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Limiting the costs of renewable portfolio standards: A review and critique of current methods

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ABSTRACT

Over half of U.S. states have renewable portfolio standards (RPSs) mandating that a minimum percentage of electricity sold derives from renewable sources. State RPSs vary widely in how they attempt to control or limit the costs of these RPSs. Approaches utilized include alternative compliance payments, direct rate caps, and cost caps on resource acquisitions, while some states employ no specific limitation at all. This paper describes how states attempt to control RPS costs and discusses the strengths and weaknesses of these various cost controls. There is no one best method; however the experience to date suggests that the most important factors in implementing an effective mechanism to curtail costs are clarity of the rule, consistency in application, and transparency for customers.

1. Introduction

Currently twenty-nine states plus the District of Columbia and Puerto Rico[1] have enacted Renewable Portfolio Standards ("RPSs") mandating that a specified percentage of the electricity sector's energy derives from renewable sources. (www.dsireusa.org). These RPSs generally (although not always) increase the wholesale costs of electricity to utilities with the attendant costs being passed on to consumers. One estimate found that state RPSs, on average, have thus far increased electricity rates by about one percent (Wiser and Barbose, 2008). However, the mechanisms for calculating these impacts vary considerably from state to state. Future cost impacts are of course more difficult to calculate (Chen et al., 2007). As state RPSs ramp up their renewable targets and solar and distributed generation set-asides in coming years, RPS cost impacts will be an increasing concern for industry and customers alike.

State legislators, public utility commissions, and other regulatory agencies have struggled to manage the costs of implementing their RPSs in the face of political pressure and statutory mandates to protect ratepayers from excessive costs of RPS compliance. For example, according to one staff member of the New Mexico Public Service Commission, electricity rates have increased four to five percent over the past six years due to the RPS requirements. Many states thus utilize mechanisms to curtail what electricity providers spend, and consequently what ratepayers must pay, to implement their RPSs.

This paper explains the primary cost limitation mechanisms being used today, discusses differences in design across states, and draws conclusions about how such mechanisms should be designed and implemented. A summary of states' cost impact limitation mechanisms is shown in Table 1.

2. Review of utility regulation and restructuring

The U.S. electricity market is an eclectic mix of traditionally regulated (or "cost-of-service") utilities—whose prices are regulated by a government body—and restructured (also known as "competitive") markets, in which multiple retail providers compete for customers. While most states operate as either regulated or competitive markets, a few employ a hybrid of both approaches. For example, in Oregon and Nevada, respectively, only commercial and industrial customers and very large customers have the freedom to choose their electric suppliers. Restructured power markets with retail choice operate in the Northeast, the Mid-Atlantic, Texas, Oregon, and parts of the Midwest. In Table 1 traditionally regulated states are shown in standard font, restructured states in *italics*, and hybrid states in *underlined italics*.

It is useful to briefly review how utilities operating under a cost-of-service model recover costs as compared to those operating in a restructured market because RPS cost limitation mechanisms often derive from cost recovery calculations. For example, utilities held to a cap on retail revenue requirements must make calculations and projections that generally arise in rate-making procedures. Additionally, although regulatory structure is not the

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[1] This paper focuses on the approaches of the twenty-nine states.

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Table 1
Summary of states' cost limitation mechanisms. States with restructured electricity markets are shown in italics, hybrid states in underlined italics, and traditionally regulated states in standard font. States in parentheses utilize a mechanism analogous to the listed cost limitation.

Approach	Description	States
Annual cost caps		
on utilities' annual revenue requirement	Limits additional costs as % of expected annual net retail revenue requirement.	Kansas, *Ohio*, *Oregon*, Washington, (*Maryland, Delaware, Maine*)[a]
Retail rate impact limitation	Limits additional costs as % of expected total of customers' bills.	Colorado, *Illinois*, Missouri, New Mexico
Set surcharge on customers' bills	Caps monthly surcharge on customers' bills at a set amount.	Arizona[b], *Michigan*, North Carolina
Cap on total expenditures	Above-market price contracts limited by total fund of $770+ million allocated among IOUs.	*California*
Alternative compliance payment	Sets an amount utilities pay to a central fund instead of procuring renewable energy; serves as de facto cap.	*Connecticut, D.C., Delaware, Illinois, Maine, Maryland, Massachusetts, New Hampshire, New Jersey*, *Ohio, Oregon, Pennsylvania, Rhode Island*, (*Texas*)[c]
Public benefits funds	Funds renewable energy in the state, thus indirectly mitigating cost impacts to consumers of RPS requirements. Often Alternative Compliance Payments fund PBFs.	*Connecticut, D.C., Delaware, Illinois, Maine, Massachusetts, , New Hampshire, New Jersey, New York*[d], *Ohio*, *Oregon*, *Pennsylvania, Rhode Island*, (*California*, Minnesota, *Michigan*, *Montana*, Wisconsin)[e]
Cap on individual contracts	Limits procurement of contracts priced above set % above market-price.	*Montana*, Hawaii
Ad hoc agency discretion:		
No cost cap, "just and reasonable" review	No set limitations on costs. PUCs use traditional reasonableness review. May include waivers.	Iowa, Minnesota, Wisconsin
Rider review	PUC reviews utilities' riders under just and reasonable standard	Arizona, Eastern Wisconsin
Contract review	PUC reviews procurement contracts under modified just and reasonable standard.	*Nevada*
Other off-ramps (waivers, freezes)[f]		Arizona, *California*, Colorado, *Connecticut, Delaware*, Hawaii, *Illinois*, *Maryland, Maine, Michigan*, Minnesota, Missouri, *Montana*, *Nevada*, *New Hampshire, New Jersey*, New Mexico, North Carolina, *Ohio*, *Oregon*, *Pennsylvania, Rhode Island, Texas*, Washington, Wisconsin

[a] These states use alternative compliance mechanisms, but also have an "off-ramp" provision which allows a utility to request delays or waivers of its compliance if it can prove compliance costs exceed a set % of its annual sales revenues.
[b] Utilities may adopt the sample tariff, or one "substantially similar." This provides more flexible surcharge pricing than N.C. or Michigan.
[c] Texas's penalty provision may constitute a de facto price ceiling, analogous to an alternative compliance mechanism. PUCT Substantive Rule 25.173(p).
[d] New York's PBF, centrally administered, is funded by a non-bypassable volumetric "System benefits/RPS charge" applied to all major utilities' customers' bills.
[e] These states have PBFs that are not funded by ACPs.
[f] For a comprehensive list of waivers, see Union of Concerned Scientists' RPS Toolkit on Escape Clauses, at http://go.ucsusa.org/cgi-bin/RES/state_standards.

determining factor, the absence of regulatory rate-making oversight in restructured states appears to favor the use of alternative compliance mechanisms and public benefits funds which are more readily implemented in those markets.

In a cost of service jurisdiction, utilities are entitled to a monopoly in their service area and a fair rate of return on capital investments in return for their commitment to serve the public with reliable and non-discriminatory service. The rate of return is calculated based on the interest rates of utilities' liabilities (in debt and equity). When a retail utility is faced with an earnings shortfall, due for example to the projected costs of a new power plant or new regulatory requirements, it undergoes a rate proceeding conducted by the state's public utility commission. In a "rate case," the utility must demonstrate its projected net revenue requirement for a test year including its variable operating costs, annual fixed costs, expected depreciation, and tax gross-up. Traditionally, the test year has been a historic year. Increasingly, regulatory commissions are allowing utilities to establish rates on the basis of anticipated costs of a future test year. Annual fixed costs are calculated as the utility's fixed capital or rate base multiplied by its commission approved rate of return which is typically based on its weighted average cost of capital. Thus derives the classic formula in the cost of service regime:

$$R = O + B(r)$$

where R is the net revenue requirement, O the operating costs, B the capital costs, or "rate base," and r the rate of return.

In a separate proceeding for rate design, rates are determined, among other things, by allocating big R among various ratepayer classes. One major critique of the cost of service model is that, because recovery is prospectively based on the utility's estimates of operating costs, rate base, and rate of return of a historic or future test year, a utility is likely to over- or under-recover its actual costs in the coming years. Another concern is that utilities are motivated to maximize their retail revenue requirements to increase profits. These criticisms may be applicable to the budgeting approaches described herein for cost-of-service utilities.

In restructured states such as Texas, Maryland, and New York, retail electricity providers recover their costs of capital investment through direct sales in the market. There are no rate proceedings, although regulators may retain discretion to freeze rates or otherwise protect consumers if competition fails to do so. Several vertically integrated investor-owned utilities remain in partially restructured states, such as Illinois, where traditional cost-of-service models apply. Cost recovery in restructured states is not assured and providers must look to market forces to allocate their budgets, even in the face of mandates to acquire expensive new renewable resources.

3. Annual cost caps

An appealingly simple approach to limiting RPS costs is to cap the annual costs of implementation. In practice, however, cost caps can be quite complex and suffer from a lack of transparency.

3.1. Cap on utilities' annual revenue expenditure

Several states cap utilities' expenditures on renewable resources for RPS compliance at a set percentage of the utilities' annual retail revenue requirements (the R in the rate case formula $R=O+B(r)$). In these states, utilities that spend a specified percentage of their annual revenue requirement on renewables may be deemed in compliance with the RPS even if they have not met the annual RPS targets. The general formula for this cost cap is

$$C_{RetailRevenue} = \frac{I_{renewables} + I_{alternatives}}{R} \times 100$$

where $C_{Retail\ Revenue}$ is the retail revenue percentage, $I_{renewables}$ the incremental cost of renewable resources, $I_{alternatives}$ the annual costs of alternative compliance mechanisms (renewable energy credits, alternative compliance payments), R the net retail revenue requirement.

It should be noted, however, that only Oregon and Washington strictly set the denominator above to R. Although the Kansas cost cap excuses utilities from penalties for noncompliance if the "incremental rate impact of renewables" exceeds one percent, the impact is based on the revenue requirement from the last rate case.[2] In the restructured state of Ohio, the incremental costs of compliance are compared against "reasonable expected costs of generation" which may not necessarily include the traditional elements of R, depreciation, tax gross-up, and a rate of return.[3] These states are nonetheless discussed herein as their approaches are procedurally similar to, and raise similar concerns as, a strict revenue requirement cap. Overall, the most contentious aspect of this approach is typically how to determine the incremental cost of the renewable resources. With many state RPSs just underway, many states are still working through such determinations.

Ohio, Oregon, Kansas, and Washington utilities all count the levelized annual "incremental costs" of obtaining eligible renewable resources against the cap. The Washington legislature requires utilities to calculate this levelized incremental cost as the difference between the levelized delivered cost of the eligible renewable resource, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resources that do not qualify as eligible renewable resources, where the resources being compared have the same contract length or facility life (Wa. Admin. Code §§ 194-37-170 et seq, 2011). Oregon's mandate further clarifies that the calculation of levelized annual incremental costs should capture the costs of capital, operating costs, financing, transmission and distribution costs, load following and ancillary services, additional assets, and R&D (Or. Rev. Stat. §§ 469A.100 et seq, 2011). Ohio utilities, on the other hand, may not count against its three percent cap those "construction or environmental expenditures of generation resources" that are commission-approved and passed on to consumers through a surcharge (Ohio Admin. Code § 4901:1-40-07). The substitute non-qualifying resources against which the costs of renewables are compared may vary, although most states currently use a natural gas-fired resource as the proxy resource to represent the cost of non-qualifying electricity (OPUC, 2009).

In addition to the costs of any built renewable resources, the actual annual costs of meeting a state's RPS also often include the costs of renewable energy credits ("RECs"), of acquiring renewable resources via power purchase agreements ("PPAs") or on the spot market, and alternative compliance payments ("ACPs") if the RPS permits. States differ on whether these costs count in the cap. Oregon's cap of four percent of a utility's annual net retail requirement includes the incremental levelized costs of building renewables, as discussed above, as well as the cost of unbundled RECs, and the cost of ACPs (Or. Rev. Stat. §§ 469A.100 et seq, 2011). In Ohio, utilities may not count ACPs toward the cap nor may they recover ACP payments from ratepayers (Rev. Code Ohio § 4928.64, 2011). This limitation reduces the likelihood that utilities will rely on ACPs to meet the RPS unless faced with harsher penalties for noncompliance. For the integrity of the cap, the incremental costs of compliance should be least-cost measures. For this purpose, Washington and Oregon provide that only "prudently incurred costs" are recoverable, a point that will likely be argued in ratemaking or RPS compliance proceedings (Wa. Stat. § 19.285.050, 2011; Or. Rev. Stat. §§ 469A.100 et seq, 2011).

With respect to the denominator of the above equation, states appear generally to allow utilities to base the annual revenue requirement or its analog on a future test year. Washington is one such example (Rev. Code Wa. 19.285.050, 2011; Wa. Admin. Code, §§ 194-37-170 et seq, 2011). In Ohio, too, utilities may compare incremental costs against the "reasonable expected costs of generation" (Ohio Admin. Code § 4901:1-40 et seq, 2011; Ohio Rev. Code Ann. § 4928.64, 2011). An alternative to basing R on the projections of a coming year would be to set the cap off a prior year or of some specified average. Kansas bases its impact calculus on the R used in a utility's previous rate case. Such an approach likely results in a cap that is more certain, less administratively burdensome, and more evenly administered amongst utilities. Another important consideration is whether utilities exclude the incremental compliance costs (the numerator of the cap) from the total net revenue requirement. Oregon excludes these costs so as not to inflate the revenue requirement above that which is required using only conventional resources. Without this modification, the revenue requirement assumes the presence of eligible renewable resources and thereby increases the funds available for renewables under the cap.

Apart from how the cap is calculated, states may choose to implement the cap as either mandatory or voluntary. The Washington legislature made clear, for example, that its cap is voluntary: "a utility may elect to invest more than [the] amount" set forth in the four percent rate cap, and will still be entitled to recover its prudently incurred costs of complying with the RPS (Rev. Code Wa. 19.285.050, 2011). Oregon, Ohio, and Kansas are also voluntary, leaving spending ultimately to the utilities' discretion though presumably subject to approval by their respective commissions.

Finally, states may use a variation of this retail revenue impact as an optional "off-ramp" (or waiver) provision where prices for the RPS are getting too high. In Maryland, in addition to alternative compliance payments, utilities may request that the Maryland Public Service Commission delay the incremental increases in renewable targets if the actual or anticipated cost of compliance is for solar, greater than or equal to 1% of the electric supplier's total annual electricity sales revenues; or for non-solar resources, the greater of 10% of electricity supplier's total annual retail sales or the Tier 1 percentage requirement for that year (Md. Pub. Util. Co. Code §§ 7-701 et seq, 2011).

3.2. Rate cap

Related but not equivalent to a cap on annual net retail revenue requirements is an annual rate impact limitation or "rate cap." A utility's annual retail revenue requirement or the equivalent in deregulated states is apportioned among various ratepayer classes to derive unit rates. The rate cap limits RPS compliance expenditures to an amount that raises the rates of different

[2] Kansas Corporation Commission Staff has expressed concern with the rules and how they should be applied going forward.

[3] No utility has yet triggered Ohio's cost cap and so there is no formal guidance on how the state agency will interpret the provisions of the statute and the implementing rules.

customer classes by a set percentage over a specified period of time. Thus, the formula for this approach generally follows:

$$C_{ratecap} = (l)(B_{net})$$

where $C_{rate\ cap}$ is the rate cap, l the % rate impact limitation, and B_{net} the customers' bills.

Applications of this formula vary, however. The rate impact limitation may be calculated incrementally, or averaged cumulatively over a longer period of time. Customers' bills, B_{net}, may be based on customers' actual costs, or more similarly to the retail revenue requirement cap, on their projected costs.

An incremental rate cap specifies the allowable rate increase for a given year. Colorado's cap authorizes its investor-owned utilities to collect up to two percent of customers' bills annually for the purpose of meeting the RPS (Colo. Code Reg., 4 CCR 723-3-3661(a), 2011). New Mexico's cap ramps up to three percent of customers' aggregated annual electric bills by 2015 (N.M. Admin. Code § 17.9.572.11(C), 2011). Illinois's investor-owned utilities, by 2012, are limited to spending the greater of either an additional 2.015% of the amount paid per kilowatt-hour by eligible customers during the 2007 baseline year or an additional 0.5% of the amount paid per kilowatt-hour by those customers during the previous year on renewable energy resources procured pursuant to the RPS (Ill. Comp. Stat. 20 ILCS 3855/1-75(c), 2011).

In contrast, a cumulative or average rate cap limits the rate increase over a longer period of time. Missouri uses a hybrid cumulative annual rate cap that poses some interesting issues in design and efficacy. Based on the mandate of Missouri's legislature, as of January 2011, utilities in Missouri may spend up to the "maximum average retail rate" increase of one percent to implement the RPS (Rev. Stat. Mo. § 393.1030.2(1), 2010). The Missouri Public Service Commission ("PSC") decided that, in light of the "average" language and the goal of smoothing out "spikes in compliance costs and recovery caused by new technology coming on-line in the beginning of implementation" (Missouri Register, 2010)) the rate cap would be both cumulative over a ten-year period and calculated annually. The planned approach requires utilities to estimate their incremental costs of compliance for each year, based on the difference in levelized costs of a portfolio under the RPS and one without, over a ten-year period. The average annual increase over this succeeding ten year period should not surpass one percent (Mo. Code State Reg., 4 CSR 240-20.100(5)(A), 2011). On its face, this approach appears to limit the annual incremental cost of compliance to approximately one percent of customers' bills for that year while allowing some years to cost more, others less. Yet regulators in the state admit they are worried about how this will work administratively.

Otherwise, the rate cap approach creates many of the same issues inherent to the net retail revenue impact discussed above: what costs of compliance count toward the incremental costs of compliance; what avoided costs establish the base against which the impact is measured; and is the cap mandatory or voluntary? The rate caps in Colorado, Illinois, and Missouri are statutory and mandatory. In Colorado, because utilities have been allowed to loan money into the renewable fund (and earn interest thereon), the cap has not actually served to limit utility expenditures on renewables and this has become an important point of contention. In New Mexico, utilities may petition the New Mexico Public Regulation Commission for a waiver of any above-cap cost requirements, but may not exceed the cap for large customers (>10 million kWh per year) (N.M. Admin. Code § 17.9.572.11(C), 2011). Even when mandatory, however, a rate cap does not necessarily provide transparent customer protection. For example, in Colorado, the PUC has granted utilities waivers from the cost impact calculation for selected resources that are applied toward their RPS compliance obligation.

3.3. Critique of cost caps

Depending on how they are administered, cost caps may be administratively burdensome, non-transparent, and insufficiently protective of consumers. The annual process of determining the cap is time intensive. Moreover, as illustrated by New Mexico, without clear rules, the case-by-case process of determining caps may result in extremely skewed results for different entities. Whether the measures chosen are least-cost is also of grave concern to critics of cost caps. State PUCs likely vary with respect to how stringently they review the renewable measures set forth in utilities' annual compliance plans against a least-cost standard.

Most worrisome about the current approach to implementing caps is that the cap may be looking like no cap at all. Basing the cap on rates or even on revenue requirements allows costs already sunk on compliance to be imbedded in the denominator from which the cost cap derives. As the denominator increases, so does the cost to consumers. While such costs are often necessary to actually fund the aggressive goals of some states, administrators have expressed concern with the lack of transparency to consumers. While statutes may promise a rate increase no greater than a certain percent, the actual cumulative rate increases over many years may be much greater. For example, according to the Colorado PUC staff, after accounting for resources excluded from Colorado's rate impact calculation under a special waiver provision, renewable expenditures since its first compliance year in 2007 have actually far exceeded the two-percent rate cap. (Dalton, W.J., 2009, 2010). According to one estimate by New Mexico Public Regulation Commission Staff, New Mexico's rate increase may be closer to twenty percent over 2006 by 2020.

Another point of contention in determining the retail revenue requirement for purposes of calculating the rate impact of renewables is the inclusion of hypothetical costs in the "no-renewable" base case. For example, the Colorado PUC has required that utilities include both a carbon adder and a capacity credit in their system modeling to determine the rate impact. The carbon adder artificially inflates the apparent cost of the no-renewable revenue requirement while the capacity credit benefits the renewable resource. But neither the carbon cost nor the renewable capacity credit really exists at the present time. The impact of these hypothetical costs and benefits is to artificially diminish the apparent incremental cost of renewable compliance. This approach has been widely criticized in Colorado PUC proceedings by the parties most concerned with the cost impacts of renewable energy acquisitions while being supported by renewable energy advocates.

4. Surcharge on customers' bills

A relatively straight-forward way for utilities to recover RPS compliance costs is through a surcharge, also called a "rate rider" or adjuster, on consumers' bills. Riders allow utilities to directly incorporate into rates the fluctuating prices of traditional operating costs, such as fuel and labor costs, without undergoing multiple rate cases. Some commissions have allowed utilities to treat RPS compliance costs similarly and add cost recovery to customers' bill. States use various methods of calculating riders; for example, a flat system benefits charge or a usage-based adder. Overall, identifying the incremental costs of renewable resources via a bill surcharge—whether calculated on a flat-rate basis or per kWh—allows customers to see how much they are paying for RPS compliance.

A usage-based rider is generally set at a per kWh price. To cover the incremental cost of compliance with Arizona's Renewable Energy Standard, Arizona utilities may assess a monthly surcharge "substantially similar" to the one set forth in the sample tariff upon approval by the Arizona Corporation Commission ("ACC") (Ariz. Admin. Code R 14-2-1808, 2011). The Sample Tariff provides for a monthly surcharge assessed as $.004988 per kWh,[4] and utilities must substantiate their claims for this recovery in a proceeding based on the estimates of their annual implementation plans and the costs likely incurred. In order to protect customers, the rule appears to cap the overall surcharge at a flat rate of $1.05 for residential, $39.00 for small non-residential, and $117.00 for large non-residential. In 2008, most cooperative utilities did adopt the sample tariff's caps. Arizona's cap is not a ceiling, however. The state's largest utility proposed, and the ACC approved, a surcharge well-above the sample rate based on its calculated financing needs. Moreover, the state allows utilities to adjust the surcharge in their tariffs as needed. Additionally, the surcharge does not capture all costs of compliance as utilities may also drop large renewable construction projects into rate base.[5]

A variation of a usage (kWh)-based rider is one in which the rider is calculated as a percentage of a customer's total bill in dollars. Colorado has interpreted its two percent rate cap to allow its utilities to collect an additional two percent from each customer's monthly bill, itemized as the "Renewable Energy Standard Adjustment" or "RESA", to fund RPS compliance. In Colorado, utilities may bank unused portions of annual recovery toward future costs. However, this has led to criticism that the utilities are also incentivized to overspend the funds available under the RESA and earn their commission-authorized rate of return on funds advanced to the RESA, even if, as in the case of one major Colorado utility, the RPS compliance targets have been met or exceeded.[6]

4.1. *Critique of surcharges*

Overall, riders are more administratively efficient because they minimize the need for rate cases. North Carolina's rider was passed, in part, due to the lobbying efforts of utilities to avoid rate cases. And, in Michigan, which requires a rate case to establish a rider, few utilities have yet done so. With the exception of the banking allowed by Colorado, most states still require the utilities to go through some administrative process of truing up their incremental cost of compliance. The processes are much less cumbersome than rate cap true-ups, however. Another advantage of a surcharge as a cost limitation and recovery mechanism is that utilities have more certainty in their investment decisions. The surcharge caps set a clear benchmark. Utilities feel more assured that they can recover at least as much as they need, so long as they do not spend more than the statutory caps. One regulator has commented that this approach avoids imposing a "moving target" on utilities, as opposed to some of the cost caps for example.

The approach presents potential trade-offs for both customers, electricity providers, and the environment, as well. For customers, when costs are passed through with less scrutiny than in a ratemaking case, there is no guarantee that the surcharge is funding least-cost resources. Colorado's two-percent surcharge, passed directly through to customers, raises these concerns as well as whether the cap is actually protective. As described above, the RESA rider allows utilities to automatically recover the *maximum* allowable rate and bank recovery toward future costs, or even earn a return on advancing future funds. In Colorado as in many other RPS states, proponents have often argued that the RPS targets represent a floor, not a ceiling, and so utilities should be able to acquire renewables up to the limit of the cost cap. In contrast, RPS critics argue that the cap should represent an unambiguous limitation on the cost of meeting RPS targets, not a de facto minimum level of expenditures. Finally, whereas North Carolina and Michigan's surcharges are fixed and cannot be amended except by legislation, those states' RPSs may be compromised if the costs of renewables surpass what has been forecasted. North Carolina may reach its overall projected expenditures in just 5–6 years (N.C. Gen. Stat. § 62-133.8(i), 2011).

Arizona's hybrid approach attempts to remedy some of these issues by permitting utilities to apply capital expenditures to rate base and adjustable surcharges upon petition. However, the trade-off is less administrative efficiency and more of a moving target on actual costs. With so many off-ramps from the fixed tariff, customers' protection ultimately rests with the Commissioners' decisions to approve implementation plans.

5. Cap on utilities' total expenditures

One state that currently limits compliance costs to a specified dollar amount for its investor-owned utilities is California. California's approach is the so-called AMF Program (above-market price referent funds program) (Cal. Pub Util. Code § 399.15, 2011; Cal Pub. Res. Code §25740.5, 2011).The total AMFs available for the implementing period is equivalent to the amount of funds that would have been available if utilities were still required to charge a Public Goods Charge to its customers through 2012: over $770 million. Public Utilities Code § 399.15 provides that each of the state's major investor-owned utilities is allocated a specific amount of this total from which it will be eligible for cost recovery of above-market contracts in its rates subject to certain criteria.[7] Contracts must meet specific eligibility criteria related, in part, to cost-competitiveness and longevity (Cal. SB 1036, 2007; Cal. Resolution E-4199, 16, 2009). The cap is voluntary in that a utility is relieved of procuring any other above-market cost contracts in compliance with the RPS once it reaches the cap, but may petition the California Public Utility Commission ("CPUC") to approve above-cap cost recovery. The CPUC may also require a utility to procure additional renewables after the utility has reached the cap. In this regime, all contracts eligible for AMF-funds, and the entire contract price, must be counted against the cap.

The CPUC must determine whether a contract is eligible for AMF-funds by considering the difference between a project's levelized contract price (per MWh) and a specific market price referent ("MPR"). Annually, the CPUC adopts by resolution MPRs based on the presumptive cost of electricity from a non-renewable energy source, including the long-term market price of electricity for fixed contracts, the long-term fuel and operating costs for comparable new generating facilities, and the value of the electricity's characteristics such as peaking or baseload. Thus, the positive difference between a contract price and the MPR counts toward the electrical corporations' cost limitation. The CPUC does not review unbundled RECs purchases—permitted for compliance since 2010—under the AMF program and so their costs do not count against the utilities' cap (Cal. Pub Util. Code §

[4] This is 5.7 times the amount initially allowed.

[5] For example, Arizona Public Service Company is seeking to put its $500 million new 100-MW PV system into rate base. Interview with Staff at Arizona Corporation Commission (Dec. 3, 2010); Docket E-0 1345A- 10-0262, APS Application (July 2010).

[6] In recently issued decisions C11-1079 and C11-1080, the Colorado PUC has also expressed concern with the "deviations between budgeted RESA expenditures and actual charges against the RESA account (Colorado Public Utilities Commission, 2011a,b)."

[7] BVES $ 328,376; PG&E $ 381,969,452; SDG&E $ 69,028,864; SCE $ 322,107,744; Total $ 773,434,436. Resolution E-4199, 16.

399.15, 2011). For price protection, the CPUC has set a de facto REC price cap of $50 and limits utilities to meeting 25% of their compliance obligations with tradable RECs.

5.1. Critique of California's cap

The AMF program constitutes a significant change from the state's former cost curtailment program. The California legislature amended the former cost curtailment process of using Supplemental Energy Payments (SEPs) to cover above-market costs in 2007 in order to streamline the process. Formerly, utilities collected a Public Good Charge ("PCG") via customers' bills, part of which was transferred to the New Renewables Resource Account (NRRA) in the Renewable Resource Trust Fund to fund SEPs. The California Energy Commission administered these funds for the above-market costs of electric corporations. There was no individual utility cap. Once the funds were fully allocated, utilities were required to procure in fulfillment of the RPS only those renewable resources that were at or below market price. In contrast, the new method utilizes rate increases, not the PCG, and requires the CPUC's approval of both the above-market costs and the procurement contracts in order for cost recovery of AMFs that fall within each utility's overall cap. The CPUC has identified several added benefits of the new methodology: (1) to further promote the goals of RPS program (in-state, long-term, stable), (2) to support viable least-cost best-fit renewable energy projects, (3) to allocate AMFs transparently, and (4) to result in simpler administration of AMFs (Resolution E-4199, 10, 2009).

On the other hand, California's current approach presents two disadvantages for utilities. First, the process is administratively burdensome. A utility must seek agency approval for every contract. Second, it is unclear whether the specified caps will allow utilities to meet California's aggressive RPS targets. Once a utility reaches its cap, the utility would be required under this approach to seek cost recovery to procure additional resources. Utilities therefore may not be inclined to petition to exceed the cap in order to meet the RPS. It is worth noting that the CPUC may have alleviated this concern when it permitted unbundled RECs for compliance.

6. Alternative compliance payments

6.1. Alternative compliance payment as de facto cap

Many restructured states utilize an alternative compliance payment ("ACP"), either alone or in conjunction with other cost curtailment mechanisms. The ACP enables electric distributors and retail providers to pay a specified amount into a central fund in lieu of procuring renewable energy or buying RECs. For those states in which the ACP is recoverable,[8] the ACP serves as a de facto cap in that it sets the price ceiling for the cost of compliance. Where ACPs are required, the ACP price constitutes the cost of RPS compliance. The alternative electricity suppliers in Illinois (distinct from the vertically-integrated utilities discussed above) must fulfill half of their RPS requirements through ACPs, for example (Ill. Comp. Stat. 220 ILCS 5/16-115D, 2011). In states where the ACP is optional, rational entities will tend to opt for other means of compliance (RECs, PPAs, etc.) up to point at which those costs are equivalent to or higher than the ACP. Where prices of procurement surpass the ACP price, without additional incentives or obligations, utilities will opt for the ACP which sets the ceiling price. Whether ACPs are recoverable, how they are priced, and other nuances contribute to the efficacy of this mechanism as a cost cap. This section discusses some of the states that rely on ACPs for RPS cost control and their overarching issues.

States differ with respect to the burden utilities bear for obtaining approval of ACP costs from the state agencies. In Maine, Massachusetts, New Hampshire, New Jersey, and Rhode Island, utilities may recover any cost of ACPs deemed reasonable and prudent by the state commissions (35-A Maine Rev. Stat. § 3210, 2011 ; Mass. Gen. Law ch. 25A, § 11F, 2011; N.H. Rev. Stat. § 362-F, 2011; N.J. Stat. § 48:3-87, 2011; R.I. Gen. Laws § 39-26-1 et seq., 2011). In contrast, the ACP costs incurred by providers in Delaware, Oregon, Maryland, Pennsylvania, and D.C. may only be passed on to consumers if they demonstrate in addition to general reasonableness (1) the ACP is the least cost measure to ratepayers compared to the purchase of renewable energy credits to comply with the RPS; or (2) there are insufficient renewable energy credits available for the electric supplier to comply with the RPS causing the Commission to find a force majeure (26 Del. Code § 358, 2011; Md. Pub. Util. Co. Code §§ 7-701 et seq, 2011; Penn. Stat., 73 P.S. § 1648.3, 2011; Penn. Admin. Code, 52 PA ADC § 75.67, 2011; D.C. Code § 34-1431 et seq, 2011; Or. Rev. Stat. §§ 469A.100 et seq, 2011). Maryland also allows cost recovery if (3) a wholesale electricity supplier defaults or otherwise fails to deliver RECs under a commission-approved supply contract (Md Public Util Comp § 7-706, 2011). Additionally, whereas cost recovery of ACPs generally occurs as a specific surcharge on customers' bills, at least one state allows utilities to petition the state agency for inclusion of ACPs in rate base. Prudence review by a state commission subjects a utility's ACPs to the commission's further scrutiny. Oregon has expressly prohibited ACPs from being recovered in rate base (Or. Rev. Stat. §§ 469A.100 et seq, 2011).

ACP prices also vary. The total ACP is calculated by multiplying the alternative compliance payment rate by the number of deficient kilowatt-hours. The ACP rate may be established by statute or by state regulators. For example in New Jersey, the ACP is $50 per MWh, while the solar ACP drops from over $700 per MWh to about $600 per MWh by 2016 (N.J. Admin. Code § § 14:8-1.1 et seq, 2011). State legislatures may also establish guidelines for ACPs via statute. Although Texas does not currently have an ACP, the state legislature has expressly authorized its commission to establish an ACP which, for compliance that could otherwise be satisfied with a REC from wind, may not be less than $2.50 per credit or greater than $20 per credit (Texas Util Code § 39.904(o)). Presently Texas has only a penalty provision that itself serves as a de facto cap by penalizing entities $50 for each MWh a utility falls short of compliance with the RPS targets. Finally, Illinois's AC payments are derived from the state's statutory rate cap. The state Power Agency sets the ACP price for each service area equal to "the maximum allowable annual estimated average net increase" calculated in the annual procurement planning of the state's large utilities for that service area (PUCT Substantive Rule 25.173(p) (2011).

Some states may "freeze" increasing RPS targets if costs of compliance exceed a specific indicator. Maine uses its ACP as such an indicator. The Maine PUC may suspend annual increases in the RPS standard if ACPs are used to achieve more than 50% of the compliance obligation of utilities. Alternatively, the Maine PUC may also suspend the RPS if it determines that meeting the target is overly burdensome to customers.

6.2. ACPs generally fund public benefits funds with several exceptions

ACPs are extremely important in reducing the overall cost impacts to consumers of increasing renewable generation

[8] Where not recoverable, as in Ohio (discussed above), the ACP merely serves as a penalty for non-compliance.

because they often help fund a central public benefits fund that supports renewable development in the state. States with PBFs include: California, Connecticut, D.C., Delaware, Illinois, Maine, Massachusetts, Minnesota, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, and Wisconsin.

PBFs are viewed as a complement to, not an integral part of, most state RPSs with the exception of New York. In New York, the New York State Energy Research and Development Authority (‘‘NYSERDA’’) administers the state's 30x15 RPS with funds collected from a non-bypassable volumetric ‘‘System Benefits/ RPS Charge’’ on major utilities' customers' bills (NY PSC Order Case 03-E-0188, 2004; http://www.nyserda.org/rps/index.asp). The RPS portion of this charge was approximately $2.87 in 2007 for a typical residential customer and $30.24 for a typical non-residential customer. NYSERDA solicits renewable projects with these funds, which have culminated to date in 38 facilities under contract to provide a combined 4,276,140 MWh of renewable energy per year, from approximately 1,532 MW of new renewable capacity.

PBFs in most other states are managed by a neutral entity that solicits projects based on specific criteria. Many state PBFs are managed by a governmental office. Others are managed by corporations or non-profit organizations created specifically to manage the fund (e.g. Oregon, Rhode Island, and Connecticut). At least one state, Arizona, allows utilities to manage renewable energy funds (Az. Corp. Comm. Dec. No. 69663, 86 2007). With respect to funding, a few states fund their PBFs for renewables from something altogether separate from ACPs, such as a public purpose charge (Oregon, New Jersey) or leftover savings from other projects (Michigan). Some states also keep separate funds collected for specific set-asides. For example, Maryland and Massachusetts require that ACPs for the solar obligation only be used to support new solar resources in the state (Md. Code § 9-20B-05, 2011 ; Code Mass. Reg., 225 CMR 14.07, 2011).

6.3. Critique of ACPs and public benefits funds

Where they exist, ACPs become the ultimate price ceiling on compliance for utilities and their consumers. In this way, they are extremely important for consumer protection, particularly where the costs of RECs or renewables are unknown or prohibitively high. At the same time, because ACPs set the ceiling, the price must be properly set or else risk the integrity of the RPS. If the ACP price is too low, electricity providers as rational business entities may be encouraged to choose the alternative and not procure renewables. If too high, on the other hand, or if not-recoverable, the ACP merely becomes a penalty and not a safety valve. In states where cost recovery of compliance is a near foregone conclusion, however, the ACP price may do nothing to affect utilities' procurement decisions even if it means higher prices for consumers. In addition to price, the efficacy of the ACP as a cost limitation mechanism also rests on how effectively ACP funds are used to procure renewable resources. If ACPs are not used, or not used efficiently, to fund renewable projects, they cannot be considered a cost curtailment mechanism. By not efficiently funding renewable projects today, faulty ACPs either inhibit the ultimate goals of the RPS or raise the costs of eventually meeting those goals by drawing out the process of compliance.

Different issues arise with PBFs that are not funded by ACPs. A hard-line surcharge such as that of New York funds renewables with more certainty than other approaches, but does not necessarily ensure that the state reaches its targets and at the lowest price. The government administrator likely does a better job on average than a utility considering least-cost alternatives, however.

7. Cap on contract price

Two states, Montana and Hawaii, utilize a cost limitation on a per-contract basis. In both states, utilities may petition the state agencies in the event that they are unable to meet their RPS obligations and request for a waiver if contracts for procuring generation or renewable energy credits were above-market price for other available resources. In Montana, a competitive retail provider is not obligated to take electricity from an eligible renewable resource unless the total cost of electricity from that eligible resource, including the associated cost of ancillary services necessary to manage the transmission grid and firm the resource, is less than or equal to bids in the competitive bidding process from other electricity suppliers for the equivalent quantity of power over the equivalent contract term (Mt. Code Admin. 69-3-2007, 2011; Mt. Admin. Rules 38.5.8301(4)). In contrast, a regulated public utility in Montana is not obligated to take electricity from an eligible renewable resource unless the cost per kilowatt-hour of the generation does not exceed by more than 15% the cost of power from other alternate available generating resources. In Hawaii, utilities may petition the Public Utilities Commission for a waiver of a penalty for failure to meet the RPS (Haw. Rev. Stat. Ann. § § 269-92, 2011). The Commission may grant such a waiver if it determines a utility is unable to meet the RPS "due to reasons beyond the reasonable control of an electric utility" including, in part, inability to acquire sufficient cost effective renewable electrical energy (Haw. Rev. Stat. Ann. § § 269-92, 2011). "Cost-effective" means the ability to produce or purchase electric energy or firm capacity, or both, from renewable energy resources at or below avoided costs consistent with the methodology set by the PUC.

7.1. Critique of cap on individual contracts

This mechanism is likely cost-protective of consumers, holding the cost of compliance close to the cost of alternate sources (i.e. gas). Because the cap is generally enforced by state regulatory bodies, however, this approach may create an administrative hurdle that could prevent utilities from acquiring the most cost effective resource. Moreover, the ultimate discretion lies with the agency to determine whether the resources are really least-cost. As discussed more below, such discretion leads to uncertainty for utilities, investors, project developers, customers, and the state. On the other hand, if utilities utilize this limitation to its potential, the mechanism could severely reduce the integrity of the RPS as the price of renewables may often be higher than alternative resources.

8. Ad hoc agency discretion to curtail costs

Some states have not relied on specific cost curtailment mechanisms but instead look to the state commissions to limit excessive costs to consumers by exercising their traditional duty to ensure just and reasonable rates. Depending on whether the state is restructured or not, and on its legislative mandates, states without a cap often rely on their statutory obligation to ensure just and reasonable rates in rate cases, the review of rate riders, and the approval of individual contracts. The states without a defined cap include Minnesota, Wisconsin, Iowa, and Nevada. Additionally, almost all states embody state regulatory agencies with sufficient discretion to waive certain compliance provisions where concerns of cost and fairness are raised.

8.1. Just and reasonable review in ratemaking

In Minnesota, pursuant to the cost-of-service model, utilities may recover any prudently and reasonably incurred costs if approved by the Minnesota Public Utilities Commission. There are no specified caps on rate increases or utilities' budgets for implementing the RPS. The legislature granted the PUC the authority, however, to grant modifications or waivers of utilities' compliance obligations upon request if the commission find it is "in the public interest" to do so (Minn. Stat. § 216B.1691, Subd. 2b, 2011). The enacting legislation clarifies that the PUC must consider, among other factors, "the impact of implementing the standard on its customers' utility costs, including the economic and competitive pressure on the utility's customer." With regard to a request for a waiver based on costs to customers, the PUC may only grant a waiver "if it finds implementation would cause significant rate impact." There are no additional rules or regulations that clarify exactly what constitutes a "significant rate impact." To date, all 118 electric providers in the state have complied with the law every year since it was revised in 2005, and not one has requested a compliance deadline extension. Therefore, because no utilities have yet come forward with a petition for a waiver, Staff at the PUC was unable to discuss the process further. Decisions would likely be made on a case by case basis unless the legislature amends the statute in the coming years.

Iowa's Alternative Energy Law ("AEL"), which requires the state's two vertically-integrated utilities either to own a certain amount of renewable energy in the state or to procure long-term contracts for such sources in the utilities' service area, applies only the traditional just and reasonable cost standard to renewable procurement (Iowa Code § 476.43, 2009). For new facilities, the state's Utility Board may adopt individual utility or uniform statewide facility rates "sufficient to stimulate the development of alternative energy production" that are deemed reasonable in light of economic and other factors. Power purchased by contracts must be competitively priced, "based on the electric utility's current purchased power costs." The AEL targets are sufficiently conservation that they likely do not require significant cost curtailment.

8.2. Contract review

Pursuant to the legislation enacting Nevada's Energy Portfolio Standard, the Public Utility Commission of Nevada ("PUCN") must review and approve every new contract for renewable energy procurement or energy efficiency under a *modified* just and reasonable standard (Nev. Admin. Code § 704.8885, 2011). The modified standard requires the PUCN to consider factors such as price reasonableness, characteristics of the resource, fitness and viability of the project, and the terms and conditions of the contract. With respect to price reasonableness, the PUCN must explicitly consider: (1) consistency with long-term planning, (2) reasonableness of price indexing; (3) environmental costs and reductions; (4) net economic impact and environmental costs and benefits; (5) economic benefits to the state; (6) diversity of energy resources; (7) transmission costs and benefits; and (8) the utility's long-term avoided costs. The review of whether specific contracts are just and reasonable may impact whether the utility may be exempted from meeting all of its compliance obligations. A utility may petition the PUCN for exemption from an administrative fine or other action resulting from its failure to meet the RPS and must show that there was not a sufficient supply of contracts with just and reasonable terms available to the utility. This review is likely similar to that in Hawaii and Montana but less constrained as the PUCN appears to have greater discretion to consider factors besides the costs of alternative sources.

8.3. Freeze provisions

Some states have statutory or regulatory freeze provisions that allow agencies to freeze incremental increases of RPS targets when compliance costs reach specific cost caps. Some states also give state agencies more discretion to freeze the RPS if costs become excessive. For example, New Hampshire's statute states that the PUC, after notice and hearing, may accelerate or delay by up to one year, any given year's incremental increase in class I or II renewable requirements for "good cause". PUC rules state that the term "good cause" means that the acceleration or delay would reasonably be expected to: (1) increase investment in renewable energy generation in New Hampshire; or (2) mitigate cost increases to retail electric rates for New Hampshire customers without materially hindering the development of renewable resources.

8.4. Waivers

In addition to cost limitations, most states also expressly provide state agencies the discretion to grant entities waivers. Some provisions appear broad enough to allow for waivers due to cost impacts to consumers. In Ohio, in addition to the net revenue requirement rate cap and an alternative compliance payment, the Commission may identify the existence of force majeure conditions and grant waivers (Ohio Admin. Code § 4901:1-40 et seq, 2011). The North Carolina PUC may modify or delay the RPS provisions if the PUC determines that it is "in the public interest" (N.C. Gen. Stat. § 62-133.8(i), 2011). In New Mexico, utilities may seek a waiver for "good cause" (N.M. Rule 14-2-1816, 2011). Waivers may be from the RPS compliance targets or, as in Colorado, from the rate impact provisions themselves (Colorado PUC, 2007).

8.5. Critique of agency discretion

Utilizing traditional commission review to set the cost of RPS compliance on one hand makes a lot of sense. Utilities and commissions follow traditional administrative processes to work through issues that are at the same time novel and familiar. In doing so, they also hew to the regulatory compact. Utilities likely can recover costs they can reasonably justify. Moreover, there is no seemingly arbitrary point (a cap) at which compliance obligations stop short of the RPS targets. Further, customers are not lured into a false sense of security from a non-transparent cap.

On the other hand, traditional agency review creates its own risks and an enormous amount of uncertainty. In addition to a significant administrative burden, there is a risk that case-by-case decisions to approve utilities' costs of compliance may be arbitrary, politically motivated, or unfair, may favor one stakeholder group over another, and may prioritize utilities' return on investment over the costs to consumers. The more discretion that is left to a state commission, a body that is subject to political influence or other motivations, the greater the level of uncertainty to electricity providers and consumers alike.

9. Conclusion

In the face of the uncertain and likely increasing costs of implementing state RPSs, lawmakers, regulators, and interested parties must walk a fine line between consumer protection and maintaining the integrity of the policies. The range of mechanisms designed to mitigate the costs of RPS compliance embodies these competing concerns. At first glance, a hard-line cost cap would appear to protect consumers from excessive price increases due to increasing renewable energy penetration. A closer look suggests that many states with a cap actually utilize a hybrid incremental cost cap that may compromise consumer protection and transparency in order to satisfy aspirational renewable targets and utilities' needs. Alternatively, traditional agency discretion in rate regulation leaves state commissioners with the job of balancing dueling considerations of consumer protection and RPS integrity. Although an ample reserve of discretion must be left to state commissions to allow for flexibility in this extremely complicated area of renewable energy policy, there must be safeguards to ensure waivers are limited and granted in an even-handed fashion. Additionally, implementation of the various mechanisms described above also raises issues of utilities' ability to recover, transparency, and administrative burdens.

Although the costs of implementing state RPSs are uncertain, it is clear that the transition to cleaner energy will not come free. While utilities and regulators must work to mitigate cost increases shouldered by consumers, they should not hide cost increases through sunk costs, complex administrative proceedings, convoluted opaque rate cap methodologies, or misnomers. Given how intricately different state electricity markets are structured, we do not presume to prescribe only one preferred cost limitation approach that will work in all cases. Rather, this preliminary survey suggests that the most important factors in implementing any effective and credible mechanism to curtail costs are clarity of the rule, consistency in application, and, above all, transparency for customers.

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