Feasibility of U.S. renewable portfolio standards under cost caps and case study for Illinois

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\textbf{Abstract}

Recently enacted state Renewable Portfolio Standards (RPSs) collectively require that U.S. electricity generation by non-hydro renewables more than double by 2025. These goals are not certain to be met, however, because many RPSs apply cost caps that alter requirements if costs exceed targets. We analyze here the 2008 Illinois RPS, which is fairly typical, and find that at current electricity prices, complete implementation will require significant decreases in renewables costs, even given the continuation of federal renewables subsidies. Full implementation is possible but not assured. The statutory design raises additional concerns about unintended potential consequences. The fact that windpower and solar carve-outs fall under a single cost cap means that in failure mode, a less cost-effective technology can curtail deployment of a more cost-effective one. Adjacent-state provisions mean the bulk of the windpower requirement can be met by existing facilities in Iowa, where new builds will likely also occur. The Illinois RPS, like that of many other states, appears to combine objectives inherently in conflict: preferences for local jobs, for specific technologies, for environmental benefits, and for low costs. Revisiting the legislation may be needed to make legislative success likely and ensure that failure modes do not compromise goals.

\textit{Keywords:} Renewable Portfolio Standard, Renewable Energy, Illinois

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1. Renewable Portfolio Standards in the U.S.

Renewable Portfolio Standards (RPSs) – broadly speaking, requirements that qualifying renewables produce at least some designated portion of the electricity sold in a given region [1, 2] – mandate a significant transformation of the U.S. electricity system in coming decades. RPSs recently enacted by 29 states will collectively require that U.S. electricity generation from qualified renewables more than double by 2025. Legislative targets, if met, collectively mandate that ∼9% of the nation’s electricity be generated by qualified renewables by 2025, up from ∼4% (non-hydro) in 2009 [3, 4, 5]. Interest in a national level RPS is high as well. House Bill HR 2454, which passed the House in 2009 but did not make it to a vote in the Senate, would have imposed a national requirement of ∼20% renewables generation by 2020 [6], twice as large as combined state RPS requirements. Given the magnitude of these proposed changes, it is worth examining the feasibility of existing legislation. We examine the recently enacted Illinois RPS, a fairly typical statute that can be a useful model for understanding implications of renewables mandates more widely in the United States.

Analyzing a single state can produce national-level insight because many existing state RPS statutes are broadly similar [7]. The definition of qualified renewables generally includes wind, solar photovoltaic, solar thermal generation, and biofuels. (Statutes vary on inclusion of hydropower and municipal solid waste combustion, but these are expected to be an insignificant portion of new capacity [8]). While some states restrict a portion of their requirements to particular generation types (e.g., separate requirements for solar in IL, NJ, OH, AZ, and NV), in all statutes the majority of the requirements are either unrestricted or can be met by wind power, the lowest-cost non-hydro renewables generation technology at present [8]. Most RPSs also share a common means of defining renewables requirements (as a percentage of annual retail sales) and a common enforcement mechanism (purchase of Renewable Energy Credits, or RECs, which are awarded to qualifying generators for each MWh of power produced). Utilities purchase RECs either bundled with or independent of actual electricity sales and tender the credits to demonstrate compliance with RPS requirements. In this way, RECs both subsidize renewable electricity and provide a means of demonstrating RPS compliance without further complicating electricity markets. Most RPSs are also similar in phase-in speed, beginning with a relatively modest initial requirement of a few percent of annual retail sales and then ramping up at about a percentage point or two per year over a decade to a final target of 10% – 25% (Figure 1). Because most state RPSs were implemented in a relatively tight span of five years (from 2006-2011), their phase-in will produce a steady increase in U.S. demand for renewables generation.

The recent origin of most state RPSs means that states have little experience base to guide their expectations, as there are few useful long-term examples of how renewables costs evolve as an RPS matures. Studies of the short-term initial phases of young RPSs have focused primarily on the volume of renewables installed rather than on prices [9, 6, 10, 11, 12] (with some exceptions, e.g. [6, 13]). The few early RPSs that are old enough to be near full implementation are not good analogues for the 2006-2011 statutes.

REC prices are set by market conditions and, as a result, do not necessarily reflect the cost of renewables generation. For example, an oversupply of wind capacity in the Illinois region has resulted in recent REC prices that are significantly lower than the values needed to make wind profitable.
Total renewables generation requirements as percentages of retail sales for 27 states with RPS standards set as percentages of retail goals and the District of Columbia (all who list requirements in the DSIRE database [4]). Several statutes discussed in the text are highlighted (IL, NJ, CA, and the proposed federal standard of HR2454). While the details of implementation can vary from state to state, with the exception of California the overall targets and phase-in rates are broadly similar. RPS requirements tend to begin at a low value of a few percent of total generation, increase at a rate of a percentage point or two per year, and top out at $\sim 20\%$. The clustering of RPS legislation in 2006-2011 means that the bulk of U.S. renewables requirements reach their peak in 2020-2025. For Maine, we show only the portion of the RPS that must be satisfied by new builds.

since all involve special conditions or circumstances that differentiate them from more recent statutes. Iowa, the earliest RPS (1983), had requirements so small ($\sim 1\%$ of state electricity sales; [4, 14]) that they could not be expected to affect the renewables industry significantly. Maine (2000) allowed existing facilities to contribute to the renewable portfolio and the RPS was initially met by existing hydropower rather than new construction [6]. Texas (1999) possesses such anomalously strong wind resources that development of windpower in the state could be driven largely by the federal Production Tax Credit and Investment Tax Credits with the state RPS playing a much less significant role. (The Production Tax Credit and Investment Tax Credits, henceforth “PTC”, reimburse qualifying renewable generators for up to 30% of the installed cost. See Appendix A.1 for further discussion.) Current Texas REC prices remain so low ($\sim 1$ per MWh; [15]) that the state RPS is not a significant subsidy for windpower in Texas, and current construction implies that Texas wind capacity will reach its 10 GW target almost fifteen years ahead of RPS-mandated requirements [16]. Prediction of the expected evolution of renewables implementation under the 2006-2011 statutes therefore requires new analysis.
2. Cost Caps in U.S. Renewable Portfolio Standards

RPS legislation may be driven by any or all of several separate motivations, including: environmental protection (both for air quality and climate purposes); support of the nascent renewables industry; and creation of local jobs [17]. The details of state RPSs suggest that multiple motivations are often present. Stimulating local jobs appears to be a common goal, since locally generated power is often given favorable treatment. Supporting the renewables industry is likely also a common goal, as many statutes appear to assume that by requiring a large enough volume of renewables generation, they can help the industry reduce costs (through economies of scale, industry learning, and/or technological improvements). These statutes contain cost-limiting mechanisms (“cost caps”) that limit the total expenditure of subsidies at a value too small to allow full implementation in the current cost landscape. In other words, RPS success hinges on the assumption that the “renewables premium” – the excess cost of renewables over conventional electricity generation – will drop enough to allow the legislation to reach its stated goals.

Cost caps in RPS statutes fall into two broad types, one of which typically implies an expectation of eventual decreases in renewables premiums. Under any RPS, private investors will add renewables capacity as long as it is profitable to do so, i.e. as long as the available subsidy they can receive per unit of power generated (generally cost-capped REC sales + the PTC) meets or exceeds the renewables premiums they must bear. Because a cost cap limits the magnitude of that subsidy, it provides means for legislators to privilege one type of risk over another. The cap becomes relevant only if renewables generation cost exceeds legislative expectations, and in that event it limits consumer or taxpayer spending at the a trade-off of failure to achieve the RPS goals. RPSs cost caps can be categorized according to their means of implementation: they either 1) impose non-compliance penalties on utilities if the RPS requirement is not met, or 2) freeze the RPS requirement if costs to consumers exceed some benchmark value, generally a benchmark percentage of wholesale or retail electricity sales.

RPS cost caps of type 1, with penalties specified in dollars per non-compliant unit of energy ($/MWh), should result in either full compliance with the statute or near-complete lack of compliance. If renewables premiums are lower than mandated penalties, investors will build renewables capacity and be confident that the REC price will compensate them for the extra cost of renewables generation. If renewables premiums are higher, investors will decline to build and utilities will opt to pay penalties instead of purchasing RECs. Although the mechanism and motivation for cost caps need not be related, states adopting this approach (e.g. CT, DE, NH, NJ, MA, MD, ME, PA, RI, and TX [18]) tend to set their non-compliance penalties higher than the current renewables premium, suggesting that the cost caps are a hedge against unexpected REC price increases.

RPS cost caps of type 2, on the other hand, appear to be driven by industry support motivations, and in failure mode would result in partial compliance. In these statutes, the cost cap is set as a fixed dollar amount or a fraction of electricity sales. The capped

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4 A local preference also allows the additional benefit of extraction of federal money for in-state businesses via the PTC.

5 In some states, penalty payments are in turn distributed as renewables subsidies to ensure that at least some are built. These RPSs have some of the characteristics of type 2 RPSs.
total subsidy then remains approximately constant (rising only with electricity sales or legislated increases in the cap) while the renewables requirement ramps up over time, so that the available subsidy per unit of renewable energy declines. The cost cap is always set to be large enough to stimulate investment initially, when renewables requirements are low, but typically small enough that the renewables premium must decrease in order to achieve full compliance. If renewables premiums do not decline sufficiently, a point will arrive where the capped subsidies over the lifetime of a generation plant no longer exceed the renewables premium and renewables investment will cease. The final outcome would then be a smaller-than-anticipated pool of renewables generators who would receive higher-than-anticipated REC prices (in $/MWh). States adopting this approach (e.g. CA, CO, IL, MI, MO, MT, NC, NM, NY, OH, OR, and WA [18]) generally set their final caps lower than the current renewables premium, suggesting that the legislators assume that enactment of the RPS will result in gradually lowering renewables costs.

It is apparent even with back of the envelope estimates that the Illinois and other similar type 2 cost caps represent a “bet” on a lowered renewables premium. The Illinois cap limits the total cost of REC sales to 2% of retail sales (on a 25% RPS requirement), which means that the price support available to each unit of renewable energy is no more than 2%/25% = 8% of the retail price. Since wholesale rates are approximately three times less than retail rates, the cap allows a renewables premium of 3 × 8% ≈ 25%. But generation by the cheapest qualifying renewable in Illinois, windpower, costs approximately double the wholesale price, i.e. its premium is ∼ m/kWh. Even with the inclusion of price support from the federal PTC, which reduces construction costs by 30%, capped REC sales in Illinois cannot make up the remaining necessary subsidy.

The Illinois cost cap is in fact even tighter than the above estimates imply, because the RPS contains a small (∼ 1.5%) but expensive solar carveout that would consume significant amounts of the available subsidy in the current cost landscape. The cost of solar generation is somewhat uncertain at present, especially after recent declines, but in 2011 was approximately six times the national mean wholesale rate or two times the retail rate. The total cost of the solar requirement would then be estimated as ∼ 1.5% × 2 = 3% of retail sales, or, with the PTC providing a ∼ 30% support, 2% of retail sales, equal to the entirety of the Illinois capped subsidy.

The discrepancy between the current cost landscape for renewables and that envisioned by the Illinois RPS statute is not atypical, and many state RPSs would require drops in renewables premiums of similar magnitude to allow implementation. Of several type 2 RPSs examined (CO, IL, OH, WA, and NJ), only that of WA and NJ are feasible under current conditions. (See Table 1, which shows current renewables premiums for wind and solar and cost-capped state price supports, and Appendix A.1.1 and Appendix A.1.2 for detailed discussion of the premiums calculation). The largest necessary drop is that of the specific solar requirement in the OH statute, which can be fulfilled only with a drop in solar prices of nearly a factor of 3 (or corresponding increases in conventional costs). The comparison of Table 1 suggests that any concerns about the feasibility of the Illinois RPS statute would be shared widely across states.

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6It is possible that investors would continue to build renewables when subsidies do not offset the renewables premium at the time of building only if they were anticipating that increased conventional generation costs or national policy change will later reduce their competitive disadvantage, effectively reducing the renewables premium.
Table 1: Comparison of current renewables premiums with legally provided price supports for renewables: the Federal Production Tax Credit / Investment Tax Credit (PTC) and cost caps on REC prices from selected state Renewable Portfolio Standards (RPSs). All are adjusted to comparable units for simplicity and shown in cost per unit energy ($/MWh), in % of wholesale electricity rates, and, for comparison with other proposed environmental legislation, in equivalent $ per ton CO₂ avoided by that renewable generation (assuming 1.1 ton per MWh, representative of coal generation). The renewables premium is the price support needed for renewables generation: the difference between the estimated cost of renewables generation and expected revenues from electricity sales. If the total price supports (PTC + state RPS caps) are less than the renewables premium, the RPS cannot be fully implemented in current conditions. Wind is used as a proxy for a general renewables premium, and solar premiums and supports shown separately for those states whose RPSs contain separate requirements and cost caps for solar. (IL is not shown because its solar carveout is not associated with a separate cost cap). Wind and solar premiums are each shown for two conditions, for a typical Illinois site and for the best available sites (e.g. Iowa or Texas for wind, Arizona or Nevada for solar). These cases are captured by wind capacity factors of 33% and 40% and solar capacity factors of 15% and 20%. Conditions applicable to the Illinois RPS are shown in regular font and the others italicized. Note that state cost caps are calculated using local rather than national wholesale rates; see Appendix A.1.1 and Appendix A.1.2 for calculations and discussion. For three of five RPSs shown here (CO, IL, and OH for both wind and solar), total price supports are less than the current cost premium, meaning the statutes can only fulfill their goals if renewables costs drop or electricity prices rise. For OH solar, the necessary cost drop is a factor of nearly three.

<table>
<thead>
<tr>
<th></th>
<th>Wind</th>
<th>Solar</th>
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<tbody>
<tr>
<td>Premium</td>
<td>$/MWh</td>
<td>% wholesale</td>
</tr>
<tr>
<td>40% CF (33% CF) PTC</td>
<td>$25 ($35)</td>
<td>60% (90%)</td>
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<tr>
<td>40% CF (33% CF) CO Cap</td>
<td>$8</td>
<td>20%</td>
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<tr>
<td>40% CF (33% CF) IL Cap</td>
<td>$7</td>
<td>18%</td>
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<tr>
<td>40% CF (33% CF) OH Cap</td>
<td>$9</td>
<td>26%</td>
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<tr>
<td>40% CF (33% CF) WA Cap</td>
<td>$18</td>
<td>45%</td>
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<tr>
<td>15% CF (20% CF) PTC</td>
<td>$15 ($20)</td>
<td>40% (50%)</td>
</tr>
<tr>
<td>15% CF (20% CF) NJ Cap (in 2016)</td>
<td>$594</td>
<td>1500%</td>
</tr>
<tr>
<td>15% CF (20% CF) OH Cap (in 2024)</td>
<td>$50</td>
<td>125%</td>
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The reductions in renewables premiums needed for RPS success can be achieved through either or both of two mechanisms, either reductions in renewables costs or increases in electricity prices. Both changes make renewable energy more cost-competitive. In some states, increased electricity prices would also benefit RPS viability by a second mechanism that loosens costs caps. In these states (e.g. CO, OH, and WA), the cost cap is re-scaled each year to electricity prices, so that if wholesale prices rise, renewables generators not only receive greater income from the electricity they sell but are also permitted a larger total subsidy. Conversely, RPSs with targets high enough to affect electricity markets and depress wholesale prices can then inadvertently punish renewable

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7 Although in theory it would be possible to structure an RPS so that the cost cap was loosened with falling rather than rising electricity rates (for example, the cap could apply to the total electricity cost to the consumer rather than just to REC sales, so that lower electricity rates permitted higher REC
generators for any price decreases they bring about. This scenario does not apply to Illinois, which is among the smaller number of states that peg the cost cap to a fixed value, but rising electricity prices do aid in RPS feasibility simply by providing greater revenue to renewables generators and reducing their need for price support (i.e., whittling down the renewables premium).

In the analysis that follows, we therefore consider two scenarios that bracket projections of future electricity rates: one in which electricity prices are flat and another in which prices rise linearly over the RPS-phase-in period to 60% above present rates (equivalent to a 3.3%/year growth from the current $35/MWh to $55/MWh in 2025)\(^9\). This latter scenario is something of an upper limit on plausible price increases. The EIA predicts actual electricity price decreases of 2% to 10% by 2021, driven by expectations of declining coal and natural gas prices [3]. We take as our maximum-price case the estimated 2025 generation costs of new conventional facilities from a relatively pessimistic projection (Exxon-Mobil \(\sim\) $55/MWh [20]).

In the sections that follow, we predict the evolution of Illinois RPS for this set of scenarios. We describe the details of the Illinois statute (Section 3); evaluate existing renewables capacity and site quality evolution as capacity is added (Section 4); calculate the REC prices needed to sustain renewables construction in both scenarios and compare them to the legislative cost cap (Section 5), and finally compute the necessary declines in the cost of renewables generation that are needed to meet the cost cap (Section 6). Throughout the analysis, when parameters are uncertain we adopt the assumptions that most favor renewables, to produce a robust test of RPS feasibility.

3. The Illinois Renewable Portfolio Standard

In its current form (after several amendments), the Illinois RPS will require that 25% of the state’s electricity consumption come from renewable resources by the year 2025. Requirements began at 2% in 2009 and will rise steadily to the ultimate goal of 25%, with targets based on the previous year’s sales. (The Illinois RPS and its phase-in are described in detail in [21]). The phase-in is similar to that of many other state RPSs (Figure 1), and as in other states, utilities demonstrate compliance through REC purchases\(^9\). The Illinois statute contains individual distinctive features, however, including specific carve-outs for particular renewable types and a somewhat loose preferences for local generation.

The Illinois RPS contains explicit mandates for individual technologies, requiring that \(\sim 70\%\) of the renewable portfolio be wind and that a gradually increasing fraction be solar. The Illinois RPS solar requirement begins in 2013 at a small fraction of the renewable portfolio (\(\sim 0.25\%\)) and ramps up by 2016 to 6% of the renewable portfolio.

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\(^8\)Renewable generation is a wholesale “price taker” since the most common renewables operate with low marginal cost and, moreover, reduce natural gas demand and potentially prices [19].

\(^9\)We have further assumed that all wholesale electricity price increases are passed directly into the retail prices additively.

\(^{10}\)In some cases, compliance may (or must) be achieved with Alternative Compliance Payments. However, revenue from these payments are used to purchase RECs and the payment amount each year is set by the previous year’s REC prices, effectively meaning that compliance is demonstrated entirely through REC purchases.
i.e. 1.5% of total electricity supply (6%×0.25)\(^{11}\). While the wind carveout will likely have no significant import since wind is the default (cheapest) renewable choice in Illinois regardless, the solar requirement does have significant implications, as suggested in Section 2, because of the large price difference between solar and wind\(^{12}\). The remainder of the portfolio may be satisfied with a typical list of qualified renewables – wind, solar (PV or thermal), landfill gas, biomass, biodiesel, or hydropower\(^{13}\) – but in practice the portfolio is likely to be met mostly with wind.

The Illinois statute expresses preference for local building of renewables capacity with in-state and neighboring-state restrictions, but the in-state restriction is short-lived. As of 2011, RECs may be purchased from qualified renewables not only in Illinois but in all neighboring states (Wisconsin, Indiana, Kentucky, Missouri, and Iowa). The regional requirement is further weakened by an opt-out allowing the regulating agency (the Illinois Power Agency, or IPA), to permit the purchase of RECs from other states at any time if the local resources are not in his or her judgment “cost-effective”. In practice, the IPA is granted wide discretion to void any requirement of local purchase.

The total burden on Illinois ratepayers is constrained by a “type 2” cost cap, with no limit on the price per REC but an absolute limit placed on the total cost of REC purchases. The cost cap is described in the statute in somewhat complex terms, and has a complex ramp up from 2007-2011, but from 2011 forward is a relatively simple absolute cap fixed at \(\sim 2\%\) of 2011 retail electricity sales, as discussed previously\(^{14}\). As the renewables requirement increases over time, the maximum allowable price per REC, if implementation is complete, drops from a peak of \(\sim $33/MWh\) in 2011 to \(\sim $7/MWh\) in 2025 (and then tightens slowly over time due to increasing electricity demand, though this is a secondary effect). These capped REC prices are significantly lower than the current renewables premium even after the PTC, as Table 1 shows, meaning feasibility of implementation is a concern.

\(^{11}\)The Illinois RPS was first passed in 2007 as part of Public Act 99-0481 and subsequently amended in 2009 by Public Act 96-0159, in 2010 by House Bill 6202 and in 2011 by S.B. 1652. The RPS was originally applicable to only investor-owned Electrical Utilities (EU’s); the 2009 amendment extended it to Alternative Retail Electricity Suppliers (ARES) as well, though somewhat differently in application. The total renewables requirement is the same but the wind carve-out is different, with EU’s required to supply 75% of their renewable portfolio from wind and ARES only 60%. This difference is unlikely to have practical significance as the portfolio is likely to be met almost entirely with windpower regardless. Because ARES and EU’s each supply approximately half of the state’s electricity, the effective statewide wind carve-out is \(\sim 70\%\) of the RPS, \(((0.5)(75\%) + (0.5)(60\%) \approx 70\%)\). EU’s and ARES’s are given the same final solar carve-out, at 6% of the portfolio, but are treated differently in the initial stages of the RPS. EU’s must ramp up their solar portfolios beginning in 2013 as 0.5% of the portfolio and rising steadily to 6% in 2016, after which the solar carve-out remains constant. ARES’s have no ramp up and their solar carve-out simply begins in 2016 at 6%. In addition, there is a 1% distributed generation requirement, though this is unlikely to have any import since there is already enough capacity in small wind generation in Iowa to meet the requirement.

\(^{12}\)The solar carveout accepts both solar thermal generation and photovoltaic (PV) generation, but given the price advantage of solar PV [3], we do not expect solar thermal to contribute significantly to the Illinois RPS.

\(^{13}\)Hydropower is a qualified renewable under the Illinois RPS provided that it does not require the building of new dams or significant expansion of existing ones.

\(^{14}\)The final cost cap is the greater of 2.015% of the 2007 retail sales or an incremental amount which, to good approximation, is 2% of the 2011 retail sales. See Appendix A 2 for more complete description of the terms of the IL cap.
4. Evolution of the Illinois RPS: Existing Capacity and Site Quality

An important factor in determining the success or failure of an RPS is the quality and availability of renewable resources. We therefore analyze the amount of pre-existing capacity that can be used to meet the Illinois RPS requirements, the amount of additional capacity that would be needed, and the quality of sites on which that additional capacity would be built. We restrict our analysis to wind, since existing solar generation is negligible in any of these states and solar insolation is roughly constant across the Midwest region. The Illinois solar requirement, if met, would be satisfied by new builds with negligible siting differences. The situation for windpower is different, however, both because wind speeds are spatially variable and because significant wind capacity already exists. We consider in the analysis only Iowa and Indiana in addition to Illinois, which we assume will be the dominant contributors to the Illinois requirement, since these states dominate regional wind resources and the other states in the eligible region with acceptable wind potential (Missouri, Michigan, and Wisconsin) have their own large RPS requirements. Indiana does have an RPS, but compliance is voluntary, and the Iowa RPS is such a small fraction of the state’s existing capacity that it provides little competition with Illinois for REC sales.

We find that existing capacity as of 2011 in these three states is sufficient to meet the majority of the Illinois RPS requirements: $\approx 85\%$ of the specific wind carveout and $\approx 65\%$ of the projected total non-solar requirements. Fulfilling the Illinois RPS requirements would require some new wind capacity builds, but the total required depends on site quality. Assuming the entire unrestricted RPS is met with wind (as is the overwhelming likelihood), total required new capacity would be 4 GW on the best Iowa sites with capacity factors of $40\%$; 7 GW on the best Illinois sites with capacity factors of $33\%$; and even greater volumes if site quality is lower. Since new generation facilities are rationally built on the most favorable available sites, investors must turn to less ideal locations as builds progress, lowering electricity yields and resulting in higher costs per unit of electricity generated. “Site-depletion” can lead both to increased total required capacity and to higher generation costs from increasingly poor siting. We therefore analyze site quality in the three states that are the most likely source of Illinois REC sales to forecast the location and cost of future wind capacity builds. (We optimistically neglect in this analysis constraints of access to

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15The Illinois solar carveout will require $\sim 1$ GW of solar generation capacity, but the eligible states have less than 0.01 GW of solar capacity [22].

16The energy derivable from wind is highly sensitive to its velocity, scaling as $v^3$.

17RPSs of Missouri and Michigan further favor in-state generation and will likely keep RECs produced in these states out of the Illinois market.

18The Iowa Utilities Board encourages and permits Iowa wind generators to sell RECs out-of-state (Iowa Utilities Board Order, Docket No. AEP-07-1).

19Existing capacity in the three states is already 6.7 GW, with the bulk in Iowa (3.7 GW) but significant generation also in Illinois (1.8 GW) and Indiana (1.2 GW). Since the total renewable generation ultimately required by the Illinois RPS is given as a fraction of electricity sales in 2025 (and thereafter), estimating it requires assuming a growth rate of electricity demand. We estimate that rate at 1% per year, consistent with EIA expectations [3]. Given Illinois 2010 retail sales of $1.4 \times 10^8$ MWh, this implies a requirement of non-solar REC sales of $4 \times 10^7$ MWh in 2025. Given capacity factors of 33% (typical for Illinois, whose best wind sites have average wind speeds of 7-7.5 m/s) to 40% (typical for Iowa, whose best wind sites have wind speeds of 8-8.5 m/s), the total 2025 installed wind capacity required by the Illinois RPS would be 8-10 GW for the wind carveout alone, and 10-14 GW for the total non-solar RECs.
transmission lines and other infrastructure. Those considerations could lead to use of sub-optimal wind sites and higher renewables costs).

Wind site quality in Iowa, Illinois, and Indiana has been extensively modeled as part of the Eastern Wind Integration and Transmission Study (EWITS) sponsored by the U.S. Department of Energy [24]. The study is itself based on an analysis of wind speeds known as the Eastern Wind Dataset [25], performed by AWS Truepower with coordination from the National Renewable Energy Laboratory. The Eastern Wind Dataset is a 3-year simulation of 10-minute wind speeds generated with a mesoscale model (two kilometer spatial resolution) driven by reanalysis input from the NCAR-NCEP Global Reanalysis and the North American Regional Reanalysis. The EWITS then uses these wind speeds to estimate site quality in terms of capacity factors, i.e. the ratio of estimated actual power output to name-plate power for a model wind turbine installation. (While the name-plate power or installed capacity is simply a measure of the size and number of turbines built, the actual electricity those turbines generate depends on the wind speed distribution at each site.) We use the EWITS capacity factors in our analysis, but do not use the estimates of potential wind farm power output subsequently derived from them. The power output estimates are based on a modeled turbine spacing and therefore installed capacity per area that appears excessively high, exceeding that of existing wind farms in the three states more than threefold[20][26]. We therefore use the surveyed turbine spacings of Denholm et al. [26] (2009) and assume there is some error in the EWITS. Note that this choice does not affect the comparison of relative site quality.

Even with this adjusted estimate of site capacity, Illinois, Iowa, and Indiana have more than sufficient wind potential to meet the Illinois RPS using only wind sites currently considered suitable for commercial wind installations (Figure 2). Indeed, site depletion is negligible regardless of which state windpower would be sited in. Each state is able to meet the entire Illinois RPS on sites with capacity factors dropping no more than 12% (34-30% for Indiana and Illinois; 41-38% for Iowa). However, Iowa sites are clearly superior to those in Illinois or Indiana, meaning that under the legislation as currently written, we would expect the majority of the wind installations stimulated by the Illinois RPS to be built in Iowa. The initial terms of the legislation, with an Illinois-only preference, do suggest that a part of the legislative motivation was in-state job creation. It seems possible then that the Illinois legislature may revisit the siting requirements as evolution of the RPS becomes clear. In the remainder of analysis we therefore consider cases both of the legislation as it currently stands (with wind builds to occur in Iowa) and also of a potential future amendment that reinstates the in-state requirements (so that wind builds occur in less wind-endowed Illinois).

To calculate the capacity factor, EWITS uses the distribution of simulated wind speeds, averaged on ten-minute intervals, to produce a distribution of turbine power outputs, for three possible turbine choices. The average electrical power produced, and therefore the capacity factor, is then extracted from the power output curve of the optimal turbine choice for the site in question. Finally, the EWITS assumes a turbine spacing and estimates a total power output per area of wind farm. Assumed turbine spacings appear excessively high, however. Average EWITS modeled wind farm installed capacity per area in IL, IN, and IA are 13.9 ±0.3, 11.9 ±0.4, and 11.2 ±0.3 W/m², respectively. Actual wind farms in IL, IN, and IA compiled by [26] average 4.0 ±0.4, 2.4 ±0.6, and 3.3 ±0.5 W/m² respectively [26]. It is possible that spacing in existing farms is unnecessarily broad, but a 2010 NREL study of windpower potential assumed an installed capacity per area for Illinois of only 5 W/m² [27]. Note that the standard rule of thumb of turbine spacing of 5 rotor diameters perpendicular to the prevailing wind and 10 rotor diameters along it for a typical 2 MW turbine yields a capacity density of 5.4 W/m².
Figure 2: Estimated capacity factors for new wind generation installations as a function of total installed wind capacity in Illinois and the two most wind-endowed neighboring states (Iowa and Indiana) that will be permitted to sell RECs to satisfy the Illinois RPS after 2011. (The other RPS-defined neighboring states – Wisconsin, Missouri, Kentucky, and Michigan – would not be competitive for wind generation). Since capacity factors directly factor into profitability, sites with higher capacity factors will be (or have been) built on first; as wind penetration grows, marginal capacity factors decrease. Capacity factors here are from the Eastern Wind Integration and Transmission Study and turbine spacing is based on reported wind farm characteristics in the three states [26]. Vertical lines denote existing capacity in Iowa, existing capacity in the combined three states, and capacity required to meet the Illinois RPS non-solar requirement, which we assume will be fulfilled largely by wind. The requirement is calculated as described in the text, assuming a 1% annual growth of electricity demand. Currently existing capacity in the three states is sufficient to meet 65% of the total non-solar Illinois RPS requirement (and ≈ 85% of the wind-specific requirement). Note that for future builds, the worst plausible wind sites in Iowa are comparable to the best sites in Illinois or Indiana, suggesting that economics would drive future builds to Iowa.

5. Evolution of the Illinois Renewable Portfolio Standard: Renewables Premium versus the Cost Cap

While the lack of site depletion effects is helpful for RPS implementation in not driving renewables costs higher, fulfilling legislative goals would require actual decreases in renewables premiums. In the following two sections we determine the conditions that would permit complete implementation of the Illinois RPS, first by comparing the evolving cost cap with the REC prices necessary to support investment at current renewables costs (in both electricity price scenarios outlined), and then by computing the necessary renewables cost drops.

Predicting the evolution of Illinois REC prices under the cost cap must require some
assumptions, because although the total cost cap is set by the terms of the RPS legislation (Section 3), the available subsidy per unit of renewable electricity in conditions of fulfillment of RPS requirements depends on the amount of renewables generation required, which in turn is set by electricity demand. We assume that demand grows at an annual rate of 1% from reported IL electricity sales in 2009 [22], consistent with EIA expectations [3]). With this assumption, the mean REC price allowed under the cost cap grows from its initial statutory limit of $25/MWh in 2008 to $33/MWh in 2011 as a loosening cap outpaces growth in renewables requirements, and then after 2011, when the cap is fixed but requirements still grow, steadily drops to a 2025 value of $7/MWh. Both the statutory increases in renewable portfolio fraction and secondarily the growing volume of electricity sales produce this gradual tightening of the available subsidy per unit of renewable electricity.

Estimating the necessary subsidy needed to drive investment in new renewables installations also requires assumptions, even when using current renewables premiums, because of the details of financing of renewables installations and the complicated nature of the requirements for the Illinois RPS. The necessary REC prices for the wind and solar carve-outs in the Illinois legislation can be derived from current renewables premiums for the respective technologies, but the remaining ~ 24% of the RPS can be met with any eligible technology. While wind is currently the cheapest renewable [8], in past years the unconstrained RECs have been trading in the Illinois market at some discount to wind-specific RECs 21. As a most optimistic, though not necessarily most realistic estimate, we assume that the historic discount persists for the remaining phase-in period of the RPS, with unrestricted REC prices remaining at 65% of the wind REC price.

To determine the wind premium, we first estimate wind costs by tallying installation and maintenance costs using information from [28] and estimating capacity factors as per Figure 2. For both wind and solar, we assume optimistically that the PTC is renewed and remains in force, and neglect all taxation expenses. Cost estimates include a contribution from integration costs (provision of backup generation capacity), but neglect transmission costs, as these may not be borne by the renewables generators. We assume financing via a 20-year loan at 6% interest rate, and assume that wind-generated electricity is sold at the current Illinois wholesale electricity rate of $35/MWh (3.5 cents/kWh) [15, 20]. The resulting wind premiums inclusive of the PTC, and therefore the necessary REC prices, are then $15/MWh and $20/MWh for stimulating investment in Iowa and Illinois, respectively. (Note that these premiums are slightly higher than the nationwide numbers of Table 1 because of Illinois’ low electricity prices, which make the state less favorable for renewables. See Appendix A.1.1 for full derivation and further discussion.)

Solar premiums are more difficult to estimate even at present, because the cost of solar experienced a significant drop in 2011. We use in this analysis third-quarter 2011 costs as tracked by the SEIA [30], $3.45/Wp install cost which translates to $245/MWh before the PTC in Illinois and $170/MWh after it. In the higher insolation Southwest these costs would translate to $130/MWh after the PTC, which is broadly consistent with actual power purchase agreements (PPAs) signed in 2011 Q4 in California that range from $110-145/MWh [31] (See Appendix A.1.2 for full calculations and discussion). Costs are still in flux, however, and recent California solar generation contracts and unpublished industry

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21In 2011 unconstrained RECs traded at 65% of wind RECs; in 2010 at 88%; and in 2009 at 65%.
information suggest that the cheapest solar projects may now achieve costs as much as ∼30% lower than the 2011 SEIA values [32, 33]. While some part of those low projections may be due to temporary oversupply in the panel market, we include these estimates in this analysis as a lower bound on uncertain current solar costs and show the uncertainty range in figures. (See Appendix A.1.2 for full derivation of costs and further discussion). In this analysis we use only values for utility-scale generation, because costs and solar premiums are lowest for this size class. (Small-scale residential installations are nearly twice as expensive, although that difference is offset somewhat by the fact that residential generators in Illinois are permitted net-metering, i.e. to essentially receive retail rather than wholesale prices). As with wind, we assume projects are financed with a 6%, 20 year loan. With these assumptions, the REC price needed to drive solar investment in Illinois becomes with the SEIA estimates $130/MWh, nine times that needed to support wind. With the most optimistic cost estimates, the premium is $80/MWh. Regardless of the uncertainty in solar costs, it is evident that current necessary price supports of $15/MWh for wind, $10/MWh for unrestricted renewables, and $80-130/MWh for solar power do not permit fulfillment of an RPS with an eventual $7/MWh average cost cap of the RPS. Successful implementation of the Illinois RPS requires some significant change to the economic landscape for renewable power generation.

The infeasibility of the Illinois RPS in the current cost landscape is also readily seen by comparing the tightening cost cap to the available price supports (Figure 3). While the available subsidy in 2011 exceeds the renewables premium, that situation will change as the RPS requirements ramp up and so the cost cap tightens. The discrepancy between available subsidy and needs is exacerbated by the ramp-up of the solar requirement beginning in 2012, but even amending the RPS to remove the solar requirement would not make full implementation feasible in the current cost landscape. Amending to restrict wind to Illinois would make fulfillment significantly more difficult. Figure 3 shows that the cost cap would be “broken” – i.e. the mean necessary REC price for full implementation would exceed the permissible cap – by 2015 for the existing legislation and 2014 if amended to Illinois-only.

In fact, the cost cap is already “broken” in a more relevant sense: already in 2011, the cost cap projections averaged over the lifetime of a renewables facility (20 years) do not provide the subsidy necessary for investors to recover their costs in a situation of full implementation (dashed line in Figure 3). If renewables investors are rational, construction of new capacity will continue only at a rate too low to permit full implementation. This legislative failure may not be apparent for another decade, though, since oversupply of capacity will keep REC prices low. Existing capacity in IL, IA, and IN is sufficient to meet projected Illinois RPS requirements until 2020, and only then will new capacity requirements force REC prices to rise. (This projection depends on the isolation of IL, IN, and IA from other REC markets; if demand from other state RPSs competes with Illinois, the failure may set in earlier).
Figure 3: The IL cost cap (red), 20-year averaged cap (dashed red) and mean REC under various scenarios (black) as a function of time. Scenarios include possible amendments to the RPS to restrict wind to Illinois and to remove the solar carveout. The cost cap estimates are based on full compliance with statutory requirements, on 2009 electricity consumption, and on assumption of 1% annual growth. The mean REC rate is estimated using current wind and solar costs and electricity prices; see Appendix A.1.1 and Appendix A.1.2. The cap initially increases as its statutory loosening outpaces the ramp-up of RPS requirements, but then decreases from 2011 when the cap is fixed but renewables requirements continue to grow. The times when necessary REC rates exceed the cost cap are marked with black dots both on the cost curves and on the x-axis below. These mark times when new generators would be unable to recover their annualized costs even in first year of operation. Even with if the solar requirement is removed and permission to use Iowa wind remains, the REC rate exceeds the cap by 2017. The 20-year averaged cap decreases steadily from a high of $16 per REC in 2008 to around $6.50 in 2025. The only period when the 20-year average cap exceeded necessary REC support, allowing new builds, was prior to 2010.
Figure 4: The IL cost cap (red), 20-year averaged cap (dashed red) and mean REC rate under various scenarios (black) as a function of time, with wholesale prices rising linearly from the current value of $35 per MWh to a peak of $55 per MWh in 2025. The cost cap estimates are again based on full compliance with statutory requirements, on 2009 electricity consumption, and on assumption of 1% annual growth. The mean REC rate is again estimated using current wind and solar costs; the wholesale rate increases are assumed passed directly to the retail rate. See Appendix A.1.1 and Appendix A.1.2. With strong increases in wholesale rates, the instantaneous cap is not broken with Iowa wind and drops below the 20-year averaged cap in 2024. With Illinois wind, the instantaneous cap is broken in 2014. If the solar carve-out is removed and Iowa wind permission continues, necessary REC support falls below the 20-year averaged cap by 2014, well before new builds must resume in 2020.
The previous analysis assumed current electricity prices; we repeat the analysis for the scenario of a 60% increase in electricity prices by 2025 described previously (Figure 4). The rising electricity prices mean that Iowa wind generation would reach grid parity by 2024 (presuming the PTC is renewed) and require no subsidy. The entire RPS subsidy would then be devoted to the solar requirement, and the RPS could achieve full compliance below the cost cap, but only after 2020-2024.


RPS success can be ensured by various combinations of three factors: decrease in solar costs, decrease in wind costs, and increase in electricity prices. In this section we explore combinations that would permit fulfillment of legislative goals, i.e. that would provide sufficient incentive for renewables builds with an ultimate average cost cap of $7/MWh. We show the wind and solar costs necessary for RPS fulfillment at current electricity prices in Figure 5 and at a series of increasing electricity prices in Figure 6. In Figure 5, conditions of RPS success even with Illinois wind are marked in green, of success with Iowa wind in yellow (plus green), and of failure in red. Although the PTC is also a major factor in RPS success, we do not consider cases in which the PTC is not renewed, as RPS success is almost prohibitive without it. Because current solar costs are somewhat uncertain, we have marked both the SEI 2011 Q3 cost and a lower estimate based on unpublished estimates of the lowest cost 2011 projects [33].

If electricity rates remain flat, both solar and wind costs must likely decrease substantially in order for the Illinois RPS to succeed as written (Figure 5). Wind costs must drop by at least 15% (to $1.7/W install cost and cost reductions are proportional in both installed and O&M costs) for RPS success, even were solar at grid parity given the PTC (henceforth “PTC grid parity”). If solar costs at present are as stated by the SEIA, solar must drop by at least 6% (to $3.24/Wp) even if Iowa wind were at PTC grid parity. PTC grid parity for either technology is far from certain, however, as it would require reductions of 30% for Iowa wind and 75% for solar (to $1.4/W and $0.9/Wp, respectively). In more plausible success scenarios where both technologies continue to require addition subsidy from REC sales, their necessary cost decreases trade off against each other because both are included under a single cost cap. The resulting “parameter space” for RPS success is then irregularly shaped, with vertical or horizontal boundaries if one of the technologies reaches grid parity and a sloping boundary if both technologies require RPS subsidy. In this tradeoff region, drops in the cost of either technology can be viewed as freeing up RPS funding under the cost cap that can be used to support the other technology instead.

Higher electricity prices reduce renewables premiums and make the success of the Illinois RPS more feasible (Figure 6). The benefits of higher electricity costs are stronger for wind than they are for solar. For wind, each $5/MWh increase in electricity prices reduces the necessary wind cost decrease by ten percentage points (i.e. $0.2/Wp), so that a rise of less than $20/MWh brings wind to PTC grid parity. Were wind at PTC grid parity, each $5/MWh increase in electricity prices would reduce the necessary solar cost decrease by only three percentage points (i.e. $0.1/Wp). This difference in relative benefit occurs because solar costs are still so high that the bulk of solar income is subsidy and so increasing electricity prices provide a smaller relative relief from necessary support. (For utility-scale solar facilities at the SEIA 2011 Q3 costs, average solar revenue from
Figure 5: Wind and solar costs needed for success of the Illinois RPS given current electricity rates, inclusive of support from the PTC. Required costs are determined by setting the mean REC rate equal to the $7 per REC cap and solving for the necessary solar cost as a function of the wind cost. (Unrestricted RECs are assumed to trade at their current discount). The parameter space which leads to RPS failure is marked in red; that of success with an Illinois-only wind restriction in green; and that of success with Iowa wind but failure with an Illinois restriction in yellow. Points of interest are marked with letters along both axes. Axes show both install costs (in $/W full capacity for wind and $/Wp for solar), the resulting levelized cost of electricity and expected REC prices (post-PTC premium), assuming capacity factors typical of the Midwest for solar and Iowa for wind. Since the current cost of solar is uncertain, we mark the likely range with two dots and an arrow. All are shown as true costs, without the PTC, (which reduces effective costs by roughly 30%). At current renewables costs (upper right corner) the RPS would clearly be in failure, even were solar costs at the lower edge of current estimates (tip of arrow). If solar install costs are above $3.24/Wp (A), the solar carveout would break the cost cap on its own even were wind at PTC grid parity. Wind would reach PTC grid parity at $1.2/W for Illinois wind or $1.4/W for Iowa wind (D), drops of 40% and 30% from current costs. For solar to reach PTC grid parity, install costs must fall to $0.90/Wp (B), a drop of 75% from 2011 Q3 SEIA estimates. If solar did reach PTC grid parity, or if the solar carveout were removed and all subsidy could go to wind, the necessary wind install costs would be $1.2/Wp with an Illinois restriction (E) and $1.7/Wp without (F), cost reductions of 25% and 15%. If neither technology is at PTC grid parity, the necessary cost reductions trade off against each other (diagonal line), although not with a 1:1 slope.

Increased electricity prices do benefit solar strongly in an indirect way, however, if wind is not yet at grid parity, by freeing up cost cap dollars that would otherwise be needed to subsidize wind generation. Once wind has been brought to grid parity, further electricity rate increases have little effect on solar cost-effectiveness, but at that point conditions allow or are very near to permitting complete fulfillment of the RPS, with minimal further necessary drops in solar costs. In this scenario, higher electricity prices can ensure RPS success by reducing the support necessary for wind and permitting the full RRS subsidy to support the solar carveout.
Figure 6: Wind and solar costs needed for success of the Illinois RPS at various wholesale electricity prices. Costs are shown both as installed ($/Wp) and levelized cost of generated electricity ($/MWh) without the PTC. (The PTC reduces effective costs by roughly 30% for both technologies). Since the current cost of solar is uncertain, we mark the likely range with two dots and an arrow. Lines represent the minimum costs needed for RPS success at each labelled wholesale electricity price. Calculations of feasibility assume the RPS remains as written, i.e. that Iowa wind is permitted at 40% capacity factor and that the PTC remains in force. For every $5/MWh increase in prices, the allowable wind install costs increase by 10% ($0.2/Wp). If the wholesale rate hits $55/MWh, wind reaches PTC grid parity even at current costs (horizontal line), permitting all subsidy to go to the solar carveout. In that case, the Illinois RPS goals are achievable even at the higher end of current estimates of solar costs. If solar costs lies at the lower end of those estimates, the Illinois RPS could be fulfilled given a rise in electricity prices of ∼ 30% (to ∼ $47/MWh).

7. Discussion

Some partial validation of the above analysis can be derived from considering the brief history of the Illinois RPS to date (2008-2011). The RPS has achieved full compliance in each year since implementation, with wind REC prices consistently decreasing, from $32.50/MWh in 2008 to $19.78 in 2009 [21], to $4-$5 in 2010 and ~ $1 in 2011[34, 35]. These decreasing REC prices do not reflect the subsidy needed for new builds, though, but instead the condition of oversupply in the REC market, as existing capacity in eligible Midwest states is more than sufficient to satisfy the current Illinois RPS requirements. This oversupply appears to have driven the Illinois REC price down to that of the nationwide REC market [15]. A more reasonable proxy for the subsidy needed to stimulate investment is the long-term REC price given to renewables facilities that have negotiated 20-year contracts to supply RECs and electricity to Illinois utilities. The average price for bundled electricity and RECs under these agreements ranges from $50 and $55/MWh in 2010 for the two largest utilities in Illinois, Ameren and ComEd. Given the current wholesale electricity price of $35/MWh, these values suggests a necessary subsidy of some $15-20/MWh, very similar to our estimated premiums. (It could also be possible that current premiums are higher, leading to losses at present, but that investors expect a
long-term increase in wholesale prices and so more profitable conditions later). If renewables premiums are as high as we have estimated and as the long-term REC prices suggests, then it is inescapable that the Illinois RPS cannot succeed without significant changes to the renewables and electricity cost landscape.

It is also worth reiterating that there is no plausible means of meeting RPS objectives under the cost cap in any scenario if the federal PTC is not renewed. For wind in particular, the Illinois state RPS merely tops up the subsidy of the PTC, which provides twice as much support as would 2025 capped REC sales (Table 1 and Appendix A.1). The same conditions hold for other states with similar cost caps. The dependence on the PTC is also significant in light of recent proposals for a federal RPS. If such a federal RPS replaces the PTC, federal REC prices would have to rise considerably over current state-level REC prices, because they would have to reflect the full cost of renewables, including the subsidy currently provided by the PTC. A cost cap on a 20% federal RPS would therefore need to be significantly larger than current state caps to have similar feasibility of success: e.g. 6% of the retail rate for a federal RPS to be analogous to the Illinois cap of 2% of retail sales in the current cost landscape.

Our analysis suggests that even with a continued PTC, the success of the Illinois RPS hinges on cost decreases for renewables that are possible but not certain. The least uncertain forecast is that of wind costs, since the wind industry is relatively mature, though that maturity also means that potential fractional cost decreases are not large. In 30 years of wind turbine installation from the early 1980s onwards, the cost of installed windpower steadily decreased up until 2001, then plateaued and actually increased by 25% through 2010. That trajectory is characteristic of a maturing technology whose initial large efficiencies of scale and technological advancements have already been captured. Turbine price increases over 2001-2010 were driven by a combination of factors including supply shortages, increased materials and labor costs, and increased design complexity. These factors seem to be relaxing somewhat, and installed costs decreased by ~10% in 2011. Nevertheless, cost projections from the EIA suggest that the wind premium will remain at or above current levels through 2020.

Solar costs may have more room for movement than those of wind, since the industry is less mature and both manufacturing and technology breakthroughs are possible (as suggested by the sudden drop in panel cost in 2011). The necessary solar cost for RPS fulfillment depends steeply on wind cost evolution, though. A wind cost drop of 32% puts wind in PTC grid parity, at which point the needed solar cost drop is only 6% from SEAI 2011 estimates, readily achievable (or already achieved). But if wind cost drops are slightly less strong, the pressure on solar grows sharply. If wind costs drop 15% the minimal needed for RPS fulfillment, solar power costs would need to drop by 75% to PTC grid parity, a likely prohibitive requirement. The solar cost reductions of the last

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22 A similar transfer of subsidy to REC prices has been previously seen in New Jersey, where the solar market was supported by both a rebate program and by REC sales until 2007. When rebates were eliminated, REC prices jumped to compensate for the lost subsidy (pers. comm. with Benjamin Hunter, Renewable Energy Program Administrator with the Office of Clean Energy, New Jersey BPU).

23 Over the last decade, wind installed costs increased from a low of ~ $1.5 per W of nameplate capacity in 2001 to the ~ $2/W in 2009, driven largely by increases in turbine prices which doubled from $0.7/W to $1.5/W over the same time period.

24 More distantly, the EIA suggests wind costs may decrease again between 2020-2035, largely after the Illinois phase-in, to bring wind near grid parity in 2035.
decade (first a steady $\sim 3\%$/year reduction and then an abrupt 2011 drop) have been driven largely by reduction in module prices [30]. Solar generation costs are now in fact dominated by installation, integration, and other expenses, with the modules themselves a secondary factor. Current estimates of module costs of $1/W_p$ mean that of the SEIA utility-scale costs of $3.45/W_p$, $2.45/W_p$ is taken up non-module expenses [36, 37]. For this reason caution should be applied when envisioning steep reductions in solar costs, especially on short timescales. Recent cost figures do suggest that sharp improvements in non-module costs are already occurring: best-in-industry solar costs of $2.50/W_p$ with an estimated $0.80/W_p$ module cost imply that some firms have achieved an over 40% reduction in non-module expenses [36, 33]). Nevertheless, solar would achieve PTC grid parity only with total costs less than $1/W_p$, highly unlikely in the timeframe of the Illinois RPS.

In summary, while the Illinois RPS may prove feasible through continued reductions in wind and solar costs and/or an unforeseen rise in wholesale electricity rates, it is also possible that the legislation may not be fully implemented as written. We note that the combination of price supports for both solar and wind under a single cost cap exacerbates the danger of non-fulfillment since it allows the technologies to have pernicious effects on each other: any technology that does not meet cost expectations will curtail deployment of the other. If cost reductions in either technology do not materialize, REC markets would remain high, since investment could not proceed otherwise, and total spending would be driven up to the legislative cost cap, triggering a freeze on the renewables requirement. Illinois ratepayers would then find themselves paying a higher subsidy per unit of renewable energy than they had intended. In this failure mode, both individual subsidy levels and the overall outcome may be significantly out of line with voters’ and legislators’ expectations. It is also useful to note that “meeting cost expectations” has differing meaning for solar and wind. Because windpower is closer to PTC grid parity, equivalent fractional drops in costs disproportionately alter the relative levels of support that wind and solar need. In the present cost landscape, meeting the final Illinois RPS wind and unrestricted requirement would take twice the subsidy as would meeting the final solar carveout. In virtually all scenarios of RPS success, though, the subsidy absorbed by the solar carveout exceeds that provided to the remaining 94% of the renewable portfolio.

8. Conclusions

Analysis of the conditions that allow success of the Illinois RPS highlights the danger of combining multiple objectives in a single piece of legislation. The different objectives that can underlie RPS legislation may be in conflict, and that conflict can result in unforeseen and undesired consequences. (See also [21]). The desire for lower prices can be in conflict with the goal of local jobs creation. Local job stimulation from the Illinois RPS is likely to be quite small, as existing wind farms in IL, IN, and IA alone can satisfy the Illinois RPS for a decade, and under current statutory language, new builds thereafter would almost certainly occur in more wind-endowed Iowa. The evolution of the Illinois RPS then would largely involve transfer of ratepayer dollars to Iowa (though longer-term, wind projects in Iowa may benefit the Illinois economy indirectly by boosting Illinois manufacturing [38]). Restricting qualifying renewables to new facilities would however cause currently depressed REC prices to rise, and restricting new builds to Illinois would
again raise REC prices and hinder RPS success under its cost cap. The local-vs.-cheap conflict occurs in the case of solar as well. Although there is no meaningful difference in insolation between the Midwestern states currently eligible for solar REC sales under the Illinois RPS, restricting eligibility to the Midwest and excluding sunny states such as AZ, NV, and CA makes solar power some 30% more expensive than if drawn from the best solar sites. Removing siting restrictions on qualifying solar facilities would make fulfillment of the Illinois RPS more feasible, but at the tradeoff of transferring funds out of state.

The objectives of helping renewables industries and mitigating climate change may also be in conflict. Because solar electricity generation is substantially more expensive than windpower at present, and therefore requires higher price support per unit of energy, distributing subsidy to solar generators does not produce the greatest reduction in carbon emissions. The equivalent carbon price needed to support solar energy, even after the PTC, is currently nearly $120/ton CO$_2$ (Table 1). For a given amount of spending, the greatest climate change benefit in the short term is obtained by supporting the most cost-effective carbon-free generation technology, i.e. windpower (or possibly carbon sequestration, which is not covered by either the RPS or the PTC). In the long term, of course, the additional solar builds driven by solar requirements in state-level RPSs may help the industry reduce costs, and this assumption likely forms part of the underlying legislative motivation. Finally, the co-mingling of requirements for different technologies under a single cost cap means that either of the technology carve-outs in the Illinois RPS can throw the legislation into failure mode if its costs do not drop sufficiently, freezing requirements for all renewables. This destructive interaction is the most easily addressable conflict inherent in the Illinois RPS, however, as it can be eliminated simply by amending the statute to divide the cost cap between the two technology requirements.

The similarity of state RPSs suggests that the Illinois experience is not likely to be unique. The similar timescale for implementation of most state-level RPSs implies that many states may face similar difficult decisions in upcoming years as their cost caps tighten. The Illinois RPS can therefore offer lessons that help guide not only expectations of existing RPS evolution but design of future legislation. Most simply, legislators can wherever possible attempt to insulate overall legislative success from the failure of individual assumptions and goals. Independent cost caps on separate technology requirements are an obvious solution that avoids pernicious effects of one technology on another. More broadly, it is useful be clear on the relative importance of different objectives and to transparently evaluate the inevitable tradeoffs. Analysis both of conditions necessary for success and of the likely evolution of the RPS in failure mode should be part of the legislative design process. If RPS success requires substantial cost decreases in renewables, it is worth evaluating whether the RPS can help bring about those decreases. Most importantly, once the cost landscape is made clear and legislators and ratepayers are unified on goals for renewable energy, the legislation should be crafted to permit those objectives to be met. While an RPS may have some indirect benefits even if it does not meet its renewables goals\textsuperscript{25}, the key design criterion should be maximizing the likelihood of the success of the legislation, since an RPS that fails can result in misallocated outlays with suboptimal environmental benefit and loss of public support for renewable energy.

\textsuperscript{25}Indirect RPS benefits even in failure mode include changes to planning and zoning laws, creation of REC markets, and acknowledgement of transmission problems [39]
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Appendix A.

Appendix A.1. Renewables Premiums

At present, the cost of generating electricity from most renewable technologies exceeds that of generating electricity from conventional fossil-fueled sources. In this paper we define the “renewables premium” as the excess cost of renewables generation over the market value of that electricity (which is largely set by conventional generation). The renewables premium is then the additional subsidy that must be received by renewable investors in order to drive investment in the renewables industry at current prices. Note that the relevant factor for investors is the renewables premium over the lifetime of the facility; investors may build in conditions of insufficient current subsidy if they expect future increases in electricity prices that effectively reduce the renewables premium.

The renewables premium is necessarily technology-specific, not only because of differing costs for the different renewable technologies but because of differing prices received for the sale of electricity generated. Although electricity is an entirely fungible product – once it is on the grid, electricity produced by a wind farm cannot be distinguished from that from a coal plant – individual generators do not necessarily receive the mean wholesale price because electricity may be sold on an hourly basis, with prices varying both diurnally and seasonally. Some renewables also have different modes of sale (long-term contracts or net metering for solar).

The renewables premiums for a given technology is then given by

\[ RP_i = C_i - P_i \]

where \( RP_i \) is the renewables premium for renewable technology \( i \), \( C_i \) is the cost of generation, and \( P_i \) is the market value of the electricity produced. All these terms are normally expressed in units of $/MWh.

The cost \( C_i \) is the levelized cost of generation, given in current dollars, defined as:

\[
\frac{(\text{install cost})(\text{amortization}) + (\text{fixed O&M})}{(\text{hr/yr})(\text{capacity factor})} + (\text{marginal O&M}) + (\text{integration cost}).
\]

The first term describes fixed costs, divided by the total energy produced; the latter two terms describe costs that are incurred as a function of energy produced. The amortization factor accounts for the cost of financing upfront expenses and is set by the interest rate and loan period. (Amortization is the process of repaying a debt over time in regular installments). The amortization rate used here is the percentage of the loan amount (install cost) that must be paid annually. Fixed O&M costs are those which are incurred regardless of whether or not generation occurs. Since they are typically given in the literature as annual costs per unit capacity, they are not multiplied by an amortization factor. The (hr/yr) factor translates an annual cost in $/MW per year into $/MWh.

The PTC and ITC (“PTC” throughout this paper) are federal-level subsidies that effectively reduce the cost of renewables generation by reimbursing qualifying renewable projects for up to 30% of the initial construction cost. The ITC, originally enacted in 2008, offers qualifying renewables (which include small wind and solar) a tax credit of
30% of costs\textsuperscript{26}. The PTC, originally enacted as part of the Energy Policy Act of 1992, initially offered qualifying renewables (which include all wind and solar) a somewhat less advantageous subsidy of a tax credit per unit of energy generated of $22/MWh for wind and $11/MWh for solar for the first ten years of operation only. The PTC has been renewed and modified numerous times since 1992, however, and its most recent incarnation (via The American Recovery and Reinvestment Act of 2009) allows eligible facilities in service prior to 2013 to opt to receive the more favorable ITC subsidies instead. In practice all generators take this option. The combined effect of the PTC / ITC in their current forms is that all wind and solar facilities receive a 30\% subsidy, with new, large wind facilities (>100 kW capacity) receiving it through 2012 and solar facilities through 2016, when the ITC itself expires. Throughout this paper we assume that both statutes will be extended in their current form through 2025, because the analysis would be moot otherwise: Illinois and other state RPSs almost certainly cannot succeed without the federal support. We estimate the value of the PTC (in $/MWh) for each technology (wind and solar) simply by taking the product of the installed cost, the amortization rate, and the PTC fraction (30\%) and dividing by the annual energy produced. That PTC value is then subtracted from the estimate of generation cost $C_i$.

We discuss below the remaining inputs and assumptions used to derive the renewables premiums for wind and solar used in this work. Throughout this paper, when parameters are uncertain we adopt the assumptions that most favor renewables.

Appendix A.1.1. Wind Premium

Generation costs. The cost of wind generation ($C_{wind}$) is dominated by the cost of wind turbines, but turbine installation, operations and maintenance, and grid integration contributions are not negligible\textsuperscript{[lp]}. In this work wind install costs are taken as $2 \mbox{ Watt of peak capacity}$, as estimated for the U.S. in 2011 by Wiser et al 2011 (\cite{15}) at Lawrence Berkeley National Laboratory, who assembled a historical record of U.S. wind costs from sources such as the EIA, FERC, SEC, state-level public utilities commissions, Windpower Monthly magazine, and the AWEA. The 2011 estimate represents a 10\% drop from 2010 costs. Over the past three decades, U.S. wind install costs decreased from $\sim 5 \/mbox{/W}$ in the 1980’s to a low of $1.5 /W$ in 2000, and then rebounded to nearly $2.2 /W$ in 2010 (costs are stated in dollars per Watt of name-plate capacity). The price increases of the last decade were driven largely by turbine prices which were raised by supply shortages, increased material costs, increased design complexity, and manufacturers’ unwillingness to tolerate the low profit margins of previous years\textsuperscript{[lp]}. Some of these upward price pressures are relaxing, but it is not clear that turbine prices will fall back to the 2000 low (a 30\% drop).

Note that installed generation capacity costs are independent of site quality. To determine the cost per actual electricity produced, they must be multiplied by a capacity factor: the actual output of a generator over a period of time divided by the output if the generator were always operating at full nameplate capacity. Capacity factors of existing facilities in the United States range from 20\% to nearly 50\%\textsuperscript{[15]}. In this work we adopt two different capacity factors to represent excellent wind sites (typical of Iowa)\textsuperscript{[lp]}.

\textsuperscript{26}The American Recovery and Reinvestment Act of 2009 modified the ITC by allowing generators to receive a Treasury Department grant rather than a tax credit.
and merely good sites (typical of Illinois), using 40% and 33%, respectively, drawn from the wind-site analysis in Section 4.

We assume here that capital expenditures on wind installations are financed by a twenty-year loan at an annual interest rate of ~ 6%, making the amortization rate 9%. A 6% interest rate is on the lower end of the range of rates collected by [15], so this assumption is slightly optimistic for windpower, but consistent with the benchmark value of 5.8% used in a 2008 NREL study of the effect of financing variables on wind costs [40]. A study of financing costs for Euro-area onshore wind (World Economic Forum, with data collected by Bloomberg New Energy Finance) suggests 2011 interest rates of ~ 6% [41], only a few tenths of a percent above the 2008 U.S. rate. From the compilation of [15], twenty year loans are currently being offered for windpower projects, though most loans are shorter, making a twenty year duration a slightly optimistic assumption. The optimistic assumptions on loan duration and rates make our windpower costs some 10% lower than if mean values in [40] were used.

Operations and maintenance costs as reported by new wind facilities are again collected by [15], who estimate a mean of ~ $ 10/MWh. (Wind generation is characterized by both fixed and marginal O&M costs, but the costs in [15] have been converted to the unit $/MWh, giving the appearance of being marginal only). Integration costs, which include provision of backup capacity to buffer intermittent renewable generators, are estimated by the AWS Truewind survey at ~ $5 per MWh [25] by simulation of incorporating windpower into the electricity grid of the Eastern United States. Note that some fraction of integration costs might not be borne by generators themselves, resulting in an additional implicit subsidy and reducing the renewables premium slightly, but the amount is so small relative to total wind costs that it does not significantly affect the overall analysis. We do not include the costs of building additional transmission (which are expected to be small, $3.5/MWh, <5% of generation costs [3]), on the assumption that these too would not be borne by individual renewables generators and so not relevant to RPS feasibility. (In fact, if transmission costs are reflected in wholesale rates, they benefit renewables by driving up their electricity revenue and reducing renewables premiums).

The resulting levelized cost of wind generation then becomes $65/MWh at a 40% capacity factor and $75/MWh at 33%. We neglect costs associated with taxation (i.e. we essentially assume the maximum possible accelerated depreciation).

\[
\left( \frac{\$2/W}{(8760 \text{ hr/yr})(0.40)} \right) \left( \frac{10^6 \text{ Wh}}{\text{MWh}} \right) + \left( \frac{\$10}{\text{MWh}} \right) + \left( \frac{\$5}{\text{MWh}} \right) \approx \$65/\text{MWh}
\]

\[
\left( \frac{\$2/W}{(8760 \text{ hr/yr})(0.33)} \right) \left( \frac{10^6 \text{ Wh}}{\text{MWh}} \right) + \left( \frac{\$10}{\text{MWh}} \right) + \left( \frac{\$5}{\text{MWh}} \right) \approx \$75/\text{MWh}
\]

These cost estimates are consistent with wind cost estimates from the IEA 2010 [42] and the 2011 World Economic Forum reports [41] that range from $60/MWh to $110/MWh depending on cost, siting, and financing assumptions.

These generation costs are effectively reduced by the PTC, which provides a rebate based on initial construction costs. Using the same equation, we find that the PTC is valued at $15 and $20 / MWh for 40% and 33% capacity factors, respectively, reducing the effective generation cost of wind for Iowa-type sites from $60 to $45 / MWh and for Illinois-type sites from $75 to $55/MWh. Note that the PTC provides greater support.
relative to revenues for worse wind sites because the size of the rebate is based on peak installed capacity, not on actual electricity generated.

\[
\left(\frac{\$2/\text{W}}{\text{hr/yr}}\right)\left(0.09\right) \left(\frac{10^6 \text{ Wh}}{\text{MWh}}\right) \approx \$15/\text{MWh}
\]

\[
\left(\frac{\$2/\text{W}}{\text{hr/yr}}\right)\left(0.33\right) \left(\frac{10^6 \text{ Wh}}{\text{MWh}}\right) \approx \$20/\text{MWh}
\]

**Market value of wind electricity.** Because wind speeds in Illinois, Iowa, and Indiana peak during the night when electricity demand and prices are at a minimum, wind generators likely receive a lower average price than the mean wholesale price. We have however optimistically assumed that wind generation will receive the full wholesale price. We do use two different wholesale rates in this paper. For estimating a mean national wind premium in Table 1, we use an approximate 2010 national wholesale rate of $40/MWh reported by [15], but for the Illinois-specific analysis in the remainder of the paper we use Illinois rates which are slightly cheaper, at $35/MWh in 2010 [29]. (This value is consistent with the Great Lakes mean wholesale rate reported in [15]). Regional Iowa prices are lower, but we optimistically assume that Iowa wind generators receive the Illinois wholesale price [15].

Because wholesale electricity prices of $35/MWh are significantly smaller than the wind generation costs calculated above, even given the contribution of the PTC, windpower requires additional price support. The resulting wind premium, the necessary additional level of support that would come from state RECS, is for Iowa wind $30/MWh without the PTC and $15/MWh with it ($65 - $35 = $30, and subtracting the $15 PTC subsidy leaves $15). For wind from Illinois, the wind premium would be $40/MWh without the PTC and $20/MWh with it. In both cases, the PTC provides half the necessary support, and state RECS would have to provide the other half for windpower to be economically feasible. In wind-endowed Iowa, the cost of generating windpower is a bit less than twice the wholesale rate (the wind premium is slightly less than the wholesale rate). In less wind-endowed Illinois, windpower costs are more than 2x wholesale, i.e. in the current cost landscape, Illinois wind generators would have to receive more in state and federal subsidies than they would in revenues from selling windpower.

**Appendix A.1.2. Solar Premium**

**Solar generation costs.** The upfront cost of solar photovoltaic facilities is the dominant factor in levelized solar generation costs, even more so than for wind. Solar photovoltaics require an order of magnitude less O&M per unit electricity generated than do wind turbines and their installation costs are higher, both because of solar module itself is more expensive per unit of electricity generated, but also because of significant other installation costs (labor and parts for initial grid integration).

We use here two separate sources for solar. First, we use total installed cost numbers for the third quarter of 2011 compiled by the Solar Energy Industries Association [30] using data from PV installers, manufacturers, state agencies, and utilities. These are broadly consistent with inferred solar costs deduced from actual power purchase agreements (PPAs) signed in 2011 Q4 in California [31]. We then repeat the calculations using a lower-bound set by the cheapest 2011 solar projects [33] and consistent inferred costs
deduced from contracts signed by solar facilities currently under development that will begin contributing to the California RPS in 2013-2015 [32]. Note that the 2011 drop in solar costs means that values listed in the IEA 2010 report [42] are out of date.

The installed cost of solar PV exhibits significant economies of scale, with utility-scale projects costing about half as much as residential projects. The compiled install costs from SEIA are $6.24/Wp for residential installations, $4.94/Wp for commercial, and $3.45/Wp for utility-scale projects (where Wp refers to “Watts peak”, the DC power output given illumination with a solar-like light source of intensity 1000 W/m²). The mean install cost of solar therefore depends on the size breakdown of projects. For this work we assume that all projects contributing to the Illinois RPS are utility scale. This puts a lower bound on the premium but is also the more appropriate assumption for projections as large-scale solar generation ramps up in Illinois. (The size breakdown assumption is in fact less important to the mean solar premium than it may seem, because the different size classes also receive different electricity prices. The smaller and more expensive facilities are permitted net-metering, i.e. effectively receiving the higher retail rate, which partially compensates for their higher upfront costs).

Note that while solar costs are reported in dollars per Watts peak (Wp) scaled to an insolation of 1000 W/m², no region on Earth receives an average insolation so high. For a Midwestern state like Illinois, actual power produced over a typical year is only 15% of nominal capacity. In high-insolation areas like the U.S. Southwest, the effective capacity factor can reach 20%. (Values are based on the NREL PVWatts model, [23]). Throughout this work we compute solar premiums for both the Midwestern region specified in the Illinois RPS and for these maximum U.S. insolation regions.

To calculate generation cost in \$/MWh we assume again that new installations are financed by a twenty year, 6% loan leading to an amortization rate of 9% per year. We include operations and maintenance for completeness, though these are nearly negligible at only \$0.012 per watt of peak capacity per year. (O&M costs are reported by the EIA in 2010 [43] based on data collected by the Office of Integrated Data Analysis from industry and governments sources, including the DOE Fuel Offices and the National Laboratories). The marginal O&M cost is reported as zero.

All cost calculations here assume a fixed-axis, utility scale project. Some utility-scale projects are now beginning to use single-axis tracking systems (e.g. First Solar’s “AV Ranch One”). Tracking systems increase generated power but require increased installed and O&M costs. Because new projects at present have not converged on a single choice, and include both tracking and non-tracking options, we assume that the net cost differential is currently small and can be neglected. Tracking systems do represent a possible avenue for decreasing the levelized cost of solar generation, if their costs can be reduced in the future. In this case the cost analysis would have to take into account and adjusted capacity factor to represent the higher generation permitted with tracking.

Using the SEIA utility-scale figure of $3.45/Wp, the estimated cost of solar generation is $245/MWh at a typical Midwest capacity factor of 15%. That is, the cost of generating electricity by solar photovoltaics in the Midwest is approximately seven times the current wholesale electricity price.

\[
\left( \frac{\$3.45/W}{9\%/yr} + \frac{\$0.012/Wp/yr}{(8760)(0.15)Wh/W/yr} \right) \times 10^6 \frac{Wh}{MWh} \approx \$245/MWh
\]
For desert Southwest sites with capacity factor of 20%, the costs are 25% lower. (The ratio of capacity factors is \(0.15/0.20 = 0.75\). Solar costs then drop to $185/MWh.

To compare to PPA-derived estimates, or to calculate the solar premium, we need to take the federal PTC into account. As with wind, the federal PTC reimburses 30% of the installed cost for solar, offsetting $70/MWh and $55/MWh of the solar premium for the 15% and 20% capacity factors respectively assuming SEIA Q3 pricing. (Again, note that the PTC provides a greater relative subsidy for worse sites).

\[
\left( \frac{($3.45/W)(9%/yr)(0.3)}{(8760)(0.15)Wh/W/yr} \right) \left( 10^6 \frac{Wh}{MWh} \right) \approx 70/MWh
\]

and for higher-insolation areas, the PTC benefit is

\[
70/MWh \cdot 0.75 \approx 55/MWh. \quad (A.1)
\]

The SEIA-based solar generation cost inclusive of the PTC is then $175/MWh in the Midwest, and $130/MWh in the desert Southwest. These costs are consistent with 2011 California utility-scale solar PV PPAs (for projects coming online in 2011), which range from $110/MWh to $145/MWh [31].

There are several indications that costs are in fact now lower or are expected to become so in the near future. A 2012 request for proposals for renewable energy projects from the Southern California Public Power Authority places a ceiling on solar bids of $110/MWh. And California PPAs signed in 2011-2012 for solar projects expected to come online after 2012 are reported at approximately $100/MWh [44]. These values suggest an anticipated install costs within the upcoming few years approximately 30% lower than the SEIA Q3 2011 costs, or approximately $2.50/Wp. Costs of $2.50/Wp are also consistent with unpublished reports of the most cost-effective 2011 solar projects [33]. In the analysis here, we include this lower estimate as a lower bound on the uncertainty in current solar costs.

With costs at $2.50/Wp, the pre-PTC levelized cost becomes $180/MWh in the Midwest

\[
\left( \frac{($2.50/W)(9%/yr) + $0.012/Wp/yr}{(8760)(0.15)Wh/W/yr} \right) \left( 10^6 \frac{Wh}{MWh} \right) \approx 180/MWh
\]

and $135/MWh in the high-insolation Southwest (lower by 25%). The value of the PTC itself decreases to $50 in the Midwest and $40 in the Southwest, so that post-PTC costs become $130/MWh in the Midwest and $95/MWh in the Southwest.

\[
\left( \frac{($2.50/W)(9%/yr)(0.3)}{(8760)(0.15)Wh/W/yr} \right) \left( 10^6 \frac{Wh}{MWh} \right) \approx 50/MWh
\]

\[
\left( \frac{($2.50/W)(9%/yr)(0.3)}{(8760)(0.20)Wh/W/yr} \right) \left( 10^6 \frac{Wh}{MWh} \right) \approx 40/MWh \quad (A.2)
\]

**Market value of solar electricity.** Unlike windpower, the value of solar-produced electricity likely exceeds the mean wholesale price, because solar production peaks in the middle of the day at times when electricity demand is generally largest and so prices
highest. In Illinois, the average peak time wholesale price in 2010 was $45 per MWh [29] for the largest utility in the State (Commonwealth Edison) and we adopt this as the market value for solar electricity from utility-scale facilities. Because we consider here only utility-scale facilities, we disregard the smaller PV installations (< 40 kW capacity) that in Illinois are permitted net metering and so receive the full retail rate of $100/MWh. The higher cost of the smaller installations means their net premiums are higher and so they are less cost-competitive.

**Renewables premium for solar electricity.** Combining received prices \( (P_i = $45/MWh) \) with the average post-PTC Midwest solar generation cost of \( C_i = $175/MWh \) with it yields an average solar premium for a typical Midwest $130/MW. This $130/MWh price is the SREC price needed to stimulate solar investment under the Illinois RPS. That is, Midwest solar requires more than eight times the subsidy per unit electricity as does wind at SEIA Q3 installed costs. If installed costs are driven down to $2.50/Wp, then the REC price for Midwest sites would be $85/MWh.

For comparison, using 2011 Q3 prices net metered residential projects in the Midwest have a premium (after the PTC) of $230/MWh and commercial projects a premium of $200/MWh, uncompetitive compared to utility-scale despite the net metering benefits.

**Appendix A.2. Cost Caps**

In this section we discuss the derivation of cost-cap-limited REC prices in $/MWh for five states (IL, CO, OH, WA, and NJ) that are shown in Table 1. Because the cost caps of different states are specified in very different terms, they cannot be compared without converting them to equivalent units. All calculations here are done in current U.S. dollars, using RPS data from the Union of Concerned Scientists Renewable Electricity Standards Toolkit [18]. We begin with a discussion of cost caps that apply to the mean REC rate and then discuss solar-specific caps.

**Appendix A.2.1. General RPS Cost Caps**

**Illinois.** The Illinois cost cap is stated in somewhat complicated terms and has a complicated phase-in. The total allowable dollar amount of the RPS program is always set by pegging it to a percentage of the retail sales of a base year, but both the percentage and base year change over time (though usefully for analysis, by 2011 all base years lie in the past, removing any uncertainty in total cap amount). In 2008, the RPS could not cost more than 0.5% of the total retail sales in 2007. In 2009, the cap is the greater of an additional 0.5% of the 2008 retail sales or 1% of the 2007 retail sales. In 2010, the cap is again the greater of an additional 0.5% of the 2009 sales or 1.5% of the 2007 sales. In 2011 the cap is the greater of an additional 0.5% of the 2010 sales or 2% of the 2007 sales. After 2011, the cap is fixed at the greater of 2.015% of the 2007 sales or the incremental amount from 2011. For the sake of simplicity, and since it makes little difference, we simply assume that the cap is 0.5% of the retail sales in 2008, 1% in 2009, 1.5% in 2010, and 2% in 2011 and thereafter. Each year’s retail sales is calculated by adopting the 2010 sales and a 1% annual growth rate. In this way, the mean cost cap for Illinois in a given year, \( y \), can be expressed as:

\[
\frac{(\text{cap percentage})(\text{retail price})}{(\text{RPS requirement})(1.01)^{y-2011}} \tag{A.3}
\]
For example, in 2025, when the RPS requirement is 25% of retail sales and the cost cap is \(\sim 2\%\) of the 2011 retail sales, the cap can be translated into dollars per MWh as

\[
\frac{(2\%)(\$100/\text{MWh})}{(25\%)(1.01)^{2025-2011}} \approx \$7/\text{MWh}.
\]

If the mean REC rate exceeds the cost cap value approximated in Equation A.3, then the RPS will go into failure mode and the tendered RECs will be less than the number required by the legislation. Failure mode need not mean that all RECs must trade at the average capped value, though, since solar and wind RECs trade in separate markets. A cost cap of an average \$7/MWh in 2025 could be met if, for example, even if solar RECs trade at $100/MWh, if all the rest of the RECs trade at $1/MWh (since 6% \times $100/MWh + 94% \times $1/MWh \approx $7/MWh \lesssim 2025 cost cap).

**Colorado.** The Colorado RPS, which was adopted in 2004 by ballot initiative and expanded in 2007 by House Bill 1281, will implement a 20% renewables requirement for investor-owned utilities in 2020. The cost of RPS compliance is limited to 2% of retail sales and the retail rate in Colorado, at $83/MWh, is somewhat lower than that of Illinois. The cost cap will therefore be \(\approx \frac{(2\%)(83/\text{MWh})}{20\%} = \$8.3/\text{MWh}\) assuming that electricity prices do not increase out-of-pace with inflation. The Colorado cap is slightly higher than that of Illinois because the smaller requirement and continued pegging of the cost cap to current retail sales outweigh the effect of the state’s lower electricity prices.

**Ohio.** The Ohio legislature enacted an RPS as part of Senate Bill 221 in 2008. The bill will require that 12% of the state’s electricity come from non-solar renewables (there is a separate solar carve-out) in 2025. However, utilities are not required to comply with the full requirement if the expected cost of compliance exceeds 3% of the cost of producing the state’s electricity in absence of the RPS. At the regional wholesale rate of $35 per MWh [15], this cost cap limits the 2025 non-solar REC rate to \(\frac{(3\%)(35/\text{MWh})}{12\%} \approx \$8.75/\text{MWh}\) on average.

**Washington.** Washington State enacted an RPS by ballot initiative that constitutes a 15% renewables requirement in 2020. The Washington RPS comes with a cost cap that allows utilities to fall out of compliance if the renewable energy increases their costs by more than 4%. Their cost cap is therefore \(\frac{(4\%)(66/\text{MWh})}{15\%} \approx \$18/\text{MWh}\).

**Appendix A.2.2. Solar Cost Caps**

**New Jersey.** The New Jersey RPS contains a significant solar carve-out calling for 5316 GWh of solar generated electricity in 2026. The cost of the solar program is effectively capped by a non-compliance penalty which is scheduled to decrease from $711/MWh in 2009 to $594/MWh in 2016 when the solar requirement is 1150 GWh. Prior to the passage of the Solar Advancement Act in 2010, the solar carveout was also limited to 2% of the state’s retail sales, but this limit has now been removed.

**Ohio.** The Ohio RPS also includes a solar carve-out that reaches 0.5 of the electricity sales in 2025. The carve-out is subject to the general RPS cap, but is effectively limited by a noncompliance penalty which is currently set at $400/MWh, but decreases by $50 every other year until reaching a minimum of $50/MWh in 2024. Note that this limit is over ten times lower than the New Jersey limit and substantially less than the solar premium calculated above.
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