PUBLIC COMMENT RECEIVED FROM 01/06/15 – 02/16/15

(NOTE: 2nd Hearing in RPS Cost Cap Regs. was 1/7/15 – hearing record closed 2/16/15)

DATE	PERSON/ORGANIZATION
01/06/15	Bill Cook, Chief of Staff, *Senate Republican Caucus*
01/07/15	David T. Stevenson, Director, *Ctr. for Energy Comp. (CRI)*
01/10/15	Gary Myers (Cover email w/3 .pdf attach.)
01/27/15	D. Stevenson, Director, *Ctr. for Energy Comp. (CRI)*
02/04/15	Charlotte King, President, *League of Women Voters of DE*
02/09/15	Amy Roe, Ph.D., *DE Chapter of the Sierra Club* (w/8 .pdf attach.)
02/10/15	Lisa Locke, Exec. Dir., *DE Interfaith Power & Light*
02/10/15	Michael K. Messer, *Linde, LLC*
02/12/15	Pamela Knotts, *DE Public Service Commission*
02/13/15	Dana Sleeper, Exec. Dir., *MDV-SEIA*
02/15/15	G. Myers – Supplemental Comments (Cover email w/3 .pdf attach.)
02/15/15	Coralie Pryde
02/16/15	Jeremy Firestone, *Univ. of DE, College of Earth, Ocean & Environmt.*
02/16/15	Andrea B. Maucher, *DE Division of the Public Advocate*
02/16/15	Dale Davis, President, *DE Solar Energy Coalition*
02/16/15	A. Maucher, *DE Div. of the Public Advocate* (corrected, w/attach.)
02/16/15	Joseph Otis Minott, Esq., Exec. Dir., *Clean Air Council*
02/16/15	Bruce H. Burcat, Exec. Dir., *Mid-Atlantic Renewable Energy Coalition*

Vest, Lisa A. (DNREC)

From:	Vest, Lisa A. (DNREC)
Sent:	Wednesday, January 07, 2015 11:43 AM
To:	Cook, Bill (LegHall)
Cc:	Cherry, Philip J. (DNREC); Underwood, Robert (DNREC); Noyes, Thomas G. (DNREC)
Subject:	FW: RPS Cost Cap Letter
Attachments:	RPS Cost Cap Letter from GOP Leaders.docx

Bill –

This will acknowledge receipt of your email below, along with the attached letter signed by Sen. Simpson, Rep. Short, Sen. Lavelle, and Rep. Hudson. Please be advised that I have entered this letter into the formal hearing record which is being developed in this ongoing regulatory promulgation.

Given the fact that the public hearing scheduled for this evening has been publicly noticed for over a month, there is a logical expectation that the hearing will, in fact, take place this evening, as scheduled. Thus, the Department will proceed with holding this public hearing tonight, as previously scheduled, beginning at 6:00 p.m.

It should be noted that this hearing record will remain open for receipt of additional public comment regarding these proposed regulations through close of business on Thursday, Jan. 22, 2015.

As always, thank you so much for your participation in DNREC's public hearing process.

Lisa A. Vest
Public Hearing Officer
State of Delaware - DNREC
89 Kings Highway
Dover, DE 19901
(302) 739-9042
Fax: (302) 739-1174

When one tugs at a single thing in nature, he finds it attached to the rest of the world. - John Muir

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From: Cook, Bill (LegHall)
Sent: Tuesday, January 06, 2015 12:15 PM
To: Vest, Lisa A. (DNREC)
Subject: RPS Cost Cap Letter

Lisa:

I've been asked, in my capacity as Chief of Staff for the Senate Republican Caucus, to send you the attached letter from the GOP leaders of the Delaware State Senate and House of Representatives regarding the Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions.

Best Regards,
ill Cook

Office: 302-744-4161

Lisa A. Vest
Public Hearing Officer
Department of Natural Resources and Environmental Control
State of Delaware
89 Kings Highway
Dover, DE 19901

Re: **102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions (NOPR: 18 DE Reg. 432 (Dec. 1, 2014))**

We have concerns about how cost cap regulations are being implemented. DNREC views the 1% solar and 3% total RPS thresholds as being a limit on the increase in RPS costs from year to year. This interpretation would allow a total cost increase to ratepayers of up to 47% by 2025 without a freeze on the RPS requirements. However, the statutory language states the cost cap should be measured as a "comparison of total RPS costs to 'the total retail cost of electricity for retail electric suppliers' in a particular compliance year". We interpret this to mean if the cumulative cost of the RPS requirements exceeds 3% the RPS requirements should be frozen until such time as the costs are reduced below the threshold.

We understand DNREC consulted the Attorney General's Office and received an opinion supporting their reading is correct. We request a complete copy of the opinion be released to the public, and a public hearing scheduled for January 7, 2015 be re-scheduled to a later date so the public has time to review and comment on the opinion.

We also urge DNREC to adopt a cumulative cost cap to ratepayers of 1% for solar, and 3% for total RPS cost to trigger a freeze. While encouraging the use of power from renewable sources, we recognize the need for competitive electric rates in Delaware to encourage economic growth. We also want to protect the poor and middle class, who are already struggling to pay utility bills, from the damage of even higher bills.

Sincerely,

F. Gary Simpson

Senate Minority Leader Gary Simpson

Daniel B. Short

House Minority Leader Danny Short

Senate Minority Whip Greg Lavelle

Deborah Hudson

House Minority Whip Deborah Hudson

Stevenson Exh. #2

Caesar Rodney Institute
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Lisa Vest
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This is the only comment (written) submitted at 2nd hearing (1/7/15)

1/7/15

Dear Ms. Vest;

I am submitting additional comments regarding DNREC's **102 Implementation of Renewable Portfolio Standards Cost Cap Provisions** printed in the Delaware Register 12/1/14, regarding how the Director of DNREC will determine if a freeze will be triggered in the accelerating requirement for renewable power.

Delaware Code Chapter 26, §354 (j) states the formula for the percentage cost of the RPS program to determine if a freeze has been triggered, "the total cost of complying with this requirement during a compliance year exceeds 3% of the total retail cost of electricity for retail electricity suppliers during the same compliance year". The formula is straightforward and is consistent with the language of Section 4.0 in the proposed regulation as shown in this example:

$$\text{Compliance Cost \%} = \frac{\text{RPS Compliance Cost for CY 2013}}{\text{Retail Cost of Electricity for CY 2013}} = \frac{\$7/\text{month}}{\$135/\text{month}} = 5.2\%$$

However, DNREC's proposed "Determination by the Director" in section 5.0 changes the formula as shown in the sample below. Nothing in the code supports the formula in Section 5.0 comparing cost to a previous compliance year. The freeze should be triggered by the simple formula above.

$$\text{Compliance Cost \%} = \frac{\text{RPS Compliance Cost for CY 2013 - RPS Compliance Cost for CY2012}}{\text{Retail Cost of Electricity for CY 2013}}$$

$$= \frac{\$7/\text{month} - \$3/\text{month}}{\$135/\text{month}} = 3\%$$

The timing recommended in Section 8.0 suggests the Energy Division should have submitted the calculations for the 2013 Compliance Year by 12/31/2014. We would like a copy of those calculations.

We understand DNREC consulted the Attorney General's Office and received an opinion supporting the code interpretation in Section 5.0. We request a complete copy of the opinion be released to the public, and, that the comment period be extended to allow ample time for analysis and comment.

David T. Stevenson
Director, Center for Energy Competitiveness
e-mail: DavidStevenson@CaesarRodney.org
Phone: 302-236-2050
Fax: 302-734-2702

Vest, Lisa A. (DNREC)

From:	Gary Myers <garyamyers@yahoo.com>
Sent:	Saturday, January 10, 2015 8:53 AM
To:	Vest, Lisa A. (DNREC)
Cc:	Noyes, Thomas G. (DNREC)
Subject:	DNREC NOPR 18 DE Reg. 432 (Dec. 1, 2014) "REPSA Cost Cap Rules" - Submission of Comments by Gary Myers
Attachments:	REPSA 2014 Cost Cap comments cover letter.pdf; REPSA Cost Cap 2014 G. Myers Comments - Final.pdf; Stock_et_al-2.pdf

Dear Hearing Officer Vest:

Attached are three electronic files (.pdf format) that I ask be made a part of the record in the above captioned rule-making proceeding.

Two of the files (those entitled "cover letter" and "G. Myers comments") represent the comments and brief I wish to file in the matter. The two files should be kept together so, as I explain in the cover letter, the comments can be accurately identified as mine.

The third file (Stockmayer *et al.* article) is submitted as anther "background" document. It is referenced in my comments and I am providing a copy for the Division's and your consideration. I ask that it be made part of the record as was done with other earlier "background" submissions by me.

Can you please confirm receipt and filing of these documents?

If Mr. Noyes would provide me with the e-mail addresses of those persons and entities who have already filed comments, I would be happy to send them (via e-mail) electronic copies of my comments. This would give other commenters a chance to reply to my arguments.

If you have any questions, please let me know.

Gary Myers
217 New Castle Street
Rehoboth Beach, DE 19971
<garyamyers@yahoo.com>
(302) 227-2775

217 New Castle Street
Rehoboth Beach, DE 19971
January 10, 2015

Lisa Vest
Hearing Officer
Delaware Department of Natural Resources
and Environmental Control
89 Kings Highway
Dover, DE 19901

By electronic mail and US mail

Re: *DNREC, NOPR 18 DE Reg. 432 (Dec. 1, 2014)*
"102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions"
Comments of Gary Myers

Dear Hearing Officer Vest:

Pursuant to the notice posted in the December 1, 2014, Register of Regulations, and the provisions of 29 Del. C. §§ 10116 & 10118(a), I am submitting the attached post-hearing comments for consideration in the above-captioned DNREC rule-making proceeding. I ask that they may be made part of the record in the proceeding.

1. Two filing cautions. The comments have been constructed separately and contain only a footer reference to my name or other identifying information. Consequently, this cover letter should accompany them into the record. Similarly, I have also submitted (as e-mail attachments) electronic copies of the comments and this letter. Those two electronic files should also be kept linked or connected in order to identify the electronic version comments as mine.

2. I also wish to incorporate into this submission the "Bloom Energy surcharge" comments that I submitted as part of my earlier comments filed in response to the 2013 NOPR concerning the cost cap rules. Those comments (Part 3 of the January 21, 2014 Myers submission) dealt with why Bloom Energy surcharges are part of "costs of compliance" under 26 Del. C. § 354(i) & (j). The Division has accepted that conclusion and I submitted the arguments in those earlier comments only if another commenter argued otherwise. Although I press those arguments, I have not re-copied those comments into this 2015 filing. I ask that they be considered if - in this second go-round - a commenter makes an argument that Bloom Energy surcharges should not be counted as "compliance costs."

If you have any questions, please contact me.

Respectfully submitted,

Gary Myers
(302) 227-2775
<garyamyers@yahoo.com>

Enclosure

G. Myers' 2015 comments on 2014 NOPR proposed cost cap rules

cc: Thomas Noyes,

Div. of Climate & Energy (w. enc.) (by e-mail only)

Comments of Gary Myers January 10, 2015

DNREC, NOPR, 18 DE Reg. 432 (Dec. 1, 2014)

102 Implementation of Renewable Energy Portfolio Standards
Cost Cap Provisions

<u>*Glossary*</u>

§ 354(i) – 26 Del. C. § 354(i).

§ 354(j) – 26 Del. C. § 354(j).

SS 1 - Senate Substitute No. 1 for Senate Bill No. 119, 145th Gen. Assembly, 2d Sess., *enacted as* 77 Del. Laws ch. 451 (2010), *and codified in various provisions of* 26 Del. C. §§ 354-363.

2010 REPSA amendments - same as SS 1.

SS 1 SD – floor proceedings on SS 1 in the Senate (June 22, 2010).

SS 1 HD – floor proceedings on SS 1 in the House of Representatives (June 29, 2010).

RH Dict. - *Webster's unabridged dictionary* (Random House 2d ed. 2001)

Delmarva or *DP&L* - Delmarva Power & Light Company

2012 IRP - Delmarva Power and Light Co., *2012 Integrated Resource Plan* (PSC Dckt. No. 12-544, unsealed version filed March 18, 2013)

2014 IRP - Delmarva Power and Light Co., *2014 Integrated Resource Plan* (PSC Dckt. No. 14-559, filed Dec. 2, 2014)

2014 DP&L REC Compliance - Delmarva Power and Light Co., *Retail Electric Supplier's RPS Compliance Report, June 1, 2013 -May 31, 2014* (filed with PSC Oct. 1, 2014)

Bloom 2014 Report - Diamond State Generators Partners, *Annual Report for QFCP-RC Operations June 2013-May 2014* (filed with PSC June, 2014)

NREL - J. Heeter, *et al.*, Delmarva Power and Light Co., *Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards* (Nat'l. Renewable Energy Lab. & Lawrence Berkeley Nat'l. Lab. May, 2014)

Stockmayer - G. Stockmayer, *et al.*, *Limiting the costs of renewable portfolio standards: A review and critique of current methods*, 42 Energy Policy 155 (2012)

1. **Introduction**

Back in 2010, Colin O'Mara, then-Secretary of DNREC, told the members of the House on the floor of their chamber that if they passed SS 1 they would be enacting "price protections'" for consumers where "there currently are none" and would "ensure ratepayers that there won't be any adverse impacts from this legislation."[1] Those protections, added as subsections 354(i) & (j), he emphasized, would impose "an actual price control," in the form of a "circuit breaker," "whereby if the, if the ratepayer impacts exceed a certain amount, that the entire program freezes in place."[2] As he told it, the protections would be iron-tight. Thus, in the case of the solar energy carve-out:

> So under the legislation, if the -- as soon as there's a 1 percent impact from the solar portion of the bill, the, the target level freezes in place for that entire calendar year and then starts up again after it. You'll ***never*** have more than a 1 percent impact in any given year for the solar, for the solar portion of the, of -- the solar requirements as written in the legislation.[3]

The House passed SS 1. The Senate, already having heard similar representations about "circuit breakers" to protect consumers from th impacts of renewable costs, had earlier signed on. The Governor quickly assented.

The question now in this rule-making is whether the then-Secretary's promises are to be honored in the Division's rules. Or will this rules throw aside his promise of an "actual price control" to "circuit break" high costs in favor of a discretionary power vested in the Director that would allow consumers to suffer dollar impacts that go beyond the percentage limited amounts directed by the legislation.

a. The Cost Cap is Already Busted_

Subsection 354(j) commands the Director to impose a freeze on any further compliance with the percentage renewable energy standards (26 Del, C. § 354(a)) if his Division "determines that the total cost of complying with this requirement during a

1 SS 1 HD at 6-7 (O'Mara).

2 SS 1 HD at 6-7 (O'Mara).

3 SS 1 HD at 13-14 (O'Mara) (emphasis added). A more detailed recount of what transpired in the legislative floor proceedings for SS 1 - and the representations made there - is set forth in part 2 of these comments.

compliance year exceeds 3% of the total retail cost of electricity for retail electricity suppliers during the same compliance year." He has the same obligation as to the solar renewable energy requirements: to impose a freeze on further compliance if "the total cost of complying with this requirement during a compliance year exceeds 1% of the total retail cost of electricity for retail electricity suppliers during the same compliance year."

It would be hard to deny that the percentage triggers set forth in the above two "freeze" subsections have already been pulled. Back in its 2012 IRP filing, Delmarva Power projected that the total cost of complying with the overall renewable energy procurement requirements for the just-closed 2013-14 compliance year would hover around 5.24 % of the total electric supply and delivery bill for a typical residential customer of DP&L.[4] Under Delmarva's 2012 predictions, that percentage would climb to 5.78 % by compliance year 2017-18.[5]

In its more recent 2014 IRP filing, DP&L forecasts even higher percentage levels. For the 2018-19 compliance period, DP&L projects total renewable compliance costs to reach 6.86 % of a residential customer's bill with solar compliance costs coming in at 1.54 %. By 2020, those percentages grow higher, to 7.17 % and 2.51 %, respectively.[6]

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4 2012 IRP at pg. 102, Table 10. DP&L assumed that a typical customer would use 1000kwh of electricity during the monthly billing period.

5 2012 IRP at pg, 102, Table 10. In this table the percentages were derived by applying the total costs of compliance against a customer's assumed electric supply, transmission, and distribution charges. As set forth in part 5 of these comments, the correct comparison base is the supplier's cost of electric supply - which can be approximated as only the electric supply portion of a customer's bill without additional transmission or distribution charges. If the supply portion is used for DP&L's projections, the applicable percentages for the 2013-14 compliance year would be 7.4 % for renewables overall and 1 % for the solar carve-out. For the later 2017-18 compliance year, the percentages utilizing the supply cost figure only, would be 7.6 % for overall renewable compliance costs and 1.8 % for solar compliance costs.

6 2014 IRP at pg. 74, Table 10. In the 2014 IRP numbers, DP&L adds back into the customer's "total bill" amount, the customer's renewable energy compliance costs. That was not done in the 2012 IRP table. Again, if one compares compliance costs against the more appropriate electric supply costs alone then the percentages get even bigger. For compliance year year 2018-19, the percentages are 12.2 % (overall) and 2.7 % (solar). For the 2020-21 compliance year, the percentages move to 12.1 % (overall) and 3.6 % (solar),

Delmarva is not the only one to report that the percentage limits set forth in subsections 354(i) & (j) are breached and will continue to be left behind for years to come. Using public information, researchers from the National Renewable Energy Laboratory and the Lawrence Berkeley National Laboratory project that Delaware's renewable compliance costs exceed the statutory cost cap limits now, and into the future. As they see it:

> In Delaware, Delmarva Power & Light's RPS procurement costs for 2012 appear to have exceeded the 3 % cost cap; however, the administrative rules for implementation of the cost cap are still under development (as of this writing) and it is therefore not yet practically enforceable.[7]

See also NREL at pg. 50, Fig. 11 (chart reflecting that for Delaware the estimated historical cost amounts exceed the 3 % cost cap). *Accord* NREL at pgs. 42-43, Figs. 9 & 10 (charts showing that for Delaware RPS charges in 2012 approximate or exceed 4 % of average statewide retail electricity rates).

b. DP&L Customers Bear Very High Renewable Compliance Costs

If one wants to know why the cost cap protection levels have already been breached, one need only look at what DP&L's customers pay for renewable energy compliance. Those compliance costs are very, very high.

For the period June 2013 through May, 2014, the Diamond State Generators QFCPP generated 181,157 MWh of electricity. During the same period, DP&L customers paid to Diamond State a total of $29,621,843 (that's $ 29 million) in QFCPP surcharges.[8] Thus, each MWh of QFCPP production earned (on average) $163.51 in surcharges. Given that the DNREC Secretary has assigned 2 REC equivalencies to each MWh of QFCPP production, each REC equivalency used during the 2013-14 compliance year ended up costing DP&L customers (on average) $ 81.76. That *$ 81* number is multiples over the *$ 25* per MWh alternative compliance payment amount that the General Assembly set long ago as the maximum amount an electric supplier (and now DP&L) should pay for a substitute REC.[9]

7 NREL at pg. 49.

8 Bloom 2014 Report at pg. 3.

9 *See* 26 Del. C. § 358(d). In 2013-14, 303,817 of these $ 81 REC equivalencies were used to

The problem does not get any better on the solar carve-out side. Under the Secretary's equivalency ratios, 3 MWh of production, or 6 QFCPP REC equivalencies, are deemed equal to one SREC equivalency. DP&L used 4,874 SREC equivalencies to meet the 2013-14 solar carve-out requirements.[10] Each of those equivalencies cost DP&L customers (on average) $ 490.50. Again that number is above the $ 400 alternative solar compliance payment that was to cap the cost of a SREC fill-in.[11]

In fact, if you add the costs paid by customers for QFCPP REC equivalencies and for actual RECs used for the 2013-14 year, the average cost per REC (or its equivalency) was $47.89.[12] Once more that exceeds by more than 100 % the legislatively imposed ACP for the cost of a substitute REC.

Once again, outside observers see the same conclusion. NREL at pg. 29 ("In the case of Delaware, the state's lone distribution utility , Delmarva Power & Light, has met much of its compliance obligation with long term bundled PPAs, *and the above market costs of these resources are greater than spot market REC prices.*") (emphasis added).[13]

c. The Crucial Question

Against this backdrop, the crucial question for this rule-making is what "consumer protection" did the General Assembly impose when it enacted subsections 354(i) and (j). The "plain reading" of the text of those provisions reveals them to be exactly what then-Secretary O"Mara said they would be: "actual price controls' that would act as automatic

fulfill the overall total REC requirement of 697,195 RECs.

10 2014 DP&L REC Compliance Report at pgs. 1 & 3.

11 26 Del, C. § 358(e).

12 DP&L reported REC purchase costs for the 393,175 RECS used in the 2013-14 year as $ 8,547,916. 2014 DP&L REC Compliance Report at pg. 3. The 303,817 QFCPP REC equivalencies used cost $ 24,840,078.

13 The surveyors calculated the "above-market" prices for RECs and SRECs under several of DP&L's renewable energy contracts as well as the $241/MWh price under the Bloom Energy commitment. This led them to conclude that "Delmarva's RPS surcharge, which serves to recover the entirety of the above-market costs of the utility's RPS resources costs in each year, *equated to an average above-market cost of $55/mwh in 2012.*" NREL at pg. 29 n. 24 (emphasis added).

"circuit breakers" and freeze further compliance with the renewable energy portfolio requirements if the incremental costs of renewable compliance turn out to exceed the statutorily described percentage limits. That is a description of a "cost cap:" a reasonable, predictable, and easy to administer, limit on the costs that customers should be called upon to shoulder to meet renewable energy benchmarks.

But the Division's proposed rules paint a different mechanism. Rather than have a simple, easy to apply, cap formula to protect consumers against excessive costs, the Division suggests a yearly exercise that allows it to assay the costs and benefits of renewable energy requirements regardless of the above=cap consumer pocketbook costs. Various factors are to be determined and weighed, and then the Director will finally determine how much customers should or should not pay for renewable energy compliance. But it's hard to find the Division's construct in the statutory text. Maybe just as significant, when the General Assembly considered SS 1 and its cost cap provisions, the legislators were cognizant of the environmental, health, and economic development benefits of encouraging renewable energy sources.[14] With that knowledge, the legislature, in the enacted text, struck the balance between those benefits and the dollar and cents burdens electric customers should be forced to pay. That balance was struck in the percentage cost cap limits, enforced by two freezes. The Division cannot point to anything in the text (or even the legislative history) that suggests that once having set the tip-point, the legislature was then willing to allow the Director to revisit and reset the balance each and every year.

14 SS 1 HD 8-9, 17-20 (O'Mara); SS 1 SD 9-11 (McDowell), 25-26 (Bushweller), 28-29 (Simpson).

2. The § 354(i) & (j) "Circuit Breakers" - New, Easily-Administered Provisions to Protect Electric Consumers from Having Excessively Higher Electric Bills Due to Renewable Energy Mandates

As this proceeding drags through its second round, it is important to recall and repeat - one more time - exactly why the subsection 354(i) and (j) cost cap rules came about and how they were sold by their proponents to the General Assembly membership.

The two subsections were added as part of the 2010 reworking of the State's Renewable Energy Portfolio Standards Act. These 2010 amendments had three goals. First, some changes would "strengthen" the renewable energy portfolio requirements by increasing (and extending) the annual percentage requirements for upcoming years. Second, other modification would provide new incentives for electric suppliers to look to local labor and local manufacturing to meet the increased renewable energy levels demanded of them. And third, several changes would add protections for all electric consumers to guard against them having to bear any significant adverse cost consequences that might arise from both the old, and now strengthened, renewable energy portfolio requirements.

Subsections 354(i) & (j) were the major mechanisms to achieve this third goal. The two provisions came highly touted to the legislative floors. Senator McDowell, the prime sponsor of the bill, told his Senate colleagues, that the bill – in these two subsections - "provides consumer protection by limiting any rate impact it may create."[15] And on the House side, co-sponsor Representative D.E. Williams echoed the provisions' significance. As he reported to House members, "very importantly, what it adds that the prior versions of this did not have is ratepayer protection by introducing limits of cost impacts on this."[16] On the House floor, then- Secretary O'Mara told the Representatives that by including the subsections, the proponents of the bill were "trying to make sure there's price protections in place where currently there are none."[17] As the Secretary explained: there are "right now no price protections in place under current law in the State of Delaware" so the two subsections would add "the circuit breaker that does freeze

15 SS 1 SD at 3 (McDowell). *See also* SS 1 SD at 4 (McDowell) (bill "provides for ratepayer protection against cost impacts").

16 SS 1 HD at 3-4 (Williams).

17 SS 1 HD at 6 (O'Mara).

the program if there are adverse rate impacts."[18]

Moreover, the sponsors and Secretary O'Mara all described the consumer protection provisions as easily administered and decisive. Both Senator McDowell and the Secretary used the metaphor of a "circuit breaker" to describe the protections afforded by subsections 354(i) and (j). Senator McDowell said:

> [a]ny time the cost impact of the photovoltaic goes up by 1 percent, the utility involved can push what we like to call a circuit breaker. In other words, they can suspend the program for that year and simply extend the portfolio forward a year for their utility.[19]

In more detail, he outlined:

> [w]e've also built safety valves into this bill. I told you about the circuit breaker that we have put in where any utility who can show that its rates are going up or would go up by 1 percent in case of -- of solar, the retail electric would go up by 1 percent in a year in the cases of solar, or 3 percent in the overall, they could push the circuit breaker and suspend their participation in the program for one year. And so that is a very, very serious rate production -- ratepayer protection.[20]

In the other chamber, Secretary O'Mara offered a similar picture of how

18 SS 1 HD at 7-8 (O'Mara). In responding to a Representative's question about the experience in California with similar ambitious renewable percentage targets, Secretary O'Mara said that one of the two failures in California was that "they did not put the consumer protections in place we're talking about, so there have been adverse impacts there because they did not take that step." SS 1 HD at 18 (O'Mara). According to him, the Delaware bill was an effort to "correct those two mistakes and learn from their, learn from their - the problems that they've had there so we don't replicate their mistakes." *Id.* Earlier, the Secretary had said that the consumer protection related to solar percentages (§ 354(i)) were "more stringent and much more – has much greater ratepayer protection than New Jersey or Maryland – both of which have a 2 percent [solar] carve out – because we believe we need to protect ratepayers during this tough economic time." SS 1 HD at 14 (O'Mara).

19 SS 1 SD at 4-5 (McDowell).

20 SS 1 SD at 9 (McDowell). *See also* SS 1 SD at 26-27 (McDowell) (offering similar description of circuit breaker protection applicable to all utilities).

subsections 354(i) & (j) would work:

> But most importantly, by having a circuit breaker, if you will, an actual price control, whereby if the, if the ratepayer impacts exceed a certain amount, that the entire program freezes in place, we can ensure ratepayers that there won't be any adverse impacts from this legislation.[21]

The mechanics he explained would be:

> So under the legislation, if the -- as soon as there's a 1 percent impact from the solar portion of the bill, the, the target level freezes in place for that entire calendar year and then starts up again after it.[22]

Finally, both legislative chambers heard the bill's sponsor and major proponent promise that the consumer impact protections would be triggered by the percentage formulas, have real bite, and not be illusory. Again, Senator McDowell said:

> *[a]ny time* the cost impact of the photovoltaic goes up by 1 percent, the utility involved can push what we like to call a circuit breaker. In other words, they can suspend the program for that year and simply extend the portfolio forward a year for their utility.[23]

In other words, according to the Senator:

> [t]he biggest thing and part of which is what I've called the circuit breaker, *whereby, if their rates go -- start to go up, and they can demonstrate by empirical data that their rates are going up more than or as much as the numbers we have here, which is 3 percent overall, 1 percent for solar, as a result of participating in the solar, their rates go up in one year by 1 percent or more, they can push the circuit breaker and they don't have to comply.*[24]

21 SS 1 HD at 6-7 (O'Mara).

22 SS 1 HD at 13 (O'Mara).

23 SS 1 SD at 4-5 (McDowell) (emphasis added).

24 SS 1 SD at 26-27 (McDowell) (emphasis added).

In the House, Secretary O'Mara was just as explicit. Speaking to the solar requirements cost cap provision, he said:

> [y]ou'll *never* have more than a 1 percent impact in any given year for the solar, for the solar portion of the, of – the solar requirements as written in the legislation.[25]

In sum, the legislative proceedings show that subsections 354(i) and (j) were meant to give electric consumers a real "wallet" entitlement: protection against bearing in their electric bills significant costs arising from the incremental costs incurred to comply with renewable energy portfolio requirements. Moreover, this entitlement was meant to be easily invoked and to have real effect.

25 SS 1 HD at 13-14 (O'Mara) (emphasis added).

3. Proposed Rule §§ 5.2 and 5.3 Conflict with the Enacted Text and Must be Struck in Favor of the Statutory Formula

Subsections 354(i) & (j) set forth a common formula that the Division is to use to determine if a the renewable or solar mandate must be brought to a halt or freeze. The Division must determine whether "the total cost of complying with this requirement during a compliance year exceeds [the applicable 1 or 3] % of the total retail cost of electricity for retail electricity suppliers during the same compliance year." Under that plain text, the two key inputs - the "total cost of complying" and the "total retail cost of electricity for retail electricity suppliers" - must be based on the same compliance year. The *total* cost of complying *"during a compliance year"* is to be assayed against the total retail cost of electricity for retail electricity suppliers *"during the same compliance year."* The formula's steps are simple. First, one simply divines the total cost of compliance for the particular compliance year. Second, one applies the applicable cost cap percentage to the total retail cost of electricity for suppliers in the same compliance year. If the product of the latter is smaller than the former cost of compliance number, then the cap has been breached.

This textual formula represents a typical "incremental cost" analysis routinely used to measure additional costs or impacts. The "total cost of compliance" component represents the additional, or incremental, costs paid for electric supply in a regime with renewable energy requirements, as compared to the total costs for a similar supply unburdened by the renewable energy mandates.[26] Under subsections 354(i) & (j), if those incremental costs exceed the applicable 1 or 3 percent of the unburdened electric supply costs, then a cost cap freeze is called for. That is how at least outside observer has read Delaware's cost cap: assigning Delaware to an "annual cost cap category," Under that classification, the incremental cost of renewable energy (as compared to cost of energy without renewables) in a single year is then divided by the annual revenue for the same year to see if it exceeds the percentage cap limit.[27]

Ohio's, Oregon's, and Washington's renewable cost cap statutes are similarly assigned to the same "annual cost cap" category.[28] When one lays those states' statutory provisions aside subsections 354(i) & (j), one can see that the other jurisdictions' cap formulas read much the same - and capture the same incremental cost structure. They

26 NREL at pg, 3-4.

27 Stockmayer, 42 Energy Policy at 156, Table 1; § 3.1 at 157.

28 *See* Ohio Rev. Code § 4928.64; Ore. Rev. Stat. § 469A.100; Wash. Stat. § 19.285.050.

judge the "cost impact" of the renewable mandate by first segregating the incremental costs incurred to comply with the renewable requirement versus the cost of electric supply without a renewable mandate. Then they apply that figure to see if it is above the specified percentage of either the cost of generation supply (without the mandate) or the gross revenue paid by customers. In each case, this comparison - and the cap - are based on a single year.

In its original 2013 version of the proposed cost cap rules, the Division adopted the statutory formula for deciding when a freeze is triggered, although the Division did misdefine the elements of the "total retail cost of electricity for retail electricity suppliers" component.

But now, in the "new" proposed rule §§ 5.2 and 5.3 the Division does an about-face and tenders a different formula for the cost cap trigger. Under these new proposed provisions, a cap is to be considered if "the increase in the [Renewable or Solar] Energy Cost of Compliance over the previous compliance year is equal to or greater than [1 or 3] percent of the Total Retail Cost of Electricity." No longer is the cost cap analysis confined to a single compliance year. Rather, under these proposed rules, in year x, one first figures or retrieves the total costs of compliance for the previous compliance year (x-1). Then, one figures the total cost of compliance for the year x compliance year. Third, one takes the year x-1 compliance amount and subtracts that number from the year x compliance amount. This apparently gives the difference (or "increase") in compliance costs between the x and x-1 years. If that delta is positive - an "increase," then one goes two further steps. One computes 1 or 3 per cent of the total retail cost of electricity, apparently for year x (although the rules do not allude to which year). Then one takes the delta between the two years compliance costs and lays it against the percentage product figure. Only when the delta exceeds the percent amount can a freeze be applied.

The Division calls the formula in its proposed rules a "year-to year" comparative analysis for purposes of the cap. The 2014 proposed rules are not the first time that DNREC has tried to impose such a "year-to-year" comparison method on the language of subsections 354(i) & (j). In the Bloom Energy proceedings before the PSC in 2011, then-Secretary O'Mara offered a similar "interpretation" of the cost cap regime. In response, the consultants hired by the PSC expressed curiosity about how the Secretary's method could be squared with the statutory phraseology in subsections 354(i) & (j). *See* PSC Dckt. No. 11-362, New Energy Opportunities, Inc., *Report on Delmarva Power's Application for Approval of a New Electric Tariff Applicable to Proposed Bloom Energy Fuel Cell Project* (Oct. 3, 2011) at pg. 45 (suggesting that Secretary's formulation that compared present year RPS costs to previous year's costs "views the 1% and 3% thresholds as being a limit on the increase in RPS costs from year to year" and that such formula is different from a "comparison of total RPS costs to 'the total retail cost of electricity for retail electric suppliers' in a particular compliance year" - the latter being the language used in the statutory subsections).

a. Proposed Rule §§ 5.2 and 5.3 Conflict with the Plain Text and Structure of of Subsections 354(i) & (j)

But far, far more importantly, the Division's proposed §§ 5.2 and 5.3 are directly contrary to enacted text.

First in subsections 354(i) & (j) there is not any mention of any "previous compliance" year to be factored into the cost cap analysis. There is also no mention of the Division looking to see if there is any "increase" in compliance costs from those in a previous compliance year. There is not a word about comparing a prior year's cost of compliance to the current year's costs of compliance. Instead, the text of the subsections makes a specific point of keying compliance costs and the total retail costs of electricity to suppliers to numbers arising *from the same compliance year.* The Division's proposed rules, which involve cross-compliance year numbers, cannot be grounded in any text in subsection 354(i) or (j).

Second, the enacted text specifically calls for imposing a freeze if the "*total* cost of complying" with a renewable energy requirement "during a compliance year" exceeds the specified percentage of the total retail cost of electricity for suppliers. In contrast, the Division's year-to-year approach only compares *a part* of the present year's compliance costs to the applicable percentage amount of the total retail electricity costs for suppliers. The "total" cost of presently complying is not used; instead it is only that *part* of present year compliance costs that are *above* last year's compliance costs that are looked to make the comparison. The Division's rules thus operate in a world where the statutory term "total" is deemed to mean "some part" or "partial."

Third, the legislative history repeatedly recounts that one overall goal sought by the proponents of SS 1 was to bring both municipal electric companies and the Delaware Electric Cooperative within the renewable energy portfolio regime and, while doing so, to provide to their customers and members the same scope of customer price protections that were to be now accorded to customers taking service from DP&L and other electric suppliers. Thus, Senator McDowell told his Senate colleagues that the "circuit breaker" cost cap/freeze protections would be applicable to all three utilities: DP&L, the Co-op, and municipal utilities.[29] Secretary O'Mara told the House members the same thing: "[t]he price protections that we discussed earlier are embedded also in the, in the special language that is carved out for the munis and the, and the co-op."[30]

But if the "price protections" set forth in subsections 354(i) & (j) were also "embedded" in the statutory price protection provisions applicable to the Co-op and municipal electric companies, it is even more difficult to endorse the Division's "year-to-year" comparison cap methodology. For just as the text of subsections 354(i) & (j) do, the statutory cost cap provisions governing the Co-Op and municipals call for a cap on renewable compliance expenditures if incremental compliance costs *in a particular year* exceed a specified percentage of the utility's *purchased power costs in the same year.*

Thus, the Co-op and municipal cost cap provisions simply say:

> (f) The total cost of complying with eligible energy resources shall not exceed 3% of the total cost of the purchased power of the utility for any calendar year.
>
> (g) The total cost of complying with the solar photovoltaic program shall not exceed 1% of the total cost of the purchased power of the affected utility for any calendar year.[31]

Again, in these provisions there is no mention of divining the increase of compliance costs in one calendar year over those costs in a previous calendar year. Nor is there any reference to taking any such increase and holding it up against the percentage of purchased power costs for this year. Instead, the "total cost of complying' in one calendar year cannot go beyond the specified percentage of the purchased power costs *for the same calendar year.* It's the same formula - albeit in slightly different phraseology - that is set forth in subsections 354(i) & (j).

b. Proposed Rule §§ 5.2 and 5.3 Are Illogical

It is unclear exactly what proposed §§ 5.2 and 5.3 are meant to do. By giving

29 SS 1 SD at 26-27, 33 (McDowell).

30 SS 1 HD at 12 (O'Mara).

31 26 Del. C. § 362(e) & (f).

them a "year-to-year" label, the Division implies that they are meant to reign in the growth of renewable costs from one year to the next. That is supported by the first calculation under the new rules: that of finding how much renewable costs increased above those incurred the prior compliance year.

But if the cap was to limit such increases, the statutory provision would more easily achieve that goal by simply defining how many percentage points this year's renewable costs could exceed last year's. The statutory text does not do that. Similarly, one could devise a cap as limiting the year-to-year increase to a specified percentage of last year's overall cost of retail electricity or more broadly the overall cost of electricity to customers. Such would show how much "rates" have grown over last year's and limit such impacts. But proposed rules §§ 5.2 and 5.3 do neither of these. Instead, they mark the increase in renewable costs to a percentage of *this year's* total costs of electricity. That percentage tells nothing about an increase in rates or revenues over the last compliance year. It is simply an arbitrary limit. The problem is that the Division cannot change the comparison figure to a percentage of *last year's* overall revenues or electric supply costs. The text of subsections 354(i) & (j) do not speak to a prior compliance year, but the total retail costs of electricity for the same compliance year.

In contrast, the statutory formula looks not to yearly increases but rather to the "impact" of renewable mandates on customers' bills. As noted before, it measures the incremental costs paid by customers over that which they would have paid without the renewable mandates and caps those incremental costs at a specified percentage of supply costs. It charts how customers bills "go up" over the benchmark supply cost without the mandate due to the renewable requirements. That's the better measure of what customers pay for the renewable mandate and what "impact" those incremental costs have on their bills.

Proposed rule §§ 5.2 and 5.3 cannot be squared with the relevant statutory text, n or with the overall statutory cost cap scheme. The two provisions must be struck and replaced with a formula consistent with the same year analysis method called for in the explicit text of subsections 354(i) & (j).

4. Proposed Rule §§ 5.3-5.8 Are Contrary to the Statutory Scheme and Ultra Vires and Must be Struck

Before the legislative houses, both Senator McDowell and then-Secretary O'Mara portrayed the percentages in both subsections 354(i) & (j) as not just necessary, but sufficient (if not exclusive), grounds for a renewable energy portfolio "freeze." In the picture they painted, once the total costs of renewable energy compliance reach the relevant 1 or 3 percent figure, the "circuit breaker" trips to "suspend participation"[32] so that "the entire program freezes in place."[33]

Unfortunately, the Division has chosen to continue to paint a different landscape in its proposed rule §§ 5.3-5.8. Those provisions (which mirror similar provisions that were proposed in the 2013 version) make the statutory percentage levels necessary, but not sufficient, conditions for a "freeze." Proposed rule §§ 5.3-5.8. To throw in another metaphor, the statutory percentage levels in these proposed rules are not "stop" signs but merely "rumble strips." Once the statutory levels are reached, a "freeze" ensues *only* if the Director then works through an all-encompassing list of considerations (assigned to four factors) and then determines a freeze is called for. Proposed rule §§ 5.4-5.8. Yet, this four-factor superstructure constructed by the proposed rules is not to be found in the text of subsections 354(i) & (j) and indeed runs counter to their language. And, as shown above, the "additional considerations" regime is inconsistent with the "intent" of the legislature as reflected in the legislative history recounted in part 2 of these comments. Consequently, proposed rule §§ 5.3 through 5.8 must be struck. Instead, the Division's rules must be rewritten to reflect that breach of either of the two statutory percentages caps is - in itself - sufficient to require the Director to declare a relevant "freeze."

a. Background Principles

The first duty in any rule-making – as indeed the primary obligation of any executive branch action – is to take care that the laws be *faithfully executed.* Del. Const., art. III, § 17 (emphasis added). An agency's duty is to ensure execution of the General Assembly's law, not to make up the law on its own. Consequently, "an administrative body exercising purely statutory powers must find in the [legislative] act its warrant for the exercise of any authority it claims." *State v. Berenguer*, 321 A.2d 507, 509 (Del. Super. 1974) (Walsh, J.) (internal quotation and citation omitted). And the concurrent

32 SS 1 SD at 5, 9 (McDowell).

33 SS 1 HD at 7, 13 (O'Mara).

principle is that an agency has no authority to choose to suspend the operation - in full or in part - of a law previously enacted; the power to suspend law rests exclusively with the General Assembly. Del. Const. art. I, § 10 ("no power of suspending laws shall be exercised but by authority of the General Assembly"). No general warrant empowers an agency to nullify a law it does not like – or that the agency believes will lead to bad results - simply by failing to faithfully implement it.

This bar against executive branch suspension of laws plays out in two ways. First, if an agency wishes to forego adhering to the terms of a statute, it must point to a *legislative provision* that explicitly allows for such a "suspension" and also charts the factual circumstances that must exist to trigger the agency's action. *See, e.g., Marshall Field & Co. v. Clark*, 143 U.S. 649, 680-94 (1892). Second, any such power to suspend or to ignore statutory provisions is not to be lightly inferred from legislative text; it must be clear and definite. As a Delaware court said years ago: "[i]mplied authority in an executive officer to repeal, extend or modify a law may not lawfully be inferred from authority to enforce it." *State v. Retowski*, 175 A. 325, 327 (Del. Gen. Sess. 1934). Moreover, by the rule-making process, an agency cannot change the legislative scheme. Thus, again in the language of one Delaware court:

> Legislation, however, may not be enacted under the guise of its exercise by adopting a rule or regulation which is out of harmony with, or which alters, extends or limits the Act, or which is inconsistent with the clear legislative intent as therein expressed. *Thus, as in the present case, where a right is granted to a class by statute, the agency administering such statute may not by the adoption and promulgation of a rule or regulation add to the condition of that right a condition not stated in the statute, nor may it exclude from that right a class of persons included within the terms of the statute.*

Wilmington Country Club v. Del. Liquor Commission, 91 A.2d 250, 255 (Del. Super. 1952) (emphasis added). Accordingly, an agency cannot, by rule-making, impose a blanket prohibition on issuing some category of permits when the legislative scheme sets forth a process to obtain permits premised on a case-by-case consideration of various statutorily-described factors. *See In the Matter of Dept. of Natural Resources and Environmental Control*, 401 A.2d 93, 95-96 (Del. Super. 1978) (Walsh, J.). Logically, the converse is just as true: an agency cannot, by rule, make discretionary a decision that the statutory scheme makes mandatory.

b. The Proposed Rule §§ 5.3-5.8 Discretionary Process Violates § 354(i) & (j)

Sections 5.3-5.8 of the proposed regulations violates these first principles. The provisions of subsections 354(i) and (j) speak explicitly in terms of a freeze to be implemented if the total costs of SREC or REC compliance exceed the specified percentage of the total retail costs of electricity of electric suppliers. Those percentage levels are the "circuit breakers" described by Senator McDowell and Secretary O'Mara on the legislative floors. The two "safety valves" were put into place to protect a specified class – electric consumers – from suffering significant adverse electric billings from the renewable energy portfolio requirements. These two "circuit breakers" were "very, very serious ratepayer protection[s]," needed not only to fill a gap in earlier Delaware renewable legislation but to prevent the possible adverse rate impacts that seemingly plagued similar ambitious renewable efforts in other states such as California.

But proposed rules §§ 5.3 through 5.8 alter all these consumer protections. The proposed rules remake the "circuit breaker" metaphor used by Senator McDowell and Secretary O'Mara into a "fuse and penny" regime. If costs of compliance exceed the applicable percentage cap, the Director does not freeze or suspend the renewable program. Rather, he embarks on a four-factor analysis to determine whether a freeze is to be imposed. He is to consider a whole gamut of inputs, from overall energy market conditions, "avoided cost benefits," "external" savings from cleaner energy, to economic development advantages. Only if – after some unspecified weighing of these open-ended factors – the Director decides a freeze is appropriate will one be forthcoming. If the factors, in his mind, point otherwise he can refuse to impose a freeze and, inserting the penny, continue the "normal" renewable portfolio requirements. Of course, to do so will cause consumers to continue to finance costs of compliance in excess of the percentage cap amounts set forth in the statutory subsections.

Initially, proposed rule §§ 5.3-5.8 make both Senator McDowell and former Secretary O'Mara into liars. The Senator told his colleagues that "[*a*]*ny time*" the cost impact goes up beyond the 1 solar cap percentage level, the solar renewable program will be suspended.[34] Secretary O'Mara had a similar description: the new provisions would provide "an actual price control whereby if the ratepayer impacts exceed a certain

34 SS 1 SD at 4-5 (McDowell). *See also* SS 1 SD at 9 (McDowell) ("any utility who can show that its rates are going up or would go up by 1 percent in case of -- of solar, the retail electric would go up by 1 percent in a year in the cases of solar, or 3 percent in the overall, they could push the circuit breaker and suspend their participation in the program for one year").

amount that the entire program freezes in place."[35] It would be a "circuit breaker *that does freeze* the program if there are adverse rate impacts."[36] In fact, he represented that "[y]ou'll *never* have more than a 1 percent impact in any given year for the solar, for the solar portion of the, of – the solar requirements as written in the legislation."[37] Yet all of these statements will not hold true under proposed rule §§ 5.3-5.8. For under it, if the Director deems a freeze unwarranted under the four-factor test, there will be times the "program" will not freeze even though the cost impact exceeds the statutory percentage limit. So too, under §§ 5.3-5.8 even if solar compliance costs of compliance exceed 1 per cent of total retail costs in any given year, consumers might be still forced to pay such higher than cap rates if the Director determines economic development demands it, or some other law provides some form of offsetting economic benefits to consumers. In such a case, contrary to the former Secretary's promise, consumers will see more than a 1 percent impact in their bills.

Second, the proposed rule § 5.4 regime is inconsistent with the normal understanding of what constitutes a "cost cap." One does not generally view a "cost cap" as an invitation to undertake a process to properly value renewable energy or to determine the effect renewable energy might assert on energy prices. Rather, as Secretary O'Mara recognized, a "cost cap" is "an actual price control," directed at putting a reasonable and predictable limit on the costs customers will have to bear as a result of suppliers' efforts to meet renewable energy portfolio obligations. The process set forth in proposed §§ 5.3-5.8 is far afield from a "cost cap."

But, most importantly, none of the four factors set forth in proposed rule §§ 5.3-5.8 are mentioned in the 2010 legislation or in subsections 354(i) and (j). None of the factors were mentioned by anyone on the legislative floors in 2010. In addition, on the legislative floor, there was nary of peep about the power of the Director (then Energy Coordinator) to override the percentage "circuit breakers." The four trumping factors, and their definitions (proposed rules §§ 5.4 through 5.8), are creations of the Division, not the legislature. And as noted, they change the whole "cost cap" scheme.

The proposed rule §§ 5.3-5.8 superstructure is then nothing more than a "suspension" of the "circuit breaker" cost cap formulas set forth in subsections 354(i) and (j). Given that, it is incumbent on the Division to show that the General Assembly –

35 SS 1 HD at 6-7 (O'Mara).

36 SS 1 HD at 7-8 (O'Mara) (emphasis added).

37 SS 1 HD at 13-14 (O'Mara) (emphasis added).

by explicit language - gave the agency the power to override the statutory formula "circuit breakers." It is not enough for the Division to assert some implicit grant of such power; it must point to an explicit legislative direction, with conditions announced by the legislature. Del. Const. art. I, § 10.

(1) The Director "*May* Freeze"

So far in this protracted proceeding the Division has failed to point to any statutory provision that it says compels or allows the four-factor freeze regime outlined in proposed §§ 5.3-5.8. The proposed rule discretionary regime was challenged on legal grounds in comments in response to the 2013 proposal. Yet, the Division has still not put into the record in this proceeding any response to those legal challenges. In fact, it has said nothing about the font of its authority to override or forego a freeze called for by the statutory criteria.

Perhaps the Division might will argue that the use of the phrase the "Energy Coordinator . . . may freeze" in both subsections 354(i) and (j) provides the needed legislative endorsement for the proposed rule's multi-factor trumping regime. The Division may say that it's the use of the word "may," rather than "shall," in describing the freeze power, that vests the Director with final discretion about whether to impose a freeze.

But in statutory linguistics the word "may" can often reflect both "permission" coupled with "obligation," rather than permissive "discretion." As the Delaware judges, sitting en banc, said years ago:

> But the word, "may," ordinarily permissive in quality, is frequently given a mandatory meaning, *and is given that meaning where a public body or officer is clothed by statute with power to do an act which concerns the public interest, or the rights of third persons. In such cases, what they are empowered to do for the sake of justice, or the public welfare, the law requires shall be done. The language, although permissive in form, is, in fact, peremptory.*

duPont v. Mills, 196 A. 168, 173 (Del. Court *en banc* 1937) (emphasis added). This interpretive principle – that "may" can mean "must" - has a long pedigree. *See Supervisors of Rock Island County. v. U.S.*, 71 U.S. (4 Wall) 435, 44-47 (1866) (outlining prior cases and applying principle). *Cf. Wilson v. U.S.*, 135 F.2d 1005, 1009 (3d Cir.

1943) (citing Delaware and federal case law) *See also Nevada Power Co. v. Watts*, 711 F.2d 913, 920-921 (10th Cir. 1983).[38]

Here the use of the word "may" in subsections 354(i) and (j) fits comfortably within the peremptory meaning articulated in *Mills*. First, those subsections were added to the RESPA in 2010 to "provide consumer protections by limiting any rate impacts."[39] In fact, both Secretary O'Mara and sponsoring Senator McDowell told legislators that these provisions were key components to the 2010 changes: that they brought cost protections to customers that had been previously missing from the REPSA. And in the two subsections, the General Assembly (followed by the Governor) laid out when a freeze was to be declared. The criteria were outlined to protect bill-paying consumers..[40] If that is so, then it would seem illogical for the General Assembly to then turn around and allow an executive employee (the Director) to ignore the such protections granted to consumers by decreeing "no freeze" even if the statutorily-described cap percentages have been met. In such a context, the consumer protection provisions so highly touted in 2010 would then be nothing more than illusory promises easy to be ignored or evaded.

Of course, context is crucial in order to tilt the term "may" either to permissive discretion or peremptory obligation. *See State ex rel. Foulger v. Layton*, 194 A. 886, 889 (Del. Super. 1937). And it is true that the § 354(i) and (j) subsections use both "may" and "shall" in their consumer protection dictates. The Director "may freeze" the REPSA obligations if his office determines the percentage levels have been breached and then

38 Even in lay usage, the term "may" is often used to denote obligation, rather than discretionary choice. For example, in my youth when I misbehaved, my mother would frequently be quick to tell me that "you *may* go to your room for what you just did." I never took the "may" in her directive to mean that I could exercise some level of discretion and choose not to obey the banishment and instead stay in the kitchen.

39 SS 1, Synopsis.

40 Or in the words of the Supreme Court 150 years ago:

> The power is given, not for [the officer's] benefit, but for [the third party's]. It is placed with the depositary to meet the demands of right, and to prevent a failure of justice. It is given as a remedy to those entitled to invoke its aid, and who would otherwise be remediless.

Supervisors of Rock Island, 71 U.S. at 1009.

any such freeze "shall be lifted" if compliance costs can reasonably be expected to again go to sub-cap percentage levels. Often, such use of both "may" and "shall" in the same provision can suggest an intentional legislative intent to differentiate the permissive from the obligatory. *Foulger*, 194 A. at 889. *Cf. U.S. ex rel. Siegel v. Thoman*, 156 U.S. 353, 359-60 (1895). But in the context of *these* subsections, that rule is hardly ironclad. In fact, the use of the differing words reflects the differing nature of the Director's called-for actions. The REPSA statute sets forth escalating statutory renewable percentage requirements for each successive year. Subsections 354(i) and (j) allow the Coordinator (now Director) to decree a halt to both compliance and to the escalator if certain statutorily-described criteria have been met. In that case, he "may" decree a suspension of the program and a stop to the escalator. The "may" power is simply a grant of *permission* to go outside the otherwise applicable statutory framework once the described cap dollar criteria have been found to exist. It is not a grant of discretion, but simply a grant of power – to be exercised on behalf of consumers - to put a stop to the otherwise called-for obligation and percentage change. In that context, "may" is just as imperative as "shall." In contrast, the later reference to the freeze "shall be lifted" is of course obligatory. It is a call for a return to the normal statutory scheme if the cost cap limits will likely not be breached. In this context - where power is granted to make a deviation from the otherwise governing statutory scheme - both "may" and "shall" impose obligatory duties.

In the context of subsections 354(i) and (j), the Director's duty is clear: once the statutory cost cap percentage has been reached, it is his duty to freeze the program and the annual percentage requirements. He might have to consult with the PSC about the mechanics of such a freeze, but he lacks the power go further, override the consumer protections which are at the heart of the two subsections, and refuse to impose the called-for freeze.

(2) The "Coordinator in consultation with the Commission"

The Division may also rely upon the language in subsections 354(i) and (j) that directs the Director to act "in consultation with the [PSC]." The Division may argue that such consultative obligation suggests that the Director must have some discretionary authority to impose, or forego, a freeze. Of course, the initial problem is that the proposed rule §§ 5.3-5.8 do not speak to any consultation with the PSC before the Director makes his decision whether to ignore or honor the percentage cost cap limits. There is no mention of any PSC input into his four-factor consideration process. The decision whether to ignore the "circuit breaker," and continue the RESPA obligations and yearly increases, is vested solely in the Director.[41]

More significantly, the problem with seeing discretion being granted by these requirements for PSC "consultation" is that the exact same phrase is used later in the same subsections when they outline when the Director is to to lift a previously imposed freeze. In the latter context, there is also a requirement for the Coordinator (Director) to consult with the PSC. But in those instances, the underlying command to the Director is not "may," but "shall." Instead of granting discretion to the Director in either scenario, the requirements for PSC consultation in both contexts are simply directions that the Director should work with the PSC about the mechanics for implementing the Director's freeze and renewal decisions.[42] The language is not a dictate for the Director to confer with the PSC about whether a freeze should be imposed, or should later be lifted, even though the applicable statutory cap criteria have been fulfilled.

c. Conclusion

In sum, the proposed rule §§ 5.3-5.8 multi-factor regime is not only "out of harmony with," but also "alters" the provisions of subsections 354(i) and (j), and it does so "in a manner inconsistent with the clear legislative intent as therein expressed."[43] Just as importantly, it deprives electric consumers of a right granted to them by the General Assembly, the right to have the RESPA program freeze if compliance costs exceed a certain specified percentage. Instead, proposed rule §§ 5.3-5.8 adds – impermissibly – further conditions to this legislatively granted consumer right. It must be withdrawn because it is a process unauthorized by the General Assembly.[44]

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41 Proposed Rule § 8.3. In fact, the proposed rules only require the Director to consult with the PSC once he has completed the discretionary analysis and decided to go with a freeze. Proposed Rule § 6.1.

42 The provisions of 26 Del. C. § 362(b) support this view that the duty to consult with the PSC does not imply a grant of discretion to the Director, but merely reflects a directive for coordination in the freeze mechanics with the PSC. That provision directs the PSC to adopt rules "to specify the procedures for freezing the minimum cumulative solar photovoltaic requirements as authorized under § 354(i) and (j)." Unfortunately, the PSC has punted the whole process to DNREC. 26 DE Admin. Code 3008, § 3.2.21.

43 *Wilmington Country Club*, 91 A.2d at 255.

44 The definitions in the definitional section of the proposed rules that are linked to the discretionary regime under §§ 5.3-5.8 should also be vacated. So should the administrative

5. The "Total Retail Costs of Electricity" Definitions in Proposed Rule §§ 2.0 and 4.4 Are Inconsistent with Statutory Text and the Statutory Cost Cap Scheme

Under the proposed rules the cost cap limit is set by applying the 1 or 3 % figure against the "Total Retail Costs of Electricity."[45] In turn, the term "Total Retail Costs of Electricity" is specifically defined as:

> the total costs *paid by customers [of DP&L] for the supply, transmission, distribution and delivery of retail electricity* to non-exempt customers, including those served by a third party suppliers, during a respective compliance year.

Proposed rule § 2.0 "Total Retail Costs of Electricity" (emphasis added). *See similarly* Proposed rule § 4.4 ("The Division will determine the Total Retail Costs of Electricity as *all customer costs* for non-exempt load for a particular compliance year.") (emphasis added). Two things are central to these rules: (1) that the total costs of electricity are to be measured by the costs paid by retail customers and (2) such costs include not only the amounts paid for retail electric energy but also the charges for the delivery and distribution of such energy commodity. The problem is that the proposed rules' definitions - and their focus on customers' costs, all costs, and distribution and delivery charges - go directly against the text of subsections 354(i) & (j).

First, both subsections 354 (i) and (j) apply the statutory cost cap percentages against "the total retail cost of electricity *for retail electricity suppliers*." (emphasis added). That text specifically keys the benchmark figure to the "cost of electricity for *retail electricity suppliers*," not the costs for retail customers or retail end-users. The statutory text says nothing about "costs paid by customers," or "all customer costs," or even all revenues or costs *received by* retail electricity suppliers.[46] Rather, it cites as the reference the costs *of* electricity *for* retail electricity suppliers: the outlay, expense, or

process set forth in proposed rule §§ 8.3-8.5. In addition, proposed rule § 7.2 - that allows the Director to choose to lift a prior freeze even if the costs of compliance will likely continue to be above the statutory percentage levels - must also be struck.

45 Proposed rule §§ 5.2 & 5.3.

46 In fact, the Division, in its 2013 version of its proposed rules, references the costs "expended by retail electricity suppliers." It has now changed the focus from suppliers to customers. The Division does not explain how such a change is supported by the statutory language.

price *incurred, borne, or paid by* retail electric suppliers to produce or procure electricity.[47] If the statutory choice, expressed in enacted text, is to have any effect, that is the crucial component: the cost of electricity for suppliers.

So what costs do retail electric suppliers pay for "electricity?" The answer is provided by REPSA's definition of a "retail electricity supplier." It's an entity "that sells *electric energy* to end use customers."[48] It can be an independent "power producer" or an electric distribution company acting in a capacity as a standard offer supply provider.[49] A retail electric supplier's business and its commodity is "electric energy." A retail supplier thus bears the costs of procuring (at wholesale), or producing on its own, the "electric energy" that it will then sell to end-use customers. But such "retail electric" or "retail electricity" supplier does not bear the work or costs of delivering or distributing its electrical energy commodity. In the restructured electric world that prevails for DP&L, distribution and delivery services are separate and distinct from the sale of electric energy and are provided by Delmarva in its role as an electric distribution company.[50] An end-user customer must be separately charged for the delivery services and the charges for the electricity supplied by the standard offer provider or a third party supplier.[51] DP&L bears the costs of delivery and customers pay to it the separate charges for delivery. Retail electricity suppliers simply do not accrue any costs for delivery or distribution; those services are not a "cost of electricity" for them. Delivery and distribution costs and charges are thus not within the statutory component and thus cannot be included in the proposed rule's "total Cost of Retail Electricity."

So what is in, the cost of electricity for suppliers? For sure it includes the costs the electricity supplier incurs to procure the electric energy it then re-sells. That might be described as the supplier's "wholesale" cost of power. Yet the exact phrases in subsections 354(i) & (j) are the total *retail* cost of electricity for retail electricity

47 "Cost" is commonly defined to mean "1. The price paid to acquire, produce, accomplish, or maintain something." RH Dict. at 457.

48 26 Del. C. § 352(22) (emphasis added). *Cf.* 26 Del. C. § 352(21) ("retail electricity product" is "electrical energy product"); 26 Del. C. § 10001(14) ("electric supplier" "sells electricity to end users").

49 26 Del. C. § 352(22).

50 26 Del. C. § 10001(10), (12).

51 26 Del. C. § 10006(a)(5).

suppliers. The adjective *retail* suggests that the described amount includes more than suppliers' "wholesale" costs of power. Instead the term suggests that the benchmark should include not just the "true wholesale purchase costs" of the retail electric suppliers but also the suppliers' additional costs incurred in order to retail the electrical energy. The benchmark would thus include wholesale costs plus the suppliers' retail costs for selling the product.

The Division, for purposes of the cost cap, could require electric suppliers to report their "wholesale costs" and their additional retailing costs. But there is a ready stand-in for those amounts: the retail electric charges for electricity separately billed on an end user's bill. Presumably, the amount a supplier charges end-users for "electric supply" represents its costs for the product. The Division could thus require the suppliers directly, or DP&L (if it has such information), to thus report the total amounts charged, or received, for the separate electric supply services in the compliance year. This aggregated amount could then be deemed the "total retail cost of electricity for retail electricity suppliers." And that amount could then be used in calculating the cost cap for that compliance year.

Of course, the above amount must exclude several charges. First, as explained initially, the total amount cannot include any delivery or distribution charges. Second, it cannot include any amount that would also be included in the "total cost of compliance." Thus, the total retail cost of electricity should not include any of the QFCPP surcharge amounts. QFCPP surcharges are not a cost for retail electric suppliers. Similarly, the total aggregate cannot include any amounts collected by DP&L in fulfilling its almost exclusive responsibility to procure RECs and SRECs for all non-exempt load. Those charges are now delivery charge elements, not costs incurred or borne by retail electric suppliers. Finally, in the context of post-2012 "transitional" electric supply contracts the costs of any REC or SREC costs embedded in the supply charges must be excluded from the "total retail costs of electricity."

Indeed, the above analysis is supported by the text of the similar cost cap protection applicable in the case of the Delaware Electric Cooperative and municipal electric companies. For them, the total cost of complying with their own versions of renewable energy requirements "shall not exceed [3 or 1] % of the total cost of the *purchased power of the [affected] utility* for any calendar year."[52] The statutory benchmark for them is the "total cost of the purchased power of the utility." Or, in other

52 26 Del. C. § 363(f), (g) (emphasis added).

words, the calculation looks to the total cost that was (or will be) paid by the utility to purchase the power it will use during the relevant calendar year? Here too, this statutory wording looks to the outlays made, or prices paid, *by the utility* in order to purchase just the power commodity. The benchmark does not include amounts charged or collected for delivery or any delivery or distribution charges or components. It is limited to the cost of the electric energy that the utility purchased and then sold to the utility's members or customers. Again, that represents the utility's "costs" for electric energy supply.

It is quite legitimate to look to this language related to the cost cap for the electric cooperative and municipal electric ventures to give meaning to the phraseology used in the DP&L cost cap subsections. After all, all of the cost cap cap regimes were enacted in the same legislation. Indeed, the proponents of the bill indicated that the DP&L caps and the Co-op and municipal caps – although worded somewhat differently – were congruent.[53] Thus, if the Cooperative's and municipals' cost cap provisions are premised on 1 and 3 percentages applied to "the total cost of the purchased power of each utility for any calendar year" then a comparable baseline should be used under subsections 354(i) and (j). "[T]he total retail cost of electricity for retail electricity suppliers" should equate to the "total cost of the purchased [or produced] power" of retail electric suppliers. The above resolution is consistent with the structure of the 2010 REPSA amendments.

The proposed definition of "Total Retail Electricity Costs" and proposed rule § 4.4 must be rewritten to confirm to the statutory text and the statutory scheme. Any new definition should only include in the term the aggregate amount of costs or charges received by electric suppliers for providing their electric energy product. It cannot include any delivery costs or any charges or any costs that might be included in the total costs of compliance.

53 SS 1 SD at 26-27 (McDowell) (noting that the bill provided the same 1% and 3% cost cap circuit breakers protections for DP&L, the municipal utilities, and the Delaware Cooperative).

6. The "Freeze" Provisions in Proposed Rules §§ 6.0 and 7.0 Need to Modified to Explain the Effects of a Freeze

Just as in the earlier 2013 roll-out, the current proposed rule §§ 6.0 and 7.0 outline the mechanics for imposing (and lifting) a "freeze." But, once again, the sections do not delineate exactly what that term entails. The rules should be modified to give explicit guidance about what a "freeze" means., and what effect it has. DP&L, its retail consumers, the PSC, and the Division itself need to understand exactly what obligations cease once a "freeze" is declared.

Subsections 354(i) & (j) each actually contain two "standstill" directives. For example, under § 354(j), the Director may freeze "the *minimum cumulative eligible energy resources requirement*" if "the total cost of complying with *this requirement* during a compliance year" exceeds the applicable 3 percent cap. (emphasis added). The "requirement" that is so "frozen" is the one expressed in subsection 354(a): the obligation to include in the total amount of retail sales of electricity to Delaware end-users a minimum percentage of electric energy sales with eligible energy resources. Once a "freeze" is imposed, it is this "requirement" that ends: a retail electric supplier (before) – and DP&L (now) – no longer has the duty to accumulate any additional RECs and SRECs to meet the annual percentage number that would otherwise would prevail under subsection 354(a).[54] This "freeze" is the "cost cap" - part of the consumer protections granted under subsections 354(i) & (j). Once such "freeze" is in place, the responsible entity – now DP&L and suppliers with transitional contracts - need not acquire further RECs or SREC for REPSA compliance purposes. And, end-use customers need not pay for any further RECs or SRECs as part of their billings.[55] That is the *first* freeze: the one specifically so denominated in the subsections.

This "freeze" (reflecting a stay of any further obligation to procure RECs and SRECs) only ends when the Director finds that "the total cost of compliance can

54 26 Del. C. § 354(e) (since the 2012 compliance year, DP&L has held the responsibility for procuring RECs, SRECs, and any other attributes to comply with subsection (a) of section 354). this section). *See also* 26 Del. C. § 354(h) (compliance with subsection 354(a) percentage minimums is met by accumulating equivalent volume of RECs and SRECs).

55 26 Del. C. § 358(f)(1) (retail supplier can only recover "actual dollar for dollar costs incurred in complying with a state mandated renewable energy portfolio standard"). If the "compliance" requirement is lifted under the "freeze" procedure, then the supplier, and now DP&L, cannot incur and bill any additional costs to comply with the frozen mandate.

reasonably be expected to be under the [applicable 1 or 3 %] threshold." But until such finding is forthcoming, the whole REPSA obligation remains suspended.

The second standstill directive in subsections 354(i) and (j) relates to what happens after the first freeze is in effect: "[i]n the event of a freeze, the *minimum cumulative percentage* from eligible energy resources shall remain at the percentage for the year in which the freeze was instituted." (emphasis added).[56] This initially applies when the Director investigates whether to enter a "resumption" order. In making his determination whether expected compliance costs will be below the applicable cost cap percentage, he is to use the annual percentage figure that prevailed during the "freeze" year.

So, under subsections 354(i) & (j) there are two "stoppages." One is the "cost cap" freeze ending any further obligation to procure and pay for further RECs and SRECs. The second is the "freeze" in the otherwise escalating yearly renewable percentage amounts.

Both then-Secretary O'Mara and Senator McDowell alluded to this two-step freeze process in explaining the new consumer protection to the legislative members. Thus, Secretary O'Mara explained:

> But most importantly, by having a circuit breaker, if you will, an actual price control, whereby if the, if the rate payer impacts exceed a certain amount, *that the entire program freezes in place,* we can ensure ratepayers that there won't be any adverse impacts from this legislation.[57]

Further:

> So under the legislation, if the -- as soon as there's a 1 percent impact from the solar portion of the bill, the, *the target level freezes in place for that entire calendar year and then starts up again after it. You'll never have more than a 1 percent impact in any given year for the solar, for the solar*

56 Thus, the "cost cap" freeze suspends the "minimum cumulative eligible energy resources *requirement"* while the second directive defers any increase in the "minimum cumulative *percentage."*

57 SS 1 HD at 7-8 (O'Mara) (emphasis added).

> *portion of the, of – the solar requirements as written in the legislation.*[58]

And Senator McDowell told the Senators the same sort of thing:

> [a]ny time the cost impact of the photovoltaic goes up by 1 percent, the utility involved can push what we like to call a circuit breaker. *In other words, they can suspend the program for that year and simply extend the portfolio forward by a year for their utility.*[59]

And:

> We've also built safety valves into this bill. I told you about the circuit breaker that we have put in where any utility who can show that its rates are going up or would go up by 1 percent in case of -- of solar, the retail electric would go up by 1 percent in a year in the cases of solar, or 3 percent in the overall, they could push the circuit breaker *and suspend their participation in the program for one year.*[60]

Thus, both the Secretary and Senator speak of first freezing or suspending participation in the program – ending the need to expend additional sums to procure further RECs or SRECs (the cost cap) - and then, secondly, extending the portfolio forward a year, that is, maintaining the percentage level for compliance from the earlier freeze year.

Admittedly, both the Secretary and the Senator in their legislative floor comments seemingly assumed that the "freeze" provision would come into play *within* a compliance year. They assume that someone – either the utility, the electric supplier, the PSC, or the State Energy Office – would be able to track the "total retail cost of electricity for retail electricity suppliers" as well as the "total cost of complying" contemporaneously and concurrently on an on-going basis throughout each compliance year. When compliance costs (measured over some time frame) exceeded (or were projected to exceed) the cost cap percentages as applied to retail electric suppliers' "total retail cost of electricity" (during the same time frame period), a cost cap freeze would

58 SS 1 HD at 13 (O'Mara) (emphasis added).

59 SS 1 SD at 4-5 (McDowell) (emphasis added).

60 SS 1 SD at 9 (McDowell) (emphasis added).

then be called and the program would be suspended. After that, no more RECs and SRECs would have to be procured, and customers would not be obligated to pay any further REC and SREC costs. Presumably, the suppliers would then be able to somehow lower their total compliance costs for the next year and then the program would start up again the succeeding compliance year (although at the minimum percentage level applicable to the earlier "frozen" year).[61]

SS 1 seemingly charged the PSC to come up with a the rules to how to continuously monitor compliance costs and total retail costs of electricity for retail electric suppliers.[62] But the PSC did not create any such mechanisms for on-going, intra-year monitoring of either compliance costs or total retail costs of electricity. Instead, the PSC simply repeated the statutory formulas and deferred to the Director and Energy and Climate Division for implementation. 26 DE Admin. Code 3008 § 3.2.21.

61 Senator McDowell also suggested that the "circuit breaker" freeze was to be done on a utility-by-utility basis, with each utility holding the power to pull the "circuit breaker" trigger during a compliance year. Under such a scenario, it might be possible for a utility to track its own costs of compliance and its own retail costs of electricity to make the intra-year cost comparisons. But such a single utility view of the freeze process is hard to square with the text of subsections 354(i) and (j). Those provisions speak to obligations and costs in the plural, not the singular. Thus, the statutory language speaks in terms of freezing the minimum eligible energy and solar photovoltaic requirements "for regulated *utilities*" (plural). not a single "regulated utility" or a singular retail electricity supplier. So too, as to the "total retail cost of electricity" figure, the statutory text reference is to such total cost "for retail electric *suppliers*" rather than the cost for a singular "supplier." The costs to be determined and utilized are those for plural "suppliers" rather than a single supplier. Of course, once you must measure costs of compliance against multiple retail electric suppliers' costs of electricity, it is hard to see how there can be any utility-by-utility application of the freeze provisions. Finally, such a single utility process is even more difficult now that DP&L holds the almost exclusive responsibility to procure RECs and SRECs for its entire delivery load. Under such a change, DP&L acquires RECs and SRECs for all its delivered load, and its customers bear those total costs of compliance. Yet not all of the electricity which necessitate such RECs or SRECs will be sold by DP&L; other suppliers can still make retail sales of electric supply. Thus, to have symmetry between compliance costs and retail electric supply costs for suppliers, you have to apply the freeze across the board. And you must look to the electric supply costs for all electric suppliers, not just the SOS supply costs for DP&L.

62 26 Del. C. § 362(b).

The presently proposed rules – almost out of necessity – use an "end-of-year" time frame to determine whether a freeze is required under either subsection 354(i) or (j). The total cost of compliance, as well as the total retail cost of electricity for retail electricity suppliers, are to be computed and compared after the end of a compliance year, using the full costs for the entire compliance year. Proposed rule §§ 4.0 & 8.0.

But if the annual year-end, look-back analysis is the only practical one, then the question becomes how to apply the two-step freeze components in that context. If the cost of compliance for the just completed compliance year exceeds the applicable cost cap percentage what happens? Under the statutory text, and the legislative floor statements, it would appear that a freeze should then be called and "the entire program" frozen or suspended. This would mean that compliance in the present year would be halted in its entirety – at least going forward. Neither DP&L, nor its customers, would have any further obligation to acquire, apply, or pay for any RECs and SRECs for that present year. The exception to such a suspension would arise only if the Director - contemporaneous with his announcement of the freeze – would also find that the costs of compliance for the present year could be expected to be under the cost cap percentage limit. If such determination was made, then compliance in the present year could move forward, but utilizing the prior year's renewable and solar percentage levels. If the Director cannot make such a finding for the present year, the suspension would continue through the entire present compliance year. Indeed, it would continue through any later compliance years until the Director can make the relevant finding that compliance costs will be under the freeze percentage as applied to a future year's expected total retail cost of electricity for retail electricity suppliers..

The proposed rules should make explicit what is entailed in a "freeze," DP&L, its customers, the PSC, and indeed the Division need to know what are each's obligations if a "freeze" is declared.

7. Proposed Rule § 9.0 is Not Authorized by Law and Is Without Record Basis and Must be Struck

In proposed rule § 9.0, the Division proposes to grant an across-the-board exemption from the cost cap/freeze requirements. Under such provision, even if a freeze is imposed, customers would presumably have to continue to pay above-cap threshold renewable costs if those costs can be tied to pre-existing contracts for the production of RECs, SRECs, renewable energy supply, or other environmental attributes. The contracts would thus trump the statutory cost-cap limits; customers would have to pay for the contract RECs, SRECs, and equivalencies even if such payments mean costs that are way above the percentage cap limits on renewable compliance costs.

So far in this proceeding, the Division has never pointed to any statutory provision that empowers it to grant such an exemption from the statutory cost-cap provisions in the case of such described contracts. Subsections 354(i) and (j) do not contain any mention of such an exclusion from the cost cap "circuit breakers" and the resulting "freeze." Nor has the Division pointed to any other statute or even any regulation which grants it, or DNREC, any such power to craft a cost cap waiver for such contracts. The Division, under fundamental principles of administrative law, cannot simply make up such an exclusion out of thin air.

Second, there is no factual record developed in this matter that supports the need for such a broad administrative exemption from a statutory scheme. Rather, the Division has simply declared the broad waiver rule *ex ante* without developing any record about the extent, nature, and indeed terms of any such exempted contracts. Issues about how subsequent statutory changes can, or cannot, alter or abrogate prior actions or contracts undertaken in reliance on prior law are difficult legal inquiries. *See, e.g.,* PSC Final Findings, Opinion and Order No. 8150 at ¶¶ 43-46 (May 12, 2012) (declining to grant or extend exemption to electric supplier for the contracts and investments it previously made to be able to fulfill present and future REPSA requirements which had become arguably "stranded" when the REPSA law was changed in 2011 to shift the responsibility to fulfill those requirements from electric suppliers to DP&L). Those issues are not amenable to an administrative blanket rule, such as that proposed in § 9.0. Rather, they can only be resolved by statute or by a proceeding that develops the facts that such issues might turn on. For example, the question of how much protection should be afforded a pre-existing contract for RECs might turn on when the contract was entered into: was it signed before or after the enactment of the statutory cost cap provisions? If the contract came afterwards, is there not a claim that both DP&L and the counter-party were on more than adequate notice that the contractual commitments could be altered by the extant statutory cost cap strictures that warned that REC procurement could be curtailed? So too, the record would need to include some facts about how DP&L negotiated for such type of a contract with full knowledge of the cost cap and freeze possibilities. Did DP&L and its counter-party assume the risk of such a change? Still the present record is devoid of any of these most basic underlying facts?

These comments do not portend to provide answers to the legal question about pre-existing contracts and pre-existing cost cap statutes. Rather, such questions should be addressed and resolved on a developed factual record and with a more through investigation. The Division cannot simply impose its own resolution - broadly applicable to all contracts - in the absence of any factual record supporting its rule and without a single reference to a statutory provision that explicitly grants it the authority to exempt certain contracts from the reach of a duly enacted cost cap law.

Proposed Rule § 9.0 is *ultra vires* and must be struck.

8. Other Technical Glitches in Proposed Rules

a. § 2.0 Definitions

"Exempt sales" and "Non-exempt sales"

The two definitions describe the sales in terms of "the retail customer sales of a Commission-Regulated Electric Company." But the coverage provisions of REPSA extend to total retail sales made by all suppliers, except sales made to large industrial customers. Thus exempt and non-exempt load may be served by third party suppliers, not just by DP&L. In fact the proposed definition of "Total Retail Costs of Electricity" recognize such scope. In contrast the exempt/non-exempt sales definitions appear to limit the scope to only DP&L supply sales. The limitation should be removed.

"REC costs of compliance," "Renewable Energy Cost of Compliance," and "Solar Renewable Energy Cost of Compliance"

There seems to be two, almost identical, definitions for REC/Renewable costs of compliance. The REC one should be removed. Similarly, as it now stands, the definitions for Renewable and Solar costs of compliance are not parallel definitions. They should be reworked to read the same, subject to the necessary REC and SREC differences.

All of the "cost of compliance" definitions refer to "the total costs expended by a Commission-Regulated Electric Company." The definitions should be broadened to include costs incurred, or expended, by customers, not just DP&L or indeed by any supplier. Payments to the Green Energy Fund are costs directly incurred, and paid, by customers, not by DP&L[63] Similarly, QFCPP surcharges are paid directly by consumers to Bloom Energy and DP&L with DP&L only acting as a collection agent.[64] But, as the Division recognizes in proposed rule §§ 4.2 & 4.3, both the Green Energy monies and the QFCPP surcharges are "compliance costs" even though they are amounts paid by consumers, not by DP&L or by a supplier. Those payments are instead costs incurred by customers, not costs expended by DP&L. Yet the definitional sections - in conflict with

63 26 Del. C. § 1014(a) (DP&L to include charge in rates, collect monies from consumers, and pay over monthly to State's Green Energy Fund).

64 26 Del. C. § 364(b), (d)(1)(i).

proposed rule §§ 4.2 & 4.3 - would apparently exclude them as costs of compliance. The DP&L expenditure phrase should be struck from the definitions.

"REC offset hours" and "SREC offset hours"

The phrases should be changed to "REC equivalency hours" and "SREC equivalency hours." The QFCPP provisions concerning QFCPP output and renewable obligations speak of such output being the "equival[ent]" of a REC that can be used to "fulfill" - not offset - the governing renewable energy percentage requirements.[65] The rule's definitions should track the statutory language.

"Surcharge payments"

The present definition only encompasses amounts "*paid to*, or *received by*, *customers* of a Commission-Regulated Electric Company *from* a QFCPP and a Commission-regulated Electric Company." (emphasis added). Thus, it only covers monies *received* by customers, not amounts paid by them *to* a QFCPP or to DP&L. Given that most QFCPP payments flow to Bloom Energy, and not to customers, the definition should be reworked to include such payments within the costs of compliance.

b. § 4.2.3

This provision should be amended to include both the costs of Alternative Compliance Payments *and* Solar Alternative Compliance Payments,

65 26 Del. C. § 353(d).

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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*, <u>*Oregon*</u>, 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.	<u>*California*</u>
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*, <u>*Oregon*</u>, *Pennsylvania, Rhode Island*, (<u>*California*</u>, Minnesota, *Michigan*, <u>*Montana*</u>, Wisconsin)[e]
Cap on individual contracts	Limits procurement of contracts priced above set % above market-price.	<u>*Montana*</u>, 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.	<u>*Nevada*</u>
Other off-ramps (waivers, freezes)[f]		Arizona, <u>*California*</u>, Colorado, *Connecticut, Delaware*, Hawaii, *Illinois, Maryland, Maine, Michigan*, Minnesota, Missouri, <u>*Montana*</u>, <u>*Nevada*</u>, *New Hampshire, New Jersey*, New Mexico, North Carolina, *Ohio*, <u>*Oregon*</u>, *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.

Acknowledgments

The authors would like to thank the staffs at state regulatory agencies across the U.S. that provided their valuable insight and time. Many of the concerns raised with respect to RPS cost control mechanisms were identified in discussions with state regulatory agency staff who could only speak without attribution. The opinions expressed herein are solely those of the authors and do not necessarily reflect the views of any state regulatory body or governmental authority.

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Vest, Lisa A. (DNREC)

From: David Stevenson <davidstevenson1948@gmail.com>
Sent: Tuesday, January 27, 2015 12:39 PM
To: Vest, Lisa A. (DNREC); Cherry, Philip J. (DNREC); Underwood, Robert (DNREC); Noyes, Thomas G. (DNREC)
Subject: Public Comments on 102 Implementation of RPS Cost Cap Provisions
Attachments: rps cost cap provisions comments jan 22 2015.docx

These comments replace and extend comments made on January 7, 2015, and December 2, 2014. Thank You.

--
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1/27/15

Dear Ms. Vest;

I am submitting additional comments regarding DNREC's **102 Implementation of Renewable Portfolio Standards (RPS) Cost Cap Provisions** printed in the Delaware Register 12/1/14, regarding how the Director of DNREC will determine how a freeze of the accelerating requirement for renewable power will be triggered.

Electricity is a vital commodity for citizens and businesses in Delaware. By law, Delaware electricity retailers must purchase power from renewable resources, such as wind and solar. The required percentage of renewable power has increased each year starting in 2010. Price protections are critical and the Delaware Legislature recognized this need when legislating cost cap protection in 2010. A freeze on the increasing requirements was to be implemented if the purchase of Renewable Energy Credits (REC) caused electric bills to rise over 3%, or Solar Renewable Energy Credits (SREC) raised bills by over 1%.

We must report the cost is greatly exceeding the cost cap for all Delmarva Power customers. The actual costs for the 2013 Compliance Year (CY), June 1, 2013 through May 31, 2014, have not been released. However, in July, 2014, Delmarva Power began showing the cost of the RPS on electric bills. A review of bills for a Standard Offer of Service customer for the period July to December, 2014 showed the RPS was adding over 5% to cost in substantial violation of Delaware Code 26, Section 354 (i & j). The percentage will probably be higher for large industrial companies as the divisor, the cost of electricity, will be lower.

The recently released "Delaware Housing Needs Assessment 2015-2020" describes how about 30,000 Delaware families below the poverty level are paying 50% or more of their income for utility bills. The U.S. Energy Information Agency "Electric Power Monthly" for December, 2014, shows Delaware's industrial electric rates are 25% higher than states we compete with for jobs, such as, Virginia. If we want to create jobs and move people out of poverty we need lower electric rates.

Freezing the RPS would not necessarily end the growth of renewable energy in Delaware. The only viable renewable power source in Delaware is solar power. Onshore wind speeds are insufficient to build economically competitive wind farms in Delaware, and the capital cost of offshore wind is prohibitive. Small scale, distributed solar projects are the only renewable option to create jobs in Delaware. We can continue to fund these projects with the Enhanced Green Energy Fund (EGEF) available from the Sustainable Energy Utility (SEU), along with a more generous standard Green Energy Fund subsidy. Solar installations with existing contracts for SRECs that exceed the amount needed to meet the Minimum Compliance Percentage could also be offered EGEF grants that trade up-front payments for SRECs produced in the future. An

SREC auction planned for the second quarter of 2015 should be postponed until the need for a freeze for the 2013 Compliance Year is determined.

We have several specific objections to the proposed regulation:

- The freeze should be applied if the total cumulative compliance cost of meeting the RPS goes over 1% or 3% of the retail cost of electricity, rather than 1% or 3% year over year as proposed
- The freeze should be automatic if the caps are exceeded without consideration of un-priced positive or negative metrics not defined in Delaware Code
- The determination to freeze the annual compliance requirement should be decided quickly at the end of a compliance year, not delayed by 255 days, or almost 9 months as proposed.
- Based on the proposed rules, a determination of whether a freeze has been triggered for the 2013 Compliance Year was due from the Director of the Division of Energy & Climate by January 6, 2015. The results for the 2013 Compliance Year should be announced immediately along with a decision to freeze the RPS so the cost premiums to electric customers do not continue to accumulate
- RECs/SRECs, renewable energy supply, or environmental attributes contracted after the cost cap legislation, Senate Substitute 1 for Senate Bill 119, was signed into law July 28, 2010, shall be void if such products cause the 1% or 3% cost cap to be exceeded. After a freeze is determined, the Minimum Compliance Percentage shall be the same as the Compliance Year the cost cap was exceeded. We recommend canceling contracts for Eligible Energy Resources based on the date generation began with the newest generation canceled first.

We are providing additional comment for the five points summarized above. In general, we note the rules appear to be written to provide maximum protection for the suppliers of renewable power. There is little protection for electric ratepayers as shown in the proposed cost cap regulation. In fact, it is difficult to imagine the Director would ever determine a freeze was called for using the proposed rules. We implore DNREC to reconsider the rules to put more emphasis on protecting electric customers.

<u>The freeze should be based on a 3% cumulative cost</u>

Delaware Code Chapter 26, §354 (i) & (j) state a freeze will be triggered if as follows, "the total cost of complying with this requirement during a compliance year exceeds 3% of the total retail cost of electricity for retail electricity suppliers during the same compliance year". The formula is straightforward and is consistent with the language of Section 4.0 of the proposed regulation. However, DNREC's proposed "Determination by the Director" in section 5.0 changes the formula to subtract the compliance cost of the previous compliance year. Nothing in the code supports a formula comparing cost to a previous compliance year. Compounding a 3%/year increase from 2010 to 2025 (the peak year in the RPS schedule) results in an allowed electric rate increase of 56%, or $75/month for a residential customer. This is an absurd interpretation of legislative intent especially given the extensive debate in the following year by both the legislature and the Public Service Commission (PSC) over a, supposed, increase of $1/month for the Bloom Energy Fuel Cell Project. The freeze should be triggered by the simple formula; RPS compliance cost 2013 CY/total retail cost of electricity 2013 CY.

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DNREC released a summary of an opinion from the Attorney General's Office stating "Interpreting the statute so that a minimum cumulative requirement refers to the cumulative increase from the beginning of the program would lead to an unreasonable or absurd result because at that rate the statutory compliance schedule could not be achieved". The entire basis of the RPS was renewable power sources needed temporary subsidies until they could become competitive with conventional power sources. The support of subsidies was to gradually decline as the cost of renewable power sources such as wind and solar declined. Indeed, the cost of wind and solar power has declined dramatically. The National Renewable Energy Laboratory reports the cost of onshore wind power was cut in half from the early 1990's to about $75/MWh now, and expects costs to drop another 15% by 2020, and 20% by 2025. Solar power systems that sold for $8.00/watt as recently as 2007 now sell for $2.80, and prices are expected to continue to fall. While the cost for renewable power is declining, the cost for conventional power is rising. The Delmarva Power 2014 IRP forecasts power costs will increase 3% a year through 2024, or 33% in total. However, the forecast did not include new plans to increase capacity cost, or take into account the rising cost of carbon dioxide permits. New EPA regulations for ozone, emissions and the Clean Power Plan for existing power plants were also not considered and could potentially double the rate of increase used in the IRP.

In July, 2014, Delmarva began showing the cost of the RPS on electric bills. A review of bills for a Standard Offer of Service customer for the period July to December, 2014 showed the RPS was adding 5.1% to cost ($39.20/$762.38 for 4.86 MWh), or $8.07/MWh. For the same period, the Qualified Fuel Cell Provider (QFCP) tariff added $4.26/MWh at the equivalent price of $76.20/REC ($17,447,853 net cost/228,988 RECs per Delmarva's monthly reports). According to the 2014 IRP, RECs on the spot market sell for $15. Had Delmarva simply purchased RECs on the spot market instead of the QFCP the RPS cost would have dropped to $4.65/MWh for this SOS customer, or 2.96%, just below the cost cap. Given the declining cost of wind and solar power, and the increasing cost of conventional power, it appears the 3% cost cap was not unreasonable at all. It may well be the QFCP project, which uses non-renewable natural gas and gets twice the RECs as a wind farm for each MWh of power, will be what puts cost over the 3% cap.

<u>There is no basis for using un-priced factors in establishing a freeze</u>

We find no support in the Delaware Code for using the four points discussed in proposed sections 5.4.1 to 5.4.4 in the determination of whether the Director shall implement a freeze. Also, the four points don't stand up to scrutiny.

The primary purpose of deregulating the electricity supply market in Delaware was to allow market competition to lower prices. Using lower market price for power as a reason not to freeze the RPS requirements (5.5) defies common sense when lower prices are an intended consequence of Delaware energy policy.

Section 5.6 states the Director should consider avoided system cost and price suppression effects attributable to renewable energy. Both of these items are already priced into the market and do not require a separate accounting. Price suppression is widely discussed and is factored into Locational Marginal Prices in the PJM Reliability Pricing Model. Avoided system costs show up in the Capacity Market and Transmission prices shown on electric bills.

Section 5.7 suggests externality benefits such as avoided health costs presented in Delmarva Power's Integrated Resource Plan (IRP) should be considered to offset the high costs of the RPS. Intervener comments in PSC Docket 12-544, Delmarva Power's 2012 Integrated Resource Plan show a wide gap in the interpretation of Externality cost. DNREC will point to an IRP calculation that considers regulatory changes in air pollution laws that will lead to avoided health costs by 2022 for all emission sources of $1 to $2 billion in Delaware. Others questioned those findings. The definitive answer came in the May 14, 2013 IRP workshop where Delmarva Power's consultant, ICF International, submitted a report titled "Air Quality & Health Impacts Assessment for Delmarva Power's 2012 IRP". Large increases in renewable power, and large decreases in coal power were expected between 2013 and 2022 but emissions of air pollutants related to health impacts from those sources showed essentially no change. No change in pollution means no improvement in health impacts. Will DNREC selectively pick data from the IRP or consider all the facts?

Section 5.8 states the job creation attributed to renewable energy development will be considered. In 2014 the only renewable energy jobs related to the RPS program were in solar panel installation as the only solar manufacturer closed in 2013. Eighty percent of the RPS will be met with out-of-state wind farms that add cost without adding Delaware jobs. Nationally, 3,300 MW of solar capacity was installed in 2012 by 89,250 people in the installation business, or 37 KW per employee (according to the Solar Energy Industry Association). The PSC reported 3,500 KW, and Delmarva Power reported 5,500 KW of new solar capacity was installed in Delaware in 2014 creating 95 to 150 jobs. Jobs are also lost because higher electric rates dampen economic development. Delmarva estimates total RPS compliance cost will be $56.3 million in 2015 CY. A 2012 report calculated each $147,000 in electric premiums costs one job, so the RPS will cost 383 jobs, at least 2.5 times the number of jobs created. The RPS program cannot be called a job creator for Delaware.

The freeze should be automatic if the caps are exceeded without consideration of un-priced positive or negative metrics not defined in Delaware Code

<u>Determination of a freeze should be immediate, not delayed 9 months</u>

The Energy & Climate Division is to calculate the cost of compliance for each Compliance Year. It is unbelievable DNREC proposes a 9 month time line (Section 8.0) to implement a freeze while electric bill premiums continue to accumulate. This delay could add up to $1 million a year to electric bills for large industrial customers. The RPS cost is now shown on monthly electric bills. Surely, Delmarva Power can quickly provide the data for a calculation of compliance year cost without the extensive calculations suggested in Section 5.0. The Director should be able to quickly announce a freeze. Challenges to the freeze could occur after the announcement. The proposed time line needs major revision.

<u>Contracts signed after the Cost Cap legislation was approved should be void if they cause the cost cap to be exceeded</u>

Delaware Code Chapter 26, §354 (i) & (j) state "In the event of a freeze, the minimum cumulative percentage from eligible energy resources shall remain at the percentage for the year in which the freeze is instituted". Section (a) provides the annual compliance level. The RPS requirement for CY 2013 was 9.4%

for RECs and 0.6% for SRECs. The load requirement for the upcoming CY 2015-16 is 6,812,559 MWh according to the 2014 IRP (Table 2, page 65). If the RPS is frozen at CY 2013 levels the RPS requirement would be 40,875 SRECs and 640,381 RECs.

The IRP (Table 3) shows 50,376 SRECs contracted after July, 2010, and an oversupply position of 9,501. RECs contracted from three onshore wind farms total 338,627 with only one of the projects contracted before July, 2010. The 301,754 REC shortfall would be made up with equivalent RECs from the Qualified Fuel Cell Project (QFCP). Every MWh produced by the QFCP counts for two RECs (Del 26, Chapter 1, §353 (1)(a) & (b)). IRP Table 5 projects 228,636 MWh/year, or 457,272 RECs/Year from the QFCP. Delmarva Power will have banked approximately 220,000 excess QFCP RECs by May, 31, 2015 and these should be applied first to CY 2015. Therefore, Delmarva should only buy 118,636 MWh (220,000 RECs/2) from the QFCP, or about 52% of production. If the freeze continues in future Compliance Years, Delmarva would only buy 150,877 MWh/year from the QFCP or 66% of production.

Delaware Code Section §364 (l) protects a QFCP from "future" changes in legislation. It does not protect the QFCP, or solar and wind providers who signed contracts after the cost cap legislation was approved. The Fuel Cell Tariff was written in such a way as to pass essentially all risk from the project onto electric ratepayers. Fortunately for electric ratepayers, the cost cap issue was missed. Delmarva Power is not obligated to pay $166.87/MWh to Diamond State Generation Partners, the QFCP, for RECs not needed to meet RPS Minimum Compliance Percentage. The same goes for wind farms, or to SREC auction winners in the 2012, 2013, or 2014 auctions for SRECs that would raise electric rates above the 1% or 3% caps. Renewable power generators should be rolled back based on the principal the last to generate, first to be cut.

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From:	Letty Diswood <letty.diswood@verizon.net>
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Subject:	Comments DNREC ON REG. 102 RPS COST CAP PROVISIONS
Attachments:	RPS REG 102 LETTER 2-4-15 FINAL.pdf

TO: Lisa A. Vest, Public Hearing Officer, DNREC
FROM: Charlotte F. King, President, LWV of Delaware and Chad Tolman, Chair, Climate Change Committee, LWV of Delaware
TOPIC: **League of Women Voters of Delaware COMMENTS ON DNREC'S REGULATION 102 IMPLEMENTATION OF RENEWABLE ENERGY PORTFOLIO STANDARDS COST CAP PROVISIONS**

Thank you,

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LWVDE COMMENTS ON DNREC'S REGULATION 102 IMPLEMENTATION OF RENEWABLE ENERGY PORTFOLIO STANDARDS COST CAP PROVISIONS

February 4, 2015

To: Lisa A. Vest
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DNREC
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Dear Ms. Vest,

Thank you for extending the deadline for public comments on **Regulation 102 Implementation of Delaware's Renewable Energy Portfolio Standards Cost Cap Provisions** to February 16.

A basic discussion of Renewable Portfolio Standard (RPS), including what various states are doing to encourage generation of electricity from renewable energy sources, can be found on Wikipedia.[1] In discussing cost caps, the article says that all states with an RPS either place caps on the cost of their programs or include some form of 'escape clause' whereby the regulatory authority may suspend the program or exempt utilities from meeting its requirements. Such measures are intended to strike a balance between the desire to reduce the adverse health and climate change impacts of fossil fuel use with the anticipated higher costs of electrical energy from renewable energy sources.

A more detailed description of RPS programs in Delaware[2] and other states can be found in the **Database of State Incentives for Renewables & Efficiency**, sponsored by the U.S. Department of Energy. It points out that Delaware's first RPS in 2005 required the "retail electricity supplier to purchase 10% of the electricity sold in the state from renewable sources by compliance year (CY) 2019-2020."
More detail on Delaware's current RPS, adopted in 2010, is shown in Table 1 and can be found in 26 *Del. C.* § 351 - § 364.[3]

Table 1. Abbreviated Schedule 1[4]

Start of CY[a] (June 1)	Minimum Cum. % EER[b]	Minimum Cum. % Solar PV[c]
2010	5.0%	0.018%
2015	13.0%	1.0%
2020	20.0%	2.25%
2025	25.0%	3.5%

[a] CY = Calendar Year, June 1- May 31

[b] EER = Eligible Energy Resources., which include solar PV, wind, geothermal, ocean energy (including tides and currents) and fuel cells powered by renewable fuels.[5] The Minimum Cumulative % EER includes the Minimum Cumulative % Solar PV.

[c] PV = Photovoltaics

Table 1 is abbreviated to show only the years divisible by 5; the minimum total installed EER and Solar PV was intended to increase each year from 2010 to 2025 – in the absence of a freeze. The text of the Code says:[6]

"(c) Beginning in compliance year 2010, and in each compliance year thereafter, the Commission may review the status of Schedule I and report to the legislature on the status of the pace of the scheduled percentage increases toward the goal of 25% from eligible energy resources. <u>If the Commission concludes at this time that the schedule either needs to be accelerated or decelerated, it may also make recommendations to the General Assembly for legislative changes to the RPS."</u> (underline added for emphasis) It goes on to say:

"(i) The State Energy Coordinator in consultation with the Commission, <u>may freeze the minimum cumulative solar photovoltaics requirement</u> for regulated utilities if the Delaware Energy Office determines that the total cost of complying with this requirement during a compliance year exceeds 1% of the total retail cost of electricity for retail electricity suppliers during the same compliance year. In the event of a freeze, the minimum cumulative percentage from solar photovoltaics shall remain at the percentage for the year in which the freeze is instituted. The freeze shall be lifted upon a finding by the Coordinator, in consultation with the Commission, that the total cost of compliance can reasonably be expected to be under the 1% threshold. The total cost of compliance shall include the costs associated with any ratepayer funded state solar rebate program, SREC purchases, and solar alternative compliance payments."

"(j) The State Energy Coordinator in consultation with the Commission, <u>may freeze the minimum cumulative eligible energy resources requirement</u> for regulated utilities if the Delaware Energy Office determines that the total cost of complying with this requirement during a compliance year exceeds 3% of the total retail cost of electricity for retail electricity suppliers during the same compliance year. In the event of a freeze, the minimum cumulative percentage from eligible energy resources shall remain at the percentage for the year in which the freeze is instituted. The freeze shall be lifted upon a finding by the Coordinator, in consultation with the Commission, that the total cost of compliance can reasonably be expected to be under the 3% threshold. The total cost of compliance shall include the costs associated with any ratepayer funded state renewable energy rebate program, REC purchases, and alternative compliance payments."

It is clear from the Code that the State Energy Coordinator, in consultation with the Commission, has discretion in whether to institute a schedule freeze based on more than just the cost of electricity reflected in customer utility bills; in fact the Commission may even recommend to the General Assembly that the RPS schedule be accelerated. The League feels strongly that externalities (costs to society that do not appear on utility bills) should be given a heavy weight when the state Energy Coordinator considers whether to freeze the compliance schedule because electric bills are increasing because of a transition away from fossil fuels to renewable energy sources. Our position is based in part on a LWVDE study completed in 2011 that resulted in the following recommendations being sent to Governor Markell on June 24, 2011:

The League of Women Voters of Delaware supports an aggressive and comprehensive energy use/climate change plan for Delaware. Some key points that should be included:

- ***Accelerate bringing new green businesses, jobs and industries to Delaware, and investigate emerging energy technologies.***
- ***Set targets and a timetable for reducing Delaware's total greenhouse gas emissions.***
- ***Plan for extensive adaptation measures at all levels of government for climate change impacts that cannot be avoided---especially sea level rise.***
- ***Support public education and outreach; expand renewable energy and climate change in Delaware curriculum standards.***
- ***<u>As Delaware calculates energy costs, full life cycle analyses with all externalities must be included</u>. (underline added for emphasis)***
- ***Social and economic justice must be considered in implementing energy and climate change policy.***

At the national Convention 2014 of the LWVUS, the Delaware League led a successful effort to pass the following Resolution:

The LWVUS should support a price on carbon emissions that will increase in stages, as part of an overall program to improve energy efficiency and to replace fossil fuels with renewable energy, fast enough to avoid serious damage to the climate system.

A price on carbon in Delaware would provide an incentive for speeding the replacement of fossil fuels by renewable energy resources. Delaware, because of its long coastline, the lowest average elevation of any state in the country (only about 60 feet), and the large fraction of its natural and man-made resources near the coast,[7] is especially vulnerable to climate change, sea level rise and coastal flooding. Rather than shrinking back from increasing the percentage of electricity from renewable energy (RE) sources because of relatively small increases in our electric bills, we should be taking a leadership position among the states in reducing our carbon emissions through a combination of rapidly developing our major RE resources – offshore wind and solar PV – and also increasing our energy efficiency in all the ways we can – including better land use, transportation and building codes. We may be able to show that we can not only save our state from losing most of its land area to sea level rise, but by working vigorously to protect our environment, we can also provide great economic opportunities and jobs for our people.

The Social Cost of Carbon (SCC) is the total cost to society of each added ton of CO2 that could be avoided by replacing fossil fuels by renewable energy sources or improving energy efficiency. A recent study at Stanford University indicates that the commonly used figure of $37 a ton might be much too low. The recently published result indicates that the SCC could be as high as $220/ton.[8] Study co-author Delavane Diaz, in the Department of Management Science and Engineering at Stanford's School of Engineering, in a statement accompanying the study's release, said, "If the social cost of carbon is higher, many more mitigation measures will pass a cost-benefit analysis. Because carbon emissions are so harmful to society, even costly means of reducing emissions would be worthwhile." About 1.1 ton of CO2 is produced per MWh in a power plant burning coal, and about 0.6 ton in one burning natural gas.[9] If the $220/ton of CO2 for the SCC is correct, it corresponds to a cost to society of about 24¢/kWh for electricity produced from coal and 13¢/kWh for electricity from natural gas. These numbers can be compared to Delmarva Power's total cost of electricity to Standard Offer Service customers of about 15¢/kWh for the past 4-5 years.[10]

While it was once anticipated that electricity from renewable energy sources – especially solar PV – would be much more expensive per kWh than electricity from the grid, the large and rapid decrease in the price of solar panels in recent years has meant that solar PV in many U.S. cities is now less expensive than electricity from the grid, which still comes mostly from burning fossil fuels. A recent report from a study at North Carolina State University says, "...our analysis shows that in 46 of America's 50 largest cities, a fully financed, typically-sized solar PV system is a better investment than the stock market, and in 42 of these cities, the same system already costs less than energy from a residential customer's local utility."[11] Boston, New York City, Philadelphia and Washington, DC are all ranked in the top 14 out of the 50 largest cities for the value of solar PV to customers. As fossil fuels become more expensive to find and extract - especially if a price on carbon is adopted – we anticipate that electricity from the grid will become more expensive in the future, even as the cost of renewable energy sources continues to decrease.

As we learned at the hearing on Jan. 7, the DNREC Division of Energy and Climate has concluded, based in part on advice from the Deputy Attorney General (DAG), that the 3% and 1% caps on the increases in total electricity costs attributable to EER and solar PV that trigger the consideration of a freeze in the compliance Schedule 1 refer to year over year increases and not to the cumulative cost of electricity over the life of the RPS. We completely agree with DNREC and the DAG.

In summary, the League fully supports:

- The earlier strengthening of Delaware's RPS from 10% of the electricity sold in CY 2019-2020 from EER to 25% in CY 2025-2026, with a 3.5% solar PV carveout.

- Serious consideration of all externalities – especially the higher costs of health care and the damage to property and natural resources resulting from continued fossil fuel use when deciding when to freeze or accelerate the RPS schedule.

- DNREC's position that the 3% and 1% cost caps that trigger consideration of freezing scheduled EER and solar PV minimums refer to year over year price increases.

- A price on carbon emissions from all sources in Delaware, including electricity generation, and serious statewide efforts to improve energy efficiency.

Thank you for your consideration.

Sincerely,

Charlotte King, President, League of Women Voters of Delaware

Chad Tolman, Chair, Climate Change Committee

cc: Tom Noyes, Phil Cherry, David Small, DNREC; Dallas Winslow, Chair, Delaware PSC

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[1] **Renewable Portfolio Standard**. At: http://en.wikipedia.org/wiki/Renewable_portfolio_standard

[2] **Database of State Incentives for Renewables & Efficiency**, Delaware RPS. At: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=DE06R

[3] **Delaware Code, Title 26, Public Utilities of the Delaware Code, Chapter 1. Public Service Commission, Subchapter III-A. Renewable Energy Portfolio Standards § 351 - § 364.** At: http://delcode.delaware.gov/title26/c001/sc03a/

[4] Ref. 3. § 354 (a)

[5] For details see Ref. 3. § 352 (6) Definitions

[6] Ref. 3 , § 354 (c), (i) and (j)

[7] **Preparing for Tomorrow's High Tide: Sea Level Rise Vulnerability Assessment for the State of Delaware**, July 2012. At: http://www.dnrec.delaware.gov/coastal/Pages/SLR/DelawareSLRVulnerabilityAssessment.aspx

[8] Tom Zeller, **Economic Impacts of Carbon Dioxide Emissions Are Grossly Underestimated, a New Stanford Study Suggests**. Forbes, Jan. 13, 2015. At: http://www.forbes.com/sites/tomzeller/2015/01/13/economic-impacts-of-carbon-dioxide-emissions-are-grossly-underestimated-a-new-stanford-study-suggests/

[9] **How much carbon dioxide is produced per kilowatthour when generating electricity with fossil fuels?** U.S. Energy Information Administration, 2012. At: http://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11

[10] C. Tolman, Delmarva Power bills for 2010-2014.

[11] Jim Kennerly and Autumn Proudlove, **Going Solar in America: Ranking Solar's Value to Consumers in America's Largest Cities**. NC Clean Energy Technology Center, NC State University, Jan. 2015. At: http://nccleantech.ncsu.edu/wp-content/uploads/Going-Solar-in-America-Ranking-Solars-Value-to-Customers_FINAL1.pdf?utm_source=January

Vest, Lisa A. (DNREC)

From:	Amy Roe <amywroe@gmail.com>
Sent:	Monday, February 09, 2015 10:41 PM
To:	Vest, Lisa A. (DNREC)
Cc:	Noyes, Thomas G. (DNREC); Underwood, Robert (DNREC); Stephanie Herron
Subject:	Public Comment, RPS Cost Cap Regulations
Attachments:	Sierra_Club_2015_02_09_rps_cost_cap.pdf; Carley 2011.pdf; Epstein et al 2011.pdf; Heeter et al 2014.pdf; Remais et al 2014.pdf; Schwantiz et al 2015.pdf; Stockmayer et al 2012.pdf; Yin and Powers 2010.pdf

Dear Ms. Vest,

On behalf of the Delaware Chapter of the Sierra Club, I respectfully submit the attached comments on the proposed regulation 102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions.

I have also attached documentation from journals and technical reports.

Thank you for the opportunity to comment.

Regards,

Amy Roe, Ph.D.

Delaware Chapter of the Sierra Club

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Delaware Chapter of the Sierra Club

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February 9, 2015

Lisa Vest
Hearing Officer
DNREC
89 Kings Highway
Dover, DE 19901
Lisa.Vest@state.de.us

Dear Ms. Vest:

On behalf of the Delaware Chapter of the Sierra Club, I respectfully submit the following comments on the proposed regulation 102 Implementation of Renewable Energy Portfolio Standards Cost Cap Provisions.

The RPS has numerous direct and indirect benefits for ratepayers and Delawareans. Peer-reviewed literature on the impact of renewable energy policy document benefits to include fuel price and supply stability, energy security, resilience to grid reliability fluctuations, reduced consumption of fossil fuels resulting in lower attendant air pollution and improved health, improved local economic development and technological advancement opportunities, and the development of local labor markets (Carley 2011, Heeter et al., 2014, Schwanitz et al. 2015, Yin and Powers, 2010). Schwanitz et al., (2015) even found that the externalized co-benefits of decarbonizing the energy supply in this study rivaled the total cost of the policy.

1.0 Purpose

These rules govern how the Director of the Division of Energy & Climate (Director) and the Division of Energy & Climate (Division) administer their obligations under 26 Del.C. §354(i) & (j). The statute directs when and whether the Director may institute a freeze on the implementation of the Renewable Energy Portfolio Standards as provided for in 26 Del.C. §354(a).

We are pleased to see that the proposed regulation maintains the intent of previous legislation in stating that "...the director ***may*** institute a freeze...." (emphasis added). We interpret this to mean that a freeze is not mandatory, even if the cost of compliance meets the 1% for solar renewable energy and 3% for renewable energy thresholds.

4.0 Calculation of the Cost of Compliance

National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory's technical report "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards" (Heeter et al., 2014) describe the limitations to calculating the costs and benefits of RPS programs. These include the calculation of costs based on those borne by the utilities, not the net costs to society, inconsistencies in the timing of how alternative compliance payments and/or penalties are passed on to ratepayers, the omission of cost or benefit information in calculations, fluctuations in REC prices and lack of transparency in REC prices (Heeter et al., 2014: iv – v).

We object to the non-weighted inclusion of the Green Energy Fund, alternative compliance payments and Qualified Fuel Cell Provider Project into the calculation of the Cost of Compliance in §4.2.1, §4.2.3 and §4.2.4 for renewable energy and §4.3.1, §4.3.3 and §4.3.4 for solar renewable energy.

We acknowledge that 26 Del. C. § 354(i) and (j) specify that the total cost of compliance shall include the costs associated with any ratepayer funded state renewable energy/solar energy rebate program, REC/SREC purchases, and renewable energy/solar energy alternative compliance payments. However, we suggest that the regulations should weight the impact of the Green Energy Fund, alternative compliance payments and Qualified Fuel Cell Provider Project in the calculations.

The Green Energy Fund does not directly support compliance with the Renewable Portfolio Standard, except when used as an alternative compliance payment (26 Del. C. §358(d)). As the cost of the Green Energy Fund alternative compliance payment is set in the Delaware Code, and is used as an alternative for utilities to buy out of compliance with the Renewable Portfolio Standard, this "penalty" is not set by market conditions and should not be fully weighted in the cost cap.

Likewise, any other alternative compliance payment is bounded by the cost restrictions of the Delaware Code and may not reflect the actual costs of implementing the Renewable Portfolio Standard. The calculation of the cost of compliance should be based upon the "real cost" of providing renewable energy credits and solar renewable energy credits to fulfill the requirements of the Renewable Portfolio Standard. To allow alternative compliance payments to be incorporated in full into the cost calculation has the potential to skew the calculations.

Stockmayer et al., (2012: 156-157) discuss the controversial nature of this dilemma of using an alternative compliance payment in the cost cap calculation, noting that the State of Ohio forbids this practice.

The sole utilization of Qualified Fuel Cell Provider Projects in the RPS is for natural gas-fired Bloom Boxes. We object to any costs utilized for the purchase of fossil fuels or utility incentives for electricity generated from natural gas to be used toward the cost cap of the Renewable Portfolio Standard. The cost burden of financing schemes for Delaware Economic Development Office investment contracts should not provide an opportunity to cap the RPS. Doing so is acting contrary to the purpose and legislative intent of the RPS.

We therefore suggest the following changes in language:

> 4.2 The Division shall calculate the Renewable Energy Cost of Compliance for a particular compliance year to be:
>
> > 4.2.1 <u>25 percent of</u> the total of contributions to that portion of the Green Energy Fund used to support the development of renewable resources, plus
> >
> > 4.2.2 the cost of RECs and SRECs retired to satisfy the RPS requirement, plus
> >
> > 4.2.3 <u>25 percent of</u> all Alternative Compliance Payments, plus
> >
> > 4.2.4 <u>0 percent of</u> the cost of QFCPP offsets to the RPS <u>that utilize natural gas and 100% of the cost of QFCPP offsets to the RPS that use non-fossil fuels</u>.
>
> 4.3 The Division shall calculate the Solar Renewable Energy Cost of Compliance for a particular compliance year to be:
>
> > 4.3.1 <u>25 percent of</u> the total of contributions to that portion of the Green Energy Fund used to support the development of photovoltaic renewable resources, plus
> >
> > 4.3.2 the cost of SRECs retired to satisfy the RPS requirement, plus
> >
> > 4.3.3 <u>25 percent of</u> all Solar Alternative Compliance Payments for the solar photovoltaic requirement, plus
> >
> > 4.3.4 <u>0% of</u> the cost of QFCPP offsets to the solar photovoltaic carve-out <u>that utilize natural gas and 100% of the cost of QFCPP offsets to the RPS that use non-fossil fuels</u>.

<u>5.0 Determination by the Director</u>

We support the year over year calculation of Renewable Energy Compliance Cost in §5.2 and Solar Renewable Energy Compliance Cost in §5.3. The year-over-year calculation reflects the increasing annual amount of renewable energy required to meet a 25% renewable energy portfolio by 2025 and a 3.5% solar carve-out by 2025.

We support the criteria to be utilized by the Director, including market conditions, avoided cost benefits, externality benefits and the economic impacts of the deployment of renewable energy. In §5.7, pertaining to the externality costs of health and mortality costs and environmental impacts, we suggest that the language be changed to read

> §5.7 Externality benefits of changes in energy markets ~~may~~ must include externality savings in health and mortality costs and environmental impacts due to policies promoting cleaner energy in Delaware and regional energy generation.

We object to the reliance on the IRP filed by the Commission-Regulated Electric Company in §5.7 to be used to understand the costs and benefits of health, mortality and environmental externality costs for the following reasons:

1. The IRP process is not designed thoroughly enough to be utilized for the purpose of establishing a cost cap to freeze the RPS,
2. The meetings of the IRP are not noticed in a way that the ratepayers would be aware that they have such an implication for the RPS,
3. The IRP only accounts for the externality costs of coal, and does not conduct externality cost-benefit analysis for natural gas or nuclear power.
4. The Public Service Commission oversees the IRP process, not DNREC, and can make any changes to the use of externality calculations at any time in the future, which could place the Department in an ill-fated position.

It is therefore inappropriate for the Department to rely upon the analysis conducted for another agency to fulfill the important need of understanding the costs and benefits of renewable energy in comparison to conventional fuels.

Instead, the regulations should be revised so that Department conducts cost-benefit externality analysis for health, mortality and environmental externalities for all conventional fuels utilized by the utility (including coal, natural gas, and nuclear). This analysis should be conducted on a regular schedule, but need not be conducted annually. It may utilize IRP documentation, but should not be limited to the constraints of the IRP process.

As advised by Remais et al. (2014), the consideration of health benefits and externalities should involve early discussions between modelers and policy-makers, should identify the full range of potential positive and negative pathways to health impacts within predefined boundaries, and should make explicit the criteria used to determine which exposure–outcome relationships are included in the model.

We ask that §5.8, which defines economic development benefits of renewable energy, also weigh these benefits against the state and federal subsidies given to fossil fuel distribution companies and electricity generation companies, including subsidies from the Delaware Economic Development Office in the form of offset credits, NOx and pollution credits, and grants/funding for power plants and natural gas pipelines needed for power plants, in addition to other state and federal subsidies and tax credits for fossil fuels.

We also suggest the following change in language:

5.4 In making the determination, the Director ~~may~~ will consider:

Furthermore, a public notice of an impending determination, public hearing, and public comment prior to the determination by the Director should be included in the regulations. We ask that this public notice should specify the DNREC Public Notice Email Distribution List. While this is somewhat addressed in §8.0 Administration for annual review, the public process for enacting a freeze should be very clear and included in this section.

6.0 Implementation

We support the notifications listed in this section if a freeze is imposed. However, we suggest that the notifications should also include the DNREC Public Notice Email Distribution List.

7.0 Lifting a Freeze

A process in this section should be included that enables members of the public to petition the Director to lift a freeze. We suggest language that clearly defines the process that members of the public may engage in to lift a freeze, including a number of signatures on a petition to initiate a review process.

The process for lifting a freeze should also include a public notice of a determination by the Director, public hearing and public comment prior to action by the Director.

The process for lifting a freeze is unclear about how the criteria in §5.0 will be utilized by the Director, including consideration of market conditions, avoided cost benefits, externality benefits and the economic impacts of the deployment of renewable energy, in addition to the program costs.

8.0 Administration

According to the language in this section, the Director must make a determination annually on the cost of compliance and enact a freeze. We would like the public notice of this annual review to be clarified and to include greater opportunity for public involvement. Specifically:

8.3 Within 30 days of receipt of the calculations of the cost of compliance from the Division, the Director shall make a draft determination as described in Section 5.0 of these regulations, publicly notice the draft determination through the DNREC Public Notice Email Distribution List, and present to the Registrar for publication.

8.4 The public will have 30 days from the publication and public notice of the Director's draft determination to offer comment and request a public hearing. The Director may grant a public hearing or alter or amend the determination based on review of the public comments.

8.5 The Director shall make a final determination and present it to the Registrar for publication and public notice via the DNREC Public Notice Email Distribution List within 15 days of receipt of public comments. The determination shall be effective upon its publication.

8.6 Decisions of the Director may be appealed via the Environmental Appeals Board within 60 days of publication and public notice of the final determination.

Thank you for the opportunity to comment on these important regulations.

Amy Roe, Ph.D.
Conservation co-Chair

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Yin, Haitao and Nicholas Powers, 2010. Do state renewable portfolio standards promote in-state renewable generation? *Energy Policy*, 38 (2), 1140-1149.

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Review

Estimating the Health Effects of Greenhouse Gas Mitigation Strategies: Addressing Parametric, Model, and Valuation Challenges

Justin V. Remais,[1] *Jeremy J. Hess,*[1,2] *Kristie L. Ebi,*[3] *Anil Markandya,*[4] *John M. Balbus,*[5] *Paul Wilkinson,*[6] *Andy Haines,*[6] *and Zaid Chalabi*[6]

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BACKGROUND: Policy decisions regarding climate change mitigation are increasingly incorporating the beneficial and adverse health impacts of greenhouse gas emission reduction strategies. Studies of such co-benefits and co-harms involve modeling approaches requiring a range of analytic decisions that affect the model output.

OBJECTIVE: Our objective was to assess analytic decisions regarding model framework, structure, choice of parameters, and handling of uncertainty when modeling health co-benefits, and to make recommendations for improvements that could increase policy uptake.

METHODS: We describe the assumptions and analytic decisions underlying models of mitigation co-benefits, examining their effects on modeling outputs, and consider tools for quantifying uncertainty.

DISCUSSION: There is considerable variation in approaches to valuation metrics, discounting methods, uncertainty characterization and propagation, and assessment of low-probability/high-impact events. There is also variable inclusion of adverse impacts of mitigation policies, and limited extension of modeling domains to include implementation considerations. Going forward, co-benefits modeling efforts should be carried out in collaboration with policy makers; these efforts should include the full range of positive and negative impacts and critical uncertainties, as well as a range of discount rates, and should explicitly characterize uncertainty. We make recommendations to improve the rigor and consistency of modeling of health co-benefits.

CONCLUSION: Modeling health co-benefits requires systematic consideration of the suitability of model assumptions, of what should be included and excluded from the model framework, and how uncertainty should be treated. Increased attention to these and other analytic decisions has the potential to increase the policy relevance and application of co-benefits modeling studies, potentially helping policy makers to maximize mitigation potential while simultaneously improving health.

CITATION: Remais JV, Hess JJ, Ebi KL, Markandya A, Balbus JM, Wilkinson P, Haines A, Chalabi Z. 2014. Estimating the health effects of greenhouse gas mitigation strategies: addressing parametric, model, and valuation challenges. Environ Health Perspect 122:447–455; http://dx.doi.org/10.1289/ehp.1306744

Introduction

Climate change poses one of this century's most significant public health challenges (Chan 2009). There is growing recognition that strategies to reduce greenhouse gas (GHG) and climate-active aerosol emissions ("mitigation" strategies) will affect numerous upstream drivers of public health, including indoor and outdoor air pollution, water security and quality, food security and quality, and physical activity, with the potential for beneficial and adverse impacts (Table 1; Haines et al. 2009; Little and Jackson 2010; Newmark et al. 2010).

Importantly, many mitigation-related health impacts accrue sooner than the impacts projected from climate change. Studies published in the *Lancet* in 2009 highlighted this, suggesting significant net health benefits across several mitigation strategies and settings (e.g., Haines et al. 2009). Studies in this series used modeling to estimate the differences in, and magnitude of, health co-benefits of mitigation actions in various sectors, as well as discussing the potential for adverse health impacts, or co-harms. Subsequent analyses in the United States extended these findings (Grabow et al. 2012; Maizlish et al. 2013).

Studies estimating the ancillary health effects of mitigation strategies (termed "co-benefits" from here forward, with the acknowledgment that co-harms also may result) use a range of modeling approaches, drawing expertise from public health, agriculture, environmental sciences, urban planning, and other disciplines to generate policy-relevant outputs. We reviewed several specific issues with modeling co-benefits of mitigation strategies, including those related to model framework, structure, and choice of parameters, and the implications of these for policy uptake. Some of these issues are common to other types of modeling, so our discussion could be applied to similar concerns arising in the development of health impact assessments (European Centre for Health Policy 1999; Kemm 2007) and the modeling of certain climate change adaptation activities, which also have co-benefits and co-harms (Cheng and Berry 2013). We focused specifically on mitigation co-benefits modeling, however, for several reasons: First, all co-benefits modeling of climate change mitigation policies necessarily requires attention to these issues, whereas not all health impact assessment efforts, or efforts to quantify ancillary impacts of adaptation strategies, do. Second, GHG emission reduction policies can influence a range of major risk factors that contribute substantially to global disease burden, whereas climate change adaptation strategies result in health co-benefits predominantly by increasing resilience to existing climate variability. Third, the field of health impact assessment studies is much broader and would require a wider-ranging discussion. And fourth, to date there has not been a

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systematic consideration of the methodological issues related to modeling health co-benefits of climate change mitigation policies.

Modeling of co-benefits generally takes the basic approach shown in Figure 1, employing a wide variety of methods such as comparative risk assessment (Smith and Haigler 2008), complex mechanistic components (such as those describing building physics, e.g., Wilkinson et al. 2009); and macroeconomic, technological, and behavioral models (National Research Council 2010). The range of modeling approaches commonly used is detailed in Supplemental Material, Table S1; the table also includes central estimates of health co-benefits reported by selected studies.

Several overlapping challenges are common to co-benefits modeling studies [Bell et al. 2008; Haines et al. 2009; HEI (Health Effects Institute) International Scientific Oversight Committee 2010; Matus et al. 2008; Patz et al. 2008; Smith and Haigler 2008], including the following:

- Modeling the time course of strategies that are phased in over time, and the resulting time-varying levels of exposures to health drivers;
- Taking into account the varying lag times between changes in exposure and changes in health outcomes according to the health outcome concerned;
- Incomplete methods for quantifying and conveying the degree and sources of uncertainty associated with the modeling outputs;
- Debate over key parameters, such as discount rates and terms involved in the economic valuation of health outcomes; and
- Estimating future economic development pathways and GHG emissions, and projecting trends in demographics, health status, and levels of exposures to health drivers over the relevant time course.

This review is an initial effort to address some of these challenges, with a focus on modeling issues (time course of exposures and impacts; uncertainty; and low-probability/high-impact effects) and issues affecting relevance (discount rate selection, decision analysis, and inclusion of factors affecting policy uptake and system dynamics). We conclude with recommendations to advance the rigor and consistency of co-benefits modeling.

Key Modeling Issues

Health co-benefits models typically begin with a mapping exercise that proceeds to a more formal mathematical model describing relationships between model components and outcomes of interest. This process may involve identification of specific indicators of health impacts. A number of different frameworks are available (e.g., Hambling et al. 2011), and the relationships identified in the mapping process can be formally quantified and assessed using a variety of strategies.

Initial mapping to model construction. Modeling can be used to answer a specific set of policy questions regarding the health impacts of particular mitigation options. An important initial step is developing a conceptual framework linking the mitigation policy to specific public health drivers in the near- and mid-term over which beneficial health impacts accrue. Modeling efforts begin with description of the system boundaries, major associations between different model components, outcome indicators and their metrics, and definition of the counterfactuals (e.g., "business as usual") used for comparison. For instance, in estimating the impact of introducing low-emission cookstoves in India on health impacts of household air pollution, the initial conceptual map included population growth and demographics, proportion of the population with low-emission cookstoves, major health outcomes associated with elevated levels of household air pollution, and historical experience implementing national cookstove interventions, but not the potential effects on household income (Wilkinson et al. 2009).

The models constructed from these mapping exercises should capture the key associations between model components and the outcomes of interest within the scale and scope of the project. Unfortunately, not all relationships are well understood, and not all parameters are well studied. For instance, there are questions about the mitigation potential of cookstove interventions because stove emissions can affect climate negatively or positively (Wilkinson et al. 2009). Likewise, poor maintenance of household energy interventions such as anaerobic digesters can lead to direct emissions of potent GHGs into the atmosphere (Dhingra et al. 2011), potentially limiting their long-term performance. Although such uncertainty does not affect the resulting estimates of health impacts of a mitigation strategy, it does affect the confidence in

Table 1. Summary of major health drivers and outcomes modified by select mitigation strategies.

Sector/mitigation strategy	Health drivers	Health and related outcomes potentially affected
Energy (Burtraw et al. 2003; Markandya et al. 2009)		
Reduce fossil fuel combustion	Reduce conventional air pollutants: particulate matter, ozone, nitrogen oxides, volatile organic compounds	Cardiovascular morbidity and mortality; asthma and other respiratory diseases; developmental disorders; improved crop survival and productivity
Increase production of some types of biofuels	Increase food prices and lower availability depending on whether they compete directly with food crops	Food insecurity; malnutrition
Carbon capture and sequestration	Groundwater availability and quality; contamination with metals and minerals, sudden carbon dioxide/hydrogen sulfide releases	Various related to specific contaminants
Transportation (Cifuentes et al. 2001; Maizlish et al. 2013; Shindell et al. 2011; Woodcock et al. 2013)		
Improve fuel economy; increase adoption of electric and other noncombustion engines; tighter on-road vehicle emissions standards	Reduce conventional air pollutants	Cardiovascular morbidity and mortality; asthma and other respiratory diseases;
Increase access and convenience of active modes of transportation, including walking, cycling, and public transit	Reduce conventional air pollutants	Cardiovascular morbidity and mortality; asthma and other respiratory diseases; developmental disorders
	Increase physical activity levels	Cardiovascular morbidity and mortality; obesity and diabetes risk; risk of certain cancers; risk of dementia, depression, injury
Agriculture (Friel et al. 2009; McMichael et al. 2007)		
Reduce ruminant livestock production; capture methane emissions	Reduce ozone air pollution	Cardiovascular and respiratory morbidity and mortality
	Reduce consumption of animal products with high levels of saturated fat; reduce red and processed meat consumption; increase consumption of unsaturated fats of vegetable origin and of fruit and vegetables	Cardiovascular morbidity and mortality; risk of certain cancers including large bowel cancer
Land use in built environment (Younger et al. 2008)		
Increase green space and parks in built environment; increase shading and vegetation along roads	Increase physical activity; reduce excessive temperature exposure	Cardiovascular risk; some cancer risks; mental health

estimates of efficacy of the mitigation strategy relative to other options (Haines et al. 2009). Modelers must decide what to include and how to define the range of input parameters based on the best available evidence.

Modeling complex, time-varying exposures and impacts. Several key time-varying elements of mitigation policies must be made explicit, such as the time course for intervention implementation (e.g., low-emission cookstoves) and associated exposure changes (e.g., reductions in household air pollution). Mitigation activities may be represented in models as enacted instantaneously, in steps, or gradually phased in, although most integrated assessment models assume instantaneous and perfect implementation (first-best worlds). Most co-benefit models consider step changes in mitigation interventions (Cifuentes et al. 2001; Maizlish et al. 2013; Woodcock et al. 2013). Ideally, models should employ a time course empirically based on analogous interventions (Wilkinson et al. 2009). Similarly, exposures should be modeled to reflect those temporal characteristics most strongly associated with health outcomes—for example, peak levels are most relevant for some hazards, cumulative and long-term exposures for others (Lin et al. 2008; Murray et al. 2003; Robins and Hernan 2009). The dynamic response between disease and exposure must also be considered, requiring an accounting of cumulative exposures and associated morbidity and mortality among an age-stratified cohort over time (Matus et al. 2008). Table 2 shows the approximate time lags over which health co-benefits are likely to accrue for the strategies explored in recent co-benefit analyses (Friel et al. 2009; Jarrett et al. 2012; Wilkinson et al. 2009; Woodcock et al. 2013).

Numerous methods are available to incorporate time-varying exposures and associated time-varying health effects when appropriate, including comparative risk assessment approaches (Lin et al. 2008; Murray et al. 2003), modification of the standard static Cox proportional hazard model (Haneuse et al. 2007), and functional approximation methods that associate health outcomes with exposure history (Bandeen-Roche et al. 1999). As an alternative, co-benefits studies can use time functions not directly derived from epidemiological studies that are parameterized to simulate the time lag in health effects in response to changes in exposure. For example, Jarrett et al. (2012) used sigmoid lag functions to simulate delays in the response of depression, ischemic heart disease, and other effects to changes in exposure to physical activity.

Estimating adverse effects of mitigation strategies. The validity of a modeling analysis depends partly on inclusion of all relevant pathways among mitigation strategies, consequent exposures, and outcomes of interest. This requires including pathways that increase risk (co-harms) or decrease it (co-benefits). Potential co-harms of various mitigation strategies include reduced affordability of food leading to poor nutrition [if, for example, pastoralists in poor countries have to reduce their consumption of animal products (Friel et al. 2009)]; rising energy costs pushing the poor toward low-quality biomass fuels (Markandya et al. 2009); and increases in air pollution from combustion of biofuels (Jacobson 2007).

An example of an adverse impact with a relatively simple causal pathway is increased pedestrian and cyclist exposure to road traffic injuries resulting from an increase in active transport (DiGuiseppi et al. 1997; Jarrett et al. 2012; Woodcock et al. 2009). In one analysis, estimated increases in morbidity and mortality from pedestrian and cyclist road traffic injuries in London (UK) were more than offset by decreases in disability-adjusted life years (DALYs) lost from physical inactivity and to a lesser extent air pollution (Woodcock et al. 2009), a finding reinforced by Lindsay et al. (2011). More complex, indirect pathways can also yield adverse impacts—for example, switching some agricultural production from food to biofuel feedstocks can have complex, recursive macroeconomic effects including shifts in prices of various food staples (Chakravorty et al. 2009). In 2007, for instance, expanded biofuels production was estimated to be responsible for

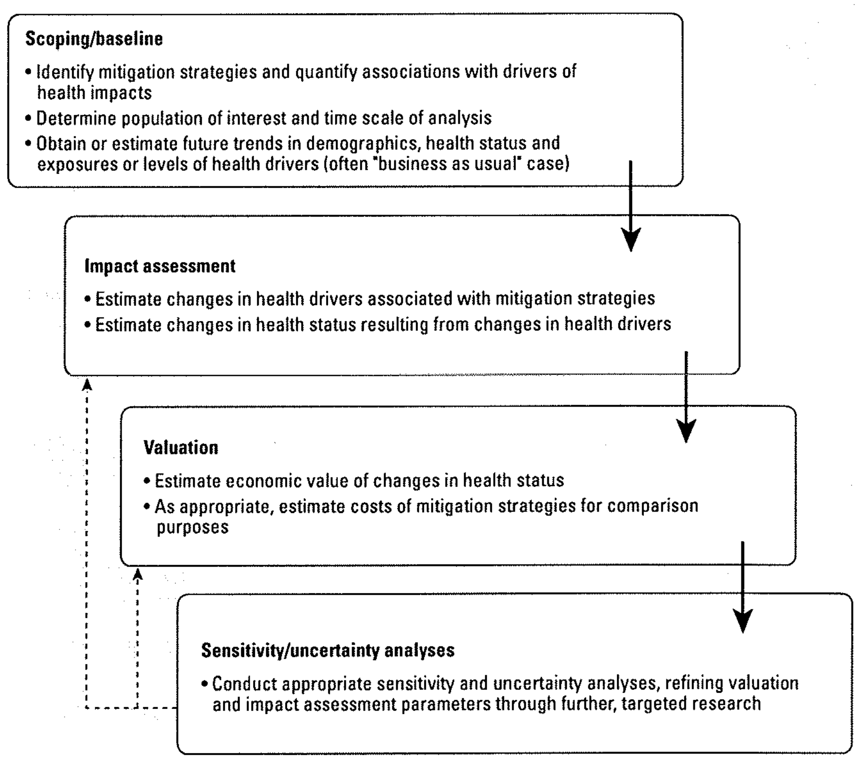

Figure 1. Model of health effects of mitigation showing scoping activities that define the initial and boundary conditions of the analysis; impact assessment; valuation procedures; and sensitivity and uncertainty analyses, the results of which can be used to further refine impact assessment and valuation analyses (dashed lines).

Table 2. Time lags over which the health co-benefits accrue for the mitigation strategies explored in recent health effects of mitigation modeling studies.[a]

Health outcome	Likely time lag for health co-benefits
Reductions in sudden cardiac death risk due to reduced air pollution	Days to weeks
Reduction in acute respiratory infections in children due to reduced air pollution	Weeks and months
Reduction in chronic obstructive pulmonary disease (COPD) exacerbations	Weeks and months
Reduction in ischemic heart disease events due to partial substitution of animal source saturated fat consumption by polyunsaturated fats of plant origin	Years
Reduction in type 2 diabetes due to change in physical activity	Years
Reduction in depression due to change in physical activity	Years
Reduction in breast and colon cancer incidence due to change in physical activity	Years
Reduction in COPD prevalence due to reduced air pollution	Decades

[a]Friel et al. (2009); Jarrett et al. (2012); Wilkinson et al. (2009); Woodcock et al. (2013).

approximately 30% of the rapid rise in grain prices (Rosegrant 2008). Such price increases, along with other economic shocks, increase undernutrition (Bloem et al. 2010; Friel et al. 2009), a major risk factor for mortality of children < 5 years of age (Black et al. 2008). One analysis found that such dynamics likely increased child mortality in East and Southeast Asia in 2007 (Bhutta et al. 2008; Christian 2010). Large uncertainties exist, including the complex relationships among supply, demand, and global food prices (Mitchell 2008); in regional resilience to price spikes (Webb 2010); and in other drivers for the multiple health end points of undernutrition (Black et al. 2008). Despite these difficulties, nutrition-mediated health effects of some biofuel policies serve as a good example of a tractable co-harms estimation problem that could be used to inform future mitigation decisions (Bloem et al. 2010; Christian 2010; Friel et al. 2009).

Low-probability events with highly adverse impacts. Certain mitigation technologies are associated with low-probability/high-impact co-harms, such as severe nuclear power plant accidents, catastrophic failures of so-called "mega-dams," and leaks from carbon capture and storage (Bickel and Friedrich 2005; Markandya et al. 2009). This class of adverse impacts is challenging to estimate: low probability high impact exposures are highly uncertain and episodic, so deterministic exposure functions cannot be directly applied. Event (i.e., accident) data for certain mitigation options are sparse, making alternative analytical approaches, such as estimating expected damage, difficult (e.g., Ha-Duong and Loisel 2010). Importantly, when the expected harms of these risks are quantified, estimated impacts can be considerably smaller than public perceptions of these risks (Krupnick et al. 1993). Incorporating risk perception heuristics—in which the public views risks associated with these events as more problematic than more routine events with the same expected value (Bier et al. 1999)—into co-benefits modeling is an important frontier to explore.

Methods for the treatment of uncertainty. Uncertainties are inherent to modeling studies and permeate complex policy decisions such as those surrounding climate change mitigation. Uncertainties in modeling health co-benefits include *a*) simulating the spatial and temporal changes in health-relevant exposures; *b*) determining the time response of the health effects due to exposure changes; *c*) comparing alternative mitigation interventions in terms of their health effects across populations and time scales; and *d*) establishing the assumed time course of future disease-specific burdens in the absence of mitigation.

There has been much discourse on dealing with uncertainty, particularly with respect to the integrated assessment models used to evaluate mitigation policies, that is relevant for co-benefits modeling (Mearns 2010; Rotmans and Van Asselt 2001a, 2001b; Visser et al. 2000; Webster et al. 2003). Co-benefits studies often take a simplistic, one-dimensional approach to propagating the multiple sources of uncertainty (Schneider and Kuntz-Duriseti 2002). Uncertainties are cascaded sequentially through model components starting with "upstream" drivers (e.g., mitigation options, emissions, carbon cycle response, and global climate sensitivity) and then "downstream" to local climate change, exposures, and health impacts. Socioeconomic change, as an example, contributes significant downstream uncertainty (Arnell et al. 2004). In some circumstances the combined uncertainty, particularly over the long term, makes it difficult to determine the balance of costs, co-benefits, and co-harms, but additional methods can help narrow estimates substantially, particularly in the near term. The following sections summarize several quantitative approaches. Overcoming challenges in integrating quantitative and nonquantitative approaches to uncertainty characterization is also very important.

Uncertainty propagation through models. Model uncertainty can be classified as structural or parametric (Refsgaard et al. 2006; Tebaldi and Knutti 2007). Structural uncertainty refers to uncertainty in the constitution of the model, such as the configuration of the air dispersion Gaussian model, the makeup of the exposure pathways (e.g., inhalation, ingestion), and the types of exposure–response relationships (e.g., linear, threshold-linear, nonlinear). Structural uncertainty also results from assumptions and simplifications used to construct the health model (Bojke et al. 2009). Parametric uncertainty, on the other hand, relates to uncertainty in the model's parameters, conditional on a specific structure, such as uncertainties in the threshold and slope of a threshold-linear exposure–response relationship, or the indoor/outdoor concentration ratio for $PM_{2.5}$ (particulate matter with aerodynamic diameter ≤ 2.5 μm). Such types of uncertainty permeate science and conventional epidemiological research, such as in the relationship between an energy efficiency intervention and exposure to household air pollutants (Table 3 shows several examples).

Although there is no single best way to characterize uncertainty in an analysis, there is a need for consistency and transparency in handling it. Indeed, many of the methods used for handling uncertainty in complex environmental models can be used in this context (Rao 2005; Refsgaard et al. 2007), as can deterministic and stochastic techniques from health impact models (Lopez et al. 2006). Several unique uncertainty issues arise in co-benefit analyses, such as the uncertainty in future projections over the time horizon of analysis

Table 3. The types of downstream uncertainties in recent health effects of mitigation modeling studies.[a]

Sector	Parametric uncertainties	Structural uncertainties
Household energy		
Specification of mitigation scenarios	Average value of reduction in GHG emissions due to insulation improvements	Feasible transitions from household fossil fuel combustion to electricity
Estimating exposures	Values of the parameters of building physics model	Occupant behavior and increased consumption of resources given higher end-user efficiency
Estimating health impacts	Values of the pollutants' relative risk coefficients	Pollutants to consider in the assessment
Urban land transport		
Specification of mitigation scenarios	Percentage increase in the level of active travel (walking and cycling)	Nonlinear "safety in numbers" effect of increase in proportion of cyclists on rates of cyclist injuries; different future "active travel visions"
Estimating exposures	The values of the parameters of the emission–dispersion air pollution model	Reduction of emissions from transport in London are representative for other European cities; reduction in transport emissions results in proportional reduction in particulate matter
Estimating health impacts	The values of the physical activity–disease relative risk coefficients	Diseases affected by physical activity; linear versus nonlinear relationships between physical activity and health outcomes
Food and agriculture		
Specification of mitigation scenarios	Percentage reduction in livestock production by 2030	Contribution of different livestock to greenhouse emissions and different assumptions about feedstocks
Estimating exposures	Percentage reduction in intake of saturated fat	Full replacement of saturated fats with unsaturated fats
Estimating health impacts	Saturated fat-ischemic heart disease mortality relative risk coefficient	Exposure–health outcome pathways

[a]Friel et al. (2009); Maizlish et al. (2013); Wilkinson et al. (2009); Woodcock et al. (2013); these uncertainties are naturally not unique to co-benefits modeling.

of disease-specific burdens in the absence of mitigation. These projections are the baseline against which burdens with mitigation are compared, and thus represent a primary source of uncertainty. The current disease burden is often adopted as the baseline; but this is rarely appropriate because development will occur and bring with it technology and other changes that will alter disease burdens, such as the ongoing, rapid increases in the burden of noncommunicable diseases in low- and middle-income countries (Remais et al. 2013).

Characterizing structural uncertainty. There are two main approaches for characterizing structural uncertainty in co-benefits modeling. The first simulates different model structures and then combines their outputs deterministically (e.g., Knutti et al. 2010); the second does the same but combines the outputs probabilistically (e.g., Min et al. 2007). The first approach is easier to implement, particularly for co-benefit analyses with a small number of alternative model structures. The output is either a series of single co-benefit projections (one for each structure or combinations of structures), or a sum of outputs weighted by the confidence in the model structure used to generate each. The second approach uses Bayesian model averaging to produce a weighted probability density function. This approach is useful when there are many alternative model structures to consider, but may not be feasible when the computational time to run each alternative model structure is high.

Structural uncertainties can have large impacts on estimated health effects of mitigation. For instance, in the Woodcock et al. (2009) analysis of the health effects of increased physical activity resulting from transport-related mitigation strategies, uncertainty in the physical activity exposure–response relationship (e.g., linear vs. square root) led to more than a doubling of the estimated health effects as measured by premature deaths or DALYs lost. To characterize the influence of structural sources of uncertainty, alternative model structures (i.e., functional forms) can be used to represent the exposure–response relationship, providing an estimate of the uncertainty in health effects as a function of structural choices.

Characterizing parametric uncertainty. Parametric uncertainty can arise in situations where there is limited information on the nominal or central value of a model parameter. For instance, in assessing the health co-benefits of mitigation in México City, México, Cifuentes et al. (2001) calculated the central estimate of the number of premature deaths avoided as 29,055 in the period 2000–2020. The authors used an estimate of the uncertainty in the relative risk in mortality for a 10-μg m^{-3} change in PM_{10} (PM with aerodynamic diameter ≤ 10 μm) concentration to calculate the 95% CI of premature deaths avoided (9,265, 56,293). An alternative approach, particularly useful when an estimate of the variance of parameter is unavailable, is to characterize the uncertainty in the relative risk as an interval (i.e., the parameter's value can be anywhere between a lower and upper bound) and compute an associated interval of model output (De Figueiredo and Stolfi 2004). Such parameter bounds can be elicited from expert opinion, literature reviews, or model simulations.

Finally, stochastic approaches are also available in which a probabilistic sensitivity analysis is carried out with parameter values drawn randomly from the respective parameter spaces. In this case, Monte Carlo (MC) simulation or Latin hypercube sampling (LHS) was used to repeatedly sample the parameter space, generating a distribution of model outputs. These methods are widely used when the uncertainty in parameters can be expressed as probability density functions (Helton et al. 2005). LHS is a stratified version of MC sampling that for the same number of samples is more likely to reproduce faithfully the probability density function than MC sampling; MC sampling, on the other hand, is easier to implement (McKay et al. 1979). Recent advances in dynamic sensitivity analysis (Wu et al. 2013) may offer promise for co-benefits analyses where complex dynamics result from the coupling of shifting time courses of mitigation phase-in, time-varying exposures, and varying lag times over which health impacts evolve.

Propagating uncertainties. Uncertainty propagation through a series of model components should be consistent with fundamental principles of error propagation, with proper linking of submodel outputs and inputs (Mekid and Vaja 2008). Yet standard error propagation can quickly become infeasible for large, multipart models. For example, in calculating the health co-benefits of GHG mitigation in the electricity sector in the United States, Burtraw et al. (2003) combined two large-scale models in which the output of one model fed into the input of the other. The first model simulated electricity demand, generation, consumption, and emissions of air pollutants; the second model took the emissions from the first and calculated the associated health impacts. Each model comprised a number of complex submodels (e.g., pollutant transport, dose response), and, although this was not attempted, only a limited propagation of uncertainties through this long chain of models and submodels would have been possible. Even when quantitative uncertainty propagation is feasible, additional information can be gained from qualitative approaches, such as storylines, that can represent uncertainties associated with different futures (e.g., Arnell et al. 2004).

Using value-of-information (VOI) analysis to identify key uncertainties that can be reduced. Given the diversity of uncertain parameters in health co-benefits modeling and the infeasibility of investigating all uncertain parameters, there is a need to determine the parameters whose uncertainty would be most easily and strategically reduced through additional research. Experts can use a VOI analysis to determine which new data will most likely yield more precise estimates. VOI analysis determines the return, or the payoff in terms of making better decisions, of collecting additional information (Yokota and Thompson 2004). VOI has been used to identify research priorities in climate change research (Rabl and Van der Zwaan 2009), although not yet to improve parameterization of models used to estimate health co-benefits of mitigation policies. Reduced parametric uncertainty can help decision makers avoid costly errors, and future co-benefits analyses may choose to express the expected return of investing in improved parameter estimates in monetary terms (Coyle and Oakley 2008).

Addressing Key Science Policy and Decision Support Issues

Co-benefits models are generally intended to inform the policy-making process, including modeling carried out in response to a specific policy question under consideration by a particular governing body. Rising interest in the links between climate change mitigation and public health will increase the possibility that such modeling may be brought to bear on policy decisions. To that end, the context in which the model outputs will be used is highly relevant to modeling decisions. Policy-making needs are context specific; and in the case of modeling health co-benefits, model parameters may differ based on how health care delivery and public health costs are borne across sectors (e.g., how care is funded and handled at various levels of government). In developing their models and presenting their findings, researchers need to work with policy makers from the outset to ensure that the questions asked and analyses conducted are policy relevant.

A number of initiatives are underway that can serve as blueprints for building closer links between researchers and policymakers, such as the World Health Organization (WHO) Evidence Informed Policy Network (EVIPNet) initiative (WHO 2011) and Regional East African Community Health Policy Initiative Project (REACH) in East Africa (East African Community 2011). Despite such precedents, questions remain as to how to address certain key decision support issues. In particular, questions remain regarding the most ethically, morally, and economically defensible approach to valuation of future human health and well-being; whether and how to use discount rates; and what tools are best for comparing disparate types of costs, benefits, and constraints.

The role of discounting and the effect of different discount rates. Discount rates are central to all decisions with long-term implications, including co-benefits analyses that account for multiple costs and benefits distributed over time (Ackerman et al. 2009; Smith and Haigler 2008). When modeling health co-benefits, the basic function of discount terms is to convert future health and climate consequences of a mitigation measure into their net present value by subjecting the stream of monetized benefits and costs to a discount rate. Several options for handling discounting include ignoring it altogether or selecting constant, variable, or multiple rates for different components.

Setting the discount rate to zero. Avoiding discounting when modeling health co-benefits is equivalent to selecting a zero rate, which equates mitigation benefits and costs experienced today with those experienced in the very distant future. This may lead to situations where the current generation makes excessive sacrifices to future generations (Lopez et al. 2006). A major reason for discounting future benefits and costs is the expectation that future generations will be better off economically than present generations (Maddison 2001). Yet given the limitations on future growth imposed by resource constraints, we may experience a period of near zero real economic growth. In that case, a discount rate of zero or close to it may be justified depending on the time period of analysis.

Setting the discount rate to a constant above zero. Setting a nonzero discount rate can have equally unacceptable consequences by making catastrophic outcomes in the distant future appear trivial at today's decision point, potentially biasing decisions against the interests of future generations (McMichael and Campbell-Lendrum 2003). Moreover, there is no consensus as to which discount rate to use (Weitzman 2001). This is problematic because widely varying policy decisions can be defended depending on the particular rate selected, posing a major challenge for analysis. One approach is to use several plausible rates to identify policies that are robust to the choice of rate (Lopez et al. 2006; Markandya et al. 2009; McKinley et al. 2005). Yet because of the strong sensitivity to the discount rate chosen, few policies may indeed be robust, and the benefits or costs may differ by large factors. For instance, in a model examining low-carbon electricity generation scenarios achieved through different degrees of emissions trading, Markandya et al. (2009) found that when the discount rate applied to lost life-years was increased from 0% to 3%, the estimated health co-benefits of low-carbon electricity generation scenarios were reduced by about 50%.

Setting variable discount rates. Some argue that a declining discount rate, which attaches increasing weight to the welfare of future generations, better reflects empirical data on individual preferences and is in agreement with various theoretical results (Dasgupta 2001; Heal 1997; Newell and Pizer 2003; Pearce et al. 2003; Reinschmidt 2002; Weitzman 2001). Although full hyperbolic discounting has not been supported by policy makers, there is a move toward declining discount rates driven by the dynamic uncertainty of future events (Pearce et al. 2003). Declining discount rates imply, for example, discounting benefits and costs that occur over the next 30 years at one rate, followed by a lower rate for benefits and costs that occur over the following 30 years and so on.

As an alternative to explicit discounting, some efforts instead use time horizons for certain terms, producing the odd result where consequences (i.e., costs or benefits) of an emission are accrued only up to a point, after which additional costs are ignored (Smith and Haigler 2008). Some have argued that smooth annual discounting functions are more sensible than the step-functions implied by such time horizons, such as those used to express the warming "costs" of an emission (Smith and Haigler 2008). Others argue that the various components common to co-benefits modeling should be discounted at different rates (Brouwer et al. 2005; Gravelle and Smith 2001).

Discount rates and their associated assumptions should be explicitly addressed in co-benefits research. For a particular intervention with both climate and health effects, rates must be specified for the costs of intervention (U.S. dollars), the impact on the global climate (tCO_2; tons of carbon dioxide and other climate-active equivalents), the health effects (DALYs or QALYs) and the monetized health benefits (U.S. dollars), as discussed by Smith and Haigler (2008). Where available, locally estimated discount rates that reflect the specific values of affected populations should ideally be used. But because these are rarely available, and because there is no consensus on the selection of universal rates, an alternative approach would be to present results using several rates, including 0% and 3%, preferred values used by policy makers. Examining the implications of declining rates (HM Treasury 2003) would also be worthwhile.

Evaluating mitigation options using decision analysis. Accounting for potential health impacts of mitigation strategies is important, but many impacts unrelated to health exist, and policy makers require that alternative mitigation strategies be evaluated on the basis of many criteria simultaneously (Konidari and Mavrakis 2007; Swart et al. 2003). Valuation methods capable of considering trade-offs among multiple cost and benefit criteria under uncertainty are thus more likely to be policy relevant. To that end, the quantitative information on health criteria must be considered alongside nonhealth criteria, including economic growth, environmental sustainability, political acceptability, cost and financing considerations, expediency, and equity issues. Each of these can in turn be divided into detailed subcriteria, resulting in a deep hierarchical structure that defies single-criterion analytical approaches. For example, a cost and financing criterion could have subcriteria that include implementation costs, health services costs from changes in disease burden, opportunity costs of capital or land, and so forth. The performance of a mitigation strategy is unlikely to be positive (or negative) across all such criteria, and comparing short-term performance on certain criteria to long-term performance can raise important ethical questions—such as how should policy makers treat a renewable energy strategy that lowers short-term economic growth (and is thus temporarily detrimental to health because of reduced employment), but increases net health over the long-term from reduced pollutant emissions? Other ethical questions are raised by the fact that multiple criteria can at times represent competing stakeholder interests, such as a policy substituting active transport for single-occupancy vehicle use that reduces health costs while also decreasing revenues in the automotive sector.

The importance of consistent summary measures. Decision makers manage considerable complexity in part by determining which criteria are most relevant. At the same time, having a few summary or principal measures that are used consistently to assess different strategies greatly improves comparability. For example, a common measure for evaluating and comparing health co-benefits across alternative mitigation strategies and across countries is the health burden (DALYs) avoided, expressed per unit population size and per $MtCO_2$ saved (Smith and Haigler 2008). Another useful and widely used measure is the net cost per ton of GHG emissions reduced. Many of the relevant outcomes, including health impacts, can, in principle, be converted into a monetary cost (Creutzig and He 2009). These costs can then be added to, or netted out, from the direct costs of the mitigation measures, giving a net cost figure per ton reduced. In calculating the measure, analysts face the problems described above (e.g., discounting, uncertainty), but the resulting information, partial as it is and with all its qualifications, is useful in deciding where to allocate scarce resources. The direct costs of mitigation may be, for example, US\$30/tCO_2, but when health co-benefits are accounted for, the figure may drop substantially or even become negative (i.e., result in net savings).

Multicriteria decision analysis (MCDA). Several decision analytical methods can be used to compare and evaluate alternative mitigation options in terms of their health and nonhealth impacts. These include traditional cost–benefit and cost-effectiveness methods used for environmental interventions (Haller et al. 2007; Hutton 2008). Because the impacts of mitigation are often multidimensional, more complex measures—and analytical methods—are needed for evaluating trade-offs. MCDA approaches have been used for this purpose in some policy areas, and their application to climate change policies is gaining momentum (Bell et al. 2001, 2003; Benegas et al. 2009; De Bruin et al. 2009; Kueppers et al. 2004; Stalpers et al. 2008; Wilbanks 2005).

There are unresolved issues in the application of MCDA methods to valuation of mitigation strategies. Traditional MCDA assumes that all criteria are evaluated at the same point in time. When comparing mitigation strategies where health is one of the criteria, assigning a relative weight to the health co-benefits criterion can be difficult because the immediate reduction in hazardous exposures does not often produce immediate health benefits (Jarrett et al. 2012; Wilkinson et al. 2010) (Table 2). This time course can be very different from those of the impacts of other criteria. In addition, because uncertainty increases into the future, issues surrounding attitudes toward risk (in the presence of uncertainty) and time preference become intertwined, complicating discount rate choices (Traeger 2009).

Strategies to extend the model domain and policy utility. Future directions for modeling co-benefits include enhancing policy relevance, addressing policy resistance, and characterizing implementation (including diffusions of new behaviors and technical shifts). Literature in recent years with respect to policy relevance highlights the importance of iteration between scientists and policy makers in developing usable science (Dilling and Lemos 2011). The National Oceanic and Atmospheric Administration (NOAA) Regional Integrated Science and Assessments (RISA) program is an example focused on climate change adaptation. RISA works with diverse user communities to advance contextual understanding of adaptation policy and management decisions; to develop knowledge on impacts, vulnerabilities, and potential response options; and to facilitate decision support tool development (NOAA 2012). Such an approach also may be particularly well suited to facilitating mitigation policy decisions.

"The counterintuitive behavior of social systems" (Forrester 1971) or "policy resistance" arises when policies that affect complex, dynamic systems result in unexpected outcomes, such as antibiotic resistance as a result of aggressive infection control or increased wildfire severity as a result of fire suppression (Sterman 2000). Systems dynamics methods (Sterman 2006) alone or in concert with other approaches such as discrete event simulation (Brailsford et al. 2010) can increase the likelihood of effective policy formulation (Thompson and Tebbens 2008) by addressing feedback loops that affect policy resistance. Many health co-benefit analyses characterize the health impacts of societal changes, such as widespread adoption of active transport policies or significant shifts in consumption of animal products, without a detailed consideration of how implementation might occur (e.g., Friel et al. 2009; Woodcock et al. 2009). Approaches such as agent-based modeling can help characterize diffusions of such innovations within populations and the role of organizations in catalyzing and maintaining significant policy shifts (Bonabeau 2002).

Conclusions and Recommendations

Estimating the health impacts of GHG mitigation strategies is a complex process that brings together disparate disciplines. Because all models are simplifications that involve assumptions, are subject to many uncertainties, and capture a subset of interactions, modeling health co-benefits requires systematic consideration of the suitability of model assumptions, of what should be included and excluded from the model framework, and how uncertainty should be treated. The ultimate goal of modeling is policy utility, and it is important for modelers to iteratively engage policy makers actively in their work. Despite the challenges, there is a great need for information on the health implications of mitigation strategies, particularly given the urgency of bringing mitigation strategies into practice and the early accrual of ancillary health impacts of these strategies. Here we have reviewed some of the challenges and controversies in modeling health co-benefits and co-harms, and some approaches to increase their utility. Recommendations to improve such models include the following:

- Modeling health co-benefits should be done in concert with policy makers from the start, and should focus on potentially feasible interventions based on policy-maker consultation; identification of policy-relevant outcomes; and incorporation, where needed, of methods to evaluate potential policy resistance. Model scoping should include consultation with policy makers and scientists from a range of disciplines to ensure that a full complement of potential impact pathways is considered. Focusing on domains and channels wherein modeling was used to affect policy may increase the potential utility of modeling efforts.
- Initial stages of analysis should identify the full range of potential positive and negative pathways to health impacts within predefined boundaries, as well as the critical uncertainties in these causal pathways, while making explicit the criteria used to determine which exposure–outcome relationships are included in the model. The assessment of the strength of evidence for exposure–outcome relationships and parameters should use systematic review (Moher et al. 2009) and consensus methods (Guyatt et al. 2008).
- The period over which the mitigation and health impacts are analyzed must be carefully assessed, both in relation to the time course between implementation of mitigation and consequent impacts, and in relation to time preferences for specific outcomes and the associated choice of discount rates. At a minimum, valuation estimates should be presented using a range of fixed discount rates including 0% and 3%, and consideration should be given to estimates using declining rates over time.
- Uncertainty in modeling results should be characterized explicitly, using quantitative and qualitative methods as appropriate. Both parametric and structural uncertainties should be considered, and at a minimum, single (and when possible multivariate) deterministic sensitivity analyses should be carried out.
- Scientists modeling health co-benefits should explicitly consider consulting with or including decision analysis experts to ensure that the results are useful in formal decision analysis processes. Such collaboration should be initiated at the inception of the modeling effort and should anticipate the ultimate application of the modeling results.

By improving the quality and rigor of health co-benefits analyses, critical decisions regarding climate mitigation strategies can be informed by health impact estimates, aiding policy makers in their efforts to maximize GHG mitigation potential while simultaneously improving health.

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RPR Review of Policy Research

The Era of State Energy Policy Innovation: A Review of Policy Instruments

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Abstract

U.S. energy and climate policy has evolved from the bottom-up, led by state governments, and internationally recognized for the use of unconventional and innovative policy instruments. This study focuses on policy instruments adopted throughout the era of state energy policy innovation that aim to diversify, decentralize, and decarbonize the electricity sector. Specific attention is devoted to the renewable portfolio standard, net metering, interconnection standards, tax incentives, public benefit funds, and energy efficiency resource standards. This analysis synthesizes the findings from the energy policy literature and provides a summary of the current state of understanding about the effects of various state energy policy instruments, and concludes with a discussion of broader trends that have emerged from the use of policy instruments in the state energy policy innovation era.

KEY WORDS: energy, environment, climate change, governance

Introduction

The U.S. electricity sector is a major contributor to global climate change. The sector accounts for roughly 40 percent of total U.S. carbon dioxide emissions and 30 percent of all U.S. greenhouse gas emissions. The majority of these emissions come from large, centralized fossil fuel plants, which generate the bulk of U.S. electric power. Alternative sources of electricity, such as renewable energy, make up only a small fraction of the total electricity mix. As the global understanding of climate change and its potentially substantial ecological effects evolves (Intergovernmental Panel on Climate Change [IPCC], 2007; Mann, Bradley, & Hughes, 1999; Nordhaus, 2010; Spielhagen et al., 2011), an increasing number of scholars, policy makers, and citizens have raised questions about the prudence of such heavy reliance on fossil fuel-based energy. As these concerns arise and gain popular support, and become compounded by other significant concerns related to energy production and consumption—including but not limited to energy security (Li, Jenkins-Smith, Silva, Berrens, & Herron, 2009; Löschel, Moslener, & Rübbelke, 2010), air pollution (Anderson et al., 2008; Bollen, Hers, & van der Zwaan, 2010), and fuel price volatility (Bolinger & Wiser, 2009; Fuss & Szolgayová, 2010)—the perceived need for a change in electricity generation and operations grows.

In response to the large number of these concerns over the past decade, and a growing consensus that the combination of these issues may require public policy solutions, state governments across the country have assumed leadership roles in the energy policy arena (Rabe, 2006). In the absence of a comprehensive federal congressional initiative to address climate change, states have introduced, on a piecemeal basis, a number of new policy instruments in an attempt to decrease their carbon footprints, increase the percentage of renewable energy in their generation portfolios, and increase the amount of generation that comes from local, dispersed energy resources. In fact, these three policy objectives—decarbonization, diversification, and decentralization—have broadly defined and guided state energy and climate policy efforts to date.

Standard policy instruments, such as a grant or tax incentive, are not well suited to deal with problems as substantial and difficult to measure as global warming or overdependence on fossil fuels; nor are they suited to deal with an industry in which private and public firms share a market, regulated and deregulated systems share power lines, utility service territories are not confined by state borders, utility development decisions last decades, and price signals cannot be observed when the consumer purchases electricity. In light of these challenges, state governments have exhibited immense creativity over the past 15 or so years in designing new and tailoring existing instruments to meet current circumstances.

Some states have already experienced notable success with the implementation of these instruments. Texas, for instance, has increased wind energy deployment significantly as a result of its Renewable Portfolio Standard (RPS) (Langniss & Wiser, 2003; Rabe, 2006), which requires that 5,880 MW of Texas's energy capacity come from renewable energy sources by 2015 (North Carolina Solar Center, 2011); installed capacity in the state increased by 2,292 MW in 2009 alone (Wiser & Bolinger, 2010). However, aside from Texas and a few other success stories, the policy literature has been slow to assess whether energy policy instruments are effectively achieving their stated objectives. This void in the literature is due to the difficulty of measuring state-level energy policy effects, further attributable to the complexity and variation of the instruments across states, the patchy nature of their state-by-state adoption, and the long time frame over which policy results become measurable. However, in recent years, both the number and the sophistication of empirical studies on state energy policies has grown, a synthesis of which could provide lessons to other states regarding how these instruments work, which ones are effective in what circumstances, and which ones work well together. This type of information will become increasingly important as the federal government's discussions of energy and climate policy evolve, and as steps are taken on the national level to address the policy concerns listed above.

After roughly a decade and a half of state leadership in energy and climate policy, specifically with the intent to impel the diversification, decentralization, and decarbonization of the energy sector, what have we learned about the effects and effectiveness of state policy tools in the U.S. electricity sector? What lessons can be extracted about the use of policies that have shaped the era of state energy policy innovation and what do these lessons suggest about the role of state energy policy in the U.S. electricity sector? This analysis seeks to synthesize the findings from the literature and provide a summary of the current state of understanding of state energy policy instruments and their role within the era of state energy policy innovation.

The narrative begins with a narrowly focused discussion on individual policy instruments, including the RPS, net metering policies, interconnection standards, public benefit funds (PBFs), energy efficiency portfolio standards, and tax incentives (see Table 1 for a visual of which states have each policy instrument, as of January 2011). The discussion in this section aims to balance a micro and a macro perspective on each of these instruments, without delving too deeply into the intricacies of each instruments' design or assuming a 1,000-ft aerial view. In order to keep this balance, the discussion focuses on general lessons about how these

Table 1. Policy Instruments Active in Each State (as of January 2011)

State	RPS [1]	Net Metering [1]	Interconnection Standards	Tax Incentives [2] [3]	PBF [3] [4]	EERS [5]
Alabama				P		
Alaska		X		K		
Arizona	X	X	X	P, C, S, K		X
Arkansas		X	X			X
California	X	X	X	K	RE, EE	X
Colorado	X	X	X	S, S*, K	RE*, EE*	X
Connecticut	X	X	X	S, K	RE, EE	X
Delaware	X	X	X		RE, EE	X
Florida		X	X	S		X
Georgia		X	X	P, C, S		
Hawaii	X	X	X	P, C	RE, EE	X
Idaho				P, S, K		
Illinois	X	X	X	S, K	RE, EE	X
Indiana		X	X	P, C, K		X
Iowa	X	X	X	P, C, S, K		X
Kansas	X	X	X	P, C, K		
Kentucky		X	X	P, C, S		
Louisiana		X, *	X	P, C, K		
Maine	X	X	X	S	RE, EE	
Maryland	X	X	X	P, C, S, K, K*		X
Massachusetts	X	X	X	P, C, S, K	RE, EE	X
Michigan	X	X	X	P, K	RE, EE	X
Minnesota	X	X	X	S, K	RE	X
Mississippi						
Missouri	X, *	X	X	P, C, S		
Montana	X	X	X	P, C, K	RE, EE	
Nebraska		X	X	S		
Nevada	X	X	X	S, K		
New Hampshire	X	X	X	K	EE	
New Jersey	X	X	X	S, K	RE, EE	
New Mexico	X	X	X	P, C, S, K	EE	X
New York	X	X	X	P, C, S, K, K*	RE, EE	X
North Carolina	X	X	X	P, C, S, K		
North Dakota	X	X		P, C, K		
Ohio	X	X	X	C, S, K, K*		X
Oklahoma	X	X		P, C		
Oregon	X	X	X	P, C, K	RE, EE	
Pennsylvania	X	X	X	K	RE, EE	X
Rhode Island	X	X		P, C, S, K	RE, EE	X
South Carolina			X	P, C, S		
South Dakota	X		X	S, K		
Tennessee				K		
Texas	X, *		X	C, S, K		
Utah	X	X	X	P, C, S		
Vermont	X	X	X	P, C, S, K	RE, EE	X
Virginia	X	X	X	P, S, K		
Washington	X	X	X	S		
West Virginia	X	X	X	P, C, K		
Wisconsin	X	X	X	P, C, S, K	RE, EE	
Wyoming		X	X	S		
District of Columbia	X	X	X		RE, EE	

Source: North Carolina Solar Center (2011).

Notes: Separate marks accompanied by asterisks indicate local policies. Includes states with separate EERS. Hawaii's EERS detaches from its RPS in 2015.

*Indicates a local policy; individual marks used for each.

X, state policy; P, property tax incentives; C, corporate tax incentives; S, sales tax incentives; K, property tax incentives; RE, renewable energy-related public benefit funds; EE, energy efficiency-related public benefit funds; EERS, energy efficiency requirements; RPS, Renewable Portfolio Standard; PBF, public benefit fund.

instruments work and whether they achieve the objectives for which they are intended, and identifies possible policy measures that may improve the efficacy of these instruments in operation. Next, the discussion turns to the potential for complementary use of a variety of these instruments. It concludes with a discussion of broader trends that have emerged in the state energy policy innovation era, and suggests avenues of future research.

Policy Instruments

Renewable Portfolio Standard

This analysis begins with a discussion of RPSs because they are one of the most popular state policy instruments, and they epitomize the complex and innovative policy design that is indicative of modern state energy policy instruments. The lessons about the effects and effectiveness of RPS policies lend a great number of insights on the role of public policy in state electricity markets. Refer to Figure 1 for a visual representation of state adoption over time. The figure lists states by the date in which an RPS became effective.

Several scholars have studied the motivations for RPS adoption and identified a number of factors empirically associated with adoption rates. The results of recent scholarship are not entirely consistent, but they do offer some common threads in the search for significant factors. Lyon and Yin (2010), for instance, point to the significance of local air pollution; local renewable potential, especially wind power; and lobbying influence of local renewable energy producers in the framing of policy choices (this last finding is also highlighted by Rabe, 2006). Matisoff (2008) concurs about states with wind potential, and about the relevance

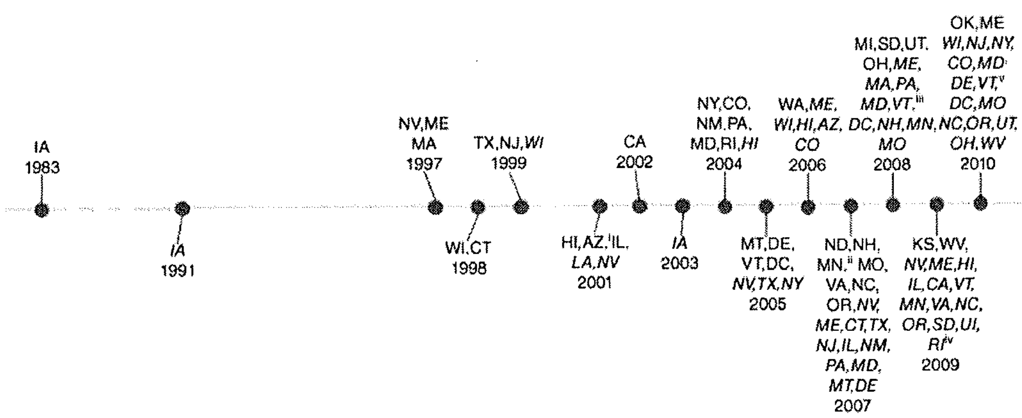

Figure 1. Timeline of RPS Adoption
Note: Dates represent when policies were enacted by legislatures. Bolding indicates initial enactment and italicization indicates revisions.
Source: North Carolina Solar Center (2011) and Carley (2009b). (i) The date of enactment of Arizona's original Environmental Portfolio Standard is not listed by North Carolina Solar Center (2011). (ii) Before this RPS, Minnesota had wind and biomass capacity mandates for Xcel Energy. (iii) The 2008 revisions added consumption- and production-based goals to this program. (iv) This is a different standard than the RPS and is capacity-based. (v) Legislation from 2010 mandates that the Vermont Public Service Board investigate an RPS (see note iii). RPS, Renewable·Portfolio Standard.

of air pollution, but also finds significance in gross state product per capita, as does Chandler (2009). Huang, Alavalapati, Carter, and Langholtz (2007) and Lyon and Yin (2010) both emphasize the significance of a factor not related to either environmental or economic impact, as well: partisan control of a state's legislature. Chandler (2009) attributes weight to an equally political, but somewhat more nuanced factor, state-level citizen ideology (Berry, Ringquist, Fording, & Hanson, 1998), which incorporates interest-group ratings of Congressional representatives, estimated ideologies of challengers, vote weights by district, and the nonlinear distribution of legislative power by party.

To date, the literature has documented a variety of RPS effects. Palmer and Burtraw (2005) and Kydes (2007) found that RPS policies effectively increase renewable energy generation, which primarily offsets or displaces natural gas generation, for a net total reduction in carbon dioxide emissions. Kydes also found that a national 20 percent RPS mandate raises electricity prices by 3 percent. Fischer (2006) found that price effects from RPS policies may vary, the direction and magnitude of which depends on the elasticity of renewable resource supplies, relative to the elasticity of alternative, nonrenewable resources. Wiser, Namovicz, Gielecki, and Smith (2007) found that to date, price effects due to RPS policies have been minor, but demonstrate great variation across states. Some, albeit anecdotal, evidence suggests that RPS policies may actually contribute to decreasing electricity costs in a few states (Wiser et al., 2007), a finding also made by Chen, Wiser, and Bolinger (2007) based on a review of 28 RPS cost-impact modeling analyses.

RPS effectiveness studies have established that some states have experienced great success with their RPS mandates (Langniss & Wiser, 2003; Rabe, 2006). Studies that consider the varied experiences of all states conclude that RPS policies are effective drivers of renewable energy development and generation (Bird et al., 2005; Carley, 2009b; Menz & Vachon, 2006; Rabe, 2006; Yin & Powers, 2010). RPS policies may increase renewable energy generation, but they have been identified by some (Bushnell, Peterman, & Wolfram, 2007; Carley, 2009b, 2011; Michaels, 2007; Rabe, 2008) as being inefficient in the achievement of other outcomes, such as a reduction in greenhouse gas emissions, a switch from conventional fossil fuels to less carbon-intensive fossil fuel generation sources, or a reduction in energy demand. These findings reveal that RPS policies may not be well suited to achieve multiple policy objectives simultaneously, such as the diversification, decentralization, *and* decarbonization of the electricity sector. Yet RPS policies are currently used by many states as a policy tool to achieve all three of these objectives.

Taking these three objectives separately, let us first consider how effective an RPS policy is at achieving diversification objectives. Carley (2009b) found that RPS policies effectively increase in-state renewable energy generation, but have yet to significantly increase in-state percentages of renewable energy electricity out of total state generation portfolios. These results confirmed others' findings: RPS policies are effective at encouraging renewable energy development, but not all states are able to translate RPS mandates into renewable energy percentage growth (Cory & Swezey, 2007; Wiser et al., 2007; Wiser, Porter, & Grace, 2004), and not all states are on the path toward meeting their RPS benchmarks (Rabe, 2008). Reasons for these shortcomings include several possibilities: enforcement mechanisms and penalties for noncompliance are too weak or ambiguously stated; states alter legislation frequently; states are not making efforts to decrease or hold steady fossil fuel generation; or states are not making efforts to decrease or hold steady total demand for electric generation.

It is possible that the inability of RPS policies to increase the share of renewable energy is due to poorly structured design features. It is also possible, however, that, although RPS policies are one of the main drivers of renewable energy generation and consequently electricity diversification, additional factors are needed to actually increase the share of renewable energy generation. Some of the most significant factors in this development involve political capacity and support of energy and environmental policy efforts (Carley, 2009b; Doris, McLaren, Healey, & Hockett, 2009; refer also to policy adoption scholars that emphasize political and citizen ideology, including Chandler, 2009; Huang et al., 2007; Lyon & Yin, 2010). Legislative support for environmental policies and bureaucratic capacity in natural resource management both assist in the growth of the percentage of renewable energy. Additionally, strong coal and petroleum interests diminish the pace of renewable energy development (Carley, 2009b).

In consideration of the decentralization potential of RPS policies, studies demonstrate that RPS policies have had mixed effects on the adoption and deployment of distributed generation systems (i.e., small-scale, localized energy systems). Carley (2009a) found that individuals in states with an RPS policy are more likely to install distributed generation units than individuals in states without an RPS policy. Out of all utilities with some distributed generation, however, those in states with RPS policies deploy less distributed generation than those in states without RPS policies. The latter finding reveals that small-scale energy systems may compete with large-scale renewable energy facilities for utility attention and resources, a finding that is also drawn by Forsyth, Peden, and Gagliano (2002) for the case of Minnesota. When a utility is mandated to meet renewable energy benchmarks, it will likely prioritize large-scale renewable energy development over distributed generation development. Doris and others (2009) suggest that states should require that utilities take customer-owned distributed generation to satisfy RPS mandates if all other requirements are met.

Finally, in consideration of the decarbonization potential of RPS policies, studies demonstrate mixed results. As already discussed, Palmer and Burtraw (2005) and Kydes (2007) found that RPS policies increase total renewable energy and, as a result, also decrease carbon dioxide emissions. Palmer and Burtraw also conclude, however, that a national RPS policy is not the most effective policy tool for reducing carbon emissions. They argue that a cap-and-trade policy is a more effective policy instrument at achieving carbon emissions. Fischer and Newell (2008) similarly find that a carbon price is the most efficient policy instrument, relative to a renewable portfolio requirement, among other climate and energy policies, when the policy objective is to reduce carbon emissions. An electricity dispatch modeling exercise, aimed at assessing the decarbonization potential of state-level RPS policies found that an increase in renewable energy generation does not necessarily translate into a significant decrease in greenhouse gas emissions (Carley, 2011). This study found that when surrounding states do not have RPS regulations, a state with an RPS may continue to generate its excess, more carbon-intensive fossil fuel power and sell it to neighboring states.

RPS benchmarks are not designed to perfectly match demand projections. That is, states do not calculate the amount of additional capacity they will need by a certain year, and then mandate that all of that capacity be met by renewable energy. As a result, renewable sources of energy do not simply replace any new capacity that would otherwise have to be built. Nor does it reduce demand for energy. Instead, new renewable energy capacity is intended to replace a portion of fossil fuel capacity that already exists. But are states actually replacing this capacity? So long as surrounding states to a state with an RPS policy do not have similar regulations, retirement of older, less efficient, and more carbon-intensive power plants may not occur (Carley, 2011). As Bushnell and others (2007) explain, "although the regulator can force its local firms to buy 'clean' products, it can't keep firms in other states from buying the 'dirty' products that the firms in the regulated states used to buy." These findings reaffirm those made by Rabe (2008), which is that RPS policies may effectively increase total renewable energy generation but are inefficient policy tools for decarbonization objectives.

An RPS is an appealing state policy instrument for a number of reasons. Of notable importance, RPS policies demonstrate great political feasibility (Rabe, 2006, 2008): they come with no explicit price tag[1]; the benchmarks start off mild and ramp up over the course of one or two decades; they aim to incentivize renewable energy, not tax the use of fossil fuels; the potential economic development benefits appeal to a broad coalition of political support (Rabe, 2006); and they are a popular "symbol" (Bushnell et al., 2007) to indicate a concern about business as usual energy and climate trends. RPS policies are often presented as a cost-effective option to help the renewable energy industry grow and help individual technologies become cost-competitive with conventional sources of fossil fuel energy. However, the supporting literature, as discussed above, reveals that RPS policies also have several disadvantages. First, having an RPS policy is not enough to significantly increase the percentage of renewable energy generation across states, at least given current RPS designs. Second, an RPS policy that is designed to increase the share of renewable energy generation will have limited ability to achieve multiple objectives simultaneously. Third, and closely related to this last point, RPS policies, as implemented at the state level, are also unable to prevent carbon leakage across state borders.

In light of these findings, how could one improve the functionality and efficacy of an RPS policy? Given that an RPS is designed, by its very nature, to increase renewable energy, as well as the percentage of renewable energy out of the total generation mix, it is most constructive to first consider how to improve an RPS policy's ability to affect renewable energy deployment. Several authors (Cory & Swezey, 2007; Doris et al., 2009; Wiser et al., 2004, 2007) recommend mechanisms for improvement of RPS efficacy, beyond political support and institution building, including the following design features.

- *RPS benchmarks* should be achievable and predictable, and ramp up steadily over time.
- *Program duration* should last long enough (i.e., multiple years) that it allows long-term contracting and financing to develop.

- *Compliance periods* should last a year or more so as to accommodate seasonal variations in renewable energy generation.
- *Participation* should be mandated for all load-serving entities, including public utilities.
- *Resource eligibility* should be clearly defined for all resources; new renewable energy generation should be prioritized over existing renewable generation.
- *Built-in flexibility* can be achieved via tradable renewable energy credits (RECs), which should involve a tracking mechanism.
- *Double counting* between REC markets and other voluntary green energy markets should be discouraged, if not outlawed.
- *Enforcement mechanisms* should be clearly defined and strictly enforced.
- *Costs* of RPS compliance should be equitably spread across all types of end-users.[2]
- *Exemptions* should be limited and cost cap language should be omitted from RPS legislation.

In the event that a state, or the national government, decides to pursue multiple electricity market objectives simultaneously, one may secondarily consider how to construct "carve-out" provisions in RPS policy design that further incentivize or, more accurately, mandate additional types of resources, such as certain distributed generation units, energy efficiency, or less carbon-intensive fossil fuels. Indeed, many states have done this, including Pennsylvania, which includes waste coal, coal mine methane, and coal gasification in its list of eligible RPS renewable energy sources. Some states have altered their RPS legislation after a couple of years with carve-out provisions, which allows for greater flexibility and an enhanced scope of RPS objectives. However, the more carve-out provisions made to specifically isolate and incentivize other technologies (e.g., poultry waste in North Carolina) or pursue other objectives entirely (e.g., energy efficiency provisions for the sake of decarbonization), the more expensive and less cost-effective—and potentially inefficient—this policy option becomes (Rabe, 2008). Therefore, instead of asking how one can improve the functionality and efficacy of an RPS policy to serve multiple objectives, perhaps one should ask whether there are more efficient policy tools that can complement an RPS policy, but specifically target a different objective(s), such as decentralization or decarbonization. Several authors have suggested that RPS policies may be more effective when implemented in conjunction with a carbon price and other supporting instruments (Carley, 2011; Doris et al., 2009). Fischer and Newell (2008) also demonstrate empirically that an "optimal" policy portfolio, comprised of both climate and energy policy instruments, is the least costly way to achieve carbon restrictions.

It is highly probable that, even despite the use of multiple policy instruments, each of which is focused on a different market failure, RPS policies will continue to encourage emission leakages across state or regional borders. The cause of leakage is attributable to the scale on which the policy instruments are applied (Bushnell et al., 2007). Electricity transactions—or "power flows"—are not limited to state borders, nor are the effects of greenhouse gas emissions. It should come as no surprise therefore that policy instruments that are implemented on the state scale but inconsistent across state borders, no matter how innovative or flexible the instruments, cannot control the leakage of electricity or emissions across state lines. Until states adopt consistent and coordinated regulations, or the national government adopts a federal RPS, state-level free-riding will likely continue. A national RPS policy, however, could have the combined benefits of correcting the market distortions associated with carbon leakage and state free-riding, and create uniformity and, in turn, predictability in renewable energy markets across the entire country (Cooper, 2008).[3]

Net Metering and Interconnection Standards

Net metering and interconnection standards are two of the most commonly adopted energy policy instruments, both of which have grown significantly in popularity in recent years. In 2005, 39 states had net metering standards and 28 states had interconnection standards. As of January 2011, 43 states have state-mandated net metering policies and three more have voluntary utility net metering programs (North Carolina Solar Center, 2011); 41 states have interconnection standards.[4] See Figure 2 for a timeline of state net metering and interconnection standard adoption.

One of several advantages to net metering and interconnection standards, relative to other energy policy instruments, is that they place the "economic burden on the private utility industry . . . at little or no cost to the state" (Stoutenborough & Beverlin, 2008; for a more extensive discussion of the advantages to these policy instruments see Network for New Energy Choices [NNEC], 2008, and Doris et al., 2009). Stoutenborough and Beverlin (2008) analyzed other factors that motivate the adoption of net metering programs and found that state ideological preference, state renewable energy potential, and degree of democratic legislative control all affect the decision to adopt net metering protocols.

The literature on net metering and interconnection standards is not particularly extensive; but there is general agreement among the applicable studies that both policy instruments have significant potential to remove the barriers to the adoption and deployment of distributed generation (DG) systems and, thereby, encourage the decentralization of the electricity market. In the only empirical analysis, to the author's knowledge, on the effectiveness of these instruments, Carley (2009a) considered the role of net metering and interconnection standards in motivating the decision of both utilities as well as utility customers to adopt and deploy distributed generation. Her empirical results demonstrated that net metering standards reduce the technical barriers to DG deployment and make DG adoption on the customer side of the meter more likely. Interconnection standards were also found to be a primary motivating factor behind customer DG adoption. These results demonstrate that integrated and consistent protocols for electricity interconnection—including connecting equipment, standard tariff payment schemes, and power quality characteristics—reduce costs and bureaucratic hassles associated with customer DG hook-ups.

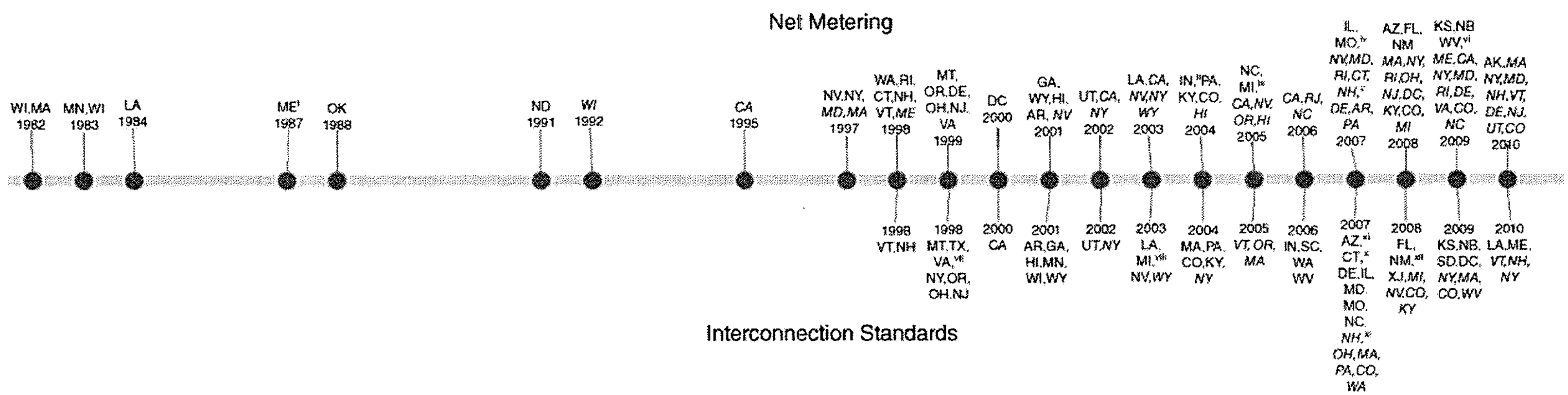

Figure 2. Timeline of Net Metering and Interconnection Standards Adoption

Note: Dates represent when policies were enacted by legislatures. Bolding indicates initial enactment and italicization indicates revisions.

Source: North Carolina Solar Center (2011). (i) Net metering was also available from 1987 to 1998. (ii) Rule revisions were underway as of 2010. (iii) A voluntary consensus agreement was approved by the Public Service Commission in 2005; net metering rules were mandated by law in 2008. (iv) Dual metering was mandated earlier for some utilities. (v) This represents the effective date of the amendments. (vi) Prior to this date, the Public Service Commission, "approved consensus filings" in 2006, effective 2007. (vii) These standards were amended later. (viii) The Public Service Commission adopted DG interconnection standards in 2003; legislation enacted in 2008 led to further interconnection standards. (xi) This DG interconnection standards rulemaking started in 2007 and is not yet finished. (x) Prior authority existed under Connecticut statutes. (xi) This represents the effective date of the amendments. (xii) Standards existed prior to this date. DG, distributed generation.

Carley also discovered that customers who are interconnected to the electric grid via net metering use a greater proportion of renewable energy-based DG than do utilities. Slightly less than half of the customer owners in her 2005 sample used renewable DG, whereas less than 25 percent of utility owners used renewable DG. These findings indicate that, although both utilities and their customers are involved in the movement toward more decentralized electricity, customer owners play a more prominent role in renewable DG development.

Forsyth and others (2002) found that in some states net metering policies alone may not be enough to effectively encourage customer adoption of distributed wind systems. Employing a case study approach of ten U.S. states with net metering policies, Forsyth et al. concluded that without extra incentives or educational programs to encourage and inform customers of DG options, respectively, DG deployment rates may remain low. Since this study was published in 2002, net metering and interconnection standard adoption rates have increased significantly, as have DG deployment rates. It is possible therefore that additional DG incentives may be less necessary for high DG deployment rates than they were previously.

One of the main cited weaknesses of net metering and interconnection standards is that some states set system capacity limits too low, which excludes many potential system owners and operators from interconnection to the electric grid (Doris et al., 2009; Forsyth et al., 2002; NNEC, 2008). For instance, the state of Indiana only allows DG systems that are 10 kW or smaller (North Carolina Solar Center, 2011) to fit within net metering protocols. These system capacity limits particularly affect decisions that commercial and industrial customers—who tend to have larger electric loads and therefore require greater DG capacity—make about whether to invest in DG and, if so, which size to purchase and whether to hook it to the grid. The obvious solution to this problem is to increase the capacity limit, and allow customers to hook systems to the grid that can satisfy their entire load, which may be up to or greater than 2 MW for some commercial or industrial customers. Doris and others (2009) also suggest that interconnection standards be made less rigid for smaller, simpler DG units, and more complex and rigid for larger units. These same authors also recommend "breakpoints" for interconnection, wherein different system sizes fall into different categories of standards; Doris et al. recommend the following breakpoint categories: 10 kW, and 2, 10, and 20 MW.

Additional mechanisms that states may adopt that have the potential to improve the effectiveness of net metering and interconnection standards include the following:

- The prohibition or limitation of the interconnection charges that utilities require from DG owners;
- The limitation of other fees, including insurance and engineering fees, and making these fees fully explicit and transparent to potential DG owners;
- The expansion of net metering or interconnection regulations to include all utilities, including public utilities;
- The allowance of "roll over" of excess generation, in which the utility carries forward any excess generation until it is consumed or expended by the end-user;

- The removal of restrictions on different classes of electricity end-users;
- The restriction of unnecessary and costly safety measures imposed by utilities, such as an external disconnection switch. Refer to NNEC (2008) and Doris and others (2009) for additional insights on the best practices and ways to improve net metering and interconnection standards.

It is clear that state-level net metering and interconnection standards are effective decentralization policy instruments, particularly when the design features seek inclusionary and nondiscriminatory practices and when paired with other incentives mechanisms for distributed generation. However, are these DG policy instruments also able to serve diversification and decarbonization objectives? Both standards effectively help shift the balance of resources—albeit slight in magnitude—toward more decentralized and less centralized sources. Thus, DG policy instruments do perpetuate a diversity of energy technologies and resources. However, when a utility is faced with both an RPS and DG standards, the RPS mandate has the potential to "trump" the DG instruments and reduce their effects on distributed generation adoption. In this case, RPS policies are the main drivers of diversification, and net metering and interconnection standards play a less prominent role in the diversification of the electricity sector.

In consideration of the DG instruments' decarbonization potential, it is important to bear in mind which types of fuel DG systems tend to use—distillate oil, natural gas, or various renewable fuels. All of these sources are less carbon-intensive than coal, which is the primary source of electricity in the United States. If net metering and interconnection standards motivate the adoption of DG units, and these systems replace power that would otherwise be generated from more carbon-intensive sources, than one could classify DG instruments as achieving decarbonization objectives. If, on the other hand, net metering and interconnection standards increase customer-owned DG in one location, a neighborhood for instance, only to result in excess generation that is shifted—or "leaked"—elsewhere, then DG instruments are not entirely effective at decarbonization. How might state governments improve the decarbonization potential of net metering and interconnection standards? States could mandate that all DG systems conform to emissions-level requirements, such as a limit on the amount of carbon dioxide per kWh of DG generation. Or states could apply extra financial incentives to renewable DG systems, such as a production incentive or feed-in tariff that provides some $/kWh payback to the DG owner.

Tax Incentives

The political appeal to using tax instruments, as well as other types of financial incentives, is that they directly reduce the cost of alternative technologies (i.e., provide a "carrot"), but do not explicitly raise the cost of conventional technologies (i.e., use a "stick"). Tax incentives help the consumer, either an individual or a company, overcome the potential economic barriers associated with large start-up costs, which are common for renewable energy sources. Tax incentives also allow governments to set limits on exactly how much is spent on renewable energy policy. Financial incentives provide a number of additional benefits, including the following: they provide a price signal to the consumer or company, which has the potential to alter behavior even in the absence of regulations; they allow consumers or companies to make their own decisions based on personalized cost–benefit considerations; and they obviate the need for governmental regulatory decisions, as well as possible compliance and enforcement costs associated with such regulations (Gunningham & Grabosky, 1998).

Despite the many advantages to using tax instruments, there are also a number of disadvantages. First, by adjusting the cost of alternative technologies, but not conventional technologies, tax incentives do little to discourage the use of carbon-intensive generation or, alternatively, encourage conservation. In fact, on some occasions, financial incentives actually encourage an increase in energy consumption (Newell, 2007). Second, although the amount spent on the incentives can be preestablished, the actual amount of alternative energy that is developed as a result of the incentives cannot be guaranteed. Third, tax incentives may affect the behavior of those who pay taxes, but will have no effect on entities that do not pay taxes. Fourth, the use of tax incentives often requires policy makers to choose favorites among a variety of alternative technologies. As a result, policy makers may devote money to technologies that have little commercial promise or are not in need of additional support. Funding may also continue for too long after a technology becomes commercially mature. Finally, the duration and amount of tax incentives may be unpredictable over time.

In an effort to mitigate the last two of these potential problems, policy makers should consider designing tax incentives that are transparent, predictable, and scale back over time as a technology matures (Geller, 2002).[5] However, it is difficult to construct tax incentives so that they are able to overcome the first two problems: a lack of encouragement to conserve energy and the inability to set renewable energy development levels. These issues are best addressed via the use of other policy tools that can complement tax instruments, yet make up for their inherent shortcomings (Gunningham & Grabosky, 1998).

The energy policy literature contains few analyses that explore the effects or effectiveness beyond this general understanding of the pros and cons of state tax incentives. Tax incentives are likely under-researched because of the immense variation in their design across location, which makes empirical evaluations of their effects difficult. Additionally, tax incentives are often implemented in conjunction with other instruments, which makes it difficult to tease out the effects of one instrument from the effects of the other in empirical evaluations.

Despite the small number of empirical studies on the topic, a number of recent analyses have presented informative insights on the performance of tax incentives. The predominant finding within this body of research is that tax incentives play mostly an assisting role to other energy policy instruments, but are not the primary drivers of alternative energy development (Bird et al., 2005; Gouchoe, Everette, & Haynes, 2002; Lewis & Wiser, 2007).

The second major finding is that tax incentives are effective at encouraging small-scale renewable energy development. Although, relating back to the first point, tax incentives are still one of several factors that affect renewable energy development and not necessarily the primary driver. A couple of studies have also pointed out that tax incentives are well suited for smaller-scale energy systems and more efficient when used at the sub-national level (Bushnell et al., 2007; Gouchoe et al., 2002). Tax incentive design features generally limit the system size and costs of eligible technologies, which often prevents tax incentives from being used for larger-scale renewable energy development (Gouchoe et al., 2002).

Third, several studies have documented the incidence of free-riding as it relates to tax incentives. Free-riders are those that would have purchased the alternative technologies regardless of the incentive; and the incentive merely serves as a bonus, or a "seal the deal" factor (Geller, 2002; Gouchoe et al., 2002; Newell, 2007).

Lastly, one study reveals that tax instruments, as well as other types of financial instruments, also have the potential to cause—or at least contribute to—leakage problems (Bushnell et al., 2007). Tax incentives reduce the costs of renewable technologies, which increases the demand for renewable energy and decreases the demand for fossil fuel generation. These trends eventually cause the price of fossil fuel generation to decrease, which causes the demand for the excess energy to increase elsewhere. Neighboring regions will then purchase this excess fossil fuel generation and the carbon-intensive electricity will leak across borders from the region with the incentive to the region without. Although, as Bushnell and others (2007) point out, financial incentives are less susceptible to leakage than other instruments, such as an RPS or cap-and-trade policy, because the price impacts of financial incentives are relatively small compared with these alternative instruments. In fact, these authors believe that tax incentives are the most efficient state or local policy tool if the policy objective is decarbonization, because other instruments have greater price impacts and therefore greater potential for leakage.

In the electricity dispatch modeling exercise referenced earlier, Carley (2011) found that tax incentives, as one instrument in a larger state policy portfolio, play a supporting but weak role in achieving decarbonization objectives. In this scenario analysis, Carley found that a tax incentive scenario of 35 percent reduced capital costs, in absence of any climate policy, only rendered landfill technologies cost-competitive with other new energy technologies in the Western Electric Coordinating Council electricity region. Landfill energy is not carbon-neutral, nor is it one of the "cleanest" of all alternative energy technologies. However, in combination with a carbon price, the same tax incentives lead to a significant increase in landfill, geothermal, and biomass deployment. Thus, one can conclude that tax incentives have a greater effect when used in combination with a regional or national climate policy. It is important to bear in mind, however, that these findings are contingent on a number of modeling assumptions, as reviewed in Carley (2011).

In summary, a tax incentive is a policy instrument that has potential to achieve multiple policy objectives. When adequately designed and paired with other policy instruments, tax incentives have the ability to perpetuate the diversification, decentralization, and decarbonization of the electricity sector. Tax incentives play a smaller role, however, in achieving each of these objectives than do other policy instruments; and as a result tax incentives often play supporting policy roles. Tax incentives have a smaller price impact than other instruments and, because of their relatively small contribution to carbon leakage, are believed by some to be one of the most effective decarbonization tools for state or local energy policy.

Public Benefit Funds

The majority of the literature on PBFs considers the effects of these funds on energy efficiency and demand-side management practices, but not on renewable energy or research and development (one exception is the finding made by Menz & Vachon, 2006, that PBF policies are not significantly associated with wind development; but their finding comes accompanied by several caveats). In consideration of these studies, it is possible to gain several insights on the decarbonization potential of PBF policies, although it is more difficult to extract information on the diversification or decentralization potential of these funds. The present analysis therefore refrains from drawing any conclusions regarding the latter, and instead focuses exclusively on the decarbonization potential of PBF policies.

The American Council for an Energy-Efficient Economy (ACEEE) has produced the bulk of the PBF effectiveness studies. Nadel and Kushler (2000) conducted a survey to explore how electric industry participants perceive the performance of PBF policies; their study concluded that industry participants consider PBF policies to be rather effective energy efficiency mechanisms, particularly when used in restructured electricity markets. Kushler, York, and White (2004) administered a follow-up survey to the original ACEEE study, and concluded once again that PBF policies were effectively inducing energy savings within the states in which they are administered. However, both reports identified a couple of PBF shortcomings that were reflected in some survey respondents' comments about PBF performance. Shortcomings that Kushler and others identified in the 2000 report include ambiguous language in PBF legislation, funding levels that are too small, administrative delays and complications, and a lack of agency support. An additional problem that these authors identified in the follow-up report is the incidence of funding raids, in which PBF funds are diverted to other state programs. Although it has yet to be tested in the literature, it is also possible that PBF funding for utility energy efficiency programs does not translate into specific electricity savings' mandates. Utilities use money accrued through PBF programs on energy efficiency programs but, without a mandate for a certain amount of electricity savings or a guarantee for a fair rate of return on their energy efficiency investments, utilities face a natural disincentive to use the PBF money in the most efficient or cost-effective manner. Therefore, the nonbinding nature of PBF policies may limit the potential electricity savings, and thus the decarbonization potential, of the policy instrument.

These various findings regarding PBF performance suggest several possible ways in which policy makers and administrators can improve the decarbonization potential of PBF policies. First, policy makers can seek to improve the design and administration of PBFs, including efforts to limit or restrict funding raids, improve the clarity of PBF legislation, or increase funding levels so that utilities can endeavor to implement more substantial energy efficiency projects. Second, states can place contingencies on PBFs and mandate certain kWh savings for each dollar of PBF support, and thereby make PBF policies more binding and less discretionary. Doris and others (2009) also suggested that states consider the following:

- Designing PBF policies with all stakeholders at the table;
- Ensuring that funding levels are consistent over a several-year time horizon;

- Designing PBF policies so that they complement other energy policy instruments already in effect;
- Developing feasible and measurable targets for PBF expenditures, and monitoring utility progress in achieving these targets.

Energy Efficiency Resource Standards (EERS)

EERS is one of the newest state-level energy policy instruments. The first EERS was adopted by Texas in 1999 and was made operational in 2003. Since 1999, 22 states in total have adopted some variant of an EERS. Refer to Figure 3 for a timeline of state EERS policy adoption. According to Matisoff (2008), factors influencing the adoption of energy efficiency policies are much like those identified with RPS policies, prominently including state citizen ideology, with air pollution levels also significant.

Because of the recent emergence of the use of this instrument as a decarbonization policy strategy, few studies have yet to verify the effects or effectiveness of EERS policies. Nadel (2006) conducted a case study analysis on the effects of EERS policies. He found that, in light of the experiences of ten states with active EERS policies, these instruments have proven to be effective mechanisms for reducing electricity consumption.

EERS policies could be further refined and improved in a number of ways. First, policy makers could make EERS benchmarks mandatory, in contrast with the voluntary EERS policies that are currently present in some states. Second, policy makers could mandate that all utilities, including public utilities, comply with EERS benchmarks. Third, policy makers could remove any exemption clauses from EERS legislation that allows a utility to opt out of policy compliance. Finally, in the event that an RPS is implemented in conjunction with an EERS as part of the same resource standard, policy makers can mandate that a specific percentage (or amount) of a resource standard come from energy efficiency and a specific percentage from renewable energy.

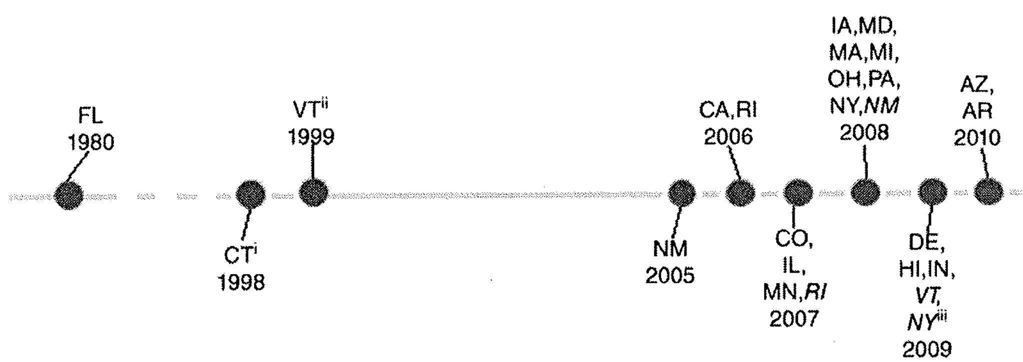

Figure 3. Timeline of Energy Efficiency Resource Standard Adoption
Note: Dates represent when policies were enacted by legislatures. Bolding indicates initial enactment and italicization indicates revisions.
Source: North Carolina Solar Center (2011) and ACEEE (2011). (i) This standard was amended later. (ii) Energy efficiency goals have been set by Efficiency Vermont since 2000. (iii) The 2009 Public Service Commission order only relates to natural gas efficiency.

Table 2 presents all policy instruments discussed above, and identifies the strengths and weaknesses attributable to each instrument, as perceived by various stakeholders involved in the adoption and implementation of these instruments. The table also includes a final column, entitled "Possible Mechanisms to Improve Policy Performance," which summarizes the findings from the literature reviewed above. This column presents ways in which policy makers and other stakeholders can seek to improve the performance of each instrument, so as to play to the strengths of the instrument and also maximize the likelihood of achieving the desired policy objective for which the policy is designed.

Complementary and Conflicting Policy Efforts

Thus far, this study has analyzed how individual policy instruments work, and identified trends, both planned and not planned, associated with each instruments' use. In the process, this study also reviewed how well various instruments work together, with a particular concern for issues involving federalism and the scale of governmental operations. The various findings reviewed above collectively demonstrate that different instruments serve different purposes or, alternatively phrased, address different market failures.

Because different policy instruments serve different purposes, one cannot conclude that more instruments automatically equate to greater policy effectiveness. In some situations, instruments that hold the same objective can be paired together to enhance the effectiveness of a policy strategy that seeks to achieve a single objective. For instance, renewable energy tax incentives and RPSs, both of which aim to increase diversification via renewable energy development, can be combined to produce a potentially greater effect on renewable energy markets than if either worked in isolation. This strategy is endorsed by Gunningham and Grabosky (1998), who refer to the use of multiple instruments for the sake of one objective as "killing one bird with two stones." However, combining two different instruments that are each designed to address a different market failure does not ensure that either market failure will be mitigated with greater effectiveness. For instance, the combination of a RPS and a net metering policy will not necessarily be a more effective decentralization strategy than if the net metering policy was implemented in isolation. As another example, some authors (Gonzalez, 2007; Sorrell & Sijm, 2003) contend that combining a carbon cap-and-trade with an RPS will raise the cost of carbon mitigation efforts but will not necessarily increase carbon savings beyond the cap. These types of instrument combinations have the potential to increase the cost of policy interventions without increasing the effectiveness. Instrument combinations of this variety are only "acceptable" so long as one policy instrument increases the efficiency of the other instrument, or provides other valuable outcomes (Sorrell & Sijm, 2003).

In the event that a state has more than one policy objective (e.g., decentralization and decarbonization), it may want to consider more than one instrument, each of which targets a different market failure (Gonzalez, 2007; Goulder & Parry, 2008; Gunningham & Grabosky, 1998; Sorrell & Sijm, 2003). The challenge with this approach is that it requires an optimal alignment of policy instruments so that they work well together and are complementary, without compromising the effectiveness

Table 2. Summary of Policy Instrument Strengths, Weaknesses, and Mechanisms for Improvement

Policy Instrument	Description	Number of States with Policy (as of January 2011)	Perceived Strengths	Perceived Weaknesses	Possible Mechanisms to Improve Policy Performance
Renewable Portfolio Standard	Mandates that a percentage (or total MW) of utility generation or sales come from renewable energy by a terminal year	29 and Washington, DC, plus seven with RPS goals	• High politically feasibility • Less explicit price tag than other instruments; costs paid by utilities and electricity consumers and not the state • Designed to encourage a slow transition toward renewable technologies • Encourages renewable energy without taxing fossil fuels • Serves as a "symbol" for involvement in state renewable energy development and policy	• Most costs likely passed along to electricity consumers • Annual percentage benchmarks may be difficult to achieve • May not satisfy multiple policy objectives at once • May not affect decisions made about fossil fuel development or generation • Contributes to carbon leakage • Less effective at reducing carbon emissions than an instrument that prices carbon explicitly	• Improve program length, benchmarks, enforcement, and cost mechanisms • Use REC trading with no double-counting • Increase mandated utility participation • May require political and institutional support as well • Policy coordination across states or regions may reduce carbon leakage and increase effectiveness • Requires careful coordination with other policy instruments
Net Metering	Requires utilities to allow customers to connect their distributed generation systems to the electric grid and may also allow net billing	43 and Washington, DC, plus three with voluntary programs	• Reduces barriers to DG deployment • Costs incurred by utilities, DG owners, and electricity consumers, not the state • Low administrative costs	• If system capacity limits are set too low, it can exclude potential customers • Does not necessarily reduce carbon emissions • Cannot guarantee resulting amount of DG development, including renewable-based DG	• Increase capacity limits and consider setting "break points" • Ensure that all fees are fully transparent • Prohibit or limit unnecessary fees or safety measures • Expand regulation to include all utilities • Remove restrictions on different customer classes • Allow excess generation "roll over" • May require extra incentives and education to increase DG deployment
Interconnection Standards	Governs how customers connect generation sources to the grid, as well as utility-customer interactions in such situations	41 and Washington, DC			

Tax Incentives	Tax-based credit, exemption, exclusion, or deduction that encourages renewable energy or energy efficiency	47 (refer to Table 1 for more detail on which states have different types of tax incentives)	• High political feasibility • Serves as a "carrot," not a "stick" • Helps consumers or companies afford high start-up costs, and make their own decisions about energy investments • Allows government to set limits on renewable energy or energy efficiency spending • Can be complementary to other policy instruments • Lower regulatory burden than other instruments • Encourages small-scale renewable energy development in particular	• Not generally the primary driver for renewable energy development • May be prone to free-riding • Does not discourage fossil fuel investment or consumption • Does not necessarily reduce carbon emissions • May lead to an increase in total energy consumption • Cannot guarantee amount of renewable energy development or energy efficiency savings • Costs paid by taxpayers • Does not affect those that do not pay taxes • May require the government to "choose favorites" among different technologies	• Create transparent, predictable incentives that phase-out over time as the technology matures • Couple with other instruments and align policy design features so as to target specific policy objectives
Public Benefit Funds for Energy Efficiency	Surcharge placed on end-users' utility bills, and used to finance energy efficiency efforts	18 and Washington, DC	• Cross-subsidizing mechanism that taxes regular electricity consumption and subsidizes energy efficiency • Costs paid by electricity consumers and not the state	• Prone to funding raids • Funds may be too small to achieve significant energy efficiency savings • Requires administration and agency support to manage the funds • Funding for energy efficiency does not ensure that a specific amount of electricity is saved • Does not discourage fossil fuel production or consumption	• Improve the clarity of PBF legislation • Avoid funding raids • Design PBF policies with all stakeholders at the table • Ensure that funding levels are consistent over a several-year time horizon • Increase total funding so as to ensure substantial energy efficiency savings • Develop targets and monitor progress • Consider mandating specific savings on a dollar per kWh basis

Table 2. *Continued*

Policy Instrument	Description	Number of States with Policy (as of January 2011)	Perceived Strengths	Perceived Weaknesses	Possible Mechanisms to Improve Policy Performance
Energy Efficiency Resource Standard	Mandates lower utility generation or consumption by a terminal year, typically with annual percentage benchmarks	18, plus 3 with goals	• High politically feasibility • Less explicit price tag than other instruments; costs paid by utilities and electricity consumers and not the state • Designed to encourage a slow transition toward energy efficiency • Encourages energy efficiency without taxing fossil fuels • Serves as a "symbol" for involvement in state energy efficiency	• Annual percentage benchmarks may be difficult to achieve • May not affect decisions made about fossil fuel development or generation • Less effective at reducing carbon emissions than an instrument that prices carbon explicitly	• Improve program length, benchmarks, enforcement, and cost mechanisms • Make benchmarks mandatory for all utilities • Remove exemption clauses • Requires careful coordination with other policy instruments • Mandate specific percentages or amounts of efficiency as a resource (if combined with an RPS)

DG, distributed generation; RPS, Renewable Portfolio Standard; PBF, public benefit fund.

or efficiency of any specific instrument (Gonzalez, 2007; Sorrell & Sijm, 2003). The potential for various instruments to work together is strong, as discussed in the section above, although an optimal policy portfolio will necessitate that much effort is put into aligning policy objectives and the policy design features of various instruments. Policy makers must remain explicit about which public policy objectives they seek to attain, and which trade-offs are made among various instrument options (Sorrell & Sijm, 2003). Some researchers also suggest that, when combining multiple instruments, policy makers ought to keep the design of each instrument simple because too much complexity can degrade the synergy between instrument combinations (Gonzalez, 2007).

Trends in the Era of State Energy Policy Innovation

The study of the effects of state energy policy instruments lends a number of insights into broader trends associated with the state energy policy innovation era. This section highlights many trends that involve the use of state energy policy instruments; identifies limitations of the collective literature in this field, as well as limitations in the scope and breadth of the present study; and suggests avenues of future research. The discussion below begins with findings that are specific to policy instruments, then discusses findings that relate to other factors that play supporting roles in state energy policy, and finally considers broader trends that mark the era of state energy policy innovation and the use of innovative energy policy instruments.

Each State Has Its Own Combination of Different Policy Instruments

Each state has selected among a wide variety of different policy instruments, and crafted unique combinations to suit its own needs and objectives. No two state policy portfolios are the same, either in the types of instruments or the design of instruments. The energy policy literature offers limited insights on which factors lead states to adopt different policy combinations. Research to date remains inconclusive as to the primary factors driving adoption of renewable energy policies in general, and insofar as a few factors are consistently found to be relevant (e.g., political ideology), they apply to a sufficiently wide variety of policies that are less helpful in the use of distinguishing one state's choices from the next. For example, Rabe (2008) explicitly describes how states that have thus far adopted renewable energy policies can be placed in all four quadrants of a typology including both high and low policy adoption rates and both high and low rates of emissions growth.

Nor does the literature offer statistical analysis of which types of policy combinations are more prevalent on the whole. However, more detailed analysis of the specific political dynamics of individual states might shed light on the reasons different objectives—greenhouse gas mitigation, decentralization, or energy market diversification—among other political and economic determinants, shifted to the foreground in different locations. Future research in this realm could provide valuable information for states that are considering various energy policy options, states that seek to revise previously enacted policies, or the national government as it considers the possibility of a national energy and climate change bill.

The Selection of Policy Objectives Requires Trade-offs

If state policy makers have multiple policy objectives, the discussion above established that they may want to consider the use of multiple policy instruments. This analysis has also found that various state policy objectives have the potential to work together in concert. But there is some evidence that simultaneous pursuit of multiple objectives is challenging and may require making trade-offs. There are three types of trade-offs in this context: (1) trade-offs involving government resources; (2) trade-offs among different policy decision criteria; and (3) trade-offs involving the resources of the governed. Regarding the first, governments are constrained by budgets, administrative abilities, and political feasibility, all of which require that policy makers carefully weigh the costs and benefits of policy efforts, and compare potential outcomes across a variety of efforts. In consideration of the second, policy makers must make trade-offs among a variety of criteria during the selection of policy instruments or efforts. For instance, one policy instrument may be the most efficient instrument, but another the most equitable. Regarding the last trade-off, that among resources of the governed, policy makers will need to be mindful of the resource constraints—fiscal, environmental, and other constraints—of the individuals and companies that are governed by these policies. These constraints may require that trade-offs be made between different resource options. For instance, at the intersection of diversification and decentralization objectives, trade-offs may be necessary between large-scale renewable energy and small-scale distributed generation. At the intersection of decentralization and decarbonization, fossil-fuel-based distributed generation and renewable-energy-based distributed generation may stand at odds. At the intersection of diversification and decarbonization, trade-offs may be necessary between advanced, efficient fossil fuels and renewable energy, or demand-side management and renewable energy. Significant efforts are necessary to coordinate policy objectives and therefore the design of instruments used to achieve these objectives, so that individuals and companies can respond to multiple incentives and regulations in the most cost-effective and efficient manner possible.

This article has focused exclusively on diversification, decentralization, and decarbonization policy objectives. It is possible that the discussion has neglected other significant policy objectives, the inclusion of which could change, or at least improve, the discussion of policy instrument effects and the trade-offs that may emerge among objectives. For instance, as documented elsewhere (Rabe, 2008), it may be the case that a primary objective for some state policy makers is economic development and job growth. These states may adopt various energy policies, such as an RPS, PBF, or tax incentives, in efforts to increase manufacturing activities, employment, and competitive advantage in a renewable energy industry. The possibility that economic development objectives guide energy policies raises several questions about the ultimate intent of state policy makers. Do policy makers seek to increase jobs via the diversification of the electricity sector, or is it to diversify the sector with the help of economic development efforts? Or is an economic development objective used to improve the political feasibility of energy legislation? This possible omission also raises questions about the conclusions drawn in this analysis: if the ultimate intent of policy makers is to increase jobs, not electricity diversification or decarbonization, are some policy instruments more or less successful at achieving this objective? These questions highlight the possibility that there may be additional objectives that guide state energy policy efforts, the evaluation of which may lend greater insights into the effects and effectiveness of energy policy instruments or the trade-offs that are necessary between conflicting or complementary policy instruments.

Location Matters . . . But How Much?

Clearly, locational considerations are a factor in a state's adoption of a new energy policy. Locational considerations also set constraints on how much new energy supply a state can pursue, because energy resource potential varies by location; and some states are better endowed with wind, solar, geothermal, or biomass resources than others. Yet states are not evenly divided by location or resource potential in either their policy efforts or their renewable energy outcomes. Carley (2009b) found that, in the time period between 1998 and 2006, both RPS adoption rates and renewable energy development was the greatest in states with average wind energy potential. States with the greatest wind energy potential lagged behind the first group, in both RPS adoption rates and renewable energy generation. The last category of states, those with the lowest wind energy potential, also had the lowest RPS adoption rates and the least renewable energy generation. These findings demonstrate that, at least up through 2006, there was a mismatch between resource endowment and policy action, and resource endowment and renewable energy development.

In the event that national energy policy legislation is passed, and that it contains a national RPS or some other renewable energy requirement, location and resource endowment will invariably become more important for two reasons. First, those states in regions with poorer energy resource endowments may struggle to meet national standards, and will potentially have to export significant sums of money to other states for RECs. Second, the same states that will be most compromised by national renewable energy legislation are those that have lagged behind other states in energy policy legislation and renewable energy development, respectively, over the past decade and a half. The failure to jumpstart renewable energy development, attract innovative energy businesses or industrial activity, or develop the political capacity to address energy and climate change issues throughout the era of state energy innovation policy will potentially put these states at a double disadvantage, and force them to play a potentially expensive game of catch-up.

Some Instruments Are More Effective at Achieving Their Objectives than Others

Net metering and interconnection standards have been found to successfully reduce the barriers to distributed generation market growth and increase consumer adoption of these small-scale energy systems. Policy instruments that aim to increase renewable energy generation demonstrate mixed results. The RPS has been found to increase total renewable energy generation, but is less successful at increasing the percentage of renewable energy generation out of all generation sources. Tax incentives contribute to renewable energy growth but are not the major drivers. Policy portfolios that aim to reduce greenhouse gas emissions demonstrate moderate to significant success, dependent on a variety of state-level electricity sector factors as well as other unaccounted for factors. However, state-level policy portfolios are not the most effective decarbonization strategy. Regional or national policy coordination is more effective than isolated state policy efforts; and policy coordination in conjunction with a carbon price is more effective than either alternative.

This article took a detailed look at how several policy instruments operate, both individually and collectively, but omitted a number of additional important instruments. Future efforts to synthesize the trends and lessons learned from the era of state energy policy innovation should incorporate insights on the effects of other instruments as well, including building codes, PBFs for renewable energy or research and development, and other financial incentives, such as grants or loans.

Status of Market Regulation Matters

The interaction between efforts to deregulate or restructure electricity markets and diversification, decentralization, or decarbonization policy interventions is not clearly established to date in the supporting literature. The empirical analyses presented in Carley (2009b) and Carley (2009a) both controlled for states' electricity market deregulation status. The parameter estimates on the deregulation variable in both analyses provided notable findings. In the former study, results revealed that, all else constant, deregulation is associated with an increase in total renewable energy development, but not an increase in the share of renewable energy. In the latter, the author found that deregulation is positively and significantly associated with utility DG adoption. These findings suggest that deregulation increases competition in the industry and encourages power producers to adopt new and innovative sources of electricity as a response to consumer demand for more diverse and alternative fuel sources. Carley (2009a) also found that, although deregulation encourages utility DG adoption, it is not associated with a greater magnitude of DG deployment. Combining the results of both essays, one may conclude that the deregulation of a state electricity market does encourage utilities to adopt nonconventional fuel sources and to make some substitutions among fuel types, as is also argued by Delmas, Russo, and Montes-Sancho (2007), and supported by Cory and Swezey (2007) and, in an analysis that explores natural gas market deregulation, Dahl and Ko (1998). However, deregulation is not a significant enough factor to substantially alter the balance of states' generation assets, as is also supported by Cory and Swezey (2007). One possible explanation for this finding is that deregulation does not discourage the continued use of coal generation from amortized power plants (Dahl & Ko, 1998; Hyman, 2006); a transition away from a heavy reliance on coal generation therefore will require more policy intervention than deregulation of a state's electricity market (Hyman, 2006). However, the literature could benefit from additional studies that evaluate empirically the relationship between regulation status and other policy interventions, and between combined policy efforts and electricity market outcomes.

Energy Policy Instruments Are Not Climate Policy Instruments

Current state public policy efforts employ energy policies for climate policy objectives—in an attempt to abate greenhouse gas emissions. Yet, several authors have concluded (Bushnell et al., 2007; Carley, 2011; Fischer & Newell, 2008; Gonzalez, 2007; Goulder & Parry, 2008; Palmer & Burtraw, 2005; Sorrell & Sijm, 2003) that renewable energy policies are not the most effective policy tool for climate policy objectives. As Rabe (2008) explains, "there appears to be a nearly inverse relationship between those policies that policy analysts tend to endorse as holding the greatest promise to reduce emissions in a cost-effective manner and the political feasibility of respective policy options." Although renewable energy or distributed generation policies provide a number of societal benefits, the most cost-effective carbon mitigation policy is one that prices explicitly the use of carbon-intensive generation. A price on carbon emissions causes utilities to seek alternative, less carbon-intensive fuel options and causes consumers to reduce their electricity use. Thus, energy policies are less cost-effective for carbon mitigation because they do not directly address the market failures associated with climate change, but also because the manner in which they are currently used is fraught with inefficiencies associated with carbon leakage.

Policy Coordination Across States Improves the Effectiveness of Policy Instruments

Many studies have established the importance of jurisdictional size and cooperation or coordination across jurisdictions as it relates to the effectiveness and efficiency of energy policy instruments (Bushnell et al., 2007; Carley, 2011; Gonzalez, 2007; Goulder & Parry, 2008; Rabe, 2006, 2008). Each of these studies raises concern about the potential problems associated with energy policies that are not consistent across regulating jurisdictions.

For the sake of illustration, let us consider two contiguous states: $state_1$ and $state_2$. Assume that $state_1$ can save X in carbon emissions from its policy portfolio and $state_2$ can save Y. If both states pursue their research agendas, then one should expect total carbon savings of $X + Y$. Some argue that inconsistency in policy efforts across jurisdictions, even if all participating states seek the same objective, makes it difficult to align policy features so as to achieve a desired outcome in the most efficient manner (Gonzalez, 2007). If this statement is true, we should expect total carbon savings to equal $X + Y - A$, where A is the lost carbon savings that results from inconsistent policy efforts across $state_1$ and $state_2$. When one jurisdiction supports an energy policy agenda and a neighboring jurisdiction does not, one would expect that total carbon savings will be less than the potential savings if the two states were to each have their own policy agenda. If $state_1$ is the state with the policy agenda and $state_2$ is the state without, one should expect total carbon savings to be X. However, as one may assume based on the discussion above, the total carbon savings that results from $state_1$ acting in isolation is actually less than X; instead, one should expect total savings to be $X - B$, where B is the lost carbon savings because of carbon leakage across state borders. Assuming that all policy instruments are optimally designed, it is likely that the carbon savings from the case of two policy agendas but with inefficiencies due to inconsistency is greater than the case of the one policy agenda with carbon leakage, or $X + Y - A > X - B$.

One could also identify additional benefits that accrue when two or more states, or an entire region, coordinate policy efforts. Although the literature has yet to devote much attention to this subject and thus this discussion still remains fairly speculative, possible benefits include: greater economic development possibilities from regional competitive advantage strategies; enhanced opportunities to participate in cap-and-trade markets; or improved policy design features of individual states as a result of either peer pressure or policy diffusion. If additional carbon saving benefits, C, accompany policy coordination, total carbon savings associated with the coordination between $state_1$ and $state_2$ is $X + Y + C$, which is the best possible outcome of all reviewed above. If one factors the loss of benefits into this equation due to a lack of complete cooperation between states, one might actually expect that total savings to equal $X + Y + C - B/n$, where n is a value that represents an improvement in carbon leakage. As more states join efforts, n increases, B/n decreases, and total carbon savings increase.

These conclusions are recognized by many state policy makers, as evidenced by recent efforts to coordinate cap-and-trade markets, as well as REC markets, across regional lines.

The Federalist Implications of State Leadership in Energy Policy Requires Further Examination

States are regarded in the federalism literature as "laboratories of democracy." States can develop policies that are smaller in scale, and are better tailored to local conditions and needs. This process may involve experimentation, borrowing lessons from other states, and, perhaps eventually, the identification of policy "winners." As is often the case, after a period of state experimentation, the national government can craft a policy agenda that employs the best practices and avoids the worst. The disadvantages to state policy leadership, on the other hand, include the possibility of duplication of efforts, a lack of regulatory consistency that may affect individuals or companies that cross state lines, budget constraints, inter-state competition, or a "race to the bottom" in policy stringency.

Have developments in the era of state energy policy innovation revealed states to be effective laboratories of democracy? An answer to this question requires two additional questions: first, have states been effective at devising and implementing energy policies that increase the diversification, decentralization, and decarbonization of the U.S. electricity sector; and, second, have states set a good example for the national government?

In response to the first question, this study highlighted the mixed evidence of the effects and effectiveness of the states' energy policy efforts or, in some cases, lack of efforts to date. Some states have taken minimal action, others substantial action. Out of those states that have crafted energy policy instruments, some have experienced early success in attaining desired outcomes. Others have encountered difficulties with their policy approaches and have gone back to the drawing board to craft new or additional mechanisms, or revise previous ones. A consideration of all states' experiences with various policy instruments reveals that some instruments are more effective at achieving various objectives, and have fewer unintended outcomes, when used at the state level. Empirical results from the various studies reviewed in the present analysis suggest that state-level policy instruments have the potential to achieve all three policy objectives reviewed in this analysis, yet states have experienced greater success in this pursuit with instruments that encourage decentralization than those that encourage diversification or decarbonization. States have experienced some success, but with limitations, with their instruments that aim to diversify the electricity sector. However, the states' ability to use policy instruments that decarbonize the electricity sector have been and will continue to be plagued by limitations, so long as states continue to use energy tools instead of climate policy tools and lack policy coordination across state or regional lines.

Regarding the second question, it is important to note that "good" is subjective. This notwithstanding, the states' experiences are exemplary in a number of ways, including but not limited to the following:

- The majority of state governments have demonstrated a concern for energy and climate issues, and translated this concern into policy action.
- Many states have crafted innovative policy tools that combine elements from other market-based instruments as well as from command-and-control instruments, with flexibility mechanisms built in.
- Many states have continually reevaluated their policy portfolios, with particular attention devoted to policy design features of their various tools. These states have demonstrated a tendency to enhance the strength—or "stretch"—of policy instruments over time.
- The majority of states have pursued an open and democratic policy process, with all stakeholders invited to the table (Pterson & Rose, 2006).
- State policy makers have demonstrated a concern for equity across "socioeconomic groups, regions, and generations" (Peterson & Rose, 2006).
- More recently, as states have begun to form regional partnerships, they have demonstrated a willingness to cooperate with states or jurisdictions that do not necessarily share the same ideology, fiscal resources, or generation assets.

Conclusion

Over the course of the era of state energy policy innovation, states have selected a variety of policy instruments that they believe to hold the greatest potential to achieve diversification, decentralization, and decarbonization objectives. Yet, the effects and effectiveness of these instruments on the U.S. electricity sector have not been entirely understood to date, as evidenced by the small pool of empirical literature on state-level energy policies. Nor has the literature presented a clear picture of how well these instruments work together, whether multiple objectives can be pursued both effectively and simultaneously, and what are the limits of state leadership in energy and climate policy.

This study sought to address some of the unanswered questions about the era of state energy policy innovation via a review and synthesis of the literature on the effects and effectiveness of different state-level energy policy instruments, and attempted to further highlight significant trends, necessary trade-offs, potential issues that may warrant public policy concern, and avenues for future research.

The need to address remaining questions and expand on these findings is ever-present. Until the United States and its global partners can reduce dependence on fossil fuels, devise advanced, efficient, and clean energy alternatives, and reduce greenhouse gas emissions, the need for optimal policy solutions will remain significant. Policy solutions will require making trade-offs and a continual reevaluation of progress.

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Notes

1 This is not to say that RPS policies do not incur costs. The actual costs of an RPS are borne by electric utilities and are eventually passed down to consumers. However, the costs are not the most obvious design feature of an RPS, as they are, for instance, with a carbon tax.

2 Some (Doris et al., 2009) also argue that the costs required to ensure RPS compliance should be recoverable in electricity rates; but not all scholars agree. Cory and Swezey (2007) argue that utilities should be prohibited from directly recovering costs of new renewable energy from their customers.

3 While some advocate for a national RPS policy on the grounds just defined, others object to the adoption of a single and uniformly applied RPS. These critics emphasize that natural resource endowments are not consistent across regions. A national RPS may therefore result in a net transfer of fiscal resources from the Eastern to the Western hemisphere (Casten, 2009) or, more specifically, from the Southeast and parts of the Northwest to the Midwest, West, and Southwest.

4 The Federal Energy Regulatory Commission (FERC) has also adopted interconnection standards for distributed generation units that connect at the transmission level. State standards regulate the interconnection of distributed generation units with the distribution level and the FERC regulates the transmission level.

5 Some also advocate for the use of production incentives in lieu of tax incentives, because production incentives provide financial compensation for the actual amount of generation output, as opposed to just the upfront costs. Production incentives, in other words, ensure that consumers chose alternative technologies that are promising enough to actually produce electricity (Gouchoe et al., 2002).

About the Author

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The implications of initiating immediate climate change mitigation — A potential for co-benefits?

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ABSTRACT

Fragmented climate policies across parties of the United Nations Framework on Climate Change have led to the question of whether initiating significant and immediate climate change mitigation can support the achievement of other non-climate objectives. We analyze such potential co-benefits in connection with a range of mitigation efforts using results from eleven integrated assessment models. These model results suggest that an immediate mitigation of climate change coincide for Europe with an increase in energy security and a higher utilization of non-biomass renewable energy technologies. In addition, the importance of phasing out coal is highlighted with external cost estimates showing substantial health benefits consistent with the range of mitigation efforts.

1. Introduction

Within documents related to the Doha Climate Change Conference in November 2012, "grave concern" was noted as there is still a "significant gap between the aggregate effect of Parties' mitigation pledges ... and aggregate emission pathways consistent with having a likely chance of holding the increase in global average temperature below 2 °C" (UNFCCC, 2012a [27,13]). Fragmentation is a suitable description of global climate policy action as countries follow their own policy agendas. On the other hand, a topical case of a region leading the way by initiating more stringent climate action is the European Union and the implementation of the "Roadmap for moving to a competitive low-carbon economy in 2050" (short: EU Roadmap). Within this Roadmap both immediate mitigation efforts and large-scale reductions of emissions by 80–95% below emissions in 1990 have been proposed, refer to [9]. Alas, pioneering with mitigation efforts in a world of fragmented climate policies leads to a question of whether initiating significant and immediate climate change mitigation can support the achievement of other non-climate objectives. More specifically, we ask whether such co-benefits exist regardless of how the rest of the world responds to Europe's pioneering action.

Using the results from eleven global integrated assessment models (IAMs), we focus our analysis on potential co-benefits connected with energy security and air pollution. With respect to energy security, we study the development of import dependence on fossil fuels as well as the impact on Europe's bill for oil and gas. We also review energy diversity indicators (Section 3.1). Regarding, the side-effects of climate change mitigation efforts on air pollution (Section 3.2), we review whether external costs avoided in the electricity sector are sizable in comparison to the overall policy cost. In addition, we highlight the sources of the greatest potential co-benefits which underlie the sectoral estimates with a focus on eight different energy sources (including nuclear, a range of renewable energies (RE), coal, oil, and gas).

To test the robustness of co-benefits across varying mitigation efforts in a fragmented world, we analyze different climate

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policies which have been implemented by eleven IAMs, refer to Kriegler et al. of this issue [20]. In particular, we look at the following subset of scenarios with a focus on the European Union:

- *Fragmentation — RefPol*: Countries have their own agenda and follow more or less stringent climate policies. This scenario is an extrapolation of unconditional climate policies that are currently in place based on the Copenhagen Pledges.
- *Concerted action — CF450*: The world jointly commits to a 450 ppm target with flexibility allowed in the models' response to the target in terms of the timing of emission reductions.
- *Inspiration — 450P-EU*: The European Union pioneers with more stringent climate policies as foreseen in the EU Roadmap 2050. Inspired by this early action, the world makes a transition to a global emission reduction path consistent with a 450 ppm target.
- *Disillusion — RefP-EUback*: The European Union pioneers with its Roadmap 2050 but does not succeed in inspiring the world to follow, the EU then returns to the less stringent climate policies of the fragmented world from 2030.
- *No policy case — Base*: Countries do not follow any climate policies, and hence, the shadow price of greenhouse gas (GHG) emissions is zero.

Studies related to ours are [4,11,12,18]. Knopf et al. [18] is a model inter-comparison exercise of the energy modeling forum, EMF 28, focused on EU 2020 and 2050 climate targets with a review of different technological futures. Their analysis of the EU Roadmap strategy suggests that a reduction of GHGs by 80% in 2050 is possible but challenging as strong cost increases take place from 2040. The authors also conclude that it is necessary to start the transformation of the energy system before 2030. References [11,12] are the official assessments carried out for the development of the EU Roadmap 2050. Capros et al. [4] discusses related energy projections of the scenarios used for the EU Roadmap 2050. Both studies are based on the model PRIMES.

In this paper we define co-benefits as a positive physical side effect of one policy (here climate policy) for another public policy objective (see also [8]). The following papers take up a similar discussion of climatic co-benefits as we do: in a single-model study McCollum et al. [23] find co-benefits in an increasing renewable energy (RE) deployment in terms of energy security and air pollution. Borenstein [2] discusses potential co-benefits of RE such as their contributions to alleviating externalities from fossil fuel burning, energy security improvements, reducing the vulnerability of energy market prices, and the creation of jobs. Due to various methodological shortcomings (e.g. the market value of electricity depends on time and location, the problem of how to account for variability) the author concludes that environmental co-benefits may be more important. Similarly, Edenhofer et al. [7] argue that a possible benefit of RE (as a decentralized energy option) is that they can play an important role in improving access to energy in rural areas. A note of caution should be raised as co-benefits should also be assessed in a more complex framework, i.e. taking account of competing public policy objectives, which to the authors' knowledge have not been completed to this date.

The paper is structured the following way. In Section 2, we introduce details of the scenario design and briefly review participating models. We also compare GHG emission reductions in these scenarios with those defined in the EU Roadmap 2050. In Section 3, we analyze co-benefit candidates as they were described above. The concluding section summarizes our findings on possible sources of co-benefits.

2. Europe's early action in a world of fragmented climate policies

In this section we provide details on the scenario framework and on participating models. We then study the consequences for the development of GHG emissions across the different scenarios. As expected the EU Roadmap 2050 implies more stringent climate policies in comparison to the unconditional Copenhagen Pledges which are the basis of the fragmented regional action scenario.

2.1. Scenario design

The current world with fragmented climate policies is characterized by diverse levels of ambition with respect to mitigating climate change. These are expressed in our scenarios with different targets across the globe for GHG emission caps and intensities, shares of RE in electricity production or final energy, and capacity targets for low carbon technologies (wind, solar, geothermal, and nuclear energy). Apart from these targets, which are based on a review of current climate policies, the development of GHG intensity rates from 2020 was projected reflecting current trends and planned policies.[1]

More specifically, the scenario 'Fragmentation' (short: RefPol) is an extrapolation of climate policies that are currently in place based on the unconditional Copenhagen Commitments and national/regional low carbon technology targets (if these exist). The European Union has a moderate GHG reduction target of 15% in 2020 with the aim of achieving a 20% share of RE in final energy by 2020. After 2020, we assume that the GHG intensity falls at least at 3% p.a. in the European Union. Fig. 1 also provides an overview of emission caps and constraints on the development of GHG intensities as imposed in other world regions. Assumptions in these regions concerning technology targets for RE shares and/or capacities for low carbon technologies are provided in [20]. Note, that neither emission trading between regions nor banking and borrowing are allowed.

As opposed to the fragmented climate policy action in different world regions, we also study scenarios of immediate 'Concerted action' where the world aims to stabilize atmospheric GHG concentrations at 450 ppm CO_2se. These constraints on GHG emissions are imposed for all sectors, incl. land-use change (short scenario name: CF450). The full basket of GHGs includes CO_2, CH_4 (GWP 25), N_2O (GWP 298), and F-gasses. Note however, that the model IMACLIM reports only CO_2 and the model POLES does not report N_2O and CH_4. To harmonize targets between models capturing different baskets of GHGs, models were provided with a cumulative carbon dioxide budget for the period 2000–2100 (1500 $GtCO_2$ and 2400 $GtCO_2$ for 450 and 550 ppm CO2e targets, respectively).

In scenarios 'Inspiration' (short: 450P-EU) and 'Disillusion' (short: RefP-EUback) the EU pioneers with more stringent

[1] Note that all climate policies have been implemented by means of equivalent regional taxes on GHG emissions' running auxiliary scenarios. These taxes represent the shadow price of the quantity instruments.

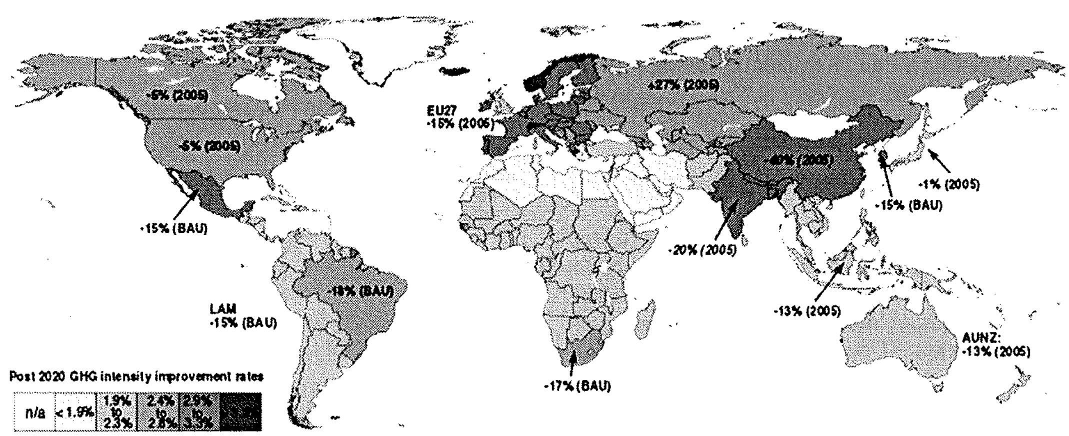

Fig. 1. Climate policies in the fragmentation scenario (RefPol) include caps for 2020 greenhouse gas emission/intensities for selected regions, targets for renewable shares, capacity targets for low carbon technologies, and projections of post-2020 greenhouse gas intensity improvement rates (see legend).

climate policies as foreseen in the EU Roadmap 2050 by targeting in GHGs a reduction of 20% in 2020 and 80% in 2050, with respect to 1990 levels. Note that land-use, land-use change and forestry sectors have been included in our study whereas they are not in the EU Roadmap. Regional carbon trajectories following from this design are used as an input for the period 2011–2030 in 450P-EU and RefP-EUback. Therefore, decisions under both scenarios are identical until 2030. From 2030 both scenarios, however, depart. In 450P-EU, inspired by the early action of the EU, the world makes a transition to a global 450 ppm path from 2030 onward. This is implemented in the models by a linear transformation of regional carbon taxes obtained in 2030 to carbon prices that are consistent with a global 450 ppm trajectory in 2050 (note that technology targets are included). Utilizing this scenario design means that foresight models can implement the scenario in a way where there is no anticipation of the transition to a concerted action. In the RefP-EUback scenario, the EU pioneering with its Roadmap 2050 does not succeed in inspiring the world to follow. The EU then returns to the less stringent climate policies of the RefPol from 2030. This is implemented by relaxing the EU carbon price to the carbon price of RefPol over the period 2030–2050. Again, the foresight models can implement the scenarios so that foreseeing the fallback of carbon prices is not possible.

Finally, we include a 'no policy case' in our scenario framework (short: Base). In this scenario, countries do not follow any climate policies, and hence, the shadow price of GHG emissions is zero. This acts as a baseline when reviewing co-benefits in Section 3.1 and calculating policy costs as well as external costs avoided within Section 3.2.

2.2. Overview on participating models

The scenario framework has been implemented by eleven global IAMs: four inter-temporal general equilibrium models (MESSAGE, MERGE-ETL, REMIND, and WITCH), three computational general equilibrium models (GEM-E3, IMACLIM, and WorldScan), and four partial equilibrium models (DNE21+, IMAGE, GCAM, and POLES). Differences across the models w.r.t. their economic coverage, assumptions on technologies and technical change as well as trade are provided in the Appendix, Table 5. A discussion of these differences is taken up in the following analysis. Models also differ in their regional resolution. The mapping of native model regions to the 27 EU member states is not exact for the following models: GCAM additionally includes EFTA and Turkey, while for IMACLIM and MESSAGE they are EFTA, Turkey, and former Yugoslavia. IMAGE as well as MERGE-ETL additionally includes EFTA and former Yugoslavia. DNE21 + does not include the Baltic States. These differences should be kept in mind throughout the paper.

Furthermore, as part of the AMPERE study, all models have harmonized their long-term population and GDP trajectories. Input for all models is based on the medium-fertility variant of the UN World Population Prospects Revision 2010 [29]. Regarding the development of economic growth, a medium growth scenario has been computed for GDP utilizing the method developed in [21] and also documented in [19]. In this scenario, technology leaders are assumed to grow at a medium rate and countries catch-up to their level of development at a medium speed of convergence. The assumptions on economic and population growth translate to a global GDP growth of about 3.5% in the period 2005–2050. It slows down at the EU-27 level from 1.7% growth to 1.5% by 2100. Scenario assumptions for the development in the EU are comparable to projections used by the European Commission.

Note that throughout Sections 2.3 to 3.1 we define that a cross-model result x is robust if

$$x = \frac{Q_3 - Q_1}{Q_2}, \quad \text{with} \begin{cases} x < 0.2 & \text{robust,} \\ 0.2 < x < 0.3 & \text{less robust,} \\ 0.3 < x & \text{mixed,} \end{cases}$$

where Q_3 is the upper quartile, Q_1 is the lower quartile, and Q_2 is the median. The ratio is also known as the robust coefficient of variation. Our choice in the definition of 'robust', 'less robust', and 'mixed' is somewhat arbitrary. It is, however, motivated by the numerical values obtained for harmonized population and GDP developments. Note that despite the harmonization, we see some variations across the models in these variables (0.07–0.12 and 0.03–0.07, respectively). This is caused by small differences in implementing the population and GDP growth scenarios (e.g. conversion of purchasing power parities to monetary exchange rates) and the aggregation of native model regions to the region that results in the best mapping to EU27. Thus, due to this inevitable spread, we define 0.2 as the threshold for robustness.

2.3. Emission reductions compared to EU Roadmap 2050

Having defined the scenarios, we first compare the RefPol and 450P-EU scenarios to the more common 450 ppm scenario at both, the global and EU levels. Across all models, RefPol shows higher GHG emissions at the global level in comparison to CF450. Regarding 450P-EU, one model (IMACLIM) did not find a feasible solution. For the other models 450P-EU is close to a 450 ppm path at a global level. In the case of Europe most models have GHG emissions in RefPol below Europe's path that would be consistent with a global 550 ppm regime in the first half of this century but above the 450P-EU and 450 ppm paths (CF-450). Therefore, we relate RefPol with 'moderate action' and 450P-EU with 'stringent action' (which is also the case for RefP-EUback for the period 2011–2030).

Next we turn to the question of how GHG reductions in IAMs compare to the EU Roadmap targets. According to this policy study, cost-effective milestones along this path are the achievement of GHG reductions by about 40% and 60% below 1990 levels by 2030 and 2040, respectively.[2] Note again, that we include emissions from land-use, land-use change and forestry. For the comparison, we take 1990 emission levels from the UNFCCC reporting (taking account for the definition of Europe in each model) [28].,

Roadmap targets (incl. indicative sectoral reductions) and model means (incl. coefficient of variation in brackets) are shown in Table 1. The reduction of GHG emissions tend to be robust or less robust across all scenarios. At the lower range are GCAM and MESSAGE. Results are far less robust for non-CO_2 emissions. This is due to larger uncertainties connected with non-CO_2 data and due to different model strategies to comply with targets which are imposed on the full GHG basket. For example, WITCH reduces Non-CO_2 in 2050 by 63% whereas GCAM shows a reduction of only 8% (450P-EU). CO_2-reductions realized for fossil fuels & industries (FF&I) show a smaller spread ranging from less robust to robust. Though, not shown in Table 1, data for 450P-EU and CF-450 are very close to each other. These scenarios are – as expected – those closest to the EU Roadmap targets. A reason for this lies in the scenario design in that from 2030 onward models follow a 450 ppm path. This means that models do not necessarily meet later reduction targets as long as they do not overshoot the carbon budget. In case Europe rolls back its Roadmap in 2030 (RefP-EUback), we find that emission levels are almost back to those in the RefPol by 2050.

3. Identifying co-benefits

In this section we take a closer look at potential co-benefits of climate change mitigation and we focus on those connected with energy security (Section 3.1) and air pollution (Section 3.2). We

Table 1
Comparing EU Roadmap targets (rel. to 1990) with the median of emissions in % across scenarios and models (coefficient of variation in brackets; land-use, land-use change and forestry sectors are included) in the EU. IMACLIM and POLES are not included for GHG and Non-CO2 results as these models do not comprise the full basket of Kyoto gasses. Abbreviation: FF&I refers to fossil fuels and industryrefers to fossil fuels and industry.

Reduction	Scenario	2030	2040	2050	2100
GHG	Roadmap	40–44%	60%	79–82%	N/A
	RefPol	24 (0.30)	34 (0.21)	44 (0.16)	72 (0.04)
	450P-EU	34 (0.18)	51 (0.19)	67 (0.35)	96 (0.14)
	RefP-EUback	34 (0.21)	41 (0.17)	48 (0.18)	74 (0.10)
Non-CO_2	Roadmap	72–73%	N/A	70–78%	N/A
	RefPol	32 (0.82)	39 (0.61)	41 (0.60)	44 (0.90)
	450P-EU	38 (0.49)	45 (0.30)	49 (0.15)	59 (0.39)
	RefP-EUback	38 (0.49)	40 (0.59)	40 (0.61)	47 (0.88)
FF&I CO_2	Roadmap, Power	54–68%	N/A	93–99%	N/A
	Roadmap, Industry	34–40%	N/A	83–87%	N/A
	RefPol	24 (0.34)	37 (0.20)	45 (0.18)	80 (0.12)
	450P-EU	38 (0.21)	57 (0.37)	73 (0.26)	107 (0.12)
	RefP-EUback	38 (0.23)	45 (0.13)	51 (0.14)	82 (0.07)

define co-benefits as a positive physical side effect of one policy (here climate policy) for another public policy objective (see also [8]). Note that, Borenstein [2] and others are skeptical about the possibility to calculate such co-benefits as there are large uncertainties connected with the methods to compare costs (e.g. how to separate between private and public benefits or how to monetarize environmental externalities). Edenhofer et al. [7] add that as policies typically target multiple objectives, an assessment of co-benefits would need to account for this. They argue that additional welfare effects of co-benefits can conceptually only occur when these other objectives have not been addressed by appropriate policy instruments. In addition to the difficulty around cost calculation methods, there are also large uncertainties connected with our knowledge about the fundamental processes that govern the complex human–environment system in its past, present, and future. These uncertainties translate into different modeling approaches, input assumptions, and choices in the level of details.

Given these large methodological and model uncertainties, we keep our analysis at the level of a qualitative discussion with regard to energy security and trade expenditures. In the case of external costs avoided, we provide rough estimations comparing the costs and benefits of and from EU's pioneering action.

3.1. Improving energy security and reducing trade expenditures

With respect to energy security, a region benefits when its self-sufficiency ratio in supplying energies can be increased or when the resilience of the energy system against uncertain risks can be improved, as for example achieved by diversifying energy sources, refer to [1,5] for a detailed review. Upon exploring pathways for a sustainable energy transition, Riahi et al. [25] find that energy efficiency and RE have the potential to double the share of domestic energy supply. Borenstein [2] and Edenhofer et al. [7] however point out that the contribution of RE to energy security is likely to be small once the variability of RE is taken into account. According to the authors, advantages of higher RE shares tend to be associated with environmental

[2] Note, Knopf et al. [18] find that the 20% reduction target in 2020 is not consistent with the cost-effective milestones set in the EU Roadmap. General conclusions made in the EU Roadmap and related documents are, however, supported by their study.

benefits, [2,7], or access to energy for less developed regions, [7], rather than energy security.

For our analysis, we follow Riahi et al. [25]. and McCollum et al. [23] who calculate a compound energy security indicator applicable to the IAMs participating in our study. It accounts for a region's self-sufficiency in energy supply as well as for its resilience strength. The former is represented by the share of traded energy at the primary level, whereas the latter measures the diversity of energy supply (at primary level and for electricity generation) based on the Shannon–Wiener index. While our choice of this indicator is motivated by a desire for the analysis to not become too complicated and is dependent on the coverage of all possibilities to, e.g., generate electricity, the compound energy security indicator offers an opportunity to produce results comparable to the literature. There are other energy security indicators and for a review of their pros and cons refer to [1,5,21].

The portfolio of possible supply resources we account for at the primary energy level includes biomass, coal, gas, geothermal, hydro, nuclear, ocean, oil, solar, and wind. Potential sources for generating electricity are biomass, coal, gas, geothermal, hydro, nuclear, ocean, oil, solar, and wind. We use the same definition of the indicator, *DI*, and its compound, *CDI*, as in [16] and calculate

$$DI = -\sum_i (p_i * ln(p_i)), CDI = -\sum_i (1-m_i) * (p_i \ln(p_i)),$$

with p_i as the share of primary energy (PE) type (or the share of a power generation technology) i in total supply, and m_i as the share of PE resource i supplied by net imports. The classification of *CDI* is the same as for *DI*. Note that decarbonization can also decrease the indices.

Table 2 shows the index for the diversity of PE supply and electricity generation across different scenarios as model means (with the coefficient of variance given in brackets). Across all scenarios with climate policies, the diversity of PE supply increases by 2030. Differences between these scenarios are small as they are almost independent of early action, concerted action, or levels of stringency. For the no policy baseline, however, comparatively high values are only reached at the end of the century, which makes the diversification of primary energy a co-benefit of climate change mitigation. Note that the findings are robust for all models and scenarios.

The diversity indicator of electricity supply is already above 1.5 for all scenarios from 2005 onward, although the coefficient of variation increases in some scenarios and leads to less robust findings. The development of the compound index, which also incorporates import dependencies, is again robust for all models and scenarios (this is of course also due to the high aggregation level of the index which blurs differences in model strategies). For scenarios fostering climate policies, the category tends to reach around 1.5 already by 2030. This is only achieved in the no policy base by 2100. This suggests a co-benefit exists with respect to energy security in general, as it can be enhanced relative to Base in climate policy scenarios regardless of the level of stringency or its timing.

In the following we examine the development of import dependency on fossil resources (coal, gas, and oil) since co-benefits are connected with lower or less vulnerable trade expenditures for importing fossil fuels in case of increasing or instable price developments at global fossil fuel markets.

Table 2
Trends of energy diversity indicators. Abbr.: PE – primary energy. Numbers in brackets give the coefficient of variation across models.

Index for Europe	Scenario	2005	2030	2050
Diversity of PE supply	Base	1.43 (0.03)	1.43 (0.09)	1.52 (0.19)
	RefPol	1.43 (0.03)	1.64 (0.08)	1.72 (0.11)
	450P-EU	1.44 (0.02)	1.69 (0.10)	1.72 (0.12)
	RefP-EUback	1.43 (0.03)	1.67 (0.09)	1.71 (0.10)
	CF-450	1.43 (0.03)	1.54 (0.14)	1.72 (0.16)
Diversity of electricity	Base	1.54 (0.08)	1.55 (0.24)	1.56 (0.38)
	RefPol	1.54 (0.08)	1.79 (0.12)	1.73 (0.27)
	450P-EU	1.54 (0.05)	1.83 (0.10)	1.74 (0.16)
	RefP-EUback	1.54 (0.08)	1.82 (0.12)	1.73 (0.30)
	CF-450	1.54 (0.08)	1.70 (0.12)	1.73 (0.07)
Compound index	Base	1.26 (0.06)	1.22 (0.16)	1.36 (0.23)
	RefPol	1.26 (0.06)	1.45 (0.14)	1.60 (0.21)
	450P-EU	1.27 (0.02)	1.53 (0.17)	1.64 (0.18)
	RefP-EUback	1.27 (0.06)	1.51 (0.16)	1.63 (0.18)
	CF-450	1.26 (0.06)	1.41 (0.22)	1.61 (0.22)

Table 3 presents an import dependency indicator that calculates the share of fossil energy resources traded at the primary energy level. This indicator has also been used in [16]. We find that by 2050 Europe's import dependency could be reduced below today's level in scenarios with climate policies, although the spread across models is large. Note that the indicator only increases until 2030 in Base and RefPol. Note that trends are consistent with results found in [12], where in 2050 decarbonization scenarios range between 35 and 45% compared to 58% for both, the reference and current policies scenarios. As in our scenarios, the import dependency is affected only in later decades, driven by installed capacities of RE and a decline in domestic consumption. While these trends differ across the decarbonization scenarios in [12], resulting indicators show a spread of 10%.

The large spread in the indicator across models in this study is due to different strategies across models regarding decarbonization options and due to differences in a model's input assumptions. For example, DNE21+ builds its emission reduction strategy on strongly reducing CO_2 emissions from the residential and commercial sectors and by completely capturing carbon dioxide emissions of electricity supply, which is most pronounced in 450P-EU. Also, DNE21+ is a model with a high variety of energy supply technologies and CCS plays a large role as well as the transition to a hydrogen based society. On the other hand, the highest shares of RE in primary energy are seen in 450P-EU for the models IMAGE, MERGE-ETL, and REMIND ranging from 43 to 53% by 2050. Only these models in the corresponding scenario are in the range of RE shares seen in decarbonization scenarios within the EU Roadmap [12], i.e. 41–59% by 2050. A reason for a high

Table 3
Indicator on import dependency of Europe on fossil resources (coal, gas, and oil). Numbers in brackets give the coefficient of variation across models.

Scenario	2010	2030	2050
Base	48% (0.15)	49% (0.24)	46% (0.36)
RefPol	49% (0.19)	50% (0.41)	38% (0.88)
450P-EU	48% (0.13)	45% (0.30)	25% (1.17)
RefP-EUback	48% (0.12)	43% (0.33)	29% (1.17)
CF-450	48% (0.13)	47% (0.42)	33% (0.73)

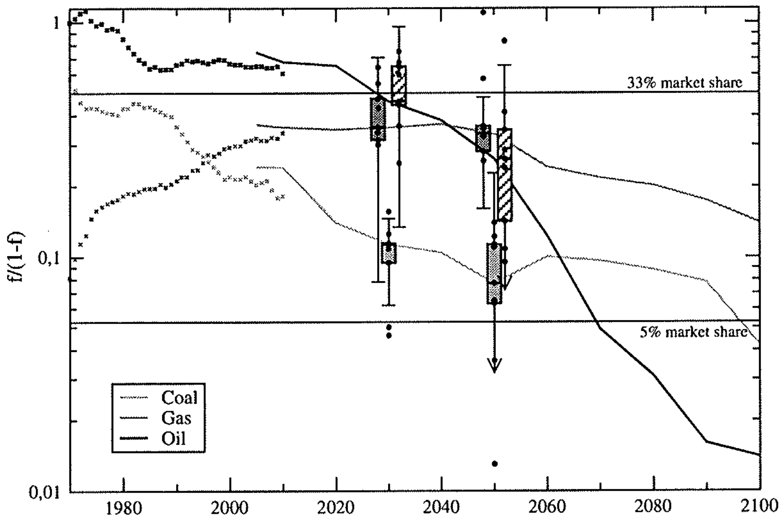

Fig. 2. Fisher–Pry plot (upper panel).

RE share in, e.g., IMAGE, is that on-shore wind is a particular low-cost option (measured by levelized cost of electricity – LCOE). A second pillar in the RE mix of IMAGE is biomass in combination with CCS.

In all models, the import of oil is being reduced strongly in upcoming decades across all climate policy scenarios. Compared to 2010, oil imports in 2050 decrease between 46% (0.71) and 54% (0.54) in climate policy scenarios and 29% (0.51) in the Base. Since oil prices are increasing during the same time (most pronounced in climate policy scenarios), this is combined with a lower bill for oil. The reduction potential compared to the Base in 2050 is up to 40–50% (with mixed robustness). How coal and gas bills are affected is even more diverse across models since models opt for different roles of coal and gas in future markets. For example, some models see a renaissance of coal possible as CCS technologies mature. Others, see gas to take a bridging role before renewable energies have the lion's share in the markets. This is also underlined in Figs. 2–4 showing the market ratio of fossil primary energy carriers f (as $f/(1-f)$) over time in a semi-logarithmic plot (Fisher–Pry graph) for 450P-EU, RefP-EUback, and RefPol (upper panel, middle panel, and lower panel, resp.). Historical data are also included and shown as crosses.[3] Lines show the development of model means, the range of models is indicated for 2030 and 2050 using standard box plots.[4] Furthermore, the two black lines indicate market shares of 5% and 33%.

Concluding, the analysis in this section leads to the identification of co-benefits connected with energy security and trade expenditures. However, the spread across models is large as multiple pathways are available to decarbonize the energy system – especially with regard to CCS linked to gas and/or coal.

[3] Note, smaller deviation in 2005 from historical and model data are due to different regional definitions and differences in accounting methods.

[4] To avoid overlapping boxes, they are not exactly located at 2030 and 2050.

3.2. External costs avoided within the electricity sector

Ever since the ExternE project was commissioned by the European Commission in 1995, cross-benefits of major policies have increasingly been reviewed. While doubts may persist in the validity of externality estimates, especially in terms of climate change damages, other key metrics such as health related damage costs from air pollution have been acknowledged to give a good approximation of the order of magnitude of the associated external cost [18]. This consideration is an important one as external costs in terms of monetary valuations tend to be heavily driven by respiratory effects. The EXIOPOL project estimated that for the EU in 2000 67.2% of the total external cost was attributed to air pollution and that this is consistent with a 369 billion Euro valuation [26]. With a heavy focus on the EU, EXIOPOL assessed the damages from the emissions of pollutants and applied these estimates to an evaluation of EU Directive 2009/28/EC, [10], which focuses on a 20% share of RE in gross energy consumption and a 10% share of biofuels within transport. Focusing on GHGs, airborne pollutants, particulate matter and sulfur dioxide, the EXIOPOL project estimates that a decrease in CO_2 emissions of almost 150 Mt in 2020 leads to 11.6 billion Euros of benefits for the EU-27 [14].

Utilizing external cost estimates for electricity generation in 2020 sourced from the CASES (Cost Assessment of Sustainable Energy Systems) project, [3], we conduct a similar calculation for a range of models and a range of climate policies. Using estimates for the external cost of electricity generation for a range of energy types and a range of factors, such as human health, loss of biodiversity, and other various impacts from non-CO_2 gasses (including nitrogen oxides, particulates, and sulfur dioxide), we compare the implied external cost to the range of policy costs sourced from the models participating in the AMPERE project. Table 4 reviews the range of external cost estimates sourced from CASES that will be applied to the changes in electricity produced within the model results. For oil, solar PV, hydro, and biomass we have utilized an average of a range of specific technologies types provided within CASES to couple these with the broader categories reported by the

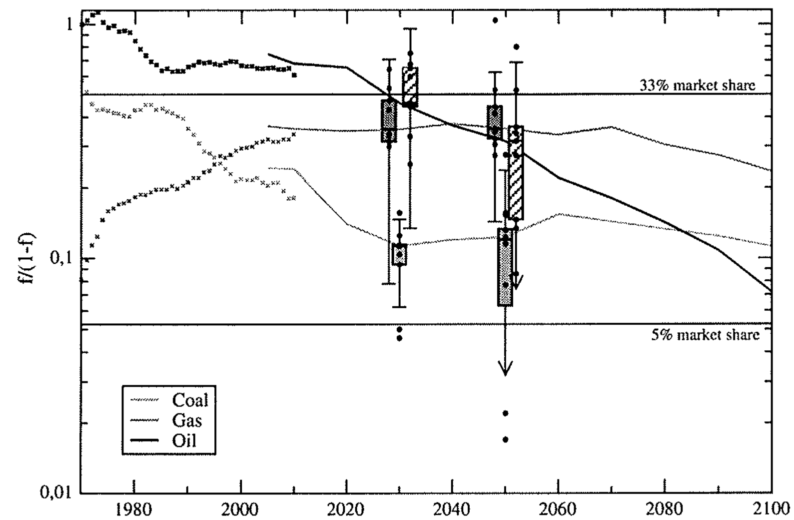

Fig. 3. Fisher–Pry plot (middle panel).

modeling teams within the AMPERE project. While this adds some uncertainty into the analysis, the discussion surrounding Fig. 6 will address the impact of the most notable source of potential bias this being differences in the source of biomass used for electricity production. CASES provides external cost estimates for both biomass from straw and biomass from woodchips with a differential in the external cost estimates of almost 3:1. Within this analysis, we have applied the average of these two costs and hence assume a 50–50 split between straw and woodchip based biomass. Fig. 6 shows the potential improvement if only woodchip based biomass were to be utilized, however it should be acknowledged that even with this allowance made the external cost associated with woodchip based biomass electricity production remains higher than that of gas without CCS.

Consistent with larger emission decreases and higher RE shares than in EU Directive 2009/28/EC and reviewed in the EXIOPOL project, Fig. 5 reviews the issue of whether there are co-benefits of following a range of climate policies. Fig. 5 shows that in 2020 the external costs avoided from electricity generation that can be associated with following different climate policies rival the total cost of following that policy. Shading within Figs. 5 and 6 represent the area between the 25th and 75th percentiles and highlight the clustering of individual model observations (marked as white rectangles). It should be noted that these estimates for external costs avoided are only for electricity production and are likely to increase as other sectors are added to these numbers. It is important to note that external costs are calculated using the CASE estimates (Euro cents per kWh) for each fuel type and the levels of energy in each scenario separately. These

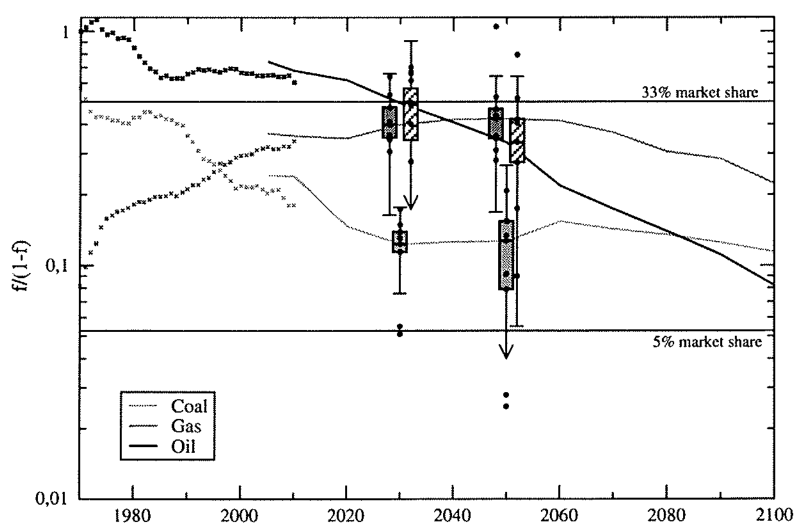

Fig. 4. Fisher–Pry plot (lower panel) showing the development of market shares f for fossil energy technologies at primary energy level. The upper panel shows 450P-EU, the middle panel RefP-EUback, and the lower panel shows RefPol. Historical data are indicated by crosses, source of data: ENERDATA.

Table 4
External costs of energy produced by impact category (2005 Euro cents per kWh). Abbr.: SO_2 – sulfur dioxide, NO_x – nitrogen oxides.

	Nuclear	Oil	Gas	Coal
			wo CCS	wo CCS
Human health	0.090	2.035	0.519	0.855
Loss of biodiversity	0.006	0.133	0.060	0.078
Crop N deposition & crops O3	0.001	0.028	0.016	0.017
Crops SO2	−0.0001	−0.0016	−0.0002	−0.0005
Materials: SO2 & NO_x	0.001	0.040	0.007	0.014
Other pollutants – h. health	0.020	0.050	0.023	0.055
Radionuclides generic	0.0020	0.0002	≈0	0.0001
	Wind	Solar PV	Hydro	Biomass
Human health	0.041	0.546	0.050	0.981
Loss of biodiversity	0.003	0.030	0.002	0.202
Crop N deposition & crops O3	0.001	0.006	0.001	0.016
Crops SO2	≈0	−0.0003	≈0	−0.0003
Materials: SO2 & NOx	≈0	0.008	≈0	0.009
Other pollutants – h. health	0.014	0.086	0.003	0.161
Radionuclides generic	≈0	0.0003	≈0	0.0003

are then aggregated so that they can be compared to the Base scenario, resulting in external costs avoided. While some of these externalities may be accounted for in reality through non-climate based policy making and regulations, IAMs usually start from a no policy baseline and this is how we approach this analysis with respect to the differences between the Base and the climate policy scenarios.

Note that the mitigation/policy costs included in Fig. 5 are not fully comparable; however they nevertheless show that the external costs avoided from electricity alone tend to rival the aggregate cost of the climate policies reviewed. Mitigation costs from the general equilibrium models (Table 5) are given in terms of GDP losses (GEM-E3, MERGE-ETL, MESSAGE, REMIND, WITCH, and WorldScan). The mitigation costs for the partial equilibrium models are given in terms of the dead-weight loss area under the MAC curve (GCAM, IMAGE, and POLES) or in terms of additional energy system costs (DNE21+). WITCH has also reported the additional energy system cost and these estimates are included in Fig. 5. Upon reviewing these results, the differences between these mitigation cost concepts need to be kept in mind. Nevertheless, Fig. 5 includes lines which link the estimates of external costs avoided with the policy costs in terms of GDP loss for the five models which utilize the GDP loss policy cost metric. Of the five models, three show policy cost levels which are already below the estimates of external costs avoided for the electricity sector when the CASES generic climate change costs are accounted for in the RefPol and 450P-EU scenarios. Two models (MESSAGE and REMIND) show higher policy costs of approximately 15 billion Euros and 50 billion Euros, respectively, for the RefPol scenario. In the case of the 450P-EU scenario this differential is approximately 12 billion Euros and 43 billion Euros for these same models.

Irrespective of these differentials, the overall amount of emission reductions in comparison to the Base scenarios, the amount of emission reductions in other sectors, and the associated benefits of these reductions from these additional sectors are all issues which need to be considered. In the case of the CF450 scenario, all five models show benefits from following the policy based on external costs avoided in the electricity sector alone. As there is uncertainty concerning the cost of climate change damages, Fig. 5 shows external costs avoided with and without climate impacts. Introducing these climate change related costs inflate the estimates differently across the models, however four of the five models which report GDP loss based policy cost show relatively stable increases.

All of the models have a notable share of RE within Base and while the energy mixes to meet the different policies do differ, the one constant is that decarbonization in all models is associated with the decrease of coal without CCS technologies within electricity. A common trend across most models is the immediate decrease in the use of traditional coal-fired power stations, unless notable and rapid land-use changes are possible. Global concerted effort that coincides with the cost-effective solution for each model (CF-450) results in lower policy costs within the EU and less aggressive reductions than those shown in the policies where the EU pioneers with immediate action. Fig. 5 shows that the gain of co-benefits through external costs avoided is possible, even upon reviewing the reduction of externalities from electricity alone, with and without the impact of climate damages. Additional external costs avoided should be added to these estimates to account

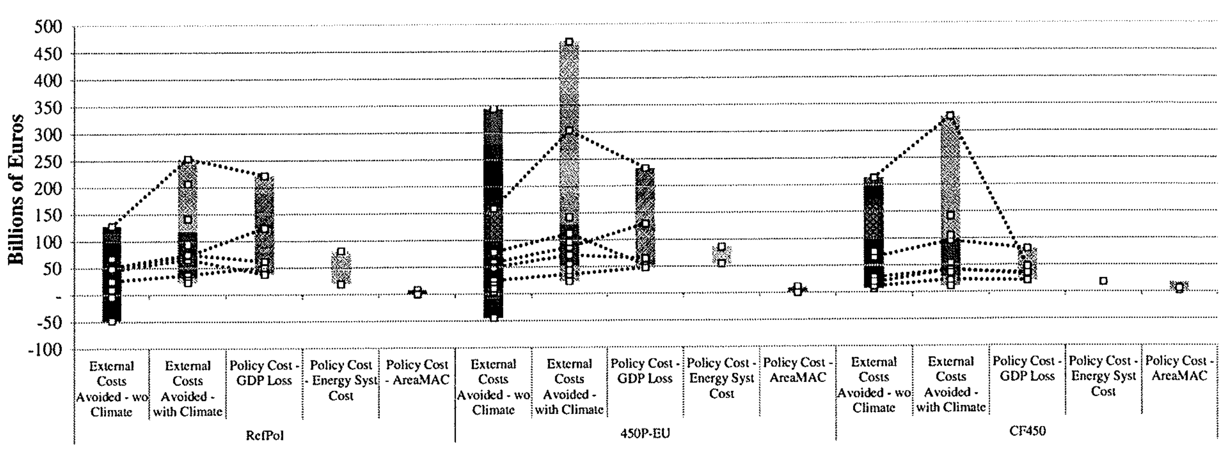

Fig. 5. External costs avoided from changes to electricity production in 2020 costs avoided calculated using Base scenario (billions 2005 Euros).

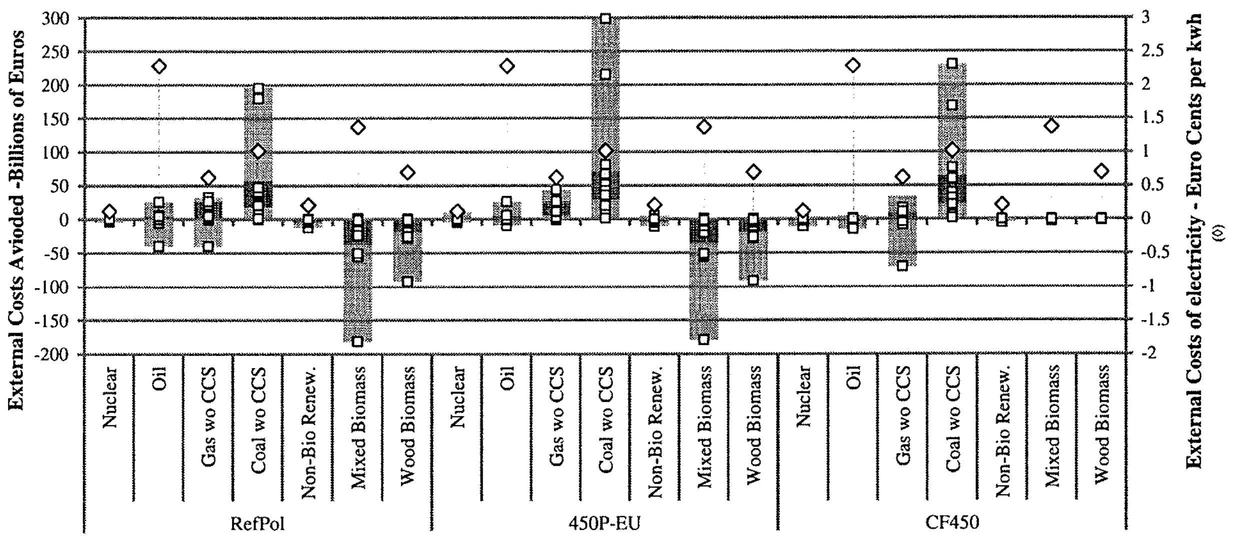

Fig. 6. External costs avoided from changes to electricity production in 2020 calculated using Base scenario (billions 2005 Euros).

for changes in transportation and other sectors. For example, within the EXIOPOL project a 10% biofuel share consistent with meeting EU Directive 2009/28/EC and achieving an 8% decrease in total emissions was attributed to a benefit of 4 billion Euros [14]. The issue of energy security and RE energy has also been reviewed with respect to co-benefits in Section 3.2; [7,15,22] should also be considered in addition to the analysis within this section.

Fig. 6 presents the range of external costs avoided across technology types (without climate impacts). Reducing traditional coal-fired power plants provides the greatest co-benefit due to the amount of external costs associated with this technology. Note that coal without CCS has the third highest external cost per kWh as denoted by the height of the diamonds in Fig. 6 and across the categories in Table 4. The cost of coal without CCS is lower than the external cost for oil and mixed biomass in terms of Euro cents per kWh, upon using the assumed 50–50 split between straw and woodchip based biomass. The benefits of a greater share of non-biomass RE than in the no policy scenario Base assist decarbonization aimed at meeting the climate policy target without a significant increase in external costs. The impact of biomass is an important issue as the CASES estimates show that the source of the biomass will have a notable impact upon the external costs estimates. Uncertainties concerning the impact of biomass are present within this analysis due to the likelihood of different mixes of biomass sources in each model and/or scenario. The potential impact of this is shown within Fig. 6 with the external costs defined for woodchip based biomass alone being almost half of that associated with the mixed biomass case. Human health and biodiversity loss are where noticeable differences in the costs between straw and wood chip based biomass occur.

Indeed, the source of biomass is important within IAM studies as while providing notable emission reduction potential, these models also may not fully capture the negative externalities of this fuel source. Creutzig et al. [6] note that while IAMs tend to notably rely upon bio-energy, life-cycle emissions of these fuel sources are highly uncertain overall and IAMs tend to insufficiently account for induced land-use changes. Upon directly incorporating external cost estimates into the MARKAL model, Rafaj and Kypreos [24] found large reductions in coal use which were heightened when both local and global externalities were accounted for. While Klaassen and Riahi [17] found that accounting for externalities within the MESSAGE-MACRO model resulted in little reduction in carbon dioxide emissions (due to carbon leakage), significant decreases in sulfur emissions did occur irrespective of the existence of DESOX technologies within their baseline. With co-benefits acknowledged, Klaassen and Riahi [17] conclude with the acknowledgment that damage costs for SO_2 and NO_x are underestimated due to the exemption of damages to sensitive ecosystems and historical buildings, as well as the valuation of mortality impacts. These limitations are also valid for the external cost estimates utilized within this paper.

To conclude the discussion, we now focus on a comparison of the external costs avoided in comparison to the CF450 scenario using the RefPol and 450P-EU scenarios. In doing so, we are able to review how these interim policy measures differ in comparison to a fully flexible global climate policy. The majority of observations in Fig. 7 show the expected relationship between higher abatement/emissions and higher external costs avoided/suffered. With respect to external costs avoided in comparison to CF450, the MERGE model stands out with similar emission reductions and less external costs avoided in comparison to other models due to either more coal w/o CCS and/or biomass prevailing in these MERGE results. Four models (DNE21, GEM-E3, MESSAGE, and REMIND) cluster together with a range of relative abatement of 10–15% more CO_2 emission reductions compared to the 1990 level. GCAM has strong CO_2 emission reductions in both RefPol and 450P-EU as the model has a relatively low decrease in energy demand with respect to other models, while IMACLIM also does strong CO_2 abatement in the RefPol scenario. Two models (WITCH and WorldScan) have fewer emission abatement in the 450P-EU scenario with respect to the CF450 scenario which reflect how much abatement is conducted outside the EU or in other GHGs.

Across the scenarios reviewed (RefPol and 450P-EU), the consideration of external costs from the electricity sector

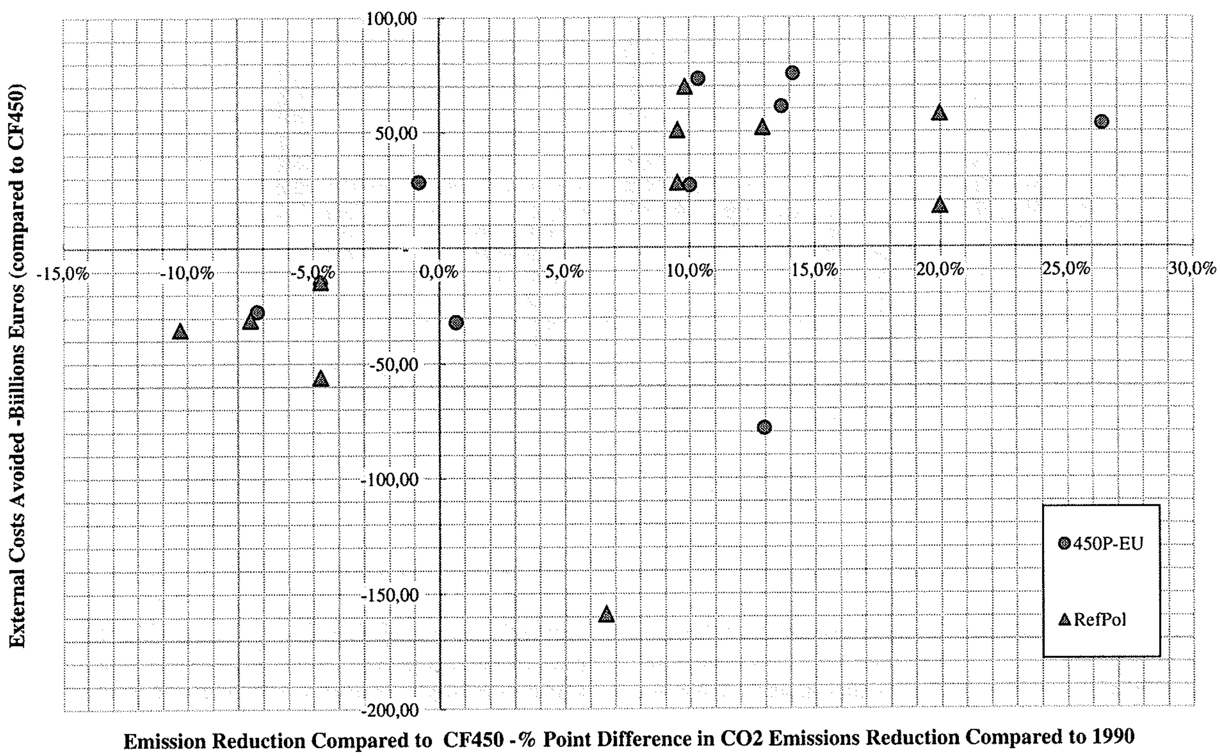

Fig. 7. External costs avoided and CO_2 emission reductions in comparison to CF450 scenario.

leads to evidence that non-climate co-benefits are likely to include the reduction of coal without CCS and the promotion of non-biomass RE. It is acknowledged that a definitive choice between the policy scenarios within this analysis would need a broader range of benefits and a more direct comparison to the costs of these policies. As such, these results on external costs avoided should be treated as being indicative of the potential co-benefits of climate policies (with sizable external costs avoided related to the electricity sector), while identifying reduced coal and increased RE as reasonable co-benefits related to a range of targets for CO_2 abatement — subject to caveats, such as caution based on the source of biomass.

4. Conclusions

Within this paper, we study co-benefits of climate change mitigation for the EU across eleven different IAMs and a range of decarbonization scenarios. We review non-climate synergies related to energy security and lower trade expenditures. In addition, we analyze external costs avoided in the electricity sector and identify those technologies with the greatest potential benefit in terms of externalities reduced. Our assessment yields the following results:

- *Improving energy security and reducing trade expenditures*: We find a tendency for the oil bill to be lower under climate policies and a reduction of import dependencies on fossil resources. But results show a large spread across models since decarbonization pathways vary. At the same time the diversity of PE supply improves in all climate policy scenarios across the models and it has been identified as being robust. Thus, the diversity of energy supply constitutes a co-benefit. Models are, however, mixed regarding the relative flexibility in the electricity sector.
- *External costs avoided within the electricity sector*: We find that in 2020 the co-benefit of decarbonizing the electricity sector tends to result in potential benefits which rival the total cost of the policy. These benefits are related to the reduction of coal without CCS in favor of non-biomass RE. An important issue to consider w.r.t. externalities is the source of biomass, which can lead to notably different estimates of external costs avoided. For example, in this analysis we have looked at costs associated with wood based biomass in comparison to a mixed source which includes 50% straw. However, IAMs will likely have different sources utilized across models and/or scenarios. Note that we have been conservative in applying the mixed sources external costs estimates within the sectoral calculations.

As a general result we furthermore find that the spread across models is larger than across climate policy scenarios, suggesting that a multi-model analysis is necessary to identify robust results given the large uncertainties surrounding climate change causes and impacts. In light of this, the analysis has focused upon identifying results which are robust and consistent across models.

Acknowledgment

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Appendix A

Table 5
Overview on model characteristics. Abbr.: agri — agriculture, aggr. — aggregated, LU — land-use, regional mapping: + if a native model region is larger than EU27 and — if smaller, U uranium, C coal, O oil, G gas, TC — technological change, exTC exogenous TC, enTC endogenous TC, AEEI autonomous energy efficiency improvements, agro — agro-products, elec — electricity, o — other.

Model	Economic coverage	Regional resolution	Technology and TC	Trade
DNE21+	energy	19 regions, EU27−	exTC	C, O, G, LNG, bio fuel, elec
GCAM	economy, energy, LU	14 regions, EU27+	exTC	C, O, G, U, agro
GEM-E3	economy, energy, agri	9 regions, EU27	exTC	agro, C, O, G, power, o. goods
IMACLIM	economy, energy, agri	12 regions, EU27+	enTC, LBD	all sector products
IMAGE	energy, agri	26 regions, EU27+		
MERGE-ETL	aggr. economy, energy	8 regions, EU27+	exTC, LBD	C, O, G, U, biomass, capital & energy-intensive good
MESSAGE	aggr. economy, energy, LU	11 regions, EU27+	exogenous for energy	C, O, G, U, LNG, elec, other energy
POLES	economy, energy, agri	21 regions, EU27	exTC, enTC	C, O, G, U, biomass
REMIND	aggr. economy, energy	11 regions, EU27		C, O, G, U, capital good
WITCH	aggr. economy, energy	13 regions, EU27	exTC, enTC	C, O, G
WorldScan	aggr., energy, economy	5 regions, EU27	exTC	C, G, O

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Full cost accounting for the life cycle of coal

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Each stage in the life cycle of coal—extraction, transport, processing, and combustion—generates a waste stream and carries multiple hazards for health and the environment. These costs are external to the coal industry and are thus often considered "externalities." We estimate that the life cycle effects of coal and the waste stream generated are costing the U.S. public a third to over one-half of a trillion dollars annually. Many of these so-called externalities are, moreover, cumulative. Accounting for the damages conservatively doubles to triples the price of electricity from coal per kWh generated, making wind, solar, and other forms of nonfossil fuel power generation, along with investments in efficiency and electricity conservation methods, economically competitive. We focus on Appalachia, though coal is mined in other regions of the United States and is burned throughout the world.

Keywords: coal; environmental impacts; human and wildlife health consequences; carbon capture and storage; climate change

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Introduction

Coal is currently the predominant fuel for electricity generation worldwide. In 2005, coal use generated 7,334 TWh (1 terawatt hour = 1 trillion watt-hours, a measure of power) of electricity, which was then 40% of all electricity worldwide. In 2005, coal-derived electricity was responsible for 7.856 Gt of CO_2 emissions or 30% of all worldwide carbon dioxide (CO_2) emissions, and 72% of CO_2 emissions from power generation (one gigaton = one billion tons; one metric ton = 2,204 pounds.)[1] Non–power-generation uses of coal, including industry (e.g., steel, glass-blowing), transport, residential services, and agriculture, were responsible for another 3.124 Gt of CO_2, bringing coal's total burden of CO_2 emissions to 41% of worldwide CO_2 emissions in 2005.[1]

By 2030, electricity demand worldwide is projected to double (from a 2005 baseline) to 35,384 TWh, an annual increase of 2.7%, with the quantity of electricity generated from coal growing 3.1% per annum to 15,796 TWh.[1] In this same time period, worldwide CO_2 emissions are projected to grow 1.8% per year, to 41.905 Gt, with emissions from the coal-power electricity sector projected to grow 2.3% per year to 13.884 Gt.[1]

In the United States, coal has produced approximately half of the nation's electricity since 1995,[2] and demand for electricity in the United States is projected to grow 1.3% per year from 2005 to 2030, to 5,947 TWh.[1] In this same time period, coal-derived electricity is projected to grow 1.5% per year to 3,148 TWh (assuming no policy changes from the present).[1] Other agencies show similar projections; the U.S. Energy Information Administration (EIA)

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projects that U.S. demand for coal power will grow from 1,934 TWh in 2006 to 2,334 TWh in 2030, or 0.8% growth per year.[3]

To address the impact of coal on the global climate, carbon capture and storage (CCS) has been proposed. The costs of plant construction and the "energy penalty" from CCS, whereby 25–40% more coal would be needed to produce the same amount of energy, would increase the amount of coal mined, transported, processed, and combusted, as well as the waste generated, to produce the same amount of electricity.[1,4] Construction costs, compression, liquefaction and injection technology, new infrastructure, and the energy penalty would nearly double the costs of electricity generation from coal plants using current combustion technology (see Table 2).[5]

Adequate energy planning requires an accurate assessment of coal reserves. The total recoverable reserves of coal worldwide have been estimated to be approximately 929 billion short tons (one short ton = 2,000 pounds).[2] Two-thirds of this is found in four countries: U.S. 28%; Russia 19%; China 14%, and India 7%.[6] In the United States, coal is mined in 25 states.[2] Much of the new mining in Appalachia is projected to come from mountaintop removal (MTR).[2]

Box 1.

Peak Coal?

With 268 billion tons of estimated recoverable reserves (ERR) reported by the U.S. Energy Information Administration (EIA), it is often estimated that the United States has "200 years of coal" supply.[7] However, the EIA has acknowledged that what the EIA terms ERR cannot technically be called "reserves" because they have not been analyzed for profitability of extraction.[7] As a result, the oft-repeated claim of a "200 year supply" of U.S. coal does not appear to be grounded on thorough analysis of economically recoverable coal supplies.

Reviews of existing coal mine lifespan and economic recoverability reveal serious constraints on existing coal production and numerous constraints facing future coal mine expansion. Depending on the resolution of the geologic, economic, legal, and transportation constraints facing future coal mine expansion, the planning horizon for moving beyond coal may be as short as 20–30 years.[8–11]

Recent multi-Hubbert cycle analysis estimates global peak coal production for 2011 and U.S. peak coal production for 2015.[12] The potential of "peak coal" thus raises questions for investments in coal-fired plants and CCS.

Worldwide, China is the chief consumer of coal, burning more than the United States, the European Union, and Japan combined. With worldwide demand for electricity, and oil and natural gas insecurities growing, the price of coal on global markets doubled from March 2007 to March 2008: from \$41 to \$85 per ton.[13] In 2010, it remained in the \$70+/ton range.

Coal burning produces one and a half times the CO_2 emissions of oil combustion and twice that from burning natural gas (for an equal amount of energy produced). The process of converting coal-to-liquid (not addressed in this study) and burning that liquid fuel produces especially high levels of CO_2 emissions.[13] The waste of energy due to inefficiencies is also enormous. Energy specialist Amory Lovins estimates that after mining, processing, transporting and burning coal, and transmitting the electricity, only about 3% of the energy in the coal is used in incandescent light bulbs.[14]

Thus, in the United States in 2005, coal produced 50% of the nation's electricity but 81% of the CO_2 emissions.[1] For 2030, coal is projected to produce 53% of U.S. power and 85% of the U.S. CO_2 emissions from electricity generation. None of these figures includes the additional life cycle greenhouse gas (GHG) emissions from coal, including methane from coal mines, emissions from coal transport, other GHG emissions (e.g., particulates or black carbon), and carbon and nitrous oxide (N_2O) emissions from land transformation in the case of MTR coal mining.

Coal mining and combustion releases many more chemicals than those responsible for climate forcing. Coal also contains mercury, lead, cadmium, arsenic, manganese, beryllium, chromium, and other toxic, and carcinogenic substances. Coal crushing, processing, and washing releases tons of particulate matter and chemicals on an annual basis and contaminates water, harming community public health and ecological systems.[15–19] Coal combustion also results in emissions of NO_x, sulfur dioxide (SO_2), the particulates PM_{10} and $PM_{2.5}$, and mercury; all of which negatively affect air quality and public health.[20–23]

In addition, 70% of rail traffic in the United States is dedicated to shipping coal, and rail transport is associated with accidents and deaths.[20] If coal use were to be expanded, land and transport infrastructure would be further stressed.

Summary of methods

Life cycle analysis, examining all stages in using a resource, is central to the full cost accounting needed to guide public policy and private investment. A previous study examined the life cycle stages of oil, but without systematic quantification.[24] This paper is intended to advance understanding of the measurable, quantifiable, and qualitative costs of coal.

In order to rigorously examine these different damage endpoints, we examined the many stages in the life cycle of coal, using a framework of environmental externalities, or "hidden costs." Externalities occur when the activity of one agent affects the well-being of another agent outside of any type of market mechanism—these are often not taken into account in decision making and when they are not accounted for, they can distort the decision-making process and reduce the welfare of society.[20] This work strives to derive monetary values for these externalities so that they can be used to inform policy making.

This paper tabulates a wide range of costs associated with the full life cycle of coal, separating those that are quantifiable and monetizable; those that are quantifiable, but difficult to monetize; and those that are qualitative.

A literature review was conducted to consolidate all impacts of coal-generated electricity over its life cycle, monetize and tabulate those that are monetizable, quantify those that are quantifiable, and describe the qualitative impacts. Since there is some uncertainty in the monetization of the damages, low, best, and high estimates are presented. The monetizable impacts found are damages due to climate change; public health damages from NO_x, SO_2, $PM_{2.5}$, and mercury emissions; fatalities of members of the public due to rail accidents during coal transport; the public health burden in Appalachia associated with coal mining; government subsidies; and lost value of abandoned mine lands. All values are presented in 2008 US$. Much of the research we draw upon represented uncertainty by presenting low and/or high estimates in addition to best estimates. Low and high values can indicate both uncertainty in parameters and different assumptions about the parameters that others used to calculate their estimates. Best estimates are not weighted averages, and are derived differently for each category, as explained below.

Climate impacts were monetized using estimates of the social cost of carbon—the valuation of the damages due to emissions of one metric ton of carbon, of $30/ton of CO_2equivalent (CO_2e),[20] with low and high estimates of $10/ton and $100/ton. There is uncertainty around the total cost of climate change and its present value, thus uncertainty concerning the social cost of carbon derived from the total costs. To test for sensitivity to the assumptions about the total costs, low and high estimates of the social cost of carbon were used to produce low and high estimates for climate damage, as was done in the 2009 National Research Council (NRC) report on the "Hidden Costs of Energy."[20] To be consistent with the NRC report, this work uses a low value of $10/ton CO_2e and a high value of $100/ton CO_2e.

All public health impacts due to mortality were valued using the value of statistical life (VSL). The value most commonly used by the U.S. Environmental Protection Agency (EPA), and used in this paper, is the central estimate of $6 million 2000 US$, or $7.5 million in 2008 US$.[20]

Two values for mortality risk from exposure to air pollutants were found and differed due to different concentration-response functions—increases in mortality risk associated with exposure to air pollutants. The values derived using the lower of the two concentration-response functions is our low estimate, and the higher of the two concentration-response functions is our best and high estimate, for reasons explained below. The impacts on cognitive development and cardiovascular disease due to mercury exposure provided low, best, and high estimates, and these are presented here.

Regarding federal subsidies, two different estimates were found. To provide a conservative best estimate, the lower of the two values represents our low and best estimate, and the higher represents our high estimate. For the remaining costs, one point estimate was found in each instance, representing our low, best, and high estimates.

The monetizable impacts were normalized to per kWh of electricity produced, based on EIA estimates of electricity produced from coal, as was done in the NRC report tabulating externalities due to coal.[2,20] Some values were for all coal mining, not just for the portion emitted due to coal-derived electricity. To correct for this, the derived values were multiplied by the proportion of coal that was used for electrical power, which was approximately 90% in all years analyzed. The additional impacts from nonpower uses of coal, however, are not included in this analysis but do add to the assessment of the complete costs of coal.

To validate the findings, a life cycle assessment of coal-derived electricity was also performed using the Ecoinvent database in SimaPro v 7.1.[25] Health-related impact pathways were monetized using the value of disability-adjusted life-years from ExternE,[26] and the social costs of carbon.[20] Due to data limitations, this method could only be used to validate damages due to a subset of endpoints.

Box 2.

Summary Stats

1. Coal accounted for 25% of global energy consumption in 2005, but generated 41% of the CO_2 emissions that year.
2. In the United States, coal produces just over 50% of the electricity, but generates over 80% of the CO_2 emissions from the utility sector.[2]
3. Coal burning produces one and a half times more CO_2 emissions than does burning oil and twice that from burning natural gas (to produce an equal amount of energy).
4. The energy penalty from CCS (25–40%) would increase the amount of coal mined, transported, processed, and combusted, and the waste generated.[4]
5. Today, 70% of rail traffic in the United States is dedicated to shipping coal.[20] Land and transport would be further stressed with greater dependence on coal.

Life cycle impacts of coal

The health and environmental hazards associated with coal stem from extraction, processing, transportation and combustion of coal; the aerosolized, solid, and liquid waste stream associated with mining, processing, and combustion; and the health, environmental, and economic impacts of climate change (Table 1).

Underground mining and occupational health

The U.S. Mine Safety and Health Administration (MSHA) and the National Institute for Occupational Safety and Health (NIOSH) track occupational injuries and disabilities, chronic illnesses, and mortality in miners in the United States. From 1973 to 2006 the incidence rate of all nonfatal injuries decreased from 1973 to 1987, then increased dramatically in 1988, then decreased from 1988 to 2006.[27] Major accidents still occur. In January 2006, 17 miners died in Appalachian coal mines, including 12 at the Sago mine in West Virginia, and 29 miners died at the Upper Big Branch Mine in West VA on April 5, 2010. Since 1900 over 100,000 have been killed in coal mining accidents in the United States.[14]

In China, underground mining accidents cause 3,800–6,000 deaths annually,[28] though the number of mining-related deaths has decreased by half over the past decade. In 2009, 2,631 coal miners were killed by gas leaks, explosions, or flooded tunnels, according to the Chinese State Administration of Work Safety.[29]

Black lung disease (or pneumoconiosis), leading to chronic obstructive pulmonary disease, is the primary illness in underground coal miners. In the 1990s, over 10,000 former U.S. miners died from coal workers' pneumoconiosis and the prevalence has more than doubled since 1995.[30] Since 1900 coal workers' pneumoconiosis has killed over 200,000 in the United States.[14] These deaths and illnesses are reflected in wages and workers' comp, costs considered internal to the coal industry, but long-term support often depends on state and federal funds.

Again, the use of "coking" coal used in industry is also omitted from this analysis: a study performed in Pittsburgh demonstrated that rates of lung cancer for those working on a coke oven went up two and one-half times, and those working on the top level had the highest (10-fold) risk.[31]

Mountaintop removal

MTR is widespread in eastern Kentucky, West Virginia, and southwestern Virginia. To expose coal seams, mining companies remove forests and fragment rock with explosives. The rubble or "spoil" then sits precariously along edges and is dumped in the valleys below. MTR has been completed on approximately 500 sites in Kentucky, Virginia, West Virginia, and Tennessee,[32] completely altering some 1.4 million acres, burying 2,000 miles of streams.[33] In Kentucky, alone, there are 293 MTR sites, over 1,400 miles of streams damaged or destroyed, and 2,500 miles of streams polluted.[34–36] Valley fill and other surface mining practices associated with MTR bury headwater streams and contaminate surface and groundwater with carcinogens and heavy metals[16] and are associated with reports of cancer clusters,[37] a finding that requires further study.

The deforestation and landscape changes associated with MTR have impacts on carbon storage and water cycles. Life cycle GHG emissions from coal increase by up to 17% when those from deforestation and land transformation by MTR are included.[38] Fox and Campbell estimated the resulting emissions of GHGs due to land use changes in the Southern Appalachian Forest, which encompasses areas of southern West Virginia, eastern Kentucky, southwestern Virginia, and portions of eastern Tennessee, from a baseline of existing forestland.[38] They estimated that each year, between 6 and 6.9 million tons of CO_2e are emitted due to removal of forest plants and decomposition of forest litter, and possibly significantly more from the mining "spoil" and lost soil carbon.

The fate of soil carbon and the fate of mining spoil, which contains high levels of coal fragments, termed "geogenic organic carbon," are extremely uncertain and the results depend on mining practices at particular sites; but they may represent significant emissions. The Fox and Campbell[38] analysis determined that the worst-case scenario is that all soil carbon is lost and that all carbon in mining spoil is emitted—representing emissions of up to 2.6 million tons CO_2e from soil and 27.5 million tons CO_2e from mining spoil. In this analysis, the 6 million tons CO_2e from forest plants and forest litter represents our low and best estimates for all coal use, and 37 million tons CO_2e (the sum of the high bound of forest plants and litter, geogenic organic carbon, and the forest soil emissions) represents our high, upper bound estimate of emissions for all coal use. In the years Fox and Campell studied, 90.5% of coal was used for electricity, so we attribute 90.5% of these emissions to coal-derived power.[2] To monetize and bound our estimate for damages due to emissions from land disturbance, our point estimate for the cost was calculated using a social cost of carbon of \$30/ton CO_2e and our point estimate for emissions; the high-end estimate was calculated using the high-end estimate of emissions and a social cost of carbon of \$100/ton CO_2e; and the low estimate was calculated using the point estimate for emissions and the \$10/ton low estimate for the social cost of carbon.[20] Our best estimate is therefore \$162.9 million, with a range from \$54.3 million and \$3.35 billion, or 0.008¢/kWh, ranging from 0.003 ¢/kWh to 0.166 ¢/kWh.

The physical vulnerabilities for communities near MTR sites include mudslides and dislodged boulders and trees, and flash floods, especially following heavy rain events. With climate change, heavy rainfall events (2, 4, and 6 inches/day) have increased in the continental United States since 1970, 14%, 20%, and 27% respectively.[39,40]

Blasting to clear mountain ridges adds an additional assault to surrounding communities.[16] The blasts can damage houses, other buildings, and infrastructure, and there are numerous anecdotal reports that the explosions and vibrations are taking a toll on the mental health of those living nearby.

Additional impacts include losses in property values, timber resources, crops (due to water contamination), plus harm to tourism, corrosion of buildings and monuments, dust from mines and explosions, ammonia releases (with formation of ammonium nitrate), and releases of methane.[41]

Methane

In addition to being a heat-trapping gas of high potency, methane adds to the risk of explosions, and fires at mines.[20,42] As of 2005, global atmospheric methane levels were approximately 1,790 parts per billion (ppb), which is an 27 ppb increase over 1998.[43] Methane is emitted during coal mining and it is 25 times more potent than CO_2 during a 100-year timeframe (this is the 100-year global warming potential, a common metric in climate science and policy used to normalize different GHGs to carbon equivalence). When methane decays, it can yield CO_2, an effect that is not fully assessed in this equivalency value.[43]

According to the EIA,[2] 71,100,000 tons CO_2e of methane from coal were emitted in 2007 but

Table 1. The life cycle impact of the U.S. coal industry

	Economic	Human health	Environment	Other
Underground coal mining	1. Federal and state subsidies of coal industry	1. Increased mortality and morbidity in coal communities due to mining pollution	1. Methane emissions from coal leading to climate change	
		2. Threats remaining from abandoned mine lands	2. Remaining damage from abandoned mine lands	
MTR mining	1. Tourism loss	1. Contaminated streams	1. Loss of biodiversity	
	2. Significantly lower property values	2. Direct trauma in surrounding communities	2. Sludge and slurry ponds	
	3. Cost to taxpayers of environmental mitigation and monitoring (both mining and disposal stages)	3. Additional mortality and morbidity in coal communities due to increased levels of air particulates associated with MTR mining (vs. underground mining)	3. Greater levels of air particulates	
	4. Population declines	4. Higher stress levels	4. Loss and contamination of streams	
Coal mining	1. Opportunity costs of bypassing other types of economic development (especially for MTR mining)	1. Workplace fatalities and injuries of coal miners	1. Destruction of local habitat and biodiversity to develop mine site	1. Infrastructure damage due to mudslides following MTR
	2. Federal and state subsidies of coal industry	2. Morbidity and mortality of mine workers resulting from air pollution (e.g., black lung, silicosis)	2. Methane emissions from coal leading to climate change	2. Damage to surrounding infrastructure from subsidence
	3. Economic boom and bust cycle in coal mining communities	3. Increased mortality and morbidity in coal communities due to mining pollution	3. Loss of habitat and streams from valley fill (MTR)	3. Damages to buildings and other infrastructure due to mine blasting
	4. Cost of coal industry litigation	4. Increased morbidity and mortality due to increased air particulates in communities proximate to MTR mining	4. Acid mine drainage	4. Loss of recreation availability in coal mining communities

Continued

Table 1. *Continued*

	Economic	Human health	Environment	Other
	5. Damage to farmland and crops resulting from coal mining pollution	5. Hospitalization costs resulting from increased morbidity in coal communities	5. Incomplete reclamation following mine use	5. Population losses in abandoned coal-mining communities
		6. Local health impacts of heavy metals in coal slurry	6. Water pollution from runoff and waste spills	
	6. Loss of income from small scale forest gathering and farming (e.g., wild ginseng, mushrooms) due to habitat loss	7. Health impacts resulting from coal slurry spills and water contamination	7. Remaining damage from abandoned mine lands	
	7. Loss of tourism income	8. Threats remaining from abandoned mine lands; direct trauma from loose boulders and felled trees	8. Air pollution due to increased particulates from MTR mining	
	8. Lost land required for waste disposal	9. Mental health impacts		
	9. Lower property values for homeowners	10. Dental health impacts reported, possibly from heavy metals		
	10. Decrease in mining jobs in MTR mining areas	11. Fungal growth after flooding		
Coal transportation	1. Wear and tear on aging railroads and tracks	1. Death and injuries from accidents during transport	1. GHG emissions from transport vehicles	1. Damage to rail system from coal transportation
		2. Impacts from emissions during transport	2. Damage to vegetation resulting from air pollution	2. Damage to roadways due to coal trucks
Coal combustion	1. Federal and state subsidies for the coal industry	1. Increased mortality and morbidity due to combustion pollution	1. Climate change due to CO_2 and NO_x derived N_2O emissions	1. Corrosion of buildings and monuments from acid rain
	2. Damage to farmland and crops resulting from coal combustion pollution	2. Hospitalization costs resulting from increased morbidity in coal communities	2. Environmental contamination as a result of heavy metal pollution (mercury, selenium, arsenic)	2. Visibility impairment from NO_x emissions

Continued

Table 1. *Continued*

	Economic	Human health	Environment	Other
		3. Higher frequency of sudden infant death syndrome in areas with high quantities of particulate pollution 4. See Levy *et al.*[21]	3. Impacts of acid rain derived from nitrogen oxides and SO_2 4. Environmental impacts of ozone and particulate emissions 5. Soil contamination from acid rain 6. Destruction of marine life from mercury pollution and acid rain 7. Freshwater use in coal powered plants	
Waste disposal		1. Health impacts of heavy metals and other contaminants in coal ash and other waste 2. Health impacts, trauma and loss of property following coal ash spills	1. Impacts on surrounding ecosystems from coal ash and other waste 2. Water pollution from runoff and fly ash spills	
Electricity transmission	1. Loss of energy in the combustion and transmission phases		1. Disturbance of ecosystems by utility towers and rights of way	1. Vulnerability of electrical grid to climate change associated disasters

only 92.7% of this coal is going toward electricity. This results in estimated damages of \$2.05 billion, or 0.08¢/kWh, with low and high estimates of \$684 million and \$6.84 billion, or 0.034¢/kWh, and 0.34¢/kWh, using the low and high estimates for the social cost of carbon.[20] Life cycle assessment results, based on 2004 data and emissions from a subset of power plants, indicated 0.037 kg of CO_2e of methane emitted per kWh of electricity produced. With the best estimate for the social cost of carbon, this leads to an estimated cost of \$2.2 billion, or 0.11¢/kWh. The differences are due to differences in data, and data from a different years. (See Fig. 1 for summary of external costs per kWh.)

Impoundments

Impoundments are found all along the periphery and at multiple elevations in the areas of MTR sites; adjacent to coal processing plants; and as coal combustion waste ("fly ash") ponds adjacent to coal-fired power plants.[47] Their volume and composition have not been calculated.[48] For Kentucky, the number of known waste and slurry ponds alongside MTR sites and processing plants is 115.[49] These

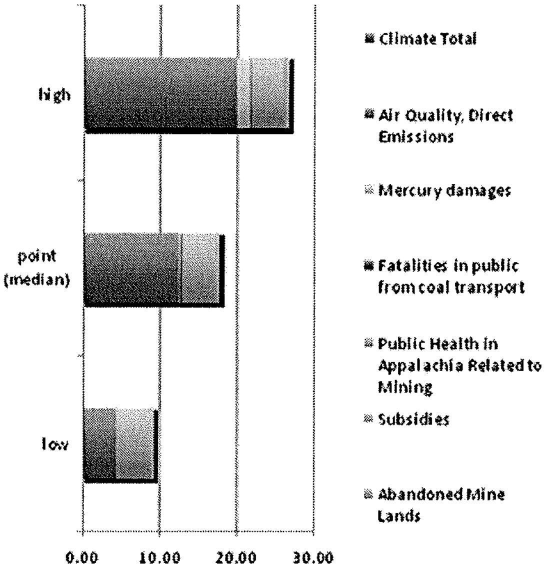

Figure 1. This graph shows the best estimates of the externalities due to coal, along with low and high estimates, normalized to ¢ per kWh of electricity produced. (In color in *Annals* online.)

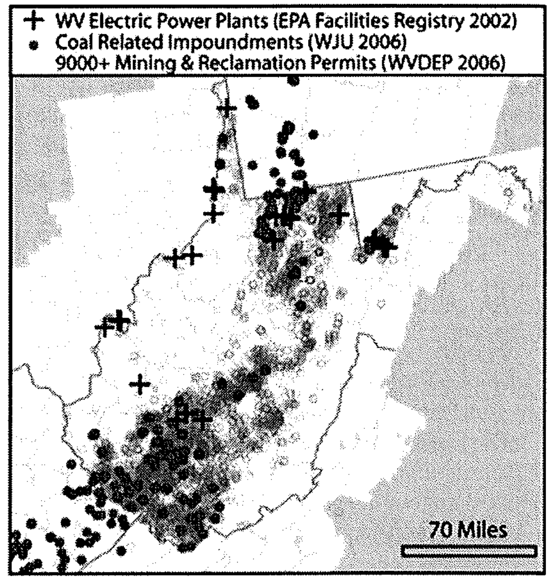

Figure 2. Electric power plants, impoundments (sludge and slurry ponds, CCW, or "fly ash"), and sites slated for reclamation in West Virginia.[44–46] (In color in *Annals* online.) Source: Hope Childers, Wheeling Jesuit University.

sludge, slurry and coal combustion waste (CCW) impoundments are considered by the EPA to be significant contributors to water contamination in the United States. This is especially true for impoundments situated atop previously mined and potentially unstable sites. Land above tunnels dug for long-haul and underground mining are at risk of caving. In the face of heavier precipitation events, unlined containment dams, or those lined with dried slurry are vulnerable to breaching and collapse (Fig. 2).

Processing plants

After coal is mined, it is washed in a mixture of chemicals to reduce impurities that include clay, non-carbonaceous rock, and heavy metals to prepare for use in combustion.[50] Coal slurry is the by-product of these coal refining plants. In West Virginia, there are currently over 110 billion gallons of coal slurry permitted for 126 impoundments.[49,51] Between 1972 and 2008, there were 53 publicized coal slurry spills in the Appalachian region, one of the largest of which was a 309 million gallon spill that occurred in Martin County, KY in 2000.[48] Of the known chemicals used and generated in processing coal, 19 are known cancer-causing agents, 24 are linked to lung and heart damage, and several remain untested as to their health effects.[52,53]

Coal combustion waste or fly ash

CCW or fly ash—composed of products of combustion and other solid waste—contains toxic chemicals and heavy metals; pollutants known to cause cancer, birth defects, reproductive disorders, neurological damage, learning disabilities, kidney disease, and diabetes.[47,54] A vast majority of the over 1,300 CCW impoundment ponds in the United States are poorly constructed, increasing the risk that waste may leach into groundwater supplies or nearby bodies of water.[55] Under the conditions present in fly ash ponds, contaminants, particularly arsenic, antimony, and selenium (all of which can have serious human health impacts), may readily leach or migrate into the water supplied for household and agricultural use.[56]

According to the EPA, annual production of CCW increased 30% per year between 2000 and 2004, to 130 million tons, and is projected to increase to over 170 million tons by 2015.[57] Based on a series of state estimates, approximately 20% of the total is injected into abandoned coal mines.[58]

In Kentucky, alone, there are 44 fly ash ponds adjacent to the 22 coal-fired plants. Seven of these ash ponds have been characterized as "high hazard" by the EPA, meaning that if one of these impoundments spilled, it would likely cause significant property damage, injuries, illness, and deaths. Up to 1 in 50 residents in Kentucky, including 1 in 100 children, living near one of the fly ash ponds are at risk of developing cancer as a result of water- and air-borne exposure to waste.[47]

Box 3.

Tennessee Valley Authority Fly Ash Pond Spill

On December 2, 2008 an 84-acre CCW containment area spilled when the dike ruptured at the Tennessee Valley Authority Kingston Fossil Plant CCW impoundment, following heavy rains. Over one billion gallons of fly ash slurry spilled across 300 acres.

Local water contamination

Over the life cycle of coal, chemicals are emitted directly and indirectly into water supplies from mining, processing, and power plant operations. Chemicals in the waste stream include ammonia, sulfur, sulfate, nitrates, nitric acid, tars, oils, fluorides, chlorides, and other acids and metals, including sodium, iron, cyanide, plus additional unlisted chemicals.[16,50]

Spath and colleagues[50] found that these emissions are small in comparison to the air emissions. However, a more recent study performed by Koornneef and colleagues[59] using up-to-date data on emissions and impacts, found that emissions and seepage of toxins and heavy metals into fresh and marine water were significant. Elevated levels of arsenic in drinking water have been found in coal mining areas, along with ground water contamination consistent with coal mining activity in areas near coal mining facilities.[16,17,60,61] In one study of drinking water in four counties in West Virginia, heavy metal concentrations (thallium, selenium, cadmium, beryllium, barium, antimony, lead, and arsenic) exceeded drinking water standards in one-fourth of the households.[48] This mounting evidence indicates that more complete coverage of water sampling is needed throughout coal-field regions.

Carcinogen emissions

Data on emissions of carcinogens due to coal mining and combustion are available in the Ecoinvent database.[25] The eco-indicator impact assessment method was used to estimate health damages in disability-adjusted life years due to these emissions,[25] and were valued using the VSL-year.[26] This amounted to \$11 billion per year, or 0.6 ¢/kWh, though these may be significant underestimates of the cancer burden associated with coal.

Of the emissions of carcinogens in the life cycle inventory (inventory of all environmental flows) for coal-derived power, 94% were emitted to water, 6% to air, and 0.03% were to soil, mainly consisting of arsenic and cadmium (note: these do not sum to 100% due to rounding).[25] This number is not included in our total cost accounting to avoid double counting since these emissions may be responsible for health effects observed in mining communities.

Mining and community health

A suite of studies of county-level mortality rates from 1979–2004 by Hendryx found that all-cause mortality rates,[62] lung cancer mortality rates,[60] and mortality from heart, respiratory, and kidney disease[17] were highest in heavy coal mining areas of Appalachia, less so in light coal mining areas, lesser still in noncoal mining areas in Appalachia, and lowest in noncoal mining areas outside of Appalachia. Another study performed by Hendryx and Ahern[18] found that self-reports revealed elevated rates of lung, cardiovascular and kidney diseases, and diabetes and hypertension in coal-mining areas. Yet, another study found that for pregnant women, residing in coal mining areas of West Virginia posed an independent risk for low birth weight (LBW) infants, raising the odds of an LBWs infant by 16% relative to women residing in counties without coal mining.[63] LBW and preterm births are elevated,[64] and children born with extreme LBW fare worse than do children with normal birth weights in almost all neurological assessments;[65] as adults, they have more chronic diseases, including hypertension and diabetes mellitus.[66] Poor birth outcomes are especially elevated in areas with MTR mining as compared with areas with other forms of mining.[67] MTR mining has increased in the areas studied, and is occurring close to population centers.[62]

The estimated excess mortality found in coal mining areas is translated into monetary costs using the VSL approach. For the years 1997–2005, excess age-adjusted mortality rates in coal mining areas of Appalachia compared to national rates

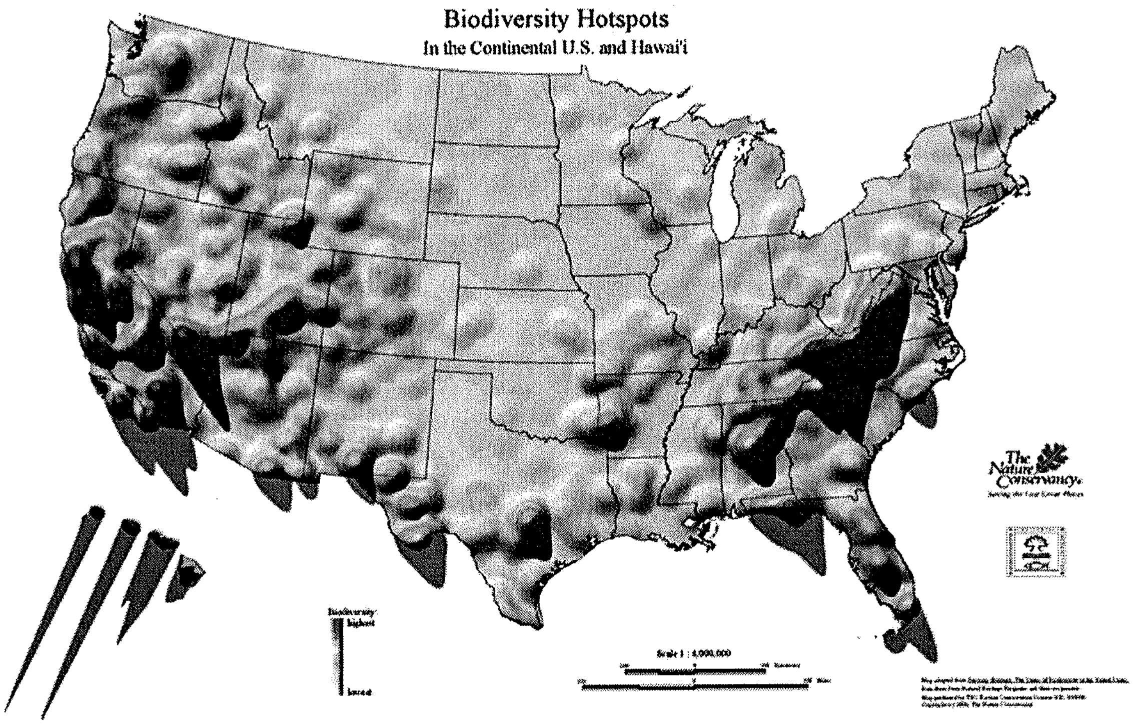

Figure 3. Areas of highest biological diversity in the continental United States. Source: The Nature Conservancy, Arlington, VA. (In color in *Annals* online.)

outside Appalachia translates to 10,923 excess deaths every year, with 2,347 excess deaths every year after, adjusting for other soci-oeconomic factors, including smoking rates, obesity, poverty, and access to health care. These socio-economic factors were statistically significantly worse in coal-mining areas.[18,62,68]

Using the VSL of \$7.5 million,[20] the unadjusted mortality rate, and the estimate that 91% of coal during these years was used for electricity,[2] this translates to a total cost of \$74.6 billion, or 4.36¢/kWh. In contrast, the authors calculated the direct (monetary value of mining industry jobs, including employees and proprietors), indirect (suppliers and others connected to the coal industry), and induced (ripple or multiplier effects throughout the economies) economic benefits of coal mining to Appalachia, and estimated the benefits to be \$8.08 billion in 2005 US\$.

Ecological impacts

Appalachia is a biologically and geologically rich region, known for its variety and striking beauty. There is loss and degradation of habitat from MTR; impacts on plants and wildlife (species losses and species impacted) from land and water contamination, and acid rain deposition and altered stream conductivity; and the contributions of deforestation and soil disruption to climate change.[16,20]

Globally, the rich biodiversity of Appalachian headwater streams is second only to the tropics.[69] For example, the southern Appalachian mountains harbor the greatest diversity of salamanders globally, with 18% of the known species world-wide (Fig. 3).[69]

Imperiled aquatic ecosystems

Existence of viable aquatic communities in valley fill permit sites was first elucidated in court testimony leading to the "Haden decision."[70] An interagency study of 30 streams in MTR mining-permit areas focused on the upper, unmapped reaches of headwater streams in West Virginia and Kentucky.[71] In performing this study, the researchers identified 71 genera of aquatic insects belonging to 41 families within eight insect orders. The most widely distributed taxa in 175 samples were found in abundance in 30 streams in five areas slated to undergo MTR.

Electrical conductivity (a measure of the concentration of ions) is used as one indicator of stream health.[72] The EPA recommends that stream conductivity not exceed 500 microsiemens per cm (uS/cm). In areas with the most intense mining, in which 92% of the watershed had been mined, a recent study revealed levels of 1,100 uS/cm.[72]

Meanwhile, even levels below 500 uS/cm were shown to significantly affect the abundance and composition of macroinvertebrates, such as mayflies and caddis flies.[73] "Sharp declines" were found in some stream invertebrates where only 1% of the watershed had been mined.[74,75]

Semivoltine aquatic insects (e.g., many stoneflies and dragonflies)—those that require multiple years in the larval stage of development—were encountered in watersheds as small as 10–50 acres. While many of these streams become dry during the late summer months, they continue to harbor permanent resident taxonomic groups capable of withstanding summer dry conditions. Salamanders, the top predatory vertebrates in these fishless headwater streams, depend on permanent streams for their existence.

Mussels are a sensitive indicator species of stream health. Waste from surface mines in Virginia and Tennessee running off into the Clinch and Powell Rivers are overwhelming and killing these filter feeders, and the populations of mussels in these rivers has declined dramatically. Decreases in such filter feeders also affect the quality of drinking water downstream.[76]

In addition, stream dwelling larval stages of aquatic insects are impossible to identify to the species level without trapping adults or rearing larvae to adults.[77] However, no studies of adult stages are conducted for mining-permit applications.

The view that—because there are so many small streams and brooks in the Appalachians—destroying a portion represents a minor threat to biodiversity is contrary to the science. As the planet's second-oldest mountain range, geologically recent processes in Appalachia in the Pleistocene epoch (from 2.5 million to 12,000 years ago) have created conditions for diversification, resulting in one of the U.S. biodiversity "hotspots" (Fig. 3).

Thus, burying an entire 2,000 hectare watershed, including the mainstream and tributaries, is likely to eliminate species of multiple taxa found only in Appalachia.

Researchers have concluded that many unknown species of aquatic insects have likely been buried under valley fills and affected by chemically contaminated waterways. Today's Appalachian coal mining is undeniably resulting in loss of aquatic species, many of which will never be known. Much more study is indicated to appreciate the full spectrum of the ecological effects of MTR mining.[78]

Transport

There are direct hazards from transport of coal. People in mining communities report that road hazards and dust levels are intense. In many cases dust is so thick that it coats the skin, and the walls and furniture in homes.[41] This dust presents an additional burden in terms of respiratory and cardiovascular disease, some of which may have been captured by Hendryx and colleagues.[17–19,60,62,67,68,79]

With 70% of U.S. rail traffic devoted to transporting coal, there are strains on the railroad cars and lines, and (lost) opportunity costs, given the great need for public transport throughout the nation.[20]

The NRC report[20] estimated the number of railroad fatalities by multiplying the proportion of revenue-ton miles (the movement of one ton of revenue-generating commodity over one mile) of commercial freight activity on domestic railroads accounted for by coal, by the number of public fatalities on freight railroads (in 2007); then multiplied by the proportion of transported coal used for electricity generation. The number of coal-related fatalities was multiplied by the VSL to estimate the total costs of fatal accidents in coal transportation. A total of 246 people were killed in rail accidents during coal transportation; 241 of these were members of the public and five of these were occupational fatalities. The deaths to the public add an additional cost of $1.8 billion, or 0.09¢/kWh.

Social and employment impacts

In Appalachia, as levels of mining increase, so do poverty rates and unemployment rates, while educational attainment rates and household income levels decline.[19]

While coal production has been steadily increasing (from 1973 to 2006), the number of employees at the mines increased dramatically from 1973 to 1979, then decreased to levels below 1973 employment levels.[27] Between 1985 and 2005 employment in the Appalachian coal mining industry declined by 56% due to increases in mechanization for MTR and