ELLEN F. ROSENBLUM
Attorney General

FREDERICK M. BOSS
Deputy Attorney General

DEPARTMENT OF JUSTICE
APPELLATE DIVISION

March 2, 2016

The Honorable Thomas A. Balmer
Chief Justice, Oregon Supreme Court
Supreme Court Building
1163 State Street
Salem, OR 97310

Re: *Scott Bolton v. Ellen Rosenblum*
SC S063879

Dear Chief Justice Balmer:

Petitioners Scott D. Bolton, Dave Robertson, Nicholas Blosser, and Paul Cosgrove have filed ballot title challenges in the above-referenced matter. Pursuant to ORS 250.067(4), the Secretary of State is required to file with the court the written comments submitted in response to the draft ballot title. Those written comments, under the cover of Elections Division Compliance Specialist Lydia Plukchi's letter, are enclosed for filing with the court. Pursuant to ORAP 11.30(7), we also have enclosed for filing with the court the draft and certified ballot titles, together with their respective cover letters.

Sincerely,

/s/ Rolf C. Moan

Rolf C. Moan
Senior Assistant Attorney General
rolf.moan @doj.state.or.us

RCM:aft/7208299

cc: Gregory A. Chaimov
Steven C. Berman
Jill Odell Gibson
Margaret Ngai/without encl.

IN THE SUPREME COURT OF THE STATE OF OREGON

SCOTT D. BOLTON, DAVE ROBERTSON, NICHOLAS BLOSSER, Petitioners, v. ELLEN F. ROSENBLUM, Attorney General, State of Oregon, Respondent.	Supreme Court No. S063879 RESPONDENT'S ANSWERING MEMORANDUM TO PETITIONS TO REVIEW BALLOT TITLE RE: INITIATIVE PETITION NO. 73

Petitioners seek review of the Attorney General’s ballot title for Initiative Petition 73 (IP 73). They argue that the caption, result statements, and summary do not substantially comply with ORS 250.035’s requirements. *See* ORS 250.085(2) (Oregon Supreme Court reviews ballot titles for “substantial compliance with the requirements of ORS 250.035”). In fact, the caption, result statements, and summary do substantially comply with ORS 250.035.

A. The caption substantially complies with ORS 250.035(2)(a).

ORS 250.035(2)(a) requires the caption for a state measure’s ballot title to contain up to 15 words that “reasonably identif[y]” the measure’s “subject matter.” The subject matter is “the ‘actual major effect’ of a measure or, if the measure has more than one major effect, all such effects (to the limit of the available words).” *Lavey v. Kroger*, 350 Or 559, 563, 258 P3d 1194 (2011) (citations omitted). The caption satisfies those requirements. It reads:

Increases electricity percentages required from renewable sources; reduces new buildings’ permissible “net energy consumption” (undefined)

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

1. The caption accurately describes the measure's effect on certain utilities' renewable-energy obligations.

In part, the proposed measure amends ORS 469A.052. ORS 469A.052(1) creates certain requirements for any "electric utility that makes sales of electricity to retail electricity consumers in an amount that equals three percent or more of all electricity sold to retail electricity consumers." ORS 469A.052(1)(c) and (d) currently require that, for 2020-2024, at least 20% of "electricity sold by [such a] utility to retail electricity consumers * * * must be qualifying electricity"; for subsequent years the required minimum is 25%.

ORS 469A.005(9) defines "qualifying electricity" as "electricity described in ORS 469A.010." ORS 469A.010 describes three categories of electricity (which means, in light of ORS 469A.005(9), that each category constitutes "qualifying electricity"): (1) "electricity generated from a renewable energy source," with some qualifications (ORS 469A.010(1)); (2) "electricity from hydroelectric generators" (this category is described by ORS 469A.010(3), which calls "hydroelectric energy * * * an important renewable energy source"); and (3) "electricity that the Bonneville Power Administration has designated as environmentally preferred power, or has given a similar designation for electricity generated from a renewable resource" (ORS 469A.010(2)). In short, "qualifying electricity" generally is defined as

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

electricity from a “renewable energy source,” although it appears that some electricity—electricity designated by the BPA as “environmentally preferred power”—could constitute qualifying electricity without necessarily coming from a “renewable energy source.”

In turn, ORS 469A.005(10) defines “renewable energy source” as “a source of electricity described in ORS 469A.025.” ORS 469A.025 describes a number of electricity sources (thereby defining them as “renewable energy sources”): wind; solar energy; wave, tidal and ocean thermal energy; geothermal energy; some forms of biomass and biomass-byproducts; hydroelectric energy, with qualifications; combustion of municipal solid waste, with qualifications; and hydrogen gas, with qualifications.

In short, ORS 469A.052 currently requires that, for 2020-2024, at least 20% of the electricity that certain utilities sell must be “qualifying electricity”—a term that, for the most part, connotes electricity from “renewable energy sources.” For 2025 on, ORS 469A.052 increases the required minimum to 25%.

Section 4 of IP 73 would increase the percentage of qualifying electricity that utilities described in ORS 469A.052(1) must sell to consumers. For 2020-2024, IP 73 requires that 22% of their electricity sales (instead of the existing 20%) “be qualifying electricity.” Section 4 of the measure increases that

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

required minimum to 30-45% for 2025-2039 and to 50% for subsequent years (instead of the 25% that currently applies from 2025 on). The caption describes that effect accurately by noting that the measure "[i]ncreases electricity percentages required from renewable sources."

a. Petitioner Cosgrove identifies no basis for modifying that aspect of the caption.

Petitioner Paul Cosgrove argues that the caption should substitute the phrase "qualifying electricity" (a phrase that IP 73 uses and that current law defines) for the phrase "renewable sources." (Petition 2). For two reasons, however, the caption's use of "renewable sources" is appropriate. First, and as already noted, ORS 469A.005 and ORS 469A.010 define "qualifying electricity" as generally meaning electricity that comes from a "renewable energy source" or from a "renewable resource." Thus, the caption—in stating that the measure would increase the percentage of electricity from renewable sources—is accurate, even though it appears that some electricity can be "qualifying electricity" without necessarily coming from a renewable energy source. Second, the phrase "qualifying electricity," as Mr. Cosgrove agrees (Petition 7), is not a phrase that most voters are likely to understand. For that reason as well, the phrase "renewable sources" is preferable.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

Mr. Cosgrove argues in the alternative that the caption should put "renewable" in quotation marks, to indicate that IP 72 uses a special definition of the word. (Petition 2). Placing the phrase in quotation marks would be inappropriate, however. Quotation marks might inaccurately suggest that the proposed measure defines what a "renewable" source is, when in fact *current law* defines the phrase "renewable energy source." *Cf. Carley/Towers v. Myers,* 340 Or 222, 229, 132 P3d 651 (2006) ("this court has approved the use of specially defined terms in quotation marks, followed by the word 'defined' in parentheses, to signal that the proposed measure specially defines the terms"). ORS 469A.005(10) defines "renewable energy source," and § 6 of IP 73—although it renumbers the provision as ORS 469A.005(*11*)—leaves that definition unchanged.

b. Petitioner Bolton identifies no basis for modifying that aspect of the caption.

Petitioners Scott Bolton and Dave Robertson ("petitioner Bolton") similarly criticize the caption for using the phrase "renewable sources." (Petition 1). Mr. Bolton notes that the legislature's definition of "renewable energy sources" is perhaps narrower than a typical voter's understanding; he suggests, for example, that the caption might mislead voters into believing that all hydropower qualifies as a "renewable source," even though not all electricity

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

produced by hydropower is defined by existing law as "qualifying electricity." (Petition 3-4). Yet the possibility that some voters' understanding of "renewable sources" may be broader than the pertinent legislative definition does not make the caption inaccurate. Because current law generally defines "qualifying electricity" as electricity from a "renewable energy source" or from a "renewable resource," the caption accurately describes the measure as "increas[ing the] electricity percentages required from renewable sources." And as discussed above, "qualifying electricity" is not a phrase that will be familiar to most voters, or that will succeed in alerting them about the measure's subject matter.

Second, Mr. Bolton criticizes the caption for not telling voters that utilities must satisfy requirements for producing electricity from renewable sources only in years when they do not qualify for ORS 469A.100's exemption. (Petition 1). He notes that ORS 469A.100(1) exempts utilities from complying with qualifying-electricity requirements "during a compliance year to the extent that the incremental cost of compliance, the cost of unbundled renewable energy certificates and the cost of alternative compliance payments under ORS 469A.180 exceeds four percent of the utility's annual revenue requirement." Significantly, however, the proposed measure does not alter that aspect of current law; it leaves the current exemption in ORS 469A.100(1) undisturbed.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

Nothing requires the caption to tell voters that the measure, in increasing the percentages of electricity sales that must come from renewable resources, leaves intact an already-existing exemption.

Third, Mr. Bolton criticizes the caption for failing to state that not all utilities are affected by the proposed increases in the percentage of sales that must come from qualifying electricity. (Petition 1, 6). He thus appears to suggest that the caption should clarify, as the summary does, that the requirements apply only to utilities that "sell[] at least 3% of all electricity sold to consumers" in the state. But the caption, in stating that the proposed measure "[i]ncreases electricity percentages required from renewable sources," is accurate. It does not state that the proposed increase would apply to each and every entity that produces or supplies electricity. Although the caption does not specifically identify those who must comply with the proposed increases, that is a result of the caption's 15-word limit. In any event, the summary explains that the requirements at issue apply to utilities that "sell[] at least 3% of all electricity sold to consumers."

Finally, Mr. Bolton criticizes the caption for purportedly "describ[ing] coal-generated electricity as being 'phase[d] out,'" and for "fail[ing] to identify to what entities the ban on charging for coal-generated electricity applies." (Petition 1). In fact, although the ballot title *summary* notes that IP 73 provides

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

that "electric companies must eliminate coal-generated electricity sales by 2030," the caption makes no reference to that aspect of the measure.

2. The caption appropriately describes IP 73's effect on standards for new buildings, and appropriately does not describe the measure's effect on charges for coal-generated electricity.

Section 9 of IP 73 would amend ORS 455.511 by adding a subsection (4), which would require the Director of the Department of Consumer and Business Services to

> require updates to the energy efficiency standards of the state building code to ensure a 65% reduction in the annual net energy consumption of newly constructed buildings by 2032, as compared to the requirements of the 2014 state building code.

Neither § 9 nor existing law define "net energy consumption." Accordingly, the caption informs voters that IP 73 would "reduce[] new buildings' permissible 'net energy consumption' (undefined)."

Petitioner Nicholas Blosser argues, in effect, that the caption—rather than describing § 9 of IP 73, should have described § 3(1), which would provide that electric companies "shall eliminate all coal-fired resources from [their] electricity supply" by 2030 or by the end of "the year in which a coal-fired resource is fully depreciated, whichever is earlier." Although the ballot title summary describes § 3, the caption appropriately does not describe § 3. The caption's 15-word limit permits a description of *either* § 9 or of § 3. A

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

description of § 3 is unnecessary, as § 3 is closely related to the other portions of the measure—the portions affecting the types of electricity that electricity companies and utilities can sell—that the caption's first clause (addressing electricity that must come from "renewable sources") already refers to.

In contrast, a description of § 9 is appropriate because § 9 is differs significantly from the rest of the measure. Section 9, rather than focusing on electric companies and utilities, and on the types of electricity that they sell, affects the construction industry. It affects all newly constructed buildings, and would require a two-thirds reduction in permissible "net energy consumption" over the next 16 years. Consequently, the caption appropriately describes § 9, and it appropriately does not refer to § 3.

Petitioner Blosser also criticizes the reference to § 9 as "incomplete and confusing"; in part, he argues that the description, in referring to "net energy consumption," uses "technical language" that most voters will not understand. (Petition 4). Although the meaning of the phrase "net energy consumption" is not necessarily self-evident, "net energy consumption" is the phrase that § 9 uses, and neither IP 73 nor current law defines the phrase. The caption appropriately uses the phrase, while noting that the phrase is undefined.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

B. The "yes" result statement complies with ORS 250.035(2)(b).

ORS 250.035(2)(b) requires a ballot title's "yes" result statement to describe the "result," in no more than 25 words, if the proposed measure becomes law. The Attorney General's "yes" result statement reads:

> **Result of "Yes" Vote:** "Yes" vote increases percentage of electricity sales required from renewable sources; renewable energy certificates (RECs) expire; reduces permissible "net energy consumption" (undefined) for new buildings.

1. The statement appropriately refers to the measure's impact on electricity sales that must come from renewable energy resources.

As is true of the caption, the "yes" result statement's reference to "increase[d] percentage of electricity sales from renewable sources" accurately informs voters of significant results that the proposed measure would create.

Mr. Blosser argues that the "yes" result statement suffers from the same defects that he purports to identify with respect to the caption. (Petition 5). Mr. Cosgrove asserts, as he did with respect to the caption, that the "yes" result statement should either substitute "qualifying electricity" for "renewable sources" or place "renewable" in quotation marks. (Petition 8). Mr. Bolton also criticizes the "yes" result statement for one of the same reasons that he criticizes the caption. (Petition 7). For the same reasons recounted already with respect to the caption, this court should reject each of those arguments.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

2. The "yes" result statement appropriately refers to the measure's impact on renewable energy certificates (RECs).

The "yes" result statement appropriately describes IP 73's effect on the ability of utilities to use "renewable energy certificates" (RECs) to meet their obligations to sell electricity from renewable energy sources. As OAR 330-160-0015(15) states, one "renewable energy certificate" (REC) "is created in association with the generation of one Megawatt-hour (MWh) of Qualifying Electricity." ORS 469A.070(1)(a) and (b) provide that, for an electricity utility to comply with its "renewable portfolio standard" each year (that is, to comply with ORS 469A.052's requirement that a utility sell a certain percentage of "qualifying electricity"), it generally must do so by "[u]sing * * * renewable energy certificates." *See also* ORS 469A.050(1) (describing standard in ORS 469A.052 as the "renewable portfolio standard"). ORS 469A.140(1) authorizes the sale, trade, and transfer of RECs. ORS 469A.140(2) entitles a utility to use an REC to help satisfy its renewable portfolio standard for a future year, by allowing RECs to "be banked and carried forward indefinitely for the purpose of complying with a renewable portfolio standard in a subsequent year."

Section 7 of the proposed measure, however, amends ORS 469A.140(2) so that if an REC is "issued after the effective date of this Act," it may be used to satisfy a renewable portfolio standard only if it is used for that purpose

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

within three years. Accordingly, the "yes" result statement informs voters that, under the measure, "renewable energy certificates (RECs) expire."

Mr. Blosser asserts that the "yes" result statement should not refer to the proposed limitation on using RECs, in part because that limitation is not sufficiently significant to warrant a mention. (Petition 7). Yet the measure's impact on how utilities can use RECs, and the proposed imposition of a three-year limit—compared to the current ability to use an REC "indefinitely"—is undoubtedly one of the measure's results. Consequently, the "yes" result statement appropriately refers to that aspect of the measure. *See* ORS 250.035(2)(b) (requiring statement to describe the "result" if the proposed measure becomes law).

Mr. Blosser further argues that the phrase "renewable energy certificates (RECs) expire" is inaccurate, because it suggests that, under the proposed measure, *all* RECs would expire regardless of when they were issued. (Petition 6). He notes that the measure would create a three-year limit only with respect to RECs that issue after the measure becomes law. (*Id.*). Mr. Bolton also describes the reference to RECs "expir[ing]" as inaccurate; he asserts that the purpose for which utilities may use RECs is not limited to satisfaction of a renewable portfolio standard, and that other entities who are not bound by renewable portfolio standards use RECs. (Petition 8). Thus, although IP 73

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

creates a limited time within which to use RECs for compliance purposes, the measure does not dictate that RECs will "expire" with respect to any other purposes. (*Id.*).

Significantly, however, the "yes" result statement does not state that, under IP 73, *all* RECs would expire. Moreover, the statement, in observing that RECs will "expire" under the measure, is accurate; under the measure, certain certificates' ability to satisfy qualifying-electricity standards will (in contrast to current law) terminate after three years. The "yes" result statement is accurate, and it substantially complies with ORS 250.035(2)(b)'s requirements.

C. The "no" result statement complies with ORS 250.035(2)(c).

ORS 250.035(2)(c) requires a ballot title's "no" result statement to describe the "result," in no more than 25 words, if the proposed measure is rejected. The Attorney General's "no" result statement reads:

> **Result of "No" Vote:** "No" vote retains current minimum percentages for electricity sales from renewable sources; RECs do not expire; retains current net energy consumption standard for new buildings.

Mr. Cosgrove argues that the "no" result statement should either substitute "qualifying electricity" for "renewable sources" or place "renewable" in quotation marks. (Petition 8). Mr. Blosser also criticizes the "no" result statement for the same reasons that he criticizes the "yes" result statement.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

(Petition 8). Mr. Bolton asserts that the "no" result statement generally "carries forward the problems with the caption and, like the yes result statement, [inaccurately] refers to RECs as expiring." (Petition 9). For the same reasons recounted already, this court should reject those arguments.

D. The summary complies with statutory requirements.

ORS 250.035(2)(d) requires a ballot title summary to provide a "concise and impartial statement" of up to 125 words "summarizing the state measure and its major effect." The summary must "provide voters with enough information to understand what will happen if the measure is approved." *Caruthers v. Kroger*, 347 Or 660, 670, 227 P3d 723 (2010). It should not, however, "speculate about the possible effects of a proposed measure." *Pelikan/Tauman v. Myers*, 342 Or 383, 389, 153 P3d 117 (2007).

The Attorney General's summary satisfies those requirements. It reads:

> **Summary:** If utility sells at least 3% of all electricity sold to consumers, current law generally requires—for 2020-2024—at least 20% of electricity sales to be "qualifying electricity," which includes electricity from "renewable energy sources" (defined by current law); subsequently, required minimum is 25%; to meet minimums, may use RECs (issued for each MegaWatt hour of renewable electricity produced; may be sold/transferred, used for future years). Proposed measure increases required minimum: 22% for 2020-2024, 30-45% for 2025-2039, 50% subsequently; new RECs usable for three years to meet minimums; electric companies must eliminate coal-generated electricity sales by 2030; would reduce, by 2032, new buildings' permissible "net energy consumption" (undefined) by 65%. Other provisions.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

1. Petitioner Bolton identifies no basis for modification.

Mr. Bolton asserts that the summary "carries forward the problems with the caption" and the result statements. (Petition 9). For the reasons recounted when discussing the caption and result statements, this court should reject that assertion.

Mr. Bolton also asserts that the summary misleads voters by stating that "'qualifying electricity' * * * includes electricity from 'renewable energy sources' (defined by current law)." (Petition 9). He asserts that the summary suggests that "qualifying electricity" encompasses renewable energy sources and other sources when, in fact (according to him) the phrase "renewable energy sources" is broader than the phrase "qualifying electricity." (Petition 9-10). He is mistaken. ORS 469A.005(9) defines "qualifying electricity" as "electricity described in ORS 469A.010." ORS 469A.010 describes three categories of electricity, each of which—as discussed earlier—involves a "renewable energy source" (a phrase defined by ORS 469A.005(1) and ORS 469A.025) or a "renewable source." At the same time, it appears that some of the electricity described in the third category—"electricity that the Bonneville Power Administration has designated as environmentally preferred power" (ORS 469A.010(3))—can constitute qualifying electricity without necessarily

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

coming from a "renewable energy source." As a result, "qualifying electricity" *is* a broader term than "renewable energy source."

Mr. Bolton appears to argue that the summary fails to "alert voters that 'electric companies,' the term IP 73 uses [in § 3] to identify the electricity providers that may not charge for coal-generated electricity, is not defined for purposes of IP 73." (*See* Petition 7-8, making that argument with respect to the "yes" result statement, although the summary alone—and not the "yes" result statement—refers to § 3). This court should reject that argument, because § 2(c) of IP 73 expressly states that "'[e]lectric company' has the meaning given that term in ORS 757.600" (which defines "electric company"). Mr. Bolton notes that IP 73 does not *expressly* declare that § 2's definitions apply to § 3 (the section that requires "electric companies" to eliminate coal-fired resources from their electricity supplies). (Petition 8). His theory seems to be that § 2, by defining "electric company" "*[a]s used in this section*" (emphasis added), adopts a definition that applies *only* to § 2, and not to any other section.

It is not self-evident, however, that Oregon courts would agree with that theory, given that § 2 of IP 73 contains nothing but definitions, and given that—if Mr. Bolton's theory were correct—all of § 2 would be superfluous. As a result, it would be inappropriate for the ballot title to suggest, despite § 2's

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

express definition of "electric company," that the phrase "electric company" (as used in § 3 of IP 73) is "not defined."

Finally, Mr. Bolton criticizes the summary for purportedly stating that "RECs are issued to utilities that produce more qualifying electricity than required." (Petition 10). In fact, although the *draft* ballot title's summary contained that statement, the certified ballot title's summary does not.

2. Petitioner Blosser identifies no basis for modification.

Mr. Blosser criticizes the summary's use of the word "sales" in its statement that, under IP 73, "electric companies must eliminate coal-generated electricity sales by 2030." (Petition 8). He argues that, under IP 73, as of 2030 "[c]oal-generated electricity may not be provided to consumers, whether by sale or otherwise." (Petition 4). Mr. Blosser is mistaken. Section 3(1) of the measure provides that an electric company "shall eliminate all coal-fired resources from its electricity supply." But something qualifies as an "electricity supply," as defined by § 2(d), only if it constitutes energy that is "supplied to *and included in the electricity rates* of retail electricity consumers." (Emphasis added.) As a result, the measure does not necessarily prohibit electric companies from providing coal-generated electricity; it only prohibits them from doing so if they include that electricity "in the *electricity rates*" that consumers pay. Thus, the summary accurately states that the measure provides

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

that "electric companies must eliminate coal-generated electricity *sales* by 2030." (Emphasis added.)

Mr. Blosser criticizes the summary for not explaining that, under current law, "there are no restrictions on the use of electricity from coal." (Petition 8). Yet the summary accurately informs voters of the pertinent existing legal obligations affecting the utilities at issue—it informs voters that those utilities are generally required to sell a certain percentage of "qualifying electricity," which includes electricity from renewable energy sources. And by also informing voters that the proposed measure would not permit electric companies to sell coal-generated electricity after 2029, the summary implicitly tells voters that no similar prohibition or limitation currently exists.

Mr. Blosser argues that the summary, like the caption, does not sufficiently "explain to voters * * * what Sections 8 and 9 do." (Petition 8). Mr. Blosser is mistaken. Section 9 would amend ORS 455.511 by requiring the Director of the Department of Consumer and Business Services (DCBS) to

> require updates to the energy efficiency standards of the state building code to ensure a 65% reduction in the annual net energy consumption of newly constructed buildings by 2032, as compared to the requirements of the 2014 state building code.

As noted earlier, neither IP 73 nor existing law defines "net energy consumption." Hence, the summary accurately describes § 9 by stating that IP

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

73 “would reduce, by 2032, new buildings’ permissible ‘net energy consumption’ (undefined) by 65%.”

Furthermore, the summary appropriately does not refer to § 8. Section 8 amends ORS 455.505—which currently requires the Director of DCBS to “adopt rules establishing uniform energy conservation standards for inclusion under the state building codes”—so that it also requires the director to review, at least every three years, “the energy conservation standards of the state building code,” and to “propose updates to the standards to ensure compliance with the energy efficiency requirements of ORS 455.511(4).” In other words, § 8—unlike § 9—does not require or impose any substantive change to energy conservation or building standards; it merely requires DCBS to “ensure compliance” with substantive requirements that are found in a separate statutory provision. As a result, § 8 does not reflect a “major effect” of IP 73, and the summary appropriately makes no reference to it. *See* ORS 250.035(2)(d) (requiring a ballot title summary to provide a “concise and impartial statement” of up to 125 words “summarizing the state measure and its major effect”).

Mr. Blosser argues that the summary “unduly focuses on renewable energy certificates,” and that it instead should devote more words “to [IP 73’s] coal phase-out requirements.” (Petition 8). But as this memorandum’s earlier discussion of RECs reflect, how current law defines RECs—and, accordingly,

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-4402

how IP 73 affects REC use—is complicated. The measure's impact on sales of coal-generated electricity is easier to explain, and that explains the difference in the number of words used to describe the measure's various aspects. That difference does not reflect any violation of ORS 250.035(2)(d), or any basis to modify the summary.

E. Conclusion

This court should approve the certified ballot title without modification.

Respectfully submitted,

ELLEN F. ROSENBLUM #753239
Attorney General
PAUL L. SMITH #001870
Deputy Solicitor General

/s/ Rolf C. Moan
ROLF C. MOAN #924077
Senior Assistant Attorney General
rolf.moan@doj.state.or.us

Attorneys for Respondent
Ellen F. Rosenblum, Attorney General,
State of Oregon

Thomas Alicia F

From:	PLUKCHI Lydia <lydia.plukchi@state.or.us>
Sent:	Thursday, February 11, 2016 11:01 AM
To:	THOMAS Alicia F
Subject:	Initiative Petition #73 Appeal
Attachments:	073cbt.pdf; 073cmts.pdf; 073dbt.pdf

OFFICE OF THE SECRETARY OF STATE

JEANNE P. ATKINS
SECRETARY OF STATE

ROBERT TAYLOR
DEPUTY SECRETARY OF STATE

ELECTIONS DIVIS

JIM WILLIAM
DIRECTOR

255 CAPITOL STREET NE, S
SALEM, OREGON 9731

(503) 986-151

February 11, 2016

The Hon. Ellen Rosenblum, Attorney General
Benjamin Gutman, Solicitor General
Dept. of Justice, Appellate Division
400 Justice Building
Salem, OR 97310

Via Email

Dear Mr. Gutman:

In accordance with ORS 250.067(4) please file the attached comments with the court as part of the record in the ballot title challenge filed by Steven Berman, Gregory Chaimov and Jill Gibson on Initiative Petition **2016-073**. Also attached are the draft and certified ballot titles with their respective transmittal letters.

Sincerely,

Lydia Plukchi
Compliance Specialist

ELLEN F. ROSENBLUM
Attorney General

FREDERICK M. BOSS
Deputy Attorney General

DEPARTMENT OF JUSTICE
APPELLATE DIVISION

December 23, 2015

Jim Williams
Director, Elections Division
Office of the Secretary of State
255 Capitol St. NE, Suite 501
Salem, OR 97310

Re: Proposed Initiative Petition — Increases Percentage of Electricity Required From Renewable Sources; Reduces New Buildings' Permissible Net Energy Consumption
DOJ File #BT-73-15; Elections Division #2016-073

Dear Mr. Williams:

We have prepared and hereby provide to you a draft ballot title for the above-referenced prospective initiative petition. The proposed measure relates to increasing the amount of electricity produced by renewable energy sources.

Written comments from the public are due to you within ten business days after your receipt of this draft title. A copy of all written comments provided to you should be forwarded to this office immediately thereafter.

A copy of the draft ballot title is enclosed.

Sincerely,

Alicia Thomas
Legal Secretary

AFT/7037153

Enclosure

Nicholas Blosser
6330 SE 32nd Avenue
Portland, OR 97202

Margaret Ngai
5623 SE Insley Street
Portland, OR 97206

DRAFT BALLOT TITLE

Increases percentage of electricity required from renewable sources; reduces new buildings' permissible net energy consumption

Result of "Yes" Vote: "Yes" vote increases percentage of electricity sales required from renewable sources; renewable energy certificates (RECs) expire; will reduce permissible net energy consumption for new buildings.

Result of "No" Vote: "No" vote retains current minimum percentages for electricity sales from renewable sources; RECs do not expire; retains current net energy consumption standard for new buildings.

Summary: If a utility sells at least 3% of all electricity sold to consumers, current law generally requires—for 2020-2024—at least 20% of utility's electricity sales to be "qualifying electricity," which includes electricity from "renewable energy sources" (defined by current law); subsequently, required minimum is 25%; to meet minimums, may use RECs (RECs are issued to utilities that produce more qualifying electricity than required, may be sold/transferred between utilities). Proposed measure increases required minimum: 22% for 2020-2024, 30-45% for 2035-2039, 50% subsequently; RECs would expire after three years; electric companies must phase out coal-generated electricity sales by 2030; would reduce, by 2032, new buildings' permissible net energy consumption by 65%. Other provisions.

GIBSON
LAW FIRM

January 8, 2016

VIA EMAIL – irrlistnotifier@sos.state.or.us

The Honorable Jeanne Atkins
Secretary of State
Elections Division
255 Capitol Street NE, Ste. 501
Salem, OR 97310-0722

Re: Public Comment on Initiative Petition 73 (2016)

Dear Secretary Atkins,

I represent Paul Cosgrove, an elector in the State of Oregon who wishes to comment on the draft ballot title for IP 73 (2016). Thank you for the opportunity to provide comments.

I. INTRODUCTION

A. Current Law

The 2007 Legislature created a Renewable Portfolio Standard (RPS) that requires utilities to provide a certain percentage of "qualifying electricity" as part of their retail electricity sales. *See* ORS ch 469A. Specifically, by 2025 "qualifying electricity" must comprise at least 25% of the electricity sold by utilities that deliver over 3% of the retail electricity sales in Oregon. ORS 469A.052. The RPS also requires interim performance obligations of 5% in 2011; 15% in 2015; and 20% in 2020.

The Legislative Assembly established strict requirements regarding what constitutes "qualifying electricity." In order for electricity to count towards a utility's RPS mandate, two statutory conditions must be met. First, "electricity may be used to comply with a renewable portfolio standard only if the electricity is generated by a facility that becomes operational on or after January 1, 1995." ORS 469A.020(1). Second, the electricity must be generated utilizing certain allowable "*types* of renewable energy." ORS 469A.025(1) (emphasis added). Only four types of renewable energy – wind, solar, wave, and geothermal – qualify as "renewable" without any additional conditions. *Id.* Although electricity generated by hydropower and biomass is commonly considered to be renewable, these types of energy sources are not "renewable" for purposes of complying with the RPS unless certain requirements are met. *See* ORS 469A.025(3), (4). Due to the Legislature's restrictions, hydropower produced from 31 Bonneville Power Administration facilities does not qualify as renewable energy. *See* Exhibit 1. Likewise, biomass is not "renewable" if it includes wood that has been treated with certain preservatives. ORS 469A.025(3).

The RPS affects both large for-profit utility companies and small public or not-for-profit utility companies, although the differences between the two are significant. Oregon has 37 Consumer Owned Utilities (COUs), which are either operated by municipalities or public utility districts, or are not-for-profit rural electric cooperatives. These COUs collect rates sufficient to cover their costs of operations. COUs are locally governed by elected boards and governments. COUs mostly serve rural areas and are not generally large enough to invest in their own generation facilities; thus they must purchase their power from others. Currently, Oregon COUs purchase 85% of their power under Federal Hydro System (BPA) contracts. Importantly, COUs generate no energy from coal. Oregon's largest COU is Eugene Water & Electric, which provides approximately 4.97% of the state's retail electricity sales. http://www.puc.state.or.us/docs/statbook2014WEB.pdf). The next largest, Umatilla Electric Cooperative, provides approximately 2.86% of the state's retail electricity sales, but is expected to cross the 3% threshold next year, thus requiring it to meet the same renewable requirements as a large for-profit utility. *See Id.*

In contrast, Oregon's largest and second largest utilities are Investor Owned Utilities (IOUs) and they provide 37.4% and 27.5% of the state's retail electricity sales, respectively. *Id.* IOUs are business organizations managed to provide profits for their stockholders and are governed by boards elected by stockholders. Oregon's IOUs own and operate generating facilities and are allowed to earn a rate of return of 8-10% on these capital investments. 91% of Oregon's electric energy sales derived from coal come from IOUs' combined power resource mix.

A key feature of the RPS was the establishment of Renewable Energy Certificates (RECs), a system that allows utilities to comply with the renewable mandates without having to actually produce electricity generated from the required sources. Instead, utilities are allowed to buy RECs, which are tradable commodities that represent the "environmental, economic, and social benefits" associated with one megawatt-hour of electricity generated by certain renewable energy sources. OAR 330-160-0015. RECs are at the heart of Oregon's renewable energy programs, and in recognition of the difficulties confronting COUs to meet compliance mandates, the 2014 Legislature passed HB 4126 to expand the use of RECs by COUs, such as Umatilla Electric Cooperative.

B. IP 73

IP 73 would impact both large for-profit utilities and smaller public and not-for-profit utilities that deliver over 3% of retail electricity sales. Specifically, Section 3 would prohibit all coal-fired resources by 2030, or the year in which the resource was fully depreciated, whichever is earlier. Section 4 would increase the RPS requirement that 25% of electricity must come from renewable sources by 2025, to 50% by 2040 - essentially doubling the compliance standard. And the interim performance obligations are increased from 20% to 22% by 2020; from 25% to 30% by 2025; 40% by 2030, and 45% by 2035.

Section 6 codifies the definition of "renewable energy certificate" currently provided by rule in OAR 330-160-0015. Section 7 states that RECs issued after the effective date of the measure "that are not used by an electric utility or electricity service supplier to comply with a renewable portfolio standard in the calendar year in which the certificates were issued may be banked and carried forward up to the three compliance years immediately following the compliance year in which the renewable energy certificates were issued for the purpose of complying with a renewable portfolio standard in one of those three subsequent compliance years." In other words, RECs would expire three compliance years after issuance. Currently, RECs do not expire; thus, this proposed limitation on the use of RECs would be a significant change that would greatly impact the REC market.

Section 8 requires the director of the Department of Consumer and Business Services to periodically review and update the state building code so that by 2032 the energy consumption standard for new buildings is set at an amount that is 65% less that the 2014 standard.

II. DRAFT BALLOT TITLE

The Attorney General has proposed the following ballot title for IP 73:

Increases percentage of electricity required from renewable sources; reduces new buildings' permissible net energy consumption

Result of "Yes" Vote: "Yes" vote increases percentage of electricity sales required from renewable sources; renewable energy certificates (RECs) expire; will reduce permissible net energy consumption for new buildings.

Result of "No" Vote: " No" vote retains current minimum percentages for electricity sales from renewable sources; RECs do not expire; retains current net energy consumption standard for new buildings.

Summary: If a utility sells at least 3% of all electricity sold to consumers, current law generally requires-for 2020-2024-at least 20% of utility's electricity sales be "qualifying electricity," which includes electricity from "renewable energy sources" (defined by current law); subsequently, required minimum is 25%; to meet minimums, utility may use RECs (RECs are issued to utilities that produce more qualifying electricity than required, may be sold/transferred between utilities). Proposed measure increases required minimum to: 22% for 2020-2024, 30-45% for 2035-2039, 50% subsequently. RECs would expire after three years; electric companies must phase out coal-generated electricity sales by 2030; would reduce, by 2032, new buildings' permissible net energy consumption by 65%. Other provisions.

III. COMMENTS ON THE DRAFT BALLOT TITLE

A. The Caption

Under ORS 250.035(2)(a), the caption is limited to fifteen words and must "reasonably identif[y] the subject matter" of a measure - described in case law as its "actual major effect" or, if more than one major effect, all effects describable within the available word limit. *Lavey v. Kroger*, 350 Or 559, 563, 258 P3d 1194 (2011); *see also Greenberg v. Myers*, 340 Or 65, 69, 127 P3d 1192 (2006) (Attorney General may not select and identify in caption only one of multiple subjects, such that caption understates scope of subject matter). To ascertain the subject matter of a measure, the Oregon Supreme Court typically considers the "changes that the proposed measure would enact in the context of existing law." *Rasmussen v. Kroger* (S059261), 350 Or 281, 285, 253 P3d 1031 (2011); *see also Rasmussen v. Kroger*, 351 Or 358, 361, 266 P3d 87 (2011) (when major effect would substantively change existing law, ballot title should inform voters of scope of change). Because the caption is the "cornerstone" of the ballot title, it must identify the subject matter of the proposed measure in terms that will "inform potential petition signers and voters of the sweep of the measure." *Terhune v. Myers*, 342 Or 475, 479, 154 P3d 1284 (2007); *see also Greene v. Kulongoski*, 322 Or 169, 174-75, 903 P2d 366 (1995) (explaining that caption may not obscure measure's effect or make it difficult for voters to understand measure's subject).

We believe the draft caption fails to comply with the above standards because of the term "renewable sources." IP 73 does not increase the percentage of electricity required from "renewable sources;" it increases the percentage of electricity required from "qualifying electricity." *See, e.g.,* Section 4(g) ("At least 50 percent of the electricity sold by the utility to retail electricity consumers in calendar year 2040 and subsequent calendar years must be *qualifying electricity*.) (emphasis added). As described above, "qualifying electricity" is defined as electricity that complies with the facility age restrictions contained in ORS 469A.020 and the energy source restrictions contained in ORS 469A.025. Thus, describing "qualifying electricity" as "renewable sources" is misleading and inaccurate. To correct this deficiency, the caption should refer to "qualifying electricity" instead of "renewable sources." Additionally, the term "qualifying electricity" should be followed by the parenthetical "(defined). *See Carley/Towers v. Myers*, 340 Or 222, 132 P3d 651, 655-56 (2006) ("this court has approved the use of specially defined terms in quotation marks, followed by the word 'defined' in parentheses, to signal that the proposed measure specially defines the terms and uses it in that specially defined sense"); *Hunnicutt v. Myers,* 340 Or 83, 86, 127 P3d 1182 (2006) (illustrating principle).

Alternatively, if the caption continues to use the term "renewable resources," the above-described deficiency may be corrected by putting the term in quotation marks followed by "(defined)." Because of the strict limitations on the types of energy sources that may be used to comply with the RPS, the term "renewable" without quotation marks renders the caption misleading and overinclusive. "Renewable" is a trendy word often used by the general public to refer to something that is from a natural source. "Renewable" is defined as "a natural resource of source of energy, not depleted when used."
http://www.oxforddictionaries.com/us/definition/american_english/renewable. However, as used

in IP 73, "renewable sources" refers to the specifically defined sources of energy listed in ORS 469A.025. Section 6(11). An energy source not included in this definition is not considered "renewable" even if it is otherwise a natural source of energy that is not depleted when used. For example, hydropower produced from older dams and biomass that includes wood treated with certain preservatives are not "renewable." *See* Exhibit 1. Using quotation marks will alert voters that the term has a specific definition that may differ from their own definition.

Also, the caption overstates IP 73's effect on energy consumption. The captions states that the initiative "reduces new buildings' permissible net energy consumption;" however, the initiative would only require standards that set a goal of such energy reduction. The caption is written in a manner that could cause voters to mistakenly believe that new buildings would be required to reduce net energy consumption, but that is an overstatement. Reduced energy consumption would be a goal of the new building code, but the code cannot "ensure" such reduction and no mechanism is included in the initiative to enforce the new standard. While the word "permissible" attempts to capture the uncertainly of the reduction, it still implies that the initiative would reduce energy consumption, and such effect is not known at this time. To correct this deficiency, the caption should clearly reflect that the initiative would only require certain standards, but would not reduce the amount of energy new buildings consume.

The following captions would comply with statutory requirements:

Increases percentage of electricity required from "qualifying electricity" (defined); Establishes stricter energy standards for buildings

Increases percentage of electricity required from "renewable sources" (defined); Establishes stricter energy standards for buildings

B. The Result of "Yes" Vote Statement

ORS 250.035(2)(b) requires a ballot title to contain a "simple and understandable statement," of not more than 25 words, explaining what will happen if the measure is approved. As the Oregon Supreme Court has observed, the "yes" vote result statement should describe "the most significant and immediate" effects of the ballot initiative for "the general public." *Novick/Crew v. Myers,* 337 Or 568, 574, 100 P.3d 1064 (2004).

IP 63's "yes" statement is also noncompliant because voters are not notified that the initiative adopts a special definition for "qualifying electricity" and "renewable resources." This will likely result in voters mistakenly believing that all types of renewable energy, as commonly understood, may be used to comply with the initiative. Additionally, as discussed above, the statement should make clear that the initiative would only require stricter standards, not reduce the amount of energy new buildings could consume.

C. The Result of "No' Vote Statement

ORS 250.035(2)(c) requires a ballot title to contain a "simple and understandable statement," of not more than 25 words, explaining what will happen if voters reject the measure. This means that the statement must explain to voters "the state of affairs" that will exist if the initiative is rejected, i.e. the status quo. Also, a "no" vote result statement should "address[ ] the substance of current law *on the subject matter of the proposed measure*" and "summarize [ ] the current law accurately." *Novick/Crew* at 577, 100 P.3d 1064 (emphasis in original).

For the reasons stated above, we believe the term "qualifying electricity" should be used followed by the word "defined;" or, alternatively, the term "renewable sources" should be put in quotation marks followed by the word "defined."

D. The Summary

ORS 250.035(2)(d) requires that a ballot title contain a "concise and impartial statement of not more than 125 words summarizing the state measure and its major effects." The purpose of a ballot title's summary is to give voters enough information to understand what will happen if the initiative is adopted. *Whitsett v. Kroger*, 348 Or 243, 252, 230 P.3d 545 (2010).

The summary adequately describes most of IP 73; however, the sentence regarding energy consumption should be modified to adequately convey that the initiative would only require stricter standards, not reduce the amount of energy new buildings could consume.

Thank you for considering our comments to the draft ballot title.

Very truly yours,

Jill Gibson

Steven C. Berman
sberman@stollberne.com

January 8, 2016

VIA EMAIL

Jeanne Atkins
Secretary of State
Elections Division
255 Capital Street NE, Suite 501
Salem, OR 97310

Re: Initiative Petition No. 73 for the General Election of November 8, 2016

Dear Secretary Atkins:

I represent Nicholas Blosser regarding the ballot title for Initiative Petition No. 73 for the General Election of November 8, 2016 (the "Initiative"). Mr. Blosser is an elector in the State of Oregon and one of the Initiative's co-chief petitioners. This letter is written in response to your office's public notice, dated December 23, 2015, which invites comments on the draft ballot title for the Initiative.

Mr. Blosser respectfully submits that the caption, results statements and summary for the draft ballot title do not meet the requirements of ORS 250.035(2). Mr. Blosser requests that the Attorney General certify a ballot title that corrects those deficiencies and substantially complies with the statutory requirements.

I. An Overview of Initiative Petition No. 73

The Initiative has three major effects. First, it phases out coal-generated electricity by 2030. Second, the Initiative increases Oregon's renewable electricity requirements. Finally, the Initiative establishes increased energy efficiency for newly constructed buildings.

Current law does not require electric companies to transition away from using coal-fired resources as part of their electricity supplies. The Initiative amends current law by requiring electric companies to transition off of coal-fired resources. That transition must occur before January 1, 2030 or the year in which a coal-fired resource is fully depreciated, whichever is earlier. Initiative, § 3.

The Initiative also increases the renewable energy requirements in Oregon's Renewable Portfolio Standard. Current law sets certain minimum thresholds large utilities must meet for sales to "retail electricity consumers." By 2011, "at least" five percent of the electricity sold must be renewable energy. By 2015, that minimum increases to 15%. By 2020, the minimum is 20%. By 2025, the minimum is 30%. ORS 469A.052(1). If a utility becomes a large electric utility after June 2007, then within four years, at least 5% of the electricity it sells must come from renewable sources; within ten years, the minimum increases to 15%; within 15 years, the minimum increases to 20%; and, within 20 years, the minimum increases to 25%. ORS 469A.052(3).

The Initiative increases the amount of energy that must come from renewable sources. The predominant means by which the Initiative accomplishes this effect is by raising the minimum renewable electricity thresholds for large utilities. Under the Initiative, by 2020, "at least" 22% (as opposed to 20% under current law) of electricity sold by a utility must be renewable. By 2025, that minimum increases to 30% (from 25% under current law). The Initiative imposes additional new minimum thresholds for subsequent years. By 2030, "at least" 40% of the electricity sold must be from renewable sources; by 2035, that minimum is 45%; by 2040, that minimum is 50%. Initiative, §§ 4(1)(c)-(g). For any utility that becomes a large electric utility after June 2007, within 15 years, "at least" 22% of the electricity sold must be renewable (as opposed to 20% under current law). Within 20 years, that minimum threshold is 30% (as opposed to 25% under current law). The Initiative imposes new minimum thresholds for subsequent years. Within 25 years, "at least" 40% of the electricity sold must be renewable; within 30 years, at least 45% must be renewable; and, within 35 years, at least 50% of the electricity sold must be renewable. Initiative, §§ 4(3)(c)-(g). To ensure that large utilities generate their own renewable electricity, the Initiative limits how long *newly* issued renewable energy certificates may be banked and carried forward.[1] Under the Initiative, certificates issued *after* the effective date of the Initiative may only be banked and carried forward for three years. Initiative, § 7(2). Utilities will no longer be able to hold onto certificates indefinitely as a way to compensate for using and selling non-renewable electricity. As a result, electric utilities will sell more recently generated renewable electricity. The Initiative also amends ORS 469A.075, by adding a new requirement for the implementation plans that must be adopted by each electric company subject to a renewable portfolio standard. Under the Initiative, that implementation plan must include procurement options for meeting the requirements of the renewable portfolio standard *and* minimizing the risk of exceeding the cost limitation in ORS 469A.100. Initiative, § 5.

The Initiative also requires increased energy efficiency standards for newly constructed buildings. Section 9 amends ORS 455.511 to require that the state building code require all newly constructed buildings consume 65% less energy by 2032 than required by the code in effect in 2014. Section 8 requires that the code be updated every three years, beginning in 2017, to ensure compliance by 2032. In other words, under sections 8 and 9, the state building code will be consistently revised, with increased energy efficiency standards, in order to achieve a 65% reduction in energy consumption for new construction by 2032.

[1]Under current law, an electric utility can comply with the renewable portfolio standards by using bundled or unbundled renewable energy certificates. ORS 469A.070(1)(a), (b). Renewable energy certificates may be banked, sold or transferred. ORS 469A.140. Certificates may be banked "indefinitely." ORS 469A.140(2).

II. The Draft Ballot Title

A. The Caption

ORS 250.035(2)(a) provides that a ballot title must contain a "caption of not more than 15 words that reasonably identifies the subject matter of the state measure." The caption must "state or describe the proposed measure's subject matter accurately, and in terms that will not confuse or mislead potential petition signers and voters." *Lavey v. Kroger*, 350 Or 559, 563 (2011) (citations omitted; internal quotation marks omitted). The "subject matter" of an initiative is its "actual major effect." *Lavey*, 350 Or at 563 (citation omitted; internal quotation marks omitted). The "actual major effect" is the change or changes "the proposed measure would enact in the context of existing law." *Rasmussen v. Kroger*, 350 Or 281, 285 (2011). "The caption is the cornerstone for the other portions of the ballot title." *Greene v. Kulongoski*, 322 Or 169, 175 (1995). As the "headline," the caption "provides the context for the reader's consideration of the other information in the ballot title." *Greene*, 322 Or at 175.

The draft caption provides:

Increases percentage of electricity required from renewable sources; reduces new buildings' permissible net energy consumption

Mr. Blosser respectfully submits that the caption is flawed for two reasons. First, the caption is underinclusive, because it fails to mention that the Initiative requires electric utilities to phase out coal generated electricity from their electricity supplies. "When the Attorney General chooses to describe the subject matter of a proposed measure by listing some of its effects, [s]he runs the risk that the caption will be underinclusive and thus inaccurate." *Towers v. Myers*, 341 Or 357, 361 (2006). *See also McCann v. Rosenblum*, 354 Or 701, 706 (2014) ("[w]hen the Attorney General chooses to describe a measure by listing the changes that the proposed measure would enact, some changes may be of 'sufficient significance' that they must be included in the description"). A caption that is underinclusive, because it does not notify readers of all the major effects of an initiative, is statutorily noncompliant. *Towers*, 341 Or at 362. Each major effect of an initiative should be conveyed in the caption.

The coal phase out mandated by the Initiative is a significant change in Oregon energy policy. Under the Initiative, by 2030, electric utilities will not be permitted to include coal-generated electricity as part of their electricity supply. Coal-generated electricity may not be provided to consumers, whether by sale or otherwise. It cannot be part of the energy delivered to consumers (or part of the energy a utility purchases for delivery to consumers). That is a major effect of the Initiative that must be mentioned in the caption, and throughout the ballot title.

The second flaw with the caption is that the description of the energy efficiency requirements of sections 8 and 9 is both incomplete and confusing. "[R]educes new buildings' net permissible energy consumption" is technical language that would be incomprehensible to most voters and potential petition signers. Moreover, that phrase does not fully describe what Sections 8 and 9 do. Those provisions of the Initiative require increased energy efficiency standards in new construction, so that energy consumption will be reduced. Voters and potential petition signers reading the caption would have no way of knowing that the Initiative increases energy efficiency requirements.

A caption that complies with the statutory requirements would provide:

Requires increased electricity from renewable sources; phases out coal-generated electricity; increases new buildings' efficiency

B. The Results Statements

ORS 250.035(2)(b) and (c) require that the ballot title contain "simple and understandable statement[s] of not more than 25 words that describe[ ] the result if the state measure is" approved or rejected. The yes statement "should describe the most significant and immediate effects of the ballot initiative for the general public." *McCann*, 354 Or at 707 (internal quotation marks omitted; citation omitted). The yes statement must "provide the voter with sufficient substantive information to understand the policy choice proposed by the measure's operative terms." *Rasmussen v. Rosenblum*, 354 Or 344, 348 (2013). A result of yes statement is not statutorily compliant if it is inaccurate, confusing or misleading. "To substantially comply with [ORS 250.035(2)(b)], an *accurate* description of the change that will be caused by the measure is key." *Lavey*, 350 Or at 564 (emphasis in original). *See also Dixon v. Rosenblum*, 355 Or 364, 374 (2014) (referring certified ballot title to Attorney General for modification because result of no statement was "confusing, if not misleading"). The results statements cannot create even an "erroneous inference" of current law or the impact an initiative would have on current law. *McCormick v. Kroger*, 347 Or 293, 300 (2009).

The draft results statements provide:

"Yes" vote increases percentage of electricity sales required from renewable sources; renewable energy certificates (RECs) expire; will reduce permissible net energy consumption of new buildings.

"No" vote retains current minimum percentages for electricity sales from renewable sources; RECs do not expire; retains current net energy consumption standards for new buildings.

Mr. Blosser respectfully submits that the result of yes statement is flawed in three ways. For the reasons set forth above: (1) the result of yes statement must address the coal phase out required by the Initiative; and, (2) the description of the Initiative's increased energy efficiency standards for new construction is inaccurate and incomplete. The third flaw with the result of yes statement is that the phrase "renewable energy certificates (RECs) expire" is inaccurate, potentially confusing and not properly included as part of the result of yes statement.

Under current law, electric utilities may use renewable energy certificates to meet the Renewable Portfolio Standard. Those certificates may be banked and carried forward indefinitely. ORS 469A.140. The Initiative, by its own terms, does not change existing law as to any certificate issued prior to the Initiative's effective date. That is made explicit in the first sentence of Section 7. As for certificates issued *after* the effective date of the Initiative, those certificates may be banked and used for up to three years following the year in which the certificate is issued. Initiative, § 7. Simply put, Section 7 affects only *newly* issued certificates, but not certificates that are issued at any time before the Initiative becomes effective.

The discussion of energy certificates, and the phrase "renewable energy certificates (RECs) expire," is not helpful to voters. The result of yes statement does not explain what energy certificates are, or how future certificates expiring will affect or change Oregon law or policy. The phrase is entirely uninformative. It is not "simple and understandable," as required by ORS 250.035(2)(b), and will only confuse voters.

Mr. Blosser respectfully submits that the result of yes statement should not address renewable energy certificates at all. The fact that newly issued certificates (but not current certificates) will sunset within three years is not one of "the most significant and immediate effects of the ballot initiative." *McCann*, 354 Or at 707. Rather, the most immediate and significant effects of the ballot initiative are: (1) a phase out of coal from electricity supplies; (2) the increase in electricity sold that must come from renewable sources; (3) the increased energy efficiency required for new construction. The sunset on newly issued certificates relates only to the second effect. As to that second effect, whether Oregon law will require an increase in the use and sale of renewable energy is a "policy choice proposed by the measure's operative terms," *Rasmussen*, 354 Or at 348. The limitation on *future* certificates is just a part of that policy choice.

The phrase "energy certificates (RECs) expire" is inaccurate, because it does not differentiate between existing certificates and certificates that are issued after the Initiative goes into effect. A voter or potential petition signer reading the certified result of yes statement would be left with the mistaken impression that if the Initiative is approved, *existing* certificates would expire. That is not what the Initiative does. Rather, the Initiative merely sets a three-year sunset on certificates issued after the Initiative takes effect. The phrase "energy certificates (RECs) expire" is incorrect, and must be revised.

The phrase "renewable energy certificates (RECs) expire" also is potentially misleading. It is undisputed that the Initiative would *increase* renewable energy requirements. However, voters and potential petition signers – who cannot be expected to know the nuances of Oregon's energy policy, what "renewable energy certificates" are or how they work – reasonably could conclude from the result of yes statement that the Initiative *reduces* renewable energy requirements. The word "expire" in conjunction with "renewable energy" creates the improper inference that the Initiative somehow cuts back on renewable energy requirements. For that additional reason, the phrase should not appear in the result of yes statement.

The result of yes statement should not include reference to the nuanced issue of renewable energy certificates. It is a subsidiary effect that would be confusing to voters and cannot be adequately described within the 25-word limit set forth in ORS 250.035(2)(b). The Initiative's limited effect on future renewable energy certificates may appropriately be (and should only be) addressed in the summary.

The result of no statement is flawed for the same reasons as the result of yes statement. The discussion of renewable energy certificates in the second clause also miscasts the Initiative's impact on current law, and would leave voters with the erroneous impression that under the Initiative *all* certificates (including existing certificates) would expire. Any discussion of renewable energy certificates is better left for the summary.

Results statements that comply with the statutory requirements would provide:

"Yes" vote requires increased electricity from renewable sources; phases out coal-generated electricity from electricity supplies by 2030; requires increased energy efficiency for new buildings.

"No" vote retains current minimum percentages for renewable electricity; no phase-out of coal generated electricity; retains current energy efficiency standards for new buildings.

C. The Summary

ORS 250.035(2)(d) requires that the ballot title contain a "concise and impartial statement of not more than 125 words summarizing the state measure and its major effect." "The goal of the summary is to help voters understand what will happen if the measure is approved and the breadth of its impact." *Yugler v. Myers*, 344 Or 552, 556 (2008) (citation omitted; internal quotation marks omitted). To meet that requirement, the summary must set forth the "significant changes to existing law" made by an initiative. *Stacey v. Myers*, 342 Or 437, 443 (2007). Mr. Blosser respectfully submits that the summary is flawed for the following reasons:

- Over two-thirds of the summary – the first six lines – address current law. While some discussion of current law may be appropriate, the summary still must meet its primary goal of describing what the Initiative actually does. Here, the lengthy description of current law distracts voters from the major effects of the Initiative.

- Despite its length, the Initiative's description of current law is underinclusive. The description of current law does not set forth for voters that under current law, there are no restrictions on the use of electricity from coal, or that current law sets minimum standards for building energy efficiency.

- The summary unduly focuses on renewable energy certificates. As was discussed above, the Initiative's impact on renewable energy certificates is a subsidiary effect. Yet, almost a quarter of the summary (30 words) addresses renewable energy certificates. In contrast, only 11 words are devoted to the Initiative's coal phase out requirement, and only 11 words address the increased energy efficiency required by the Initiative.

- The description of the impact and effect of Sections 8 and 9 of the Initiative is relegated to the second to last sentence, is insufficient and uninformative. As is set forth above, the Initiative requires that, by 2032, the state building code require newly constructed buildings be 65% more efficient than currently required, and that those code changes be gradually implemented. The phrase "would reduce, by 2032, new buildings' permissible net energy consumption by 65%" misses the mark. That phrase does not explain to voters and potential petition signers what Sections 8 and 9 do, and will not help voters understand what will happen if the Initiative passes.

- One of the Initiative's other major effects – the phase out of coal – also is not discussed until the second to last sentence of the Initiative. The summary uses the misleading and inaccurate phrase "coal-generated electricity *sales*" (emphasis added). However, as discussed above, the phase out applies not just to sales, but to including coal as part of an electric utility's electricity mix. "Sales" is inaccurate and misleading.

Thank you for your consideration of these comments. Please notify me when a certified ballot title is issued.

Very truly yours,

Steven C. Berman

SCB:jjs
cc: client

Davis Wright Tremaine LLP

Suite 2400
1300 SW Fifth Avenue
Portland, OR 97201-5630

Gregory A. Chaimov
503.778.5328 tel
503.778.5299 fax

gregorychaimov@dwt.com

January 8, 2016

VIA EMAIL– irrlistnotifier.sos@state.or.us

Elections Division
Office of the Secretary of State
255 Capitol St NE, Suite 501
Salem, OR 97310

Re: Public Comment on Initiative Petition 2016-073

Dear Secretary Atkins:

On behalf of Scott D. Bolton and Dave Robertson, registered Oregon voters, we are providing the following comments on the draft ballot title.

The Secretary of State notified the public of the following draft ballot title December 23, 2015:

Increases percentage of electricity required from renewable sources; reduces new buildings' permissible net energy consumption

Result of "Yes" Vote: "Yes" vote increases percentage of electricity sales required from renewable sources; renewable energy certificates (RECs) expire; will reduce permissible net energy consumption for new buildings.

Result of "No" Vote: "No" vote retains current minimum percentages for electricity sales from renewable sources; RECs do not expire; retains current net energy consumption standard for new buildings.

Summary: If a utility sells at least 3% of all electricity sold to consumers, current law generally requires—for 2020-2024—at least 20% of utility's electricity sales to be "qualifying electricity," which includes electricity from "renewable energy sources" (defined by current law); subsequently, required minimum is 25%; to meet minimums, may use RECs (RECs are issued to utilities that produce more qualifying electricity than required, may be

> sold/transferred between utilities). Proposed measure increases required minimum: 22% for 2020-2024, 30-45% for 2035-2039, 50% subsequently; RECs would expire after three years; electric companies must phase out coal-generated electricity sales by 2030; would reduce, by 2032, new buildings' permissible net energy consumption by 65%. Other provisions.

COMMENTS ON DRAFT TITLE

CAPTION

The draft caption provides:

Increases percentage of electricity required from renewable sources; reduces new buildings' permissible net energy consumption

ORS 250.035(2)(a) provides that the ballot title caption must contain "not more than 15 words that reasonably identif[y] the subject matter of the state measure." The caption is the "cornerstone for the other portions of the ballot title." *Greene v. Kulongoski*, 322 Or 169, 175, 903 P2d 366 (1995). As the "headline" for the ballot title, the caption "provides the context for the reader's consideration of the other information in the ballot title." 322 Or at 175. A caption complies substantially with the requirements of ORS 250.035(2)(a) if the caption identifies the subject matter of the proposed measure in terms that will not confuse or mislead * * *voters. 322 Or at 174-75. In addition, the caption, like other parts of the ballot title, must not be under-inclusive, *Terhune v. Myers*, 338 OR 544, 559, 112 P3d 1188 (2005), or over-inclusive. *Brady v. Kroger*, 347 Or 518, 524, 225 P3d 26 (2009).

The "subject matter" of a measure, as that term is used in ORS 250.035(2)(a), must be determined with reference to the "significant changes" that would be brought about by the measure. *Phillips v. Myers*, 325 Or 221, 226, 936 P2d 964 (1997).

This Court has insisted that a caption describe a proposed measure's subject matter accurately because of the central importance of the caption to the decision-making process of petition signers and voters:

> The caption, which is the first information that most potential petition signers and voters will see, is pivotal. It must "inform potential petition signers and voters of the sweep of the measure." *Terhune v. Myers*, 342 Or 475, 479, 154 P3d 1284 (2007). A caption should not "understate or overstate the scope of the legal changes that the proposed measure would enact." *Kain/Waller v. Myers*, 337 Or 36, 40, 93 P3d 62 (2004).

Frazzini v. Myers, 344 Or 648, 654, 189 P3d 1227 (2008). The caption does not meet this standard.

The draft caption suffers from problems that flow through other sections of the draft title.

First, the draft caption should not use the undefined term "renewable sources." The term is over-inclusive because the potential increase in percentage of electricity would not be from "renewable sources," a term not defined for purposes of ORS 469A.052, which IP 73 would amend, and which, in ordinary usage, means a broader group of sources than ORS 469A.052 covers. Instead, IP 73 would require increases in percentages of "qualifying electricity," a term defined for use in ORS 469A.052 and that includes only a limited subset of energy sources commonly understood as renewable.

The use of the undefined term "renewable sources" is also likely to mislead or confuse voters because the Oregon renewable portfolio standard of which ORS 469A.052 is a part uses the similar but statutorily defined term "renewable energy source," ORS 469A.005(10), 469A.025, and the two concepts are not interchangeable.

The source from which covered utilities may have to obtain a percentage of electricity is a statutorily defined and described concept called "qualifying electricity." ORS 469A.005(9), 469A.010. "Qualifying electricity" is a subset of another statutorily defined concept, "renewable energy source," ORS 469A.005(10), 469A.020, 469A.025, which is, in turn, a subset of the commonly understood concept of renewable sources: solar, wind, hydropower, biomass, hydrogen and fuel cells, geothermal energy, and tides and waves. http://bit.ly/1lLCQtf, http://on.nrdc.org/1ntdgoH.

The Legislative Assembly has narrowed the commonly understood list of renewable sources to produce the statutory concept "renewable energy source." This legal concept excludes renewable sources such as biomass, depending on the kind of biomass, who burns the biomass, and how much, ORS 469A.025(3), (6)(b), hydropower, depending on the location of the facility, 469A.025(4)(a), and hydrogen, depending on the source of the hydrogen, ORS 469A.025(7)(a).

The Legislative Assembly further narrows the legal concept of "renewable energy source" to arrive at the concept of "qualifying electricity." Most significantly, "qualifying electricity" excludes almost all current hydropower. The Bonneville Power Administration's hydropower facilities became operational before 1995, http://1.usa.gov/1YRCLsZ, and ORS 469A.020(1)–(4) limits qualifying electricity to hydropower generated by a facility that becomes operational on or after January 1, 1995.

The difference between "renewable energy" and "qualifying electricity" is material because almost half of the power supplied in Oregon comes from hydropower that does not qualify as "qualifying electricity." http://1.usa.gov/1RS3roZ. Thus, voters are likely to believe—incorrectly—that large quantities of hydropower are available to covered utilities to meet a "renewable" requirement.

In addition to being over-inclusive, "renewable sources" also has an unfair positive connotation as demonstrated by the incorporation of a portion of the term into the name of the campaign supporting IP 73: "Renew Oregon." http://www.reneworegon.org/campaign.

Second, the draft caption violates the teaching of *Rasmussen v. Rosenblum*, 354 Or 344, 345-48 (2013), by omitting the electricity providers to which IP 73's "increase[d] percentage" applies. In *Rasmussen*, this Court required modification of a caption that implied a measure applied to all estates, when the measure applied only to estates that passed to family members or trusts. The draft caption here suffers from the same kind of problem. There is no statement of who these requirements apply to, a significant omission because any increased percentage of "qualifying electricity" will be required of fewer than 10 percent of the state's electricity providers. There are 39 providers of electricity in Oregon. http://1.usa.gov/1P0zywE. Only three provide at least three percent of the electricity supply. http://1.usa.gov/1JJZ1bQ.

Third, the draft caption is over-inclusive and misleading because the draft caption does not inform voters that the percentage increase in the sale of qualifying electricity is only a *potential* outcome of IP 73. An increase may or may not occur depending on the cost of the qualifying electricity. Under current law, utilities are not required to provide qualifying electricity at the required statutory percentage to the extent that to do so would cause the utility to exceed the cost cap expressed in ORS 469A.100(1):

> Electric utilities are not required to comply with a renewable portfolio standard during a compliance year to the extent that the incremental cost of compliance, the cost of unbundled renewable energy certificates and the cost of alternative compliance payments under ORS 469A.180 exceeds four percent of the utility's annual revenue requirement for the compliance year.

Thus, the statement that the measure "increases"—as in "will increase" —is "speculation" about the actions of individuals and markets years in the future, which the Supreme Court prohibits. *Ascher v. Kulongoski*, 322 Or 516, 523, 909 P2d 1216 (1996).

Fourth, the draft caption does not alert voters that the key terms of IP 73 used in the caption are undefined and, in context, appear to provide meanings different than in current law. The caption should alert voters that the measure proposes a concept that is different from current law, or, at a minimum, alert voters that it is not clear whether the terms used to express the concept convey a meaning different from current law.

The key to the energy consumption sections is the meaning of the phrase "annual net energy consumption of newly constructed buildings," which is the subject of rules the Building Codes Division, under IP 73, must adopt. However, neither the Building Code nor the measure defines the phrase or the component terms of the phrase.[1]

The absence of definitions highlights a key difference between the scope of the current Building Code and the scope of IP 73's new energy consumption standard.

First, the energy consumption standard in IP 73 applies only to "buildings." The Building Code, however, has a much broader scope. The Building Code applies to "buildings *and other structures and the installation of mechanical devices and equipment therein*." ORS 455.020(1) (emphasis added). As a result, IP 73 would apply to the energy consumption of a building, but not to the energy consumption of the mechanical devices or equipment in the building.

Second, the different scope of IP 73 is reinforced by the difference in terminology between current law and the amendment IP 73 would make. The measure uses a different preposition—"of" in place of "in"—when referring to the thing that consumes energy. Current law, ORS 455.511(3), refers to "energy efficiency *in* buildings that are newly constructed, reconstructed, altered or repaired" (emphasis added) —a term that covers mechanical devices and equipment within or inside the buildings. IP 73, by way of contrast, adds a new subsection to ORS 455.511 that refers to "energy consumption *of* newly constructed buildings."

These differences in terminology in the same law lead to the conclusion that the energy consumption requirement of IP 73 is different from the energy consumption requirement in the current Building Code. *State ex rel. Dept. of Trans. v. Stallcup*, 341 Or 93, 101, 138 P3d 9 (2006) (court presumes difference in meaning from difference in terminology in same law).

Finally, because the Attorney General may, when crafting the certified title, use specific terms in section 3 of IP 73, we offer these additional comments for guidance:

By its terms, section 2 of the proposed measure provides definitions for section 2 and section 2 alone: "As used in this section," not "As used in this section and section 3 of this 2016 Act." Section 2, therefore, does not provide definitions for section 3. Consequently, none of the terms used in section 3 is defined, except to the extent definitions that apply to chapter 757 of the Oregon Revised Statutes apply by virtue of section 1 of the proposed measure.

Section 1 adds section 3 to chapter 757 of the Oregon Revised Statutes, but not to any specific series of statutes within the chapter. As a result, only definitions that apply to all of

[1] ORS 276.905 defines an "energy consumption analysis" for purposes of construction of public facilities, but that concept is not part of the Building Code that IP 73 would amend.

ORS chapter 757 apply to section 3. ORS 756.010 and 757.005 provide the only definitions that apply to all of ORS chapter 757 and, thus, to section 3. The only terms that section 3 uses that are defined in ORS 756.010 and 757.005 are "customer," "rate," and "service."

The consequence of providing limited definitions for terms in section 3 is that IP 73 uses key terms that are (1) not part of common speech, (2) specially defined for purposes of utility regulation laws—sometimes in different ways in different utility regulation laws, and (3) not defined in the measure. Where used, the ballot title should note that these key terms are undefined:

- "Electricity," defined in ORS 757.600, but not defined for section 3.
- "Electric company," defined in ORS 757.600, but not defined for section 3.
- "Retail electricity consumer," defined in ORS 757.360, ORS 757.600, and ORS 757.915, but not defined for section 3.

Because section 2 of IP 73 does not provide definitions for section 3, the following key terms in section 3, which are not part of common speech or current law, are left undefined:

- Allocation of electricity.
- Coal-fired resource.
- Electricity supply.
- Fully depreciated.

Because these terms were sufficiently important to attempt to provide definitions, the ballot title should, when using the terms, note the lack of definition.

The following are ways a caption could address some, if not all, of the problems with the draft caption:

> **May increase "electric utilities'" sales of "qualifying electricity," decrease new buildings' "net energy consumption" (undefined)**

> **Increases percentage of sales of "qualifying electricity"; reduces new buildings' permissible "net energy consumption" (undefined)**

RESULT OF "YES" VOTE

"ORS 250.035(2)(b) and (c) require 'simple understandable' statements of not more than 25 words that describe the result if voters approve the proposed measure and if they reject it." *Wyant/Nichols v. Myers*, 336 Or 128, 138 (2003). The purpose of this section of the ballot title is to "notify petition signers and voters of the result or results of enactment that would have the greatest importance to the people of Oregon." *Novick v. Myers*, 337 Or 568, 574, 81 P3d 692 (2004). The yes statement builds upon the caption. *Hamilton v. Myers*, 326 Or 44, 51, 943 P2d 214 (1997).

The draft yes statement reads as follows:

> **Result of "Yes" Vote:** "Yes" vote increases percentage of electricity sales required from renewable sources; renewable energy certificates (RECs) expire; will reduce permissible net energy consumption for new buildings.

The draft yes result statement carries over the problems of the draft caption and also fails to comply with ORS 250.035(2)(b) in additional ways.

First, the draft yes statement does not inform voters that a result of the passage of IP 73 as written will be an increase in rates charged for electricity. Whether electricity rates will go up as a result of electric utilities producing or acquiring a greater percentage of "qualifying electricity" according to the terms of this measure is not a matter of speculation. First, there is no dispute that producing or acquiring "qualifying electricity" entails a cost the producer or purchaser would not otherwise incur. The following information from the United States Department of Energy confirms that there is a cost to obtaining electricity from the renewable sources that constitute "qualifying electricity": http://1.usa.gov/1PGFE8f.

The higher cost of "qualifying electricity" over non-qualifying electricity is an assumption built into Oregon law. The reason there is a cap on the cost of "qualifying electricity" that an electric utility must obtain, ORS 469A.100, is that the cost of "qualifying electricity" is higher than the cost of electricity that is not "qualifying electricity."

Government analyses, whether state or federal, demonstrate that increasing the percentage of renewable energy sources in a power company's portfolio increases the cost of electricity to consumers. *See generally* Costs and Benefits of Renewables Portfolio Standards in the United States (Lawrence Berkeley Nat Lab July 2015) (enclosed as Exhibit 1). For example, a California report shows that the increase in percentage from 20 percent to 33 percent means more than a seven-percent increase in the cost of electricity. 33% Renewables Portfolio Standard Implementation Analysis, p. 1 (Cal PUC June 2009) (enclosed as Exhibit 2). Voters should know that an increase in the percentage of "qualifying electricity" will lead to an increase in electricity rates.

We appreciate that, for IPs 63 and 64, the Attorney General concluded that, because of the four-percent cost cap on "qualifying electricity," an increase in cost to customers was not sufficiently certain to state that costs would increase. However, the same logic leads to the conclusion that an increase in sales of "qualifying electricity" is not sufficiently certain to state that sales of "qualifying electricity" will increase. To avoid misleading voters, all parts of the ballot title should be consistent.

Second, it is inaccurate, and therefore, misleading, to state that IP 73 causes renewable energy certificates to "expire." Under IP 73, the three utilities that may be required to provide certain percentages of qualifying electricity in the future will have a limited time within which to use renewable energy certificates RECs. But IP 73 does not limit the time during which anyone else, including manufacturers, governments, and the state's other 36 utilities may use a REC nor does IP 73 limit the three covered utilities from using RECs for a purpose other than meeting any required percentage of "qualifying electricity."

RECs accrue to anyone producing "qualifying electricity." Energy Trust of Oregon REC Report, p. 5 (March 23, 2015) (home solar panels), http://bit.ly/1JM1a6X. According to the Oregon Department of Energy, a "REC can be used to comply with [a requirement to obtain a percentage of electricity from 'qualifying electricity'], a voluntary utility customer program, or by anyone who makes environmental or renewable claims associated with renewable energy facilities." http://1.usa.gov/1P0zUDf. Large quantities of RECs are used by Oregon businesses, such as Intel Corporation, and governments, such as the Port of Portland. Energy Trust of Oregon REC Report, p. 10. Under current law, there is no limit on the duration of use of a REC for any purpose.

Section 7 of IP 73 limits the number of years a covered utility may carry a REC forward to meet a requirement that its electricity sales contain a certain percentage of "qualifying electricity." IP 73 does not limit the duration of a REC in any other circumstance, such as when by businesses other than covered utilities or by covered utilities for a voluntary customer program.[2]

A way to address some, if not all, of the concerns raised about the draft yes statement include:

> **Result of "Yes" Vote:** "Yes" vote potentially increases "electric utilities'" sales of "qualifying electricity," electricity costs; decreases new buildings' "net energy consumption" (undefined); limits uses of "renewable energy certificates."

[2] An example of a voluntary program that IP 73 does not affect is PacifiCorp's Blue Sky program through which, at customers' requests, the company "purchases renewable energy certificates from newly developed renewable energy facilities." http://bit.ly/1S0GEau.

RESULT OF "NO" VOTE

The Attorney General issued the following draft no statement:

Result of "No" Vote: "No" vote retains current minimum percentages for electricity sales from renewable sources; RECs do not expire; retains current net energy consumption standard for new buildings.

ORS 250.035(2)(c) requires the no statement to "us[e] the same terms" as the yes statement "to the extent practical." ORS 250.035(3) reinforces the requirement by requiring that the no and yes statements "be written so that, to the extent practicable, the language of the two statements is parallel." However, the no statement should not simply rephrase, in the negative, the yes statement. *See Terhune v. Myers*, 342 Or 136, 143, 149 P3d 1139 (2006). The no statement should endeavor to describe the current state of the law.

The draft no statement does not comply with ORS 250.035(2)(c) because the statement carries forward the problems of the draft caption and draft yes statement, only in a mirror image. In addition, the draft no statement inaccurately describes the current state of the law by stating current law in reference to an inaccurate description of the results of the measure's passing. Because the draft description of the results of a yes vote is too broad—describing results that will not occur—the no result statement also describes the results of a no vote too broadly. For example, IP 73 does not cause RECs to expire. Consequently, a no vote will not prevent RECs from expiring.

One way to address some of the concerns raised about the no statement is:

Result of "No" Vote: "No" vote retains "electric utilities'" required sales percentage of "qualifying electricity"; no limit on using renewable energy certificates, required increase in new buildings' energy efficiency.

SUMMARY

The Attorney General issued the following draft summary:

Summary: If a utility sells at least 3% of all electricity sold to consumers, current law generally requires—for 2020-2024—at least 20% of utility's electricity sales to be "qualifying electricity," which includes electricity from "renewable energy sources" (defined by current law); subsequently, required minimum is 25%; to meet minimums, may use RECs (RECs are issued to utilities that produce more qualifying electricity than required, may be

> sold/transferred between utilities). Proposed measure increases required minimum: 22% for 2020-2024, 30-45% for 2035-2039, 50% subsequently; RECs would expire after three years; electric companies must phase out coal-generated electricity sales by 2030; would reduce, by 2032, new buildings' permissible net energy consumption by 65%. Other provisions.

The draft summary does not accurately or adequately summarize the measure and its major effects, as required by ORS 250.035(2)(d), because the draft summary carries forward problems with the draft caption and result statements, except for noting that the electricity to which the potentially increased percentage applies is "qualifying electricity." The summary is inaccurate, however, and, therefore, misleading, when referring to "qualifying electricity" as "include[ing] electricity from 'renewable energy sources[.]'" By using the term "includes," the summary gives the misimpression that "qualifying electricity" comes from "renewable energy sources" and some other source or sources. Webster's Third New International Dictionary, p. 1143 ("include" means to "comprise as a discrete or subordinate part or item of a larger aggregate, group, or principle"); Bill Drafting Manual, p. 7.2 (Leg Counsel 2014) ("'Includes' is used if the definition extends the meaning"). The relationship is the other way around. "Renewable energy sources" is a concept broader than "qualifying electricity."

The draft summary does not accurately or adequately summarize the measure and its major effects, as required by ORS 250.035(2)(d), because the summary carries forward the problems with the caption, yes result statement, and no result statement. The summary is also misleading and incomplete when stating that "current law *generally requires*" that—for 2020-2024 —at least 20% of the utility's electricity sales be "qualifying electricity." (Emphasis added) To say that there is a "general requirement" implies there is an exception to a requirement without informing voters of the nature of the exception. The exception here, however, is key, because, as explained above at page 4, the exception—the four-percent cost cap—makes any so-called requirement entirely contingent on events years in the future. Thus, there is no "requirement," general or otherwise, but only the potential for a requirement.

The summary errs, and, therefore, misleads voters, when stating that "RECs are issued to utilities that produce more qualifying electricity than required[.]" The statement gives voters the misimpression that RECs are surplus to utilities' needs and, therefore, unimportant. First, RECs accrue based upon generation of "qualifying electricity," regardless of whether all of the "qualifying electricity" is needed by the person generating the "qualifying electricity" to meet compliance standards. Second, RECs accrue, not just to utilities, but to anyone who produces "qualifying electricity."

In a related vein, stating the specific percentages of "qualifying electricity" that would be applicable in specific years is less a "major effect" of the proposed measure than a more general explanation of the scope of the activity required by whom under what circumstances at what time. The words used to state the specific percentages and dates could be better used to describe additional major effects of the proposed measure.

If the summary retains the specific percentages of "qualifying electricity," the date 2035 should change to 2025, a difference from the proposed measure that appears to be a typographical error.

As with the clause on "increase[d] percentage," the clause about coal misleads voters by failing to inform them to what electricity providers the ban on charging applies. As the summary states, the coal-charging section of IP 73 applies to undefined entities called "electric companies."[3] The summary should alert voters that the term is undefined because current law contains a definition of the term for use in the rest of utility laws. ORS 757.600(13).

Another major problem with the summary is that IP 73 does not "phase out" charging for coal-generated electricity. We understand the Attorney General may have chosen "phases out" to express that IP 73 would end coal generation in the future. Expressing a future end may be permissible, but expressing the future end as the result of phasing is not. To "phase out" means to "stop production or operation by phases[.]" Webster's Third New International Dictionary, p. 1695. In common understanding, therefore, phasing suggests a smooth transition. IP 73 does not stop "by phases" or provide any transition. Instead, IP 73 prescribes two alternative firm end dates: December 31, 2030, or when a coal-generation asset is fully depreciated, whichever is sooner. "Phases out" is not only inaccurate but also inconsistent with the use of the term in previous ballot titles where measures actually proposed to start or stop activities "by phases." *E.g.*, *Rasmussen v. Kroger*, 351 Or 195, 198 (2011) ("Phases out estate and inheritance taxes"); *Sizemore v. Myers*, 332 Or 417, 421 (2001) ("Establishes phase-in for new deductions").

By using the term "sales" to describe the activity IP 73 bans, the draft summary misleads voters to believe that IP 73 will stop electricity providers from providing electricity generated from coal. The concept of "sale" includes a "transfer" of property. Webster's Third New International Dictionary, p. 2003 (unabridged ed. 2002). IP 73, however, does not stop the transfer of coal-generated electricity; instead, IP 73 only bans charging for the electricity. The caption should make this point clear by referring to the ban as being on charging for—*i.e.*, including in electricity rates electricity generated from coal.

As with the increase in the percentage of qualifying electricity, the elimination of coal-generated electricity in rates is, at most, a hypothetical effect of the measure. There is only one coal-fired facility in Oregon, the Boardman Plant, which is, according to plans approved by state regulators, scheduled to stop using coal no later than December 31, 2020. *See* http://bit.ly/1TAtIWo. If that were not enough, the end of coal use at the plant by December 31,

[3] As explained below at pages 5 - 6, section 2 of IP 73 does not provide definitions for section 3.

2020, is subject to a court order. *See* Consent Decree, *Sierra Club v. Portland General Electric Company*, United States District Court (Oregon) Case No. 3:08-cv-100136-HA (Sept. 3, 2011) (Exhibit 3 enclosed). The plant will, under approved depreciation schedules, not be fully depreciated until after December 31, 2020. *See* Oregon Public Utility Commission Order No. 14-297 (Sept. 2, 2014) (Exhibit 4 enclosed). (As a result of 2009 SB 101, electric utilities are also prohibited from increasing their ownership of coal resources. *See* https://olis.leg.state.or.us/liz/2009R1/Downloads/MeasureDocument/SB101.) Thus, cessation of coal use is coming as a result of actions already taken—not IP 73. Voters are entitled to know that the deadline IP 73 offers may be nothing more than a symbolic gesture.

An alternative summary that would address some, if not all, of these concerns, would read:

> **Summary**: Current law requires "electric utilities," under certain circumstances, to sell certain percentages of "qualifying electricity." Some forms of renewable energy produce "qualifying electricity." "Electric utilities," "electricity service providers" may carry forward renewable energy certificates (REC)—evidence of production of "qualifying electricity"—to comply with requirement to use "qualifying electricity." Building Code currently requires certain energy efficiencies in new buildings. Current law prohibits "electric companies" and "electricity service suppliers" from acquiring coal-fired resources. Measure increases potential sales percentages of "qualifying electricity," consumer's cost of electricity. Measure restricts time "renewable energy certificates" may be carried forward. Measure increases "net energy consumption" (undefined) of new buildings by 65%. Measure requires electric companies (undefined) to stop including electricity from coal-fired resource (undefined) in electricity rates (undefined). Definitions. Other provisions.

Thank you for your consideration.

Very truly yours,

Davis Wright Tremaine LLP

Gregory A. Chaimov

GAC/jan
Enclosures

DWT 28614768v1 0088375-000027

UNITED STATES DISTRICT COURT

DISTRICT OF OREGON

PORTLAND DIVISION

SIERRA CLUB, a non-profit corp., NORTHWEST ENVIRONMENTAL DEFENSE CENTER, a non-profit corp., FRIENDS OF THE COLUMBIA GORGE, a non-profit corp., COLUMBIA RIVERKEEPER, a non-profit corp., and HELLS CANYON PRESERVATION COUNCIL, a non-profit corp., Plaintiffs, v. PORTLAND GENERAL ELECTRIC COMPANY, an Oregon Corporation, Defendant.	Civil No.: 3:08-cv-01136-HA CONSENT DECREE

WHEREAS, Portland General Electric Company ("PGE") is an Oregon corporation;

WHEREAS, PGE has been, at all times relevant to this lawsuit, the majority owner and operator of the Boardman Power Plant, which is located in Boardman, Oregon;

WHEREAS, on January 15, 2008, Plaintiffs filed a notice of intent to sue PGE for declaratory and injunctive relief and civil penalties for alleged violations, at the Boardman facility, of the Clean Air Act.;

WHEREAS, the Complaint in this matter was filed on September 30, 2008;

WHEREAS, the Complaint seeks declaratory and injunctive relief, the imposition of civil penalties, and Plaintiffs' attorneys' fees and costs of litigation;

WHEREAS, PGE denies liability for the allegations set forth in the complaint;

WHEREAS, Plaintiffs and Defendant (the "Parties") have negotiated this Consent Decree ("Decree") in good faith and at arm's length and agree that the settlement of this action through this Consent Decree without further litigation avoids substantial risks and costs of a protracted proceeding, is in the public interest and provides certainty for utility customers and is a fair, reasonable, and appropriate means of resolving all claims in this action;

WHEREAS, the Parties further anticipate that this Decree will achieve significant reductions of emissions from the Boardman Power Plant and thereby significantly improve air quality;

WHEREAS, the Parties consent to the entry of this Decree without further trial, argument, or appeal;

WHEREAS, pursuant to 42 U.S.C. § 7604(c)(3) of the Clean Air Act ("Act"), this Consent Decree is being forwarded to the United States Department of Justice and to the United States Environmental Protection Agency ("EPA") for the statutorily-mandated forty-five (45) day review period;

NOW, THEREFORE, it is hereby ORDERED AND DECREED as follows:

1. This Court has jurisdiction over the Parties and the subject matter of this action pursuant to § 304 of the Clean Air Act, 42 U.S.C. § 7604, the citizen suit provision of the Act, and pursuant to 28 U.S.C. § 1331.

2. Venue is proper in this judicial district under § 304(c) of the Act, 42 U.S.C. § 7604(c), and under 28 U.S.C. § 1391.

3. Upon entry, the provisions of this Consent Decree shall apply to and be binding upon the Parties, as well as the Parties' officers, employees, agents, successors and assigns.

4. Commencing on or before December 31, 2020, PGE shall permanently cease the combustion of coal, coke, petroleum coke, lignite, waste coal, or tires at its Boardman plant.

5. For each calendar year from 2015 through 2020, annual emissions of sulfur dioxide from the Boardman coal-fired boiler shall not exceed the caps specified in the table below:

Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Tons of SO_2	9,500	9,000	8,500	8,170	6,850	6,700

6. For the purposes of determining compliance with the SO_2 emission caps in the previous paragraph, PGE shall measure all SO_2 emissions using continuous emissions monitoring systems ("CEMS") certified and operated in compliance with the version of 40 C.F.R. § 75.33 in effect as of the date of lodging of this Decree. However, for purposes of compliance with this Decree, the missing data procedures in Table 1 of that version of 40 C.F.R. Part 75 for monitor data availability of "90 or more, but below 95" may be applied for all periods of monitor data availability below 90 percent. By every April 15 beginning April 15, 2016 and ending April 15, 2021, PGE shall report to plaintiffs Boardman's total SO_2 emissions (in tons) for the previous calendar year.

7. Within 180 days of entry of this Decree, PGE shall submit an application to the Oregon Department of Environmental Quality to modify the Boardman Title V permit to incorporate into that permit the emission caps set forth in Paragraph 5 as applicable

requirements. During the term of the Consent Decree, once the emission caps set forth in Paragraph 5 have been included in the Title V permit, PGE agrees not to seek modification of that permit to change or eliminate those caps for the Boardman coal-fired boiler.

8. Within 30 days of entry of the Decree, PGE agrees to pay $2,500,000 to the Oregon Community Foundation to be provided as grants for the following types of environmentally beneficial projects:

a. 40% of the funds for (1) the purchase of interests in land in the Columbia River Gorge area to protect clean air and provide for habitat protection and/or (2) habitat restoration projects on federal or state land in the Columbia River Gorge area under the conditions set forth in Exhibit A;

b. 25% of the funds for (1) the purchase of interests in lands in Union or Wallowa Counties to protect clean air and provide for habitat protection and/or (2) habitat restoration projects in the Eagle Cap or Hells Canyon Wilderness Areas under the conditions set forth in Exhibit A;

c. 20% of funds to support renewable distributed generation projects under the conditions set forth in Exhibit A; and

d. 15% of the funds to support community-based efforts to reduce air pollution and its impacts on public health and the environment in Oregon and Washington under the conditions set forth in Exhibit A.

9. None of the following organizations or their officers, employees, agents, successors or assigns, are eligible for the funds made available under the previous paragraph: Sierra Club, Northwest Environmental Defense Center, Friends of the Columbia Gorge, Columbia Riverkeeper, Hells Canyon Preservation Council, the Citizens' Utility Board ("CUB"),

the Renewable Northwest Project, Oregon Environmental Council, the NW Energy Coalition, or PGE.

10. PGE shall allow up to three representatives of the plaintiffs a reasonable opportunity to observe dry sorbent injection ("DSI") pilot test(s) at the Boardman Plant that are undertaken pursuant to OAR 340-223-0030(2) to evaluate compliance with sulfur dioxide emission limits and the potential side effects of compliance with those limits as set forth in the BART rule (OAR 340-223-0010 *et seq*). Plaintiffs shall coordinate with PGE regarding scheduling such observations and shall provide PGE the names of the representatives at least 30 days prior to such observations. Plaintiffs' representatives shall submit to such procedures necessary to protect property and personal safety. No cameras or recording devices will be allowed. Plaintiffs understand and agree that plaintiffs and plaintiffs' representatives will need to sign one or more confidentiality agreements regarding observation of the pilot test(s).

11. In the event that PGE submits studies to the Oregon Department of Environmental Quality pursuant to OAR 340-223-0030(2) in support of a petition to allow the applicable sulfur dioxide limits in the BART rule to be exceeded for the reasons set forth in OAR 340-223-0030(3) (*i.e.*, where compliance with the applicable limits would be technically infeasible, would prevent compliance with mercury emission limits, or would cause a significant air quality impact for particulate matter), PGE shall also provide to plaintiffs, upon request directed to PGE as provided in Paragraph 12 below, the data generated by the pilot test(s) related to PGE's petition to exceed the applicable sulfur dioxide limits as set forth in OAR 340-223-0030(3) and any final reports generated related to the petition. Plaintiffs understand and agree that plaintiffs and plaintiffs' representatives will need to sign one or more confidentiality agreements regarding any non-public data or final reports provided pursuant to this Paragraph.

12. Any notifications under this Consent Decree shall be directed to the individuals at the addresses specified below by United States Mail or Overnight Courier and e-mail, unless these individuals or their successors give notice of a change to the other Parties in writing.

As to Plaintiffs:

Aubrey Baldwin
Pacific Environmental Advocacy Center
10015 SW Terwilliger Blvd.
Portland, OR 97219
e-mail: abaldwin@lclark.edu

As to Defendant:

Stephen A. Redshaw
Associate General Counsel
Portland General Electric Co.
121 SW Salmon Street
1WTC1301
Portland, OR 97204
e-mail: stephen.redshaw@pgn.com

13. The Parties agree to cooperate in good faith in order to obtain the Court's review and entry of this Consent Decree.

14. Pursuant to 42 U.S.C. § 7604(c)(3), this Consent Decree shall be lodged with the Court and simultaneously provided to the United States for review and comment for a period not to exceed forty-five (45) days.

15. If the United States does not object or intervene within forty-five (45) days of receipt, the Parties shall submit a joint motion to the Court seeking entry of the Consent Decree.

16. Entry of this Consent Decree shall resolve any and all claims of Plaintiffs under the Clean Air Act and Oregon's State Implementation Plan relating to any actions taken by PGE at the Boardman Power Plant prior to entry of the Decree, including but not limited to those claims and actions alleged or that could have been alleged in the Complaint and Notice Letter in

this action. The failure of any Party to comply with any requirement contained in this Consent Decree will not excuse the obligation to comply with other requirements contained herein.

17. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the Parties with respect to the settlement embodied in this Consent Decree, and supersedes all prior agreements and understandings among the Parties related to the subject matter herein. No document, representation, inducement, agreement, understanding, or promise constitutes any part of this Consent Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

18. Within 30 days of entry of this Decree, PGE agrees to transfer by wire to Pacific Environmental Advocacy Center the amount of $1,000,000 to cover plaintiffs' attorneys' fees, plaintiffs' expert witness fees, and plaintiffs' costs for this case through the date of lodging. Counsel for Plaintiffs shall provide wire transfer instructions to counsel for PGE at least ten (10) days prior to the date payment is due.

19. Plaintiffs expressly reserve their right to petition the Court for recovery of additional costs and fees incurred after the Consent Decree is lodged, including but not limited to their costs and fees incurred in any Consent Decree enforcement process. PGE expressly reserves its right to object to the recovery of any additional costs and fees.

20. Modifications to this Consent Decree may be made only upon written agreement of the Parties which shall be filed with the Court.

21. Pursuant to 42 U.S.C. § 7604(c)(3), the United States shall be provided with the opportunity to review and comment upon any proposed modification to this Consent Decree.

22. This Consent Decree shall remain an enforceable order of the Court until terminated pursuant to Paragraph 23.

23. Any party may move for termination of this Decree once PGE has met all of the requirements of the Decree. If no party moves for termination of the Decree, the Decree shall terminate automatically by its own terms as of June 30, 2021. In no event shall this Consent Decree terminate until the permits that PGE must apply for under the terms of this Consent Decree have been validly issued and have taken effect, except that the Decree shall terminate on June 30, 2021 even if the permitting authority has failed to issue the required permits.

24. Until termination of this Consent Decree, this Court shall retain jurisdiction over both the subject matter of this Consent Decree and the Parties to this Consent Decree to enforce the terms and conditions of this Consent Decree. During the term of this Consent Decree, any Party to the Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree. Prior to applying to the Court for relief, the Parties agree to meet and confer to determine whether the dispute can be resolved through informal negotiations among the Parties. As part of the meet and confer obligation, the Parties shall discuss whether to submit their dispute to a mutually-agreed-upon alternative dispute resolution forum rather than seeking Court intervention.

25. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind such Party to this document.

26. This Consent Decree may be signed in counterparts.

THE UNDERSIGNED PARTIES enter into this Consent Decree and submit it to this Court for approval and entry.

Dated: July 18, 2011

Bill Corcoran
Sierra Club

Dated: __________, 2011

Mark Riskedahl
Northwest Environmental Defense Center

Dated: __________, 2011

Michael Lang
Friends of the Columbia Gorge

Dated: __________, 2011

Brett VandenHeuvel
Columbia Riverkeeper

Dated: __________, 2011

Brian Kelly
Hells Canyon Preservation Council

Dated: __________, 2011

Stephen Quennoz
Portland General Electric Company

IT IS SO ORDERED.

Dated: __________, 2011

The Honorable Ancer L. Haggerty
United States District Judge

Dated: ____________, 2011

Bill Corcoran
Sierra Club

Dated: July 14, 2011

Mark Riskedahl
Northwest Environmental Defense Center

Dated: ____________, 2011

Michael Lang
Friends of the Columbia Gorge

Dated: ____________, 2011

Brett VandenHeuvel
Columbia Riverkeeper

Dated: ____________, 2011

Brian Kelly
Hells Canyon Preservation Council

Dated: ____________, 2011

Stephen Quennoz
Portland General Electric Company

IT IS SO ORDERED.

Dated: ______________, 2011

The Honorable Ancer L. Haggerty
United States District Judge

Dated: __________, 2011

____
Bill Corcoran
Sierra Club

Dated: __________, 2011

____
Mark Riskedahl
Northwest Environmental Defense Center

Dated: July 14, 2011

____
Michael Lang
Friends of the Columbia Gorge

Dated: __________, 2011

____
Brett VandenHeuvel
Columbia Riverkeeper

Dated: __________, 2011

____
Brian Kelly
Hells Canyon Preservation Council

Dated: __________, 2011

____
Stephen Quennoz
Portland General Electric Company

IT IS SO ORDERED.

Dated: ____________, 2011

____
The Honorable Ancer L. Haggerty
United States District Judge

Dated: __________, 2011

____
Bill Corcoran
Sierra Club

Dated: __________, 2011

____
Mark Riskedahl
Northwest Environmental Defense Center

Dated: __________, 2011

____
Michael Lang
Friends of the Columbia Gorge

Dated: July 14, 2011

____
Brett VandenHeuvel
Columbia Riverkeeper

Dated: __________, 2011

____
Brian Kelly
Hells Canyon Preservation Council

Dated: __________, 2011

____
Stephen Quennoz
Portland General Electric Company

IT IS SO ORDERED.

Dated: __________, 2011

____
The Honorable Ancer L. Haggerty
United States District Judge

Dated: __________, 2011

____
Bill Corcoran
Sierra Club

Dated: __________, 2011

____
Mark Riskedahl
Northwest Environmental Defense Center

Dated: __________, 2011

____
Michael Lang
Friends of the Columbia Gorge

Dated: __________, 2011

____
Brett VandenHeuvel
Columbia Riverkeeper

Dated: July 14, 2011

____
Brian Kelly
Hells Canyon Preservation Council

Dated: __________, 2011

____
Stephen Quennoz
Portland General Electric Company

IT IS SO ORDERED.

Dated: ____________, 2011

____
The Honorable Ancer L. Haggerty
United States District Judge

Dated: __________, 2011

Bill Corcoran
Sierra Club

Dated: __________, 2011

Mark Riskedahl
Northwest Environmental Defense Center

Dated: __________, 2011

Michael Long
Friends of the Columbia Gorge

Dated: __________, 2011

Brett VandenHeuvel
Columbia Riverkeeper

Dated: __________, 2011

Brian Kelly
Hells Canyon Preservation Council

Dated: __________, 2011

Stephen Quennoz
Portland General Electric Company

IT IS SO ORDERED.

Dated: Sept 12, 2011

The Honorable Ancer L. Haggerty
United States District Judge

ORDER NO. 14 297

ENTERED SEP 02 2014

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1679

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Detailed Depreciation Study of Electric Utility Properties.		ORDER

DISPOSITION: STIPULATION ADOPTED

I. INTRODUCTION

On December 5, 2013, Portland General Electric Company (PGE) filed the results of a detailed depreciation study of its utility properties (as of December 31, 2013). Based on the December 31, 2012, plant balances, PGE proposed changes in depreciation parameters that would have resulted in an annual depreciation decrease of about $2.2 million, not including PGE's new Tucannon River Wind Farm and Port Westward II generating facilities. PGE filed separate proposed depreciation parameters to be used for those two generating facilities.

In its filing, PGE requested that the Commission approve the results of the study so that the new depreciation rates could be implemented in PGE's (then) upcoming general rate case (docket UE 283, filed February 13, 2014). PGE's filing was assigned to this docket.

A prehearing conference was held on January 28, 2014, and a schedule adopted. Parties appearing at the prehearing conference were PGE, the Oregon Public Utility Commission Staff (Staff), and the Citizens' Utility Board of Oregon (CUB).

On June 3, 2014, Staff filed a motion requesting that the schedule in this matter be suspended, pending the filing of a stipulation among all parties with joint supporting testimony. On June 30, 2014, the parties filed their stipulation and supporting testimony. However, their filing was not perfected until July 25, 2014, when the parties filed their last supporting witness affidavit.

In the stipulation, the net annual difference in depreciation expense when comparing the final settlement position to the depreciation study as-filed is a reduction of approximately

$11.5 million for existing assets ($11.3 million in rate case) and a reduction of $8.2 million for the new plants (on an annualized basis). The stipulation resolves all issues in this docket.

II. THE STIPULATION

The stipulation, signed by PGE, Staff, and CUB, is attached as Appendix A and received into evidence.

The terms of the stipulation are technical in nature. The parties agree that certain changes shown in the exhibit attached to the stipulation should be made for the identified lives, curves, net salvage value, and rates. Except for those changes, the parameters should remain as filed by PGE.

The parties agree that PGE should use the Average Service Life (ASL) depreciation procedure for all new generating plants placed in service after December 31, 2012. PGE will continue to use the straight-line Equal Life Group (ELG) method for all existing assets and accounts.

Under the terms of the stipulation, PGE will make a compliance filing by submitting the depreciation technical update filing to the Commission no later than one year after a new generating facility comes on line. PGE's filing will consist of an attestation by its chief financial officer that the company is using the ASL method for the new generating plant(s) and will include sample accounting entries that demonstrate its use.

The parties stipulate that the revised depreciation parameters set forth in their exhibit are reasonable and should be adopted, to be implemented on the effective date of PGE's impending rate case (docket UE 283).

The parties also agree that PGE shall file another detailed depreciation study of its utility property not later than December 31, 2018. The depreciation parameters detailed in this stipulation will be used until the effective date of the next depreciation study.

III. TESTIMONY IN SUPPORT OF STIPULATION

A. Introduction

Each of the parties sponsored a witness to support the stipulation. Their testimony is received into evidence.

As explained in the testimony, in its filing PGE requested that the Commission prescribe the depreciation rates derived from, and included with, the Iowa curve and life combinations and that the rates be fixed until the effective date of the next depreciation study. The depreciation rates proposed by PGE would have resulted in an annual depreciation expense decrease of about $2.2 million, based on a comparison of 2012 depreciation expense using filed depreciation study rates to 2012 depreciation expense using previously approved depreciation parameters.

Staff and CUB independently reviewed PGE's depreciation study. Staff developed a set of proposed Iowa curves, average service lives, and net salvage rates for each of the plant accounts. Staff performed an independent review of PGE's depreciation statistics and recommended depreciation parameters for numerous depreciation groups, and proposed two types of adjustments. The first type concerns Iowa curves and projected average service lives. The second type concerns net salvage rates.

B. Iowa Curves and Average Service Lives

Staff and PGE each used the actuarial retirement rate methodology to analyze historical retirement date to help determine Iowa curves and average service lives for each depreciation group. Where Staff's position was "reasonably close" to PGE's, PGE accepted Staff's position.[1] When PGE did not agree with Staff's initial recommendation, Staff and PGE discussed their differences to establish the most appropriate life parameters for each account. In their testimony, the witnesses describe their resolution of two such issues in some detail.

Staff's Iowa survivor curve-projection life selection was based on PGE's raw data and data from other electric companies nationwide. Staff recommended several changes to PGE's proposed curve-life combination for depreciable property groups.

C. Net Salvage Rates

1. Generation Assets

In determining net salvage rates for its generation facilities, PGE relied primarily on site specific decommissioning studies, historical retirement date, and input from in-house engineering personnel. PGE's net salvage rates for the hydro generation accounts resulted from site specific decommissioning studies performed at each of the hydro facilities in 2009. Staff objected to the results of PGE's studies because the net salvage estimates were outside the range of most estimates used by other utilities. PGE countered with the argument that a site specific estimate was more reliable than statistics of net salvage rates approved for other utilities. As a compromise, the parties agreed to discount the expected inflation estimate to reflect the uncertainty of when the facilities would be shut down.

The net salvage rates for the other production assets, such as Accessory Electric Equipment and Miscellaneous Power Plant Equipment, Staff recommended net salvage range for these accounts was 0 percent to -6 percent with the 0 percent net salvage relating to the wind facilities. The parties agreed that the net salvage component for these type of assets should be the same regardless of the type of generating facility, therefore, a

[1] Staff-CUB-PGE/100 at 7.

compromise of -6 percent for all assets in Account 345 and 345.01 and a net salvage percent of -2 percent for all assets in Account 346 and 346.01.

2. Transmission Assets

For transmission tower assets, PGE proposed a net salvage rate of -25 percent, based on the average of net salvage rates used by other utilities. PGE believed that industry experience was more pertinent, since very few retirements have been recorded upon which to base a statistical estimate. Staff recommended a net salvage rate of 0 percent, based on judgment due to the lack of historical data. The parties agreed on a net salvage rate of -10 percent for this depreciation study. Net salvage experience and industry trends will be analyzed in the next depreciation study to determine if an adjustment is necessary.

For transmission poles and fixtures, PGE agreed to use Staff's proposed net salvage rate for this study, based on the average of other utilities and the lack of recent activity. For transmission overhead conductor and devices, PGE proposed a reduction in the currently approved net salvage rate to -35 percent because there has been very little activity in the past 12 years. Staff recommended a net salvage rate of -27 percent. The parties agreed to a compromise position of -30 percent for this study.

3. Distribution Assets

For distribution poles, towers and fixtures, PGE recommended a net salvage rate of -65 percent, based on its historical analyses of the period 1971-2013 and its general knowledge of the effort required to remove distribution poles. Staff recommended a net salvage rate of -50 percent, based on the recent trend for less net salvage. The parties agreed on a net salvage rate of -60 percent for this study.

For distribution overhead conductors and devices, PGE recommended a net salvage rate of -75 percent, based on historical data for the period 1971-2013. Staff recommended a net salvage rate of -57 percent, reflecting statistical results in recent years. The parties agreed to a net salvage rate of -70 percent, putting a greater emphasis on the overall net salvage statistics.

For distribution underground conduit, PGE recommended a net salvage rate of -15 percent, while Staff proposed a net salvage rate of -11 percent. The parties agreed to a net salvage rate of -13 percent, reflecting the most recent 5 year period.

For the meters subaccount, PGE recommended a net salvage rate of -10 percent, while Staff recommended -8 percent. The parties agreed to use Staff's proposed rate to reflect new technology.

For street lighting, PGE recommended a net salvage rate of -60 percent, based on historical net salvage data, the current prescribed net salvage percent, and expectations of future costs.

Staff recommended a net salvage rate of -27 percent, based on the recent 5 year trend. The parties agreed to a net salvage rate of -35 percent, reflecting recent trends and the estimates of other comparable utilities.

D. ASL/VG versus ELG

PGE has been using the Equal Life Group (ELG) Procedure to calculate depreciation rates since 1978. Staff recommended using Average Service Life (ASL, i.e. VG, Vintage Group) procedure to calculate depreciation rates. Staff s recommendation is consistent with the following statement set forth by NARUC, "in comparison with the VG procedure, the ELG procedure results in annual accruals that are higher during the early years of a vintage's life, thereby causing an increase in depreciation expense and revenue requirements during these years"[2] Staff also considered NARUC's discussion that "the use of the ELG procedure has not been approved by the Federal Energy Regulatory Commission (FERC) for use in the gas, oil, and electric industries." PGE argued, "attempting to switch from the ELG procedure to the Vintage Group/Broad Group procedure will result in an unnecessary reduction of $32.2 million in annual depreciation expense. Not only does the switch in procedure cause a major swing in annual depreciation expense, but future depreciation expense will also be unnecessarily higher."[3]

Depreciation has a significant effect on the revenue requirement of a utility, and depreciation expense represents a large percentage of total operating expenses, therefore, for settlement purpose, Staff proposed a "hybrid procedure" that is the combination of ELG and VG procedures to calculate depreciation rates. In the stipulation, the parties agree that for existing plant facilities as of December 31, 2012, PGE will continue to use the ELG procedure to calculate depreciation rates. The parties agreed to use the ASL/VG procedure for all new generating facilities that are built after December 12, 2012. The parties further agreed to submit a "Technical Update" or compliance filing to the Commission within one year after each new facility is placed in-service, showing plant dollars placed in-service, accounts, and parameters used as agreed to in the settlement.

E. Conclusion

The witnesses recommend that the Commission approve their stipulation. They further recommend that the commission order PGE to implement the depreciation, amortization and net salvage rates proposed in the stipulation as of the effective date of the general rate case order in docket UE 283. For the portion of 2014 prior to the effective date of the general rate case order, the company shall use current depreciation, amortization and net salvage rates.

[2] Public Utility Depreciation Practices, National Association of Regulatory Utility Commissioners at 176.
[3] Staff-CUB-PGE/100 at 13-14, citing PGE data response 006.

IV. RESOLUTION

As noted above, the terms of the stipulation are technical in nature. In their testimony, the witnesses explain the technical terms of the stipulation and providing supporting exhibits. Their testimony confirms that the review and analysis of PGE's filing was thorough and the resulting settlement is reasonable. The stipulation should be adopted.

V. ORDER

IT IS ORDERED that

1. The stipulation between Portland General Electric Company, the Oregon Public Utility Commission Staff, and the Citizens' Utility Board of Oregon is adopted;

2. Portland General Electric Company shall implement the depreciation, amortization and net salvage rates proposed in the stipulation as of the effective date of the general rate case order in docket UE 283.

Made, entered, and effective SEP 0 2 2014.

COMMISSIONER ACKERMAN WAS UNAVAILABLE FOR SIGNATURE

Susan K. Ackerman
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1679

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Detailed Depreciation Study of Electric Utility Properties.	**STIPULATION**

This Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), and the Citizens' Utility Board of Oregon ("CUB") (collectively, the "Stipulating Parties").

On December 5, 2013, PGE filed with Oregon Public Utility Commission ("Commission") the results of a detailed depreciation study of its utility properties as of December 31, 2012, which included proposed depreciation lives, curves, and net salvage rates (collectively the "parameters") and depreciation rates for PGE's generation, transmission, distribution, general plant, and intangible assets. Based on the December 31, 2012, plant balances, the change in depreciation parameters proposed by PGE would have resulted in an annual depreciation decrease of approximately $2.2 million, not including PGE's new Tucannon River Wind Farm and Port Westward II generating facilities. In addition, PGE filed proposed depreciation parameters to be used for the Tucannon River Wind Farm and Port Westward II generation facilities.

On February 13, 2014, PGE filed an application for a general rate revision, Docket UE 283, to be effective January 1, 2015. The depreciation rates that will be used in Docket UE 283 are the rates set in this docket.

On May 22, 2014, PGE, Staff and CUB participated in a Settlement Conference at the Commission's office in Salem, Oregon. The discussions resulted in a compromise settlement of the Parties. Exhibit "102, Table1" to this stipulation, attached hereto, sets forth the detailed account-by-account depreciation parameters and rates that parties agree should be adopted by the Commission.

PGE, Staff and CUB request that the Commission issue orders in this docket implementing the terms of this Stipulation. As a compromise position on the issues in controversy, the Parties have agreed to depreciation parameters and rates that would result in a decrease of approximately $11.5 million on an annual basis from that originally proposed in this docket based on plant data at December 31, 2012. Applying the stipulated depreciation parameters, including those applicable to new generation facilities, to PGE's 2015 test year in docket UE 283 results in the revenue requirement changes summarized in Exhibit "102, Table1".

TERMS OF STIPULATION

1. This Stipulation resolves all issues regarding PGE's application seeking a change in depreciation rates applicable to its plant.

2. The Parties agree that the changes shown in Exhibit "103, Table2" to this Stipulation should be made for the identified lives, curves, net salvage value, and rates. With the exception of the parameters set forth in Exhibit "103, Table2" to this Stipulation, the parameters should remain as filed in PGE's Study.

3. Exhibit "102, Table1" to the Stipulation is a complete list of all PGE depreciation parameters for all plant accounts by location.

4. As part of this settlement the Parties agree that PGE should use the Average Service Life depreciation procedure for all new generating plants placed in service after

December 31, 2012. Regarding the new generating plants that will come on line between 2013 and 2016 that are currently in development the list for these new plants is shown on Exhibit "102, Table1, Note 1." PGE will continue to use the straight-line, Equal Life Group method for all existing assets and accounts. This approach and resulting depreciation parameters and rates are included in the parameters listed in Exhibit "103, Table2".

5. PGE will make a compliance filing by submitting the depreciation technical update filing to OPUC no later than one year after a new generating facility comes on-line that will consist of an attestation by the CFO that PGE is using the Average Service Life for the new generating plant(s) as well as sample accounting entries that demonstrate its use.

6. The revised depreciation parameters described above and set forth in Exhibit "102, Table1" are reasonable and should be adopted.

7. The revised depreciation rates shall be implemented on the effective date of PGE's pending general rate request in Docket UE 283.

8. No later than the end of 2018, PGE shall file with the Commission another detailed depreciation study of its utility property. The depreciation parameters detailed in Stipulation Exhibit 102, Table1 will be utilized until the effective date of the next depreciation study.

9. The Stipulating Parties recommend and request that the Commission approve the adjustments described herein as appropriate and reasonable resolutions of all issues in this docket.

10. The Stipulating Parties agree that this Stipulation is in the public interest and will result in rates that are fair, just and reasonable and, if approved, will meet the standard in ORS 756.040.

11. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the parties. Without the written consent of all parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in the instant or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

12. The Stipulating Parties have negotiated this Comprehensive Settlement as an integrated document. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right to: (i) withdraw from the Stipulation, upon written notice to the Commission and other Parties within five (5) business days of service of the final order that rejects this Stipulation, in whole or material part, or adds such material condition; (ii) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlement embodied in this Stipulation; and (iii) pursuant to ORS 756.561 and OAR 860-001-0720, to seek rehearing or reconsideration or to appeal the Commission order under ORS 756.610. Nothing in this paragraph provides any Party the right to withdraw from this Stipulation as a result of the Commission's resolution of issues that this Stipulation does not resolve.

13. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-01-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to support this Stipulation (if

specifically required by the Commission), and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting an explanatory brief and written testimony per OAR 860-001-0350(7), unless such requirement is waived. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

14. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 2nd day of June, 2014.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting an explanatory brief and written testimony per OAR 860-001-0350(7), unless such requirement is waived. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

14. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 27th day of June, 2014.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
(Attorney)

CITIZENS' UTILITY BOARD OF OREGON

deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

14. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 27th day of June, 2014.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

PORTLAND GENERAL ELECTRIC
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AT DECEMBER 31, 2012	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	STEAM PRODUCTION PLANT								
	BOARDMAN								
311.00	STRUCTURES AND IMPROVEMENTS	90 - S1.5 *	(1)	103,163,606.77	76,864,062	27,331,161	3,287,441 **	3.19	8.0
312.00	BOILER PLANT EQUIPMENT	65 R3 *	(1)	227,278,716.19	143,601,262	85,950,241	10,459,682 **	4.60	8.0
312.00	BOARDMAN DECOMMISSIONING ACCRUAL			0.00	27,346,614	17,400,389	2,175,804 **	-	8.0
312.01	RAIL CARS	25 S0 *	0	9,758,265.28	7,667,449	2,090,816	261,352 **	2.68	8.0
314.00	TURBOGENERATOR UNITS	60 - S0.5 *	(1)	90,135,376.46	56,819,219	34,217,513	4,184,520 **	4.62	8.0
315.00	ACCESSORY ELECTRIC EQUIPMENT	80 - R2.5 *	(1)	23,582,186.18	17,351,098	6,466,312	778,811 **	3.30	8.0
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	65 - R1 *	(1)	5,809,273.23	3,970,515	1,890,791	229,095 **	3.95	8.0
	TOTAL BOARDMAN			459,721,426.11	333,620,837	175,353,223	21,356,704	4.65	8.0
	COLSTRIP								
311.00	STRUCTURES AND IMPROVEMENTS	90 - S1.5 *	(5)	115,308,214.32	94,985,340	26,088,285	958,829	0.83	27.2
312.00	BOILER PLANT EQUIPMENT	65 - R3 *	(5)	216,919,862.50	169,869,621	57,896,235	2,175,748	1.00	26.6
314.00	TURBOGENERATOR UNITS	60 - S0.5 *	(5)	75,385,578.58	40,157,331	38,876,526	1,644,217	2.18	23.7
315.00	ACCESSORY ELECTRIC EQUIPMENT	60 - R2.5 *	(5)	23,556,967.88	16,545,900	8,186,916	256,139	1.09	24.2
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	55 R1 *	(5)	6,349,149.23	4,741,028	1,922,431	84,395	1.33	22.8
	TOTAL COLSTRIP			437,496,772.51	326,299,217	131,072,393	5,119,328	1.17	25.6
	TOTAL STEAM PRODUCTION PLANT			897,218,198.62	661,920,054	306,425,616	26,476,032	2.95	11.6
	HYDRAULIC PRODUCTION PLANT								
331.00	STRUCTURES AND IMPROVEMENTS								
	FARADAY	100 - R2.5 *	(50)	6,479,397.20	1,212,226	8,506,871	224,986	3.47	37.8
	NORTH FORK	100 - R2.5 *	(115)	8,250,917.28	1,580,460	16,160,307	420,381	5.09	38.5
	OAK GROVE	100 - R2.5 *	(50)	3,398,112.29	1,458,859	3,638,309	99,796	2.94	36.5
	OAK GROVE - TIMOTHY LAKE	100 - R2.5 *	(50)	2,252,149.63	810,067	2,568,158	66,267	2.94	38.8
	PELTON	100 - R2.5 *	(110)	5,645,635.78	1,872,777	9,983,058	263,270	4.66	37.9
	RIVER MILL	100 - R2.5 *	(80)	2,753,573.44	889,480	4,067,952	115,450	4.19	35.2
	ROUND BUTTE	100 R2.5 *	(75)	9,696,059.00	2,341,042	14,627,061	385,957	3.98	37.9
	SULLIVAN	100 - R2.5 *	(30)	9,437,850.41	1,476,588	10,790,618	499,841	5.30	21.6
	TOTAL STRUCTURES AND IMPROVEMENTS			47,923,595.23	11,642,487	70,362,334	2,075,950	4.33	33.9
332.00	RESERVOIRS, DAMS AND WATERWAYS								
	FARADAY	100 - R3 *	(50)	24,223,754.94	11,961,676	24,374,007	625,247	2.56	39.0
	NORTH FORK	100 - R3 *	(115)	22,104,599.29	15,651,253	31,873,636	849,138	3.84	37.5
	OAK GROVE	100 - R3 *	(50)	14,728,508.43	14,428,936	7,663,824	193,663	1.31	39.6
	OAK GROVE - TIMOTHY LAKE	100 - R3 *	(50)	4,740,064.79	5,207,421	1,902,676	52,696	1.11	36.1
	PELTON	100 - R3 *	(110)	10,223,106.37	8,252,401	13,216,122	362,037	3.54	36.5
	RIVER MILL	100 - R3 *	(80)	52,789,000.05	8,988,578	86,031,730	2,145,074	4.06	40.1
	ROUND BUTTE	100 - R3 *	(75)	103,758,407.21	25,289,701	156,287,512	3,895,851	3.75	40.1
	SULLIVAN	100 - R3 *	(30)	23,381,331.65	4,831,799	25,563,932	1,100,692	4.96	22.9
	TOTAL RESERVOIRS, DAMS AND WATERWAYS			255,948,830.73	94,611,715	346,913,439	9,284,398	3.63	37.4

ORDER NO.

PORTLAND GENERAL ELECTRIC
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AT DECEMBER 31, 2012	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
333.00	WATER WHEELS, TURBINES AND GENERATORS								
	FARADAY	90 - S1 *	(50)	6,608,291.00	2,914,660	6,997,777	189,402	2.87	36.9
	NORTH FORK	90 - S1 *	(110)	6,887,358.20	4,808,993	9,654,459	279,711	4.06	34.5
	OAK GROVE	90 - S1 *	(50)	6,438,763.32	2,695,592	6,962,553	188,685	2.93	36.9
	PELTON	90 - S1 *	(100)	3,964,266.16	4,137,997	3,790,535	115,856	2.92	32.7
	RIVER MILL	90 - S1 *	(60)	5,666,409.59	2,183,139	8,016,398	215,831	3.81	37.1
	ROUND BUTTE	90 - S1 *	(70)	13,170,715.97	7,767,838	14,622,379	392,371	2.98	37.3
	SULLIVAN	90 - S1 *	(30)	9,206,560.54	3,018,905	8,949,624	415,581	4.51	21.5
	TOTAL WATER WHEELS, TURBINES AND GENERATORS			51,942,364.80	27,527,125	58,993,725	1,797,437	3.46	32.8
334.00	ACCESSORY ELECTRIC EQUIPMENT								
	FARADAY	60 - R2.5 *	(30)	2,300,700.84	1,009,001	1,981,911	62,329	2.71	31.8
	NORTH FORK	60 - R2.5 *	(75)	949,835.89	505,575	1,156,637	39,264	4.13	29.5
	OAK GROVE	60 - R2.5 *	(30)	2,372,228.34	748,450	2,335,447	71,867	3.03	32.5
	PELTON	60 - R2.5 *	(75)	2,231,610.73	690,153	3,215,166	99,259	4.45	32.4
	RIVER MILL	60 - R2.5 *	(45)	2,528,354.14	843,022	2,823,092	86,091	3.41	32.8
	ROUND BUTTE	60 - R2.5 *	(35)	1,909,870.89	736,560	1,841,765	54,801	2.87	33.6
	SULLIVAN	60 - R2.5 *	(25)	4,270,652.93	674,739	4,663,577	221,169	5.18	21.1
	TOTAL ACCESSORY ELECTRIC EQUIPMENT			16,563,253.76	5,207,500	18,017,595	634,780	3.83	28.4
335.00	MISCELLANEOUS PLANT EQUIPMENT								
	FARADAY	55 - R0.5 *	(15)	227,707.67	86,661	175,003	7,484	3.29	23.4
	NORTH FORK	55 - R0.5 *	(50)	453,549.96	248,429	431,896	16,764	3.70	25.8
	OAK GROVE	55 - R0.5 *	(5)	90,217.98	41,306	53,423	2,055	2.28	26.0
	OAK GROVE - TIMOTHY LAKE	55 - R0.5 *	(5)	2,761.24	1,393	1,506	63	2.28	23.9
	PELTON	55 - R0.5 *	(40)	180,729.78	126,495	120,527	5,606	3.10	22.6
	RIVER MILL	55 - R0.5 *	(30)	20,116.12	4,858	21,283	774	3.85	27.5
	ROUND BUTTE	55 - R0.5 *	(30)	769,105.69	275,231	724,606	28,737	3.74	25.2
	SULLIVAN	55 - R0.5 *	(25)	109,225.68	18,312	118,221	6,437	5.89	18.4
	TOTAL MISCELLANEOUS PLANT EQUIPMENT			1,853,414.12	802,894	1,652,465	67,920	3.66	24.3
336.00	ROADS, RAILROADS, AND BRIDGES								
	FARADAY	80 - R1.5 *	(15)	1,976,298.06	567,846	1,704,895	49,998	2.53	34.1
	NORTH FORK	80 - R1.5 *	(50)	1,662,876.54	527,674	1,966,641	61,300	3.69	32.1
	OAK GROVE	80 - R1.5 *	(5)	2,215,114.33	2,153,069	172,801	5,323	0.24	32.5
	OAK GROVE - TIMOTHY LAKE	80 - R1.5 *	(5)	107,015.18	18,306	94,058	2,810	2.63	33.5
	PELTON	80 - R1.5 *	(40)	2,151,532.99	694,407	2,317,740	68,183	3.17	34.0
	RIVER MILL	80 - R1.5 *	(30)	458,019.14	114,105	481,320	14,109	3.08	34.1
	ROUND BUTTE	80 - R1.5 *	(30)	1,192,102.68	393,917	1,155,817	36,749	3.08	31.5
	TOTAL ROADS, RAILROADS, AND BRIDGES			9,762,958.92	4,469,327	7,893,272	238,472	2.44	33.1
	TOTAL HYDRAULIC PRODUCTION PLANT			363,994,417.66	144,261,046	503,832,830	14,098,857	3.87	35.7

PORTLAND GENERAL ELECTRIC
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AT DECEMBER 31, 2012	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	OTHER PRODUCTION PLANT								
341.00	STRUCTURES AND IMPROVEMENTS								
	BEAVER - CT	70 - R2 *	(8)	31,384,599.71	27,842,665	6,052,703	369,866	1.18	16.4
	COYOTE SPRINGS - CT	70 - R2 *	(8)	10,792,756.11	6,593,574	5,062,505	203,418	1.88	24.9
	PORT WESTWARD - CT	70 - R2 *	(10)	40,951,570.86	4,719,732	40,326,996	1,246,251	3.04	32.4
	TOTAL STRUCTURES AND IMPROVEMENTS			83,128,926.68	39,156,071	51,442,204	1,819,535	2.19	28.3
341.01	STRUCTURES AND IMPROVEMENTS - WIND	40 - R4	(9)	32,813,735.10	4,812,435	30,954,537	910,651	2.78	34.0
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES								
	BEAVER - CT	50 - R3 *	(8)	51,221,330.42	48,220,046	7,098,991	475,497	0.93	14.9
	BEAVER UNIT 8 - CT	50 - R3 *	(8)	1,301.12	765	640	38	2.92	16.8
	COYOTE SPRINGS - CT	50 - R3 *	(8)	35,792,019.04	21,039,639	17,615,742	743,942	2.08	23.7
	PORT WESTWARD - CT	50 - R3 *	(10)	9,462,372.34	4,494,496	5,914,114	182,391	1.93	32.4
	KB PIPELINE	50 - R5 *	(8)	19,373,076.01	15,259,576	5,664,346	347,713	1.79	16.3
	TOTAL FUEL HOLDERS, PRODUCERS AND ACCESSORIES			115,850,098.93	89,013,522	36,293,833	1,749,581	1.51	20.7
344.00	GENERATORS								
	BEAVER - CT	45 - R1 *	(8)	92,274,545.94	57,013,831	42,642,679	2,863,947	3.10	14.9
	BEAVER UNIT 8 - CT	45 - R1 *	(8)	3,829,309.44	2,091,118	2,044,536	135,042	3.53	15.1
	COYOTE SPRINGS - CT	45 - R1 *	(8)	123,550,931.60	49,065,311	84,369,695	4,270,941	3.46	19.8
	PORT WESTWARD - CT	45 - R1 *	(10)	188,072,933.42	31,102,803	175,777,424	7,200,621	3.83	24.4
	TOTAL GENERATORS			407,727,720.40	139,273,063	304,834,334	14,470,551	3.55	21.1
344.01	GENERATORS - WIND	30 - R3	(9)	860,382,974.39	127,377,520	810,439,922	35,197,604	4.09	23.0
345.00	ACCESSORY ELECTRIC EQUIPMENT								
	DISPATCH GENERATION	40 - R2.5	(5)	7,166,364.41	1,356,275	6,240,072	218,737	3.05	28.5
	BEAVER - CT	40 - R2.5 *	(6)	12,901,411.46	11,380,180	2,295,316	168,732	1.31	13.6
	BEAVER UNIT 8 - CT	40 - R2.5 *	(6)	75,506.20	17,759	62,280	3,845	5.09	16.2
	COYOTE SPRINGS - CT	40 - R2.5 *	(8)	11,549,937.95	7,022,985	5,219,949	263,497	2.28	19.8
	PORT WESTWARD - CT	40 - R2.5 *	(6)	8,909,074.88	1,965,498	7,478,122	275,599	3.09	27.1
	TOTAL ACCESSORY ELECTRIC EQUIPMENT			40,602,296.90	21,742,697	21,295,739	930,410	2.29	22.9
345.01	ACCESSORY ELECTRIC EQUIPMENT - WIND	30 - R2.5	(8)	24,958,049.06	2,866,156	23,589,376	1,063,450	4.26	22.2
346.00	MISCELLANEOUS PLANT EQUIPMENT								
	BEAVER - CT	55 - R2 *	(2)	4,303,163.78	3,422,973	966,254	61,121	1.42	15.8
	COYOTE SPRINGS - CT	55 - R2 *	(2)	2,060,507.64	1,207,375	894,343	38,090	1.85	23.5
	PORT WESTWARD - CT	55 - R2 *	(2)	2,876,766.10	404,039	2,530,263	83,999	2.92	30.1
	KB PIPELINE	55 - R2 *	(2)	78,841.79	64,122	16,297	1,024	1.30	15.9
	TOTAL MISCELLANEOUS PLANT EQUIPMENT			9,319,279.31	5,098,509	4,407,157	184,234	1.98	23.9
346.01	MISCELLANEOUS PLANT EQUIPMENT - WIND	35 - R2.5	(2)	647,553.98	132,834	731,671	29,059	3.43	25.2
	TOTAL OTHER PRODUCTION PLANT			1,575,630,636.75	429,472,806	1,283,988,773	58,355,075	3.58	22.8
	TOTAL PRODUCTION			2,868,843,252.93	1,235,653,908	2,094,247,219	96,930,064		

PORTLAND GENERAL ELECTRIC
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AT DECEMBER 31, 2012	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	TRANSMISSION PLANT								
352.00	STRUCTURES AND IMPROVEMENTS	60 - R2.5	(15)	17,407,069.85	6,797,117	13,221,013	353,866	2.03	37.4
353.00	STATION EQUIPMENT	55 - R2	(15)	241,319,092.06	82,695,466	194,816,490	5,630,960	2.33	34.9
354.00	TOWERS AND FIXTURES	70 - R3	(10)	46,808,291.56	21,550,183	29,938,938	866,584	1.85	34.5
355.00	POLES AND FIXTURES	50 - R1.5	(50)	20,460,355.74	9,396,543	21,293,991	669,961	3.27	31.8
356.00	OVERHEAD CONDUCTORS AND DEVICES	60 - R2.5	(30)	74,129,949.12	57,901,127	38,457,807	918,417	1.24	41.9
359.00	ROADS AND TRAILS	60 - R4	0	339,371.32	146,519	192,853	6,660	1.97	28.9
	TOTAL TRANSMISSION PLANT			400,464,129.65	178,489,955	297,933,092	8,446,468	2.11	35.3
	DISTRIBUTION PLANT								
361.00	STRUCTURES AND IMPROVEMENTS	70 - R1.5	(25)	36,822,187.13	12,249,928	33,777,806	796,858	2.16	42.4
362.00	STATION EQUIPMENT	54 - S0	(20)	384,524,570.26	120,825,481	340,604,004	11,185,779	2.91	30.4
364.00	POLES, TOWERS AND FIXTURES	48 - R1	(60)	325,204,225.23	233,516,446	286,810,314	10,281,367	3.18	27.9
365.00	OVERHEAD CONDUCTORS AND DEVICES	48 - S0.5	(70)	533,059,150.98	324,305,182	581,695,375	20,060,538	3.76	29.0
366.00	UNDERGROUND CONDUIT	75 - R4	(13)	15,523,566.14	9,517,421	8,024,232	176,763	1.14	45.4
367.00	UNDERGROUND CONDUCTORS AND DEVICES	50 - S1.5	(70)	624,820,668.61	351,739,956	710,455,181	21,951,949	3.51	32.4
368.00	LINE TRANSFORMERS	45 - R3	(20)	306,548,578.44	158,484,717	209,373,577	7,431,903	2.42	28.2
369.01	SERVICES - OVERHEAD	65 - R1.5	(45)	40,361,949.72	37,798,996	20,725,831	658,812	1.63	31.5
369.03	SERVICES - UNDERGROUND	60 - R4	(45)	337,639,570.26	263,527,773	226,049,604	6,287,797	1.86	36.0
370.00	METERS	30 - S1.5	(8)	5,613,935.16	594,883	5,468,167	284,811	5.07	19.2
370.01	METERS - AMI	15 - S2.5	(8)	112,581,575.01	20,648,101	100,940,000	8,356,515	7.42	12.1
370.02	METERS - RETAINED	16 - L0.5	(8)	7,523,316.60	1,781,367	6,343,815	867,815	11.54	7.3
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	30 - R4	0	376,133.46	253,970	122,163	7,254	1.93	16.8
373.01	CIRCUITS - OTHER	48 - S0.5	(30)	21,175,639.91	15,125,414	12,402,918	451,214	2.13	27.5
373.02	FIXTURES, ORNAMENTAL POSTS AND DEVICES	28 - L1	(30)	28,661,421.75	27,473,507	9,786,341	611,172	2.13	16.0
373.07	SENTINEL LIGHTING EQUIPMENT	29 - L0.5	(30)	8,483,865.88	9,442,510	1,586,516	99,584	1.17	15.9
	TOTAL DISTRIBUTION PLANT			2,788,920,374.58	1,587,286,652	2,654,366,844	89,510,151	3.21	28.5
	GENERAL PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	40 - R0.5	(5)	50,907,101.98	22,999,381	30,453,096	1,475,457	2.90	20.6
390.10	STRUCTURES AND IMPROVEMENTS - LEASE								
	CSS	SQUARE	0	6,709.18	2,976	3,733	622	9.27	6.0
	EASTPORT	SQUARE	0	58,032.12	54,037	3,995	1,019	1.76	3.8
	ERC TUALATIN	SQUARE	0	276,892.45	172,976	103,916	19,174	6.92	5.4
	HILLSBORO	SQUARE	0	59,238.14	53,297	5,941	5,942	10.03	1.0
	SALEM	SQUARE	0	84,421.47	51,711	32,710	13,516	16.01	2.4
	WILSONVILLE	SQUARE	0	155,328.32	101,221	54,107	24,048	15.48	2.2
	WTC	SQUARE	0	19,375,468.37	5,536,920	13,838,548	450,037	2.32	30.7
	TOTAL STRUCTURES AND IMPROVEMENTS			20,016,090.05	5,973,138	14,042,950	514,358	2.57	27.3
	OFFICE FURNITURE AND EQUIPMENT								
391.10	FURNITURE AND EQUIPMENT	15 - SQ	0	16,154,320.04	5,067,207	11,087,113	1,777,770	11.00	6.2
391.20	COMPUTERS AND EQUIPMENT	5 - SQ	0	50,495,108.71	21,120,607	29,374,501	10,624,019	21.04	2.8
	TOTAL OFFICE FURNITURE AND EQUIPMENT			66,649,428.75	26,187,814	40,461,614	12,401,789	18.61	3.3

PORTLAND GENERAL ELECTRIC
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2012

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST AT DECEMBER 31, 2012 (4)	BOOK RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	TRANSPORTATION EQUIPMENT								
392.04	HEAVY DUTY TRUCKS	19 - S2	10	10,310,358.99	7,478,261	1,801,062	127,752	1.24	14.1
392.05	MEDIUM DUTY TRUCKS	15 - S1.5	10	13,096,541.35	7,837,401	3,949,487	460,131	3.51	8.6
392.06	LIGHT DUTY TRUCKS	12 - L2	10	8,585,404.78	5,761,784	1,965,081	327,545	3.82	6.0
392.08	TRAILERS	25 - S0	10	5,035,199.33	2,414,441	2,117,238	149,598	2.97	14.1
392.09	AUTOS	11 - S1.5	10	1,174,746.91	422,708	634,565	106,935	9.10	5.9
392.10	HELICOPTER	20 - S4	10	2,703,076.25	564,801	1,867,967	122,855	4.54	15.2
	TOTAL TRANSPORTATION EQUIPMENT			40,905,327.61	24,479,396	12,335,400	1,294,816	3.17	9.5
393.00	STORES EQUIPMENT	20 - SQ	0	2,851,685.89	1,067,992	1,783,694	154,568	5.42	11.5
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	20 - SQ	0	11,124,758.65	4,201,984	6,922,774	840,771	7.56	8.2
395.00	LABORATORY EQUIPMENT	17 - SQ	0	9,949,815.87	2,780,784	7,169,032	918,162	9.23	7.8
	POWER OPERATED EQUIPMENT								
396.01	MAN LIFT	14 - S1.5	5	25,760,291.28	13,170,098	11,302,179	1,477,363	5.74	7.7
396.02	DIGGER	15 - S3	5	8,491,374.37	4,659,141	3,407,665	328,124	3.86	10.4
396.03	CRANE	20 - L3	5	4,868,443.43	3,235,875	1,389,147	102,937	2.11	13.5
396.07	CONSTRUCTION EQUIPMENT	20 - L1	5	5,680,167.07	3,479,017	1,917,161	174,793	3.08	11.0
	TOTAL POWER OPERATED EQUIPMENT			44,800,266.15	24,544,130	18,016,152	2,083,217	4.65	8.6
	COMMUNICATION EQUIPMENT								
397.01	LINE EQUIPMENT	15 - SQ	0	1,833,384.96	544,039	1,289,346	116,297	6.35	11.1
397.03	RADIO, MICROWAVE AND TERMINAL EQUIPMENT	15 - SQ	0	69,486,640.99	31,953,470	37,533,171	5,863,891	8.44	6.4
397.06	MOBILE RADIO EQUIPMENT	15 - SQ	0	598,856.17	303,999	294,857	25,475	4.25	11.6
397.07	TELEPHONE EQUIPMENT	15 - SQ	0	688,064.05	439,897	248,167	49,235	7.16	5.0
	TOTAL COMMUNICATION EQUIPMENT			72,606,946.19	33,241,405	39,365,541	6,054,998	8.34	6.5
398.00	MISCELLANEOUS EQUIPMENT	20 - SQ	0	129,175.32	93,653	35,522	2,261	1.75	15.7
	TOTAL GENERAL PLANT			319,940,526.26	145,569,868	170,585,775	25,740,417	8.05	6.6
	TOTAL DEPRECIABLE PLANT			6,366,168,383.40	3,146,999,173	5,117,131,930	220,527,100	3.47	23.2
	NONCEPRECIABLE / ACCOUNTS NOT STUDIED								
302.00				144,231,675.68	29,535,287				
303.00				212,946,637.54	122,646,130				
310.00				4,160,671.10					
317.00				24,903,797.00	5,327,284				
330.00				8,047,625.51	1,341,061				
332.00	BULL RUN			0.00	883,971				

PORTLAND GENERAL ELECTRIC
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AT DECEMBER 31, 2012

ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST AT DECEMBER 31, 2012 (4)	BOOK RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
337.00			4,276.00					
340.00			48,946.01	275,794				
347.00			2,213,947.65					
350.00			11,230,107.76	(6,753)				
360.00			20,358,924.85	(1,115)				
370.03			0.00	(8,216)				
374.00			460,131.00					
389.00			7,195,860.64	(3,816)				
392.01			0.00	241,194				
399.00			54,486.00					
TOTAL NONDEPRECIABLE / NOT STUDIED			433,867,108.74	159,031,030				
TOTAL ELECTRIC PLANT			6,800,035,492.14	3,306,030,202	5,117,131,930	220,627,100		

* Curve shown is interim survivor curve. Each facility in the account is assigned an individual probable retirement year.
** Annual depreciation expense based on method previously approved by the OPUC in Order No. 10-478.

Notes:
1.) Accrual rates for facilities to be placed in service after December 31, 2012 using the ASL/VG procedure are as follows.

	Rate	Survivor Curve	Net Salvage Percent	Remaining Life	Using ELG Procedure Rate	Using ELG Procedure Remaining Life
Port Westward II						
341.00	2.52	70 - R2 *	(7)	42.5	3.22	33.2
342.00	2.57	50 - R3 *	(7)	41.7	2.87	37.3
344.00	2.93	45 - R1 *	(7)	36.6	5.61	19.1
345.00	2.85	40 - R2.5 *	(6)	37.2	3.76	28.2
346.00	2.50	55 - R2 *	(2)	40.8	3.40	30.0
Carty	Rate					
341.00	2.52	70 - R2 *	(6)	42.1	3.15	33.6
342.00	2.57	50 - R3 *	(6)	41.3	2.85	37.2
344.00	2.93	45 - R1 *	(6)	36.2	5.30	20.0
346.00	2.52	55 - R2 *	(2)	40.5	3.34	30.5
Tucannon River	Rate					
341.01	2.82	40 – R4 *	(12)	39.8	2.99	37.4
344.01	3.74	30 - R3 *	(12)	30.0	4.44	25.2
345.01	3.54	30 - R2.5 *	(6)	29.9	4.81	22.0
346.01	2.94	35 - R2.5 *	(2)	34.7	4.00	25.5
Sunway 1	Rate					
344.00	4.85	25 - S2.5 *	(2)	17.2	5.20	16.0
Sunway 2	Rate					
344.00	5.53	25 - S2.5 *	(2)	14.1	5.73	13.7
Sunway 3	Rate					
344.00	5.44	25 - S2.5 *	(2)	15.8	5.62	15.3

ORDER NO. 14 297

PORTLAND GENERAL ELECTRIC
COMPARISON OF ESTIMATED SURVIVOR CURVES, NET SALVAGE
AND CALCULATED ANNUAL DEPRECIATION RATES

			2012 PGE PROPOSED PARAMETERS		2012 STAFF PRESETTLEMENT PARAMETERS		05-22-14 SETTLEMENT PARAMETERS	
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2012	SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVOR CURVE	NET SALVAGE PERCENT	SURVIVOR CURVE	NET SALVAGE PERCENT
	(1)	(2)	(3)	(4)	(19)	(20)	(19)	(20)
	STEAM PRODUCTION PLANT							
311.00	STRUCTURES AND IMPROVEMENTS							
	BOARDMAN	103,163,607	90 - S1.5	(1)	90 - S1.5	(1)	90 - S1.5	(1)
	COLSTRIP	115,308,214	90 - S1.5	(5)	90 - S1.5	(5)	90 - S1.5	(5)
	TOTAL STRUCTURES AND IM	218,471,821						
312.00	BOILER PLANT EQUIPMENT							
	BOARDMAN	227,276,716	65 - R3	(1)	65 - R3	(1)	65 - R3	(1)
	COLSTRIP	216,919,921	65 - R3	(5)	65 - R3	(5)	65 - R3	(5)
	TOTAL BOILER PLANT EQUIP	444,196,637						
312.01	RAIL CARS	9,758,265	25 - S0	0	25 - S0	0	25 - S0	0
314.00	TURBOGENERATOR UNITS							
	BOARDMAN	90,135,378	60 - S0.5	(1)	60 - S0.5	(1)	60 - S0.5	(1)
	COLSTRIP	75,365,521	60 - S0.5	(5)	60 - S0.5	(5)	60 - S0.5	(5)
	TOTAL TURBOGENERATOR U	165,500,899						
315.00	ACCESSORY ELECTRIC EQUIPMENT							
	BOARDMAN	23,582,186	60 - R2.5	(1)	60 - R2.5	(1)	60 - R2.5	(1)
	COLSTRIP	23,556,969	60 - R2.5	(5)	60 - R2.5	(5)	60 - R2.5	(5)
	TOTAL ACCESSORY ELECTR	47,139,154						
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT							
	BOARDMAN	5,803,273	55 - R1	(1)	55 - R1	(1)	55 - R1	(1)
	COLSTRIP	6,346,149	55 - R1	(5)	55 - R1	(5)	55 - R1	(5)
	TOTAL MISCELLANEOUS POV	12,149,422						
	TOTAL STEAM PRODUCTION PL	897,218,199						
	HYDRAULIC PRODUCTION PLANT							
331.00	STRUCTURES AND IMPROVEMENTS							
	FARADAY	6,479,397	100 - R2.5	(60)	100 - R2.5	(25)	100 - R2.5	(50)
	NORTH FORK	8,260,817	100 - R2.5	(196)	100 - R2.5	(80)	100 - R2.5	(115)
	OAK GROVE	3,398,112	100 - R2.5	(68)	100 - R2.5	(28)	100 - R2.5	(50)
	OAK GROVE - TIMOTHY L	2,252,150	100 - R2.5	(68)	100 - R2.5	(28)	100 - R2.5	(50)
	PELTON	5,645,636	100 - R2.5	(153)	100 - R2.5	(75)	100 - R2.5	(110)
	RIVER MILL	2,753,573	100 - R2.5	(105)	100 - R2.5	(43)	100 - R2.5	(80)
	ROUND BUTTE	9,696,059	100 - R2.5	(89)	100 - R2.5	(36)	100 - R2.5	(75)
	SULLIVAN	9,437,850	100 - R2.5	(31)	100 - R2.5	(19)	100 - R2.5	(30)
	TOTAL STRUCTURES AND IM	47,923,595	average=	(100)	average=	(41)	average=	(70)
332.00	RESERVOIRS, DAMS AND WATERWAYS							
	FARADAY	24,223,755	100 - R3	(63)	100 - R3	(55)	100 - R3	(50)
	NORTH FORK	22,104,599	100 - R3	(190)	100 - R3	(118)	100 - R3	(116)
	OAK GROVE	14,728,506	100 - R3	(63)	100 - R3	(41)	100 - R3	(50)
	OAK GROVE - TIMOTHY L	4,740,085	100 - R3	(66)	100 - R3	(41)	100 - R3	(50)
	PELTON	10,223,105	100 - R3	(163)	100 - R3	(110)	100 - R3	(110)
	RIVER MILL	52,789,060	100 - R3	(105)	100 - R3	(63)	100 - R3	(80)
	ROUND BUTTE	103,758,407	100 - R3	(89)	100 - R3	(53)	100 - R3	(75)
	SULLIVAN	23,381,332	100 - R3	(31)	100 - R3	(19)	100 - R3	(30)
	TOTAL RESERVOIRS, DAMS /	255,048,831	average=	(100)	average=	(69)	average=	(70)
333.00	WATER WHEELS, TURBINES AND GENERATORS		90 - S1	(60)	90 - S1	(43)	90 - S1	(50)
	FARADAY	6,606,291	90 - S1	(156)	90 - S1	(41)	90 - S1	(110)
	NORTH FORK	6,687,358	90 - S1	(68)	90 - S1	(14)	90 - S1	(50)
	OAK GROVE	6,438,763	90 - S1	(183)	90 - S1	(29)	90 - S1	(100)

	PELTON	3,964,266	90	S1	(105)	90	S1	(22)	90	S1	(85)
	RIVER MILL	5,066,410	90	S1	(89)	90	S1	(19)	90	S1	(70)
	ROUND BUTTE	13,170,716	90	S1	(31)	90	S1	(7)	90	S1	(30)
	SULLIVAN	9,206,561		average=	(105)		average=	(22)		average=	(70)
	TOTAL WATER WHEELS, TUR	51,942,965									
334.00	ACCESSORY ELECTRIC EQUIPMENT										
	FARADAY	2,300,701	60	R2.5	(60)	60	R2.5	(25)	60	R2.5	(30)
	NORTH FORK	840,836	60	R2.5	(190)	60	R2.5	(75)	60	R2.5	(75)
	OAK GROVE	2,372,220	60	R2.5	(63)	60	R2.5	(20)	60	R2.5	(30)
	PELTON	2,231,611	60	R2.5	(183)	60	R2.5	(70)	60	R2.5	(75)
	RIVER MILL	2,528,354	60	R2.5	(105)	60	R2.5	(40)	60	R2.5	(40)
	ROUND BUTTE	1,809,671	60	R2.5	(89)	60	R2.5	(34)	60	R2.5	(35)
	SULLIVAN	4,270,653	60	R2.5	(91)	60	R2.5	(12)	60	R2.5	(20)
	TOTAL ACCESSORY ELECTR	16,583,254		average=	(105)		average=	(40)		average=	(45)
335.00	MISCELLANEOUS PLANT EQUIPMENT										
	FARADAY	227,708	55	R0.5	(60)	55	R0.5	(3)	55	R0.5	(15)
	NORTH FORK	453,550	55	R0.5	(190)	55	R0.5	(10)	55	R0.5	(50)
	OAK GROVE	80,218	55	R0.5	(58)	55	R0.5	(3)	55	R0.5	(5)
	OAK GROVE - TIMOTHY L	2,761	55	R0.5	(68)	55	R0.5	(3)	55	R0.5	(5)
	PELTON	180,730	55	R0.5	(183)	55	R0.5	(9)	55	R0.5	(40)
	RIVER MILL	20,116	55	R0.5	(105)	55	R0.5	(7)	55	R0.5	(30)
	ROUND BUTTE	769,106	55	R0.5	(109)	55	R0.5	(4)	55	R0.5	(20)
	SULLIVAN	109,226	55	R0.5	(36)	55	R0.5	(2)	55	R0.5	(20)
	TOTAL MISCELLANEOUS PLA	1,853,414		average=	(106)		average=	(5)		average=	(25)
336.00	ROADS, RAILROADS, AND BRIDGES										
	FARADAY	1,976,298	80	R1.5	(60)	80	R1.5	(1)	80	R1.5	(15)
	NORTH FORK	1,662,877	80	R1.5	(190)	80	R1.5	(4)	80	R1.5	(50)
	OAK GROVE	2,215,114	80	R1.5	(58)	80	R1.5	(1)	80	R1.5	(5)
	OAK GROVE - TIMOTHY L	107,015	80	R1.5	(68)	80	R1.5	(1)	80	R1.5	(5)
	PELTON	2,151,633	80	R1.5	(183)	80	R1.5	(3)	80	R1.5	(40)
	RIVER MILL	458,019	80	R1.5	(105)	80	R1.5	(2)	80	R1.5	(30)
	ROUND BUTTE	1,192,103	80	R1.5	(89)	80	R1.5	(2)	80	R1.5	(30)
	TOTAL ROADS, RAILROADS,	9,762,959		average=	(110)		average=	(2)		average=	(25)
	TOTAL HYDRAULIC PRODUCTIC	383,994,418									
	OTHER PRODUCTION PLANT										
341.00	STRUCTURES AND IMPROVEMENTS										
	BEAVER - CT	31,384,000	70	R3	(8)	70	R2	(8)	70	R2	(8)
	COYOTE SPRINGS - CT	10,792,758	70	R3	(8)	70	R2	(8)	70	R2	(8)
	PORT WESTWARD - CT	40,951,671	70	R3	(10)	70	R2	(10)	70	R2	(10)
	TOTAL STRUCTURES AND IM	83,128,929									
341.01	STRUCTURES AND IMPROVE	32,813,735	40	R4	(9)	40	R4	(9)	40	R4	(9)
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES										
	BEAVER - CT	51,221,330	45	R3	(8)	50	R3	(8)	50	R3	(8)
	BEAVER UNIT 8 - CT	1,301	45	R3	(8)	50	R3	(8)	50	R3	(8)
	COYOTE SPRINGS - CT	35,792,019	45	R3	(8)	50	R3	(8)	50	R3	(8)
	PORT WESTWARD - CT	8,462,372	45	R3	(10)	50	R3	(10)	50	R3	(10)
	KB PIPELINE	19,373,076	45	R3	(8)	50	R3	(8)	50	R3	(8)
	TOTAL FUEL HOLDERS, PROI	115,850,099									
344.00	GENERATORS										
	BEAVER - CT	92,274,546	35	R2	(8)	45	R1	(8)	45	R1	(8)
	BEAVER UNIT 8 - CT	3,829,309	35	R2	(8)	45	R1	(8)	45	R1	(8)
	COYOTE SPRINGS - CT	123,550,932	35	R2	(8)	45	R1	(8)	45	R1	(8)
	PORT WESTWARD - CT	188,072,953	35	R2	(10)	45	R1	(10)	45	R1	(10)
	TOTAL GENERATORS	407,727,720									
344.01	GENERATORS - WIND	860,382,974	30	R3	(9)	30	R3	(9)	30	R3	(9)
345.00	ACCESSORY ELECTRIC EQUIPMENT										
	DISPATCH GENERATION	7,166,364	40	R2.5	(5)	40	R2.5	(6)	40	R2.5	(6)
	BEAVER - CT	12,901,411	40	R2.5	(8)	40	R2.5	(6)	40	R2.5	(6)
	BEAVER UNIT 8 - CT	75,508	40	R2.5	(4)	40	R2.5	(6)	40	R2.5	(6)

	COYOTE SPRINGS - CT	11,549,938	40	R2.5	(8)	40	R2.5	(6)	40	R2.5	(6)
	PORT WESTWARD - CT	8,909,075	40	R2.5	(10)	40	R2.5	(6)	40	R2.5	(8)
	TOTAL ACCESSORY ELECTR	40,602,297									
345.01	ACCESSORY ELECTRIC EQU	24,958,049	30	R2.5	(9)	30	R2.5	(6)	30	R2.5	(6)
346.00	MISCELLANEOUS PLANT EQUIPMENT										
	BEAVER - CT	4,303,164	55	R2	(8)	55	R2	(2)	55	R2	(2)
	COYOTE SPRINGS - CT	2,060,508	55	R2	(8)	55	R2	(2)	55	R2	(2)
	PORT WESTWARD - CT	2,876,766	55	R2	(10)	55	R2	(2)	55	R2	(2)
	KB PIPELINE	78,842	55	R2	(8)	55	R2	(2)	55	R2	(2)
	TOTAL MISCELLANEOUS PLA	9,319,279									
346.01	MISCELLANEOUS PLANT EQL	847,554	35	R2.5	(9)	35	R2.5	(2)	35	R2.5	(2)
	TOTAL OTHER PRODUCTION PL	1,575,630,637									
	TOTAL PRODUCTION	2,866,843,263									
	TRANSMISSION PLANT										
352.00	STRUCTURES AND IMPROVE	17,407,070	60	R2.5	(15)	60	R2.5	(15)	60	R2.5	(15)
353.00	STATION EQUIPMENT	241,319,092	52	R2	(15)	55	R2	(15)	55	R2	(15)
354.00	TOWERS AND FIXTURES	46,808,282	70	R3	(25)	70	R3	(10)	70	R3	(10)
355.00	POLES AND FIXTURES	20,460,350	48	R1	(80)	60	R1.5	(50)	50	R1.5	(50)
356.00	OVERHEAD CONDUCTORS A	74,129,949	60	R2.5	(35)	60	R2.5	(30)	60	R2.5	(30)
359.00	ROADS AND TRAILS	339,371	60	R4	0	60	R4	0	60	R4	0
	TOTAL TRANSMISSION PLANT	400,464,130									
	DISTRIBUTION PLANT										
361.00	STRUCTURES AND IMPROVE	36,822,187	65	R2	(25)	70	R1.5	(25)	70	R1.5	(25)
362.00	STATION EQUIPMENT	384,524,570	54	S0	(20)	54	S0	(20)	54	S0	(20)
364.00	POLES, TOWERS AND FIXTUI	325,204,225	43	R1	(65)	48	R1	(50)	48	R1	(60)
365.00	OVERHEAD CONDUCTORS A	533,059,151	48	S0.5	(75)	48	S0.5	(60)	48	S0.5	(70)
366.00	UNDERGROUND CONDUIT	15,523,568	75	R4	(15)	75	R4	(13)	75	R4	(13)
367.00	UNDERGROUND CONDUCTO	624,820,069	50	S1.5	(70)	50	S1.5	(70)	50	S1.5	(70)
368.00	LINE TRANSFORMERS	306,548,578	45	R3	(20)	45	R3	(20)	45	R3	(20)
369.01	SERVICES - OVERHEAD	40,361,950	50	S0	(45)	65	R1.5	(45)	55	R1.5	(45)
369.03	SERVICES - UNDERGROUND	337,639,570	57	R4	(45)	60	R4	(45)	60	R4	(45)
370.00	METERS	5,613,935	28	S1.5	(10)	30	S1.5	(8)	30	S1.5	(8)
370.01	METERS - AMI	112,561,575	15	S2.5	(10)	15	S2.5	(8)	15	S2.5	(8)
370.02	METERS - RETAINED	7,523,317	18	L0.5	(10)	18	L0.5	(8)	18	L0.5	(8)
371.00	INSTALLATIONS ON CUSTOM	376,133	30	R4	0	30	R4	0	30	R4	0
373.01	CIRCUITS - OTHER	21,175,640	48	S0.5	(60)	48	S0.5	(30)	48	S0.5	(30)
373.02	FIXTURES, ORNAMENTAL PO	28,661,422	28	L1	(60)	28	L1	(30)	28	L1	(30)
373.07	SENTINEL LIGHTING EQUIPM	8,483,868	20	L0.5	(60)	20	L0.5	(30)	20	L0.5	(30)
	TOTAL DISTRIBUTION PLANT	2,768,920,374.56									
	GENERAL PLANT										
390.00	STRUCTURES AND IMPROVE	50,907,102	40	R0.5	(5)	40	R0.5	(5)	40	R0.5	(5)
390.10	STRUCTURES AND IMPROVEMENTS - LEASE										
	CSS	6,709		SQUARE	0		SQUARE	0		SQUARE	0
	EASTPORT	58,032		SQUARE	0		SQUARE	0		SQUARE	0
	ERC TUALATIN	276,082		SQUARE	0		SQUARE	0		SQUARE	0
	HILLSBORO	59,238		SQUARE	0		SQUARE	0		SQUARE	0
	SALEM	84,421		SQUARE	0		SQUARE	0		SQUARE	0
	WILSONVILLE	155,328		SQUARE	0		SQUARE	0		SQUARE	0
	WTC	19,375,469		SQUARE	0		SQUARE	0		SQUARE	0
	TOTAL STRUCTURES AND IM	20,016,090									
	OFFICE FURNITURE AND EQUIPMENT										
391.10	FURNITURE AND EQUIPN	16,154,320	15	SQ	0	15	SQ	0	15	SQ	0
391.20	COMPUTERS AND EQUIP	50,495,109	5	SQ	0	5	SQ	0	5	SQ	0

	TOTAL OFFICE FURNITURE A	66,649,429								
	TRANSPORTATION EQUIPMENT									
392.04	HEAVY DUTY TRUCKS	10,310,359	19	S2	10	19	S2	10	19	S2	10
392.05	MEDIUM DUTY TRUCKS	13,096,541	15	S1.5	10	15	S1.5	10	15	S1.5	10
392.06	LIGHT DUTY TRUCKS	8,585,405	12	L2	10	12	L2	10	12	L2	10
392.08	TRAILERS	5,035,199	25	S0	10	20	S0	10	25	S0	10
392.09	AUTOS	1,174,747	11	S1.5	10	11	S1.5	10	11	S1.5	10
392.10	HELICOPTER	2,703,076	20	S4	10	20	S4	10	20	S4	10
	TOTAL TRANSPORTATION EC	40,905,326									
393.00	STORES EQUIPMENT	2,851,690	20	SQ	0	20	SQ	0	20	SQ	0
394.00	TOOLS, SHOP AND GARAGE	11,124,759	20	SQ	0	20	SQ	0	20	SQ	0
395.00	LABORATORY EQUIPMENT	9,949,816	15	SQ	0	17	SQ	0	17	SQ	0
	POWER OPERATED EQUIPMENT										
396.01	MAN LIFT	25,760,291	14	S1.5	5	14	S1.5	5	14	S1.5	5
396.02	DIGGER	8,491,374	15	S3	5	15	S3	5	15	S3	5
396.03	CRANE	4,668,443	20	L3	5	20	L3	5	20	L3	5
396.07	CONSTRUCTION EQUIPM	5,880,187	20	L1	5	20	L1	5	20	L1	5
	TOTAL POWER OPERATED E	44,800,296									
	COMMUNICATION EQUIPMENT										
397.01	LINE EQUIPMENT	1,833,385	15	SQ	0	15	SQ	0	15	SQ	0
397.03	RADIO, MICROWAVE ANC	69,480,641	15	SQ	0	15	SQ	0	15	SQ	0
397.06	MOBILE RADIO EQUIPME	598,856	15	SQ	0	15	SQ	0	15	SQ	0
397.07	TELEPHONE EQUIPMENT	668,064	15	SQ	0	15	SQ	0	15	SQ	0
	TOTAL COMMUNICATION EQI	72,606,946									
398.00	MISCELLANEOUS EQUIPMEN	128,175	20	SQ	0	20	SQ	0	20	SQ	0
	TOTAL GENERAL PLANT	319,940,626									
	TOTAL DEPRECIABLE PLANT	6,366,158,383									

LBNL-187516

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Costs and Benefits of Renewables Portfolio Standards in the United States

G. Barbose[1], L. Bird[2], J. Heeter[2], F. Flores[2], and R. Wiser[1]

[1] Lawrence Berkeley National Laboratory (LBNL)
[2] National Renewable Energy Laboratory (NREL)

Energy Technologies Area

July 2015

This is a pre-print of an article accepted for publication in *Renewable and Sustainable Energy Reviews.*

The work described in this report was funded by the Strategic Programs Office and the Solar Energy Technologies Office of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

DISCLAIMER

Table of Contents

Table of Figures

Abstract

Most state renewables portfolio standard (RPS) policies in the United States have five or more years of implementation experience. Understanding the costs and benefits of these policies is essential for RPS administrators tasked with implementation and for policymakers evaluating changes to existing or development of new RPS policies. This study estimates and summarizes historical RPS costs and benefits, and provides a critical examination of cost and benefit estimation methods used by utilities and regulators. We find that RPS compliance costs constituted less than 2% of average retail rates in most U.S. states over the 2010–2013 period, although substantial variation exists, both from year-to-year and across states. Compared to RPS costs, relatively few states have undertaken detailed estimates of broader societal benefits of RPS programs, and then only for a subset of potential impacts, typically some combination of avoided emissions and human health benefits, economic development impacts, and wholesale electricity market price reductions. Although direct comparison to RPS cost estimates is not possible, the available studies of broader RPS benefits suggest that in many cases these impacts may at least be of the same order of magnitude as costs, highlighting a need for more refined analysis.

1. Introduction

Renewables portfolio standards (RPS) require electricity providers to obtain specific amounts of renewable energy generation over time and are prevalent within the United States. In total, 29 U.S. states plus Washington DC have adopted some form of mandatory RPS requirement, with most policies enacted during the latter half of the 1990s and 2000s. Roughly 51 GW or two-thirds of all non-hydroelectric renewable capacity additions from 1998 through 2013 occurred in states with active or impending RPS targets, suggesting that these policies—alongside other state and federal policies and voluntary renewable energy markets—have played an important role in driving U.S. renewable electricity growth.[1]

With the proliferation of RPS programs has come renewed interest in understanding their costs and benefits. In recent years, this interest has frequently manifest within the context of legislative proposals to repeal or roll-back existing RPS programs, often on the basis that the policies impose undue burdens on utility ratepayers [7]. Aside from these politically charged debates, information about RPS costs is often needed as part of routine administrative and reporting functions. In particular, utilities or regulators are often required to estimate RPS compliance costs annually in order to fulfill statutory reporting requirements, to develop surcharges used to recover RPS-related costs, or to ensure that utilities do not exceed statutory cost caps [8] and [9]. Occasionally, states have also undertaken more expansive cost-benefit analyses, either on a prospective basis to inform the development of new RPS policies or, less frequently, on a retrospective basis to evaluate existing programs and inform possible revisions.

Estimating RPS costs and benefits entails a wide variety of methodological issues. In some states, certain aspects of the cost calculation methodology may be specified in statute or in implementing rules issued by the public utility commission (PUC), and a number of states (e.g., New Mexico, Minnesota, Washington) have recently conducted or initiated regulatory proceedings to develop consistent RPS cost calculation methods across utilities. In general, RPS cost estimates developed by utilities and regulators represent a net cost, accounting for avoided costs of displaced conventional generation. RPS programs, however, may also yield other forms of benefits or broader societal impacts, such as avoided air pollutant emissions, human health effects, reduced water consumption, fuel diversity, economic development, and electricity price stability. These broader benefits and impacts typically are not included within routine state or utility analyses, though they may be contained within occasional broader evaluations.

This article summarizes state-level RPS costs to date—drawing in part on original analysis and in part on a synthesis of estimates developed by utilities and regulators—and considers how those costs may evolve going forward given scheduled increases in RPS targets and cost containment mechanisms incorporated into existing policies. In doing so, the article seeks to provide a reasonably comprehensive empirical benchmark for gauging the costs of these important policies, and highlights key methodological issues critical to interpreting and refining cost estimates going forward. In addition, the article synthesizes available analyses of broader social benefits or impacts of state RPS programs, including emission and human health impacts, economic development, and wholesale electricity market price suppression—though, for a variety of reasons, the results of those studies are not directly compared to RPS cost estimates.

2. Methods

This analysis adds to a relatively small, but varied, literature analyzing RPS costs across states. At the national level, cost impacts of a proposed federal RPS have been studied with the use of modeling tools [10], [11] and [12]. At the state level, Morey and Kirsch [13] use regression analysis to examine the impact of various policies, including an RPS, on electricity rates, using historical data. Chen et al. [14] examined prospective, rather than retrospective, RPS studies, many of which were funded by nongovernmental organizations and were conducted to inform new RPS policies that were then under consideration.

2.1 RPS Costs

We estimate *incremental* RPS costs—that is, the net cost to the utility or other load-serving entity (LSE) above and beyond what would have been borne absent the RPS—during the period 2010-2013. We describe RPS compliance costs in terms of two metrics, though focus our discussion of results primarily on the second:

- *Dollars per megawatt-hour of renewable energy required or procured*, representing the average incremental cost of RPS resources relative to conventional generation;
- *Percentage of average retail electricity rates*, representing the dollar magnitude of incremental RPS costs relative to the total cost of retail electricity service (generation, transmission, and distribution).

In general, our RPS cost-calculation methods depend on the structure of the state's retail electricity market. In particular, for states with competitive retail electricity markets (herein termed "restructured" states), we generally estimate RPS compliance costs based on the cost of renewable energy certificates (RECs) and alternative compliance payments (ACPs). For states with traditional regulated, monopoly retail electricity markets, we instead synthesize RPS compliance cost estimates published by utilities and regulators, and highlight key methodological variations. Further details on the data sources and methods used to compute incremental RPS costs are provided below, with additional information in Heeter et al. [15].

2.1.1 States with Restructured Markets

Load serving entities (LSEs) in restructured markets typically meet RPS requirements by purchasing and retiring RECs, which represent the renewable energy attribute—in effect, the renewable energy premium above conventional power. RECs can be, and often are, transacted separately from the underlying electricity commodity. Moreover, because LSEs in restructured markets typically do not have long-term certainty regarding their load obligations, they often purchase RECs primarily through short-term transactions, although longer-term (10- to 20-year) contracting has become more prevalent recently, in order to improve the financeability of renewable generation projects. Most states with restructured markets include an ACP mechanism whereby an LSE may alternatively meet its obligations by paying the program administrator an amount determined by multiplying the LSE's shortfall by a specified ACP price (e.g., $50/MWh). ACP prices serve, more or less, as a cap on REC prices, because LSEs generally would not pay more than the ACP rate for RECs.

Many RPS policies divide the overall RPS target into multiple resource tiers or classes, each with an associated percentage target. These often consist of some combination of a "main tier" for those resources deemed to be most preferred or most in need of support (e.g., new wind, solar, geothermal, biomass, small hydro), one or more "secondary tiers" (e.g., for existing renewables that predate the RPS, large hydro, municipal solid waste), and a solar or distributed generation (DG) set-aside. REC pricing and ACP rates vary by tier, with the highest prices typically associated with solar/DG set-asides, followed by main tiers, and the lowest REC pricing for secondary tiers. REC pricing also varies by state, depending on many factors (e.g., the stringency of the target, eligibility rules, REC banking provisions, etc.). Pricing may be correlated among states in a region to the extent that renewable generators can sell RECs into multiple states in the region.

With a few exceptions, RPS compliance cost estimates for restructured states have not been developed. We therefore develop estimates of RPS compliance costs for these states, relying primarily on published data for REC and ACP prices and volumes, with slight variations for several states (New York, Illinois, Delaware).[2] For REC prices, we rely on data reported by public utility commissions (PUCs) for the average price of RECs used for compliance in each year, where available. If PUC-reported REC price data are unavailable, we instead rely on REC market bid-offer price sheets prices published by REC brokers, supplemented where possible with REC pricing data for long-term contracts with deliveries during 2010–2013. Data on the volumes of REC retirements and ACPs, along with ACP prices, were generally based on data published in utility or PUC compliance reports or otherwise obtained directly from PUC staff.

We translate REC plus ACP costs into an aggregate $/MWh cost by dividing by the sum total dollar costs of REC purchases and ACPs by the amount of renewable generation required in each year, and we translate REC plus ACP costs into a percentage of average retail electricity rates based on the volume of retail sales by RPS-obligated LSEs and average statewide retail electricity prices published by the U.S. Energy Information Administration [16].

The method and data sources used to compute RPS compliance costs for restructured states are subject to a number of important limitations that must be weighed when considering the results. First, by focusing exclusively on the direct costs associated with RECs and ACPs, this approach to estimating RPS compliance costs ignores certain costs, such as those related renewables integration or network transmission upgrades.[3] At the same time, RPS programs may result in additional cost savings for LSEs and ratepayers not captured in the REC and ACP-based approach – most notably, wholesale electricity market price suppression, which is discussed separately in Section 3.2. Second, broker-published REC price indices may be a poor proxy for the average price of all RECs used for compliance; thus, to the extent this source of data was used, some inaccuracy in the derived cost estimate may result. Third and finally, REC prices in a given state and year reflect the balance of supply and demand for RECs – rising to the ACP level if a state or region is undersupplied and falling precipitously if over-supplied. As a result, compliance costs derived from REC prices do not necessarily reflect the incremental cost to the electric system, per se, but rather the incremental cost borne specifically by LSEs. Notwithstanding the aforementioned limitations, we suggest that the compliance costs presented here represent a reasonable first-order estimate of the net cost of RPS policies borne by obligated LSEs in restructured states.

2.1.2 States with Regulated Markets

For traditionally regulated states, we do not develop independent estimates of incremental RPS costs, but rather leverage estimates developed by utilities and regulators in those states, and translate those data into a common set of metrics for comparison. These published cost estimates are typically contained within annual utility compliance filings or annual status reports issued by the state PUC; see Heeter et al. [15] for a list of the specific source documents.

The derivation of RPS compliance costs is considerably more complex in traditionally regulated states than in restructured states. This is because utilities in regulated states typically comply with RPS requirements through long-term power-purchase agreements (PPAs) with renewable electricity generators or by direct ownership of renewable generation, and the directly observable expenses associated with these resources include both the cost of RECs and the cost of the underlying electricity. Determining RPS compliance costs in these cases therefore requires an estimate of the cost of non-renewable generation avoided as a result of the RPS, to then be used as the benchmark for determining the incremental cost of RPS resources.

Not surprisingly, utilities and regulators have relied on widely varying approaches to estimate costs of avoided non-renewable generation, though in general these approaches fall into three general categories: the cost of a generic proxy conventional generator (e.g., a combined-cycle natural gas generator), wholesale electricity market prices, or production cost modeling. Some states may use a hybrid of these approaches, for example, using wholesale electricity market prices for avoided energy costs and the carrying cost of a combustion turbine as a proxy for avoided capacity costs. These varied avoided cost approaches each offer advantages and disadvantages; for example, wholesale market prices may be relatively simple and transparent, but may represent a poor counterfactual for the costs a utility avoids by virtue of procuring renewable electricity to meet its RPS. Conversely, modeling approaches may allow for a more comprehensive and realistic accounting of avoided costs and system-level interactions (including integration costs) but often require large amounts of data and complex models that are not easily vetted by regulatory staff and stakeholders.

Beyond the choice among the basic options identified above, a host of other inter-related methodological issues also vary across individual utilities and can substantially influence the calculated incremental costs, such as:

- Whether RPS compliance costs represent short- or long-term incremental costs, which in turn may influence assumptions about avoided generation capacity costs
- Whether to include costs of renewables procured prior to enactment of the RPS
- Whether to include costs of renewables procured beyond the minimum level needed to meet the target in a given year
- Whether to include indirect expenditures, such as integration, transmission, and administrative costs attributable to the RPS

- Whether to include incremental cost of energy efficiency programs in cases where some portion of the RPS target may be met with energy efficiency

Given our reliance on RPS cost estimates published by individual utilities and regulatory agencies, several important limitations apply to cost comparisons for regulated states. First, cost estimates are wholly unavailable for a number of states or are available for only a subset of utilities or years; thus the summary is less comprehensive than in the case of restructured states. Second, although we present data on a statewide basis, costs for individual utilities may vary significantly around the statewide average. Third, the methods and conventions used by utilities and regulators vary considerably and are often not completely transparent. The comparisons across states are thus imperfect. Finally, disconnects often exist in regulated states between the timing of RPS obligations and when costs are incurred. For example, utilities often procure renewable resources in advance of compliance obligations, and some utilities provide up-front incentives for renewable DG in exchange for RECs generated over each system's lifetime of operations.

2.2 RPS Benefits

The RPS incremental costs we report are net costs accounting for a narrow set of benefits—namely the benefits accruing to the utility in the form of reduced costs for non-renewable generation. However, policymakers have often pursued RPS policies due also to potential broader societal benefits or impacts [18] and [19]. Although relatively limited in number and scope, a number of states or utilities have conducted analyses of broader societal benefits of their RPS programs. Most are prospective in nature, assessing not only current RPS impacts but also future impacts, and have focused primarily on three types of impacts: avoided emissions and human health benefits, economic development impacts, and wholesale electricity price reductions.

We summarize the results of these benefits studies in Section 3.2, translating the estimated dollar impacts into units of dollars per MWh of renewable electricity generated, for the purpose of comparison. As will be discussed, however, the methods and level of rigor vary substantially, which limits the comparability of benefits across states. Comparison between benefits and costs is also challenging, because of potential double-counting (e.g., where emissions are already priced and therefore captured within incremental compliance costs) and misalignment of timeframes between cost and benefit estimates. In addition, certain quantified impacts—such as economic development and wholesale electricity market price suppression—may, in fact, be more precisely viewed as wealth transfers rather than true societal benefits. For these reasons and others, we stop short of providing a direct comparison between RPS compliance costs and the broader RPS benefits and impacts estimated within the set of studies examined.

3. Results and Discussion

The following subsections discuss the results of our analysis with regard to RPS costs (Section 3.1) and benefits (Section 3.2).

3.1 RPS Costs

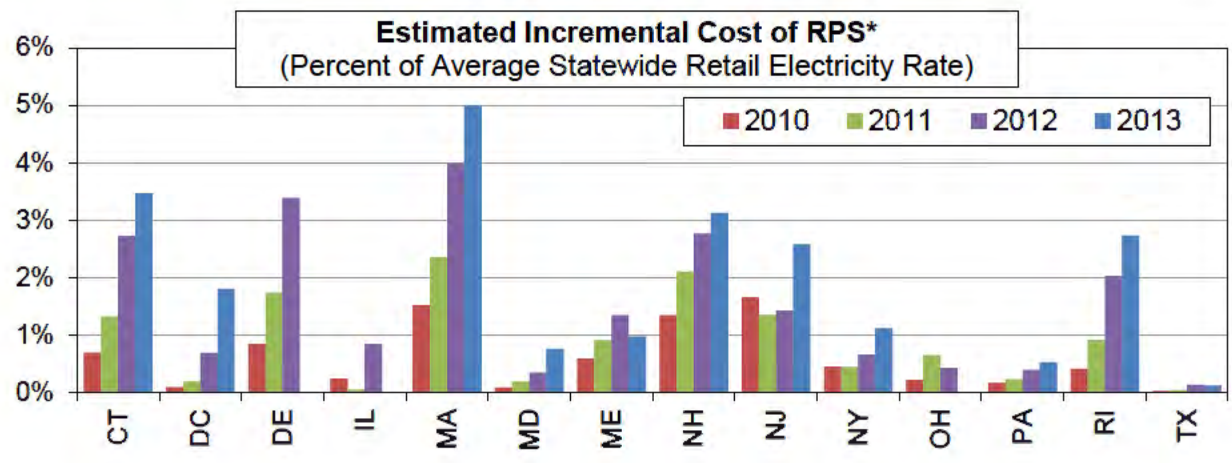
Our analysis of RPS compliance costs focuses on the 2010-2013 period, separately describing the costs in restructured and traditionally regulated states. We then illustrate the extent to which scheduled increases in RPS targets may put upward pressure on compliance costs, and highlight other drivers of future RPS costs. Finally, we show how existing RPS cost containment mechanisms may limit cost growth (and achievement of the RPS targets).

3.1.1 States with Restructured Markets

Based on the cost calculation approach described earlier in Section 2.1.1, RPS compliance costs in restructured markets during 2010-2013 ranged from well below $10/MWh of renewable energy generated in some states and years to upwards of $60/MWh in others, in large part reflecting differences in REC and ACP prices across states and years. For example, low main-tier REC prices in Maryland, Pennsylvania, and Texas led to correspondingly low incremental RPS costs in those states (less than $5/MWh). Conversely, relatively high main-tier REC prices among northeastern states, which rose over the period of analysis, led to correspondingly high and increasing RPS incremental costs in those states, rising to $37–$47/MWh in 2013.

Differing mixes of resource tiers within each state's RPS also contributed to variations in compliance costs. In particular, RPS costs were generally low for states with large secondary-tier targets, because REC pricing for those tiers is typically quite low, reflecting a typical surplus of supply for these lower-value resources. In Maine for example, the secondary tier (which consists primarily of existing large hydroelectric generation) constituted roughly 85%–90% of the RPS requirement each year, leading to overall RPS compliance costs of less than $5/MWh. Conversely, RPS compliance costs have tended to be higher in states with relatively high solar set-aside requirements, as SREC prices have generally been high compared to other tiers, though SREC prices have softened substantially in recent years. For example, New Jersey has relatively high solar set-aside targets—ranging from 4% of total RPS obligations in 2010 (when SREC prices averaged roughly $600/MWh) to 16% of RPS obligations in 2013 (by which time average SREC prices fell to $135/MWh). This combination of conditions contributed to relatively high average incremental RPS costs ($20–$30/MWh) over the 2010-2013 period.

Figure 1 expresses incremental RPS compliance costs as percentages of average retail electricity rates. In effect, these values would represent the impact of RPS compliance costs on retail electricity prices and consumer electricity bills were those costs passed fully and immediately to customers. Measured in terms of this metric, incremental RPS costs constituted less than 2% of average retail rates in most states during 2010–2013. In 2013, RPS costs averaged 1.2% of retail rates among restructured states with available data (on a weighted average basis, according to each state's retail sales), ranging from below 0.5% in several states to 3.5%–5.0% among most of the New England states. In general, the observed variations across states and years reflect the same kinds of differences as noted above (i.e., variations in REC and ACP prices and differences in the composition of the states' targets). In addition, and importantly, the RPS compliance costs shown in Figure 1 also reflect the stringency of RPS targets. It is for that reason that, in most states, costs increased over the period shown, as RPS percentage targets simultaneously rose.



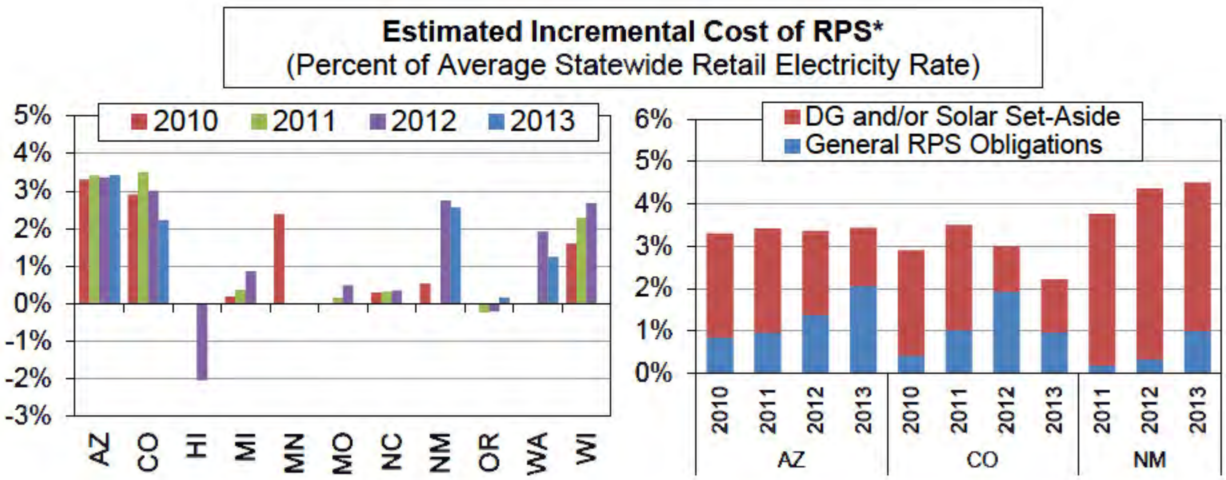
** Incremental costs are estimated from REC and ACP prices and volumes far each compliance year, which may differ fram calendar years. If available, REC prices are based an average prices reported by the PUC (DC, IL, MD, ME, OH, NJ, PA); they are otherwise based on published spat market prices, supplemented with data on lang-term contract prices where available. Incremental costs for NY are based an NYSERDA's annual RPS expenditures and estimated REC deliveries.*

Figure 1: Estimated incremental RPS cost over time in states with restructured markets (% of retail rates)

3.1.2 States with Regulated Markets

In traditionally regulated markets, compliance costs for general RPS requirements (i.e., excluding any solar or DG set-asides) were generally near or below roughly $20/MWh, ranging from -$25/MWh in Hawaii (2012) to $44/MWh in Wisconsin (2010). Cost variations among states partly resulted from different underlying renewable energy costs, but they also reflect differences in the methods used to calculate incremental costs. For example, the Wisconsin Public Service Commission estimated incremental costs using historical energy spot-market prices as the basis for avoided costs; those market prices were depressed in 2010, owing to the economic downturn, in turn resulting in relatively high calculated incremental RPS costs for that year. Regional electricity market prices rebounded in subsequent years, leading to declining RPS compliance costs in Wisconsin. In California, the PUC and utilities have used two different approaches to calculating avoided costs from RPS purchases—with the PUC relying on the all-in cost of a combined cycle gas generator and the utilities relying on wholesale electricity market prices. Using the PUC's avoided cost method yields RPS compliance costs equal to -$24/MWh in 2011 and -$4/MWh in 2012 (i.e., a net cost savings in both years), while the utilities' methods result in RPS cost estimates of $43/MWh in 2011 and $50/MWh.

Figure 2 presents incremental RPS compliance costs for regulated states as percentages of average retail electricity rates. As shown in the left-hand graphic of Figure 2, RPS costs for the majority of states shown were near or below 2% of average retail rates over the 2010-2013 period. Hawaii and Oregon are at the low end, both with negative incremental costs (i.e., net savings). Missouri also had very low costs because its utilities met their obligations largely or entirely with renewable resources procured prior to enactment of the RPS (for which incremental costs were deemed to be zero). In general, the values in Figure 2 reflect the totality of renewable generation procured by utilities each year, which in the case of most states was well in excess of the minimum RPS requirement. For Oregon and Missouri, the calculated costs are instead based on only those resources applied towards the RPS requirement in the years shown, although the utilities in those states also procured substantially greater amounts of renewables, banking the excess for compliance in future years.



* *Incremental costs are based on utility- or PUC-reported estimates and are based on either RPS resources procured or RPS resources applied to the target in each year. Data for AZ include administrative costs, which are grouped in "General RPS Obligations" in the right-hand figure. Data for CO are for Xcel only. Data for NM in the left-hand figure include SPS and PNM in all years shown, but data in right-hand figure include only SPS. States omitted if data on RPS incremental costs are unavailable (CA, IA, KS, MT, NV).*

Figure 2: Estimated incremental RPS cost over time in regulated states (% of retail rates)

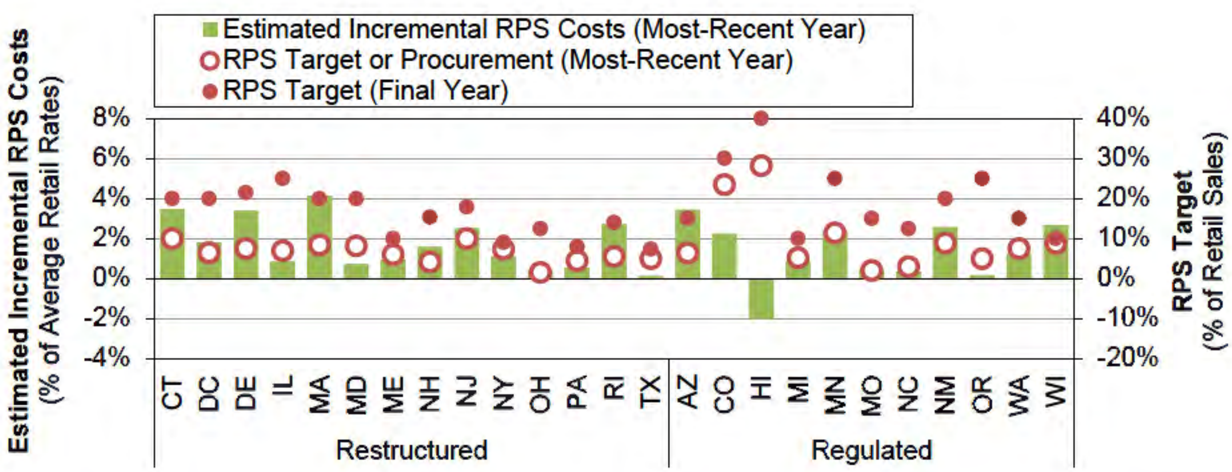
Estimated costs for Arizona, Colorado, and New Mexico were relatively high among the set of regulated states in Figure 2, for several reasons. As shown in the right-hand panel of the figure, DG and/or solar set-aside requirements in those states constituted the bulk of total RPS compliance costs in most years. That trend, however, is partially an artifact of the timing of costs for those resources: utilities meet those obligations in large part through rebates and performance-based incentives that are paid upfront (or over several initial years of production) in exchange for RECs delivered over each DG system's lifetime. As Figure 2 shows, those costs have declined over time, as utilities reduced incentive levels and moved away from upfront rebates. In addition, RPS costs in Colorado were relatively high because Colorado's RPS procurement levels were substantially higher than the levels in other states shown in Figure 2. The state's largest utility, Xcel Energy, attained renewable procurement levels equal to 15%–23% of retail sales during 2010–2013, compared to renewable procurement levels of 5%–10% in most of the other states shown.

The statewide averages presented in Figure 2 mask some variability in RPS costs among utilities in a number of states. In Washington, for example, all three investor-owned utilities and the state's largest municipal utility reported costs in 2012 of around 0.5%–1.4% of retail rates, but many of the smaller publically owned utilities reported higher costs (as high as 8%–9%). Minnesota utilities reported 2010 RPS costs of 0.1%–8.6% of average retail rates (most were around 1%–

3%). New Mexico's statewide averages are based on only two utilities, which reported costs of 1.5% and 4.5% in 2013. In general, intra-state variability is rooted in many of the same factors that drive differences in RPS costs across states (e.g., the cost and type of renewable energy resources procured, methodological differences, etc.).

3.1.3 Future RPS Costs

Comparing across all states, both restructured and regulated, and excluding any secondary resource tiers, RPS compliance costs ranged from -2.0% to 4.1% of average retail rates in the most recent year for which data were available (Figure 3). The corresponding RPS targets or procurement levels in those years (the open circles in the figure) ranged widely, from 2%–28% of retail sales, though in most cases fell within the band of 5%–9% of retail sales. Although certainly compliance costs in each state and year are impacted by the prevailing target or procurement level, other conditions also strongly impact RPS costs, including regional REC supply/demand balance, the presence of solar or DG set-asides, and cost-calculation methods.



** For most states shown, the most-recent year RPS cost and target data are for 2012 or 2013. MA does not have single terminal year for its RPS; the final-year target shown is based on 2020. Excluded from the chart are those states without available data on historical incremental RPS costs (CA, KS, HI, IA, MT, NV). The values shown for RPS targets and costs exclude any secondary RPS tiers (e.g., for pre-existing resources). For most regulated states, data for the most-recent historical year reflect actual RPS procurement percentages in those years.*

Figure 3: Estimated incremental RPS costs compared to recent and future RPS targets

That being said, RPS obligations are scheduled to rise going forward, reaching their peak in most states during 2020–2025, and those rising targets may place upward pressure on future RPS compliance costs. To provide an indication of this potential upward pressure, Figure 3 also shows the final-year RPS target in each state (the closed circles), which rise to 7%–40% of retail sales across the set of states shown and to at least to 15% in most states. Compared to the most recent RPS targets or procurement levels, final-year RPS targets constitute, on average, roughly a three-fold increase in RPS obligations.

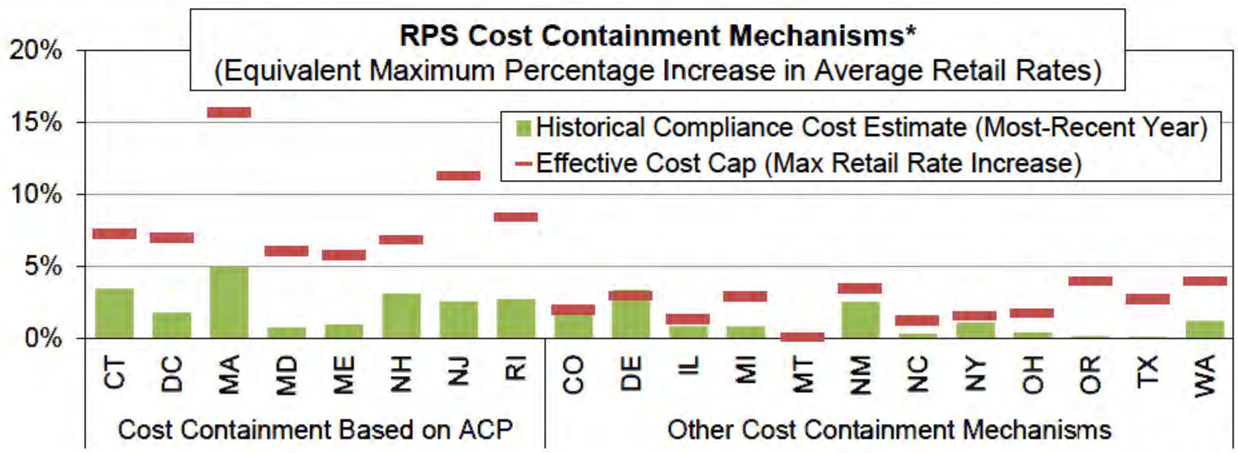
The trajectory of future RPS compliance costs will, of course, depend on other factors as well. First and perhaps foremost is the underlying cost of renewable energy technologies. Second is the price of natural gas, because gas-fired electricity is the typical baseline point of comparison for cost calculations in regulated states and can impact equilibrium REC pricing in restructured markets. Third, RPS costs may be strongly impacted by changes to federal tax incentives, most notably the investment tax credit for solar and production tax credit for wind and other renewables. Fourth, environmental policies, such as greenhouse-gas and air-pollution regulations, including EPA's recent Clean Power Plan proposal, could raise the cost of non-renewable resources and thus reduce the incremental cost of renewables. Finally, future RPS costs could be affected by cost-containment mechanisms built into many state RPS policies that, if they become binding, would limit attainment of the RPS targets (see Section 3.1.4).

Prospective RPS cost studies conducted for individual states or utilities help gauge the potential trajectory of future RPS compliance costs. Chen et al. [14] synthesized the results of 28 distinct state- or utility-level RPS cost impact analyses, finding that 70% of the studies in their sample projected retail electricity rate increases of no greater than 1% in the year that each modeled RPS policy reaches its peak percentage target. Five of the studies projected net reductions in retail rates, while two studies projected rate impacts greater than 5%. However, much has changed on the RPS landscape since that study. More recent analyses have estimated the following rate impacts for final target years: 10% in California [20], 2.2%–4.8% in Connecticut [21], 7.9% in Delaware [22], 1.1%–2.6% in Maine [23], 0.3%–1.7% for Northern States Power in Minnesota [24], 2.2% for Great River Energy in Minnesota [25], and -0.5% (a reduction) in North Carolina [26]. The scope, methods, and assumptions vary widely among prospective cost studies, limiting their comparability to one another and to the historical cost data presented earlier. They nevertheless suggest a range of RPS cost changes in response to rising targets.

3.1.4 Cost-Containment Mechanisms

Most RPS policies include one or more cost-containment mechanism, though as discussed in Stockmayer et al. [8], their efficacy may be imperfect. The most common approaches are ACPs and rate impact/revenue requirement caps. Other cost-containment mechanisms include surcharge caps, renewable energy contract price caps, renewable energy funding caps, and financial penalties for non-compliance. Beyond such prescriptive mechanisms, regulators in many states also varying forms of discretionary power that also provide a measure of control over RPS costs. The most explicit example may be cases where the RPS law explicitly grants authority to the PUC to delay or freeze RPS requirements or to issue waivers to individual utilities if costs are deemed excessive. In addition, PUCs in regulated states typically provide some level of direct oversight over utilities' procurement decisions and cost recovery, which may also serve to control compliance costs.

Figure 4 translates, where possible, existing RPS cost-containment mechanisms into the equivalent maximum percentage increase in average retail rates for the year in which each state's RPS target reaches its peak. In effect, these values represent the maximum potential annual RPS cost for the single year in which each state reaches its final target. To provide an indication of the level of head-room available in each state, Figure 4 also presents actual statewide-average RPS costs for the most recent historical year available.



** For states with multiple cost containment mechanisms, the cap shown here is based on the most-binding mechanism. MA does not have a single terminal year for its RPS; the calculated cost cap shown is based on RPS targets and ACP rates for 2020. "Other cost containment mechanisms" include: rate impact/revenue requirement caps (DE, KS, IL, NM, OH, OR, WA), surcharge caps (CO, MI, NC), renewable energy contract price cap (MT), renewable energy fund cap (NY), and financial penalty (TX). Excluded from the chart are those states currently without any mechanism to cap total incremental RPS costs (AZ, CA, IA, HI, KS, MN, MO, NV, PA, WI), though some of those states may have other kinds of mechanisms or regulatory processes to limit RPS costs.*

Figure 4: RPS cost caps compared to recent historical costs

Among states relying on ACPs for cost containment (grouped on the left in Figure 4), RPS costs are generally capped at 6%–9% of average retail rates. The effective caps are higher in Massachusetts (16%) and New Jersey (13%) owing to relatively high solar set-aside targets and/or ACP levels. Given that current RPS targets in these states are well below their final-year targets, recent RPS compliance costs are well below the effective cost caps. Rising RPS targets in these states, however, will not only require increasing volumes of REC purchases, but will also tend to put upward pressure on REC prices, which are already trading near their respective ACPs in many Northeastern states. At the same time, ACP rates generally will remain fixed (in real or nominal terms) or, in the case of many states' solar ACPs, will decline over time. This combination of possible upward pressure on REC prices and fixed or declining ACPs could constrain achievement of RPS targets and push total compliance costs toward the maximum levels shown in Figure 4. Tempering that trend will be any continued reductions in renewable energy costs and/or increases in wholesale power prices.

Among states with other, non-ACP forms of cost containment (grouped on the left in Figure 4), the effective cost caps are relatively restrictive, typically equating to 1%–4% of average retail rates. Cost caps have already become binding in several of these states (e.g., Illinois, New Mexico, and Missouri [not shown]). Several other states appear to have surpassed their caps, but for various reasons those caps have not yet been binding (e.g., Colorado, Delaware, and Kansas [not shown]). Other states are approaching their caps (e.g., North Carolina and Ohio). In Oregon, cost caps may become an issue for some utilities, even though historical compliance costs have been low. New York is also likely to hit its cap, although this is by design because the cap is based on a schedule of revenue collections adopted by the PSC and deemed necessary for achievement of the target. In Montana, the cost cap effectively prohibits any net cost from RPS resources. Texas and Michigan are both seemingly at low risk of reaching their cost caps, even though the caps are on par with other states within the group. In Texas, scheduled increases in the RPS target are relatively small, and installed renewable capacity in the state already well exceeds the final-year (2015) target. In Michigan, the cost cap is specified in terms of a maximum customer surcharge, and the state's two large IOUs reduced their surcharges substantially in 2014; both utilities project attainment of their RPS targets without any significant increase in surcharges [27] and [28].

3.2 RPS Benefits

Few studies have quantified the benefits of RPS policies. This section examines three categories of benefits that have been studied: emissions and human health, economic development impacts, and wholesale market price impacts. It is important to consider RPS benefits in conjunction with RPS costs. However, making direct cost-benefit comparisons—and benefit comparisons across states—is difficult because of the wide variety of methods and levels of rigor used for cost and benefit calculations, selective evaluation of only a subset of potential benefits, and possible overlap between costs and benefits (i.e., some benefits might already be included in some cost calculations).

3.2.1 Emissions and Human Health

One of the most often quantified environmental benefits of renewable energy is avoided air-pollutant emissions and associated human health benefits. Typically, estimates of avoided emissions focus on CO_2, sulfur dioxide (SO_2), and nitrogen oxides (NO_X). In some cases, the human health benefits of these reduced emissions are estimated by applying monetary values to, for example, the reduced morbidity or mortality from air-quality improvements. In other instances, monetary impacts are estimated based on the avoided cost of compliance with environmental regulations.

There are two common approaches to estimating RPS emissions impacts. The most robust approach is to conduct detailed modeling of the electric system with and without renewable generation to determine the mix of plants that would be operating and the overall system emissions in each scenario. This approach is best because it accounts for hourly operation—renewable facilities may displace different types of conventional generators throughout each day. A simplified approach is to estimate the marginal generating unit that would typically not be operating because of the renewable generator and apply the unit's emission rate to the displaced generation. This simplified approach yields approximate results.

Table 1 summarizes estimates of the emissions and associated monetary benefits from RPS policies for several states where data are available. Of the studies shown in the table, only the Maine study used a simplified emission rate method to estimate avoided emissions. All the others conducted more detailed electric system modeling to understand avoided emissions. Overall, estimates of air-quality benefits range from tens to hundreds of millions of dollars annually or about \$4–\$23/MWh of renewable generation. Some studies present a wide range of estimates depending on assumptions. Often, the value of avoided CO_2 emissions drives the estimates, because the magnitude of CO_2 reductions is largest. Assumptions about the value of CO_2 also influence results substantially. An interagency assessment of the social cost of carbon found a range of $11–$89/metric ton of CO_2 for the year 2010 (in $2007 dollars), depending on the discount rate used [29]. The NYSERDA study used a similar range for valuing avoided CO_2 emissions, while most of the other studies used a single estimate for CO_2 value, typically at the lower end of (or below) the interagency working group estimates.

Table 1. Summary of estimates of emissions and human health benefits of state RPS

State	Estimated Monetary Impact	Benefits $/MWh of RE	Period	Description	Source
CT	Not estimated	N/A	2020	Avoided CO_2 emissions of 0.39–0.53 tons/MWh of renewable generation	Brattle Group et al. 2010 [30]
OH	Not estimated	N/A	2014	CO_2 emissions reduced from 116.36 million metric tons in reference case to 116.16 (-0.17%), and to 115.79 (-0.5%) in scenarios	PUCO 2013 [31]
ME	$13 million	$7/MWh	Annual	Avoided allowance costs for 96 tons for SO_2, 1,629 tons for NO_X and 1.1 million tons for CO_2	LEI 2012 [23]
DE	$980–$2,200 million	N/A	2013–2022	Human health benefits due to improvements in air quality from emission reductions in power generation and other sectors	DPL 2012 [22]
IL	$75 million	$11/MWh*	2011	Avoided allowance costs for 5.5 million tons of CO_2 and 4,765 tons of NO_X	IPA 2013 [32]
NY	Not estimated	N/A	2002–2006	4,028 tons of NO_X, 8,853 tons of SO_2, and 4.1 million tons of CO_2	NYSERDA 2013a [33]
	$312–$2,196 million	$3–22/MWh	2002–2037	Value of avoiding 50.29 million tons of CO_2	NYSERDA 2013b [34]
	$48 million	$0.5/MWh	2002–2037	Value of avoiding 278 pounds of mercury, 15,214 tons of NO_X and 14,987 tons of SO_2	NYSERDA 2013b [34]

*Estimated based on 6.9 million MWh of renewable energy needed to meet the 2011 RPS requirements [35] and [36].

Many factors must be considered to compare emissions-reductions benefits with incremental costs. Where cap-and-trade policies are in place, RPS policies may not reduce emissions of capped pollutants unless there is a set-aside for renewable energy. Even in this instance, the increased production of emissions-free renewable electricity will reduce the cost of complying with the cap-and-trade program as approximated by the marginal allowance price. If allowance prices are used to estimate benefits, however, they must not already be captured in the estimated incremental cost of the renewable energy. For example, allowance prices should already be embedded in wholesale electricity prices, so, if wholesale prices are used in cost calculations, those estimates should already account for these impacts. Similarly, if a proxy plant used to calculate the incremental RPS cost includes allowance prices or carbon costs, then these emissions impacts are captured in the incremental cost assessment. The comparison is complicated further because benefits estimates are often forward looking, while the incremental costs are based on historical compliance. For these reasons, it is difficult to compare these estimates to the incremental costs discussed previously; however, treatment of these issues varies across states.

3.2.2 Economic Development Impacts

Policymakers often seek to achieve economic development goals with RPS policies, and in some states quantification of these impacts is required by law. The impacts include jobs, direct investment from construction and operation of facilities, tax revenues, and indirect and induced economic impacts, which result from the purchase of goods and services.[4] An RPS can also affect economic activity by influencing electricity prices. One key issue is whether the assessment examines gross impacts (e.g., new jobs supported) versus net impacts that consider shifts in employment. Understanding net impacts requires detailed analysis of changes in the operation of other generating units, fuel use, utility revenues, electricity prices, and residential and commercial energy expenditures [37]. Many states focus on impacts within their boundaries, but employment shifts can occur regionally. Furthermore, some assessments focus on only one aspect of the economic impacts.

The methods used for economic assessments have varying degrees of rigor. Simplified methods, which yield estimates of gross impacts, include input-output models or case-study approaches often focused on specific renewable energy facilities. Input-output models (e.g., IMPLAN, RIMS II)—the most common method for gross-impact analysis—calculate direct, indirect, and induced economic impacts by quantifying relationships between economic sectors at a point in time, but they cannot analyze changes in electricity prices. More sophisticated economic-modeling tools can assess net impacts, including econometric models that assess impacts on the economy as well as computable general equilibrium models (CGE models) that examine the flow of goods and services through the economy (see EPA 2011 [18] for detail on methods and models available).

Table 2 summarizes economic-impact estimates for RPS policies in several states. Overall, these states estimated economic impacts on the order of hundreds of millions of dollars for the construction period (one-time) and, in some cases, tens of millions of dollars in annual economic benefits over the project lifetime. These estimates translate to about $5–$27/MWh of renewable generation. One study found the RPS increased electricity prices and reduced gross state product by less than 1%. The methods and assumptions used to conduct assessments varied considerably across states. Illinois, Maine, Michigan, and Oregon conducted economic-impact assessments using input-output models, case studies, or anecdotal information on the impacts of renewable energy facilities; these typically assessed gross impacts. Connecticut and New York used more detailed modeling approaches, including econometric models; however, in some instances, they focused on only one economic-impact aspect of the RPS. Those studies that estimated gross impacts (e.g., jobs supported) do not consider net job impacts and thus cannot capture the true economy-wide impact of increased renewable-energy use.

Table 2. Summary of RPS economic-impact estimates

State	Benefit	Benefit/MWh of RE	Period	Description	Source
CT	Negative to positive gross state product (GSP) impact	N/A	Through 2020	Modeling showed retail electricity prices increased 0.86% to 3.48%, which reduced GSP 0.01% to 0.03%. One scenario showed an increase in GSP of 0.02%.	CEEEP and R/ECON 2011 [21]
IL	$5,980 million	$27/MWh*	25-year lifespan	Total economic impact at the state level of the 23 largest wind farms installed by 2012	IPA 2013 [32]
ME	$1,140 million	$4/MWh	Construction	2% increase in GSP	LEI 2012 [23]
	$7.3 million	$0.6/MWh	Annual, during project lifespan	$6.3 million annually in tax revenue for local governments and $1 million of revenue/year for private landowners during the operating life of the projects	LEI 2012 [23]
MI	$159.8 million	N/A	Construction	Economic impacts of four wind farms built in Michigan	MPSC 2013 [38]
NY	$1,252 million	$13/MWh	Project lifespan	Present value of the total direct investments in New York during the life of the projects	NYSERDA 2013b [34]
	$921 million	$9/MWh	Project lifespan	Cumulative impact on GSP	NYSERDA 2013b [34]
OR	Not estimated	N/A	Project lifespan	Estimated jobs resulting from renewable energy projects, based on survey	ODOE 2011 [39]

*Estimated assuming a 30% capacity factor and 25-year life.

3.2.3 Wholesale Market Price Impacts

Finally, some studies have attempted to assess reductions in wholesale market prices resulting from additional renewable generation (Table 3). Renewable generation can depress wholesale market prices by eliminating more expensive generating sources from the dispatch stack, which reduces the market clearing price paid to all generators. The studies summarized here estimated that each MWh of renewable energy reduces wholesale electricity prices by roughly $1/MWh, which translates into a renewable energy benefit of \$2–\$50/MWh of renewable generation. Typically, these wholesale-price estimates were derived through production cost modeling of the electricity system, running scenarios with and without the renewable generation on the system. The significance of these estimates is limited in a number of ways. First, wholesale-price suppression is a short-term effect that could change with changing market conditions. Second, these estimates focus on energy prices but do not assess capacity-related impacts or the need for new transmission or infrastructure investments that may be required with renewable generation. And third, although consumers benefit from lower wholesale market prices, the reductions represent transfer payments from generators to consumers, and therefore do not represent a net welfare gain to society.

Table 3. Summary of wholesale-market-price impact estimates for RPS renewables

State	Benefit	Benefit \$/MWh of RE	Period	Description	Source
ME	\$4.5 million	\$2/MWh	2010	Savings for consumers from reduced electricity prices. Extrapolating from a study by ISO New England, LEI estimated that 625 MW new wind in Maine would reduce wholesale prices by \$0.375/MWh of total Maine retail sales.	LEI 2012 [23]
MA	\$328 million	~\$50/MWh	2012	Savings for consumers from reduced wholesale electricity prices	EOHED and EOEEA 2011 [40]
IL	\$177 million	\$26/MWh	2011	Renewable energy lowers wholesale prices by \$1.3/MWh (all generation) due to low operating costs	IPA 2013 [32]
MI	N/A	N/A	2011	2% decline in wholesale prices attributed to wind generation, net imports, and decrease in load	Potomac Economics 2012 [41]
NY	\$455 million	\$5/MWh	Project lifespan	Savings for consumers from reduced wholesale energy and capacity prices	NYSERDA 2013b [34]
OH	Not estimated	N/A	2014	Renewable energy lowers wholesale prices by \$0.05–\$0.17/MWh (all generation)	PUCO 2013 [31]

4. Conclusions and Policy Implications

The policy implications of this work are several-fold. First, despite frequent claims that state RPS policies have imposed massive costs on ratepayers, experience to-date suggests that any rate impacts that have thus far occurred are likely quite modest, with compliance costs below 2% of average retail rates in most states. Going forward, RPS targets are scheduled to rise substantially in most states, which may exert upward pressure on compliance costs, though future RPS costs will also be heavily impacted by other market and policy dynamics. Some of those other drivers, such as reductions to federal tax incentives for renewables, may exacerbate upward pressure on RPS costs; whereas other dynamics—such as falling renewable technology costs, rising gas prices, and new federal environmental regulations—may serve to temper cost growth. Regardless of those uncertainties, cost containment mechanisms built into most existing RPS policies will limit cost growth to less than 10% of retail rates in most states, and in many states to less than 5%.

Our analysis also serves to highlight key methodological issues associated with estimating RPS costs, which are likely to become more critical as cost caps increasingly become binding. These methodological issues are perhaps most acute for traditionally regulated states, where RPS compliance is achieved primarily through bundled PPAs or utility-owned renewable generation. In these states, the central methodological issue is the approach used to estimate avoided non-renewable generation costs. As our comparisons suggest, and as the dueling cost estimates in California directly illustrate, the approach to this issue can substantially drive the ultimate result. Given the tradeoffs involved, and the widely varying market and regulatory conditions across states, a one-size-fits-all approach to estimating avoided costs is likely inappropriate and impractical. However, utilities and regulators may wish to take a fresh look at current practices, with consideration of methods used elsewhere, with particular attention to the methods used to estimate avoided generation capacity costs. Other key issues to consider include: whether to include costs of renewables procured prior to enactment of the RPS; whether to include costs of renewables procured beyond the minimum level needed to meet the target in a given year; and whether to include indirect expenditures, such as integration, transmission, and administrative costs attributable to the RPS.

For restructured states where compliance is achieved primarily through the purchase and retirement of RECs, perhaps the most fundamental constraint in developing reliable compliance cost estimates is a limited availability of representative REC pricing data, especially in states with growing reliance on longer term contracts. To address this limitation, several PUCs require individual suppliers to annually report the total cost of RECs retired for compliance each year, and broader adoption of this practice would greatly facilitate improved cost estimation. In addition, although rarely considered outside of occasional program evaluations, PUCs in restructured states may also wish to consider other RPS-related cost impacts (both positive and negative) to utilities and ratepayers, beyond the direct cost of RECs and ACPs. On the cost-side of ledger are integration-related costs, as well as any "socialized" transmission infrastructure costs directly attributable to new renewable generation. Although previous studies suggest that these costs would generally be small at current renewable energy penetration levels, such costs may become more significant as RPS targets ramp up. On the benefits-side of the ledger are the impacts of low-marginal-cost renewable generation supplies on electricity market prices (the so-called "merit order effect"). Although suppression of electricity market prices is properly construed as a wealth transfer between producers and consumers, rather than net gain in total social welfare and can be temporary, the study results nevertheless suggest that it may offset much of the direct costs of RECs and ACPs borne by LSEs.

Finally, further investigation of the benefits of these policies is important to ongoing policy-making efforts, particularly given that initial motivation for state RPS policies was often rooted in broader societal benefits and impacts. Unfortunately, relatively few states have undertaken analyses of these broader impacts, and where such studies have been conducted they've typically focused only a limited sub-set of potential impacts – most often, those impacts associated with emissions reductions and human health, local economic development, and wholesale electricity market price suppression. Although methodological differences among these studies preclude perfect comparison, the results to-date suggest that these impacts, in many cases, may be of the same order of magnitude as the incremental costs imposed on the electric system. As policy-makers consider changes to existing RPS programs or development of new programs, they may therefore wish to evaluate the broader societal impacts of state RPS programs, beyond simply a narrow consideration of the costs to electric utilities and ratepayers. Such efforts may be facilitated through the development of best practices or standardized methodologies and tools for estimating RPS program benefits.

Acknowledgements

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC, under contract DE-AC36-08GO28308. LBNL's contributions to this report were funded by the Office of Energy Efficiency & Renewable Energy of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The authors would like to thank individual reviewers who provided comments on earlier drafts of this work, as well as Jarett Zuboy for editorial assistance.

References

[1] Carley S. State renewable energy electricity policies: An empirical evaluation of effectiveness. Energy Policy 2009; 37:3071–81.

[2] Delmas M., Montes-Sancho M. U.S. state policies for renewable energy: Context and effectiveness. Energy Policy 2011; 39:2273–88.

[3] Eastin L. An Assessment of the Effectiveness of Renewable Portfolio Standards in the United States. Electricity J 2014; 27(7):126-37.

[4] Shrimali G., Kniefel J. Are government policies effective in promoting deployment of renewable electricity resources? Energy Policy 2011; 39:4726-41.

[5] Yin H., Powers N. Do state renewable portfolio standards promote in-state renewable generation? Energy Policy 2010; 38:1140–9.

[6] Zhao Y., Tang K., Wang L. Do renewable electricity policies promote renewable electricity generation? Evidence from panel data. Energy Policy 2013; 62:887-97.

[7] Center for the New Energy Economy (CNEE). State Renewable Portfolio Standards Hold Steady or Expand in 2013 Session. 2012. http://www.aeltracker.org/graphics/uploads/2013-State-By-State-RPS-Analysis.pdf.

[8] Stockmayer G., Finch V., Komor P., Mignogna R. Limiting the costs of renewable portfolio standards: A review and critique of current methods. Energy Policy 2012; 42:155-63. http://dx.doi.org/10.1016/j.enpol.2011.11.060.

[9] Climate Policy Institute (CPI). Limiting the Cost of Renewables: Lessons for California. 2012; http://climatepolicyinitiative.org/wp-content/uploads/2012/06/Limiting-the-Cost-of-Renewables-Lessons-for-California.pdf.

[10] Bird L., Chapman C., Logan J., Sumner J., Short W. Evaluating renewable portfolio standards and carbon cap scenarios in the U.S. electric sector. Energy Policy 2011; 39(5):2573–85. doi:10.1016/j.enpol.2011.02.025

[11] Fischer C. Renewable Portfolio Standards: When Do They Lower Energy Prices? Energy J 2010; 31(1):101–19.

[12] Wiser R., Bolinger M. Can deployment of renewable energy put downward pressure on natural gas prices? Energy Policy 2007; 35(1):295-306. http://dx.doi.org/10.1016/j.enpol.2005.11.021

[13] Morey M.J., Kirsch L.D. Retail rate impacts of state and federal electric utility policies. Electricity J 2014; 26(3):35-49. http://dx.doi.org/10.1016/j.tej.2013.03.001

[14] Chen C., Wiser R., Bolinger M. Weighing the Costs and Benefits of State Renewables Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections. LBNL-61590. Berkeley, CA: Lawrence Berkeley National Laboratory. 2007.

[15] Heeter J., Barbose G., Bird L., Weaver S., Flores-Espino F., Kuskova-Burns K., et al. A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards. NREL/TP-6A20-61042/LBNL-6589E. 2014. http://www.nrel.gov/docs/fy14osti/61042.pdf

[16] U.S. Energy Information Administration (EIA). Electric Power Annual, Detailed State Data. 2013. Accessed February 2014: http://www.eia.gov/electricity/data/state

[17] Wiser R., Bolinger M. 2012 Wind Technologies Market Report. DOE/GO-102013-3948. Washington, D.C.: U.S. Department of Energy. 2013. http://www1.eere.energy.gov/wind/pdfs/2012_wind_technologies_market_report.pdf.

[18] U.S. EPA. Assessing the Multiple Benefits of Clean Energy: A Resource for States. 2011. Accessed February 2014: http://epa.gov/statelocalclimate/resources/benefits.html; http://epa.gov/statelocalclimate/documents/pdf/epa_assessing_benefits.pdf.

[19] Cory K.S., Swezey B.G. Renewable Portfolio Standards in the States: Balancing Goals and Rules. Electricity J 2007; 20(4):21–32. Accessed February 2014: http://www.sciencedirect.com/science/article/pii/S1040619007000358.

[20] California Public Utilities Commission (CPUC). 33% Renewables Portfolio Standard: Implementation Analysis Preliminary Results. 2009.

[21] Center for Energy, Economic, and Environmental Policy (CEEEP), and Rutgers Economic Advisory Service (R/ECON). A Review of Connecticut's Renewable Portfolio Standards. 2011. http://www.ctenergy.org/pdf/RPSFINAL.pdf.

[22] Delmarva Power & Light Company (DPL). 2012 Integrated Resource Plan. 2012. Accessed February 2014: http://depsc.delaware.gov/electric/12-544%202012%20IRP.pdf.

[23] London Economics International LLC (LEI). MPUC RPS Report 2011 - Review of RPS Requirements and Compliance in Maine. Maine Public Utilities Commission. 2012. Accessed February 2014: http://www.maine.gov/tools/whatsnew/attach.php?id=349454&an=1.

[24] Xcel Energy. Renewable Energy Standard Rate Impact Report. Minnesota Public Utilities Commission. 2011. Docket No. E999/CI-11-852 (October 25).

[25] Great River Energy. Initial RES Rate Impact Report. Minnesota Public Utilities Commission. 2011. Docket No. E-999/CI-11-852 (October 25).

[26] RTI International. The Economic, Utility Portfolio, and Rate Impact of Clean Energy Development in North Carolina. 2013. RTI Project Number 0213597.000.

[27] Detroit Edison (DTE). DTE Electric Company's Application for Biennial Review and Approval of Its Amended Renewable Energy Plan. June 3, 2013.

[28] Consumers Energy Company. Consumers Energy Company's 2012 Renewable Energy Annual Report. 2013.

[29] Interagency Working Group on Social Cost of Carbon. Technical Support Document: - Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866, May 2013 (revised November 2013). http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf

[30] The Brattle Group, Connecticut Light & Power, and The United Illuminating Company. Integrated Resource Plan for Connecticut. 2010. http://www.ct.gov/deep/lib/deep/air/ozone/ozoneplanningefforts/att-c.pdf.

[31] Public Utilities Commission of Ohio (PUCO). Renewable Resources and Wholesale Price Suppression. 2013. Accessed February 2014: http://www.midwestenergynews.com/wp-content/uploads/2013/09/PUCO-renewable-energy-standard-study.pdf.

[32] Illinois Power Agency IPA. 2013 Annual Report: The Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts. 2013. http://www2.illinois.gov/ipa/Documents/201304-IPA-Renewables-Report.pdf.

[33] NYSERDA. The New York State Renewable Portfolio Standard Performance Report, Through December 31, 2012. 2013. Accessed February 2014: http://www.nyserda.ny.gov/Publications/Program-Planning-Status-and-Evaluation-Reports/-/media/Files/Publications/PPSER/NYSERDA/2013-rps-report.pdf.

[34] NYSERDA. NYSERDA Renewable Portfolio Standard Main Tier 2013 Program Review, Volume 2 — Main Tier Current Portfolio Analysis. 2013. Albany, NY.

[35] Illinois Power Agency (IPA). Order: Petition for Approval of Procurement Plan. 2010. 10-0563. December 21.

[36] Zuraski R. (Illinois Commerce Commission, Springfield, IL). Email message to G. Barbose. (Lawrence Berkeley National Laboratory). Personal Communication. January 3, 2014.

[37] Steinberg D., Porro G., Goldberg M. Preliminary Analysis of the Jobs and Economic Impacts of Renewable Energy Projects Supported by the Section 1603 Treasury Grant Program. 2012. NREL / TP-6A20-52739. Golden, CO: NREL

[38] Michigan Public Service Commission (MPSC). Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards. 2013. Accessed February 2014: http://www.michigan.gov/documents/mpsc/implementation_of_PA295_renewable_energy_411615_7.pdf

[39] Oregon Department of Energy (ODOE). Employment Assessment of the Oregon RPS. 2011. Accessed February 2014: http://www.oregon.gov/energy/docs/general/2011RPSAssessment.pdf.

[40] Executive Office of Housing and Economic Development (EOHED) and Executive Office of Energy and Environmental Affairs (EOEEA). Recent Electricity Market Reforms in Massachusetts: A Report of Benefits and Costs. 2011. Accessed February 2014: http://www.mass.gov/eea/docs/doer/publications/electricity-report-jul12-2011.pdf.

[41] Potomac Economics. 2011 State of the Market Report for the MISO Electricity Markets. 2012. Accessed February 2014: http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf.

[1] A variety of other analyses – including Carley [1], Delmas and Montes-Sancho [2], Eastin [3], Shrimali and Kniefel [4], Yin and Powers [5], and Zhao et al. [6] – have sought to estimate the effects of RPS polices on renewable generation using econometric or other more-sophisticated means, and have found varied impacts, depending on the methods, scope, and timeframe of their analyses.

[2] Costs are calculated as: $C = \sum_{i=1}^{n}\left[\left(P_{REC,i} \times Q_{REC,i}\right) + \left(P_{ACP,i} \times Q_{ACP,i}\right)\right]$, where C is the calculated incremental compliance cost (in dollars) for a particular state in a particular compliance year, n is the number of resource tiers within the RPS, P_{REC} is the average annual REC price, Q_{REC} is the number of RECs retired for RPS compliance purposes, P_{ACP} is the ACP price, and Q_{ACP} is the number of ACPs issued.

[3] Although data on actual integration costs are not widely available, a variety of studies have modeled integration costs at much higher renewables penetration levels than currently exist in most RPS states (e.g., >20% of load served by wind), and have typically estimated integration costs less than $5/MWh of renewable energy generated [17], suggesting that our omission of integration costs does not substantially bias the results.

[4] See the RIMS II user's guide for more in-depth discussion of these components.

33% RENEWABLES PORTFOLIO STANDARD
Implementation Analysis Preliminary Results

Exhibit 4
Page 1 0f 96

June 2009

Prepared by:

California Public Utilities Commission

PAUL DOUGLAS
Project Lead
RPS Program and Project Supervisor

ELIZABETH STOLTZFUS
Project Manager

ANNE GILLETTE
JACLYN MARKS
Lead Authors

Technical Analysis by:
Energy and Environmental Economics, Inc.
Aspen Environmental Group

Special Thanks to:

ARNE OLSON – Energy and Environmental Economics
SUSAN LEE – Aspen Environmental Group
SIMON EILIF BAKER – CPUC

Acknowledgements

This report is the product of collaboration between the California Public Utilities Commission (CPUC) Energy Division staff and a team of consultants. The CPUC Project Lead was Paul Douglas, and the Project Manager was Elizabeth Stoltzfus. The CPUC team also included Anne Gillette, Jaclyn Marks, and Simon Baker. We would like to emphasize that the views and analyses expressed in this report are not the views of the CPUC, but rather the contributors to this report.

We are grateful for the technical analysis and expertise that the consultants provided to this effort. In particular, we would like to thank Arne Olsen, Ren Orans, Snuller Price, Amber Mahone, and Doug Allen from Energy Environmental Economics, Inc., and Carl Linvill, Susan Lee, and Brewster Birdsall of Aspen Environmental Group, the primary consultant study team. We would also like to thank Eric Toolson and Wenxiong Huang from PLEXOS Solutions, LLC., and Tim Mason, Ryan Pletka, and Derek Djeu from Black and Veatch.

In addition to the consulting team, we would like to thank Gary DeShazo, Grant Rosenblum, and Judith Sanders from the California Independent System Operator for their technical input throughout the analysis and for their future contribution to Phase 3 of this analysis.

The staff at the CPUC contributed significantly to validating the technical analysis as well as reading through various drafts of this report. We are especially grateful to our management, Julie Fitch and Nancy Ryan for their continued guidance and support in helping to craft this report. We would also like to thank Dan Hartmann and Amy Baker for the graphics, and Simon Baker for supporting this effort since its inception a year ago. Our report also benefited from careful editing and review from other colleagues at the CPUC, including Kristin Ralff-Douglas, Keith White, Pete Skala, Molly Sterkel, Billie Blanchard, Chloe Lukins, Burt Mattson, Anne Simon, Victoria Kolakowski, Janet Econome, Peter Allen, Sara Kamins, and Iain Fisher. We would also like to thank Terrie Prosper for copy editing this report.

Lastly, we would like to thank the participants of the 33% RPS Implementation Analysis Working Group and the Transmission Constrained Working Group in the long-term procurement plans proceeding who provided their technical expertise through attending workshops, working group meetings, conference calls, and technical comments.

Contents

Tables

Exhibit 4
Page 5 of 96

Figures

Exhibit 4
Page 6 of 96

1 Executive Summary

California lawmakers are currently developing legislation to increase the current 20% by 2010 Renewables Portfolio Standard (RPS) to 33% by 2020. The California Public Utilities Commission (CPUC) and California Energy Commission (Energy Commission) have endorsed this change and it is a key greenhouse gas (GHG) reduction strategy in the California Air Resources Board's (ARB) Assembly Bill (AB) 32 Scoping Plan. As the principal agency responsible for implementing the current RPS program, the CPUC has learned many lessons that can help guide the design of a higher mandate. In addition, several recent analyses have cast light on various aspects of renewable energy development and integration. Drawing on these resources and new analyses, staff at the CPUC developed this report in order to provide new, in-depth analysis on the cost, risk, and timing of meeting a 33% RPS. This report does not recommend a preferred strategy on how to reach a 33% RPS, but rather provides an analytical framework for policymakers to weigh the tradeoffs inherent in any future 33% RPS program for California.

Summary of key findings include:

- **Timeline:** Achieving 33% RPS by the year 2020 is highly ambitious, given the magnitude of the infrastructure buildout required.
- **Resources:** To meet the current 20% RPS by 2010 target, four major new transmission lines are needed at a cost of $4 billion. Three of these lines are already underway. To meet a 33% RPS by 2020 target, seven additional lines at a cost of $12 billion would be required. In addition, the 33% RPS target is projected to require almost a tripling of renewable electricity, from 27 terawatt hours (TWh) today to approximately 75 TWh in 2020.
- **Cost:** Electricity will be higher in 2020 regardless of the RPS requirements.
    - Even if California makes no further investments in renewable energy, this analysis projects that average electricity costs per kilowatt-hour will rise by 16.7% in 2020 compared to 2008 in real terms.
    - In 2020, the total statewide electricity expenditures of achieving a 20% RPS are projected to be 2.8% higher compared to a hypothetical all-gas scenario, where new electricity needs are met entirely with natural gas generation.
    - In 2020, the total statewide electricity expenditures of achieving a 33% RPS utilizing the current procurement strategy is projected to be 7.1% higher compared to the 20% RPS, and 10.2% higher compared to an all-gas scenario.
- **Policies:** Achieving a 33% RPS by 2020 requires tradeoffs amongst various policy goals and objectives. If the 2020 timeline is the most important policy priority, California must start implementing mitigation strategies such as planning for more transmission and generation than is needed to reach just 33%, pursuing procurement that is not dependent on new transmission, or concentrating renewable development in pre-permitted land that would be set aside for a renewable energy park.

Exhibit 4
Page 7 of 96

APPROACH

Four Unique Renewable Resource Cases Created for Analysis

In order to conduct the implementation analysis, four unique renewable resource cases were developed. Each case represents a different 33% RPS procurement strategy to reaching the 33% RPS target. All cases assume current statutorily defined out-of-state deliverability requirements for renewables into California. Thus, these cases cannot be used to analyze the option of allowing out-of-state tradable renewable energy credits (REC) with no delivery requirement for RPS compliance.

- **33% RPS Reference Case:** This case represents California's current renewable procurement path, which is heavily dependent on new technologies, such as central station solar thermal.
- **High Wind Case:** This case demonstrates less reliance on in-state solar thermal and more reliance on less expensive wind resources in California and the Mexican state of Baja California.
- **High Out-of-State Delivered Case:** This case relies on construction of new, long-line, multi-state transmission to allow California utilities to procure large quantities of low-cost wind and geothermal resources from other western states (as noted above, this case does not include the use of tradable RECs with no delivery requirement).
- **High Distributed Generation (DG) Case:** This case assumes limited new transmission corridors can be developed to access additional renewable resources needed to achieve a 33% RPS. Instead, extensive, smaller-scale, renewable generation is interconnected to the distribution system or close to transmission substations.

In addition, a **20% RPS Reference Case** was developed to serve as a benchmark for cost comparisons between the cost of the current 20% RPS program and a 33% RPS in 2020. This reference case is comprised of California's likely renewable energy mix in 2020 based upon current state law and existing RPS contracts. As such, this case provides the most relevant benchmark against which to measure the incremental cost of various paths to meeting the higher 33% RPS target.

Two additional scenarios were developed to provide further points of reference:

- **All-Gas Scenario:** This scenario represents the resource mix in 2020 if no additional renewables were developed beyond 2007, and the rest of California's electricity needs were met with gas-fired generation. It supports comparisons between the cost of continuing investments in mostly natural gas and implementing a 33% RPS in 2020.
- **2008 Costs:** This scenario represents the current cost of electricity in California. It supports comparisons across the 2020 scenarios of increases relative to today's costs.

The report uses the four different possible 33% RPS cases to assess the costs and tradeoffs of each approach. It should be noted that:

- Projected costs are based on renewable technology costs and not the contract prices.
- The cost analysis assumes current technology costs, and makes no assumptions about the cost trajectory (up or down) of particular technologies over time due to potential transformation of the market.
- Average electricity costs per kilowatt hour are expressed as statewide averages and are not indicative of individual utilities' rates or the actual bills that consumers will pay.

Three Illustrative Timelines Created for Analysis

This report then uses the 33% RPS Reference Case to construct three illustrative timelines for achieving a 33% RPS. These timelines demonstrate how and when the state could plausibly build the necessary renewable generation and transmission to reach a 33% RPS. The timelines also offer insights into the increased need for public and private sector resources in order to quickly process the increased number of transmission and generation applications over the next 10 years.

- **Illustrative Timeline 1: Historical experience without process reform**

  This scenario is based on the state's experience with generation and transmission development over the last 10-15 years. The timeline assumes transmission planning, permitting, and construction processes that are almost entirely sequential.

- **Illustrative Timeline 2A: Current practice with process reform and no external risks**

  This scenario represents the development trajectory if California successfully implements transmission and generation process reforms that are already underway. Although not plausible since it does not include external risks that are beyond the state's control, this timeline serves to isolate the effect of the process reforms, and is the reference point that Timeline 2B is built upon.

- **Illustrative Timeline 2B: Current practice with process reform and external risks**

  This scenario represents the development trajectory if California successfully implements process reforms, but includes negative impacts and delays from external risks outside the direct control of state agencies, such as emerging technology risk, financing difficulties, and public opposition or legal challenges.

FINDINGS

Key Findings from Timeline Analysis:

The report finds that a 33% RPS in 2020 is highly ambitious, given the magnitude of the infrastructure buildout required

The magnitude of the infrastructure that California will have to plan, permit, procure, develop, and integrate in the next ten years is immense and unprecedented. This goal is more attainable with a commitment of significant new staff resources in both the public and private sectors. The conclusions below are based on an implementation analysis of the 33% RPS Reference Case.

- Timeline 1 reaches a 33% RPS in 2024. Using past practices as a guide, the scale of the transmission and generation buildout will take at least 14 years if implementation starts today. This timeline, however, assumes no external risks.
- Timeline 2A reaches a 33% RPS in 2021. This timeline assumes successful implementation of numerous process reforms now underway, which speed achievement of the 33% RPS from 2024 to 2021. This timeline represents a best case scenario as it assumes no external risks, no resource constraints in processing numerous transmission and generation applications, and that the California ISO is able to successfully implement its planned new process to review and approve more than one major transmission application per year.
- Timeline 2B does not reach the 33% RPS since two resource zones fail to develop due to risks outside of the state's control.

Numerous external risks could undermine the time savings achieved by process reforms

Several factors outside direct state control could undermine the gains realized through the various reform initiatives. These external risks could delay attainment of the 33% RPS target well beyond 2020, especially if California continues on its current renewable resource contracting path.

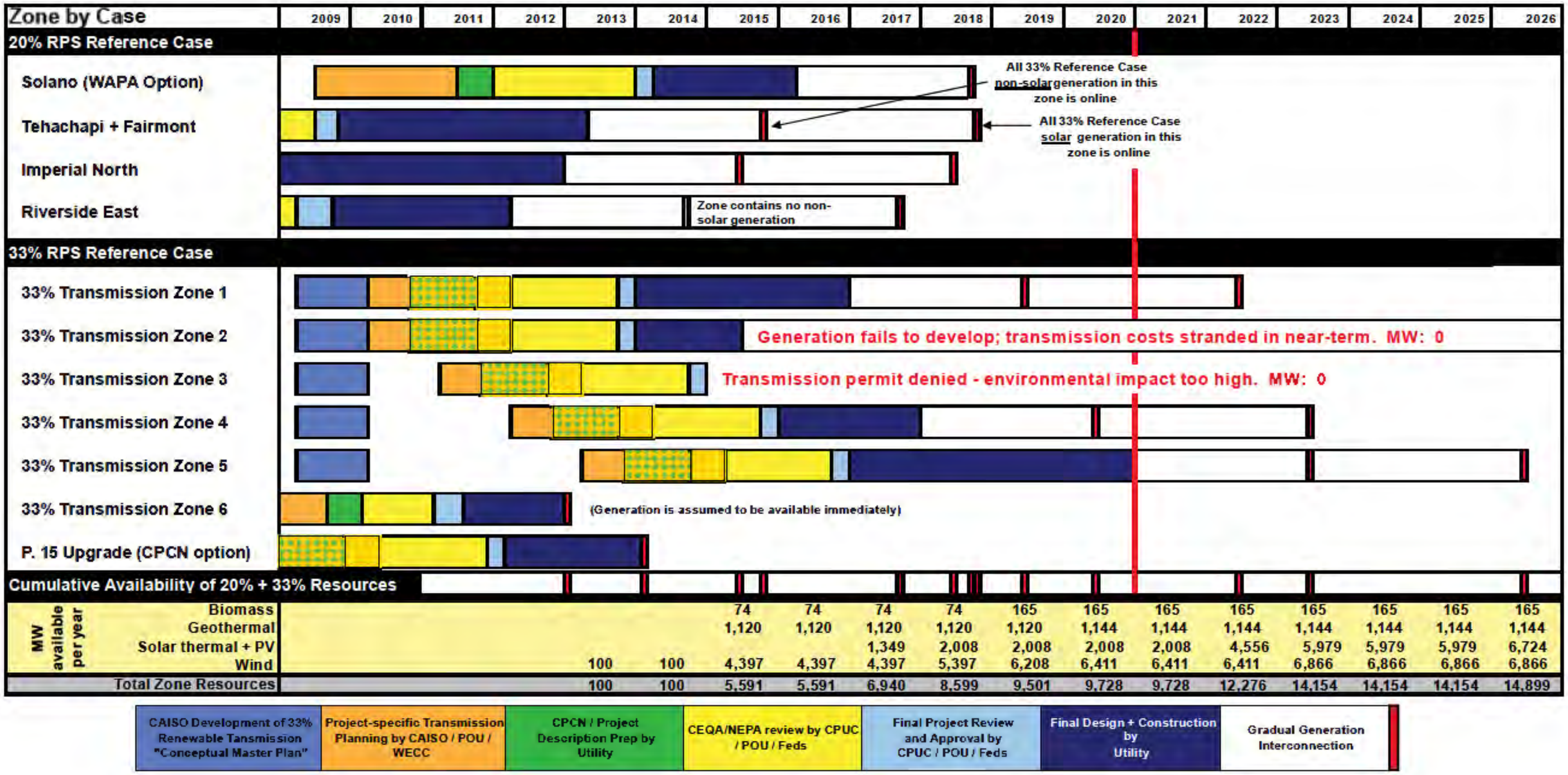
- Timeline 2B (see Exhibit A) illustrates how unanticipated contingencies could affect the timing of reaching the 33% RPS goal. External risks delaying this timeline include:
  - California's high reliance on relatively new technologies and companies
  - Scale of new infrastructure investment, which this analysis estimates at approximately $115 billion between now and 2020, in an uncertain financial environment
  - Environmental impacts of generation and transmission facilities that may require the use of large areas of undeveloped and perhaps pristine land
  - Legal challenges and public opposition to large-scale renewable energy infrastructure

California must start implementing mitigation strategies if achieving a 33% RPS by the year 2020 is the most important policy priority

Timeline 2B provides an example of a scenario in which, despite successful implementation of ambitious reforms, two resource zones fail to develop due to external risks. While Timeline 2B presents a hypothetical example, it illustrates the potential impact of real risks that California's current procurement strategy is not prepared to mitigate. Specifically, California's current procurement path is focused almost solely on central station renewable generation that is dependent on new transmission. In order to mitigate the risk that one resource zone would fail to develop, thereby delaying the achievement of a 33% RPS by several years, the state should consider a procurement strategy that adequately considers the time and risk, in addition to price, associated with particular renewable generation resources. The state may also wish to adopt risk mitigation strategies, such as:

- Planning for more transmission and generation than needed to reach just 33%
- Pursuing procurement, such as distributed solar photovoltaics (PV), which is not dependent on new transmission
- Concentrating renewable development in pre-permitted land that would be set aside for a renewable energy park

Exhibit A. Illustrative Timeline 2B for the 33% RPS Reference Case: Current Practice With Process Reform and External Risks



MW available per year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Biomass							74	74	74	74	165	165	165	165	165	165	165	165
Geothermal							1,120	1,120	1,120	1,120	1,120	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Solar thermal + PV									1,349	2,008	2,008	2,008	2,008	4,556	5,979	5,979	5,979	6,724
Wind					100	100	4,397	4,397	4,397	5,397	6,208	6,411	6,411	6,411	6,866	6,866	6,866	6,866
Total Zone Resources					100	100	5,591	5,591	6,940	8,599	9,501	9,728	9,728	12,276	14,154	14,154	14,154	14,899

Source CPUC/Aspen

Result: The 33% RPS Reference Case is not achieved due to unexpected problems with the development of two zones and delays in deployment of large-scale solar projects. Regardless of the nature of the risks that may actually occur, realization of any risk could cause delay and have a significant impact on timing. Although the state does not have direct control over many of the risks facing renewable energy development, it could adopt strategies that would mitigate specific risks.

Exhibit 4
Page 12 of 96

Key Findings from Renewable Resource and Cost Analysis

A 33% RPS is projected to require almost a tripling of renewable electricity, and nearly a doubling of new transmission lines

The 33% RPS Reference Case is projected to require an additional 75 TWh of renewable electricity, or nearly a tripling compared to the 27 TWh of delivered renewable electricity generated at the end of 2007. It is also projected to require seven new transmission lines to deliver the additional 75 TWh of electricity.

Exhibit B. Renewable Generation and Transmission Needed in 2020

20% RPS Reference Case would require	33% RPS Reference Case would require
35 TWh of new renewable electricity in 2020, in addition to **27 TWh** of generation from renewables in existence at the end of 2007	**75 TWh** of new renewable electricity in 2020, in addition to **27 TWh** of generation from renewables in existence at the end of 2007
4 New Major Transmission Lines at cost of **$4 Billion**	7 Additional Major Transmission Lines at cost of **$12 Billion**

Electricity will be higher in 2020 regardless of the RPS requirements

Real electricity costs will be significantly higher in 2020 compared to 2008, regardless of whether California pursues a 20% or 33% RPS (see Exhibit B).

- Even if California makes no further investments in renewable energy (the all-gas scenario), the analysis projects that average statewide electricity costs per kilowatt hour will rise by 16.7% in 2020 compared to 2008 in real terms. This increase results from the need to maintain and replace aging transmission and distribution infrastructure, anticipated investments in advanced metering infrastructure and other smart grid capabilities, the cost of repowering or replacing generators to comply with once-through cooling regulations, and the cost of procuring new conventional generating resources to meet load growth.
- In 2020, the total statewide electricity expenditures of the 20% RPS Reference Case is projected to be 2.8% higher compared to the all-gas scenario.
- In 2020, the total statewide electricity expenditures of the 33% RPS Reference Case is projected to be 7.1% higher compared to the 20% Reference Case, and 10.2% higher compared to the all-gas scenario.

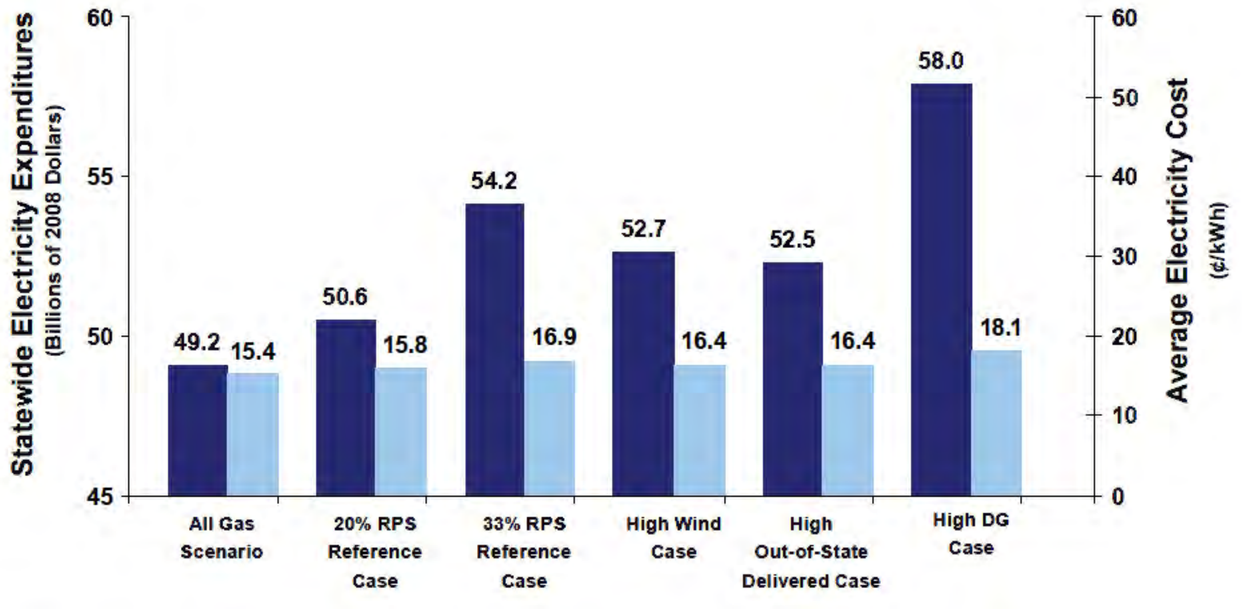
The 33% RPS Reference Case is the most expensive case relative to the alternative 33% RPS cases requiring new transmission lines; but it is still much less costly than the High DG Case (see Exhibit B)

The cost premium of meeting a 33% RPS does not vary greatly between the High Out-of-State Delivered Case and the High-Wind Case. Statewide electricity expenditures under these cases are $1.5 and $1.8 billion lower than the 33% RPS Reference Case, respectively, with the cost savings largely resulting from replacing large quantities of solar thermal resources with less costly wind resources.

The High DG Case adds almost twice the incremental costs of the 33% RPS Reference Case

The cost premium of the High DG Case is significantly higher than the 33% RPS alternative cases, with a 14.6% cost premium compared to the 20% RPS Reference Case, and a 7.0% cost premium compared to the 33% RPS Reference Case. This is due to the heavy reliance on solar PV resources, which are currently more expensive than wind and central station solar.

Exhibit C. Statewide Electricity Expenditures and Average Electricity Cost in 2020



Source CPUC/E3

Exhibit 4
Page 14 of 96

Findings from Sensitivity Analysis

Projecting the costs of different renewable and fossil-fired energy sources out to 2020 requires numerous assumptions about future conditions including load growth, equipment costs, and fuel prices. Many of these variables are highly uncertain, and some significantly influence the model's results. Accordingly, the study includes sensitivity analysis in three key areas, finding that:

- A 33% RPS can serve as a hedge against natural gas prices, but only under very high natural gas and GHG allowance prices. Thus, the hedging value in itself is not a very strong justification to do a 33% RPS.
- The interplay between energy efficiency achievement and renewable energy procurement highlights the need to analyze and plan for the interactions among the state's various policy goals. If the state does not plan for interactions, then a 33% RPS by 2020 could result in a surplus of energy or capacity and excess consumer costs.
- Dramatic cost reductions in solar PV could make a solar DG strategy cost-competitive with central station renewable generation. More analysis is necessary to determine the programmatic strategies necessary to achieve a high-DG scenario as well as the feasibility of high penetrations of solar PV on the distribution grid.

POLICY OBJECTIVES AND TRADEOFFS

Achieving a 33% RPS will require tradeoffs amongst various policy goals and objectives

There are multiple renewable procurement strategies that California could pursue to reach a 33% RPS, but each procurement path will reach the 33% RPS target on a different timeframe and will perform differently across the broad range of RPS policy objectives that stakeholders and decision-makers have articulated. See Exhibit D for a comparison of how each 33% RPS Case performs across the RPS policy objectives.

Exhibit D. Comparison of 33% RPS Cases Across RPS Policy Objectives

Policy Objective	33% RPS Reference Case	High Wind Case	High Out-of-State Delivered Case	High-DG Case
Cost	◒	●	●	○
Timing	○	◒	◒	◒
GHG Emission Reductions	●	●	●	●
Resource Diversity (Hedging Value)	●	●	●	●
Local Environmental Quality Air Quality	●	◒	○	●
Local Environmental Quality Land Use	○	◒	◒	●
In-state Economic Development	◒	◒	○	◒
Long-Term Transformation	●	○	○	●
Technology Development Risk	○	●	●	○

Legend:

● Case performs well ○ Case performs poorly ◒ Case is neutral

California IOUs are currently on a procurement path that in effect prioritizes long-term market transformation over other policy objectives. California's IOUs are depending on new renewable technologies, including solar thermal, to meet their RPS obligations. This procurement strategy may lead to long-term market transformation of the central station solar market, but due to risks inherent to new technologies, this strategy could result in higher prices and a longer development period that could delay achievement of a 33% RPS to after 2020.

RPS Policy Objectives Should Be Prioritized

As this analysis has shown, many of the policy objectives are mutually exclusive and in conflict with one another. Currently, the RPS procurement process is in effect dictating the timing, cost, and policy objectives of a future 33% RPS program. Thus, the tradeoffs are being decided through the utility procurement process, not by the policymakers or regulators. Using current RPS contracts as an example, market transformation and in-state economic development are the primary policy objectives that are being prioritized at the expense of meeting a 2020 timeline and minimizing customer costs. This results from lack of having a stated priority preference. Some of the key questions to help determine a priority preference include:

- Should California focus public investment and system planning efforts on developing and integrating technologies with significant long-term transformational potential such as solar thermal or solar PV?
- Should California focus on developing in-state resources? Up to what cost? What is the correct balance between in-state economic development and higher customer costs?
- Is California willing to delay the 2020 target in order to develop primarily California resources and stimulate new technologies and market transformation?
- Should California waive renewable energy delivery requirements for out-of-state resources if it is necessary to meet the 2020 target or pursue a lower cost strategy?
- Should the CPUC encourage the utilities to procure increased amounts of (currently) high-cost solar PV to mitigate the potential negative impact of delay due to failure of a resource zone?

NEXT STEPS

This report presents the preliminary results of the 33% RPS Implementation Analysis and does not include results from Phase 3, the final phase of this analysis. By the end of 2009, the final results will incorporate additional analyses. First, the California ISO will complete a study to determine the resource requirements to integrate the intermittent renewable resources needed for a 33% RPS. Second, the transmission cost estimates will be updated based on the latest information from the Renewable Energy Transmission Initiative (RETI) and the California ISO's conceptual transmission planning process. Finally, CPUC staff will identify and articulate solutions and strategies for addressing many of the risks and challenges identified throughout this report.

2 Introduction

The CPUC, in conjunction with the Energy Commission, is responsible for implementing the state's Renewables Portfolio Standard Program, which is one of the most ambitious renewable energy standards in the country. California lawmakers are contemplating increasing the current RPS mandate, which is 20% renewable energy by 2010, to 33% renewable energy by 2020. A 33% renewable goal could further California's efforts to address climate change and lead the nation in proactive clean energy policy. The CPUC supports this more aggressive 33% renewable energy standard and recommended it as a key electric sector strategy in the Energy Commission/CPUC joint recommendations to the California Air Resources Board to help California meet its climate change targets established in AB 32, the Global Warming Solutions Act of 2006. The ARB adopted this recommendation in December 2008. [1]

The CPUC's Energy Division staff initiated this study in August 2008 in order to provide a quantitative analysis of the costs and risks of alternative means of achieving a 33% RPS by 2020.[2] The report seeks to answer two key questions: 1) How much will it cost to meet a 33% RPS, and 2) how will the state reach a 33% RPS by 2020? Working with a broad stakeholder group, including the investor-owned electrical utilities, industry experts, ratepayer advocates, and environmental groups, the study team, which consisted of CPUC staff and a consulting team, developed the preliminary results presented in this report. The report analyzes four different possible 33% RPS alternatives and articulates the costs and tradeoffs of each approach. The study team used the 33% RPS Reference Case to construct three illustrative timelines for achieving a 33% RPS. These timelines demonstrate how and when the state could plausibly build the necessary renewable generation and transmission to reach a 33% RPS. CPUC staff will issue a final report by the end of 2009, which will be informed by additional analysis that the California ISO is conducting.

POLICY GOALS AND OBJECTIVES

California has been leading the country with aggressive renewable energy targets since the establishment of the RPS in 2002. Senate Bill (SB) 1078 established Public Utilities Code Section 399.11 - 399.15, which created California's first RPS law and mandated a 20% RPS by 2017.[3] Just three years later, in 2005, the legislature amended the statute to accelerate this goal to 20% by 2010.[4] Current statute expressly prohibits the CPUC from requiring an RPS level beyond the 20% target.

---

[1] California Air Resources Board, "Climate Change Scoping Plan," Approved December 11, 2008. Available at: http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

[2] CPUC Decision (D.)07-12-052, which authorized the 2007 long-term procurement plans (LTPPs), directed Energy Division staff to work with stakeholders to refine a methodology for evaluating a 33% RPS by 2020 within the context of LTPP.

[3] Senate Bill 1078 (2002), Section 3, Article 16, PU Code Section 399.11(a)(b)(c)

[4] Senate Bill 107 (2006)

In November 2008, Governor Schwarzenegger issued Executive Order S-14-08, requiring state agencies to establish the Renewable Energy Action Team to streamline the review of transmission and renewable generation projects as well as commit state agencies to work towards achieving 33% of retail sales from renewable energy by 2020.[5] The legislature is currently considering several different bills that would mandate a 33% RPS by 2020.

Through legislation and other measures, state policymakers have articulated various policy goals and objectives that a 33% RPS should address:

- **Greenhouse Gas Emission Reductions**. California can avoid significant GHG emissions by replacing one-third of the state's energy supply with renewable resources. As part of its strategy to reduce emissions to 1990 levels by 2020, ARB has estimated that a 33% RPS could reduce GHG emissions by 21.3 million metric tons of carbon dioxide equivalent (MMTCO$_2$e), satisfying nearly 12% of the total required GHG reductions.
- **Long-Term Market Transformation.** An aggressive RPS target should help to drive the energy technology transformations needed to lower costs, upgrade current infrastructure, and achieve long-term GHG reductions beyond 2020. Scientists estimate that deep cuts in global GHG emissions of 50% to 85% below current levels by 2050 are necessary to prevent the worst impacts from climate change.[6]
- **Resource Diversity.** Higher levels of renewable energy generation can improve the diversity and security of California's energy supply, provide hedging value, and reduce dependence on fossil fuels with volatile prices, particularly natural gas.
- **Local Environmental Quality and Public Health.** Renewable generation can improve local air quality and public health, principally through reduced emissions of criteria pollutants at gas-fired power plants in California.
- **Economic Development.** Renewable technologies can create local manufacturing, installation, maintenance, and operational jobs.
- **Least-Cost, Best Fit.** Public Utilities Code Section 399.14 requires a renewable project selection process called "least-cost, best-fit," which allows the utility to select the project based on the value to the ratepayer and the utility. The statute requires the CPUC to consider estimates of indirect costs associated with the project, including new transmission investments and ongoing utility expenses resulting from integrating and operating renewable energy resources. Consequently, this report describes both the cost and "fit" attributes of four different portfolios of renewable resources.
- **Timing**. Since the ARB has linked a 33% RPS to the 2020 climate change goals, the speed at which renewable resources can be developed and integrated into the power grid is very important.

[5] California Governor's Executive Order S-14-08, "Governor Schwarzenegger Advances State's Renewable Energy Development," November 17, 2008. Available at: http://gov.ca.gov/press-release/11073/.

[6] Intergovernmental Panel on Climate Change, "Climate Change 2007: Synthesis Report," 2007, Section 5.4, pg. 66-67, Assessment of the Intergovernmental Panel on Climate Change, Valencia, Spain. California Governor Schwarzenegger committed California to reduce statewide GHG emissions to 80% below 1990 levels by 2050 in Executive Order S-3-05, June 1, 2005. Available at: http://gov.ca.gov/executive-order/1861/.

STUDY OVERVIEW

Several other studies and processes have examined, or are now examining, a particular aspect of a California 33% RPS. Some of these studies have occurred in the past, while others are occurring in parallel with this analysis. These studies include:

- Center for Resource Solutions report prepared for the CPUC (2005)[7]
- E3's modeling work to develop the GHG Calculator in support of the joint CPUC/Energy Commission proceeding to develop recommendations for the ARB on implementation of AB 32 for the electricity sector[8]
- California ISO Preliminary Report on Renewable Transmission Plans (2008)[9]
- California ISO's Integration of Renewable Resources Program[10] to evaluate the generation performance characteristics and gas-fired generation needed to support increased levels of various types of renewable resources
- Energy Commission 2009 Integrated Energy Policy Report (IEPR) proceeding
- Ongoing work of RETI and other transmission planning processes to facilitate the interconnection of renewable generators

This study provides a more in-depth, granular, and comprehensive analysis of different possible renewable scenarios compared to these previous studies. It draws heavily on most of the sources described above for data and assumptions, including RETI and the GHG Calculator, both of which were scrutinized and evaluated through stakeholder processes. The analysis also used a stakeholder working group to vet and refine the study methodology, assumptions, and inputs, especially when the assumptions differed from existing studies. For example, the renewable technology cost numbers from RETI were used, except the financing assumptions were modified to incorporate recent changes in financial markets. This report also incorporates new resource potential identified in RETI and other sources, existing resources from the Western Electricity Coordinating Council's (WECC) most recent west-wide study cases,[11] and proposed projects under development (identified through utility procurement solicitations). As a result, the renewable energy project and cost data underlying this analysis is the best publicly available data to date.

In addition, this study is the first effort to create comprehensive generation and transmission timelines that illustrate the many steps required to bring renewable energy projects in California from conception to commercial operation. This study elevates the analysis from a general discussion of perceived barriers into illustrative timelines that depict the magnitude of the coordination challenge associated with a 33% RPS.

---

[7] http://www.resource-solutions.org/lib/librarypdfs/Achieving_33_Percent_RPS_Report.pdf

[8] http://www.ethree.com/CPUC_GHG_Model.html

[9] http://www.caiso.com/2007/2007d75567610.pdf

[10] See http://www.caiso.com/1c51/1c51c7946a480.html for status and documents related to this program.

[11] The analysis is built off of the November 2008 version of the WECC's Transmission Expansion Planning and Policy Committee (TEPPC) 2017 database.

Assumptions

Like any modeling effort, this study makes a number of simplifications in order to represent a complex problem in manageable proportions. Likewise, the analysis includes assumptions about the future that are not known today. First, this study is a statewide analysis, and not limited to the investor-owned utilities (IOUs). Second, this analysis used high-level estimates of renewable integration and transmission costs, which will be updated in the next phase of this study. Third, the technology costs presented in this analysis reflect the costs to build and operate the renewable project with a reasonable profit, but are not based on actual contract prices. Many of the other assumptions are stated below or are explained in the relevant sections throughout the report and in the methodology discussion found in Appendix B.

Study Outputs

This report presents the preliminary results of the first two phases of this three-phase study. The key outputs are described below.

Four Unique 33% RPS Cases

The study team developed four unique 33% RPS cases, or renewable resource portfolios, for achieving a 33% RPS by 2020. Each case addresses a different possible scenario. For example, the 33% RPS Reference Case reflects California's current renewable procurement path, which is focused partly on new technologies, such as central station solar. Three alternative 33% RPS cases were developed, which test the costs and benefits of a particular resource strategy, including higher levels of wind energy, out-of-state resources, and distributed renewable resources.

> **Renewable Resource Portfolio**
>
> A resource portfolio is a collection of renewable resources by quantity and technology type selected based on different constraints or policy objectives.

A fifth case was developed, termed the 20% RPS Reference Case, to serve as a point of comparison for any cost changes associated with a 33% RPS. The 20% RPS Reference Case reflects current state law and utility procurement. Two additional scenarios were developed to provide further points of reference: an all-gas scenario, which represents the resource mix in 2020 if no additional renewables were developed beyond 2007, and the rest of California's electricity needs were met with gas-fired generation, and 2008 Costs, which represents the current cost of electricity in California.

Estimates of Renewable Generation and Transmission

This report presents plausible estimates of the type and amount of renewable generation and transmission needed to reach a 33% RPS. The Energy Commission's 2007 IEPR load forecast was used to project electricity sales to 2020. The study team calculated the quantity of new renewable resources needed to meet the 33% RPS and then selected renewable resources to fill this need. The study also provides a high-level estimate of the new transmission investment needed to integrate and deliver renewable resources to load centers. However, the study did not undertake a detailed engineering analysis of the ability of the renewable resources to connect to the existing grid. It also does not reflect the conceptual transmission plans that RETI is currently developing, since these were not available at the time of this analysis. As a result, the transmission investment assumed in the cases does not represent an "optimal" or least-cost transmission plan. The study team will update the transmission results in the final phase of this study based on the transmission conceptual plans that RETI and the California ISO are developing.

Electricity Costs in 2020

All electricity costs are presented in 2008 dollars unless noted otherwise. This analysis calculated statewide electricity expenditures, which is an economic cost, for the different RPS cases in the year 2020, as well as the average cost per kWh in 2020. All costs include federal production and investment tax credits and state property tax incentives. This analysis did not calculate ratepayer bill impacts, which depend on policy design, cost allocation, and how economic costs are recovered through different rate classes. In addition, this analysis employed simplified assumptions for transmission costs and integration costs in lieu of detailed California ISO analysis. These cost assumptions will be updated in the final report following further analysis.

To estimate the cost of constructing new renewable resources, the study team relied primarily on data developed for the state's RETI process. RETI developed cost and performance information for hundreds of potential projects throughout California, representing tens of thousands of megawatts of renewable energy resources. Additional resource characterizations came from the GHG Calculator.

For most of the projects, the costs are the developer costs to build and operate the project with a reasonable profit. The project costs are not the negotiated contract prices. However, projects that were projected to cost less than a combined cycle gas turbine (CCGT) power plant were assumed to be at least as expensive as a CCGT, even if some renewable resources may be slightly less expensive to develop. E3 made the assumption that the CCGT cost serves as a floor for the cost of a renewable power purchase agreement (PPA) since until low-cost renewables are widely available, it is unlikely that developers will agree to supply power to California utilities below the market rate for new conventional resources. This assumption has a modest, upward impact on the total cost of complying with a 33% RPS.

Illustrative Timelines for Generation and Transmission Facilities

As mentioned above, this analysis created illustrative timelines for the generation and transmission facilities needed to meet a 33% RPS. These timelines show the time needed to reach a 33% RPS under three scenarios: a) historical experience without process reform, b) current practice including process reform and no external risks, and c) current practice with process reform and external risks. The study team constructed timelines only for the 33% RPS Reference Case and did not perform this analysis on the other three alternative 33% RPS cases.

This analysis also identified several external risks that are outside of the state's control. These risks include technology risk, financing risk, environmental impacts, and potential legal challenges and public opposition to transmission and generation permits. The report shows how these risks could cause delay despite the progress the state is making in streamlining current renewable generation and transmission permitting processes.

3 33% RPS Resource Portfolio Results

This section describes the renewable resource mixes developed for each 33% RPS case and presents the impact of these resource mixes on total statewide electricity expenditures, average statewide electricity costs, and GHG emissions relative to an all-gas scenario and the 20% RPS Reference Case. A brief overview of the methodology is provided below, with a more complete description in Appendix B.

In order to conduct the analysis, E3 first created an RPS Calculator, which is a Microsoft Excel spreadsheet model developed to aggregate the renewable cost and performance data and select renewable resources needed to meet the RPS target. The model identifies transmission investments that deliver renewable resources to load and conventional resources that are needed to meet energy and peak demand growth. It also calculates the cost and GHG impacts of a given portfolio of resources in 2020. Second, E3 calculated the renewable resource need to determine how much renewable energy the state needs to procure between now and 2020 to meet the 33% RPS. E3 used the Energy Commission's 2007 IEPR load forecast to project statewide electricity load in 2020, which included assumptions on the state's achievement of energy efficiency, demand response, combined heat and power, and the California Solar Initiative.[12] In order to fill this need, data was collected drawing from the sources described in Table 1. Next, each renewable project was placed into a resource zone, which is an aggregation of renewable resources in a contained geographic area. These zones were then ranked by both economic and environmental factors. From this data, the study team developed five different renewable energy cases, which are described in Table 2.

[12] California Energy Commission, "California Energy Demand 2008 – 2018 Staff Revised Forecast," CEC-200-2007-015-SF2, November 2007: http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF

Table 1. Data Sources Used in 33% RPS Implementation Analysis

Data Source	Description
CPUC Energy Division project database (ED Database)	The Energy Division maintains a database of renewable energy projects representing approximately 56 TWh of electricity that the IOUs have selected through RPS solicitations.[13] The projects are in various stages of completion, ranging from projects under negotiation (i.e., short-listed for negotiating a contract by an IOU), to projects that are online. Incorporating short-listed projects distinguishes this study from prior analyses by enabling it to take advantage of information about commercial interest in specific new renewable projects.
Renewable Energy Transmission Initiative	The RETI process developed a detailed and comprehensive database of renewable resource potential in California and neighboring states.[14] The RETI analysis provided a stakeholder-vetted engineering assessment of renewable resources at the project level by location and technology type. The RETI dataset relies on proxy projects that are based on expressed commercial interest, it does not include short-listed projects. In addition to renewable resource information, the RETI database categorized clusters of renewable development into renewable resource zones, which were extremely valuable in the estimates of resource development and transmission need.
The GHG Calculator	E3 developed a database of renewable resource potential throughout the WECC as part of its GHG modeling analysis for the CPUC, ARB, and the Energy Commission. The study team relied on the E3 database for information on renewable resources outside of California.[15]
Estimates of distributed renewable energy potential	E3 developed new estimates of the technical potential to connect distributed renewable generation in California. While the distributed solar photovoltaic technical potential estimates that were developed for this study are very high-level, they are useful for the purpose of testing the benefits and costs of distributed renewables relative to central station power plants to achieve a 33% RPS.

[13] The CPUC maintains a public version of this database: www.cpuc.ca.gov/renewables

[14] Renewable Energy Transmission Initiative: www.energy.ca.gov/reti/documents/index html

[15] The E3 database compiled the data through GIS date from the National Renewable Energy Laboratory, the Energy Information Administration, the Energy Commission, and the Western Governor's Association. More detailed information is available here: http://ethree.com/CPUC GHG Model html.

Table 2. 2020 Cases Developed for the 33% RPS Implementation Analysis

Case Name	Description
20% RPS Reference Case	Utilities procure 35 TWh of additional renewables to meet a 20% RPS target by 2020.
33% RPS Reference Case	Utilities procure 75 TWh of additional renewables to meet a 33% RPS target by 2020. There is heavy emphasis on projects that are already either contracted or short-listed with California IOUs, which includes a significant proportion of solar thermal and solar photovoltaic resources.
High Wind Case	Assumes less reliance on in-state solar thermal and more reliance on the less expensive wind resources in California and Baja.
High Out-of-State Delivered Case	Allows construction of new, long-line, multi-state transmission to allow California utilities to procure large quantities of low-cost wind and geothermal resources in other western states. Does not use tradable renewable energy certificates as a compliance tool. Thus, all out-of-state electricity is delivered to California.
High DG Case	Assumes limited new transmission corridors are developed to access additional renewable resources to achieve a 33% RPS. Instead, extensive, smaller-scale renewable generation is located on the distribution system and close to substations.

RENEWABLE RESOURCES NEEDED

Table 3 shows the calculation of the quantity of renewable resources that California utilities must procure between 2008 and 2020 to meet a specified RPS target – for both a 20% and a 33% RPS.

Table 3. New Renewable Resources Required to Meet a 33% RPS by 2020 in TWh

	20% RPS	33% RPS
2020 retail sales forecast [16]	308	308
Required RPS resources	62	102
RPS resources claimed by utilities in 2007 [17]	27	27
Resources needed to reach RPS	*35*	*75*

RESULTING RPS RESOURCE MIXES

Figure 1 provides the renewable energy resource mixes for each RPS case, which were derived using the RPS Calculator. The renewable energy resource mixes for each case vary significantly across portfolios. The 33% RPS Reference Case has the most large-scale solar compared to all of the other cases. The High Out-of-State Delivered Case contains the largest proportion of out-of-state resources, such as geothermal energy, and nearly as much wind as the High Wind Case.

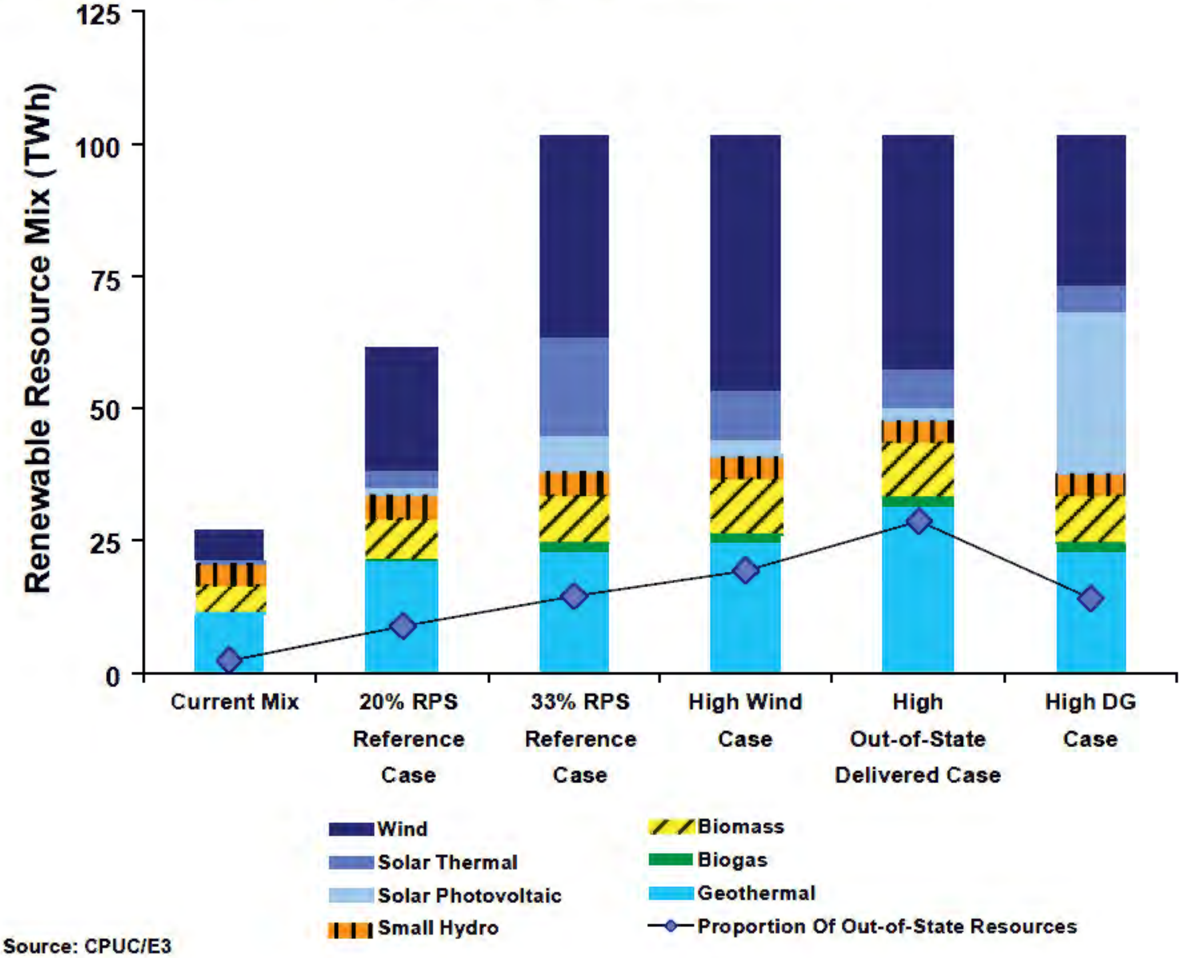
[16] Source: California Energy Commission, 2007, "California Energy Demand 2008 - 2018 Staff Revised Forecast," Energy Commission-200-2007-015-SF2, (excludes sales by California water agencies) extrapolated from 2018 to 2020 based on historic growth trends

[17] Source: Energy Commission 2007 Net System Power Report

The bioenergy and small hydro proportions do not vary greatly across the cases. The High DG Case includes a much larger proportion of solar PV than any other case.

Figure 1 also shows the level of renewable energy from the various resources in each case, inside and outside of California. All cases assume existing statutorily-required out-of-state energy delivery requirements.[18] The High Out-of-State Delivered Case and the High Wind Case have a higher proportion of renewable energy developed outside of California compared to the other cases. Thus, this study does not examine the potential for or costs and benefits of the use of tradable RECs with no delivery requirement as a compliance mechanism in the RPS program.

Figure 1. Renewable Resource Mixes in 2020 under Different Cases



Source: CPUC/E3

[18] California Public Resources Code Section 25741(a) states that facilities located in California or with their first point of interconnection in the state are automatically deemed "delivered," eligible renewable energy from out-of-state facilities must be "scheduled for consumption by California end-use retail customers" to be counted for compliance with the RPS program. The RPS statute also allows "electricity generated by an eligible renewable energy resource [to] be considered 'delivered' regardless of whether the electricity is generated at a different time from consumption by a California end-use customer. The Energy Commission's RPS Eligibility Guidebook interprets this to mean that out-of-state energy may be "firmed" and "shaped," or backed up or supplemented with delivery from another source, before it is delivered to California.

Exhibit 4

Page 26 of 96

Table 4 shows the locations of the renewable resources in the 33% RPS Reference Case. The resources fall into two categories: those that need additional transmission development, and those that do not. Resources that do not need new in-state transmission were aggregated into relatively homogenous clusters. Similar tables for the three alternative 33% RPS cases are included in Appendix C.

Table 4. Locations of Renewable Resource Zones in 33% RPS Reference Case

Resource Zones Selected in Reference Cases		
Included in 20% and 33% RPS Reference Cases		
	MW	**GWh**
Tehachapi	3,000	8,862
Distributed CPUC Database*	525	3,118
Solano	1,000	3,197
Out-of-State Early*	2,062	6,617
Imperial North	1,500	9,634
Riverside East	1,350	3,153
Included in 33% RPS Reference Case Only		
Mountain Pass	1,650	4,041
Carrizo North	1,500	3,306
Out-of-State Late*	1,934	5,295
Needles	1,200	3,078
Kramer	1,650	4,226
Distributed Biogas*	249	1,855
Distributed Geothermal*	175	1,344
Fairmont	1,650	5,003
San Bernardino - Lucerne	1,800	5,020
Palm Springs	806	2,711
Baja	97	321
Riverside East Incremental	1,650	3,869
Total	**23,798**	**74,650**

* Aggregations of renewable resources that do not need new in-state transmission development.

RPS COSTS IMPACTS AND GHG EMISSION REDUCTIONS

This section describes the cost impacts for each RPS case. Specifically, the 33% RPS cases are compared to the 20% RPS Reference Case. These costs, however, are uncertain for a number of reasons. Chief among these are: a) Use of planning-level data regarding technology cost and performance from RETI and other sources rather than contract prices associated with any particular project; b) Assumption of no changes in renewable technology costs or performance over time; c) Use of high-level estimates of transmission and renewable integration costs; d) Natural gas prices are highly volatile and may be very different from forecasted values; e) Use of a number of assumptions about GHG regulation including the cost of carbon dioxide (CO_2) allowances in 2020 and the allocation of allowance auction revenues to electric utility ratepayers. While new data that is forthcoming from RETI and the California ISO may help to refine cost estimates, uncertainty is inherent in any long-term planning exercise, which should be kept in mind when interpreting these results.

<u>All-Gas Scenario and 20% RPS Reference Case</u>

Average California electricity costs per kilowatt-hour are expected to increase substantially between now and 2020 even without new investments in renewable resources. Table 5 shows California's projected statewide electricity expenditures in 2008 and in 2020 for an all-gas scenario in which no new renewable projects are built after 2007. This all-gas scenario is designed to show the overall change in the California electricity system by 2020 if no additional renewable resources are built after 2007. Average electricity costs per kilowatt-hour are expected to increase by 16.7% from 2008 to 2020 under the all-gas scenario. This increase results from the need to maintain and replace aging transmission and distribution infrastructure, anticipated investments in advanced metering infrastructure and other smart grid capabilities, the cost of re-powering or replacing generators to comply with once-through cooling regulations, and the cost of procuring new conventional generating resources to meet load growth. Under the 20% RPS Reference Case (current law), the average electricity costs per kilowatt-hour increase would be 19.7% compared to 2008.

Table 5. Projected California Electricity Costs in 2020 (billions of 2008 dollars)

Category	2008	All-Gas Scenario in 2020	20% RPS Reference Case in 2020	33% RPS Reference Case in 2020
Existing and New Conventional Generation Fixed Costs	$8.5	$11.8	$11.1	$9.9
Existing and New Conventional Generation Variable Costs	$13.2	$16.5	$14.2	$11.6
Existing Transmission and Distribution	$15.1	$20.5	$20.5	$20.5
New Transmission for Renewables	N/A	N/A	$0.5	$1.8
New Renewable Generation and Integration	N/A	N/A	$4.3	$10.8
CO_2 Allowances[19]	N/A	$0.4	- $0.03	- $0.5
Total Statewide Electricity Expenditures	**$36.8**	**$49.2**	**$50.6**	**$54.2**
Average Statewide Electricity Cost per kWh	**$0.132/kWh**	**$0.154/kWh**	**$0.158/kWh**	**$0.169/kWh**

[19] Assumes that revenues from the auction of 108 MMT of CO_2 allowances (based on estimate 2008 electric sector emissions) are used to reduce utility rates. Does not include additional CO_2 costs that are reflected in higher market prices.

Implication: Electricity costs will increase significantly in 2020 compared to 2008, regardless of whether California mandates a 33% RPS or not.

33% RPS Cases

As shown in Table 6 and Figure 2, the cost premium from the 20% RPS Reference Case to the 33% RPS Reference Case is 7.1%, or $3.6 billion more in the year 2020. Table 6 also shows that the cost impact of meeting a 33% RPS does not vary greatly between the High Out-of-State Delivered Case and the High-Wind Case. Statewide electricity expenditures under these cases are $1.5 billion and $1.7 billion lower than the 33% RPS Reference Case, respectively, with the cost savings largely resulting from replacing large quantities of solar thermal resources with less costly wind resources (see Figure 13 in Appendix B for the levelized cost of each generation technology). The cost similarity between the High Wind Case and the High Out-of-State Delivered Case indicates that remote wind resources can be constructed and delivered to California at a similar, though slightly lower, cost compared to building local resources, which are of lower quality and also require in-state transmission upgrades. On the other hand, the out-of-state resource costs could be even lower through trading RECs with no delivery requirement since the scenarios studied here all assume California deliverability and thus transmission investment.

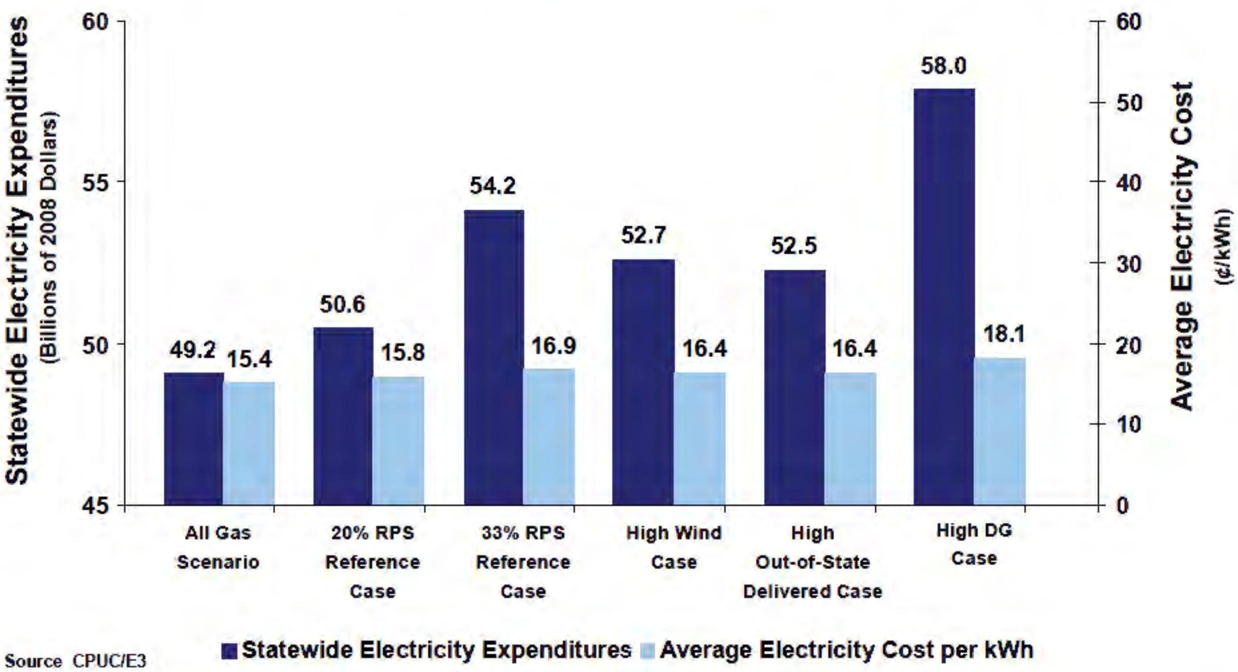
The cost impact of the High DG Case is significantly higher than the 33% RPS Reference Case, with a 14.6% cost premium compared to the 20% RPS Reference Case, and a 7% cost premium compared to the 33% RPS Reference Case. This is due to the heavy reliance on solar PV resources, which are currently much costlier than wind and central station solar.

Implication: The cost of a 33% RPS is higher than a 20% RPS under all four of the 33% RPS cases studied and the 33% RPS Reference Case is higher than all of the alternative RPS cases, except for the High DG Case.

Table 6. Costs and Cost Differences Between Alternative RPS Cases in 2020

Category	20% RPS Reference Case	33% RPS Reference Case	33% High Wind Case	33% High Out-of-State Delivered Case	33% High DG Case
Total Statewide Electricity Expenditures	$50.6	$54.2	$52.7	$52.5	$58.0
Average Statewide Electricity Cost	$0.158/kWh	$0.169/kWh	$0.164/kWh	$0.164/kWh	$0.181/kWh
Difference Relative to 20% RPS Reference Case	N/A	+$3.6	+$2.1	+$1.9	+$7.4
Percent Difference Relative to 20% RPS Reference Case	N/A	+7.1%	+4.2%	+3.8%	+14.6%
Difference Relative to 33% RPS Reference Case	N/A	N/A	-$1.5	-$1.7	+$3.8
Percent Difference Relative to 33% RPS Reference Case	N/A	N/A	-2.8%	-3.1%	+7.0%

Figure 2. Statewide Electricity Expenditures and Average Electricity Cost in 2020



Source CPUC/E3

Exhibit 4
Page 30 of 96

GHG Emission Reductions

This study only analyzed the GHG emissions associated with electricity generation and did not review the lifecycle emissions of each renewable technology, since that was beyond the scope of this analysis. The results indicate that a 33% RPS would reduce CO_2 emissions by approximately 29 million metric tons as compared to the all gas scenario, in which no new renewable projects are built after 2007. The CO_2 savings are similar for all of the 33% RPS cases, and are broadly consistent with the results of the GHG Calculator and the ARB analysis cited in the ARB Scoping Plan, which is 21.3 $MMTCO_2E$, despite differences in ARB's methodology for developing the 2020 baseline and a different set of electric sector CO_2 emission reduction measures.

SENSITIVITY OF RESULTS TO CHANGES IN INPUTS

In order to determine the sensitivity of the results to changes in key input assumptions, sensitivity analysis was conducted on the following factors: natural gas CO_2 allowance prices, higher levels of achievement of demand-side strategies such as energy efficiency and demand response, and the effect of a dramatic reduction in the installed cost of solar PV.

Natural Gas and CO_2 Price Sensitivity

The natural gas (gas) and CO_2 allowance price sensitivities are designed to test the results at the endpoints of a range of price expectations reflecting both the recent experience of price volatility and reasonable expectations.[20] Gas and CO_2 allowance prices are assumed to move together because increases in the price of either commodity will enhance the competitiveness of renewable resources by increasing the cost of fossil resources (relative to renewable generation) and reducing the overall cost impact of achieving a 33% RPS. Decreases in the cost of either commodity will have the opposite effect. The following endpoints were used to test effects of higher and lower gas and CO_2 allowance prices on the portfolios:

- **High Gas and CO_2 Allowance Prices:** 2020 gas price of \$13.50/MMBtu at Henry Hub (\$10.31/MMBtu in 2008 dollars delivered to California generators) and CO_2 allowance price of \$100/tonne (\$74.36 in 2008 dollars).
- **Low Gas and CO_2 Allowance Prices:** 2020 gas price of \$6/MMBtu at Henry Hub (\$4.74/MMBtu in 2008 dollars delivered to California generators) and CO_2 allowance price of \$15/tonne (\$11.15 in 2008 dollars).

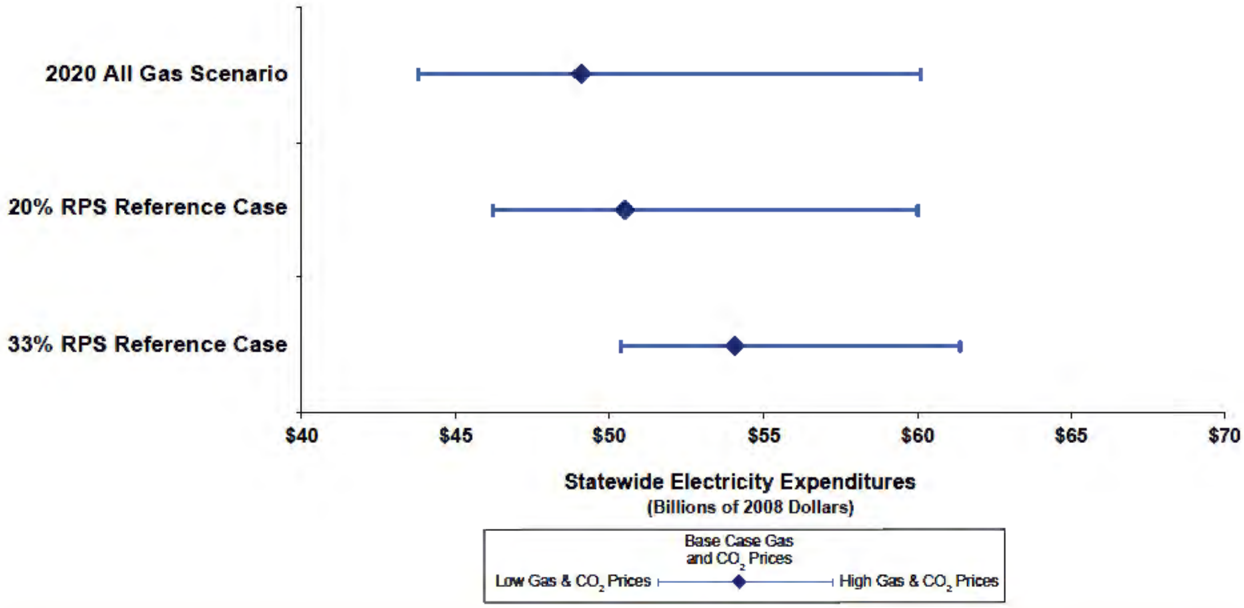
These alternative assumptions were compared to the Base Case assumptions used in the RPS Calculator: 2020 gas price of \$8.46/MMBtu at Henry Hub (\$6.57/MMBtu in 2008 dollars delivered to California generators) and CO_2 allowance price of \$42.46/tonne (\$31.58 in 2008 dollars).[21]

[20] The high and low gas numbers are based on E3's expert judgment utilizing data from the Henry Hub over the past few years.

[21] Based on the Market Price Referent (MPR) methodology, see CPUC Decision 08-10-026

Figure 3 displays the range of statewide expenditures for the low, base, and high natural gas and CO_2 allowance prices. The range for the all gas scenario is \$14.8 billion. The range of the 20% RPS Reference Case deceases to \$12.5 billion and to \$9.7 billion in the 33% RPS Reference Case. The alternative 33% RPS cases are not included in Figure 3 because their ranges are all approximately the same as the 33% RPS Reference Case.

Figure 3. Impact of Gas and CO_2 Allowance Prices on Statewide Expenditures



Implication: An increase in renewable energy penetration can decrease the range of statewide electricity expenditures by decreasing exposure to volatile fossil fuel prices. This could serve as a potential hedging strategy against volatile fossil fuel prices.

Impact of High Gas and CO_2 Allowance Prices

Figure 3 also shows that with High Gas and CO_2 allowance prices, the incremental cost of achieving the 33% RPS Reference Case is \$1.7 billion or 2.9% higher relative to the 20% RPS Reference Case. This is substantially lower than the \$3.6 billion or 7.1% cost impact under the Base Case Gas and CO_2 price assumptions.

Impact of Low Gas and CO_2 Allowance Prices

Under the Low Gas and CO_2 allowance prices, the incremental cost of achieving a 33% RPS compared to a 20% RPS is \$4.5 billion, resulting in an increase of 9.7% relative to the 20% RPS Reference Case. However, it should be noted that while lower gas and CO_2 allowance prices raise the *relative* cost of achieving RPS goals, they exert a downward effect on electricity costs overall, such that overall electric costs are still lower under the Low Gas and CO_2 allowance prices with 33% RPS than under the Base Case gas and CO_2 allowance price assumptions with a 20% RPS.

Figure 3 also shows that the statewide electricity expenditures for the all gas scenario are still not as high as the expenditures for the 33% RPS Reference Case, despite the decreased volatility. This means that gas prices would need to exceed \$13.87/MMBtu and CO_2 allowance prices would need to exceed \$100/tonne for renewable energy to be an effective hedge against fossil fuel prices at a penetration level of 33%.

Implication: While renewable energy can provide a hedge against volatile fuel prices, a 33% RPS provides an effective hedge only against a combination of very high natural gas and CO_2 allowance prices. Thus, the "hedging value" associated with resource diversity is not a very strong policy justification for establishing a 33% RPS.

Low-Load Sensitivity: Sensitivity of Results to Accelerated Demand-Side Goals

California's energy policy goals call for aggressive achievements of energy efficiency and demand response as well as high penetrations of renewable energy. Success in achieving energy savings through efficiency programs may result in lower costs of complying with a 33% RPS by reducing the amount of renewable projects required to reach the goal. A low-load scenario could also result from other factors, such as an economic slowdown.

A Low-Load sensitivity was developed to test the interactive effects between aggressive demand-side measures and a 33% RPS. The assumptions are based on the Accelerated Policy Case scenario presented in the GHG Calculator and described in the joint Energy Commission/CPUC Final Decision on Greenhouse Gas Regulatory Strategies.[22] The Accelerated Policy Case has lower electric demand and lower retail sales than the 2007 IEPR load forecast used in the 33% RPS Reference Case due to assumptions explained in Table 7.

[22] CPUC Final Decision on Greenhouse Gas Regulatory Strategies, D.08-10-037, Proceeding R.06-04-009, pp. 34 - 36.

Table 7. Assumptions in the 33% RPS Implementation Analysis Reference Cases Compared to the Low-Load Sensitivity

	20% and 33% RPS Reference Case	Low-Load Sensitivity
Energy Efficiency (EE)	Energy Commission load forecast assumes 16 TWh of embedded EE (80% of the CPUC's 2020 EE goals)[23]	'High goals' EE scenario from GHG Calculator based on CPUC Itron Goals Update Study: 37 TWh[24]
Customer-Installed Solar PV	Energy Commission load forecast, 847 MW nameplate of customer-installed PV[25]	3,000 MW nameplate of customer-installed PV
Demand Response	Energy Commission load forecast (no incremental demand response)	5% reduction in peak demand, no energy savings (capacity only)
Combined Heat and Power (CHP)	Energy Commission load forecast (no incremental CHP assumed)	1,574 MW nameplate small CHP 2,804 MW nameplate larger

The Low-Load sensitivity assumes that electricity load growth in California is reduced from 43 TWh in the 33% RPS Reference Case to 11 TWh due to aggressive demand-side policies, while peak load growth is reduced from 10,600 MW to 2,000 MW. Because of this reduction in projected 2020 retail sales, the RPS resources needed in the 33% RPS Reference Case are reduced from 75 TWh to 64 TWh in the Low-Load sensitivity. *In the absence of mitigating factors, this would be expected to result in a substantial reduction in the incremental cost of achieving a 33% RPS relative to a 20% RPS.*

However, Table 8 shows that the statewide incremental electricity expenditures of the 33% RPS Reference Case compared to the 20% RPS Reference Case is *higher* under Low-Load assumptions than under Base Case assumptions – $4 billion in incremental costs under Low-Load assumptions versus $3.6 billion under the Base Case load. This result is counterintuitive – all else being equal, one would expect the incremental costs of the Low-Load sensitivity to be lower since it requires a smaller quantity of renewable generation. Further exploration is required to determine the cause of this counterintuitive result.

[23] The Energy Commission assumed the remaining 20% of the 2020 EE goals impacts were "uncommitted," and therefore excluded from the state's official forecast. In D.07-12-052, the CPUC assumed that 100% of the 2020 EE goal impacts would be realized for procurement purposes. The Energy Commission load forecast does not take into account the Big Bold goals the CPUC established in D.07-10-032.
[24] This scenario does not take into account the Big Bold goals the CPUC established in D.07-10-032.
[25] The 2007 IEPR load forecast assumed 847 MW of customer-side PV, a fraction of the 3,000 MW California Solar Initiative goal.

Table 8. Statewide Electricity Expenditures in 2020 for the 20% and 33% RPS Reference Cases Under the Low-Load Sensitivity (billions of 2008 dollars)

Costs	Base Case Loads	Low-Load Sensitivity
Total Electricity Expenditures, 20% RPS Reference Case	$50.6	$46.4
Total Electricity Expenditures, 33% RPS Reference Case	$54.2	$50.4
Incremental cost of 33% RPS Reference Case	$3.6	$4.0
Percent Difference Relative to 20% RPS Reference Case	7.1%	8.6%

Table 9 shows the net qualifying capacity[26] of all resources added for the 20% and 33% Reference Cases under both the Base Case and Low-Load sensitivity. After considering peak demand growth, an assumed 17% planning reserve margin, and the need to replace generators using once-through cooling, the total need for new capacity is 19,022 MW. Demand-side achievements reduce the needed capacity to 9,053 MW under the Low-Load Sensitivity.

Exactly 19,022 MW of capacity is added under the 20% Reference Case. However, 21,002 MW of capacity is added under the 33% RPS Reference Case, resulting in a capacity surplus of 1,980 MW. *This occurs because of the timing challenges of adding new renewables.* The model adds conventional resources to meet demand growth in the early years, before most of the renewable resources are online. The addition of large quantities of new renewables in the later years results in a temporary capacity surplus. The 2020 surplus is relatively small – 1,980 MW – under Base Case load growth assumptions. However, the surplus amounts to ***5,313 MW*** under the Low-Load sensitivity.[27] *Under the Low-Load sensitivity, the pace of required renewable resource development is so rapid compared to load growth that a substantial surplus of capacity is all but unavoidable.*

Under the 20% RPS Reference Case, demand-side programs result in substantial avoided capacity investments, or capacity savings. However, avoided capacity investments from demand-side programs are reduced under the 33% RPS Reference Case and dramatically reduced under the Low-Load sensitivity. This reduced savings from avoided capacity investments outweigh cost savings resulting from decreased renewable energy procurement. This causes the incremental cost of the 33% RPS Reference Case to be higher under the Low-Load sensitivity than under the Base Case load growth assumptions.

Note that this effect is due strictly to the need to procure *capacity* to meet peak demand requirements, and it occurs irrespective of the *energy* benefits of new renewables. It is possible that this peak capacity surplus could allow earlier retirement of fossil peaking generators. However, further study would be required to identify candidate generators and ensure that they

[26] Net qualifying capacity is the capacity value of the resource that can be counted toward resource adequacy requirements. This value is equal to the nameplate capacity for thermal generators, but is based on expected output during peak periods for intermittent renewable resources.

[27] Note that this analysis likely understates this effect, because renewable resource integration costs were treated as a simple, $/MWh adder. If new conventional resources are required to integrate wind and solar generation, the resulting capacity surplus would be larger under the 33% RPS cases.

are not needed to meet local reliability requirements or to ensure reliable system operations while integrating thousands of megawatts of new intermittent renewables.

Table 9. 2020 Capacity Balance Under the 20% and 33% RPS Reference Cases for the Base Case and Low-Load Sensitivity Load Growth (MW)

2020 Capacity Need, Additions, and Surplus	Base Case Loads		Low-Load Sensitivity	
	20% RPS Reference Case	33% RPS Reference Case	20% RPS Reference Case	33% RPS Reference Case
Growth in Peak Demand, 2008-2020	10,602	10,602	2,082	2,082
Additional Capacity Needed to Meet 17% Planning Reserve Margin[28]	1,802	1,802	354	354
Cumulative Retirements of Once-Through Cooling Generators[29]	6,617	6,617	6,617	6,617
Required Additions in Dependable Capacity	***19,022***	***19,022***	***9,053***	***9,053***
Dependable Capacity From New Renewables[30]	4,604	13,024	3,243	11,352
Capacity Added From Once-Through Cooling Repowering[31]	2,883	2,883	2,883	2,883
Cumulative Combustion Turbines and CCGTs Added for Resource Adequacy[32]	11,535	5,095	2,927	131
Total Capacity Additions	***19,022***	***21,002***	***9,053***	***14,366***
Capacity Surplus[33]	**0**	**1,980**	**0**	**5,313**

Implication: If the state does not plan for interactions between energy efficiency, fossil retirements, and a 33% RPS, then a 33% RPS by 2020 could result in a surplus of energy or capacity and excess consumer costs. This interplay highlights the need to analyze and plan for interactions among the state's various policy goals. An integrated approach is needed to ensure that policy goals result in a resource plan that effectively furthers the important, underlying policy objectives and produces an efficiently integrated electricity system at an acceptable cost.

---

28 Calculated as 17% of peak demand growth

29 Based on a high-level analysis of once through cooling generators that are candidates for retirement

30 Based on summer, peak period net qualifying capacity values, available at http://www.caiso.com/202f/202f9a882ec90.xls

31 These generators are assumed to be needed to meet local reliability requirements, and are therefore the same in all cases.

32 Remaining resources needed to meet resource adequacy requirements

33 There is a capacity surplus in 2020 in the 33% RPS Reference Case because conventional resources are required to meet load growth in the early years, before the renewables can come online.

This result highlights the need for coordination among demand-side and supply-side programs to ensure compatibility and efficiency. For example, if the RPS portfolio is likely to result in substantial penetration of new solar thermal resources with storage, the resulting capacity surplus would reduce the need for demand response. Alternatively, if the RPS portfolio is heavy in wind resources that produce mostly at night, efficiency programs that target night time energy use such as outdoor lighting programs would be substantially less valuable. These interactions also depend strongly on the timing of new resource development; implementing California's aggressive energy policy goals over a longer period of time would reduce the likelihood of negative interactions among the various programs because programs could be adjusted along the way more easily.

Solar PV Cost Reduction Sensitivity

The Solar PV Cost Reduction sensitivity explores the impact of lower solar PV costs on the cost of meeting a 33% RPS. The solar energy industry is currently small relative to other renewable technologies, and technological innovations continue to improve solar PV's performance and reduce the cost of manufacturing. The solar PV industry expects that continued technological improvements and economies of scale will substantially reduce the cost of solar technology by 2020. The pace of such innovation is highly uncertain, however, and the delivered cost of energy depends on a number of other factors besides the manufactured component cost, not least of which is the continued willingness of the federal government to grant generous tax incentives, such as the investment tax credit. Despite this uncertainty, it is helpful to consider how solar PV innovation might change the cost impacts of a resource mix with high solar PV penetration.

The Solar PV Cost Reduction sensitivity is based on the thin-film cost sensitivity included in the RETI Phase 1B report,[34] and assumes that market transformation reduces the installed cost from approximately \$7/Watt-equivalent (W-e)[35] today for crystalline solar PV to \$3.70/W-e for thin-film solar PV by 2020. RETI derived this number from goals and cost targets that solar PV manufacturers and developers provided. This assumption lowers the delivered energy cost of a typical solar PV facility from \$306/MWh to approximately \$168/MWh. These cost reductions were modeled as a *sensitivity*, meaning that the impact of the cost reductions were simply calculated on the High DG and 20% RPS and 33% RPS Reference Cases.

The impact of this sensitivity is presented in Figure 4. As a result of the assumed cost reductions, statewide electricity expenditures decrease by \$4.6 billion under the High DG Case and by \$1.9 billion under the 33% RPS Reference Case. Statewide electricity expenditures are \$53.4 billion under the High DG Case and \$52.3 billion under the 33% RPS Reference Case. Thus, the Solar PV Cost Reduction sensitivity results in the High DG Case having similar overall costs to the 33% RPS Reference Case and other renewable resource mixes that depend on central station renewable generation.

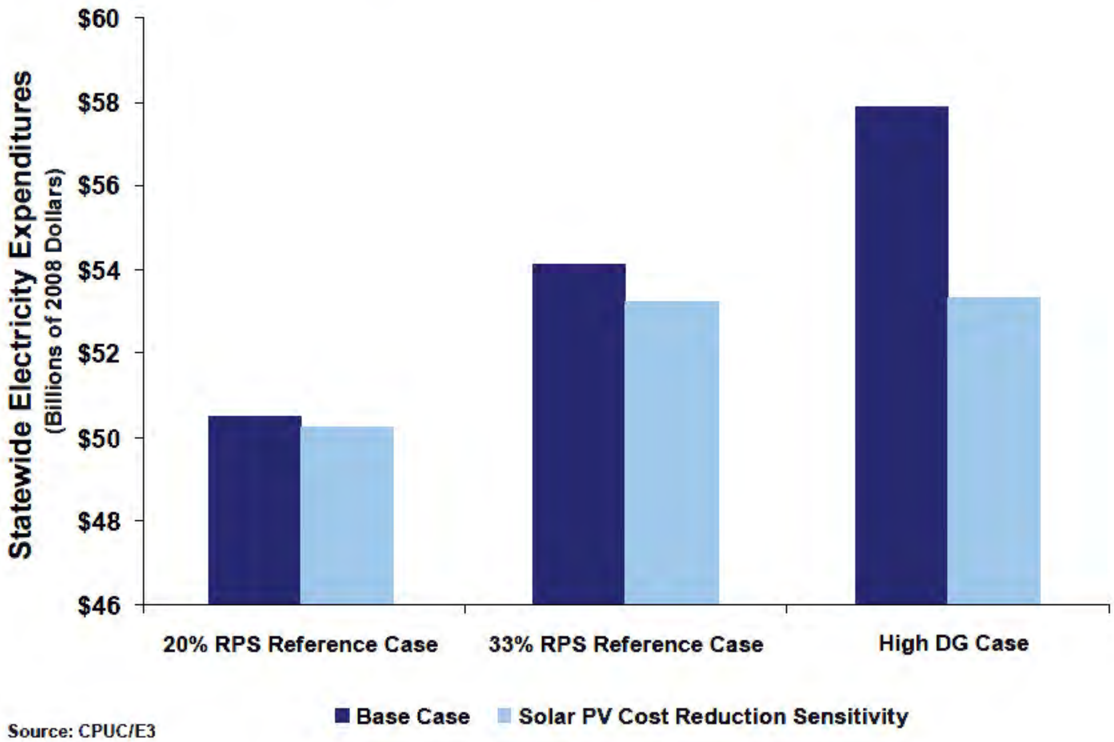
[34] The RETI Phase 1B report is available at:
http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF

[35] Watt-equivalent is a term used for solar PV that refers to grid-equivalent Watts after considering DC-AC conversion losses. \$7/Watt-equivalent corresponds to approximately \$5.83/nameplate Watt, and \$3.70/W-e corresponds to \$3.08/nameplate Watt.

These study results, however, are uncertain and come with a number of caveats. First, and most importantly, the thin-film sensitivity number used is very aggressive and the distributed solar PV technical potential estimates are not based on an engineering analysis. Second, there was no detailed analysis conducted of the cost difference of developing solar PV at various sizes and locations. Instead, rooftop solar PV was assigned an 8% cost premium and a 21% capacity factor penalty relative to ground-mounted solar PV. Third, simple, high-level assumptions were made about the distribution and transmission costs – or savings, depending on location – associated with interconnecting solar PV. Fourth, an implementation analysis of integrating such high levels of solar PV on the distribution system was not included in the analysis. Finally, the solar PV industry is still relatively small (though growing rapidly), and there is some question whether the solar PV industry can manufacture and supply the equipment at this level without leading to supply-chain constraints. A next step could be to conduct an implementation analysis on the market and regulatory barriers associated with the levels of solar PV in the High DG Case.

Implication: If solar PV experiences significant cost reductions, then a renewable portfolio with substantial quantities of solar PV could be much more cost-effective compared to today's solar PV market prices. The cost-effectiveness of the overall portfolio will depend on the program delivery costs; the High DG Case only uses the technology cost of solar PV, and not the deployment or program implementation costs, which would be higher due to siguificantly higher transaction costs to deploy thousands of solar PV projects.

Figure 4. Cost Savings Due to Solar PV Cost Reduction Sensitivity



Source: CPUC/E3

Exhibit 4
Page 38 of 96

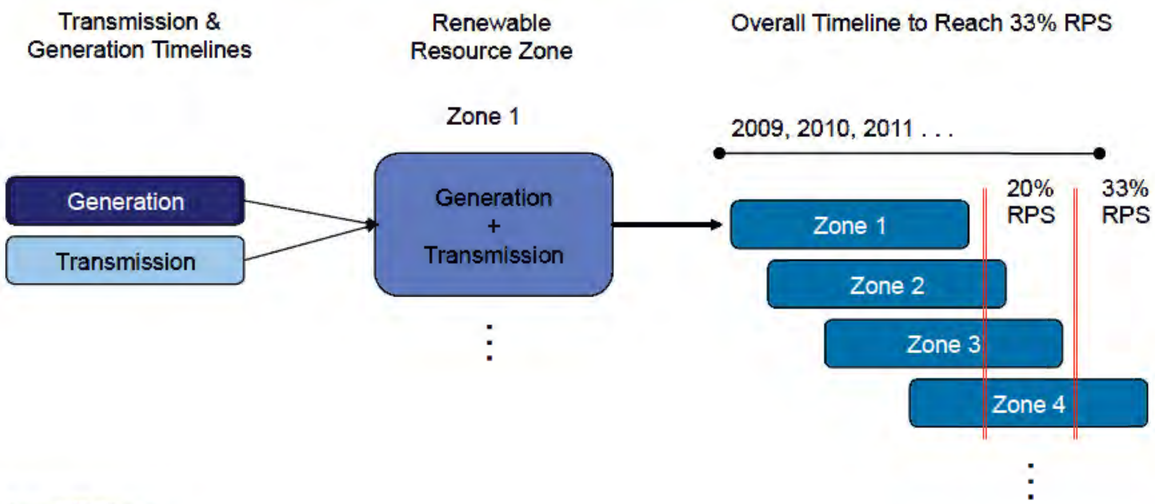
4 33% RPS Reference Case Illustrative Timelines

This section addresses the question of timing: whether the renewable generation and transmission needed for a 33% RPS can be built by 2020. Through the analysis described in this section, CPUC staff sought to understand the nature of the generation and transmission resources needed over time and the impact of ongoing reforms on the development of those resources, to identify areas where further reform is needed, and to understand the potential impacts of various risks on progress towards the 33% RPS goal.

To simplify this timeline analysis and to evaluate California's current resource contracting path, only the time and implementation challenges associated with the development of the 33% RPS Reference Case were evaluated. This section identifies some of the factors that could affect the timing of the generation and transmission development in the 33% RPS Reference Case, and thus the date by which the state could reasonably expect to reach a 33% RPS.

In order to construct illustrative timelines for the 33% RPS Reference Case, the project team first created generic timelines that estimate the permitting and construction times for generation projects – by technology, size, and permitting jurisdiction – and for transmission projects. These generic generation and transmission timelines were then used to create timelines for each resource zone selected in the 33% RPS Reference Case. Finally, the resource zone timelines were combined to create an overall timeline for the 33% RPS Reference Case. Those generation projects in the Reference Case that are *not* dependent on new in-state transmission were assumed to be developed in parallel with the "zone" resources, so that the 33% RPS is achieved with the full development of the last zone. Figure 5 illustrates this process.

Figure 5. Process for Developing 33% RPS Reference Case Timelines



Source: CPUC/Aspen

Exhibit 4
Page 39 of 96

INDIVIDUAL RESOURCE ZONE TIMELINES

In order to quantify the time needed to develop all the transmission and generation required in the 33% RPS Reference Case, individual timelines were developed for each of the resource zones included in the 33% RPS Reference Case, using the methodology and generation and transmission timelines described in Appendix B. The resource zones that need new transmission are listed in Table 10. In some cases, two resource zones can share one major transmission project.

Table 10. Renewable Resource Zones that Need New Transmission for 20% and 33% RPS Reference Cases

Resource Zone	MW	GWh
Included in 20% and 33% RPS Reference Cases		
Tehachapi	3,000	8,862
Solano	1,000	3,197
Imperial North	1,500	9,634
Riverside East	1,350	3,153
Included in 33% RPS Reference Case Only		
Riverside East (incremental)	1,650	3,869
Mountain Pass	1,650	4,041
Carrizo North	1,500	3,306
Needles	1,200	3,078
Kramer	1,650	4,226
Fairmont	1,650	5,003
San Bernardino - Lucerne	1,800	5,020
Palm Springs	806	2,711
Baja	97	321

Transmission and Generation Development in a Resource Zone

Because of its longer development horizon, transmission is nearly always the critical path item in the development of a zone. Speeding the approval and development of transmission projects would thus facilitate earlier development of resource zones. This result is already well understood in California, and significant efforts are underway at both the state and federal level to expedite the review, planning, and permitting of appropriate transmission lines to support delivery of renewable resources.

Generation projects in California are subject to environmental review and permitting by county, state, or federal agencies, depending on the project's technology type, size, and location (see Figure 15 in Appendix B for a description of these categories and permitting jurisdictions). Table 11 shows how the generation projects in the 33% RPS Reference Case are distributed among permitting jurisdictions. Although this distribution is particular to the set of resources chosen for the 33% RPS Reference Case, the table gives a sense of the order of magnitude of the permitting required under any 33% RPS portfolio.

Table 11. Permitting Jurisdiction for Generation Projects in the 33% RPS Reference Case

Jurisdiction	Number of Generation Projects
Solano County	9 projects
Kern County	10 projects
Imperial County	7 projects
Riverside County	11 projects
Los Angeles County	13 projects
San Bernardino County	16 projects
San Luis Obispo County	6 projects
Energy Commission (sole or joint)	30 projects
Bureau of Land Management or Other Federal Agency (sole or joint)	46 projects in California (mainly Southern CA) 2 projects in Baja (Presidential Permit) 21 projects other Out-of-State or International Imported

Implication: The number of projects that may require review and approval by these jurisdictions now and in the coming years highlights the need for a major increase in trained specialists and staffing and consulting resources to process these permit applications within the timeframe of a 33% RPS by 2020.

Transmission and Generation Timing Considerations

Some delay is generally expected between completion of a transmission line and full use of that line. This delay results from the generation developer's need for certainty about transmission availability before investing capital into project development activities. Assuming that renewable generation developers will not begin construction until a final permit for the required transmission line is issued,[36] all generation projects in a renewable zone would have to complete construction in parallel with the construction of the transmission line in order to avoid the generation-transmission time lag. Such rapid and simultaneous generation development seems unlikely, particularly in the case of capital-intensive technologies like solar thermal and geothermal.

This situation may be exacerbated in California in the next few years because of the amount of generation that is dependent on new transmission and that must come online quickly. For example, if multiple generators in a renewable resource zone are dependent on one major transmission project, and they all plan their project development schedules around estimates of that transmission's availability, they may all enter the permitting phase at the same time, potentially overloading the relevant permitting authority and leading to delays in the issuance of

[36] Generators are often not able to secure full financing until transmission assurance is received. Without financing, many generators will not be able to move far into the permitting process, leaving even more work to be done after the transmission permit is issued.

Exhibit 4
Page 41 of 96

site permits. For instance, the illustrative San Bernardino-Lucerne resource zone in Figure 6 includes many projects requiring Bureau of Land Management (BLM) and Energy Commission approval, and concurrent permitting of all projects could prove to be a challenge.

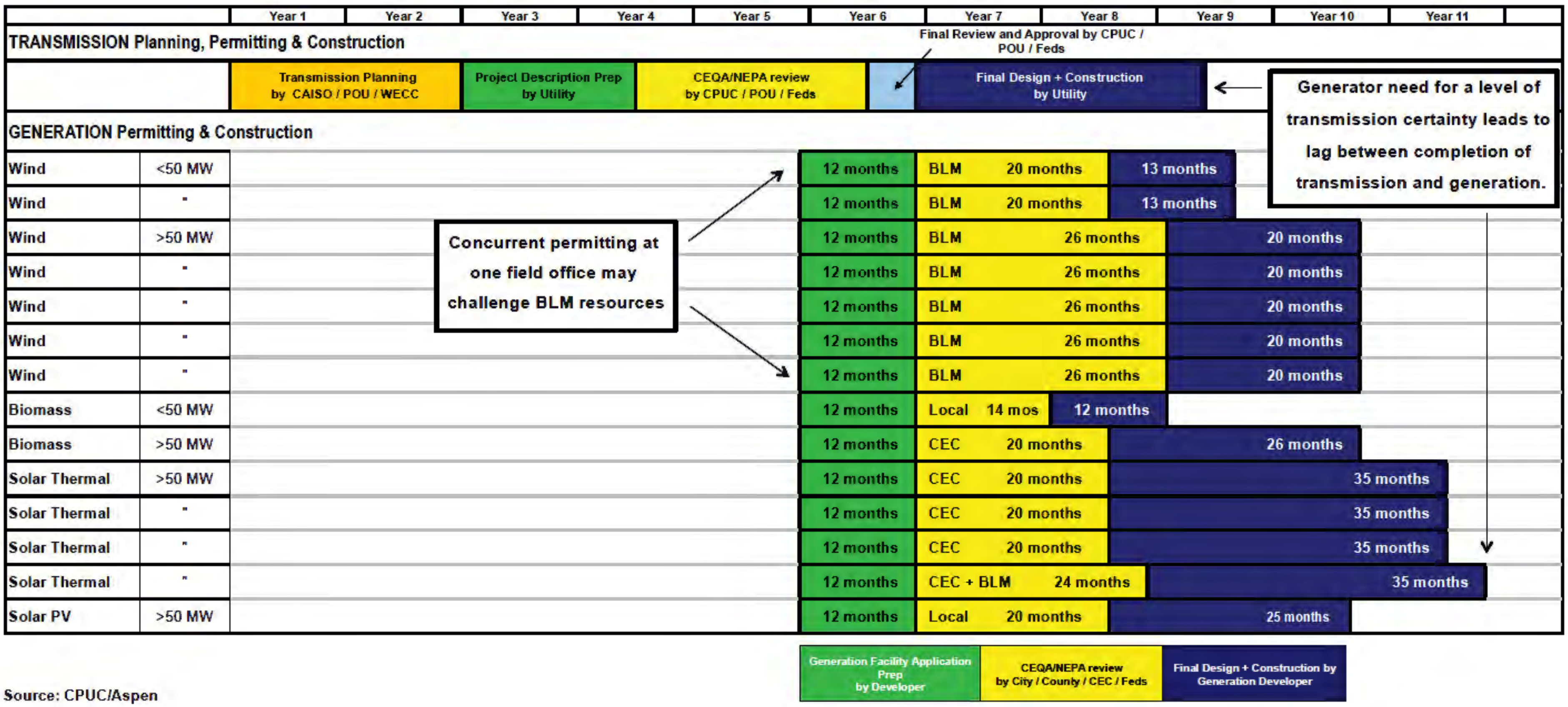
Implication: The interaction between transmission and generation time lag can be a significant source of time delay. State and federal agencies should focus on ensuring that permitting agencies are prepared to process large numbers of generation applications in a timely manner, particularly in areas where new transmission is expected or already permitted.

Figure 6 presents an illustrative timeline for the San Bernardino-Lucerne resource zone and demonstrates how the timelines for a mix of renewable generation projects and one major new transmission line are combined to provide an overall timeline for the development of that resource zone. This zone timeline also highlights the interaction between the timing of transmission and generation development that can result in a lag between transmission completion and full utilization of that line.

Figure 6 Timeline Assumptions:

- Individual generation projects in this zone are those included in the 33% RPS Reference Case; one major new transmission line and perhaps some smaller lines would be needed to access and deliver the required amount of generation.
- Generation and transmission timelines are based on the generic timelines described in the Methodology (Appendix B). They reflect recent experience with actual projects.
- Development of generation begins one year before final approval of the required transmission line because of the need for a degree of certainty regarding transmission availability to facilitate generation project financing.

Figure 6. Example of Generation and Transmission Timelines Combined to Create a Resource Zone Timeline (San Bernardino – Lucerne Resource Zone)



Source: CPUC/Aspen

__Result__: The transmission in this zone takes longer to develop than the generation. However, the generation developers' need for a degree of certainty regarding transmission availability in order to obtain financing and invest in project development causes them to delay project development until several years into the transmission development process. This results in a 29-month period between completion of the transmission and full development of the zone.

Exhibit 4
Page 43 of 96

ILLUSTRATIVE TIMELINES FOR THE 33% RPS REFERENCE CASE

Following the completion of timelines for each of the zones in the 33% RPS Reference Case, the resource zone timelines were combined to create an overall timeline for the 33% RPS Reference Case. CPUC staff adapted this overall 33% RPS timeline to depict three scenarios using the distinct sets of assumptions presented in Table 12. Timeline 1 depicts the state's relatively recent historical experience in transmission and renewable development, but does not include process reforms or external risks. Timeline 2A and 2B reflect the possible effects of the state's current and ongoing reforms to expedite and streamline the permitting and review processes. Unlike Timeline 2A, Timeline 2B considers the possible effects of external risks that could undermine the efforts at reform. Timeline 2A is not realistic or plausible since it does not include external risks, but rather provides a reference point upon which Timeline 2B is built.

Table 12. Description of Illustrative Timelines for the 33% RPS Reference Case

Timeline	Description
Illustrative Timeline 1: Historical experience without process reform	This scenario is based on the state's experience with generation and transmission development over the last 10-15 years. Timeline assumes transmission planning, permitting, and construction processes that are almost entirely sequential.
Illustrative Timeline 2A: Current practice with process reform and no external risks	Development trajectory if California successfully implements transmission and generation reforms that are already underway. Timelines are unrealistic because they assume no delays from external factors that are not addressed by current reforms.
Illustrative Timeline 2B: Current practice with process reform and external risks	Development trajectory if state successfully implements reforms, but factors outside the direct control of state agencies, such as technology failure, financing difficulties, and legal challenges, cause delay or failure of some projects necessary to achieve the 33% RPS Reference Case.

Several assumptions are common to all of the timelines:

- For purposes of this timeline analysis, "achievement of the 33% RPS target" implies achievement of the full 33% RPS Reference Case buildout, which was developed to serve 33% of 2020 retail sales. The 33% RPS Reference Case is not updated to account for expected load growth after 2020 that would cause the 33% RPS target, an energy and not a capacity goal, to increase slightly every year, even though, in all of the timelines, the 33% RPS goal is not achieved until after 2020.
- A delay of 30 months – an approximation of the delay depicted in Figure 6 – is assumed to occur between transmission completion and full generation buildout in all scenarios, since California has not yet implemented processes that would address this delay.
- The resource zones in the 20% RPS Reference Case (the zones at the top of each timeline) are assumed to be accessed by actual transmission projects that are already in some late stage of development or are otherwise expected to have shorter development timelines due to jurisdiction and location.

- Development horizon for the Baja zone (Zone 6) is constant in all three scenarios, as it would be only minimally affected by the California process reforms assumed in Timelines 2A and 2B.
- No specific generation is associated with the Path 15 upgrade, but this upgrade was identified as likely needed to maintain reliability under the 33% RPS Reference Case, given the large amount of generation added in Southern California, relative to Northern California. The assumed short time horizon reflects transmission planning efforts now underway. Other upgrades will no doubt be needed to maintain system reliability; this analysis did not attempt to identify all of those upgrades.

ILLUSTRATIVE TIMELINE 1: HISTORICAL EXPERIENCE WITHOUT PROCESS REFORM

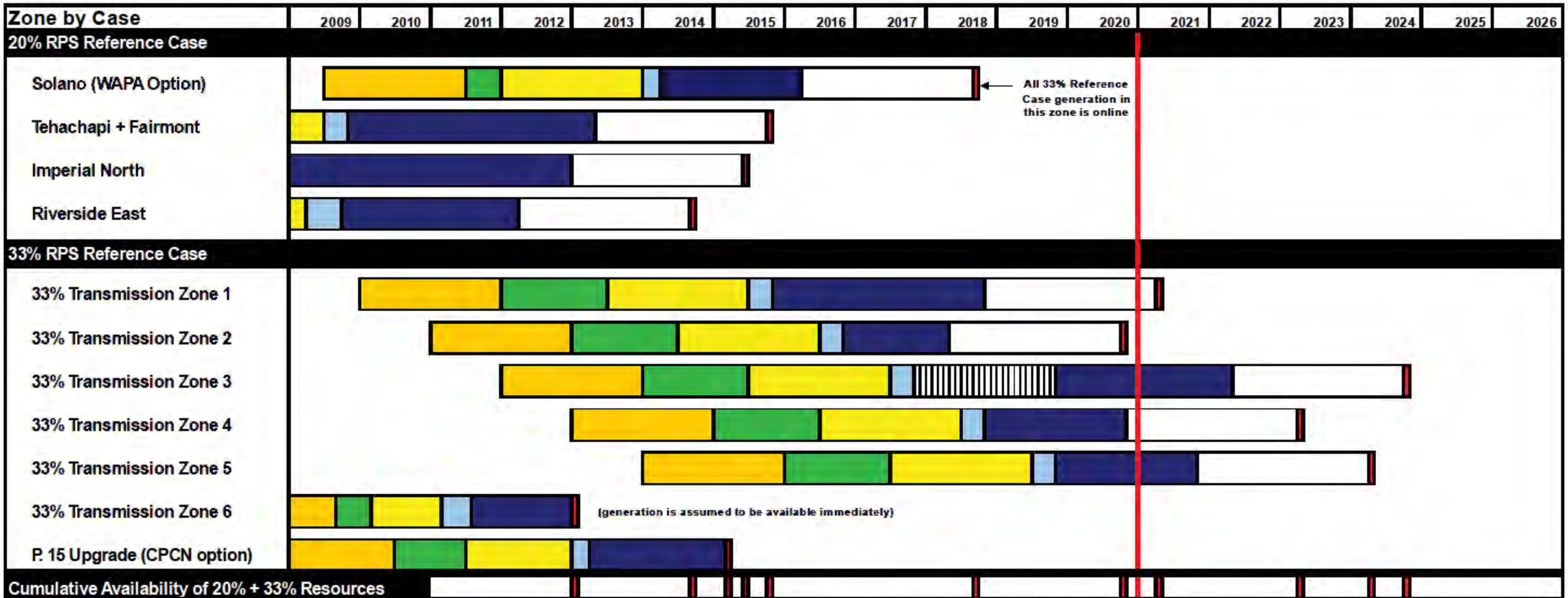
Timeline 1 (Figure 7) reflects the timeline for achieving the 33% RPS Reference Case under the "historical experience without process reform" scenario. The purpose of this timeline is to demonstrate the time savings achieved if current and ongoing process reforms are successful. Under this scenario, the 33% RPS Reference Case is achieved in 2024. Because the 33% RPS Reference Case closely mirrors California's recent renewable resource development path (as represented through IOU contracts), this timeline indicates that the state would be unlikely to meet a 33% RPS by 2020, if past transmission planning and permitting processes and the associated transmission-generation time interactions were to continue. This timeline does not assume any external risks, such as those associated with Timeline 2B (Figure 9), so this timeline is not realistic.

Timeline Assumptions:

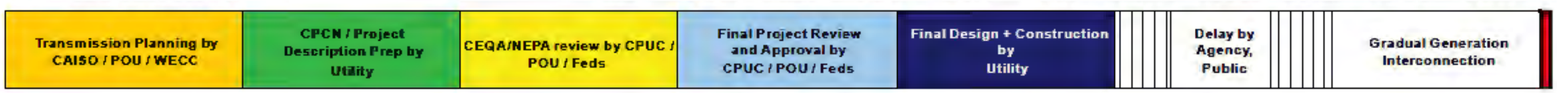
- Timelines for each phase of the generation and transmission development processes are based on California experience over the last 10-15 years.
- Transmission planning, permit preparation, environmental review, and final project design/construction happen in sequence, with very little overlap.
- One new transmission project enters the development process each year, starting in 2009. Timelines are shortened in cases where real transmission projects already in some stage of development would access a zone identified in the 20% or 33% RPS Reference Cases.
- One significant, two-year delay is assumed for the transmission project needed to access Zone 3. Based on recent experience, such a delay could result from permitting delays at a federal agency, or other factors. This delay is assigned randomly for illustrative purposes only, and does not relate to any specific concerns anticipated with Zone 3. The purpose of the delay is to illustrate that the delay of any transmission project, regardless of which one, significantly impacts the 33% RPS schedule.
- Beyond one 2-year delay to a transmission project's construction, *Timeline 1 assumes none of the other external delays that are considered in Timeline 2B.*

Implication: California must implement changes to its transmission and generation planning and permitting processes now to achieve a 33% RPS by 2020. Several critical reforms have already been implemented, and several more are in the early stages of development and implementation. Timeline 1 reflects empirical experience in California to date, and highlights how crucial it is that the process reforms now underway in California be implemented successfully.

Figure 7. Illustrative Timeline 1 for the 33% RPS Reference Case: Historical Experience Without Process Reform



MW available per year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Biomass							74	74	74	74	74	74	165	165	165	165	165	165
Geothermal							1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,144	1,144	1,144	1,144
Solar thermal + PV						1,349	2,008	2,008	2,008	2,008	2,008	3,508	6,056	6,056	7,479	9,875	9,875	9,875
Wind					100	100	4,397	4,397	4,397	5,397	5,397	5,397	6,208	6,208	6,411	7,672	7,672	7,672
Total Zone Resources					100	1,449	7,599	7,599	7,599	8,599	8,599	10,099	13,549	13,549	15,199	18,856	18,856	18,856



Source: CPUC/Aspen

Result: The 33% RPS Reference Case is achieved in 2024, assuming no external risks.

Note: While the CPUC averages approximately 18 months for California Environmental Quality Act review and Certificate of Public Convenience and Necessity approval for transmission siting cases in general, more conservative assumptions were used here to account for the likely larger and more controversial nature of these new required projects.

Exhibit 4
Page 47 of 96

ILLUSTRATIVE TIMELINE 2A: CURRENT PRACTICE WITH PROCESS REFORM AND NO EXTERNAL RISKS

Timeline 2A (Figure 8) reflects the timeline for achieving the 33% RPS Reference Case under "current practice with process reform and no external risks." The purpose of this timeline is to provide a reference point to show the effects of process reforms without the potential undermining effects of any external risks not within the state's control. This timeline assumes the full implementation of several process reforms instituted at California agencies and other entities within the last three years, as well as successful implementation of other reforms that are now only in the early stages of development and implementation.

Timeline Assumptions:

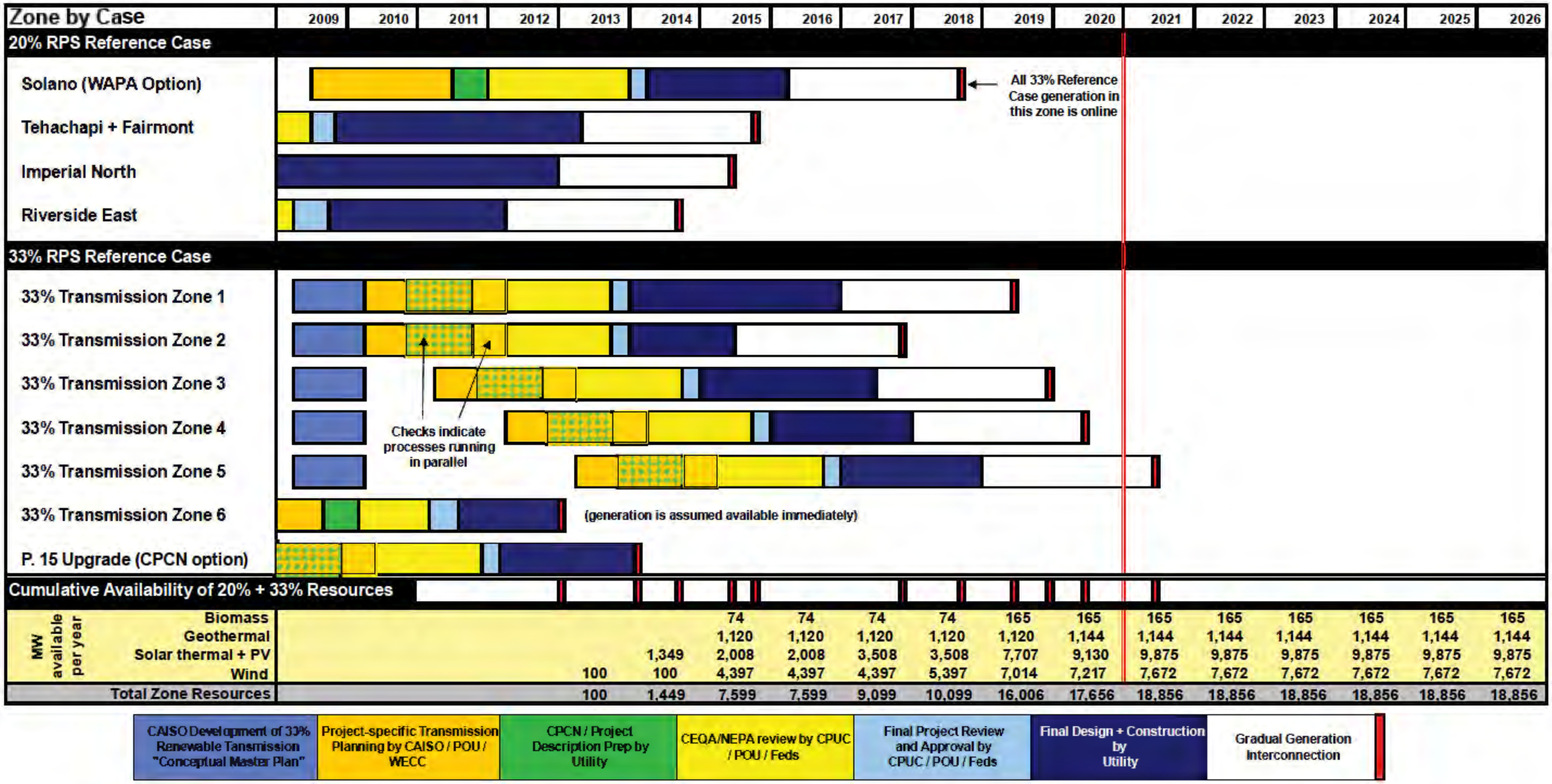
- Reflects successful implementation of the significant process reforms currently underway at the California ISO and the CPUC. These reforms, which are described in this section, are administrative in nature and do not require any changes to existing law.
- Two new transmission projects enter the development process in 2010 as a result of RETI, the California ISO's Generation Interconnection Process Reform, and other processes, with one major renewable transmission project beginning development each year between 2011 and 2013.
- The two-year delay assumed in Timeline 1 for the transmission project needed to access Zone 3 is removed since this timeline is meant to show only the effects of process reform. Assumes no resource constraints in processing transmission and generation permitting applications.
- All of the transmission lines needed for the 33% RPS are assumed to involve the California ISO planning process, rather than a planning process at a publicly-owned utility (POU). This assumption is applied to simplify the presentation of the timing of transmission planning. Although a mix of POU-and California ISO-controlled lines will likely be developed, this assumption is not unreasonable, given the California ISO's responsibility for planning and operating most of the state's grid.
- *Timeline 2A assumes none of the other external delays that are beyond the state's control. These risks are factored into Timeline 2B.*

Timeline 2A indicates that the generation and transmission infrastructure required for a 33% RPS could be developed by 2021 with the successful implementation of these reforms, assuming no external delays (those outside the direct control of the state). The 33% RPS is achieved three years earlier in Timeline 2A than in Timeline 1. While Timeline 2A is likely unrealistic since it assumes no risks beyond those addressed by these reforms, it highlights the importance of current efforts underway to reform planning and permitting processes. Timeline 2B will show the potential impact of external risks, those outside of the state's control, on the gains realized through the reforms highlighted in Timeline 2A.

.

Implication: Efforts underway to reform generation and transmission planning and permitting processes could significantly speed the rate at which California is able to achieve a 33% RPS.

Figure 8. Illustrative Timeline 2A for the 33% RPS Reference Case: Current Practice With Process Reform and No External Risks



MW available per year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Biomass							74	74	74	74	165	165	165	165	165	165	165	165
Geothermal							1,120	1,120	1,120	1,120	1,120	1,144	1,144	1,144	1,144	1,144	1,144	1,144
Solar thermal + PV						1,349	2,008	2,008	3,508	3,508	7,707	9,130	9,875	9,875	9,875	9,875	9,875	9,875
Wind					100	100	4,397	4,397	4,397	5,397	7,014	7,217	7,672	7,672	7,672	7,672	7,672	7,672
Total Zone Resources					100	1,449	7,599	7,599	9,099	10,099	16,006	17,656	18,856	18,856	18,856	18,856	18,856	18,856

Source: CPUC/Aspen

__Result__: The 33% RPS Reference Case is achieved in 2021, assuming no external risks that could result in delay.

Exhibit 4
Page 49 of 96

DESCRIPTION OF REFORMS EMBEDDED IN TIMELINES 2A AND 2B

Development of the generation and transmission infrastructure required for a 33% RPS could be achieved by 2021 with the successful implementation of the significant process reforms discussed here, assuming there are no external delays – those outside the direct control of the state. California planning and permitting entities must give high priority to process improvements today. Given the long lead times needed to develop transmission and generation projects, a delay of even a year or two may hinder the state's ability to reach its renewable goals in time.

Reform 1: Improvements to California ISO Procedures for Interconnecting Generation Facilities

The California ISO has recently implemented two very important reforms that will help expedite generator interconnection to the transmission grid. The Generation Interconnection Process Reform (GIPR) has increased the speed and efficiency of studying interconnection requests by planning common transmission solutions for groups of generation projects and integrating such planning into the California ISO annual transmission planning process. In addition to projects in the "serial" study group[37] that are nearing study completion, GIPR intends to complete its first set of interconnection cluster studies by the second quarter of 2010, which will help clear much of the existing transmission interconnection request backlog. The California ISO's new Location-Constrained Resource Interconnection process is the second reform that is expected to help renewable generators. This process provides a framework for planning and sharing the costs of large transmission facilities that interconnect location-constrained renewable resource areas. In May 2009, the California ISO applied this cost-sharing mechanism for the first time to an interconnection that will access renewable generation in the Tehachapi wind resource area.

- The GIPR and Location-Constrained Resource Interconnection reforms contribute to the 2-year planning process assumed in Timelines 1, 2A, and 2B.

Reform 2: Streamlining Transmission Permitting

The siting of a transmission line includes the review required under the California Environmental Quality Act (CEQA) – at least one full year of environmental studies – as well as a determination that the line is needed, through the issuance of a Certificate of Public Convenience and Necessity (CPCN). The CPUC is working to streamline all aspects of this process, while considering fully the environmental and economic impacts of any proposed project.

CEQA Review

In 2006, the CPUC issued directives[38] that streamline the pre-filing, post-filing, and proceeding phases of the transmission permitting process. CPUC staff makes use of streamlining tools such as project-specific memoranda of understanding with federal agencies and mitigated negative declarations whenever possible. In 2008, CPUC staff prepared streamlining recommendations to address and clarify the complex mitigation issues associated with permitting and constructing new transmission. In 2009, the CPUC initiated a series of workshops to be held every 6-9

---

[37] The "serial group" consists of generation projects that, for a number of reasons, continued in the serial study process that characterized the interconnection process prior to the adoption of the Generation Interconnection Process Reform's cluster study approach.

[38] ftp://ftp.cpuc.ca.gov/puc/energy/environment/060713_transmissionprojectreviewstreamliningdirective.pdf

months with state and federal resource agencies to facilitate better coordination on permitting, considering staffing shortages and increasing workloads. Further, through close coordination during the pre-filing phase, CPUC staff aims to streamline the CPUC's environmental review by ensuring that all the requisite information, and no duplicative work, is provided with the CPCN application. Utility responsiveness and cooperation is critical to the success of these staff efforts. Finally, the CPUC is investigating new technologies that might reduce the environmental impact of necessary transmission infrastructure, thereby reducing public opposition and the risk of delay.

- Successful application of these reforms is illustrated in the reduction in the time assumed for CEQA/ National Environmental Policy Act (NEPA) review from 24 months in Timeline 1 to 18 months in Timelines 2A and 2B.

Need Determination

In addition to CEQA review, the CPUC has a statutory obligation to examine the "need" for any proposed transmission line, and during the CPCN application process the CPUC has carried out this "need determination" in parallel with its CEQA review. Typically, the California ISO has made a finding of need before a project reaches the CPUC under its Federal Energy Regulatory Commission-approved tariff and North American Electric Reliability Council/WECC reliability standards. This evaluation considers reliability, economic, and operational benefits of proposed transmission upgrades to California ISO ratepayers. This analysis is conducted in the California ISO's Transmission Planning Process.

In a 2006 decision, the CPUC adopted a procedure by which the CPCN process could be streamlined by granting, under certain circumstances, a presumption of reasonableness to the California ISO's need determination. The CPUC and California ISO are currently working together to refine and streamline this procedure and the overall permitting process by improving the coordination of their respective transmission review and approval processes in a number of ways, including alignment of the alternatives that are considered in the California ISO's economic and the CPUC's environmental analyses. The improvements under consideration will expedite the "need determination" required for transmission applications by coordinating the processes of the CPUC and the California ISO to reduce gaps and redundancies in the current process. Such coordination aims to reduce the amount of time involved in determining the need for a transmission line, reduce the risk of legal challenges of that determination, and reduce the amount of time involved in planning the lines and preparing CPCN applications.

- Successful coordination on "need determination" is reflected in Timelines 2A and 2B by the overlap between application development, environmental review, and transmission planning – resulting in savings of 12-18 months – and by the reduction of "final approval" from 4-5 months to 3 months. This coordination could also prevent additional delays due to legal challenges of need determinations.

Reform 3: Streamlining Generation Permitting

The Energy Commission and other state and federal agencies involved in permitting and siting renewable generation projects have taken several steps that may help to streamline their review of renewable generation facilities. In August 2007, the Energy Commission and the BLM signed a memorandum of understanding in order to conduct a joint environmental review of renewable projects that fall under both of their jurisdictions. The BLM is also developing a programmatic environmental impact statement for solar facilities, and the Governor's Executive Order S-14-08 directs the Energy Commission and the Department of Fish and Game to conduct programmatic environmental review of renewable generation in the Colorado and Mojave Deserts. This work will help to identify areas in the desert where renewable generation might cause the least environmental harm, and would help to facilitate the permitting of solar facilities in those areas.

The work will also consider the impact of transmission necessary to deliver those renewable resources to load, and may help to streamline the environmental review of those transmission lines. While this reform is very important, it does not improve existing resource and staff constraints at these agencies, which must be addressed if streamlining of the generation permitting process is going to be successful. See Table 11 for a summary of the number of renewable generation projects each agency would need to process under the 33% RPS Reference Case.

- While Timelines 2A and 2B do not change the 30 month transmission-generation time lag assumption, they do account for generation streamlining by assuming no increase in processing time, even given the magnitude of new projects that would require generation permits at approximately the same time.

Reform 4: The Renewable Energy Transmission Initiative

RETI will help reduce the amount of time needed to develop plans of service for transmission lines. Specifically, RETI stakeholders are developing conceptual transmission lines and prioritizing line segments that the California ISO will review immediately under its detailed planning process in 2009-2010. RETI's efforts to involve a broad range of stakeholders at the federal, state, and local levels early in the planning process may also mitigate delays later in the process, especially in the CPCN approval process.

- RETI's efforts are reflected in the assumption in Timeline 2A and 2B that two new transmission projects enter the development process in 2010, rather than the one new project per year assumed in Timeline 1.

Reform 5: California ISO Planning for Renewable Resources in 2010 Transmission Planning Process

In the third quarter of 2009, the California ISO plans to issue a conceptual transmission plan based on the results of Phases 1 and 2 of RETI. This study, which will be informed by the first results from the GIPR study process, will be a conceptual master plan for achieving a 33% RPS by 2020 and will allow the California ISO to efficiently design a reliable transmission system for California and the WECC. This plan will go before the California ISO Board in the first quarter of 2010, along with the California ISO's 2010 Transmission Plan.

During 2010, the California ISO will begin the Large Project stakeholder study processes for the highest priority components of its conceptual master plan, followed by further projects in subsequent years. In order to ensure the development of a reliable transmission system, built in a least-cost manner, the California ISO has indicated that the planning for the transmission needed for a 33% RPS must be staged through at least 2014. The order in which projects enter the stakeholder study process is a critical question that will be informed in coming months and years by RETI, GIPR, the Long-Term Procurement Plans, and other processes, largely in the context of the California ISO's Annual Transmission Planning Process.

- The California ISO's plans are reflected in the addition of the "conceptual master plan" to Timelines 2A and 2B, and the staged planning of individual renewable transmission projects through the first quarter of 2015.

Implication: Transmission planning is a time-intensive process, and the California ISO's estimation of the time required to plan transmission for a 33% RPS is a key driver of the Timeline 2A and 2B results. Thus, successful execution of the California ISO's plan – beginning with the study planned for completion in September 2009 – is crucial.

Reform 6: Transmission Corridor Designation

The federal government and the state have recently enacted legislation to require designation of transmission corridors. Designation of such corridors can help streamline environmental review of transmission facilities proposed within those corridors, and can minimize stakeholder concerns, provided that stakeholders were fully engaged in the designation process. The federal government has identified numerous corridors in California, and the CPUC anticipates that these corridor designations will be extremely valuable in permitting new transmission facilities. The legislature has also directed the Energy Commission to identify transmission corridors in California, and the Energy Commission may initiate corridor designation for some of the paths that RETI identifies as valuable in the longer-term. *Once corridors are identified, an important next step is to secure the ability to use those corridors, perhaps through the purchase of high-priority corridors.*

- Corridor designations contribute to the reduction of the CEQA/NEPA review time from 24 months in Timeline 1, to 18 months in Timelines 2A and 2B.

ILLUSTRATIVE TIMELINE 2B: CURRENT PRACTICE WITH PROCESS REFORM AND EXTERNAL RISKS

As noted, Timeline 2A is not a realistic timeline, since it assumes no external development risks cause delay to generation or transmission projects. Experience indicates that large infrastructure projects can be delayed for many reasons. In the case of renewable energy infrastructure, many of these risks, such as technology, financing, and permitting risk, can be identified, but not necessarily predicted. See the text after Figure 9 for more discussion of these external risks.

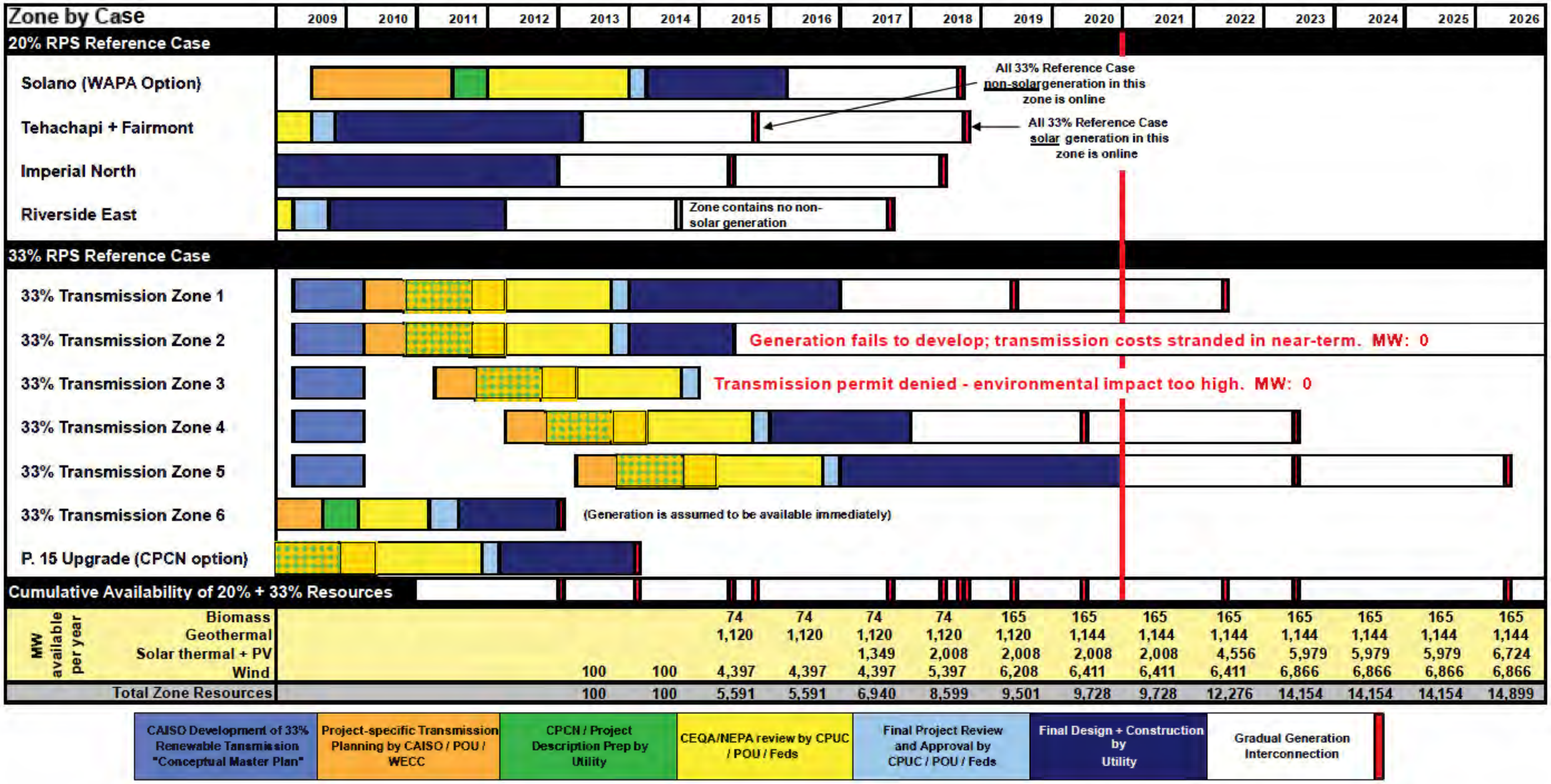
In Timeline 2B, "current practice with process reform and external risks," (Figure 9) the state encounters numerous project development delays that undermine the reforms identified in Timeline 2A. As a result, the 33% RPS Reference Case is not achieved. *The specific time delays shown in Timeline 2B, and the zones to which those delays are assigned, represent one possible scenario, given the risks that are known today*. There are several specific reasons that achievement of the 33% RPS is hindered in Timeline 2B:

- All timelines and reforms in Timeline 2A are assumed in Timeline 2B, but negative outcomes to several external risks now facing the state are realized. Timeline 2B maintains the assumption from Timeline 2A that there are no resource constraints in processing transmission and generation permitting applications.
- Generation in one zone fails to develop, resulting in new transmission capacity that goes unused in the near-term (stranded costs).
- Transmission to one zone is denied its permit because of environmental concerns or other opposition.
- Construction of the last transmission project is delayed by two years due to workforce and human resource constraints or the inability to finance the project.
- Solar projects throughout California take three years longer to develop than previously anticipated due to financing difficulties, performance failure, permitting difficulties, or other factors.[39]
- The outcomes above, and their implications for the 33% RPS time horizon, are not fully realized until 2014 and later. New generation and transmission development would likely begin to replace the failures/major delays, but 2014 may likely be too late to change course for a 2020 deadline. This analysis did not consider the addition of "replacement zones" to the 33% RPS Reference Case or procurement strategies not dependent on new transmission.

Implication: California's current procurement path is focused almost solely on central station renewable generation that is dependent on new transmission. In order to mitigate the risk that one resource zone would fail to develop, delaying the achievement of a 33% RPS by several years, the state should implement a procurement strategy that adequately considers the time and risk, in addition to price, associated with particular renewable generation resources. The state may also wish to adopt risk mitigation strategies, such as planning for more transmission than needed to reach just 33%, pursuing procurement that is not dependent on new transmission, or other solutions.

[39] This assumption is not particularly pessimistic, given the large number of solar thermal projects in the 33% RPS Reference Case relative to capacity installed worldwide to date (see Figure 14). Timeline 2B still assumes the interconnection of nearly 5,000 MW of solar thermal resources over the course of about 6 years.

Figure 9. Illustrative Timeline 2B for the 33% RPS Reference Case: Current Practice With Process Reform and External Risks



Source: CPUC/Aspen

__Result__: The 33% RPS Reference Case is not achieved due to unexpected problems with the development of two zones and delays in deployment of large-scale solar projects. Regardless of the nature of the risks that may actually occur, realization of any risk could cause delay and have a significant impact on timing. Although the state does not have direct control over many of the risks facing renewable energy development, it could adopt strategies that would mitigate specific risks.

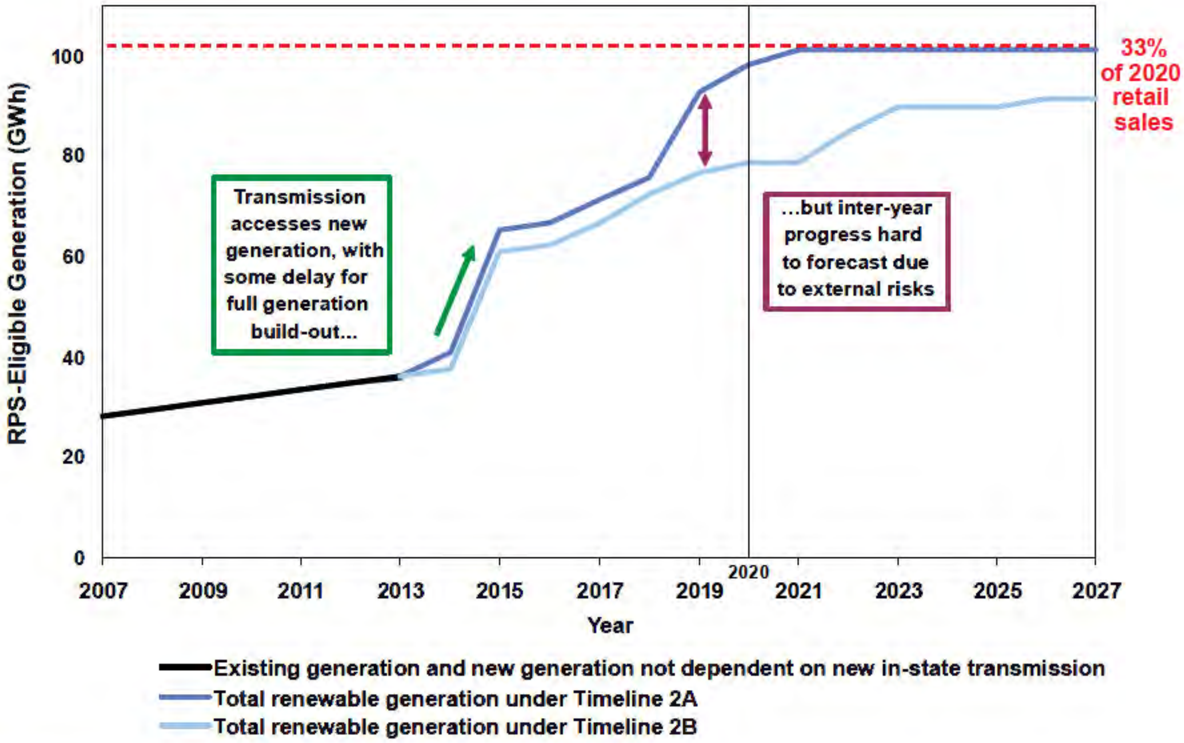
Exhibit 4

Page 55 of 96

ANNUAL RENEWABLE GENERATION BUILDOUT

The uncertainty around the external risks that are modeled in Timeline 2B makes it difficult to predict the renewable buildout on a year-to-year basis. Figure 10 illustrates the difference in the year-to-year progress achieved in Timelines 2A and 2B. This figure shows that administrative reforms speed up the renewable resource buildout, but inter-year progress is difficult to forecast due to external risks.

Figure 10. Annual Renewable Generation Buildout for Timelines 2A and 2B



Source CPUC/E3

Implication: 33% RPS legislation should provide flexibility around annual targets or compliance rules due to the uncertainty around the renewable resource buildout year-to-year.

Exhibit 4
Page 56 of 96

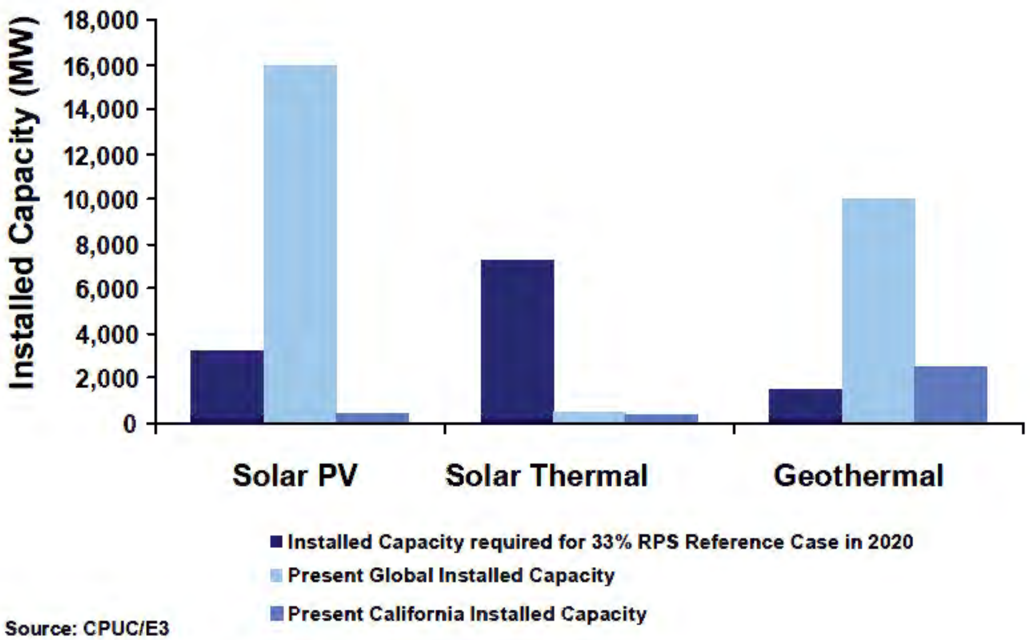
EXTERNAL RISKS THAT COULD DELAY 33% RPS RENEWABLE BUILDOUT

Below, some of the external risks that affect renewable energy development are described in more detail. These risks are outside the direct control of state agencies, and are included in Timeline 2B.

Reliance on New Technologies and Companies

Solar thermal and large-scale solar PV are promising technologies that show significant potential for providing reliable renewable power at competitive prices over the long-term. Solar technology participation in California's renewable energy solicitations has sharply increased in recent years, and the state's utilities are signing and negotiating thousands of megawatts of contracts for utility-scale solar power. The 33% RPS Reference Case includes over 7,000 MW of proposed solar thermal projects and over 3,000 MW of proposed solar PV. These new and emerging technologies, however, face some of the highest risks in terms of project viability. Unlike on-shore wind energy, and to a lesser degree geothermal energy, some solar thermal and solar PV technologies are not yet deployed widely on a utility-scale. Figure 11 shows the global installed capacity of solar PV, solar thermal, and geothermal resources as of 2008 to the right of the quantity of resources required to meet the 33% RPS Reference Case.

Figure 11. Global and Statewide Installed Capacity Versus Installed Capacity of 33% RPS Reference Case in 2020[40]



Source: CPUC/E3

[40] Wind is excluded from this chart to maintain scale. There was more than 121,000 MW of worldwide global installed wind capacity in 2006, compared to about 10,000 MW assumed in California in 2020 in the 33% RPS Implementation Analysis. Global Installed capacity numbers are from the "Renewables Global Status Report 2009." The California installed capacity for solar PV and solar thermal are from the Energy Commission's Energy Almanac. The installed capacity for geothermal is from the Geothermal Energy Association's website. All numbers are through 2008.

Exhibit 4

Page 57 of 96

As indicated in Figure 11, there is currently only about 500 MW of solar thermal capacity installed worldwide. The 7,000 MW of solar thermal included in the 33% RPS Reference Case would represent a 14-fold increase in global installed capacity. Both solar PV and geothermal technologies have been installed around the world in quantities exceeding those required to meet the 33% RPS target in California by 2020. However, the 33% RPS Reference Case would require increasing worldwide installed solar PV and geothermal capacity by about 15%, relative to 2008 levels. Likewise, the High DG Case includes about 15,000 MW of solar PV; this represents nearly a doubling of global solar PV capacity in California over the next 10 years, which is in addition to strong solar PV demand in other countries.

Reliance on technologies untested at this scale is risky. The primary risk is that relatively new solar thermal technologies will not be able to operate at utility-scale. Furthermore, assuming that each new technology ultimately does reach commercialization, there is still substantial risk that unanticipated technical hurdles will delay projects and prevent the necessary solar resources from coming online by 2020. A variation of this scenario is reflected in Timeline 2B: solar resources are assumed to require five years longer to develop than anticipated in Timeline 1. It should also be noted that technological breakthroughs for renewables could occur, but past experience indicates that these breakthroughs would need to occur nearly immediately in order to influence a 2020 timeline.

In addition to technology risk, many renewable energy technologies are evolving rapidly and the changing nature of the renewable energy sector means that clear market leaders have not emerged from among the many renewable energy developers. Over the next several years, it is likely that a number of these companies will fail as companies with superior technologies or better access to capital gain market share. This level of uncertainty in the market represents both a risk and an opportunity for California. It is a risk because not all of the state's renewable energy contracts are likely to result in commercially operational projects by 2020. On the other hand, it is an opportunity, since California's investment in renewable energy today is likely to further development of the renewable energy market overall. This highlights the tension between meeting the 33% RPS goal by 2020 and furthering long-term market transformation. If California values long-term market transformation, then a strategy that relies heavily on emerging technologies could accomplish that goal. However, this strategy will be less likely to achieve the 2020 target than a strategy that relies only on mature technologies.

Implication: California's high reliance on relatively new technologies and companies risks achievement of the 33% RPS in 2020. A planning process that allows balancing of time, risk, and cost associated with renewable development should provide opportunities for emerging technologies to demonstrate commercialization at projected costs without compromising stated policy goals.

Generation and Transmission Financing

Table 13 shows the estimated amount of capital investment required to construct all of the facilities selected in the 20% and 33% RPS Reference Cases. This figure includes the costs of new transmission lines as well as new renewable and conventional generating facilities needed to meet the RPS target and serve load reliably. Building the generation and infrastructure necessary to reach the 20% RPS Reference Case requires almost $52 billion of capital, while achievement of the 33% RPS Reference Case is estimated to require more than twice as much, approximately $115 billion. These numbers do not reflect the net costs to the ratepayers, but rather the amount of investment capital that will be needed to finance a 20% or 33% RPS.

Table 13. Cumulative Statewide Capital Investment Required Through 2020 Under the 20% and 33% RPS Reference Cases (billions of 2008 dollars)

	20% RPS Reference Case	33% RPS Reference Case
New Renewable Generation	$32.8	$95.3
New Transmission	$4.0	$12.3
New Conventional Generation	$15.0	$6.9
Total Capital Investment Required	***$51.8***	***$114.5***

In light of the magnitude of the capital investment required to achieve the state's RPS goals and serve load reliably, the current economic downturn poses another risk to the achievement of the state's 33% RPS goal by 2020. As credit availability has tightened in 2009, some companies are finding it harder to raise the capital they need to develop renewable generation and transmission projects. In addition, many of the newer renewable technology companies are still actively seeking venture capital, which is less plentiful than in recent years.

Some of the financing challenges may be mitigated in the short term by the American Recovery and Reinvestment Act (ARRA) of 2009 that President Obama signed into law on February 17, 2009. However, it is unclear to what extent ARRA is a solution given that these projects must begin construction in the next two years if they are to benefit from these new federal provisions. Moreover, tightened credit requirements are likely to be a long-lasting legacy of the current financial crisis, which may make it more difficult and expensive for renewable project developers to obtain financing for projects needed to achieve a 33% RPS by 2020.

Implication: Achieving a 33% RPS by 2020 is projected to require almost $115 billion of total investment, which is more than double the estimated $52 billion investment needed to reach the 20% RPS. If investors are going to provide the capital, they will need to have a high degree of confidence in specific renewable projects, in the ability of the California ISO and utilities to construct the needed transmission to integrate the renewable resources into the California grid, and in the willingness of policymakers to allow utilities to recover the costs from ratepayers.

Environmental Impacts

New renewable projects and transmission lines may create a range of significant and long-lasting environmental impacts. Many impacts may be reduced through engineering, design, and the use of careful construction practices. Other impacts are likely to remain significant and potentially unavoidable. Specifically, renewable projects using wind and solar technologies involve especially large areas: a single solar project can cover as much as 10,000 acres of land, about one-third of the total land area of San Francisco, completely converting the land to energy production.

Environmental impact analyses for new large renewable generation projects are now under way. The Energy Commission and BLM are reviewing applications for solar projects using different solar thermal technologies and local agencies are reviewing projects of large-scale wind and solar PV technologies. The completed analyses demonstrate that these projects have the potential to create a range of significant and long-lasting environmental impacts.

Some of the environmental impacts that can result from large renewable generation facilities, which are now being studied in an attempt to develop appropriate mitigation, are the following:

- A permanent loss of habitat for protected wildlife species and special status plants would occur. The availability of adequate mitigation land to compensate is uncertain, especially for expansive solar projects.
- Large projects would create blockage of wildlife corridors, potentially constraining or eliminating important linkages between sensitive population groups.
- Birds and bats can collide with wind turbines if located in areas with notable or threatened avian populations.
- A permanent change in the visual character of open spaces or agricultural areas would occur, inserting large expanses of industrial features to previously uninterrupted vistas. Desert views would also be affected by glare from the mirrors and towers used in some solar thermal technologies. Wind turbines would alter hilltop and ridgeline views.
- Limited supplies of groundwater would be used for regular cleaning of thousands of mirrors and panels for solar installations.
- Public lands in the desert would be converted from open space, available for multiple uses such as recreation, mining, and grazing, to a single exclusive purpose – power generation.
- A cumulative loss of resources would occur as the impacts above are realized throughout California – especially in the desert, where over 100 projects are already proposed.

Implication: Environmental permitting agencies will face difficult choices in the years ahead, as they struggle to balance environmental conservation and renewable and GHG emission reduction goals. Such choices, made in the context of permit applications for individual generation and transmission projects, will greatly affect the date by which the state can achieve a 33% RPS.

Legal challenges and public acceptance of environmental impact

Permitting agencies must weigh carefully the environmental and economic benefits associated with proposed renewable generation projects and transmission lines, against the environmental harm done by such extensive infrastructure development. The process of approving generation and transmission projects can be delayed as a result of public opposition or associated legal challenges. While no transmission line approval granted by the CPUC has been successfully challenged in court in the past 15 years, most projects are met with increasing amounts of public opposition. New transmission lines needed to deliver remote renewable resources would likely range in length from 20 to 200 miles, and large-scale renewable development in desert areas would also require transmission upgrades within most of the coastal metropolitan areas to deliver the energy to loads. Transmission lines in these areas face property and right-of-way constraints and have traditionally faced substantial public opposition.

Public opposition to local, Energy Commission, and BLM approvals of large renewable generation projects also appears to be increasing. The public and various interest groups have raised particular concerns about the scale and magnitude of large-scale solar projects in the desert. Projects currently proposed in the Southern California desert would each cover 3,000 to 10,000 acres depending on technology and generation capacity, and over 70 of these projects have filed applications with the BLM on nearly 700,000 acres. While not all of these projects will ultimately be needed or constructed, the 33% RPS Reference Case would include construction of roughly 30 large solar projects in the Southern California desert, which could result in the environmental impacts described above. Valid concerns about such impacts, as well as NIMBY (Not In My Back Yard) concerns, may be raised in the permitting process and lead to delay or even denial of permits.

Implication: Public opposition to large-scale renewable energy infrastructure could delay or halt progress towards a 33% RPS. RETI works to reduce opposition by involving stakeholders early in the development process, but the state may also consider other options for reducing the risk of public opposition, including different procurement strategies or concentrated renewable development in one or more renewable energy parks. Tradeoffs in terms of resource quality and price may be warranted if it appears that development in more cost-effective areas faces too great a risk of delay.

5 Summary of 33% RPS Cases

This section shows how the 33% RPS cases perform against the various policy goals and objectives of a 33% RPS, based on the results described in Sections 3 and 4. Through a number of executive orders and state law, state policymakers have articulated numerous policy goals and objectives for achieving a 33% RPS, which are outlined in Section 1. In this section, quantitative and qualitative analysis of the performance of alternative strategies is presented for meeting a 33% RPS in addressing state policy goals and objectives. Table 14 depicts these findings.

CASE OVERVIEW

Commonalities among all the cases:

All of the 33% RPS cases result in GHG emission reductions similar to those established by the ARB in its Scoping Memo. As mentioned previously, GHG emission reductions are measured based on the emissions reduced during generation. A lifecycle GHG analysis was beyond the scope of this analysis. The 33% RPS cases also perform equally well in reducing reliance on fossil fuels and increasing resource diversity. As demonstrated through the natural gas and CO_2 allowance price sensitivity analysis, all of the 33% RPS cases provide a hedge against fluctuating natural gas prices, but at a relatively high cost.

Differences among the cases:

Each of the 33% RPS cases has a different impact on ratepayers. While a detailed implementation analysis was not conducted on any of these alternative strategies, the timing does seem to differ across the cases since different technologies have different construction durations and transmission needs. As for development risk, different technologies face different risks, depending on whether the technology is emerging or commercially proven.

The cases may differ in terms of economic impacts as well. All cases result in higher electric rates, reducing disposable income for California consumers. However, renewable infrastructure construction, operations, and maintenance result in some local job creation, depending on how much of the infrastructure is located in California. Regardless of where the project is located, economic benefits could accrue to California if renewable companies establish their operations in California. Lastly, local environmental quality differs across the cases since different technologies have different land and air quality impacts.

33% RPS Reference Case (current IOU procurement strategy)

- *Cost Impact:* 7.1% cost premium compared to the 20% RPS Reference Case. Most expensive case relative to other alternative 33% RPS cases except for the High DG Case.
- *Economic Development:* More in-state jobs compared to the High Out-of-State Delivered Case.
- *Local Environmental Quality:* High reliance on large-scale solar technologies could decrease local environmental quality due to land impacts, but high reliance on in-state generation could displace existing fossil fuel generation and reduce local air and water pollution.
- *Timing:* High reliance on central station renewable resources, which require new transmission, suggests a higher likelihood of delays.
- *Development Risk*: Many external risks, such as reliance on new, unproven technologies could delay the 2020 target beyond the transmission delays.
- *Long-Term Market Transformation:* Reliance on new solar technologies could lead to future cost-reductions and technology breakthroughs.
- *Conclusion:* This case is most likely to miss the 2020 target timeline due to the amount of significant transmission required and its heavy reliance on new, unproven technologies. This case does excel in long-term market transformation.

High-Wind Case

- *Cost Impact*: 4.1% cost premium compared to the 20% RPS Reference Case.
- *Economic Development*: Case results in similar in-state job creation to 33% RPS Reference Case, and lower rates means higher disposable personal income.
- *Local Environmental Quality:* Wind technologies have both positive and negative effects. Wind has a smaller land footprint compared to solar, but can lead to bird mortality. In addition, wind technologies could require a greater amount of fossil generation to backup the generation during non-peak hours, which could decrease local air quality.
- *Timing:* Wind technologies have a shorter development period compared to other renewable technologies, which could facilitate achievement of a 33% RPS by 2020. On the other hand, wind technologies also need new transmission.
- *Development risk:* Less of a concern for wind since the technology is mature.
- *Long-Term Market Transformation:* Wind technologies contribute less to long-term market transformation since the technology is mature.
- *Conclusion:* This is a cost effective way of achieving a 33% RPS, but is likely to miss the 2020 timeline because of the amount of transmission required. While it performs reasonably well with the other policy categories, it does not excel in any of them.

High Out-of-State Delivered Case

- *Cost Impact:* 3.8% cost premium compared to the 20% RPS Reference Case.
- *Economic Development:* This case creates fewer in-state jobs compared to the 33% RPS Reference Case due to a higher reliance on out-of-state resources; however, lower rates mean higher disposable personal income.
- *Local Environmental Quality:* Greater reliance on out-of state resources could preserve sensitive lands in California, but out-of-state resources may not help improve local air quality since local fossil resources may still have to run for resource adequacy purposes.
- *Timing:* Out-of-state resources may have shorter development timelines since much of the out-of-state development is focused on wind, but a high reliance on new, multi-state transmission line development adds risk.
- *Development risk:* Less of a concern for out-of-state resources since wind and geothermal are mature technologies.
- *Long-Term Market Transformation:* Wind and geothermal technologies contribute less to long-term market transformation since the technologies are mature.
- *Conclusion:* Of the cases studied, this case provides the lowest cost strategy to achieve a 33% RPS, although the cost is not much less than the High Wind Case. High reliance on multi-state transmission introduces an element of risk into the 2020 timeline. This risk could be mitigated through tradable RECs with no delivery requirement, which would also lower the cost of out-of-state resources. This case does not perform well on the other policy preferences.

High Distributed Generation Case

- *Cost Impact:* 14.6% cost premium compared to the 20% RPS Reference Case. This cost is substantially higher than the 33% RPS Reference Case and alternative 33% RPS cases since this case relies on distributed generation, primarily solar PV, to fill the 33% RPS resource needs.
- *Economic Development:* Could create more jobs than the other cases since rooftop PV is labor intensive; however, California electricity expenditures would be nearly $4 billion higher than the 33% RPS Reference Case, which would lead to lower economic development and job growth for other businesses overall.
- *Local Environmental Quality*: Performs well since case minimizes transmission and maximizes rooftop installations. It can also improve local air quality by displacing in-state local fossil generation.
- *Timing:* Could perform well on timing and could assist meeting the 33% RPS in 2020, though transaction costs and potential supply constraints to meet the high number of installations make timing uncertain.

- *Development risk:* Such large amounts of solar PV on the distribution grid could create grid reliability problems, which could slow development. In addition, this strategy would require nearly a doubling of global solar PV capacity, which could lead to supply chain constraints, affecting the timing.
- *Long-Term Market Transformation:* Case could benefit medium-term market transformation of the solar PV market and lead to future cost-reductions.
- *Conclusion:* A high DG strategy could facilitate achieving a 33% RPS in 2020 as well as mitigate some of the need for transmission and transform the market for solar PV technologies. However, less is known about the feasibility of this case, including the willingness of building owners to rent their rooftops, impacts on grid reliability, effectiveness of utility programs and other delivery channels, and whether both manufacturing capacity and a trained workforce will be available to meet this large increase in demand. This case has the highest cost unless there are significant cost breakthroughs in solar PV technologies.

Table 14. Comparison of 33% RPS Cases Across RPS Policy Objectives[41]

Policy Objective	33% RPS Reference Case	High Wind Case	High Out-of-State Delivered Case	High-DG Case
Cost	◒	●	●	○
Timing	◍	◒	◒	◒
GHG Emission Reductions	●	●	●	●
Resource Diversity	●	●	●	●
Local Environmental Quality Air Quality	●	◒	◍	●
Local Environmental Quality Land Use	◍	◒	◒	●
Economic Development	◒	◒	◍	◒
Long-Term Transformation	●	◍	◍	●
Technology Development Risk	◍	●	●	◍

Legend:

● Case performs well ○ Case performs poorly ◒ Case is neutral

[41] This study only preformed an implementation analysis on the 33% RPS Reference Case. Thus, evaluation of other cases for all criteria (except for cost and GHG reductions) is based on a qualitative analysis drawing from over seven years of experience in implementing the RPS program.

6 Findings

The purpose of this report is to provide new and in-depth analysis on the cost, timing, and risks of a 33% RPS for the State of California. This report does not recommend a preferred strategy on how to reach a 33% RPS, but rather provides an analytical framework for policymakers to understand the tradeoffs inherent in any 33% RPS program for California. The analysis also highlights the need to prioritize different policy objectives as well as the need to start considering mitigation strategies to lesson the effects of delay from external risks.

KEY FINDINGS OF THIS REPORT

Achieving a 33% RPS will require tradeoffs between various policy goals and objectives

There are multiple strategies the state could pursue to reach a 33% RPS, but each portfolio will have different cost impacts, reach the 33% RPS target at a different date, and perform differently across the broad list of stated policy goals and objectives. For example, the results of this analysis show a relationship between timing and the maturity of various technologies. Specifically, using proven technologies increases the chances of reaching the target date of 2020, while relying on new technologies decreases the chances of making the target date. This relationship is evident in the current procurement strategies that the California IOUs are pursuing. The IOUs are currently signing multiple contracts with solar thermal projects, which reflects risks inherent to the emerging nature of the technology, including higher prices and performance risk. While this strategy has the potential for long-term market transformation, it risks high costs and failure to meet the 33% RPS in 2020.

Table 15 provides four examples that illustrate how a specific policy priority results in different renewable procurement strategies. A "Least-Cost" policy priority, for example, demonstrates a preference for low-cost renewables, most likely from outside of California. The "2020 Timeline" policy priority focuses on achieving a 33% RPS by the fixed deadline of 2020, with a high reliance on commercialized technologies and high levels of DG, while "In-State Jobs" priority relies most heavily on procurement strategies that will lead to the most in-state job development. "Market Transformation" relies heavily on developing market transformational technologies such as solar thermal, but also contains the highest risk of missing the 2020 deadline. Each of these policy-driven procurement strategies also demonstrates the tradeoffs that would have to be made in terms of the other policy preferences and objectives.

Table 15. Sample Renewable Procurement Options Based on Policy Priorities

Least-Cost Renewables	2020 Timeline
Procurement Priority: 1. In-state development of lower-cost resources and commercialized technologies, such as wind and biomass.[42] 2. Least-cost renewable energy delivered to California, including construction of new interstate transmission lines. 3. Procurement of out-of-state renewable energy facilitated through tradable RECs with no delivery requirement. *Cost*: Lowest *Timing*: 2020 likely since the lower cost resources also have shorter development periods. Based on program experience, out-of-state resources can be built faster than in-state resources. *Market Transformation:* Low as there is heavy focus on existing technology.	*Procurement Priority:* 1. Near-term renewable energy projects in California, with focus on commercial technologies that do not need new transmission, such as DG. 2. Viable out-of-state resources delivered to California over existing transmission. 3. Procurement of out-of-state renewable energy facilitated through tradable RECs with no delivery requirement. *Cost*: Medium High *Timing*: 2020 likely because of high reliance on existing transmission, existing technologies, and high DG. *Market Transformation:* Medium low, since there is heavy focus on existing technology, although it could contribute to solar PV price reductions.
In-State Jobs[43]	**Market Transformation**
Procurement Priority: 1. High focus on in-state renewables including both high and low cost renewables and those that require new in-state transmission. *Cost*: Highest - higher rates could have unintended consequences and lead to job loss in other sectors. *Timing*: Post 2020 likely, but heavy focus on DG could help mitigate the time lag of potential transmission bottlenecks and potential permitting issues. *Market Transformation:* Medium high if there is a mixture of new and existing technologies.	*Procurement Priority:* 1. Emphasis on emerging, likely higher-cost renewables, such as solar thermal, with significant transformational benefits. *Cost*: Medium High *Timing*: Post 2020, highest risk due to technology uncertainty. *Market Transformation:* Highest due to significant investment in new technologies.

These priority portfolios show that a low-cost strategy may be able to achieve a 33% RPS by 2020 using commercial technologies and out-of-state resources. However, a strategy that prioritizes mostly in-state development or market transformation will cost more and take more time to achieve. Given the large number of contracted solar thermal resources and current

[42] These numbers do not include a full study of renewable integration costs. As a result, the relative cost of this strategy could change once Phase 3 is complete, including California ISO analytical input.
[43] Only accounts for jobs directly resulting from RPS.

emphasis on in-state development, the 33% RPS Reference Case more closely reflects the "In-State Jobs" and "Market Transformation" procurement options described in Table 15. It is important to note that the IOUs are procuring at a very aggressive rate and it is expected that they will be at or close to a 33% RPS on a contract basis in the near future. As a result, the state may be already beyond the point where a purely "least-cost" strategy could be adopted.

California must start implementing mitigation strategies if a 33% RPS by 2020 is the most important policy priority

Timeline 2B provides an example of a scenario in which, despite successful implementation of ambitious reforms, two resource zones fail to develop due to external risks. While Timeline 2B presents a hypothetical example, it illustrates the potential impact of real risks that California's current procurement strategy is not prepared to mitigate. Specifically, California's current procurement path is focused almost solely on central station renewable generation that is dependent on new transmission. In order to mitigate the risk that one resource zone would fail to develop, delaying the achievement of a 33% RPS by several years, the state should consider a procurement strategy that adequately considers the time and risk, in addition to price, associated with particular renewable generation resources. The state may also wish to adopt risk mitigation strategies, such as planning for more transmission and generation than needed to reach just 33%; pursuing procurement, such as distributed solar photovoltaics (PV), which is not dependent on new transmission; or concentrating renewable development in pre-permitted land that would be set aside for a renewable energy park.

OTHER FINDINGS

The magnitude of a 33% RPS is unprecedented and will require nearly a tripling of renewable electricity in the next 10 years

To meet the current 20% RPS by 2010 target, four major new transmission lines are needed at a cost of $4 billion. To meet a 33% RPS by 2020 target, seven additional lines at a cost of $12 billion would be required. The 33% RPS target is projected to require an increase from 27 terawatt hours (TWh) of delivered renewable energy today to approximately 75 TWh in 2020.

Electricity costs will be higher in 2020 compared to 2008, regardless of whether California mandates a 33% RPS or not

Even if California makes no further investments in renewable energy, the analysis projects that average electricity rates per kilowatt-hour will rise by 16.7% in 2020 compared to 2008. In 2020, the total statewide electricity expenditures of the 20% RPS Reference Case is projected to be 2.8% higher compared to the all-gas scenario. The total statewide electricity expenditures of the 33% RPS Reference Case is projected to be 7.1% higher compared to the 20% Reference Case, and 10.2% higher compared to the all-gas scenario.

Several critical process reforms have been implemented or are in the early stages of development and implementation that can help speed achievement of a 33% RPS

These reforms will help increase the pace of renewable development. Even under very optimistic assumptions and after the process reforms have been implemented, the 33% RPS target by 2020 is highly ambitious. This is due to the risk from external factors and the magnitude of the infrastructure that California will have to develop, procure, and integrate in the next 10 years.

A 33% RPS could theoretically serve as a potential hedging strategy against volatile fossil fuel prices, but only if natural gas and CO_2 price allowances are very high

In theory, an increase in renewable penetration decreases the range of electricity expenditures by decreasing exposure to volatile fossil fuel prices. While a 33% RPS can provide this hedge, it only provides an effective hedge under very high natural gas and CO_2 prices. Thus, the "hedging value" from resource diversity is not a very strong justification for establishing a 33% RPS.

The interplay between energy efficiency achievement and renewable energy procurement highlights the need to analyze and plan for interactions among the state's various policy goals

Under a low-load scenario that could result from successful implementation of energy efficiency and other demand-side programs, the 20% Reference Case results in substantial capacity savings. On the other hand, the 33% RPS Reference Case results in less incremental capacity savings, which means that a 33% RPS will create capacity that is not needed to serve load, resulting in excess costs to consumers. This finding highlights the need to analyze interactions among the state's various GHG reduction programs. An integrated approach that considers both supply side and demand side programs is needed to ensure that the various programs result in a resource plan that furthers the underlying policy objectives of a comprehensive GHG reduction strategy.

Dramatic cost reductions in solar PV could make a solar DG strategy cost-competitive with central station renewable generation

Under the Solar PV Cost Reduction sensitivity, the total costs of the High DG Case are very similar to the costs of the 33% RPS Reference Case. The solar PV industry is predicting dramatic cost reductions in the coming years even though solar PV is currently the most expensive renewable technology studied in this report. Solar PV on the distribution system has numerous advantages, which include avoiding transmission and land use if sited on rooftops. However, even if solar PV technology costs drop dramatically, the deployment costs associated with thousands of megawatts of distributed PV could still be a challenge. In addition, capturing these megawatts could require a policy mechanism different from the RPS. More analysis is necessary to determine the programmatic strategies necessary to achieve a high-DG scenario as well as the feasibility of high penetrations of solar PV on the distribution grid.

RPS OBJECTIVES SHOULD BE PRIORITIZED

As this analysis has shown, many of the policy objectives are mutually exclusive and in conflict with one another. Currently, the RPS procurement process is effectively dictating the timing, cost, and policy objectives of a future 33% RPS program. Thus, the tradeoffs are being decided through the utility procurement process, not by the policymakers or regulators. Using current RPS contracts as an example, market transformation and in-state economic development are the primary policy objectives that are being prioritized at the expense of meeting a 2020 timeline and minimizing customer costs. This results from lack of having a stated priority preference. Some of the key questions to help determine a priority preference include:

- Should California focus public investment and system planning efforts on developing and integrating technologies with significant long-term transformational potential such as solar thermal or solar PV?
- Should California focus on developing in-state resources? Up to what cost? What is the correct balance between in-state economic development and higher customer costs?
- Is California willing to delay the 2020 target in order to develop primarily California resources and stimulate new technologies and market transformation?
- Should California waive renewable energy delivery requirements for out-of-state resources if it is necessary to meet the 2020 target or pursue a lower cost strategy?
- Should the CPUC encourage the utilities to procure increased amounts of (currently) high-cost solar PV to mitigate the potential negative impact of delay due to failure of a resource zone?

NEXT STEPS

This report captures the preliminary results and conclusions from Phase 1 and Phase 2 of the 33% RPS Implementation Analysis. Phase 3, which CPUC staff intends to finalize by the end of 2009, will integrate the California ISO's renewable integration analysis, RETI and the California ISO's conceptual transmission plans, and the Energy Commission's analysis of once-through cooling fossil plant retirements. In addition, CPUC staff will attempt to identify and articulate possible solutions to many of the risks and challenges identified throughout this report.

As stated previously, the study team did not perform an implementation analysis of the High Wind, High DG Case, or the High Out-of-State Delivered Case. Further analysis of the High Wind Case could help understand potential challenges to developing high levels of wind energy in California and other states. An implementation analysis of the High DG Case could help better understand the costs, reliability impacts, and barriers to implementing such large amounts of solar PV on the distribution grid. For the High Out-of-State Delivered Case, more analysis could help identify possible challenges to developing out-of-state resources and delivering them to California.

Lastly, given the findings from the low-load sensitivity, more analysis could help better understand the interplay between retiring fossil resources, achievement of the aggressive demand-side goals, and a 33% RPS.

Appendix A: List of Acronyms

Acronym	Definition
AB	Assembly Bill
AB 32	(California) Assembly Bill 32 – Global Warming Solutions Act of 2006
ARB	(California) Air Resources Board
ARRA	American Recovery and Reinvestment Act
Aspen	Aspen Environmental Group
BLM	Bureau of Land Management
California ISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CEQA	California Environmental Quality Act
CHP	Combined Heat and Power
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
CO_2	Carbon Dioxide
CREZ	Competitive Renewable Energy Zone
CSI	California Solar Initiative
DG	Distributed Generation
DR	Demand Response
EE	Energy Efficiency
ED	Energy Division
EIR	Environmental Impact Report
E3	Energy and Environmental Economics
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GIPR	Generation Interconnection Process Reform
GW	Gigawatt
GWh	Gigawatt-hour
IEPR	Integrated Energy Policy Report
IOU	(Large) Investor-Owned Utility
IRRP	Integration of Renewable Resources Program
ISO	(California) Independent System Operator
ITC	Investment Tax Credit
kWh	kilowatt-hour
LTPP	Long-Term Procurement Plans
MMBtu	Millions of British thermal units
$MMTCO_2E$	Millions of Metric Tons of Carbon Dioxide Equivalent
MPR	Market Price Referent
MW	Megawatt
MWh	Megawatt-hour
NEPA	National Environmental Policy Act
NIMBY	Not In My Backyard
PEA	Proponent's Environmental Assessment

Acronym	Definition
POU	Publicly-Owned Utility
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaic
REC	Renewable Energy Credit
RETI	Renewable Energy Transmission Initiative
RFO	Request For Offer
RPS	Renewables Portfolio Standard
SB	Senate Bill
TWh	Terawatt-hour
W-e	Watt equivalent

Appendix B: Methodology

STUDY STRUCTURE

Study team and stakeholder process

The consultant study team was comprised of E3, Plexos Solutions (Plexos), and Aspen Environmental Group. Plexos conducted production simulation model runs to provide variable costs and GHG emissions. Although not part of the study team, Black and Veatch contributed to this effort by calculating the availability of rooftop space in urban areas as well as rural lands for siting solar PV projects, in addition to its contributions to the RETI work. CPUC Energy Division staff assisted the consultant team throughout the study period.

The 33% RPS Implementation Analysis Working Group and Transmission Constrained Working Group also contributed to this analysis. Energy Division formed these working groups after a 33% RPS workshop in August 2008. The working group members contributed significantly to this analysis through meetings, data submittals, written comments, and informal discussions. More specifically, the Implementation Analysis Working Group helped develop the 33% RPS Implementation Analysis Work Plan and the Transmission Constrained Working Group contributed to the development of the High DG Case. The working group met in December 2008 and January 2009 to review the study's initial analysis and preliminary results and provided valuable feedback and guidance to the study team.

Study Phases

This study has three phases, which are described below:

Phase 1: August 2008 – December 2008

In Phase 1, the study team utilized data from RETI and other data sources to compile the cost and location of renewable resources available throughout the West. The team also developed an environmental scoring method that built upon RETI's efforts. This information was used to develop resource zone rankings to select draft portfolios for each of the 20% and 33% RPS cases presented below. Stakeholders also provided comments on the 33% RPS cases developed during this phase.

Phase 2: December 2008 – May 2009

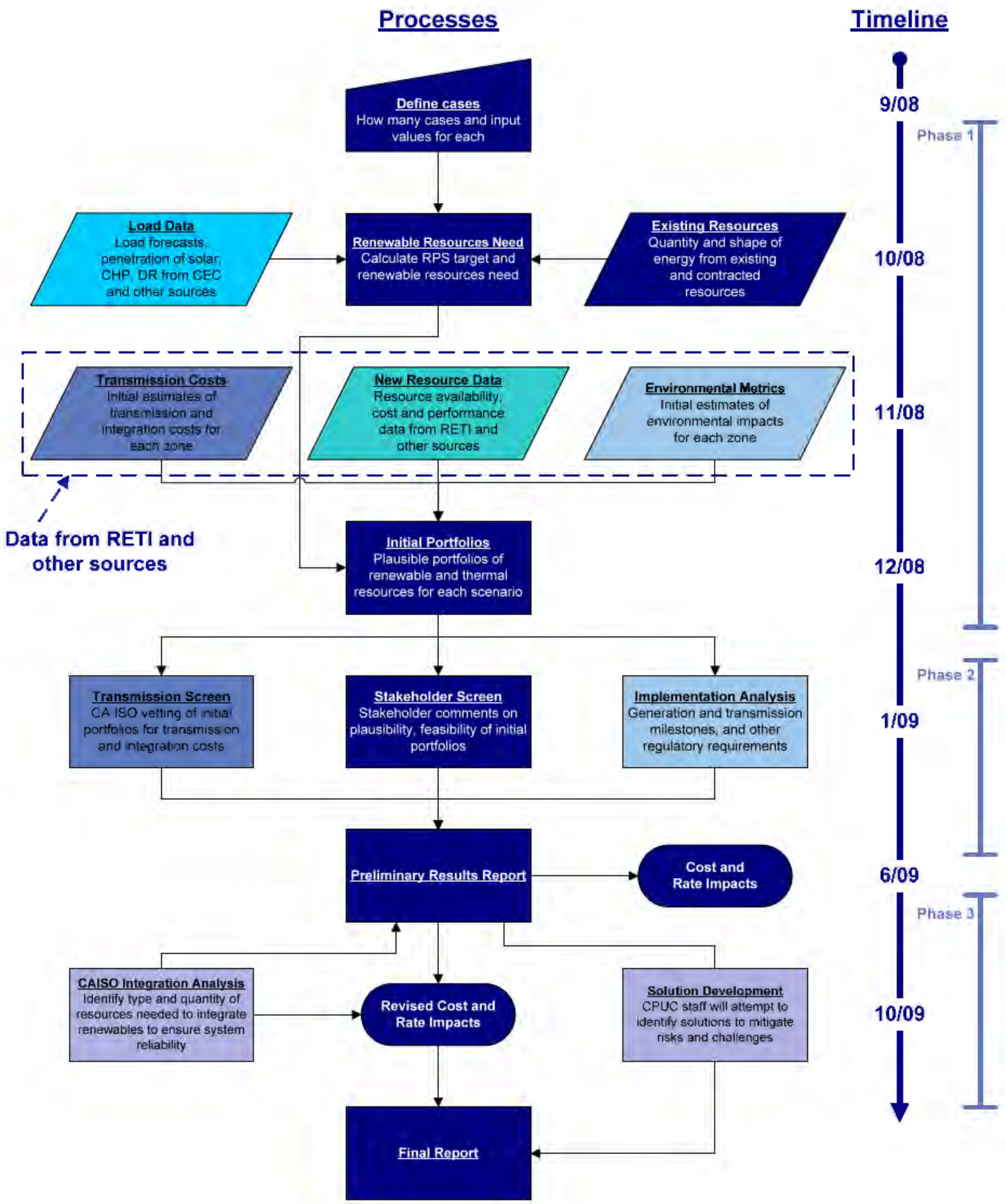
In this phase, the draft portfolios were refined based on stakeholder feedback. Production simulation model runs for the 20% and 33% RPS Reference Cases were conducted to determine the variable costs and GHG emission reductions, and the results were then used to assess the costs and GHG emissions for the alternative 33% RPS cases. The team also analyzed historical generation and transmission development and constructed timelines to illustrate the steps necessary to build new transmission and renewable energy projects in California. This report is the final deliverable of this phase.

Phase 3: April 2009 – Fourth Quarter 2009

The California ISO will identify the type and quantity of resources needed to reliably integrate the 33% RPS resource portfolios that were developed in Phase 2 of this study. Studies on once-through cooling retirements are expected to be completed in the next six months, which will also help inform the quantity and timing of new resources needed to integrate intermittent renewable resources. Based on these analyses, the study team will refine assumptions about the quantity and cost to integrate intermittent renewable resources into the grid.

In addition, RETI and the California ISO will finalize the conceptual transmission plans needed to reach a 33% RPS during the summer of 2009, which will identify the transmission buildout and cost needed to reach a 33% RPS. This will be incorporated into the analysis. Finally, CPUC staff will attempt to identify solutions to mitigate or overcome the risks and challenges identified in this analysis. The final deliverable of this study is the final report, currently scheduled for fourth quarter of 2009.

Figure 12. 33% RPS Implementation Analysis Study Flow Chart Depicting Phases 1-3



Source: CPUC/E3

Exhibit 4
Page 75 of 96

METHODOLOGY TO CONSTRUCT RENEWABLE RESOURCE PORTFOLIOS

As described above, Phase 1 of this analysis focused on developing initial resource portfolios for each of the 20% and 33% RPS cases, which are composed of specific renewable projects. The study team assembled resource portfolios to meet a 33% RPS target and estimated cost impacts using the RPS Calculator. This section describes in more detail the methodology for constructing these renewable resource portfolios.

RPS Calculator

The RPS Calculator[44] is a Microsoft Excel spreadsheet model developed to aggregate the renewable cost and performance data and select renewable resources needed to meet the RPS target. The model also identifies transmission investments that deliver renewable resources to load and conventional resources that are needed to meet energy and peak demand growth, and calculates the cost and GHG impacts of a given portfolio of resources in 2020.

Renewable Resources Needed by 2020

The analysis starts with a statewide calculation of the renewable resources that California utilities must procure between 2008 and 2020 to meet a 33% RPS by 2020. The resources needed are calculated as the total required quantity of renewable energy in 2020 (33% of retail sales) minus the actual renewable generation that was claimed by California utilities in 2007.

To fill this renewable resource need, the study team gathered the best available data on renewable energy project development and renewable resource potential in California and throughout the West, and used the RPS Calculator to select portfolios of renewable resources.

Renewable Portfolio Data Sources

The analysis relied on four primary sources of data regarding renewable energy costs, resource potential, and commercial interest, each of which provided a level of granularity and accuracy that distinguishes this study from previous analyses. See Section 3 for a description of each data source.

1. CPUC Energy Division project database (ED Database) [45]
2. Renewable Energy Transmission Initiative[46]
3. The GHG Calculator[47]
4. Estimates of distributed renewable energy potential[48]

[44] The RPS Calculator can be found on the CPUC RPS website: http://www.cpuc.ca.gov/renewables
[45] The CPUC maintains a public version of this database: http://www.cpuc.ca.gov/NR/rdonlyres/F07E249B-C36A-4A38-8D36-BDB88CDB154B/0/RPS_Project_Status_Table_1st_Quarter_2009.xls
[46] Renewable Energy Transmission Initiative: http://www.energy.ca.gov/reti/documents/index.html
[47] As part of its GHG modeling, E3 developed estimates of the cost and performance of renewable resources throughout the Western Interconnection based on data provided by NREL and Energy Information Administration. Detailed descriptions of the methodology can be found on E3's GHG modeling website: http://www.ethree.com/CPUC_GHG_Model.html
[48] Black and Veatch assisted this analysis by estimating large rooftop acreage in urban areas throughout California.

It should be noted that there may be some overlap and duplication of potential projects in the resource supply curves. In addition, renewable energy projects that came online in late 2007 and 2008 may not be represented in a few of the cases. Finally, while the analysis incorporates project information from IOU solicitations, it does not include information about new and projected municipal and cooperative utility renewable energy projects. These slight inaccuracies are insignificant enough that they should not affect the results of the cost and timeline analyses in any meaningful way.

Distributed Renewable Energy Potential

As mentioned above, this analysis includes original estimates of the technical potential to develop and interconnect renewable generation at the distribution level, which are included in all of the 33% RPS cases. Estimates in this study were based on a three screens: 1) the ability to 'easily' interconnect, 2) suitable sites, and 3) willing customers. The first screen was based on an analysis of peak load served by each distribution feeder on the IOUs' systems. Available interconnection capability was then allocated among multiple distributed resource types including solar PV, biogas, biomass, and CHP. The second screen was based on GIS[49] mapping conducted by Black and Veatch for RETI and for this analysis. The third screen is based on simple rules of thumb. In addition to the urban solar PV projects that one normally thinks of as "distributed," this study also included an estimate of 20 MW ground-mounted solar PV systems in rural areas based on the RETI assessment. Since few of these rural systems are expected to meet the 'easy' interconnection criteria, an increased cost of interconnection was incorporated.

Table 16. Screens and Criteria to Estimate Urban Solar PV Potential

Screen	Criteria
'Easy' Interconnection	Peak PV output < 30% of peak load at point of interconnection, and PV location within 3 miles of substation. Available capacity was allocated among distributed resource types.
Suitable Sites	In urban areas, available large roof area (greater than 0.5 acre flat roof) multiplied by 65% usable space. In rural areas, available land with low slopes near substations
Willing Customers	Participation assumed for 1/3 of the sites identified as "suitable sites" with 'easy' interconnection

Table 17 shows the statewide technical potential for each distributed resource used in the High DG Case.

[49] Geographic Information System

Table 17. High Level Distributed Renewable Technical Potential

Technology	Type	Capacity (MW)	Notes
PV	Large Roofs (> 0.5 acre)	3,810	Based on satellite imagery
PV	Small Roofs	2,224	One third of remaining 'easy' connection potential
PV	Ground Mounted	2,266	One third of remaining 'easy' connection potential
PV	Ground Mounted (> 30% of peak load at point of interconnection)	9,000	Exceeds the size for 'easy' connection and gets a cost penalty of $68/kW-year
Biogas	Distribution Connected	249	
Biomass	Distribution Connected	34	
Total		**17,583**	

Defining Renewable Resource Zones

A resource zone is an aggregation of renewable projects by geographic location, technology type and/or resource quality. The resource zones were adopted from RETI and the GHG Calculator are organized around clusters of projects in defined geographic locations. For these zones, this study assumes that a new transmission "trunk line" must be constructed in order to deliver the energy to load centers. Other "zones" may include projects that are not geographically connected, but which do not need transmission and share other similar characteristics that allowed them to be grouped together for computational simplicity. These include "distributed"[50] and out-of-state projects in the CPUC Database and the RETI database.

Determining Resource Portfolio Costs and Rankings

All costs are expressed in 2008 dollars, unless noted otherwise. With the exception of the Solar PV Cost Reduction Case, this study is confined to existing renewable technologies and assumed constant technology costs over the study period. This study did not attempt to predict breakthroughs in technological development or changes in capital or operational costs. In addition, high-level estimates of transmission costs and renewable integration costs were based on a literature review. The California ISO is developing a full network model of the 33% RPS Reference Case, which can be used to improve the transmission cost estimates. The California ISO will also provide an estimate of the resources needed to reliably integrate intermittent technologies. This information will be used to update the 33% RPS cost information in Phase 3 of this analysis.

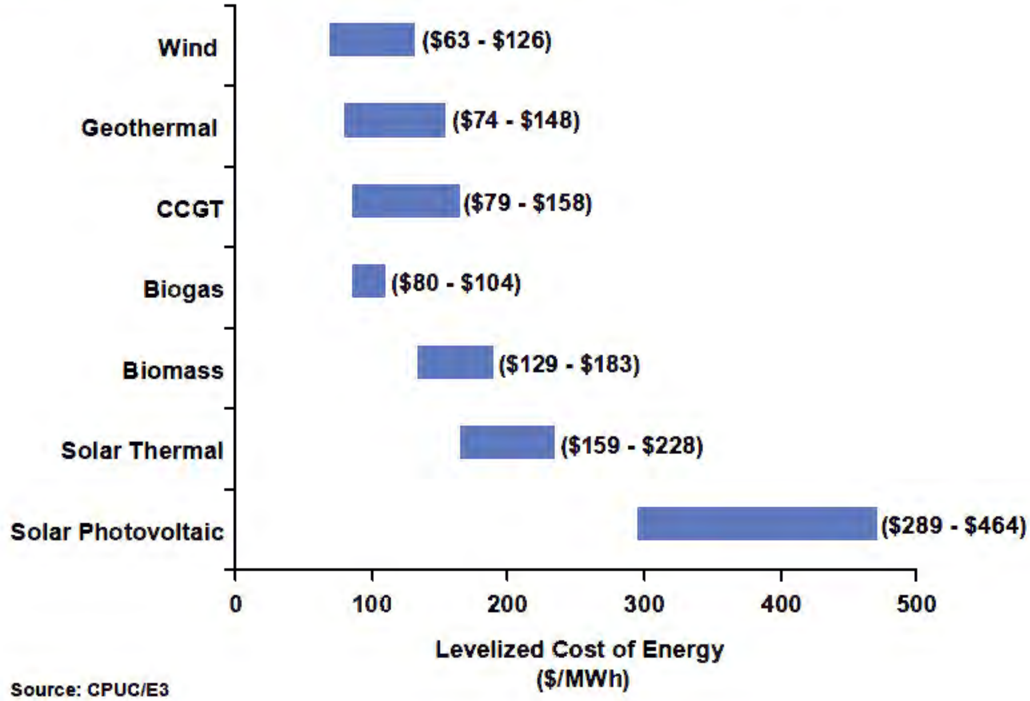
Estimates of the cost of constructing new renewable resources relied primarily on RETI data, which includes cost and performance information for hundreds of potential projects throughout

[50] In this context, "distributed" means simply projects that do not need large new transmission trunk lines in order to interconnect and deliver their energy to load.

California. This represents tens of thousands of megawatts of renewable development. The GHG Calculator contains characterizations of resources that RETI did not analyze, including biogas and small hydro. Based on these resource characterizations and assumptions about project finance, the RPS Calculator outputs a levelized cost of energy that represents the developer cost for each project used for project ranking. Figure 13 shows the resulting developer cost ranges ($/MWh) for each renewable technology considered in this analysis, along with a CCGT benchmark. The solar PV costs are for crystalline PV that is ground-mounted with single-axis tracking.

The project costs do not represent the negotiated contracted price. For most of the projects, the costs are the developer costs to build and operate the project with a reasonable profit. The exception to this assumption is renewable projects that cost less than the cost of a CCGT. These renewable projects were assumed to be at least as expensive as a CCGT since it is unlikely that developers will agree to supply power to California utilities at below the market rate for new conventional resources. This assumption has a modest, upward impact on the total cost of complying with a 33% RPS.

Figure 13. Developer Levelized Cost of Generation by Technology Type[51]



Source: CPUC/E3

[51] This analysis assumes a 20-year PPA with an independent developer. Costs are expressed in 2008 dollars. The renewable technology costs within each technology vary due to project size and location. The CCGT costs vary by natural gas prices.

Exhibit 4
Page 79 of 96

Determining project value based on avoided costs and environmental scoring

Using the data sources described above, projects are ranked using a modified version of RETI's "net value" approach. The net value is the developer cost of energy from the renewable resource minus the value the resource provides. This value includes avoided energy costs, avoided capacity costs, and avoided GHG allowances purchases. This analysis placed a heavy emphasis on projects that either have a PPA or are in negotiations with a California IOU based on demonstrated commercial interest by treating developer costs as "sunk"[52] for ranking purposes.

In addition to using the avoided costs to rank projects, the study team also determined an environmental score for each project. Starting with the RETI Environmental Working Group's assessment, a project scoring system was developed that considers five additional environmental permitting risk factors, which are described below. This composite environmental metric aims to discern individual projects that may have the fastest or the slowest environmental permitting timelines. After totaling the five factors, projects with the lowest scores are associated with the lowest permitting risk and fastest permitting timelines. Each of these five risk categories was converted into a cost factor to incorporate into the RPS Calculator.

Table 18. Environmental Permitting Risks Factored into Renewable Project Rankings

Factor	Description
Factor 1: All RETI Environmental Issues	Captures total ranking score of each renewable resource zone that the RETI Environmental Working Group defined.
Factor 2: Transmission Footprint	Emphasizes the constraint new transmission line right-of-way represents since the permitting of new transmission lines can be especially time-consuming and challenging.
Factor 3: Pre-Identified versus Proxy Projects[53]	Since proxy projects lack a project sponsor, they are likely to take substantially longer to permit than the "pre-identified projects" that have been developed by specific project developers.
Factor 4: Proximity to Sensitive Lands	Captures visual and aesthetic impacts (views from sensitive lands are generally the highest priority for protection), cumulative impacts, and public opposition. Siting of generation or transmission near sensitive lands generally increases the likelihood of public opposition.
Factor 5: Projects on Federal Land	Federal site permitting can take much longer than the state-only process due to requirements to comply with the NEPA, often in addition to the state CEQA requirements.[54]

[52] These projects are assumed to be available at zero cost for ranking purposes. This ensures that projects with active developer interest are selected first inside each zone, and increases the odds that a zone with active projects is selected. These projects are assigned a cost based on generic resource characterizations when calculating the cost impacts.

[53] RETI identified projects "proxy projects," or projects located in areas with resource potential, even though there was no project sponsor.

[54] It also appears that federal land management agencies are understaffed to handle the significant number of pending (and anticipated) applications for renewable generation and transmission projects, thus the additional consideration of this factor in the scoring system.

Cost Metrics and Sensitivity Analysis

E3 estimated California's annual electricity expenditures in 2020, which is the combined revenue requirement of all of California's utilities (IOU and POU). In addition to the cost of constructing new resources, E3 projected changes in utility costs in a number of areas such as transmission, distribution, fuel costs, and CO_2 allowance price. The result is a projection of California's total electricity expenditures in 2020 under each of the cases. Changes in the state's total electricity expenditures between the 20% RPS Reference Case and the 33% RPS cases represent the incremental costs of complying with a 33% RPS. Sensitivity analysis was then conducted for key variables such as natural gas prices and CO_2 allowance prices, load growth, and solar PV costs.

E3 also calculated the average electricity cost per kWh in 2020, which is the statewide electricity expenditures divided by total retail sales. While this metric is informative, it does not show the bill impact for different customer classes. California's retail rate designs vary for each electric utility in the state, so the bill impacts of achieving a 33% RPS could be somewhat higher or somewhat lower for any individual household or business. For example, the IOU residential rates for lower levels of usage are currently capped at 2001 levels as a result of AB 1X,[55] passed in the immediate aftermath of the California Energy Crisis. This rate cap would last until 2022 under current law, so absent a change to these provisions, the costs of achieving 33% RPS could not be recovered from these sales for lower levels of usage. This would have the effect of increasing the "per kWh" charge, or cost of a 33% RPS that is levied on all remaining usage. As a result, non-residential customers would see proportionately higher bills than they would if all customer usage was billed for RPS costs. A detailed analysis of the distributional impacts of a 33% RPS on customers was beyond the scope of this analysis.

Table 19. Cost Metrics

Metric	Definition
Statewide electricity expenditures in 2020	Combined revenue requirement of all California utilities (IOU and POU)
Average electricity cost per kWh in 2020	Statewide electricity expenditures divided by total retail sales

Development of Renewable Cases

In order to compare the costs of a 33% RPS to existing state policy, E3 created a 20% RPS Reference Case. Next, E3 created a 33% RPS Reference Case, representing primarily the results of recent IOU solicitations, as well as three alternative 33% RPS cases to test different policy objectives. The 33% RPS Reference Case prioritizes all projects that have resulted from recent solicitations (approved, pending approval, or short-listed) and are therefore represented in the CPUC Database. The alternative 33% RPS cases prioritize projects that the CPUC has *approved*, but do not prioritize projects that are *pending approval* or *short-listed*. This results in an additional 39 TWh of energy that can be met through selection of other renewable resources from the RETI and E3 databases.

[55] The CPUC issued D.01-05-064 on May 14, 2001 to implement AB 1X: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/7185.htm

20% RPS Reference Case

The 20% RPS Reference Case assumes that California utilities procure only enough resources to maintain the current statutory target of a 20% RPS in 2020. This case focuses primarily on resources that can be integrated through new transmission corridors that are already approved by the CPUC or are expected to be added in the near term such as Tehachapi and Sunrise.

33% RPS Reference Case

The 33% RPS Reference Case places the heaviest emphasis on projects in the ED Database, which represent projects that have been short-listed or contracted by IOUs. The 33% RPS Reference Case assumes that most of the projects in that database are developed by 2020. Since IOUs have selected a substantial number of solar thermal and solar PV projects in recent solicitations, these resources are heavily represented in the 33% RPS Reference Case. The case includes 7,200 MW of solar thermal and 3,200 MW of central utility-scale solar PV resources, along with other wind, geothermal, and biomass resources. As such, this case probably represents a high bookend on the amount of solar thermal that could realistically be developed by 2020.

High Wind Case.

The High Wind Case replaces most of the solar resources in the 33% RPS Reference Case with wind resources in California and Mexico. Instead of relying on the higher cost solar thermal resources that are heavily represented in recent IOU solicitations, this case represents the lowest-cost resources that can be developed in-state without assuming major, new interstate transmission.

High Out-of-State Delivered Case

The High Out-of-State Delivered Case assumes that new, long-distance transmission lines are developed to access high-quality renewable resources from out-of-state resources in the WECC. The case includes a 3,000 MW transmission line bringing wind energy from Wyoming and a 1,500 MW transmission line bringing principally geothermal resources from northern Nevada. Like the High Wind Case, this case relies more heavily on wind than solar resources. However, in this case a larger proportion of the wind is anticipated to come from outside of California.

High DG Case

The High DG Case is intended to examine the implications of the state relying heavily on distributed resources such as solar PV to meet a 33% RPS. Motivations for such a case include increasing public opposition to large transmission or generation projects that have long development times, large upfront investments, and environmental complexities. The High DG Case assumes that it would be difficult or impossible to construct new, high-voltage transmission projects to accommodate renewable resources, beyond those lines assumed for the 20% RPS Reference Case. To fill the renewable resource need, this case relies on estimates of the technical potential of solar PV and other distributed renewable resources. It does not fully examine the approaches needed to deploy this case, however.

Table 20. Assumptions in all 2020 Cases

Category	Assumption
Load forecast	Energy Commission's 2007 IEPR reference case or mid-case load forecast
Fuel price forecast	The Market Price Referent methodology, updated with new natural gas prices, was used to develop the base case forecast
CO_2 allowance price forecast	The Market Price Referent methodology was used for CO_2 price forecasts to develop the base case forecast
Energy efficiency achievement	No incremental energy efficiency assumed beyond what is already incorporated in the Energy Commission's 2007 IEPR load forecast
Demand response achievement	No incremental demand response assumed beyond what is already incorporated in the Energy Commission's 2007 IEPR load forecast
Combined Heat and Power (CHP) achievement	Energy Commission 2007 IEPR base-case load forecast assumption for CHP penetration
Customer-installed solar PV	Energy Commission 2007 IEPR load forecast, 847 MW nameplate of customer-installed PV[56]
GHG allowance allocation	GHG emissions allowances are auctioned. Auction revenue from allowances equal to 2008 electricity sector emissions is returned to utilities
Resource characterizations	Reference case resource cost assumptions based on RETI and E3 data for renewable generation and the Market Price Referent[57] for new combined-cycle gas turbines

[56] The 2007 IEPR load forecast assumed 847 MW of customer-side PV, a fraction of the 3,000 MW California Solar Initiative goal.

[57] D.08-10-026 approved the 2008 MPR Methodology. Resolution E-4214 calculated the 2008 MPR based on this methodology. MPR-related documents can be accessed on the CPUC website: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

TIMELINE METHODOLOGY

In order to evaluate the feasibility of achieving the 33% RPS Reference Case by 2020, this study determined reasonable timelines for the sequence of steps required to plan, permit, and construct the generation and transmission identified in the 33% RPS Reference Case. This assessment provides a pragmatic "reality check" of the state's ability to reach California's 33% RPS target since it realistically assesses implementation timelines as well as major factors and uncertainties driving those timelines. This study only performed a timeline implementation analysis on the 33% RPS Reference Case since this case represents the IOUs' current procurement strategy. The 33% RPS Reference Case, however, represents only one of many plausible development scenarios that could meet a 33% RPS. In addition, an implementation assessment of the distributed and out-of-state resources that contributed to the 33% RPS Reference Case was not performed.

The study team began its assessment by identifying the key milestones and lead times involved in bringing new transmission and generation online. Distinct sets of milestones were identified for different categories of generation and transmission projects, and the team analyzed empirical evidence as to the timing of the completion of those milestones. Various simplifying assumptions were made, as detailed below. These assumptions result in somewhat optimistic estimates of the time required to develop renewable energy.

Renewable technology assumptions:

- Over the next 10 to 15 years, all currently proposed renewable projects will obtain the necessary financing to construct the project and commence operations
- All of the proposed renewable energy technologies will operate as proposed
- Renewable energy development companies will succeed in bringing all of their projects online
- There will be no manufacturing bottlenecks or other supply chain constraints, which could slow project development

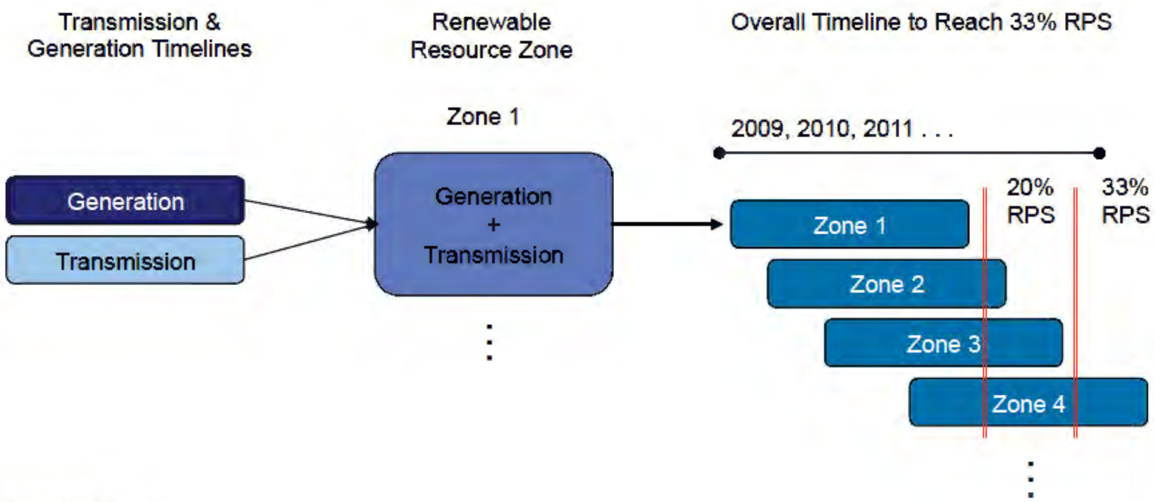
Transmission assumptions:

- The transmission expansions identified are conceptual and are meant to provide a general sense of the number of major new transmission lines and the number of applications for a CPCN or permit application required to access the renewable resources included in the 33% RPS Reference Case. These conceptual expansions have not been subject to detailed transmission planning and project design
- Does not identify additional transmission upgrades that would likely be needed within the study period to accommodate load growth and reliability requirements, and to make the renewable resources included in the 33% RPS Reference Case fully deliverable to load centers
- Transmission lines assumed to be sited within United States BLM utility corridors (if on BLM land) or adjacent to existing transmission lines (if not on BLM land), though distance from existing lines was not estimated

The study team then created generic timelines for the generation and transmission facilities needed to achieve the 33% RPS Reference Case. Once the building blocks of the individual generation and transmission timelines were in place, these individual timelines were combined into one overall timeline for the 33% RPS Reference Case.

Figure 14 illustrates the process of combining the generic transmission and generation timelines into timelines for each resource zone, and subsequently combining the individual resource zone timelines into the three illustrative timelines for achieving the full 33% RPS Reference Case portfolio.

Figure 14. Timeline Development Flow Chart



Source: CPUC/Aspen

Generic generation and transmission timelines

Transmission planning, permitting, and construction require substantial lead times, generally longer than those required for generation facilities. The timelines for transmission and generation facilities are interdependent. The completion date of a new transmission line dictates the earliest possible online date for a generation project that needs that transmission to deliver the energy to load. The relationship between transmission and generation affects a renewable developer's willingness to invest in the project development efforts. Renewable developers will only invest in project development if they believe the required transmission will be available when needed and at a cost suitable for their project's economics. Generation development in any resource zone can occur at the same time that transmission development is occurring for that zone, but generation development may extend beyond completion of the transmission line due to the challenges associated with simultaneously completing the transmission and generation.

Generic Transmission Timeline

The 33% RPS Reference Case assumes the development of seven major generic new transmission lines to the selected resource zones, beyond those new lines already assumed in the 20% RPS Reference Case.

This analysis only identifies and evaluates the large (200 kV and above) transmission lines that require a CPCN from the CPUC or a similar approval from a POU, because of the lengthy review required for such major lines. Several smaller lines would likely be required before 2020 to maintain grid reliability under the 33% RPS Reference Case, but because these lines are generally reviewed and permitted much faster than the large transmission lines, they are not considered to be critical path and are not considered in this analysis.

The typical timeline for new transmission is estimated to be approximately eight years, as shown in Table 21. The transmission planning timeline of 24 months takes into consideration increased efficiencies expected from GIPR[58] currently taking place at the California ISO as well as coordination of interconnection studies with the overall transmission planning process. Although the steps below are shown in sequence, portions of the work often proceed in parallel. Section 4 of this report describes efforts to gain efficiencies in the transmission development process by further coordinating the steps below.

Table 21. Generic Timeline for an IOU-Owned Transmission Line > 200 kV, Based on Past Transmission Permitting Experience

Transmission Development Process	Timing
Transmission Planning Process • ISO interconnection studies/transmission planning and board approval • IOU development of plan of service (may overlap with the above)	24 months
PEA/CPCN Application preparation by IOU[59]	18 months
CEQA/NEPA review and environmental documentation by local, state, and/or federal agency, resulting in an environmental impact statement	24 months
CPUC approval	3 months
Final design and construction	30 months
TOTAL	**99 months (8.25 years)**

[58] GIPR is expected to increase the speed and efficiency of studying interconnection requests by planning common transmission solutions for groups of generation projects and integrating such planning into the California ISO annual transmission planning process.

[59] PEA = Proponent's Environmental Assessment.

While the CPUC averages approximately 18 months for CEQA review and CPCN approval for transmission siting cases in general, more conservative assumptions were used here to account for the likely larger and more controversial nature of these new required projects. For purposes of this assessment, a transmission line is assumed to be 100 miles long, with some segments on federal land, and located entirely within the boundaries of California. The duration of final design and construction varies widely, however, depending on the utility's readiness to move forward with the route that is finally selected. This schedule can be shortened up to three months if the utility were to start preliminary engineering immediately upon issuance of the draft Environmental Impact Report (EIR) since the transmission route usually does not change significantly from the draft to the final EIR.

Generic Generation Timeline

The 33% RPS Reference Case requires the development of nine new resource zones, comprising approximately 19 GW. The analysis suggests that the nine resource zones can be accessed by seven new transmission lines. The typical timeline estimated for renewable resource selection and development is 42 to 93 months (3.3 to 7.8 years), depending on the type of renewable generation. The components of the timeline are shown in Table 22.

Table 22. Generic Renewable Generation Timeline for an IOU-Contracted Resource

Renewable Project Development Process	Timing
Request for Offer issuance and review	3 months
Negotiation of PPA and submittal to CPUC	5-12 months
CPUC review and approval of PPA	4-6 months
Project design, site control, and permit application preparation	12 months on average
Permitting and development: Renewable resource permitting and development, including environmental documentation by municipality, county, Energy Commission, and/or federal lead agency	18-60 months
TOTAL	**42-93 months (3.5 - 7.8 years)**

The permitting and development section in Table 22 includes a range of timeframes for permitting at various agencies and a range of construction durations from under one year for the smallest projects up to multiple years for more complex facilities. The permitting requirements for generation are dictated by technology type, location, and size. There are six categories of generation projects for purposes of permitting, each with a distinct timeline depending on the complexity of environmental permitting and the agencies involved. Similarly, construction durations vary by resource type and size. The timelines in Figure 15 and Figure 16 present estimates of permitting and construction timelines for various categories of generation projects. These timelines represent expected (not minimum or maximum) timelines, and are based on a review of recently developed renewable generation projects. This information was used to aggregate renewable projects in each zone to determine a timeline for each resource zone needed for a 33% RPS.

Figure 15. Standard Permitting Timelines for Categories of Renewable Generation Projects

Project Size & Jurisdiction	Resource Type	Year 1	Year 2	Year 3	Year 4
SMALL - LOCAL	Any renewable (<50 MW)	Application Prep	City / County CEQA		
SMALL - FEDERAL	Any renewable (<50 MW) on Federal land	Application Prep	City / County CEQA Federal Agency NEPA		
LARGE - LOCAL	Solar PV, Wind	Application Prep	City / County CEQA		
LARGE - STATE	Geothermal, Solar Thermal, Biomass, Biogas (> 50 MW)	Application Prep	CEC CEQA Equivalent		
LARGE - FEDERAL + STATE	Geothermal, Solar Thermal, Biomass, Biogas (> 50 MW) on Federal land	Application Prep	CEC CEQA Equivalent Federal Agency NEPA		
LARGE - FEDERAL + LOCAL	Solar PV, Wind	Application Prep	City / County CEQA Federal Agency NEPA		

Source: CPUC/Aspen

Figure 16. Standard Construction Timelines for Categories of Renewable Generation Projects[60]

Resource	Size	Year 1	Year 2	Year 3	Year 4
SOLAR PV	Small (<50 MW)	12 months			
SOLAR PV	Large (>50 MW)	25 months			
SOLAR THERMAL	Small (<50 MW)	16 months			
SOLAR THERMAL	Large (>50 MW)	35 months			
WIND	Small (<50 MW)	13 months			
WIND	Large (>50 MW)	20 months			
BIOMASS, GEOTHERMAL	Small (<50 MW)	12 months			
BIOMASS, GEOTHERMAL	Large (>50 MW)	26 months			

Source CPUC/Aspen

[60] Timelines can vary greatly within the size ranges presented in the figure, i.e. between a 5 MW and a 49 MW plant, and between a 50 and 500 MW plant. The small number of completed large-scale PV and solar thermal plants also makes it very difficult to generalize construction times; the large solar PV and thermal plants contracted for development in California would be the first projects at that scale globally. The construction duration estimates here are meant to be illustrative.

Appendix C: Resource Zones and Resource Mix for each Renewable Case

RESOURCE ZONES USED IN RPS CALCULATOR

Resource Zone Name	Description or Source
Alberta	GHG Calculator Zone
Arizona-Southern Nevada	GHG Calculator Zone
Baja	RETI Competitive Renewable Energy Zone (CREZ)
Barstow	RETI CREZ
British Columbia	Combination of RETI CREZ/ GHG Calculator Zone
Carrizo North	RETI CREZ
Carrizo South	RETI CREZ
Colorado	GHG Calculator Zone
Cuyama	RETI CREZ
Distributed Biogas	Biogas resources from RETI and E3 that are assumed to be able to come online without substantial new transmission
Distributed Biomass	Biomass resources from RETI that are assumed to be able to come online without substantial new transmission
Distributed CPUC Database	Resources of all types from the CPUC Database that are assumed to be able to come online without substantial new transmission
Distributed Geothermal	Geothermal resources from RETI that are assumed to be able to come online without substantial new transmission
Distributed Solar	Solar resources from RETI that are assumed to be able to come online without substantial new transmission
Distributed Wind	Wind resources from RETI that are assumed to be able to come online without substantial new transmission
Fairmont	RETI CREZ
Imperial East	RETI CREZ
Imperial North	RETI CREZ
Imperial South	RETI CREZ

Resource Zone Name	Description or Source
Inyokern	RETI CREZ
Iron Mountain	RETI CREZ
Kramer	RETI CREZ
Lassen North	RETI CREZ
Lassen South	RETI CREZ
Montana	GHG Calculator Zone
Mountain Pass	RETI CREZ
Needles	RETI CREZ
NE Nevada	GHG Calculator Zone
New Mexico	GHG Calculator Zone
Northwest	GHG Calculator Zone
Not Assigned	Resources listed in RETI database that are a) not assigned to a geographic zone and b) assumed to require new transmission
Owens Valley	RETI CREZ
Out-of-State Early	Out-of-state resources from CPUC database that are either under contract or short-listed and expected to come online in the near term
Out-of-State Late	Out-of-state resources from CPUC database that are either under contract or short-listed and expected to come online in the long term, plus 1,400 MW of additional out-of-state wind resources assumed to be available to California utilities
Palm Springs	RETI CREZ
Pisgah	RETI CREZ
Remote DG	RETI estimates of PV potential modified for RPS Calculator
Reno Area/Dixie Valley	GHG Calculator Zone
Riverside East	RETI CREZ
Round Mountain	RETI CREZ
San Bernardino - Baker	RETI CREZ
San Bernardino - Lucerne	RETI CREZ
San Diego North Central	RETI CREZ
San Diego South	RETI CREZ
Santa Barbara	RETI CREZ

Resource Zone Name	Description or Source
Solano	RETI CREZ
South Central Nevada	GHG Calculator Zone
Tehachapi	RETI CREZ
Twentynine Palms	RETI CREZ
Utah-Southern Idaho	GHG Calculator Zone
Victorville	RETI CREZ
Wyoming	GHG Calculator Zone

RESOURCE ZONE AND RENEWABLE MIX FOR ALL RPS CASES[61]

20% RPS Reference Case

Resource Zones Selected in 20% RPS Reference Case	MW	GWh
Tehachapi	3,000	8,862
Distributed CPUC Database	525	3,118
Solano	1,000	3,197
Out-of-State Early	2,062	6,617
Imperial North	1,500	9,634
Riverside East	1,350	3,153
Total	9,437	34,581

Resource Mix – 20% RPS Reference Case	In-State		Out-of-State		Total	
	MW	GWh	MW	GWh	MW	GWh
Biogas	30	223	-	-	30	223
Biomass	241	1,687	87	610	328	2,297
Geothermal	1,240	9,515	58	445	1,298	9,959
Hydro - Small	22	95	15	66	37	161
Solar PV	830	1,774	-	-	830	1,774
Solar Thermal	996	2,431	-	-	996	2,431
Wind	4,016	12,240	1,902	5,497	5,917	17,737
Total	7,375	27,965	2,062	6,618	9,436	34,582

[61] Some of the MW and GWh totals may be off by one digit. This is due to rounding.

33% RPS Reference Case

Additional Resource Zones Selected in 33% RPS Reference Case	MW	GWh
Resources from 20% RPS Reference Case	9,437	34,581
Mountain Pass	1,650	4,041
Carrizo North	1,500	3,306
Out-of-State Late	1,934	5,295
Needles	1,200	3,078
Kramer	1,650	4,226
Distributed Biogas	249	1,855
Distributed Geothermal	175	1,344
Fairmont	1,650	5,003
San Bernardino - Lucerne	1,800	5,020
Palm Springs	806	2,711
Baja	97	321
Riverside East Incremental	1,650	3,869
Total	**23,798**	**74,650**

Resource Mix – 33% RPS Reference Case	In-State		Out-of-State		Total	
	MW	GWh	MW	GWh	MW	GWh
Biogas	279	2,078	-	-	279	2,078
Biomass	391	2,737	87	610	478	3,346
Geothermal	1,439	11,027	58	445	1,497	11,471
Hydro - Small	25	111	15	66	40	177
Solar PV	3,235	6,913	-	-	3,235	6,913
Solar Thermal	6,764	16,652	534	1,304	7,298	17,956
Wind	7,573	22,899	3,399	9,809	10,972	32,709
Total	**19,706**	**62,417**	**4,093**	**12,234**	**23,799**	**74,650**

High Wind Case

Additional Resource Zones Selected in High Wind Case	MW	GWh
Resources from 20% RPS Reference Case	9,437	34,581
Distributed Biogas	249	1,855
Distributed Geothermal	175	1,344
San Bernardino - Lucerne	1,800	5,020
Palm Springs	806	2,711
Distributed Wind	468	1,289
Out-of-State Late	1,934	5,295
Fairmont	1,650	5,003
Baja	1,500	4,966
San Diego South	903	2,583
Round Mountain	500	2,759
Distributed Biomass	162	1,138
Pisgah	1,800	4,589
Barstow	450	1,163
Riverside East Incremental	150	354
Total	21,984	74,650

Resource Mix – High Wind Case	In-State		Out-of-State		Total	
	MW	GWh	MW	GWh	MW	GWh
Biogas	279	2,078	-	-	279	2,078
Biomass	634	4,442	87	610	721	5,052
Geothermal	1,655	12,541	58	445	1,713	12,985
Hydro - Small	22	95	15	66	37	161
Solar PV	1,162	2,483	-	-	1,162	2,483
Solar Thermal	3,163	7,715	534	1,304	3,697	9,019
Wind	9,575	28,419	4,802	14,454	14,376	42,873
Total	16,490	57,773	5,496	16,879	21,985	74,651

High Out-of-State Delivered Case

Additional Resource Zones Selected in High Out-of State Delivered Case	MW	GWh
Resources from 20% RPS Reference Case	9,437	35,051
Distributed Geothermal	175	1,344
Distributed Biogas	249	1,855
Out-of-State Late	1,934	5,295
San Bernardino - Lucerne	1,800	5,043
Reno Area/Dixie Valley	1,500	8,596
Palm Springs	806	2,711
Round Mountain	500	2,759
Wyoming	3,000	10,493
Distributed Biomass	162	1,138
Fairmont	140	402
Riverside East Incremental	150	354
Total	19,853	74,651

Resource Mix – High Out-of State Delivered Case	In-State		Out-of-State		Total	
	MW	GWh	MW	GWh	MW	GWh
Biogas	279	2,078	-	-	279	2,078
Biomass	575	4,030	87	610	662	4,640
Geothermal	1,655	12,541	938	7,142	2,593	19,683
Hydro - Small	22	95	27	131	49	226
Solar PV	969	2,072	-	-	969	2,072
Solar Thermal	2,101	5,153	534	1,304	2,635	6,457
Wind	5,756	17,681	6,910	21,813	12,666	39,494
Total	11,357	43,650	8,496	31,000	19,853	74,650

High Distributed Generation Case

Additional Resource Zones Selected in High Distributed Generation Case	MW	GWh
Resources from 20% RPS Reference Case	9,437	34,581
Distributed Biogas	249	1,855
Distributed Geothermal	175	1,344
Distributed Wind	468	1,289
Out-of-State Late	1,934	5,295
Distributed Biomass	162	1,138
Remote DG	9,000	19,236
Distributed Solar	5,186	9,558
Riverside East Incremental	150	354
Total	**26,761**	**74,650**

Resource Mix – High Distributed Generation Case	In-State		Out-of-State		Total	
	MW	GWh	MW	GWh	MW	GWh
Biogas	279	2,078	-	-	279	2,078
Biomass	403	2,825	87	610	490	3,435
Geothermal	1,415	10,859	58	445	1,473	11,303
Hydro - Small	22	95	15	66	37	161
Solar PV	15,068	30,678	-	-	15,068	30,678
Solar Thermal	1,095	2,674	534	1,304	1,629	3,978
Wind	4,484	13,529	3,302	9,488	7,785	23,017
Total	**22,766**	**62,738**	**3,996**	**11,913**	**26,761**	**74,650**

ELLEN F. ROSENBLUM
Attorney General

FREDERICK M. BOSS
Deputy Attorney General

DEPARTMENT OF JUSTICE
APPELLATE DIVISION

January 26, 2016

Jim Williams
Director, Elections Division
Office of the Secretary of State
255 Capitol St. NE, Ste. 501
Salem, OR 97310

Re: Proposed Initiative Petition — Increases Electricity Percentages Required from Renewable Sources; Reduces New Buildings' Permissible "Net Energy Consumption" (Undefined)
DOJ File #BT-73-15; Elections Division #2016-073

Dear Mr. Williams:

We have reviewed the comments submitted on the draft ballot title for the above-referenced initiative petition. We provide the enclosed certified ballot title, reflecting changes to the ballot title's caption, "yes" result statement, and summary.

This letter summarizes the comments we received, our responses to those comments, and the reasons we declined to make some of the proposed changes. ORAP 11.30(7) requires this letter to be included in the record in the event that the Oregon Supreme Court reviews the ballot title.

A. The caption

The draft ballot title's caption read:

Increases percentage of electricity required from renewable sources; reduces new buildings' permissible net energy consumption

1. Why we have not modified the first clause in the caption.

Commenter Paul Cosgrove criticizes the caption's use of the phrase "renewable sources," and suggests (as do commenters Scott Bolton and Dave Robertson) that the caption use the phrase "qualifying electricity" instead. But because "qualifying electricity"—as defined by current law—encompasses "renewable energy sources," and because "qualifying electricity" is not a phrase that most voters are likely to understand, we have decided not to make the proposed change.

In the alternative, Mr. Cosgrove suggests that if the phrase "renewable sources" is to remain in the ballot title, it should be accompanied by quotation marks. Placing the phrase in quotation marks would be inappropriate, however. First, the phrase "renewable sources" is not the precise phrase referenced in the proposed measure; instead, the measure references a longer phrase—"renewable energy sources," as used in current law. IP 72, § 6. For that reason alone, use of quotation marks would be misleading. Second, use of quotation marks might inaccurately suggest to voters that the proposed measure defines the pertinent phrase, when in fact the *legislature* already has defined "renewable energy sources." *Cf. Carley/Towers v. Myers*, 340 Or 222, 229, 132 P3d 651 (2006) ("this court has approved the use of specially defined terms in quotation marks, followed by the word 'defined' in parentheses, to signal that the proposed measure specially defines the terms"). ORS 469A.005(10) already defines "renewable energy source," and section 6 of the proposed measure—although it would require that provision to be renumbered as ORS 469A.005(*11*)—leaves that definition unchanged. For that reason also, quotation marks would be inappropriate.

Commenters Scott Bolton and Dave Robertson criticize the caption for failing to inform voters that, under the measure, utilities will be required to increase the percentage of electricity sales that derive from "qualifying electricity" only if ORS 469A.100's potential exemption to qualifying-electricity requirements is not triggered. They note that ORS 469A.100(1) exempts utilities from complying with qualifying-electricity requirements "during a compliance year to the extent that the incremental cost of compliance, the cost of unbundled renewable energy certificates and the cost of alternative compliance payments under ORS 469A.180 exceeds four percent of the utility's annual revenue requirement for the compliance year." Significantly, however, the proposed measure does not alter that aspect of current law; it leaves the current exemption in ORS 469A.100(1) undisturbed. Accordingly, the caption makes no reference to that exemption; that is, nothing requires the caption to tell voters that the measure, in increasing the required percentages of electricity sales that must come from renewable resources, leaves intact an already-existing exemption.

Commenters Bolton and Robertson also criticize the caption for failing to tell voters that not all utilities are affected by the proposed increase in the minimum amount of electricity sales that must come from qualifying electricity. They thus appear to suggest that the caption should clarify, as the summary does, that the requirements at issue apply to utilities that "sell[] at least 3% of all electricity sold to consumers" in the state. But the caption, in stating that the proposed measure "[i]ncreases percentage of electricity required from renewable sources," is accurate. That statement does not assert that the proposed increase would apply to each and every entity that produces or supplies electricity. Although the caption does not specifically identify those who must comply with the proposed increases, that is a result of the caption's 15-word limit. In any event, the summary explains that the requirements at issue apply to utilities that "sell[] at least 3% of all electricity sold to consumers."

2. Why we have modified the second clause in the caption but have not added a reference to the proposed measure's coal-related requirements.

The second clause in the caption reads, "reduces new buildings' permissible net energy consumption." That phrase describes section 9 of the proposed measure, which would amend ORS 455.511 to add the following subsection:

> (4) The director [of the Department of Consumer and Business Services] shall require updates to the energy efficiency standards of the state building code to ensure a 65% reduction in the annual net energy consumption of newly constructed buildings by 2032, as compared to the requirements of the 2014 state building code. In establishing the code changes required by this section, the director shall consider generally accepted construction codes and standards.

Mr. Cosgrove suggests that the caption "overstates IP 73's effect on energy consumption"; he asserts that rather than reducing net energy consumption, IP 73 "would only require standards that set a goal of such energy reduction." Yet the caption already accurately explains that the proposed measure would reduce the "permissible" level of net energy consumption. It thereby conveys that, whether or not builders ultimately comply with the new standards, the measure will affect the level of "net energy consumption" that is considered permissible under the law.

Commenter Nicholas Blosser asserts that the caption's description of the proposed reduction in permissible energy consumption is "incomplete and confusing," and that it uses "technical language that would be incomprehensible to most voters." Although the meaning of "net energy consumption" is not necessarily self-evident, "net energy consumption" is the phrase that section 9 of the measure uses in amending ORS 455.511, and the proposed measure does not define that phrase. Further, chapter 455 of the Oregon Revised Statutes does not appear to define the phrase. Accordingly, we have chosen to continue to use the phrase that IP 73 uses.

At the same time, we agree with commenters Bolton and Robertson that, because neither current law nor the measure defines "net energy consumption," the caption—and the rest of the ballot title—should note that the phrase is undefined. As a result, we have placed "net energy consumption" in quotation marks and noted that the phrase is undefined. To make room for the word "undefined," we have changed "increases percentage of electricity" to "increases electricity percentages."

Mr. Blosser also describes the caption as "underinclusive, because it fails to mention that [section 3 of] the Initiative requires electric utilities to phase out coal generated electricity from their electricity supplies." *See* IP 73, § 3(1) (requiring electric company to "eliminate all coal-fired resources from its electricity supply" no later than January 1, 2030). Although we have described section 3 in the summary, we were unable to do so in the caption (or in the result statements) due to the applicable word limitation. That is, if we described section 3 in the caption, we would need to omit the explanation that the measure "reduces new buildings' permissible net energy consumption." We concluded that the caption needed to refer to the reduction required by section 9 for two reasons. First, section 9 reflects a significant aspect of the proposed measure; it affects all newly constructed buildings, and would require a 2/3 reduction in permissible "net energy consumption" over the next 16 years. Second, because section 9 affects the construction industry and those involved in it, it is quite different from the other portions of the measure, which focus on electric companies and utilities and the types of electricity that they may sell. In contrast, the measure's effect on the ability to sell coal-generated electricity can be viewed as closely related to the other portions of the measure—the portions affecting the types of electricity that electric companies and utilities can sell—that the caption's first clause (addressing electricity from "renewable sources") already refers to.

The certified caption reads:

Increases electricity percentages required from renewable sources; reduces new buildings' permissible "net energy consumption" (undefined)

B. The "yes" result statement

The draft ballot title's "yes" result statement read:

> **Result of "Yes" Vote:** "Yes" vote increases percentage of electricity sales required from renewable sources; renewable energy certificates (RECs) expire; will reduce permissible net energy consumption for new buildings.

For the same reasons recounted with respect to the caption, we have placed "net energy consumption" in quotation marks and noted that the phrase is "undefined." To make room for the word "undefined," we have changed "will reduce" to "reduces."

Each commenter offered additional criticisms of the "yes" result statement that mirror criticisms that were offered with respect to the caption. We respond to those criticisms by relying on the explanations we provided above with respect to the caption.

In addition, Mr. Bolton and Mr. Robertson suggest that the "yes" result statement should inform voters that "a result of the passage of IP 72 as written will be an increase in rates charged for electricity." But because nothing in the proposed measure or existing law necessarily compels that conclusion, we have declined to adopt their suggestion.

Mr. Blosser asserts that the "yes" result statements should not refer to the proposed limitation on using renewable energy certificates (RECs), in part because that limitation is not sufficiently significant to warrant a mention. On the one hand, it is true that the manner in which a utility can use an REC to satisfy renewable portfolio standards could be described as a "subset" of a broader subject that the proposed measure addresses—the broader subject being the percentages of electricity sales that must come from renewable energy sources. On the other hand, the measure's impact on how utilities can use RECs, and the proposed imposition of a three-year limit (compared to current law's declaration that RECs may be used "indefinitely"), is undoubtedly one of the measure's results. Consequently, the "yes" result statement appropriately refers to that impact.

Mr. Blosser argues that the phrase "renewable energy certificates (RECs) expire" is inaccurate, because it suggests that, under the proposed measure, *all* RECs would expire regardless of when they were issued. In fact, he notes, the measure would create a three-year limit only with respect to RECs that issue after the measure becomes law. Mr. Bolton and Mr. Robertson also describe the reference to RECs as "expir[ing]" as inaccurate; they assert that the purpose to which a utility is authorized to use an REC is not limited to satisfying qualifying-electricity standards, and they assert that other entities who are not bound by those standards use RECs. Thus, although IP 72 creates a limited time within which to use RECs for the purpose of meeting qualifying-electricity requirements, the measure does not dictate that RECs will "expire" with respect to any other purposes.

Significantly, however, the "yes" result statement does not expressly state that, under the proposed measure, *all* RECs would expire. Moreover, the "yes" result statement, in observing that RECs will "expire" under the measure, is accurate: Under the measure, certain certificates' ability to satisfy qualifying-electricity standards will (in contrast to current law) terminate after three years. Consequently, we have not modified the portion of the statement stating that RECs will "expire."

The certified "yes" result statement reads:

> **Result of "Yes" Vote:** "Yes" vote increases percentage of electricity sales required from renewable sources; renewable energy certificates (RECs) expire; reduces permissible "net energy consumption" (undefined) for new buildings.

C. The "no" result statement

The draft ballot title's "no" result statement read:

> **Result of "No" Vote:** "No" vote retains current minimum percentages for electricity sales from renewable sources; RECs do not expire; retains current net energy consumption standard for new buildings.

The commenters' suggestions for altering the "no" result statement mirror suggestions that we chose not to adopt with respect to the caption and "yes" result statement. We thus respond to those suggestions by relying on the responses that we articulated earlier in this letter.

The certified "no" result statement reads:

> **Result of "No" Vote:** "No" vote retains current minimum percentages for electricity sales from renewable sources; RECs do not expire; retains current net energy consumption standard for new buildings.

D. The summary

The draft ballot title's summary read:

Summary: If a utility sells at least 3% of all electricity sold to consumers, current law generally requires—for 2020-2024—at least 20% of utility's electricity sales to be "qualifying electricity," which includes electricity from "renewable energy sources" (defined by current law); subsequently, required minimum is 25%; to meet minimums, may use RECs (RECs are issued to utilities that produce more qualifying electricity than required, may be sold/transferred between utilities). Proposed measure increases required minimum: 22% for 2020-2024, 30-45% for 2035-2039, 50% subsequently; RECs would expire after three years; electric companies must phase out coal-generated electricity sales by 2030; would reduce, by 2032, new buildings' permissible net energy consumption by 65%. Other provisions.

Mr. Cosgrove criticizes the summary's statement that IP 73 "would reduce, by 2032, new buildings' permissible net energy consumption by 65%," on the grounds that it fails to convey that "the initiative would require stricter standards, not reduce the amount of energy new buildings would consume." Yet the summary's description—that the measure "reduce[s] * * * new buildings' permissible net energy consumption"—mirrors section 9's text, which requires standards that will "ensure a 65% reduction in the annual net energy consumption of newly constructed buildings."

Mr. Blosser suggests that the summary should state "that current law sets minimum standards for building energy efficiency." Yet the summary already implicitly refers to any current standards that apply, by noting that the measure would reduce the permissible level of net energy consumption by 65%.

Mr. Blosser asserts that the word "sales"—in the phrase "phase[s] out coal-generated electricity sales"—is inaccurate; he argues that, under the measure, "[c]oal-generated electricity may not be provided to consumers, whether by sale or otherwise." Mr. Blosser is mistaken. Section 3(1) of the proposed measure provides that an electric company "shall eliminate all coal-fired resources from its electricity supply." But something qualifies as an "electricity supply," as defined by section 2(d), only if it constitutes energy that is "supplied to *and included in the electricity rates* of retail electricity consumers." (Emphasis added.) As a result, the measure does not necessarily prohibit electric companies from providing coal-generated electricity to consumers; it only prohibits them from doing so if they include that electricity "in the electricity rates" that consumers must pay. Accordingly, the caption accurately states that the measure "phases out coal-generated electricity *sales*," and it does not state that the measure would eliminate coal-generated electricity. (Emphasis added.)

Mr. Blosser criticizes the summary for not explaining that "under current law, there are no restrictions on the use of electricity from coal." Yet the summary accurately informs voters of the pertinent existing legal obligations affecting the utilities at issue—it informs voters that those utilities are generally required to sell a certain percentage of "qualifying electricity," which includes electricity from renewable energy sources. And by informing voters that the proposed measure would not permit electric companies to sell coal-generated electricity after 2029, the summary implicitly informs voters that no similar prohibition or limitation currently exists.

Mr. Blosser criticizes the summary for devoting more words to REC-related explanations than to the proposed measure's effect on sales of coal-generated electricity. But how current law defines RECs—and, accordingly, how the proposed measure affects REC use—is somewhat complicated. The measure's impact on sales of coal-generated electricity is easier to explain, and that explains the difference in the number of words used to describe the measure's various aspects.

In addition to criticizing the summary for the same reasons that they criticize other portions of the draft ballot title, Mr. Bolton and Mr. Robertson assert that the summary misleads voters by stating that "'qualifying electricity' * * * includes electricity from 'renewable energy sources' (defined by current law)." They assert that the summary suggests that "qualifying electricity" encompasses renewable energy sources and other sources when, in fact (according to them) the phrase "renewable energy sources" is broader than the phrase "qualifying electricity." They are mistaken. ORS 469A.005(9) defines "qualifying electricity" as "electricity described in ORS 469A.010." ORS 469A.010 describes three categories of electricity, most of which come from a "renewable energy source," but it appears that one of those categories—"electricity that the Bonneville Power Administration has designated as environmentally preferred power" (ORS 469A.010(3))—can constitute qualifying electricity without necessarily coming from a "renewable energy source." As a result, "qualifying electricity" *is* a broader term than "renewable energy source," even if "qualifying electricity" does connote, for the most part, electricity from "renewable energy sources."

Finally, petitioners Bolton and Robertson make three criticisms that the Attorney General agrees with. First, they observe that the summary, by stating that "RECs are issued to utilities that produce more qualifying electricity than required," may mislead voters. As they observe, OAR 330-160-0015(15) provides that one REC "is created in association with the generation of one MegaWatt-hour (MWh) of Qualifying Electricity"; in other words, a utility—in order to have RECs issued to it— need not produce *more* qualifying electricity than it is required to. It instead will receive an REC any time that it generates a single MWh of qualifying electricity. As a result, we have modified the summary so that it more accurately describes how RECs are issued.

We also have modified the summary to clarify that the proposed measure would not render *all* RECs unusable after three years; the summary, as modified, reflects that the three-year limit will apply only to RECs issued after the measure's effective date, and will apply only if an entity wishes to use an REC to satisfy ORS 469A.052's qualifying-electricity requirements.

To make room for the clarifications described above, we have eliminated the words "a" and "utility's" from the summary's first sentence.

Second, Mr. Bolton and Mr. Robertson criticize the summary for using the phrase "phases out" when it states that the measure "phases out coal-generated electricity sales," instead of simply stating that the measure requires coal-generated-electricity sales to be eliminated no later than 2030. We agree that, in the summary, use of the word "eliminates" would be more accurate, particularly given that the summary explains that companies may have until 2030 to stop making coal-generated-electricity sales (we note that use of "eliminates" by itself, without the additional explanation that companies may have until 2030 to comply with the requirement, might give the mis-impression that the measure would require companies to *immediately* stop selling coal-generated electricity).

Third, Mr. Bolton and Mr. Robertson accurately note that the summary, instead of stating that the measure will make the required minimum sales of qualifying electricity 30-45% for "2035-2039," should identify "2025-2039" as the correct span of years.

The certified summary reads:

> **Summary:** If utility sells at least 3% of all electricity sold to consumers, current law generally requires—for 2020-2024—at least 20% of electricity sales to be "qualifying electricity," which includes electricity from "renewable energy sources" (defined by current law); subsequently, required minimum is 25%; to meet minimums, may use RECs (issued for each MegaWatt hour of renewable electricity produced; may be sold/transferred, used for future years). Proposed measure increases required minimum: 22% for 2020-2024, 30-45% for 2025-2039, 50% subsequently; new RECs usable for three years to meet minimums; electric companies must eliminate coal-generated electricity sales by 2030; would reduce, by 2032, new buildings' permissible "net energy consumption" (undefined) by 65%. Other provisions.

E. Conclusion

Upon further review of the proposed measure, and in response to the comments we received, we have modified the draft ballot title's caption, "yes" result statement, and summary. We certify the attached ballot title under ORS 250.067(2).

Sincerely,

/s/ Rolf C. Moan

Rolf C. Moan
Senior Assistant Attorney General
rolf.moan@doj.state.or.us

RCM:aft/7115029

Enclosure

Nicholas Blosser
6330 SE 32nd Avenue
Portland, OR 97202

Steven Berman
Stoll Berne PC
209 SW Oak St Ste 500
Portland OR 97204

Margaret Ngai
5623 SE Insley Street
Portland, OR 97206

Jill Gibson
Gibson Law Firm LLC
1500 SW Taylor St
Portland OR 97205

Greg Chaimov
Davis Wright Tremaine LLP
1300 SW 5th Ave Ste 2400
Portland OR 97201

Certified by Attorney General on January 26, 2015.
/s/ Rolf Moan
Assistant Attorney General

BALLOT TITLE

Increases electricity percentages required from renewable sources; reduces new buildings' permissible "net energy consumption" (undefined)

Result of "Yes" Vote: "Yes" vote increases percentage of electricity sales required from renewable sources; renewable energy certificates (RECs) expire; reduces permissible "net energy consumption" (undefined) for new buildings.

Result of "No" Vote: "No" vote retains current minimum percentages for electricity sales from renewable sources; RECs do not expire; retains current net energy consumption standard for new buildings.

Summary: If utility sells at least 3% of all electricity sold to consumers, current law generally requires—for 2020-2024—at least 20% of electricity sales to be "qualifying electricity," which includes electricity from "renewable energy sources" (defined by current law); subsequently, required minimum is 25%; to meet minimums, may use RECs (issued for each MegaWatt hour of renewable electricity produced; may be sold/transferred, used for future years). Proposed measure increases required minimum: 22% for 2020-2024, 30-45% for 2025-2039, 50% subsequently; new RECs usable for three years to meet minimums; electric companies must eliminate coal-generated electricity sales by 2030; would reduce, by 2032, new buildings' permissible "net energy consumption" (undefined) by 65%. Other provisions.

NOTICE OF FILING AND PROOF OF SERVICE

I certify that on March 2, 2016, I directed the original Respondent's Answering Memorandum to Petitions to Review Ballot Title Re: Initiative Petition No. 73 to be electronically filed with the Appellate Court Administrator, Appellate Records Section, and electronically served upon Gregory A. Chaimov, attorney for petitioners Scott D. Bolton and Dave Robertson; Steven C. Berman, attorney for petitioner Nicholas Blosser; and Jill Odell Gibson, attorney for petitioner Paul S. Cosgrove, by using the court's electronic filing system.

I further certify that on March 2, 2016, I directed the Respondent's Answering Memorandum to Petitions to Review Ballot Title Re: Initiative Petition No. 73 to be served upon Margaret Ngai, chief petitioner, by mailing a copy, with postage prepaid, in an envelope addressed to:

Margaret Ngai
5623 SE Insley Street
Portland OR 97206

/s/ Rolf C. Moan

ROLF C. MOAN #924077
Senior Assistant Attorney General
rolf.moan@doj.state.or.us

Attorney for Respondent
Ellen F. Rosenblum, Attorney General,
State of Oregon