LBNL-44E

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Reading the Tea Leaves: How Utilities in the West Are Managing Carbon Regulatory Risk in their Resource Plans

Galen Barbose, Ryan Wiser, Amol Phadke, and Charles Goldman

Environmental Energy Technologies Division

March 2008

Download from *http://eetd.lbl.gov/ea/EMS/EMS_pubs.html*

The work described in this report was funded by the Permitting, Siting. and Analysis Division of the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Disclaimer

This document was prepared as an account of work sponsored by the United States Government. While this document is believed to contain correct information, neither the United States Government nor any agency thereof, nor The Regents of the University of California, nor any of their employees, makes any warranty, express or implied, or assumes any legal responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by its trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or The Regents of the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

Ernest Orlando Lawrence Berkeley National Laboratory is an equal opportunity employer.

LBNL-44E

Reading the Tea Leaves: How Utilities in the West Are Managing Carbon Regulatory Risk in their Resource Plans

Prepared for the
Office of Electricity Delivery and Energy Reliability
U.S. Department of Energy

At the request of the Western Interstate Energy Board

Principal Authors

Galen Barbose, Ryan Wiser, Amol Phadke, and Charles Goldman

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

March 2008

The work described in this report was funded by the Permitting, Siting, and Analysis Division of the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Acknowledgements

The work described in this report was funded by the Permitting, Siting and Analysis Division of the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The study was conducted in response to a request by the Western Interstate Energy Board (an arm of the Western Governors Association), who are interested in supporting coordination of regional electric infrastructure, including assessing factors that could significantly affect the region's future generation mix, demand-side resources, and transmission system infrastructure needs. The authors would like to thank Larry Mansueti (DOE Office of Electricity Delivery and Energy Reliability) and Doug Larson (Western Interstate Energy Board) for their support of this project. For their review and helpful comments on a draft of this report, the authors would also like to thank: Mark Bolinger (Lawrence Berkeley National Laboratory), Phil Carver (Oregon Department of Energy), David Clement (Seattle City Light), Joe Eto (Lawrence Berkeley National Laboratory), Sy Goldstone (California Energy Commission), Corinne Grande (Seattle City Light), Lucy Johnston (Synapse Energy Economics), Clint Kalich (Avista), Brian Lanspery (Idaho Public Utilities Commission), Ron Lehr (independent consultant), Lainie Motamedi (California Public Utilities Commission), Philip Poppoff (Puget Sound Energy), David Schlissel (Synapse Energy Economics), Lisa Schwartz (Oregon Public Utilities Commission), Rich Sedano (Regulatory Assistance Project), and Garrett Voerman (Seattle City Light). Any remaining errors or omissions remain our own.

Table of Contents

List of Figures and Tables

Executive Summary

The long economic lifetime and development lead-time of many electric infrastructure investments requires that utility resource planning consider potential costs and risks over a lengthy time horizon. One long-term and potentially far-reaching financial risk currently facing the electricity industry is the uncertain cost of future carbon dioxide (CO_2) regulations. Recognizing the potential magnitude of this risk, many utilities – sometimes spurred by state regulatory requirements – are beginning to actively assess carbon regulatory risk within their resource planning processes, and to evaluate options for mitigating that risk. However, given the relatively recent emergence of this issue and the rapidly changing political landscape, methods and assumptions used to analyze carbon regulatory risk, and the impact of this analysis on the selection of a preferred resource portfolio, vary considerably across utilities.

In this study, we examine the treatment of carbon regulatory risk in utility resource planning, through a comparison of the most-recent resource plans filed by fifteen investor-owned and publicly-owned utilities in the Western U.S. Together, these utilities account for approximately 60% of retail electricity sales in the West, and cover nine of eleven Western states. This report has two related elements. First, we compare and assess utilities' approaches to addressing key analytical issues that arise when considering the risk of future carbon regulations. Second, we summarize the composition and carbon intensity of the preferred resource portfolios selected by these fifteen utilities and compare them to potential CO_2 emission benchmark levels.

Utilities' analysis of carbon regulatory risk

Utilities in the West are increasingly accounting for the possibility of future carbon regulations when developing their long-term resource strategies, but current practice varies considerably. Our review of recent Western utility resource plans yields the following key findings (with recommendations based on these findings summarized in Text Box ES-1):

- ***Almost without exception, Western utility resource plans incorporate future carbon regulations into their portfolio analysis, but often assume relatively moderate carbon emission prices.*** All fifteen utilities in our sample, except LADWP, estimated candidate portfolio costs with a future carbon tax or cap-and-trade system (see Figure ES-1). Eleven utilities included carbon regulations in their base-case portfolio analysis, assuming levelized carbon emission prices, over the 2010-2030 timeframe, ranging from \$4 to \$20 per short ton of CO_2 (2007\$). Most utilities' base-case carbon price assumptions are near the low end of the spectrum relative to EIA's projections of carbon emission prices under a number of federal policy proposals (the 2003 and 2007 McCain-Lieberman bills and the Bingaman 2006 proposal), and relative to a set of projections developed by Synapse Energy Economics (Johnston et al. 2006) that synthesize the results from modeling studies of various policy proposals. Eleven utilities conducted scenario analyses to evaluate portfolio costs under alternate carbon emission price projections to their base-case. Although most considered a reasonably broad range of scenarios (i.e., levelized prices exceeding \$30-40/ton), several utilities did not examine prices representative of a relatively aggressive carbon policy (e.g., Nevada Power and Sierra Pacific considered a maximum levelized price of only \$7/ton, and Avista considered levelized prices up to \$22/ton).

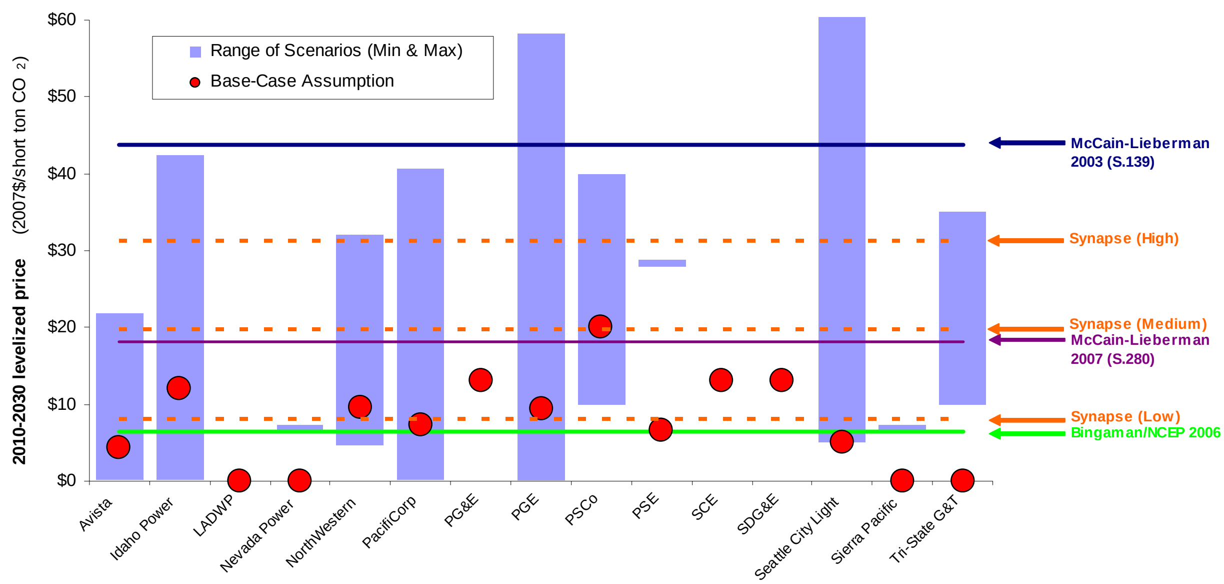


Figure ES - 1. Levelized CO_2 Emission Prices Used in Utility Resource Plans (2010-2030)

Notes: See Table A - 3 in the appendix for notes on conventions and assumptions used to construct the figure.

- ***Most utilities evaluated a range of low-carbon candidate portfolios with aggressive levels of energy efficiency and renewables.*** As indicated in Figure ES-2, all but three utilities (Sierra Pacific, Nevada Power, and Tri-State) evaluated at least one candidate portfolio with a composite CO_2 emission rate (based on all new, physical demand- and supply-side resources in the portfolio) of less than half that of a natural gas-fired combined cycle gas turbine (CCGT). Utilities' low-carbon candidate portfolios generally reflect aggressive underlying levels of energy efficiency and new renewables. Of the fifteen utilities, nine included in all candidate portfolios the "maximum achievable" energy efficiency program savings, with incremental annual energy savings ranging from 0.6% to 1.3% of total retail sales and cumulative savings ranging from 30% to 73% of projected retail sales growth over their planning periods. All fifteen utilities also evaluated candidate portfolios with new renewables, and most evaluated one or more candidate portfolio in which renewables constitute at least 50% of all new supply-side resources in the portfolio and 10% of the utility's total retail sales. Thirteen of the utilities are subject to a renewables portfolio standard (RPS), but most of these utilities evaluated candidate portfolios with new renewables above and beyond the level strictly needed for RPS compliance. Utilities' consideration of low-carbon resources other than energy efficiency and renewables was much more limited. Six utilities evaluated candidate portfolios containing coal-fired integrated gasification combined cycle (IGCC) generation with carbon capture and storage (CCS). One utility also evaluated CCS in combination with pulverized coal and natural gas-fired CCGT generation. Only two utilities evaluated candidate portfolios with new nuclear.

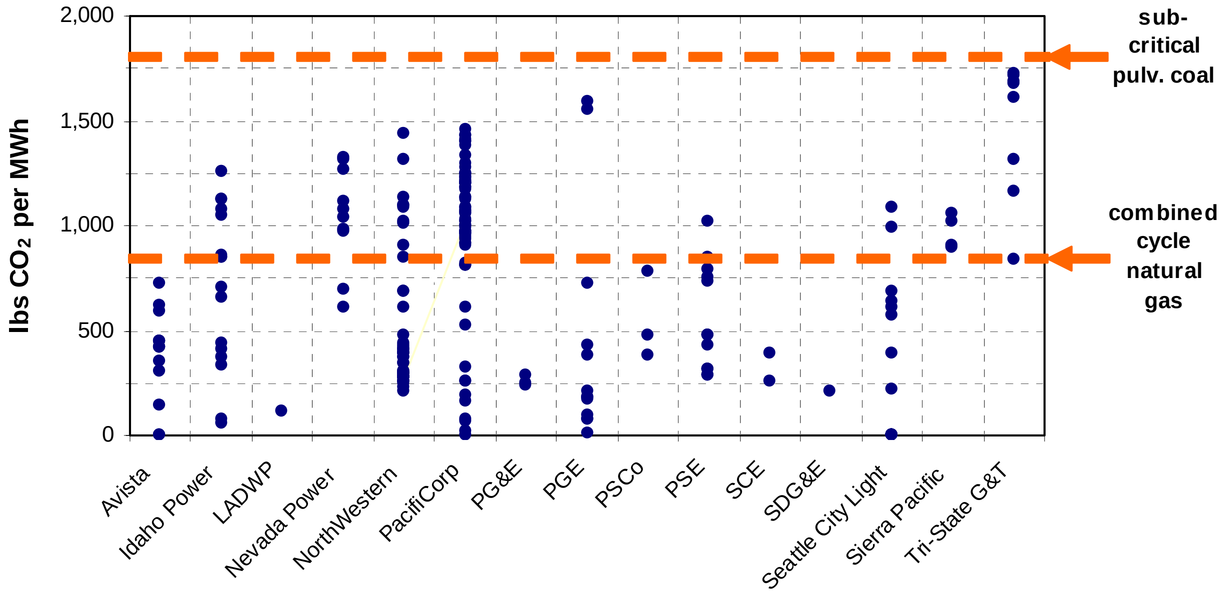


Figure ES - 2. Composite CO_2 Emission Rates of Candidate Portfolios

Notes: Composite emission rates are equal to the average emission rate of all new supply and demand-side resources in the portfolio, weighted by the annual energy production (or savings, in the case of energy efficiency) of each resource in the last year of the planning period. Avista and Seattle City Light both evaluated multiple zero-carbon candidate portfolios, which are super-imposed upon one another in the figure (and therefore not individually discernable). Avista's resource plan identified the composition of 15 candidate portfolios, shown in the figure; however, the utility constructed a larger number of candidate portfolios. See Appendix A for additional conventions and assumptions used to construct the figure.

- ***When modeling the impact of carbon regulations on portfolio costs, utilities often ignore potentially significant indirect impacts.*** Though Western utility resource plans generally considered the potential direct emissions cost of future carbon regulations when estimating the cost of their candidate resource portfolios, relatively few plans acknowledge and evaluate the full range of potentially significant, indirect effects of carbon regulations on their planning environment. These indirect effects could include changes in: wholesale electricity market prices, natural gas prices, air pollutant permit prices, load growth, coal plant retirements, regional generation and transmission expansion, continued availability of existing federal incentives for various generation technologies, generation capital costs, and technology development.

- ***It is often unclear how, or if, utilities' analysis of uncertainty in carbon emission costs informed the selection of their preferred portfolios.*** Utilities can account for *expected* carbon regulation costs by including a projection of carbon emission prices in their base-case portfolio analysis. Because utilities typically rely quite explicitly on their base-case results when selecting a preferred portfolio, it is generally clear that their assumptions about expected carbon regulatory costs had the opportunity to influence their portfolio selection. In contrast, accounting for *uncertainty* in carbon costs requires that candidate portfolio costs be compared across a range of carbon emission price projections. As mentioned previously, eleven utilities evaluated candidate portfolio costs under multiple carbon price scenarios. However, of these eleven utilities, six made no reference in their resource plan to variation in portfolio costs across carbon price assumptions when explaining the rationale for selecting their preferred portfolio. As a result, it was unclear what, if any, role these utilities' analyses of carbon cost uncertainty might have played in selecting their preferred portfolios. The other five utilities did explicitly refer to results from alternate carbon price scenarios when selecting their preferred portfolios, but their approaches to incorporating this information into the decision-making process differed substantially, and the utilities generally provided little explanation about how they made tradeoffs between reducing expected cost and reducing uncertainty in cost.

Text Box ES - 1. Recommendations for Analysis of Carbon Regulatory Risk

Utilities in the West are making important strides in accounting for the financial risks associated with future carbon regulations when developing their long-term resource strategies. At the same time, their assumptions and methods vary considerably, and reveal a number of opportunities for potential improvement. Accordingly, we offer the following recommendations for consideration by utility resource planners, regulators, and other stakeholders participating in the resource planning process.

- Analyze potential costs and financial risks associated with future carbon regulations.
- Consider including a reasonable estimate of the "most likely" carbon policy in the base-case scenario.
- Consider evaluating a broad range of carbon price projections to account for the risk associated with uncertainty in future carbon regulations.
- Consider evaluating a diverse set of low-carbon candidate portfolios.
- Consider constructing candidate portfolios that include the maximum achievable energy efficiency potential.
- Consider valuing the avoided carbon costs of energy efficiency and the reduced carbon regulatory risks.
- Consider constructing candidate portfolios that include the full range of renewable generation options available, and with quantities of new renewables that exceed RPS requirements.
- Consider undertaking efforts to develop sufficiently credible assumptions about the future commercial availability and cost of IGCC with CCS, CCGT with CCS, and nuclear power, so that utilities can evaluate these resources in their planning analysis.
- Consider devoting more analytic effort to accounting for the potentially significant indirect effects of future carbon regulations, such as the effects on electricity market and natural gas prices, load growth, and coal plant retirements.
- Consider developing more transparent methods and criteria for incorporating information about carbon cost uncertainty into the portfolio selection process, and for balancing the twin goals of minimizing portfolio expected cost and minimizing portfolio risk.

Carbon intensity of utilities' preferred resource portfolios

Utility resource plans typically culminate by identifying a single, preferred resource portfolio, consisting of a projection of supply- and demand-side resource acquisitions over the duration of the planning period (typically 10-20 years). Although preferred resource portfolios identified in utility resource plans generally do not represent binding, long-term commitments, they nevertheless provide perhaps the best public indication of utilities' current long-term resource strategies. In order to characterize Western utilities' exposure to carbon regulatory risk and their strategies for mitigating that risk, we compare the composition and carbon intensity of their preferred resource portfolios (see Figure ES-3). This analysis reveals a number of key trends:

- ***Energy efficiency and renewable generation are the dominant low-carbon resources in utilities' preferred portfolios.*** All utilities selected preferred portfolios that include an expansion of existing energy efficiency programs and new renewables, and more than half of the utilities selected portfolios in which energy efficiency and renewables together constitute at least 50% of all new energy resources. Only three utilities (Sierra Pacific, Nevada Power, and Tri-State) selected preferred portfolios in which either energy efficiency or renewables constitute less than 10% of all new resources.

- ***Natural gas is a common, although not universal, component in utilities' preferred portfolios.*** Twelve utilities' preferred portfolios include natural gas-fired generation, typically representing 30% or more of the total portfolio, though some utilities included only a small amount of natural gas-fired peaking capacity.

- ***Other types of low-carbon resources – most notably, new nuclear power and CCS – play a relatively minor role in utilities' preferred portfolios.*** Only two utilities (PSCo and Idaho Power) selected preferred portfolios with new nuclear,[1] and only one utility (PSCo) selected a portfolio containing IGCC with CCS (although Idaho Power's preferred portfolio includes IGCC without CCS). Three utilities also included small amounts of CHP in their preferred portfolios (i.e., 5-10% of new resources).

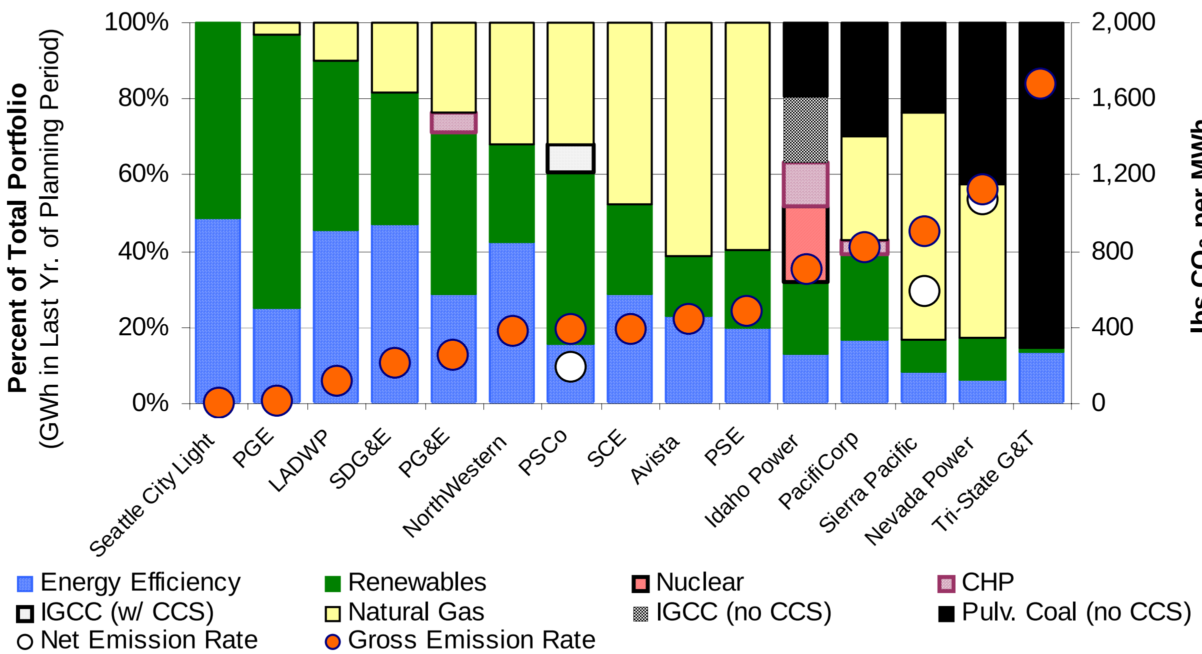


Figure ES - 3. New Resources in Utilities' Preferred Portfolios

Notes: Gross emission rate refers to the composite emission rate of all new supply- and demand-side resources. Net emission rate also accounts for emission reductions associated with planned retirements over the planning period. See Appendix A for conventions and assumptions used to construct the figure.

---

[1] PSCo added new nuclear power to its preferred portfolio beginning in 2022, but Figure ES-3 focuses on the composition of its preferred portfolio through 2020 and thus does not show the addition of new nuclear power.

- ***Pulverized coal without CCS remains a prevalent element in the preferred portfolios of utilities serving inland states.*** Five of the eight inland utilities selected preferred portfolios containing pulverized coal without CCS, representing anywhere from 20% to more than 90% of new resources in the portfolio. In contrast, none of the seven utilities whose service territories are confined to coastal states selected preferred portfolios with any coal-fired generation. Of these utilities, four are subject generator emission performance standards that effectively preclude them from constructing or contracting with coal-fired generation lacking CCS.

- ***Utilities generally are not planning to retire existing coal-fired generation for the specific purpose of reducing carbon emission costs or regulatory risks.*** Most of the fifteen utilities own coal-fired generation, but only two utilities (PGE and PSCo) evaluated retiring existing coal plants as a strategy for reducing carbon emissions and related regulatory risks. Of these two utilities, only PSCo ultimately included the retirement within its preferred portfolio. Sierra Pacific and Nevada Power also assumed in their portfolio construction process that particular coal plants would be retired within their planning periods, but these assumptions were not driven by any apparent consideration of potential carbon emissions or regulatory costs.

.

- ***The carbon intensity of utilities' preferred portfolios varies widely.*** Variation in the carbon intensity of utilities' preferred portfolios reflect dramatic differences in the composition of the portfolios. Among the ten utilities whose preferred portfolios contain no new coal without CCS, the composite CO_2 emission rates (focusing just on new supply- and demand-side in the portfolio) range from zero to approximately 475 lbs/MWh, depending largely on the amount of new natural gas-fired generation in the portfolio. The five utilities that included new coal without CCS in their preferred portfolios have composite emission rates ranging from approximately 700-1,600 lbs/MWh, depending on the relative contribution from coal. Differences in the carbon intensity of utilities' resource strategies may, in part, reflect differences in analysis of carbon regulatory risk (e.g., carbon price assumptions, the extent to which low-carbon resources and candidate portfolios were evaluated, etc.). However, other factors (e.g., state policies, fundamental strategic objectives, resource availability, and needs) likely play an important role as well and, in many cases, may predominate.

1. Introduction

The long economic lifetime and development lead-time of many electric infrastructure investments requires that utility resource planning consider potential costs and risks over a lengthy time horizon. One long-term – and potentially far-reaching – risk currently facing the electricity industry is the uncertain cost of future carbon dioxide (CO_2) regulations. Recognizing the importance of this issue, many utilities (sometimes spurred by state regulatory requirements) are beginning to actively assess carbon regulatory risk within their resource planning processes, and to evaluate options for mitigating that risk.[2] However, given the relatively recent emergence of this issue and the rapidly changing political landscape, methods and assumptions used to analyze carbon regulatory risk, and the impact of this analysis on the selection of a preferred resource portfolio, vary considerably across utilities.

At the request of the Western Interstate Energy Board (WIEB)[3], we examine the current treatment of carbon regulatory risk in utility resource planning, through a comparison of the most recent resource plans filed by fifteen investor-owned and publicly-owned utilities in the Western U.S. (see Table 1).[4, 5] Together, these utilities account for approximately 60% of retail electricity sales in the West, and cover nine of eleven Western states.[6] Our comparative analysis has two related elements.

First, we compare and assess the utilities' approaches to addressing key analytical issues that arise when considering the risk of future carbon regulations, including:

- assumptions about the future design of carbon regulations and the cost of carbon emissions;
- the type and quantity of low-carbon resources analyzed in the resource plan;
- the effects of carbon regulations on other aspects of the utility planning environment (e.g., effects on load growth, natural gas prices, and fossil plant retirements); and

---

[2] Utilities face at least two distinct sets of risks related to global climate change: the first, which we address in this study, are the financial risks associated with future regulatory actions; the second, which we do not address in this report, are the risks associated with climate change, itself (i.e., the physical impacts of climate change on electricity consumption and on generation and transmission infrastructure).

[3] WIEB is the energy policy arm of the Western Governors Association.

[4] We use the term *resource plan* as a catch-all phrase to include what are variously referred to as *integrated resource plans, least-cost plans, long-term procurement plans, default electric supply plans*, and so on. Also, note that, with a few exceptions, our review is limited to the resource plans, themselves, and did not include other documentation submitted within related regulatory proceedings, workshops, advisory group processes, etc.

[5] This work builds off of previous efforts at Berkeley Lab to evaluate Western utility resource plans, including Bolinger and Wiser (2005), which examines the treatment of renewable energy; and Hopper, Goldman, and Schlegel (2006), which examines the treatment of energy efficiency. It also builds off of past work that has explored the implications of environmental regulatory risk on utility policy, planning, and investment decisions (see, e.g., Andrews and Govil 1996, Bokenkamp et al. 2005, Cavanagh et al. 1993, Clemmer and Freese 2006, Gardiner and Associates 2006, Johnston et al. 2006, Repetto and Henderson 2003, and Wiser et al. 2005). Finally, see Keeler (2008) for a discussion of cost recovery and ratemaking issues associated with implementation of a federal cap-and-trade policy.

[6] Our sample does not include utilities from Arizona or New Mexico. Arizona suspended its integrated resource planning requirements in 1999, although utilities there are required to file 10-year plans for transmission expansion. The New Mexico Legislature recently passed legislation requiring utilities to file integrated resource plans, but the state's utilities have not yet filed their first set of plans under the new rules.

- the manner in which uncertainty in portfolio costs associated with future carbon regulations is considered in the process of selecting a preferred resource portfolio.[7]

Second, we summarize the composition of the preferred resource portfolios selected by the fifteen utilities and characterize the carbon intensity of these preferred resource portfolios. We benchmark the carbon footprint of the new resource additions associated with these preferred portfolios against the Energy Information Administration (EIA)'s projections of generation additions in the West under a number of federal climate policy proposals.

Table 1. Utility Resource Plans Included in This Study

Utility	Service Territory	Year of Resource Plan	Portfolio Construction Period*
Avista	Idaho, Washington	2007	2008-2027
Idaho Power	Idaho, Oregon	2006	2006-2025
Los Angeles Department of Water and Power (LADWP)	California	2006	2006-2025
Nevada Power	Nevada	2006	2007-2026
NorthWestern	Montana	2007	2008-2027
PacifiCorp	Oregon, Utah, Wyoming, Washington, Idaho, California	2007	2007-2016
Pacific Gas & Electric (PG&E)	California	2006	2007-2016
Portland General Electric (PGE)	Oregon	2007	2008-2012
Public Service Company of Colorado/Xcel (PSCo)	Colorado	2007	2008-2020
Puget Sound Energy (PSE)	Washington	2007	2008-2027
Southern California Edison (SCE)	California	2006	2007-2016
San Diego Gas & Electric (SDG&E)	California	2006	2007-2016
Seattle City Light	Washington	2006	2007-2026
Sierra Pacific	Nevada, California	2007	2008-2027
Tri-State Generation and Transmission	Colorado, New Mexico, Wyoming, Nebraska	2007	2007-2025

***** The portfolio construction period refers to the time horizon over which each utility identified the composition of its entire set of candidate resource portfolios, although some utilities estimated the net present value of portfolio costs over a longer time horizon. Note that PacifiCorp constructed candidate portfolios through 2026, but identified the composition of some of its candidate resource portfolios only through 2016, and PSCo constructed the supply-side of its candidate portfolios out through 2046, but identified demand-side targets only through 2020.

The remainder of this report is organized as follows:

- **Section 2** provides additional background, highlighting the potential impact of carbon regulations on the electric sector.
- **Section 3** summarizes utilities' planning assumptions about future carbon regulations and emission costs, as well as any alternate scenarios explored.

[7] We do not address utilities' assumptions about the cost and performance of different types of resources (low-carbon or otherwise); however this is another important topic for the analysis of carbon regulatory risk. See Bolinger and Wiser (2005) for information on utilities' cost and performance assumptions about various renewable electricity sources.

- **Section 4** describes the type and quantity of low-carbon resources included in utilities' candidate resource portfolios and the overall carbon intensity of candidate portfolios evaluated.
- **Section 5** highlights the extent to which utilities accounted for the full range of potentially-significant, indirect impacts of carbon regulations on their planning environment.
- **Section 6** discusses the manner in which utilities incorporated carbon risk into the process of selecting a preferred portfolio, from among the full set of candidate portfolios.
- **Section 7** summarizes the composition of the preferred resource portfolios selected by the fifteen utilities and compares these resources to EIA's own projections of resource additions in the West under the McCain-Lieberman and Bingaman proposals for federal climate legislation.
- **Section 8** highlights key findings and identifies emerging best practices for managing carbon regulatory risk in utility resource planning.
- **Appendix A** summarizes conventions and assumptions used to compare resource plans and construct figures throughout the report.
- **Appendix B** describes EIA's projections of emission reductions in the electric sector under a range of federal policy proposals.

2. The Importance of Carbon Regulatory Risk for Utility Resource Planning

The specter of future carbon regulations has emerged as a fundamental cost uncertainty for electric utilities, reflecting perceptions within the industry that regulations are increasingly likely within the typical resource planning horizon and the potentially far-reaching – but highly uncertain – impact of such regulations on electric resource economics. For example, with respect to the first of these two factors, a recent poll of approximately 100 senior electricity industry executives found that about half expected federal climate change legislation to be enacted by 2009, and more than 90% expected such legislation to be adopted by 2014 (GF Energy 2007).

These sentiments are, no doubt, fueled in part by the array of legislative proposals introduced in the U.S. Congress over the past several years and by the fact that, in the absence of federal legislation, many states have begun taking action on their own to limit greenhouse gas emissions.[8] In the West, California, Colorado, Oregon, Washington, New Mexico, Arizona, and Utah have all established statewide greenhouse gas emission reduction goals. These states, with the exception of Colorado, have joined with the Canadian provinces of British Columbia and Manitoba to form the Western Climate Initiative (WCI), which has established the objective of developing a regional cap-and-trade system and/or other market-based mechanisms to reduce their combined emissions to 15% below 2005 levels by 2020 (WCI 2007).[9] While many states' emission reduction goals have been established solely through executive order, California, Oregon, and Washington have passed legislation formally codifying their emission reduction goals, and California's law creates the regulatory authority to enforce those goals.[10] California and Washington have also both established emission performance standards for electric power generation that effectively prohibit the states' utilities from building or signing new long-term contracts with coal-fired power plants lacking carbon sequestration, and Montana adopted a more limited standard that applies only to new, utility-owned or leased coal-fired power plants.[11] Finally, Montana, Oregon, and Washington require that new power plants mitigate a portion of their projected carbon emissions.[12]

---

[8] For summaries of existing state and regional carbon policies throughout the U.S., see Johnston et al. (2006), Pew Center (2006), and Pew Center (2007).

[9] Colorado, Alaska, Idaho, Kansas, Nevada, Wyoming, as well as the Canadian provinces of Ontario, Quebec, Saskatchewan, and the Mexican state of Sonora are participating as observers in WCI.

[10] California's Assembly Bill (AB) 32, enacted in 2006, caps statewide emissions at 1990 levels in 2020, and directs the California Air Resources Board to develop regulations to achieve the 2020 goal. Washington's Substitute Senate Bill (SSB) 6001, enacted in 2007, also caps statewide emissions at 1990 levels in 2020, and ratchets down the cap to 25% below 1990 levels in 2035, and, in 2050, to the lesser of 50% below 1990 levels or 70% below projected emissions in 2050. Oregon House Bill 3543, enacted in 2007, caps statewide emissions at 10% below 1990 levels in 2020 and 75% below 1990 levels in 2050.

[11] California's Senate Bill (SB) 1368, enacted in 2006, prohibits the state's utilities from taking new ownership interest in, or signing new contracts with a term of five or more years for, baseload generation with a CO_2 emission rate exceeding that of a combined-cycle natural gas unit. Washington's SSB 6001, adopted in 2007, includes essentially the same set of provisions. Montana House Bill 25 (HB25) prohibits the State's public utility commission from approving an application by a utility to lease or acquire an equity interest in a coal plant constructed after 2006, unless the plant captures and sequesters at least 50% of the CO_2 emissions.

[12] Montana HB25 requires that utilities implement cost-effective carbon offsets if acquiring an equity interest or entering into a lease with a power plant fueled by natural gas or synthetic gas, constructed after 2006. Pursuant to Oregon House Bill 3283, enacted in 1997, the Oregon Energy Facility Siting Council requires that new baseload gas-fired generation and new non-baseload generation mitigate all projection CO_2 emissions in excess of a specified

Many states outside the West are also developing significant policies and regulations to reduce greenhouse gas emissions. Of particular note, ten states in the Northeast and Mid-Atlantic regions (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) have formed the Regional Greenhouse Gas Initiative (RGGI) and are currently in the process of developing and implementing a regional cap-and-trade system specifically targeting CO_2 emissions in the power sector.[13]

Notwithstanding the growing consensus throughout the industry that some type of carbon regulations will be adopted in the future, the specific form and timing of those regulations is highly uncertain, and thus so are the implications for electric resource economics and utility investment decisions. To broadly gauge the possible impact, Figure 1 shows the effect of carbon emission prices on the incremental operating costs of various types of generation resources, including: energy efficiency, renewable energy, nuclear power, gas-fired combined cycle gas turbine (CCGT), pulverized coal-fired generation, integrated gasification combined cycle (IGCC) with and without carbon sequestration (CCS).[14]

For reference, we also show the Energy Information Administration's (EIA) analysis of projected CO_2 emission prices that would result under three different legislative proposals: the McCain-Lieberman Climate Stewardship Act of 2003 (S.139), draft legislation prepared by Senator Bingaman in late 2006, and the McCain-Lieberman Climate Stewardship and Innovation Act of 2007 (S.280). All three of these proposals would establish economy-wide cap-and-trade systems for greenhouse gas emissions, but they differ significantly in terms of the size and timing of the emission cuts and other key provisions (see Appendix B for additional details on EIA's projected electric sector impacts under these three policy proposals). EIA's projections of CO_2 emission prices across the three policy proposals range from a low of \$6/short ton of CO_2 to a high of \$44/short ton of CO_2, when levelized over the 2010-2030 period. At the lower end of this range, an emission price of \$6/short ton would add about \$6/MWh to the operating cost of unsequestered coal-fired power generation and about \$3/MWh to the cost of a CCGT. In contrast, an emission price of \$44/short ton would have a much more dramatic effect on the relative economics of different resource options, adding about \$41/MWh to the operating cost of coal-fired generation without CCS, and about \$18/MWh to the cost of a CCGT (see Figure 1).

---

level (approximately 15-20% below the emission rate of the most efficient CCGT). Applicants for site certificates can mitigate their excess CO_2 emissions through cogeneration, by implementing mitigation projects directly or through a third party, or by providing an up-front payment (currently set at \$1.27 per short ton of CO_2) to the Climate Trust, a designated third-party provider of mitigation projects. Washington's House Bill 3141, enacted in 2004, is similar to the Oregon law, except that it is applicable to all baseload plants regardless of fuel source, and requires all projects to mitigate a flat 20% of projected CO_2 emissions. Among the set of mitigation options, applicants can pay a mitigation fee of \$1.60 per metric ton CO_2.

[13] Under RGGI, a cap on CO_2 emissions in the power sector across participating states will initially be set at 2009 levels, the year that the cap-and-trade program begins operation, and will be reduced to 10% below 2009 levels in 2019. Once implemented, the program may be extended to other sectors within the participating states.

[14] Although federal carbon policies proposed thus far have generally been based on a cap-and-trade approach, future carbon regulations could take various forms as well, including carbon taxes, generator emission performance standards, or technology-specific requirements (e.g., requirements that all new coal-fired generation come equipped with carbon capture capabilities).

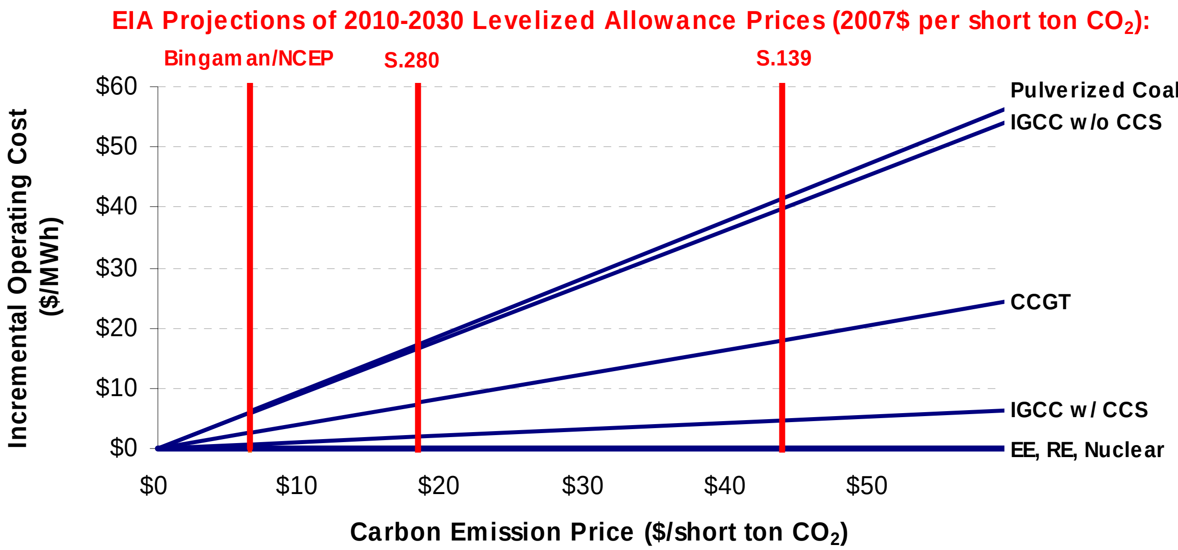


Figure 1. The Effect of Carbon Regulations on the Operating Cost of Different Resources

3. Carbon Regulations and Emission Prices Modeled in Utility Resource Plans

The starting point in quantitatively evaluating carbon regulatory risk is to develop specific assumptions about the carbon regulations that could plausibly be implemented over the lifetime of the resource investments being considered. Given the high degree of uncertainty in the nature and timing of future carbon regulations, utilities often develop a range of alternate assumptions to evaluate through scenario analyses. In this section, we describe the carbon regulations that utilities in our sample posited when estimating the cost of alternate candidate portfolios, with particular attention to their projections of potential carbon emission prices under a carbon tax or cap-and-trade system.[15] Additional methodological issues related to the assessment of carbon regulatory risk are addressed in later sections of the report.

3.1 Utility projections of carbon emission prices

With only one exception (LADWP), all of the utilities in our review incorporated a future carbon tax or cap-and-trade system into their portfolio analysis, either as part of their base-case analysis, in alternate scenarios, or both.[16] To some extent, this trend reflects resource planning requirements established by state public utility commissions (PUCs). In California, Montana, Oregon, and Washington, investor-owned utilities are required to include carbon emission costs in their resource planning analysis and/or to evaluate risks associated with future carbon emission regulations. And in Nevada and Utah, state regulations require that utilities consider environmental externalities (which can function as a proxy for future emissions regulation compliance costs) in their resource plans, but do not refer to carbon emissions specifically.

In Figure 2, we compare utilities' base-case and alternative CO_2 price projections in terms of the levelized price over the period 2010-2030. The levelized prices capture differences in utilities' assumptions about both the overall magnitude of future carbon emission prices and the timing of when carbon regulations would come into effect. We benchmark these assumptions against EIA's projections of carbon emission allowance prices under the three federal policy proposals identified previously: the original 2003 McCain-Lieberman bill (S.139), draft legislation prepared by Senator Bingaman in late-2006, and the 2007 McCain-Lieberman bill (S.280). To capture a wider set of potential policies and modeling methods and assumptions, we also show the low-, mid-, and high-range CO_2 price projections developed by Synapse Energy Economics (Johnston et al, 2006). Synapse developed these projections, in part, by synthesizing the results of eleven modeling studies of five separate federal policy proposals (all issued prior to 2006).

---

[15] From the perspective of evaluating future resource investments, carbon taxes and cap-and-trade systems are functionally similar, in that both establish a standardized price per unit of emissions, although prices are likely to be less volatile under a carbon tax (Parry and Pizer 2007). Other important differences exist between the two policies, as well as among cap-and-trade designs. Most of these differences relate primarily to distribution effects and are therefore largely immaterial from the specific perspective of a utility evaluating future resource investments; however, one design issue that is relevant to utility resource investment decisions is whether allowances are freely allocated for *new* fossil-fuel fired power plants.

[16] Bolinger and Wiser (2005) found that only seven of the twelve utilities in their review of the previous batch of Western utility resource plans evaluated portfolio costs under carbon regulations, indicating the increasing recognition by electric utilities of the significance of carbon regulatory risk.

Eleven of the fifteen utilities in our sample included carbon regulatory costs in their base-case portfolio analysis, with 2010-2030 levelized carbon emission price projections ranging from $4 to $20 per short ton of CO_2 (2007$). With the exception of PSCo, utilities' base-case carbon price projections are well below Synapse's mid-range carbon price estimate and EIA's allowance price projection for S.280, and several are even somewhat below Synapse's low range projection. It would therefore appear that some, if not most, utilities – especially those with no carbon regulation in their base-case analysis (LADWP, Nevada Power, Sierra Pacific, and Tri-State) – may be underestimating the "most likely" cost of carbon emissions.[17]

Given the inherently speculative nature of projecting future policy outcomes, it may be particularly important for resource planners to model candidate portfolio costs under a broad range of carbon emission prices. Eleven of the utilities in our review conducted scenario analyses to evaluate portfolio costs under alternate carbon price projections to their base-case, including three of the four utilities that assumed no carbon regulations in their base-case (Nevada Power, Sierra Pacific, and Tri-State). Most of these utilities evaluated scenarios with levelized carbon prices of $30/ton or greater, consistent with a relatively aggressive carbon policy. Several utilities (Avista, Nevada Power, and Sierra Pacific), however, examined a more-limited range of carbon price scenarios, and four utilities (LADWP, PG&E, SCE, and SDG&E) examined no alternate carbon price scenarios. These utilities therefore had limited ability to assess the exposure of their candidate portfolios to carbon regulatory risk.

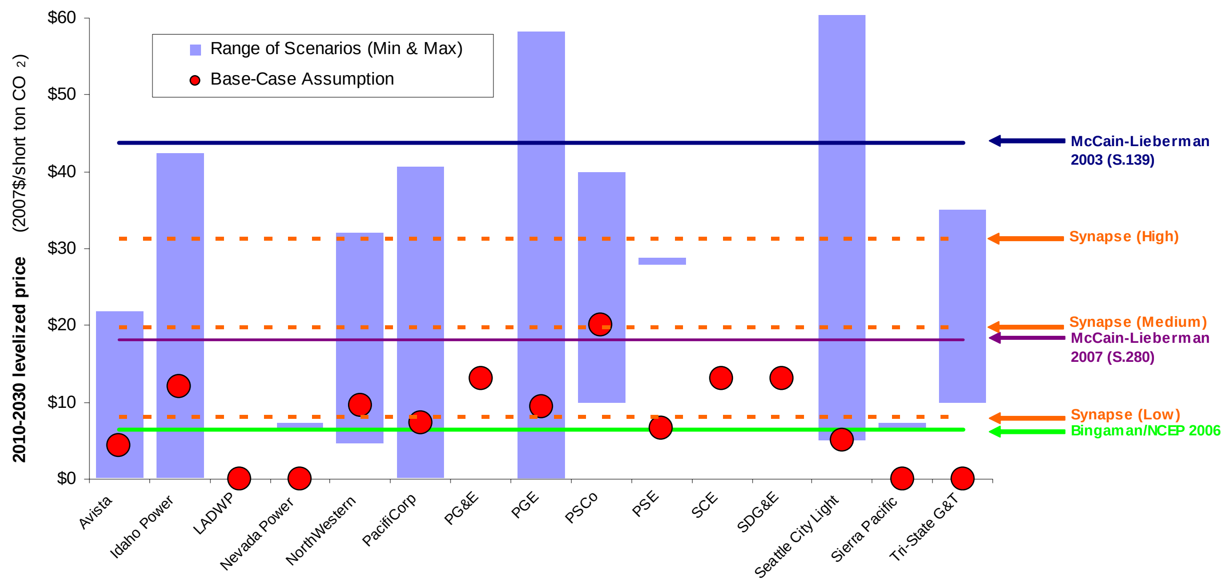


Figure 2. Levelized CO_2 Emission Prices Used in Utility Resource Plans (2010-2030)

Notes: The base-case price shown for Avista is the mean value from the utility's stochastic analysis, and the range of scenarios represents both the range of projections used in its stochastic analysis and the range of projections used in its deterministic scenario analyses. See Table A - 3 in the appendix for additional notes on conventions and assumptions used to construct this figure.

[17] Consider also that the most recent proposal by Senator Bingaman has a safety-valve price of $12/metric ton, rather than the $7/ton safety-valve price in earlier proposals that many utilities used as the basis for their base-case carbon price projection.

Table 2. Carbon Emission Price Projections in Utility IRPs

Utility	Model Run	Description	Basis for Projection
Avista	Base-case	Carbon prices modeled stochastically, based on eight distinct projections, each assigned a probability. The mean value rises from $9/metric ton (nominal) in 2015 to $14/ton in 2027. The low projection is $0. The high projection rises from $33/ton in 2015 to $60/ton in 2026	Mean value of distribution based on NCEP 2004 safety valve price; highest projection based on EIA analysis of McCain-Lieberman 2005
	Scenario	$33/metric ton (nominal) in 2015 rising to $60/ton in 2026	EIA analysis of McCain-Lieberman 2005
Idaho Power	Base-case	Constant $14/ton (2006$) starting in 2012	Oregon PUC requirement
	Scenario	Constant $50/ton (2006$) starting in 2012	
Nevada Power	Scenario	$6.08/short ton (2006$) in 2010, rising to $8.29/ton in 2026	NCEP 2004 safety valve price
NorthWestern	Base-case	$9.57/ton (nominal) in 2010 rising to $14.56/ton in 2027	2010 average of other IRP projections and MIT study, with 2.5% escalation
	Scenario	$9.57/ton (nominal) in 2016 rising to $12.56/ton in 2027	Same as above, but start date shifted to 2016
	Scenario	$9.65/ton (nominal) in 2010 rising to $83/ton in 2027	MIT Future of Coal study
PacifiCorp	Base-case	$4/ton (2008$) in 2010, rising to $8/ton in 2012 and constant thereafter	no information
	Scenario	$4/ton (2008$) in 2010, rising to $15/ton in 2016 and constant thereafter	Oregon PUC requirement
	Scenario	$4/ton (2008$) in 2010, rising to $38/ton in 2016 and constant thereafter	
	Scenario	$4/ton (2008$) in 2010, rising to $61/ton in 2016 and constant thereafter	
PG&E	Base-case	$8/ton (nominal) in 2004, 5% annual escalation	California PUC requirement
PGE	Base-case	$7.72/short ton (nominal) in 2010, with 5% annual escalation through 2025 and rising with inflation thereafter	NCEP 2004 safety valve price
	Scenario	Constant $10/short ton (1990$) starting in 2009	Oregon PUC requirement
	Scenario	Constant $25/short ton (1990$) starting in 2009	
	Scenario	Constant $40/short ton (1990$) starting in 2009	
PSCo	Base-case	$20/short ton (nominal) in 2010, 2.5% annual escalation	Comparison of fourteen projections for various federal policy proposals, including S.280 and safety-valve prices from 2005-07 Bingaman proposals
	Scenario	$10/short ton (nominal) in 2010, 2.5% annual escalation	
	Scenario	$40/short ton (nominal) in 2010, 2.5% annual escalation	
PSE	Base-case	$7/ton (nominal) in 2012, 5% annual escalation	NCEP 2004 safety valve price
	Scenario	$24.81/ton (nominal) in 2012, rising to $70.68 in 2027	EPA analysis of Jeffords 2005
SCE	Base-case	$8/ton (nominal) in 2004, 5% annual escalation	California PUC requirement
SDG&E	Base-case	$8/ton (nominal) in 2004, 5% annual escalation	California PUC requirement
Seattle City Light	Base-case	Constant $5/short ton (2006$) starting in 2007	Assumed offset price for compliance with existing city resolution
	Scenario	Constant $5/short ton (2006$) from 2007-2013 and prices rising from $20.87/ton in 2014 to $84.22/ton in 2026.	Base-case through 2013; prices in 2014-2026 based on same target as described below, but with delayed timetable
	Scenario	$20.87/short ton (2006$) in 2010 rising to $99.85/ton in 2026	Global Energy Decision analysis of carbon price needed to meet Kyoto target by 2020, assuming 2010 start date
Sierra Pacific	Scenario	$6/short ton (2007$) in 2010, rising to $8/ton in 2027	NCEP 2004 safety valve price
Tri-State	Scenario	Constant $10/ton (2007$) starting in 2007	no information
	Scenario	Constant $25/ton (2007$) starting in 2007	
	Scenario	Constant $35/ton (2007$) starting in 2007	

Notes: Carbon price projections are denoted in $/metric ton or $/short ton if utilities specified which units were used; otherwise, prices are shown simply as $/ton, which we treated as $/short ton when computing levelized prices in Figure 2.

Table 2 provides further details on the emission price projections underlying the levelized values shown in Figure 2, and the basis for those projections. The emission price projections used by investor-owned utilities in California and Oregon are based on decisions by the state PUCs that partially dictate what carbon prices are to be used in resource plans.[18] Specifically, the California PUC requires investor-owned utilities to assume, for their resource planning and procurement activities, an emission price of $8 per ton of CO_2 (nominal) starting in 2004, escalating at 5% per year (CPUC 2005). Oregon requires its utilities to conduct scenario analyses with carbon prices of $0, $10, $25, and $40 per ton (1990$), although the projections used by Oregon utilities suggest that state resource planning rules leave some room for interpretation regarding the timing of those prices. For example, PacifiCorp's carbon emission prices ramp up over a 4-6 year period beginning in 2010, while PGE's carbon prices begin at their full value in 2009.[19]

Where state PUCs have not provided specific guidance or requirements regarding carbon price assumptions, utilities often relied on recent federal legislative proposals as the basis for the carbon price projections in their resource plans. Six utilities used some variation of the safety-valve price initially recommended by the National Commission on Energy Policy (NCEP 2004), either as their base-case carbon price or for an alternate scenario. Avista, PSCo, and PSE also evaluated carbon price projections based on one or more relatively aggressive federal policy proposal, including the Jeffords Clean Power Act of 2005 (multi-pollutant legislation) and the 2005 and 2007 McCain-Lieberman proposals. Interestingly, no utilities considered emission prices specifically indicative of a state or a regional cap-and-trade program, despite the fact that policy developments are already underway in many Western states and through the WCI that may be more indicative of a near-term carbon regulatory regime than a federal policy.

3.2 Other types of carbon regulations considered

Future carbon regulations could take various forms other than a federal carbon tax or cap-and-trade system. As described previously, a number of Western states have already adopted generation carbon emission performance standards (California, Montana, and Washington) and/or carbon emission mitigation requirements (Montana, Oregon, and Washington). Utilities in states with existing emission performance standards and/or mitigation requirements all accounted for these regulations within their resource plans, provided that the regulations were in place at the time that the resource plan was prepared. In addition, several utilities considered expansions to existing state carbon regulations. Specifically, PacifiCorp considered a scenario in which an emission performance standard similar to the one already adopted in California and Washington is implemented throughout the utility's six-state service territory. PGE, meanwhile, assumed that Oregon's existing carbon emission mitigation standard for new baseload power plants would apply to coal-fired baseload generation (not just natural gas-fired generation, as is currently the case). However, beyond these examples, no utilities considered potential carbon policies, at either the state or federal level, other than a carbon tax or cap-and-trade.

[18] New Mexico also recently adopted regulations requiring its utilities to include scenario analyses in their resource plans, based on carbon prices of $8, $20, and $40 per metric ton of CO_2 (dollar denomination unspecified) beginning in 2010, escalating at 2.5% per year.
[19] The Oregon PUC recently opened a proceeding (Docket No. UM 1302) to re-examine carbon emission price scenarios, and to consider requiring that utilities include carbon emission prices in their base-case scenario and conduct "trigger analysis" to identify the level of future carbon prices that would trigger a major shift in optimal resource selection.

4. Consideration of Low-Carbon Resource Options and Portfolios

Low-carbon supply- and demand-side resources represent a physical hedge against the financial risks associated with future carbon regulations.[20] A utility's ability to assess the cost and value of mitigating its exposure to carbon regulation risk is therefore contingent upon its consideration of a diverse array of low-carbon resources and candidate resource portfolios.

To varying degrees, existing state laws and regulations may require that utilities consider certain low-carbon resources in their resource plans. In some cases, these laws and regulations lay out relatively broad principles. For example, many Western states require that, in their resource plans, utilities evaluate energy efficiency and renewables on an "equivalent" or "comparable" basis to conventional supply side options. Similarly, Montana and Washington requires their utilities to acquire all cost-effective energy efficiency, and California's "loading order" policy requires investor-owned utilities to acquire all cost-effective energy efficiency and renewable generation before investing in traditional supply-side options. In other cases, state laws and regulations establish specific goals or minimum levels of low-carbon resources that utilities are required to obtain. The most prevalent example is state renewables portfolio standards (RPS) – currently in place in eight of eleven Western states (Arizona, California, Colorado, Montana, Nevada, New Mexico, Oregon, and Washington) – which require utilities to obtain specific quantities of renewables, thereby setting a floor on the amount of renewables considered in resource plans. Similarly, energy efficiency portfolio standards (as in Colorado) and long-term energy efficiency goals (as in California) set floors on the amount of energy efficiency that utilities include in their resource plan.

Notwithstanding the various statutory and regulatory requirements mentioned above, utilities generally have discretion in deciding the type and quantity of resources to consider for their candidate portfolios. In most cases, utilities construct candidate portfolios entirely by hand. Several utilities (Avista, PacifiCorp, and PSCo) relied, to varying degrees, on capacity expansion models to construct their candidate portfolios, although even these utilities imposed various constraints on their models that affected the composition of candidate portfolios (e.g., by pre-specifying certain resources and by specifying the type, quantity, and timing of particular resources available for the model to select).

In this section, we describe the type and quantity of new low-carbon resources included within each utility's set of candidate portfolios and the overall carbon intensity of their candidate portfolios over the time frame identified in Table 1.[21] We begin by examining the manner and

[20] At the present time, a utility could attempt to *financially* hedge its exposure to carbon regulatory risk by investing in offset projects or by purchasing emission allowances through international carbon markets or voluntary U.S. markets, with the intent of using those allowances to comply with future regulations; however, there is no guarantee that such offsets or allowances would be honored under a future mandatory regulatory scheme, especially if some approach other than a cap-and-trade were adopted. In the future, if a mandatory cap-and-trade program were established in the U.S., a utility could, at that point, financially hedge its exposure to future regulatory changes (e.g., a tightening of the cap) by banking excess credits or by purchasing allowance derivatives, if such products were developed.

[21] Utility resource plans sometimes contain a preliminary description of numerous resource options, some of which may not ultimately be included in any candidate portfolios. The focus of this section, however, is limited to those resources actually included in candidate portfolios, as presented in public resource plans (i.e., we did not review

extent to which utilities incorporated energy efficiency into their candidate resource portfolios. We then turn to renewable generation, and then to other low-carbon resources, including integrated coal-gasification combined-cycle (IGCC) generation with and without carbon capture and sequestration (CCS), nuclear power, and combined heat and power (CHP).[22] We conclude the section by summarizing the carbon intensity of the full set of candidate portfolios evaluated in each utility's resource plan.

4.1 Energy efficiency

All fifteen utilities included future energy efficiency programs in at least some of their candidate resource portfolios (see Table 3).[23] Nine of the utilities established their energy efficiency targets largely outside of their portfolio analysis (if not outside of their resource plan as a whole), and thus included a fixed quantity of energy efficiency in all of their candidate portfolios. The other six utilities constructed candidate portfolios with different amounts of energy efficiency, in some cases reflecting varying assumptions about market potential or avoided costs.

Nine utilities (Avista, LADWP, NorthWestern, PGE, PG&E, PSE, SCE, SDG&E, and Seattle City Light) report that they included the "maximum achievable" energy efficiency potential in all candidate portfolios, and three of these utilities (PG&E, SCE, and PSE) considered alternate estimates of the maximum achievable potential. Maximum achievable energy efficiency potential is the portion of the total cost-effective potential that could be achieved over a given time-span, assuming that the utility funds 100% of the incremental cost of more-efficient equipment, and taking into account naturally-occurring customer investment in energy efficiency as well as practical constraints to inducing further adoption (e.g., stock turnover, market barriers, and the capability of program administrators to ramp up programs over time) [Rufo and Coito 2002, National Action Plan 2007]. The other six utilities, with the possible exception of PacifiCorp, imposed what are effectively non-economic caps on the quantity of energy efficiency considered in their resource plan – either by only pursuing a sub-set of cost-effective measures and/or by funding less than 100% of incremental measure cost. These six utilities evaluated energy efficiency savings targets well-above historical levels, although they may not have assessed all cost-effective, achievable energy efficiency savings opportunities in their resource plans.

- Nevada Power and Sierra Pacific capped the level of energy efficiency included in their candidate portfolios at the maximum quantity allowed for compliance with Nevada's RPS (equal to 25% of the total annual RPS target). The utilities' plans provide no indication of how their energy efficiency targets compare to the cost-effective and achievable potential.

---

working papers, stakeholder presentations, etc.). Also, we note that the quality of utilities' evaluation of options for mitigating carbon regulatory risk depends not only on the type and quantity of low carbon resources considered, but also on their assumptions about the cost and performance of those resources. Bolinger and Wiser (2005) address this latter issue, as it pertains to renewables; however, further work may be warranted to examine utilities' cost and performance assumptions for low-carbon resources, more broadly.

[22] Although conventional natural gas-fired combined cycle generation (CCGT) is relatively low carbon compared to unsequestered coal-fired generation, we do not include any discussion of utilities' treatment of CCGT in this section, other than to note here that all utilities did include CCGT resources within their candidate portfolios.

[23] See Hopper et al. (2006) for a more extensive discussion of the treatment of energy efficiency in recent utility resource plans.

- PSCo examined two different energy efficiency targets in its resource plan: the minimum savings required to meet Colorado's statutory energy efficiency portfolio standard (cumulative program savings over 2006-2018 equal to 5% of the utility's total retail sales and peak demand in 2006) and an Enhanced DSM target equal to 50% of the full economic potential over the planning period. PSCo projects that the Enhanced DSM level can be achieved by funding 60% of incremental measure costs.
- Tri-State included five new energy efficiency programs in several candidate portfolios. These programs passed a preliminary set of qualitative screens (e.g., related to ease of implementation, demonstrated success, etc.), with projected market penetration levels based on program incentives covering 60% of incremental measure costs.
- Idaho Power included in its candidate portfolios a specific set of energy efficiency programs determined within its resource plan to be cost-effective, with savings levels based on utility funding equal to 50% or 75% of incremental measure costs.
- PacifiCorp's approach to evaluating energy efficiency, referred to as a "decrement analysis", puts the utility somewhat outside the scope of this comparison. In particular, PacifiCorp developed its preferred supply-side portfolio accounting only for a continuation of current energy efficiency programs. It then derived the avoided cost of that portfolio for different energy efficiency load shapes, which it plans to use to evaluate the cost-effectiveness of energy efficiency resource opportunities going forward. PacifiCorp's resource plan provides an estimate of the amount of additional cost-effective energy efficiency that *could* be acquired based on the avoided cost values derived in its resource plan, but the utility does not actually include this quantity of energy efficiency in its set of candidate portfolios.

Twelve of the fifteen utilities developed energy efficiency targets through some assessment of cost-effectiveness (exceptions being Nevada Power, Sierra Pacific, and Tri-State). Evaluating energy efficiency cost-effectiveness requires a projection of avoided costs, one component of which may be avoided carbon emission costs. Most of the twelve utilities that performed a cost-effectiveness assessment appear to have incorporated their base-case carbon price projection into the assessment. The only possible exceptions are PGE and Seattle City Light, whose plans do not provide any indication of whether carbon prices were incorporated into the cost-effectiveness analysis, and LADWP, which did not include carbon emission costs in any element its resource planning analysis.

In order to assess the value of energy efficiency in mitigating carbon regulatory risk (as opposed to simply reducing expected carbon emission costs), utilities may need to evaluate energy efficiency cost-effectiveness and economic potential across a range of future carbon price projections. Only one utility, PSE, included such a sensitivity analysis *within its resource plan*.[24] PSE developed five distinct estimates of the maximum achievable energy efficiency potential, each based on a different projection of avoided costs incorporating either the base-case or an

[24] Energy efficiency targets evaluated in utilities' resource plans are often based on market potential studies. It is possible that, in estimating economic potential, some market potential studies may have considered the value of energy efficiency in reducing carbon regulatory risk (e.g., based on a sensitivity analyses around future carbon emission costs or by imposing a proxy, risk-reduction adder/multiplier). However, utilities' resource plans generally provide few details about the specific assumptions and methods used in underlying energy efficiency market potential studies; thus, we are unable to conclude, simply from a review of utilities' resource plans, whether the energy efficiency targets evaluated in the plans reflect consideration of the value of energy efficiency as a hedge against uncertain future carbon emission costs.

alternate carbon price assumption. The utility selected three of these energy efficiency targets to group with eight supply-side candidate portfolios, yielding a total of 24 integrated demand- and supply-side candidate portfolios, which it then evaluated through its portfolio analysis. This approach allowed the utility to assess whether additional energy efficiency, beyond what is cost-effective under base-case carbon price assumptions, might nevertheless be justified in light of the incremental net savings anticipated under higher carbon prices.

Table 3. Utility Approaches to Incorporating Energy Efficiency into Candidate Portfolios

Utility	Percent of Candidate Portfolios with Energy Efficiency	No. of Energy Efficiency Targets Evaluated in Candidate Portfolios*	Basis for Quantity of Energy Efficiency Included in Candidate Portfolios	Avoided Carbon Costs Incorporated into Assessment of Energy Efficiency Cost-Effectiveness
Avista	100%	1	Maximum achievable potential	Base-case carbon prices
Idaho Power	100%	1	Specific programs that pass the TRC and utility cost tests and other screens; measures funded at 50% or 75% of incremental cost	Base-case carbon prices
LADWP	100%	1	Maximum achievable potential	No information
Nevada Power	100%	1	Maximum amount eligible for RPS	n/a
NorthWestern	100%	1	Maximum achievable potential	No information
PacifiCorp	100%	n/a	Existing programs included in all portfolios; decrement analyses conducted to evaluate new programs	Base-case carbon prices
PG&E	100%	3	Maximum achievable potential (3 alternate estimates)	Base-case carbon prices
PGE	100%	1	Maximum achievable potential	No information
PSCo	100%	2	(1) minimum legislative EEPS requirement or (2) 50% of the full economic potential	Base-case carbon prices
PSE	100%	3	Maximum achievable potential (3 alternate estimates)	Base-case and scenario carbon costs
SCE	100%	2	Maximum achievable potential (2 alternate estimates)	Base-case carbon prices
SDG&E	100%	1	Maximum achievable potential	Base-case carbon prices
Seattle City Light	100%	1	Maximum achievable potential	No information
Sierra Pacific	100%	1	Maximum amount eligible for RPS	n/a
Tri-State	25%	2	(1) Five new programs that pass qualitative screens, with incentives covering 60% of measure cost, and (2) No programs	n/a

***** *This column indicates how many distinct energy efficiency targets were evaluated within the portfolio analysis. A number one (1) indicates that all portfolios included the same amount of energy efficiency; a number two (2) indicates that candidate portfolios included one of two alternate energy efficiency targets; and so on.*

Figure 3 shows the maximum amount of future energy efficiency that each utility included in its candidate portfolios. We segment the utilities according to whether or not their target is based on the maximum achievable potential. We express energy efficiency targets in terms of two metrics: (1) the average annual incremental savings as a percent of total retail load and (2) the cumulative savings over the planning period as a percent of projected retail load growth (absent future utility-funded energy efficiency programs).[25]

The nine utilities on the left-hand side of the figure included in all candidate portfolios their estimate of the "maximum achievable" energy efficiency program savings. The maximum levels of energy efficiency considered by these utilities ranged in terms of average annual savings from 0.6% to 1.3% of total retail load, and in terms of cumulative savings, from 30% to 73% of projected load growth. Differences in the maximum achievable potential of these utilities may reflect myriad factors, including differences across utilities in climate, end-use saturations, state building and appliance codes, load growth, and avoided supply-side resources, as well as potentially different methodologies used to estimate maximum achievable potential. The other six utilities did not evaluate candidate portfolios with the maximum achievable energy efficiency potential. Not surprisingly, the maximum level of energy efficiency in these utilities' candidate portfolios was notably less, with average annual savings ranging from 0.2% to 0.6% of total retail load, and cumulative savings ranging from 10% to 31% of projected load growth.

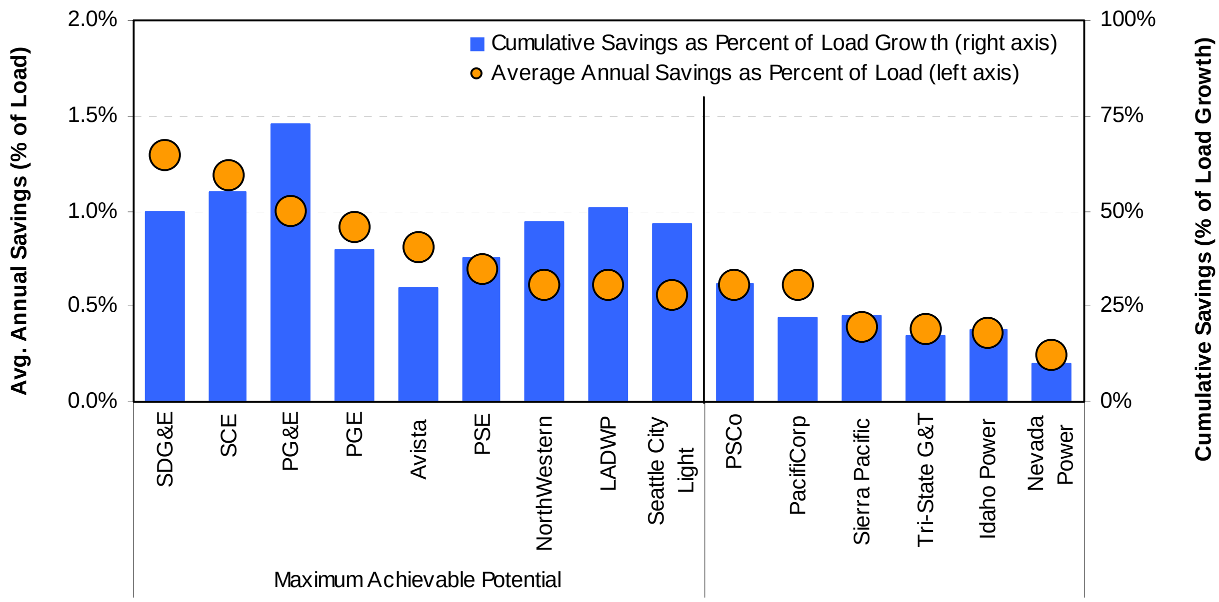


Figure 3. Maximum Energy Efficiency Program Savings in Candidate Portfolios

Notes: See Appendix A for conventions and assumptions used to construct the figure.

4.2 Renewable generation

Table 4 shows the percentage of each utility's candidate portfolios that include new renewable generation. We distinguish between utilities with and without an RPS at the time of their latest

[25] These values represent estimated energy savings from utility-funded energy efficiency programs considered for implementation over the planning period, but not savings associated with utility programs implemented prior to the planning period, energy efficiency codes and standards, or "naturally-occurring" energy efficiency adoption.

resource plan. For utilities with an RPS, we specifically show the percentage of candidate portfolios that include renewable generation beyond the level required for RPS compliance.[26]

The two utilities without an RPS (Idaho Power and Tri-State) both evaluated candidate portfolios with new renewables, though to quite different degrees. Idaho Power included new wind and geothermal in all of its candidate portfolios, while Tri-State included wind in just two of its eight candidate portfolios, and did not consider any other type of renewable generation. Of note, neither utility evaluated portfolios with biomass, despite the likely availability of such resources.

Table 4. Percentage of Candidate Portfolios with New Renewable Resources

Utility	No. of Candidate Portfolios Described in Resource Plan	Percent Exceeding Min. RPS Needs	Wind	Biomass	Solar	Geothermal	Small Hydro or Upgrade
Utilities *without* an RPS							
Idaho Power	16	n/a	100%	–	–	100%	–
Tri-State G&T	8	n/a	25%	–	–	–	–
Utilities *with* an RPS							
Avista	15	73%	73%	80%	–	80%	93%
LADWP	1	0%	100%	100%	100%	100%	–
Nevada Power	10	0%	*unspecified*		100%	*unspecified*	
NorthWestern	50	12%	90%	26%	4%	22%	–
PacifiCorp	69	99%	99%	*	*	*	–
PG&E	3	100%	100%	100%	100%	100%	–
PGE	13	92%	62%	54%	–	54%	92%
PSCo	3	67%	67%	67%	67%	33%	–
PSE	12	25%	100%	100%	–	–	–
SCE	2	100%	100%	100%	100%	100%	50%
SDG&E	1	100%	100%	100%	100%	–	–
Seattle City Light	17	6%	65%	59%	–	47%	12%
Sierra Pacific	4	0%	*unspecified*		100%	*unspecified*	

Notes: Avista, PacifiCorp, and PSCo relied to varying degrees on capacity expansion models to construct their candidate portfolios, and we indicate with an asterisk (*) any resources that were available for selection in their capacity expansion models but not added to any candidate portfolio. Avista's resource plan identified the composition of 15 candidate portfolios, as described in the table; however, the utility constructed a larger number of candidate portfolios.

The remaining thirteen utilities are all subject to a state RPS. Of these, ten utilities evaluated candidate portfolios containing additional renewables beyond what is strictly required for RPS compliance (the apparent exceptions being LADWP, Sierra Pacific, and Nevada Power).[27] Several of the ten utilities, however, appear to have evaluated portfolios with renewables in excess of RPS needs for RPS-related motivations, even if not strictly required. For example,

[26] Tri-State serves load in two states with an RPS (Colorado and New Mexico); however, as a wholesale generation and transmission co-operative that supplies local, retail load-serving entities, Tri-State is not, itself, directly subject to these states' RPS requirements, and thus its resource plan does not specifically seek to comply with an RPS. That said, Tri-State may procure renewables to assist its members with their RPS compliance.

[27] This finding contrasts with Bolinger and Wiser (2005), which reviewed the previous set of resource plans issued by Western utilities and found that most utilities did not consider renewables in excess of state RPS requirements.

PGE considered acquiring additional renewables under the presumption that the renewable energy credits (RECs) could either be banked for future years of RPS compliance or sold to others. The California IOUs were specifically directed by the California Public Utilities Commission to evaluate candidate portfolios designed to meet a 33%-by-2020 renewables portfolio target, which exceeds the current statutory requirement of 20% by 2010.

Utilities with an RPS generally considered a range of different renewable generation options. Of the eleven utilities that identified specific types of renewables in their candidate portfolios, all examined portfolios with new wind generation, ten with biomass, six with solar (not counting the two Nevada utilities who have RPS set-asides for solar), eight with geothermal, and four with small hydro or upgrades to existing hydro facilities.

Figure 4 shows the maximum quantity of new renewable generation, based on expected annual energy generation, within each utility's set of candidate portfolios. We scale these values both as a percentage of all new, supply-side resources in the candidate portfolio and as a percentage of the utility's total retail load. In calculating these indicators, we focus only on new, physical resources not already under development or under contract. We exclude what are often designated as "planned" resources in utilities' resource plans – i.e., resources not yet delivering energy to the utility at the time of its resource plan, but under development or under contract, and assumed by the utility to begin deliveries as planned, for the purpose of projecting its future resource needs. We also exclude contract renewals with existing resources, as well as any short- or medium-term market purchases.

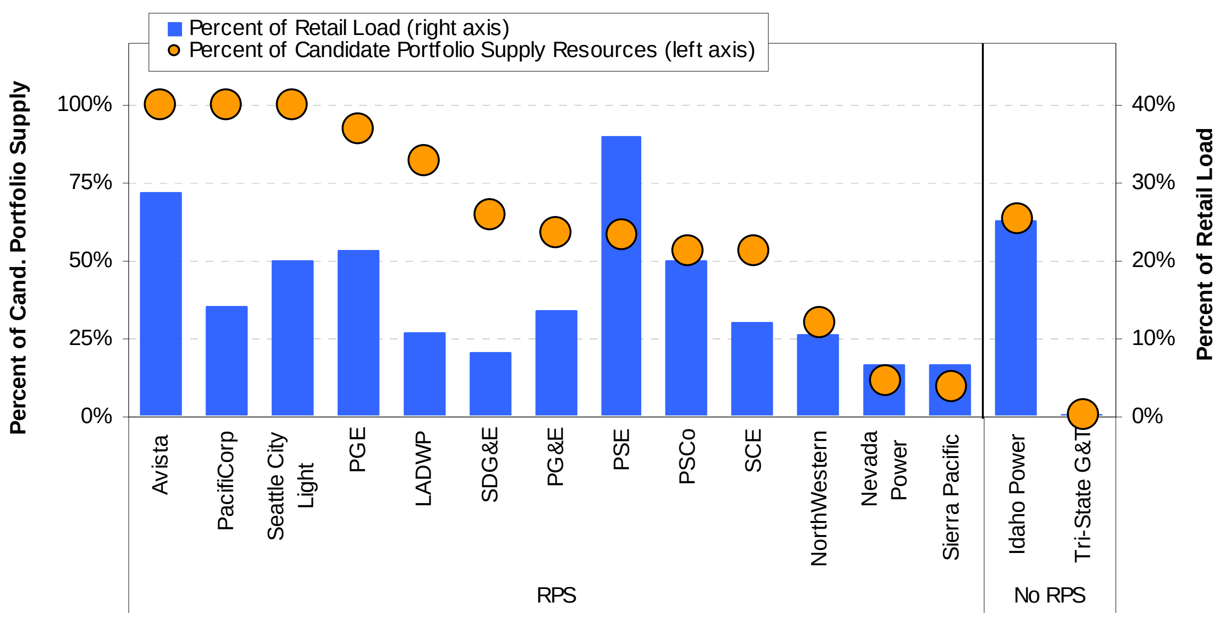


Figure 4. Maximum New Renewable Generation in Candidate Portfolios

Notes: The figure shows the maximum quantity of new renewables across each utility's set of candidate portfolios, based on expected energy production in the last year of its portfolio construction period. See Appendix A for additional conventions and assumptions used to construct the figure.

Most utilities constructed one or more candidate portfolios with incremental renewable generation representing at least 50% of all new supply-side resources over the utility's planning horizon and at least 10% of the utility's retail load. Three utilities (Avista, PacifiCorp, and Seattle City Light) evaluated one or more candidate portfolios composed entirely of new renewable generation. At the other end of the spectrum are Nevada Power, Sierra Pacific, and Tri-State, all of which examined candidate portfolios with new renewable resources comprising, at most, 12% of the new supply-side resources and 7% of retail load. As mentioned previously, the two Nevada utilities considered new renewable resources only up to their RPS needs. Tri-State limited its consideration of new renewables to 25 MW of new wind capacity.[28]

4.3 Other low-carbon generation options

Western utilities considered various other low-carbon supply options as well, including: integrated gasification combined cycle (IGCC) coal plants with carbon capture and sequestration (CCS), pulverized coal (PC) with CCS, natural gas-fired CCGT with CCS, nuclear, and combined heat and power (CHP). Table 5 shows the percentage of each utility's set of candidate portfolios including each of these low-carbon generation options. We also show the percentage of candidate portfolios including IGCC *without* CCS, even though this resource has a carbon-intensity similar to conventional pulverized coal, given the perceived potential to retrofit IGCC plants with CCS at a later point in time.

Six utilities included IGCC with CCS in some portion of their candidate portfolios; a number of these utilities, as well as several others, also examined candidate portfolios containing IGCC without CCS. Of particular note is that, with the exception of Tri-State, all utilities that evaluated candidate portfolios including conventional pulverized coal-fired generation also evaluated portfolios with IGCC, signaling growing interest in this emerging technology as an alternative to conventional coal. That said, in some cases, utilities may have considered IGCC (particularly IGCC with CCS) more for purposes of demonstration than for serious consideration as a resource that actually might be included within the preferred portfolio. For example, PSE included IGCC with CCS in a sub-set of candidate portfolios, although, in selecting its preferred portfolio, PSE categorically eliminated all candidate portfolios with CCS on the grounds that the technology is not yet commercially available. Six utilities also evaluated candidate portfolios with CHP generation, four of which included it in virtually all of their candidate portfolios. Given that CHP is likely available in most utilities' service territories, it is unclear why this resource was not more widely considered. Consideration of other types of low-carbon options was quite limited. Only one utility, NorthWestern, evaluated candidate portfolios containing pulverized coal with CCS or natural-gas fired CCGT with CCS, and only two utilities, Idaho Power and PSCo, included new nuclear power in any candidate portfolios.[29]

[28] See Bolinger and Wiser (2005) for further discussion of wind penetration caps imposed by utilities in their resource plans.
[29] Idaho Power specifically considered purchasing output from a prototype plant that the utility expects to be constructed at the Idaho National Laboratory, for which funding was authorized through the Energy Policy Act of 2005.

Table 5. Percentage of Candidate Portfolios with Other New Low-Carbon Supply-Side Resources

Utility	No. of Candidate Portfolios Described in Resource Plan	IGCC with CCS	IGCC without CCS	PC with CCS	CCGT with CCS	Nuclear	CHP
Avista	15	*	*	–	–	–	–
Idaho Power	16	6%	50%	–	–	75%	94%
LADWP	1	–	–	–	–	–	–
Nevada Power	10	–	60%	–	–	–	–
NorthWestern	50	4%	8%	40%	6%	–	8%
PacifiCorp	69	1%	52%	–	–	*	99%
PG&E	3	n/a	n/a	n/a	n/a	n/a	100%
PGE	13	8%	8%	–	–	–	–
PSCo	3	67%	–	–	–	100%	–
PSE	12	25%	33%	–	–	–	100%
SCE	2	n/a	n/a	n/a	n/a	n/a	–
SDG&E	1	n/a	n/a	n/a	n/a	n/a	–
Seattle City Light	17	–	6%	–	–	–	6%
Sierra Pacific	4	–	–	–	–	–	–
Tri-State G&T	8	–	–	–	–	–	–

Notes: Avista, PacifiCorp, and PSCo relied to varying degrees on capacity expansion models to construct their candidate portfolios, and we indicate with an asterisk (*) any resources that were available for selection in their capacity expansion models but not added to any candidate portfolio. Avista's resource plan identified the composition of 15 candidate portfolios, as described in the table; however, the utility constructed a larger number of candidate portfolios. For the three California IOUs, all resources except CHP are marked "n/a," as these utilities specify new supply-side resources other than CHP and renewables only in generic functional terms (baseload, intermediate, peaking), rather than in terms of particular technologies.

Figure 5 shows the maximum quantity of these various low-carbon resources included in each utility's candidate portfolios. Similar to the previous figure for renewable energy, we express these values as a percentage of the total quantity of new supply-side additions in the associated candidate portfolio and as a percentage of the utility's total projected retail load in the last year of its planning period.

Utilities that evaluated candidate portfolios containing IGCC without CCS or nuclear generation generally included relatively large quantities of these resources (i.e., up to 20% or more of total retail load and representing 40% or more of all supply-side resources in the corresponding candidate portfolio), reflecting the fact that these tend to be relatively large and lumpy investments. Utilities generally considered somewhat smaller quantities of IGCC with CCS, perhaps in acknowledgement of the greater level uncertainty in the commercial availability of CCS. Finally, utilities included relatively small quantities of CHP in their candidate portfolios (<20% of all new supply resources in the portfolio and <8% of total retail load), the one exception being NorthWestern, which considered a candidate portfolio consisting largely of cogeneration at the Alberta oil sands.

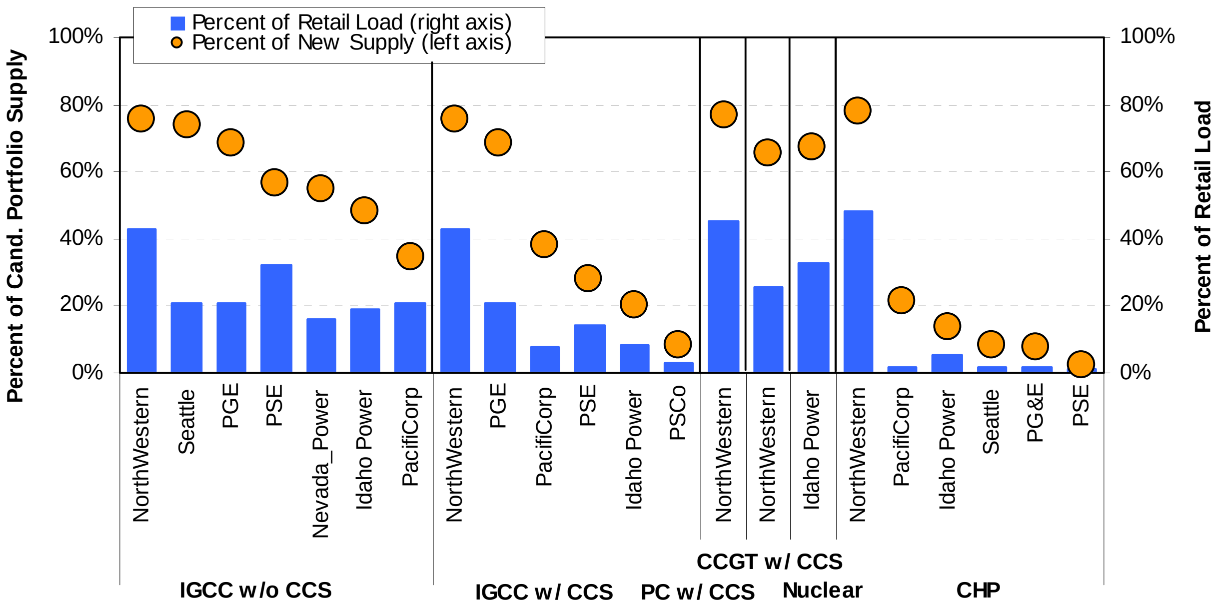


Figure 5. Maximum Amount of Other Low-Carbon Resources in Candidate Portfolios

Notes: PSCo included new nuclear power in all of its candidate portfolios beginning in 2022, but for this figure, we focus on the composition of its candidate portfolios through 2020, as this is the last year for which its resource plan identifies all candidate portfolio resources. See Appendix A for additional conventions and assumptions used to construct the figure.

4.4 Overall carbon-intensity of candidate portfolios

The degree to which utilities examined the value of mitigating carbon regulation risk in their resource plans is ultimately a function of the carbon intensity of the candidate portfolios that were examined, which itself is a function of what and to what degree different low-carbon resources were considered. Utilities that only evaluate relatively carbon-intensive candidate portfolios and that do not consider sizable amounts of energy efficiency, renewable generation, CCS, or nuclear, for example, will be unable to effectively evaluate the costs and benefits of mitigating carbon regulatory risk. Similarly, utilities that consider low-carbon resources, but only in combination with relatively high-carbon resources will also be unable to fully assess options for mitigating carbon regulatory risk.

We describe the carbon intensity of each utility's candidate portfolios in terms of their composite CO_2 emission rates. We calculated the composite emission rate of each portfolio by averaging the emission rates of the individual constituent resources in the portfolio, weighted by their expected annual energy production (or energy savings in the case of energy efficiency) in the last year of the utility's planning period. To maintain consistency across utilities and to focus on new, physical supply-side and demand-side resources, the calculation excludes contract renewals and generic short/medium-term market purchases.

As Figure 6 illustrates, most utilities did examine a reasonably large number of low-carbon candidate portfolios (or, in the case of the California utilities, examined just a small number of exclusively low-carbon candidate portfolios). The starkest exceptions are Sierra Pacific and Tri-

State, whose candidate portfolios were heavily oriented towards coal without CCS and, as previously shown, included limited quantities of renewables and energy efficiency. Nevada Power's candidate portfolios were also relatively carbon-intensive, as all but two of its ten candidate portfolios contained substantial quantities of new coal-fired generation (without CCS) and relatively low levels of incremental renewables and energy efficiency.

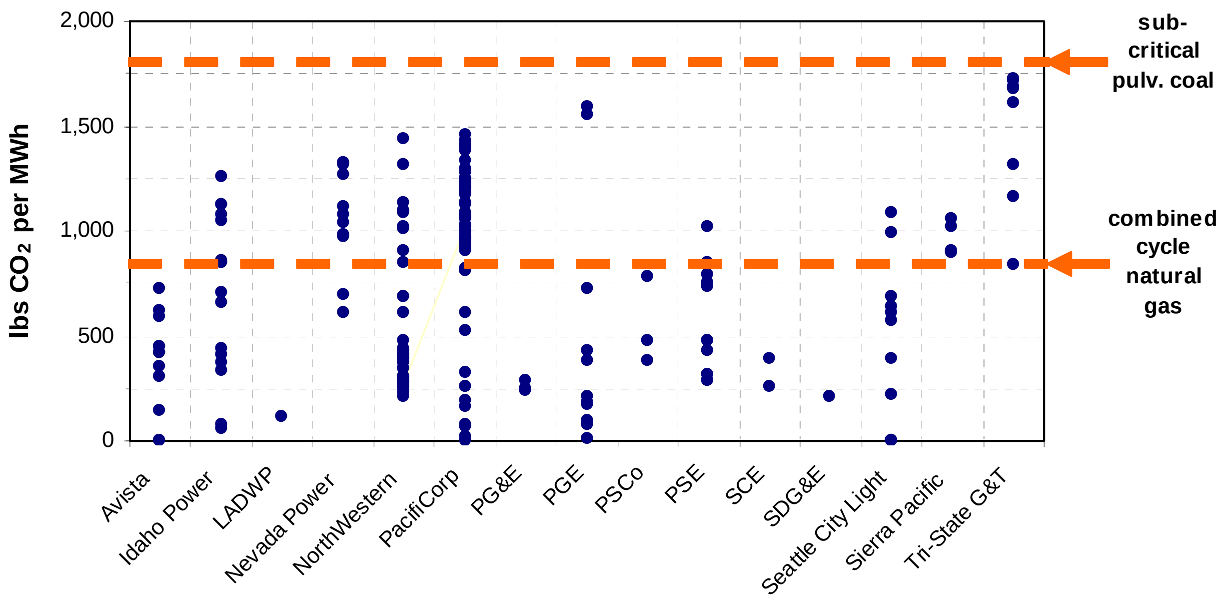


Figure 6. Composite CO_2 Emission Rates of Candidate Portfolios

Notes: Avista and Seattle City Light both evaluated multiple zero-carbon candidate portfolios, which are super-imposed upon one another in the figure (and therefore not individually discernable). Avista's resource plan identified the composition of 15 candidate portfolios, shown in the figure; however, the utility constructed a larger number of candidate portfolios. See Appendix A for additional conventions and assumptions used to construct the figure.

5. Accounting for Indirect Impacts of Carbon Regulations

Within the context of utility resource planning, the most direct effect of future carbon regulations is to increase the projected operating cost of carbon-emitting resources in the utility's candidate portfolios. All of the utilities that incorporated future carbon regulations into their portfolio analysis (i.e., all utilities except LADWP) accounted for this effect, as it is the primary impetus for considering carbon regulations in the first place.

Somewhat less recognized, however, are the many potential indirect implications of carbon regulations for utilities' resource planning environment. Table 6 lists some of the potential indirect energy market impacts, and indicates which of these each utility accounted for in its resource planning analysis.[30] Given the complex nature of many of these interactions, their significance is correspondingly uncertain, but nevertheless may be important for utilities to consider. Yet, as is clear from the table, utility resource planners are only beginning to acknowledge and evaluate these potential indirect effects.

Table 6. Indirect Carbon Regulation Impacts Incorporated into Resource Planning Analysis

Utility	Electricity Market Prices	Natural Gas Prices	Air Pollutant Permit Prices	Load Growth	Coal Plant Retirement	Regional Generation Expansion	Regional Transmission Expansion	Availability of Federal Incentives	Generation Capital Costs and Technology Development
Avista	✓			✓		✓		✓	
Idaho Power	✓								
LADWP									
Nevada Power			✓						
NorthWestern	✓								
PacifiCorp	✓	✓	✓			✓			
PG&E	*								
PGE	✓				✓				
PSCo	✓	✓		✓	✓				
PSE	✓	✓		✓		✓			
SCE	*								
SDG&E	*								
Seattle City Light	✓	✓		✓		✓			
Sierra Pacific			✓						
Tri-State G&T									

Note: The absence of a check mark (✓) indicates either that the utility did not account for a particular impact or that its resource plan did not provide sufficient detail to determine whether or not it accounted for that impact. The asterisks (*) shown for PG&E, SCE, and SDG&E indicate that these utilities did not account for carbon regulations in their electricity price forecast, but they did include their base-case carbon price as an adder when evaluating the cost effectiveness of energy efficiency and renewable energy resource acquisitions.

[30] Beyond the energy market impacts identified in the table are potential macroeconomic impacts that could also affect a utility's planning environment. PSCo is the only utility that appears to have accounted for such impacts in its portfolio analysis, by combining high carbon prices and high inflation in one of its scenarios.

5.1 Electricity market prices

Analyses of carbon policy proposals typically project that carbon regulations would lead to an increase in wholesale electricity market prices. Capturing this effect is critical to utility resource planning for at least two reasons. First, different candidate portfolios generally entail different levels of exposure to wholesale market prices; thus, ignoring the effect of carbon regulations on regional electricity market prices could create a bias toward portfolios with a heavier reliance on market purchases. Second, wholesale electricity market prices are often a key input to deriving the avoided costs from energy efficiency investments. Accounting for the effect of carbon regulations on wholesale electricity prices is therefore critical to properly valuing energy efficiency cost-effectiveness and market potential in a carbon-regulation scenario.

Carbon regulations could impact regional electricity market prices through a variety of mechanisms, the most immediate being to add an emission cost to the marginal cost of generators throughout the region, thereby raising market prices.[31] For example, a tax of $20 per ton of CO_2 would raise the operating cost of a CCGT by approximately $8/MWh, a CT by about $12/MWh, and a pulverized coal plant by about $19/MWh, with corresponding increases in wholesale electricity market prices when each type of resource is on the margin.

A utility's ability to account for the impact of carbon regulations on wholesale electricity prices depends, in part, on how the utility develops its electricity price projection. Among our sample, five utilities (Avista, Idaho Power, PacifiCorp, PGE, and PSE) used production cost models to develop electricity market price forecasts for *each* scenario considered in their plans. By incorporating the carbon prices associated with each scenario into the corresponding model run, the utilities accounted for the impact of increases in marginal generation costs on wholesale electricity market prices. Seattle City Light purchased electricity price forecasts from an energy consulting company for a set of pre-defined scenarios, rather than running simulations in-house to develop its own forecasts. Although not explicitly stated in its resource plan, the forecasts appear to have been generated using a production cost model that was run for each scenario based on the corresponding carbon emission prices.

NorthWestern and PSCo developed electricity price forecasts using a different approach, calculating electricity market prices from projections of marginal heat rates for nearby trading hubs, fuel price forecasts, and carbon price assumptions. In modeling the cost of their candidate portfolios under each carbon price scenario, the utilities used the corresponding electricity price forecast. Unlike electricity price projections developed with a production cost model, the type of approach used by NorthWestern and PSCo cannot account for the effect of carbon emission costs on the regional economic dispatch order. This effect could be particularly critical at carbon prices high enough to raise the operating cost of pulverized coal-fired generation above that of a CCGT.

The remaining utilities (Nevada Power, PG&E, SCE, SDG&E, Sierra Pacific, and Tri-State) do not appear to have accounted for the impact of carbon regulations on wholesale electricity market prices. However, the three California investor-owned utilities did include a carbon adder

[31] Carbon regulations may also impact electricity prices (over the longer term) due to effects on fuel prices, load growth, generation retirements and additions, and transmission expansion. We discuss some of these impacts below.

when calculating the cost-effectiveness of energy efficiency and renewable resources, which serves one of the two purposes of accounting for the effect of carbon regulations on regional generation costs.

5.2 Natural gas commodity prices

Depending on the economics and availability of low carbon technologies other than natural gas-fired generation, demand for natural gas may increase or decrease under carbon regulations, with a corresponding increase or decrease in natural gas commodity prices.[32] For example, in its analysis of the original McCain-Lieberman bill (S.139), EIA projects that wellhead natural gas prices in 2025 would be approximately 10% higher than in the reference case (EIA 2003), as a result of a shift from coal to natural gas in the electricity sector. Under the 2007 McCain-Lieberman proposal, EIA projects that wellhead natural gas prices in 2030 would be between 5% lower and 18% higher than in the reference case, depending on its assumptions about the availability of new nuclear generation, CCS, liquefied natural gas (LNG) imports, and biomass (EIA 2007b, 2007c). Lastly, for the 2006 Bingaman proposal, EIA's analysis projects a small (2%) increase in natural gas prices above the reference case (EIA 2007a).

An increase/decrease in natural gas prices induced by carbon regulations affects utility resource planning in two ways: by increasing/decreasing the expected cost of natural gas-fired generation included in the utility's candidate portfolios, and by increasing/decreasing electricity market prices throughout the region to the extent that gas-fired generation is the marginal supply resource. It is quite possible that these impacts could be of the same order of magnitude as the direct cost of compliance with carbon regulations. For example, a $1.00/MMBtu increase in the delivered price of natural gas to electric generation (about 13% of the current price) would raise the fuel cost of a CCGT by about $7/MWh, which is comparable to the direct carbon emission cost of a $20/ton carbon tax for a CCGT.

All of the utilities in our sample incorporated multiple gas price forecasts in their resource planning analysis; however, only four utilities <u>explicitly</u> linked gas prices and carbon prices when evaluating resource costs and/or developing electricity price forecasts:[33]

- **PacifiCorp** commissioned an outside consultant to develop separate natural gas price forecasts for each of its carbon tax and cap-and-trade scenarios, using a fundamentals-based energy market simulation. The utility incorporated these gas price forecasts both in its regional electricity market simulation, to capture the impact on electricity market prices, and also in its portfolio modeling, to account for the impact on fuel costs of natural gas-fired resources in its candidate portfolios. PacifiCorp's most recent resource plan does not report

---

[32] Under a renewables portfolio standard, natural gas prices would likely decline; see Wiser, Bolinger, and St. Clair (2005) for a summary of estimated impacts. Also, carbon regulations could lead to a decline in coal commodity prices, although analysts have generally projected this impact to be relatively modest, even for relatively stringent carbon regulations. For example, EIA's analysis of the most recent McCain-Lieberman bill projects only a 4% decline in mine-mouth coal prices in 2030, relative to the reference case, despite a 65% drop in U.S. coal consumption (EIA 2007b). None of the utilities in our sample accounted for the impact of carbon regulations on coal prices.

[33] PGE examined one scenario that combined relatively high carbon prices and high gas prices, but the utility did not systematically link carbon and gas prices.

the specific gas price projections for its carbon regulation scenarios; however, its previous resource plan, which used the same approach, projected that gas prices would be approximately 50% greater under a \$40/ton CO_2 tax scenario compared to a scenario with no carbon tax.

- **PSCo** conducted two sets of sensitivity analyses: one set where each scenario parameter was varied individually (e.g., by altering carbon emission prices only and using base-case values for all other parameters) and another set where multiple scenario parameters with a presumed correlation were varied together. In the latter case, PSCo combined its high natural gas and carbon emission price projections in one scenario, and its low natural gas and carbon emission price projections in the other scenario.

- **PSE** constructed six "integrated" scenarios, each incorporating one of three gas price forecasts (low, reference, or high). The utility developed these three gas price forecasts based, in part, on a set of off-the-shelf, fundamentals-based forecasts purchased from an energy consulting firm. PSE's "Green World" scenario assumes the highest carbon and gas prices, under the explicit presumption that high carbon emissions costs would cause generation developers to move from coal to gas (though it does not appear that the high gas price forecast was developed with any specific carbon regulation assumptions in mind). PSE used the high gas price forecast both in its portfolio modeling, to account for the effect on natural gas-fired resources in its candidate portfolios, and also in its simulation of the regional electricity market, to account for the impact electricity market prices. PSE's other five scenarios all assumed carbon emission prices based on the NCEP proposal, along with one of the three gas price forecasts, depending on the scenario theme.

- **Seattle City Light** used a series of natural gas and electricity price forecasts developed by an energy consulting company for a set of pre-defined scenarios. The two scenarios with carbon regulations also assumed high gas prices, under the stated presumption that demand for natural gas would be high as a result of the regulations. Seattle City Light used these higher gas price forecasts when modeling portfolio costs for these scenarios, and thereby accounted for the effect on natural gas-fired resources in its candidate portfolios. The carbon regulation scenarios also incorporated high electricity market price forecasts, though it is unclear how these forecasts were derived and whether they specifically reflect higher natural gas prices.

5.3 Permit prices for other capped pollutants

A reduction in traditional coal-fired power generation brought about by future carbon regulations would also tend to reduce emissions of criteria air pollutants, leading to a corresponding decline in allowance prices for those air pollutants subject to cap-and-trade regulation. As with natural gas prices, the effect of carbon regulations on the price of other air pollutant allowances could have implications both for the relative cost of potential resources considered within a resource plan and for regional electricity prices. The scale of these impacts, however, is likely to be of lesser importance than impacts on natural gas prices. For example, EIA projects that, under S.280, SO_2 allowance prices in the West would drop to zero by 2028, compared to \$350/ton in the reference case (EIA 2007b). This seemingly dramatic change would have less than a \$0.10/MWh impact on the operating cost of a super-critical coal-plant.

Only three utilities among our sample considered the potential effect of carbon regulations on the price of allowance permits for other air pollutants. As described earlier, PacifiCorp commissioned a modeling study to develop natural gas price forecasts for each of its carbon regulation scenarios, and these simulations also projected SO_2 and NO_x permit prices. PacifiCorp used these projections in its regional electricity market simulation, to capture the effect on electricity market prices, and also in its portfolio modeling, to account for the differential impact on resources included in its candidate portfolios. Nevada Power and Sierra Pacific commissioned studies to quantify the environmental costs of their candidate portfolios, which included an estimate of the costs to comply with future carbon regulations. These studies accounted for the interactive effects between carbon regulations and permit prices for SO_2 and mercury, projecting that, with a carbon tax of $7.63/ton (2006$) in 2020, SO_2 and mercury permit prices would be approximately 25% and 10% lower, respectively, compared to a no carbon tax scenario. The utilities used these permit price projections when modeling the cost of their candidate portfolios under carbon regulations, but do not appear to have accounted for the interactive effects when developing their electricity market price forecasts.

5.4 Load growth

Carbon regulations may slow load growth, to the extent that retail rates rise and customers exhibit long-run price elasticity, separate from any effects of energy efficiency programs.[34] These impacts could be relatively sizable or quite modest, depending on the particular legislation. EIA's analyses of the three carbon policy proposals highlighted in this study do show varying impacts on electricity consumption, but these projections capture the effects of both customer price elasticity and energy efficiency program activity and are therefore of limited applicability to utility resource planning.[35]

Slowed load growth is relevant to utility resource planning, first and foremost, because it reduces the utility's own resource needs. Virtually all of the utilities in our sample developed multiple load growth projections for their own customers. However, only PSE and PSCo explicitly linked future carbon regulations to their own low load growth.[36] PSE developed three load forecasts (low, reference, and high) and used the low load forecast when analyzing portfolio costs in its high carbon price scenario. Similarly, PSCo combined its high carbon price and low load growth projections in one scenario, and its low carbon price and high load growth projection in another scenario. In neither case were the load forecasts developed based on any specific carbon emission price projection.

[34] Carbon regulations could lead to increased use of plug-in hybrid electric vehicles, however, which would tend to increase load growth.

[35] In its analysis of S.139, EIA projects that load growth in the Western U.S. would be 30% lower than in the reference case, over the 2010-2025 timeframe; this is equivalent to a 0.6% reduction in the annual growth rate (EIA 2003). Under S.280, EIA projects a 26% reduction in Western load growth over the 2010-2030 timeframe, or a 0.4% reduction in the annual growth rate (EIA 2007b). Finally, for the 2006 Bingaman proposal, EIA projects that, over 2010-2030, load growth in the West would be just 5% lower than in the reference case, equal to a 0.1% reduction in the annual growth rate (EIA 2007a).

[36] PacifiCorp also examined scenarios with low load growth and high carbon prices, but only incidentally, as the utility considered *all* of its load forecasts in combination with high carbon prices. Thus, the utility did not specifically alter its load growth projections to correspond to its carbon price assumptions.

The effect of carbon regulations on regional load growth is also relevant to utility resource planning, insofar as reduced load growth moderates expected increases in electricity market prices. Three utilities (Avista, PSE, and Seattle City Light) accounted for the effect of carbon regulations on regional load growth and the corresponding impact on electricity market prices. Avista and PSE used capacity expansion models to develop their electricity price forecasts for each scenario examined and, in their high carbon price scenarios, assumed lower regional load growth (although neither utilities' resource plan indicates the magnitude of the assumed effect). Seattle City Light's electricity price forecast for its high carbon price scenarios also appears to have been developed based on an assumption that regional load growth would be lower as a result of high carbon prices, although its resource plan also lacks specifics about the size of the assumed effect.

5.5 Accelerated coal plant retirements

Carbon regulations could affect the timing of generation retirements in a number of ways, but the most significant may be to accelerate the retirement of existing coal plants. EIA's analysis of the original McCain-Lieberman climate legislation projects that almost 25% of all coal-fired generation in the West would be retired by 2025, compared to essentially none in the reference case (EIA 2003). In contrast, EIA's analysis of the 2007 McCain-Lieberman bill projects that only 4% of existing coal capacity in the West would be retired by 2030, while its analysis of the 2006 Bingaman proposal projects no such retirements (EIA 2007a, 2007b).

The effect of future carbon regulations on coal plant retirements has two-fold significance for utility resource planning. First, early retirement of a utility's own coal-fired generation will increase the size of its future resource deficit, and thus increase its incremental resource need. Eleven of the fifteen utilities in our sample own or have long-term contracts with coal-fired generation. However, only two utilities, PGE and PSCo, conducted analyses within their resource plan to explicitly examine whether carbon regulations would justify the early retirement of their own coal-fired generation.

- **PGE** estimated the carbon tax that, in combination with the cost of new emission controls needed to comply with state and federal pollution standards, would raise the cost of its Boardman coal plant above the cost of a new CCGT. PGE estimated the break-even carbon emission tax (i.e., the price at which it would be cost-effective to replace Boardman with a new CCGT) to be in the range of $21-30 per ton of CO_2. Notwithstanding this result, PGE apparently retained Boardman in its resource base when analyzing portfolio costs under a $40/ton scenario, even though, by the utility's own analysis, the plant would cease to be economic at a carbon tax of that size.

- **PSCo** identified units at three coal plants that would reach the end of their book life prior to 2022. For each plant, PSCo evaluated the cost-effectiveness of extending its life or replacing it with a new CCGT, across its set of carbon emission price projections, but using only its base-case natural gas price forecast. PSCo found that, for all three plants, life-extension was the more-economic option under its base-case carbon price projection ($20/ton), but for two of the three plants, retirement was more-economic under its high carbon price projection

($40/ton). As a result of this analysis, PSCo replaced these two coal-fired power plants with a new CCGT in two of its three candidate portfolios.

In addition to accounting for retirement of its own coal-fired power plants, it may also be important for utilities to account for coal-plant retirements throughout the region, in virtue of the potential impact on electricity market prices. A utility's ability to account for this regional effect depends, in part, on how the utility develops its electricity price forecasts. Four of the utilities in our sample (Avista, PacifiCorp, PGE, and PSE) project electricity prices using regional capacity expansion models, which may be able to simulate generation retirements under specific carbon regulation scenarios.[37] PGE's resource plan was explicit that the utility's modeling did not allow generation retirements prior to the end of each plant's original book life. The other three utilities' resource plans do not provide sufficient information to determine whether the modeling conducted to project electricity prices allows for accelerated generation retirements as a result of carbon emission costs.

5.6 Regional generation expansion

Carbon regulations could dramatically affect the type and location of generation expansion throughout the West, with significant impacts on long-term electricity market prices. As with generation retirements, a utility's ability to account for the effect of carbon regulations on regional generation expansion depends partly on whether the utility uses a regional capacity expansion model to project electricity market prices. Avista, PacifiCorp, and PSE ran their capacity expansion models for each scenario in their resource plans, and these simulations appear to have modeled differences in generation expansion throughout the region occurring under different carbon emission prices. PGE also uses a capacity expansion model to project electricity market prices. However, PGE appears to have only run its capacity expansion model for its base-case scenario, and then used the resulting schedule of regional generation additions in production cost modeling performed for each individual scenario. Thus, its price forecasts reflect regional generation additions projected to occur under its base-case carbon price assumption, but not under its alternate carbon price scenarios. Finally, Seattle City Light's electricity market price forecasts for each scenario, which the utility purchased, also appear to account for the impact of carbon regulations on regional generation expansion and the corresponding effect on electricity market prices.

5.7 Regional transmission expansion

Enactment of carbon regulations may spur transmission expansion into regions rich in low-carbon resources, especially as high-quality renewable resource areas close to load centers become fully developed. Upgrades to the existing bulk power transmission system could have significant impacts on regional electricity prices, by enabling development of lower-cost generation options and by relieving congestion. Transmission expansion may also reduce the apparent incremental cost of certain resource options – wind in particular – and thereby make it

[37] Idaho Power also used a simulation tool with a capacity expansion module that has the capability to project economic retirements, but the company's resource plan does not clearly indicate whether it used this simulation software to project market prices, and if so, whether alternate market price projections were generated for each carbon regulation scenario.

more economical for utilities to rely on increasing quantities of location-constrained low-carbon resources. Many utilities did consider the potential need for transmission projects in developing their candidate resource portfolios – that is, to meet their own needs. However, none of the utilities appear to have accounted, in a systematic way, for the effect of carbon regulations on *regional* transmission expansion.

5.8 Availability of federal incentives

Certain renewable energy and other low-carbon resources are eligible for various forms of federal financial assistance, including various types of tax incentives (e.g., the federal production tax credit – PTC – for wind and other renewable sources). Enactment of federal carbon regulations could erode political support for at least some of these incentives, if legislators viewed the two policies as duplicative, possibly resulting in an accelerated reduction or discontinuation of certain federal incentives for low-carbon generation technologies. Naturally, this would tend to increase the effective cost of those technologies and perhaps encourage other (less subsidized) types of low carbon generation options. Although a number of utilities constructed scenarios to evaluate alternate assumptions about the future availability of the PTC for renewable electricity, only Avista varied its assumptions about PTC availability depending specifically on whether carbon regulations are enacted. In particular, Avista assumed that, under all carbon regulation scenarios, the PTC would be eliminated. Aside from the PTC, no utilities varied their assumptions about other types of federal financial incentives available to low-carbon technologies, depending on the scope of future federal carbon regulations.

5.9 Capital costs and technology development

A dramatic rise in the demand for particular types of low carbon resource options (e.g., wind turbines) could create shortages in the supply chain, if only temporarily, leading to increases in capital costs. At the same time, accelerated adoption of emerging low-carbon resource technologies (e.g., IGCC with CCS, solar thermal, wave/tidal energy) could expedite "learning curve" effects, bringing down the cost and improving the performance of these technologies quicker than would occur in the absence of federal carbon regulations. It does not appear that any utilities accounted for these potential effects in their scenarios.

6. Incorporating Carbon Cost Uncertainty into the Preferred Portfolio Selection Process

6.1 Selecting a preferred portfolio

Utility resource plans typically culminate by identifying a single, preferred portfolio. The process of selecting a preferred portfolio invariably involves a comparison of candidate portfolios' expected costs under base-case assumptions. Indeed, for many utilities, this is the primary basis upon which the preferred portfolio is selected. Eleven of fifteen utilities included carbon emission prices in their base-case scenario, thereby affecting their choice of preferred portfolio, to the extent that the choice was based on a comparison of candidate portfolios' expected costs.

Many utilities also select their preferred portfolio based upon some comparison of the *uncertainty* in costs of their candidate portfolios. The overall uncertainty in the cost of a candidate portfolio is the net effect of uncertainties in numerous underlying input variables. Uncertainty in some input variables (e.g., annual rainfall, summer peak temperatures, natural gas price volatility) can be defined probabilistically based on historical data. In these cases, utilities' often use Monte Carlo methods to derive a single stochastic risk measure for each candidate portfolio, to express its overall uncertainty in cost associated with all probabilistically-defined input parameters.[38] Some utilities then employ specialized modeling tools to identify the *efficient frontier,* defined as the set of portfolios with the lowest theoretical stochastic risk for a given expected cost (and vice-versa).

Uncertainty in input variables for which historical data do not exist – such as carbon emission prices – is less amenable to probabilistic definition and stochastic modeling. Cost uncertainty associated with these types of variables is therefore often assessed by calculating candidate portfolio costs across a discrete number of alternate scenarios (i.e., scenario analysis rather than stochastic Monte Carlo analysis). When combined with stochastic risk analysis, scenario analysis can then yield a family of efficient frontiers as illustrated in Figure 7.

Regardless of whether or not it is combined with stochastic analysis, though, scenario analysis simply yields a range of portfolio costs across multiple sets of assumptions and does not produce a precisely-defined measure of uncertainty in portfolio cost. Utilities therefore face a significant challenge in incorporating cost uncertainty associated with future carbon regulations into their preferred portfolio selection process. On the one hand, the magnitude of the uncertainty and implications for the relative economics of competing candidate portfolios are likely to be quite large. However, there is not yet an established analytic and decision-making framework to meaningfully translate information about *variation* in portfolio costs across multiple carbon price scenarios into the selection of a single preferred portfolio. Furthermore, utilities must ultimately make some tradeoff between the twin objectives of minimizing expected portfolio costs and minimizing uncertainty in portfolio costs and, thus far at least, relatively little effort has been placed on how best to make such tradeoffs.

---

[38] See Bolinger and Wiser (2005) for a description and discussion of stochastic risk measures used in recent utility resource plans.

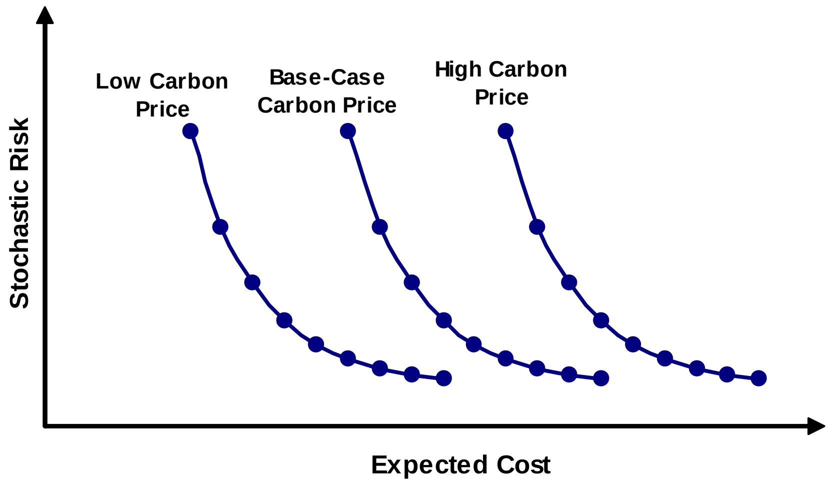


Figure 7. Efficient Frontier of Candidate Portfolios for Multiple Carbon Price Scenarios

6.2 Accounting for carbon cost uncertainty when selecting a preferred portfolio

Perhaps as a reflection of the challenges described above, many utilities in our study do not appear to have *transparently* incorporated information about variation in portfolio costs across carbon price scenarios into their choice of a preferred resource portfolio. As described in Section 3.1, eleven utilities evaluated candidate portfolio costs under multiple carbon price projections, and thus were able to *show* how candidate portfolio costs varied across carbon regulation assumptions. We reviewed the text of these utilities' resource plans to determine how, if at all, this information was *used* to inform the selection of the preferred portfolio. Six of these eleven utilities (Nevada Power, PGE, PSCo, Seattle City Light, Sierra Pacific, and Tri-State) made no explicit reference to the results of their carbon scenario analysis when explaining their rationale for selecting a preferred portfolio; it is unclear what, if any, role that scenario analysis may have had in their portfolio selection processes.[39]

The other five utilities that evaluated portfolio costs under multiple carbon price projections did rely, to some degree, on the results from that uncertainty analysis when selecting a preferred portfolio, although their methods differed substantially.

- **Avista** modeled carbon prices as a stochastic variable (see Table 2). Each portfolio's exposure to carbon regulatory risk was therefore embedded in the portfolio's overall measure of stochastic risk (in Avista's case, the standard deviation in total supply costs across all iterations of its Monte Carlo analysis). Avista justified its preferred resource portfolio by showing that it lies along the efficient frontier, and in doing so, implicitly takes into account differences in portfolios' exposure to carbon regulatory risk. That said, Avista's resource plan provides no explanation of how it selected among portfolios along the efficient frontier (i.e., on what basis it made a tradeoff between expected cost and stochastic risk).

[39] In part, this is symptomatic of the more general tendency of utility resource plans to provide only cursory and vague explanations of the rationale for choosing a particular preferred portfolio.

- **Idaho Power** stipulated probabilities for the three carbon price scenarios considered ($0, $14, and $50/ton CO_2) and calculated a "carbon risk adder" for each of its four finalist candidate portfolios, equal to the difference between the probability-weighted average portfolio cost across the three carbon price scenarios and the cost under the most likely scenario ($14/ton). The utility also calculated risk adders for a number of other scenario risks, and added all of them together to derive a single risk factor for each portfolio. The portfolios were then ranked according to both expected cost and total risk, and the preferred portfolio was selected, in part, based on these two sets of rankings. Although novel, it is not clear whether the carbon risk adder used by Idaho Power provides a particularly meaningful indication of each portfolio's exposure to carbon regulation risk,[40] or whether the risk adders derived for different types of scenario risks can meaningfully be added together.

- **NorthWestern** performed a stochastic analysis of each candidate portfolio under each of its five scenarios (base-case, two alternate carbon price scenarios, and two alternate electricity market price scenarios). This analysis yielded values for the expected cost and stochastic risk of each combination of candidate portfolio and scenario. To compare candidate portfolios, NorthWestern first computed a risk-adjusted cost for each scenario-portfolio combination by averaging the expected cost and risk, applying a 70% weight to expected cost and a 30% weight to stochastic risk. The utility then averaged each portfolio's risk-adjusted cost across all scenarios to derive a single performance parameter for each candidate portfolio, applying a 30% weight to its base-case, a 30% weight to its high carbon price scenario, a 20% weight to its high market price scenario, and 10% weights to the remaining two scenarios. Based on the resulting set of portfolio measures, NorthWestern selected the three portfolios with the lowest average risk-adjusted cost across scenarios as its three preferred portfolios (rather than selecting just a single preferred portfolio).

- **PacifiCorp** compared the cost and stochastic risk of its five finalist portfolios for each carbon regulation scenario. The five portfolios were all quite similarly constituted, and one portfolio had the lowest expected cost across all five carbon scenarios, which PacifiCorp selected as its preferred portfolio. Carbon risk was therefore ultimately a moot issue in the final selection process. However, carbon risk may have had a more material impact on the composition of the preferred portfolio through earlier stages of PacifiCorp's analysis. The utility arrived at its final set of five candidate portfolios through several iterative steps. In the initial stage, PacifiCorp used a capacity expansion model to identify the least-cost portfolios across scenarios with carbon costs of $0, $8, or $38/ton CO_2. The utility found that the model selected new pulverized coal even in the high carbon-cost scenario, provided that natural gas prices were also assumed to be high. At the next stage, PacifiCorp constructed a new set of candidate portfolios, partly by hand and partly with the aid of a capacity expansion model, and computed the expected cost and stochastic risk of these portfolios under five carbon price scenarios ranging from $0 to $61/ton. The utility found that the capacity expansion model always selected two pulverized coal plants, and that removing or deferring these resources raised both portfolio cost and risk, even under the highest CO_2 adder cases. PacifiCorp therefore concluded that these two coal resources were resilient to

[40] For example, the range between the high and low carbon prices could be widened or narrowed, and if done in the correct proportions, the carbon risk adder would remain unchanged, even though the actual risk exposure clearly would change.

carbon risk and manually added them to the final set of candidate portfolios. In addition to this portfolio analysis, PacifiCorp also conducted a "break-even" analysis to identify the carbon price at which its capacity expansion model would choose a CCGT rather than a coal-plant. That analysis revealed a breakeven price of $38/ton (2008$), which appears to conflict with the utility’s conclusions about the robustness of the coal plants manually added to the final five portfolios up to a price of $61/ton. However, the resource plan does not provide any indication that the results of the break-even analysis were used in constructing portfolios or selecting the preferred portfolio.

- **PSE** computed the cost of its twelve candidate portfolios under all scenarios, and selected its preferred portfolio by first applying several screens, one of which was that a portfolio had to score within the top four (in terms of cost) in at least one scenario. Because one scenario included high carbon prices, this screen served to value those portfolios that mitigate carbon risk. After applying the screens, two finalist portfolios remained, one of which was lower cost under expected carbon prices, and the other lower cost under the high carbon price scenario. To select the preferred portfolio between these two, PSE computed the threshold probability of its high carbon scenario occurring, such that the probability-weighted average cost of the two portfolios would be equal. PSE determined this probability to be 30%. Based on its stated assumption that there is greater than a 30% probability that its high-cost carbon scenario would occur rather than its reference-case carbon prices, the utility chose as its preferred portfolio the candidate portfolio that performed better under the high carbon price scenario.

6.3 Summary

Although these five utilities dealt with carbon regulatory risk in quite different ways, we can generalize from their approaches to identify three types of strategies that utility resource planners could consider for incorporating information about uncertainty in carbon costs into the portfolio selection process (recognizing that other approaches may also be available):

- *Integrated risk metrics*. Avista, Idaho Power, and NorthWestern derived metrics that capture uncertainty in portfolio costs associated with future carbon regulations, which required stipulating probabilities for each carbon price projection. This type of approach has certain practical advantages, for example, by allowing uncertainty in carbon regulatory costs to be integrated with other uncertainties into a single risk measure, instead of addressing individual risks in a piecemeal fashion. However, the approach is not without some limitations as well. One potential pitfall is that it could lead to a false sense of significance and precision in the resulting risk metric, given the subjective and highly uncertain nature of the underlying assumptions about the probability of each carbon price projection. It also may be difficult for stakeholders to determine how altering these critical assumptions would affect the results (e.g., if doing so would require effectively re-running the entire analysis).

- *Threshold analysis.* Another approach, exemplified by PSE’s process for choosing between its two finalist portfolios and by PacifiCorp’s break-even analysis, is to identify the threshold carbon price (or threshold probability of a particular carbon price) at which point a given candidate portfolio or resource becomes the least-cost option.[41] An advantage of this approach is that it focuses attention on the critical assumption about the likelihood of carbon prices reaching a point with significant implications for the composition of the least-cost portfolio. However, simply identifying the threshold says nothing about the magnitude of the potential upside and downside risks of each portfolio.

- *Robustness testing.* Finally, PacifiCorp's iterative portfolio construction process served to identify common resources in the least-cost portfolio across a range of carbon price projections. Though not identical, this approach bears certain similarities to "robust methods" used in other policy arenas when conditions of deep uncertainty exist, which seek to identify strategies that minimize regret across the range of uncertainties and that maintain the ability to adapt to changing circumstances (see Lempert et al. 2006).

Regardless of which, if any, of the above approaches are used to account for carbon regulatory risk, one overarching issue remains. Ultimately, some tradeoff is likely to be required between minimizing expected cost and minimizing risk. As suggested by Bolinger and Wiser (2005), this tradeoff would ideally be based on the risk preferences of ratepayers, to the extent that they bear the risk. However, most utilities did not identify the criteria used to make this tradeoff, and those that did provided little or no explanation of the underlying rationale for the specific criteria used.

To conclude, analytical methods used in utility resource planning have become increasingly sophisticated, but the decision-making processes associated with selecting a preferred portfolio have not necessarily kept pace. First, it is clear that a standard approach to incorporating carbon regulatory risk as a factor in the portfolio selection process has yet to clearly emerge, as evident by the widely divergent approaches currently used and the fact that many utilities seemingly ignored their analysis of carbon regulatory risk when selecting their preferred portfolio. Second, utility resource plans are often not transparent about the criteria used to make tradeoffs between risk (related to carbon regulations or otherwise) and expected cost, or about the basis for their criteria. Addressing both issues is essential to ensuring that utilities' resource selection reflects meaningful consideration of carbon regulatory risk.

[41] The Oregon PUC recently established a requirement that utilities include a trigger-price analysis in their resource plans.

7. The Carbon Intensity of Utilities' Preferred Resource Portfolios

Although the preferred resource portfolios identified in utility resource plans generally do not represent binding, long-term commitments, they nevertheless provide perhaps the best public indication of utilities' current long-term resource strategies. In this section, we describe the preferred portfolios selected by the fifteen utilities and their associated carbon footprint, providing a bottom-up view of possible future resource development in the West and highlighting differences in the carbon intensity of utilities' resource strategies throughout the region. We then compare the combined resources represented in utilities' preferred portfolios to generation additions in the West projected by EIA under a number of federal climate policy proposals. This comparison serves to illustrate, in a highly approximate manner, how significant a divergence from utilities' current long-term resource strategies may be required under carbon regulations that could be enacted in the future.

7.1 Preferred resource portfolio composition and carbon intensity

Figure 8 summarizes the composition and carbon intensity of each utility's preferred portfolio, based on expected energy generation/savings in the last year of the utility's portfolio construction period (listed in Table 1). We focus on describing new, physical supply- and demand-side resources, by excluding existing generation, future contract renewals, and future short/medium-term market purchases.

A number of high-level findings emerge from this summary:

- ***Energy efficiency and renewable generation are the dominant low-carbon resources being pursued by utilities in the West.*** All utilities selected preferred portfolios that include an expansion to utility-funded energy efficiency programs and new renewables, and half of the utilities selected portfolios in which energy efficiency and renewables together provide 50% or more of all incremental resource needs. Naturally, though, there is some variation across utilities. Energy efficiency contributes anywhere from less than 15% of new resources (Idaho Power, Nevada Power, Sierra Pacific, and Tri-State) to greater than 40% (LADWP, NorthWestern, SDG&E, and Seattle City Light), and renewables constitute anywhere from 1% for Tri-State to 74% for PGE. All utilities with an RPS, except for LADWP, Nevada Power, NorthWestern, and Sierra Pacific, included more renewables in their preferred portfolios than strictly required for RPS compliance. One utility, Seattle City Light, selected a preferred portfolio with energy efficiency and renewables as the only new physical resources.[42]

- ***Other types of low-carbon resources – most notably, nuclear power and CCS – play a limited role in utilities' preferred portfolios.*** The two utilities that evaluated candidate portfolios with new nuclear power, Idaho Power and PSCo, both included it in their preferred portfolios, though new nuclear power appears in PSCo's preferred portfolio after the period

[42] Seattle City Light's preferred portfolio also includes seasonal exchanges and short-term call options. However, given that these are unlikely to consist of new physical resources, we do not count them in the totals shown.

characterized in the figure (2008-2020).[43] PSCo is also the only utility to include IGCC with CCS in its preferred portfolio, of the six utilities that examined candidate portfolios with this resource. Idaho Power also included IGCC in its preferred portfolio, but without CCS. Finally, three utilities (Idaho Power, PacifiCorp, and PG&E) selected preferred portfolios with CHP, out of the six utilities that considered it.

- ***Natural gas is a common, although not universal, element in utilities' preferred portfolios.*** Twelve utilities' preferred portfolios include gas-fired generation, in most cases constituting at least 20% of the total portfolio and, for several utilities, upwards of 60%.[44] Outside of California, new gas-fired resources are split approximately 60%/40% between CCGT and CT capacity.[45] For the three California IOUs, the total quantity of new gas-fired capacity and the split between CCGT and CT are somewhat uncertain, given the lack of information in these utilities' resource plans about contract renewals and the specific type of conventional generation included in their preferred portfolios.[46]

- ***Utilities in inland states continue to pursue pulverized coal without CCS.*** Five of the eight utilities serving inland states selected preferred portfolios containing new pulverized coal generation without CCS. Of these five, Tri-State is the most heavily-reliant on new coal on a percentage basis, representing 93% of new resources. The four other utilities selected preferred portfolios in which new pulverized coal constitutes between 20% and 40% of the new resources. In contrast, none of the seven utilities whose service territories are confined to coastal states selected preferred portfolios with any coal-fired generation. Of these utilities, four are subject generator emission performance standards that effectively preclude constructing or contracting with coal-fired generation lacking CCS, and these four utilities therefore did not even evaluate candidate portfolios with new conventional coal-fired generation.[47]

- ***Retirement of existing coal-fired generation remains limited.*** Three utilities – Sierra Pacific, Nevada Power, and PSCo – plan to retire existing coal-fired generation capacity within their planning periods. Of these three, only PSCo evaluated plant retirement as an economic option within its portfolio analysis (and, moreover, from the specific perspective of reducing CO_2 emissions and associated costs). Based on the results under its high carbon price scenario, PSCo selected a preferred portfolio that replaces four existing coal-fired units (~200 MW nameplate capacity) with a new CCGT.

---

[43] PSCo constructed the supply-side of its candidate portfolios out through 2046, but identified demand-side targets only through 2020; thus, in describing its preferred resource portfolio, we focus on the period ending in 2020. Nuclear resources are added to the preferred portfolio beginning in 2022.

[44] The percentage values shown in Figure 8 for the contribution of new natural gas-fired generation to utilities' preferred portfolios are subject to a number of critical assumptions described in Appendix A.

[45] Pacific Northwest utilities may be able meet some of their incremental gas-fired resource needs by acquiring or contracting with existing CCGT facilities in the region owned by independent power producers.

[46] The California IOUs have a large volume of expiring contracts, but neither SCE nor SDG&E provide any indication about what portion of the expiring contracts are likely to be renewed. In addition, none of the three California IOUs specify particular types of non-renewable generation in their preferred portfolios.

[47] California and Washington have passed legislation to adopt generator emission performance standards that effectively prohibit utilities from building or entering into new contracts with coal-fired generation lacking CCS.

- ***The carbon intensity of utilities' preferred portfolios varies widely***. The gross emission rates of the fifteen utilities' preferred portfolios (again, based on only new supply- and demand-side resources in each portfolio) ranges from zero lbs/MWh to more than 1,600 lbs/MWh. Whether or not a particular utility's preferred portfolio falls in the lower half or the upper half is a function of whether or not it includes new unsequestered coal. The ten preferred portfolios containing no new coal without CCS all have composite emission rates less than 500 lbs/MWh, varying largely according to the amount of new natural gas-fired generation included. Utilities with resource portfolios that include new, unsequestered coal plants have emission rates ranging from approximately 700-1,600 lbs/MWh, depending on the contribution from coal.

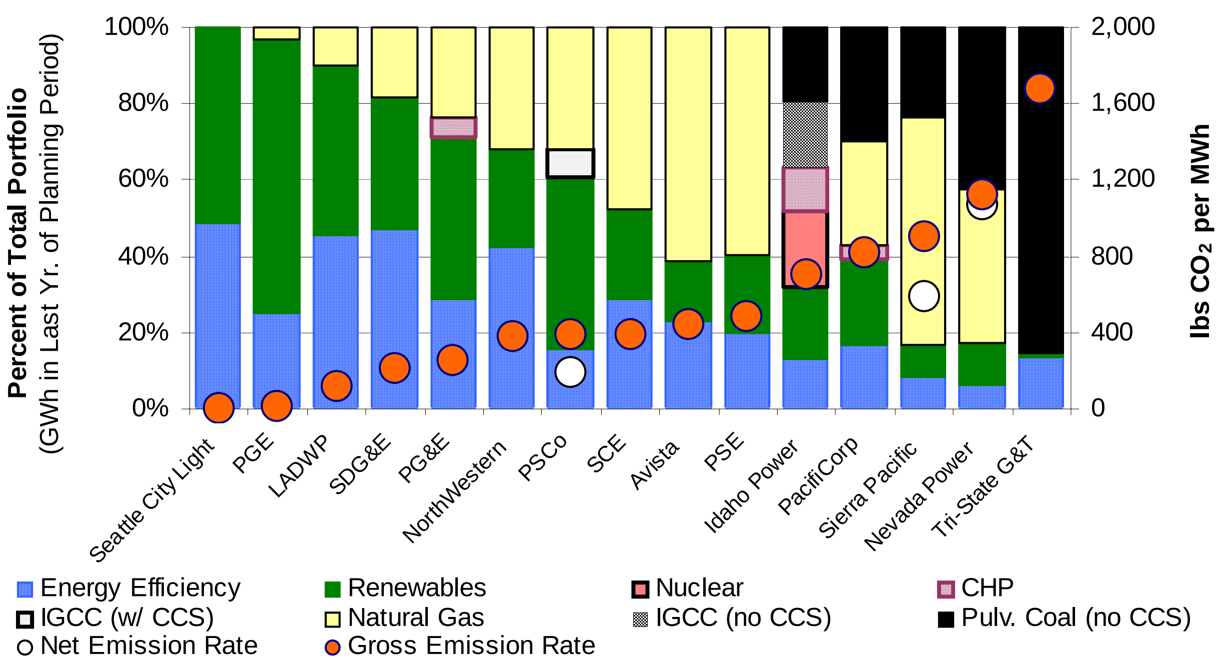


Figure 8. New Resources in Utilities' Preferred Portfolios

Notes: Gross emission rate refers to the composite emission rate of all new supply- and demand-side resources. Net emission rate also accounts for emission reductions associated with planned retirements over the planning period. See Appendix A for conventions and assumptions used to construct the figure.

Differences in the carbon intensity of utilities' preferred portfolios may, to some extent, reflect utilities' varying approaches to evaluating carbon regulatory risk, as described throughout earlier sections of this report. Although isolating the influence of individual assumptions or methods is difficult, if not impossible, we can assess whether the carbon intensity of utilities' preferred portfolios may have been unduly constrained by the range of candidate portfolios considered (see Figure 9). As the figure shows, most utilities selected neither the most nor the least carbon-intensive of the candidate portfolios evaluated, suggesting that, in general, the carbon intensity of utilities' preferred portfolios was not directly limited by the set of candidate portfolios considered. The only possible exception is Sierra Pacific, which evaluated only a small number of relatively high-carbon portfolios, and selected the least carbon-intensive of these. Several other utilities (Nevada Power, NorthWestern, and Tri-State) also selected relatively high-carbon preferred portfolios. To the extent that these choices reflect inadequate assessment of carbon regulatory risk, analytical issues other than the composition of candidate portfolios (e.g., carbon price assumptions, assumptions about the availability and cost of low-carbon resources, or the portfolio selection process) are more likely to have been the limiting factor.

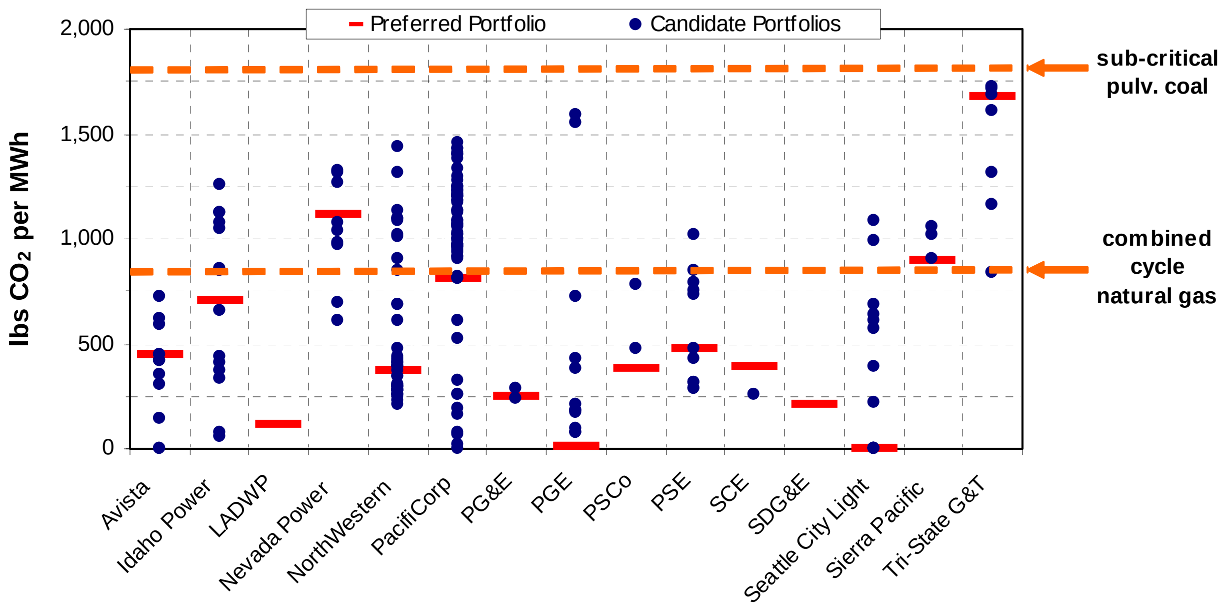


Figure 9. Carbon Intensity of Utilities' Preferred Portfolios and Candidate Portfolios

Notes: Avista and Seattle City Light both evaluated multiple zero-carbon candidate portfolios, which are super-imposed upon one another in the figure (and thus not individually discernable). Avista's resource plan identified the composition of 15 candidate portfolios, shown in the figure; however, the utility constructed a larger number of candidate portfolios. See Appendix A for additional conventions and assumptions used to construct the figure.

Aside from any issues related to the resource planning analysis, the ultimate composition and carbon intensity of utilities' preferred portfolios is also driven by a host of other factors – including various state policies directed at reducing carbon emissions or supporting particular low-carbon resource options. For example, generator emission performance standards in California and Washington, which prohibit these states' utilities from building or contracting with coal-fired generation lacking CCS, clearly have the potential to significantly impact the carbon intensity of utilities' resource strategies. Even a relatively moderate amount of coal without CCS can severely degrade a utility's carbon footprint, as illustrated by comparing PacifiCorp with Avista or PSE. Similarly, it is perhaps not a coincidence that the two utilities without an RPS at the time of their resource plan (Idaho Power and Tri-State) and PacifiCorp, which has an RPS only for a portion of its load, also rank among the highest in terms of the carbon intensity of their preferred portfolios. That said, an RPS is clearly not a sufficient condition for producing low-carbon resource strategies, as evident by Nevada Power and Sierra Pacific, both of which had much larger overall resource needs than their incremental RPS compliance needs and did not consider exceeding minimum RPS requirements. State carbon emission reduction goals, though seldom backed by regulatory power, may also drive utilities' resource strategies to some degree. This has certainly been the case in Colorado, where the governor's goal of a 20% reduction in utility sector carbon emissions by 2020 played a central role in PSCo's resource planning analysis and preferred portfolio selection (discussed further in Text Box 1).

Text Box 1. Comparison of PSCo's 2003 and 2007 Resource Plans

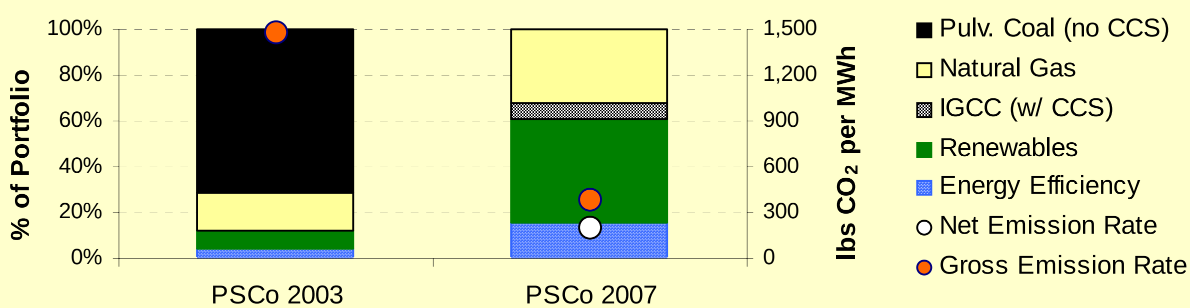
Of the utilities reviewed in this report, PSCo may exemplify the most dramatic shift between successive resource plans in a utility's analysis of carbon regulatory risk and the carbon-intensity of its preferred portfolio. In part, this evolution reflects a variety of state policies and other developments that occurred in Colorado, between PSCo's 2003 and 2007 resource plans. We highlight a few of the key developments in PSCo's resource planning and the associated changes in its long-term resource strategy, as an illustration of the growing prominence of carbon regulatory risk in utility resource planning and its implications for utility resource investments.*

- *Carbon price projections*. In its 2003 plan, PSCo evaluated portfolio costs under future carbon dioxide prices of no greater than $9/ton, while in its 2007 plan, PSCo assumed a base-case price of $20/ton (the highest of the utilities in our sample), and also evaluated portfolio costs under $10 and $40/ton scenarios.

- *Evaluation of low-carbon resource options*. For both resource plans, PSCo used a capacity expansion model to develop the least-cost supply-side portfolio under a number of alternate assumptions. However, the quantities and types of resources made available to the model differ substantially between the two plans. For the 2003 plan, the model was allowed to add up to only 800 MW of new wind resources, based on a cap of total wind nameplate capacity equal to 15% of PSCo's peak demand, and no other renewable options were available. For the 2007 plan, PSCo manually specified the renewable additions in its three candidate plans. One candidate portfolio included the minimum amount of new renewables and energy efficiency needed to meet statutory requirements. The other two candidate portfolios exceeded those requirements to differing degrees, the most aggressive of which included (through 2020) 1,800 MW of new wind resources, 425 MW of centralized solar, and smaller quantities of biomass and geothermal, as well as a 150 MW portion of an IGCC plant with CCS. With these renewables and IGCC resources manually determined, PSCo used its capacity expansion model to determine the least-cost quantity and timing of residual generation needs, met with a combination of gas-fired resources and nuclear power. No coal without CCS was considered in any candidate portfolio.

- *Coal plant retirements*. PSCo's 2007 plan differs from its 2003 plan, and from most other utilities' recent resource plans, by having explicitly evaluated the cost-effectiveness of retiring existing convention coal plants and replacing them with new natural gas-fired CCGT capacity, across a wide range of alternate carbon price scenarios. Ultimately, this analysis supported the plan's proposal to replace several existing coal units with a new CCGT.

- *Preferred resource portfolio*. PSCo's 2003 resource plan resulted in a preferred portfolio heavily dominated by conventional pulverized coal (about 71% of all new resources in the portfolio), with limited contribution from energy efficiency and new wind generation. In contrast, PSCO's 2007 preferred portfolio is dominated by zero-carbon renewables and energy efficiency, and remaining needs are met with moderately carbon-intensive resources (IGCC with 50% CCS and conventional natural gas-fired generation). Given this fundamental shift in resource strategy, the composite emission rate of PSCo's preferred portfolio declined from almost 1,500 lbs/MWh in its 2003 plan to less than 400 lbs/MWh in its 2007 plan (or about 200 lbs/MWh when accounting for the accelerated coal plant retirement).



* Our characterization of PSCo's 2003 plan is based on the settlement agreement analysis, which supplanted PSCo's original resource plan filing.

7.2 Comparison of utility preferred resource portfolios to CO_2 emission benchmarks

The set of preferred resource portfolios selected by the utilities in our sample provide a picture, albeit partial and provisional, of electric resource development in the West over the next ten to twenty years. In aggregate, natural gas-fired generation is the largest component of all incremental supply- and demand-side resources in utilities' preferred portfolios, representing 33% of all new physical resources on an energy basis (see Figure 10). Renewables (26%), energy efficiency (22%), and pulverized coal (14%) make up the lion's share of the remaining new resources, with small contributions from CHP (2%), nuclear (1%), IGCC with CCS (1%), and IGCC without CCS (1%).

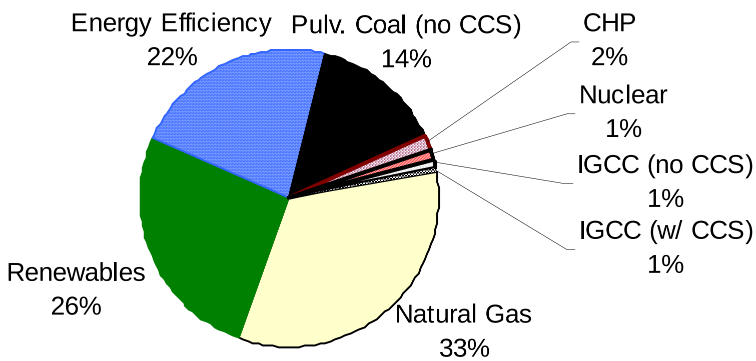


Figure 10. Aggregate Composition of Western Utilities' Preferred Resource Portfolios

Notes: See Appendix A for conventions and assumptions used to construct the figure.

As a rough approach to gauging the degree to which Western utilities' current long-term resource strategies may diverge from what could be required under future carbon regulations, we compare the composition and carbon intensity of utilities' preferred resource portfolios to EIA's projections of resource development in the Western Interconnect under three "representative" federal climate policy proposals: the McCain-Lieberman Climate Stewardship Act of 2003 (S.139); draft legislation prepared by Senator Bingaman in late 2006, which was based on recommendations of the National Commission on Energy Policy (NCEP); and the McCain-Lieberman Climate Stewardship and Innovation Act of 2007 (S.280).[48] We selected these three policy proposals for this benchmarking exercise not based on judgment that these particular bills had any specific likelihood of passage, but simply because they span a wide range, in terms of projected impacts, among policies analyzed thus far by EIA. Our comparison is limited to new physical supply-side resources only, as EIA's analysis does not specifically project utility energy efficiency program savings.[49]

[48] EIA's published analyses of these proposals provide results only at a national level. However, the National Energy Modeling System (NEMS), which EIA used to analyze these proposals, produces results for the electricity sector disaggregated into twelve regions. We obtained the model output from EIA for the three regions that together comprise the U.S. portion of the Western Interconnect, in order to compare the preferred portfolios of the fifteen utility resource plans included in our sample to EIA's projections for the West.

[49] EIA's load forecasts may implicitly account for energy savings from utility energy efficiency programs; however, these savings cannot be distinguished from reductions in energy use resulting from customers' long-run price elasticity, which are not-attributable to energy efficiency programs.

It is important to note that this comparison is imperfect given that: (a) EIA's projections cover the entire U.S. portion of the Western Interconnect, whereas our sample of utilities represents about 60% of retail sales in the West and does not include utilities from Arizona or New Mexico; (b) we show EIA projections for the year 2025, but the resource plans in our sample have planning periods that end anywhere from 2012 to 2027; and (c) although EIA's projected generation additions and utilities' preferred portfolios both exclude already-planned resources, EIA's set of planned resources likely do not include many of those identified in utilities' resource plans (in part, because of differences in the timing in when the analyses were conducted).

With these caveats in mind, Figure 11 compares the aggregate supply-side resource additions in the utilities' preferred portfolios to EIA's projection of new generation in the West in 2025 under the three federal climate proposals mentioned previously. The new supply-side resources identified in utilities' resource plans have an aggregate carbon intensity of approximately 775 lbs CO_2/MWh, which is slightly less than the emission rate of a CCGT and less than half that of unsequestered coal. This is significantly higher than the composite emission rate for EIA's projections of generation additions in the West under the two McCain-Lieberman bills (approximately 375 lbs/MWh for S.139 and 450 lbs/MWh for S.280), but notably less than under the 2006 Bingaman proposal (1,050 lbs/MWh).[50]

In the case of S.139, EIA's projection of generation additions is quite similar to the utilities' preferred portfolios in terms of the proportion of renewables and conventional natural-gas fired generation. The differing carbon intensities are, instead, attributable to the fact that EIA projected no new coal without CCS under S.139, and in its place, a substantial amount of natural gas-fired generation with CCS (which only one utility, NorthWestern, even considered) and small amounts of coal with CCS and nuclear. The difference between the carbon intensity of the utilities' preferred portfolios and EIA's projection under S.280 – although similar in magnitude to the difference with S.139 – is, instead, attributable to the fact that EIA projects less than half the new natural gas-fired generation, and in its place, significantly higher levels of renewables (50% of all new supply, as opposed to 35%) and an appreciable amount of new nuclear power (almost 15% of all new supply), which only several utilities even considered. Finally, we see that utilities' preferred portfolio are, in aggregate, quite a bit less carbon-intensive than EIA's projection of Western generation additions under the 2006 Bingaman proposal, as a result of containing only half as much coal on a percentage basis and, in its place, larger contributions from renewables and natural gas-fired generation.

[50] Although not necessarily the cause for this trend, it is interesting that most utilities' base-case carbon price assumptions were in between the levels projected by EIA for the Bingaman bill and the two McCain-Lieberman bills.

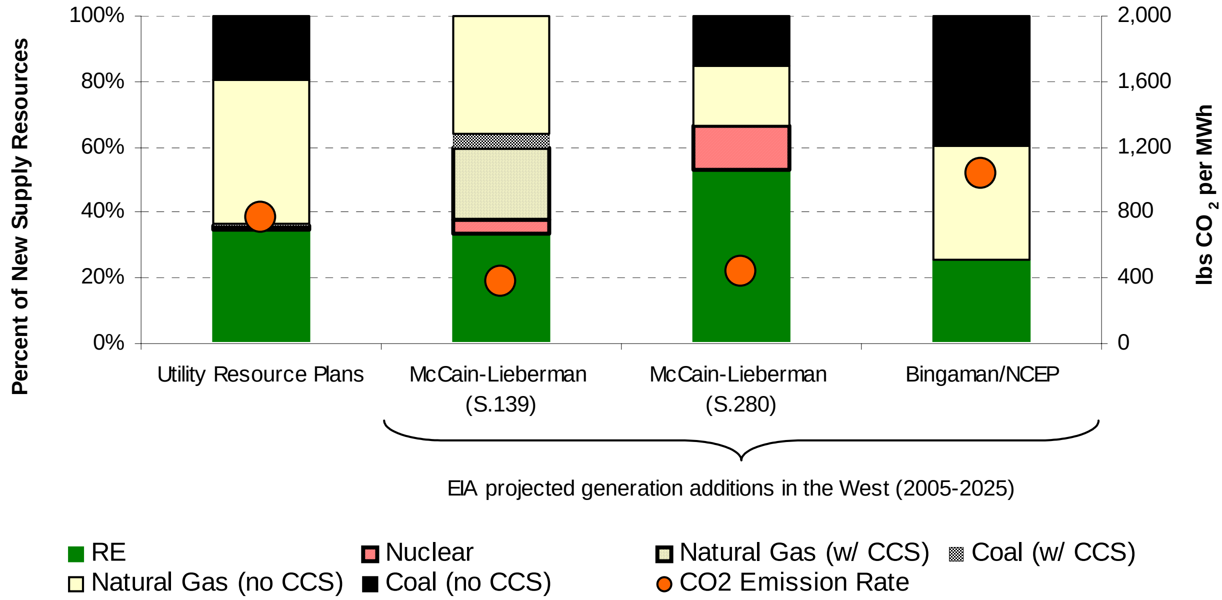


Figure 11. Comparison of Aggregate Preferred Portfolio Supply-Side Resources to EIA Projections of Generation Additions in the Western U.S. through 2025

Notes: See Appendix A for conventions and assumptions used to construct the figure.

The disparity between the carbon intensity of the set of utility preferred portfolios and EIA's projections for the two McCain-Lieberman proposals represents a potentially significant *regional* exposure to carbon regulatory risk. On a utility-by-utility basis, though, the picture is quite diverse, with some utilities potentially exposing themselves (and their ratepayers) to much greater carbon regulatory risk than other Western utilities. Figure 12 shows the carbon-intensity of just the supply-side component of each utility's preferred portfolio, compared to the West-wide average and the three EIA projections. The six utilities on the left-most side of the figure selected preferred portfolios consistent with, or even less carbon-intensive than, what the EIA projects would be required throughout the West under the two McCain-Lieberman proposals it has analyzed. In contrast, two utilities (Nevada Power and Tri-State) selected preferred portfolios that are significantly more carbon-intensive than what the EIA projects would be required on a West-wide basis, even under the quite modest 2006 Bingaman proposal.

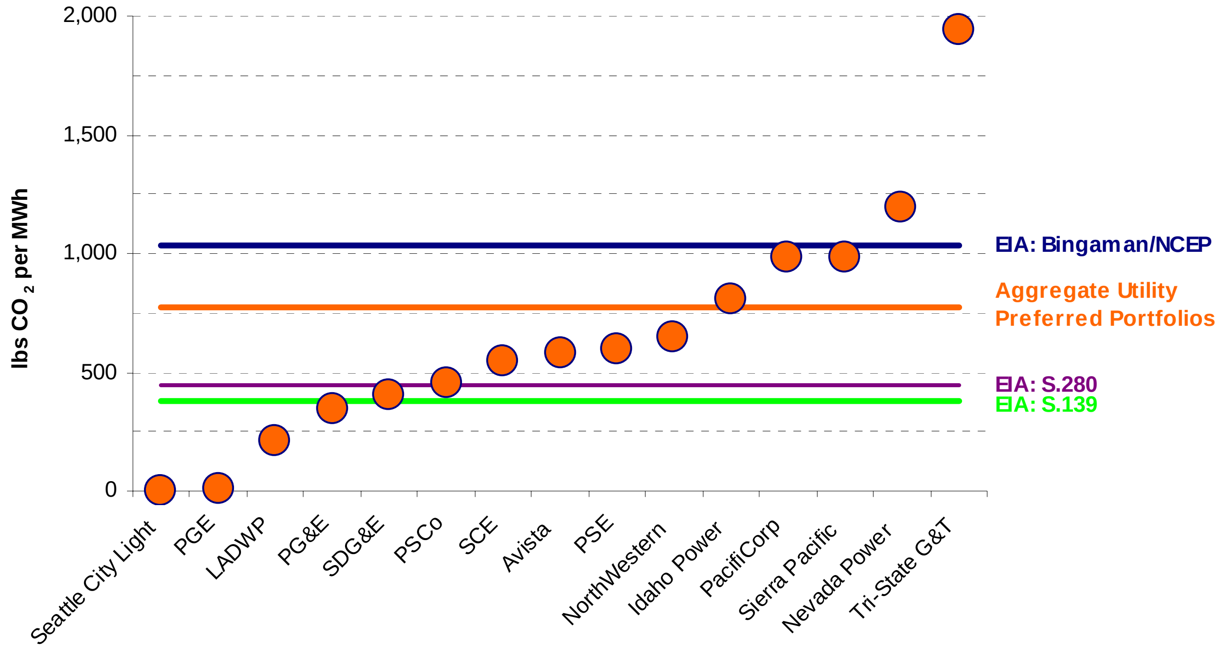


Figure 12. Comparison of Each Utility's Preferred Portfolio Supply-Side Resources to EIA Projections of Generation Additions in the Western U.S. through 2025

8. Summary, Recommendations, and Conclusion

The foregoing comparative analysis of Western utilities' resource plans has two distinct elements:

- A review and assessment of utilities' treatment of various issues related to the analysis of carbon regulatory risk; and
- A summary of the preferred resource portfolios identified in utilities' resource plans and their associated carbon footprint.

In this section, we summarize major findings and offer suggestions for utilities, regulators, and other stakeholders on how to improve analysis of carbon regulatory risk in utility resource planning.

8.1 Major findings: utilities' analysis of carbon regulatory risk

Our review of Western utility resource plans shows that utilities are increasingly taking into account the implications of future carbon regulations when developing their long-term resource strategies, although methods and assumptions used to evaluate carbon regulatory risk vary considerably. Key findings from our review of utilities' resource planning analysis are as follows:

- ***Almost without exception, Western utility resource plans analyze candidate portfolio costs subject to future carbon regulations, but often assume relatively moderate carbon emission prices.*** All fifteen utilities in our sample, except LADWP, analyzed candidate portfolio costs with a future carbon tax or cap-and-trade system, and several utilities also analyzed portfolio costs with other types of future carbon regulations (e.g., additional state generation performance standards beyond existing state requirements). Of the fourteen utilities that evaluated a carbon tax or cap-and-trade system, eleven included it in their base-case scenario, with carbon price projections ranging from $4 to $20 per ton of CO_2 (2007$), levelized over 2010-2030. This is at the lower end of the spectrum of EIA's carbon emission price projections for the range of federal policy proposals it has thus far analyzed. Eleven utilities evaluated alternative carbon emission price projections to their base-case. However, several of these utilities considered only a relatively narrow range of alternate carbon emission prices (e.g., Nevada Power and Sierra Pacific considered a maximum levelized price of only $7/ton, and Avista considered levelized prices up to $22/ton).

- ***Most utilities evaluated a range of low-carbon candidate portfolios with aggressive levels of energy efficiency and renewables.*** All but three utilities (Sierra Pacific, Nevada Power, and Tri-State) evaluated at least one candidate portfolio with a composite CO_2 emission rate (based on all new, physical demand- and supply-side resources in the portfolio) of less than half that of a natural gas-fired combined cycle gas turbine (CCGT). Utilities' low-carbon candidate portfolios generally reflect aggressive underlying levels of energy efficiency and new renewables. Of the fifteen utilities, nine included in all candidate portfolios the "maximum achievable" energy efficiency program savings, with incremental annual energy savings ranging from 0.6% to 1.3% of total retail sales and cumulative savings ranging from

30% to 73% of projected retail sales growth over their planning periods. All fifteen utilities also evaluated candidate portfolios with new renewables, and most evaluated one or more candidate portfolio in which renewables constitute at least 50% of all new supply-side resources in the portfolio and 10% of the utility's total retail sales. Although thirteen of the utilities are subject to a renewables portfolio standard (RPS), most utilities evaluated candidate portfolios containing new renewables above and beyond the level strictly needed for RPS compliance. Utilities' consideration of low-carbon resources other than energy efficiency and renewables was much more limited. Six utilities evaluated candidate portfolios containing coal-fired integrated gasification combined cycle (IGCC) generation with carbon capture and storage (CCS). One utility also evaluated CCS in combination with both pulverized coal and natural gas-fired CCGT generation. Only two utilities evaluated candidate portfolios with new nuclear.

- ***When modeling the impact of carbon regulations on portfolio costs, utilities often ignore potentially significant indirect impacts.*** Though Western utility planners are now considering the potential direct cost of future carbon regulations on their resource portfolios, relatively few resource plans acknowledge and evaluate the full range of potentially significant, indirect effects of carbon regulations on their planning environment. These indirect effects could potentially include changes in: wholesale electricity market prices, natural gas prices, air pollutant permit prices, load growth, coal plant retirements, regional generation and transmission expansion, continued availability of existing federal incentives for various generation technologies, generation capital costs, and technology development.

- ***It is often unclear how, or if, utilities' analysis of uncertainty in carbon emission costs informed selection of their preferred portfolios.*** Utilities can account for *expected* carbon regulation costs by including a projection of carbon emission prices in their base-case portfolio analysis. Because utilities typically rely quite explicitly on their base-case results when selecting a preferred portfolio, it is generally clear that their assumptions about expected carbon regulatory costs had the opportunity to influence their portfolio selection. Accounting for *uncertainty* in carbon costs requires that candidate portfolio costs be compared across a range of carbon emission price projections. As mentioned previously, eleven utilities evaluated candidate portfolio costs under multiple carbon price scenarios. However, of these eleven utilities, six made no reference in their resource plan to variation in portfolio costs across carbon price assumptions when explaining the rationale for selecting their preferred portfolio, leaving it unclear what role this uncertainty analysis could have played in selecting a preferred portfolio. The other five utilities did explicitly refer to results from alternate carbon price scenarios when selecting their preferred portfolios, but their approaches to incorporating this information into the decision-making process differed substantially, and the utilities generally provided little explanation about how they made tradeoffs between reducing expected cost and reducing uncertainty in cost.

8.2 Major findings: carbon intensity of utilities' preferred resource portfolios

Utility resource plans typically culminate by identifying a single, preferred resource portfolio, consisting of a projection of supply- and demand-side resource acquisitions over the duration of the planning period (typically 10-20 years). As part of our comparative review, we summarized the composition and carbon intensity of utilities' preferred resource portfolios, and compared the aggregate set of new resources and carbon emissions footprint embodied in these portfolios to potential CO_2 emission benchmark levels. Key findings are as follows:

- ***Energy efficiency and renewable generation are the dominant low-carbon resources in utilities' preferred portfolios.*** All utilities selected preferred portfolios with energy efficiency and new renewables, and half selected portfolios in which energy efficiency and renewables together constitute 50% or more of all new resources.

- ***Natural gas is a common, although not universal, component in utilities' preferred portfolios.*** Twelve utilities' preferred portfolios include natural gas-fired generation, typically representing 30% or more of the total portfolio, though some utilities included only a small amount of natural gas-fired peaking capacity.

- ***Other types of low-carbon resources – most notably, new nuclear power and CCS – play a relatively minor role in utilities' preferred portfolios.*** Only two utilities (PSCo and Idaho Power) selected portfolios with new nuclear, and only one utility (PSCo) selected a portfolio containing IGCC with CCS (although Idaho Power's preferred portfolio includes IGCC without CCS). Three utilities also included small amounts of CHP in their preferred portfolios (i.e., 5-10% of new resources).

- ***Utilities in inland states continue to pursue pulverized coal without CCS.*** Five of the eight utilities serving inland states selected preferred portfolios containing sub-critical or super-critical pulverized coal without CCS, representing anywhere from 20% to more than 90% of new resources in the portfolio. In contrast, none of the seven utilities whose service territories are confined to coastal states selected preferred portfolios with any coal-fired generation. Of these utilities, four are subject generator emission performance standards that effectively preclude them from constructing or contracting with coal-fired generation lacking CCS.

- ***Utilities generally are not planning to retire existing coal-fired generation for the specific purpose of reducing carbon emission costs or regulatory risks.*** Of the two utilities (PGE and PSCo) that evaluated retiring and replacing existing coal plants with less carbon-intensive resources, only PSCo ultimately included the retirement within its preferred portfolio. Sierra Pacific and Nevada Power also assumed in their portfolio construction process that particular coal plants would be retired within their planning periods, but these assumptions were not driven by any apparent consideration of potential carbon emissions or regulatory costs.

.

- ***The carbon intensity of utilities' preferred portfolios varies widely.*** Ten of fifteen utilities selected preferred portfolios with no new coal and have composite CO_2 emission rates ranging from zero to approximately 475 lbs/MWh, depending on the amount of natural gas-fired generation in the portfolio. The other five utilities, whose preferred portfolios include new coal-fired generation without CCS, have composite emission rates ranging from approximately 700-1,600 lbs/MWh, depending on the portion of the portfolio comprised of coal.

- ***In aggregate, the carbon intensity of utilities' preferred resource portfolios is more carbon-intensive than could be required under a relatively aggressive policy proposal.*** Aggregating the fifteen utilities' preferred portfolios, natural gas-fired generation is the largest component, representing about 33% of all new resources, on an annual energy basis. Renewables (26%), energy efficiency (22%), and pulverized coal (14%) make up the lion's share of the remaining new resources, with small contributions from CHP (2%), nuclear (1%), IGCC with CCS (1%), and IGCC without CCS (1%). In aggregate, the supply-side portion of the fifteen utilities' portfolios corresponds to an overall CO_2 emission rate of approximately 775 lbs CO_2 per MWh. Comparing to potential CO_2 emission benchmarks, the aggregate supply-side portion of these fifteen utilities' preferred portfolios is less carbon-intensive than EIA's projection of generation additions in the Western Interconnect under the relatively-modest 2006 Bingaman proposal (1,050 lbs/MWh), but significantly more carbon-intensive than the generation additions projected by EIA under the 2003 and 2007 McCain-Lieberman bills (375 lbs/MWh and 450 lbs/MWh, respectively).

8.3 Recommendations for the treatment of carbon regulatory risk

Utilities are making important strides in accounting for financial risks associated with future carbon regulations when developing their long-term resource strategies. At the same time, their assumptions and methods vary considerably, and reveal a number of opportunities for potential improvement. Accordingly, we offer the following set of recommendations for consideration by utility resource planners and other participants in the resource planning process. State regulators have a particularly important role in ensuring that carbon risk is appropriately addressed, given that much of the associated costs could ultimately be born by ratepayers rather than utility shareholders (e.g., if carbon regulation compliance costs are treated as a "pass-through" in utility ratemaking).

- ***Analyze potential costs and financial risks associated with future carbon regulations.*** Given the potentially far-reaching financial consequences, utilities should consider the potential cost of future carbon regulations – and the uncertainty of that cost – when developing their long-term resource strategies. The starting point in this process is to develop specific assumptions about the nature and timing of future carbon regulations that might realistically be implemented, at either the state or federal level, over the lifetime of the investments considered in the plan. Some states have already established greenhouse gas reduction policies and are currently in the process of developing a framework to implement those policies (e.g., a cap-and-trade program to implement a statewide emission cap). Utilities in these states would ideally develop assumptions about the future structure and timing of any associated state regulations, in addition to developing assumptions about potential *new* state or federal policies.

- ***Consider including a reasonable estimate of the "most likely" carbon policy in the base-case scenario.*** Given current political momentum at the state, regional, and federal levels, it would appear risky to stipulate as a baseline assumption that no carbon regulations will be enacted for the indefinite future. As such, utilities may wish to assume some level of future carbon regulation in their base-case analysis. Moreover, these assumptions would ideally be based on an informed and transparent assessment of the most likely trajectory of carbon emission prices over their planning period, while recognizing the high degree of speculation and uncertainty involved. Utilities may want to consider developing these assumptions through workshops and/or technical advisory groups, and state regulators and legislators may wish to offer specific guidance on these matters.

- ***Consider evaluating a broad range of carbon price projections to account for the risk associated with uncertainty in future carbon regulations.*** Although it may be increasingly likely that some form of carbon regulation will be enacted in the future, the form and timing of that regulation is highly uncertain. This uncertainty poses significant financial risks for utility ratepayers and shareholders (beyond the risk associated with simply ignoring the most likely cost of future carbon regulations). In order to gauge the full exposure of candidate portfolios to carbon regulatory uncertainty, it is important that utilities evaluate these portfolios across a broad range of carbon emission price projections. Workshops and technical advisory groups offer a potential forum for developing a meaningful range of carbon price projections, and state regulators and legislators may wish to offer specific guidance.

- ***Consider evaluating a diverse set of low-carbon candidate portfolios.*** A utility's ability to assess the cost and value of mitigating carbon regulatory risk is ultimately contingent upon its consideration and analysis of a diverse set of low-carbon candidate resource portfolios. To fully evaluate its risk mitigation options, utilities would ideally construct multiple low-carbon candidate portfolios composed of varying combinations of different low-carbon resources, and include these portfolios in all phases of their resource planning analysis. Utilities that do not construct any low-carbon candidate portfolios, that construct only a small number of "bookend" candidate portfolios dominated by one or another low-carbon resource, or that prematurely eliminate their low-carbon candidate portfolios before assessing potential carbon emission costs, will not be able to fully evaluate the potential costs and benefits of mitigating carbon regulatory risk.

- ***Consider constructing candidate portfolios that include the maximum achievable energy efficiency potential.*** The maximum achievable energy efficiency potential is intended to represent the cost-effective amount of energy use that can be displaced assuming the most aggressive program funding scenario and accounts for program costs and factors that influence customer adoption rates (e.g., customer awareness of energy efficiency measures and economic and non-economic barriers). The assumptions and methods used to develop estimates of the maximum achievable potential are not standardized and often are not transparent. Thus, utilities should provide a sufficient level of detail to allow for assessment of the underlying assumptions and methods (e.g., the type of cost-effectiveness test used to define the economic potential, assumptions about customer awareness, factors incorporated into the customer adoption model, and assumptions about the percentage of incremental measure cost funded by the utility).[51]

[51] For example, in its resource planning process, the Northwest Power Planning and Conservation Council develops an estimate of the maximum achievable energy efficiency potential for both "lost opportunity" and non-lost opportunity measures/strategies.

- ***Consider valuing the avoided carbon costs of energy efficiency and the reduced carbon regulatory risks.*** Carbon regulations will tend to increase the avoided cost benchmark used by the utility to evaluate energy efficiency cost-effectiveness and economic potential. For some of the utilities in our review, it was unclear what, if any, carbon emission prices were assumed when evaluating the cost-effectiveness of the energy efficiency resources considered in their plan. Utilities should consider evaluating the cost-effectiveness and economic potential of energy efficiency resources based on consistent base-case and alternative carbon price assumptions as used in the analysis of potential supply-side resources. In addition, most of the utilities in our review included a fixed level of energy efficiency across all candidate portfolios and scenarios, which precludes the utility from assessing the value that greater levels of energy efficiency may offer as a hedge against future carbon regulations that are more stringent than their base-case assumption. Utilities should therefore consider evaluating greater levels of energy efficiency than what is strictly cost-effective under base-case carbon-price assumptions, and compare the incremental total resource costs under expected conditions to the incremental costs under high carbon-price scenarios.

- ***Consider constructing candidate portfolios that include the full range of renewable generation options available, and with quantities of new renewables that exceed RPS requirements.*** In its analyses of potential federal carbon regulations, EIA projects that a significant fraction of new renewable energy additions in the West will consist of wind, biomass and geothermal resources. However, our review shows that several utilities limited their consideration of renewables only to wind energy. In order to assess the full range of options for mitigating carbon regulatory risk, utilities should evaluate the range of renewable generation options available over their planning horizon. In addition, levels of renewables in excess of state RPS requirements may be warranted, given the value that renewables offer as a hedge against carbon regulatory risks. Utilities should therefore not treat RPS requirements as a cap on future renewable additions, and should consider constructing candidate portfolios with levels of renewables that go above and beyond the minimum targets required by state RPS policies.

- ***Consider undertaking efforts to develop credible assumptions about the future commercial availability and cost of IGCC with CCS, CCGT with CCS, and nuclear power.*** Utilities' consideration of these technologies in resource planning is currently limited, in part, due to uncertainty in the cost of these resources and the timing of their future availability. Yet, aggressive federal or state carbon regulations would, if developed, likely necessitate the increased use of these low-carbon resources. Utilities and state regulators may therefore want to consider engaging in collaborative efforts to better define reasonable cost and availability assumptions for these resources, so that these technologies can be more fully evaluated in future resource plans.

- ***Consider devoting more analytic effort to accounting for the potentially significant indirect effects of future carbon regulations.*** Carbon regulations could have a number of secondary, but potentially far-reaching, effects on a utility's planning environment, beyond simply the impact of those regulations on the operating cost of its own resources. Our review suggests that many of these potentially important secondary effects are not given much attention in current resource planning processes. Over time, utilities should attempt to account for the broad range of these potential impacts in their resource planning. In the near-term, the most important secondary effects of future carbon regulations to consider may be the impacts on wholesale power prices, natural gas prices, coal plant retirements, and load growth. On a longer term basis, impacts on emissions allowance prices, regional generation and transmission expansion, availability of federal incentives, and capital costs and technology development might also be considered. Given uncertainty in these interactions, they may be best examined through scenario analyses (e.g., by constructing scenarios that include several different gas price projections in combination with high carbon prices).

- ***Consider developing more transparent methods and criteria for incorporating uncertainty in future carbon emission costs into the portfolio selection process.*** Candidate resource portfolios can be compared to one another in terms of both their expected cost and uncertainty in cost (i.e., risk), and both should be explicitly considered as part of the portfolio selection process. This is generally not an issue for expected costs, as utilities typically rely quite explicitly on the results from their base-case analysis when selecting a preferred portfolio. However, our review suggests that, in most cases, it is unclear how, or whether, analysis of alternate carbon regulation scenarios to the base-case informs the selection of the utility's preferred resource portfolio. Furthermore, even in those cases where carbon regulatory risk is explicitly considered in the portfolio selection process, it is generally unclear how tradeoffs are made between minimizing risk and other objectives, such as minimizing expected costs. It is critical that utilities develop transparent and well-founded methods for addressing both of these issues in order to provide information to regulators and stakeholders on the factors that influence their preferred resource portfolio. Given that ratepayers may bear much of the risk associated with uncertainty in future carbon regulations, utilities may want to consider undertaking research to characterize the risk preference of their customers.

8.4 Conclusion

Over the long-term, future carbon regulations may require a dramatic shift in electric infrastructure development away from conventional fossil generation technologies, and an unprecedented scale-up of investment in low-carbon resources. Long-term resource planning can serve an instrumental role in informing this possible shift, by providing a framework for analyzing the potential cost and risks associated with future carbon regulations and by assessing the various options for mitigating that risk. For utility resource planning to serve this role effectively, however, requires confidence that the specific assumptions and methods used to analyze carbon regulatory risk are reasonable, and will therefore support prudent investment decisions. State regulators and policy-makers may wish to advance this process by weighing-in on the issues discussed above, and by providing direct guidance to utilities on the appropriate treatment of carbon regulatory risk in resource planning.

References

Andrews, C. and. S. Govil, 2007, "Becoming Proactive About Environmental Risks: Regulatory Reform and Risk Management in the US Electricity Sector," *Energy Policy*, 23(10): 885-892.

Bokenkamp, K, H. LaFlash, V. Singh, D. Bachrach Wang, 2005, "Hedging Carbon Risk: Protecting Customers and Shareholders from the Financial Risk Associated with Carbon Dioxide Emissions." *The Electricity Journal*, 18(6): 11-24.

Bolinger, M. and R. Wiser, 2005, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans*, Lawrence Berkeley National Laboratory, LBNL-58450.

Cavanagh, R. Gupta, A., Lashof, D. and M. Tatsutani, 1993, "Utilities and CO_2 emissions: Who Bears the Risks of Future Regulation?" *The Electricity Journal*, 6(2): 64-75.

Clemmer, S. and B. Freese, 2006, *Gambling with Coal: How Future Climate Laws Will Make New Coal Power Plants More Expensive*," Cambridge, Massachusetts: Union of Concerned Scientists.

Gardiner and Associates, 2006, *Best Practices in Climate Change Risk Analysis for the Electric Power Sector*," A Ceres Report, Boston, Massachusetts: Ceres.

GF Energy, 2007, *2007 Electricity Outlook*.

EIA, 2003, *Analysis of S. 139, the Climate Stewardship Act of 2003*, Energy Information Administration, SR/OIAF/2003-02.

EIA, 2007a, *Energy Market and Economic Impacts of a Proposal to Reduce Greenhouse Gas Intensity with a Cap and Trade System*, Energy Information Administration, SR/OIAF/2007-01.

EIA, 2007b, *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*, Energy Information Administration, SR/OIAF/2007-04.

EIA, 2007c, *Supplement to Energy Market and Economic Impacts of S.280*, Energy Information Administration.

Hopper, N., C. Goldman, and J. Schlegel, 2006, *Energy Efficiency in Western Utility Resource Plans: Impacts on Regional Resource Assessment and Support for WGA Policies*, Lawrence Berkeley National Laboratory, LBNL-58271.

Johnston, L., E. Hausman, A. Sommer, B. Biewald, T. Woolf, D. Schlissel, A. Roschelle, and D. White, 2006, *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning*, Synapse Energy Economics.

Keeler, A.G., 2008, *State Commission Electricity Regulation Under a Federal Greenhouse Gas Cap-and-Trade Policy*, National Regulatory Research Institute, NRRI-08-01, Columbus, Ohio.

Lempert, R.J., D. Groves, S. Popper, and S.C. Bankes, 2006, "A General Method for Generating Robust Strategies and Narrative Scenarios," *Management Science*, April 2006.

National Action Plan for Energy Efficiency, 2007, *Guide for Conducting Energy Efficiency Potential Studies*, prepared by Optimal Energy, Inc. August.

NCEP, 2004, *Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges*, The National Commission on Energy Policy.

Parry, I.W.H. and W.A. Pizer, 2007, "Emissions Trading vs. CO_2 Taxes vs. Standards," in *Assessing U.S. Climate Policy Options: A report summarizing work at RFF as part of the inter-industry U.S. Climate Policy Forum*, R.J. Kopp and W.A. Pizer (eds.), Resources for the Future.

Pew Center, 2006, *Climate Change 101: State Action*, Pew Center on Global Climate Change, http://www.pewclimate.org/docUploads/101_States.pdf

Pew Center, 2006, *Learning from State Action on Climate Change: March 2007 Update*, Pew Center on Global Climate Change, http://www.pewclimate.org/docUploads/States%20Brief%20Template%20_March%202007_jgph.pdf.

Repetto, R. and J. Henderson, 2003, "Environmental Exposures in the US Electric Utility Industry.," *Utilities Policy*, 11: 103-111.

Rufo, M. and F. Coito, 2002, *California's Secret Energy Surplus: The Potential for Energy Efficiency*, prepared for the Energy and Hewlett Foundations, September 23.

WCI, 2007, *Western Climate Initiative Statement of Regional Goal*, Western Climate Initiative, http://www.westernclimateinitiative.org/ewebeditpro/items/O104F13012.pdf.

Wiser, R., Bachrach, D., Bolinger, M., and W. Golove, 2004, "Comparing the Risk Profiles of Renewable and Natural Gas-Fired Electricity Contracts," *Renewable and Sustainable Energy Reviews*, 8: 335-363.

Wiser, R., M. Bolinger, M. St. Clair, 2005, *Easing the Natural Gas Crisis: Reducing Natural Gas Prices Through Increased Deployment of Renewable Energy and Energy Efficiency*, Lawrence Berkeley National Laboratory, LBNL-56756.

Appendix A: Data Conventions and Assumptions

We employed a variety of conventions and assumptions in constructing the figures presented in this report, described below.

- **"Planned" Resources:** Utilities often have future resources already in-the-pipeline (i.e., under contract and/or under development) at the time of their plan. Utilities' typical practice is to treat these resources as part of the baseline resource projection (along with existing resources), rather than as part of the candidate portfolios. We follow utilities' convention in this regard. Thus our descriptions of utilities' candidate and preferred portfolios refer only new resource above and beyond already-planned resources, as identified in each utility's resource plan.

- **Contract Renewals:** In order to focus on new, physical resources, and to maintain as much consistency as possible across utilities, we exclude contract renewals from all calculations and figures related to the composition and carbon intensity of utilities' candidate portfolios and preferred portfolios. Many utilities were not explicit about which expiring contracts would likely be available for renewal, in which case we made some judgment about what portion of their portfolio resources would likely be met with contract renewals and reduced the reported portfolio resource quantities accordingly. In particular, we reduced the renewable resource quantities of: Seattle City Light (assumed contract renewal with Stateline wind project), SCE (assumed contract renewals with 80% of non-renewables DWR contracts), SDG&E (assumed contract renewals with 80% of non-renewables DWR contracts, with the Cabazon and Whitewater Hill wind projects, with the AES-Delano biomass project, and for 90% of the output from eight expiring LFG contracts), and Sierra Pacific (assumed contract renewals for all expiring geothermal, small hydro, and biomass contracts). Also related to this issue, PSCO developed one set of candidate portfolios under the assumption that expiring contracts are renewed, and another set of candidate portfolios under the assumption that no expiring contracts are renewed; our calculations and figures rely on the former.

- **Short- and Medium-Term Market Purchases:** Again, to focus on new, physical resources, and to maintain as much consistency as possible across utilities, we exclude new short- and medium-term contracts or market purchases (<10 years) from all calculations and figures related to the composition and carbon intensity of utilities' candidate portfolios and preferred portfolios (effectively assuming that new short- and medium-term contracts generally will not motivate construction of new, physical resources). The only utilities affected by this convention were: PacifiCorp, whose candidate portfolios included varying quantities of "front-office transactions"; PGE, whose candidate portfolios included varying quantities of power purchase agreements with a duration of less than five years or five-to-ten years; and PSE, whose candidate portfolios included varying quantities of "power bridging agreements" and capacity call options, intended to bridge the period until the utility could construct or procure long-term resources.

- **California IOU Conventional Resources:** The three California IOUs do not identify conventional (i.e., non-renewable, non-CHP) supply-side resources in their candidate and preferred portfolios in terms of particular technologies. Rather, PG&E identified new conventional generation only as "intermediate and peaking" capacity, which we assume to be evenly split between CCGT and CT resources. SCE and SDG&E also identify conventional supply-side resources in generic functional terms (i.e., baseload, intermediate, and peaking). After accounting for planned and new renewables, energy efficiency, CHP, and potential DWR contract renewals (see above) in each utility's candidate portfolios, we conclude that the two utilities' conventional supply-side needs are primarily for peaking resources. Thus, we assume that all new conventional supply-side capacity identified in their candidate and preferred portfolios consists entirely of gas-fired CTs.

- **Capacity Factors:** Some utilities identify only the nameplate capacity of resources in their candidate portfolios. In these instances, we used the default capacity factors in Table A - 1 to estimate annual energy production of each resource.

Table A - 1. Default Capacity Factors

Resource	Capacity Factor
Gas (CT)	15%
Gas (CCGT)	60%
Coal (sub-critical)	85%
Coal (super-critical)	85%
Coal (fluidized-bed)	85%
Coal (IGCC)	80%
Coal (IGCC w/ CCS)	80%
CHP	75%
Nuclear	90%
Wind	35%
Geothermal	90%
Biomass	80%
Hydro	50%

- **CO_2 Emission Rates:** For utilities that did not specify the CO_2 emission rates of individual resources considered in their plan, we used the default values in Table A - 2 when calculating composite emission rates of their candidate and preferred portfolios. Those values are an average of emission rates specified in those utilities' resource plans that provide such information.

Table A - 2. Default CO_2 Emission Rates

Resource	CO_2 Emission Rate (lbs/MWh)
Gas (CT)	1158
Gas (CCGT)	819
Gas (CCGT w/ CCS)	100
Coal (sub-critical)	1896
Coal (super-critical)	1773
Coal (fluidized-bed)	1751
Coal (IGCC)	1821
Coal (IGCC w/ CCS)	212
CHP	651
Energy Efficiency	0
Renewables	0
Nuclear	0

- **Additional Conventions and Assumptions:** The conventions and assumptions described above apply to numerous figures throughout this report. Table A - 3 identifies more-specific conventions and assumptions that apply to individual figures.

Table A - 3. Additional Conventions and Assumptions Applicable to Individual Figures

Figure 2	▪ We calculated levelized values from utilities' reported annual CO_2 emission price using a 7% real discount rate. ▪ Where necessary, conversion of utilities' reported carbon emission price assumptions to 2007 dollars was made using the actual GDP deflator from 2000-2006, and EIA's forecast of the GDP deflator for 2007-2030, from Annual Energy Outlook 2007. ▪ To calculate a levelized price over the 2010-2030 timeframe, we extended utilities' carbon price projections out to 2030, if necessary, based on the rate of growth in emission prices in the last two years of each utility's projection. ▪ If utilities' carbon price projections are not denoted specifically as short tons or metric tons, we assumed short tons.
Figure 3	▪ LADWP, NorthWestern, and Tri-State provided energy efficiency projections for only a portion of their respective portfolio construction periods, and we extrapolated these utilities' savings projections out over the full portfolio construction period. ▪ Some utilities' reported load forecasts assume future energy efficiency program activity. When calculating energy efficiency as a percentage of load growth for these utilities, we adjusted their load forecasts by adding back the assumed savings from future energy efficiency programs. ▪ The three California IOUs redact load data for 2007-2009. To estimate the projected load growth over the utilities' entire planning period (2007-2016), we extrapolated the load forecast backwards from 2010 to 2006, using annual growth rates derived from the reported 2010 and 2011 load forecast data.
Figure 4	▪ Renewable additions shown for Sierra Pacific and Nevada Power are derived by distributing their combined RPS compliance needs on a pro-rata basis between the utilities, regardless of which utility is currently receiving the RECs from existing renewables contracts. ▪ PSCo constructed the supply-side of its candidate portfolios out through 2046, but identified demand-side targets only through 2020; thus, in describing its candidate resource portfolios, we focus on the period ending in 2020 in order to maintain consistency between discussions of the demand- and supply-side. ▪ Given our focus on new, physical resources, we excluded two new renewables contracts in LADWP's candidate/preferred portfolio that are with existing resources (a contract

	with BC Hydro/Powerex for existing small hydro facilities and a contract with PPM for the Pleasant Valley wind project).
Figure 5	▪ PSCo constructed the supply-side of its candidate portfolios out through 2046, but identified demand-side targets only through 2020; thus, in describing its candidate resource portfolios, we focus on the period ending in 2020 in order to maintain consistency between discussions of the demand- and supply-side.
Figure 6	▪ PSCo constructed the supply-side of its candidate portfolios out through 2046, but identified demand-side targets only through 2020; thus, in describing its candidate resource portfolios, we focus on the period ending in 2020 in order to maintain consistency between discussions of the demand- and supply-side.
Figure 8	▪ The values shown for NorthWestern reflect the average composition of the top four supply-side candidate portfolios identified in the resource plan. ▪ PSCo constructed the supply-side of its candidate portfolios out through 2046, but identified demand-side targets only through 2020; thus, in describing its preferred resource portfolio, we focus on the period ending in 2020.
Figure 10	▪ See notes for Figure 6
Figure 11	▪ Regional data provided by EIA for S.139 did not specify CCS capacity in the West, although EIA does publish this information at a national level. We estimated Western capacity additions of natural gas with CCS and coal with CCS under S.139 by assuming that CCS is installed on the same fraction of new natural gas and coal capacity in the West as in EIA's projection of nationwide capacity additions.

Appendix B: EIA's Projections of CO_2 Emission Reductions in the Electric Power Sector under Several Federal Policy Proposals

Throughout this study, we benchmark utilities' assumptions about future carbon regulations and the carbon intensity of their preferred resource portfolios against EIA's analyses of several federal climate policy proposals: the McCain-Lieberman Climate Stewardship Act of 2003 (S.139), draft legislation prepared by Senator Bingaman in late 2006, and the McCain-Lieberman Climate Stewardship and Innovation Act of 2007 (S.280). All three proposals would establish economy-wide cap-and-trade systems for greenhouse gas emissions, but they differ significantly in terms of the size and timing of the emission cuts and other key provisions (e.g., the use of offsets and whether or not to employ a safety-valve on emission allowance prices). In all three cases, EIA projects significant impacts on CO_2 emissions and future resource investments in the electric power sector and, for S.139 and S.280, EIA projects that the electric power sector would provide a disproportionate percentage of economy-wide greenhouse gas emission reductions.

The original McCain-Lieberman climate bill issued in 2003 (S.139) proposed an economy-wide greenhouse gas cap-and-trade program, with a cap at 2000 levels during 2010-2015, and at 1990 levels from 2016 onward. EIA's projection of allowance prices under this policy equates to a levelized price of approximately $44/short ton of CO_2 in 2007$, over the 2010-2030 period (EIA 2003).[52] A CO_2 allowance price of this magnitude would have a quite dramatic effect on the relative economics of different resource options, adding about $41/MWh to the operating cost of coal-fired generation without carbon sequestration, and about $18/MWh to the cost of a CCGT (see Figure B - 1). Given these price impacts, EIA projects that total CO_2 emissions in the electric power sector would decline by 76% from 2010 to 2025, representing 68% of the cumulative, economy-wide greenhouse gas emission reductions over this period (EIA 2003).

At the other end of the spectrum in terms of the stringency of the required emission reductions, is draft climate legislation prepared by Senator Bingaman in late 2006, which is based on NCEP's policy recommendations. This bill would establish annual caps on the carbon emission intensity of the U.S. economy (i.e., emissions per unit GDP) and includes a safety-valve provision, which would limit allowance prices to $7/metric ton in 2012, increasing at 5% per year in real dollars.[53] EIA's projection of allowance prices under this policy equates to a levelized price of approximately $6/short ton (2007$) over the period 2010-2030 (EIA 2007a).[54] A carbon emission price of this magnitude would add about $6/MWh to the operating cost of unsequestered coal-fired power generation, and about $3/MWh to the cost of a CCGT (see Figure B - 1). Given these somewhat modest cost impacts, EIA projects that emissions in the electric power sector increase by 11% from 2010 to 2030, compared to the 31% increase in its reference case forecast (EIA 2007a). The projected emission reductions in the electric power

[52] EIA reports projected emission allowance prices for 2010, 2020, and 2025. To compute the levelized price over 2010-2030, we interpolated between the values for the three years reported by EIA and extrapolated the projection out for the years 2026-2030, so that it covers the same analysis period as the other two federal policy proposals discussed in this study.

[53] Note that the Bingaman-Specter bill drafted in 2007 has a higher safety valve price, starting at $12/ton in 2012 and escalating at 5% per year in real dollars.

[54] These prices are based on EIA's "phased auction" policy scenario; EIA also developed projections for several other variations of S.139.

sector, relative to the reference case, represent 30% of the cumulative, economy-wide greenhouse gas emission reductions over this period (EIA 2007a).

Lastly, the McCain-Lieberman Climate Stewardship and Innovation Act of 2007 (S.280) proposes to institute an economy-wide cap on greenhouse gas emissions beginning in 2012, ratcheting down to 22% below 1990 levels in 2030. EIA's projection of allowance prices under this policy equates to a levelized price of approximately $18/short ton (2007$) over the period 2010-2030 (EIA 2007b).[55] Carbon emission prices of this magnitude would add about $17/MWh to the operating cost of unsequestered coal-fired power generation, and about $7/MWh to the cost of a CCGT (see Figure B - 1). At these carbon costs, EIA projects that carbon emissions in the electric power sector would decline by 48% from 2010 to 2030, representing 73% of the cumulative, economy-wide greenhouse gas emission reductions over this period, relative to its reference case scenario (EIA 2007b).

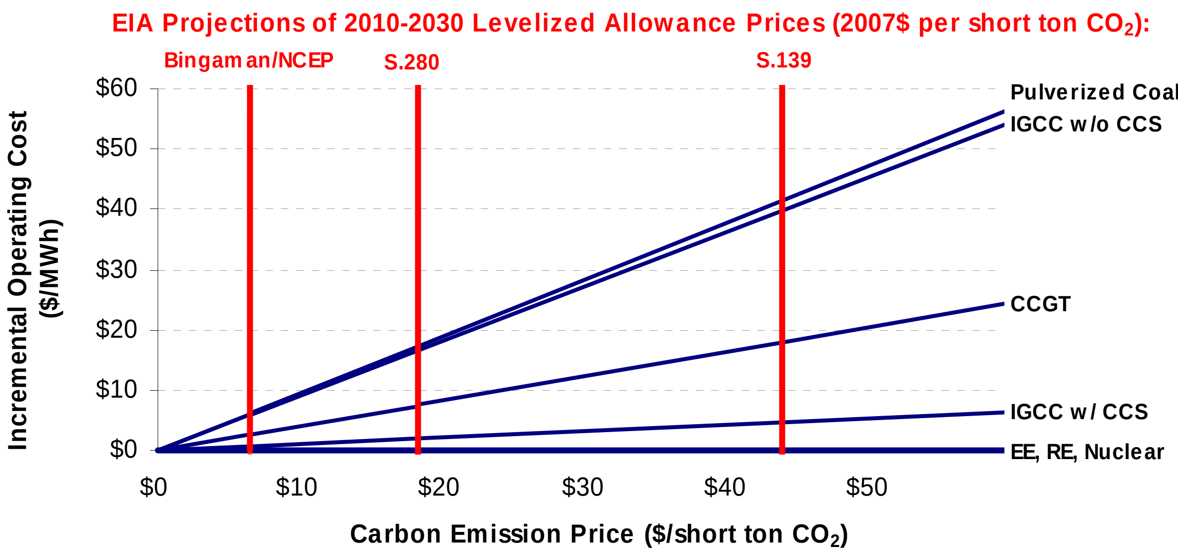


Figure B - 1. The Effect of Carbon Regulations on the Operating Cost of Different Resources

[55] These carbon emission prices are based on EIA's "core" policy scenario. EIA also developed projections for variations of S.280 and alternate assumptions about the availability of low-carbon electricity generation technologies. The highest carbon emission price projection (approximately $24/ton, levelized over 2020-2030) was for a scenario in which international offsets could not be used for compliance.