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Introduction

In the United States, markets for renewable generation – 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. But another less widely recognized driver of new renewable generation is poised to play a major role in the coming years: utility integrated resource planning (IRP). Common in the late-1980s to mid-1990s, but relegated to lesser importance as many states took steps to restructure their electricity markets in the late-1990s, IRP has re-emerged in recent years as an important tool for utilities and regulators, particularly in regions such as the western United States, where retail competition has failed to take root.

As practiced in the United States, IRP is a formal process by which utilities analyze the costs, benefits, and risks of *all* resources available to them – both supply- and demand-side – with the ultimate goal of identifying a portfolio of resources that meets their future needs at lowest cost and/or risk. 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 portfolios as candidates to fill a projected resource deficiency;
- analysis of these different "candidate" resource portfolios under base-case and alternative future scenarios; and finally,
- selection of a preferred portfolio, and creation of a near-term action plan to begin to move towards that portfolio.

Renewable resources were once rarely considered seriously in utility IRP. In the western United States, however, the most recent resource plans call for a significant amount of new wind power capacity. These planned 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.

This article, which is based on a longer report from Berkeley Lab,[i] examines how twelve investor-owned utilities (IOUs) in the western United States – Avista, Idaho Power, NorthWestern Energy (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) – treat renewable energy in their most recent resource plans (as of July 2005). In aggregate, these twelve utilities supply approximately half of all electricity demand in the western United States.

In reviewing these plans, our purpose is twofold: (1) to highlight the growing importance of utility IRP as a current and future driver of renewable generation in the United States, and (2) to suggest possible improvements to the methods used to evaluate renewable generation as a resource option. As such, we begin by summarizing the amount and types of new renewable generation planned as a result of these twelve IRPs. We then offer observations about the IRP process, and how it might be improved to more objectively evaluate renewable resources.

Planned Renewable Generation

The most recent batch of western resource plans includes a significant amount of planned renewable resource additions. In the case of the three California (PG&E, SCE, SDG&E) and two Nevada (Sierra Pacific and Nevada Power) utilities covered in this study, these additions are primarily the result of state-imposed renewables portfolio standards (RPS, sometimes referred to as "renewable energy obligations"). The seven remaining utilities in our sample are not subject to an RPS (or at least were not at the time of their most recent IRP filings – NWE and PSCo have since become subject to an RPS), 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 1 shows the cumulative, planned additions of renewable generating capacity among the twelve utilities in our sample, categorized as either RPS- or IRP-driven additions. The roughly 8,000 MW of new renewable capacity expected by 2014 is split almost evenly between each category.

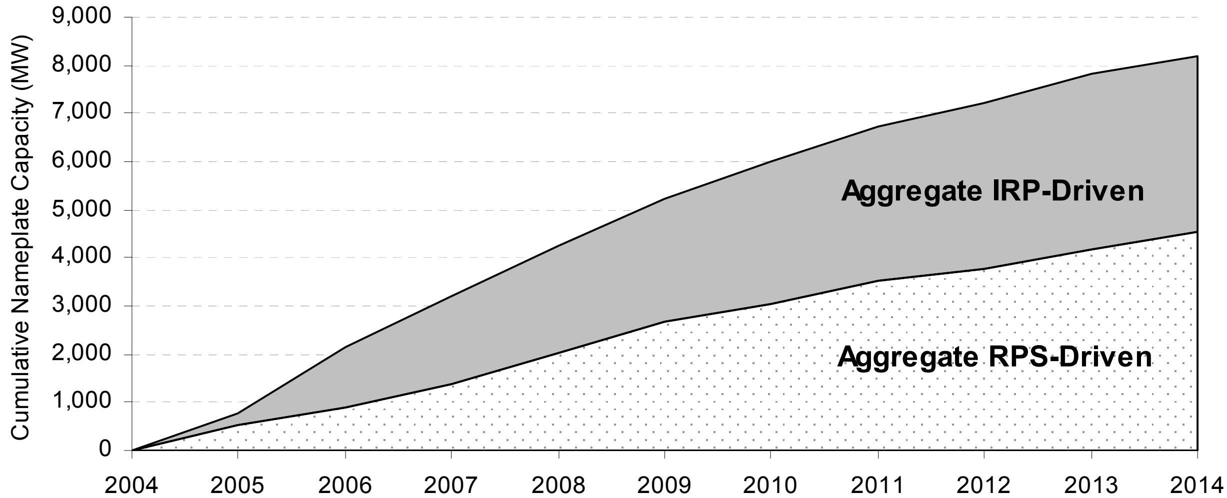

Figure 1. Planned Renewable Resource Additions in Twelve Western Resource Plans

Figure 2 breaks out the cumulative planned renewable additions from Figure 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 IRP-driven plans, Figures 1 and 2 clearly illustrate that IRP-driven resource plans may themselves be a major driver of growth in new renewables.

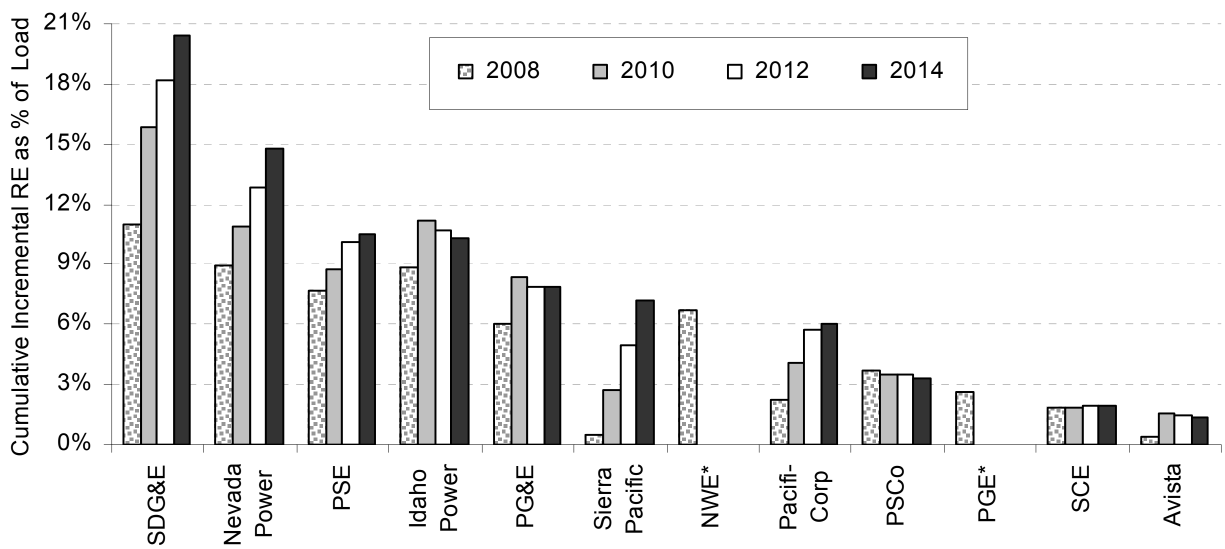

Figure 2. Cumulative Incremental Renewable Generation as a Percentage of Utility Load
*PGE's and NWE's procurement horizons end in 2007, so only their 2008 values are shown.

Many of the RPS-driven resource plans make no real effort to identify the specific renewable resources that might be used to meet the RPS requirements, under the presumption that eligible renewable sources will compete for contracts under open renewable energy solicitations. The IRP-driven plans, on the contrary, typically indicate the specific renewable resource(s) expected to meet their needs.

Figure 3 breaks out the amount and type of planned renewable capacity additions among the seven utilities in our sample that were not subject to an RPS when the plans were finalized. In aggregate, these seven utilities plan – independently of an RPS – to add 3,380 MW of wind power, 100 MW of geothermal capacity, and 75 MW of biomass over the next decade.

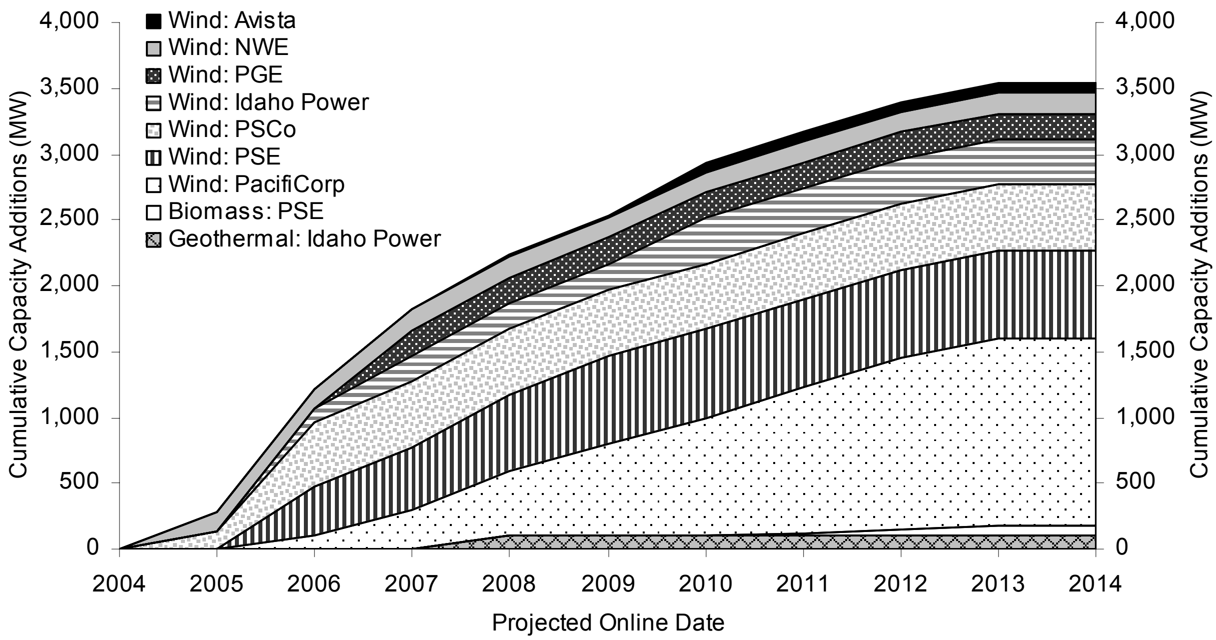

Figure 3. Cumulative IRP-Driven Renewable Capacity Additions, by Resource Type and Utility

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, this call to action is being driven by state RPS requirements. In other states, the previously scheduled expiration of the federal production tax credit (PTC) at the end of 2005 has accelerated procurement timelines.

Despite these early efforts, an emerging disconnect between resource plans and procurement reality is also evident in some instances. For example, PacifiCorp's early 2004 solicitation for 1,100 MW of renewables has so far yielded only 64.5 MW of wind under contract. Similarly, PSCo's mid-2004 solicitation for 500 MW wind power appears likely to yield only 60 MW in the near future. 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 previously scheduled expiration of the PTC at the end of 2005 – is perhaps partly to blame. But, 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.

Observations

A more detailed review of these planning efforts 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. Nonetheless, further improvements are still needed to ensure that renewables are fairly evaluated in resource planning processes. We identify the following key areas as ripe for improvement:

IRP conducted under an RPS: More often than not, utilities subject to an RPS seem to (within their IRP) view the RPS 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 reveal lower-cost ways of achieving RPS compliance, and may be particularly critical for transmission-dependent resources such as wind and geothermal power.

Number of different renewable resources considered: 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 western United States. However, other renewable resources, such as biomass, geothermal and solar-thermal electric, are also available in the western United States, and can provide power that fits well with utility needs. 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.

Quantifying the PTC: 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. At the same time, most plans are overestimating the likely availability of the credit beyond the next few years.

Assessing the indirect costs of wind power: Many of the IRPs in our sample have not credibly analyzed the capacity value, integration costs, and transmission issues associated with increased wind power production. In contrast, independent analysis of wind power's integration costs and capacity value has progressed rapidly in recent years. Utilities 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.

Construction of candidate portfolios: All of the IRPs in our sample exogenously define the maximum amount of renewable energy that can be realistically selected, either by establishing constraints within an optimization model, by pre-defining candidate portfolios, or by only accepting a certain amount of wind power even if analysis suggests that higher levels of penetration are warranted. In some cases, the maximum permissible amount of incremental wind is relatively small, and appears to have limited the amount of wind power included in the preferred portfolio. Ideally, utilities would replace exogenous wind penetration caps with results from integration (and transmission) cost studies, as prescribed above. 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.

Fuel price risk: Analysis of fuel price risk (primarily natural gas price risk) in utility resource planning has made great strides in recent years. Nonetheless, a few of the utilities in our sample have analyzed only meager deviations from current fuel prices, while others have subjected only a few pre-defined candidate portfolios to fuel price risk analysis. In such cases, opportunities for risk-mitigation through inclusion of renewables in candidate portfolios might be overlooked. Ideally, 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.

Carbon risk: The risk of future carbon regulations – which could plausibly increase the cost of coal power by more than \$10/MWh – is significant, and seven of the twelve utilities in our sample specifically analyzed this risk (three of the remaining five will be required to address it in their next IRP). As shown in Figure 4, these 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. To ensure that the risk of carbon regulation is adequately considered in portfolio selection, however, utilities should perhaps 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).

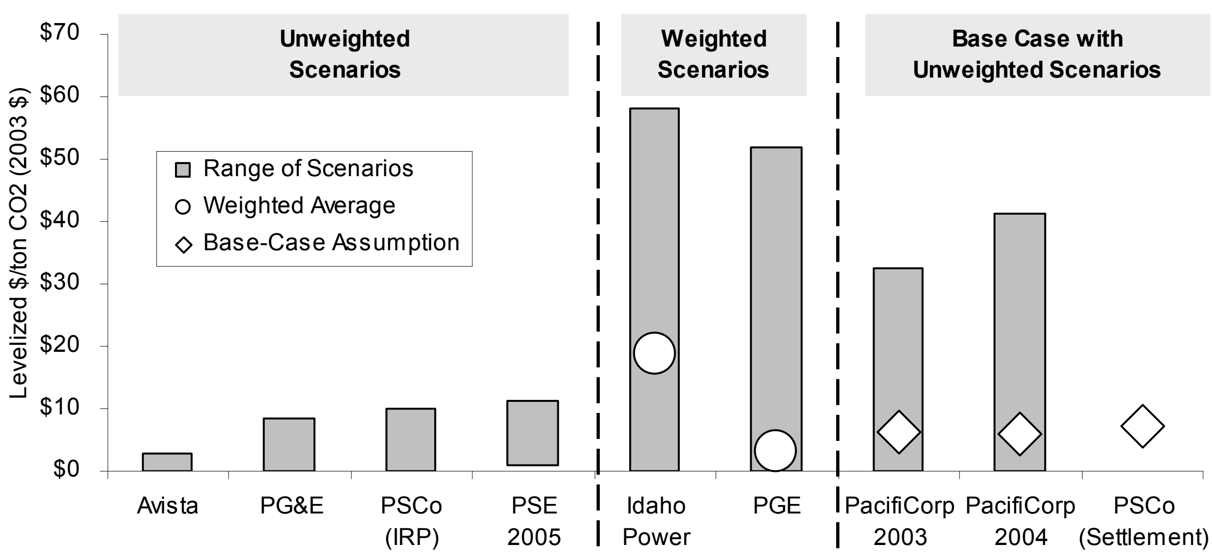

Figure 4. Summary of Carbon Regulation Scenarios in Western Resource Plans

Interaction of different risk types: Finally, steps should be taken to ensure that each type of risk analyzed has an opportunity to impact portfolio selection. For example, fuel price risk is typically addressed through stochastic analysis, ensuring that it will impact base-case results early in the analytic process. In contrast, carbon risk is typically addressed later in the process through scenario analysis, often being conducted on just a few candidate portfolios selected for further scrutiny based in large part on their favorable fuel price risk profiles.

The sequential nature of this process becomes important when one considers that the simplifying assumption made in many IRPs 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-fired peaking plants to integrate wind into the system, sometimes results in so-called "renewables" candidate portfolios being heavily laden with gas-fired generation. As a result, some of the "renewables" portfolios in our IRP sample exhibit as much (or more) exposure to natural gas price risk as do other portfolios. This somewhat counterintuitive result has, in some cases, shifted resource selection towards coal-fired generation early in the analytic process (as the price of coal has been relatively stable compared to the price of natural gas). By the time carbon risk is assessed, those renewables portfolios best able to mitigate carbon risk may have already been weeded out of the process, potentially leaving the model to choose from among a number of sub-optimal portfolios.

To be sure, some risks – including carbon risk – are better-suited for scenario rather than stochastic analysis. When *both* scenario *and* stochastic analysis are employed within an IRP, however, steps should be taken to ensure that 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. Assigning subjective probabilities to each scenario is one way to move towards this objective. Alternatively, a utility might analyze *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).

Conclusion

Utility integrated resource planning in the western United States has made great analytic strides in recent years. Partly as a reflection of this progress, the twelve utility IRPs we reviewed are calling for a significant amount of new renewable generation over the next decade. More encouraging, these calls are, in many cases, based purely on economic considerations. With the further improvements described in this article, we expect that renewables will be well-positioned to command an even greater role in future utility planning efforts.

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[i] Bolinger, M. and R. Wiser. 2005. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." LBNL-58450. Berkeley, Calif.: Lawrence Berkeley National Laboratory. http://eetd.lbl.gov/ea/ems/reports/58450.pdf