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Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans

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Environmental Energy Technologies Division

August 2005

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Office of Planning, Budget & Analysis, and the
Wind & Hydropower Technologies Program
Assistant Secretary for Energy Efficiency and Renewable Energy
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Executive Summary

Introduction

Markets for renewable energy have historically been motivated primarily by policy efforts, but a less widely recognized driver is poised to also play a major role in the coming years: utility integrated resource planning (IRP).[1] Resource planning has re-emerged in recent years as an important tool for utilities and regulators, particularly in regions where retail competition has failed to take root. In the western United States, the most recent resource plans contemplate a significant amount of renewable energy additions. These planned additions – primarily coming from wind power – are motivated by the improved economics of wind power, a growing acceptance of wind by electric utilities, and an increasing recognition of the inherent risks (e.g., natural gas price risk, environmental compliance risk) in fossil-based generation portfolios.

This report examines how twelve western utilities treat renewable energy in their recent resource plans.[2] In aggregate, these utilities supply approximately half of all electricity demand in the western United States. Our purpose is twofold: (1) to highlight the growing importance of utility IRP as a current and future driver of renewable energy, and (2) to identify methodological/modeling issues, and suggest possible improvements to methods used to evaluate renewable energy as a resource option.

Here we summarize the key findings of the report, beginning with a discussion of the planned renewable energy additions called for by the twelve utilities, an overview of how these plans incorporated renewables into candidate portfolios, and a review of the specific technology cost and performance assumptions they made, primarily for wind power. We then turn to the utilities' analysis of natural gas price and environmental compliance risks, and examine how the utilities traded off portfolio cost and risk in selecting a preferred portfolio.[3]

Planned Renewable Energy Additions

The most recent batch of western resource plans includes a significant amount of renewable resource additions. In the case of the three California and two Nevada investor-owned utilities (IOUs) covered in this study, these additions are primarily the result of state-imposed renewables portfolio standards (RPS). The seven remaining utilities in our sample, however, are not subject to an RPS (or at least were not at the time of their most recent IRP filings),[4] and plan to add renewables based solely on their own merits, as revealed through analysis of the expected cost, value, and risk mitigation benefits of renewable resources. Figure ES-1 shows the cumulative,

[1] Though we use the term "IRPs" (or more generally, "resource plans" or "plans") throughout this report, we acknowledge that terminology varies, and that not all of the utilities refer to their own filings as "IRPs."
[2] The twelve investor-owned utilities (IOUs) included in our sample include: Avista, Idaho Power, NorthWestern Energy (NorthWestern or NWE), Portland General Electric (PGE), Puget Sound Energy (PSE), PacifiCorp, Public Service Company of Colorado (PSCo), Nevada Power, Sierra Pacific, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).
[3] Not surprisingly, the plans vary in the availability and completeness of the data that are released, and our ability to summarize the treatment of renewable energy in each of the plans is therefore somewhat limited.
[4] PSCo and NorthWestern have become subject to an RPS since filing their most recent IRPs. Because the RPS was not in place at the time of IRP filing, we do not consider these utilities' planned additions to be RPS-driven.

planned additions of renewable generating capacity among the twelve utilities in our sample, categorized as either RPS- or IRP-driven additions. As shown, the ~8,000 MW of new renewable capacity expected by 2014 is split almost evenly between each category.

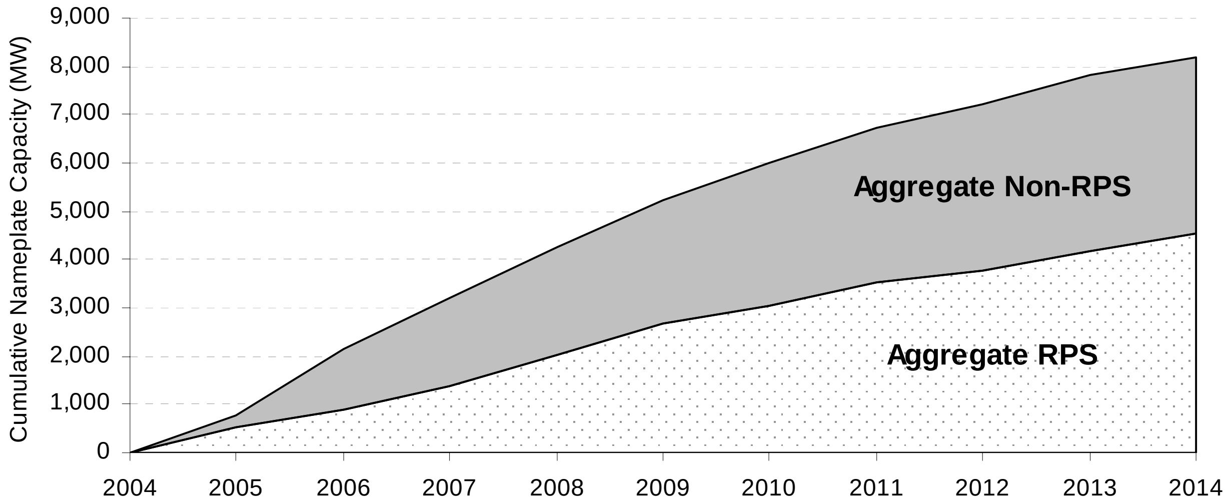

Figure ES-1. Planned Renewable Resource Additions in Twelve Western Resource Plans

Figure ES-2 breaks out the cumulative planned renewable additions from Figure ES-1 by utility, and normalizes them as a percentage of projected utility load. Perhaps the most interesting observation is that two of the four most aggressive utilities by this metric *are not* subject to an RPS. Though RPS-driven planned additions might be considered *more certain* than non-RPS plans, Figures ES-1 and ES-2 clearly illustrate that non-RPS resource plans may themselves be a major driver of growth in new renewables; whether and to what degree these planned renewable additions are subsequently achieved is an important avenue of future study.

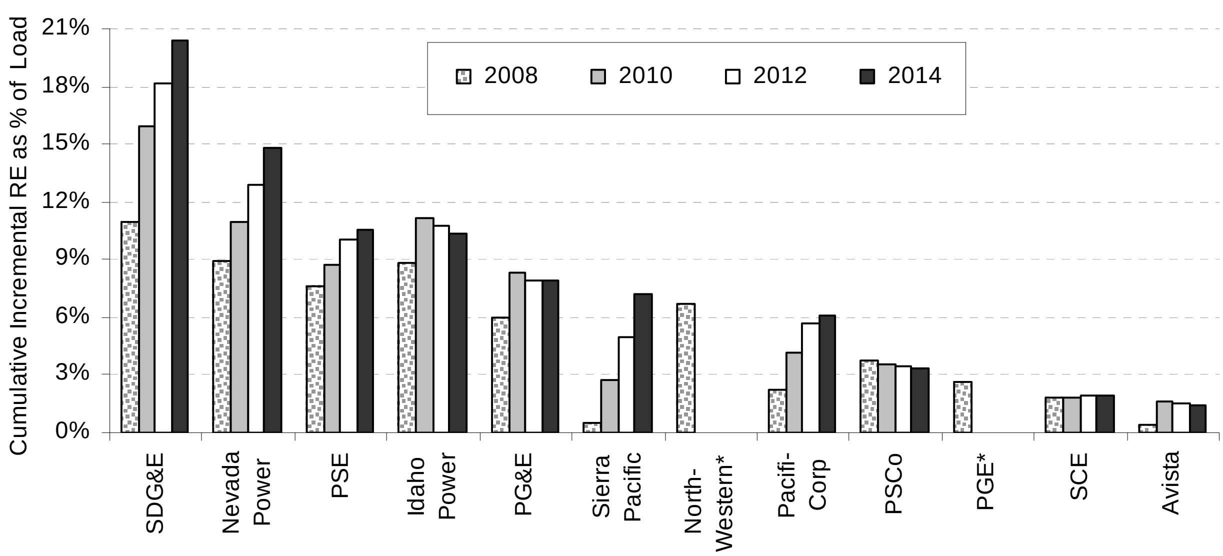

Figure ES-2. Cumulative Incremental Renewable GWh as a Percentage of Utility Load

*PGE's and NorthWestern's procurement horizons end in 2007, so only their 2008 values are shown.

Portfolio Construction

Though the content of any specific utility IRP is unique, all are built on a common basic framework: development of peak demand and load forecasts, assessment of how these forecasts compare to existing and committed generation resources, identification and characterization of various resource options and candidate portfolios to fill a forecasted resource need, analysis of different candidate portfolios under base-case and alternative future scenarios, and selection of a preferred portfolio and creation of a near-term action plan.

Our review of twelve western resource plans reveals that, in most cases, candidate resource portfolios are constructed by hand, featuring resources that are regionally available and that passed initial cost or performance screening tests. Though this "pre-selection" of candidate portfolios may simplify the modeling process – an important consideration, to be sure – it also allows human bias to influence the outcome, by limiting the universe from which the optimal portfolio emerges. If renewable resources are not accurately or adequately represented within the candidate portfolios, or if a broad range of candidate portfolios is not considered, the modeling outcome could be sub-optimal.[5] Within this context, we make the following observations on how renewable energy is treated in candidate portfolio construction:

- **A full range of renewable options is not always considered in utility resource plans.** Most plans consider wind, and some also include geothermal and other sources, within candidate portfolios. Many renewable sources are ignored, however, or screened out earlier in the process. Even if open solicitations for renewable energy are subsequently held, such an analytic approach may forfeit any insights (e.g., transmission upgrade needs) that might be gained by modeling additional specific renewable resources.

- **Exogenous caps can limit the amount of renewable energy additions.** All of the IRPs in our sample exogenously define the maximum amount of renewable energy that can be selected, either by establishing constraints on the optimization model, by pre-defining candidate portfolios, or by only accepting a certain amount of wind even if analysis results suggest that higher levels of penetration are warranted. Figure ES-3 illustrates the exogenous caps for wind power additions, both in terms of incremental capacity and incremental percentage of peak load. In some cases, the maximum permissible amount of incremental wind is relatively small, and in many cases these caps limit the amount of wind power included in the preferred portfolio.

- **State RPS policies sometimes "cap" the amount of renewable energy considered.** In four of the five original California and Nevada plans, the existence of state RPS policies led to a pre-defined amount of renewable energy in the preferred portfolio, effectively serving as a cap on *planned* renewable resource procurement. None of the California or Nevada plans publicly provides any *economic* analysis of the potential value of purchasing renewable energy at a level that exceeds the state's RPS requirements; nor do many of these plans present economic analysis of which renewable sources might best meet their RPS-driven

[5] We do note, however, that for many utilities resource planning is an indicative process – the outcome of which does not limit further analysis or acquisition of any renewable or other resources – and therefore that sub-optimal modeling results may not necessarily lead to sub-optimal procurement decisions.

needs.[6] Again, while this basic approach may be functional in RPS-states, it forfeits any insights that might be gained by modeling specific resources, and fails to provide a utility's regulators or external stakeholders information that might be useful in establishing planning and procurement expectations.

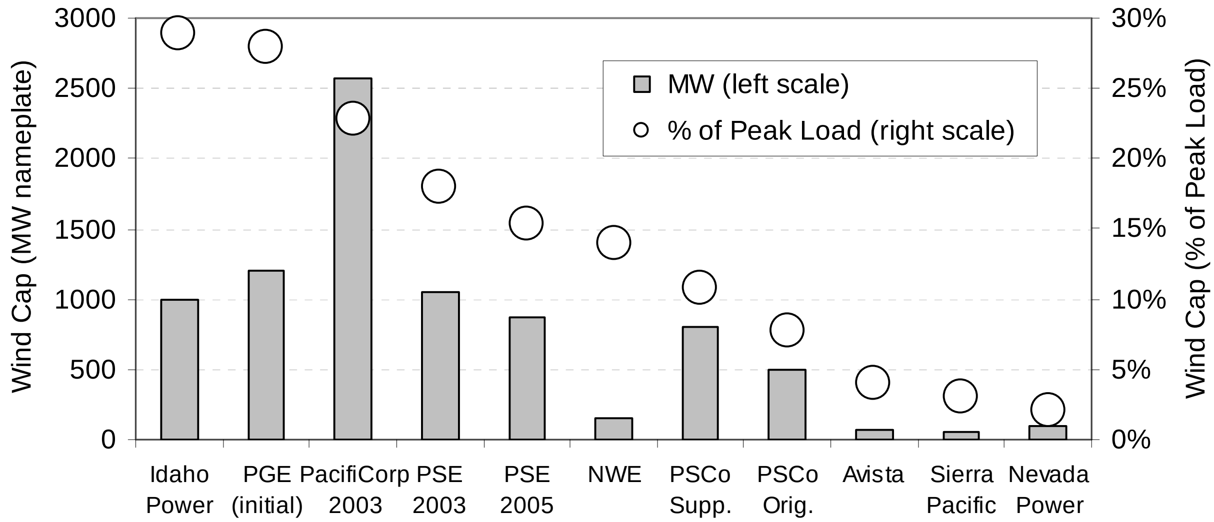

Figure ES-3. Exogenous Caps on Wind Power Capacity within Candidate Portfolios

Renewable Resource Cost and Performance Assumptions

Also important to how renewable energy fares in IRP are the cost and performance assumptions made for various renewable technologies. Based on our review of the wind power (and to a lesser extent, geothermal) cost and performance assumptions embedded in the resource plans, we make the following observations:

- **Assumptions for the total modeled cost of wind power can significantly affect wind power penetration.** Figure ES-4 breaks out the assumed cost of wind power by component, where data is available. As shown, the total modeled cost of wind power ranges from $23/MWh to $59/MWh. Not surprisingly, the total modeled cost of wind power has a strong influence on the amount of new wind included in preferred portfolios, with lower assumed costs generally leading to higher planned wind penetration.

- **The range of levelized busbar costs assumed for wind generation appears to be reasonable.** The assumed busbar costs of wind power (capital, O&M, and PTC) range from $23/MWh to $55/MWh, and seem reasonable compared to other sources. It is important to note, however, that adverse exchange rate movements, coupled with rising steel prices, tight wind turbine manufacturing capacity, and a general rush to install wind projects prior to the then-scheduled expiration of the PTC at the end of 2005, have combined to push the installed cost of wind projects sharply higher in 2005; how long this higher price environment will

[6] Note that all renewable energy projects would generally be eligible to participate in future solicitations, even if not explicitly included in the resource plans. Also note that California's utilities, in their 2005 renewable energy procurement plans, demonstrated greater analysis of various renewable energy options, and PG&E and SDG&E presented illustrative plans that would lead to over-compliance with the state RPS.

persist is unclear. Past IRP assumptions for the cost of wind may therefore not be reflective of *current* costs; this potential disparity between utility expectations and current market reality could negatively impact wind procurement efforts in the near term, and could result in higher cost assumptions in future resource plans.

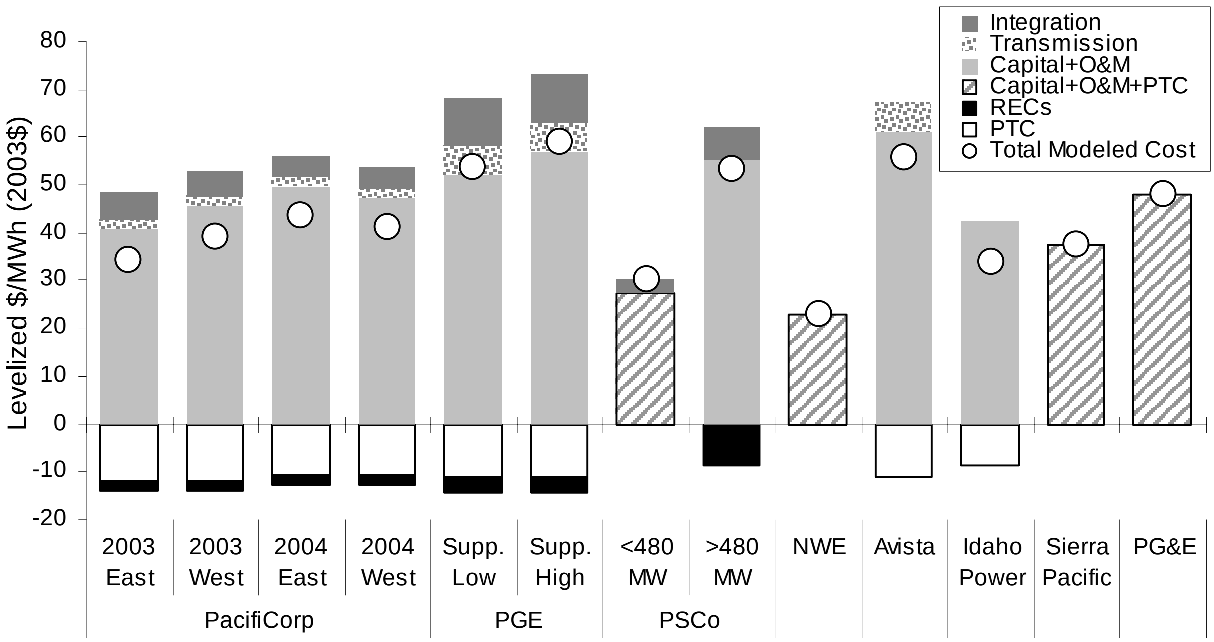

Figure ES-4. Wind Power Cost Assumptions

- **Some of the resource plans *understate* the value of the federal production tax credit (PTC), but *overstate* the likelihood of PTC extension over the planning horizon.** Some plans account for the PTC in a *pre-tax*, rather than *after-tax* manner. By doing so, these resource plans understate the value of the PTC by approximately $7/MWh. On the other hand, many of the plans assume that the PTC will remain available for a longer period of time than appears reasonable, thereby perhaps understating the likely cost of renewable energy in the longer term.

- **Transmission expansion costs are not widely evaluated.** Though many of the resource plans in our sample account for the cost of transmitting wind across *existing* power lines, the larger issue of expanding the transmission system to access greater quantities of renewable resources has, in many instances, only been addressed qualitatively. Particularly as wind additions increase in the West, it will be necessary to develop and incorporate into IRPs improved assessments of the transmission costs of accessing varying quantities of wind generation. This may allow resource plans to move away from strict and sometimes-arbitrary limits on the amount of wind additions allowed (as is sometimes current practice).

- **Integration cost assumptions by some utilities appear to be high, while others may be low.** Utilities are using increasingly sophisticated tools to evaluate the integration costs of wind power. Compared to recent analytic studies, however, wind integration costs used in *some* of the utility resource plans appear to be conservative. Figure ES-5 illustrates this point: the range of costs (and corresponding wind penetration levels) estimated by recent wind integration studies is shown to the left of the dashed vertical line, while the range of costs assumed among our sample of resource plans (where data is available) is shown to the right of that line. Still other utilities, however, have assumed that such costs are negligible, and exclude these possible costs from consideration in their plans.

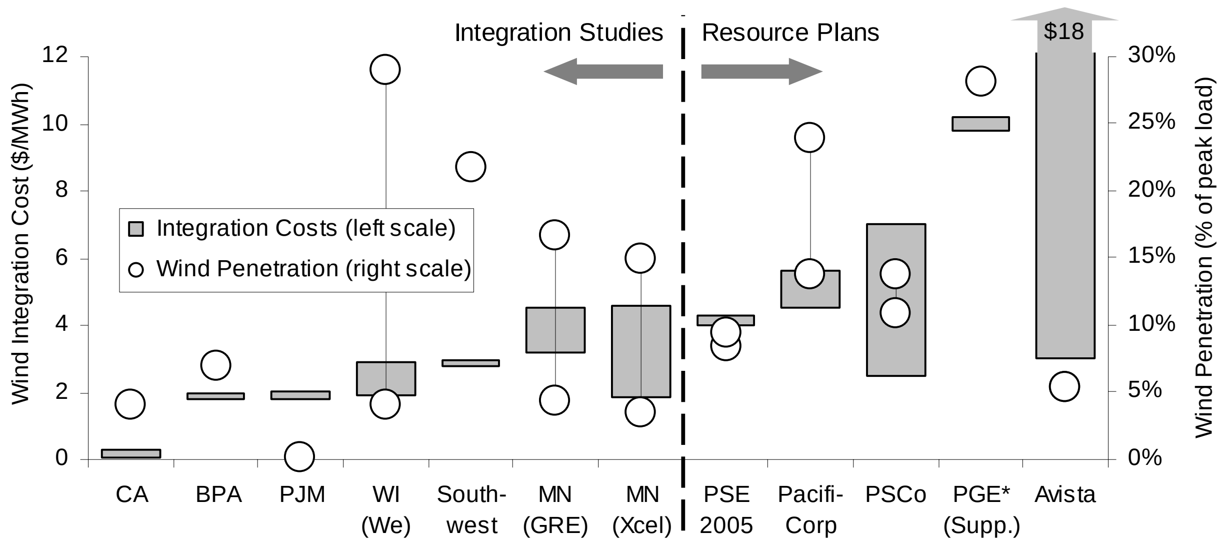

Figure ES-5. Comparison of Integration Costs in Resource Plans and Integration Studies
*PGE estimates the cost of creating a flat, base-load block of power out of variable wind production, rather than simply the cost of integrating variable wind production. As such, its cost estimate is not directly comparable to the others.

- **Some utilities cite uncertainty over integration costs as a reason to cap the amount of wind power allowed into candidate or preferred portfolios.** These caps are sometimes established at low, and somewhat arbitrary, levels, and highlight the need for *more* integration cost studies conducted at *higher* wind penetration levels. Until such studies are available, uncertainty over integration costs might be best modeled just like any other uncertain variable, using scenario and/or stochastic analysis, rather than through exogenous wind penetration caps.

- **In some cases, assumptions about wind's capacity value appear to be too low.** Virtually all of the IRPs that explicitly assigned a capacity value to wind calculated that value in a different way, and only two utilities in our sample used effective load carrying capability (ELCC), viewed by many to be the most analytically rigorous way of quantifying capacity value. Perhaps as a result, assumptions about wind's capacity value range widely, from 0% to 33% (as shown by the arrows along the right-hand axis of Figure ES-6). Some of these assumptions are lower than warranted based on recent studies of wind's ELCC (as shown by the grey bars in Figure ES-6). Further examination of wind's capacity value, focusing on the use of ELCC, is warranted in future IRPs.

- **Geothermal costs are assumed to be competitive with wind in some cases, though the range of assumed costs is wide.** The wide range of assumed levelized costs for geothermal – from $35 to $100/MWh – is striking, and suggests that geothermal costs either vary significantly by region or site, or alternatively are poorly understood by utilities. If costs at the low end of the range are to be believed, however, then geothermal arguably deserves a second look by more western utilities.

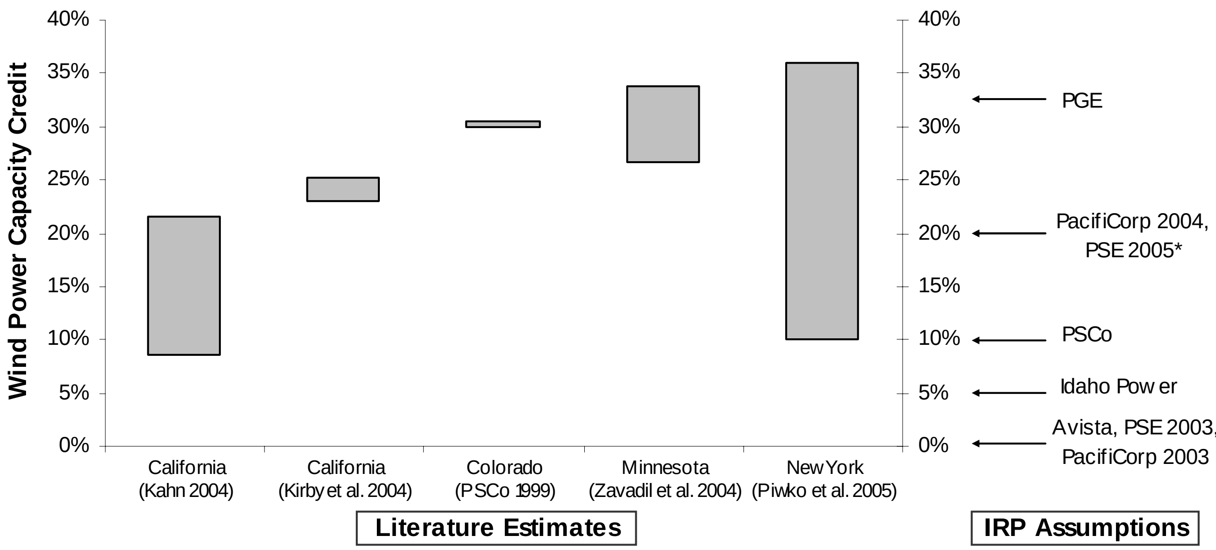

Figure ES-6. Results from Recent Studies of Wind Power's Capacity Value
**PSE 2005 assigns the lesser of 20% of nameplate capacity or two-thirds of the average capacity factor during January.*

Analysis of Natural Gas Price Risk

Assumptions for both the base-case natural gas price forecast and the expected long-term uncertainty in natural gas prices can be important in influencing resource decisions and the degree to which renewable energy is selected. Our review of western resource plans shows that all of the sampled utilities are taking natural gas price uncertainty seriously, and that the degree of analytic sophistication in applying risk analysis is increasing. Stochastic simulation is the most common approach to analyzing these risks (used in 10 of the 12 plans), though a number of plans (9 of 12) use scenario analysis either as a supplement to, or a replacement for, stochastic simulation techniques. Our review leads us to the following observations:

- **Base-case gas-price forecasts vary considerably among the plans**. In 2015, forecasted prices range from $3/MMBtu to $5/MMBtu, depending on the plan. These differences are striking, and can be attributed in part to different price forecasting methods and the different times during which the forecasts were generated. These forecasted prices are also all well below current pricing, and current future price expectations as revealed through the NYMEX futures markets. In constructing base-case price gas forecasts, we conclude that at least two factors should be considered. First, because future gas-price expectations can change rapidly, utilities should generally use the most-recent forecasts available. Second, the natural gas futures market can provide a useful benchmark against which to compare natural gas price forecasts (at least over the near-to-medium term – longer-term forecasts unfortunately have no such frame of reference), and base-case forecasts that diverge significantly from this benchmark warrant explanation and scrutiny.

- **Some utilities may not be employing a wide enough range of future gas prices.** Poor historical forecast accuracy suggests that little weight should be placed on base-case gas-price forecasts. Alternative future price paths that vary by $2/MMBtu higher or lower than the base-case forecast are certainly plausible. Though price distributions with wide uncertainty bounds are now used in a number of resource plans, some utilities may not be employing a wide enough range of future gas price scenarios, and in other instances, resource plans offer too little information to assess whether the resulting price distribution is sufficiently wide. Though a few utilities have cited the proprietary nature of private forecasts as justification for not disclosing such information, other utilities freely report on the private sector forecasts used in their plans. There appears to be no compelling reason for keeping such forecasts, or the resulting stochastic derivations, confidential.

- **None of the plans evaluate the impact of increased renewable energy investments on natural gas prices.** Recent studies show that, by reducing demand for natural gas, renewable energy deployment may put downward pressure on natural gas prices and consumer natural gas bills. None of the IRPs in our sample directly accounted for this effect. This "oversight" may be reasonable because the effect of any *single* utility's investments in renewable energy on *that* utility's gas prices is likely to be minor. This effect is better considered in a regional setting, where the impact of *aggregate* renewable energy investment on *region-wide* gas prices can be significant. While it is debatable whether renewables (and other non-gas resources) should be given credit in *electricity* IRP for reducing consumer *natural gas* bills, overall rate stability is one of the goals of IRP, and one might reasonably question why these markets are not analyzed in a more integrated fashion.

Analysis of Environmental Compliance Risk

The risk of new or more stringent environmental regulations over the IRP planning horizon is significant. Utility resource plans should evaluate this risk and, if it is expected to be significant, mitigate the risk through resource portfolios that minimize the cost impacts of current and future regulations. Resource portfolios with significant amounts of renewable energy may be able to help mitigate these risks. Our review of western IRPs leads us to the following observations:

- **Many of the western IRPs are taking on the challenge of evaluating and mitigating the risk of carbon regulation.** The risk of future carbon regulations – which could plausibly increase the cost of coal power by more than $10/MWh – is arguably most significant among all environmental regulatory risks. As a result, seven of the twelve utilities in our sample specifically analyzed this risk. And with each of the California IOUs, as well as NorthWestern Energy in Montana, now also obligated to account for the possibility of future carbon regulations, just two utilities in our sample – Nevada Power and Sierra Pacific – currently ignore this risk in their planning.

- **There is a great deal of inconsistency in *how* carbon risk is analyzed among the plans that we examined.** As shown in Figure ES-7, plans have generally adopted one of three approaches: (1) scenario analysis with no probabilities assigned, (2) probabilistic scenario analysis, and (3) inclusion of carbon risk in the base-case scenario. This variety of approaches is not surprising given the level of uncertainty about the stringency and timing of future carbon regulations. State regulators may, however, want to encourage consistency in the analysis approach and assumptions used, at least among those utilities within their state. In addition, to ensure that the risk of carbon regulation is adequately considered in portfolio selection, utilities should arguably be encouraged to include this possibility in their "base-case" analysis, with side-cases examining both greater and lower levels of regulatory stringency (see, e.g., PacifiCorp 2003 or 2004).

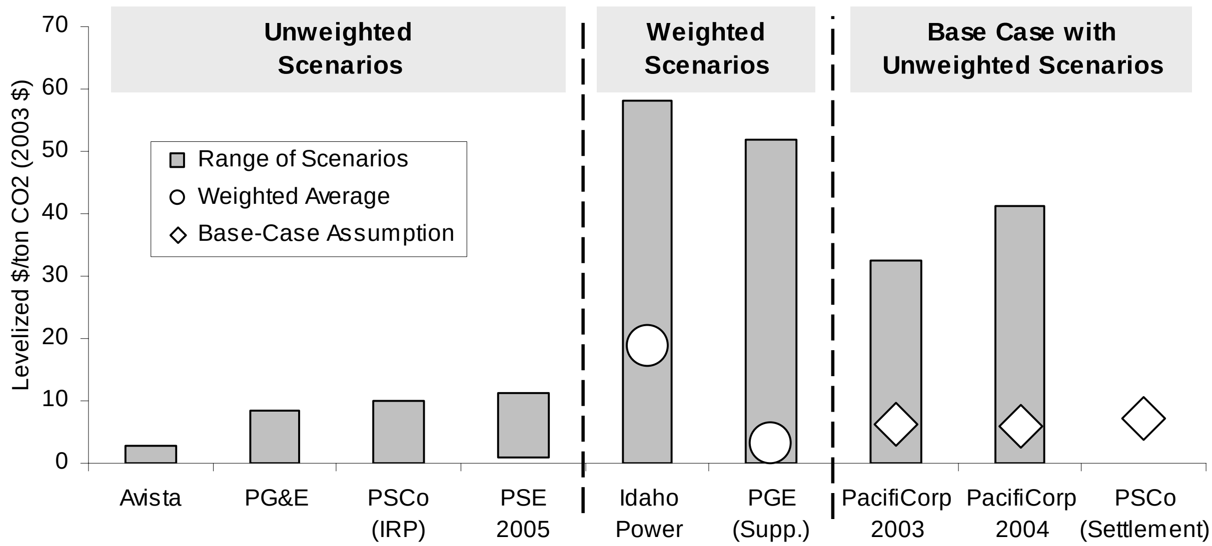

Figure ES-7. Summary of Carbon Regulation Scenarios in Western Resource Plans

- **The stringency of carbon regulation scenarios can be benchmarked to an existing literature, and some IRPs may be undervaluing this risk.** Determining an appropriate range of carbon compliance costs is challenging. As shown in Figure ES-7, resource plans assume a levelized cost of anywhere from $0 to $58/ton-$CO_2$. Though there continues to be substantial disagreement among analysts, the range of compliance costs shown in the broader modeling literature is consistent with the range used in our sample of resource plans. Some of the *specific* plans, however, may not be evaluating a sufficiently broad range of carbon regulation scenarios. Avista, for example, only evaluates a carbon regulation scenario in which a carbon tax of $2.7/ton-$CO_2$ is applied (levelized, 2003$). PGE, on the other hand, does evaluate a broader range of carbon costs, but weights the scenarios such that the weighted-average carbon cost is quite low, at $3/ton-$CO_2$ (levelized, 2003$).

- **Western IRPs do not devote as much attention to the possibility of more stringent criteria air pollution regulations.** The risk of future, more stringent SO_2, NOx, mercury, and particulate regulations is only clearly considered in *two of the twelve* plans that we reviewed. Though more stringent criteria pollutant regulations may not have the same impact on portfolio selection as the possibility of carbon regulations, analysis of this risk still has merit. As with carbon, benchmarks for the cost of complying with future air pollution regulations are readily available from the modeling literature, and could be utilized.

Balancing Portfolio Cost and Risk

Within the resource planning process, utilities ultimately have a responsibility to evaluate and balance the expected cost and risk of candidate portfolios on behalf of ratepayers, choosing the portfolio with the “best” cost-risk combination. The way in which this cost/risk tradeoff occurs is particularly important for renewable sources, which are characterized in many plans as low risk, yet potentially higher cost, resource options.

Our review of resource plans reveals that those plans vary considerably in how they define expected risk, and how they balance the expected cost and risk of different candidate portfolios. In selecting a "preferred" portfolio, a utility would ideally review consumer preferences for cost-risk tradeoffs, and select the candidate portfolio that fits most closely with the risk preferences of the majority of its customers. This approach, however, is rarely used. Instead, in all of the cases we reviewed, the cost-risk tradeoff (if made) is based on the subjective judgment of each utility, informed by any counsel provided by the utility's regulators or external stakeholders.

Separate from, but just as important as, the question of how to weight portfolio cost versus risk is the question of *how* and *when* within the IRP process to assess the cost/risk tradeoff. Some plans, for example, evaluate this tradeoff *prior to* conducting scenario analysis, with potentially significant consequences for renewable energy. Consider the following:

1) **The two main types of risk that renewable energy can help to mitigate are fuel price and environmental compliance (i.e., carbon) risk.** Though renewables are not the only supply-side resources to mitigate fuel price risk, renewables are unique among supply-side resources (barring nuclear) in their ability to mitigate carbon risk.

2) **Candidate portfolios intended as "renewables" portfolios have often ended up performing poorly with respect to fuel price risk.** The simplifying assumption made by many plans to model renewables primarily or solely as wind power, in conjunction with conservative assumptions about the capacity value of wind and the need for gas-peaking plants to integrate wind into the system, has often resulted in so-called "renewables" portfolios being heavily laden with gas-fired generation. As a result, "renewables" portfolios have often exhibited as much or more exposure to natural gas price risk than other portfolios.

3) **Fuel price risk has taken some precedence over carbon risk.** Fuel price risk has typically been addressed through stochastic analysis, ensuring that fuel price risk will impact base-case results early in the analytic process. In contrast, carbon risk has typically been addressed later in the process through scenario analysis, often being conducted on just a few candidate portfolios selected for further scrutiny *based on their attractive cost/risk tradeoff*. In other words, the cost/risk tradeoff has often been made – in part based on consideration of fuel price risk – *before carbon risk is considered,* in which case carbon risk is sometimes relegated to helping to distinguish between a few finalist portfolios.

4) **The precedence of fuel price over carbon risk may disadvantage renewable generation.** The fact that renewables portfolios have tended to perform poorly with respect to fuel price risk has, in some cases, shifted resource choice towards coal-fired generation early in the analytic process. By the time carbon risk is assessed, some renewables portfolios may have already been weeded out of the process.

These four considerations highlight the possible need for a more holistic assessment of risk, and approach to the cost/risk tradeoff. The sequential, winnowing approach currently taken by many plans eases the computational burden, but also may lead to results that are more of a function of the *manner* or *order* in which different risks were assessed rather than of the potential *likelihood* or *magnitude* of the risk itself. If some risks are better-suited for scenario rather than stochastic analysis, then steps should be taken to ensure that the results from the scenario analysis are integrated into the overall process. Otherwise, scenario analysis, and the risks analyzed with that technique, may end up as a mere sideshow to stochastic analysis. Related, a large and varied set of candidate portfolios should be evaluated for their ability to mitigate risks; otherwise, analysis results may be unduly affected by the pre-selection of possible candidate portfolios.

Finally, virtually all of the plans used the utility's weighted average cost of capital (WACC) as the relevant discount rate in calculating the expected cost of different portfolios. Given uncertainty as to whether the WACC is an appropriate discount rate to use when making decisions on behalf of electricity customers, we recommend that sensitivity analysis be conducted on this important variable.

Conclusions

Formal resource planning processes can help utilities and their regulators to consistently and fairly assess a wide range of supply- and demand-side measures in meeting customer needs. Our review of the planning efforts of twelve western utilities reveals that resource plans are becoming increasingly sophisticated in their treatment of renewable resources and the costs and risks that they both entail and mitigate. Many analytical improvements have been made in just the past few years. As highlighted in this executive summary, however, further improvements are still possible. Our most important conclusions are as follows:

1) Resource plans in RPS states should consider evaluating renewable resources as an option above and beyond the level required to satisfy RPS obligations.

2) Resource planners may wish to explore a broader array of renewable resource options.

3) The value of the federal production tax credit for renewable energy, and its risk of permanent expiration, could be more consistently addressed on an after-tax basis.

4) Methods for evaluating wind integration and transmission costs, and capacity value, should continue to be refined and applied at successively higher wind penetration levels.

5) Exogenous caps on wind penetration should potentially be eliminated, especially as analysis of wind integration and transmission costs, and capacity value, improve.

6) Resource plans would ideally evaluate a broad range of possible fuel costs, and subject a large number of candidate portfolios to such analysis (and risk analysis more generally).

7) Environmental compliance risks could be more consistently and comprehensively evaluated.

8) Steps should be taken to ensure that each risk has, as is warranted or appropriate, an opportunity to impact portfolio selection.

9) Utilities and regulators should conduct research to evaluate ratepayer risk preferences.

10) Though there may be instances in which redaction of commercially sensitive information is warranted, more consistent and comprehensive data presentation in utility resource plans would allow for far better external review.

1. Introduction

Markets for renewable energy – especially wind power – have grown substantially in recent years. This growth is typically attributed to technology improvements and resulting cost reductions, the availability of federal tax incentives, and aggressive state policy efforts. Among the state policies, renewables portfolio standards (RPS) and renewable energy funds have arguably been dominant. State RPS policies, for example, motivated approximately 45% of the 4,300 MW of wind power additions in the U.S. from 2001 through 2004, while renewable energy funds supported an additional 15% of these installations.

Despite the mounting importance of these state policy endeavors, another less widely recognized driver of renewable additions is poised to play a major role in the coming years, at least in some states: utility integrated resource planning (IRP). Integrated resource planning – common in the late-1980s to mid-1990s but relegated to lesser importance in the late-1990s to early-2000s – has re-emerged in recent years as an important tool for utilities and regulators, particularly in regions where retail competition has failed to take root.[7]

Renewable energy sources were once rarely considered seriously in utility IRP (Hirst 1994). The most recent batch of resource plans, however, are increasingly contemplating a significant amount of wind power additions. These additions appear to be motivated by the improved economics of wind power, an emerging understanding that wind integration costs are manageable, and a growing acceptance of wind by electric utilities. Equally important, utility IRPs are increasingly recognizing the inherent risks in fossil-based generation portfolios – especially natural gas price risk and the financial risk of future carbon regulation – and the benefits of renewable energy in mitigating those risks.

The treatment of renewable energy in utility resource plans is not uniform, however. Assumptions about the direct and indirect costs of renewable resources, as well as resource availability, differ, as do approaches to incorporating such resources into the candidate portfolios that are analyzed in utility IRPs. The treatment of natural gas price risk, as well as the risk of future environmental regulations, also varies substantially. How utilities balance expected portfolio cost versus risk in selecting a preferred portfolio also differs. Each of these variables may have a substantial effect on the degree to which renewable energy contributes to the preferred portfolio of each utility IRP.

This report examines how twelve western utilities treat renewable energy – primarily wind power – in their resource plans, through a comparative review and analysis of those plans. Our purpose is twofold: (1) to highlight the possible importance of utility IRPs as a current and future driver of renewable energy additions, and (2) to highlight methodological/modeling

[7] Although we use the term "IRPs" (or more generally, "resource plans" or even "plans") throughout this document to refer to the long-term planning documents filed by utilities, we acknowledge that terminology varies, and that not all of the utilities in our sample refer to their own filings as "IRPs" (e.g., some use the term "least cost plans"). We also note that the difference in terminology is not always merely semantic: e.g., the California utilities refer to their filings as "procurement plans," and these plans contain far less analysis of different resource options than one might expect from a more typical IRP.

issues, and suggest possible improvements in resource assessment methods used to evaluate renewable energy as a resource option.[8]

The remainder of this report is organized as follows:

- ***Section 2*** describes the methodology used in our evaluation of resource plans from twelve western utilities, and highlights important aspects of those plans.
- ***Section 3*** summarizes the amount and types of renewable resources selected within the preferred portfolios of each resource plan, identifying and differentiating those resources that are anticipated to serve state RPS policies from those resources expected to be additional to RPS requirements.
- ***Section 4*** highlights the approaches used in constructing alternative candidate portfolios (specifically, the degree to which renewable energy is considered in those portfolios).
- ***Section 5*** reviews the renewable resource cost and performance assumptions in each of the plans, and benchmarks some of those assumptions against other empirical estimates.
- ***Section 6*** analyzes the treatment of risk in the western resource plans. We start by discussing the evolution of risk analysis in resource planning, and then turn to the treatment of natural gas price and environmental compliance risks (carbon and other air pollutants), the two risks that most clearly favor renewable resource additions.
- ***Section 7*** describes how IRPs balance expected cost and risk in selecting the preferred resource portfolio.
- ***Section 8*** concludes the report by identifying certain aspects of IRP (relevant to renewables) that could be improved in future plans, and by providing recommendations for improvement.
- ***Appendix A*** identifies the assumptions – not otherwise described in the body of the report – that we use to manipulate the data provided in the resource plans to a comparable basis, for presentation in the report.

This report does not address in detail the specific modeling techniques that are – or should be – used by electric utilities in evaluating renewable energy options. For an earlier treatment of these issues, see Logan et al. (1995).

[8] By focusing on western U.S. markets, this report implicitly emphasizes hybrid markets characterized primarily by emerging competition in the wholesale supply of electricity but still-monopoly retail electricity service. No state in the West is currently embracing retail competition with open arms. In markets with retail electricity competition, a new term has emerged for resource planning: portfolio management. For more on this concept, see Biewald et al. (2003), Harrington et al. (2002), and Graves et al. (2004).

2. Methodology: Review of the Western Resource Plans

This report builds off of a more comprehensive effort at Berkeley Lab to evaluate resource plans from twelve western utilities.[9] Companion reports describe in more detail the resource plans and resource planning requirements, as well as the usefulness of the plans in resource adequacy discussions (Mingst et al. 2005), and also analyze the treatment of energy efficiency in the plans (Goldman et al. 2005).

2.1 Data Sources

This study was conducted through a detailed review of resource plans – each of which typically contains hundreds of pages of text, figures, supplements, and appendices – from twelve western utilities. Table 1 identifies the utility resource plans covered in this study and the nine Pacific and intermountain states in which the twelve utilities operate. The table also identifies the year and title of the respective resource plans, as well as any subsequent supplements, updates, or action plans that we reviewed. The most recently published final plans and supplements, as of July 2005, were generally used when preparing this report. In several cases, we reviewed multiple plans (PacifiCorp, PSE) or multiple revisions to a plan (PGE), either because these documents are linked in some way or because they demonstrate an evolution in the approaches or assumptions used in resource planning.[10]

The IOUs covered by the study sell approximately half of the total electricity in the western U.S., defined here as the eleven-state area encompassed by Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, Utah, Washington, and Wyoming. The remaining load is served by public power utilities (some of which have IRPs, though in many instances such plans are not readily available to the public) and IOUs that do not have formal resource planning requirements that result in public IRPs (e.g., the IOUs serving New Mexico and Arizona).

Though the content of any specific utility IRP is unique, all are built on a common basic framework:

- development of peak demand and load forecasts,
- assessment of how these forecasts compare to existing and committed generation resources,
- identification and characterization of various resource options to fill a forecasted resource need (or open position),
- analysis of different resource portfolios under base-case and alternative future scenarios, and
- selection of a preferred portfolio and creation of a near-term action plan.

[9] Because it is not associated with a specific utility, we do not review the Northwest Power and Conservation Council's (NPCC) 5th Power Plan. Coordinated, regional power planning efforts of this type are important, however, and indeed many of our recommendations call for greater regional consistency among utility resource plans, in terms of modeling approaches and assumptions – the same prescription offered by NPCC's Power Plan.

[10] Where an original resource plan as well as subsequent supplements, updates, or action plans are reviewed, we use our judgment in determining which data to present; in many cases, this report summarizes data from the original plan and the most recent supplement, in part to show the evolutionary changes to the approaches and assumptions used by a utility as it develops its "final" plan.

Table 1. Resource Plans Reviewed for this Study

Utility	Year & Name of Resource Plan	Time Frame of Plan	Location of Operations
Avista	2003 Integrated Resource Plan	2004-2023, with emphasis on 2004-2013	ID, WA
Idaho Power	2004 Integrated Resource Plan	2004-2033, with focus on 2004-2013	ID, OR
Nevada Power* **	2003 Integrated Resource Plan	2003-2022	NV
NorthWestern Energy	2004 Electric Default Supply Resource Procurement Plan	2004-2023	MT
PacifiCorp	2004 and 2003 Integrated Resource Plan	2005-2024 (2004 IRP); 2004-2023 (2003 IRP); both focus on 1st decade	OR, ID, UT, CA, WA, WY
Pacific Gas & Electric (PG&E)	2004 Long-term Procurement Plan**	2005-2014	CA
Portland General Electric (PGE)	2002 Integrated Resource Plan, February 2003 IRP Supplement, and March 2004 Final Action Plan	2003-2051, but focus on 2003-2020	OR
Public Service of Colorado (PSCo)	2003 Least-Cost Resource Plan and Settlement	Planning Horizon: 2003-2033 Acquisition Period: 2003-2013	CO, NM, WY*
Puget Sound Energy (PSE)	2003 and 2005 Least Cost Plan	2004-2023 (2003), 2006-2025 (2005)	WA
San Diego Gas & Electric (SDG&E)	2004 Long-term Resource Plan**	2005-2014	CA
Sierra Pacific	2004 Integrated Resource Plan***	2005-2024	NV, CA
Southern California Edison (SCE)	2004 Long-term Procurement Plan**	2005-2014	CA

* PSCO is in the process of divesting Cheyenne Light & Power, after which PSCO will no longer have operations in Wyoming.

** For the California plans, we also reviewed relevant 2005 renewable procurement plans, RPS compliance filings, and updated long-term procurement plan filings (filed in March 2005). We did not review the resource plans submitted by the state's IOUs to the California Energy Commission (CEC 2005), as these do not necessarily represent the "preferred" portfolios of the state's utilities.

*** For the Nevada plans, we also reviewed relevant RPS compliance reports.

Though most resource plans do result in the identification of a preferred portfolio as well as steps to move toward that portfolio, it is also important to note that, for many utilities, resource planning is fundamentally an *indicative* process used to consider a broad array of different resources and scenarios, and does not subsequently limit the analysis or acquisition of any specific renewable or other resources.

Moreover, in conducting resource plans, utilities may be constrained by regulatory requirements and deadlines that may limit (to some degree) additional useful analysis. Public input to the process – often a requirement mandated by state utility commissions – also varies considerably, from the bare minimum to significant involvement from the start. The parties around the planning table are often diverse, and include small consumer advocates, large industrial customers, environmental interests, independent power producers, state energy offices, and utility commission staff. As a result, though IRP is, at its core, an analytical exercise, in many cases it also resembles public policymaking, and must be judged within the context of the need to reach broad accord among many different interests. For more information on state resource planning requirements, and filing and approval procedures that underlie each of these plans, see Mingst et al. (2005).

2.2 Data Limitations

Not surprisingly, the resource plans reviewed in this study vary in the availability, completeness, and specificity of the data that are released, and our ability to comprehensively and consistently summarize and evaluate the treatment of renewable energy in each plan is therefore limited.

For example, resource plans from the three major California IOUs (SCE, PG&E, SDG&E) and, to a lesser extent, the Nevada utilities (Nevada Power, Sierra Pacific), are unique in that large quantities of the data in those resource plans are redacted, and therefore not available for public review and comment. Additionally, while we did review certain supplemental IRP filings, we did not seek to compile comprehensive information from other resource-related regulatory filings or other relevant external documents; as a consequence of this omission, there are very likely planned resource acquisitions that are not reflected in this study. Finally, even where an IRP reveals a substantial amount of public information, that information is not always complete or presented in a consistent format. Where possible, these gaps were filled using judgment and interpretation of related information, or through subsequent clarifications from those who prepared the plans. Ultimately, though, our review was grounded in, and in many cases limited to, the content and material that is publicly disclosed through the resource plans.

3. Planned Renewable Energy Additions

The twelve western IRPs contemplate reasonably significant renewable energy additions. In this section, we summarize the RPS- and non-RPS-driven renewable capacity additions contemplated by these plans, and then report those additions as a percent of total electricity load.[11] We conclude by describing the initial actions of the utilities in procuring renewable energy as a result of these plans. Because the resource plans present information in different ways, certain assumptions were required to summarize these data in a consistent fashion (see Appendix A.1 for a description of the assumptions that we used in this process).

3.1 RPS-Driven Renewable Energy Additions

Six western states currently have RPS requirements: California (accelerated to 20% by 2010), Nevada (20% by 2015, 5% of which is from solar), Arizona (1.1% by 2007, 60% of which is from solar), New Mexico (10% by 2011), Colorado (10% by 2015, 4% of which is from solar), and Montana (15% by 2015).[12] The utilities covered in this report that are subject to an RPS include the three major California utilities (SCE, PG&E, and SDG&E), the two major Nevada utilities (Nevada Power and Sierra Pacific), Colorado's largest utility (PSCo), and Montana's largest utility (NorthWestern). PSCo and NorthWestern's IRPs were filed prior to the passage of state RPS policies, however, so we include the renewable capacity additions contemplated by those plans in Section 3.2 (though we acknowledge that these planned additions are now expected to meet the RPS requirements). The utilities in Arizona and New Mexico are not required to file IRPs, and are therefore not covered here.[13]

Figure 1 shows the annual and cumulative new renewable capacity additions contemplated by the original California and Nevada resource plans, with cumulative data presented on a utility-by-utility basis. Cumulative capacity additions are 2,040 MW by 2008, rising to 4,550 MW by 2014 and 4,690 MW by 2024. Annual additions are as high as 660 MW, but drop precipitously in 2015 in part because RPS requirements level off at this point, and in part because the California plans only extend to 2014. Interestingly, PG&E expects to have the most significant incremental need for new renewable capacity additions (2,150 MW by 2014), followed by SCE (1,020 MW by 2014) and SDG&E (630 MW by 2014). Nevada Power and Sierra Pacific have more modest requirements, expressed in terms of capacity additions, totaling 600 MW and 150 MW by 2014, respectively.[14]

[11] See Mingst et al. (2005) for a more comprehensive summary of the overall planned resource additions (renewable and otherwise).
[12] Hawaii also has an RPS, but is not included in our analysis here.
[13] Though not required to submit IRPs as such, the New Mexico utilities are required to submit renewable energy procurement plans, in which they describe how compliance with the state's RPS will be achieved. Because these plans are not formal IRPs, they are not covered in this report.
[14] These results come from the original resource plans by the California and Nevada utilities, and are not updated with data from more recent renewable energy procurement plans (PG&E, SCE, SDG&E, Nevada utilities), or RPS compliance reports (Sierra Pacific, Nevada Power).

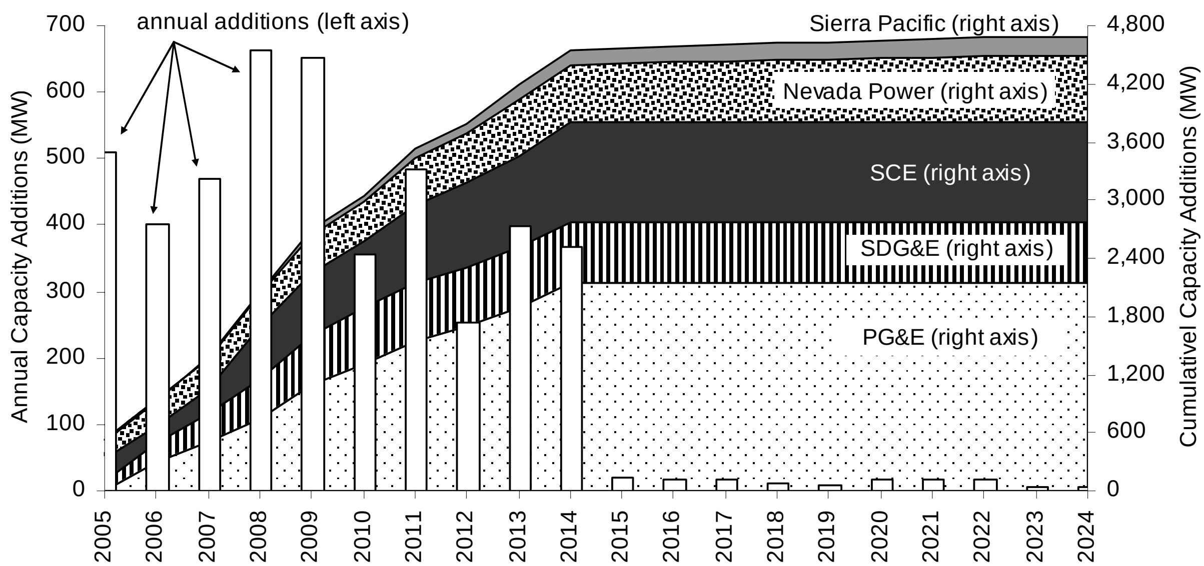

Figure 1. Cumulative and Annual RPS-Driven Renewable Capacity Additions

Many of these original California and Nevada resource plans make no real effort to identify the specific renewable resources that might be used to meet these requirements, under the presumption that eligible renewable sources will compete for contracts under open renewable energy solicitations (Figure 2). This is true for all of the plans except SDG&E (which identifies renewable technology types for all of its needs), though some of the other plans provide limited information (e.g., solar is specifically identified separately in the Nevada plans, and wind repowering is identified in PG&E's plan).[15] In aggregate, based on their original resource plans, by 2014 these five utilities contemplate the following renewable resource additions: unspecified (3445 MW), wind repowering (400 MW), wind (285 MW), solar (180 MW), geothermal (105 MW), and other (140 MW).[16]

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[15] Sierra Pacific's IRP, in its appendix, attempts to further separate its RPS needs into wind and geothermal additions. We were unable to fully understand the data provided in that appendix, however, and here report the resources as unspecified.

[16] Data presented in this section for California come from the utilities' 2004 long-term plans. In mid-2005, SCE, PG&E, and SDG&E submitted final long-term renewable procurement plans, which provide capacity additions in more detail by technology. In PG&E's case, an illustrative plan for deliveries in 2014 includes new wind (550 MW), repowered wind (400 MW), geothermal (450 MW), biomass (150 MW), biodiesel (150 MW), and solar (250 MW), totaling 1,950 MW of new renewable energy capacity. These capacity additions – which are slightly lower than the MW additions reported above – would meet 23% of PG&E's retail demand by 2014, thereby representing renewable energy growth beyond that required under the state's RPS. SCE's renewable procurement plan also provides additional detail. Assuming that contracts executed as a result of its 2003 RFP are successful, and that certain wind repowering and expansions take place, incremental needs by 2014 in SCE's "base case" total 988 MW (500 MW solar, 297 MW wind, 120 MW geothermal, 63 MW biomass, 8 MW hydropower). SDG&E's renewable procurement plan offers illustrative total renewable energy capacity estimates for 2014 as follows: biogas (45 MW), biomass (40 MW), wind (484 MW), hydropower (11 MW), solar (285 MW) and geothermal (210 MW), for a total capacity of 1,075 MW (note, however, that unlike for SCE and PG&E, this represents total capacity, not incremental capacity). Achieving these capacity installations is projected to lead to SDG&E meeting 24% of its load obligations with renewable energy.

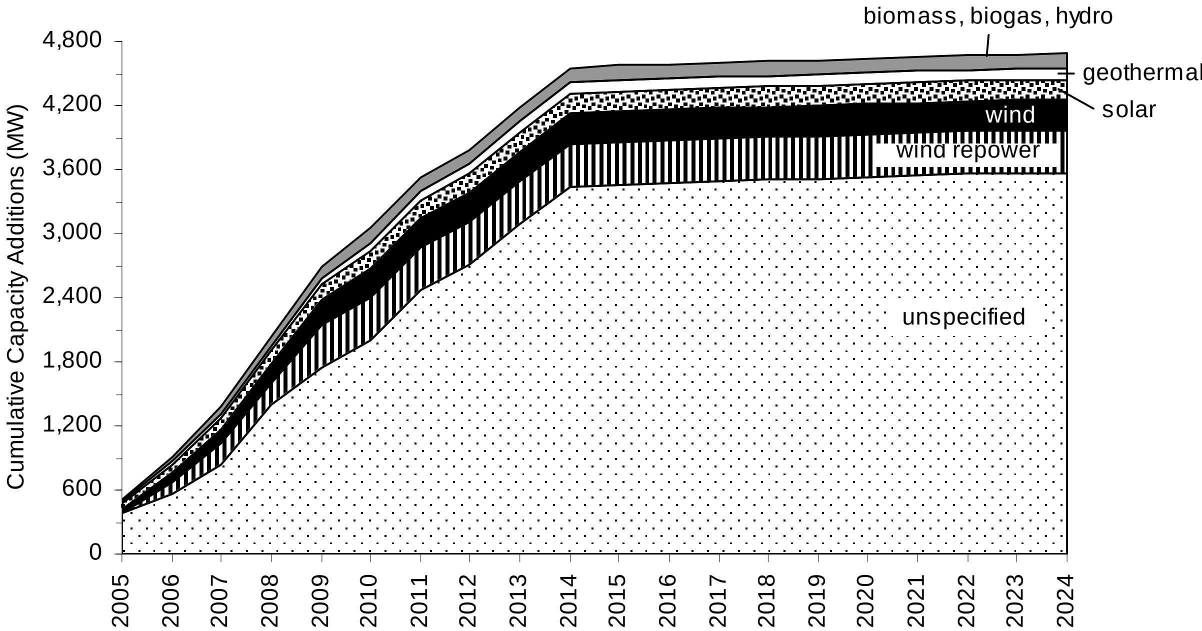

Figure 2. Cumulative RPS-Driven Renewable Capacity Additions, by Resource Type

3.2 Non-RPS-Driven Renewable Energy Additions

Perhaps more interesting than the RPS-driven demand is that a number of western IRPs include sizable renewable additions that are independent of, or above and beyond, any RPS obligations. These additions typically derive from an analysis of the expected cost and value of renewable resources, and reflect the fact that renewables, and particularly wind power, are increasingly being found to be a useful contributor to a low-cost, low-risk resource portfolio.

As shown in Figure 3, eight of the twelve western utilities in our sample include renewable energy in their plans based on its own merits, not because of a legislative RPS obligation. Seven of these eight utilities operate in states without RPS obligations. PacifiCorp's IRP commitment is the most significant in terms of nameplate capacity, rising to 1,420 MW of wind power. PSE's 2005 plan envisions 670 MW of wind power and 75 MW of biomass (by 2013), while PSCo plans for 500 MW of wind in the near future. Idaho Power plans for 350 MW of wind power and 100 MW of geothermal capacity additions. PGE and NorthWestern envision 195 MW and 150 MW of wind, respectively, by 2007, while Avista's plan calls for 75 MW of wind.[17] In aggregate, 3,380 MW of wind power and 270 MW of other renewable resources are planned.[18]

[17] Though we focus on Avista's 2003 IRP, Avista's draft 2005 IRP calls for a much more aggressive commitment to renewable energy, including 650 MW of wind and 170 MW of other renewable energy by 2026.

[18] It is worth noting that Figure 3 might actually be considered conservative, since a few of the utilities did not specify resources over the full time period shown. For example, PGE's Final Action Plan only specified wind power (or any other resource) through 2007; resource decisions in later years (i.e., 2008-2014) will be governed by future resource plans, which could call for additional renewables above and beyond the 195 MW of wind shown in Figure 3.

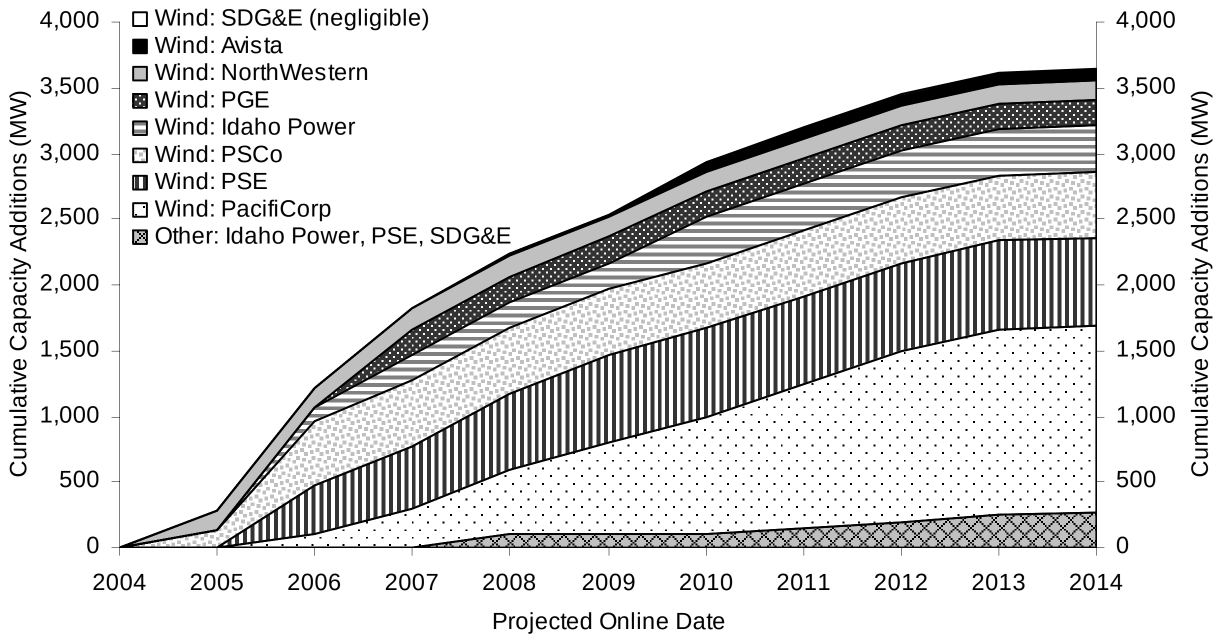

Figure 3. Cumulative Non-RPS-Driven Renewable Capacity Additions, by Resource Type and Utility

Of the five utilities with then-current RPS obligations (SCE, PG&E, SDG&E, Nevada Power, and Sierra Pacific, but excluding PSCo and NorthWestern), only SDG&E's original resource plan includes renewable energy supply above and beyond its RPS requirements (115 MW by 2014); the other California utilities do, however, clearly indicate that renewable energy projects will be allowed to compete against other generation sources in procurements not related to the RPS. Nonetheless, in their original resource plans, each of these utilities (with the exception of SDG&E) considered the RPS as representing the sum total of their *planned* renewable energy commitments, effectively capping *planned* renewable energy additions at the RPS requirements.[19] None of these utilities' plans reveal any analysis that looks at whether renewable additions above-and-beyond the RPS would have financial merit. Though it cannot be said with certainty whether such analysis would reveal additional cost-effective opportunities for renewable generation above the RPS obligations, the lack of analysis on this issue is arguably a deficiency of these plans. This issue is discussed more fully later.

Not surprisingly, given its economic position relative to other sources of renewable energy, wind power is the resource of choice among the renewable energy supply options. Geothermal, biomass, and other resources are envisioned by Idaho Power, PSE, and SDG&E, but in all other instances wind power is the renewable resource identified. As a result, in Chapter 4 we focus on the plans' assumptions for the cost and performance of wind power, with limited analysis of geothermal.

[19] In its subsequent 2005 renewable energy procurement plan, PG&E also expresses a goal of exceeding its RPS obligation, and achieving a 23% renewable energy share by 2014.

3.3 Renewable Additions as a Percentage of Utility Load

In an attempt to fairly compare the proposed incremental reliance on renewable energy among resource plans (including both RPS and non-RPS driven supply), we normalized the cumulative planned renewable additions discussed above as a percentage of projected utility load through 2014 (both in GWh). Figure 4 shows results biannually for the period 2008-2014.

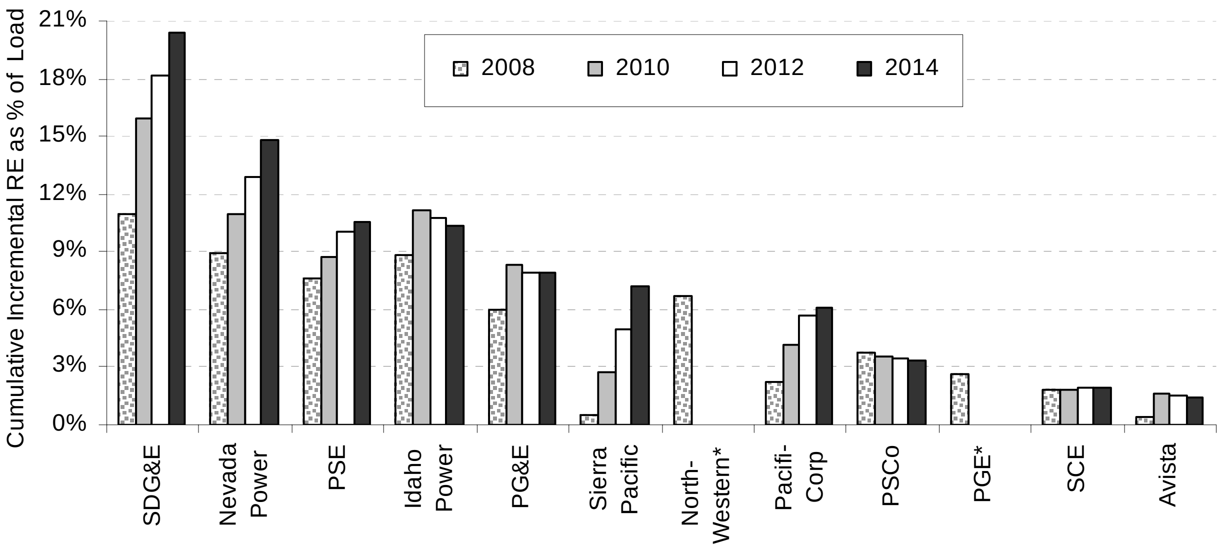

Figure 4. Cumulative Incremental Renewable GWh as a Percentage of Utility Load
*PGE's and NorthWestern's procurement horizons end in 2007, so only their 2008 values are shown.

One of the most interesting observations is that two of the four most aggressive utilities by this metric *are not* subject to an RPS. Instead, Idaho Power and PSE plan to add new renewable generation equal to about 10% of projected load simply based on cost and risk considerations. In comparison, PacifiCorp's much-heralded plan to add 1420 MW of new wind amounts to about 6% of load, and SCE will only need to add new renewable generation equal to about 2% of load in order to meet California's 20% RPS. Though RPS-driven planned additions might be considered *more certain* than non-RPS plans (as a result of RPS enforcement mechanisms in place), Figure 4 clearly illustrates that – if followed through and implemented – resource plans could themselves be a major driver of growth in new renewables.[20]

3.4 Initial Impacts of the Western Resource Plans

In nearly all cases, the utilities whose resource plans we reviewed are *beginning* to make good on their plans to procure renewables. In California and Nevada (and now Montana and Colorado), this call to action is being driven in part by state RPS requirements. In other instances, the then-

[20] Several caveats are in order here. First, Figure 4 includes the original California plans, but does not include the subsequent 2005 renewable energy procurement plans. In those plans, PG&E shows a more aggressive 10% growth by 2014, while SCE's plan also provides additional detail. Second, calculations of planned additions, especially among those plans whose utilities face RPS obligations, differ somewhat, complicating comparisons (see Appendix A.1 for details). Finally, one of the reasons that the RPS-driven percentage additions are not more significant is that some of the utilities subject to RPS requirements had been adding renewable energy prior to the development of their most recent resource plans.

scheduled expiration of the federal production tax credit (PTC) at the end of 2005 has accelerated procurement timelines.

Despite these early efforts, however, an emerging disconnect between resource plans and procurement reality is also evident in some instances (see, for example, PacifiCorp and PSCo, below). A recent increase in wind project costs – driven by a combination of weakness in the US dollar, rising steel costs, turbine shortages, and the general rush to install projects before the then-scheduled expiration of the PTC at the end of 2005 – is perhaps partly to blame. This disconnect also demonstrates the challenge of translating resource plans into actual renewable procurements, and the relatively higher uncertainty surrounding IRP-driven renewable energy additions, relative to RPS-driven additions.

Below is a high-level summary of resource-plan-related renewables procurement actions at each of the twelve utilities in our sample:

- **PacifiCorp:** In 2003, PacifiCorp began purchasing the output of the 41 MW Combine Hills wind project in Oregon. In early 2004, it issued a solicitation for 1,100 MW of renewables, and in response received bids from 6,000 MW of renewable capacity, 85% of which were wind, with the remainder geothermal and hydro. In October 2004, PacifiCorp announced that it had begun to negotiate with a short list of fifteen projects from twelve bidders representing 2,200 MW of capacity (700 MW of which could potentially come on line in 2005). As of July 2005, however, only one contract had been announced, a 20-year power purchase agreement with a 64.5 MW wind project located in Idaho.

- **Idaho Power:** In January 2005, Idaho Power released an RFP seeking 200 MW of wind power. Proposals were due in March, with a goal of identifying winning proposals by June and having projects built by the end of 2005. In July, however, Idaho Power expressed concern that the average price proposed by respondents was $55/MWh – about $12/MWh higher than the nominal levelized cost assumed in its IRP. Though the utility has – in part – attributed this unexpected price inflation to developers gaming the RFP against Idaho Power's relatively high avoided costs paid to smaller qualifying facilities, more general industry-wide cost increases at this time were perhaps also to blame (see Section 5.1).

- **Avista:** In early 2004, Avista agreed to purchase 35 MW of wind power from the Stateline project for 10 years. The seller – PPM Energy – will deliver undifferentiated power with RECs, as a way to ease Avista's discomfort with the potential cost impacts of integrating wind into its system (see Section 5.1.2.2).

- **PGE:** A 2003 all-source RFP drew ~1200 MW of proposals from wind projects at physically unique sites. PGE short-listed ~300 MW of wind projects, and in December 2004 announced that it had signed a 30-year power purchase agreement (PPA) for the full output of the 75 MW Klondike wind project expansion, beginning in December 2005.

- **PSE:** A late-2003 150 MW wind RFP, which was subsequently folded into an early-2004 all-source RFP for 355 aMW, drew an 1800 MW response from wind projects. PSE short-listed seven projects (three of which involved the sale of 150 MW wind projects), and in late 2004 announced letters of intent to purchase two wind projects totaling ~380 MW.

Construction on the 150 MW Hopkins Ridge project began in March 2005 (the ~230 MW Wild Horse wind project is expected to be built in 2006).

- **NorthWestern:** In December 2002, NorthWestern issued a wind RFP, which resulted in the selection of two wind projects (one of which ultimately pulled out of negotiations). In January 2005, NorthWestern announced that it had signed a 20-year contract to purchase the output of a 135-150 MW wind project near Judith Gap. The Montana PUC approved the contract in March 2005.

- **PSCo:** In August 2004, PSCo issued an RFP for up to 500 MW of wind power, to be on line by the end of 2006. When the PTC was subsequently extended only through 2005, PSCo accelerated the timetable for projects able to come online by the end of 2005. PSCo short-listed three projects totaling about 400 MW, but ultimately (in late March 2005) signed contracts with only two projects totaling just 129 MW. Also, in late February 2005, PSCo issued an all-source RFP for 2500 MW from dispatchable, nondispatchable, and demand-side resources. Renewable power is eligible to compete in this solicitation.

- **PG&E:** In 2004 PG&E issued a solicitation for renewable energy supplies sufficient to meet a minimum of 1% of the utility's retail sales. As a result of that solicitation, PG&E is in the process of executing four wind power contracts totaling 185-232 MW. To meet its RPS obligations, PG&E also signed renewable energy contracts under a 2002 interim renewable energy solicitation, and through bilateral negotiations with several existing biomass projects and with two wind projects seeking to repower their facilities. In total, since the RPS was established, PG&E has increased its renewable energy purchases by 1-2%. Despite this, PG&E has lagged behind the 1%/year targets, and is currently carrying a significant deficit into the 2005 compliance year. PG&E issued its 2005 renewable energy solicitation in mid-2005.

- **SDG&E:** SDG&E also issued a renewable energy solicitation in 2004; contracts had not been announced as of mid-August 2005. Despite this delay, SDG&E has aggressively increased its renewable energy purchases since the state's RPS was established. Starting from just 1% of its electricity needs in 2002, renewable energy contributed 4.5% in 2004, and is expected to contribute 5.6% in 2005. Since 2002, SDG&E has signed approximately 275 MW of new renewable energy contracts, including 120 MW of biomass/LFG and 150 MW of wind. SDG&E is conducting a new renewable energy solicitation in 2005.

- **SCE:** SCE's 2003 renewable energy solicitation has resulted in six renewable energy projects selected, totaling 142 to 428 MW (depending on whether expansion options are taken). This includes 99–270 MW of wind, 30-120 MW of geothermal, and 12.5-37.5 MW of biomass. SCE is expected to also submit for approval a contract for 500–850 MW of solar thermal capacity, and perhaps one additional wind contract, both under SCE's 2003 solicitation. Four wind repowering contracts have also been completed. Before the execution of these contracts, SCE's 2002 interim renewable energy solicitation helped the company increase its purchases from 17% of retail sales in 2002 to 18.2% in 2004; 2005 deliveries are expected to equal 18.1%. SCE is conducting a new renewable energy solicitation in 2005.

- **Nevada Power and Sierra Pacific:** Nevada's two utilities have issued three renewable energy solicitations (in 2001, 2003, and 2005) under the state's RPS. In total, since 2001 these utilities have signed 17 long-term contracts for renewable energy or renewable energy certificates (RECs), fourteen of which had been approved by the Nevada Public Utilities Commission (NPUC) as of April 2005. Four of these contracts were subsequently terminated, however, and delivery under five more of these contracts has been delayed. In part because of these terminations and delays, compliance with the state's RPS has not been achieved (just 75% of the non-solar requirement and 1% of the solar requirement were achieved in 2004). Bids were due under the utilities' third renewable energy RFP in June 2005; the utilities are seeking 500 – 1,200 GWh of non-solar renewable energy, and 5 – 150 GWh of solar energy.

4. Portfolio Construction

Though one would generally expect the extent to which renewable resources are included within candidate portfolios to be a direct function of their cost and performance (covered in Section 5), as well as their ability to mitigate certain risks (covered in Section 6), this is not always the case. Instead, utilities often establish exogenous limits to the amount of renewable sources that can be selected. This section summarizes how the various plans constructed their candidate portfolios, including which renewable resources were included, and to what extent.

4.1 Renewable Resources Modeled

As shown in Table 2, renewable resources were modeled *exclusively* as wind power in nearly half of the resource plans we examined.[21] Several more utilities include incremental wind power additions, along with other renewable resources, in at least one candidate portfolio. Specifically, Idaho Power, PacifiCorp 2003, Sierra Pacific, and SDG&E also include incremental geothermal in at least one candidate portfolio. PSE's 2005 resource plan, meanwhile, includes biomass (in addition to wind) in its candidate and preferred portfolios, as a way to circumvent transmission constraints restricting the amount of wind available to the utility. The two Nevada plans identify incremental solar requirements to meet the solar set-aside in the Nevada RPS, but do not include any analysis of what types of solar technologies might be used to meet these needs. Other utilities either do not specify the renewable resources included in their portfolios (Nevada Power, SCE, PG&E),[22] or else include a full array of resources – e.g., SDG&E included wind, geothermal, biomass, biogas, hydropower, and solar. In either of these two latter cases, it is not clear how much economic analysis was conducted to achieve these results.[23]

Some plans considered and/or initially screened other renewable sources, but ultimately excluded them from the modeling process due to cost or other factors. For example, Idaho Power initially screened (but did not ultimately include in any candidate portfolio described within its plan) biomass, solar thermal, solar PV, and landfill gas, while PGE initially screened (but did not ultimately include in any candidate portfolio described within its plan) geothermal and biomass. PSE (2003 and 2005) considered geothermal, wave energy, solar, landfill gas, and MSW, but excluded each of these resources due to some combination of high capital costs, site-specific costs, immature technology, or low resource availability in the Northwest. Meanwhile, Avista initially screened solar, in addition to wind, but did not include it.

[21] Utilities focusing exclusively on wind include Avista, NorthWestern, PGE, PSCo, and PSE 2003. Despite the general focus on wind, it is perhaps worth noting that those utilities that have already issued solicitations to begin implementing the renewables portion of their preferred portfolio acquisitions have generally allowed any renewable technology – not just wind – to respond. If other renewable resources can offer a more attractive cost-risk proposition than wind, they will be chosen over wind.

[22] Nevada Power and SCE do not specify the renewable resources included in their portfolios, though in a subsequent renewable energy procurement plan, filed in 2005, SCE did specifically include wind power, along with geothermal, biomass, hydro, and solar-thermal electric. PG&E's preferred portfolio, meanwhile, included wind repowering and other "unspecified" renewable sources, though its subsequent 2005 renewable procurement plan included wind, wind repowering geothermal, biomass, biodiesel, and solar-thermal electric in the analysis and in the preferred portfolio.

[23] In addition to modeled resources, a number of plans assume certain levels of distributed renewable generation. The two Nevada utilities, for example, include solar rebate programs in their IRPs, while the California utilities include projected distributed generation applications as a load modifier.

4.2 Inclusion of Renewables in Candidate Portfolios

Though incremental renewables were modeled in all of the resource plans we examined, the *number* of candidate portfolios in which they were included, as well as the *extent* to which they were included within each of those candidate portfolios, varies significantly. Below, we briefly summarize how each of the plans we examined constructed candidate portfolios, to what extent incremental renewables were included in those candidate portfolios, and any exogenously imposed limits on the amount of renewables that could be selected for the preferred portfolio.

Table 2. Summary of Candidate Portfolios

Utility	Number of Candidate Portfolios	Candidate Portfolios with New RE	Types of RE in Candidate Portfolios	Required to Meet RPS	Evaluated RE Above Obligation
Avista	*used optimization process**		wind	No	N/A
Idaho Power	12	9	wind, geothermal	No	N/A
NorthWestern	12	7	wind	No†	N/A
PacifiCorp 2003	26	26	wind, geothermal	No±	N/A
PacifiCorp 2004	24	0	N/A	No±	N/A
PGE (final act. plan)	26	26	wind	No	N/A
PSCo	*used optimization process**		wind	No†	N/A
PSE 2003	91	49	wind	No	N/A
PSE 2005	4	4	wind, biomass	No	N/A
Nevada Power	26	26	unspecified, unspecified solar	Yes	No
Sierra Pacific	12	12	wind, geothermal, unspecified solar	Yes	No
PG&E	1**	1	wind repowering, unspecified	Yes	No‡
SCE	1**	1	unspecified	Yes	No
SDG&E	1**	1	wind, geothermal, biomass, biogas, hydro, solar	Yes	Yes

**No candidate portfolios were developed. Instead, for each scenario examined, a capacity expansion model optimized a single portfolio based on user-defined market conditions and constraints.*
***Each of the three California utilities developed slightly different candidate portfolios based on different load growth scenarios. This is ignored here, because these portfolios did not significantly vary.*
±PacifiCorp serves a small segment of California, but the vast majority of its sales are not covered by an RPS.
†At the time their IRPs were created, neither PSCo nor NorthWestern faced an RPS.
‡PG&E considered RE additions above the state's RPS in its 2005 renewable energy procurement plan.

Table 2 gives a broad-brush overview of the portfolio construction process; specific details are discussed below.

- **Avista:** Avista used a linear programming model to select the optimal resource portfolio. Due to concerns over the integration costs (see Section 5.1.2.2) and potential reliability impacts (see Section 5.1.2.3) of wind power, however, Avista manually limited the amount of wind capacity that could be added to any portfolio to 75 MW (4% of peak load).[24] This amount (75 MW) was ultimately chosen in the first ten years of the planning horizon.[25]

[24] Appendix H of Avista's plan states "…although the model might suggest that as much as 300 MW of wind generation could be installed, the Company cannot at this time support that conclusion [due to concerns over the

- **Idaho Power:** Nine of the twelve candidate portfolios that Idaho Power constructed by hand included both wind and geothermal capacity in various combinations. Four different levels of wind capacity were modeled: 100, 200, 350, and 1000 MW (with the 1000 MW backed by 648 MW of gas-fired peaking plants). Meanwhile, 20, 50, 100, and 150 MW of geothermal were considered. Ultimately, Idaho Power selected a portfolio including 350 MW of wind and 100 MW of geothermal as the preferred portfolio.

- **NorthWestern:** Seven of the twelve – and the five top-performing – candidate portfolios that NorthWestern constructed by hand included 150 MW of wind (7% of average load, 14% of peak load, modeled as two 75 MW projects). More aggressive levels of wind penetration were not modeled (at least within those candidate portfolios presented in the plan).

- **PacifiCorp:** PacifiCorp's 2003 plan initially included in all of its hand-crafted candidate portfolios wind power at levels sufficient to meet the then-current proposed federal RPS (~1150 MW or ~5% of average load by 2013, assumed to have a flat generation profile for the sake of simplicity). In addition, one group of "alternative technology" candidate portfolios went beyond the RPS by adding an *additional* 1420 MW (~6% of average load, for a total of 11% of average load) of "profiled" wind (i.e., wind generation with an hourly profile associated with it). After initial analysis, PacifiCorp created four diversified candidate portfolios consisting of the best elements of the initial portfolios, as well as one "renewable" portfolio consisting of both the profiled and "flat" wind (i.e., 2,566 MW of wind total), plus 100 MW of geothermal. Each of the four diversified portfolios replaced the RPS "flat" wind (~1150 MW) with the 1420 MW of "profiled" wind, and one of these portfolios was ultimately selected as the preferred portfolio.

  PacifiCorp's 2004 plan subsequently assumed that the 1420 MW of wind called for in its 2003 plan (and confirmed as being economical by the response to PacifiCorp's 2003 renewables solicitation) would be built, but *did not* include any *incremental* renewables in its candidate portfolios.[26] PacifiCorp did conduct a single run (including renewables) with a capacity expansion model, which validated the 1420 MW of wind as a "planned resource," but this analysis was a "side bar" study rather than an integral part of the modeling process (subject to risk analysis, etc.).[27] Since certain assumptions in PacifiCorp's 2004 IRP are more favorable to wind (and geothermal) than under its 2003 IRP, it is somewhat unfortunate that PacifiCorp chose not to model incremental renewables in its 2004 IRP. Specifically, the 2004 IRP assigns wind a 20% capacity value (versus 0% in the 2003 IRP), assumes that wind

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magnitude of integration costs]." Though difficult to confirm elsewhere in the plan or appendix, this statement suggests that Avista may have scaled back the optimal amount of wind by as much as 75% (from 300 MW to 75 MW) due to concerns over integration costs.

[25] Avista's modeling process optimized the first ten years of the planning horizon (2004-2013) first, followed by the second ten years (2014-2023). In this way, the first ten years were emphasized. Though a mix of resources, including the 75 MW of wind, was chosen in the first ten years, only coal-fired generation was added in the second ten years. The addition of only coal-fired generation from 2014-2023 is likely a direct result of the manually imposed constraint on wind power, which otherwise would presumably have displaced some of that coal-fired generation.

[26] In its August 27, 2004 public input meeting, PacifiCorp noted that until it is able to progress towards meeting the renewables goal set out in its 2003 plan, it prefers to maintain that goal rather than add to it. See slides 16-19 of http://www.pacificorp.com/File/File42002.pdf.

[27] See slides 11-18 of http://www.pacificorp.com/File/File45033.pdf.

integration costs are slightly lower, and also contains a higher natural gas price forecast. On the flip side, the 2004 IRP assumes slightly higher busbar costs for wind than in the 2003 IRP (though the opposite is true for geothermal).

- **PGE:** All twelve candidate portfolios hand-crafted by PGE in its initial resource plan assumed that 15 MW (5 aMW) of wind would be added each year, up to 150 MW (50 aMW) total (representing 2% of average load), presuming that the Energy Trust of Oregon (ETO) would subsidize the cost to competitive levels.[28] Two of twelve candidate portfolios assumed that an *additional* 30 MW (10 aMW) of *unsubsidized* wind would be added each year, up to 930 MW (310 aMW) total.[29] Neither of these two candidate portfolios was selected, so the preferred portfolio included only the 150 MW of ETO-subsidized wind. PGE's Final Action Plan, meanwhile, evaluated 26 candidate portfolios (in place by 2007), all of which contained at least 75 MW of wind (with a maximum of 250 MW of wind) receiving the PTC as well as a $10 million subsidy from the ETO. A portfolio containing 195 MW of wind was ultimately selected.

- **PSCo:** Unlike most other utilities (Avista excepted), PSCo used a capacity expansion model from the start to construct an optimal portfolio. Because of the computational challenges involved (stemming from hundreds of thousands of possible resource combinations available to meet PSCo's needs), PSCO imposed constraints on each of the potential new resources that it modeled.[30] PSCo limited the maximum amount of wind power that could be added in any year to 320 MW (modeled as four 80 MW projects), with a cumulative cap of 2000 MW over the thirty-year planning horizon. The model further allowed two of the four candidate wind projects each year to be added even if not needed for capacity purposes (though PSCo only gives wind a 10% capacity credit, as described later), as long as the inclusion of such projects results in energy savings.

  PSCo presents numerous optimal portfolios that vary depending upon assumptions about future market conditions and natural gas prices. Over the 10-year resource acquisition period (from 2003-2013), optimal wind power additions ranged from 240-1120 MW at an assumed $3/MMBtu real gas price, from 240-1440 MW at $4/MMBtu gas, from 640-1440 MW at $5/MMBtu gas, and from 1040-1440 MW at $6/MMBtu gas (the apparent effective cap of 1440 MW represents 10% of average load and 19% of peak load). Noting a degree of discomfort (in terms of reliability concerns and integration costs) with the amount of wind capacity called for at the upper end of these ranges, PSCo ultimately chose to move forward with a solicitation for 500 MW of wind projects able to come on line before the end of 2006 (and later accelerated to the end of 2005, due to a shorter-than-expected PTC extension at the

[28] The Energy Trust of Oregon (ETO) is the non-profit administrator of the state's system benefits fund for energy efficiency and renewable energy. One of the ETO's purposes is to support the development of renewable energy, in part by buying down the above-market cost of renewable generation sold to the state's two investor-owned utilities, PGE and PacifiCorp. For information on the ETO's activities, see www.energytrust.org.

[29] Both the 30 MW annual limit and 930 MW total limit on unsubsidized wind escalate at 2.5%/year. So, including the 150 MW of ETO-subsidized wind, these two candidate portfolios with *extra* wind would result in 1100-1200 MW of wind in aggregate (i.e., slightly more than 930 MW plus 150 MW, or 1080 MW).

[30] PSCo readily acknowledges that the constraints imposed on wind, coal, and IGCC technologies lead to more gas-fired generation being called for than is optimal, particularly in the high-gas-price scenarios. This is evident by not much change in wind or coal-fired capacity between the $4 and $6 gas scenarios – presumably more of both would have been added at higher gas prices if the model were allowed more flexibility in the optimization.

time). If acquired, this 500 MW, along with 222 MW of existing wind capacity, would increase wind's penetration on PSCo's system to about 11% of peak load.[31]

Finally, as part of its comprehensive settlement with stakeholders, PSCo assumed (in revised modeling) that 480 MW of wind would result from its solicitation in progress, and made an additional 320 MW of wind available – though at a levelized cost of $53.5/MWh, as compared to the $30/MWh assumed for the first 480 MW (see Section 5.1) – to be chosen by the model if optimal. If fully selected, this additional 320 MW (along with the 480 MW being solicited and 222 MW of currently existing wind capacity) would increase wind penetration on PSCo's system to 15% of peak load. Due in large part to the higher assumed cost of the resource, just a single 80 MW project of this additional available wind capacity was selected by the model (and only under the assumption that existing generation contracts will not be extended once they expire; if existing contracts are assumed to be extended, the model does not select *any* additional wind). Thus, PSCo effectively limited the incremental amount of wind in its preferred portfolio at 480 MW by assuming a higher cost for wind capacity beyond that, presuming that the federal production tax credit would not be extended.[32]

- **PSE:** PSE's initial plan developed 91 portfolios by hand, representing various combinations of four resource mixes (all gas; coal and gas; 5% wind, gas, and coal; and 10% wind, gas, and coal), eight levels of reliability or resource adequacy, and energy efficiency. Ultimately, PSE selected one of the 5% wind, gas, and coal mixes as the preferred plan (i.e., where wind will meet 5% of PSE's load by 2013), and set a goal to have renewables meet 10% of load by 2013. The August 2003 IRP update officially adopted the 10% renewables goal as the new target,[33] and PSE's 2005 IRP maintained this goal (but modeled it as a combination of wind and biomass, rather than all wind), rejecting a higher 15% target due in part to transmission constraints that limit the amount of wind available to the utility.

- **Nevada Power:** Nevada Power used a production cost model to evaluate 26 hand-crafted portfolios, all of which appear to assume that Nevada's renewables portfolio standard will ultimately be met with an unspecified mix of renewable sources (segmented by solar and non-solar). As noted in the IRP, "Any statutory requirement that the Company may have for energy from renewable sources will be procured through a competitive bidding process and is not considered to be an option for generation expansion at this time." In other words,

[31] In March 2005 PSCo announced that, as a result of its solicitation, it had contracted with just two wind projects totaling 129 MW and expected to achieve commercial operation prior to the scheduled expiration of the PTC at the end of 2005. These two projects, along with the 222 MW of nameplate wind capacity from which PSCo already receives power, will increase wind penetration on PSCo's system to more than 5% of peak load. In announcing the two new contracts, PSCo noted the possibility of acquiring additional wind generation to come online in 2006, pending an extension of the PTC.

[32] This effect becomes evident when one considers that the revised gas price forecast used in the PSCo settlement is slightly higher than the $5/MMBtu gas price forecast assumed in the original filing. As mentioned above, this $5/MMBtu gas price scenario resulted in 640-1440 MW of wind additions in PSCo's original IRP, compared to just 480 MW (560 MW if existing contracts are assumed not to be extended) selected under the settlement scenario.

[33] The August 2003 update also employed for the first time an automated portfolio creation process, based on a simple set of rules involving pre-selected resources. This process, however, is essentially a mechanized aid in creating what are still essentially hand-crafted portfolios, and does not approach the sophistication or complexity of an automated optimization or capacity expansion process.

Nevada's RPS appears to serve as a cap on the amount of renewable energy considered in the planning process. Moreover, the company appears to have conducted no analysis on what types of renewable sources might best meet its needs under the RPS, with the exception of a confidential appendix that apparently describes the operational impacts of variable wind and solar power. This later analysis was used in the company's 2001 renewable energy RFP to limit the amount of wind purchases by Nevada Power to 100 MW (2% of peak load).

- **Sierra Pacific:** Sierra Pacific used an approach similar in most respects to that used by Nevada Power, though with twelve hand-crafted portfolios, all of which assume that Nevada's RPS will ultimately be met with a mix of renewable sources (segmented by solar, wind, and geothermal). As with Nevada Power, Sierra Pacific appears to treat the RPS as a cap on the amount of renewable energy considered in the planning process. Unlike Nevada Power, Sierra Pacific appears to have conducted some limited analysis of the relative contribution of wind and geothermal to future RPS-driven resource needs; the IRP also contains text on potential self-build options for renewable energy, a subject that will be further studied by the utility in the coming years. Sierra Pacific notes concern about the variability of wind generation (especially over 15-minute periods), and that concern led to a 50 MW aggregate limit (which represents 3% of peak load) on wind additions in Northern Nevada under the utility's 2001 renewable energy RFP. Subsequently, the utility loosened that restriction to 50 MW per project site, while allowing larger projects to bid if the supplier is able to mitigate output variability.

- **PG&E:** PG&E, like the other California utilities, *did not* publicly identify a large number of candidate portfolios and then evaluate those portfolios based on cost, risk, and other metrics. Instead, it constructed a single preferred portfolio to respond to base-case load projections (and somewhat altered portfolios to meet low- and high-load scenarios).[34] The single preferred portfolio assumed that the utility's 20% RPS would be achieved by 2010 with some combination of unspecified renewable sources and wind repowering, and no analysis of renewable energy to serve needs beyond the RPS was conducted. Instead, all incremental needs were assumed to be met with gas-fired generation (though renewable energy could compete with this conventional generation in all-source solicitations). In its subsequent 2005 renewable energy procurement plan, however, PG&E assumed that renewable energy additions would lead to a 23% contribution to retail demand by 2014; this goal does not appear to be based on an analysis of the economic merit of the increase.[35]

- **SCE:** SCE's procurement plan is similar in many respects to PG&E's, with a single preferred portfolio and some variation based on load growth projections. The state's 20% RPS is assumed to be achieved by 2010 (in fact, SCE plans to meet that target in advance of 2010), with an unspecified mix of renewable sources, and no analysis was conducted to

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[34] The low- and high-load scenarios were intended to reflect the risk of departing load in a future retail choice environment. In RPS states where retail choice is possible, the possibility of departing load is a significant risk. Note that in response to a data request from the California Energy Commission, California's three IOUs were required to submit more detailed analysis of their resource plans under a wider variety of market conditions. Much of these data are not public, however, and the utilities have been clear that this analysis did not comport with their "preferred" plans. We therefore do not cover those filings here (see CEC 2005).

[35] PG&E does, however, make a qualitative assessment of which renewable sources are expected to contribute to the achievement of the 23% target, based on busbar economics, resource need, transmission costs, and other factors.

evaluate renewable energy options above and beyond this target (though the utility notes that its needs are primarily for peaking and dispatchable generation, and that renewable sources will be allowed to compete in all-source procurements). In its subsequent 2005 renewable energy procurement plan, SCE maintains the 20% target, but develops an illustrative mix of renewable sources that might be used to meet that target based on a variety of factors.

- **SDG&E:** SDG&E's IRP also used the same basic approach as the other two California utilities, with analysis of only a single preferred portfolio. However, SDG&E's resource plan seeks to achieve a 24% renewable energy target by 2014 (after meeting the RPS requirement of 20% by 2010). No analysis is presented for why the 24% target is chosen, though the utility does illustratively present a breakdown of renewable sources that might be used to meet this goal. SDG&E's 2005 renewable energy procurement plan maintains the 24% by 2014 goal, and again provides an illustrative breakdown of renewable sources that might be used to meet that target.

4.3 Observations and Conclusions

Due to the complexities and interactions involved, resource planning generally requires sophisticated modeling analysis. Historically, some utilities would – at least as a first step – specify realistic cost and performance characteristics for a pool of potential supply- and demand-side resources, and then allow a capacity expansion model to determine what combination of those potential resources best meets their future needs (in terms of cost and risk). In other words, planners would allow the model to determine one or more candidate portfolios for further scrutiny.

Our review of twelve western resource plans reveals that, in most cases, this is not the way that candidate portfolios have been constructed in recent resource plans. Instead, with a few exceptions (PSCo and Avista), candidate portfolios appear to have been constructed by hand, featuring resources that are regionally available and that passed initial cost or performance screening tests. Though this "pre-selection" of candidate portfolios may simplify the modeling process – an important consideration, to be sure – it also allows human bias to influence the outcome, by limiting the universe from which the optimal portfolio emerges. The more candidate portfolios that are evaluated, and the more diverse those portfolios are in their composition, the more robust the end result. If resources (and particularly renewable resources, with which many utilities may not be very familiar) are not accurately or adequately represented within the candidate portfolios, however, or if a broad range of candidate portfolios is not considered, the modeling outcome could very well be sub-optimal.[36]

Within this context, we make the following observations, based on our review of how the various western resource plans are constructing candidate portfolios:

- **A full range of renewable options is not always considered in utility resource plans.** Most plans consider wind, and some also include geothermal and other sources, within

[36] Because resource planning is often an indicative process – the outcome of which does not necessarily limit further analysis or acquisition of any renewable or other resources – sub-optimal modeling results may not necessarily lead to sub-optimal procurement decisions.

candidate portfolios. Many renewable sources are ignored, however, or screened out earlier in the process due to perceived high costs or limited, project-specific opportunities. Keeping in mind that these are merely *plans*, rather than more concrete actions, limiting the universe of resource options may make analytical sense, particularly if open solicitations will ultimately be used to determine which resources are procured. On the other hand, such an approach forfeits any insights (e.g., transmission upgrade needs) that might be gained by modeling specific resources, and may also hinder developers' ability to prepare and plan for specific utility needs prior to the issuance of solicitations that define those needs. Finally, as discussed in Section 7, the simplifying assumption made early on by many plans to model renewables primarily or solely as wind power, in conjunction with conservative assumptions about the capacity value of wind and the need for gas-peaking plants to integrate wind into the system, has sometimes resulted in so-called "renewables" portfolios being heavily laden with gas-fired generation and gas price risk. Consideration of more diverse renewable energy portfolios may help avoid this situation.

- **Candidate portfolios are often constructed by hand.** As mentioned, most of the IRPs construct candidate portfolios by hand, or by using an automated process involving simple rules and pre-selected resources. Only PSCo and Avista used an optimization process to construct preferred portfolios. In order to make the optimization problem more tractable, however, both PSCo and Avista imposed exogenous constraints on the model. These constraints may play a significant role in determining the outcome of the modeling exercise.

- **Exogenous and sometimes limiting caps to renewable energy additions are often applied.** All of the IRPs in our sample exogenously define the maximum amount of renewable energy that can be realistically selected, either by establishing constraints on the optimization model (Avista and PSCo, as described above), by pre-defining candidate portfolios, or by only accepting a certain amount of wind even if analysis results suggest that higher levels of penetration are warranted. Figure 5 illustrates the exogenous caps for wind power, both in terms of incremental capacity and incremental percentage of peak load.[37] As shown, in some cases, the maximum permissible amount of incremental wind is relatively small (e.g., Avista,[38] Sierra Pacific, and Nevada Power are each less than 5% of peak load). In many of the resource plans we examined, the amount of wind power included in the preferred portfolio is equal to (and thus potentially limited by) the maximum amount of wind power allowed into any candidate portfolio. This is the case for at least NorthWestern, PSE 2003, PSCo's original resource plan, and Avista. Sierra Pacific and Nevada Power do not report renewable additions by technology, but presumably would also hit their low wind

[37] PacifiCorp, PGE, and PSCo already have existing wind capacity on their systems. Figure 5 does not take this existing capacity into account, but instead focuses just on the incremental capacity modeled in each resource plan. Only PGE's initial IRP is represented in Figure 5; PGE's Final Action Plan did model an "all wind" portfolio as part of a "bookends" analysis (i.e., an attempt to identify the range of outcomes between extreme, single-resource portfolios), but these "bookend" portfolios were not considered among the 26 candidate portfolios analyzed in the Final Action Plan, and are therefore not included here. PGE's Final Action Plan also included renewable energy in its candidate portfolios, but because the Final Action Plan is limited to near-term procurement actions, we chose to reference PGE's initial IRP filing in Figure 5.
[38] Avista's draft 2005 IRP loosens this cap, and calls for 650 MW of wind by 2024.

caps. This raises the possibility that in some cases wind power may not have been included in candidate portfolios over a broad enough range, leading to potentially sub-optimal results.

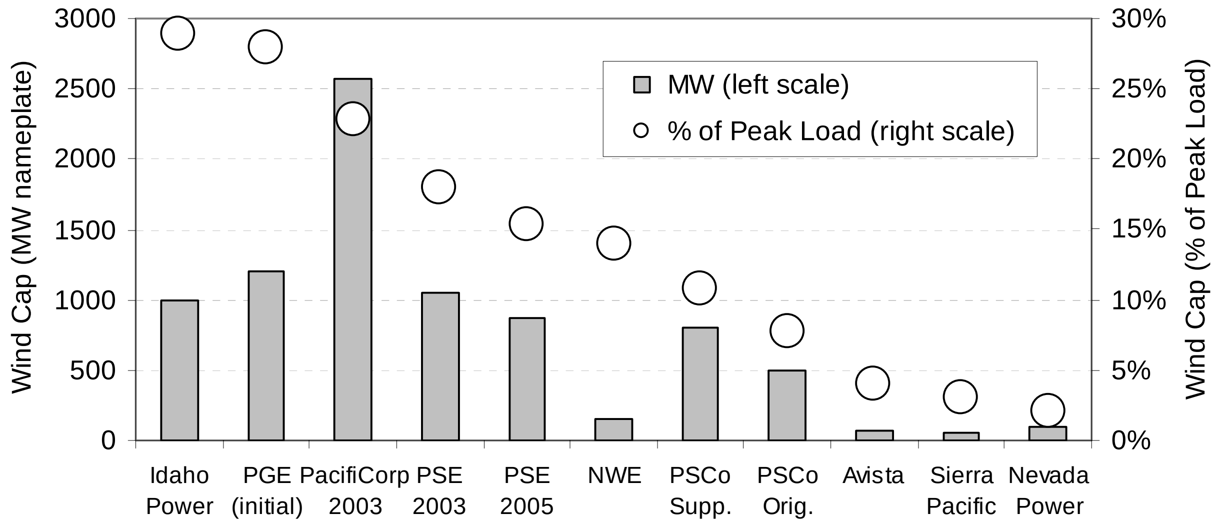

Figure 5. Exogenous Caps on Wind Power Capacity within Candidate Portfolios

- **State RPS policies sometimes "cap" the amount of renewable energy considered.** In four of the five original California and Nevada plans, the existence of state RPS policies appears to have led to a pre-defined amount of renewable energy in the preferred portfolio, and thereby effectively served as a cap on *planned* renewable resource procurement. Though renewable energy may still be eligible to participate in all-source RFPs outside of the RPS, none of the California or Nevada plans publicly provides any *economic* analysis of the potential value of purchasing renewable energy at a level that exceeds the state's RPS requirements.[39] Such analyses may be critical for transmission-dependent resources such as wind and geothermal power, and may also help to set the "ground rules" for subsequent all-source bid evaluations (e.g., consideration of natural gas and environmental regulatory risk, integration costs, etc. when evaluating renewable and conventional generation). In addition, few apparent efforts (with the notable exception of SDG&E) were made, in these original plans, to evaluate a broad range of renewable energy sources that might be used in achieving the RPS targets. Instead, the utilities often assumed RPS compliance largely with an unspecified mix of resources, under the presumption that the actual mix would be determined in subsequent competitive solicitations. Again, while this generalized approach is functional, especially in states with RPS requirements, it forfeits any insights (e.g., transmission upgrade needs) that might be gained by modeling specific resources. It may also hinder developers' ability to prepare and plan for specific utility needs prior to the issuance of solicitations that define those needs.

[39] Note that California's utilities, in their 2005 renewable energy procurement plans, demonstrated greater analysis of various renewable energy options, and PG&E and SDG&E presented illustrative plans that would lead to over-compliance with the state RPS. In general, it is perhaps worth noting that California utilities and regulators have only recently re-engaged with resource planning, and as a result, are still refining the process.

5. Renewable Resource Cost and Performance Assumptions

Having summarized how the various IRPs constructed candidate portfolios, we now turn to the specific cost and performance assumptions for the renewable resources included within those candidate portfolios. We begin with the most widely-modeled renewable resource – wind power – and then move on to the only other renewable resource included in multiple candidate portfolios and for which detailed cost and performance data are available – geothermal.

5.1 Wind Power Cost and Performance Assumptions

The two factors primarily responsible for the emerging success of renewables, and particularly wind power, within western IRPs are low expected cost and ability to mitigate certain risks. If the cost of a resource is not in the range of competitiveness, however, an attractive risk profile may not be sufficient to make up the difference. Meanwhile, in some cases, assumptions about the cost of integrating and transmitting wind power to load are a key factor preventing renewables from making even larger contributions to resource plans.

Table 3 and Figure 6 detail assumptions about wind project size, performance, and cost from the nine utilities that provide at least some useful data. Assumed project sizes range from 50 to 100 MW, while assumed capacity factors range from 29-35%. Total modeled costs range from \$23/MWh to \$59/MWh (levelized in 2003 dollars), with PGE's IRP supplement on the high end of the range (note that PGE's initial plan showed even higher costs, up to \$81.5/MWh; see Table 3),[40] and NorthWestern, PSCo, Idaho Power, and PacifiCorp 2003 at the low end of the range. Detailed wind project cost and performance data are not publicly provided by any of the California or Nevada utilities (limited information was provided by Sierra Pacific and PG&E).

In some cases, wind power is assumed to be among the cheapest sources of energy considered in these plans. For example, Idaho Power finds that – at a total modeled cost of \$33.8/MWh (2003\$, levelized over 30 years) – a 100 MW Idaho-based wind power project will have the lowest cost of delivered energy of any of the supply-side resources it considered. Similarly, PacifiCorp's 2003 IRP found that wind power located in the Northwest was the second-cheapest supply-side resource (behind CHP), at a total modeled cost of \$39.1/MWh (2003\$, levelized over 20 years). Not every utility has reached these conclusions, however. Though wind is often assumed to be competitive at the busbar, *indirect* costs such as the cost of transmitting wind power over long distances, or the cost of integrating variable wind power into the utility's system, can negatively impact wind's competitiveness.

[40] PGE's Final Action Plan used still different wind power cost assumptions, derived from wind power bid submissions to an earlier solicitation. These data are not public, however, so here we report earlier assumptions used by PGE in its initial and supplemental IRP filings (assumptions that, admittedly, have since been replaced with new ones). PGE's revisions to its initial and then supplemental cost assumptions for wind are reflective of the typically dynamic nature of resource plans, as more information is gained during the process.

Table 3. Wind Power Performance and Cost Assumptions (where available*)

	PacifiCorp				PGE[##]				PSE 2005	Avista	Idaho Power	North-Western	PSCo		Sierra Pacific	PG&E
	2003		2004		Initial IRP		Supplement						Original	Settlement		
	East	West	East	West	Low	High	Low	High					(480 MW)	(320 MW)		
Project Size (MW)	50	50	50	50	50	50	50	50	150	100	100	75	80	80	Incl.	100
Performance (%)																
Capacity Factor	36%	32%	35%	34%	33%	33%	33%	33%	32%	30%	35%	Incl.	29%	29%	Incl.	40%
Capacity Credit	0%	0%	20%	20%	33%	33%	33%	33%	20%**	0%	5%	??	10%	10%	??	??
Levelized Cost (2003$/MWh)																
Capital and O&M	40.8	45.4	49.6	47.3	54.0	64.2	51.9	57.0	Incl.‡	60.9	42.4	Incl.	Incl.	55.2	Incl.	Incl.
+PTC	-11.9	-11.9	-10.8	-10.8	-11.2#	-11.2#	-11.2#	-11.2#	Incl.‡	-11.3#	-8.6	Incl.	Incl.	0.0	Incl.	Incl.
=Busbar Cost	***28.8***	***33.5***	***38.9***	***36.5***	***42.8***	***53.0***	***40.7***	***45.8***	Incl.	***49.6***	***33.8***	***23.0***	***27.5***	***55.2***	***37.5***	***47.9***
+Transmission	2.0	2.0	2.0	2.0	6.1	6.1	6.1	6.1	Incl.†	6.2	0.0	??	0.0	0.0	??	??
+Integration	5.6	5.6	4.5	4.5	27.5	22.4	10.2	10.2	4.0	0.0	0.0	??	2.5	7.0	??	??
=Total Utility Cost	***36.5***	***41.1***	***45.4***	***43.0***	***76.4***	***81.5***	***57.0***	***62.1***	Incl.	***55.8***	***33.8***	***??***	***30.0***	***62.2***	***??***	***??***
+RECs	-2.0	-2.0	-2.0	-2.0	0.0	0.0	-3.3	-3.3	0.0	0.0	0.0	0.0	0.0	-8.8	0.0	0.0
=Total Modeled Cost	***34.4***	***39.1***	***43.4***	***41.0***	***76.4***	***81.5***	***53.8***	***58.9***	Incl.	***55.8***	***33.8***	***23.0***	***30.0***	***53.5***	***37.5***	***??***

Incl. = included, but actual value not disclosed

?? = not known whether considered or included

*Nevada Power, SCE, and SDG&E did not provide sufficient cost or performance assumptions to warrant inclusion in this table.

**PSE's actual rule is the lesser of 20% of nameplate capacity, or two-thirds of January's average capacity factor.

‡PSE 2005 states non-levelized capital costs of $1,438/kW, and fixed O&M cost of $50/kW-yr (including transmission) prior to transmission expansion, and $29.15/kW-year (not including transmission) following transmission expansion. PSE 2005 assumes that the PTC is completely phased out by 2025, with its starting value (for a 10-year period) declining linearly from $18/MWh 2006 to $0/MWh in 2025.

†PSE provides two sets of transmission cost assumptions, pertaining to costs both pre- and post-transmission expansion. Prior to the transmission expansion (to access new wind and coal projects) transmission costs are included in the $50/kW-yr fixed O&M cost. After the expansion, transmission costs are either $58.02/kW-yr (if the expansion was "participant-funded" – e.g., by PSE and the coal and wind generators served by the new capacity) or $31.81/kW-yr (if the expansion occurs as part of a joint regional process, for example overseen by an RTO with costs recovered from all system users).

#This is the value of the PTC as revealed by Avista's plan, and PGE's initial and supplemental plans. Resource planners at Avista, however, have since clarified that this value was used only in the AURORA model for modeling WECC-wide capacity expansion (to arrive at regional electricity price forecasts). Though it is not publicly documented in the plan itself, an Avista representative noted that Avista correctly valued the PTC on an after-tax basis within its revenue requirements model, which is used to create and model specific portfolios. Similarly, PGE claims that its Final Action Plan models the PTC correctly on an after-tax basis, arriving at a levelized value of about $15/MWh. We leave the value of the PTC for Avista and PGE at $11/MWh (as opposed to $15/MWh, or a similar number) because that is what is publicly stated in the resource plans from which we drew data, and because the value of $11/MWh was used in at least some of the analysis in both cases ($11/MWh was used in PGE's initial and supplemental filings, as well as Avista's AURORA modeling).

##PGE's initial and supplemental IRP filings, reported here, have since been replaced with PGE's Final Action Plan. Wind power cost data used in the Final Action Plan rely on recent wind power project bids. These bids are not publicly provided by PGE, so here we report on PGE's assumptions as used in their earlier IRP filings.

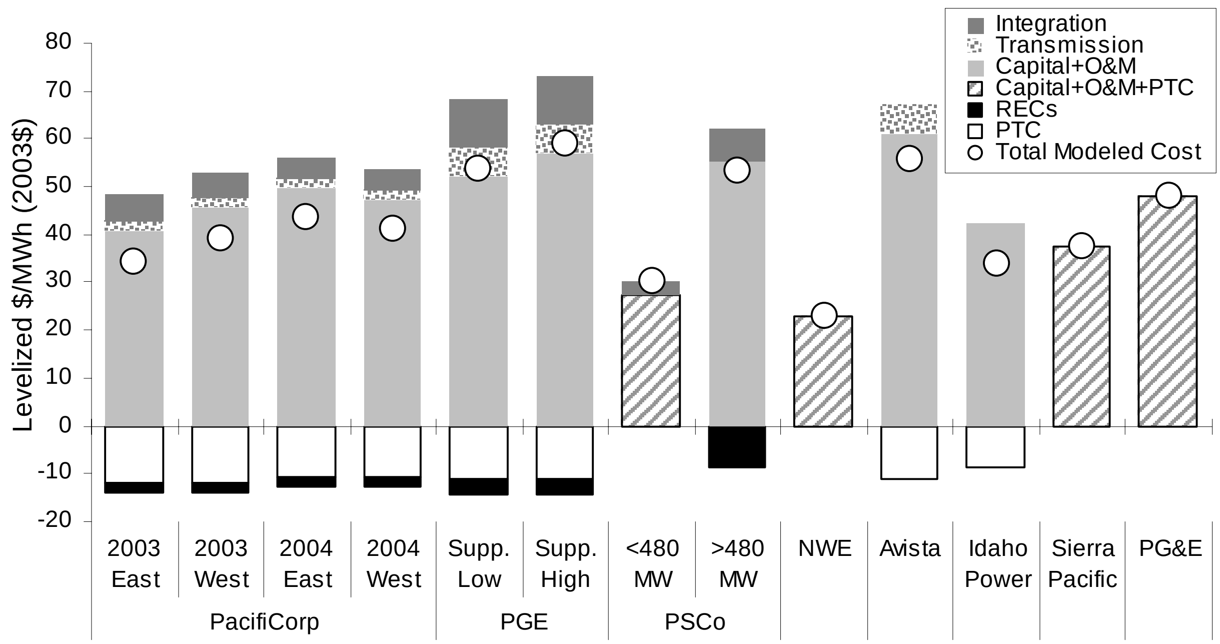

Figure 6. Wind Power Cost Assumptions

In general, and not surprisingly, the total modeled cost of wind power has a strong influence on the amount of new wind included in preferred portfolios. Figure 7 shows this relationship graphically, focusing on cumulative wind additions by 2014 as a percent of average load, for those plans for which we have data.

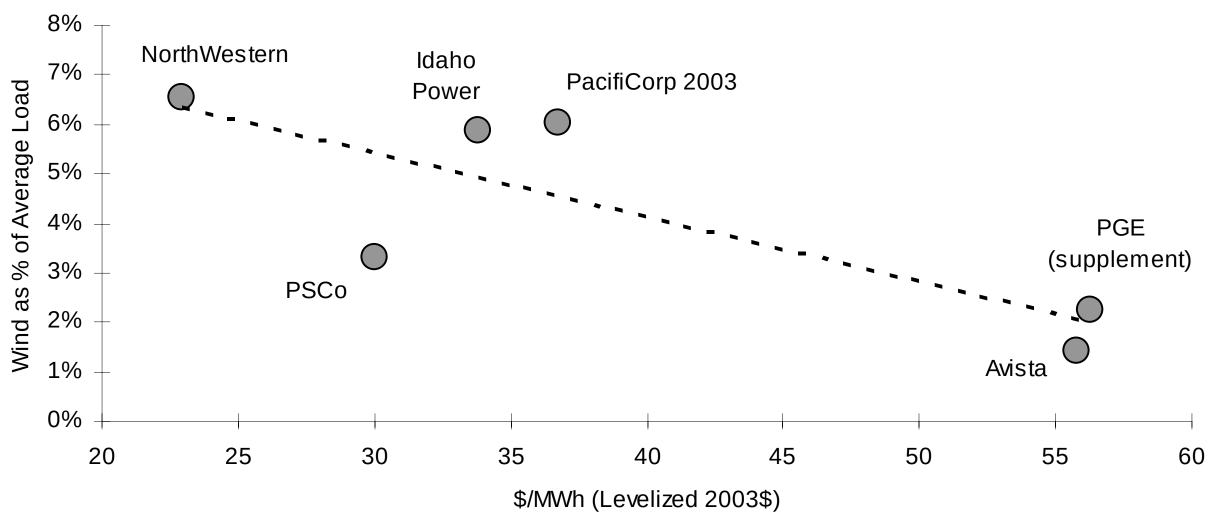

Figure 7. Modeled Wind Power Cost vs. Planned Wind Power Penetration

We disaggregated total modeled costs into the following three components (see Table 3 and Figure 6):

- busbar costs (including treatment of the production tax credit),
- indirect costs (transmission costs, integration costs, capacity credit), and

- treatment of renewable energy credits.

We review and discuss resource plan assumptions for each of these cost components. Where possible, we benchmark resource plan assumptions against other recent literature.

5.1.1 Busbar Costs

Busbar costs are defined to be the cost of wind power at the point of interconnection. As such, busbar costs include levelized capital costs and operations and maintenance (O&M) expenditures, as well as the value of the federal production tax credit (PTC). They include any facility interconnection costs (typically subsumed within capital costs), but exclude transmission and integration costs.

Assumed busbar costs range from \$23/MWh to \$55/MWh, with PSCo (for their additional, 320 MW of non-PTC wind only), Avista, PGE, and PG&E at the high end, and NorthWestern and PSCo (for their first 480 MW) at the low end (see Table 3). Variations in assumed busbar costs reflect differences in capital and O&M cost assumptions, as well as differences in the assumed value – and existence – of the PTC.

5.1.1.1 Capital and O&M

Across those IRPs for which we were able to obtain data (five of the twelve utilities), levelized capital and O&M costs range from a low of \$40.8 to a high of \$60.9/MWh (in 2003\$; the range extends to \$64.2/MWh if one includes PGE's now-supplanted initial plan). For the most part, cost assumptions are based either on the Northwest Power and Conservation Council's (NPCC) 5th Power Plan (or various drafts thereof), actual projects with which the utility has experience, or responses from recent RFPs. Only one plan, PGE, appears to build projected cost reductions into its model over time. Given the long-term nature of most resource plans, the assumption of static costs throughout time from most IRPs merits further scrutiny.

5.1.1.2 Federal Production Tax Credit (PTC)

With the potential exceptions of SCE, SDG&E, and Nevada Power, for which information was not available, all other utilities assume that the 10-year PTC will *at least* be available to wind projects that come on line in the initial years of the planning horizon:

- PacifiCorp's 2003 base case assumes that the PTC will be available over the entire planning horizon, but PacifiCorp also runs a stress test (i.e., scenario) without the PTC.
- PGE assumes that the PTC will no longer be available after 2025 (its planning horizon runs to 2051).
- PSCo (in its comprehensive settlement with stakeholders) assumes that the PTC will not be available to any wind project added to its system after 2006. Its earlier IRP, however, assumed unlimited access to the PTC over the 30-year planning period.
- Idaho Power ran scenarios with and without the PTC, and then quantified PTC risk by assigning probabilities of 70% and 30%, respectively, to those scenarios.
- Avista assumes that the PTC will be available, and does not test this assumption.

- NorthWestern's wind cost assumptions are based on an actual project proposal that was priced including the impact of the PTC.
- PSE 2005 assumes a PTC starting value of $18/MWh in 2006, declining linearly to $0/MWh in 2025.[41]
- Sierra Pacific's wind costs assumptions, for the entire planning period, appear to reflect the value of the PTC.
- PG&E's assumptions also appear to reflect the value of the PTC.

Among those IRPs that report the information, the value of the 10-year PTC – when presumed to be fully available and levelized over the project's lifetime – ranges from $8.6/MWh to $11.9/MWh (2003$ levelized). The $8.6/MWh value is somewhat of an outlier, in that Idaho Power assumes that the PTC does not escalate with inflation over its 10-year period, and also levelizes costs over 30 years, as opposed to 20-25 years in most other plans.[42] Excluding Idaho Power, the range of the PTC value tightens considerably to $10.8/MWh to $11.9/MWh (2003$, levelized). Note, however, that resource planners at Avista have since clarified that they actually used a higher PTC value within their revenue requirements model, which is used to create and model specific portfolios. Similarly, PGE claims that its Final Action Plan models the PTC on an after-tax basis, arriving at a levelized value of about $15/MWh. Though we have no reason to doubt these statements, they are not publicly documented in available IRP filings.

5.1.1.3 Comparison to Other Literature

In general, the range of levelized costs assumed for wind generation at the busbar in our sample of IRPs appears to be reasonable compared to other sources. Specifically, the EIA's *Annual Energy Outlook 2005* (AEO 2005) cites a range of $45-$60/MWh (levelized over 20 years, in 2003 dollars) for wind at the busbar (absent the PTC), depending on the strength of the wind resource. This range is slightly tighter than, but otherwise comparable to, the corresponding $40.8-$60.9/MWh range (without the PTC) in our sample of western IRPs.[43]

IRP assumptions about wind costs also appear to be reasonable relative to the prices that actual, existing wind projects are being paid. An LBNL database that contains cost and performance information for more than 2,700 MW of wind projects that came on line between 1999 and 2005 shows that the levelized busbar cost of power (in 2003 dollars, including the PTC) from these projects ranges from $15-$57/MWh (excluding the highest-cost project, which is an outlier),

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[41] In other words, a wind project coming on line in 2006 will get $18/MWh (real) for 10 years, while a project coming on line in 2016 will get $9/MWh (real) for 10 years, etc. This phase-out is intended not to replicate likely PTC policy, but rather to address the likelihood of permanent PTC expiration in as even-handed a way as possible, given the considerable uncertainty involved over timing.

[42] At the time that Idaho Power was drafting its plan, the PTC had expired, and at least one version of draft legislation to reinstate it had removed the PTC's inflation-adjustment provision. Hence, Idaho Power's assumption of a non-inflating PTC is not as unrealistic as it might otherwise seem.

[43] That said, it is worth mentioning that the AEO 2005 reference case assumes a levelized cost that is close to the low end of the previously stated range, at $48/MWh without the PTC, presumably due to an assumption that lower-cost wind resources are exploited first. At this early stage of wind development in the West, IRPs should also arguably be assuming that the most attractive wind resources will be developed first, which would suggest that the high end of the IRP-derived range is perhaps too high for the corresponding resource quality.

with a capacity-weighted average price of $32.8/MWh. This range is comparable to, though wider than, that assumed in the western resource plans: $23-$50/MWh, including the PTC.

It is important to note, however, that *new* wind projects installed in 2005 may cost significantly more than the ranges identified above, due to adverse exchange rate movements, rising steel prices, tight wind turbine manufacturing capacity, and a general rush to install wind projects prior to the previously scheduled expiration of the PTC at the end of 2005. As a result, the range of wind cost assumptions employed in our sample of western resource plans may not accurately reflect the *current* cost to build a wind project. This potential disparity between utility expectations and market reality could negatively impact wind procurement efforts (e.g., see the discussion of Idaho Power's wind solicitation in Section 3.4) and, if higher prices persist, may also lead to more pessimistic cost assumptions in future IRP filings.

Though the total levelized costs assumed in the western IRPs generally appear to be reasonable (notwithstanding recent cost increases), the value attributed to the federal PTC appears understated in at least some of the IRPs that we examined. At first glance, the value of approximately $11/MWh levelized over 20-30 years seems reasonable, given that the PTC reduces taxes by $18/MWh (2003$) for a 10-year period. However, because most IRPs account for the PTC in a *pre-tax*, rather than *after-tax* manner,[44] $11/MWh significantly understates the true value of the PTC to most wind projects. Because the PTC *directly* reduces the amount of income taxes paid, it should be thought of as providing $18/MWh of *after-tax* income. The amount of *pre-tax* income required to yield $18/MWh of *after-tax* income is $18/(1-marginal tax rate), or $27.7/MWh assuming a 35% marginal income tax rate.[45] At a 7% real discount rate, $27.7/MWh (2003$) for 10 years equals an equivalent PTC value of $18.4/MWh (2003$) levelized over 20 years, and $15.7/MWh when levelized over 30 years. These values better reflect the true value of the PTC to most wind projects.

This higher PTC value is fairly well documented in the literature. For example, in its *Annual Energy Outlook 2005*, the EIA estimates that the 20-year levelized value of the PTC to wind project owners is approximately $21/MWh in real 2003 dollars.[46] Likewise, publicly available

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[44] For example, PacifiCorp, PGE's initial and supplemental IRP filings, and Idaho Power all treat the PTC as a reduction in operating expenses (i.e., an increase in *pre-tax* operating income), while Avista calculates the present value of the 10-year PTC and subtracts that amount from the project's up-front capital costs (again, on a *pre-tax* basis). Resource planners from Avista and PGE, however, note that this method was only employed for parts of the analysis, and that the PTC was modeled correctly elsewhere.

[45] PSCo is one utility that explicitly modeled this part correctly. In its initial IRP filing, it simply assumed a busbar cost for wind that was *inclusive of the PTC* (rather than breaking the PTC out). In its *Settlement* with stakeholders, however, PSCo calculated the cost of additional wind capacity assumed not to benefit from the PTC. This calculation started with the PTC-inclusive busbar cost used in the initial IRP filing, and backed out the value of the PTC to yield an equivalent "no-PTC" busbar cost. In valuing the PTC, PSCo used the approach described above – i.e., $18/(1-marginal tax rate). Unfortunately, PSCo mistakenly treated the $18/MWh as a 30-year levelized price, which led to an overvaluation of the PTC (i.e., PSCo modeled the pre-tax PTC as being worth $27.7/MWh levelized over 30 years, which is too high). This overvaluation, in turn, led to a "no-PTC" busbar cost that was also too high, relative to the PTC-inclusive busbar cost used in its initial IRP filing. Ironically, PSCo's *overvaluation* of the PTC hurt wind's competitiveness, just as did the other utilities' *undervaluation* of the PTC.

[46] The EIA's estimate of $21/MWh exceeds our estimate of $18.4/MWh (levelized over 20 years) as a result of the EIA's assumption of a higher marginal income tax rate (38% vs. our 35%), as well as its apparent use of a 10% real discount rate (vs. our 7%).

wind power purchase agreements are sometimes priced both with and without the PTC; the differential between the two prices is consistent with the calculation offered earlier. Along the same lines, some utilities (including some in our IRP sample) have requested that respondents to wind power solicitations price their bids both with and without the PTC; such information should give utilities a more accurate sense of the value of the credit over the life of a project.

Of course, regardless of its theoretical value, the extent to which the PTC can be utilized will ultimately determine its true value to the project owner, and full and efficient utilization can be a challenge. Project owners must have sufficient taxable income – not subject to the alternative minimum tax[47] – to absorb the credit. Furthermore, unless the PTC can be "monetized" to service debt, the PTC may negatively impact the capital structure of a wind project by reducing the amount of leverage that is possible.[48] Although the PTC has its limitations, the wind industry has nevertheless proven that it can work within those limitations, and it is therefore reasonable to assume, at least in the early years of the planning period, that the PTC is fully utilized.

Finally, though it appears that some of the utility IRPs we examined have *understated* the true value of the PTC, many of the plans also appear to *overstate* the likelihood of PTC renewal over a lengthy time horizon. The duration of PTC availability is highly uncertain, but it seems unlikely that the PTC (as presently configured) would be extended for a twenty-year period. An evaluation of a broader range of PTC-extension scenarios therefore has merit in future planning efforts.

5.1.2 Indirect Costs

Wind power projects are often sited remotely from load and have variable generation profiles. As a result, transmission and integration costs may be higher for wind than for other resources, and wind's contribution to reliable capacity may be lower than for other generation sources. Below, we examine how the twelve western IRPs modeled these issues.

5.1.2.1 Transmission Costs

Avista, PGE, and PSE (2003) – three utilities in the Northwest, where the Bonneville Power Administration (BPA) owns much of the transmission system – simply assume that wind projects will have to pay at least the current BPA point-to-point tariff of $1.24/kW-month (~$15/kW-year, or ~$6/MWh), in order to deliver power. PacifiCorp, which owns transmission east of the

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[47] The alternative minimum tax (AMT) is designed to make sure that wealthy individuals and corporations do not avoid paying taxes by investing in tax shelters. In such situations, the taxpayer is required to calculate taxes as usual as well as under the AMT rules, and ultimately adopt whichever method yields a higher tax bill. If that method turns out to be the AMT, then the taxpayer may not be able to fully utilize the PTC. The September 2004 legislative extension of the PTC through 2005 also included an exemption from the requirements of the AMT for the first four years of a wind project's life. Since the PTC lasts for 10 years, however, this 4-year exemption only offers partial relief.

[48] Since the PTC is a tax credit rather than cash revenue, it typically does not directly contribute towards a lender's required minimum debt service coverage. This can limit the amount of debt that a project can take on, leading to higher-cost projects (because equity is typically more expensive than debt). In recent years, however, it has become commonplace for the equity investor to "monetize" the PTC by infusing cash payments (in an amount equivalent to the PTC) to the project, thereby allowing additional leverage to be obtained. As such, ignoring the potential impact of the PTC on capital structure seems reasonable, particularly in an exercise as broad-brush as resource planning.

cascades, where it is presumed that many of the Northwest's wind projects will be located, and whose service territory also extends beyond the Northwest, assumes a lower transmission cost of $2-4/MWh in its base case (but stress tests it at half and three times these costs). Idaho Power and PSCo both anticipate wind being developed within their control areas, and so do not reflect transmission costs. Though not stated, this is also likely the case for NorthWestern, which based its wind modeling on a proposed Montana-based project. Sierra Pacific included an analysis of wind interconnection costs as an appendix to its resource plan, but the results were not directly integrated into its subsequent analysis.

The assumed costs stated above reflect the cost of delivering wind power over current transmission lines. A bigger issue (and cost), however, involves the *availability* of those lines to transmit power from new wind projects, as well as the potential need for a major expansion of the transmission system in order to bring wind power to market. Most of the western resource plans have addressed these larger transmission issues only qualitatively. A few, however, have tried to account for transmission expansion in their modeling. PSE 2005, for example, assumes two sets of costs for a major transmission expansion to access wind and coal resources: $58.02/kW-yr (in 2006, escalating at 2.5%/year) if participant-funded, or $31.81/kW-yr if instead undertaken by an RTO or some other regional collaboration. Idaho Power also claims to have incorporated into its analysis cost estimates for upgrading the transmission system to access new resources, though a breakdown of these costs is not available. PG&E, SCE, and SDG&E also discuss transmission expansion needs and costs to access in-state wind power, either in their 2004 IRPs, or in subsequent renewable energy procurement plans. Though it is somewhat unclear how those costs are incorporated in the analysis underlying the plans, it is evident that the California utilities are considering transmission expansion needs and costs. SCE, for example, is considering a major transmission expansion in the Tehachapi area, while PG&E has estimated that $170-230 million in transmission expenditure may be required to meet the utility's 20% renewable energy target.

Especially as wind additions grow in the West, it will be necessary to develop and incorporate into IRPs improved assessments of the transmission costs of accessing varying quantities of wind generation. Few resource plans currently incorporate this capability, instead choosing to establish strict and sometimes-arbitrary limits on the amount of wind additions allowed. Improvements in this area are critical if wind power is to be accurately characterized in resource planning.

5.1.2.2 Integration Costs

Wind integration costs represent the combined impact of incorporating variable or "as-available" wind power into the grid over at least three distinct time periods:

1) Seconds: the cost of utilizing automatic generation control (AGC) to fine-tune system voltage as wind output varies over the course of seconds (known as "regulation");
2) Minutes to hours: the cost of ramping up or down the output of one or more dispatchable generators to follow a more sustained change in wind output (known as "load following"); and
3) Hours to days: the cost of altering the unit commitment of new units on an hourly or longer basis, due to uncertainty in wind output.

The science of understanding and quantifying the integration impacts and costs of wind power has solidified over the last several years. Nonetheless, integration costs will vary from utility to utility, depending in part on: the amount of wind capacity in a given system (with costs increasing, though not necessarily in a linear fashion, as wind penetration levels increase); the types of generators within the system (a hydro-based system may be better suited to integrate wind than a thermal-based system); the ability to balance supply and demand with imports/exports; and the quality of the wind power forecast (as forecast accuracy improves, wind can be integrated more efficiently). For these reasons, there is no single correct answer to – and thus some uncertainty and concern in IRPs over – what it costs to integrate wind power.

A number of utilities have conducted their own analyses – with varying levels of sophistication – of wind integration costs. In the resource plans that we examined, wind integration cost estimates range widely, from effectively $0/MWh to as high as $18/MWh ($30/MWh if one includes PGE's initial IRP filing, which has since been supplanted; see Table 4 for details; wind penetration numbers reflect both existing and planned wind capacity).[49] In addition, in strictly limiting the amount of wind considered in candidate portfolios, as described earlier in Section 4.2, several of the IRPs may be indirectly accounting for the presumed increase in integration costs (as well as presumed increases in the cost of transmission) at higher levels of wind penetration.

It is difficult to evaluate the treatment of integration costs in western IRPs, given definitional differences (e.g., PGE's IRP measured the cost transforming variable wind output into a flat product) as well as the fact that integration costs are expected to vary by utility and by the level of wind power penetration. Nevertheless, a considerable literature has developed over the last several years that has sought to quantify integration costs for a number of utilities, including some in our IRP sample. Figure 8 presents results from these studies, with costs broken out by regulation, load following, and unit commitment where available.[50] The first three studies (to the left of the vertical line) did not estimate integration costs over all three of these time frames, whereas the seven studies to the right of the vertical line did.

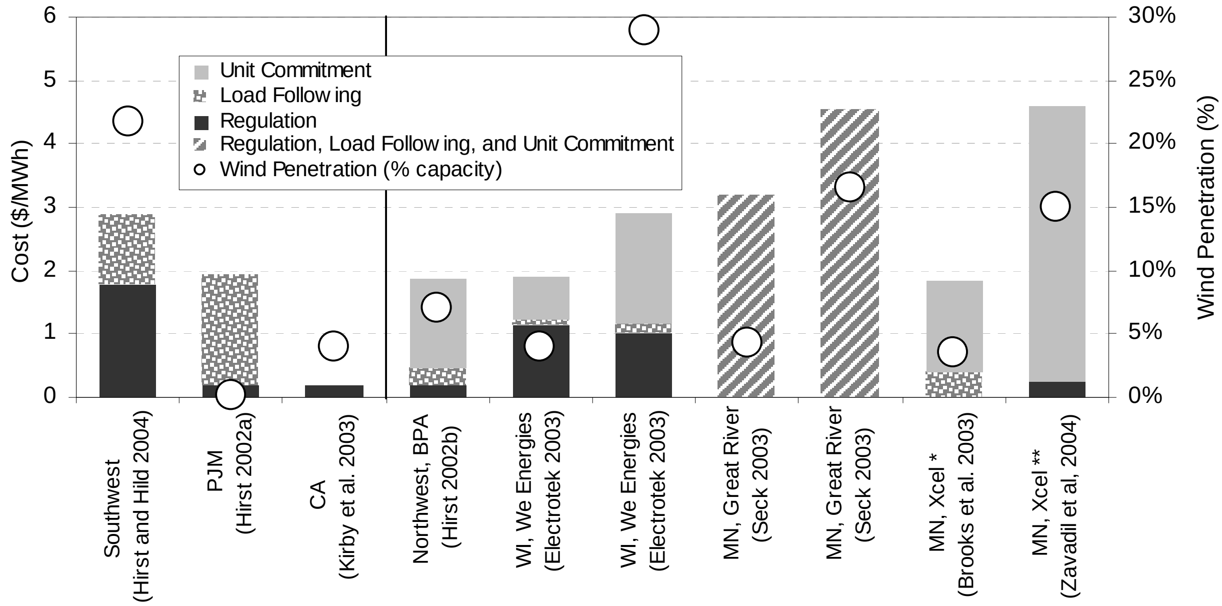
[49] The integration cost *estimates* provided in Table 4 derive from the IRP plans, but the presumed integration costs included in the *actual modeling analysis* may differ from these integration cost estimates (e.g., as shown in Table 3, Avista's modeling analysis assumes no integration costs, but the costs calculated through their integration cost studies – see Table 4 – are significant; it was these concerns that led to Avista capping wind additions at 75 MW for their 2003 IRP).

[50] It is also worth noting that BPA is now offering "network wind integration" and "shaping and storage" services for $4.50/MWh and $6.00/MWh, respectively. These services deliver flat blocks of power to the wind purchaser, and are priced competitively with integration costs assumed in the IRPs. For more information on these products, see http://www.bpa.gov/Power/PGC/wind/BPA_Wind_Integration_Services.pdf.

Table 4. Summary of Integration Cost Estimates in Western Resource Plans

Utility	Utility Filing/ Scenario	Integration Costs ($/MWh)	Wind Penetration (% of Peak Load)	Additional Comments
PacifiCorp	2003 IRP	$5.6	24%	Based on its own studies of integrating wind into its system, initial $5.6/MWh is split approximately evenly between incremental operating reserves and imbalance costs. Costs in 2004 IRP are lower due to lower assumed cost of reserves.
	2004 IRP	$4.5	14%	
PSCo	First 480 MW	$2.5	9%	Initial $2.5/MWh cost estimate based on an average of many of the studies reported in Figure 8. In settlement with stakeholders, the cost increased for next 320 MW of wind based on an assumption that costs will increase with higher levels of penetration.
	Next 320 MW	$7.0	14%	
PGE	Initial IRP	$10-$30	28%	Initial IRP estimate based on the cost of not only integrating wind, but also firming and shaping wind into a "flat" (baseload) product. This adds to the expense, and is arguably not technically necessary because load itself is not flat. Supplement estimate – which supplanted the earlier estimates – are based on informal discussions with BPA over the likely cost of converting intermittent wind output to a flat product (at least across an hour).
	Supplement	$10	28%	
Idaho Power	IRP	$0	--	Did not model integration costs, but does note that the Snake River hydroelectric system affords it considerable flexibility in economically integrating wind, implying that costs are expected to be low.
Avista	IRP	$2-18* 75 MW limit	5% 4%	Avista estimated a wide range of costs, but did not incorporate these results into its modeling. Instead, Avista cited the considerable uncertainty over, and potential magnitude of, these costs as justification for limiting its pursuit of wind to 75 MW.
North-Western	IRP	--	--	It is unclear how, if at all, NorthWestern treated wind integration costs.
PSE	2005 IRP	$4.0	8%	PSE hired a consultant to undertake a wind integration cost study. The result is a supply curve of integration costs that extends to 450 MW.
Nevada Power	IRP and 2001 RE RFP	100 MW initial limit	2%	Both of Nevada's utilities reference a joint, non-public study that looks at the operational impacts of wind power. Both express concerns about wind fluctuations within 15-minute intervals. Initial strict size limits later relaxed and applied to individual (not aggregate) projects.
Sierra Pacific	IRP and 2001 RE RFP	50 MW initial limit	3%	
PG&E	2004 Plan	--	--	Analysis of integration costs in CA is being funded by the CEC, and study results show relatively modest impacts. None of the three utilities provides any information on whether or how these costs are incorporated into their plans. In the plans, and subsequent renewable energy procurement plans, however, each utility does describe its preferences for resource characteristics. By placing greater value on dispatchable and baseload projects over as-available projects, the utilities reflect concerns about integration costs by reducing the amount of wind additions in their illustrative procurement plans.
SCE	2004 Plan-	--	--	
SDG&E	2004 Plan	--	--	

* Avista's integration cost study included the cost of altered and less-efficient dispatch of non-wind resources. Under a wet hydro year and persistence wind forecasts (30% forecast error at 90% confidence), costs are estimated to be as high as $17.66/MWh. Under a low hydro year and a perfect forecast, the cost is estimated to be as low as $1.88/MWh. Avista also looked at normal hydro years, and two intermediate levels of forecast accuracy. Generally, costs decreased with greater forecast accuracy and (surprisingly) with drier hydro conditions. Costs reported here are presumed to represent the impact of a 100 MW wind addition. Avista notes that integration costs increase by a third or more for a 300 MW project, assuming a perfect forecast. Avista also notes that these costs may not capture all of the costs of wind integration (e.g., the need to hire additional scheduling staff, etc.). Avista's draft 2005 IRP calls for 650 MW by 2024.



*Regulation costs evaluated, but estimated to be $0/MWh.
**Load following costs evaluated, but estimated to be $0/MWh.

Figure 8. Results from Recent Studies of the Cost of Integrating Wind Power into Utility Grid Systems

Because the studies presented in Figure 8 are geographically diverse, cover a wide range of wind penetration levels, use different methodologies, and do not all estimate integration costs over all three time periods of relevance, it is difficult to draw *specific* conclusions about the treatment of integration costs in western IRPs. Nonetheless, some western IRPs are clearly applying integration costs that exceed the range presented here (which, even at wind penetration levels ranging from 15-30% of peak load, does not exceed $5/MWh). This is shown graphically in Figure 9, which consolidates aggregate estimates from the integration studies shown in Figure 8 and compares them to the integration cost assumptions in our resource plan sample (wind penetration levels for the resource plans include both existing and planned wind generation). In general, the range of integration costs assumed in the resource plans (shown here to the right of the vertical dashed line) exceeds the range of cost estimates contained in the broader analysis literature (shown to the left of the vertical dashed line).

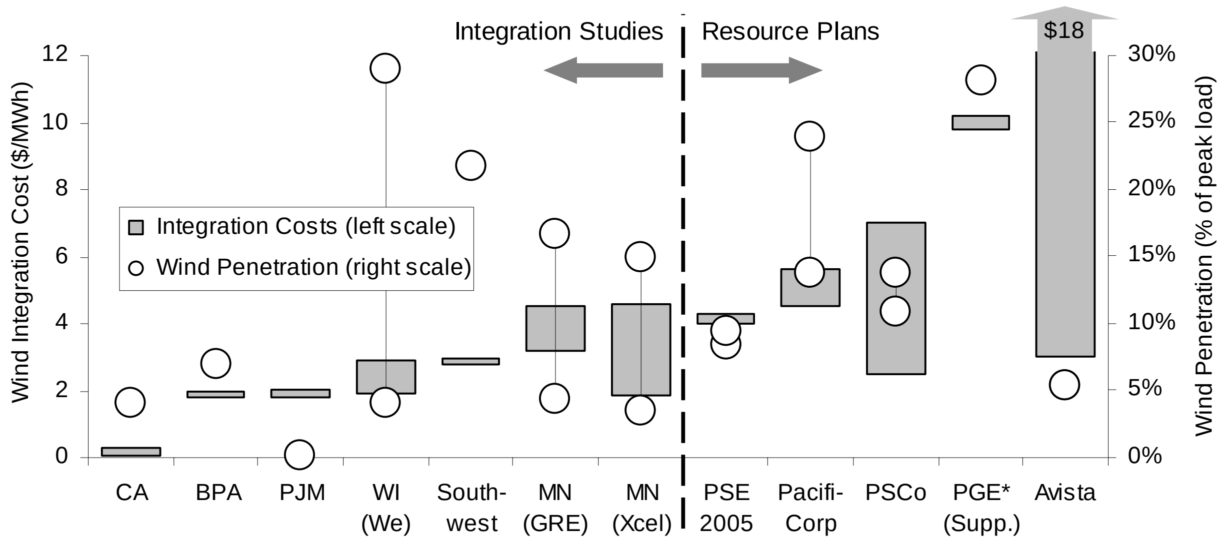


Figure 9. Comparison of Integration Cost Estimates in Resource Plans and Broader Integration Cost Literature

*PGE's supplemental IRP estimates the cost of creating a flat, base-load block of power out of variable wind production, rather than simply the cost of integrating variable wind production. As such, its cost estimates are not directly comparable to the others.

Based on the cost estimates from the literature, along with our review of integration cost assumptions in western IRPs, we make the following observations:

- **Integration cost assumptions by some utilities appear high, while others may be low.** Presuming that Avista fears that integration costs will be at or above the upper end of its estimated range, as suggested by the 75 MW (4% of peak load) cap placed on new wind in its 2003 RFP, its cost assumptions appear to be high relative to other available literature estimates. PGE's assumed integration costs may also initially appear to be high, but can not be directly compared to the others because PGE estimates the cost of creating a *flat, base-load* block out of variable wind production, rather than simply the cost of integrating variable wind production (this also has the salutary effect of increasing the capacity value of wind). The hard caps initially placed on wind power in Nevada (50 MW in the North, and 100 MW in the South, 3% and 2% of peak load, respectively) also appear to be more strict than can be supported by the broader literature. In other cases, utilities appear to assume that integration costs are zero and, in these instances, additional studies to support such an assumption may be warranted.

- **Few utilities have closely evaluated the cost of integrating increasingly large amounts of wind power.** Integration costs are expected to increase at higher levels of wind power penetration, but many of the IRPs do not explicitly account for this relationship, instead preferring to limit the risk of potentially higher integration costs by capping the amount of wind power allowed into candidate portfolios. This analytical shortcoming highlights the need for *more* integration cost studies conducted at *higher* penetration levels, and for utilities to then incorporate that new information into their IRPs, instead of exogenously limiting wind penetration. Along these lines, it is perhaps noteworthy that under its settlement with stakeholders, PSCo agreed to undertake an integration cost study at a 15% penetration level (compared to a current penetration of less than 5% of peak load), followed by another (once it reaches 10% of peak load) at 20% penetration.[51] Other utilities have also pledged to continue to study integration costs, and to use updated estimates in future IRPs.

- **Uncertainties in integration costs can be addressed through risk analysis.** Especially as additional studies are conducted, in the mean time, any uncertainty over integration costs can be modeled just like any other uncertain variable, using scenario and/or stochastic analysis. For example, in its 2003 plan, PacifiCorp subjected its base-case integration cost assumptions to scenario analysis. We would argue that this is a more appropriate way to reflect uncertainty than arbitrarily imposing exogenous limitations on the amount of wind power allowed in candidate portfolios.

5.1.2.3 Capacity Credit

A fundamental aspect of utility IRP is determining future needs, in terms of both energy *and capacity*. As wind power penetration has increased, in part based on economic merit, the question of how much dependable capacity wind power can provide to a utility system has taken on increased relevance.

Effective load carrying capability (ELCC) is the most rigorous method for determining a project's contribution to meeting capacity needs. As explained by Milligan (2002), Kahn (1991), and Kirby et al. (2003), the ELCC of a wind project (or any project) can be calculated by comparing system reliability both with and without the wind plant. The increase in system reliability *with* the wind plant is then replicated by removing the wind plant and adding a reference unit, often a gas-fired generator, until the reliability of the system matches the wind-case reliability. The capacity of the reference unit that results in this match is the ELCC of the wind plant. Though ELCC is generally recognized as a superior approach, due in part to its intensive data requirements, many RTOs and ISOs use simplified approaches to determining wind's capacity value (Porter 2003, Milligan and Porter 2005).

A great degree of methodological diversity is apparent in our review of western IRPs, leading to a range of results that establish wind's capacity value between 0% and 33%. Only two plans – PacifiCorp 2004 and SCE – used ELCC to calculate capacity value, while six utilities (Idaho Power, Avista, PSCo, PGE, PSE 2005, and SDG&E) used simplified methods. Two other plans (PacifiCorp 2003 and PSE 2003) simply assume that wind's capacity value is zero, and the treatment of capacity value for wind is not stated in several additional plans: Northwestern, Nevada Power, Sierra Pacific, and PG&E.

- **PacifiCorp:** After assigning a 0% capacity value to wind in its 2003 base case (tempered by a 15% capacity value in a scenario analysis), PacifiCorp assigned wind a 20% capacity value in its 2004 base case, derived from an ELCC calculation. While this change should have reduced the cost of candidate portfolios containing wind, PacifiCorp's 2004 IRP did not include any incremental wind in candidate portfolios; thus, this change had no impact on resource decisions.

[51] These studies will also reportedly account for the impact of geographic diversity in wind farm siting on integration costs.

- **Idaho Power:** Idaho Power used data provided by a wind developer to estimate how much power a 100 MW wind project would generate between the peak hours of 4:00 and 8:00 PM during the peak month of July. This study found that the project would generate 5 MW or more 70% of the time, and Idaho Power therefore assigned a 5% capacity credit to wind power.

- **Avista:** Using seven years of anemometer data, Avista calculated 80% confidence intervals of average theoretical wind generation by month at different sites. These confidence intervals extend below zero in all months, suggesting that wind cannot be relied upon to provide *any* generation in *any* month, and Avista therefore assigned a 0% capacity credit to wind. This conclusion appears implausible, but not enough information is presented to examine the confidence interval calculations that Avista employed. Resource planners at Avista have indicated that they will use an ELCC-based method in their 2005 plan.

- **PSCo:** Although the appendix to PSCo's 2003 least cost plan defines capacity credit in terms of ELCC, and although PSCo performed an ELCC calculation in its 1999 IRP, the 2003 plan itself uses a different method – one adopted by the Mid-Continent Area Power Pool (MAPP) – to assign a 10% capacity credit to wind in Colorado. As employed by PSCo, this method is similar to that used in Idaho – the peak hour, along with three contiguous hours, in the peak month of the year is the period of interest, and the median hourly wind output during this period sets the capacity value.

- **PGE:** PGE assumed (in its modeling) that the capacity value of wind would be 33%, equal to its assumed capacity factor. PGE believes that the true capacity value is probably lower (e.g., perhaps 20%), but given the limited amount of wind called for in its preferred portfolio (195 MW), the difference between a 20% and 33% capacity credit comes to just 25 MW – an amount too small to trouble with according to PGE, relative to its ~4000 MW peak load (Kuehne 2005). Furthermore, given that PGE's assumed integration costs were intended to replicate the cost of creating a flat product, from its perspective, wind's capacity value should roughly equal its capacity factor.[52]

- **PSE:** Without mention of rationale, PSE assigned 0% capacity value to wind in its 2003 least cost plan. Though not directly stated, PSE's 2005 plan assigns the lesser of 20% of nameplate capacity or two-thirds of the average capacity factor during the peak month of January (Maclean 2005).

- **PG&E:** Though PG&E does not provide information on its technology-specific capacity value assumptions, or the methodology used to calculate those numbers, it does calculate the amount of "reliable" capacity expected from its *aggregate* renewable energy procurement

[52] Notably in this regard, PGE's December 2004 announcement that it had agreed to purchase the entire output of the 75 MW Klondike II expansion for a 30-year period notes that PPM Energy (the seller) will provide "firming, shaping, and delivery services" that will "transform the naturally intermittent wind energy into reliable, predetermined blocks of power that are easier for PGE to integrate into its larger supply portfolio." Hence, at least for this particular wind purchase, capacity value does effectively equal capacity factor.

(e.g., its 2150 MW of renewable additions by 2014 are expected to provide 1249 MW of reliable capacity, implying a 58% capacity value in aggregate).[53]

- **SCE:** SCE's 2004 procurement plan only notes that it used a "reasonable ELCC for intermittent resources," providing no further indication of what ELCC figure was used, though a subsequent update to the plan uses a different method.[54]

- **SDG&E:** SDG&E's plan shows that its 20% renewable energy share by 2010 is expected to provide 10% of the utility's total capacity needs, implying an *aggregate* renewable energy capacity value of 50%. Data on the capacity value assigned to specific renewable energy technologies is not provided, but SDG&E notes that it calculated capacity values for different renewable technologies primarily by looking at historical production during peak periods.[55]

- **NorthWestern, Nevada Power, Sierra Pacific:** It is unclear how, if at all, NorthWestern, Nevada Power and Sierra Pacific accounted for capacity value.

Thus, within our sample, virtually all of the IRPs that explicitly assigned a capacity value to wind (even if 0%) calculated that value in a different way. With the exception of PacifiCorp's most recent IRP and SCE's 2004 plan, however, the utilities have not used ELCC as the relevant figure of merit. This is a departure from what is viewed by many to be the most analytically rigorous way of quantifying capacity value. In addition, as shown in Kirby et al. (2003), the application of simplified methods in calculating the ELCC of a wind generator should be done with care because such methods do not always provide a good estimate of the ELCC. Milligan and Porter (2005) also describe the significant errors that can occur when using certain simplifying methods to calculate the capacity value of wind, and the sometimes arbitrary approach to the development of those simplified approaches.

Recently, a number of studies using ELCC methods have estimated the capacity value of wind power in different grid systems. The shaded bars in Figure 10 present the results from five of these studies (footnote 58 describes the studies and their results in more detail), while the arrows on the right-hand side of Figure 10 designate the various capacity values for wind assumed within a subset of our resource plan sample. Though the ELCC-based study results presented by the shaded bars cannot, in most cases, be directly extrapolated to our IRP sample (PSCo being the sole potential exception[56]), it is at least apparent that assumptions of 0% capacity value

[53] In a subsequent 2005 update to the plan, PG&E uses simplified accounting conventions agreed-upon in a CPUC workshop report on resource adequacy, equating capacity value to production during peak periods.
[54] In a subsequent 2005 update to the plan, SCE instead used the accounting conventions agreed-upon in a CPUC workshop report on resource adequacy. For qualifying facility resources, SCE used a summer capacity value equal to the average capacity produced during the on-peak hours of 12:00 to 6:00 pm in the months of May – September. Capacity values for other months were calculated based on average production in all other months during the hours of 12:00 to 8:00 pm.
[55] In a subsequent 2005 update to the plan, SDG&E claims to use simplified accounting conventions agreed-upon in a CPUC workshop report on resource adequacy, also equating capacity value to production during peak periods. SDG&E also reveals dependable capacity assumptions for two wind projects already under contract, showing an assumed capacity value for these projects of 23-26%.
[56] Although PSCo conducted the study referenced in Figure 10, it now considers the results to be flawed because they were apparently generated using unrepresentative (overly optimistic) anemometer data. For more information, see page 21-23 of http://www.xcelenergy.com/docs/corpcomm/McGreeFinalPublic.pdf.

(Avista, PSE 2003, and PacifiCorp 2003) are too low,[57] and that Idaho Power's (5%) and PSCo's (10%) capacity values may also be on the low side. Three additional utilities in our sample provided no indication of how or even whether wind's capacity value was assessed (NorthWestern, Nevada Power, and Sierra Pacific), while none of California's utilities (PG&E, SCE, and SDG&E) reveal the assumptions that they used. In these instances where no data are provided, it is impossible to benchmark IRP assumptions against the external literature. More generally, it seems clear that further examination of wind's capacity value (using ELCC, and approximations of ELCC) is warranted in future IRPs.

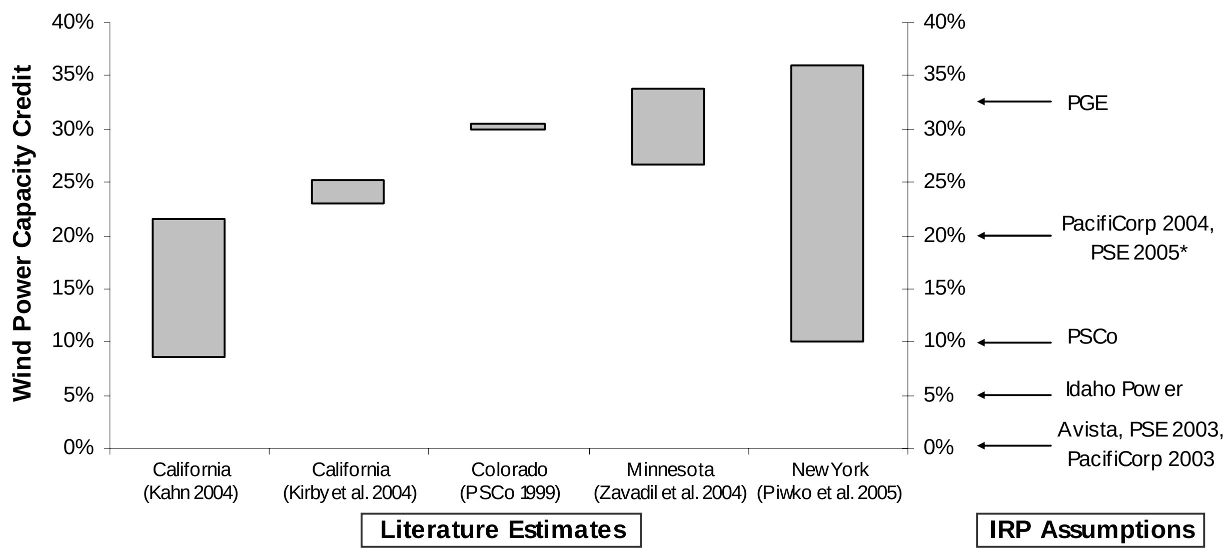


Figure 10. Results from Recent Studies of Wind Power's Capacity Value[58]
**PSE 2005 assigns the lesser of 20% of nameplate capacity or two-thirds of the average capacity factor during January.*

5.1.3 Treatment of Renewable Energy Credits (RECs)

Three of the IRPs net the assumed value of a project's renewable energy credits (RECs) against the project's combined busbar and indirect costs, to yield the final cost that is fed into the model. This crediting of RECs is based on the theory that under any future RPS, the utility will not need to purchase those RECs (because it will already hold them), and may even be able to sell them if it has exceeded its RPS obligation (or if an RPS is not adopted).

[57] Under the reliability-based ELCC method of calculating capacity value, every resource provides *at least some* capacity value (because inclusion of *any* new resource will always increase reliability), and no resource provides 100% capacity value (because no resource is immune from a forced outage).
[58] Kahn (2004) is based on 1000 MW of existing wind in SCE's service territory, and using public data. The range of outcomes reflects different outage rate assumptions, different forms of hydropower dispatch, different base years (1999, 2002, 2003), different wind regions, and different levels of wind project aggregation. Kirby et al. (2004) is based on existing wind generation in California, using confidential data from the California ISO. The range of outcomes reflects different wind resource areas (23% for Altamont; 23.5% for San Gorgonio; 25.2% for Tehachapi). PSCo is based on the 162 MW Lamar wind project, serving PSCo. PSCo conducted the study, with results presented in Lehr et al. (2001). Zavadil et al. (2004) is based on existing and potential new wind in Minnesota. The low end of the range (26.7%) reflects the addition of 1500 MW of wind to the system; the high end of the range (33.8%) reflects 400 MW of existing wind generation. Finally, Piwko et al. (2005) is based on 3300 MW of new wind at 33 different sites in New York. The low end of the range (~10%) reflects onshore wind in New York; the high end of the range (~36%) reflects a single offshore wind site.

- In both its 2003 and 2004 IRPs, **PacifiCorp** assumes that a wind project's RECs are worth $5/MWh (nominal) for the first five years of the project life ($2/MWh levelized, in 2003$). Based on stress-testing of this value at $0/MWh and $9/MWh, PacifiCorp's 2003 IRP finds that the value of RECs over this range is not significant enough to impact resource portfolio choices.
- The supplement to **PGE**'s IRP assigns a levelized REC value of $3.3/MWh (consistent with $5/MWh over 10 years) to all wind projects *not subsidized* by the Energy Trust of Oregon (ETO). RECs from subsidized wind projects are assumed to already have been paid for and retired by ratepayers through the system benefits charge that funds the ETO.
- In its comprehensive settlement with stakeholders, **PSCo** adopted a non-escalating REC value of $8.75/MWh over the life of all wind projects, with the exception of the 480 MW of wind that it planed to procure through its 2004 RFP. The text of the settlement specifically mentions the potential future value of RECs to PSCo, particularly given Colorado's new RPS.

One point of note with respect to the treatment of RECs involves the interaction of RECs with emissions reductions and emissions reduction credits. There is considerable debate in the literature (and in practice) as to whether RECs should include or exclude the value that might derive from any associated emissions reductions. One camp holds that the primary reason that renewables are valued is because they are, for the most part, free of emissions, and that value should therefore be embedded within the price of a REC. Another camp holds that emissions reductions are not necessarily a direct result of renewable generation (e.g., due to the existence of cap and trade programs, or because increasing renewable generation has the effect of reducing emissions from *another* generator), and so any emissions reduction credits should be determined and conveyed independently of the REC.

Though it is not yet clear how this debate will be resolved, what is clear is that utilities who sell off RECs are potentially more susceptible to environmental compliance risk, to the extent that carbon and other emissions reduction benefits are ultimately determined to be embedded within the REC. In this case, a utility that has sold its RECs will not be able claim the associated emissions reduction benefits. Until there is more clarity on this issue, the most conservative modeling approach might be to *not* place a value on RECs from renewable generation that is also separately credited (financially or otherwise) with reducing emissions.

5.2 Geothermal Cost and Performance Assumptions

Though wind power clearly dominates the modeling of renewables within these resource plans, other renewable resources were also considered, at least in initial screening processes, and sometimes within candidate portfolios. In this section we briefly discuss the assumed cost and performance of geothermal, the only other renewable resource to be included in multiple candidate portfolios, and for which cost and performance data are available.[59]

[59] We do not summarize the qualitative discussions about other renewable resources (e.g., solar, biomass) that did not generally advance past the initial screening process (with the notable exception PSE 2005 (for biomass), as well as the California plans, where these resources do play a role but for which detailed cost and performance assumptions are not provided).

Four utilities included some geothermal within their candidate portfolios and included at least some cost information on this resource, as shown in Table 5, though only two of these utilities providing detailed assumptions. The utilities generally assumed representative geothermal project sizes of 50 MW or less. Capacity factors range from 93-97%, where provided. In aggregate, capital, O&M, and steam costs range from $40-$49/MWh. PacifiCorp assumed that geothermal projects would opt for the 5-year federal production tax credit, rather than the 10% federal investment tax credit.[60] It is not clear how Idaho Power, Sierra Pacific, and PG&E treated these tax incentives, but each presumably included the 10% investment tax credit.

With no integration costs, the final modeled costs of geothermal ($35-$42/MWh for PacifiCorp and Idaho Power, and more than $46.9/MWh for PG&E and Sierra Pacific) are near-competitive with wind. In fact, PacifiCorp's 2004 IRP assumes lower levelized costs for geothermal than for wind (but since PacifiCorp did not model renewables in its 2004 IRP, it is not possible to assess the impact of this cost reversal). These costs are also consistent with some of the external literature: the EIA's AEO 2005 assumes a levelized busbar cost for geothermal of $44/MWh without, and $36/MWh with, the PTC (in 2003 dollars), though the authors are aware of more costly geothermal bids that have been submitted in recent renewable energy solicitations. If geothermal projects really are this cost-competitive, perhaps other utilities should take a second look at this resource.

Table 5. Geothermal Power Performance and Cost Assumptions

	PacifiCorp			Idaho Power	PG&E	Sierra Pacific
	2003	2004				
	East	East	West			
Project Size (MW)	50	30	40	50	50	??
Performance (%)						
Capacity Factor	97%	97%	94%	93%	96%	??
Capacity Credit	Full	Full	Full	Full	Full	??
Levelized Cost (2003 $/MWh)						
Capital, O&M, Steam	43.2	41.5	49.3	Incl.	Incl.	Incl.
+ITC	0.0	0.0	0.0	Incl.	Incl.	Incl.
+PTC (5 years)	-7.7	-6.9	-6.9	0.0	0.0	0.0
=Busbar Cost	***35.5***	***34.6***	***42.3***	***40.3***	***46.9***	***47.0***
+Transmission	2.0	2.0	2.0	0.0	??	??
+Integration	0.0	0.0	0.0	0.0	0.0	0.0
=Total Utility Cost	***37.5***	***36.6***	***44.3***	***40.3***	***??***	***47.0***
+RECs	-2.0	-2.0	-2.0	0.0	0.0	0.0
=Total Modeled Cost	***35.5***	***34.6***	***42.3***	***40.3***	***??***	***47.0***

Incl. = included, but actual value not disclosed
?? = not known whether considered or included

Avista and PGE also mention geothermal costs. PGE identifies approximately 50 MW of new geothermal resources that it estimates would cost the utility $70/MWh (levelized 2003$) – nearly twice as much as PacifiCorp's west-side resource. Meanwhile, Avista notes that it examined various geothermal projects, but excluded them from further consideration because they were

[60] Again, PacifiCorp's modeling of the production tax credit as a *pre-tax* reduction in operating costs understates its true value. See Section 5.1.1.3 for more information.

estimated to cost more than $100/MWh. In neither instance was geothermal included in the candidate portfolios of these two utilities.

This wide range of levelized costs – from $35 to $100/MWh – is striking, and suggests that geothermal costs are either highly project-specific and can vary significantly by region or site, or alternatively are poorly understood by utilities, compared to the costs of other resources (even wind power) that are modeled with greater consistency across plans. In the latter vein, it is worth noting that in preparing its 2004 plan, PacifiCorp had access to actual geothermal bids submitted in response to its 2003 renewables solicitation; similarly, the cost assumptions provided by Sierra Pacific are based on its 2003 renewable energy solicitation. Though not explicitly stated, one would assume that the costs presented for these utilities in Table 5 are reflective of those bids.

5.3 Conclusions

Wind and (to a lesser extent) geothermal are the two most widely modeled renewable resources among our resource plan sample. With natural gas prices expected to remain high for the foreseeable future, however, western resource plans should arguably be evaluating a broader array of renewable options as well. This is particularly true given that candidate portfolios that include significant amounts of wind are also typically laden with gas-fired capacity; other renewable resources (geothermal, biomass) might not bear this burden.

With respect to wind power, while busbar cost assumptions appear to be reasonable (notwithstanding recent cost increases), the value of the federal PTC, and the risk of its permanent expiration, could be more consistently and accurately addressed. Our review suggests that the former is often undervalued, while the latter is often overvalued.

Methods for evaluating, and in turn knowledge about, wind's capacity value and integration costs have made great advances in recent years. Most would likely agree that utilities should not only stay abreast of the latest developments and incorporate them into planning processes, but should also try to get ahead of the curve by conducting additional analyses – particularly of integration costs – at penetration levels that exceed what might result from current planning activities. Results from such studies would ideally be used in place of any exogenously imposed caps on wind penetration. Along these same lines, there is also a critical need for more information on the costs of expanding the transmission system to access larger quantities of (presumably lower cost) renewable resources; these data are not yet readily available for use in utility resource planning.

6. Risk Analysis: Natural Gas Price and Environmental Compliance Risks

Increasingly, analysts are calling attention to the benefits of renewable energy as a hedge against electricity sector risks. In particular, renewable energy may be viewed as a valuable contributor to a generation portfolio due to its ability to mitigate natural gas price risk and the risk of future environmental regulations, most notably the risk of future carbon regulation (see, e.g., Wiser et al. 2005; Bolinger et al. 2005; Wiser et al. 2004; Awerbuch 1993, 2003; Hoff 1997; Cavanagh et al. 1993).

The treatment of risks may therefore affect the degree to which IRPs rely on renewable energy versus more conventional sources of electricity production. In this section, we first discuss the emphasis on risk assessment and mitigation in recent resource planning processes. We then turn to a review of natural gas price and environmental compliance risks – the two risks most likely to impact the degree of renewables penetration – in the western resource plans.

6.1 Evolution of IRP: From Least Cost Planning to Risk Management

In the aftermath of the western electricity crisis of 2000-01, electricity regulators, electric utilities, and other stakeholders have placed considerable emphasis on the need for IRP to systematically assess and mitigate electricity sector risks.

Least-cost utility planning began as a way of identifying the least-cost sources of energy supply. Over time, integrated resource planning began to consider not only social costs (e.g., environmental externalities) and demand-side measures to reduce load, but also began to conduct more sophisticated risk assessment. Throughout the 1980s and much of the 1990s, sensitivity and scenario analyses were the preferred methods for this assessment; stochastic simulation, though also used, was somewhat less common (see, e.g., Hirst and Schweitzer 1988).

Though risk analysis has been an ingredient to IRPs for some time, at least two factors have combined to lead to its recent prominence in resource planning. First, with the western electricity crisis, a growing reliance on volatile-priced natural gas and wholesale electricity purchases, the risk of departing load, and uncertainty in market structure, attention to the risks of electricity planning has grown. Second, improvements in computing power allow a more sophisticated tool-kit, including stochastic modeling, to be used to conduct risk analysis. The result is that recent utility IRPs typically analyze a broad spectrum of risks, often using stochastic simulation and scenario analysis, and ultimately select a preferred resource portfolio based not only on its expected cost, but also based on the potential variability of those costs.[61]

The risks that are analyzed in integrated resource plans – and the analytic tools used to evaluate those risks – vary by utility. It is not uncommon for IRPs to evaluate the following risks:

- natural gas price uncertainty,
- wholesale electricity price uncertainty,

[61] The most notable exceptions are the three California procurement plans (PG&E, SCE, SDG&E), which first identified preferred portfolios, and then conducted cost and risk analysis on just those portfolios.

- variations in retail load, and departing load (the latter being a particularly acute risk for utilities in an RPS state where direct access is possible),
- hydropower output variability (i.e., drought), and
- environmental regulatory risks.

Risks for which both the *impact* and *probability* of that risk can be quantified (even if imperfectly) are typically analyzed with scenario analysis and/or stochastic modeling (e.g., gas and wholesale electricity prices, variations in retail load, and hydropower output uncertainty). Where the risk impacts can be quantified, but probabilities cannot easily be assigned, scenario analysis is most common (e.g., risk of future carbon regulation, or of departing load). Finally, where neither the impact nor the probability of a risk can be readily quantified, more qualitative approaches to describing the risks are typically used (e.g., FERC-driven market re-design).[62] Mingst et al. (2005) identify which analysis tools are used by the twelve western IRPs to address the bulleted list of risks above; in this document, we focus exclusively on the two risks most likely to impact the success of renewables in IRP: natural gas price risk and environmental compliance risk.

Another approach to assessing and accounting for the relative risk of different resources is to use risk-adjusted discount rates – i.e., discount rates that vary by resource, or even by disaggregated cost components for a single resource (e.g., fuel vs. capital costs), depending on the amount of un-diversifiable risk present. Though the idea of using risk-adjusted discount rates as a way to account for fuel price risk within IRP has been advanced for some time (see, for example, Awerbuch 1993, 1995), none of the western IRPs that we reviewed use risk-adjusted discount rates. Instead, utilities typically use their weighted average cost of capital (WACC) as the discount rate,[63] and attempt to capture risk through stochastic and/or scenario analysis, ultimately making a subjective tradeoff between cost and risk, as described in more detail below.

6.2 Natural Gas Price Risk

6.2.1 Why Does Natural Gas Price Risk Matter?

In 2002, natural gas-fired generation accounted for more than 20% of electricity generation in the western United States, and natural gas is the region's fastest growing electricity generation source. In 2003 alone, more than 85% of the capacity additions in the WECC were from gas-fired generators, and the WECC projects that from 2004 through 2013, 90% of the net additions to generating capacity will come from natural gas-fired generators (WECC 2004).

Though natural gas-fired generators have many positive attributes – relatively low environmental impacts, dispatchability, relatively low capital requirements, and rapid lead times – recent trends in the level and volatility of natural gas prices give us pause. Wellhead prices, which hovered near \$2/MMBtu in the 1990s, had risen to over \$6/MMBtu by 2005, with most price forecasts

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[62] For an earlier treatment of different methodological approaches to analyzing uncertainty in IRP, see Tonn and Schaffhauser (1994).

[63] This is also the approach adopted by the NPCC's Fifth Power Plan (NPCC 2003). Further discussion of this topic is contained in Section 7.2.

expecting prices to remain high over the IRP planning period. At the same time, it is clear that future gas prices are highly uncertain.

Short-term variability in gas prices can be readily mitigated with gas storage, fuel switching, and natural-gas hedge contracts (forwards, futures, swaps, options). Hedging long-term gas-price risk is substantially more difficult, as natural gas forwards and futures are illiquid beyond a few years. Long-term, fixed-price electricity contracts from gas-fired generators are not readily available, given difficulties in hedging the underlying fuel-price risk. Even where such contracts are available, a substantial risk of contract default exists if gas prices rise significantly.

The most obvious approach to mitigating long-term gas price risk is through ownership or purchase of electricity sources whose price is not tied to that of natural gas, most obviously coal power and renewable energy. As revealed through prior work at Berkeley Lab, these sources provide two potential "hedge" benefits. First, by replacing variable-price gas-fired generation with fixed-price electricity production, these sources directly reduce exposure to gas-price risk (Bolinger et al. 2005). Second, by reducing demand for natural gas, these sources may relieve gas-supply pressures and thereby reduce natural gas prices (Wiser et al. 2005).

The treatment of base-case gas prices and price uncertainty in IRPs may have an impact on the degree to which these plans rely on renewable sources – the higher the base-case forecast, and the more significant the expected price uncertainty, the more value a utility may place on renewable sources. On the other hand, if a utility is simply allowed to pass fuel costs through to ratepayers, it may place considerably less value on mitigating fuel price risk. In such cases, regulatory guidance on what constitutes an acceptable level of risk exposure may be necessary.

Below, we begin by discussing the base-case gas price forecasts used by the twelve western utilities in their resource plans, benchmarking those forecasts to each other and to then-current NYMEX future prices. We then turn to a discussion of the treatment of gas price uncertainty in the IRPs, and conclude with observations and some suggestions.

6.2.2 Base-Case Gas Price Forecasts

Each IRP contains a base-case gas price forecast (though such forecasts are not always publicly disclosed – PSE's 2005 IRP, for example, does not disclose its gas price forecasts, citing the intellectual property rights of the private-sector firm that generated the forecasts). Figure 11 presents, in consistent 2003 $/MMBtu at the Henry Hub, the range of prices contained in our sample of publicly available base-case gas price forecasts (details on our normalization approach are contained in Appendix A.3). Though it may be difficult to pick out any *individual* forecast from among the group, the principal purpose of Figure 11 is to demonstrate the wide range of *base-case* prices considered among the twelve western utilities' IRPs that we reviewed. For example, in 2015, projected prices range from a low of around $3/MMBtu to a high of about $5/MMBtu. This high degree of inconsistency is striking, and to a degree reflects the significant uncertainty that exists about future gas prices.

Also notable is that all of the plans forecast future natural gas prices that are substantially lower than natural gas prices have been in 2005, and also forecast prices that are significantly below the prices predicted by the NYMEX forward markets at the present time. In 2010, for example, utility gas price forecasts (at ~$3.30 to $5/MMBtu) are $1.1 to $2.8/MMBtu below the average NYMEX forward price for that year (~$6.1/MMBtu in 2003 $, based on August 5, 2005 settlement data from NYMEX).

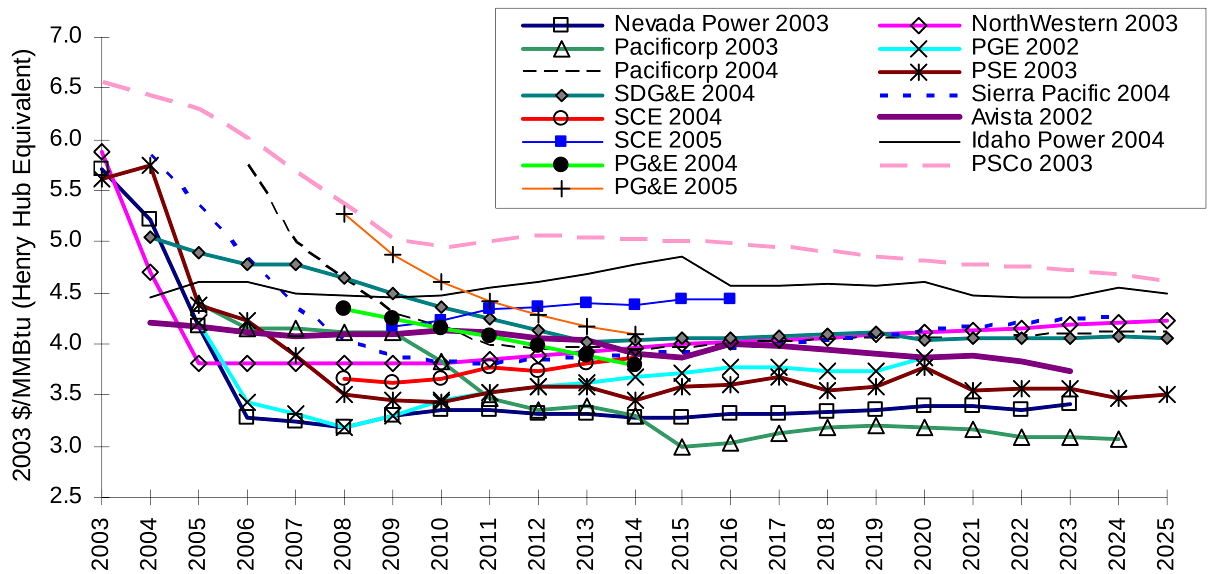


Figure 11. Base-Case Gas Price Forecasts

Variations in natural gas price forecasts among our sample of utility plans is attributable to at least two factors:

- **Different Sources for Gas-Price Forecasts**: As detailed in Text Box 1, there are considerable differences in the structure and source of each utility's forecast, depending, for example, on whether or not forward curves are employed in the near-term, as well as the source, number, and timing of long-term fundamental forecasts used thereafter.

- **Different Forecast Timing:** Our sample of IRPs is not perfectly synchronized in timing: some of the plans we reviewed date back to 2002, while others were released in early 2005. With gas prices – and future gas price expectations – having risen over this time period, this difference in timing is no doubt responsible for some of the inconsistency seen in Figure 11. Figure 12, below, plots the levelized base-case gas price forecasts from the resource plans against the date of forecast generation. As shown, price expectations have, in general, risen over the past few years, highlighting the importance of using an up-to-date forecast.

Avista used forward market price data for roughly the first five years, and then switched to a long-term price forecast from DRI-WEFA.

Idaho Power created a weighted average of a number of independent forecasts, including those from IGI Resources, PIRA, CERA, EIA, NPCC, and US Power Outlook, as well as the NYMEX forward curve.

Nevada Power makes use of NYMEX futures prices and basis differentials for the first 18 months, an interpolation (between forward market prices and the trend from 1995-2001) for the next twelve months, and the trend from 1995-2001 after that. Nevada Power also notes the use of Henwood price forecasts.

NorthWestern adopted the "medium" price forecast contained in a draft of the NPCC's 5th Power Plan.

PacifiCorp 2003 used forward market prices exclusively until May 2005, and then progressively blended forward prices with a long-term forecast from PIRA through November 2006, after which it relied solely on the PIRA forecast. **PacifiCorp 2004** employed the same methodology, with forwards through July 2007, a progressive blend of forwards and PIRA through July 2010, and solely PIRA thereafter.

PGE's IRP supplement used forward market price data for 2003 and 2004, and the EIA's reference case forecast starting in 2006 (the 2005 gas price forecast interpolates between the two).

PG&E used a combination of NYMEX forward prices and broker quotes for basis differentials (on April 19, 2004) to construct a 6-year forecast for its 2004 plan. Prices after March 2009 are based on an extrapolation using monthly energy prices and using the same monthly relationship as exhibited in the prior twelve months to March 2009. The price forecast in its 2005 plan update was current as of December 20, 2004, and presumably used the same methods as described above.

PSCo's initial plan ran a capacity expansion model under four different gas price scenarios -- $3, $4, $5, and $6/MMBtu gas (2003$). In its Settlement, however, PSCo adopted the same gas price forecast that it will use to evaluate RFP bids: a combination of long-term forecasts from CERA, PIRA, EIA, and the NYMEX forward curve. Over the 30-year planning horizon, this "four-source blend" comes out slightly higher than the original $5/MMBtu gas scenario.

PSE 2003 used forward market prices to create a 2004 price forecast. Thereafter, PSE averaged four independent long-term forecasts: the NPCC "medium" forecast, a PIRA "revisited" (updated) forecast, and two forecasts from CERA ("world in turmoil" and "technology enhanced"). **PSE 2005** used a 3-month average of forward prices collected in December 2004 as the basis for its projected gas prices for all scenarios in 2005 and 2006. From 2007 on, it relied on three CERA fundamental gas price scenarios/forecasts ("rear-view mirror," "current momentum," and "shades of green"), appropriately mapped to its own six IRP scenarios.

SCE 2004 used a long-term forecast from Global Insight. **SCE 2005**'s gas price forecast was based, in the early years, on NYMEX futures prices (plus SoCal basis differentials) from February 1, 2005. Over the long-term, these market prices were blended with an October 2004 fundamentals-based outlook from Global Insight.

SDG&E used an internal forecast of San Juan Basin prices based on escalating (on an annual basis) the previous year's price using a combination of the GDP price inflation index and an internally-created measure of market "firmness/softness." Basis differentials are estimated based on the growth in Canadian prices relative to San Juan prices, reflecting regional competitive conditions and the changing demand and supply situation at each basin. Commodity transportation charges, in-kind pipeline fuel usage costs, and an imputed market value of pipeline capacity to the San Juan Basin are added to derive a Southern California border spot price. A more recent gas-price forecast by SDG&E, not shown here, uses NYMEX futures prices and basis swaps for the first 6 years, and then escalates those prices at an average escalation rate of various recent price forecasts for future years.

Sierra Pacific makes use of NYMEX futures prices and basis differentials for 2005 and 2006, and an average of long-term forecasts from PIRA and Henwood after 2010. The interim years (2007-2010) are based on a weighted average between the forward prices and the long-term average forecasts, with the weights gradually shifting towards the latter over time.

Text Box 1. Source of Base-Case Gas Price Forecasts within Western Resource Plans

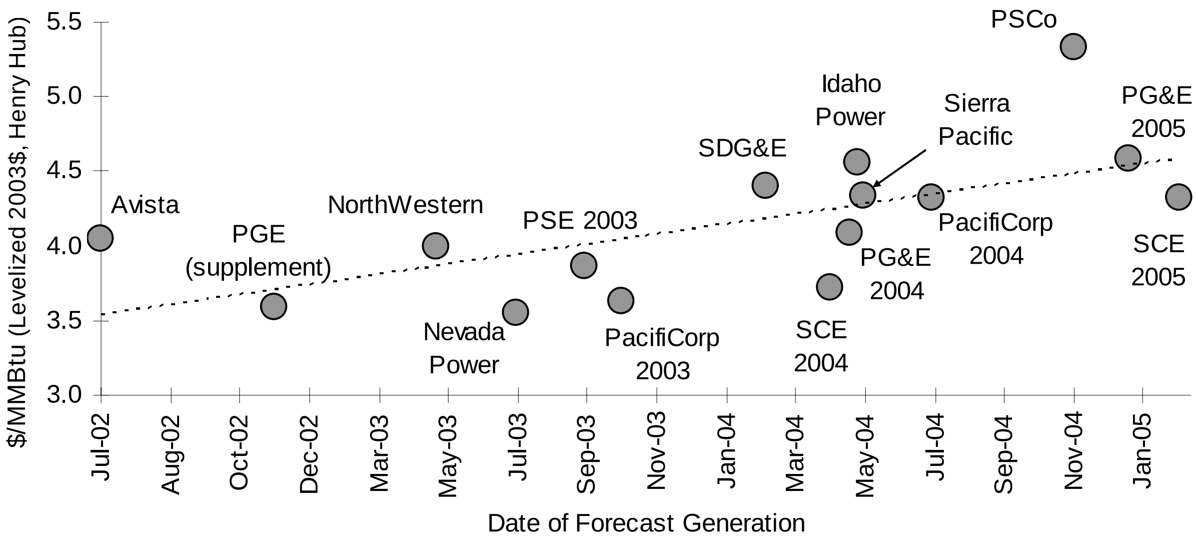


Figure 12. Levelized Gas Price Forecast vs. Date of Forecast Generation

Also important is how the base-case price forecasts compare to forward market prices at the time the forecast was generated. Many economists consider the forward price curve to be the market's best estimate of future spot prices (see, for example, Greenspan 2003a, 2003b), suggesting that forecasts should be tightly tied to the then-current forward curve.[64] Some utilities appear to be heeding this view, and have incorporated forward prices into the first few years of their IRP price forecasts (as detailed in Text Box 1).[65] On the other hand, Bolinger et al. (2005) find that EIA's long-term gas-price forecasts over the last 5 years have been systematically lower than the then-current forward curve, and that some utility IRPs have shown a similar "bias."

We conclude that, at a minimum, forward gas prices offer a useful benchmark for IRP gas price forecasts, and that any base-case gas price forecast that diverges significantly from the then-current forward market prices (at least over the period in which the two price series overlap – forward prices are likely to be of significantly shorter duration than the forecast term) merits an explanation.

Figure 13 compares the base-case forecasts from Figure 11 (though converted to nominal dollars) with then-current NYMEX natural gas futures prices. Six years is the maximum period of overlap between the forecast and the futures prices, and in many cases fewer years of overlap were available (the calendar years of overlap are indicated on the graph).

The difference between NYMEX and forecast prices (each levelized over the appropriate term) varies considerably. At the high end of the range, then-current NYMEX futures prices for 2008-

[64] Others have found evidence that near term-term forward prices do not provide unbiased estimates of future spot prices (see, e.g., Modjtahedi and Movassagh 2005).
[65] Furthermore, because they can be locked in to create price certainty, and therefore provide a risk profile similar to that of renewable energy, forward prices are arguably the "correct" prices against which to evaluate fixed-price renewable generation (Bolinger et al. 2005) – regardless of whether or not forward prices are superior to long-term fundamental price forecasts at predicting future spot prices.

2009 are about $0.70/MMBtu higher than SCE 2004's base-case forecast prices for those two years – a large enough discrepancy to warrant an explanation. Similarly, SCE 2005's forecast for 2009-2010 is about $0.62/MMBtu below then-current NYMEX prices for those years.[66] At the other end of the spectrum, then-current NYMEX futures prices for 2004-2007 are $0.32/MMBtu below Avista's forecast for those four years. In between these extremes, however, the remaining differentials are less dramatic, with eight of the plans falling within +/- $0.12/MMBtu of then-current NYMEX prices. The gas-price forecasts used in these western resource plans appear to be far more consistent with the NYMEX forward curve than EIA's recent price forecasts, presented in Bolinger at al. (2005).

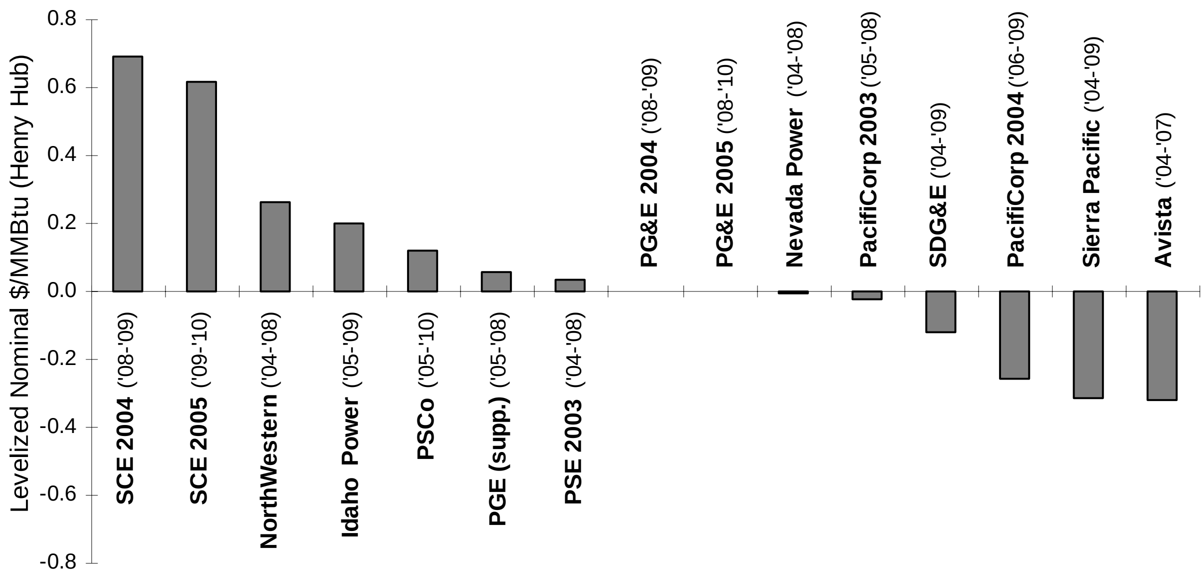
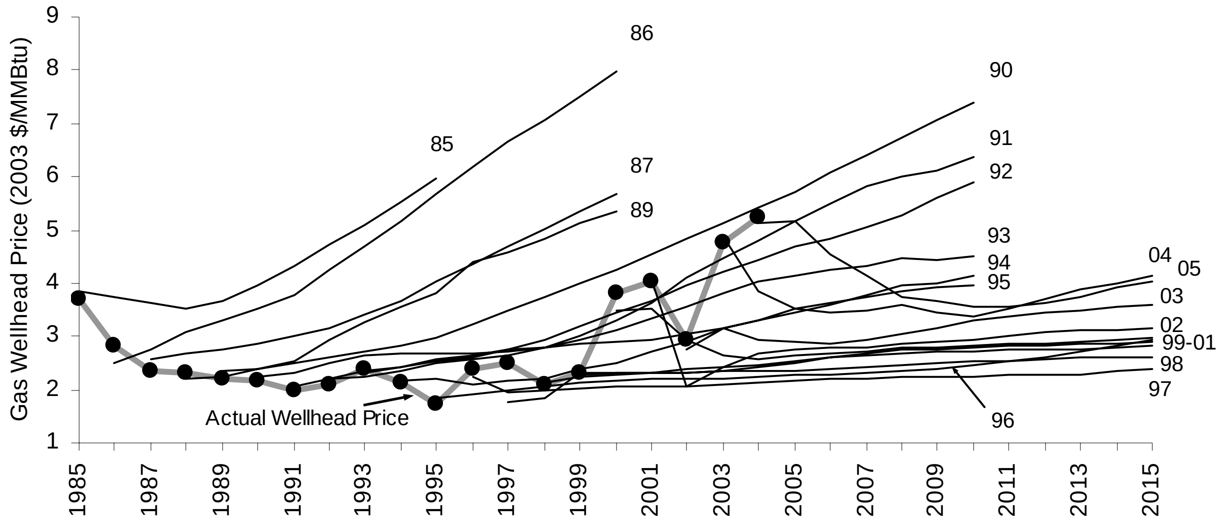


Figure 13. NYMEX Futures Strip – Base Case Gas Price Forecast (levelized over years indicated in parentheses)

6.2.3 Addressing Price Uncertainty

The history of gas-price forecasting demonstrates that little confidence should be placed on any base-case price forecast, even if that forecast does accurately reflect the then-current forward curve. Figure 14 shows EIA's Annual Energy Outlook reference-case gas-price forecasts, going back to AEO 1985, as well as the actual wellhead price of gas over time. As indicated in this graphic, the actual price path bears little resemblance to the price forecasts over this period. Moreover, the EIA's price forecasts can change dramatically over the course of just several years; from 1997 to 2005, for example, the EIA's expectations for gas prices in 2015 has risen from $2.39/MMBtu to $4.05/MMBtu (2003$). Given this historic experience, it is not unreasonable to expect that future gas prices could easily be $2/MMBtu higher or lower than the base-case forecast (Wiser and Bolinger 2004). With such a high degree of price uncertainty, it is important that IRPs evaluate different candidate resource portfolios under a wide range of future gas prices.

[66] It is somewhat ironic that, in California's RPS proceeding, SCE has proffered the view that forward market prices will typically be below forecasts of future spot prices, while SCE's own forecasts of future spot prices are lower than then-current NYMEX prices.



Source: EIA

Figure 14. EIA Annual Energy Outlook Historical Gas-Price Forecast Accuracy

Utilities have responded to this challenge in their resource plans, and generally use some combination of *stochastic* and/or *scenario* analysis to address price uncertainty. These two methods often serve different purposes.

- *Stochastic analysis* is typically used to simulate volatility around an expected price (e.g., hourly, daily, or seasonal volatility around an expected average annual price, or annual volatility around an expected 20-year average price). Inputs to the stochastic process include the projected mean or "deterministic" price path; the expected (often derived from historical) distribution of prices around the mean, including its general shape (e.g., lognormal) and size (e.g., standard deviation); a mean reversion factor that controls how quickly (if at all) the stochastic price gravitates back towards the mean over time; and in some cases, correlation coefficients between the stochastic variables. The model employs Monte Carlo analysis to generate any number of equally probable price paths around the mean. The performance of candidate portfolios is then measured under each of these varying price paths to determine the probability-weighted impact of price volatility on the expected cost of the portfolio, and to determine the distribution of the expected cost of that portfolio.

- *Scenario analysis* is typically used to measure the performance of candidate portfolios in situations where prices follow a distinctly different path from, rather than fluctuating around, expected prices. Specific scenarios are often constructed around a theme – e.g., limited access to liquefied natural gas and Alaskan gas leads to dramatically higher gas prices. Probabilities are sometimes assigned to different scenarios, though often this is not the case. In fact, scenario analysis is often conducted external to the core analysis, in a way that is intended to inform, rather than be integral to, the decision-making process. Nevertheless, because it is less complicated (and requires less computing power) than stochastic analysis, scenario analysis has historically provided the foundation of risk analysis in IRP.

As shown in Table 6, reliance on scenario analysis to analyze gas price risk seems to be diminishing, with ten of the twelve IRPs we reviewed now employing some form of stochastic analysis either instead of, or in addition to, scenario analysis. Only two plans – Idaho Power and

PSCo – rely *entirely* on scenario analysis; two additional plans – Sierra Pacific and Nevada Power – rely *primarily* on scenario analysis, but conduct stochastic analysis for their short-term energy plans.

Regardless of the approach used, also important is whether the range of prices considered in the analysis adequately covers the plausible range of future gas prices. These issues are discussed below, first for stochastic analysis and then for scenario analysis.

Table 6. Use of Scenario and Stochastic Analysis in the Western IRPs

Utility	Scenario Analysis		Stochastic Analysis
	Short-Term Price Shock	Long-Term Price Uncertainty	
Avista		✓	✓
Idaho Power		✓	
Nevada Power	✓	✓	✓*
NorthWestern		✓	✓
PacifiCorp		✓**	✓
PG&E			✓
PGE		✓	✓
PSCO		✓	
PSE		✓	✓
SDG&E			✓
Sierra Pacific	✓	✓	✓*
SCE			✓

* Stochastic analysis only conducted for short-term energy plan, not long-term resource portfolios.
** Only for PacifiCorp's 2004 IRP

6.2.3.1 Stochastic Analysis

Gas price risk lends itself to stochastic analysis: the probability that gas prices will deviate from an expected price over a certain time period can be estimated by measuring historical price volatility, and the impact of such price deviations on the cost of candidate portfolios can be readily calculated. Perhaps due to the relatively recent adoption of stochastic analysis, however, there is little consistency among IRPs in the way that stochastic prices are currently being generated and applied. Some plans create stochastic gas prices in a fairly straightforward manner, clearly specifying assumptions about price distributions, standard deviations, interaction and correlation with other stochastic variables being modeled, and degree of mean reversion built into the process. Others try to simplify, or complicate, the process, while still others are somewhat unclear on how the price distributions and probabilities are assigned.

For example, one plan unconventionally assumes a relatively high standard deviation when stochastic prices exceed average prices, and a lower standard deviation when the opposite conditions hold (presumably in an attempt to approximate a lognormal distribution). Another plan makes use of both short- and long-term standard deviations. Three plans model multiple stochastic variables and consider the interaction and correlation among them (e.g., gas prices and hydro availability), while others model stochastic gas prices in isolation. The degree of mean reversion varies among plans, and some do not even mention this aspect. Readers interested in these and other details (to the extent available) of how a subset of the western IRPs employed stochastic analysis can find more information in Text Box 2. Unfortunately, the wide variation in approach and information release does not allow one to compare the ultimate natural gas price distributions and probabilities among the plans, and does not allow one to assess whether a sufficiently large price range has been considered. Future work should explore this aspect of the plans in more detail, and perhaps seek some standardization in how stochastic prices are generated.

There are also differences in the way that the IRPs applied the resulting stochastic gas prices. In our sample, only a few plans subject *all* candidate portfolios to stochastic prices. Many employ stochastic analysis only after selecting a subset of "finalist" candidate portfolios. In three cases – PG&E, SCE and SDG&E – the stochastic prices are only applied and results presented for the preferred portfolios.[67] This narrower application often reflects computational constraints – i.e., Monte Carlo simulation and analysis takes time and computing power. It should be recognized, however, that the later in the planning process that stochastic analysis is employed, the greater the potential for suboptimal results because low-risk portfolios may be screened out based on cost *prior to* the stochastic analysis.

6.2.3.2 Scenario Analysis

In addition to, or in some cases instead of, stochastic analysis, many plans conduct scenario analysis around their base-case natural gas price forecasts in an attempt to capture the sensitivity of portfolio choice to different long-term natural gas price paths. Figure 15 depicts the levelized difference between the high- and low-gas-price scenarios and the base-case gas-price forecast, for all plans that conducted scenario analysis on gas prices.[68] As shown, with the exception of PSCo and PSE 2003, most plans generally consider there to be more upside than downside price risk; in fact, both Avista and PacifiCorp 2004 chose not to include a low-price scenario, and instead focused exclusively on high-price scenarios.

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[67] Some side cases were run by California's utilities, including different preferred portfolios for different levels of load requirements, the impact of different ownership/contracting ratios on financial results, etc. However, no public analysis is presented on the impact of gas-price variability on fundamentally different resource portfolios.

[68] In addition to "conventional" long-term high-price scenarios, both Sierra Pacific and Nevada Power also ran a "shock" case in which the price of delivered gas in a single year (2012) is twice that assumed in the base-case forecast, and also well above that assumed in the long-term high-price scenario. The purpose of this exercise was to model a situation in which temporary supply constraints result in a short-lived price spike (i.e., similar to what occurred in the winter of 2000/2001). Unlike a sustained price increase, however, the risk of a single-year price spike can be hedged through readily available short-term, fixed-price physical and financial gas contracts. This suggests that the value of modeling a single-year shock case, as opposed to a sustained high-price scenario, is likely to be limited.

Avista: Ran 200 Monte Carlo iterations on hydro generation, gas prices, and WECC loads using AURORA. Assumed that gas prices have a standard deviation of 50% when above the average price, and 25% when below the average price (done to simulate lognormal distribution of prices), and are inversely correlated (-50%) with hydro generation on an annual basis Half of the standard deviation was allocated to the annual price, and half to the monthly price.

NorthWestern: Used GenTrader to perform Monte Carlo analysis on *initial* (rather than subset of finalist) candidate portfolios, assuming 25% annual volatility in gas prices.

PacifiCorp 2003 and 2004: Initial screening analysis conducted using deterministic prices. Stochastic analysis conducted only on a subset of promising candidate portfolios. Used a "two-factor" (i.e., requiring both short- and long-term volatility estimates) mean-reversion model from Henwood to analyze four interdependent stochastic variables: gas prices, electric prices, loads, and hydro availability. All four were considered to be lognormal (except for loads in 2004 plan, assumed to be normal). Variables are semi-mean reverting in the short-term, but follow a random walk over the long term. 2003 plan used 1998-2002 Sumas gas prices (west) and 1993-2002 Opal gas prices (east), with prices capped at $20/MMBtu, to estimate short-term volatility (varying by season). 2004 plan instead used June 2001-December 2003 daily spot gas prices for Sumas (west) and average of Opal and Sumas (east). Both the 2003 and 2004 plans assume long-term (annual) volatility to be 14.51% (from literature based on prices from 1970-1996). PacifiCorp found that 100 Monte Carlo iterations were sufficient.

PG&E: Used GenTrader and other tools to predict and analyze the impact of thousands of natural gas and electricity price scenarios through Monte Carlo simulation. Based on implied volatility assumptions, 95th percentile PG&E burner-tip gas prices are $9.32/MMBtu (expected = $4.93/MMBtu) in 2006; $9.57/MMBtu (expected = $4.65/MMBtu) in 2010; and $10.45/MMBtu (expected = $4.68/MMBtu) in 2014. No information is publicly provided on the source or assumptions behind these data.

PGE: Initial plan used five stochastic electricity price series in combination with a *deterministic* gas price forecast, assuming that stochastic electricity prices capture most of the uncertainty in gas prices. In its later Supplement, however, PGE used (for tolling agreements only) a deterministic gas price when wholesale power prices were below $50/MWh, and a stochastic gas price (calculated as a function of the stochastic electricity price, rather than independently) when power prices exceeded $50/MWh (based on an observation that gas and electricity prices are highly correlated only when electricity prices are high). Ultimately, PGE's Final Action Plan performed a full stochastic analysis on gas and electricity prices.

PSE 2003: Assumed lognormal distribution of gas prices with a mean of $2.44/MMBtu (real 2002$) and a standard deviation of $1.44/MMBtu (both based on historical Sumas daily data from June 1995 – December 2002). Coefficient of variability therefore equals 59%. Applied volatility to deterministic gas prices on an annual basis (i.e., with the annual volatility applied evenly across the monthly price profile). PSE capped the resulting stochastic prices at $20/MMBtu.

PSE 2005: Assumed lognormal distribution of gas prices with a coefficient of variation of 53%. Gas prices assumed to be 95% correlated with power prices.

SDG&E: Used Henwood Energy's RiskSym, which allowed natural gas prices to vary based on historical volatility. No further information is provided.

SCE: Used Henwood Energy's RiskSym, using the standard deviation of Global Insight's gas-price forecast develop implied gas-price volatilities for input into the Monte Carlo analysis. 250 simulations were run for each of the load forecast cases. No further information is provided.

Nevada Power: For its short-term energy supply plan (2004-2006), Nevada Power used simulation techniques to evaluate ratepayer value at risk, using monthly volatilities and correlations. Nevada Power conducted sensitivity analysis – and not stochastic analysis – in evaluating its longer-term resource options.

Sierra Pacific: For its short-term energy supply plan (2005-2007), Sierra Pacific used Henwood Energy's RiskSym model, using short- and long-term volatility curves, mean reversion parameters, and correlations for load forecasts, and power and gas prices. Sierra Pacific conducted sensitivity analysis – and not stochastic analysis – in evaluating its longer-term resource options.

Text Box 2. Details on the Stochastic Analysis Process Used to Assess Gas Price Risk

Though there is only limited basis for judging whether a high-gas-price scenario is too high or not high enough (and vice versa for low-gas-price scenarios), in general the purpose of scenario analysis is to test base-case modeling results against radically different, yet still plausible, scenarios. In a review of other gas-price forecasts and scenarios, Wiser and Bolinger (2004) find that a plausible range of as much as ±$2/MMBtu for 2020 is not unrealistic. In this light, at least PSE 2003's high- and low-gas-price scenarios – which vary from the base-case forecast by just $0.3/MMBtu and -$0.5/MMBtu, respectively, over its 22-year period – appear to be overly timid.[69] The same might be said for high-price scenarios from PSCo and Nevada Power.

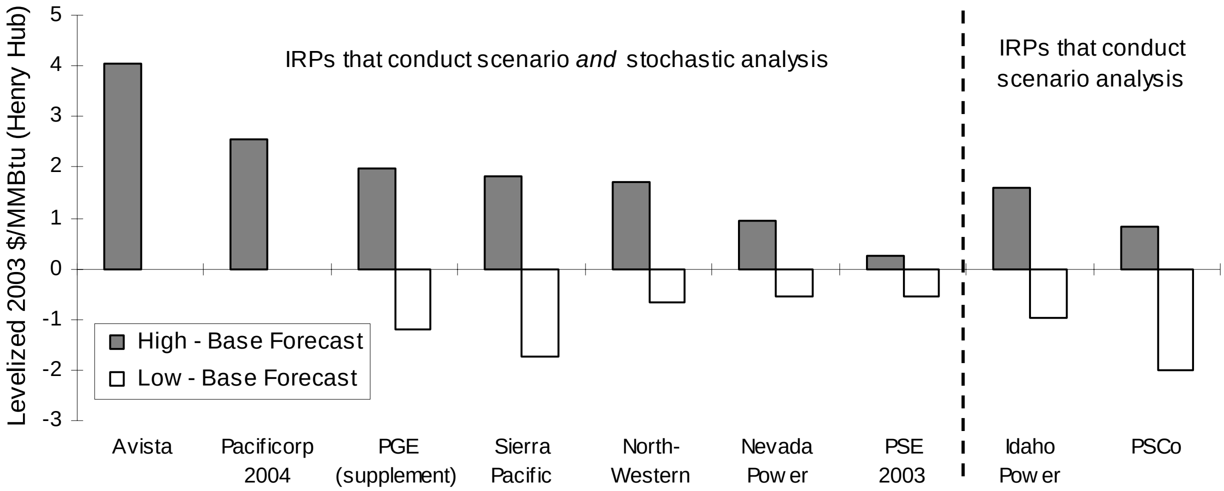

Figure 15. High and Low Deviations from Base-Case Gas Price Forecasts

6.2.4 Conclusions

Assumptions for both the base-case and the expected long-term uncertainty in natural gas prices can be important in determining resource decisions and the degree to which renewable energy is selected. Our review of western IRPs shows that all of the sampled utilities are taking natural gas price-levels and price uncertainty seriously. Stochastic simulation is the most common approach to analyzing these risks, though a number of plans use scenario analysis either as a supplement to, or a replacement for, simulation techniques. Whichever technique is used, the degree of analytic sophistication in applying these tools is increasing.

Nonetheless, our review of these plans leads us to the following observations and recommendations:

- **Base-case gas-price forecasts would ideally be current and be benchmarked to the forward curve**. Given the fundamental uncertainty about the future of natural gas prices, different price-forecasting tools, assumptions, and results are to be expected. In constructing

[69] Unlike PSE 2003, PSE 2005 does not disclose the actual gas price forecasts used in any of its scenarios. It does, however, state that "the levelized difference between the CERA gas price scenarios is approximately 27% of the low price scenario." This range of 27% is very similar to the range exhibited by PSE 2003 in Figure 15, where the levelized difference between the high and low scenarios – $0.80/MMBtu – is 24% of the levelized low-price scenario. Hence, it is reasonable to surmise that the range of gas price scenarios used in PSE's 2005 IRP are similar to (and thus, just as timid as) those in its 2003 plan.

base-case price forecasts, however, at least two factors should be considered. First, future gas-price expectations can change rapidly, and utilities should use the most-recent forecasts available. Second, the natural gas futures market can provide a useful benchmark against which to compare natural gas price forecasts over the near term, and forecasts that diverge significantly from this benchmark warrant scrutiny. Because NYMEX gas-futures are only available for 6 years, and are not terribly liquid after just 2-3 years, some utilities may also be encouraged to solicit long-term, fixed-price natural gas contracts; the prices offered for these contracts arguably represent the market's expectation for future natural gas prices.

- **Little weight should be placed on base-case gas-price forecasts, and a healthy range of price futures should be considered.** The history of gas-price forecasting shows that little confidence should be placed in the base-case forecast, and that future gas prices are effectively unknowable within a reasonable range. Price futures that vary by at least $2/MMBtu higher or lower than the base-case forecast are certainly plausible. To account for this uncertainty, whether scenario or sensitivity analysis is used, a wide range of natural-gas price futures should be considered. Our review of western IRPs demonstrates that some utilities using scenario analysis may not be using a wide enough range of future gas prices to accurately account for the significant uncertainty inherent in these forecasts.

- **Greater transparency and consistency in certain assumptions would be desirable.** Our review of those plans that use stochastic simulation to model price uncertainty shows that utilities often use different techniques to generate their price distributions, and some plans provide only limited information on their approach. As a result, it is difficult to critique the methods that are used, or to assess whether the resulting price distribution is sufficiently wide. We recommend that greater transparency be provided in both the methods and the resulting price distributions. In addition, a greater degree of consistency among the IRPs should arguably be sought in the way in which the price distribution is generated, e.g., assumptions for the shape of the distribution, its standard deviation, any mean reversion, and correlations between gas-prices and other variables (power prices, hydro availability, etc.). The utility IRPs are generally more forthcoming on the techniques and assumptions inherent in their base-case price forecasts, but even here some do not release critical forecast data (PSE 2005), and others provide only limited information on assumed basis differentials and other details. Though a few utilities have cited the proprietary nature of private forecasts as justification for not disclosing such information, other utilities freely report on the private sector forecasts used in their plans. There appears to be no compelling reason for keeping such forecasts, or the resulting stochastic derivations, confidential. Greater levels of useful public scrutiny and input would be derived if transparency was increased in these instances.

- **Candidate resource portfolios would ideally be constructed to mitigate fuel price risk.** Analysis of fuel price risk will be most informative if applied to a wide range of candidate resource portfolios that vary in their ability to mitigate those risks. Yet, as detailed in Section 6.2.3, many IRPs apply their fuel-risk analysis to only a subset of candidate portfolios for purposes of analytic tractability.[70] Though understandable, this could generate results that are sub-optimal if low-risk candidate portfolios are screened out at an early stage. In addition, the assumptions made by many plans to model renewables primarily or solely as

[70] In the extreme, analysis in the California utility resource plans only applies to the preferred portfolios.

wind power (see Section 4.1), to establish significant limits on the contribution of wind power to their systems, and to apply relatively low assumptions for wind's capacity value (see Section 5.1.2.3), sometimes result in what was intended to be "renewables" portfolios including substantial amounts of gas-fired generation to "firm" the wind generation. The "renewables" portfolios therefore sometimes exhibit as much or more exposure to gas price risk than other, more diversified portfolios. An important goal for risk analysis is to apply that analysis to a wide variety of candidate portfolios, constructed in a way that allows one to identify the benefits of individual resource options in mitigating this important risk.

- **The impact of increased renewable energy investments on natural gas prices might be considered in a regional setting.** Wiser et al. (2005) reviews thirteen studies that have evaluated the impact that renewable energy and energy efficiency can have on natural gas prices. These studies show that, by reducing demand for natural gas, renewable energy deployment can put downward pressure on natural gas prices and consumer natural gas bills.[71] None of the IRPs in our sample directly accounted for this effect.[72] This "oversight" may be reasonable because the effect of any *single* utility's investments in renewable energy on *that* utility's gas prices is likely to be minor. This effect is better considered in a regional setting where the impact of *cumulative* renewable energy investment on *region-wide* gas prices can be significant. For example, using the simplified analysis tool presented in Wiser et al. (2005), we find that new renewable additions currently called for in the WECC as a result of state RPS policies (in AZ, CA, CO, NM, and NV) and the utility resource plans included in our sample could, by 2014, reduce regional delivered natural gas prices by $0.06-$0.16/MMBtu (in 2003$), leading to consumer savings of between $7 and $18 per MWh of new renewable generation.[73] Although this projected gas price impact may not be large enough to warrant changes to western IRP gas-price forecasts, it is at least reasonable to consider whether renewables (and other non-gas resources) should be given credit in *electricity* IRP for reducing consumer *natural gas* bills. After all, rate stability is one of the goals of IRP, and to the extent that many of the utilities in our sample provide *both* electricity *and* natural gas to their customers, one might reasonably question why these markets are not analyzed in a more integrated fashion.

6.3 Environmental Regulatory Risk

6.3.1 Why Does Environmental Regulatory Risk Matter?

The laws and regulations governing the environmental impacts of electricity generators are likely to change over the lifetime of electricity supply investments, as will the cost of compliance with existing environmental regulations. These changes could impose substantial costs on electric utility shareholders and customers (Repetto and Henderson 2003). Integrated resource planning

[71] Note that the same would be true for any resource whose price is not tied to that of natural gas, including coal and nuclear power.
[72] One notable exception is that under its high-carbon-regulation scenarios, PacifiCorp assumed higher natural gas prices under the assumption that heightened carbon regulation would increase the demand for, and therefore the price of, natural gas.
[73] The calculation assumes that such policies will lead to 50,828 GWh of new renewable generation in the WECC by 2014, and that 1 MWh of renewable generation displaces 0.75 MWh of gas-fired generation. The range of gas-price reductions reflects assumed inverse elasticities of 0.8-2.0.

would, ideally, account for these risks in the same way that other electricity-sector risks are addressed in resource decisions. Namely, alternative candidate resource portfolios would be evaluated based on their ability to minimize ratepayer cost under a range of possible futures, including futures in which environmental regulatory requirements become more severe.[74]

Based on historical experience, it seems clear that future environmental requirements will be more severe than they are today. Traditional air pollutants (SO_2, NOx, mercury, fine particulates, etc.) may be regulated more tightly in the future. Perhaps more significantly, new state or federal carbon regulations are possible over the 10-30 year planning horizons of most IRPs. These new regulations may seek to grandfather then-existing generating units to some degree, but it would be imprudent to expect complete grandfathering.

Utility-owned fossil projects, in particular, would be affected by these new regulations. Even long-term power purchase agreements with fossil generators may be subject to these risks, because many such contracts pass through to the utility purchaser at least some of the risk of future environmental regulations (Wiser et al. 2004). Because renewable energy sources are unlikely to be affected by these future requirements, purchasing or owning renewable energy assets may reduce utility exposure to these environmental compliance risks. As a result, those utilities that consider seriously the risk of future environmental regulations will – all else being equal – tend to favor renewable over fossil generation.

Using assumed emission costs and profiles from PacifiCorp's 2004 IRP, Figure 16 illustrates the potential magnitude of emissions compliance costs in the year 2015 for both coal and gas-fired generation. Based on these assumptions, coal potentially faces aggregate emissions costs of $10.3/MWh, while a combined cycle gas turbine potentially incurs $4.1/MWh in aggregate costs. Even assuming a fairly modest allowance cost of $9.54/ton in 2015, CO_2 still accounts for 86% and 96% of the total emissions cost in that year for coal and gas, respectively. Clearly, the risk of future carbon regulations dominates environmental compliance risk.

[74] To account for environmental damages, it was once common for integrated resource plans to include externality adders, intended to reflect the environmental damage costs of electricity production or the expected cost of controlling emissions (see, e.g., ECONorthwest 1993). Our review of western IRPs shows that this approach is not as widespread as it once was; instead, at least for carbon, if utilities are accounting for environmental damages, they often do so through an assessment of the financial risk of future environmental regulations.

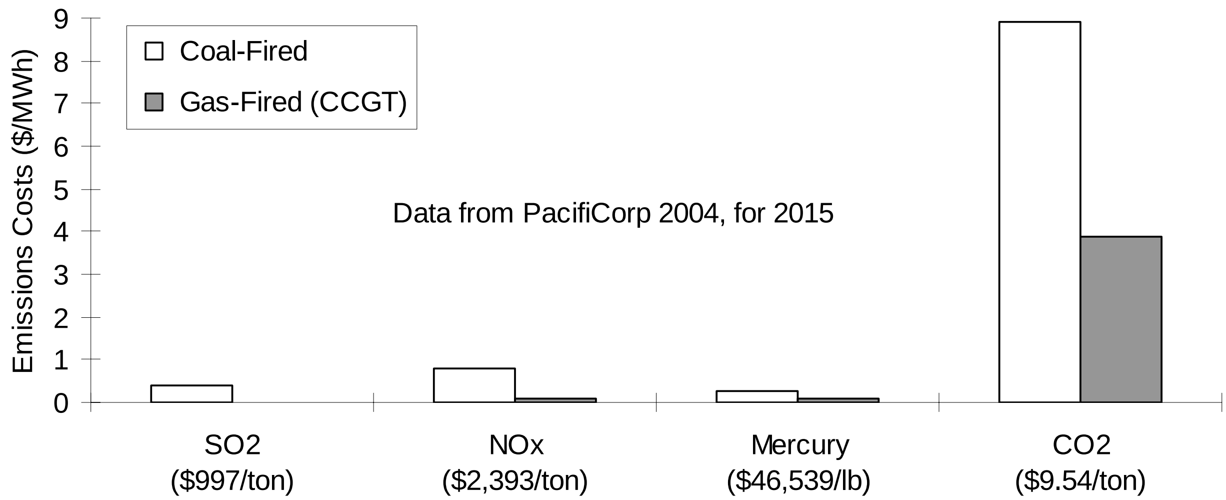

Figure 16. PacifiCorp 2004 Assumed Emissions Costs in 2015

6.3.2 Risk of Future Carbon Regulation

Over the course of a 10-30-year planning horizon, the risk of carbon regulation is significant. The Kyoto Protocol has now come into force, albeit without the participation of the U.S. Several bills that would regulate carbon emissions have been considered in the U.S. Congress and, while none are likely to become law imminently, the trend towards carbon regulation is an international one and federal policy to address greenhouse gas emissions is certainly possible in the future. At the state level, policies and regulations to limit carbon regulations have already been put in place, including ongoing efforts in Oregon, Washington, and California, and the trend toward increased attention to carbon emissions is intensifying (see, e.g., Rabe 2002). In 2004, PA Consulting surveyed 19 power generating companies (representing 29% of U.S. electricity power generation in 2003), and found that 60% of respondents believed that Congress would enact mandatory limits on carbon dioxide within ten years; roughly half of the respondents believed that carbon regulation would come within five years (PA Consulting 2004).

Given the potential for future carbon regulations to dominate environmental compliance costs, seven of the twelve utilities in our sample – Avista, Idaho Power, PacifiCorp, PGE, PSCo, PSE 2005, and PG&E – specifically analyzed the risk of future carbon regulations on portfolio selection.[75] In 2003, these seven utilities served 30% of the load in the western United States. Because the probability and severity of future carbon regulations is difficult to assess, these seven utilities universally utilized scenario – rather than stochastic – analysis to evaluate the impact of potential carbon regulations. Beyond this similarity, however, a consensus approach to the treatment of carbon risk has not yet emerged (Bokenkamp et al. 2005). Specifically, three different approaches have been taken:

[75] In some cases, utilities are required to address this risk. Any utility operating in Oregon under the jurisdiction of the Oregon Public Utilities Commission (includes PGE, PacifiCorp, and Idaho Power), for example, is required to consider the impact of a range of externality values on choice of portfolio in IRP. And, as noted later in the body of this report, California's utilities are now required to apply carbon adders in resource planning and bid evaluation.

1) **Unweighted Scenarios:** Avista, PG&E, PSE 2005, and PSCo's original plan analyzed candidate portfolio performance under one or more carbon scenarios, but did not assign probabilities or weights to those scenarios. As such, the impact of the scenario analysis on portfolio selection is unclear.
2) **Weighted Scenarios:** Idaho Power and PGE conducted multiple carbon scenarios, and did assign probabilities to those scenarios, thereby ensuring that carbon considerations will have at least some influence on portfolio selection. It is perhaps worth noting that Idaho Power's base case (given 50% probability) did include a non-zero carbon cost, while PGE's base case (given 18.75% probability) did not.
3) **Base Case with Unweighted Scenarios:** PacifiCorp and PSCo's settlement plan included carbon regulation in the base-case scenario, again ensuring at least some influence on portfolio selection. PacifiCorp also analyzed the impact of both more- and less-stringent carbon regulation (than assumed in the base case) through additional, unweighted scenarios.

With these categorizations in mind, Figure 17 and Table 7 provide additional detail on the treatment of carbon risk among these seven utilities. As shown, the assumed compliance costs range from \$0-\$58/ton CO_2 (levelized over each utility's planning horizon, in 2003 dollars), though scenarios conducted at the high end of this range were often either not assigned a probability of occurrence (in which case the scenario can not quantitatively impact portfolio selection), or else were assigned a relatively low probability (e.g., 6.25% for PGE's high-price scenario). Five of the seven utilities model the future regulation as a tax on CO_2 emissions, while three assume a cap and trade program (PSE 2005 assumes both types of scenarios). The year in which the tax or cap-and-trade program begins affects the severity of the regulation; this element is shown in the fourth column of Table 7, and is also indirectly reflected in the final column (levelized \$/ton cost assumptions), since the levelization occurs over each utility's planning horizon, rather than just the period in which carbon costs are assessed.

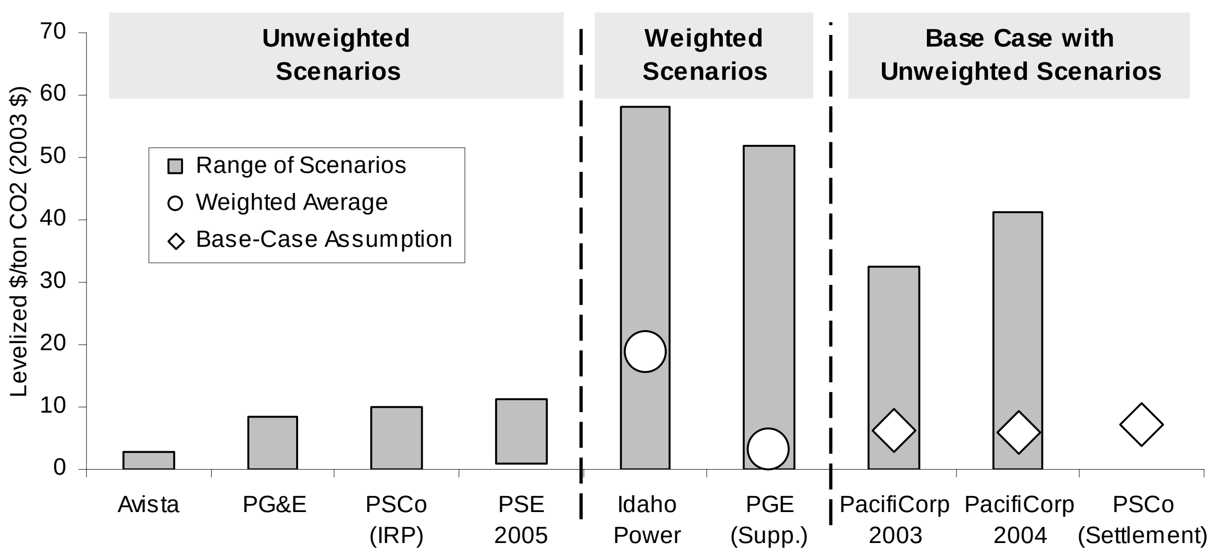

Figure 17. Summary of Carbon Regulation Scenarios in Western Resource Plans

Table 7. Summary of Carbon Regulation Scenarios in Western Resource Plans

Utility	Regulation Type	Cap Year	Start Year	Model Run	Prob-ability	\$/ton CO_2 (Levelized 2003\$)
Avista	Tax	NA	NA	Base	100%	0.0
			2004	Scenario	NA	2.7
Idaho Power	Tax	NA	NA	Scenario	30%	0.0
			2008	Base	50%	14.5
			2008	Scenario	20%	58.1
PacifiCorp 2003	Cap & Trade	2000	2009	Base	100%	6.1
		NA	NA	Scenario	NA	0.0
		2000	2013	Scenario	NA	1.1
		1990	2008	Scenario	NA	20.3
		1990	2008	Scenario	NA	32.4
PacifiCorp 2004	Cap & Trade	2000	2010	Base	100%	5.8
		NA	NA	Scenario	NA	0.0
		2000	2010	Scenario	NA	10.3
		2000	2010	Scenario	NA	25.8
		2000	2010	Scenario	NA	41.3
PGE	Tax	NA	NA	Base	18.75%	0.0
			2003	Multiple Scenarios	75%	0.0
			2003	Carbon Scenario	6.25%	52.0
			2003	Supplement Scenario	NA	13.0
PSCo IRP	Cap & Trade	NA	NA	Scenario	NA	0.0
		2000	2009	Scenario	NA	5.0
			2009	Scenario	NA	9.9
PSCo Settlement	Cap & Trade	2000	2010	Base	100%	7.2
PSE 2005	Tax	NA	2006	All Scenarios*	NA	0.8
	Cap & Trade	NA**	2010	Scenario	NA	5.1
		2000	2010	Scenario	NA	11.2
PG&E	Tax	NA	NA	Base	100%	0.0
			2006	Scenario	NA	8.5

"NA" in the probability column indicates that the scenario was not assigned a probability, which means that it impacted portfolio selection only qualitatively (if at all).
* PSE 2005 models the cost of complying with Washington state's carbon charge, passed into law in 2004, in all six of its scenarios, and assumes more stringent federal regulations in just two of the six scenarios.
** This scenario is based on the carbon regulation proposed by the National Commission on Energy Policy, where the cap is set to achieve a 75% reduction in emissions growth rates (from 1.5%/year to 0.4%/year).

The five remaining utilities in our sample – NorthWestern, Nevada Power, Sierra Pacific, SCE, and SDG&E – did not consider the risk of carbon regulation in their analysis.[76] NorthWestern notes that it does not model the potential impacts associated with environmental regulations and taxes because such policies do not currently exist. The Montana Public Service Commission,

[76] In addition, PSE's 2003 plan only obliquely considered carbon risk. Specifically, PSE 2003 looked at the impact of CO_2 credit prices on the relative economics of wind, coal, and gas, but this was a side analysis undertaken at the individual resource, rather than portfolio, level. This analysis may have been used to inform initial portfolio construction, but it is not apparent that it impacted the modeling results. PSE 2005's incorporation of carbon risk into scenario analysis represents an improvement over this earlier approach.

however, has since required Northwestern to account for the financial risk associated with carbon dioxide emissions in its *next* long-term plan. Nevada Power and Sierra Pacific make no mention of the risk of future carbon regulations in their plans.

Each of California's three major utilities was required to answer a series of questions regarding climate change in its 2004 procurement plan. All three noted that the state's aggressive commitment to renewable energy and energy efficiency is already aligned with the goal of promoting low-carbon energy sources. SDG&E specifically mentioned that its resource plan was not designed to address carbon emissions, and the utility conducted no analysis on the potential impact of future carbon regulations on its plan. SCE similarly conducted no analysis of the potential impact of carbon regulations, noting that its carbon intensity (measured as carbon emissions per unit of delivered electricity) is substantially lower than the national average. PG&E was the only California utility to consider a scenario under which carbon becomes regulated.

Recognizing the perceived limitations to the approaches taken by California's utilities in their 2004 plans, the CPUC in December 2004 directed the utilities to employ a "greenhouse gas adder" when evaluating renewable energy and fossil-energy bids over five years in duration, and in future long-term procurement plans (CPUC Decision N. 04-12-048). In a subsequent decision in April 2005 (CPUC Decision N. 05-04-024), the CPUC adopted a CO_2 adder for use in resource planning and bid evaluation of $8 per ton of CO_2 in 2004, escalating at 5% per year. With this policy in place, the ten utilities that are currently considering, or are now mandated to consider, the risk of future carbon regulation serve 42% of total utility load in the West.

6.3.3 Risk of Other Environmental Regulations

Besides carbon, the other emissions commonly accounted for in western utility IRPs include SO_2, NOx, and mercury.[77] As shown at the beginning of this section (Figure 16), the financial risk of complying with future regulations associated with each of these pollutants is likely to be relatively small compared to the potential cost of limiting carbon emissions. As such, the western resource plans generally devote less time to analyzing such risks than they do to carbon risk. In fact, *just two* of the utilities in our sample – PacifiCorp and PSCo – appear to consider the possibility of increasingly stringent *future* regulation of these criteria pollutants (e.g., multi-pollutant legislation); their cost assumptions are summarized in Table 8.[78]

Table 8. Assumed Cost of Complying with Future Environmental Regulations

	SO_2 (Levelized 2003 $/ton)	**NOx** (Levelized 2003 $/ton)	**Mercury** (Levelized 2003 $/lb)
PacifiCorp 2004	Base: $675 Scenarios: $335-$708	Base: $1,604 Scenario: $264	Base: $31,192
PSCo (settlement)	Base: $796	Base: $796	Base: $9,954

[77] In addition, Idaho Power also accounted for total suspended particulates by adopting the Oregon PUC's recommended externality value of $2,460/ton (in 2004 dollars).
[78] Presumably, even if not explicitly stated, the remainder of the resource plans do universally account for the cost of complying with *existing* regulations.

6.3.3.1 SO_2

Under Title IV of the 1990 Clean Air Act Amendments, major fossil-fuel-fired generators in the U.S. must limit their SO_2 emissions under a cap and trade program. Though not always stated, presumably all twelve utilities in our IRP sample account for the cost of participating in this existing program. Only PacifiCorp and PSCo, however, clearly account for potentially more stringent future regulations.[79] In most cases, utilities assign the projected cost of compliance directly to the capital or operating costs of affected coal-fired resources, thereby ensuring base-case level treatment.

Where stated, assumed allowance costs for *existing* regulations range from about $200-$300/ton (levelized over each plan's planning horizon, in 2003 dollars), whereas base-case assumptions for *future* regulations are higher, ranging from $675-$796/ton, as shown above in Table 8. With current SO_2 allowance prices trading around $700/ton, those utilities accounting for existing regulations that have also stated their cost assumptions (i.e., PSE 2003, PGE, and Idaho Power) appear to be well below the market, suggesting either liberal cost assumptions or else expected low internal compliance costs. Of particular analytic interest, PacifiCorp 2004 notes that SO_2 allowance prices should be inversely correlated with the cost of complying with future carbon regulations (to the extent that future carbon regulations reduce the output of coal-fired generators, resulting in a surplus of SO_2 allowances) and therefore assumes a different SO_2 price path for each of its carbon scenarios.

6.3.3.2 NOx

Though utilities in the East and other major metropolitan areas (e.g., Southern California) are increasingly subject to regulations concerning NOx emissions, many of the utilities in our sample are not currently impacted by such regulations. Perhaps as a result, three of the twelve utilities in our sample – NorthWestern, PGE, and PSE 2005 – specifically disregard the potential cost of reducing NOx emissions altogether, while just two others – PacifiCorp and PSCo – incorporate the cost of complying with future NOx regulations into their resource planning. Another three – Idaho Power, Nevada Power, and Sierra Pacific – apply "externality values" mandated by public utility commissions as a way to capture broader social costs above and beyond any cost of compliance.[80] Finally, we presume – because it is not always stated – that the remaining four utilities at least account for the cost of complying with *existing* NOx regulations, to the extent that they are subject to them.

Once again, PacifiCorp 2004 presumes that NOx compliance costs will vary inversely with assumed carbon compliance costs, ranging from roughly $260/ton (levelized in 2003 dollars) in its high carbon cost scenarios to about $1,600/ton in its low- and base-case carbon cost scenarios.

[79] Above and beyond any assumed cost for complying with the existing SO_2 program, the two Nevada utilities also applied externally mandated SO_2 "externality" adders, ranging from $5.6-$39.4/ton depending on resource and utility, in an attempt to capture broader social costs. This cost range is extraordinarily modest relative to the risk of future environmental regulations.

[80] Idaho Power used a NOx externality adder of $2800/ton (2003$), while the Nevada utilities used NOx externality values ranging from $5.6-$39.4/ton, varying by resource and utility. Again, the Nevada values are extremely low relative to the risk of future NOx regulations.

Meanwhile, PSCo (in a scenario reflective of the proposed Clear Skies Initiative) assumes levelized compliance costs of $796/ton.

6.3.3.3 Mercury

Power plant emissions of mercury – unlike emissions of SO_2 and NOx – have historically not been regulated in the U.S., and just two of the twelve utilities in our sample (PacifiCorp and PSCo) account for the potential cost of complying with future regulations to limit mercury emissions. In a scenario reflective of the proposed Clear Skies Initiative, PSCo assumes compliance costs of about $10,000 per pound of mercury (levelized over the planning horizon, in 2003 dollars), versus PacifiCorp's base-case assumptions of $90,800 per pound (in its 2003 plan) and $31,200 per pound (in its 2004 plan, reflecting the adoption of a $35,000/pound backstop price, as proposed in the Clear Skies Initiative). The March 15, 2005 release of the EPA's Clean Air Mercury Rule, which – for the first time – creates a cap and trade program to reduce power plant mercury emissions, highlights the need for more universal (and uniform) treatment of mercury compliance costs in western utility resource plans going forward.

6.3.4 Conclusions

The risk of heightened environmental regulations over the IRP planning horizon is significant. Even if the nature or magnitude of these changes is hard to predict, it would seem to be illogical to assign a zero probability of occurrence. Utility resource plans should therefore evaluate this risk and, if it is expected to be significant, seek to mitigate the risk through resource portfolios that minimize the cost-impacts of future regulations.

Our review of western IRPs leads us to the following observations and recommendations:

- **Many of the western IRPs are taking on the challenge of evaluating and mitigating the risk of carbon regulation.** With future regulations plausibly increasing the cost of coal power by as much or more than $10/MWh, the risk of future carbon regulations is arguably the most burdensome among all environmental regulatory risks. As a result, seven of the twelve IRPs that we reviewed specifically analyzed this risk. With California's three utilities and Montana's NorthWestern Energy now obligated to account for the possibility of future carbon regulations, just two utilities in our sample are currently ignoring this risk in their planning: Nevada Power and Sierra Pacific.

- **Greater consistency in how carbon risk is analyzed could be sought, and analysis of carbon risk would ideally affect portfolio selection.** There is a great deal of inconsistency in *how* carbon risk is analyzed among the plans that we examined. Some degree of inconsistency is to be expected given the level of uncertainty about the stringency and timing of future carbon regulations. State regulators may, however, want to encourage consistency in the analysis approach and assumptions used, at least among those utilities within their state. In addition, it is not always clear how seriously carbon risk is considered in portfolio selection. This is especially the case where carbon regulation does not exist in the base-case analysis, but where a separate scenario – with no probability attached – is analyzed in which carbon regulation is assumed (e.g., Avista and PG&E). To ensure that the risk of carbon regulation is adequately considered in portfolio selection, utilities should arguably be encouraged to include this possibility in their "base-case" analysis, with side-cases examining both greater and lower levels of regulatory stringency (see, e.g., PacifiCorp 2003 or 2004).

- **The stringency of carbon regulation scenarios can be benchmarked to an existing literature, and some IRPs may be undervaluing this risk.** Determining an appropriate range of carbon compliance costs is challenging. As shown earlier in Table 7, resource plans currently estimate the levelized cost of compliance at anywhere from $0 to $58/ton-$CO_2$. In fact, a great deal of research has been conducted on the future cost of carbon reductions. Though there continues to be substantial disagreement among analysts, the range in compliance costs shown in the modeling literature is consistent with the *broad* range used in our sample of resource plans (see Text Box 3). Some of the *specific* plans, however, do not appear to be evaluating a sufficiently broad range of carbon regulation scenarios. Avista, for example, only evaluates a carbon regulation scenario is which a carbon tax of just $2.7/ton-$CO_2$ is applied (levelized, 2003$). PGE, on the other hand, does evaluate a broader range of carbon costs, but weights the scenarios such that the weighted-average carbon cost is quite low – just $3/ton-$CO_2$ (levelized, 2003$).

- **Western IRPs do not devote as much attention to the possibility of more stringent criteria air pollution regulations.** Though not always stated, the cost of complying with *existing* criteria air pollutant regulations is presumably included in all twelve of the plans. Greater clarity on the assumptions made for compliance costs in these instances would be desirable. Based on our review, a number of utilities appear to be underestimating the cost of compliance with these existing regulations. More importantly, it is worth reiterating that the risk of *future*, more stringent SO_2, NOx, mercury, and particulate regulations is only considered in *two of the twelve* plans that we reviewed: PacifiCorp and PSCo. Though more stringent criteria pollutant regulations may not have the same impact on portfolio selection as the possibility of carbon regulations, analysis of this risk still has merit.

- **Benchmarks for the cost of complying with future air pollution regulations are readily available from the modeling literature, and could be utilized.** As with carbon, analyses of other proposed air pollution regulations are readily available from the EIA and other organizations. Given the results of several recent EIA analyses of proposed multi-pollutant legislation (see Text Box 3), it is not implausible to think that, by 2020, NOx, SO_2, and mercury allowance prices will exceed $1,700/ton, $1,200/ton, and $35,000/lb, respectively. All else equal, with CO_2 cost caps in place, allowance costs would be expected to be lower. These benchmarks are broadly consistent with PacifiCorp's assumptions shown earlier in Table 8, and are considerably higher than PSCo's assumptions from that same table.

The Potential Cost of Carbon Regulation

Using thirteen different energy models, Stanford's Energy Modeling Forum estimated that a carbon tax of $5-$37.5/ton-CO_2 might be required to hold carbon levels at 1990 levels by 2010, assuming no international emissions trading (to achieve a 7% reduction from 1990 levels required a tax of $12.5-$69/ton-CO_2) (Weyant 1999). The Energy Information Administration has estimated that a carbon tax of $18-$95/ton-CO_2 might be required to achieve a wide range of carbon reductions (EIA 1998), that a carbon tax of $15-$45/ton-CO_2 might be required to achieve the reductions called for in the proposed Climate Stewardship Act (EIA 2004), and that a tax of $34-$41/ton-CO_2 would be required achieve 7% reductions from 1990 level in the period from 2008-2012 (EIA 2001a). Using more optimistic assumptions, the Interlaboratory Working Group (1997; 2000) showed that CO_2 emissions in U.S. could return to 1990 levels by 2010 with a range of policy instruments and a $12.5/ton-$CO_2$ carbon tax. A recent summary of studies by Springer (2003) found that Kyoto compliance with liberal trading rules might impose compliance costs of $1-22/ton-$CO_2$ (average of $9/ton); if trade is limited to Annex B countries, permit prices range from $4-74/ton-$CO_2$ (average of $27/ton). Finally, as described in a recent report completed for the California Public Utilities Commission, Orans et al. (2004) notes that the reported cost of CO_2 emissions offset projects to date has varied widely, but with a median price of ~$7.5/ton-$CO_2$. The results of the Dutch carbon offset tenders, the UK carbon trading market, and recent World Bank Prototype Carbon Fund projects also suggest a carbon offset price of approximately $7.5/ton-$CO_2$. Meanwhile, since the launch of the European Union's Emissions Trading Scheme (EU ETS) earlier this year, CO_2 allowance prices have risen sharply, from approximately $9/ton to $27/ton (for 2006 settlement) as of June 2005.

The Potential Cost of Multi-Pollutant Legislation

EIA (2003) modeled the potential costs of the then-proposed Clear Skies Act of 2003 (S.485), finding allowance prices in 2020 (in 2001$) of $1,722/ton for NOx, $977/ton for SO_2, and $35,000/lb for mercury (the mercury price reflects the mercury cost cap proposed in the bill – without the cost cap in place, allowance prices were estimated to increase to $68,000/lb). EIA (2003) also evaluated the Clean Air Planning Act of 2003 (S.843). Without CO_2 caps in place, the analysis estimated allowance costs in 2020 (in 2001$) of $1,935/lb for NOx, $1,249/ton for SO_2, and $29,692/lb for mercury (with CO_2 caps, allowance costs are expected to be lower than these values). EIA (2001b) analyzed 3-pollutant legislation (NOx, SO_2, mercury) under varying levels of stringency, finding allowance costs in 2020 (1999$) of $1,108–2,825/ton for NOx, $719-$1,737/ton for SO_2, and $21,119–$85,225/pound of mercury.

Text Box 3. Benchmarks for the Cost of Future Environmental Regulations

7. Balancing Portfolio Cost and Risk

7.1 Introduction

The resource plans in our sample vary in the degree to which they evaluated different types of risk (e.g., fuel price vs. environmental), as well as the way in which they analyzed those risks (e.g., stochastic vs. scenario analysis). Regardless of the approach used, within the IRP process, utilities ultimately have a responsibility to evaluate and balance the expected cost and risk of candidate portfolios on behalf of ratepayers, choosing the portfolio with the "best" cost-risk combination.[81] This tradeoff between expected cost and risk is similar to an investment decision-making problem, and in fact utility resource planning is increasingly approximating the portfolio-theory approaches advocated by Awerbuch and Berger (2002).

The way in which this cost/risk tradeoff occurs is particularly important for renewable sources, which are characterized in many plans as low risk, yet potentially higher cost, resource options. Plans that place more emphasis on risk mitigation – relative to expected cost – may therefore be expected to favor renewable over conventional energy sources. This chapter begins by summarizing how the western IRPs defined portfolio cost and risk. It then discusses how the cost/risk tradeoff was made, and proceeds to discuss the implications for renewable energy.

7.2 Defining Portfolio Cost and Risk

Before deciding how to balance the expected cost and risk of numerous candidate portfolios to arrive at a single preferred portfolio, utilities must first define the cost and risk metrics of relevance. Though costs are defined in slightly different terms (as shown below in Table 9), virtually every plan used either the present value of revenue requirements (PVRR) or some closely related derivation thereof to define costs. Where stochastic analysis (through Monte Carlo simulation) was utilized, the average or mean (rather than median) simulated portfolio cost was typically used (though SCE used its deterministic PVRR).

Just as PVRR was the cost metric of choice, virtually all plans used the utility's weighted average cost of capital (WACC) as the relevant discount rate. The appropriateness of using the WACC to value assets with different risk profiles has been hotly debated in the literature for some time, with some contending that "risk-adjusted" discount rates are a preferable alternative (Awerbuch 1993, 1995). Given, however, that most utilities are already accounting for risk in their plans (e.g., through stochastic or scenario analysis), the use of resource-specific, risk-adjusted discount rates has been argued to potentially result in a "double-counting" of the impact of risk on portfolio selection (NPCC 2003). For this reason (and also because of the frequent use of the WACC in the literature on corporate investment decision-making), the NPCC formally adopted the WACC in its Fifth Power Plan, noting that the WACC "aligns the decision about investing capital with the cost of that capital to the entity making the investment decision" (NPCC 2003). That said, it is also clear that higher discount rates inherently favor resources with low capital costs and high operating costs (e.g., gas-fired generation) over resources with high capital costs and low operating costs (e.g., wind power). Also evident is that the discount

[81] Note that IRPs regularly use additional metrics in portfolio evaluation as well, e.g., degree of reliance of market purchases, the impact of portfolio choice on utility finances, reliability, environmental impacts, resource diversity, commercial viability, etc.

Table 9. Summary of Cost/Risk Tradeoff

Category	Utility	Definition of Cost	Definition of Risk	Cost/Risk Weighting	Notes
Stochastic	Avista	Average power supply expense over all Monte Carlo simulations	Coefficient of variation of cost	50%/50%	Looked at weights ranging from 70%/30% to 30%/70% and found little difference, so settled on 50%/50%. Scenarios examined after making cost/risk tradeoff.
	North-Western	Mean annual cost of portfolio over all Monte Carlo simulations	95th percentile cost	70%/30%	Also considered other risk metrics. Scenarios examined after making cost/risk tradeoff.
	Pacifi-Corp	Mean PVRR over all Monte Carlo simulations	Focus on: 95th percentile and 95th-5th percentile	Qualitative	Also considered other risk metrics. Scenarios examined after making cost/risk tradeoff.
	PGE (Final Action Plan)	Mean NPVRR over 100 Monte Carlo iterations	Mean rate variability index (RVI)	Qualitative	All 26 trial portfolios show similar risks, but very different costs.
	PSE 2003	Mean NPV of expected cost to customers over all Monte Carlo simulations	Coefficient of variation of cost	Qualitative	Renewables faired poorly in terms of cost/risk, but qualitative considerations of carbon risk drove PSE to adopt 10% renewable portfolio standard.
	PSE 2005	Mean 20-yr incremental portfolio cost (in $/MWh)	Mean of costs >90th percentile – mean of all costs	Qualitative	Cost/risk tradeoff evaluated under each of six scenarios.
	SDG&E	Mean PVRR	95% percentile cost 84% percentile cost 16% percentile cost 5% percentile cost	None	Evaluated cost and risk of *only* the preferred portfolio under low, medium and high load; no true evaluation of cost-risk characteristics of alternative portfolios at this stage.
	SCE	Deterministic PVRR	95% percentile cost	None	
	PG&E	Mean and deterministic PVRR	95% percentile cost	None	
Scenarios	Idaho Power	PV of portfolio power supply cost	Change in power portfolio supply cost	None	Preferred portfolio selected purely on the basis of lowest scenario-weighted expected cost, with no consideration given to the *uncertainty* of that cost.
	PGE (Initial IRP)	Weighted-average PVRR over 45 scenarios	Weighted-average rate variability index (RVI) over 45 scenarios	Qualitative	No tradeoff necessary, since lowest cost portfolio was also lowest risk.
	PSCo	PVRR	Change in PVRR	Qualitative	Pure scenario analysis (no stochastic at all).
	Nevada Power*	PVRR	Change in PVRR	Qualitative	Pure scenario analysis (no stochastic for long-term plan) for load, fuel, and purchased power costs.
	Sierra Pacific*	PVRR	Change in PVRR	Qualitative	

* Sierra Pacific and Nevada Power used stochastic analysis in evaluating their short-term supply plans, using both expected cost and risk metrics. This analysis is not highlighted here because our focus is on long-term resource planning, not short-term procurement.

rate appropriate for utility investors may differ from that most appropriate for utility customers. As such, if a single discount rate is used to value all assets, sensitivity analysis around that discount rate is recommended.

Especially given the use of the WACC (rather than a risk-adjusted rate) as the discount rate, it is also important to know how the expected *variation* in portfolio costs – or *portfolio risk* – is measured.[82] As shown in Table 9, where stochastic analysis was used, portfolio risk was commonly defined as either the **coefficient of variation** of cost (the standard deviation divided by the mean of simulated costs) or else some measure of the upper tail of the cost distribution, such as the **95th percentile** cost (95% of all simulated outcomes fall below this cost) or the **mean of the 90th percentile tail – overall mean** (a measure of the magnitude of potential cost increases). Though the former is among the most traditional measures of uncertainty (where uncertainty is expressed as either higher or lower costs than the mean), the latter focus on the upper tail may be appropriate in an IRP setting where concerns about extreme cost *increases* are paramount. Similarly, with cost increases in mind, PGE's Final Action Plan defined risk in terms of a rate variability index (RVI), calculated as the annual percentage electric rate increase expected to be met or exceeded in the worst 5% of all years in the planning horizon. Several other risk metrics were also considered in some of the stochastic plans, though these metrics were often not as heavily emphasized as those mentioned above:

- 5th percentile: 95% of all Monte Carlo outcomes are above this cost
- 16th percentile: 84% of all Monte Carlo outcomes are above this cost
- 84th percentile: 16% of all Monte Carlo outcomes are above this cost
- 95th-5th percentile: 90% of all Monte Carlo outcomes fall within this range
- Mean of upper tail: the average of the highest-cost 5% of Monte Carlo outcomes
- 95th percentile – mean: a measure of the magnitude of potential cost increases
- Variation from mean: the standard deviation of simulated costs

Among those plans making the cost/risk tradeoff based primarily on scenario analysis, PGE's initial IRP used the scenario-weighted average RVI, while Idaho Power, PSCo, Nevada Power, and Sierra Pacific each analyzed how portfolio costs vary (in dollars) by scenario.

7.3 Managing the Cost/Risk Tradeoff

Just as definitions of portfolio cost and risk differ, each plan also evaluated the cost/risk tradeoff differently. As implied by the first column of Table 9, however, most plans can be placed into one of two categories, based on the primary method of analysis used to manage the cost/risk tradeoff:

1) **Stochastic Simulation (with or without scenario analysis):** Eight utilities – Avista, NorthWestern, PacifiCorp, PGE (Final Action Plan), PSE (2003 and 2005), PG&E, SCE, and SDG&E – employed stochastic analysis to generate numerous cost outcomes for at least a subset of candidate portfolios. As a result, each candidate portfolio had an expected (mean)

[82] Though we focus in this report exclusively on fuel price and environmental compliance risks, we note that other types of risk – including wholesale electricity price risk, demand risk (i.e., from variations in retail load, or departing load), and hydropower availability risk (i.e., the risk of drought) – are also commonly incorporated into the cost/risk tradeoff.

cost and risk (as defined above, and in Table 9) associated with it. Avista's optimization process assigned equal weight to cost and risk while constructing the preferred portfolio. NorthWestern subjectively weighted cost (i.e., 70% weight on the mean cost) higher than risk (i.e., 30% weight on the 95th percentile cost) to arrive at a "risk-adjusted" cost for each candidate portfolio.[83] PacifiCorp, PGE, and PSE, on the other hand, evaluated the cost/risk tradeoff more qualitatively, and did not seek to arrive at a single number or optimal portfolio. Instead, the expected cost and risk characteristics of each portfolio were reviewed, and the preferred portfolio was selected subjectively based on that review. PG&E, SCE and SDG&E all used stochastic analysis, but only to analyze the cost and risk characteristics of their single preferred portfolio (under various load conditions). As a result, no true cost/risk tradeoff was made at this stage (though the details are unstated, it is possible that these considerations were addressed in portfolio construction). Finally, with the notable exception of PSE 2005, which evaluated the expected cost and risk of each candidate portfolio under all six of its scenarios (as opposed to only under a single, base-case scenario), the rest of these plans made the cost/risk tradeoff *prior to* consideration of any scenarios that were analyzed, thus seemingly relegating scenario analysis to more of a supporting role, rather than an integral part of the planning process.

2) **Scenario Analysis (with or without stochastic simulation[84]):** Five utilities – Idaho Power, PGE (initial IRP), PSCo, Nevada Power, and Sierra Pacific – relied much more heavily on scenario analysis to manage the cost/risk tradeoff. Idaho Power did not really make a tradeoff at all; instead, portfolio selection was based purely on a scenario-weighted assessment of expected costs, with no apparent consideration given to the expected variability of those costs. PGE's initial IRP, meanwhile, assigned subjective probabilities to each of its scenarios, calculated a scenario-weighted cost and risk for each portfolio, and ultimately weighed cost against risk qualitatively (though given that the preferred portfolio had both the lowest cost and lowest risk, no tradeoff was necessary). PSCo, Nevada Power, and Sierra Pacific, meanwhile, did not assign probabilities to their scenarios, and therefore evaluated the cost/risk tradeoff qualitatively.[85]

Neither those portfolios with the lowest expected cost nor those with the lowest expected risk are likely to be "ideal" for any individual ratepayer. Nor is any single tradeoff between cost and risk optimal for all ratepayers. Instead, each individual electricity consumer will have different preferences for the amount of weight to place on these two parameters. In selecting a "preferred" portfolio, an electric utility would therefore ideally: (1) review consumer preferences for cost-risk tradeoffs,[86] and (2) select the candidate portfolio that fits most closely with the risk preferences of the majority of its customers.

With the apparent exceptions of Idaho Power and the three California utilities, each resource plan in our sample made some sort of tradeoff between the expected cost and expected risk of

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[83] The candidate portfolio with the lowest risk-adjusted cost was considered to be superior to all others.
[84] PGE's initial IRP was the only long-term plan in this category to also utilize stochastic simulation (though Nevada Power and Sierra Pacific both used stochastic simulation in their short-term procurement plans); expected costs and risks for each PGE scenario represent the mean of five stochastic (electricity) price simulations.
[85] Though, at least for PSCo, other considerations – namely concerns over wind integration costs and capacity value – seemed to outweigh cost/risk considerations.
[86] Deliberative polling or rigorous telephone surveys are two of several methods that could be employed to gauge customers' risk tolerance.

each candidate portfolio. The optimal approach described above, however, is rarely used in utility resource planning. In fact, there is little evidence that any of the utilities in our sample have conducted *formal* consumer research to assess customer preferences for cost-risk tradeoffs.[87] In all of the cases we reviewed, the cost-risk tradeoff (if made) boiled down to a subjective judgment call on the part of each utility, perhaps informed by any counsel provided by the utility's regulators or external stakeholders. Even for those plans that relied on stochastic analysis, and clearly indicated a weighting for expected cost and risk (i.e., Avista and NorthWestern), the weightings themselves were subjectively determined.

The risk of the current path becomes apparent when one begins to recognize that utility ratemaking ensures that a utility's shareholders may have a very different set of cost-risk preferences than its customers. In cases where fuel costs are automatically passed through to consumers in electricity rates, for example, utility shareholders may see little *shareholder* value in mitigating fuel price risk. One should therefore not automatically assume that the weighing of expected cost and risk in utility resource planning is "optimal." Ultimately, utility regulators will likely need to step into this void and provide guidance for how this tradeoff should be made; so far, regulators have not generally sent strong signals in this regard.[88]

7.4 Implications for Renewable Energy

As described in Section 6, and so far in Section 7, most western utility resource plans are clearly becoming more sophisticated in their use of risk analysis, and the quality of that analysis has improved over time. Though these are encouraging trends, there are, as always, further improvements to be made.

Perhaps nowhere is the need for improvement more clear than at this crucial culmination of the analysis, where all that has come before is distilled into the choice of a single candidate portfolio. Specifically, though the individual building blocks of resource planning and risk analysis have evolved commendably (notwithstanding our hopefully constructive comments provided within earlier sections), the way in which these building blocks come together to influence the portfolio selection process can have important ramifications, and may ultimately shift portfolio selection away from renewables. Consider the following:

1) **The two main types of risk that renewable energy can help to mitigate are fuel price and environmental compliance (i.e., carbon) risk.** Though renewables are not the only modeled supply-side resource to mitigate fuel price risk (coal-fired generation also performs admirably in this regard), renewables are unique among supply-side resources (barring nuclear, which was not seriously considered by any of the plans within our sample) in their ability to mitigate carbon risk.

[87] PGE's plan indicates that the utility met with focus groups and learned that its customers wanted greater rate stability, even if it costs a little more (to reflect this preference, PGE developed the rate variability index (RVI) – a specialized measure of rate stability – as its preferred risk metric). Similarly, PSE's 2005 plan indicates that the company has engaged in market research to determine customer risk preferences, and that it plans to use the results to inform its hedging strategy (and presumably its resource planning as well, though that is not explicitly stated). Both of these utilities, however, ultimately made the cost-risk tradeoff on a qualitative basis.

[88] Regulators are, however, beginning to heed this call. As one example, the California Public Utilities Commission has established a consumer risk tolerance level for the utilities' short-term procurement plans, and also requires justification for sizable spot-market purchases.

2) **Candidate portfolios intended as "renewables" portfolios have often ended up performing poorly with respect to fuel price risk.** The simplifying assumption made early on by many plans to model renewables primarily or solely as wind power (see Section 4.1), in conjunction with conservative assumptions about the capacity value of wind and the need for gas-peaking plants to integrate wind into the system (see Sections 5.1.2.2 and 5.1.2.3), has often resulted in so-called "renewables" portfolios being heavily laden with gas-fired generation. As a result, "renewables" portfolios have often exhibited as much or more exposure to natural gas price risk than other, more diversified portfolios. Examples include PacifiCorp 2003,[89] PSE 2003,[90] and Idaho Power.[91] Though some additional gas-fired generation may be required in high-renewables portfolios to manage system operations, most plans do not appear to have specifically analyzed this issue (except indirectly through capacity value). Instead, the "renewables" portfolios have largely been constructed by hand to include a significant quantity of gas-fired generation; whether this much gas-fired generation is truly needed to manage wind variability is arguable.

3) **Fuel price risk has taken some precedence over carbon risk.** As shown in Section 6.2.3, fuel price risk has typically been addressed through stochastic analysis (sometimes in conjunction with scenario analysis). The use of stochastic fuel prices ensures that fuel price risk will impact base-case results, at least for some subset of, and ideally for all, candidate portfolios. In contrast, carbon risk has typically been addressed later in the process through scenario analysis, often being conducted on just a few candidate portfolios selected for further scrutiny *based on their attractive cost/risk tradeoff*. In other words, the cost/risk tradeoff has often been made – in part based on consideration of fuel price risk – *before carbon risk is considered*, in which case carbon risk is relegated to helping to distinguish between a few finalist portfolios. Examples of utilities that have made the cost/risk tradeoff prior to considering carbon risk include Avista, NorthWestern, and PSE 2003.[92] Furthermore, as shown in Section 6.3.2, in many instances, utilities have not assigned probabilities to carbon scenarios; in such cases, it is often unclear how scenario analysis impacts portfolio selection. Even in instances where the cost of complying with future carbon regulations has been included in the base case (e.g., PacifiCorp, PSCo settlement) and thus impacts the modeling process much earlier, the carbon adder has fallen within the low end of the range of costs considered within our sample, and any risk of higher (or lower) carbon costs has, again, been addressed (if at all) later in the process through scenario analysis. Thus, due more to the way in which they have been analyzed rather than resulting

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[89] In describing why its Renewable Portfolio has the highest 95th percentile PVRR of any of the five finalist portfolios, PacifiCorp's 2003 plan states: "The Renewable Portfolio reliance on natural gas combined with an overall higher cost structure appears to be a leading cause for the divergence in costs at the 95th percentile." Furthermore, "It is clear that Renewable portfolio has greater tail risks than the other portfolios."

[90] PSE's 2003 plan states: "As PSE adds wind power to the coal and gas mix, cost and risk go back up. Two factors drive the increase in cost – higher capital costs for wind power and the assumed need for additional SCGT capacity to back up the wind power energy with capacity. This additional SCGT capacity also leads to the slight increase in the risk profile, initially offsetting the benefit of adding an energy resource with no fuel price volatility."

[91] Idaho Power's renewable portfolio contained 1000 MW of wind and 50 MW of geothermal backed by 648 MW of gas-fired peaking plants. This portfolio performed poorly with respect to fuel price risk (though it was much more negatively impacted by PTC risk).

[92] Though PacifiCorp also made the cost/risk tradeoff prior to consideration of scenario analysis, its inclusion of a carbon adder in the base-case ensured that carbon risk had the potential to influence portfolio selection.

from any conscious decision, fuel price risk has seemingly had more of an impact than carbon risk on portfolio selection.

4) **The precedence of fuel price over carbon risk may disadvantage renewable generation compared to other non-gas generation alternatives.** The fact that renewables portfolios have tended to perform poorly with respect to fuel price risk in some cases has shifted resource choice towards coal-fired generation early in the modeling and analysis process. By the time carbon risk is assessed, some renewables portfolios may have already been weeded out of the process. Examples of this movement towards coal as a risk mitigation measure include Avista[93] and PSE 2003.[94]

These four considerations, and their potentially surprising outcome – a greater appreciation of coal (compared to renewable energy) as a risk-mitigating resource – highlight the possible need for a more holistic assessment of risk, and approach to the cost/risk tradeoff. The sequential, winnowing approach currently taken by many plans no doubt eases the computational burden, but also may lead to results that are more of a function of the *manner* or *order* in which different risks were assessed – as well as the way in which handcrafted candidate scenarios were defined – rather than of the potential *likelihood* or *magnitude* of the risk itself. This is not to say that coal generation has no role to play in resource portfolios, or that high renewables portfolios will necessarily have the right balance of cost and risk. Instead, our concern is that the sequential nature of the analytic process, combined with a limited number of handcrafted renewables portfolios that sometimes contain large amounts of gas-fired generation, may lead to portfolio selection results that are not optimal.

As resource planning evolves, utility planners would ideally treat all meaningful risks in an *integrated* fashion, if possible; certain risks should generally not be relegated to lesser importance simply because they are assessed through scenario, rather than stochastic, analysis. If some risks are better suited for scenario rather than stochastic analysis, then most would agree that steps should be taken to ensure that results from scenario analysis are integrated into the overall process. Otherwise, scenario analysis may potentially end up as a mere sideshow to stochastic analysis (or worse yet, deterministic modeling). One way to accomplish this objective is to assign subjective probabilities to scenarios (e.g., PGE's initial IRP); another way is to methodically assess the cost/risk tradeoff under each scenario (e.g., PSE 2005).

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[93] Appendix E of Avista's plan states: "The primary driver behind the construction of coal plants is the consideration of risk. Coal plants have low variable operating costs, making their level of fuel price risk much lower than CCCTs, for which two-thirds of the generation cost is fuel. Coal plants cost only a modest amount more than CCCTs, especially in the out years, yet the variability of net power supply expenses is significantly lower. This result is very intriguing, and the further study of coal plant economics has been identified as an action item." Recall that Avista limited the amount of wind in its preferred portfolio to just 75 MW (4% of peak load), due to concerns about integration costs.

[94] See footnote 90, describing Exhibit XII-7 of PSE's 2003 plan, which shows a portfolio consisting of coal and gas sitting much closer to the origin of a cost/risk graph than portfolios consisting of all gas or various combinations of wind, gas, and coal. Despite this graphical condemnation of renewables (and commendation of coal) on the basis of a quantitative cost/risk assessment, PSE 2003 ultimately decided to pursue a diversified portfolio including a substantial amount of wind, at least in part due to qualitative consideration of potential carbon compliance costs. In this way, PSE 2003 serves as the unwitting "poster child" for the main point being made in this Section: a regimented, stepwise process for analyzing different types of risks may lead to very different results than if risks are considered in a more holistic, or concurrent, manner.

8. Conclusions

Formal resource planning processes can help utilities and their regulators consistently and fairly assess a wide range of supply- and demand-side options in meeting customer needs. Renewable energy cost reductions, combined with a heightened concern for the risks associated with conventional sources of generation, have led to an increasing emphasis on wind and other renewable sources in utility resource plans.

Our review of the planning efforts of twelve western utilities reveals that resource plans are becoming increasingly sophisticated in their treatment of renewable resources and the costs and risks that they both entail and mitigate. Many analytical improvements have been made in just the past few years. Further improvements are still possible and needed, however. Specifically, based on the review and analysis conducted in this report, we identify the following key areas as ripe for improvement:

1) **Resource plans in RPS states should consider evaluating renewable resources as an option above and beyond the level required to satisfy RPS obligations.** More often than not, the RPS seemingly serves as a cap on *planned* renewable additions, rather than as a floor from which to build. Conducting a more formal analysis of possible renewable supply options, above and beyond any RPS requirement, might in some cases reveal additional cost-effective opportunities for renewable energy. Even where additional cost-effective opportunities are not found, such analysis may help reveal lower-cost ways of achieving RPS compliance. Such analyses may be critical for transmission-dependent resources such as wind and geothermal power, and may also help to set the "ground rules" for subsequent all-source bid evaluations (e.g., consideration of natural gas and environmental regulatory risk, integration costs, etc. when evaluating renewable and conventional generation).

2) **Resource planners may wish to explore a broader array of renewable resource options.** The overwhelming focus of the plans in our sample was directed at wind power, which is understandable given the historically promising economics of wind relative to other renewable resources, as well as the widespread wind resource throughout the West. Wind's inherent variability, however, will some day limit its contribution, and several of the utilities in our sample are already – even at the relatively low penetration levels contemplated – clearly uncomfortable with the prospect of integrating wind into their systems. Other renewable resources, such as biomass, geothermal and solar-thermal electric, are also available in the West, and can provide power that offers a good fit to utility needs while not being susceptible to carbon risk. With natural gas prices expected to remain high for some time, and with the PTC now extended to a broader array of renewable sources, these additional renewable technologies may be competitive in some instances with conventional generation, and may deserve greater attention in future IRPs.

3) **The value of the federal production tax credit for renewable energy, and its risk of permanent expiration, could be more consistently addressed.** The PTC is a major driver of wind development in the United States, and could become equally important to biomass and geothermal projects in the coming years. As such, careful assessment of the value of the credit to a project, as well as the likelihood that the credit will still exist over the duration of

the planning horizon, is important. Our analysis reveals that some plans are underestimating the value of the credit, while most plans are overestimating the likely availability of the credit beyond the next few years.

4) **Methods for evaluating wind integration and transmission costs, and capacity value, should continue to be refined and applied at successively higher wind penetration levels.** Independent analysis of both integration costs and capacity value has progressed rapidly in recent years; most would likely agree that utilities and their regulators should strive to stay current with the latest tools and findings, and apply them to their own systems at wind penetration levels above and beyond those plausibly reached in the current planning cycle. Such results can then serve as building blocks for future planning cycles. A careful evaluation of the transmission needs of progressively higher levels of wind integration is also critical if wind power is to be effectively evaluated in a resource planning context; data on the transmission costs of significant levels of wind penetration are not yet readily available.

5) **Exogenous wind penetration caps should be eliminated, especially as the analysis and tools for wind integration and transmission costs, and capacity value, improve.** Exogenous wind penetration caps would ideally be replaced with results from integration cost studies, as well as transmission cost studies. An upward-sloping "supply curve" of integration and transmission expansion costs will serve to limit the amount of wind in a portfolio to an amount that is economically defensible (based on total costs), rather than an amount that is exogenously and often arbitrarily set outside of the modeling process.

6) **Resource plans would ideally evaluate a broad range of possible fuel costs, and subject a large number of candidate portfolios to such analysis.** Analysis of fuel price risk in utility resource planning has made great strides. Nonetheless, if only meager deviations from current fuel prices are analyzed, or if only a few handcrafted candidate portfolios are subjected to fuel price risk analysis, then the hedge benefit of renewables might be undervalued, or opportunities for risk-mitigation through inclusion of renewables in candidate portfolios might be overlooked. A wide range of possible price paths should be considered, and a large and varied set of candidate portfolios should be evaluated for their ability to mitigate fuel price and other risks. Given the absence of any compelling reason to keep fuel price forecast data confidential, we also believe that greater transparency in natural gas price forecasts and forecast uncertainty is also warranted: the public benefits derived from increased scrutiny of modeling assumptions likely outweigh any private costs incurred.

7) **Environmental compliance risks could be more consistently and comprehensively evaluated.** Given the potential likelihood and impact of future carbon regulations, as well as the possibility that un-weighted carbon regulation scenarios will have little impact on portfolio selection, we recommend that all utility resource plans consider the risk of future carbon regulations in a base-case analysis. Likewise, it seems unreasonable to assign – as ten of the twelve utilities in our sample appear to have done – a 0% probability to the risk of future, more stringent air pollutant (SO_2, NOx, and mercury) regulations. More widespread and uniform treatment of these pollutants, with estimated cost impacts benchmarked against the literature, is warranted.

8) **Steps should be taken to ensure that each risk has, as is warranted or appropriate, an opportunity to impact portfolio selection.** It is appropriate to analyze different risks using different methods (e.g., stochastic vs. scenario analysis). However, where risks are analyzed using scenario analysis (e.g., carbon risk), this analysis sometimes seems to serve as a sideshow to stochastic analysis. We therefore recommend that the results of scenario analysis (or any type of risk analysis) be more consistently and clearly used in portfolio selection, and that a more integrated analysis of risks be pursued. Assigning subjective probabilities to each scenario is one way to move towards this objective. Alternatively, if a utility prefers to avoid portraying the false sense of certainty that might arise from the use of subjective probabilities, then it might assess the cost/risk tradeoff for *each* candidate portfolio under *each* scenario, and try to qualitatively draw an overarching conclusion as to which candidate portfolio performs best in the majority of scenarios (or in those scenarios considered to be most likely).

9) **Utilities and regulators should consider conducting research to evaluate ratepayer risk preferences.** Given that each utility should ultimately be selecting – on behalf of its ratepayers – a preferred portfolio based on an assessment of its overall cost and risk relative to all other candidate portfolios, information on ratepayer risk preferences seems critical. Admittedly, no single portfolio will satisfy each individual ratepayer's risk preference. Nevertheless, a portfolio selected to reflect *majority* risk preferences – as revealed through current market research – will likely be more appropriate than one selected based on some vague notion about ratepayer preferences.

10) **Finally, more consistent and comprehensive data presentation in utility resource plans would allow for far better external review.** Though there may be instances in which redaction of commercially sensitive information is warranted, many utility resource plans provide a sizable amount of public information. This information is not always clearly and consistently presented, however, making effective external review difficult.

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Appendix A. Data Manipulation Assumptions

A variety of assumptions had to be made to put the data in the various IRPs on comparable terms. Those details that were omitted from the body of the report (in Sections 3, 5, and 6) are described here.

A.1 Section 3: Planned Renewable Energy Additions

Utility	Assumptions
Avista	Data derives directly from IRP.
Idaho Power	Data derives directly from IRP.
Nevada Power	IRP assumed that all contracts signed as a result of a 2001 renewable energy solicitation would result in renewable deliveries, and that Sierra Pacific would not trade its non-solar RECs to Nevada Power (in retrospect, the first assumption is unreasonable as many of these contracts were subsequently terminated). Consistent with the resource plan, we assumed that 2001 RFP projects would come on line and deliver electricity as reported in the resource plan (and these additions are included in the data presented in Chapter 3). Incremental REC needs beyond the 2001 RFP contracts were specified in the resource plan. We translated these later data to MW of capacity using the following assumptions: (1) PV capacity factor of 16%; (2) CSP capacity factor of 28%; (3) 75% of remaining solar set-aside met with PV RECs, with 25% met with CSP RECs, (4) PV RECs continue to earn a 2.4 multiplier; and (5) non-solar capacity has weighted average capacity factor of 65%. Data provided here are reflective of the IRP, and not subsequent events (e.g., termination or delay of many of the 2001 RFP contracts, lack of early-year compliance with RPS, planned trade of RECs from Sierra Pacific to Nevada Power, as well as signing of more recent contracts based on a 2003 solicitation).
NorthWestern	Data derives directly from IRP.
PacifiCorp	Data derives directly from IRP.
PG&E	Most data derive directly from IRP. 2004 renewable deliveries, upon which percentage increases are measured, derive from PG&E's March 2005 RPS compliance filing.
PGE	IRP indicates 195 MW (65aMW) of wind by 2007; for graphics, we assume that this is built in 2007.
PSCO	IRP contemplates 500 MW by 2006. With PTC slated to expire at end of 2005, wind RFP sought to accelerate procurement to 2005; we assume 500 MW on line in 2005.
PSE	Data derives directly from IRP.
SDG&E	SDG&E's March 2005 RPS compliance filing identifies MW and MWh of renewable energy deliveries in 2004. SDG&E's IRP identifies the MW and MWh of renewable energy needed by 2010 (to hit the 20% RPS) and 2014 (to achieve a 24% internal target), by technology. The difference between the 2010/2014 figures and the 2004 figure is used to calculate incremental needs beyond 2004 deliveries. For intermediate years, we simplistically assume proportional increases in MW and MWh (note that SDG&E's March 2005 RPS compliance filing shows projections for 2005 deliveries that are far lower than the values that we obtain for 2005, based on our linear interpolation). For 2010-2014, we split the aggregate renewable additions into RPS and non-RPS components based on the size of the aggregate internal target (24%) relative to the RPS requirements (20%). To calculate cumulative incremental renewable energy as a percent of load, we had to derive a load forecast from data presented in SDG&E's IRP (SDG&E's actual load forecast is confidential), creating the possibility of some error.
Sierra Pacific	IRP assumed that solar CSP contract from 2001 renewable energy solicitation results in renewable deliveries, and this contract is included in the data presented in Chapter 3. Based on this assumption, the IRP calculated the amount of incremental solar RECs and non-solar RECs required to achieve RPS compliance. The IRP assumed that pre-existing renewable energy contract deliveries would decrease over time; instead, we assume that these contract deliveries remain constant under the presumption that existing renewable projects may receive contract extensions. Considering this pre-existing generation and the solar CSP contract, we translated the remaining REC needs to MW of capacity using the following assumptions: (1) PV capacity factor of 16%; (2) CSP capacity factor of 28%; (3) 75% of remaining solar set-aside met with PV RECs, with 25% met with CSP RECs, (4) PV RECs continue to earn a 2.4 multiplier; and (5) non-solar capacity has weighted average capacity factor of 65%. The appendix to the IRP appears to provide some break-down of the technologies that might be used to meet the non-solar portion of the RPS, with a heavy emphasis on geothermal, but data presented there could not be deciphered for this study, and were therefore not used. Data provided here are reflective of the IRP, and not subsequent events (e.g., termination or delay of many of the 2001 RFP contracts, lack of early-year compliance with RPS, as well as signing of more recent contracts based on a 2003 solicitation).

SCE	IRP provided data for SCE load, over time, and the planned percent of that load that would be supplied with renewable energy. Both load data and % renewables data are presented in several sections of the IRP, and in many cases these data do not appear entirely consistent. We took data from one of SCE's "medium load" cases, with load taken at retail, not retail load grossed up to the generator busbar. We also take % renewable assumptions from the IRP, and we assume that those percentages apply to the retail load estimates (not load, grossed up to generator busbar), because this is the approach used by SCE in their 2004 Renewable Procurement Plan. A 40% capacity factor is assumed for incremental renewable energy needs (based on SCE's March 2005 renewable energy procurement plan), and we calculate the incremental amount of renewable energy required above 2004 renewable energy deliveries (which derive from SCE's March 2005 RPS compliance filing for RPS-year 2004).

A.2 Section 5: Renewable Resource Cost and Performance Assumptions

All cost assumptions are reported in real 2003 dollars. To deflate costs or shift them from a different base dollar year, we used the historical GDP deflator (from the Department of Commerce, Bureau of Economic Analysis) through 2004, and the *Annual Energy Outlook 2005* forecast of the GPD deflator from 2005-2025.

Not all of the cost information contained in Table 3 is publicly stated in the resource plans. In some instances, we had to calculate or derive specific costs based on other costs that were available. For example, Avista's transmission costs were stated as $15/kW/year (presumably in year 2000 dollars), and we translated that into $6.2/MWh using data on project size and capacity factor, and then inflating to 2003 dollars as described above. Another example involves integration costs assumed in PGE's original plan: these costs were stated at various places throughout the plan as either $10-$30/MWh (as shown in Figure 9) or $25-$30/MWh. We used $27/MWh (low case) and $22/MWh (high case), both in 2002 dollars, to make the total modeled cost work out to $75/MWh and $80/MWh, respectively, as stated in the plan. A final example involves Avista, and how it accounted for the PTC by deducting the net present value of the 10-year PTC from the assumed capital cost of project, to yield a capital cost of $679/kW instead of $1000/kW. We used this differential of $321/kW to derive the levelized $/MWh value of the PTC assumed by Avista.

All discounting and levelization occurred at the appropriate discount rates specified in each plan. If no discount rate was specified, we assumed a 10% nominal discount rate (~7% real discount rate).

A.3 Section 6: Risk Analysis: Natural Gas Price and Environmental Compliance Risks

Natural Gas Price Forecasts: Base-case gas price forecasts (as well as low- and high-price scenarios, where applicable) were sourced either directly from numerical data provided in the IRPs, or where necessary, estimated from graphs provided in the IRPs. Where necessary, conversions from different base years or nominal dollars to 2003 dollars were made using the actual GDP deflator from 2000-2004, and Annual Energy Outlook 2005's forecast of the GDP deflator from 2005-2025. Where necessary, conversions from the particular pricing location specified in each IRP to the Henry Hub equivalent price were based on (a) 3-4 years of forward basis swap pricing from NYMEX Clearport (www.nymex.com/jsp/markets/cp_produc.jsp), and thereafter, (b) generic basis estimates provided by NPCC in Appendix B of its draft Fifth Power

Plan. The NYMEX Clearport basis differentials are quoted in nominal dollars while the NPCC differentials are in real 2000 dollars; both were deflated and inflated, respectively, to 2003 dollars using the GDP price deflator data described above.

Compliance Cost Assumptions: For carbon and other pollutants, we inflated or deflated (using the GDP deflator as described above) the compliance cost assumptions in each plan to get to 2003 dollars. We then levelized each cost stream over the particular planning horizon assumed in each plan (for PGE we levelized through 2020 rather than 2051) to yield a levelized cost stream in 2003 dollars.