size (MW)	Assumed Capacity Factor (%)	Estimated Annual Projection (GWh)
Hydro (3)	26	25	57
Landfill gas (3)	15	90	118
Biomass (8)	326	90	2,569
Wind onshore (19)	1,526	32	4,269
Wind offshore (1)	462	37	1,295
Fuel cells	67	95	558
Total (35)	2,467		8,866

The queue was updated on May 31, 2008, including an additional 1,653 MW of renewable project interconnection applications, of which 111 MW are biomass, 48 MW are landfill gas and the remaining 1,494 MW are wind (though 900 MW are from an offshore wind project with no site yet identified). It would appear that at least one biomass project of 56.4 MW has been withdrawn from the queue as well. The latest expected on-line date listed for any of these projects is December 2013, with most listed as expecting to come on-line in the 2008-2010 time frame.

On this evidence it would appear that prospective development activity has picked up considerably. ISO-NE notes that, if all of these proposed projects were to proceed as planned, they would generate more than enough RECs to satisfy the aggregate projected New England market for RECs in 2012 (estimated by ISO-NE at 5,881 GWh based on current RPS targets) and would fall about 19% short of the currently projected 2016 market (10,986 GWh). The Plan notes, however, that this does not take into account the "creep" in demand (due to overall

[92] "2007 Regional System Plan," ISO New England Inc., October 18, 2007

demand growth) under some of the state programs for credits from existing resources, which is likely to outstrip the base of existing resources and could result in a greater need for new sources of RECs. The Plan goes on to note (at page 71) that, "In the past, the region has experienced the withdrawal of a significant portion of projects in the queue before the projects were built."[93] In other words, the interconnection queue is a poor predictor of actual resource development.

And indeed there are reasons to be cautious when considering the size and nature of the turnaround signaled by the interconnection queue. First is the apparent importance of REC revenues to land-based wind projects in the region. The current high price level for RECs has had limited impact on the pace of development, implying that it is a market that will clear only under scarcity pricing conditions. It is always possible, of course, that with sufficient investment in transmission the market will clear at lower prices more reflective of supply/demand equilibrium. But the combination of a mature, capital-intensive technology with a market in which the barriers to entry are infrastructure and regulation carries the risk of abrupt swings between scarcity and oversupply, with the associated downside and volatility. As we shall see, Minnesota and Colorado are terrestrial wind markets with a larger potential resource base, where expansion of transmission infrastructure is likely to be less contentious and where the market for land-based wind appears to be less reliant on high REC revenues. Connecticut already saw a period of volatility between 2004 and 2007 when regulators expanded and then contracted the definition of eligible resources. Concern about the potential for future volatility and the difficulty in hedging that exposure may be one factor holding back investment.[94]

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[93] ISO NE notes that from the establishment of the queue in November 1997 through May 2007, a total of 229 projects had submitted interconnection requests with a total nameplate capacity of 55,340 MW; of these, 41 have been completed with total nameplate capacity of 10,340 MW, 98 projects totaling 34,500 MW have been withdrawn and 90 projects totaling 10,500 MW remain "active"

[94] The Massachusetts legislature in July 2008 passed a wide-ranging overhaul of that state's efficiency and renewable energy policies, including provisions relating to long-term contracts for eligible resources that may provide a template for addressing these concerns, but Connecticut's experience with Project 100 is not encouraging

Caution is also warranted due to the uncertain status of the Federal PTC. This is an issue generally, but the concern is most acute in regions like New England where success has been slow in coming. CL&P/UI noted in their recent IRP that their compliance strategy is reliant on an extension of the PTC through at least 2015. Yet as I've noted elsewhere, the PTC is currently due to expire at the end of 2008 and the leading proposal before Congress to renew the program would extend support for wind only through 2009.

A third obstacle to a significant turnaround in renewables in the region is transmission. Again, while this challenge is not unique to New England, the quantity of new transmission is particularly large given the location of the best terrestrial wind resources in the northern-most reaches of the region. This relates to the final note of caution, which is that the prospective ramp-up in renewables development is heavily weighted toward terrestrial wind. The October 2007 queue implies that 81% of the new renewable capacity and 63% of the energy will come from wind projects, and the updated May 2008 queue would seem only to increase the reliance on new wind to about 85% of all new capacity, including a significant increase in reliance upon offshore wind. The best of New England's terrestrial wind resources are indeed of excellent quality, as good as anything to be found in the upper Midwest, but a review of Appendix C makes it clear that the theoretical quantity of these high value resources is limited and quite diffuse.[95] Many of the best resources are on ridge lines that will be difficult to access and challenging to permit, and as will be discussed later New England terrestrial wind construction costs have so far been significantly more expensive than in other regions of the country, at a time

[95] A seminal 1991 study by Pacific Northwest National Laboratory identified less that 11,000 MW of exploitable terrestrial wind potential in New England. ISO-NE commissioned a study of the region's wind potential by Levitan & Associates, released in May 2007, which claimed a total potential of 93,821 MW, including 33,974 MW of offshore wind potential. However unlike the 1991 PNNL study, the Levitan study did not screen for environmental, recreational, land use or other restrictions that would constrain the total to that which is realistically exploitable. It also includes 8,295 MW of "deep offshore" potential, which is not developable within the queue's time horizon

when wind construction costs in general are on the rise.[96] All of these factors represent challenges to the economics of the transmission investments that will be required. The queue includes a significant amount of offshore activity, and as Appendix C makes clear, deep offshore wind is indeed New England's richest vein of renewable resources. While it seems likely that these resources will be extensively exploited, deep offshore wind is an early-stage technology that will require even higher per unit prices to clear the market, at least initially, and cannot be expected to contribute large quantities of energy in the immediately foreseeable future. As will be discussed extensively later, there are hints in each of the other three states of avenues that could prove to be more productive in such circumstances, but the current designs of New England's RPS programs within the prevailing market constraints leave them little room for maneuver. This will be a key theme in my conclusions and recommendations in Chapter Five.

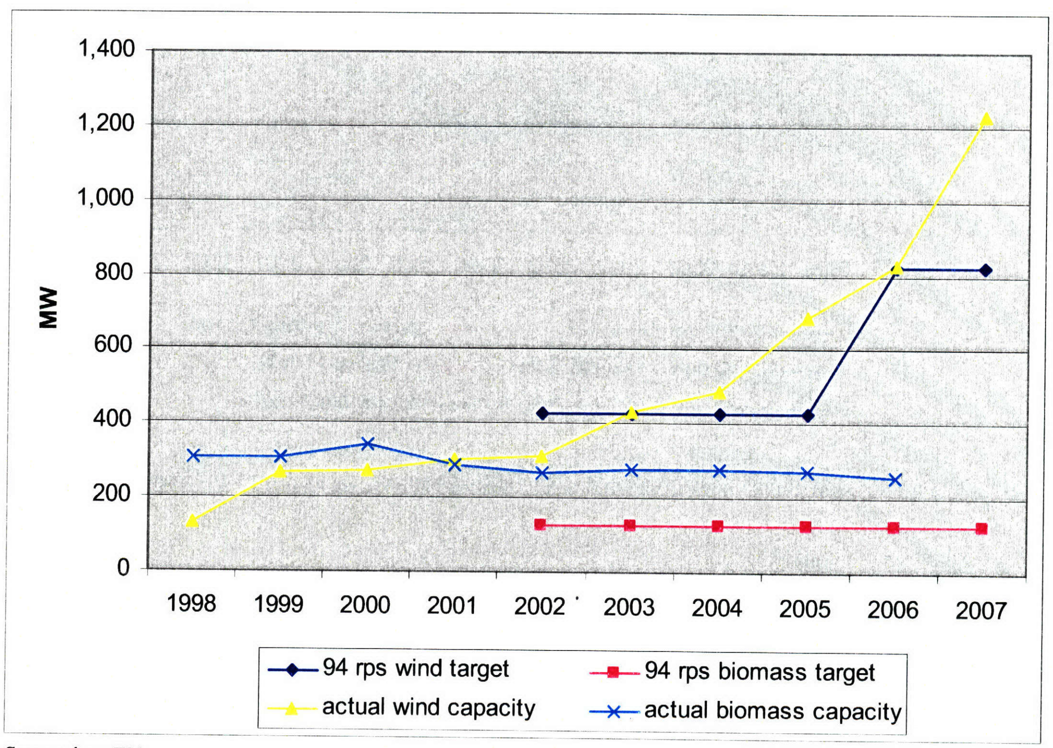
One final point can be made regarding Connecticut LSEs in particular. I noted earlier that Connecticut's RPS includes an ACP-like penalty mechanism that is not synchronized with those in the other New England state programs, meaning that it falls farther behind each year by the annual inflation adjustment included in those programs. For this reason, Connecticut LSEs will be last in line for RECs in a tight market, and a market that remains tight despite the ever-increasing ACPs in the other New England states is unlikely to provide an adequate stream of RECs at prices below the $55/MWh effective ceiling fixed by the Connecticut program. Thus, without a substantial revision to Connecticut's compliance regime, the REC obligations of the Connecticut LSEs may not provide adequate financial incentive for substantial new

[96] See, e.g., the DOE's May, 2008 "Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 2007," pp. 21-23, which documents a 27% increase in installed project costs between 2003 and 2007 on top of a near doubling of wind turbine costs over the same period; the report further notes that the increase in turbine costs appears to have accelerated in 2007, a phenomenon that is yet to be reflected in recent installed plant costs. The report also documents installed project costs for New England that are 40-50% higher than the national average.

development. As noted in the CL&P/UI IRP (its Appendix E, page E-7), the result could be significant costs to Connecticut ratepayers with little to show in the way of new renewable energy development.

Minnesota – Experience to date

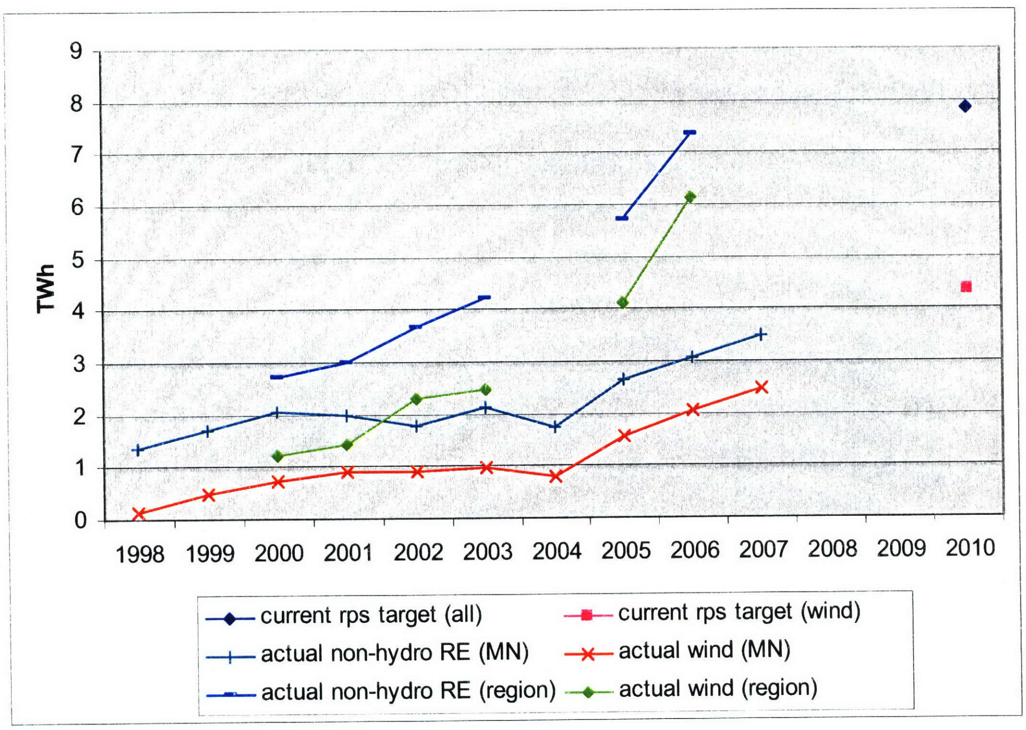
Minnesota's experience with its RPS provides a stark contrast with Connecticut. As can be seen from Figure 4.4, the development of new renewable resources in Minnesota has tracked remarkably well with the requirements established in the original 1994 legislation. The development of new resources has been dominated by wind, consistent both with the requirements of the 1994 legislation and with the indigenous resources available to Minnesota developers.



Source data: EIA

Fig.4.4 – Renewable resources in Minnesota vs. 1994 targets

Figure 4.5 presents the data (including the trend in new renewable resource development in the surrounding region) in the context of the current RPS targets.[97] The trend in new wind development in Minnesota is encouraging relative to the state's current wind energy target, though it will have to pick up speed if the target is to be met with in-state resources. The trend in all non-hydro renewables suggests that non-wind renewable resource development is lagging considerably what would be required to meet the overall RPS targets, and the current rate of in-state wind development would not appear to be sufficient to make up the difference.



Source: EIA

Fig. 4.5 – Minnesota and regional renewable resources vs. current RPS targets

Nonetheless, given that Minnesota is currently the only state in the applicable region to have adopted significant RPS obligations, the regional resource development trends give reason to believe that Minnesota LSEs will have access to sufficient eligible resources to satisfy at least

[97] The region used for this graph is the West North Central census division, comprising Minnesota, Iowa, Missouri, Kansas, Nebraska, South Dakota and North Dakota, consistent with the regional aggregation used by the EIA.

their near-term RPS obligations. Regional development of new wind generation, which cannot be attributed to RPS-style mandates in the other states in the region, is on track to outstrip significantly Minnesota's RPS targets. This trend, the exploitation of a regional wind resource potential far in excess of indigenous demand, will be re-visited in Chapter Five.

Minnesota – Projected developments

The Generator Interconnection Queue for MISO, the RTO in which Minnesota's grid is located, shows by far the largest quantity of proposed new renewable resources (in MW of capacity) of any of the RTO-managed regional markets (notably, it is also the market with the largest amount of new coal-fired capacity in the queue). MISO's queue in October 2007 included nearly 40,000 MW of new renewable power resources, with CAISO (California) and ERCOT (Texas) virtually tied for second at less than 30,000 MW.[98] However unlike CAISO (which is examined below), virtually 100% of MISO's renewables queue is comprised of wind projects (the same is true for ERCOT – another RTO with a strong exposure to the Plains wind resource – where the renewables queue is *literally* 100% wind).

MISO's very large lead in the quantity of prospective new renewable resources is particularly noteworthy for one reason – among those RTOs in which one or more states have established RPS programs MISO has the *lowest* weighted-average percentage, by a considerable margin, of total energy sales covered by RPS obligations in 2015.[99] Clearly the heightened interest in new renewable power project development in the MISO state markets, virtually all of it wind, is being driven by something other than current native RPS obligations. A clue to what that might be can be found in another statistic found in the ISO/RTO Council report – an

[98] See "Increasing Renewable Resources: How ISOs and RTOs are Helping Meet This Public Policy Objective," ISO/RTO Council, October 16, 2007, page 6, Figure 2. A May 2008 slide presentation by MISO officials indicated that wind projects in the queue had risen to "over 60,000 MW."
[99] *Ibid,* page 8, Table 3 – only SPP and AEISO are lower, neither of which have any indigenous RPS programs

unnamed source (most likely the American Wind Energy Association) is cited as estimating the MISO wind potential at approximately 400,000 MW, compared to the renewables queue of "only" 38,000 MW and an internal aggregate RPS target of far less than 10,000 MW. The 1991 PNNL study estimated that North and South Dakota and Kansas alone have 377,000 MW of exploitable wind potential.

As for Minnesota in particular, the story is very much consistent with the rest of MISO. Northern States Power, the Minnesota utility affiliate of Xcel and the largest LSE in the state, filed their 2007 Resource Plan in December 2007. The Plan (at page 1-13, Table 1-4) projects expected resource additions through 2022, which include the following renewable resources:

Table 4.2 – Projected Xcel renewable resource additions

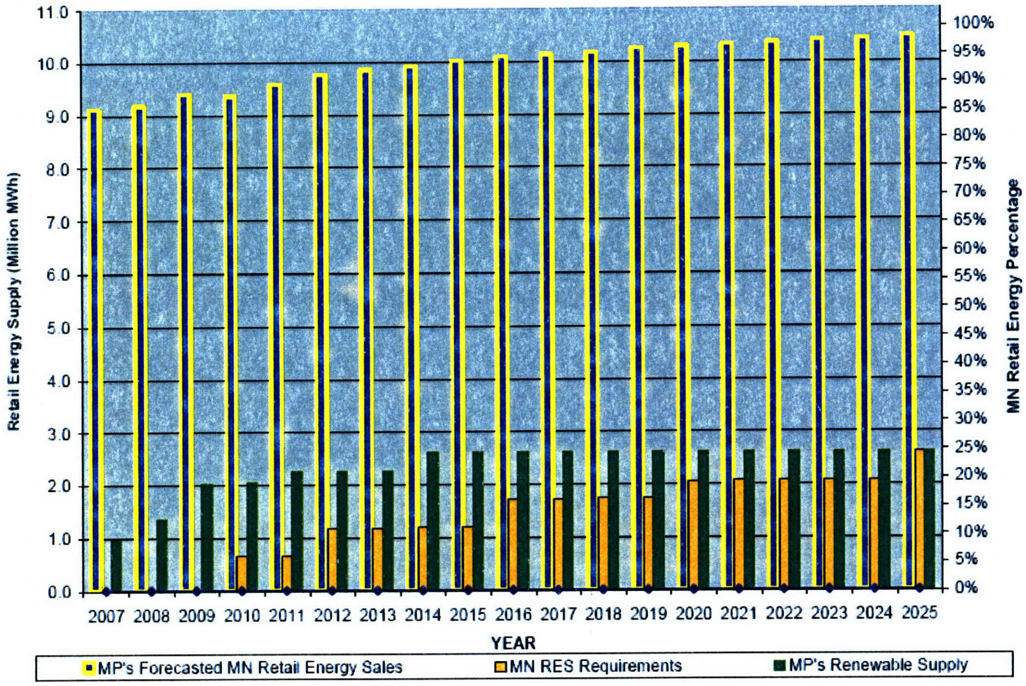
Year	Type	Size (MW)	Project
2008			
2009	Wind	100	n/a
2009	Wind	209	C-BED*
2009	Wind	100	Great Meadows (Xcel)
2010	Wind	200	n/a
2011	Wind	200	C-BED
2011	Wind	200	n/a
2012	Wind	200	n/a
2013	Wind	200	n/a
2014	Wind	200	n/a
2015	Wind	200	n/a
2016	Wind	200	n/a
2017	Wind	200	n/a
2018	Wind	200	n/a
2019	Wind	200	n/a
2020	Wind	200	n/a
2021			
2022	Wind	100	n/a

*Community-Based Energy Development, a specifically identified class of resources in the MN RPS law

Note that Xcel has simply presumed the availability of the necessary quantity of wind capacity at regular intervals, with all but three of the projects yet to be identified. Given the vast potential resource at their doorstep, and the pool of nearly 40,000 MW of specific renewables projects identified in the MISO queue, this is a luxury that LSEs in some other regions could only dream about. Even here, however, Xcel notes that the ability to procure the required amount of wind generation while staying within the rate increase limits implied under the RPS law is contingent upon the extension of the Federal PTC through at least 2015. Given the robust level of development activity and the massive wind resource indigenous to the MISO region, one might be tempted to regard this caution from Xcel with an ounce of skepticism, but (as noted above) the recent history of wind development activity even in the Plains states shows a clear pattern of curtailment whenever Congress has failed to renew the PTC.

Minnesota Power, the much smaller IOU that serves a predominantly industrial customer base primarily in the Iron Range in the northeastern part of the state,[100] provides a bit more specificity in their 2008 Resource Plan filed in October 2007. Of their 2006 retail sales of 9,078 GWh they produced/procured 786 GWh from existing hydro and biomass resources (recall that the state's indigenous biomass potential is concentrated in this region) and 345 GWh from existing wind, putting them well ahead of their projected 2010 requirement of about 700 GWh. They identified five specific Minnesota wind projects due on-line by the end of 2008 providing an additional 175 GWh, additional unspecified Minnesota and North Dakota wind projects providing a further 900 GWh by 2014, and an Iron Range biomass plant providing 380 GWh by 2011 (see pages 4 and 26 of the 2008 Resource Plan). As is shown in Figure 4.6 below, these additions would put Minnesota Power in a position to meet their 2025 RPS requirements as early as 2014.

[100] Xcel supplied 55% of 2006 retail sales, and Xcel and MinnPower together supplied 70%.



Source: Minnesota Power 2008 Resource Plan, October 17, 2007, page 33, Figure 14

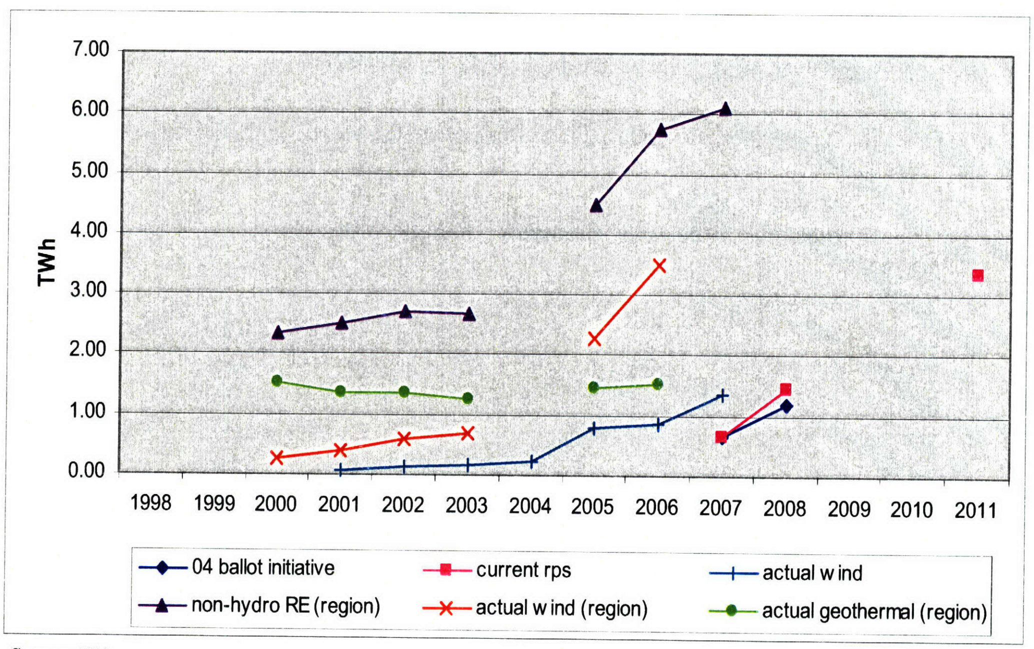
Figure 4.6 – MinnPower's plan to fulfill their RPS obligations through 2025

While Minnesota Power's projected new renewable resource additions are also dominated by wind, approximately 20% of their planned additions are from biomass, bringing to approximately 45% the proportion of their planned 2014 renewable supply portfolio supplied by hydro and biomass. This is consistent with both their locally available resource potential and with the characteristic base-loaded profile of their heavily industrial native load, but it does set their plan apart from Xcel's plan for the same period, albeit for a load less than a third the size of Xcel's.

Colorado – Experience to date

As a Phase 2 RPS Colorado's experience with its program is more limited than was the case in Connecticut and Minnesota. Nonetheless, the data presented in Figure 4.7 indicate a rather clear and immediate response to the targets that were established in 2004 and expanded in

2007, a response that is comprised virtually entirely of new wind resources. New renewable resources established since 2004 provided enough eligible generation for Colorado LSEs to meet the 2007 obligations entirely with in-state resources. More impressively, 776 MW of new wind capacity was added in 2007,[101] tripling the amount of wind generation on-line at the end of 2006 and putting Colorado on track to meet its 2011 targets well ahead of schedule and entirely from in-state resources. Regional development of new renewable resources (again, predominantly wind) has also been strong during this period, in a region where most states have yet to implement RPS-style policies. The end result is that Colorado LSEs will likely have access to a pool of eligible generation well in excess of their requirements from which to comply with their near-term targets. As with Minnesota, however, the robust wind response has not been matched by a comparable level of development of non-wind renewable resources.



Source: EIA

Fig. 4.7 – Colorado and regional renewable development vs. Colorado RPS targets

[101] Final EIA data for 2007 is not yet available, but the DOE's "Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 2007," released in May 2008, draws on several sources for this figure.

Colorado – Projected developments

Unlike the other three states studied, Colorado does not operate or participate in a functioning regional wholesale power market. For this reason, what will be built in response to Colorado's RPS will be determined by the regulatory process between the Public Utilities Commission and the IOUs (essentially Public Service Company of Colorado) and from the investment/procurement decisions of the state's public power companies and co-ops. Public Service Company of Colorado ("PSCo"), who supplied nearly 60% of all retail electricity in 2006, filed their 2007 Resource Plan on November 15, 2007, supplemented by their 2008 Renewable Energy Standard Compliance Plan on November 23, 2007. In that Plan they noted that new wind production capacity installed by the end of 2007 will be sufficient for them to meet their non-solar RPS obligations through at least 2020, yet the Plan proposed addition of 1,800 MW of incremental wind capacity between 2010 and 2020:

Table 4.3 – PSCo 2007 Preferred Resource Plan Renewable Resource Additions (in MW of capacity)

	On-site solar	CSP* Solar	Biomass	Geothermal	Wind
2008	16				
2009	4		4		
2010	1				100
2011	2	25			100
2012	1				100
2013	2				100
2014	1				200
2015	2	200			200
2016	0	200		20	200
2017	0				200
2018	1				200
2019	1				200
2020					200
Total	32	425	4	20	1800

*Concentrating solar power

The Plan is also noteworthy for the fact that it recommends the addition of far more solar capacity than would be required to meet the 4% minimum set-aside established in the 2007 RPS legislation, including 200 MW blocks each from two different CSP plants with thermal storage. PSCo bases these recommendations (along with a number of other non-renewable resource related recommendations) on two primary objectives – to reduce exposure to the use of natural gas for power generation and to reduce CO_2 emissions. They also note that the plan will give them greater access to firm, dispatchable renewable resources (such as CSP with thermal storage) than would be achievable by minimum compliance with the RPS targets.

PSCo proposes to drive the development of these forecasted resources through PUC-approved requests for proposal with full cost-of-service rate recovery, on the expressed condition that the accelerated schedule of renewable resource development can be delivered while remaining within the 2% rate impact ceiling established by the RPS legislation (one key stated assumption being an extension of the Federal PTC through 2015). In other words, whereas in New England the cost ceilings appear to be constraining expansion of renewable resources in compliance with regional RPS programs, in Colorado the legislatively-mandated rate impact limit may actually be creating headroom for the state's largest LSE to go above and beyond the minimum RPS targets, in both quantity and technology mix, in order to achieve other objectives. PSCo is proposing to utilize the IRP process and the traditional command-and-control structure of Colorado's market to push for this more aggressive approach to RPS compliance.

California – Experience to date

As the oldest of the Phase 2 programs, California has a little over five years of experience with its RPS but less than two years of experience with the newly-accelerated targets. While the data presented in Figure 4.8 below show some signs of an emerging market response since the acceleration of the program in 2006, the overall trend is far less marked than we've seen in Minnesota and Colorado. The picture is rather more one of a stubborn continuation of the stasis that gave rise to the new RPS legislation in 2002 and again in 2006 (in fact, California renewable production rose steeply from 7.8 GWh in 1983 to its peak in 1992 at 27.2 GWh and has essentially been treading water ever since).[102] While 2007 saw Minnesota's installed wind capacity grow by 45% and Colorado's installed wind capacity nearly triple, California's grew by less than 3%.[103] This may be due in part to the fact that California's indigenous terrestrial wind resource is far more modest than the wind potential in those two states, combined with the possibility that a significant proportion of the best land-based wind resources in California have already been developed (note that absolute 2007 wind production in California was greater than in Minnesota and Colorado combined, despite the much more impressive *rate* of new resource development in those two states over the past ten years).

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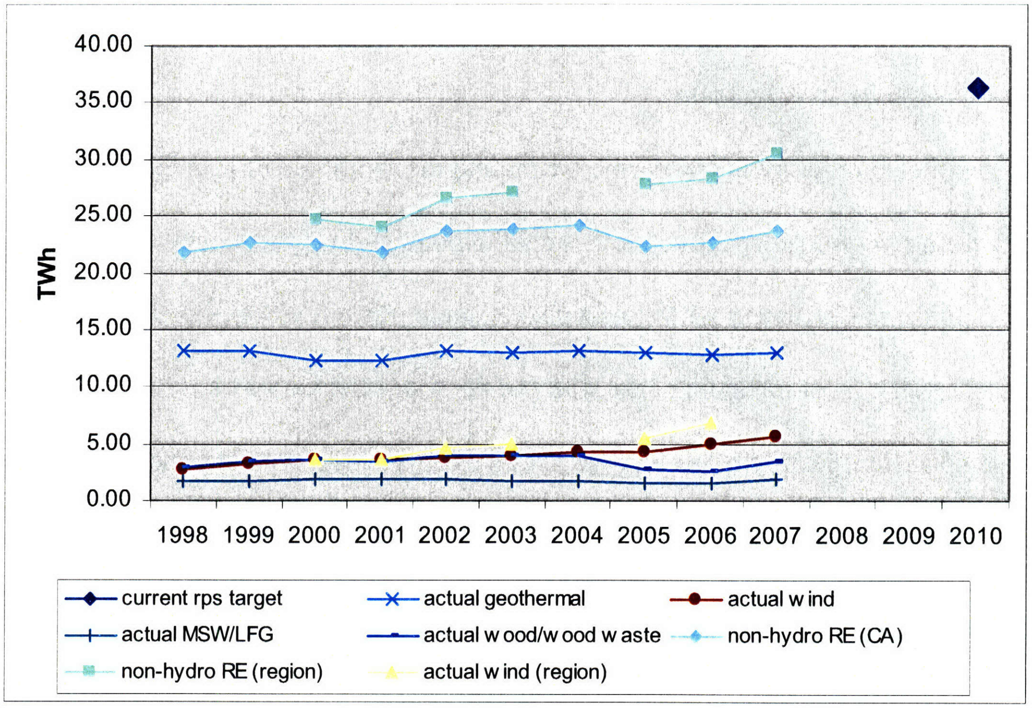
[102] See "Renewable Resources Development Report," CEC, November 2003, pg. 31, Fig. 4

[103] See "Annual Report on U.S. Wind Power Installation, Cost and Performance Trends: 2007," DOE EERE, May 2008, Table 2



Source data: EIA

Fig. 4.8 – California and regional renewable development vs. California's RPS targets

A slightly stronger development trend is evident regionally but, unlike the cases of Minnesota and Colorado, many of the states in California's immediate vicinity have instituted their own RPS programs, meaning California is not as free to look outside to procure the mandated renewable resources.

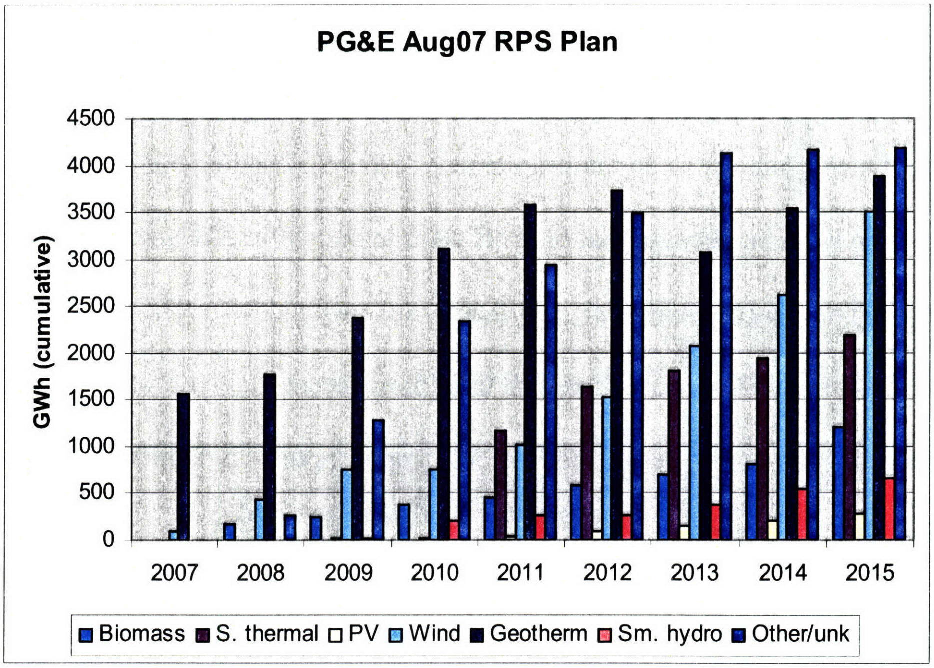
Given the aggressive 1980s development of California's wind and geothermal potential, the immaturity of the technologies necessary to develop some of the more promising categories of unexploited indigenous resources, and viewed against the sheer scale of the challenge California has set for itself, it is perhaps not too surprising that a marked incremental market response to the RPS has yet to show up in the data. Regardless of the reasons behind it, however, the recent trend in new renewable resource development has lagged far behind the pace that will be necessary if the state's LSEs are to stand any chance of meeting the 2010 threshold established in the current RPS.

California – Projected developments

Given the complexity of California's RPS and the multitude of agencies and major LSEs involved, zeroing in on a prospective view is challenging, and yet the picture that emerges of the evolving response to California's RPS, particularly under the circumstances described above, presents perhaps the most intriguing case study of the four selected states.

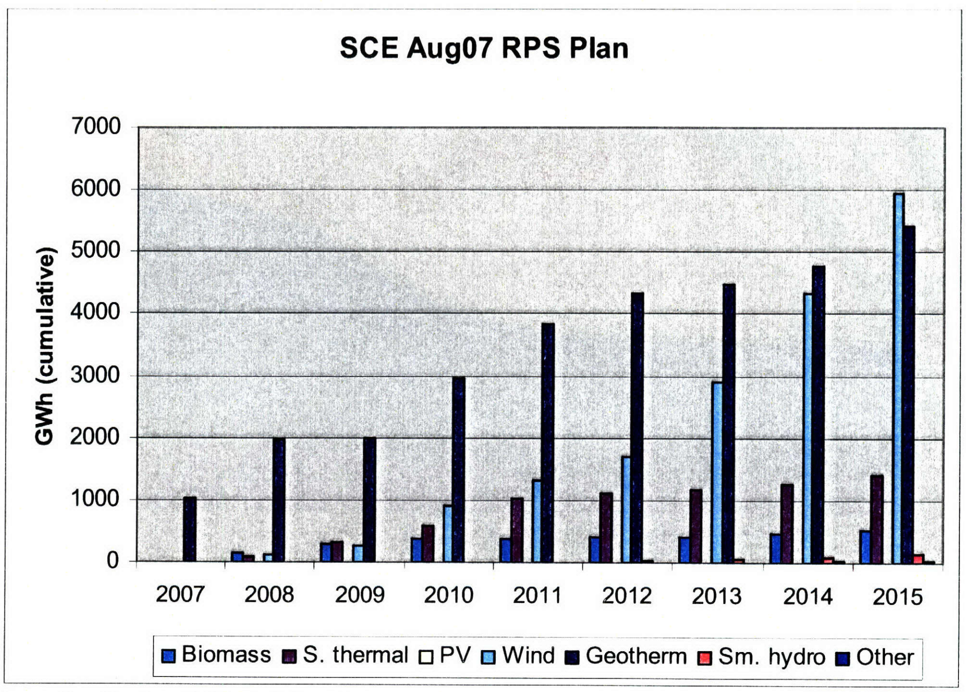
One consistent feature of all forward views presented is a dramatic increase in new renewable resources just prior to the 2010 RPS milestone date, following nearly fifteen years of essentially no growth. One might understandably view this with a certain amount of skepticism. The main impediment to development, identified by all three IOUs in their most recent resource plans, is a pressing need for significant amounts of new or expanded transmission infrastructure between numerous undeveloped pockets of concentrated renewable resources and the major load centers. California state agencies are working with the Federal Energy Regulatory Commission on innovative funding approaches for new, renewables-focused transmission infrastructure under the California Renewable Energy Transmission Initiative, but it remains to be seen how quickly progress can be made on this front.

While all three IOUs have raised concerns about their ability to meet the 2010 milestone, all have put forward plans to do so. Figures 4.9 and 4.10 below show the forecasts for incremental renewable resources through 2015 presented in RPS Compliance Reports submitted on August 1, 2007 by, respectively, Pacific Gas &Electric and Southern California Edison, the first and second largest LSEs in the state. The views presented were consistent with the history of renewables in California up to that time, with wind and geothermal expected to remain the dominant sources. Wind overtakes geothermal over time, solar thermal comes into play after 2010 and PV solar plays only a very small role during this period.



Source data: Pacific Gas & Electric Co.

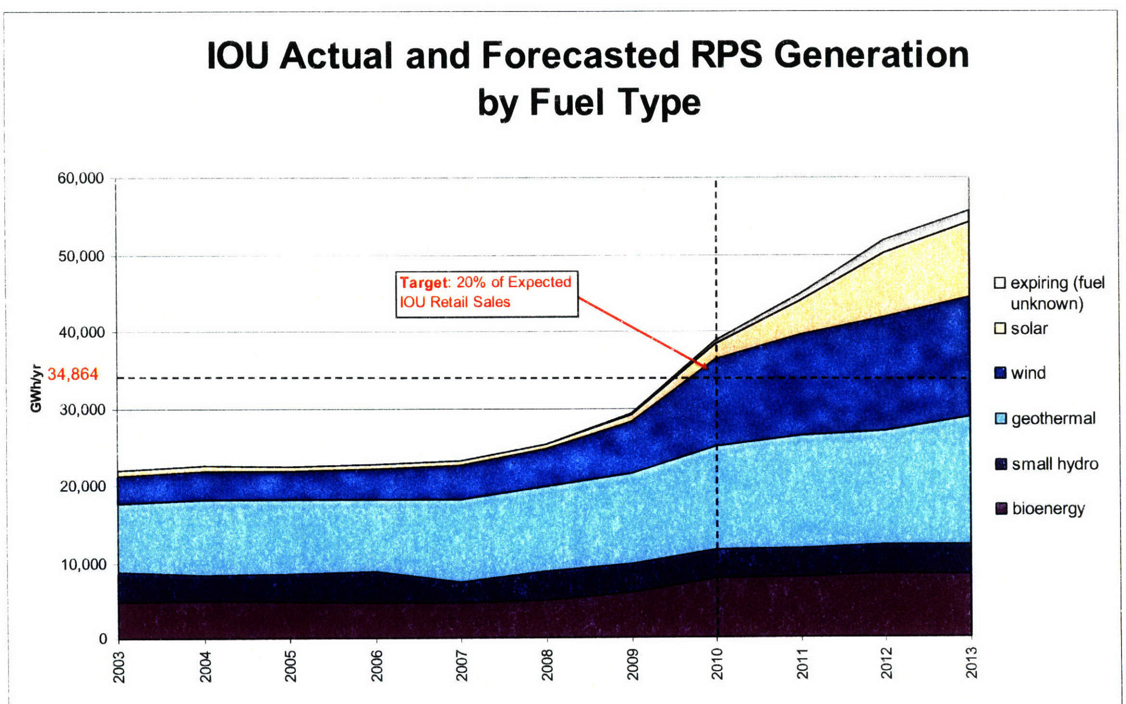
Figure 4.9 – PG&E's 2007 Renewable Resource Procurement Plan



Source data: Southern California Edison Company

Figure 4.10 – Southern California Edison's 2007 Renewable Resource Procurement Plan

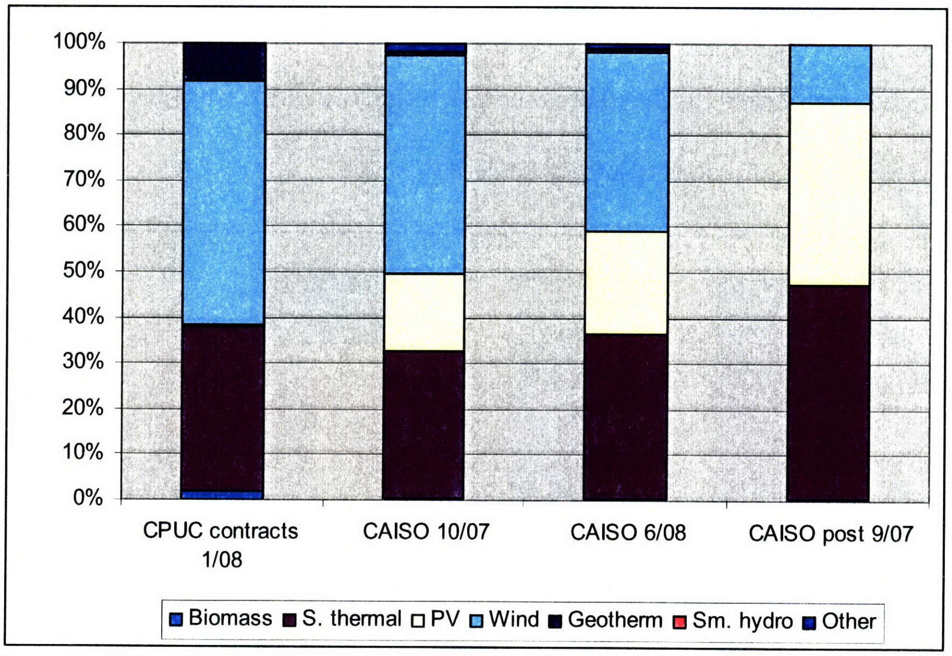
While these data were submitted only about a year ago, a closer look at other and more recent data tells a much different story. Figure 4.11 below shows the mix of resources represented in the CPUC's January 2008 inventory of approved, pending and short-listed RPS-eligible contracts. Once again the steep ramp-up in new resources can be seen just prior to 2010, but here the growth in wind and geothermal falls off significantly after 2010, with solar (both solar thermal and PV) playing a much more significant role beyond 2010. The context for this shift is the fact that all three IOUs proceeded with their most recent round of renewable resource solicitations during the intervening period, and the result appears to be a rapidly shifting mix of resources emerging from the market.



Source: CPUC Renewables Portfolio Standard Quarterly Report, January 2008

Fig. 4.11 – CPUC January 2008 forecast of renewable resource additions

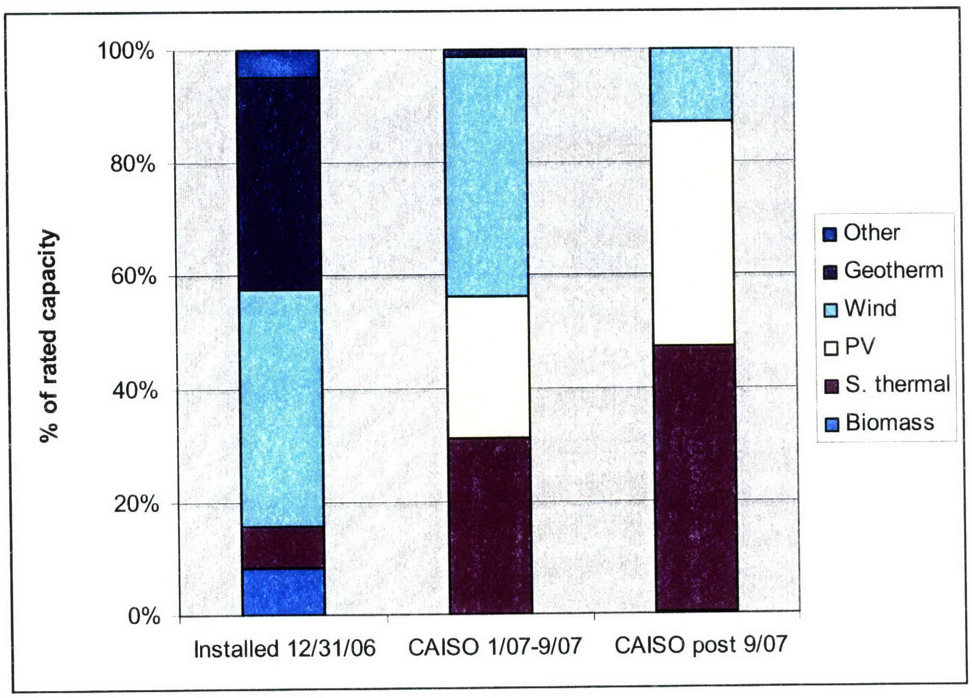
This phenomenon can be seen in the data presented in Figures 4.12 and 4.13 below, which are based on aggregated capacity ratings of projects with proposed on-line dates as late as 2015.



Source data: California Public Utilities Commission, California ISO

Figure 4.12 – Recent evolution of renewable resources in development

Fig. 4.12 shows the prospective resource mix (as a percentage of total capacity in MW) derived from two sources – CAISO's Generator Interconnection Queue and the CPUC's January 2008 inventory (which reflects a somewhat older subset of the projects included in the CAISO queue, since projects must have progressed to the contract stage to be included in the CPUC database). I have parsed the CAISO queue into three blocks – the queue as it stood in October 2007, the queue as it stood in June 2008, and the subset of projects added to the queue only since the beginning of October 2007. In so doing I have suggested an evolution of the prospective resource mix over a relatively short period of time, with the CPUC data representing the oldest cut at the prospective market, the October 2007 queue representing an intermediate view of the overall prospective market, the June 2008 queue representing an up-to-date view of the prospective overall market, and the post-September 2007 queue entries representing only the most recent prospective market data (corresponding roughly to the period following the 2007 IOU renewables solicitations). What emerges is a clear shift from a market dominated until very recently by wind and geothermal, to one that is increasingly dominated (prospectively) by solar, including a surprisingly large tranche of utility-scale PV.



Source data: EIA and CAISO Generator Interconnection Queue

Figure 4.13 – Resource mix of recently proposed projects

This point is made even more clearly in Figure 4.13, which compares the mix of resources installed in California at the end of 2006, those added to the CAISO queue between January 2007 and September 2007, and those added to the queue between October 2007 and June 2008. The apparent market shift from wind and geothermal to the two solar technologies is quite striking.

Exactly why this marked shift in resource mix is occurring is difficult to say with certainty, since the specific materials associated with the IOUs' resource solicitations are protected by confidentiality. Yet statements in the recent resource plans and other reports submitted by the IOUs, as well as in recent reports by the various California agencies, allow for a certain amount of informed speculation. As noted earlier, California's RPS program is unique in stipulating a "least cost/best fit" ranking criterion in the selection of resources; "best fit" was defined in the CPUC's June 19, 2003 decision implementing the 2002 RPS law as being "the renewable resources that best meet the utility's energy, capacity, ancillary service and local reliability needs." It is also unique (and more explicit) in denying eligibility to out-of-state resources that are "intermittent" (i.e. non-firm and non-dispatchable). The key concerns behind these unusual provisions seem to be California's recent, catastrophic experience with a policy design badly out of synch with its needs and a desire to extract maximum value out of precious existing and incremental transmission investments.

The recent resource plans filed by the LSEs note that there are two basic dimensions to solving the transmission problem – one, of course, is construction of new transmission infrastructure, but the other is to grant priority to those resources that optimize the utilization of all transmission, both existing and new. This is certainly the intent of the "least cost/best fit" provision of the RPS. Recognizing the difficulties California has had in realizing major new investment in transmission (noted by all of the LSEs and the state agencies as the single greatest impediment to meeting their RPS obligations), state agencies seem to have embraced the idea that direct cost of energy is a necessary but insufficient selection criterion. In addition to evaluating the direct cost of energy, the IOUs are indicating (and the agencies appear to be accepting) an intent to attach a valuation premium to resources in direct proportion to their ability and willingness to schedule production in a manner that optimizes the utilization of the existing transmission network and maximizes the value of planned expansions.

A similar rationale was evident in the specific mix of resources put forward in Public Service Company of Colorado's proposed renewables resource plan, but California is the first functioning wholesale power market where we've seen specific market design features pushing in this direction. Several unusual aspects of California's situation may be driving this. As has been noted, a great deal of intermittent wind generation has already been developed in California, and while there is undoubtedly more potential for land-based wind development, much of it may be either too dispersed or too inconsistent on its own to warrant higher prioritization in the transmission investment queue. Chapter Four described the extent to which the state is also highly reliant on imports from elsewhere in the WECC via a limited number of constrained transmission interties. State energy planners would understandably be reluctant to compromise the utilization of that critical infrastructure with a large addition of non-firm, non-dispatchable supplies. Finally, as has been noted, California is unusually well endowed with solar potential, concentrated in the southeastern region of the state. The operational characteristics of this resource, with its higher capacity value, its greater predictability, the proximity of its production to peak demand hours and (in the case of solar thermal) the near-term prospects for using thermal storage to make it truly dispatchable all serve to enhance its "best fit" status (geothermal and biomass can be similarly "best fit," but Figure 4.11 seems to imply that California has already developed nearly as much of its geothermal and biomass potential as is commercially feasible using currently available technology). It remains to be seen whether or not these massive new solar resources can be delivered at prices that are justified by their premium attributes, but the available data would seem to indicate that the market, and the major buyers, believe that they can. As the CPUC commented in their January 2008 *Renewables Portfolio Standard Quarterly Report* (page 6),

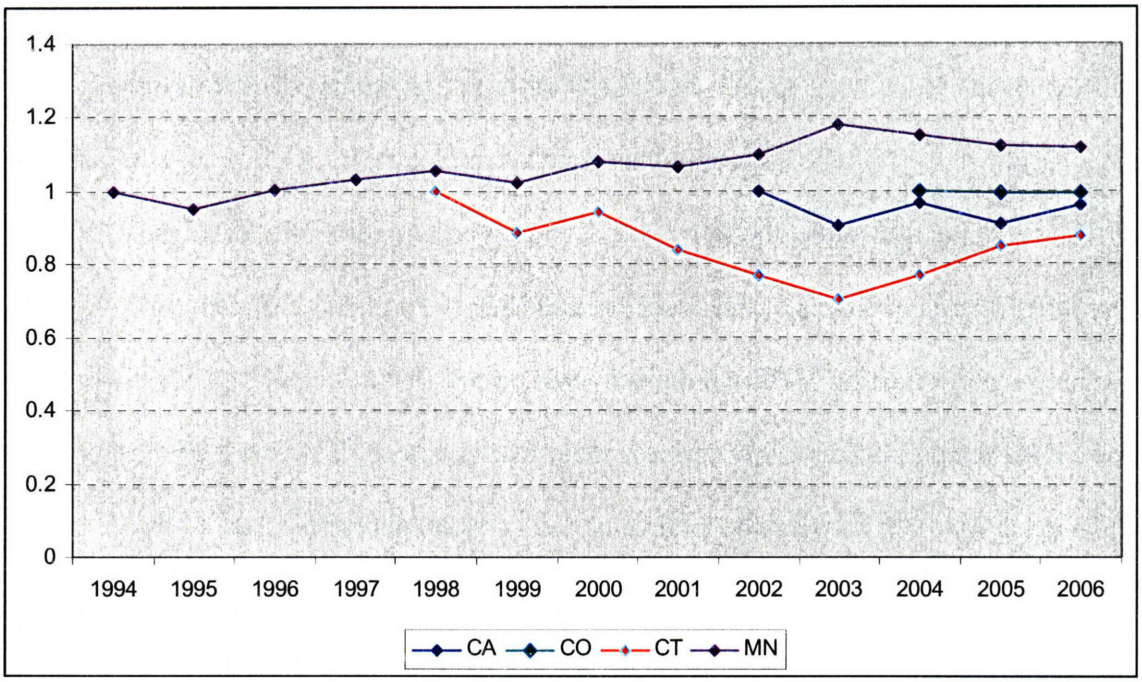
> "Solar energy has historically been a high-cost resource due to supply chain production constraints and other factors. However, its on-peak energy production and relatively consistent capacity are valuable, and increased developer activity is expected to drive prices downward. As prime wind resources are developed, leaving resources with lower capacity factors and higher prices, the price gap between wind and solar energy may narrow, making solar facilities more attractive and further boosting solar development."

A key consideration once again is the impact of those provisions of the RPS designed to limit ratepayer impacts. Will the CEC and other state agencies be willing either to establish Market Price Referents that reflect the full value of these premium attributes, or to increase the System Benefits Charge in order to fund Supplemental Energy Payments sufficient to cover the difference between the existing MPR and the delivered prices? Thus the peculiar features of California's RPS begin to make visible, perhaps most clearly among the four state programs, the balance that must be struck between the total value (as a power supply resource) of the renewable resources developed in response to these programs and the social costs that will be necessary to realize them.

D. Power Sector CO_2 Emission Rates – Has the Needle Moved?

Before I move on to an analysis of the market factors that appear to be shaping these responses to each state's RPS program, it is worth asking what impact, if any, is discernable in power sector CO_2 emissions for each state. It must be acknowledged in doing so that these programs are still early in their lifecycle, and it would be unreasonable to expect that they would have yet produced dramatic reductions in GHG emissions. Nonetheless, the foregoing examination demonstrates that there has been measurable progress in some of the states, almost exclusively in the form of terrestrial wind power, and it is fair to ask what impact has been made.

Figure 4.14 below presents the trends in power sector CO_2 emissions in each state, with the load growth impact deducted and charted from the year of initial passage of their respective RPS programs through 2006, where the initial value of 1.0 for each state corresponds to the power sector CO_2 emission rate for that initial year.



Source data: EIA

Figure 4.14 – State-by-state CO_2 emission trends (deducting load growth)

It is worth referring back to Figures 4.1, 4.4, 4.7 and 4.8 when studying this chart. No consistent pattern is evident across the states in either direction. Connecticut's emissions actually trend upward more or less in synch with the slight increase recorded in in-state renewable production, and they trend strongly downward during a period when in-state renewable production was also trending strongly downward, a counter-intuitive result but one that more likely reflects the relatively inconsequential amount of in-state renewable production in any year relative to other influences. California's data is inconclusive, and it is heavily influenced by the amount of snowpack in the Sierra Nevada and Cascade ranges available for large hydro production in any given year, but given the very small amount of new renewable activity over the period it would be difficult to draw any conclusions from this sample. Colorado's emissions remained nearly flat from 2004, but new renewable production only began in earnest during 2006, so it would be valuable to revisit this analysis once 2007 and 2008 data become available. Only Minnesota's data seems to suggest some relevant movement, with a steady decline in emissions beginning in 2003 and continuing through 2006. While there was some new wind development from 1994 through 2002, a period during which there was a fairly steady increase in emissions, the ramp-up in new wind production really began in earnest in 2003 and has continued since that time, corresponding with the period of declining emissions. To the extent that there is any causal relationship between the two phenomena, it is worth noting that Minnesota is also the only one of the four states in which the marginal generation, which wind always displaces because of its operating characteristics, is coal-fired for most of the hours of the year. An examination of the source-by-source emissions for Minnesota over this period reveals that coal-fired generation did indeed decline commensurately. The potential significance of this was discussed in Chapter Two and will be revisited in the next chapter.

E. Market Factors Shaping Industry Response

Connecticut

The average 2006 retail price of electricity in Connecticut was 14.83 cents/kWh, fourth highest in the country. [EIA data] Average 2007 wholesale prices in ISO-NE ranged from $65-$69/MWh, also among the highest in the country. [Berkeley National Laboratory data] Results from the pioneering recent forward capacity auctions indicate little near-term capacity pressure in the region, meaning that these high market prices are driven almost entirely by the combination of the amount of time that gas-fired generation is on the margin, as presented in Chapter Three, and the high delivered price of natural gas in New England relative to other regions. The other primary revenue component for renewable energy producers in a market such as ISO-NE is the market for Renewable Energy Credits. The market price for Connecticut RECs was trading in December 2007 at just below the $55/MWh ceiling price set by the penalty provisions in the RPS. [Evolution Markets data via EIA] Based on the average regional prices, therefore, a renewable energy producer in New England might expect to receive approximately $122/MWh on average, far higher than is available in less lucrative wholesale markets such as the MISO market in which Minnesota operates (see below for a comparable analysis for Minnesota). At a time when wind power developers in these less lucrative markets have seen strong initial successes, the obvious question is why developers in New England have so far failed to exploit the region's inventory of high-quality wind resources to any significant degree.

While the size of the indigenous wind resource in New England is not as great as in some other regions, a glance at Appendix C shows that very high quality wind resources can be found in northern Maine, parts of western Massachusetts and, of course, offshore. The best of the region's windy areas are comparable to anything that can be found in the Great Plains region. Thus, at least for the best early-stage projects, the dramatic difference in success rates cannot be attributed to a difference in resource quality. Available data indicates a considerable difference in construction costs between New England and other regions, but the average regional wholesale energy price plus the scope for above market pricing created by the ACP provisions in the region's RPS programs would seem to be more than adequate to accommodate these higher construction prices. According to data compiled by the Berkeley National Lab, construction costs for wind projects in New England in 2006 and 2007 were approximately 40% above the national average and a bit more than 50% higher than in the region around Minnesota. Yet the average wholesale price in ISO-NE ($67/MWh) was approximately 40% higher than the average wholesale price in MISO ($48/MWh), and the combination of average wholesale price plus REC price in ISO-NE ($122/MWh) is comfortably more than twice what appears to be the comparable number for the Minnesota market ($53/MWh). We evidently must look elsewhere for the explanation.

The answer appears to be driven by transmission. ISO-NE operates on the basis of locational marginal pricing, which means that prices in different sub-regions are set based on the location of supply relative to the location of demand, and the capacity of the transmission network to distribute one to meet the other. In other words, if there were unlimited transmission capacity throughout the region, then local wholesale power prices in Boston would be the same as they are in rural Maine. Conversely, if there is more supply in some sub-regions than there is demand; and more demand in other sub-regions than there is supply; and transmission capacity between these sub-regions is limited; then local prices will vary to reflect the transmission system's limited ability to redistribute surplus supply from some sub-regions to fill supply deficits in other sub-regions. This is very much the case in ISO-NE, where the transmission system is constrained from north to south. Thus, while the average wholesale price in ISO-NE may be in the range of $67/MWh, the local wholesale price in central Maine was lower than the average ISO-NE price by $6/MWh on average, and in Northern Maine the price was discounted on average by over $10/MWh. [Data provided by S. Knight of CPV, Inc.] Without major investments in new north-to-south transmission capacity, any significant addition of supply in northern Maine would further depress the local wholesale price,[104] leaving wind power producers in that sub-region with a combined energy-plus-REC price up to 10% below the $122/MWh that is implied by the regional average wholesale price.

It is worth noting that energy is only one of several products traded in the ISO-NE market. As noted earlier, there is now a forward market in ISO-NE for capacity, but the most recent auction prices signal a weak market for capacity in the near term. Furthermore, wind projects are able to offer firm capacity equal to only a small fraction of their total installed capacity, which means that a capacity market would do little to enhance the revenue expectations of a wind producer almost regardless of the market price.

As noted in Chapter Three, the only other (currently) commercially exploitable indigenous resource of any significance in New England is biomass for power generation. Unlike wind, biomass generators are able to offer high levels of firm capacity, and they can be designed to supply a range of other system benefits such as dispatchability and voltage regulation. But as has been noted, recent ISO-NE market prices for these non-energy services have been weak, and other providers of such services (such as simple-cycle gas-fired combustion turbines) are able to do so more cheaply than can biomass generators. Because all five of the RPS programs in New England operate on an energy-only basis, with no explicit preference for or value attributed to eligible resources capable of providing essential non-energy services, buyers have the option of satisfying their RPS obligations with energy purchased from what is today the cheapest source (wind plants) while procuring their non-energy requirements from non-renewable sources. Depending on what one is prepared to assume about future gas prices, the particular gas-fired capacity that will be built to complement the wind resources, and the

[104] The ISO NE 2007 Regional System Plan states that the amount of new generation that can be added to the system behind the three Maine trading hubs is currently less than 700 MW.

manner in which it will have to be operated, this can be seen to be the lowest all-in cost approach to compliance. On the evidence provided by the portfolio of prospective projects found in the ISO-NE interconnection queue, it would appear that greenfield biomass developers in New England are struggling to compete with this bifurcated option and cannot compete with wind on an energy-only basis.

The potential implications of these features of the New England market for compliance-driven retail price impacts are worth considering. As has been noted previously, virtually all states have attempted to impose limits on the magnitude of retail price increases resulting from compliance with RPS programs. In those states where this limit has been expressed explicitly as a percentage increase in retail electricity bills the permissible increases have been in the range of 1-3%. A very cursory analysis of the New England situation leads to a potentially different conclusion. Given Connecticut's average retail price for electricity of 14.83 cents/kWh, a 2% increase in retail prices from RPS compliance activities would be 0.30 cents/kWh, or \$2.97/MWh. If ISO-NE were to see RPS-driven production reach a 20% market penetration, the implied ceiling on the subsidy available to eligible resource owners would be \$14.85/MWh, as against the current ceiling of approximately \$60/MWh and the December 2007 traded market price of approximately \$55/MWh. Clearly if the premium required to induce exploitation of the region's indigenous renewable resources remains where it is today, the retail price increase resulting from compliance with the final targets contained in the various RPS programs could, *ceteris paribus*, approach 10%. Alternatively, an RPS-driven subsidy for eligible resources limited to a more modest 2% retail price impact (consistent with legislative expectations expressed elsewhere) would appear to fall well short of what is needed to induce any significant amount of indigenous land-based wind resource development, and offshore wind and biomass would seem to only be further out of reach. While prospective investment in new transmission infrastructure targeted specifically at unlocking the region's best renewable resources may significantly alter this equation, those investments are substantial in their own right relative to the size of the available resource, as noted previously, and they will have their own adverse impact on regional retail prices.

Minnesota

The average 2006 retail electricity price in Minnesota was 6.98 cents/kWh, the sixteenth lowest in the nation. Average 2007 wholesale energy prices in Minnesota's upper Midwest region ranged from $44-52/MWh, some of the lowest wholesale prices in the nation. Additionally, given the ample supply of capacity available in the MISO market, there is limited market value attributable in the near term to incremental capacity additions in the region. Low energy prices in the region are attributable to the large number of hours that coal-fired generation is on the margin, as was discussed in Chapter Three.

As in Connecticut and the other New England RPS programs, Minnesota's RPS as revised in 2007 allows compliance through the purchase of tradeable RECs, and the market price for these RECs can provide an indication of the compliance-driven subsidy over and above wholesale market prices available to developers of eligible resources. There is no formal compliance REC market in Minnesota, so the market value of renewable energy attributes must be derived from other sources. There is a voluntary Midwest market for RECs that at the end of 2007 indicated a value of approximately $5/MWh, compared with the contemporary Connecticut REC market price that was near its $55/MWh ceiling. As noted earlier, the Minnesota RPS imposes no explicit ceiling on retail rate impacts nor does it effectively limit the cost of compliance through an alternative compliance payment mechanism. However the legislation does empower the PUC to limit the cost of RECs administered by M-RETS and to excuse non-compliance in the event that compliance would result in a "significant" adverse retail rate impact. Picking the middle of the customary range, I will assume that anything above 2% would be considered significant. Given the average retail price of 6.98 cents/kWh, a 2% price increase would amount to 0.14 cents/kWh or $1.40/MWh. Using the final (implied) statewide target of 27.4%, the implied compliance-driven subsidy to producers would be capped at $5.11/MWh, roughly consistent with the recent REC market prices in the voluntary Midwest market. Commentary by Xcel/Northern States Power and Minnesota Power in their most recently filed resource plans indicate that the cost of compliance to date and the anticipated costs of compliance going forward appear to be below what they believe the PUC would consider significant.[105] All of these indicators point to a market in which producers of RPS-eligible electricity can expect a compliance-induced premium over wholesale energy prices of approximately $5/MWh (in 2008 $s) for the foreseeable future. Given average wholesale energy prices in the range of $48/MWh in the upper Midwest region, the implied average market-clearing price for eligible resources is in the range of $53/MWh.

I have noted that Minnesota's primary indigenous renewable resources are wind and biomass, with wind being by far the dominant resource available. Recent history shows a strong response by wind project developers, despite the relatively low market price environment created by the combination of MISO's existing mix of generating resources and the compliance regime established by Minnesota's RPS law. This may be driven in part by low construction costs. Berkeley National Lab's construction cost data shows wind project construction costs in the

[105] Again as noted earlier, Xcel explicitly conditioned this expectation on the assumption that the supplier subsidy provided by the Federal PTC would continue to be available through at least 2015.

upper Midwest in 2006 and 2007 to be the lowest in the nation, less than 70% of the cost for wind projects in New England during the same period. Minnesota's large inventory of excellent wind resources, located in areas highly receptive to their commercial development, is no doubt a contributing factor as well. And while MISO operates a LMP market similar to ISO-NE, adverse basis differentials (that is, discounts to the average regional price noted above) between the wind-rich region in the southwest corner of the state and the Minnesota Hub (near Minneapolis/St. Paul) are relatively modest and only serve to make the success of wind developers in that sub-region all the more noteworthy. That being said, a major transmission investment program is under development in Minnesota to address infrastructure constraints that would limit further development of the most promising areas.

The data on new biomass developments tells a different story, with no significant new capacity added and very little new capacity listed in the MISO interconnection queue, despite the existence of a high-quality resource base in northern Minnesota and elsewhere in MISO. As in Connecticut, Minnesota's RPS is an energy-only standard, with no stated or implied preference for resources that can provide essential non-energy grid services. Xcel/Northern States' compliance plan reflects the bifurcated compliance approach described in the Connecticut discussion above, with increased reliance on wind complemented by an increased commitment to gas-fired combustion turbines to provide the non-energy grid services that wind cannot provide. This may be due to a decision by Xcel to take a minimum-cost approach to compliance, and/or it may be driven by transmission constraints limiting access to the prime biomass resource base in the northern tier of the state, but it is noteworthy that Minnesota Power's compliance plan points in a slightly different direction.

Minnesota Power's resource plan projects that 20% of their incremental compliance requirements will be met with biomass-fired generation. This may be partially driven by the fact that the state's best biomass resources are concentrated in the retail areas dominated by Minnesota Power. But it would also appear that Minnesota Power has chosen to take advantage of the modest premium required to access the regional wind resource, proposing to blend into their compliance plan somewhat more expensive biomass resources capable of supplying essential non-energy grid services while remaining within what they believe the PUC would consider a "significant" overall retail rate impact. While Minnesota operates within the competitive MISO wholesale power market, I've noted that the state's electric sector was never restructured, which means that the Minnesota market retains some of the features of a traditional cost-of-service-regulated utility market. Xcel/Northern States' compliance plan is consistent with a low-cost supplier strategy, a strategy that would in turn be consistent with a view that their highly concentrated, predominantly urban retail base may become exposed to competitive pressure over the term of the compliance period. Minnesota Power, on the other hand, has proposed a plan that capitalizes on what they project to be a modest premium associated with a blended compliance approach; the cost pass-through features of the hybrid Minnesota electricity market; and the lower risk of competitive challenges in their sparsely populated retail markets to achieve a compliance approach that is presumably slightly more expensive in the near term but prospectively more sustainable in the long term.

There is admittedly a significant amount of speculation in this analysis. The conclusions I've drawn however, particularly regarding Minnesota Power's compliance strategy, gain greater credence after examining the industry's response to market factors in Colorado.

Colorado

The average retail price of electricity in Colorado in 2006 was 7.61 cents/kWh, below the national average of approximately 8.9 cents and exactly the median national price. Average 2007 wholesale power prices in the Mountain region ranged from $54-$56/MWh. Unlike Minnesota and Connecticut, there is no traded wholesale market in Colorado, for energy or any other grid services, rather all wholesale power is either self-generated by the LSEs or purchased by them under contract from third-party producers. In the case of the IOUs (predominantly PSCo) the costs associated with both approaches are vetted by the PUC and, when approved, passed through in retail rates along with a regulated rate of return on invested capital. The co-ops and municipally-owned utilities are self-regulated but follow a similar rate-setting procedure, absent the rate of return. Thus the "market factors" affecting the development of renewables in Colorado are not so much driven by a market as they are driven by the integrated resource planning process and the regulatory bargain that can be struck between the regulating entities and the LSEs. The relatively low average wholesale price reflects the fact that Colorado's generation mix is still heavily weighted toward coal. The fact that it is slightly higher than the Minnesota wholesale market may reflect the much larger role natural gas plays in Colorado's generation mix. The difference might be greater but for the fact that Colorado's wholesale prices are set on a blended cost-of-service basis rather than by hourly bids submitted by the marginal generator.

While the RPS law allows compliance through the purchase of tradeable RECs, no market or market administrator is specified. As a result, there is currently no discoverable compliance market price for renewable attributes in Colorado. A voluntary REC market that operates in the West indicated a market value at the end of 2007 of nearly $13/MWh, more than twice what it was in the voluntary Midwest market though still well below the Connecticut REC market. Colorado's RPS imposes an explicit cap of 2% on the compliance-driven retail rate increases that will be granted to the IOUs. Given the average wholesale price, a 2% increase would equate to 0.15 cents/kWh or $1.52/MWh. Given that the state's final RPS target is 20%, the implied ceiling on pricing for renewable attributes is approximately $7.60/MWh. Using the average wholesale price of $55/MWh, the ceiling price for eligible resources under Colorado's RPS could be said to be approximately $62.60/MWh. As will be discussed below, Colorado's largest LSE foresees the ability to exceed their RPS obligations by a considerable margin at a cost that is at or below the 2% ceiling.

Colorado's primary eligible resources are dominated by wind, with a very significant solar potential as well and a much smaller biomass potential (with a promising geothermal resource that is not exploitable with current technology). I have documented the robust early response by wind developers to Colorado's RPS, and in the case of wind the indigenous resource economics and market pricing circumstances are very similar to Minnesota. Construction costs for wind projects in 2006 and 2007 in the Mountain region were right at the national average as compiled by Berkeley National Lab, about 10% higher than in Minnesota and about a 28% discount to New England. Given Colorado's vast wind potential, and assuming a substantial investment in new transmission infrastructure, the state could easily supply its RPS goals several times over with wind without exhausting its inventory of premium wind sites, and apart from a very small set-aside for solar in the RPS law there is nothing preventing the LSEs from doing so.

As noted earlier, however, the compliance plan recently filed by PSCo takes a different approach. Based on the wind project economics they are seeing, PSCo is proposing to the PUC to use the headroom provided by the 2% rate ceiling not only to go well beyond the current RPS targets (with nearly three times as much wind energy as they would require), but also to diversify their renewable portfolio into other, currently more costly resources. In the case of Colorado this means solar, specifically utility-scale concentrating solar power plants with thermal storage systems. The plan is still dominated by wind, but they propose to source about a third of their renewable energy by 2016 from dispatchable CSP, along with a much smaller percentage from new geothermal and biomass plants, while keeping the resulting increase in retail rates within the 2% cap set by the legislature. PSCo's stated rationale for this more costly diversification is to advance the maturity of, as well as their operational familiarity with, technologies that they expect to offer premium attributes beyond those offered by wind power. An additional motivation may well be that Colorado, unlike Minnesota, has over the past ten years significantly increased its exposure to natural gas as the marginal fuel for generation. While the targeted wind development is explicitly intended to mitigate that exposure by displacing gas *consumption*, the wind plants will still need to be supplemented by gas-fired plants (both existing and new) for reliability and other grid services. By contrast, the firm capacity and dispatchability offered by the CSP with thermal storage, biomass and geothermal plants are very likely attractive precisely because they go even farther than wind in reducing the state's exposure to natural gas. This response to market forces, which I've suggested is also the one being pursued by Minnesota Power using indigenous biomass, is again one that leverages an even more traditional command-and-control electricity market and an equally attractive wind resource, while treating the legislatively-imposed rate cap (which in this case has been made explicit) as an opportunity rather than a constraint.

California

The average 2006 retail price in California was 12.82 cents/kWh, eighth highest in the country. Average 2007 wholesale power prices were approximately $59/MWh, also among the highest in the country. California's wholesale market most closely resembles that of New England in structure, and as in New England gas-fired generation is on the margin nearly all the time. California's lower wholesale price relative to New England is most likely driven by a difference in the average delivered price of gas to the two regions.

California's RPS does not currently permit compliance through the purchase of unbundled RECs, so there is no REC market to provide a clear market signal for the premium available to eligible resource providers over and above the prevailing wholesale power price.[106] Nor does the California RPS use a stated or implied ceiling on the retail price impact of compliance to control the cost of the program. True to its reputation for complexity, the California RPS utilizes the completely unique and administratively burdensome MPR/SEP mechanisms described in Chapter Three. In short, the MPR is a proxy for the marginal fossil-fired generating capacity on the system (currently a gas-fired combined cycle plant), and the SEP (funded by the revenues collected through a system benefits charge added to customer bills) is available, at the discretion of the CPUC, to cover the difference between an LSE's cost to purchase supply from an eligible resource and the hypothetical cost to purchase from the MPR. On this basis it could be said that the system benefits charge collected to fund the SEPs, plus any difference between the hypothetical price of supply from the MPR and the prevailing wholesale power price, constitutes the current ceiling on the retail price impact of compliance with the RPS. The system benefits charge currently stands at an average of approximately 0.25 cents/kWh (2% of customers' bills), of which "at least 51.5%" must be used to fund renewables

[106] It was noted earlier that the WREGIS REC market went live in mid 2007 thanks in large part to the efforts of California's CEC; the CPUC is monitoring the market and has yet to allow compliance via the purchase of RECs.

contract costs in excess of the MPR. At California's final RPS target of 20%, the SBC is sufficient to fund a subsidy of 1.25 cents/kWh or $12.50/MWh *if 100% of the funds collected are utilized to subsidize above-market RPS compliance purchases*. The hypothetical price of supply from the current MPR varies depending on the length of the contract in question and when the plant is expected to come into service. The CPUC in September of 2007 set values ranging from $78.90/MWh to $94.68/kWh, but for simplicity of comparison the MPR value for a 15-year contract commencing in 2011 (roughly the middle of the matrix) was $83.07/MWh. The California Energy Commission, in its 2007 Energy Report,[107] notes that the quantification of the benchmark established by the MPR is heavily dependent on the discounting methodology used, and the CEC advocates a methodology that would add from $3 to $16.75 per MWh to the MPR benchmark (the adder for a 15-year contract commencing in 2011 would be $8.35/MWh). Using the CPUC benchmark, and assuming that all of the funds collected under the system benefits charge are available to reimburse the above-market costs for eligible resources, the market clearing price for renewable providers is currently approximately $95.57/MWh (at the high end, the MPR price for a 20-year contract commencing in 2015 is $94.68/MWh, resulting in a market-clearing price of as high as $107.18/MWh). As is clear from the CEC discussion referenced above, California's MPR methodology is open to a wide range of interpretation, with the CEC's preferred approach leading to a market-clearing price as high as $123.93/MWh for a 20-year contract commencing in 2015.

Operating alongside these market price signals, however, is the qualitative "least cost/best fit" mechanism that was described earlier. This mechanism directs LSEs to rank eligible projects in order of how well they "fit" with the LSE's particular system requirements. As we have seen, despite the very high apparent market clearing price for eligible resources

[107] California Energy Commission, *2007 Integrated Energy Policy Report*, CEC-100-2007-008-CMF, pp 141-142

relative to Colorado and Minnesota, California's actual renewables production has stayed stubbornly in the range of where it has been since 1991. The LSEs, the agencies or both appear to have determined that the best way to break this logjam is to use the least cost/best fit criteria to drive prioritization of projects based on the optimal use and build-out of the transmission system, rather than expect transmission planning to be driven simply by the location of the projects offering the lowest energy prices. And based on the most recent round of renewable solicitations, the market appears to have responded with far more solar and far less wind than had characterized the prospective industry response only a short while ago.

California's solar resource potential is far greater than its land-based wind resource potential, but wind and conventional geothermal (which California also has in abundance) have until recently been the dominant resources in the renewables mix. Unlike the terrestrial wind resource (which is distributed in pockets across various sub-regions of the state), solar potential is highly concentrated in the southern and southeastern sections of the state. Solar (particularly CSP coupled with thermal storage systems) offers more firm capacity value, much less intermittency, better load-following characteristics, more dispatchability, a closer and more reliable fit to the daily demand profile – and as a result it adds less strain and provides more benefits to grid operators in California than does wind. These benefits to transmission planning appear to be expressing themselves in the LSEs' rank ordering of proposed projects. Furthermore, the market-clearing price for eligible resources, to the extent that it can be pinned down, certainly appears to be at the high end of the range, though perhaps not quite as high as in Connecticut. But solar has until now been a considerably more expensive option, and while least cost/best fit provides qualitative guidance it does not set aside a specific market for "better fit" but more expensive eligible resources. Thus it remains to be seen whether or not the current generation of resources under consideration by the LSEs will be able to clear the market as it stands. If not, will the agencies revise or relax the current market constraints in a manner that will allow them to do so?

Chapter Five

Conclusions and Recommendations

As expected, the close examination of four state RPS programs over the last two chapters has afforded a more nuanced view of the state-level RPS phenomenon than can be gleaned from a cursory survey. The opportunity to do so has only recently become available, as some of the more ambitious state programs have now had the chance to accumulate multiple years of experience in practice. The information provided points toward possible opportunities to refine the renewable portfolio standard as an important policy tool for achieving the reductions in power sector GHG emissions that will be required if the U.S. is to stand any reasonable chance of achieving the goals embedded in most mainstream climate assessments.

A cursory survey of RPS, such as the one I presented in Chapter One, presents a picture of uneven progress and, where there has been progress, what I will characterize as a "lowest common denominator" approach to renewables development, at least when the phenomenon is assessed in terms of its efficacy as a central feature of power sector climate policy. The combination of aggressive targets and timetables; objectives framed almost exclusively in terms of the quantity of energy produced; and a desire to limit compliance-driven retail rate increases generally to 1-3%[108] has led to a near-monopoly of early compliance activities by terrestrial wind power.

Of the major categories of largely untapped and eligible renewable resources, terrestrial wind power is clearly the most mature. As a result, with the exception of opportunities to

[108] To put the cost limits described here in perspective, the German Renewable Energy Sources Act is seen as a very successful example of the feed-in tariff ("FIT") approach to renewables policy support, with significant growth not only in wind but in solar PV and other renewable technologies. In 2005, FIT-subsidized renewables production constituted just over 7% of all German electricity and resulted in a retail rate increase of 3%; the equivalent retail rate impact for the 20% penetration targeted for 2020 would be just under 9%.

expand incrementally more traditional eligible resources (such as small, low-head hydro and landfill gas) terrestrial wind in many regions offers the least costly and most immediately accessible means by which LSEs can fulfill the energy-denominated RPS obligations that have been imposed upon them. This is particularly true when the advantages bestowed upon wind development by most RPS programs are coupled with direct producer subsidies like the Federal PTC. Yet while a focus on the expansion of land-based wind power production is likely to produce measurable reductions in power sector GHG emissions, the expected reductions are quite marginal when viewed against the total reductions likely to be required of the power sector and the timetable on which those reductions must take place. Given the magnitude of the task presented, no measurable contribution should be dismissed as unimportant. Nonetheless, a review of the sources of power sector GHG emissions makes it quite apparent that the ultimate objective will not be reached without largely or completely replacing the role of conventional coal-fired power plants. It turns out that that role is multi-faceted and cannot adequately be captured in the number of kWh they produce, prodigious though that number might be.

The most cost-effective approaches available to reduce the need for conventional coal plants are ones that eliminate the need for their services altogether, through investment in a broad range of untapped opportunities to improve efficiency and reduce consumption. But as attractive as many efficiency opportunities are, we cannot conserve our way out of our reliance on conventional coal plants. Low-carbon supply options will be required, most likely a very large quantity of them, capable either alone or in combination of replicating the multi-faceted role of conventional coal plants.

Two basic strategies have been suggested to facilitate this transition – one is to make the low-carbon alternatives less expensive, and the other is to make conventional coal more expensive – and they are not mutually exclusive. A carbon pricing scheme is likely to be more coldly efficient in bringing forward the optimal mix of replacement technologies, but without complementary policies designed to promote the commercialization of specific acceptable alternatives, a carbon pricing approach risks unintended consequences and a chaotic and costly transition period. An RPS can be a powerful tool in the timely development of renewable alternatives, by granting privileged market access to appropriate technologies. Appropriate renewable technologies are those likely to compete, either alone or in combination with other measures, directly with advanced natural gas plants, low-carbon coal technologies and nuclear power in the race to replace the role of conventional coal plants. Furthermore, the privileged market access afforded by an RPS is likely to be of greatest value in accelerating the progress of early-stage technologies toward competitiveness with conventional coal in a carbon pricing world, and of least value when extended to mature technologies.

Table 4.1 presented a ranking of the leading RPS-eligible renewable technologies against these two fundamental criteria – ability to compete for the role played by conventional coal plants, and relative stage of technological maturity – leading to a framework for evaluating the effectiveness of various RPS programs in addressing the essential challenge in power sector climate policy. Terrestrial wind power, the main beneficiary so far of the state-by-state RPS phenomenon, ranks very poorly on both criteria. The singular focus on energy production that characterizes nearly all state RPS policies, combined with a bias toward dramatic results and a mandate to limit rate impacts, has created what I will refer to as the "iron triangle" of current RPS policy design, a privileged market space into which only terrestrial wind currently fits. This has led to an overstimulation of interest in terrestrial wind power at the expense of renewable technologies that are less likely to deliver large amounts of affordable energy in the near term, but are better suited as replacements for conventional coal plants in the longer term, and are more likely to experience significant advances in cost and performance as a result of the privileged market access an RPS can provide.

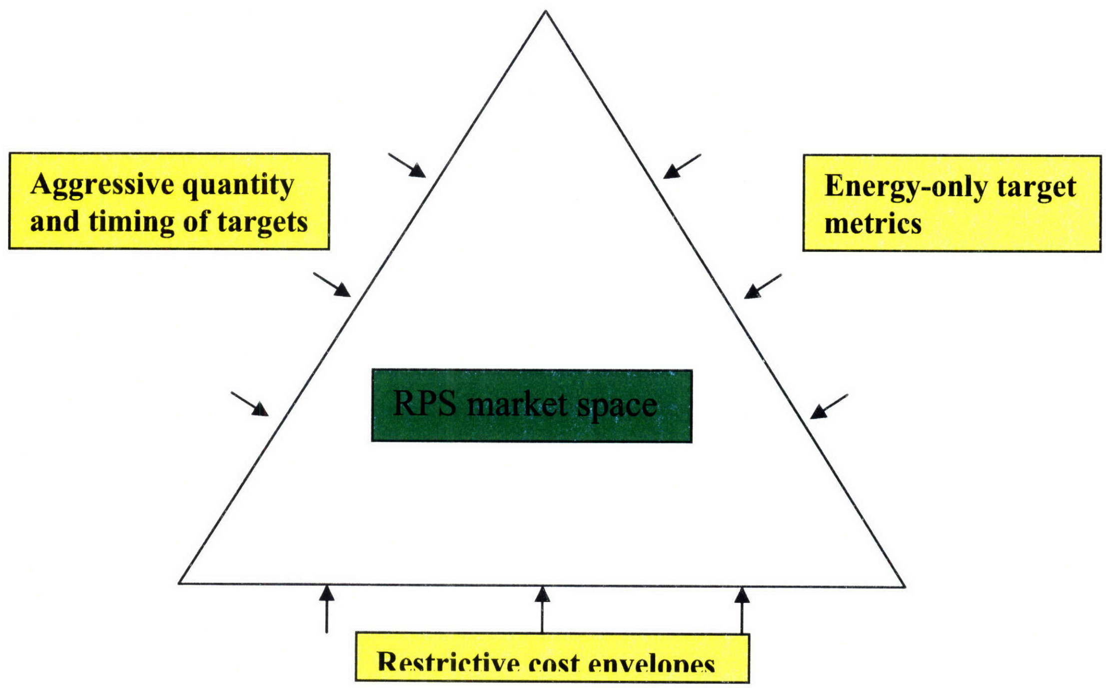


Figure 5.1 - The "Iron Triangle" of current RPS design – bulk energy, lots of it, fast, and cheap

Another trend that emerges from a general survey of the RPS landscape is regional variation in new market penetration by eligible technologies. While statistics on the overall rate of growth in renewable power production are impressive, nearly all of this growth (at least for grid-connected production) is from land-based wind, and nearly all of that growth is taking place in those states with access to the Great Plains wind resource. Perhaps more surprisingly, with the exception of Texas these states represent markets where the market-clearing price threshold for renewables is heavily weighted by coal and is thus far below the price ceiling available in regions like New England and California, where progress has been notably slower. From the perspective of climate this trend is not necessarily problematic – the geographical distribution of GHG mitigation measures is irrelevant. Indeed, production from any renewable source in these markets is more likely to displace coal-fired production than would be the case in many other markets. But state-level RPS policies are almost universally designed to forbid compliance through the purchase of RECs from sources not capable of physically delivering energy to the local grid. Because of this, there is a risk that the pace of development of some of our best renewable resources may be constrained, with the commensurate risk that the mandated development of less impressive regional resources elsewhere will continue to struggle, while overall the advance of renewables may be less cost-effective than would otherwise be the case.

While this broad analysis points to general concerns with the climate-related efficacy of current RPS programs, the detailed analyses of four state programs presented here identify several more encouraging developments and point toward potentially productive refinements. Rather than organize these observations in a state-by-state manner, I will present them topically, synthesizing the contributions from the various state analyses as I go. As will become apparent, these suggested refinements should not be viewed individually but rather in combination with each other. Indeed, each subsequent recommendation follows to some extent from the foregoing recommendations.

1. Introduce technology bands, with a bias toward early-stage technologies. This is the most basic of the recommended reforms, though it is intimately related to several of the follow-on recommendations. The idea is simple enough in concept – renewable technologies that are otherwise considered desirable (see below) would be placed into two or more bands, or tiers, on the basis of an assessment of their technological maturity. Those in an early stage of development and likely to experience significant cost and performance improvements with each doubling of production (known as the *progress ratio*) would be allotted the greatest share of the mandated portfolio obligations. (Importantly, those obligations would not be denominated in bulk kWh but rather in something such as firm capacity value, or the percentage of the total program cost envelope allocated, a key point that I will develop under a subsequent recommendation) LSEs would face far smaller procurement obligations for more mature technologies, and the procurement obligations for the most mature technologies would be phased out altogether over a fixed period of time, the rationale being that, once a technology has evidenced the transition to the low progress ratios that characterize mature technologies, it is unlikely to benefit from the opportunities created by an RPS policy regardless of whether or not it has achieved parity with competing technologies.

The challenge in practice, of course, is that assignment to tiers by relative technological maturity would have to be done administratively. Such an assessment would be vulnerable to political pressure from mature technology advocates, and the assessment of future progress ratios for any given technology at any given point in its development is far from an exact science. Perfection in this case would be the enemy of the good, however, since a broadly valid classification is achievable, and the allocation of technologies to bands can be revisited on a regular basis. Political lobbying cannot be neutered completely, but its impact can be blunted as it is in many similar cases, by delegating the assessments to professionals in the state regulatory agencies rather than relying on a legislative allocation.

Connecticut's decision to create multi-tiered RPS eligibility, similar in principle to many other state programs, is a step in the direction recommended here. Colorado's program also creates a specific set-aside for a certain subset of renewable technologies. But the approach taken, not only in Connecticut and in Colorado but in many other states as well, falls short of what I am recommending in important ways. Connecticut's main tier (Class I) gives preference to the "cleanest" technologies (except, arguably, natural gas fuel cells), but it mixes mature technologies (terrestrial wind, landfill gas, low-head hydro) indiscriminately with early-stage technologies (deep offshore wind, solar PV, wave/tidal, advanced biomass). It also denominates compliance in bulk kWh of energy, and it establishes an ambitious goal of procuring 20% of all energy by 2020 from eligible resources with comparably ambitious interim milestones. As a result, compliance is likely to be dominated by mature technologies capable of producing large amounts of energy relatively cheaply by the legislated milestone dates, regardless of what other attributes those technologies may or may not possess. In the process, the program will effectively suppress the development of early-stage technologies that could have benefitted tremendously from the opportunity, but that would not be expected to become major contributors of affordable energy production until the latter years of the program. To put it differently, building 5,000 MW of new land-based wind capacity in New England will have only a very marginal impact on the commercial feasibility of building the next 5,000 MW of land-based wind, and if that first 5,000 MW of wind is not commercially viable on a stand-alone basis once a carbon price is actually implemented, the viability of the next 5,000 MW is unlikely to be much different. By contrast, building 500 MW of deep offshore wind (New England's primary high-quality renewable resource), while currently a more costly option per kWh of energy delivered, would be expected to have a significant impact on the commercial feasibility of building the next 500 MW, which would in turn most likely have a significant impact on the commercial feasibility of the next 1,000 MW, and so on. What is today a much more costly option would experience dramatic improvements in cost and performance as a result. If Connecticut has a choice of how to spend the envelope of funds effectively allocated to its RPS policies, it would seem far more beneficial in the long term to spend them disproportionately (though perhaps not exclusively) on a technology like offshore wind.

Colorado's approach is somewhat better in setting aside a market specifically for a class of early-stage technologies (solar). But the set-aside is quite small, and the impressive overall program targets (again denominated entirely in units of bulk energy) combined with the program cost ceiling (overall retail rate increases of no more than 2%) imply that that the targeted investment in development will be dominated overwhelmingly by mature technologies, primarily wind. As we have seen, the largest Colorado LSE has taken the initiative, afforded by the combination of Colorado's very attractive wind resource and the Federal PTC, to advance the development of an early-stage technology (solar thermal with thermal storage) that is expected to be a very valuable grid resource in the future. But they are pushing the letter of the policy design to do so, and they are relying on the state utility regulators to approve the associated increased costs, albeit costs that they forecast will be within the legislatively-mandated cost envelope. Colorado has a tremendous terrestrial wind potential, and based on the evidence presented in Chapter Four it is evident that very little assistance from the RPS, if any, is required to promote its development. PSCo seems to understand that allocating a much larger percentage of the RPS program cost envelope to a currently more expensive but potentially more valuable early-stage technology, one that may not contribute large volumes of energy production until the program's latter stages, will pay greater dividends in the long run. Policymakers should take heed.

Indeed, the United Kingdom is already implementing exactly this type of reform.[109] Britain has had a RPS-style policy, called the Renewables Obligation, in place since 2002. In its 2007 Energy White Paper the Government noted that the budget expenditures to promote

[109] See H.M. Government, Department of Trade and Industry, "Meeting the Energy Challenge: A White Paper on Energy," pp 143-168.

renewables were being monopolized by land-based wind projects, the quality of the land-based wind resources being developed was declining as penetration rates increased, and there was no apparent value being created in the form of material improvements in cost and performance. In response, the Government proposed to create technology bands, with technologies grouped according to their relative technological maturity, and to shift the emphasis of the Renewables Obligation program away from mature technologies like land-based wind and toward the support of the least mature technologies.

2. Replace (or supplement, as with California's "least cost/best fit" overlay) the energy-only denominations of the RPS targets with one or more metrics that combine energy with attributes like firm capacity, dispatchability, peak coincidence, potential scale and others necessary to facilitate a transition from conventional coal plants to renewable alternatives. This type of reform was alluded to in the foregoing discussion on technology bands, and it is important to see them as complementary. While it is important to shift the emphasis of RPS policies away from bulk quantities of energy and toward targeted allocations of program funding, it is equally important that the allocation criteria be based not only on relative technological maturity, but also on the inherent grid service capabilities of the various technologies. In this case the denomination of choice for compliance would not be bulk kWh hours of energy alone, or at all, but rather a blend of attributes that might include, *inter alia*, firm capacity value, dispatchability, load following or peak coincidence, in addition to or instead of total production of energy. The particular mix of attributes would reflect the particular system requirements of each LSE, in collaboration with state regulators if so desired. The long-term strategic appeal of such an approach is suggested in the responses by Minnesota Power and PSCo to their respective state RPS policies. It is expressed more directly in California's "least cost/best fit" policy provision, the innovative responses to which are only now beginning to take on significant dimensions. California's specific approach is famously complex, but I would contend that that need not be the case.

I have already discussed the importance of this type of feature in promoting those renewable technologies that are best fit for the purpose of replacing conventional coal plants. A related but more immediate potential benefit also emerges from the California case study. Transmission has been identified literally everywhere as a critical impediment to further development of renewable resources, in some regions (like California and New England) being more difficult and potentially more costly than in others (like Minnesota and Colorado). What the California policy seems to acknowledge are the inherent benefits to transmission expansion from prioritizing those resources that are more concentrated, with higher firm capacity value, more dispatchable and with greater peak coincidence. Such resources are likely to require less transmission investment per MW of capacity, see higher rates of transmission utilization and allow for more optimal asset management when operated in conjunction with conventional generation that is sharing the same transmission and distribution facilities. Each of those attributes contributes to a lowering of the bar that must be cleared for approval of and investment in any major new transmission asset. So in addition to promoting those technologies best suited to tacking the central challenge of power sector climate policy, this reform may well also accelerate removal of the main obstacle to more rapid development of our renewable resources. That's at least one aspect of policy on which the LSEs and the state agencies in California seem to concur, and it is also evident in Colorado's promotion of Generation Development Areas. I can see no reason why the same benefits would not accrue to transmission planners elsewhere.

3. Be prepared to buy less and pay more per project today, in order to get more for less in the future. This reform flows naturally from the first two reforms discussed above. The value of this specific policy refinement comes most clearly into relief when comparing Connecticut's experience with those of Minnesota and Colorado. In the case of those two states, and most explicitly in the case of Colorado, the particular combination of a tremendous (and readily developable) regional wind resource with a fairly typical view of program cost limits (and, importantly, the Federal PTC, the value of which may soon be replaced by a carbon pricing policy) has created the opportunity for some enterprising LSEs to propose paying somewhat higher prices today to promote a limited quantity of projects based on early-stage technologies with the potential to provide a wider range of grid services in the future.

Connecticut, like most states in the Northeast, faces a far more difficult situation. Despite a much higher market-clearing price threshold, these states have struggled to induce significant new investment in renewables. While massive new transmission investments may reveal that there is ample room for terrestrial wind development at these price levels, the much higher costs experienced to date by terrestrial wind developers in the region, the much smaller and more dispersed terrestrial wind resource in the region, and the open question of how the new transmission will be paid for, all combine to favor a more modest expectation. By contrast, the region possesses one of the country's premier deep offshore wind resources, in both size and quality, but offshore wind is a far less mature technology, currently costing much more per kWh, than is the case for terrestrial wind. The current program cost ceilings in the region, expressed in dollars per unit of energy purchased, are already at levels that, were the programs objectives to be fully met at current prices, would result in retail rate increases several times as high as the rate limits enforced in most other states. Yet given the maturity of the dominant renewable resource identified in the ISO-NE interconnection queue (i.e. terrestrial wind), it is unlikely in this scenario that renewable production costs would decrease dramatically simply as a result of the commercial experience that would be gained through RPS-driven development.

The answer for New England, and other regions like it, may not lie in looking for ways to unleash large amounts of bulk energy from mature technologies while staying within what are already relatively high per kWh price caps. The answer, instead, may lie in paying even higher per unit rates today for a smaller quantity of energy from more promising early-stage technologies. Setting smaller interim kWh targets for deep offshore wind and advanced biomass CHP could pay tremendous benefits down the road by accelerating commercialization of New England's premier untapped resource. Deep offshore wind also allows greater concentration of facilities, promises higher firm capacity value, more predictability and better peak coincidence. Biomass CHP has high value as a replacement for baseload conventional coal plants. The cost of the revised programs would be kept constant as a result of lower interim bulk energy targets. In so doing, early-year program resources that would have been spent subsidizing bulk energy purchases from mature technologies can be shifted toward initially paying more per unit for fewer kWh, from projects featuring earlier-stage technologies (*a la* Recommendation #1) promising to deliver a wider array of system benefits (*a la* Recommendation #2). The programs would be expected to take longer to gain momentum, but the long-term outcomes are potentially far more valuable. The alternative, at least for states like Connecticut, seems akin to the banging of one's head against a wall with little to be gained from finally breaking through. While the suggested policy refinement would codify a trend that may already be emerging in other regions (e.g. Colorado), it could be the key that finally unlocks long-term value in regions like New England that have struggled to gain traction with their RPS policies as currently designed.

4. If and when imposing RPS program cost ceilings, replace per-kWh alternative compliance payment mechanisms with some form of overall program cost envelope, such as a limit on compliance-driven retail rate increases. This reform is really an adjunct to Recommendation #2. The ACP mechanism so common among many programs, particularly those in the Northeast and Mid-Atlantic, at first blush offers the prospect of greater simplicity. After reviewing the four state programs in detail, however, this mechanism appears to suffer from two shortcomings. First, it absolutely forecloses on the opportunity to develop promising early-stage technologies by subjecting them to per kWh price ceilings that reflect the expected cost of far more mature technologies. A cost limit expressed in aggregate rate impacts gives regulators and LSEs the leeway to pay above-average rates for a small amount of energy from early-stage technologies while paying below-average rates for a larger amount of bulk energy from mature renewable technologies. Again, we've seen examples in Colorado and, possibly, in Minnesota of LSEs doing exactly that.

The second inherent shortcoming in the ACP mechanism is that it operates immediately to restrict the quantity and quality of renewable production, by expressing the limit in every kWh purchased. An overall cost envelope, by contrast, allows higher prices to be paid in early years for initial quantities of renewable production without breaching limits, and as renewable production costs hopefully decline with increasing volumes, greater quantities of the same resource can be purchased in the future without adjusting the caps. When the ACP approach is combined, as it is in New England, with inherently high-cost energy even from mature technologies, the trap that is created is that LSEs are locked buying large quantities of energy from mature renewable technologies unlikely to experience significant improvements in cost over time. As a result, they incur prices near the cap today that are likely to remain at or near those levels for the duration of the program. By converting to an overall cost envelope and combining it with lower interim targets as suggested in Recommendation #3, LSEs and regulators are free to experiment in the early part of the program with a mix of technologies, from early-stage to mature, in order to maximize the program's long-term benefit.

5. If and when imposing RPS program cost ceilings, scale back energy volume targets and replace them with lower energy and capacity targets that can fit within the same envelope, particularly in the early years of the program. This is essentially a corollary to Recommendations #2 and #3, and indeed it was suggested in the respective discussions. Imposing procurement obligations for early-stage technologies and/or technologies that promise a wider array of system benefits will in most cases require the payment of higher prices per kWh purchased. Keeping overall program cost limits at roughly the same level, a level that has to date proven broadly popular with state legislatures, implies that lower interim volume targets would need to be set. While the initial result, in quantities of early year renewable production, may be less dramatic, I have already made the case at length that the long-term program outcome would be greatly enhanced, by accelerating the commercialization of technologies that are currently being squeezed out of most state compliance activities, and by encouraging the commercialization of technologies better suited to replacing conventional coal than those that currently dominating most regions' RPS-driven renewables development.

While none of the four states studied presents an example of this type of policy reform, the direction in which California is heading suggests such a possibility. At the end of the California discussion in Chapter Four I asked rhetorically whether California state agencies would be prepared to accommodate the higher unit prices that would almost certainly be required to develop successfully the early-stage, multi-faceted technologies that are coming to dominate the California renewables queue. To the extent that they will do so, the next question that arises is whether or not they will be prepared to accept the higher total program costs resulting from a combination of higher than expected unit prices with the same, aggressive unit quantities and the same, aggressive schedule. It is always possible that they will take this additional step as well, but I would argue that it is not necessary to do so. If, as I have argued, the near-term acceleration of early-stage technologies leads to a rapid improvement in cost and performance, in line with historical learning curve experience, then policymakers should be comfortable with a compliance timeline that is a curve rather than a straight line, with lower targets in the early years followed by more aggressive targets in later years.

6. Allow some level of compliance through the purchase of RECs from non-local sources, while focusing local compliance activities on indigenous early-stage technologies. This is potentially the most controversial recommendation, since it will be seen to conflict with those whose primary agenda in supporting RPS is to promote local investment and/or regional energy self-sufficiency. But it does not have to be so, and indeed I would argue that if such a reform were implemented in concert with the foregoing recommendations it would produce a more sustainable local renewables industry by concentrating local investment on the highest quality and most abundant local resources.

From a climate policy perspective the logic of this approach is unassailable. As we saw in Chapter Three, high-quality pools of renewable resources are unevenly distributed across the country, such that the optimal distribution of investment in renewables development would result in the deployment a varied portfolio of technologies to exploit different pools of resources in different regions. This is often cited as one of the primary benefits of a national RPS, but there is no fundamental reason why the web of state-level programs couldn't achieve much the same end.

Experience to date across the range of RPS programs only tends to confirm this. Terrestrial wind is currently the highest profile and most commercially exploitable renewable resource using existing technology, and as a result it has been the primary focus of attention in nearly every state RPS program. Nonetheless, the RPS era has seen the great preponderance of successful wind development occurring in those states with access to the Plains wind resource, despite the fact that the prices to clear the renewables markets in those states are considerably lower than in regions that have had far less success. Even if the premium price markets can manage to break through the current barriers to land-based wind, they will never be able to produce as much electricity from land-based wind, at as low a price, and with as much predictability and firm capacity value as can be developed in the Plains states. And yet, looking for instance at the four states examined here, the current ISO-NE interconnection queue implies that the lion's share of the public resources local legislators are prepared to invest in renewables development will be spent subsidizing land-based wind production at prices considerably higher than what can be realized in Minnesota and Colorado.

This is not to say that RPS policies in regions outside of the Great Plains should not encourage some terrestrial wind development. But it seems counter-productive to spend considerably more than necessary to promote a technology with limited local prospects, in the process diverting precious public resources away from the commercialization of technologies to exploit the region's most plentiful renewable resources. As an example, allowing Connecticut LSEs to comply with some portion of their near-term RPS obligations through the purchase of RECs from Midwestern wind developers could produce a number of salutary effects. First, while development of the best of New England's terrestrial wind would no doubt still take place, the creation of a wider market for RECs from Plains wind projects should promote a more aggressive development of that vast resource than would otherwise be possible. Second, while expanding LSE compliance options should lead to increased competition and lower average REC price, the creation of a deeper, more diversified REC market should also produce an offsetting benefit by dampening REC price volatility. Third, as we saw in Chapter Three (and reinforced in the discussion around Figure 4.14), wind power produced in the region stretching from the Mississippi to the Rockies is far more likely to displace conventional coal plants than in almost any other part of the country, both because of the quantity and quality of the wind resource and because of the amount of time that coal is on the margin in the region. Fourth, because the LSEs' costs per kWh for that portion of their compliance obligation would be considerably less than it is today, more program funding would be available to promote the development of the best of New England's indigenous renewable resources. Policymakers could stipulate that a major share of compliance purchases may only be made from a specified band of early-stage technologies exploiting key regional resources, with lower interim kWh targets than currently imposed ramping up to comparably aggressive targets in the back end of the program. Adopting this approach is likely to accelerate the development of the targeted resources into major sources of regional energy supplies. At the same time, there would be a greater likelihood that the region will become a center for the commercial development of such technologies than would be the case for other technologies with brighter prospects elsewhere. In short, this reform is not only sensible climate policy, but it is also sensible economic development policy.

The objection will be raised that this conflicts with the goal of promoting regional self-reliance. Even if one accepts that such a goal is achievable in most regions of the country, there remains the question of whether the benefits of greater self-reliance would be justified by the cost. But leaving that debate for another day, if regional energy self-reliance is a policy goal, it is best promoted by the commercial development of a region's most plentiful and attractive resources. On the other hand, promoting self-reliance based on technologies and resources that are far more plentiful and far more cost-effectively deployed in other regions of the country seems at least as likely to impede local economic development as to enhance it. Virtually every region of the country is blessed with at least one indigenous renewable resource with the potential to enhance energy self-reliance without fostering an energy cost disadvantage with other regions.[110] The primary exception is the Southeast, which lacks any notable renewable resource base. Indeed, the southeastern states have largely for that reason been the greatest obstacle to the establishment of a national RPS. But in spite of this, or perhaps because of it, the states in the rest of the country need not wait for a national RPS to reap the benefits of a more wide open set of renewables policies that leverage each region's most attractive resources.

I have pointed to the potential economies in transmission infrastructure to be gained from a focus on only the most concentrated, highest-value resource pools. In order for states to fully benefit from opening their RPS programs to inter-regional compliance markets, they should consider diverting some or all of the headroom thus created to the formation of regional or multi-regional compacts for the construction of long-distance HVDC transmission infrastructure. This would allow states to access not only the RECs but also the physical production from the country's best pools of renewable resources. Regardless of the possible merits of the idea, however, such a recommendation is beyond the scope of this thesis and is thus best left for others to pursue.

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[110] See, e.g., Palmer and Burtraw, "Electricity, Renewables and Climate Change," May 2004, Table 6 and related discussion.

Each of these six recommendations throws up a number of questions that warrant further consideration. The objectives here, however, were:

1) To establish the role played by climate change risk mitigation as a primary policy goal in the establishment of state-level RPS programs;
2) To establish a context for what would constitute a meaningful contribution by the power sector to climate change risk mitigation;
3) To analyze in detail the design and experience with a selected group of state RPS programs in order to evaluate their fitness to deliver the meaningful contribution claimed for them by many of their proponents; and
4) On the basis of the findings of that analysis, to recommend a set of specific policy refinements that could significantly enhance the efficacy of these policies in this regard.

I have found that strengths and weaknesses in the design of RPS programs as weapons in the battle against climate change have begun to emerge from the vital process of experimentation that is taking place in the laboratory of the states. The great benefit of that process is the opportunity it offers for periodic reassessment and improvement. Some of the more ambitious state programs have now accumulated enough useful experience to provide the basis for the analysis presented here. That analysis points to the package of reform presented above, each supported by specific findings in this report, as promising opportunities to ensure that renewable portfolio standards can actually deliver the goods.

Appendix A

Summary of U.S. State RPS Program Features

	1st passed	Name of legislation [1]	Last revised	1st reqt.	1st target	Final date	Final target	Special funding?	Stated intent [2]	Share of retail?	Comments/concerns	Outs? [3]
AZ	1996 2000	ACC 62506 [regulatory]/AAC R14-2-1801 et seq.	2006	2006	1.25%	2025	15%	No	n/a	59%	No buy-outs, existing resources ineligible; but modest targets, long timeframe	No
CA	2002	SB 1078	2006	2003	Base	2010	20%	SBC [10], $135m/yr	1,2,3,4,5,6	64%	Solid targets/timeline, lax compliance stds.	1
CO	2004	Ballot Initiative 37/C.R.S. Title 40, Art. 2, §124	2007	2007	3%	2020	20%	No	1,2,4,5,8	94%	Solid target, no escape, but existing resources eligible	No
CT	1998	Public Act 98-28, An Act Concerning Restructuring/C.G.S. §16-245a	2007	2006	5%	2020	27%	SBC + ACP [11]	n/a	93%	Aggressive target; existing resources eligible; compliance payment option; η incl.	3 ($55)
DE	2005	SB 74/26 D.C. §351-363	2007	2007	1%	2019	20%	SBC, $3m/yr + ACP	1,2,4,6,9,10	75%	of availability	2 [6], 4
DC	2005	Bill #15-747/P.L. #15-340 (2005)/§34-1431 et seq.	n/a	2007	4.05%	2022	11.40%	ACP + loan pmts	1,2,3,4,9	100%	Very weak program: low ACPs, low target, long time	2 ($25)
HI	2004	SB2474/Act 95, SLH 2004/HRS §261-91 to -95	2006	2010	10%	2020	20% [7]	No	1,2,3	100%	Cost cap mechanism compromises an otherwise promising program	6
IL	2007	Act 095-0481 §1-75c et seq.	n/a	2008	2%	2025	25%	SBC (renewables + coal w/ccs)	1,2,4,5,10,11		Reasonably aggressive, but allows existing resources and includes price caps	5,7
IA	1983	I.C. §476.41 et seq.	n/a	1999	105MW	1999	105MW	No	11,12	74%	First-in-the-nation, simple, insignificant	No
ME	1997	Electric Industry Restructuring & Renewable Resources, Title 35-A, Part 1, Ch 32, §3210	2007	2008	30/1%	2017	30/10%	ACP receipts	3,4		1997 30% reqt seemed high but was filled w/existing resources; '07 10% reqt has market and ACP escape options	2[8],6
MD	2004	HB 1308/C. of M. §7-701 et seq.	2007	2006	3.50%	2022	9.50%	ACP receipts	2,3,4,9	73%	Weak goals/timing, low ACP ($20) for non-solar, harsh for solar but with liberal outs	4,7
MA	1997	M.G.L. Ch. 25A, §11f, ch. 164	n/a	2003	1%	2009+	4%+1pa	ACP receipts	n/a	82%	Modest goals, ACP out, pending revision	2 [8]
MN	1994	Radioactive Waste Management Facility Auth. Law/M.S. 216B.2423-2424	2007	2010	15%	2020	30% [9]	Xcel-funded $16m/yr	n/a	100%	Very strong program, but with vague but very broad powers granted to PUC to relax requirements for a variety of reasons	No, but
MT	2005	SB 415/M.C. 69-3-2001	n/a	2008	5%	2015	15%	SBC	1,2,4,5	58%	Low bar, very lax compliance requirements	2($10),7
NV	1997	SB 372/NRS 707.7801 et seq.	2005	2005	6%	2015	20%	Lock-box billing	1,2,8,11	88%	Strong, sophisticated, but w/availability out	5
NH	2007	H.B. 873/NHS 362-F	n/a	2008	4%	2025	23.80%	ACP receipts	1,2,4,5,6,7		Modest new res goal (18%), long time, ACP	2 [8]
NJ	1999	The Electric Discount and Energy Competition Act, P.L. 1999, Ch. 23/NJS 48:3-49 et seq.	2006	2004	3.25%	2021	22.50%	ACP + SBC	2	98%	Very strong program, only negative is the eligibility of existing in-state resources	2 (strict)
NM	2004	SB 43	2007	2006	5%	2020	20%	No(coop SBC only)	1,2,11	88%	Otherwise strong program undermined by very liberal compliance standards	6,7
NY	2004	PSC Case 03-E-0188 [regulatory]	n/a	2006	0.81%	2013	6.56%	SBC	1,2,3,4,7,9,13	82%	Very weak; odd, one-of-a-kind program	No
NC	2007	SB 3	n/a	2010	0.02%	2021	12.50%	No	2,4,9		Modest target, escapes, but strong η reqt.	7
OH	2008	SB 221	n/a	2009	0.25%	2025	12.50%	ACP receipts			Modest RE target w/in broad "clean" reqts.	6,7
OR	2007	S 838	n/a	2011	≤5%	2025	≤25%	SBC + ACP	4,5	100%	3 tiers of obligations, big carve-outs	2,7
PA	2004	Act 213, SB 1030/73 P.S. §1648.1 et seq.	2004	2006	5.70%	2020	18%	$55m + ACP	n/a	97%	The program's a joke; absurd eligibility, very lenient escape options, clean renew limited	2($45),5
RI	2004	H 7375/RIGL §39-26-1 et seq.	n/a	2007	3%	2019	16%	SBC + ACP	1,2,4,5,6,7	99%	Modest program, typical NEPOOL	2 [8]
TX	1999	Electric Utility Restructuring Law, SB 7/TX Util. Code §39.904	2005	2002	400MW	2015	5880MW	No	2	76%	No escape, strong response obscure the fact that the '15 oblig is v modest (~4.2%)	No
WA	2006	Ballot Initiative 937/R.C.W. 19.285, Energy Independence Act	n/a	2012	3%	2020	15%	Penalty receipts	1,2,5,11	88%	Modest targets, light penalties	2($50),7
WI	1998	1997 Act 204/W.S. §196.378-379	2006	2010	various	2016	10%	No	n/a	100%	Very modest goals, but tight compliance	No

	η incl?	REC trading?	Geographic eligibility[4]	Local bonus?	Cap or Energy	Multiple tiers? [5]	Coop/Muni included?	RTO market?	Existing resources?	Large hydro?	MSW?	CHP?	All fuel cells?
AZ	No	WREGIS	2	Yes	Energy	1	Yes/No	No	No	No	Yes	No	No
CA	No	WREGIS	3	No	Energy	No	Not really	Yes	Limited	No	Yes	No	No
CO	Legacy	Yes	5	Yes	Energy	1,3,14	Yes	No	Yes	No	No	Yes	Yes
CT	Yes	NEPOOL-GIS, NYS, PJM-E	4 (ISO NE)	No	Energy	5, 6	No	Yes	Mixed	No	Limited	Yes	Yes
DE	No	PJM-EIS	4 (PJM)	Yes	Energy	1,3,14	Not really	Yes	post-1997	No	No	No	No
DC	No	PJM	4 (PJM)	No	Energy	6	No	Yes	Yes	Limited	Limited	No	No
HI	Yes	No	1	Yes	Energy	5 (limit)	Yes	No	Yes	No	Yes	Yes	No
IL	~10%	Yes	1	Yes	Energy	7 (≥75%)	Yes	Yes	Yes	No	No	Yes	No
IA	No	Yes	1	Yes	Cap	No	No	No	No	No	Yes	No	No
ME	No	NEPOOL-GIS	4 (ISO NE)	No	Energy	Not really	No	Yes	Yes/No	<100MW	Yes/No	Yes/No	Yes
MD	No	Yes	4 (PJM)	No	Energy	3,6	No	Yes	Sunsets	Sunsets	Sunsets	No	No
MA	No	ISO-NE	4 (ISO NE)	No		No	No	Yes	No	No	No	No	No
MN	No	Yes	3	No	Energy	7 (≥83%)	Yes	Yes	Yes	<100MW	Yes	No	Yes
MT	No	WREGIS	3	Yes	Energy	8	No	Yes	Sm hydro	No	No	No	No
NV	≤25%	Yes	2	Yes	Energy	1,3(≥5%),5	No	No	Y exc DSM	No	Yes	Yes	No
NH	No	NEPOOL-GIS	4 (ISO NE)	No	Energy	3,9(31.5%)	Yes	Yes	Limited	No	No	No	No
NJ	No	PJM-EIS	4 (PJM)	No	Energy	3(≥10%),6	No	Yes	In-state only	No	No	No	No
NM	No	WREGIS	2	Yes	Energy	1,3,7,10,11	Yes	No	Limited	New (?)	No	No	No
NY	No	No	3	Yes	Energy	1,13	No	Yes	No	No	No	No	Yes
NC	≤40%	Yes	3	≥75%	Energy	3,5,12	Yes	Yes/no	No	No	No	Yes	No
OH	No	In theory	1(50%)/3	No	Energy	3	No	Yes	post-1998	Yes	No	Yes	Yes
OR	Legacy	Limited	4 (WECC)	No	Energy	No	Yes	No	Limited	No	No	No	No
PA	Yes	No	4	Yes	Energy	3,6(<50%)	No	Yes	Yes	Yes	Yes	Yes	Yes
RI	No	NEPOOL-GIS	4	No	Energy	No	No	Yes	Very ltd.	No	No	No	No
TX	No	Yes (w/in TX)	1	Yes	Cap	10% non-7	Yes	Yes	880MW	Yes	No	No	No
WA	Sort of	Yes	2,4 (PNW)	Yes	Energy	No	Yes	No	No	No	No	No	No
WI	No	Only new res.	3	No	Energy	No	Yes	Yes/no	Yes	<60MW	No	No	No

	[1] Where I have not listed a name for the legislation, there either was none or it was some variation on "a renewable portfolio act;" I've listed names only where they provide some valuable insight	
	[2] Stated intended benefits: 1. Economic development/employment; 2. Improved air quality/environment; 3. Energy security; 4 Diversity/reliability/in-state resources; 5. Lower prices/price stability;	
	6 Public health; 7. Climate change; 8. Conserve water; 9. Lower cost/create mkt for renew; 10. T&D benefits; 11. Conserve non-renew; 12. Improve the η of non-renew energy; 13. Social equity	
	[3] Escape options: 1. Prices above approved mkt plus funds available from SBF; 2. Retailer compliance payments (per MWh); 3. Wholesale supplier compliance payments (per MWh); 4. Large	
	industrial loads; 5. Insufficient availability; 6. Unavailable at "reasonable" (e.g., avoided) cost; 7. Aggregate retail rate impact (e.g. must be less than 1%)	
	[4] Geographic eligibility: 1. In-state resources only; 2. In-state or physically interconnected; 3. Deliverability to state; 4. Deliverability to region or control area; 5. No restrictions	
	[5] Separate set-asides: 1. Distributed generation; 2. Residential installations; 3. Solar; 4. CHP; 5. Efficiency/Conservation; 6. "Clean" renewables (e.g., not hydro, not MSW); 7. Wind;	
	8. Community-based; 9. Existing resources; 10. Geothermal; 11. biomass; 12. Livestock waste; 13. Voluntary green energy sales; 14. Premiums paid for in-state resources	
	[6] DE's compliance payments escalate from a very low level ($25/MWH) for the first year of non-compliance, to increasingly onerous levels ($80 in the third year)	
	[7] The State of Hawaii and the DOE have entered into a non-binding MOU that Hawaii will target 70% from renewables by 2030	
	[8] ME, MA, NH and RI ACPs each start at $57.12/MWh in 2007 and escalate annually with inflation	
	[9] Data shown applies only to Xcel; MN established a separate, less stringent schedule for the other two IOUs and the coops, but Xcel supplies over 2/3 of all retail electricity in the state	
	[10] SBC = System Benefit Charge; the specific name varies, but it refers to a charge added to customer bills to fund a specified public benefit, such as development of renewables	
	[11] ACP = Alternative Compliance Payment; refers to the amount the retail electricity provider can pay to meet the RPS obligation without actually supplying energy from a renewable source	

Appendix B

Description of Bulk Power Grid Ancillary Services

The following pages have been excerpted from the North American Electric Reliability Council's "Reference Document: Interconnected Operations Services," prepared by the Interconnected Operations Services Subcommittee, Draft 2.2, 12 March 2001, pp 1-11.

The full document can be accessed online at http://www.nerc.com/docs/pc/IOSrefdoc.pdf.

Section 1. Overview

1.1 Scope and Purpose

This Interconnected Operations Services (IOS) Reference Document was developed by the Interconnected Operations Services Subcommittee in response to a directive from the NERC Operating Committee in November 2000. This IOS Reference Document:

- Defines and describes the characteristics of INTERCONNECTED OPERATIONS SERVICES (IOS)
- Describes the necessity of IOS as 'reliability building blocks' provided by generators (and sometimes loads) for the purpose of maintaining BULK ELECTRIC SYSTEM reliability.
- Explains the relationship between OPERATING AUTHORITIES and IOS SUPPLIERS in the provision of IOS.
- Provides sample standards that could be used to define the possible obligations of OPERATING AUTHORITIES and IOS SUPPLIERS in the provision of IOS
- Describes sample methods for performance measurement in the provision of IOS
- Describes sample methods for the certification of IOS RESOURCES.

1.2 Definition of Terms

The definitions of IOS described in this IOS Reference Document are as follows:

REGULATION. The provision of generation and load response capability, including capacity, energy, and MANEUVERABILITY, that responds to automatic controls issued by the OPERATING AUTHORITY.

LOAD FOLLOWING. The provision of generation and load response capability, including capacity, energy, and MANEUVERABILITY, that is dispatched within a scheduling period by the OPERATING AUTHORITY.

CONTINGENCY RESERVE. The provision of capacity deployed by the OPERATING AUTHORITY to reduce AREA CONTROL ERROR to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Council contingency requirements. CONTINGENCY RESERVES are composed of CONTINGENCY RESERVE–SPINNING and CONTINGENCY RESERVE–SUPPLEMENTAL.

REACTIVE POWER SUPPLY FROM GENERATION SOURCES. The provision of reactive capacity, reactive energy, and responsiveness from IOS RESOURCES, available to control voltages and support operation of the BULK ELECTRIC SYSTEM.

FREQUENCY RESPONSE. The provision of capacity from IOS RESOURCES that deploys automatically to stabilize frequency following a significant and sustained frequency deviation on the INTERCONNECTION.

SYSTEM BLACK START CAPABILITY. The provision of generating equipment that, following a system blackout, is able to: 1) start without an outside electrical supply; and 2) energize a defined portion of the transmission system. SYSTEM BLACK START CAPABILITY serves to provide an initial startup supply source for other system capacity as one part of a broader restoration process to re-energize the transmission system.

The six IOS above are a core set of IOS, but are not necessarily an exhaustive list of IOS. Other BULK ELECTRIC SYSTEM reliability services provided by generators or loads could potentially be defined as IOS.

The following related terms are used in this IOS Reference Document:

BULK ELECTRIC SYSTEM. The aggregate of electric generating plants, transmission lines, and related equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission facilities are interconnected.

CONTINGENCY RESERVE – SPINNING. The portion of CONTINGENCY RESERVE provided from IOS RESOURCES consisting of:

- Generation synchronized to the system and fully available to serve load within T_{ccs} minutes of the contingency event; or
- Load fully removable from the system within T_{ccs} minutes of the contingency event.

CONTINGENCY RESERVE – SUPPLEMENTAL. The portion of CONTINGENCY RESERVE provided from IOS RESOURCES consisting of:

- Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within T_{ccs} minutes of the contingency event; or
- Load fully removable from the system within T_{ccs} minutes of the contingency event.

CONTROL AREA. An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation directly to maintain its interchange schedule with other CONTROL AREAS and contributes to frequency regulation of the INTERCONNECTION.

DEPLOY. To authorize the present and future status and loading of resources. Variations of the word used in this IOS Reference Document include DEPLOYMENT and DEPLOYED.

DYNAMIC TRANSFER. The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one CONTROL AREA into another.

INTERCONNECTED OPERATIONS SERVICE (IOS). A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected BULK ELECTRIC SYSTEMS.

INTERCONNECTION. Any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.

IOS SUPPLIER. An entity that offers to provide, or provides, one or more IOS.

IOS RESOURCE. The physical element(s) of the electric system which is (are) capable of providing an IOS. Examples of an IOS RESOURCE may include one or more generating units, or a portion thereof, and controllable loads.

MANEUVERABILITY. The ability of an IOS RESOURCE to change its real- or reactive-power output over time. MANEUVERABILITY is characterized by the ramp rate (e.g., MW/minute) of the IOS RESOURCE and, for REGULATION, its acceleration rate (e.g., MW/minute^2).

OPERATING AUTHORITY. An entity that:

1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives – generation/demand balance, transmission security, and/or emergency preparedness; and
2. Is accountable to NERC and one or more Regional Reliability Councils for complying with NERC and Regional Policies; and
3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

OPERATING RESERVE. That capability above firm system demand required to provide REGULATION, load forecasting error, equipment forced and scheduled outages, and other capacity requirements.

1.3 IOS Are Building Blocks of Reliability

IOS are the elemental 'reliability building blocks' from generation (and sometimes load) necessary to maintain BULK ELECTRIC SYSTEM reliability. These 'reliability building blocks' have historically been provided by integrated utilities, configured as CONTROL AREAS, using internally owned resources. In contrast, in many areas of North American today, the introduction of competitive electricity markets has resulted in restructuring to separate transmission and generation functions, as well as other traditionally integrated functions. Increasingly, some of the entities responsible for reliability of BULK ELECTRIC SYSTEMS do not own all of the resources necessary for reliability but must obtain these resources, in particular generator-provided services, through a market process or through commercial arrangements.

This IOS Reference Document identifies six basic reliability services from generation (and sometimes load) that must be provided, regardless of regulatory environment, market structure, or organizational framework, to ensure BULK ELECTRIC SYSTEM reliability. These functions are the raw materials that OPERATING AUTHORITIES must assemble for deployment on a regional and interconnection basis to achieve BULK ELECTRIC SYSTEM reliability.

The IOS presented in this paper were chosen as such because their unique physical characteristics lend themselves to separate measurement methods and reliability criteria. These IOS can be combined in various ways to support commercially relationships – simply because a function is an IOS should not naturally lead to the conclusion that the marketplace should buy and sell that specific IOS separately.

Figure 1 illustrates the relationship between the IOS and reliability objectives. Some of the 'reliability building blocks' from generation are used to achieve generation and load balance, which is fundamental to maintaining a stable BULK ELECTRIC SYSTEM and INTERCONNECTION frequency within defined limits. These generation and demand balancing IOS are REGULATION, LOAD FOLLOWING, and CONTINGENCY RESERVE.

Other IOS are used to maintain a secure transmission network. REACTIVE SUPPLY FROM GENERATION SOURCES and FREQUENCY RESPONSE are examples of IOS for system security.

Finally, IOS can be used for emergency preparedness and restoration, such as the IOS SYSTEM BLACK START CAPABILITY.

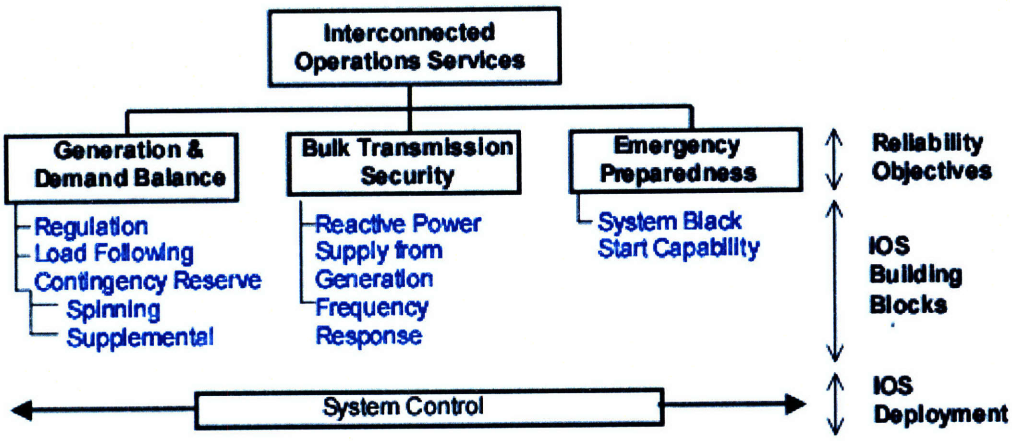


Figure 1 – IOS as Reliability Building Blocks

Section 2. Description of IOS

2.1 Generation and Demand Balancing IOS

Control Area Obligations

In their simplest form, generation and demand balancing IOS are capacity and the ability to raise and lower output or demand in response to control signals or instructions under normal and post-contingency conditions. Generators, controllable loads, or storage devices may provide these capabilities. Energy may also be delivered by a resource as a byproduct of providing the balancing capability.

The OPERATING AUTHORITY aggregates and deploys resources providing these services to meet the CONTROL AREA generation and demand balancing obligations, defined by control performance standards in NERC Operating Policy 1. These resources may supply a diverse mix of IOS, since balancing occurs in different time horizons and under both pre- and post-contingency conditions.

Section E of NERC Operating Policy 1 requires that a CONTROL AREA meet the following criteria:

- **Control Performance Standard 1 (CPS1).** Over a year, the average of the clock-minute averages of a CONTROL AREA's ACE divided by –10B (B is the CONTROL AREA frequency bias) times the corresponding clock-minute averages of the INTERCONNECTION'S frequency error shall be less than a specific limit;
- **Control Performance Standard 2 (CPS2).** The ten-minute average ACE must be within a specific limit (L_{10}) at least 90% of the time within each month; and
- **Disturbance Control Standard (DCS).** For reportable disturbances, the ACE must return either to zero or to its pre-disturbance level within a specified disturbance recovery time (defined in IOS Reference Document as T_{DCS}[1] minutes) following the start of a disturbance.

Operating Reserves

Policy 1 also requires a CONTROL AREA to provide a level of OPERATING RESERVES sufficient to account for such factors as forecasting errors, generation and transmission equipment unavailability, system equipment forced outage rates, maintenance schedules, regulating requirements, and load diversity. Policy 1 states that OPERATING RESERVES consist of REGULATION and CONTINGENCY RESERVES, and that OPERATING RESERVES can be used for the reasons listed above. OPERATING RESERVES may be comprised of: (1) available capacity from resources providing REGULATION and LOAD FOLLOWING services, (2) CONTINGENCY RESERVES, (3) available FREQUENCY RESPONSE capacity, and (4) load-serving reserves or backup supply.

Load-serving reserves are the responsibility of a LOAD-SERVING ENTITY. They are designed to account for errors in forecasting, anticipated and unanticipated generation/resource and transmission outages, and maintenance schedules that impact the delivery of energy to the LOAD-SERVING ENTITY. These reserves support the reliability of individual LOAD-SERVING ENTITIES, rather than the interconnected BULK ELECTRIC SYSTEMS. As a result, they are not an IOS and are not addressed in this IOS Reference Document.

1 The disturbance recovery time is defined in Policy 10 as a variable T_{DCS} to recognize that the specified recovery time stated in Policy 1 may change.

Overview of Generation and Demand Balancing IOS

Table 1 summarizes the IOS necessary to provide generation and demand balancing services and shows the reliability objective associated with each.

Table 1 – Overview of Generation and Demand Balancing Resources

IOS		Reliability Objective	
		Normal operating state	**Post-contingency**
REGULATION		Follow minute-to-minute differences between generation and demand.	
LOAD FOLLOWING		Follow generation and demand imbalances occurring within a scheduling period.	
FREQUENCY RESPONSE[2]			Arrest deviation from scheduled frequency.
CONTINGENCY RESERVES	SPINNING		Restore generation and demand balance, usually after a contingency.
	SUPPLEMENTAL		Restore generation and demand balance after a contingency

Figure 2 compares the use and deployment period of the load and generation balancing services.

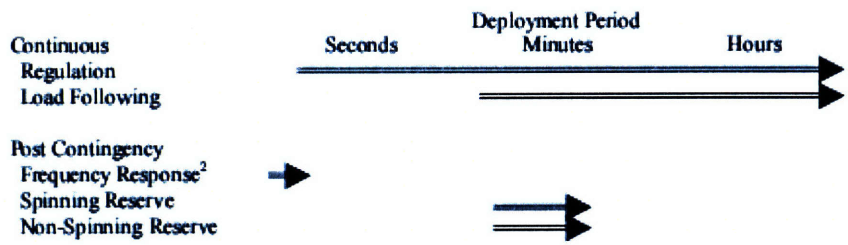


Figure 2 – Deployment Period for Load and Generation Balancing Services

[2] In this IOS Reference Document, FREQUENCY RESPONSE is treated as an INTERCONNECTION security function, rather than a generation and demand balancing function. It is shown in Table 2 and Figure 2 only for the purpose of showing the deployment times relative to those of the generation and demand balancing IOS.

Description of REGULATION AND LOAD FOLLOWING

REGULATION and LOAD FOLLOWING require similar capabilities and are addressed together in this IOS Reference Document. A major difference is that LOAD FOLLOWING resources are deployed over a longer time horizon and over a generally wider range of output than resources providing REGULATION. The LOAD FOLLOWING burden imposed by individual loads tends to be highly correlated while the REGULATION burden tends to be largely uncorrelated.

REGULATION provides for generation and demand balancing in a time frame of minutes. The CONTROL AREA continuously determines the required changes (up and down) to the real power output of regulating resources to correct ACE to within CPS bounds.

LOAD FOLLOWING addresses longer-term changes in demand within scheduling periods. LOAD FOLLOWING resources, under automatic or manual control, chase (and to an extent anticipate) the longer term variations within a scheduling period. Figure 3 distinguishes the time horizons of REGULATION AND LOAD FOLLOWING IOS.

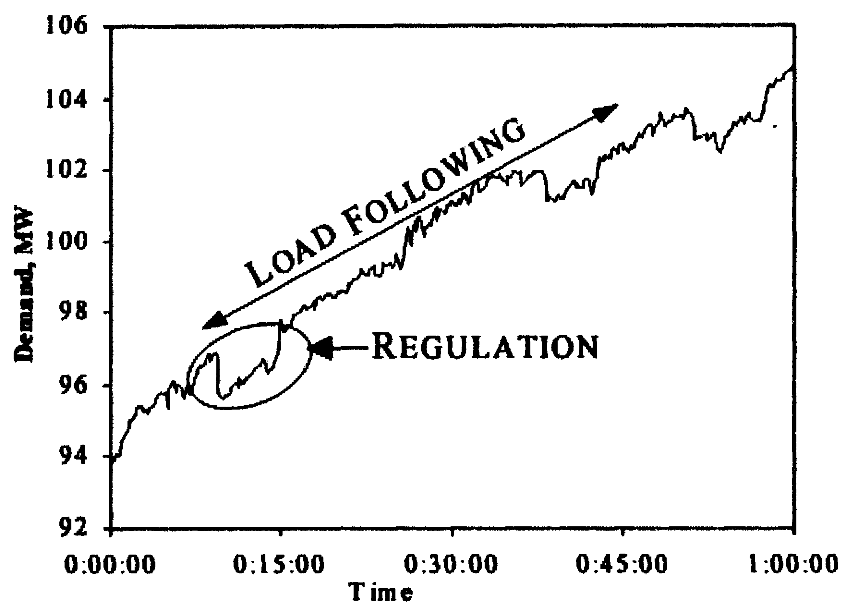


Figure 3 – REGULATION and LOAD FOLLOWING

Description of Contingency Reserve

In addition to committing and controlling resources to ensure continuous balance between generation and demand, NERC Policy 1 requires an OPERATING AUTHORITY to return generation and demand to a balanced state (or at least to the same level of imbalance as the pre-contingency state) within ten minutes following a contingency. CONTINGENCY RESERVE provides standby capability to meet this requirement.

Following a contingency, FREQUENCY RESPONSE will immediately begin to arrest the frequency deviation across the INTERCONNECTION. Within the affected CONTROL AREA, resources providing REGULATION will begin to adjust outputs within seconds in response to signals from the CONTROL AREA's AGC. In addition, the OPERATING AUTHORITY may deploy, if necessary, CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL. These reserves are used to restore the pre-contingency generation and demand balance, FREQUENCY RESPONSE capacity, and REGULATION capacity. In all cases, the CONTINGENCY RESERVE must be sufficiently activated so that within T_{DCS} (or less) the pre-contingency generation/demand balance and FREQUENCY RESPONSE capacity are restored. Delivery of these reserves must be sustainable for the minimum reserve deployment period.

The time line below graphically shows the operating relationship between FREQUENCY RESPONSE, CONTINGENCY RESERVE and an individual LOAD-SERVING ENTITY'S reserve or backup supply.

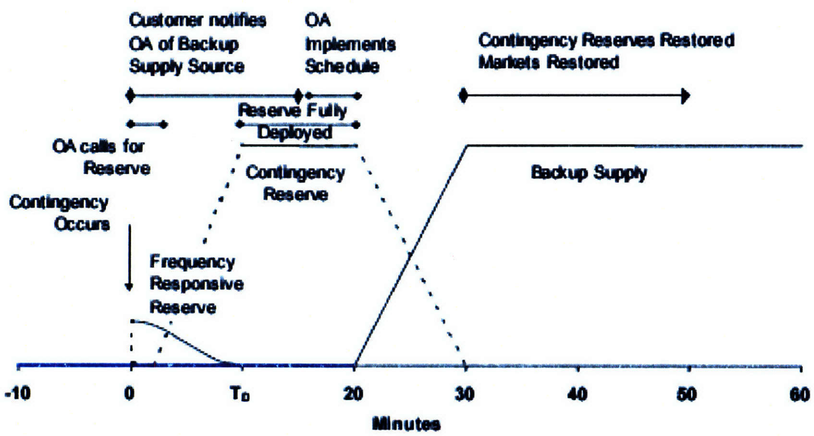


Figure 4 – Operating Reserve Timeline

Coordinated post-contingency operating plans are necessary to ensure CONTROL AREAS are able to deploy and restore CONTINGENCY RESERVE in a timely manner. These plans must outline the reserve obligations of CONTROL AREAS, OPERATING AUTHORITIES, and LOAD-SERVING ENTITIES. These arrangements should delineate when and how schedules will be curtailed, which CONTROL AREA or OPERATING AUTHORITY is responsible to deploy CONTINGENCY RESERVE, and when and how replacement schedules, if any, will be implemented.

Transmission Losses

Although the previous discussion focused on the mismatch between generation and demand due to randomly varying loads as well as control and scheduling errors, the losses associated with use of the transmission system must also be recognized. Real power losses are actually another type of demand and, if not compensated for, can cause a deficiency in reserves and system frequency degradation, thus threatening system reliability.

All electrical flows impact system losses. This includes transmission customer uses, native load uses, parallel flows, and other uses. All scheduled users of the transmission system are responsible for providing losses associated with their use of the system. The CONTROL AREA is responsible to balance total system demand, including losses.

The difference in real-time between actual system losses and resources scheduled to supply system losses is provided by REGULATION and LOAD FOLLOWING. For this reason, the IOS Reference Document does not treat losses as a separate IOS. Instead losses are handled in the market, through scheduling processes, in accordance with transmission tariffs and contracts. Any differences between scheduled and actual losses are addressed through REGULATION and LOAD FOLLOWING, or possibly through ENERGY IMBALANCE measures, if a transmission customer is delivering energy to compensate for losses.

Energy Imbalance

Energy and scheduling imbalances are measures of how well a transmission customer is meeting its balancing obligations at a specific point or points on the system. Such imbalances are calculated as the difference between actual and scheduled energy at a point of receipt or point of delivery over a scheduling period.

The provision of generation and demand balancing in a pre-contingency state for a transmission customer is done through the use of scheduled delivery of resources to serve the transmission customer's load, along with the provision of REGULATION and LOAD FOLLOWING.

Although existing transmission tariffs may treat energy imbalance as a service, the IOS Reference Document considers energy imbalance, including scheduling imbalances with generators, as energy mismatch measurements. Energy imbalance is a measure of historical performance averaged over a time period. IOS are *capabilities* that are deployed in the present & future to meet reliability objectives. Both energy imbalance and IOS can be measured, and can have reliability criteria and economic terms. However, energy imbalance only describes past performance, while IOS are services that may be deployed now and in the future for reliability purposes.

2.2 Bulk Electric System Security IOS

System security refers to the ability of BULK ELECTRIC SYSTEMS to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Two fundamental capabilities needed to maintain BULK ELECTRIC SYSTEM security are the ability to[3]:

1. Maintain system voltages within limits to maintain INTERCONNECTION reliability under normal and emergency conditions. This is accomplished by coordinating the following minimum components of transmission system voltage control:
   - Load power factor correction;
   - Transmission reactive compensation (capacitors, reactors, static var compensators, etc.);

3 Refer to Operating Policy 2 B and Planning Policy I D for Control Area standards related to voltage control.

- Generator interconnection requirements with the transmission provider (relay and control, power factor, voltage, etc.);
- CONTROL AREA coordination; and
- REACTIVE POWER SUPPLY FROM GENERATION SOURCES (IOS)

2. Automatically and rapidly arrest frequency excursions due to contingencies on BULK ELECTRIC SYSTEMS. This capability constitutes the FREQUENCY RESPONSE IOS.

Reactive Power Supply from Generation Sources

REACTIVE POWER SUPPLY FROM GENERATION SOURCES comprises the following essential capabilities from generators (and possibly some loads): reactive capacity, reactive energy, dynamic and fast-acting responsiveness through the provision and operation of an Automatic Voltage Regulator (AVR), and the ability to follow a voltage schedule. REACTIVE POWER SUPPLY FROM GENERATION SOURCES is used by the OPERATING AUTHORITY to maintain system voltages within established limits, under both pre- and post-contingency conditions, and thereby avoid voltage instability or system collapse.

Interconnection Requirements - Reactive

In addition to the use of this generation-based IOS, the OPERATING AUTHORITY maintains transmission security through the coordinated use of static reactive supply devices throughout the system, and may develop and impose reactive criteria on LOAD-SERVING ENTITIES. Requirements for the non-generator components are addressed in other NERC, Regional Reliability Council, and local standards and interconnection requirements.

As an example, minimum interconnection requirements include NERC Planning Standard III C S1, which states: "All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator." The intent is that there be no supplementary excitation control (reactive power or power factor control) that limits emergency reactive power output to less than reactive power capability.

Generator power factor and voltage regulation standards can be a condition of interconnection to satisfy area or local system voltage conditions. Voltage regulating capacity and capabilities that are provided to meet minimum interconnection requirements do not imply that those generators are qualified IOS SUPPLIERS.

Frequency Response

FREQUENCY RESPONSE is the capability to change, with no manual intervention, an IOS RESOURCE's real power output in direct response to a deviation from scheduled frequency.

The need for FREQUENCY RESPONSE extends beyond the boundaries of a CONTROL AREA to meet the reliability needs of the INTERCONNECTION. Hence it is aligned with a transmission security objective rather than the load and generation balancing objective. FREQUENCY RESPONSE is not required to meet the CONTROL AREA needs related to DCS. CONTINGENCY RESERVE is used for that purpose.

FREQUENCY RESPONSE is achieved through an immediate governor response to a significant change in INTERCONNECTION frequency. The cumulative effect of the governor response within the INTERCONNECTION provides an INTERCONNECTION-wide response to a frequency deviation (i.e., all

CONTROL AREAS will "see" a frequency change and contribute their frequency response in proportion to the frequency change). This governor action arrests the frequency deviation and allows other slower responding control actions to effectively restore system frequency and affected CONTROL AREA's ACE.

2.3 Emergency Preparedness

Emergency preparedness refers to the measures taken to prepare for the rare occasions when all or a major portion of a BULK ELECTRIC SYSTEM or INTERCONNECTION is forced out of service. When this occurs, the capability must exist to restore normal operations as quickly as possible. This is called system restoration. System restoration requires:

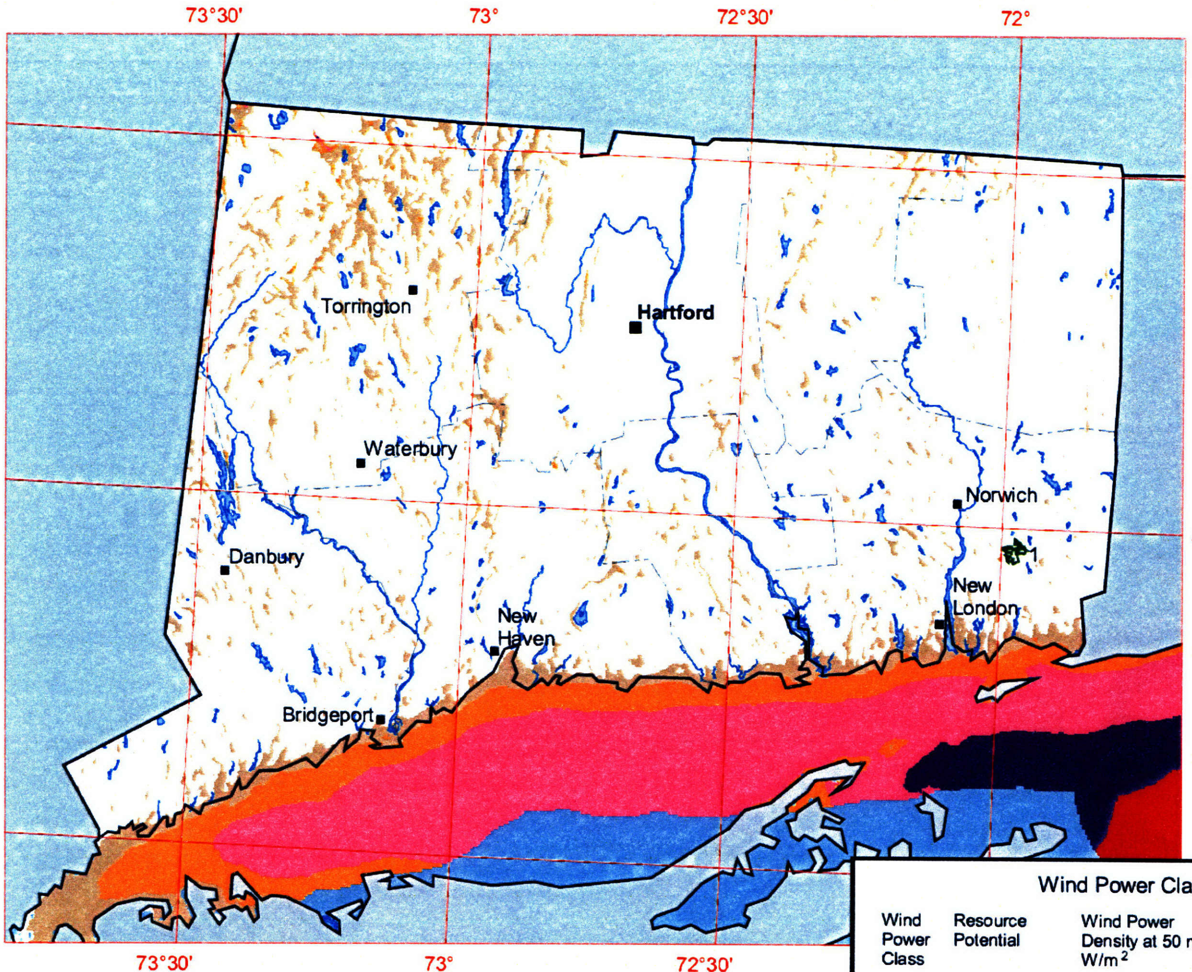
- SYSTEM BLACK START CAPABILITY – Generating units that can start themselves without an external electricity source and can then energize transmission lines and restart other generating units;
- Non-black start generating units that can quickly return to service after offsite power has been restored to the station and can then participate in further restoration efforts;
- Transmission system equipment, controls, and communications (including ones that can operate without grid power), and field personnel to monitor and restore the electrical system after a blackout;
- System control equipment and communications (including ones that can operate without grid power); and
- Personnel to plan for and direct the restoration operations after such a blackout.

The IOS Reference Document deals only with the first of these five aspects of system restoration, as it is a critical reliability services that must be provided by generation resources. Other NERC Planning and Operating Standards address other elements of this service. NERC Planning Standards 4A, System Black Start Capability, state that: "Following the complete loss of system generation (blackout), it will be necessary to establish initial generation that can supply a source of electric power to other system generation and begin system restoration." These initiating generators are referred to as SYSTEM BLACK START CAPABILITY.

NERC Operating Policy 6 D, Operations Planning – System Restoration, requires: Each system, CONTROL AREA, and Region shall develop and periodically update a logical plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of the system. For further reference, see Policy 5 E, Emergency Operations-System Restoration.

Appendix C

Maps of New England's Wind Potential



Connecticut

50 m Wind Power

The annual wind power estimates for this map were produced by TrueWind Solutions using their Mesomap system and historical weather data. This work was commisioned by the Massachusetts Technology Collaborative, in conjunction with the Connecticut Clean Energy Fund and Northeast Utilities, and the results have been validated by NREL.

Indian Reservation

1 Mashantucket Pequot

S. Department of Energy
ational Renewable Energy Laboratory

NREL

20 0 20 40 60 Kilometers

10 0 10 20 30 40 Miles

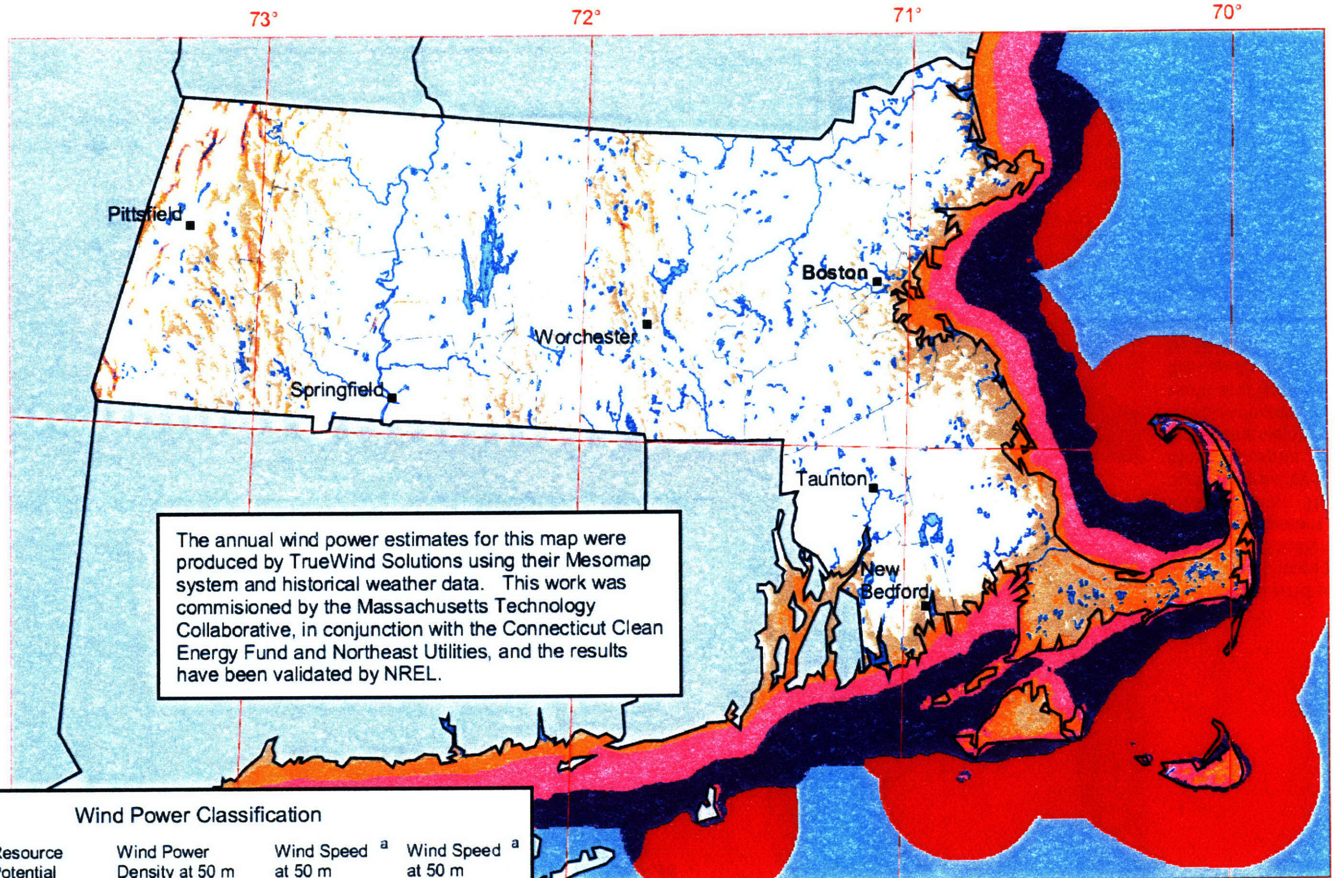
-FEB-2007 1.1.3

Wind Power Classification

Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m^2	Wind Speed [a] at 50 m m/s	Wind Speed [a] at 50 m mph
1	Poor	0 - 200	0.0 - 5.6	0.0 - 12.5
2	Marginal	200 - 300	5.6 - 6.4	12.5 - 14.3
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	> 800	> 8.8	> 19.7

[a] Wind speeds are based on a Weibull k value of 2.0

Massachusetts - 50 m Wind Power



Wind Power Classification

Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m²	Wind Speed [a] at 50 m m/s	Wind Speed [a] at 50 m mph
1	Poor	0 - 200	0.0 - 5.6	0.0 - 12.5
2	Marginal	200 - 300	5.6 - 6.4	12.5 - 14.3
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	> 800	> 8.8	> 19.7

[a] Wind speeds are based on a Weibull k value of 2.0

U.S. Department of Energy
National Renewable Energy Laboratory

NREL

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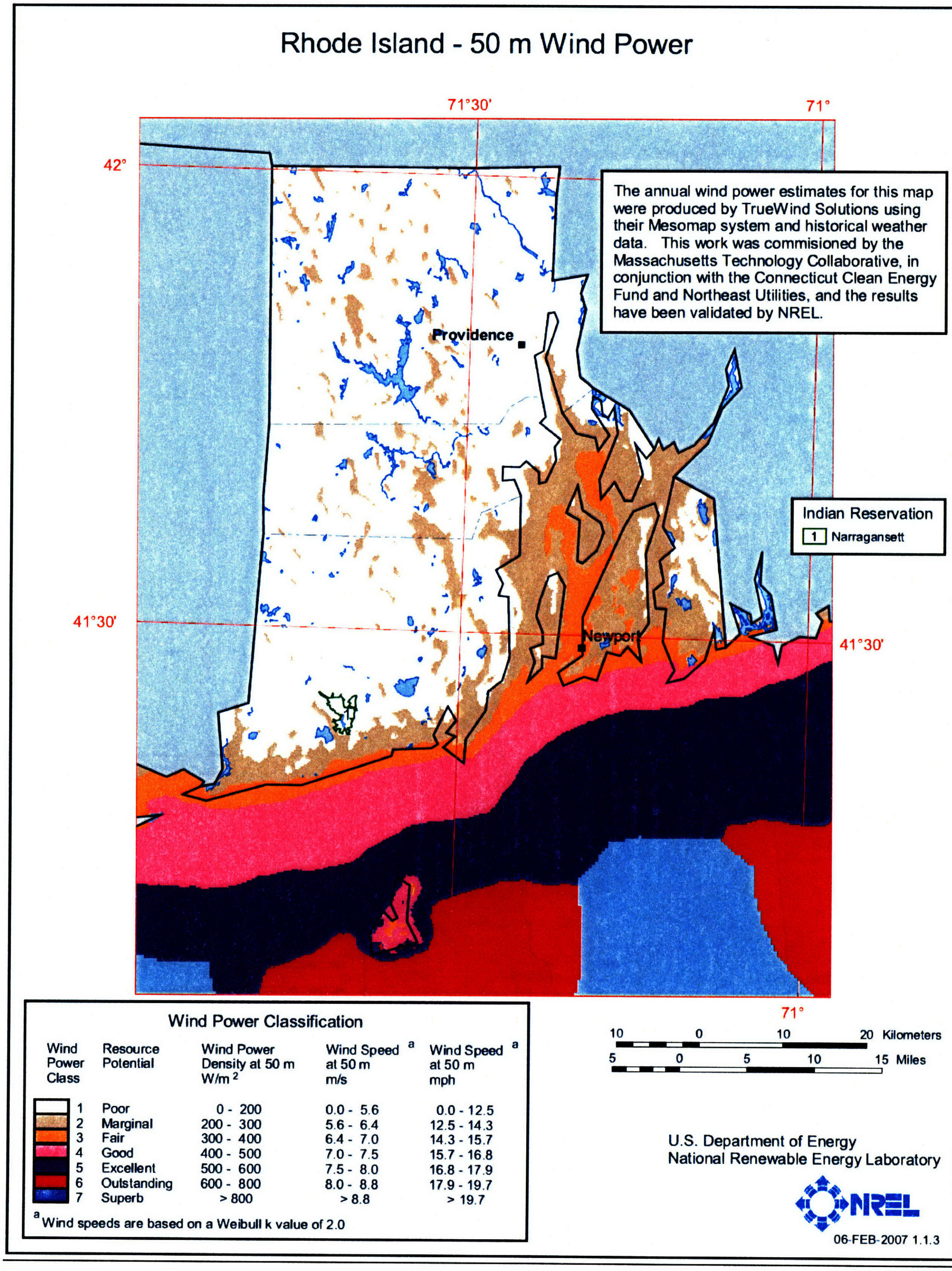
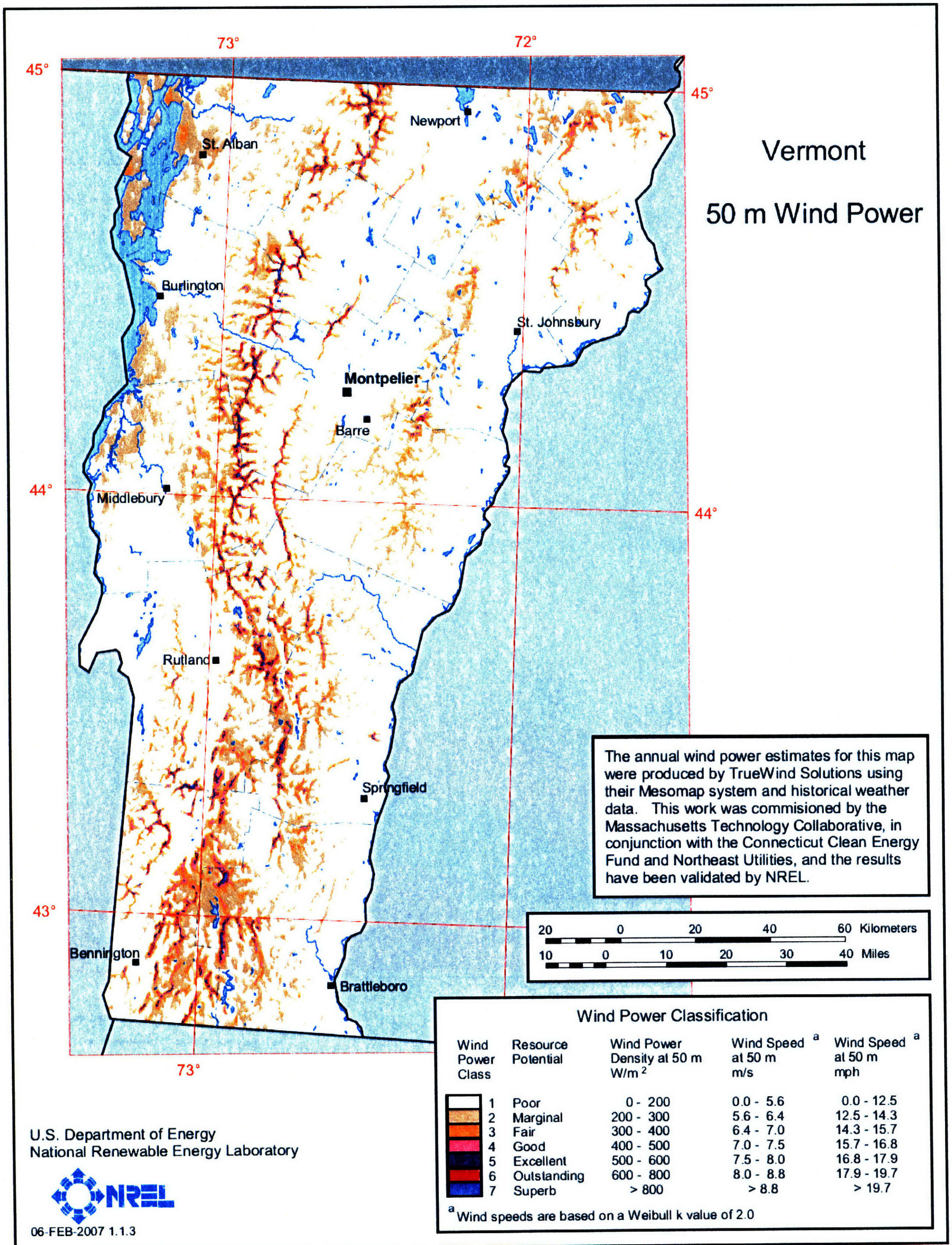
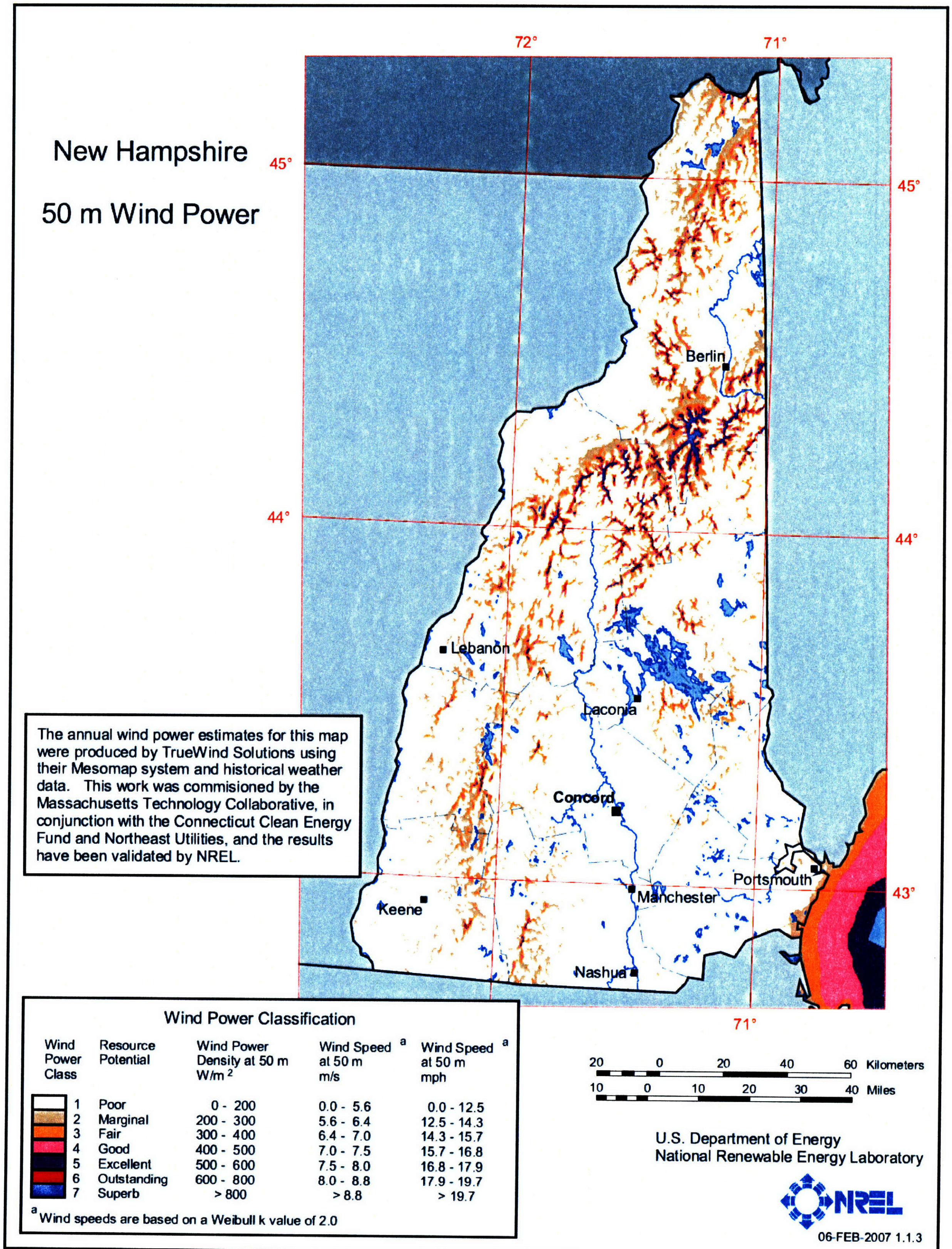


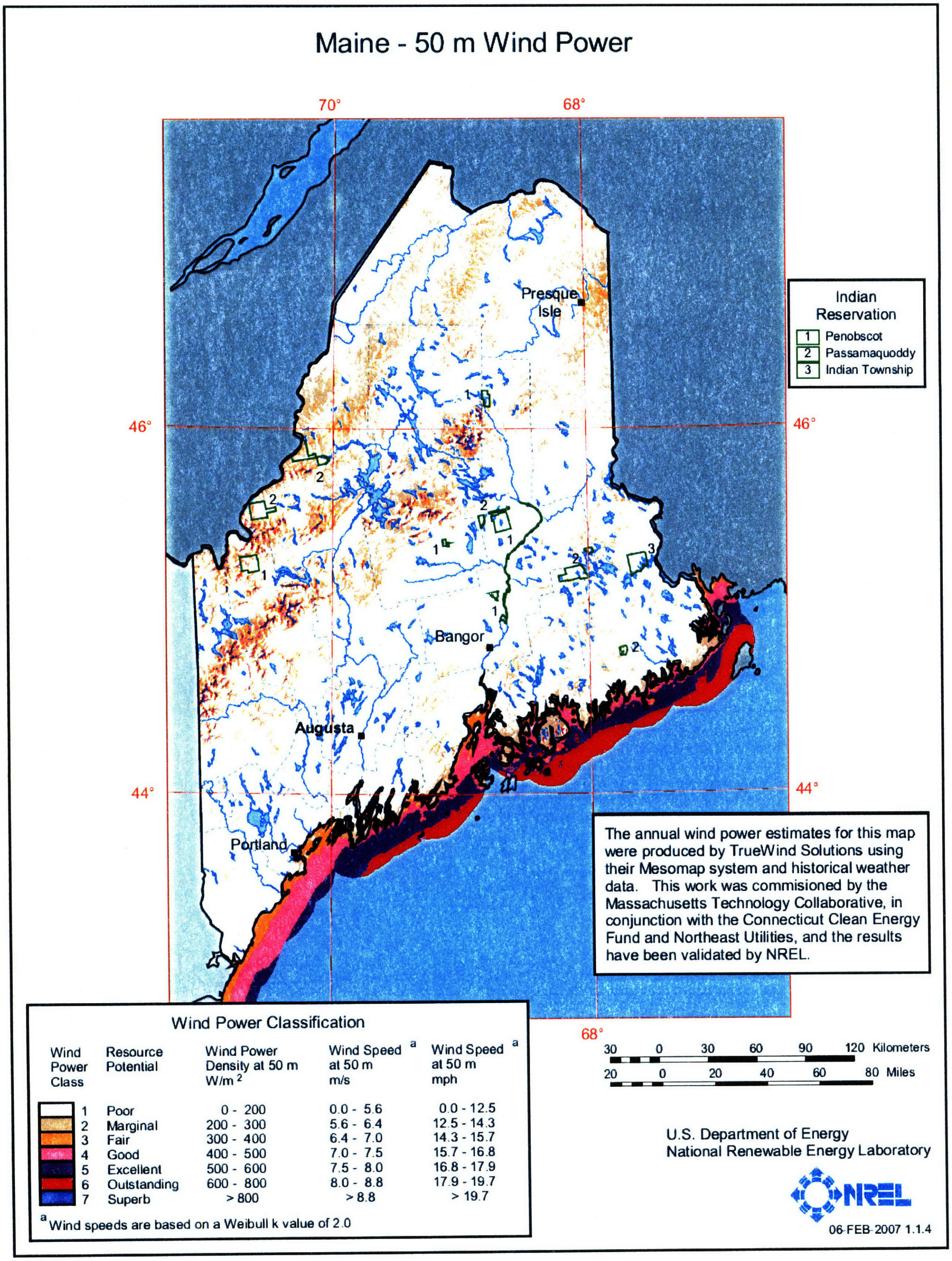
Source: U.S. Department of Energy, National Renewable Energy Laboratory



Source: U.S. Department of Energy, National Renewable Energy Laboratory



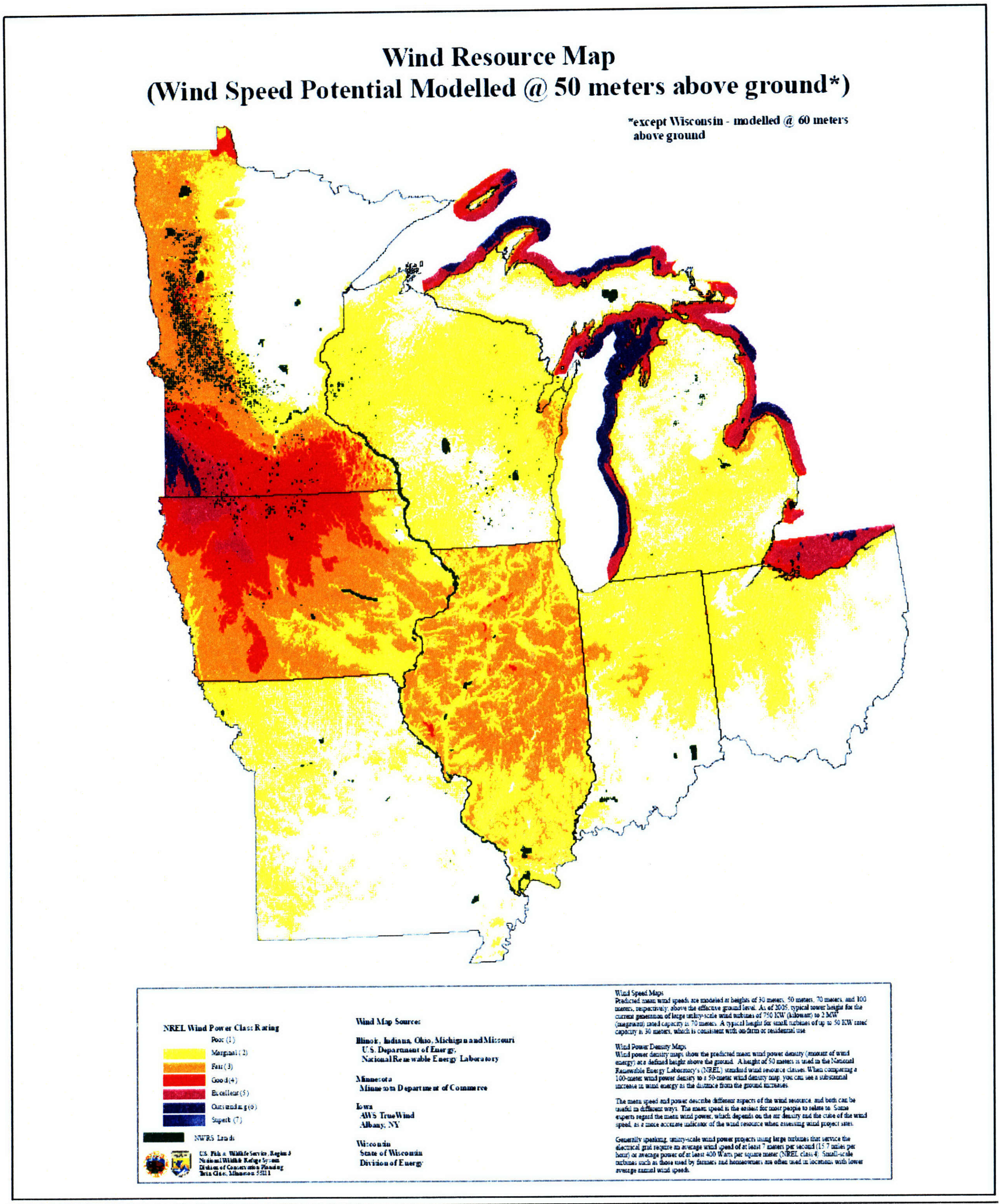
Source: U.S. Department of Energy, National Renewable Energy Laboratory



Source: U.S. Department of Energy, National Renewable Energy Laboratory

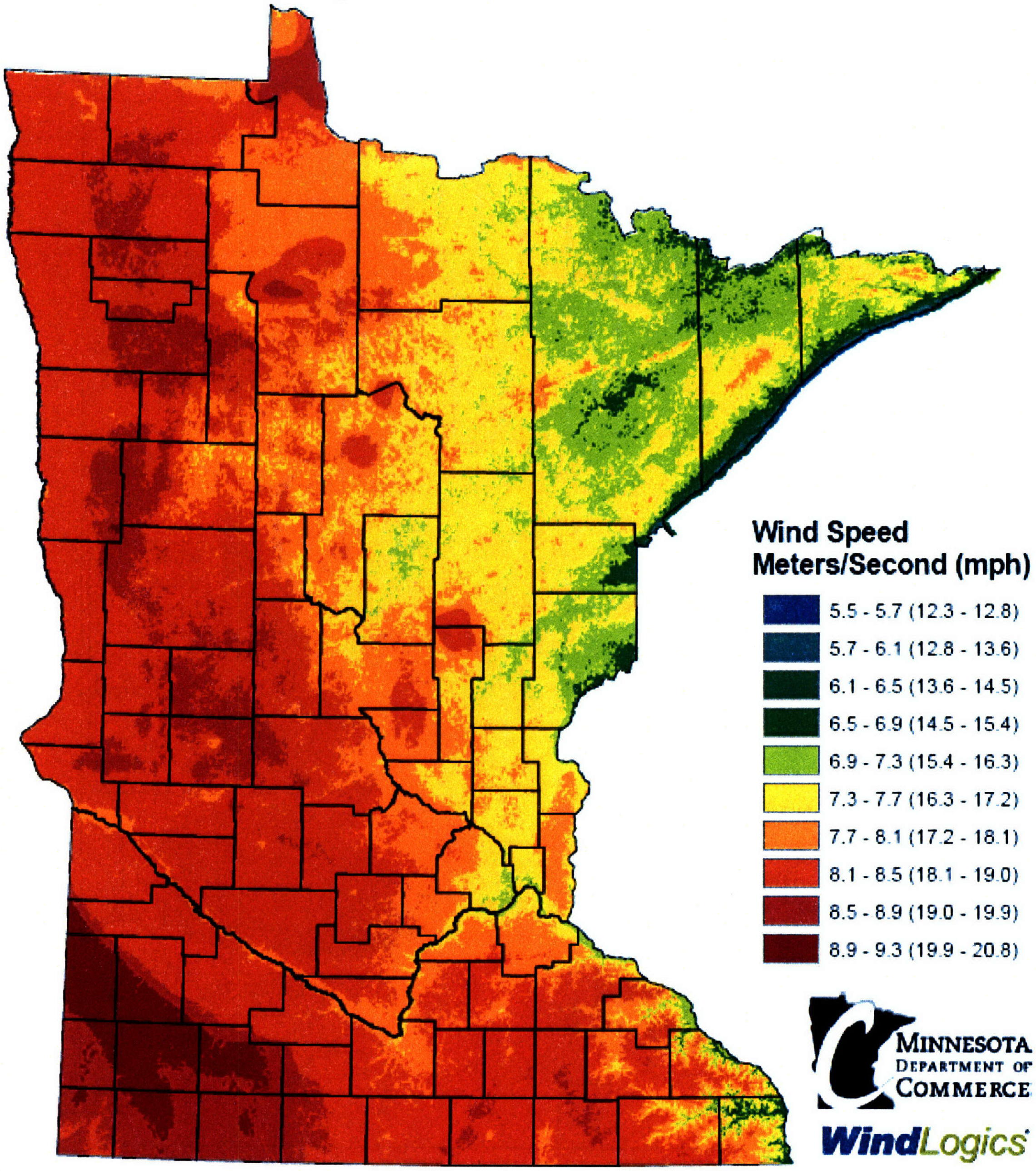
Appendix D

Maps of Minnesota's Wind Potential



Source: U.S. Fish and Wildlife Service, Region 3, National Wildlife Refuge System, Division of Conservation Planning

Minnesota's Wind Resource by Wind Speed at 100 Meters



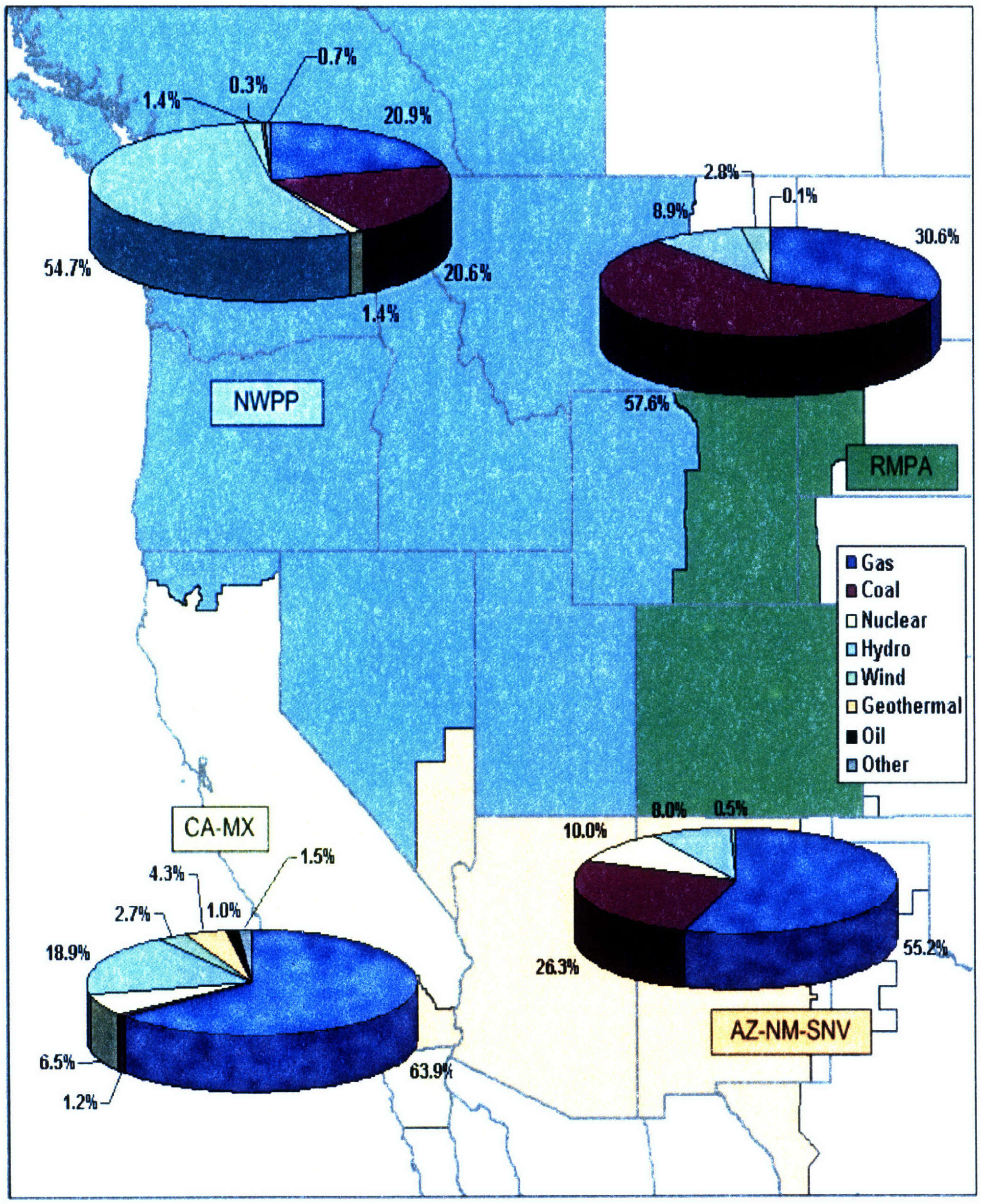
This map has been prepared under contract by WindLogics for the Department of Commerce using the best available weather data sources and the latest physics-based weather modeling technology and statistical techniques. The data that were used to develop the map have been statistically adjusted to accurately represent long-term (40 year) wind speeds over the state, thereby incorporating important decadal weather trends and cycles. Data has been averaged over a cell area 500 meters square, and within any one cell there could be features that increase or decrease the values shown on this map. This map shows the general variation of Minnesota's wind resource and should not be used to determine the performance of specific projects.

January 2006

Source: Minnesota Department of Commerce

Appendix E

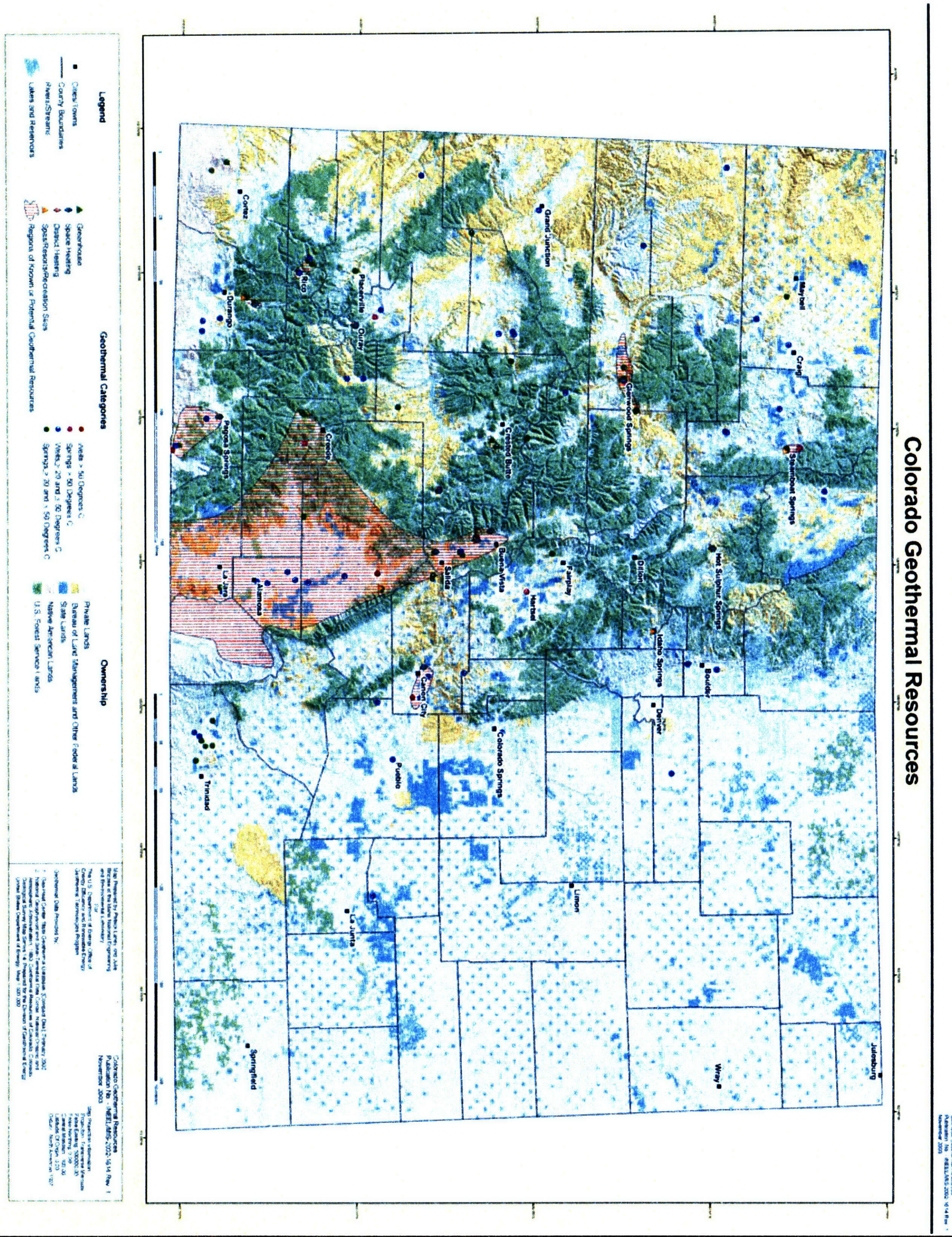
Sub-regional Resource Variations with the Western Electricity Coordinating Council



Source: "Colorado's Electricity Future," Colorado Energy Forum, Sept. 2006, pg 28

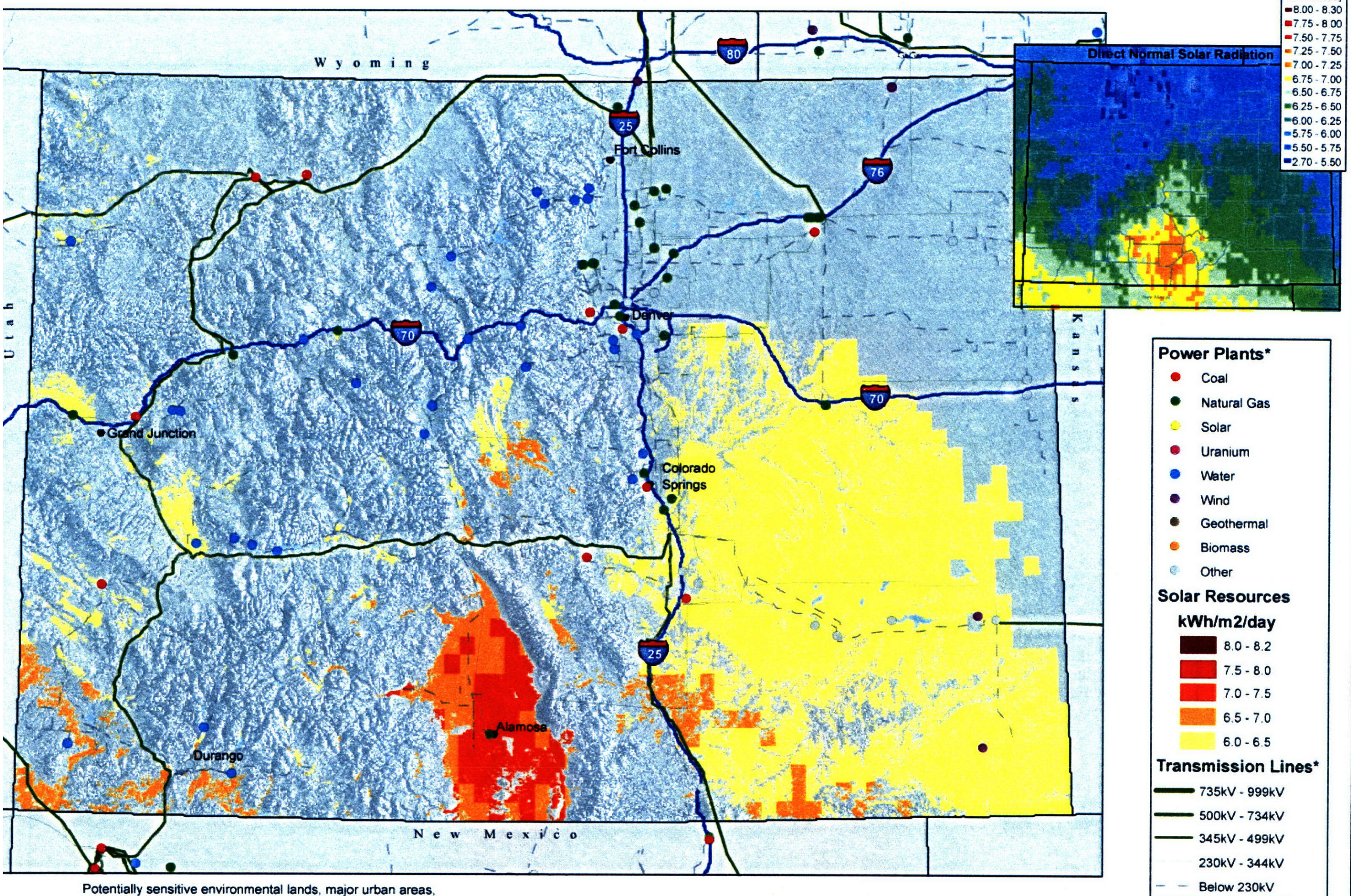
Appendix F

Maps of Colorado's Renewable Resource Potential



Source: U.S. Dept. of Energy, Idaho National Engineering and Environmental Laboratory

Concentrating Solar Power Prospects of Colorado



Potentially sensitive environmental lands, major urban areas, water features, areas with slope > 3%, and remaining areas less than 1 sq.km were excluded to identify those areas with the greatest potential for development.

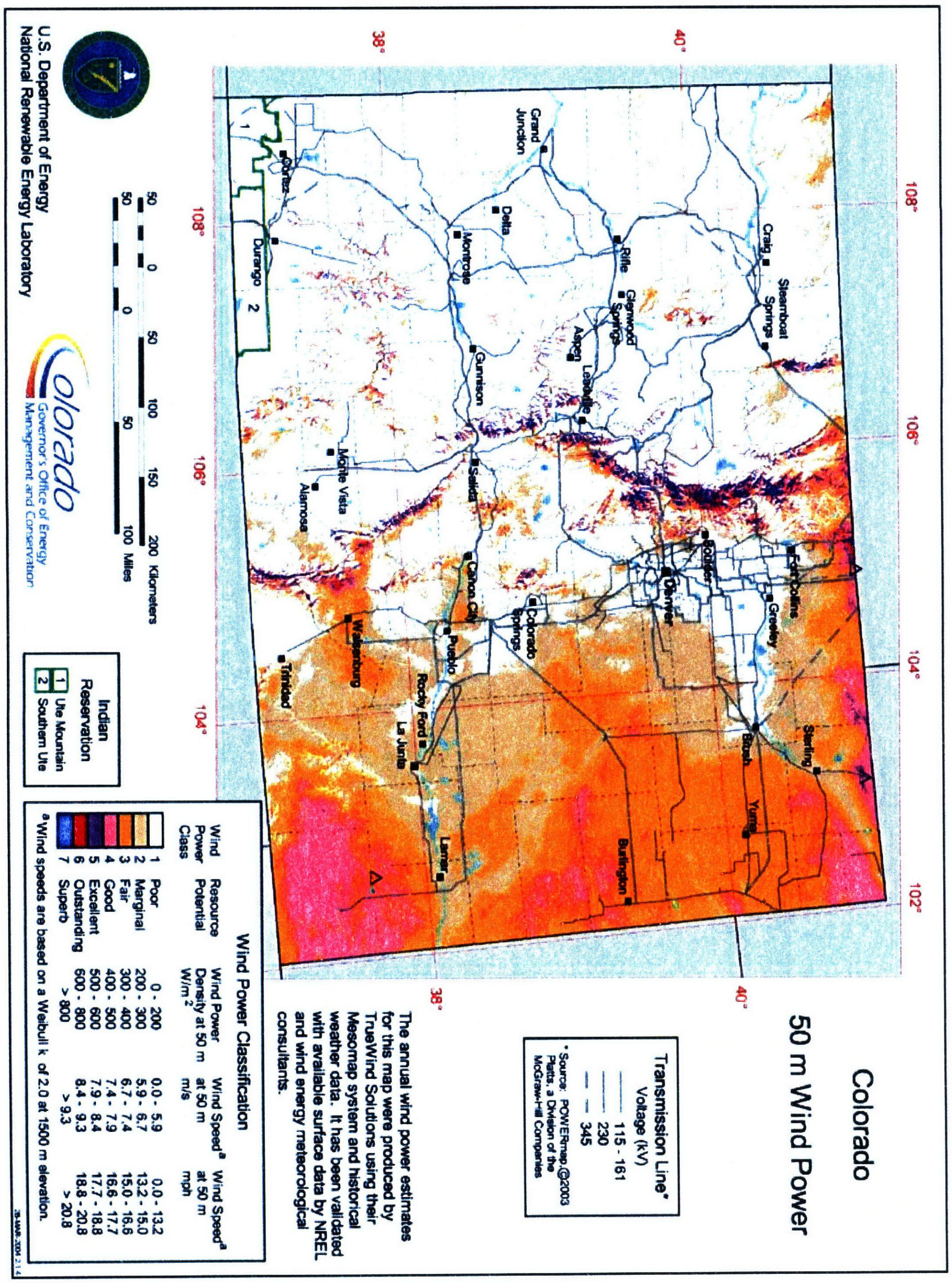
The direct normal solar resource estimates shown are derived from 10 km SUNY data, with modifications by NREL.

* Source: POWERmap, ©2007 Platts, a Division of the McGraw-Hill Companies

NREL

July 2007

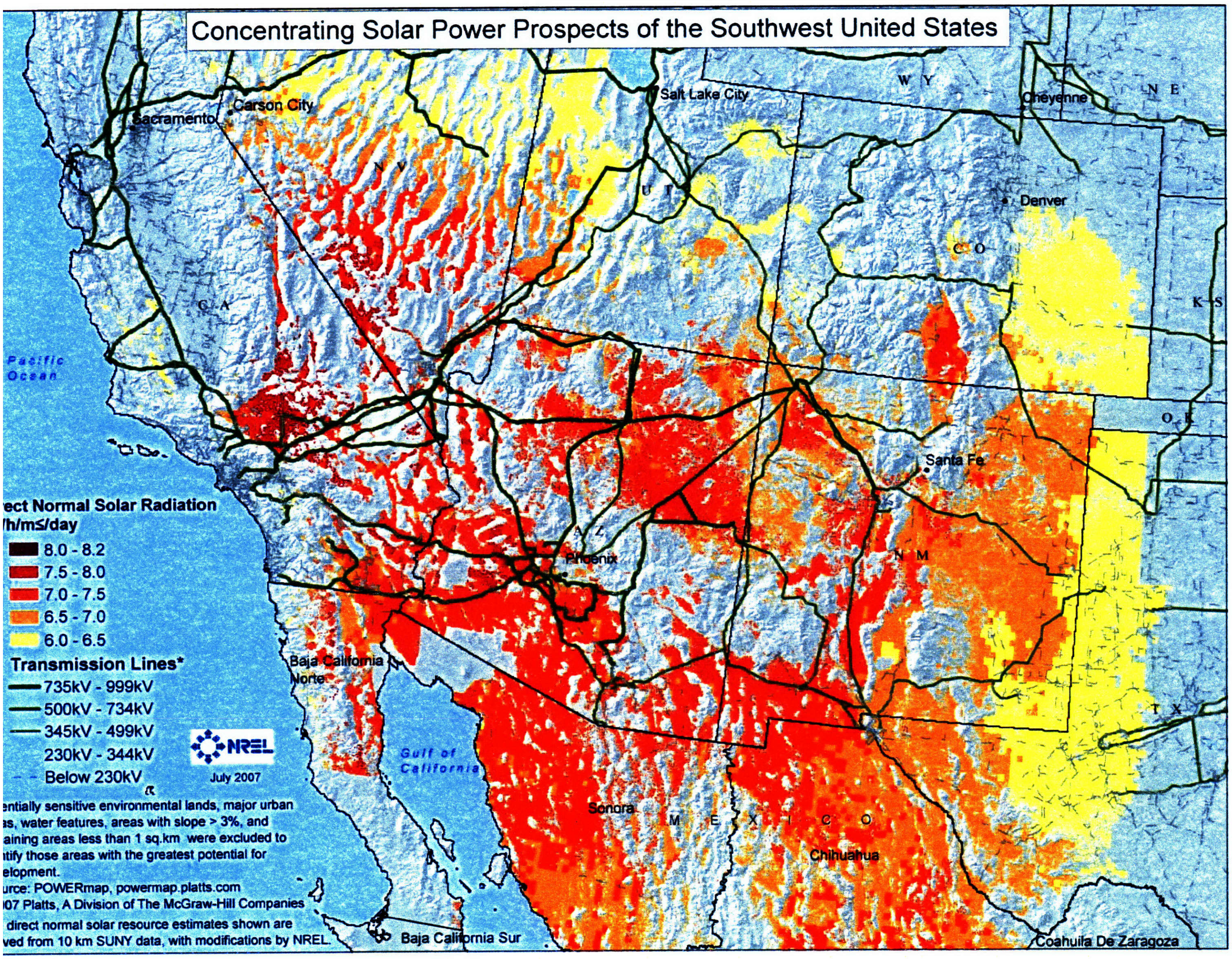
Source: U.S. Dept. of Energy, National Renewable Energy Laboratory



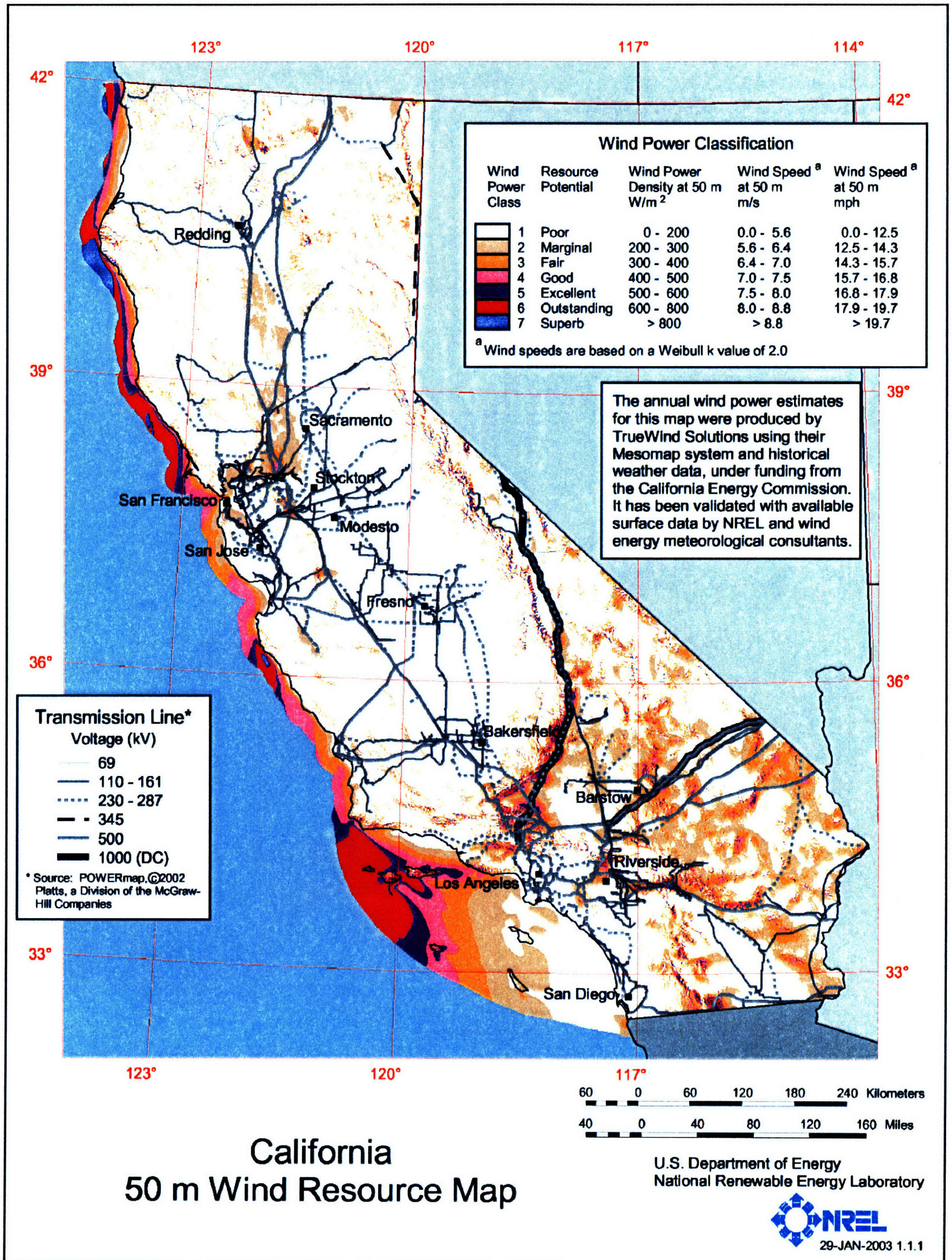
Source: U.S. Department of Energy, National Renewable Energy Laboratory

Appendix G

Maps of California's Renewable Resource Potential

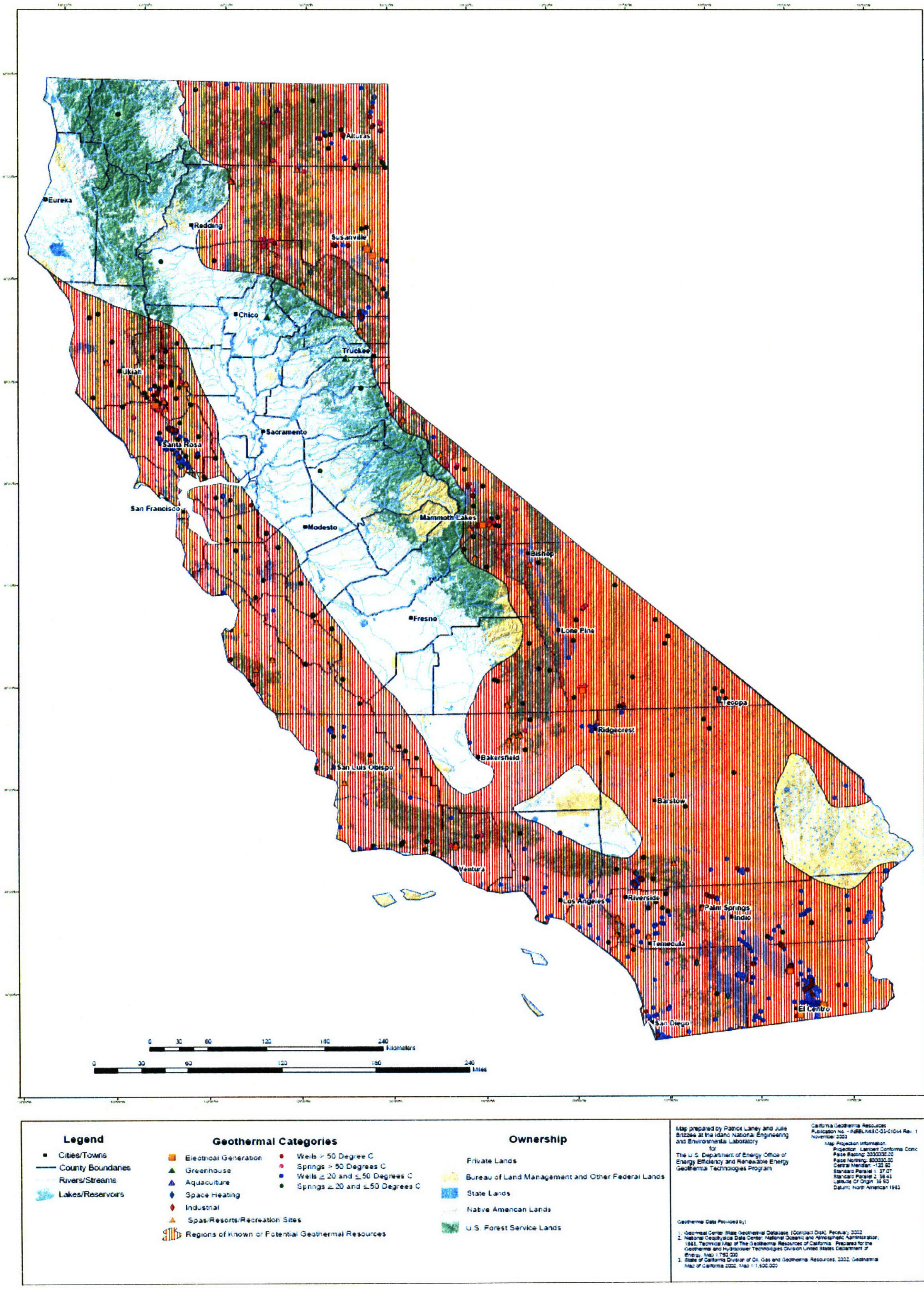


Source: U.S. Department of Energy, National Renewable Energy Laboratory



Source: U.S. Department of Energy, National Renewable Energy Laboratory

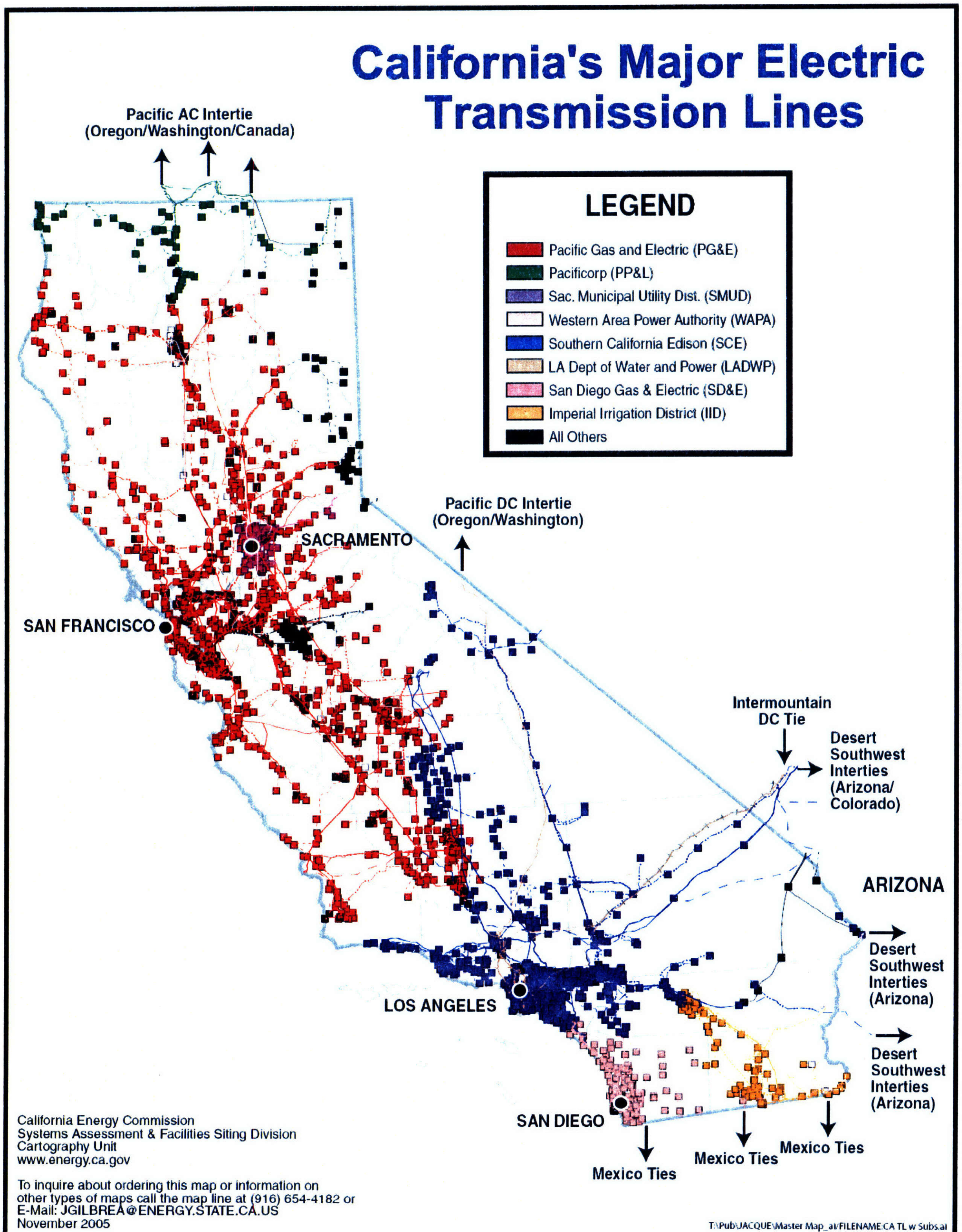
California Geothermal Resources



Source: U.S. Department of Energy, Idaho National Engineering and Environmental Laboratory

Appendix H

Maps of California's Regional Transmission Interties



Source: California Energy Commission

Appendix I

Considerations of Energy Independence and Economic Development

I have argued that the public policy agenda driving the recent popularity of RPS policies is predominantly the emergence of climate change as a leading political issue. But I have noted that energy independence is a leading consideration for many proponents of these policies, either alongside or instead of concerns about greenhouse gases. Economic development is also frequently cited, though while I will touch on it here I consider it to be more of a threshold issue than a causal one (that is, a policy inspired by other considerations is said by proponents to be desirable as well because it will have a neutral to positive impact on economic development). I have made it clear that a thorough treatment of either one of these issues is beyond the scope of this paper. But given that some, and perhaps many, of those advocating these policies do so primarily or even solely out of interest in one or both of these non-climate considerations, I wanted to briefly address them here.

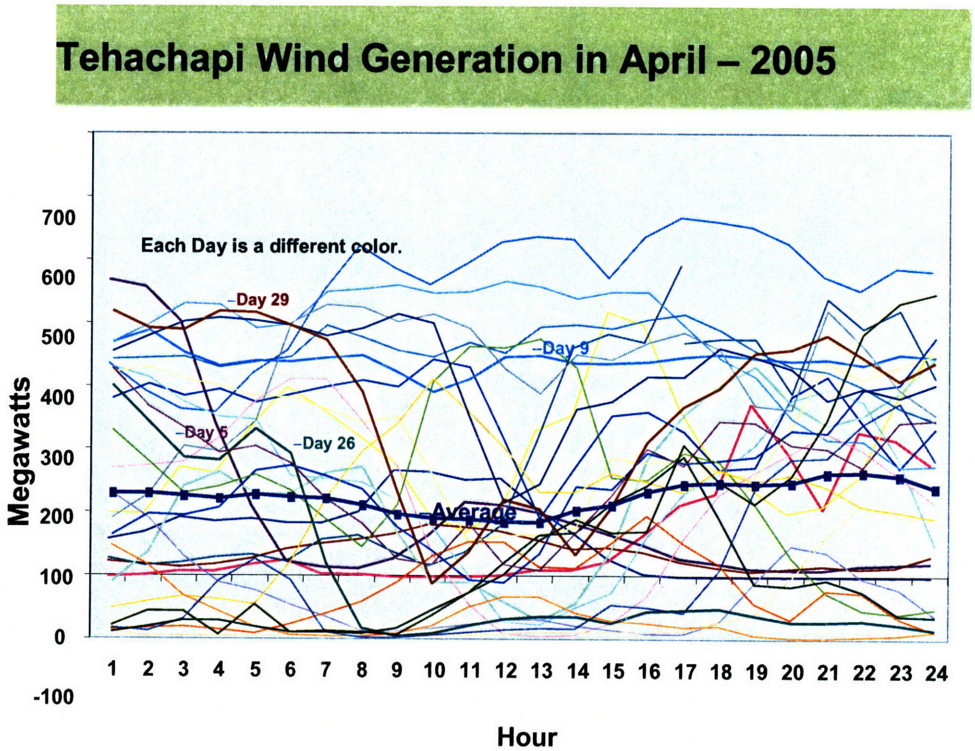
Energy Independence

This phrase can connote a number of things. For many advocates, and to the broader public to which they are speaking, it means reducing or even eliminating our reliance on imported energy (I would argue that most would consider imports from Canada to be outside the scope of their concerns, such that the issue is non-North American supplies). For some this phrase takes on the more nuanced sense of energy *security*, in the sense of reducing our vulnerability to energy price manipulation by foreign suppliers, a concern said to apply to domestic as well as imported supplies of certain fuels. For others, the phrase is used to refer to *regional* energy independence or energy security. This was discussed, for example, during the Minnesota State Senate debate on their 2007 RPS legislation, with at least one senator arguing that the RPS would be beneficial in part by reducing the State of Minnesota's dependence on energy supplied from other parts of the United States.

Taking the most common connotation first, it is impossible to conceive of a credible argument that the production of electricity from renewable primary energy sources has any material connection to the issue of energy independence. The only power production that relies to any noticeable extent on imported (i.e. non-North American) fuel sources is gas-fired generation using imported liquefied natural gas ("LNG"). LNG constitutes on average less than 5% of all natural gas consumed in the United States, and most analysts expect imported LNG to continue to play a very small role in U.S. natural gas consumption for the foreseeable future. Recent discoveries of domestic shale gas deposits alone (in formations such as the Barnett Shale, the Marcellus Shale and the Haynesville Shale) are estimated to hold at least fifty years of supply at current rates of consumption, over and above previously proven conventional North American gas reserves. The U.S. and Canada are entirely self-sufficient in coal and uranium supplies and will continue to be so for a very long time, and oil is used to produce less than 2% of all U.S. electricity. Clearly imported energy is a transportation issue. Shifting to electric transportation (plug-in hybrids, electric rail, etc.) is a viable import substitution strategy in theory, but there is nothing to say that the shift will be based on renewables. There are ample domestic supplies of coal, uranium and even natural gas to support a substantial transportation-driven increase in electricity consumption. To maintain (quite reasonably) that renewables are the preferred supply source for such an increase in electricity production becomes a debate between categories of domestic energy sources. There is simply no compelling case that building wind or solar power installations in and of itself will decrease our reliance on imported energy in any material way.

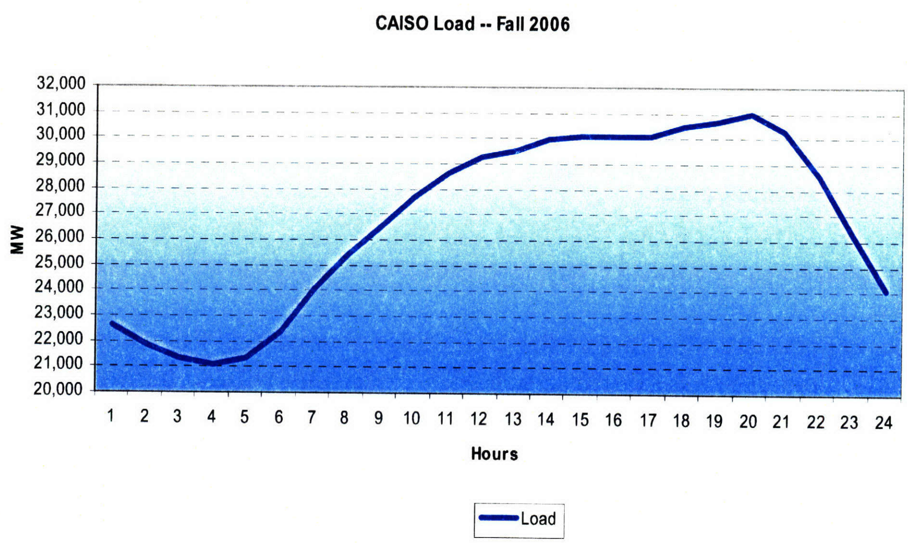
The argument regarding price vulnerability is a more interesting one. Some would argue that our increasing reliance on natural gas as a fuel for power generation increases our exposure to a commodity the price of which is driven by forces beyond our control, even if it is domestically produced. Replacing power generated by natural gas with power produced from renewables reduces that exposure and thus increases our energy security, or so the argument goes. There are a few fundamental flaws in this line of argument. First, while natural gas prices in North America have historically been influenced by oil prices (which in turn are driven by the global supply/demand dynamics), they have never been linked directly to oil prices as they are in Europe and Japan, and in recent years they have even lost much of their indirect link to oil. During the dramatic run-up in oil prices over the past two years, natural gas prices have fluctuated seasonally much as they have for many years, but they have not echoed the rise in oil prices on a thermal equivalency basis. With oil prices trading at $120/bbl, North American natural gas prices in the past would have moved up toward the range of $17-20/mcf (as did happen in Europe and Japan), but in fact they haven't moved anywhere near that level. The gradual erosion of the traditional fuel-switching market is possibly to blame for this weakened linkage, but whatever the reason, the North American natural gas market increasingly operates independently of the world oil and natural gas markets. A significant increase in reliance on imports could change that, but given the strong and improving domestic supply situation referenced above, that would take a much larger shift to LNG than is reasonably foreseeable.

A second flaw in this argument is that most of the renewable production being installed today will rely on rapid-response natural gas-fired generation to balance their variability and unpredictability. Up to a certain level of market penetration they may reduce the total amount of natural gas burned for power generation, but they are as likely to increase as they are to decrease our reliance on gas-fired generators for energy, reliability, grid stability and even price stability.



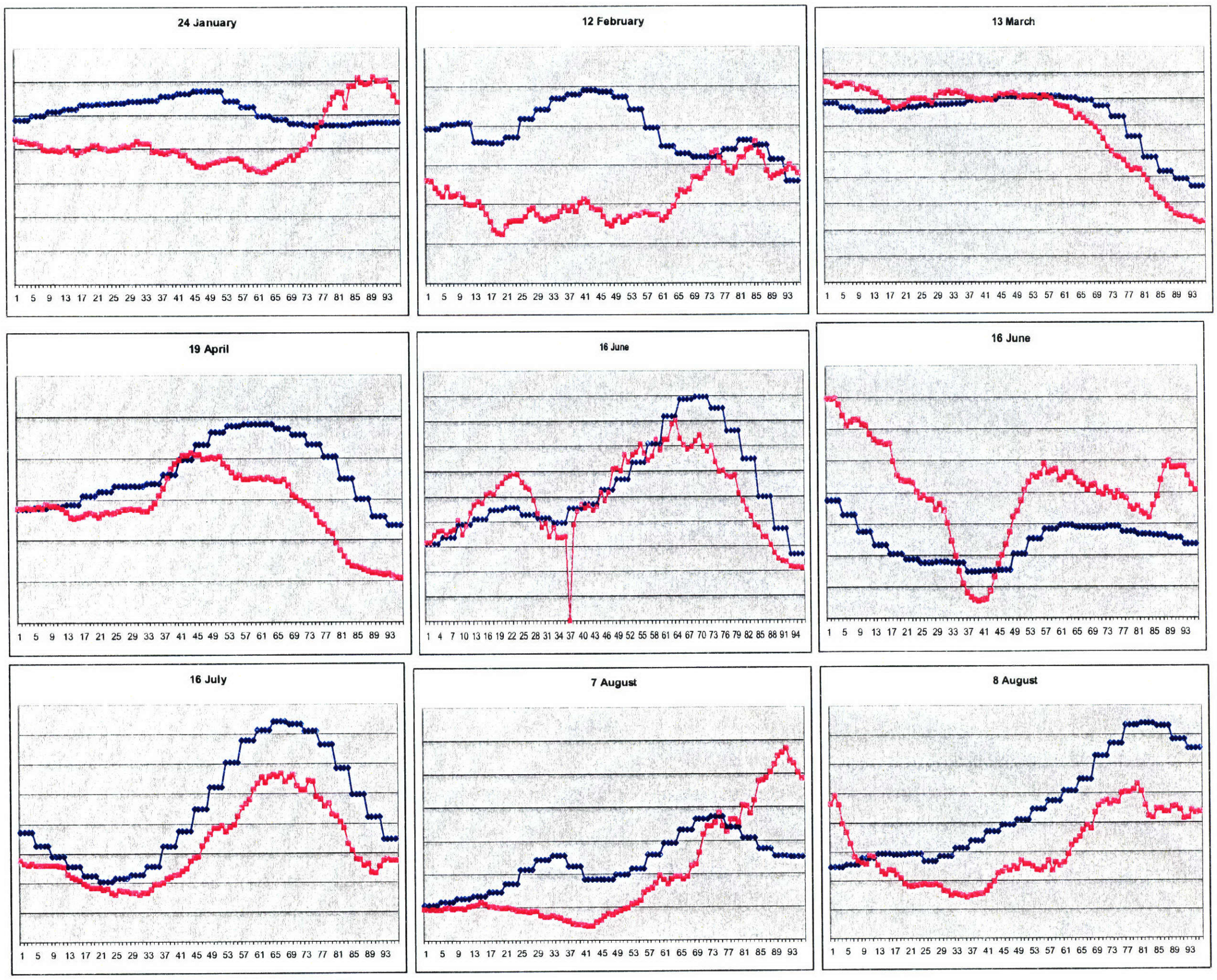
Source: California ISO

Figure I.1 – Tehachapi wind complex daily production profile, April 2005



Source: CAISO

Figure I.2 – Typical California shoulder-period daily load profile



Source data: E.ON Energie AG at http://www.eon-netz.com/frameset_reloader_homepage.phtml?top=Ressources/frame_head_eng.jsp&bottom=frameset_english/law_eng/law_windenergy_eng/ene_win_windreport_eng/ene_win_windreport_eng.jsp

Figure I.3 – Wind output forecasting in Germany, 2008 (blue = day-ahead forecast, pink = actual)

Of greater concern are the changes they will drive in consumption patterns. Figure I.1 shows the production pattern of California's 730 MW Tehachapi wind complex for the month of April 2005. Figure I.2 depicts a typical daily load profile for California during a shoulder-period month (spring and fall are considered "shoulder periods" coming between summer and winter peak periods). It is clear that any correspondence between the two (and there is very little) is purely coincidental. Figure I.3 compares the day-ahead production forecast with actual production for eight randomly selected days in 2008 for the approximately 7,600 MW of wind turbines connected to Germany's E.On, one of the largest and most experienced wind fleets in the world (the fleet's average production level is approximately 1,325 MW, or about 18% of the installed production capacity). While it may not necessarily be representative of the of the Tehachapi resource, it does give an indication of the state of the art in terrestrial wind forecasting. The complementary consumption of gas required to smooth this highly variable and stochastic input year-around is unmatched by any other North American natural gas markets, and at any meaningful scale the natural gas transportation and storage infrastructure needed to meet such a demand profile without a noticeable degradation in grid service quality simply does not exist.[111] It could be built, at great expense, but without it power generation will become even more vulnerable to, and in fact will further exacerbate, volatility in the North American gas market.

A third flaw in this line of argument is that the energy security goal of reducing our reliance on natural gas for power generation is in direct conflict with the climate goal of using renewables to replace coal-fired power generation. With wind the predominant renewable technology, and at the scale of production expected for the near future, renewable power production does indeed displace primarily natural gas, a trend that is used to bolster its claims to increase energy security. But it is that very trend that compromises the effectiveness of renewables as a climate measure, by relying on a technology that on its own in most markets can only replace non-firm (i.e. non-coal) capacity on the grid. Thus in nearly all current cases renewables leave conventional coal-fired power largely untouched, and where they are able to displace coal-fired generation they do so at the cost of increased reliance on natural gas (this phenomenon can be seen very clearly in the most recent IRP submitted by Minnesota's Northern States Power). For renewables to have a meaningful impact on power sector greenhouse gas emissions they will need to replace a plentiful domestic resource (coal), and at present trends they will do so only by *increasing* our reliance on natural gas, not decreasing it.

The third argument relating to energy independence is the regional one. It is argued that increased generation using local renewable resources will reduce a region's vulnerability to supply disruptions and volatility in energy sources transported from other parts of North America. Since it is reasonable to assume that most of those expressing this concern are not seriously suggesting a risk of being held hostage by other parts of the country or by Canada, this is primarily an issue of transportation and storage infrastructure. The Northeast has long had a legitimate concern about its vulnerability to a long supply chain from the main North American natural gas producing regions, but recent rail disruptions have raised similar concerns in coal-burning regions like the North Central and the Southeast. The problem with this argument is again related to the actual renewable technologies being stimulated by current RPS policies. While deploying a fleet of terrestrial wind farms in northern New England and New York State may reduce the annual quantity of natural gas required for power production, the production characteristics are such that the region would continue to be heavily reliant on natural gas-fired generation, perhaps even more so. More importantly, at any meaningful scale the variability and unpredictability of the renewable resource could actually exacerbate, rather than alleviate, the region's exposure to any bottlenecks and weak links in the transportation and storage infrastructure linking it to gas producing areas. Widespread deployment of different renewable technologies, including deep offshore wind with its steadier and more predictable production profile, could be beneficial, but as I have demonstrated in the main body of the paper this is not the outcome that is being driven by current RPS policies.

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[111] It is often claimed that Denmark's ability to absorb a large amount of wind generation without major grid stability problems proves that this concern is misplaced. There is ample evidence that Denmark is able to manage the variability of its wind production only by reliance on its proximity to, and ample transmission export capacity with, the Norwegian grid (which is 95% hydro) and the German grid (with its ample base of load-following coal plants); Denmark exports as much as 85% of all the wind power produced, much of it at a negligible or zero price, and re-imports it primarily as hydroelectric power from Norway or coal-fired power from Germany. See Sharman, Hugh, "Why wind power works for Denmark," *Proceedings of ICE* (U.K.), May 2005, pp 66-72.

Economic Development

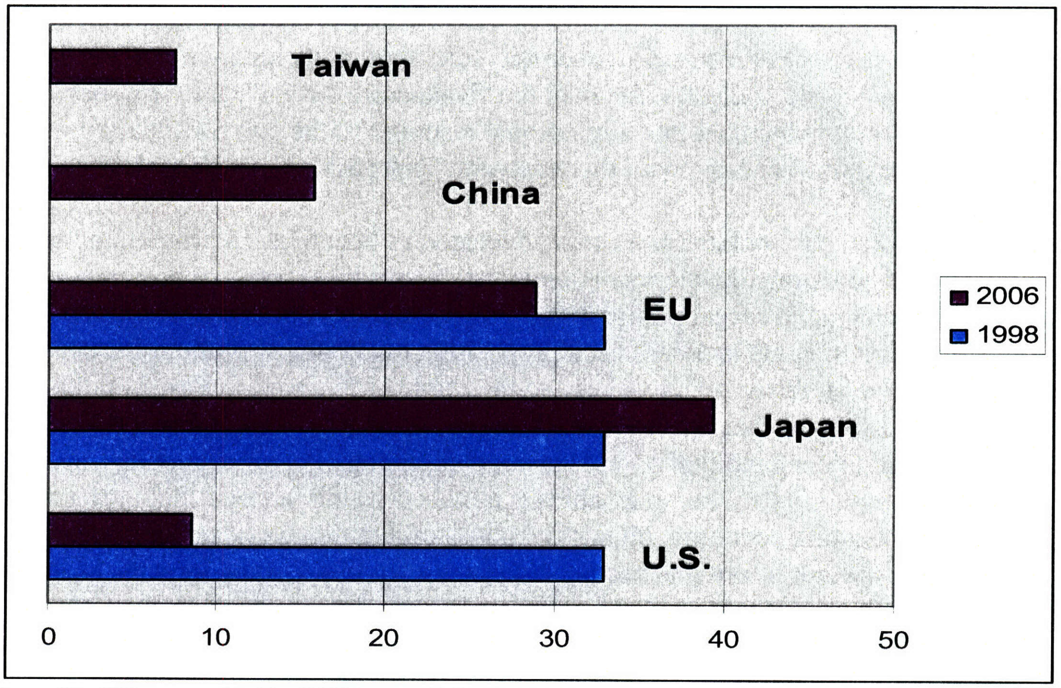
I am not an economist, and I will not attempt even a cursory quantitative analysis of the claims and counterclaims made regarding the net economic impact of increased electricity production from renewables. However I will point to some of the questions that must be raised in response to the claim that public support for renewable electricity will have a net positive impact on short to medium term jobs growth.

The two main arguments for a positive economic impact are (1) that these are growth industries that will spawn a net increase in high-skilled jobs and local investment, and (2) that this mode of production will displace energy produced from fuels that are expected to increase in price and volatility in coming years, and in so doing it will reduce our long-term energy costs. One could say that there is another line of argument, dealing with the value of nature's services that would otherwise be unavailable were we to continue with "business-as-usual." I will suggest that this is an evaluation that is captured more directly in the debate around carbon pricing and figures only very indirectly in the RPS debate.

The key challenge in making the first of these two arguments is that one needs to make the case that the economic stimulation created by investment in renewable power generation is due to the fact that it's *renewable*, not simply due to the investment itself. It is presumed that these investments are made in place of investments in fossil-fueled generation to meet a given demand, so it cannot be said that all of the employment in constructing and operating these facilities as well as manufacturing their components is an incremental effect of the fact that they are renewable. This point will come up several times in the following discussion.

Another key question has to do with the price of energy from these sources. In a very limited number of cases these sources of supply are less expensive than the current sources, but in the vast majority of cases they are more expensive, at least for the foreseeable future and accounting for all of the costs associated with integrating them into the grid. Every state program acknowledges this at least implicitly, by imposing caps on retail rate increases driven by compliance with their RPS policies, and it is widely noted that even these limits are achievable only if the additional subsidy provided by favorable Federal tax treatment (currently worth at least $25/MWh on an after-tax basis) is extended well into the next decade. This is quite clearly an effective tax on electricity prices, and it seems straightforward that tax increases have a negative economic impact unless offset or reinvested in some productive way. Investments in new renewable facilities do create jobs, but how many of them are truly incremental to what would have been created by investment in fossil generation, and whether that incremental job creation more than offsets any job destruction caused by the imputed electricity tax, is something that needs to be rigorously examined if one wishes to make this claim.

Leaving to one side for a moment the incremental issue, most current renewable power production, like most other power generation, is capital-intensive but not terribly labor-intensive. A typical 500 MW wind farm today could represent new investment in the range of $750 million, and in the very short term it would create a couple of hundred construction jobs. But it creates only a few dozen permanent positions, or about 0.5 direct jobs per $1 million of investment. Energy efficiency investments, by comparison, are estimated to produce about 10 direct jobs per $1 million of investment (according to the U.S. Department of Labor). The manufacturing impact is also debatable. These projects are intended to displace investment in natural gas-fired and coal-fired power plants, the components of which are overwhelmingly produced (or at least available) domestically. Certainly some investment has been made in domestic manufacturing of many of the components that go into renewable power facilities, but the picture is still very mixed. Figure I.4 below illustrates the trend in solar PV cell manufacturing over the past ten years.



Source data: Slide presented by Sen. Jeff Bingaman during his 2008 Compton Lecture at MIT

Figure I.4 – Share of market (approximate) for manufacture of solar PV cells, by country

Wind turbine manufacturing is equally dominated today by non-U.S. suppliers (even GE, a major player in wind, sources many components for its U.S. wind installations from outside of the U.S. and assembles them here). Beyond GE (whose U.S. market share has shrunk from 60% to 44% over the past three years), the U.S. wind market in 2007 was dominated by suppliers from Europe, Japan and India [U.S. Department of Energy]. There is some expectation that a more robust and consistent set of policies promoting renewables will attract more investment in local manufacturing, but this would be manufacturing to support projects that are displacing investment in conventional power generation, so claims for a net domestic manufacturing impact should be closely examined.

The second argument – that these sources of power will be cheaper and risk-reducing on a life-cycle basis by displacing fuels destined to become much more expensive and volatile – is unfortunately one that is impossible to substantiate except after the fact. This very same argument was used to justify the PURPA provisions supporting cogeneration and renewables in the late nineteen-seventies, and less than ten years later it appeared to be well off the mark.

Maybe it will be different this time, but the recent supply-side developments in North American natural gas referenced above do not provide an encouraging sign. The argument would be bolstered by the imposition of carbon pricing, but then government can always make the alternatives less attractive through direct intervention. I would maintain that the argument for life-cycle savings is commonly understood to refer to the underlying future prices and price volatility of the fuels themselves, which are unknowable.

I hasten to add that in no way do I intend this as an argument against supporting renewable power generation. A very sound economic case for renewables (one to which I strongly subscribe) is that the present mode of power production has external societal costs that are not currently reflected in the price of electricity, and that in the long term renewable production will carry lower societal costs than the "business-as-usual" case. But behind that argument is the acknowledgement that any rational response to the current situation will carry a higher net price per unit of energy, with the renewable approach simply being less costly.

To summarize, RPS policies are often advocated as beneficial in promoting "energy independence" and economic development, and those issues have featured prominently alongside climate change in recent public discussion around the expansion of these policies. The foregoing discussion attempts to assess each proposition qualitatively without the benefit of a thorough quantitative analysis, which is beyond the scope of this paper. Based on this discussion, I would suggest that the case for a material impact on "energy independence" (however one might understand that phrase) is not compelling. As for economic impact, displacing carbon-based fuels with renewables is almost certainly an essential measure to avoid the potentially devastating economic impacts of a loss of nature's services due to climate change, but it is debatable whether or not that benefit comes with an incremental increase in local jobs growth in the short to medium term. RPS policies properly designed can become powerful tools in our long-term battle against dangerous climate change, and I would argue that that should be reason enough to pursue them.

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