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HOW LEAST-RISK RESOURCE PLANNING CAN PAVE THE WAY FOR RENEWABLE ENERGY

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EXECUTIVE SUMMARY

Fossil fuel-fired generating resources are currently risky investments, yet investor-owned utilities overwhelmingly invest capital in fossil fuel resources rather than less-risky renewable energy resources. States inadvertently incentivize these investments through resource planning rules that focus on reducing upfront costs rather than mitigating long-term risks. Many utilities conduct some form of long-term resource planning in which they forecast future energy and capacity needs and evaluate different resource options that are capable of meeting these needs. Under traditional resource planning, utilities must select the "least-cost" portfolio of available resources to satisfy their procurement needs. This practice likely discourages significant investments in renewable resources, which generally have higher initial costs than conventional generating facilities. "Least-risk" resource planning is an alternative approach that may promote renewable energy by encouraging utilities to invest in resources with predictable long-term operating expenses and minimal vulnerability to risk and uncertainty.

The impetus for least-risk planning arises from incentives created by the electricity ratemaking process. The traditional cost-of-service ratemaking formula creates incentives for utilities to construct large, capital-intensive generating facilities, which earn a profit for investors. However, because consumers are forced to pay for these investments over the course of many years, these facilities can expose ratepayers to significant risk if the plants fail to perform as expected or incur additional unanticipated costs over time.

Many states have promulgated integrated resource planning rules to deter unnecessary investment and protect ratepayers from unanticipated costs. These rules direct utilities to create integrated resource plans, or IRPs, in which the utilities must project their long-term energy and capacity needs and identify resource mixes capable of satisfying these needs over a ten- to twenty-year period. State resource planning rules typically require utilities to identify the least-cost portfolio of available resources capable of satisfying projected demand.

During the IRP process, utility planners typically conduct scenario or sensitivity analyses to determine how uncertain variables, such as fuel price volatility or stringent environmental compliance obligations, could impact a portfolio's costs over the planning horizon. This process forces each utility to make assumptions or predictions about what future conditions will be or what outcomes are most likely to occur. Because levelized cost calculations necessarily include projections of uncertain future costs, such as fuel costs or environmental compliance costs, levelized cost projections should in theory account for risk and uncertainty. However, a portfolio can have low levelized costs under some future scenarios, but very high costs under others, and the utility has discretion to decide which scenarios are most probable. As a result of this discretion, under least-cost planning policies, levelized cost calculations may fail to account for foreseeable, high-risk outcomes that a utility deems unlikely to occur. Consequently, a preferred least-cost portfolio may be significantly less resilient to changing circumstances than other resource mixes.

Least-cost planning policies may inadvertently incentivize risky resource investments for a number of reasons. First, levelized cost calculations generally reflect a utility's internal assumptions about future conditions, and final cost projections typically represent a portfolio's costs under the future outcomes that a utility subjectively thinks are most likely to occur. Second, least-cost planning policies rarely mandate that utilities comprehensively assess potential risk and uncertainty or justify their probability determinations, and PUCs subsequently have minimal oversight authority over portfolio cost projections. Third, least-cost requirements may prevent utilities from including non-least-cost resources in their rate bases, and therefore these utilities have little incentive to calculate levelized costs that significantly deviate from business-as-usual conditions.

The way in which utilities balance cost and risk through resource planning, moreover, has substantial implications for renewable resources, which many planners view as low-risk, yet high-cost, generating resources. Renewable resources have the capacity to mitigate risks associated with fuel price volatility or future environmental regulations. When utilities and regulators place greater value on a portfolio's risk mitigation potential than projected cost, preferred resource portfolios should include a greater proportion of renewable generating capacity. However, cost continues to be the deciding factor in a majority of resource planning decisions, and renewable resources have struggled to compete with historically low natural gas prices.

Least-cost planning policies may inadvertently incentivize risky resource investments for a number of reasons. First, levelized cost calculations generally reflect a utility's internal assumptions about future conditions, and final cost projections typically represent a portfolio's costs under the future outcomes that a utility subjectively thinks are most likely to occur. Second, least-cost planning policies rarely mandate that utilities comprehensively assess potential risk and uncertainty or justify their probability determinations, and PUCs subsequently have minimal oversight authority over portfolio

cost projections. Third, least-cost requirements may prevent utilities from including non-least-cost resources in their rate bases, and therefore these utilities have little incentive to calculate levelized costs that significantly deviate from business-as-usual conditions.

Least-risk resource planning presents an alternative planning policy that aims to reduce ratepayer exposure to risk and uncertainty. Least-risk resource planning directs utilities and regulators to quantify the risks and uncertainties associated with all resource options. It then requires utilities to select the resource portfolio that most effectively reduces exposure to plausible or unreasonable risks under all potential outcomes. Least-risk planning is an emerging concept in the context of integrated resource planning, and while some states have revised their IRP requirements to incorporate least-risk provisions, there are currently no uniform standards to define this planning approach.

Least-risk planning policies have the potential to help mitigate the risks created by least-cost planning. First, an effective least-risk planning policy will require each utility to comprehensively assess portfolio vulnerability to all foreseeable risks and evaluate the probabilities of uncertain outcomes. Second, least-risk planning policies will direct each utility to justify the assumptions it made when predicting uncertain future conditions and explain the conclusions it reached regarding the probabilities of potential outcomes. Third, least-risk planning policies will allow for public participation and regulatory oversight over the planning process. PUCs will also have the authority to enforce least-risk planning requirements when making IRP approval decisions. Finally, least-risk planning policies will provide each utility with some assurance that investments in least-risk resources will be eligible for cost recovery.

There are a number of general steps that regulators can follow to develop and implement effective least-risk planning regimes. First, regulators must review and revise existing resource planning regulations to replace least-cost resource requirements with least-risk mandates. Second, regulators must develop least-risk planning rules establishing threshold risk assessment parameters. Third, regulators must ensure that utilities effectively implement least-risk planning requirements. Finally, regulators must connect resource plan approval to the ratemaking process to provide a level of assurance that utility investments in least-risk resources may be eligible for cost recovery (and that ratepayers are not on the hook for higher risk investments).

Utilities that adequately seek to minimize exposure to risk and uncertainty will be better able to adapt to the energy realities of the 21st century. However, utilities are unlikely to alter their existing resource planning practices on their own accord. Least-risk planning will be necessary to facilitate the transition away from the current high-risk, fossil fuel-dependent electricity system, and it is up to state regulators to establish least-risk resource planning policies that prioritize risk mitigation over short-term cost reduction. When effectively implemented and enforced, these policies should mitigate risks to ratepayers and investors and advance renewable energy development by equalizing the playing field between renewables and fossil fuels.

I. Introduction

Before electric utilities invest in new generating resources, most states require them to engage in some form of long-term resource planning that forecasts future load and capacity needs and evaluates various resource options capable of meeting these needs. These planning requirements help protect electricity consumers from unduly high electricity rates by preventing utilities from investing in unnecessary energy resources. Resource planning requirements are therefore valuable state policies that help inform energy development over the course of many years. One shortfall of these policies, however, is that utilities are traditionally required to select the least-cost portfolio of resources identified through the resource planning process to satisfy their future energy and capacity needs.[1] This requirement may lead utilities to overlook significant risks and uncertainties that can impact a resource's cost or performance over its lifetime. Moreover, prioritizing cost reduction over risk mitigation may deter investments in renewable resources and energy storage, which are generally low-risk, yet potentially high-cost resources.[2] Least-risk resource planning presents an alternative policy option that prioritizes risk mitigation and long-term cost stabilization over short-term cost reductions. This planning approach encourages utility investments in resources with predictable long-term costs, such as renewable energy and energy storage resources. By replacing least-cost planning policies with least-risk planning policies, states can reduce ratepayer vulnerability, eliminate a barrier to renewable energy development, and facilitate the transition to a more resilient, sustainable energy system.

The traditional cost-of-service ratemaking formula typically dictates how utilities may allocate a resource's costs among ratepayers. This ratemaking formula enables a utility to recover its operating expenses and the value of any authorized capital investments through consumer electricity rates.[3] Utilities are entitled to earn an additional rate of return (*i.e.* a profit) on capital expenditures, but not on operating expenses.[4] The ratemaking formula thus encourages utilities to build power plants and electricity infrastructure, because utilities will only earn a direct rate of return on those types of investments. Of course, this profit incentive may also encourage utilities to overbuild. Least-cost planning aims to curtail this dynamic by requiring utilities to create Integrated Resource Plans (IRPs or resource plans) identifying the resource portfolios capable of satisfying long-term energy and capacity needs at the lowest costs.[5]

Integrated resource planning also attempts to protect ratepayers from unanticipated cost increases in the future. Electricity rates are set prospectively by state Public Utility Commissions (PUCs), which means that utilities must project their anticipated future operating expenses.[6] However, energy price forecasting is notoriously difficult, and history is full of examples of unexpected fuel price increases. Although the prospective ratemaking rule might suggest that utilities are responsible for operating cost increases that occur between ratemaking proceedings, cost increases resulting from rising fuel prices are often passed onto ratepayers through fuel adjustment clauses.[7] Fuel adjustment clauses enable utilities to quickly adjust their electricity rates between ratemaking proceedings in response to unanticipated fuel price fluctuations.[8] Utilities are not entitled to profit off of fuel-based rate adjustments,[9] but the availability of these clauses reduces the incentive for utilities to accurately project future fuel costs. Ratepayers are therefore vulnerable to risks presented by future fuel cost increases.

Cost-of-service ratemaking enables utilities to earn a profit on capital investments, which encourages construction of large power plants.

A resource's costs may also rise in response to future environmental regulations, such as greenhouse gas emissions limitations. If regulations require installation of additional emission controls, expenses associated with regulatory compliance will likely constitute capital expenditures that are recoverable through the utility's rate base. If these regulations instead require operational changes, these operating cost increases will be passed on to consumers through a subsequent ratemaking proceeding. Utilities therefore have little incentive to invest in resources with stable, predictable operating costs.

RATEMAKING FORMULA

$$R = (B \times r) + O$$

R: revenue requirement
B: rate base
r: rate of return
O: operating expenses

In fact, the ratemaking formula may perversely encourage utilities to invest in resources that may require future upgrades to comply with future regulatory requirements, because utilities will earn a profit on facility retrofits. Least-cost regulatory requirements may exacerbate, rather than mitigate, this dynamic in an uncertain regulatory setting. This is because utilities are typically encouraged or required to invest in least-cost resources. If a utility cannot show that regulatory changes are likely to occur, least-cost planning will incentivize the utility to invest in the lower-cost resource and modify the resource as necessary to comply with future regulations. Ratepayers thus bear the risk that the costs associated with utility resource investments may rise over time. Where fossil fuel-dependent generating resources are involved, the risk of future cost increases is significant.

This does not mean that utilities or their investors are entirely unaccountable for risky resource investments. State PUCs have broad authority to determine whether utilities are entitled to a rate of return on their capital investments.[10] PUC decisions involving coal plant investments indicate that regulators may be increasingly inclined to prohibit utilities from passing on certain future costs to consumers.[11] For example, in 2008, the Texas PUC limited the Southwestern Electric Power Company's ability to pass some future carbon mitigation costs onto consumers.[12] Under the PUC's decision, any carbon costs exceeding $28 per ton must be born by the utility, rather than ratepayers.[13] Utilities and their investors may therefore also be vulnerable to risks presented by unanticipated cost increases, at least insofar as future carbon costs are concerned.

In the future, PUCs may prohibit utilities from passing high carbon costs onto ratepayers.

Despite this vulnerability, least-cost planning requirements may discourage utilities from adequately evaluating resource portfolio exposure to risks and uncertainties, and may encourage utilities to invest in capital-intensive resources that are disproportionately vulnerable to cost increases. The integrated resource planning process traditionally mandates that a utility identify the least-cost resource mix to satisfy future energy and capacity needs. In this context, the least-cost resource mix generally refers to the combination of resources with the lowest levelized cost.[14] Levelized cost represents the total cost of building and operating a generating resource over its projected lifespan, averaged over a per-kilowatt-hour or megawatt-hour basis.[15] This cost estimate aims to encompass all anticipated costs, including capital expenditures, operations and maintenance costs, fuel costs, taxes, and environmental compliance costs.[16] Utility IRPs typically define levelized costs as the present value of revenue requirement, or PVRR, which also includes resource depreciation and return on investment.[17]

Because levelized cost calculations include all projected costs associated with the resource over the entirety of the planning period, utility planners must attempt to predict a number of uncertain costs, including those associated with environmental regulations and fuel prices.[18] In theory, a least-cost resource should also be a low-risk resource, because a resource with the lowest levelized cost should have the lowest potential for cost increases over the planning horizon. However, a portfolio may be least-cost under some scenarios, yet very high-cost under others, and the utility ultimately must decide which future scenarios are most probable.

Under least-cost planning policies, levelized cost calculations may be inaccurate for a number of reasons. First, resource cost projections reflect underlying utility assumptions regarding future conditions or the probability that certain outcomes will occur, and utility biases may influence these assumptions and probability determinations. Second, least-cost planning policies typically fail to require utilities to comprehensively assess risk and uncertainty or justify their probability determinations. PUCs therefore exercise minimal oversight or enforcement authority over levelized cost projections. Finally, least-cost requirements may prohibit utilities from including non-least-cost resources in their rate bases, which may encourage utilities to create very conservative cost projections reflecting business-as-usual policy assumptions. For example, a utility in a least-cost jurisdiction benefits from assuming that fuel and environmental compliance costs will remain low, because these assumptions increase the potential for the utility to build (and earn a rate of return on) large capital investments. If these assumptions are inaccurate, the utility can pass future operating cost increases on to consumers.

Least-cost planning incentivizes investments in natural gas-fired generating facilities, which have uncertain long-term operating costs.

SHORTFALLS of LEAST-COST PLANNING

- utility assumptions and biases may influence resource cost projections
- no mandate to comprehensively assess risk or justify probability determinations
- minimal or no PUC oversight over cost projections
- may limit cost recovery for non-least cost resources and discourage investments in renewable resources

As a result of these dynamics, traditional least-cost resource planning policies likely discourage significant investment in renewable resources and energy storage, which currently tend to have higher capital costs than conventional generating resources. PUCs in states with strict least-cost requirements may determine that investments in renewable resources are imprudent and thus deny a utility from recovering these capital costs through electricity rates.

"Least-risk" resource planning provides a policy alternative that may encourage utility investment in renewable energy. Least-risk planning aims to minimize vulnerability to risk and uncertainty by requiring utilities to select resource portfolios with the least exposure to potential risks over the planning period. This planning method requires utilities to evaluate the foreseeable risks and benefits associated with various energy resources and identify the resource portfolios that are least vulnerable to risk and uncertainty during the planning period. In this context, "risk" primarily refers to the threat of future cost increases or operating restrictions. In addition, least-risk planning policies can encourage utilities to account for certain externalities associated with specific generating resources, such as negative environmental impacts.

Least-risk resource planning alleviates a number of the concerns associated with least-cost planning. First, an effective least-risk planning policy will require each utility to comprehensively assess portfolio vulnerability to all foreseeable risks and evaluate the probabilities of uncertain outcomes. Second, least-risk planning policies will direct each utility to justify the assumptions it made when predicting uncertain future conditions and explain the conclusions it reached regarding the probabilities of potential outcomes. Third, least-risk planning policies will allow for public participation and regulatory oversight over the planning process, and PUCs will have the authority to enforce least-risk planning requirements when making IRP approval decisions. Finally, least-risk planning policies will provide each utility with some assurance that investments in least-risk resources will be eligible for cost recovery. When effectively implemented, these policies should mitigate risks to ratepayers and investors, and may also advance renewable energy development by equalizing the playing field between renewables and fossil fuels.

LEAST-RISK PLANNING SAFEGUARDS

- require comprehensive assessment of all foreseeable risks and uncertainties
- utilities must justify assumptions and explain probability determinations
- requires public participation and regulatory oversight and enforcement
- clarifies that least-risk resource investments may be eligible for cost recovery

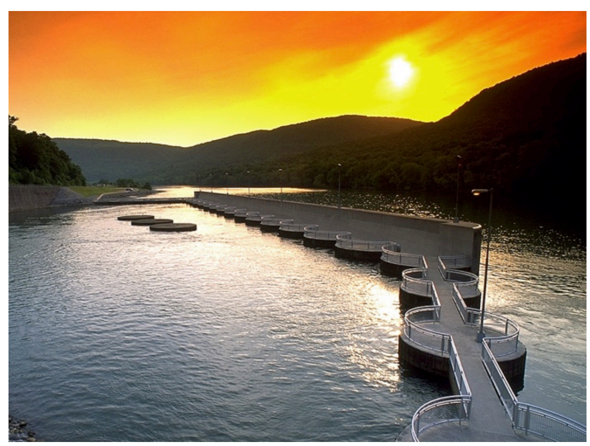
Least-risk planning policies should promote renewable energy development by encouraging investment in resources with minimal environmental externalities and predictable operating expenses.

Least-risk planning policies should promote renewable energy development by encouraging investment in resources with minimal environmental externalities and predictable operating expenses. Renewable resources are an attractive addition to a diversified resource portfolio due to their ability to mitigate risks associated with fuel price volatility or environmental compliance obligations. Likewise, increased energy storage capacity will increase reliability and further hedge against future fossil fuel price increases. When regulators prioritize long-term risk mitigation over short-term cost reduction, preferred portfolios should include more renewable energy and storage capacity than traditional least-cost portfolios. Least-risk planning policies aim to prevent cost projections from superseding risk considerations, and they may be necessary to ensure that utilities assess the long-term benefits of renewables in addition to capital costs.

The U.S. electricity sector is entering into an era of dramatic change as states transition to a cleaner, more resilient energy system. Utilities that engage in strategic, risk-focused resource planning will be better able to adapt to the shifting energy needs and goals of the 21st Century. However, vertically integrated investor-owned utilities are regulated monopolies, and thus are not subject to the competition that generally drives industrial innovation.[19] Regulated utilities are therefore unlikely to implement innovative, least-risk planning practices on their own accord. Instead, policymakers must adopt resource planning policies that require utilities to prioritize risk mitigation. These policy frameworks must be sufficiently flexible to enable utility planners to respond to shifting legal and regulatory conditions.

This paper 1) explains how least-risk planning can help promote renewable energy, 2) examines how a few states have employed risk-focused resource planning in practice, and 3) builds off of these examples to recommend improvements to resource planning rules and practices. Least-risk planning is an emerging alternative to least-cost resource planning, and no state has yet established a pure least-risk planning regime. This paper provides examples from existing planning regulations and utility resource plans to illustrate the least-risk planning concept.

Part II of this report introduces the concept of integrated resource planning and provides a general overview of utility resource planning. Part III describes emerging risks and uncertainties that have the potential to impact our evolving energy sector. Part IV explains the concept of least-risk planning and provides examples of how risk-focused planning requirements may be applied in practice. Part V explores the implications least-risk planning may have on renewable energy development. Finally, Part VI provides an overview of the steps regulators can take to develop and implement effective least-risk planning regimes. This report concludes that least-risk planning policies should be developed and implemented throughout the country to reduce investor and ratepayer vulnerability to risk and incentivize renewable energy development.



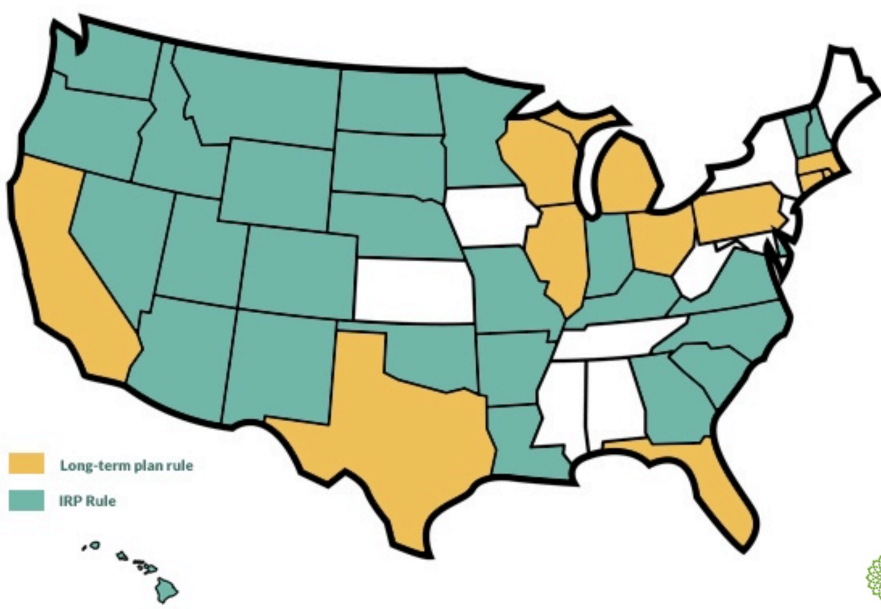
Pumped hydroelectric facilities function as giant batteries. The Tennessee Valley Authority's 1,652 MW Raccoon Mountain Pumped Storage Plant, shown here, pumps water from a lower reservoir during periods of low demand and releases it through four hydroelectric generators during periods of high demand. High-capacity energy storage facilities can help balance variable renewable energy and mitigate ratepayer risk.

II. Integrated Resource Planning

Many utilities engage in integrated resource planning to identify the resources they will need to satisfy electricity demand in the future. Integrated resource planning is a process in which utilities evaluate a range of potential resource options that can satisfy projected future energy and capacity requirements. The federal Energy Policy Act of 1992 defined "**integrated resource planning**" as "a planning and selection process for new energy resources that evaluates the full range of alternatives . . . in order to provide adequate and reliable service to its electric customers at the lowest system cost."[20] The ultimate objective is to identify electric generating resources that will reliably meet consumer demand and comply with regulatory requirements over an extended period of time, typically ranging from ten to twenty years.[21] The integrated resource planning process traditionally requires utilities to identify the least-cost resource mix that will satisfy future load and reliability needs.[22] In this context, least-cost resource mix generally refers to the combination of resources with the lowest levelized cost over the full planning horizon.[23]

A resource's "**levelized cost**" is the expected cost of electricity averaged on a per megawatt-hour basis over the life of the generating resource. This cost estimate aims to encompass all projected costs associated with the resource, including capital expenditures, operations and maintenance costs, fuel costs, and environmental compliance costs.[24] Levelized cost estimations thus require an evaluation of potential risks and uncertainties that may cause costs to increase in the future.

STATES WITH INTEGRATED RESOURCE PLANNING OR SIMILAR PROCESSES



One of the objectives of integrated resource planning is to prevent imprudent resource investments. The traditional cost-of-service ratemaking model creates incentives for utilities to make large capital investments in generating resources and infrastructure. By requiring utilities to project long-term resource needs and costs, integrated resource planning aims to prevent long-term investments in unnecessary or unduly expensive resources. This Part explains how the traditional ratemaking formula incentivizes utilities to invest in capital-intensive resources, and explores how integrated resource planning aims to safeguard ratepayers from unnecessary costs.

A. IMPLICATIONS OF COST-OF-SERVICE RATEMAKING

The impetus for least-risk resource planning stems from the traditional utility ratemaking model and the underlying investment incentives this model creates. Vertically integrated investor-owned electric utilities typically earn revenue through cost-of-service electricity rates established by state public utility commissions, or PUCs.[25] These rates must be just and reasonable for utilities and electricity customers, and they are designed to enable utilities to recover their operating expenses and earn reasonable rates of return on capital investments.[26] Under the traditional cost-of-service ratemaking formula, utilities are entitled to earn rates of return on their rate bases, which include all capital investments the utilities made in providing electricity service.[27] Capital investments include the costs of building and maintaining generating facilities and other infrastructure used to create and transmit electricity to end users.[28] Utilities are also entitled to recover all reasonable operating expenses, which include all non-capital costs necessary to deliver electricity to consumers, including fuel costs.[29] Under the traditional formula, operating costs do not earn a rate of return.[30]

Historically, this cost-of-service ratemaking formula has incentivized utilities to invest in large, capital-intensive generating resources, such as fossil fuel-fired power plants, which earn a rate of return for investors.[31] The costs of these facilities could be included in electricity rates for multiple decades, and if a facility is removed from service prematurely, ratepayers could potentially be forced to pay for a facility that no longer provides power.[32] To protect ratepayers from potentially exploitative rates resulting from unnecessary capital investments, PUCs developed a series of mitigating doctrines to ensure that only reasonable investments get included in a utility's rate base. Under the prudent investment doctrine, a utility is only entitled to recover "prudent" capital investments.[33] Under the used and useful doctrine, a utility is not permitted to include a prudent capital investment in its rate base unless the facility is both necessary and placed into service.[34] Finally, electricity rates are established prospectively, so a utility is required to project its future operating expenses at the time of the ratemaking proceeding.[35] Therefore, if operating costs rise above a utility's projections, the utility may lose revenue.

While the prudent investment and used and useful doctrines were designed to protect ratepayers from exploitative rates, they expose utilities to significant risk in the event that a facility never enters into service. This is precisely what happened during the nuclear power boom of the 1970s, when rising construction costs, inaccurate demand projections, and the 3 Mile Island incident led utilities to cancel construction on or abandon dozens of nuclear plants before the facilities entered into service.[36] Though these plants were not used and useful, most PUCs allowed the utilities to recover at least some of their costs from ratepayers. While the utilities often did not earn a rate of return on the failed investments, ratepayers nonetheless were forced to pay for the utilities' failures.[37] Some states, however, prohibited the utilities from recovering their investments entirely, at great expense to the utilities and their investors.[38] The controversy surrounding these stranded nuclear plant costs revealed the limitations of the prudent investment and used and useful doctrines in preventing risky capital investments in large, expensive generating facilities.

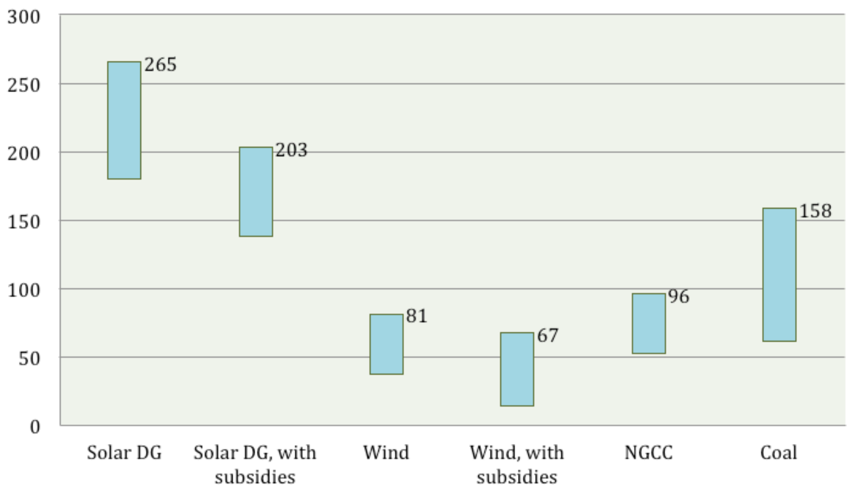
A nuclear power plant can cost billions of dollars.

B. EMERGENCE OF INTEGRATED RESOURCE PLANNING

Integrated resource planning emerged in the 1980s in response to the nuclear cost overruns and fuel shortages of the late 1970s.[39] These planning rules were primarily designed to function within the electricity sector of the 1980s, in which large-scale, fossil fuel-fired power plants were the dominant generating resources available.[40] Regulators wanted to protect ratepayers from unanticipated rate increases and directed utilities to identify resource portfolios that would satisfy increases in energy demand at the lowest cost to consumers.[41] As of 2011, 27 states had adopted integrated resource planning rules directing utilities to project their future energy and capacity needs and identify portfolios of low-cost resources capable of satisfying consumer energy demands over an extended time frame.[42]

In the resource planning context, all anticipated and foreseeable costs associated with a resource are levelized over the planning horizon. These costs typically include initial capital expenditures and operating and maintenance costs, fuel costs, and environmental compliance costs.[43] While some costs, such as capital expenditures and operating and maintenance costs, may be relatively easy to estimate, costs tied to fuel prices or environmental regulatory requirements are more uncertain over extended timeframes. Utility planners must nonetheless attempt to predict what future costs may be imposed on specific generating resources under a variety of potential

LEVELIZED COST RANGES (in U.S. dollars per megawatt hour)



Data from Lazard's Levelized Cost of Energy Analysis v. 8.0 (2014)

The levelized costs of renewable energy resources have decreased dramatically over the past decade. In 2014, the levelized cost of distributed solar generation ranged from $138 to $203 per megawatt-hour when federal tax credits were accounted for. The levelized cost of wind power ranged from $37 to $81 per megawatt-hour without federal incentives, and dropped as low as $14 per megawatt-hour with federal tax credits. In comparison, when fuel price fluctuation was taken into account, the levelized cost of natural gas combined cycle technology ranged from $52 to $96.

scenarios. Accordingly, during the integrated resource planning process, utilities typically conduct scenario or stochastic analyses[44] to evaluate risks and uncertainties associated with, for example, natural gas prices, wholesale electricity rates, and environmental regulations.[45] However, the risks considered and evaluative methods used vary among utilities, and final cost calculations may differ dramatically.[46]

Utilities should aim to estimate costs as accurately as possible during the integrated resource planning process, because integrated resource plans (IRPs) heavily influence a utility's ability to recover the value of its investments through electricity rates. As section A explained, PUCs generally allow utilities to recover capital costs for "prudent" investments in resources that are "used and useful."[47] In many states, IRPs inform PUC decisions on whether a utility's investment in a new generating facility was necessary or "prudent."[48] While IRPs are rarely binding on utilities, PUCs generally determine that resource investments are necessary and prudent if the investments are consistent with PUC-approved or "acknowledged" IRPs.[49]

This process provides PUCs with a degree of oversight over integrated resource planning that may influence the manner in which a utility addresses risk and uncertainties. A risk-averse PUC, for example, may refuse to acknowledge an IRP that fails to adequately account for potential fuel price volatility or foreseeable carbon regulations. On the other hand, a PUC may require strict compliance with least-cost planning mandates and may refuse to acknowledge an IRP where the preferred resource mix is not least-cost, even if the least-cost alternative exhibits more vulnerability to risk. Because a failure to obtain PUC acknowledgment of an IRP indicates that the PUC may later refuse to approve investments in resources identified in the IRP, utilities are heavily incentivized to comply with PUC directives regarding utility planning practices.

III. Addressing Risk and Uncertainty in an Evolving Electricity Sector

Although utility planning has arguably improved since the emergence of integrated resource planning, it has not prevented significant investments in potentially risky resources. The U.S. electricity sector is currently adjusting to a series of disruptive conditions and developments, and uncertainties regarding future fuel prices and climate change regulations are creating significant challenges for utility resource planning. The entrenched least-cost resource planning model appears ill-suited for today's evolving electricity sector and may prevent utilities from adequately mitigating exposure to emerging risks.

This section describes some of the emerging risks and sources of uncertainty that may impact the evolving 21st century energy sector, and discusses how utility resource planning practices are responding—or failing to respond—to changing market and regulatory conditions.

A. VOLATILITY IN THE POWER SECTOR

The American electricity sector is currently undergoing a period of substantial change, which, according to a recent Ceres report, has created "a level and complexity of risks that is perhaps unprecedented in the industry's history."[50] Climate change may present the most significant source of uncertainty for electric utilities. It is extremely likely, if not inevitable, that greenhouse gas emissions from existing power plants will be subject to some form of regulation over the coming decade. Indeed, many states and regions

already regulate greenhouse gas emissions from electric power plants,[51] and greenhouse gas emissions from both new and existing sources will likely be regulated under section 111 of the Clean Air Act in the near future.[52] Fossil fuel resources may therefore be disproportionately vulnerable to cost increases stemming from future regulatory actions, and utilities with carbon-intensive generation resources expose their investors and ratepayers to significant levels of risk.

The electricity sector is responsible for approximately 40% of the nation's carbon dioxide emissions.[53] According to a California survey of utility IRPs, most regulated utilities now assess risks associated with potential carbon costs during the IRP process.[54] Most utilities surveyed conducted some form of scenario analysis in which they imposed a range of hypothetical carbon costs on potential resource portfolios.[55] However, the California survey was unable to determine whether these utilities considered the potential carbon costs associated with their existing generation assets, or whether these scenario analyses only evaluated prospective generation options.[56] Perhaps more importantly, these carbon risk analyses did not appear to influence every utility's final portfolio selection, and cost continued to have the strongest influence on the majority of portfolio selections.[57]

While utilities and regulators increasingly acknowledge the risks associated with coal-fired electricity, they have not acknowledged the risks associated with replacing coal with another fossil fuel, natural gas. Over the last ten years, more than 120 proposals to construct new coal-fired power plants have been canceled due to environmental and cost concerns.[58] EPA's proposed New Source Performance Standards for greenhouse gas emissions from new electricity generating units effectively prohibit the construction of new coal plants without carbon capture and sequestration.[59] Due to increased regulation of coal-fired power and recent decreases in natural gas prices, utilities have looked to natural gas to fuel future energy demands. However, this increased reliance on natural gas may actually increase utilities' risk exposure.

Natural gas combined cycle facilities typically emit between 800 and 1,000 pounds of carbon dioxide per megawatt hour.

Historically, natural gas prices were very volatile, but the recent explosion of hydraulic fracturing (fracking) has contributed to historically low fuel prices.[60] Utilities appear to assume that natural gas prices will remain low for the foreseeable future,[61] yet this assumption may be shortsighted. For example, researchers at Credit Suisse and the University of Pittsburgh found that it costs significantly more to extract gas through fracking than through traditional drilling.[62] According to this data, the average cost to produce natural gas from a new well using hydraulic fracturing is around $9–$10 per MMBtu (million British Thermal Units).[63] However, natural gas currently sells for around $4 per MMBtu.[64] It appears, then, that current natural gas prices may be artificially, and temporarily, low. Increases in regulatory

To prevent global temperatures from increasing more than two degrees Celsius, sixty to eighty percent of current fossil fuel reserves must remain in the ground.

oversight over natural gas extraction activities or the emergence of a robust natural gas export market could cause prices to rise dramatically.[65] Moreover, natural gas-fired generation stations produce greenhouse gas emissions,[66] and thus are not immune to the carbon regulatory risks discussed above. Even without regulatory changes, some economists believe the natural gas sector's economic viability is overstated and that natural gas prices will have to rise—perhaps substantially—in the foreseeable future.[67]

Many utilities, however, fail to seriously address natural gas fuel price uncertainties in their resource planning processes. California's 2008 IRP survey found that all utilities conducted fuel price forecasting, yet very few of the IRPs assessed market price uncertainty through scenario analysis.[68] Of the utilities that did engage in this analysis, most merely adjusted fuel prices up or down by a set percentage.[69]

The electricity sector's generally slow and inconsistent response to addressing the risks and uncertainties associated with carbon emissions is raising concerns in the investment community.[70] Preventing global temperatures from rising more than 2°C will require substantial reductions in fossil fuel consumption through 2050.[71] According to the Carbon Tracker Initiative, this means that 60–80% of current identified coal, oil, and gas reserves must never be combusted, yet the top 200 fossil fuel companies have allocated an estimated $674 billion for locating and extracting additional reserves.[72] If stringent carbon emissions limitations are implemented, these companies will be left with significant stranded assets. In a recent Ceres report, Navigant Consulting noted that utilities with carbon-intensive resource portfolios could experience revenue reductions up to 20%.[73] These losses would be passed on to consumers or utility shareholders, and could cause the credit ratings of investor-owned utilities to drop.[74] The average credit rating for the electric utility industry has already dropped from an A to a BBB, signifying a heightened investment risk that, in turn, increases utility financing costs.[75] Moreover, in the event that stringent emissions restrictions are implemented, inefficient coal-fired power plants may become uneconomical to operate, and utilities may opt to retire these facilities rather than invest in expensive emissions controls. These premature retirements could further compound existing financial risks.[76]

B. ADAPTING TO CHANGING CONDITIONS: RESOURCE PLANNING IN A VOLATILE MARKET

In 2012, the National Association of Regulatory Utility Commissioners hosted a workshop called the Energy Risk Lab, which is an interactive simulation game designed to assess utility and regulatory responses to real-world energy policy shifts.[77] The game required participants to respond to a number of regulatory scenarios, including potential carbon pricing, gas price volatility, a national Clean Energy Standard, fracking moratoria, and new emissions regulations under the Clean Air Act.[78] Participants were required to develop and manage resource portfolios that could comply with environmental regulations, maintain reliability, and control costs under changing regulatory conditions.[79] At the end of the workshop, participants that strategically planned ahead for future risks and developed diverse portfolios of low-risk resources achieved the most successful long-term outcomes.[80] Participants that failed to implement a comprehensive strategy to respond to future risks, and instead only reacted to one variable at a time, "suffered rapidly increasing costs, an inability to maintain reliability, and delays in complying with regulations."[81] According to Miles Keogh, the game's organizer, the exercise provided important insights into resource planning: first, a strategic approach to risk mitigation yields more favorable results than a reactive approach, and second, portfolios with diverse resources outperformed lower-cost portfolios with only a single resource type.[82]

Warren Gretz, NREL (1991)

Public Service Company of Colorado's Cherokee Station is a coal-fired power plant located near downtown Denver. The utility aims to retire the plant's four coal-fired units by 2017, sixty years after the facility entered into service in 1957.

Utilities have an opportunity to mitigate many of the foreseeable risks discussed above by engaging in comprehensive, risk-focused resource planning. However, while some utilities acknowledge risks presented by fossil fuel investments and consider the risk-reduction benefits of renewable resources,[83] cost continues to be the deciding factor in a majority of resource planning decisions.[84] As a result, renewable resources have struggled to compete with historically low natural gas prices, and utilities continue to make high-risk investments in fossil fuel resources.[85]

Through the integrated resource planning process, regulators traditionally require utilities to identify the least-cost resource portfolio that will satisfy projected demand over the course of the planning horizon. Existing least-cost planning structures allow utilities to make assumptions regarding the costs and risks associated with renewable and fossil fuel resources, and many utilities impose constraints on renewables within their analyses that may manipulate modeling results.[86] In many instances, IRPs may reflect utilities' resource preferences and biases, and thus may apply unrealistic assumptions regarding future costs.[87] Least-cost planning analyses may not adequately address potential cost increases resulting from policy reforms, and current resource planning practices may thus expose utilities, investors, and ratepayers to unacceptable levels of risk.[88]

The outcomes from the Energy Risk Lab demonstrate how important strategic, risk-based resource planning is in an evolving regulatory environment. To remain profitable, utilities must adequately address risks and opportunities associated with future greenhouse gas emissions limitations, fuel availability and price volatility, environmental regulations, and federal and state energy policies. These risks and opportunities affect all stakeholders. Moreover, investors, ratepayers, and regulators cannot avoid risk simply by following the status quo. The Brattle Group estimates that the total capital invested in the U.S. electricity system will double by 2030.[89] Generating resources built today may still be operational forty years from now, and regulators must ensure that utilities invest capital wisely. Regulators can best minimize risks to ratepayers by requiring utilities to engage in careful, comprehensive resource planning that emphasizes risk reduction over least-cost requirements. Part IV discusses resource planning policies that aim to reduce vulnerability to foreseeable risks and uncertain outcomes.

To remain profitable in the 21st Century electricity sector, utilities must minimize their exposure to a variety of risks and uncertainties associated with fuel price volatility and greenhouse gas emissions regulation. Renewable energy resources like wind and solar power help to mitigate ratepayer and investor vulnerability to these sources of risk.

IV. Least-Risk Resource Planning

"Least-risk resource planning" refers to resource planning practices designed to minimize exposure to future risks and uncertainties. Least-risk resource planning directs utilities and regulators to quantify the risks and uncertainties associated with all resource options. Utilities then must select the resource portfolio that most effectively reduces exposure to foreseeable or unreasonable risks. This planning model helps to ensure that ratepayer and investor concerns are accounted for by allowing stakeholders to participate in the planning process, and it provides state utility regulators with enforcement authority to ensure that utilities are adequately addressing risk and uncertainty. This Part provides an overview of the least-risk resource planning concept and describes existing resource planning requirements and practices designed to reduce exposure to risk and uncertainty.

A. AN OVERVIEW OF LEAST-RISK RESOURCE PLANNING

Least-risk resource planning aims to reduce vulnerability to risk and uncertainty by evaluating a wide range of potential future scenarios and outcomes and identifying a resource portfolio that will best ensure long-term price stability under all potential outcomes.[90] Least-risk planning is an emerging concept in the context of integrated resource planning, and there are currently no uniform standards to define this planning approach. In this paper, the term "least-risk resource planning" refers to an alternative resource planning process comprised of components borrowed from state resource planning rules and guidelines, utility IRP practices, and policy analyses. While no state has developed or implemented a pure least-risk planning regime, some states have incorporated least-risk planning requirements into their IRP regulations or guidelines.[91] A recent Ceres report identified a variety of benefits stemming from such "risk-aware regulation," including consumer benefits from lower-risk long-term investments, utility benefits from a more predictable business environment, investor benefits from reduced threats to cost recovery, regulatory benefits from increased transparency and improved decision-making, and societal benefits from a "cleaner, smarter, more resilient electricity system."[92]

BENEFITS OF LEAST-RISK PLANNING

Consumers: low-risk resource investments
Utilities: increased economic stability and regulatory certainty
Investors: reduced risk of stranded costs and cost recovery denials
Regulators: increased transparency and informed decision-making
Society: more sustainable, resilient electricity system

To better understand the strengths and benefits of least-risk planning, it helps to compare this new planning approach with the established least-cost approach. Under traditional least-cost resource planning, utilities aim to identify the combination of resources that will satisfy demand and capacity needs at the lowest cost over the entirety of the planning horizon. Utility planners typically conduct scenario or sensitivity analyses to determine how specific uncertainties, such as fuel price volatility or increased regulatory controls, could impact a resource portfolio's costs over the planning horizon.[93] Utilities generally select the resource portfolio with the lowest cost over the majority of possible futures. However, when there is a substantial degree of uncertainty surrounding different possible future scenarios, a preferred resource portfolio may be least-cost under a number of scenarios, yet very high-cost under other scenarios.[94]

For example, many utilities now conduct scenario analyses to measure the impacts of potential carbon regulations.[95] Under scenarios that assume no carbon costs will be imposed over the planning horizon, the analysis may conclude that a natural gas plant will have a lower levelized cost than a wind power facility. However, under a scenario that assumes carbon costs will be imposed, the wind facility may be the least-cost resource. If most scenarios assume no carbon cost, the natural gas plant will likely be the preferred resource because it is the least-cost resource under most potential futures, and the carbon cost future will be viewed as an improbable outlier. However, the scenario assuming a carbon cost will be imposed over the planning horizon may be more likely to occur than the scenarios that assume no carbon price will be imposed. In this case, the natural gas plant might be the least-cost resource under a variety of less-probable futures, while the wind facility is the least-cost resource under the most probable future. This outcome is possible because state planning regulations generally do not assign probabilities to future scenarios. Least-cost planning rules may direct utilities to assess specific scenarios, but utilities generally have discretion to decide whether the scenarios will actually occur during the planning horizon. PUCs can ask utilities to defend their assumptions, but when there is significant uncertainty involved, PUCs may hesitate to substitute their judgment for that of the utilities.

Least-risk resource planning, on the other hand, aims to prevent high-risk resources from being selected through the planning process by assessing a portfolio's vulnerability to potential risks and uncertainties across all scenarios. In contrast to least-cost planning, least-risk planning incorporates additional metrics into the resource planning process to estimate the potential for long-term cost stability or volatility.[96] Utility planners model

IRP SCENARIO EXAMPLES

- high/low fuel prices
- high/low carbon costs
- high/low capital costs (specific resource types)
- high/low load growth
- high/low wholesale electricity prices
- subsidies available/not available
- high/low precipitation
- solar PV penetration
- high/low consumer energy efficiency
- high/low RPS mandates

for a range of specific risks and metrics, and they may analyze resource portfolios in light of desirable or undesirable outcomes, such as preventing negative environmental impacts or creating new employment opportunities.[97] The following section provides a brief overview of utility risk assessment methods.

B. ASSESSING RISK AND UNCERTAINTY

Risk assessment is the cornerstone of least-risk resource planning. Analytical tools and methods such as least-risk scenario analyses enable planners to measure potential cost impacts resulting from foreseeable yet uncertain occurrences.[98] A recent report by the National Renewable Energy Laboratory (NREL) notes that many states have introduced risk parameters and least-risk metrics into the planning process, which help utilities identify resource portfolios that are less vulnerable to future cost variability.[99] Risk parameters can address a variety of both negative and beneficial impacts; for example, planners may wish to determine the potential environmental impacts of each candidate portfolio or assess potential economic or societal impacts, such as a portfolio's potential to create jobs in the utility's service area.[100]

While it is essential for utilities to address risk and uncertainty, accurately calculating each portfolio's potential risk exposure adds significant complexity to the resource planning process. In an attempt to simplify this process, researchers at the Nicholas Institute for the Environmental Policy Solutions developed an alternative least-risk metric designed to calculate each portfolio's total exposure to identified risks. In their working paper, authors Patrick Bean and David Hoppcock introduce a least-risk metric that "minimizes the maximum regret" across the range of scenarios considered in the planning analysis.[101] Under this metric, the "regret" is the difference between a resource's cost and the least-cost option under the same scenario.[102] The least-cost resource under a specific scenario would therefore have a regret of $0. Each resource's regret is calculated under each scenario, and these regrets are then added together to calculate the resource's "maximum regret."[103] Under this metric, a resource that is least-cost under a majority of scenarios may have a higher maximum regret than alternative resources if its costs are disproportionately high under a specific scenario.

MINIMIZING THE MAXIMUM REGRET

STEP 1: Calculate the net levelized cost or present value of revenue requirement for each resource portfolio across all scenarios.

STEP 2: Determine the least-cost portfolio under each scenario.

STEP 3: Determine a "regret score" for each portfolio by subtracting the PVRR of the least-cost portfolio under each scenario.

STEP 4: Calculate the "maximum regret" for each portfolio by selecting the highest regret score for each portfolio across all scenarios.

STEP 5: Identify the portfolio with the lowest maximum regret.

Patrick Bean & David Hoppcock, *Least-Risk Planning for Electric Utilities* (2013)

While calculating the maximum regret for each resource would enable utility planners to determine each resource's total risk exposure under a series of scenarios, the metric treats each scenario as equally probable, and thus gives each scenario equal weight when assessing total risk exposure. However, some individual futures may have a significantly higher probability of actually occurring than others. By treating all scenarios as equally probable, risk exposure determinations may fail to account for the most realistic outcomes. One solution may be to incorporate each scenario's probability of occurrence into the analysis. Oregon, for example, requires that utility planners identify a base-case scenario reflecting what the utility considers the most likely future for carbon regulation.[104] One downside of this approach is that it increases the potential for utility biases to distort the analysis. However, PUC oversight over utility assumptions and probability estimates may help to minimize this distortion.

C. RESOURCE PLANNING RULES AND GUIDELINES

Utilities that effectively adapt to changing circumstances in the electricity sector will be more likely to succeed in the coming decades, and some regulators and utility planners have begun to consider factors beyond cost in the planning process. A handful of states recently amended their integrated resource planning regulations to reflect concerns over future environmental regulations, fuel price volatility, market dynamics, and climate change.[105] States like Arizona, Colorado, Hawaii, and Oregon have developed methods to incorporate least-risk planning requirements into established resource planning models.[106] Arizona's planning rules were revised to promote diversification of utility generation portfolios, decrease reliance on fossil fuels, and address environmental impacts such as air emissions.[107] Arizonan utilities now must identify and assess a number of risks and uncertainties and describe ways in which these risks can be effectively managed.[108] In Colorado, the PUC recently promulgated Resource Planning Rules that replace the term "least-cost" with "cost-effective," which it defines as "the reasonableness of costs and rate impacts in consideration of the benefits offered by new clean energy and energy-efficient technologies."[109] The rules require utilities to include at least three alternative resource plans in their IRPs that include more renewable or demand-side resources than their base portfolios.[110] In general, these rules reflect an emerging understanding that resource investments today face potential risks that were unforeseen twenty years ago.

Oregon provides a practical example of how regulators can integrate least-risk planning practices into utility resource planning requirements. In 1989, the Oregon PUC adopted least-cost planning as the state's preferred resource planning approach.[111] Under this approach, the goal of resource planning was "to ensure an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest."[112] The Oregon PUC subsequently revised its resource planning requirements in 2007 to instead direct utilities to select the portfolio "with the best combination of expected costs and associated risks and uncertainties."[113]

Oregon's resource planning rules include substantive and procedural requirements to facilitate a least-risk planning process. From a substantive standpoint, each resource plan must include a variety of components, many of which are designed to address risk and uncertainty.[114] Utilities must evaluate how each candidate resource portfolio performs over a range of risks and uncertainties, and plans must include an analysis of the uncertainties surrounding each portfolio.[115] A plan must identify any key assumptions the utility made about the future scenarios used in the analysis and determine whether any state or federal energy policies could present a barrier to the plan's implementation.[116] These Guidelines help ensure that all reasonably foreseeable risks and uncertainties are addressed in the planning process and impose a degree of accountability on utilities to prevent improbable assumptions from guiding the planning process. The public participation provisions provide an additional level of oversight and give ratepayers the opportunity to review the risk analysis before a plan is finalized.

Oregon's Guidelines create a hybrid least-cost/least-risk planning regime that encourages utilities to select portfolios with the best balance of cost and risk, but they do not directly require utilities to select a portfolio that is most effective in reducing exposure and vulnerability to risk and uncertainty. The guidelines do help ensure that utilities will provide the PUC with sufficient information regarding the impacts of risk and uncertainty on the utility's preferred portfolio. In addition, they enable the PUC to reject an IRP that fails to adequately account for risk. However, the effectiveness of these provisions ultimately depends on how utilities implement the guidelines during the IRP process, and how stringently the PUC enforces these requirements.

D. UTILITY IMPLEMENTATION OF RESOURCE PLANNING RULES

Resource planning practices and methodologies vary considerably between utilities, even between utilities operating within the same jurisdiction. The manner in which a utility implements resource planning requirements can have a significant influence on the composition of its preferred resource portfolio and associated exposure to risk.

PacifiCorp and Portland General Electric's (PGE) 2013 IRPs help to illustrate the variation between utility IRP practices operating within the same jurisdiction.[117] Both utilities operate within the state of Oregon, and thus are subject to Oregon's IRP Guidelines. However, the two utilities' applications of these Guidelines differ significantly. The two IRPs also reflect differing assumptions about uncertain variables and assign different probabilities to potential outcomes. These assumptions appeared to influence the manner in which each utility evaluated risk and uncertainty through the IRP process. The following discussion describes how the two utilities differ in implementing Oregon's IRP Guidelines.

PGE's PLANNING PROCESS

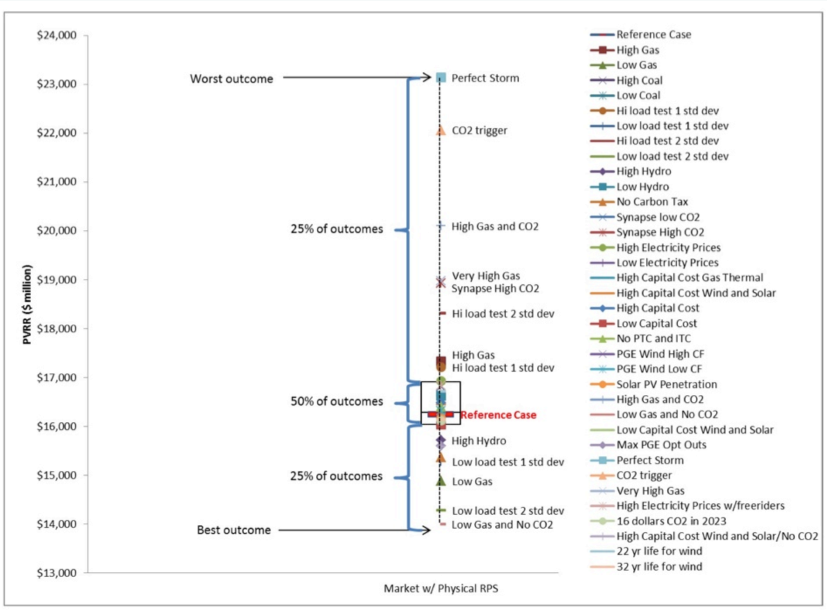
Oregon's IRP Guideline 1 directs each utility to consider a number of sources of risk and uncertainty.[118] Guideline 4 mandates that each IRP include an "[e]valuation of the performance of the candidate portfolios over the range of identified risks and uncertainties."[119]

In compliance with these directives, PGE created a series of candidate resource portfolios and evaluated these portfolios under 36 future scenarios. These scenarios reflected risks associated with, for example, fuel and CO_2 prices, capital costs, availability of tax incentives, and wholesale energy prices.[120] PGE designed these future scenarios to evaluate how reasonably foreseeable outcomes could impact portfolio costs.[121] The utility also used stochastic analysis, which aims to mimic real-world variability, to address risks associated with electricity demand and natural gas prices.[122]

Oregon's IRP Guideline 1(c)(1) directs utilities to measure both the severity and variability of potential costs.[123] In implementing this Guideline, PGE measured *severity* as the average of each candidate portfolio's four highest cost outcomes under all 36 future scenarios.[124] This approach aimed to determine the highest cost, and therefore greatest risk, each portfolio could face. To measure *variability* of cost outcomes, PGE calculated the average cost of each portfolio's four highest-cost futures, and then subtracted the reference case cost (the reference case was the future scenario PGE deemed most likely to occur).[125] This approach aimed to determine each portfolio's exposure to cost risks due to external or market variables in relation to the reference case.[126] After determining the severity and variability of potential outcomes, PGE assessed the durability of each portfolio by calculating the percentage of time each portfolio would outperform other portfolios in the individual futures, and subtracting the percentage of time that the portfolio would underperform.[127]

Together, these cost analyses enabled PGE to identify each resource portfolio's exposure to risk. First, PGE identified how specific future variables, such as high natural gas prices, would impact each portfolio's cost and performance. Second, PGE determined how costly (i.e. risky) each portfolio could potentially be. Third, PGE compared these

PGE'S PORTFOLIO COST AND RISK ANALYSIS



To identify the resource portfolio with the best combination of cost and risk, PGE created box-and-whisker plots to measure the highest, lowest, and reference case outcomes for each candidate resource portfolio. PGE's Figure 10-5 shows these scenario cost outcomes for PGE's Market with Physical RPS candidate portfolio. The utility then compared these cost distributions for all of the 2013 IRP candidate portfolios.

PGE 2013 IRP, fig. 10-5: Candidate Portfolio Cost Detail Across All Futures, Market with Physical RPS. Image curtesy of Portland General Electric.

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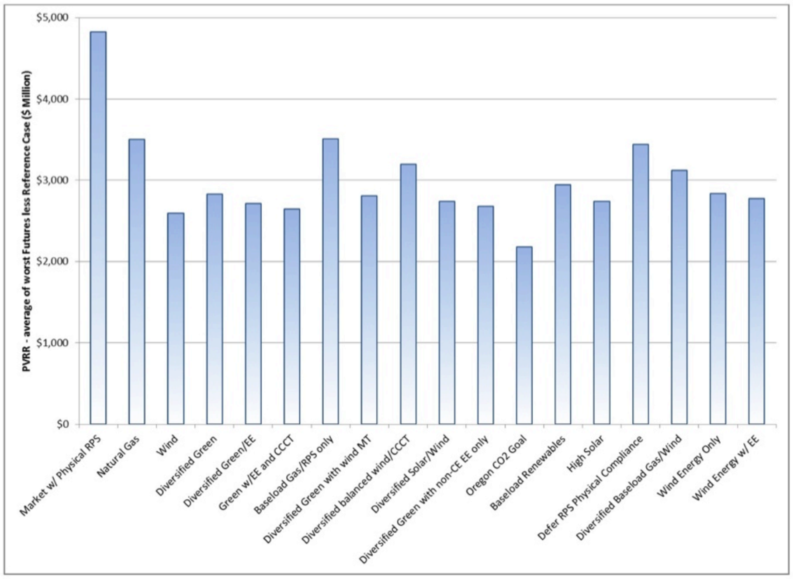
PGE'S PORTFOLIO COST AND RISK ANALYSIS: COST VARIABILITY



PGE 2013 IRP, fig. 10-3: Candidate Portfolio Risk: Average of Four Worst Outcomes Less Reference Case (Variability). Image curtesy of Portland General Electric.

To measure each portfolio's potential cost variability, PGE averaged each portfolio's four worst cost outcomes under 36 scenarios, then subtracted the portfolio's cost under the reference case scenario from this average. This measure of cost variability provides insight into each portfolio's potential risk exposure, by comparing the difference between each portfolio's anticipated cost and worst-case cost outcomes. Portfolios with greater cost variability have more exposure to risk.

potential high-cost outcomes with the portfolios' costs under the most likely outcome (the reference case). This step essentially aimed to identify how vulnerable each portfolio was to risk.

Finally, Oregon's Guideline 1(c) mandates that utilities select a resource portfolio with the best combination of cost and risk.[128] PGE identified the three portfolios with the best overall cost and risk performances as viable candidates, and selected the portfolio with the lowest estimated cost as its preferred resource portfolio.[129] PGE's preferred portfolio recommended adding 1,049 MW of wind power, two 395 MW natural gas combined cycle facilities, 463 MW of peaking supply, 428 MW of energy efficiency, 90 MW of demand response, and 30 MW of dispatchable standby generation.[130]

PACIFICORP'S PLANNING PROCESS

PacifiCorp's 2013 IRP followed a more complicated approach to implementing Oregon's IRP Guidelines. Due to the complexity of PacifiCorp's methodology, a simplified description of the key components of the utility's approach is introduced here. First, the utility developed 19 input scenarios reflecting five key variables identified by the utility and other stakeholders: 1) CO_2 prices; 2) natural gas and wholesale electricity prices; 3) policy assumptions on tax incentives and RPS requirements; 4) policy assumptions on coal plant compliance obligations; and 5) energy efficiency rates.[131] Next, PacifiCorp used System Optimizer simulations to generate resource portfolios and calculate each portfolio's levelized cost under each input scenario.[132] PacifiCorp then conducted stochastic simulations for each portfolio that randomly applied five "risk" variables: load variation, natural gas prices, wholesale power prices, hydro availability, and thermal unit availability.[133] To measure potential CO_2 emissions compliance costs, PacifiCorp conducted scenario analyses for zero, medium, and high CO_2 costs.[134]

In implementing Guideline 1(c)(1)'s requirement that utilities measure both cost variability and the severity of bad cost outcomes, PacifiCorp calculated the stochastic average cost and risk-adjusted average cost for each portfolio. The stochastic average cost (which PacifiCorp called the "*stochastic mean PVRR*") is the average of each portfolio's variable operating costs under each stochastic simulation, plus the portfolio's levelized capital and fixed costs determined by the System Optimizer simulations.[135] This calculation represented the total potential cost for each portfolio.[136] The risk-adjusted average cost (which PacifiCorp called the "*risk-adjusted mean PVRR*") aimed to incorporate the risk of unlikely yet high-cost outcomes by adding five percent of each portfolio's highest variable production cost to the portfolio's stochastic average cost.[137]

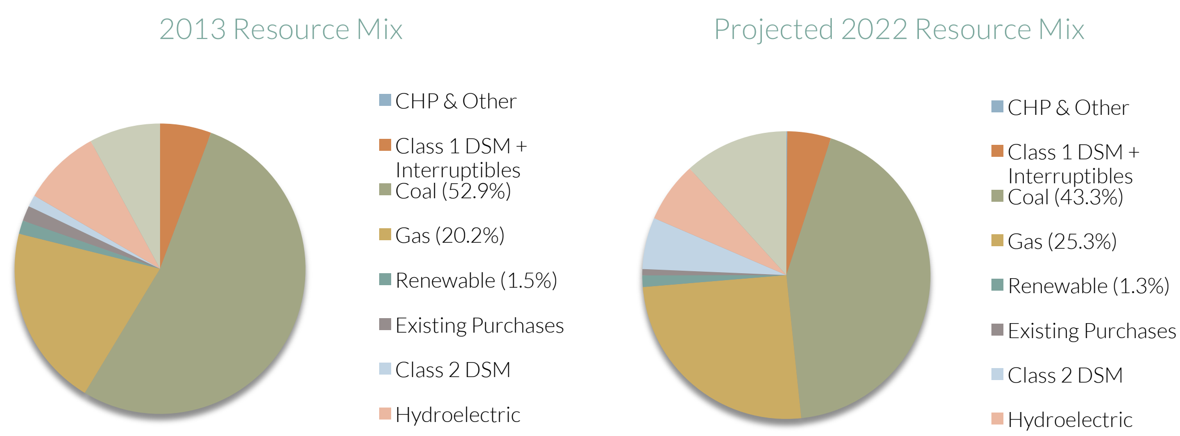
Finally, to identify a preferred resource portfolio with the best combination of cost and risk as required by Guideline 1(c), PacifiCorp conducted a three-step screening process. First, it conducted a pre-screening that eliminated portfolios that were "clear cost and/or risk outliers in relation to other portfolios."[138] It then identified portfolios with the lowest cost and risk thresholds among any of the three CO_2 price scenarios.[139] In the final screening, these top-performing portfolios were evaluated based on risk-adjusted average cost, CO_2 emissions, and supply reliability.[140] PacifiCorp ultimately selected a preferred resource portfolio under which the utility will continue to rely primarily on coal and natural gas for generating capacity.[141] Their preferred portfolio recommended adding 2,813 MW of natural gas (combined cycle), 1,593 MW of energy efficiency, 653 MW of wind power, 362 MW of natural gas peaking capacity, 293 MW of distributed and 10 MW of utility-scale solar power, and 193 MW of demand-side management to PacifiCorp's existing resource mix.[142]

SCENARIO DEVELOPMENT

As these descriptions illustrate, PGE and PacifiCorp's implementation of Oregon's IRP Guidelines differ significantly. The two utilities also followed very different approaches when developing their resource portfolios and future scenarios.

PGE developed distinct candidate resource portfolios to meet its future energy and capacity needs.[143] It then developed future

PACIFICORP'S CURRENT AND PROJECTED RESOURCE CAPACITY MIX, 2013 & 2022



PacifiCorp 2013 IRP, fig. 8.28: Current and Projected PacifiCorp Resource Capacity Mix for 2013 and 2022 (2013) scenarios, which primarily included a single variable, such as a high carbon price or a low natural gas price.[144] The remaining scenarios included credible combinations of distinct variables, such as high CO_2 costs with high natural gas costs.[145] PGE then evaluated each candidate portfolio's performance under each future scenario. This method allowed the utility to build candidate portfolios based around specific resources (such as renewables) and assess the impacts that individual variables (such as high carbon costs) would have on portfolio performance. This approach gave PGE the flexibility to decide what kinds of resources it wanted to invest in, and then evaluate whether these resources would perform well and remain cost effective under a variety of uncertain outcomes.

PacifiCorp, on the other hand, relied on its modeling software to build its candidate resource portfolios. The utility developed scenarios based around general themes, in which multiple variables were imposed together. These scenario themes largely reflected the utility's underlying policy assumptions. For example, 11 of the 19 scenarios used in the company's 2013 IRP were developed under an "environmental policy" theme reflecting assumptions regarding future environmental regulations.[146] PacifiCorp then used its System Optimizer software to build resource portfolios that were optimized to each scenario's conditions.[147] In other words, PacifiCorp decided what future conditions might occur, and used computer software to determine what kinds of resources would be most cost-effective under each potential scenario. Unlike PGE's approach, this method constrained PacifiCorp's ability to select specific resource types (such as renewables) and evaluate their performance under different outcomes.

POLICY ASSUMPTIONS

PGE and PacifiCorp also differed in their assumptions regarding future energy policies, which ultimately appeared to influence the composition of their preferred portfolios.

In its 2013 IRP, PGE predicted that the federal production and investment tax credits for renewables would be renewed at their current rates through 2023, at which time these incentives would be replaced with a carbon cost of $16 per ton, which would increase by 8% a year.[148] PGE's preferred portfolio directs the utility to add 357 MW of new wind resources in 2020, 504 MW of wind in 2025, and 188 MW of wind in 2030.[149]

In contrast, PacifiCorp's 2013 IRP assumed that the federal tax incentives for renewables would be allowed to expire, and while it also predicted that federal carbon costs of $16 a ton would be imposed in 2022, it assumed these costs would increase by only 3% a year.[150] During the pre-screening phase of its scenario analysis, PacifiCorp eliminated a portfolio developed under the assumption that future policies would favor renewable energy development.[151] The utility rejected the portfolio including 450 MW of new solar PV and between 1,100 and 2,900 MW of new wind resources[152] as an improbable risk outlier in relation to its other fossil fuel-dependent portfolios.[153] PacifiCorp also determined that portfolios calling for extensive coal plant retirements were high cost and high risk compared to portfolios with limited or no coal plant retirements.[154] Under the utility's preferred resource portfolio, PacifiCorp's renewable resource holdings will drop from 9.9% of its total generating capacity in 2013 to 9.3% in 2022.[155]

PGE & PACIFICORP IRP ASSUMPTIONS AND WIND ENERGY ADDITIONS

Assumptions and Wind Energy Additions	PGE	PacifiCorp
Federal Tax Incentives	Renewed through 2023	PTC expired ITC expires in 2016
Carbon Cost	$16/ton in 2023; increasing 8% per year	$16/ton in 2022; increasing 3% per year
Total Wind Capacity Additions	1,049 MW	650 MW

PacifiCorp's preferred portfolio did include an additional 432 MW of wind in 2024 and 218 MW of wind in 2025, for a total of 650 MW of new wind generation over the planning period.[156] These wind power additions represented the minimum renewable capacity that the utility requires to comply with its RPS obligations.[157] PacifiCorp concluded that "new wind resource additions are not cost effective given deteriorating policy and market conditions."[158] These "deteriorating policy and market conditions" included PacifiCorp's assumption that the federal Production Tax Credit will not be renewed.[159]

PGE and PacifiCorp's IRP scenario modeling and portfolio selections illustrate the extent to which a utility's subjective assumptions and biases may ultimately influence its renewable resource investments. PGE assumed that future policies will favor renewable energy development, while PacifiCorp assumed that future policies will continue to support coal-fired generation. As a result, PGE's preferred portfolio included nearly 400 more megawatts of wind capacity than PacifiCorp's preferred portfolio.[160] This portfolio variation is even more significant given the fact that PacifiCorp is a much larger utility, with more than three times the net generating capacity of PGE.[161]

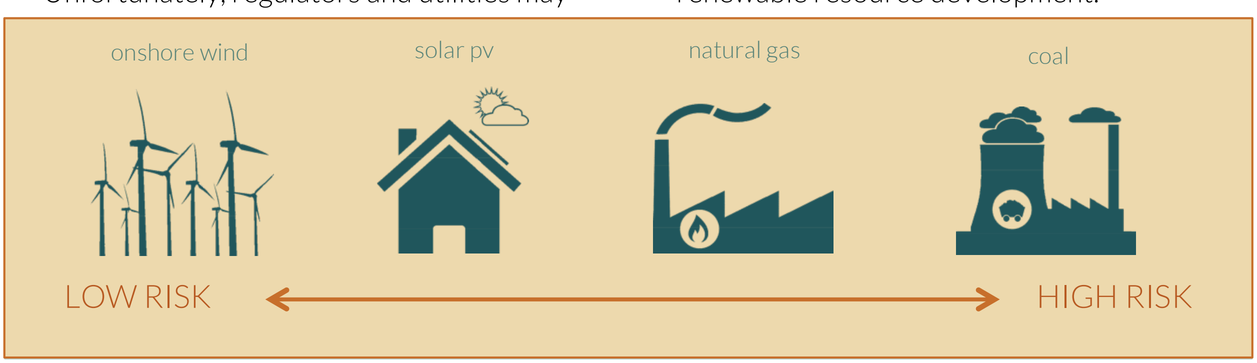
The PGE and PacifiCorp examples further help to illustrate how separate utilities within the same jurisdiction may implement relevant resource planning requirements differently from one another. These implementation discrepancies highlight the importance of PUC oversight during the planning process. Oregon's IRP Guidelines direct utilities to balance cost and risk and to identify key assumptions about the future.[162] Both utilities complied with this directive, but their respective assumptions differed from one another, particularly in regards to renewable energy policies. The Oregon PUC must therefore provide diligent oversight throughout the planning process to ensure the utilities' assumptions are in line with the state's energy objectives. In general, if an IRP does not adequately address foreseeable sources of risk and uncertainty, the PUC should withhold IRP acknowledgement until the utility revises its assumptions and analyses. PUC oversight is therefore an essential component of least-risk planning.

As the PGE and PacifiCorp comparison helps illustrate, the manner in which a utility accounts for risk and uncertainty during the planning process will likely influence the composition of its preferred portfolio. Failure to adequately implement risk-focused resource planning requirements could lead a utility to underinvest in resources that mitigate exposure to risk, such as renewables. Part V explores some of the potential implications that resource planning policies may have for renewable energy development.

V. Fossil Fuels vs. Renewable Resources: Assessing Risks and Benefits Through Long-Term Planning

Least-risk resource planning has significant implications for renewable energy development, primarily because renewable resources and energy storage generally have higher upfront costs than conventional generation resources, yet may be less vulnerable to foreseeable risks and potential cost increases. Renewable energy is a valuable addition to utility resource portfolios due to its ability to mitigate risk and reduce vulnerability to uncertain outcomes, including impacts associated with rising fuel prices and future carbon regulations. Ceres recently ranked resources according to their relative vulnerability to risk, and its analysis "shows a clear division between renewable resources and non-renewable resources," with renewables occupying the low-risk side of the spectrum, and fossil fuel resources occupying the high-risk portion.[163] States and utilities that aim to reduce exposure to risks associated with potential carbon regulations or fuel price increases should therefore favor investments in renewable resources over fossil fuel-dependent generating facilities.[164]

Unfortunately, regulators and utilities may not fully appreciate or identify the risk mitigation potential of renewable resource options. Moreover, least-cost resource planning mandates may create a barrier to renewable energy development by preventing utilities from investing in low-risk generation and storage resources if the corresponding costs are higher than alternative resources. The explosion in natural gas extraction has led many utilities to conclude that natural gas-fired generation is the least-cost, least-risk resource option. However, this conclusion may fail to account for various risks and uncertainties associated with fossil fuel resources. The risk assessment methods and assumptions commonly employed by utilities during the resource planning process may downplay some of these risks and fail to fully account for the benefits of renewable resources. As a result, utility resource portfolios may be disproportionately reliant on natural gas-fired facilities, exposing ratepayers and investors to unnecessary risks. This section explores the implications that portfolio cost and risk analyses may have on renewable resource development.



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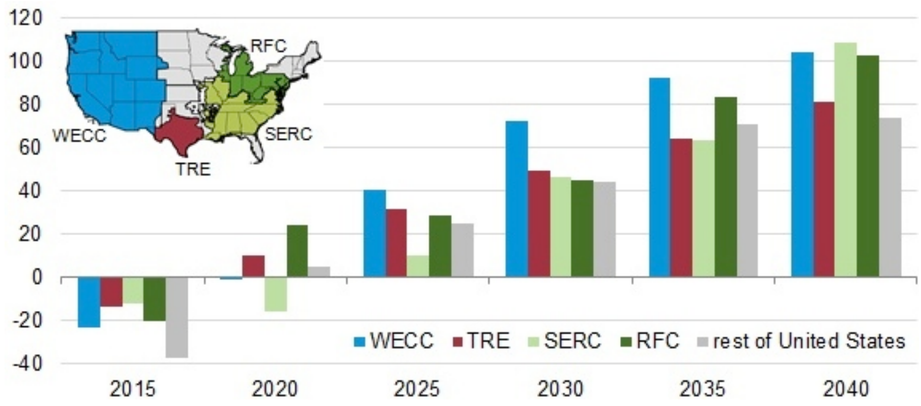
A. THE DANGER OF EQUATING LOW NATURAL GAS PRICES WITH LONG-TERM RISK MITIGATION

In the late 1990s and early 2000s, state regulators and utilities began to address the risks associated with fossil fuel-dependent portfolios through the resource planning process and began to consider renewable resources' potential to mitigate risks stemming from climate change and fuel price volatility.[165] During the same time period, coal-fired power development started to decline. According to a recent Ceres report, "[m]ore than 120 proposals for new coal-fired power plants have been canceled over the last decade due to concerns about environmental and financial risks."[166] By 2005, many western utilities had determined that wind energy was both a low-cost and low-risk resource, and had committed to add significant wind energy capacity to their existing resource portfolios.[167] Renewable energy technologies advanced rapidly, and improvements in manufacturing processes and increases in production rates helped drive down costs.[168] At the same time, policies such as state renewable portfolio standards and federal tax credits for large-scale wind and solar facilities provided incentives for utilities to invest in renewables. Wind power began to compete against conventional generation resources on a least-cost basis; for example, in 2003, Idaho Power determined that a 100-megawatt wind project was the least-cost resource available, with a projected levelized cost of $33.80 per megawatt hour over a thirty-year period.[169] For a while, it appeared that the combination of risk-oriented planning, technological advancement, and adoption of favorable policies would hasten the transition to a renewable electricity sector.

Todd Spink, NREL (2006)

Then the U.S. electrical sector experienced a fundamental shift. As it became increasingly evident that coal would not be the fossil fuel of choice for the 21st century, natural gas companies greatly expanded the use of hydraulic fracturing, or fracking, and the price of natural gas plummeted.[170] As natural gas fuel prices dropped, the focus of utility resource planning shifted accordingly. Utilities appeared to equate low market prices with reduced long-term risk, and formerly pro-renewable utilities began to favor natural gas as a low-cost alternative to coal. For example, in its 2003 IRP, PacifiCorp noted that renewable resources were an attractive portfolio addition, particularly because these

Projected Natural Gas-Fired Generation Increases by NERC Region, 2015–2040
(million megawatt hours)



U.S. Energy Information Administration (2014)

resources could mitigate risks associated with natural gas price volatility.[171] However, in the utility's 2013 IRP, PacifiCorp asserted that the "economic benefits of new renewable resources have deteriorated,"[172] and its preferred portfolio did not include any additional wind capacity prior to 2024.[173] According to data from the U.S. Energy Information Administration, natural gas combined cycle (NGCC) facilities are currently the least-cost generating resources available,[174] and are also the most commonly constructed new fossil fuel-fired generating facilities.[175] PacifiCorp's Preferred Portfolio, for example, would add more than 3,000 MW of new natural gas capacity over the 20-year planning period, while retiring more than 2,000 MW of coal capacity.[176]

The boom in natural gas development appears to correspond with a declining utility interest in renewable resources.[177] Cost currently appears to be the primary factor influencing most resource procurement decisions, and many utilities appear wary of the uncertainty surrounding future renewable technology prices.[178] Utilities further assert that the variability and intermittency of renewable generation make it difficult to estimate future energy and capacity availability, and most utilities do not include storage in their planning models due to insufficient data and projected expense of existing storage technologies.[179] In short, utility resource plans now appear to favor investments in natural gas generation due to projections that natural gas will remain a low-cost fuel for the foreseeable future. At the same time, utilities are avoiding investments in significant new renewable capacity due to the uncertainties surrounding future costs and the availability of incentives.

The reliance on natural gas, however, may be shortsighted. First, natural gas prices have historically been very volatile; for example, on November 16, 2001, day-ahead gas prices were $1.72 per million British thermal units (MMBtu), and on February 25, 2003, prices were $18.41 per MMBtu.[180] It is entirely possible that this price volatility will return in the future, particularly if U.S. exports increase as projected, or environmental controls are imposed on extraction activities. Second, natural gas plants emit significant quantities of carbon dioxide, with NGCC facilities typically emitting between 800 and 1,000 pounds of CO_2 per MW/h,[181] and these resources are therefore vulnerable to cost increases resulting from future carbon regulations.

Third, natural gas is a water-dependent form of electricity generation, and thus is vulnerable to potential water shortages resulting from drought and competing demands for limited water resources.[182] And finally, as the underlying costs and contamination risks associated with hydraulic fracturing come to light, jurisdictions may impose restrictions on fracking activities. For example, fracking generates large amounts of waste water that developers must dispose of.[183] It recently came to light that oil and gas developers in California had injected nearly three billion gallons of fracking wastewater into underground aquifers that the drought-stricken state could have used for irrigation or drinking water.[184] Concerns over groundwater contamination such as this may encourage state and local governments to impose fracking moratoria that could reduce fuel availability and raise prices.

Joshua Doubek (2011)
Water tanks preparing for a fracking operation.

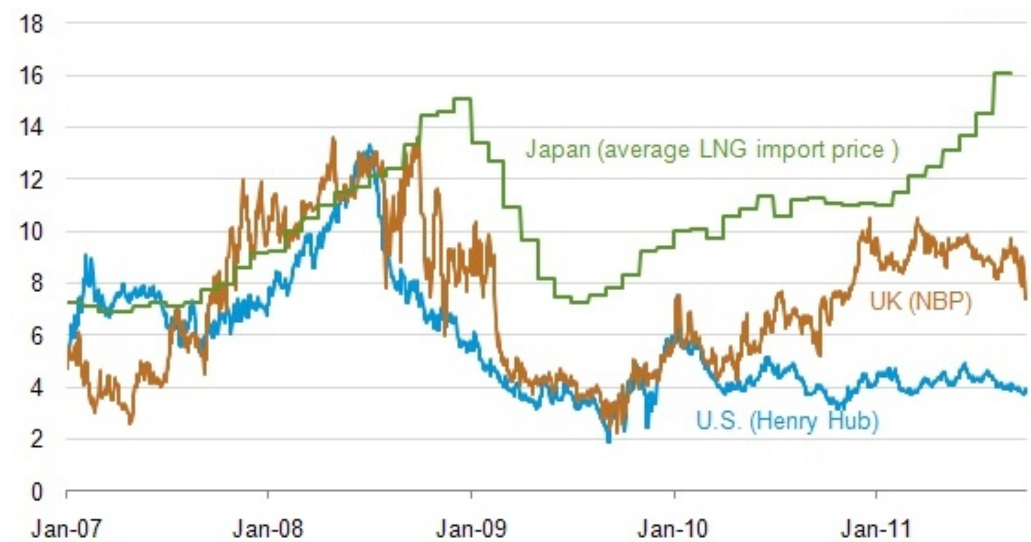
The following section explores how utilities evaluate these fossil fuel-related risks through the resource planning process, and considers the corresponding implications for renewable energy development.

B. ADDRESSING FOSSIL FUEL-RELATED RISK AND UNCERTAINTY

The way in which utilities balance cost and risk through resource planning has substantial implications for renewable resources, which many planners view as low-risk, yet high-cost, generating resources.[185] Fuel price volatility and potential greenhouse gas regulation are significant sources of risk and uncertainty for utility resource investments, and fossil fuel resources are particularly vulnerable to cost increases associated with these variables. Renewable resources have the capacity to mitigate risks associated with rising fuel prices or future environmental regulations. Therefore, when utilities and regulators place greater value on a portfolio's risk mitigation potential than projected cost, preferred resource portfolios will likely include a greater proportion of renewable generating capacity. To fully capitalize on the mitigation potential of renewable resources, utility planners must effectively identify and address foreseeable risks and uncertainties through the planning process.

Fuel price volatility presents a significant risk for fossil fuel-fired generating resources, and many states direct utilities to assess fuel price risks in their IRPs.[186] However, when utilities are allowed to pass fuel prices on to consumers, they have little incentive to mitigate fuel price risks.[187] Indeed, when utility planners assess natural gas fuel price impacts, they generally appear to rely on third-party price forecasts, which project that natural gas prices will stay low for the foreseeable future.[188] In a 2005 report on balancing cost and risk in utility resource plans, researchers with the Lawrence Berkeley National Laboratory cautioned that planners should not overly rely on base-case natural gas price forecasts, which have historically been

Trends in Natural Gas Spot Prices at Major Global Markets 2007–2011 $/MMBtu



U.S. Energy Information Administration (2011)

inaccurate.[189] Instead, the authors recommended that planners evaluate resource portfolio performance against a wide range of potential natural gas prices,[190] and design candidate resource portfolios to minimize exposure to fuel price volatility.[191]

Moreover, regulators and public participants cannot ensure that utilities adequately assess fuel price volatility risks unless utilities disclose their data. For example, North Carolina's IRP rules require that utilities consider risks associated with fuel costs,[192] yet in its 2013 IRP, Duke Energy Progress (DEP) did not provide the underlying basis for its cost projections. In the IRP, DEP applied the utility's "fundamental fuel price projections" to assess natural gas price volatility through its portfolio analysis.[193] According to the utility, these fuel cost estimates, which were not disclosed in the IRP, were either developed internally by the utility or based off of "other sources."[194] It is unclear whether the utility evaluated potential impacts over a range of fuel prices, or if it only assessed a single price projection. Regulatory and public oversight over the IRP process can help ensure that utilities are applying credible cost projections in their risk analyses, but effective oversight is dependent on transparent data disclosure.

Future environmental regulation presents another source of uncertainty for the resource planning process. It is extremely likely that some form of carbon regulation will be implemented within the near future, and many utilities now assess potential carbon compliance requirements in their resource plans.[195] According to IRP surveys conducted by the Regulatory Assistance Project and Lawrence Berkeley National Laboratory, however, methods for analyzing carbon risks vary greatly between utilities,[196] and relatively few utilities conduct comprehensive evaluations of potential emissions costs and controls applicable to both existing and future resources.[197] For example, 58% of DEP's generating capacity consists of fossil fuel resources,[198] yet the utility's 2013 IRP does not assess the economic impacts that forthcoming federal carbon emissions regulations may have on its existing resources.[199]

Additional regulatory risks arise in the context of water use and availability. Generating electricity through natural gas combustion is a water-intensive process; natural gas extraction, processing, and electricity generation collectively consume hundreds of billions of gallon of fresh water each year.[200] State-imposed regulatory constraints on natural gas-related water consumption would have immense implications for the industry, and some form of controls will likely be implemented in coming years as climate change-related water shortages become more prevalent.[201] Regulations may also be imposed to protect drinking water supplies from contamination resulting from natural gas extraction. Fracking activities have reportedly contaminated fresh groundwater in a number of states,[202] and additional regulations may be imposed to safeguard drinking water supplies in the future. However, few utilities appear to evaluate risks associated with future availability of water resources. PNM is a notable exception. In its 2014 IRP, the New Mexico utility conducted a drought sensitivity analysis, which found that drought conditions would require the utility to curtail low-cost fossil fuel generating facilities and replace the lost baseload generation with higher cost wholesale energy purchases.[203] This analysis is highly relevant in arid states like New Mexico, but many states could face potential water shortages due to climate change.

The manner in which a utility evaluates risk and uncertainty has significant implications for renewable energy development. For example, after completing the scenario analyses for its 2014 IRP, PNM concluded that potential fuel and carbon emissions costs would largely determine the timing of the utility's future renewable resource additions.[204] When PNM modeled for high natural gas and carbon costs, the planning software added new wind energy resources to the utility's portfolio in 2018.[205] However, when low natural gas and carbon prices were assumed, the software did not add new wind resources until 2029.[206] This example illustrates the impact that projected cost inputs may have on the composition of a utility's preferred resource portfolio; if a utility assumes that fuel and carbon prices will remain low, its modeling software may determine that renewables are not cost effective additions to the final resource mix. Such a conclusion, however, fails to account for the significant risk that fuel prices or carbon costs will rise over the course of the planning horizon. It is therefore essential for utilities to assess a range of credible future conditions, and for regulators to carefully review IRPs to ensure that the utilities' analyses are not distorted by improbable assumptions or inherent biases.

PNM NATURAL GAS and CARBON PRICE SCENARIO MODELING

VARIABLE	LOW SCENARIO	HIGH SCENARIO
Natural Gas Price	<\$4/MMBtu (2013–2015) \$4–5/MMBtu (2016–2025) \$6/MMBtu (2026–2035)	\$5/MMBtu (2013–2015) \$10/MMBtu (2016–2025) \$7–8/MMBtu (2026–2035)
Carbon Price	Federal regulation starts in 2026 \$10/ton CO_2 (2027)	Federal regulation starts in 2018 ~\$35/ton CO2 (2025) \$55/ton CO2 (2035)
Year 100 MW Wind Added	2029	2018

C. ASSESSING RISKS AND BENEFITS OF RENEWABLE RESOURCES

The manner in which utilities address risks and benefits associated with renewable energy can have substantial implications for utility investment in these resources. However, utility treatment of renewables in resource planning varies significantly. Utilities attempt to predict the future cost and performance potential of renewable resources, and these predictions shape IRP modeling outcomes and portfolio composition. Renewable resource technologies introduce a number of new variables into the planning process, which may complicate IRP modeling analyses. In addition, utility risk assessment practices ultimately influence the amount of renewable generating capacity included in a preferred portfolio, and these analyses may be shaped by subjective assumptions or inherent biases that distort assigned resource values. When utilities aim to mitigate risks associated with fossil fuel resources and capitalize on the benefits offered by renewable resources, preferred resource portfolios should include a greater percentage of renewable generating capacity.

Utilities make varying assumptions about the costs and availability of renewable resources and use different processes to develop candidate portfolios that may influence how renewables perform through modeling analyses.[207] Cost assumptions can significantly influence how a resource performs through modeling and scenario analyses, and inaccurate assumptions about the costs associated with wind energy integration and transmission can prevent additional wind capacity from being seriously considered as an available resource.[208] When utilities evaluate solar energy, their analyses may not account for the benefits distributed generation may provide to the grid.[209] Moreover, utilities may impose arbitrary limits on the amount of renewables included in candidate portfolios that do not accurately reflect the cost, performance, or risk mitigation potential of these resources.[210]

Renewable energy technologies also create a number of new variables for resource planning, and modeling for renewable resources may present a challenge for some utilities. To project the levelized costs of resources such as solar PV and wind, utilities must address a number of unique risks and uncertainties, including 1) the future availability of federal and state tax incentives; 2) integration costs for both utility-scale and

UNCERTAIN COST VARIABLES FOR RENEWABLE RESOURCES

- federal and state tax incentives
- integration costs
- rate of DG deployment
- capacity and load variability
- back-up generation needs
- technological advancements

distributed systems; 3) rates of customer-sited deployment over the planning period; 4) variability in capacity and load; 5) the need for spinning reserves and firming generation; and 6) potential technological advancements over the planning period that may significantly impact the capacity of variable renewable resources, such as widespread availability of distributed energy storage. In addition, external factors such as natural gas price volatility and future environmental regulations may have a substantial impact on the value of renewable resources. Utilities may be unfamiliar with collecting and analyzing these types of data, but failing to do so may lead to incomplete or inaccurate projections of potential outcomes.

Moreover, the risk assessment methods employed by utilities during the planning process may influence the extent to which renewables are included in the preferred resource portfolio, yet the manner in which utilities assess and balance the projected costs and benefits of renewables may vary significantly.[211] Individual utilities may evaluate different risks, or use different tools or metrics to measure specific types of risk.[212] Utilities make assumptions and predictions about whether future policies will favor renewable resources, and these assumptions influence their cost projections and the composition of their preferred resource portfolios. Furthermore, utilities may allow their subjective biases to influence risk assessment through scenario analysis by favoring results from scenarios they consider more probable, and downplaying or ignoring results from scenarios they consider less likely to occur.[213]

Examples from PGE and Duke Energy Progress's 2013 IRPs help to illustrate how a utility's subjective policy assumptions and a

PGE's Biglow Canyon Wind Farm in Sherman County, Oregon. *CREDIT: Tedder (2009)*

state's resource planning standards work together to influence the renewable generating capacity included within a preferred resource portfolio. PGE operates in Oregon, and thus is subject to the Oregon PUC's "least-cost/least-risk" IRP Guidelines.[214] As Part IV discussed, PGE's 2013 IRP assumed that the federal production and investment tax credits for renewables would be renewed at their current rates through 2023, at which time they would be replaced with a carbon cost of $16 per ton.[215] PGE's preferred resource portfolio would add 357 MW of new wind resources in 2020, 504 MW of wind in 2025, and 188 MW of wind in 2030.[216]

In contrast, Duke Energy Progress (DEP) operates in North Carolina, which imposes both statutory and regulatory least-cost planning requirements.[217] In its 2013 IRP, DEP determined that, absent the availability of federal and state subsidies, solar and wind technologies are not economically competitive resource options.[218] DEP assumed that federal tax credits for solar will expire in 2017 and that federal subsidies for wind resources would not likely be available in the near future.[219] Duke Energy, DEP's parent company, has the second-highest carbon emissions of any electric utility in the United States,[220] yet DEP's analysis failed to assess

DEP's Marshall Steam Station, a 2.09 gigawatt coal plant in Terrell, North Carolina. *CREDIT: Cdtew at English Wikipedia (2013)*

the benefits that additional renewable resources could provide in mitigating risks stemming from forthcoming federal carbon emissions regulations.[221] DEP's preferred portfolio would add 364 MW of new solar resources and only 100 MW of new wind resources through 2028.[222] These additions represent the minimum level of renewable energy the company must obtain to comply with its RPS obligations.[223]

These examples illustrate how a utility's subjective assumptions shape its IRP conclusions and renewable resource investments. In addition, the PGE and DEP examples demonstrate how state planning standards may influence a utility's portfolio composition. In North Carolina, it is state policy "to require energy planning and fixing of rates in a manner to result in the *least cost mix* of generation and demand-reduction measures which is achievable."[224] North Carolina's regulations require IRPs to identify "the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system."[225] Oregon, in contrast, directs utilities select a resource portfolio with "the best combination of cost and risk."[226] DEP's overarching cost concerns appeared to influence and restrict its evaluation of renewable resource options.

Where regulators and utilities aim to reduce risks associated with fossil fuel resources (such as carbon costs) and capitalize on the benefits associated with renewable resources (such as tax incentives), preferred resource portfolios should include a greater proportion of renewable generating capacity. In contrast, where regulators and utilities are primarily concerned with identifying least-cost resources, preferred portfolios include minimal renewable capacity.

Least-risk planning policies direct utilities to calculate risk-adjusted levelized costs, and therefore aim to capture the value of potential externalities that may arise over a resource's lifespan. Least-risk analysis helps to reduce ratepayer and investor vulnerability to risk by anticipating potential future cost increases. Renewable resources, which typically have high capital costs (although these are declining) but low vulnerability to risk and uncertainty, help to mitigate the fossil fuel-associated risks described in this Part. Effective least-risk planning policies prioritize a resource's risk mitigation benefits and thus help to level the playing field between renewables and conventional energy resources.

VI. Establishing an Effective Least-Risk Planning Policy

The energy sector is evolving at a rapid pace, creating new challenges and opportunities for electricity regulators, utilities, and consumers. Least-risk resource planning represents a promising energy policy for the shifting environment of today's electricity sector. Utilities that adequately seek to minimize exposure to risk and uncertainty will be better able to adapt to the energy realities of the 21st century. Least-risk planning may help facilitate the transition away from the current high-risk, fossil fuel-dependent electricity system, yet utilities are generally conservative organizations and are unlikely to alter their existing resource planning practices on their own accord. It is therefore up to state regulators to adopt resource planning policies that prioritize risk mitigation over short-term cost reduction.

Regulators can follow a series of general steps to develop and implement effective least-risk planning regimes. First, regulators must review existing resource planning regulations and revise any least-cost resource requirements. Second, regulators must develop least-risk planning rules establishing threshold risk assessment parameters. Third, regulators must effectively enforce these planning requirements. Fourth, regulators must connect resource plan approval to the ratemaking process to provide some certainty that investments in least-risk resources may be eligible for cost recovery. This Part explores these steps in greater detail and provides examples from existing state planning rules and utility IRPs to help illustrate how regulators should apply specific planning requirements in practice.

STEPS TO DEVELOP AN EFFECTIVE LEAST-RISK PLANNING POLICY

STEP ONE: revise least-cost resource requirements

STEP TWO: develop least-risk planning rules and guidelines

STEP THREE: implement and enforce least-risk planning rules

STEP FOUR: connect IRP approval to ratemaking process

A. STEP 1: REVISE LEAST-COST RESOURCE REQUIREMENTS

Before a state can establish an effective least-risk planning system, regulators must ensure that the necessary legal foundation is in place to enable risk-focused resource planning. In many states, this step may entail revising existing laws and regulations to eliminate entrenched least-cost resource requirements, which may directly or indirectly prohibit resource planning practices that lead utilities to select a non-least cost resource portfolio. In other states, this step may necessitate revising existing regulations to reduce ambiguity and clarify that utilities should identify and select resource portfolios with less exposure to risk and uncertainty.

Some states impose least-cost requirements through legislation,[227] while others implement least-cost requirements through utility regulations.[228] States also use varying terminology in their resource planning directives. Some states explicitly require utilities to select the "least cost" resource mix, while other states use terms like "cost effective" or "reasonable cost." For example, North Carolina's regulations state that utilities must "determine an integrated resource plan that offers the least cost combination (on a long-term basis) of reliable resource options for meeting the anticipated needs of its system."[229] New Mexico's regulations specify that the objective of utility resource planning is "to identify the most cost effective portfolio of resources to supply the energy needs of customers."[230] Hawaii's IRP Framework directs utilities to provide "safe and reliable utility service at *reasonable cost*."[231]

Least-cost resource requirements may dissuade utilities from investing in renewable resources, such as distributed solar PV systems.

The first step in establishing an effective least-risk planning policy involves eliminating any least-cost resource requirements within existing laws and regulations. These revisions should direct utility planners to identify and select the portfolio of resources with minimal exposure to risk and uncertainty. It is imperative that policymakers define statutory and regulatory terms as precisely as possible, particularly where the terminology is open to multiple interpretations. For example, the term "cost effective" can be interpreted in multiple ways, depending on the context in which it is used. Regulatory ambiguity creates uncertainty for utility planners, which in turn likely encourages utilities to focus their planning efforts on conventional resources with a history of PUC approval. Where statutory and regulatory texts use ambiguous terminology, these terms should be precisely defined to clarify that risk and uncertainty must be considered within resource cost calculations.

B. STEP 2: DEVELOP LEAST-RISK PLANNING RULES

The second step in developing an effective least-risk planning policy is to adopt and implement least-risk planning rules that establish requirements and parameters for the planning process. These rules should provide sufficient flexibility to enable planning practices to adapt to changing circumstances, such as new greenhouse gas regulations. There are a number of general components that all least-risk planning policies should employ. These general components are discussed briefly below, with supporting examples from existing state IRP rules and guidelines.

1. Establish Least-Risk Planning Goals and Objectives

Effective least-risk planning policies must specify that the goal or objective of the planning process is to identify a resource portfolio that minimizes exposure to risk and uncertainty. Oregon's IRP Guidelines, for example, specify that the primary goal of integrated resource planning is to select a resource portfolio "with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[232] In addition, IRPs "must be consistent with the long-run public interest."[233] Regulators should clearly specify that risk mitigation is a primary objective of the planning process.

2. Specify Risks, Uncertainties, and Other Factors that Utilities Must Consider

Least-risk planning policies should require that utilities identify and account for risks and uncertainties associated with all available resource options. The most effective policies will require utilities to consider specific risks identified in the planning rules, as well as additional risks and uncertainties identified by the utility during the planning process. Identified risks and uncertainties that are commonly addressed in IRP rules include risks associated with fuel costs, wholesale energy costs, transmission and distribution costs, and cost of complying with environmental regulations.[234] Regulators should also direct utilities to identify and assess any additional risks and uncertainties that may impact a portfolio's long-term performance.

Some state planning rules direct utilities to assess specific sources of risk and uncertainty. For example, Oregon's IRP Guideline 1 specifies that at a minimum, utilities must address a variety of sources of risk and uncertainty, including fuel prices, energy prices, and "costs to comply with any regulation of greenhouse gas emissions."[235] Guideline 8 also establishes detailed requirements for evaluating the potential cost impacts of various CO_2 compliance scenarios.[236] Some states direct utilities to evaluate a portfolio's reliance on uncertain variables or risk mitigation potential. For example, the New Mexico Public Regulation Commission's rules require utilities to assess different resource options' "susceptibility to fuel interdependencies,"[237] and to "consider and describe ways to mitigate ratepayer risk."[238] By requiring an evaluation of a resource's vulnerability to risk and its capacity to minimize this exposure, regulators encourage utilities to consider both the costs and benefits associated with various resource options.

Some IRP rules require utilities to consider and evaluate additional non-cost impacts of various resources or the resource plan itself. For example, the Hawaii IRP Framework requires utilities to consider the impacts that their resource and action plans will have on "the utility's customers, the environment, culture, community lifestyles, the State's economy, and society."[239] Under New Mexico's rules, utility IRPs must describe the environmental impacts of existing supply-side resources, including water consumption rates and emissions rates for CO_2, criteria pollutants, and mercury.[240]

Requiring utilities to evaluate broader social and environmental impacts during the planning process should help to minimize potential externalities that could negatively impact public welfare on a state or regional level. However, there are also potential downsides to granting utilities the discretion to consider broad, imprecise impacts, such as conflicts with community values. For example, a utility could potentially cite community aesthetic concerns to justify eliminating wind resources from its preferred portfolio. To prevent these types of outcomes, regulators could direct utilities to assess both local and statewide impacts, and to balance conflicting interests with the aim of minimizing specific risks, such as detrimental environmental or public health impacts. In general, planning policies should prioritize reduced vulnerability to foreseeable risks and should avoid defining "risk" so broadly that utilities may avoid evaluating certain resources for arbitrary reasons.

3. *Specify the Level of Risk Analysis Required*

Least-risk planning rules should provide guidance or parameters for the level and type of risk analysis that utilities must conduct during the resource planning process. Risk modeling and analysis can be expensive and time-consuming, and small utilities may lack the resources to conduct complex stochastic modeling. At a minimum, however, least-risk planning policies should require utilities to conduct scenario analyses to evaluate how individual resources and resource portfolios perform over a broad range of potential risks and uncertainties. Regulators should also direct utilities to describe the scenarios they evaluate, and identify any assumptions they make that could influence modeling outcomes. Finally, all planning policies should establish some procedural requirements for addressing potential carbon risks through scenario analyses.

Many states already require utilities to conduct some form of scenario analysis, which typically provides the overarching structure for utility risk analysis. For example, Hawaii's

IRP Framework requires each utility to develop a “manageable range of Scenarios” that must “reflect possible futures dealing with uncertain circumstances and risks facing the utility, other stakeholders, and the utility’s customers.”[241] Oregon’s IRP Guidelines require utilities to create a variety of resource portfolios that represent “various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations.”[242] Utilities then “must evaluate how each candidate portfolio performs over a range of risks and uncertainties.”[243] Utilities must use at least two risk metrics to measure both cost variability and “severity of bad outcomes,” and utilities should include an explanation of how their preferred portfolios “appropriately balance cost and risk.”[244] These rules direct utilities to evaluate how different portfolios perform under various potential outcomes, but provide planners with the flexibility to design their own modeling and analytical processes.

Least-risk planning rules should require each utility to provide a detailed description of the scenarios it uses, an explanation of how and why it developed the specific scenarios accompanied by supporting data, and a description of any underlying assumptions the utility made regarding future outcomes or scenarios. This information can help facilitate regulatory and public oversight over IRP risk analyses, by giving overseers an opportunity to review utility predictions and assumptions and promote consistency with public policy goals. If a utility’s assumptions are unrealistic or conflict with state energy objectives, regulators then have an opportunity to intervene and direct the utility to revise its analyses.

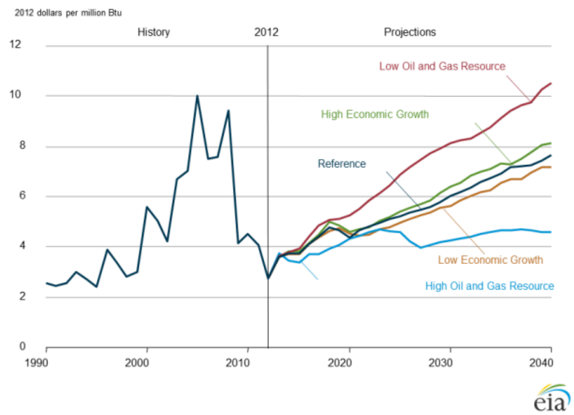
A number of states currently require utilities to identify their IRP assumptions. These provisions may provide a useful model for other states to follow when establishing or revising their own planning rules. For example, Oregon’s IRP Guidelines require utilities to identify any “key assumptions about the future (e.g. fuel prices and environmental compliance costs) and alternative scenarios considered.”[245] The Hawaii IRP Framework requires that IRPs include a full description of “[t]he assumptions and the basis of the assumptions underlying the Scenarios and Resource Plans, and the key drivers of uncertainty that may have a significant impact on the assumptions."[246] New Mexico's IRP rules list specific assumptions that utilities must identify in their resource plans, including assumptions regarding capital costs, operating costs, fuel cost forecasts, and emissions rates.[247] The assumptions a utility applies to its resource planning can significantly impact the composition of its preferred resource portfolio, and it is imperative that regulators have sufficient information to identify and evaluate these assumptions and predictions.

Regulators can help ensure the effective implementation of least-risk planning requirements by crafting policies with specific, well-defined parameters that leave little room for interpretation. These policies should require utilities to sufficiently justify the assumptions and probability determinations that influence the resource compositions of their preferred portfolios. Regulators should also establish uniform procedures for evaluating risks associated with fuel price volatility and carbon regulation.

a. FUEL PRICE VOLATILITY

IRPs typically include base-case natural gas price forecasts, which reflect anticipated fuel prices over the planning horizon.[248] These price forecasts vary considerably among utility IRPs.[249]

The U.S. Energy Information Administration (EIA) provides both short and long term fuel price projections. EIA's projections are largely based off of Henry Hub spot market price trends.[250] Regulators seeking uniformity in IRP fuel price forecasting could direct utilities to model their base-case natural gas price forecasts off of EIA's long-term price forecast.



EIA, Annual Average Henry Hub Spot Prices for Natural Gas in Five Cases, 1990–2040, eia.gov (2014)

In addition to spot market price curves, utilities can also base their natural gas price forecasts off of forward market price curves. Forward market price curves reflect the prices that natural gas futures are trading for on the New York Mercantile Exchange (NYMEX).[251] Researchers at LBNL concluded that forward gas market price curves provide a good reference point for IRP gas price forecasts, because they may best predict future spot market prices.[252]

However, natural gas price forecasts have historically been inaccurate, and utilities should not place too much reliance on any base-case gas price forecasts.[253] Utilities should therefore assess how their candidate portfolios perform under a wide range of potential natural gas prices. Resource planning rules should mandate that utilities conduct scenario analyses to address a variety of futures in which gas prices differ from available price forecasts.

EIA's natural gas price forecasts assess how a number of variables may impact natural gas prices over time. In its 2014 Annual Energy Outlook, EIA projected how gas prices would respond under scenarios reflecting high and low economic growth (and thus high and low fuel demand) and high and low oil and gas resource availability.[254] At a bare minimum, utility IRPs should assess how these four scenarios would impact portfolio costs.

b. CARBON REGULATION

In a report on "Managing Carbon Regulatory Risk in Utility Resource Planning,"[255] researchers with LBNL identified a series of "best practices" for evaluating carbon risks, which include modeling for scenarios with a wide range of carbon prices, evaluating a variety of low-carbon resource portfolios, identifying both direct and indirect potential effects of carbon regulation, and effectively balancing portfolio cost and risk.[256] In addition, utility plans should include a probable carbon value in the base case analysis or reference case portfolio, to ensure that all portfolios are measured against a combination of resources that adequately reflect the changing regulatory environment.[257] Finally, utilities should assess the implications of potential carbon regulations on their business models as a whole, including impacts on existing resources, long-term power purchase agreements, market and transmission price, and future procurement options.[258] This analysis will enable utilities to identify their cumulative exposure to carbon risk and develop long-term strategies to mitigate this risk.

Oregon's IRP Guideline 8 establishes a process for utilities to follow in assessing the regulatory compliance costs they anticipate for carbon dioxide and other air pollutants.[259] Guideline 8 directs utilities to assess a series of CO_2 compliance scenarios that range from the current regulatory level to "the upper reaches of credible proposals by governing entities."[260] This analysis should identify and address upstream emissions "that would likely have a significant impact" on the utilities' resource procurement decisions.[261] Guideline 8(c) directs utilities to conduct a "trigger point analysis" in which the utility must identify a CO_2 compliance scenario that would "trigger" the utility to select a "substantially different" resource portfolio.[262] The utility then must develop a substitute resource portfolio to comply with this "triggering" compliance scenario, and compare the projected cost and risk performance of the substitute portfolio to that of the preferred portfolio.[263] These carbon compliance and "trigger point" analyses help to ensure that utilities adequately consider the carbon intensity and vulnerability of various resource portfolios under a range of possible regulatory futures.

Scenario analysis is an essential component of the resource planning process because it enables utilities to identify the impacts that potential outcomes or uncertain variables may have on different resources. Utilities are thus able to identify a resource's vulnerability to

EVALUATING CARBON RISKS

- model for scenarios with wide range of carbon prices
- evaluate multiple low-carbon resource portfolios
- include a probable carbon value in base case analysis or reference case portfolio
- identify potential direct and indirect impacts of carbon regulation
- assess implications of carbon regulation on business as a whole

specific risks and uncertainties, and build preferred portfolios that effectively mitigate exposure to foreseeable risks. Resource planning policies should therefore direct utilities to conduct comprehensive scenario analyses that evaluate the impacts from a broad range of variables and foreseeable outcomes. Planning rules should also require utilities to identify and justify any assumptions that influence the composition of a preferred resource portfolio.

4. Require Risk-Focused Resource Ranking and Resource Selection

Least-risk planning rules should require utilities to rank individual resource options and resource mix portfolios on the basis of cost and on the basis of relative exposure to risk and vulnerability to uncertain outcomes. For example, Oregon's IRP Guidelines mandate that IRPs include a ranking of resource portfolios by both cost and risk metrics and an interpretation of these ranking results.[264] Ranking resources based on both their costs and exposure to risk helps to inform the broader IRP process by ensuring that regulators, ratepayers, and other stakeholders are adequately informed of the cost and risk trade-offs associated with potential resource portfolios.

Utilities should be required to select resource portfolios that reduce or minimize investor, ratepayer, and taxpayer exposure to risk. In Oregon, for example, utilities are required to "select the portfolio that represents the best combination of cost and risk for the utility and its customers."[265] In addition, resource plans should include an explanation of a preferred resource portfolio's exposure to known and foreseeable risks and vulnerability to uncertain variables. This explanation would demonstrate to regulators that the utilities adequately addressed and accounted for risk and uncertainty in selecting their preferred resource mixes. It would also help ensure that regulators and stakeholders are adequately informed of the risks associated with planned resource investments prior to IRP approval.

5. Transparency, Public Participation, and Regulatory Oversight

To ensure effective implementation, least-risk planning rules should include provisions requiring transparency and providing for public participation and regulatory oversight. Utility resource investments generally impact three broad classes of people: 1) investors; 2) ratepayers; and 3) members of the public. Public participation and regulatory oversight are therefore essential components of least-risk planning, because they help ensure that the diverse interests of these stakeholders are represented and protected. Stakeholders require access to detailed information and data to ensure that their interests are protected, and transparency is thus extremely important throughout the planning process. Public participation provisions should give ratepayers the opportunity to review the risk analysis before a plan is finalized.

Some states require utilities to seek public input throughout the planning process. In Oregon, for example, utilities are encouraged to allow significant public involvement in the resource planning process and are required to submit draft IRPs for public review and comment.[266] New Mexico's IRP rules mandate that utilities incorporate a public advisory process into their IRP development to solicit input and commentary on resource planning and acquisition issues.[267] Hawaii's IRP Framework requires establishment of an Advisory Group, which aims to provide the utility with community perspectives by representing "diverse community, environmental, social, political, or cultural interests."[268] Utilities are required to consider the group's input, though they are not obligated to follow the group's recommendations.[269] Utilities are also encouraged to convene public meetings or forums to obtain input from individuals whose interests may not be represented by the Advisory Group.[270]

Public input may have a significant impact on the resource planning process. PNM, New Mexico's largest electricity provider, was inspired to revise its solar PV modeling technique after receiving public input on solar energy's contributions to the grid.[271] As a result, PNM included additional solar PV capacity in its preferred resource portfolio.[272] PNM's public advisory process also encouraged the utility to update its sensitivity analysis examining the energy impacts of drought conditions.[273] These examples illustrate how public oversight can benefit the planning process when utilities seriously consider stakeholder input.

While public participation is an important component of effective resource planning, many utilities deny the public access to relevant data and information regarding resource cost projections and modeling results. For example, in its 2013 IRP, DEP redacted all of its resource cost projections, screening results, and information regarding its renewable energy purchases.[274] This lack of transparency made it extremely difficult, if not impossible, for members of the public to comment on the adequacy of DEP's analyses.

After receiving stakeholder input through New Mexico's public advisory process, PNM revised its preferred resource portfolio to include additional solar PV capacity.

Effective public oversight requires transparent access to utilities' levelized cost projections and resource screening and modeling results. Regulators should narrowly construe what constitutes confidential utility business information to ensure that the public has access to relevant economic data, such as levelized and avoided cost data, and cost projections for future resource investments. Ultimately, effective least-risk planning will require public participation and regulatory oversight. Regulators should therefore ensure their rules protect these critical aspects of the least-risk process.

C. STEP 3: IMPLEMENT AND ENFORCE LEAST-RISK PLANNING RULES

Once states adopt least-risk planning rules, utilities and regulators must effectively implement the planning framework with the aim of minimizing exposure to risk and uncertainty. Well-crafted least-risk planning policies should minimize the potential for a utility's subjective assumptions to influence the composition of its preferred portfolio. However, these policies will work only if utilities adequately implement the risk-focused planning requirements. Regulators can offer guidance and direction throughout the planning process to help facilitate effective implementation. Ultimately, PUC enforcement authority is the strongest mechanism in the regulatory toolbox to ensure utilities effectively implement planning requirements. Therefore, the next step in establishing an effective least-risk planning policy is to ensure that regulators have the authority and capacity to enforce risk assessment requirements.

Enforcement should incorporate regulatory oversight over the planning process and should allow regulators to withhold approval of resource plans that do not adequately address potential risk or uncertainty. This enforcement authority should enable PUCs to withhold acknowledgment for individual IRP components, as well as for a complete plan. Regulators should also have authority to require additional analyses and revisions to plan components or action items. For example, if a utility fails to adequately explain or justify its assumptions regarding future risks or uncertainties, the PUC must have authority to require additional analyses applying justifiable

Utilities that assume that future conditions will follow a business-as-usual trajectory and assign a low probability to conceivable future scenarios will likely develop resource portfolios with less resilience to changing circumstances.

future assumptions. Likewise, if a utility's preferred portfolio would expose ratepayers to undue risk, the PUC should direct the utility to revise its scenario and sensitivity analyses and identify a portfolio with less vulnerability to risk and uncertainty.

The PGE and PacifiCorp comparison introduced in Part IV helps to illustrate the importance of effective implementation and enforcement of risk-focused planning requirements. Part IV's discussion explored the different methods that the two utilities employed in implementing Oregon's IRP Guidelines.[275] While PacifiCorp claimed its 2013 IRP complied with Oregon's risk assessment requirements, its preferred resource portfolio relied extensively on existing coal resources and anticipated minimal investment in renewable resources.

Part IV argued that the Oregon PUC must provide diligent oversight to ensure that preferred IRP portfolios will not expose ratepayers to unreasonable risk. In regards to PacifiCorp's 2013 IRP, this is precisely what the Oregon PUC did. In an order entered on July 8, 2014, the PUC partially acknowledged PacifiCorp's 2013 IRP.[276] In doing so, however, the PUC required PacifiCorp to revise certain components of the IRP and comply with additional requirements when preparing subsequent resource plans.[277] The PUC also refused to acknowledge one of the IRP's specific action items involving investments in new pollution controls at one of the utility's existing coal plants.[278]

The PUC also indicated that it shared stakeholder and staff concerns that PacifiCorp's analyses of its existing coal resources failed to adequately account for foreseeable costs and risks.[279] In response, the PUC directed PacifiCorp, Commission staff, and interested stakeholders to participate in several workshops to determine the appropriate parameters of PacifiCorp's coal analyses in future IRPs.[280] The PUC also directed PacifiCorp to submit quarterly updates on coal plant compliance requirements, pollution control investments, and any major capital expenditures the utility intended to make on its existing coal plants.[281]

CREDIT: PDTillman (2010)

PacifiCorp owns or partially owns eleven coal-fired power plants in five states, including the 387 megawatt Cholla coal plant in Arizona. The Oregon PUC directed PacifiCorp to file a special update to its 2013 IRP addressing the utility's anticipated investments in pollution control equipment at the plant.

The Oregon PUC's order on PacifiCorp's 2013 IRP illustrates how regulatory oversight and enforcement of resource planning rules can strengthen utility risk assessment practices. Moreover, diligent PUC enforcement of least-risk planning rules can guide utilities to select resource portfolios that mitigate ratepayer exposure to risk and uncertainty.

THE HAWAIIN ELECTRIC COMPANIES' 2013 IRP

Recent actions by the Hawaii PUC provide an example of regulatory enforcement of utility resource planning requirements. In 2011, the Hawaii PUC revised its IRP rules "to allow for a more effective, inclusive and comprehensive planning process that acknowledges the dynamic and constantly changing utility environment that exists today."[282] The revised Framework consists of an extensive list of requirements and principles governing utility resource planning, and includes a number of risk-focused provisions. The Framework directs the PUC to determine whether utility plans are in the public interest and authorizes the commission to review and approve, reject, reject in part, or require modification of the utility's plan.[283] The PUC is also required to monitor the utility's implementation of an approved plan.[284]

In April of 2014, the Hawaii PUC rejected the Hawaiian Electric Companies' (HECO) IRP Report for failure to comply with the state's IRP Framework.[285] The PUC found the IRP to be non-compliant with the Framework in a number of ways, including its failure to provide sufficient support for its proposed course of action over the next five years, its failure to rank or prioritize the final resource plans, and its failure to comply with scenario planning principles.[286]

In regards to HECO's analytical shortcomings, the PUC determined that HECO's analyses failed to "adequately demonstrate the feasibility or accurately determine the cost of incorporating extensive amounts of variable renewable generation." The utilities' modeling techniques also did not sufficiently assess the impacts of high penetrations of variable renewables.[287] In regards to HECO's failure to rank its final resource plans, the PUC explained that the Framework's ranking requirement was designed to ensure transparency in the utility's decision-making process, which the utilities failed to do.[288]

The PUC further found that HECO had failed to comply with the Framework's scenario planning provisions, which in part require the utility to "review the Resource Plans to identify common themes, resources, programs, and actions that demonstrate robust value to costs and risks."[289] The Commission characterized this provision as "the very crux of the scenario planning concept," and found that HECO's IRP contained no discussion or analysis to clarify whether this review was conducted.[290] The PUC found that the utility failed to sufficiently demonstrate how it evaluated its resource plans to "balance cost and risk."[291]

On the basis of the PUC's decision alone, it would seem that HECO's resource planning practices were superficial or cursory. However, HECO's 2013 IRP is a 774-page document with far more detailed and thorough analyses than the average utility IRP. The PUC's refusal to acknowledge the IRP appears to be motivated in part by the Commission's conclusion that the utility's analyses failed to adequately consider the public interest or the state's policy goals. To address these broader shortfalls, the PUC's Order included an exhibit titled, "Commission's Inclinations on the Future of Hawaii's Electric Utilities."[292] In this document, the PUC addressed HECO's failure to adapt to changing societal conditions, explaining that the "IRP Action Plan appeared to be, in part, a series of unrelated capital projects without strategic focus on the clear issues facing the utility, and did not indicate further progress towards a sustainable business model."[293]

The Hawaii PUC's decision is largely a byproduct of the state's energy circumstances—Hawaii's electricity rates are among the highest in the country, and in many instances renewable resources are the least-cost resource option.[294] Nevertheless, it is a compelling example of regulatory IRP requirements, and it may be representative of a changing tide in utility resource planning, and perhaps electricity regulation in general.

D. STEP 4: CONNECT IRP APPROVAL TO RATEMAKING

One final step in developing an effective least-risk resource planning policy is to link resource plan approval with utility cost recovery. Utilities recover the value of their resource investments through consumer electricity rates, and most states only authorize cost recovery for prudent investments in resources that are used and useful.[295] States generally do not consider IRP approval decisions to constitute ratemaking,[296] and they typically require utilities to obtain a separate Certificate of Convenience and Necessity (CCN) prior to investing in new generation resources.[297] However, a least-risk planning policy should include a provision establishing that proposed investments are presumptively prudent and necessary so long as the resource was identified as part of a least-risk portfolio within an acknowledged IRP. Such a provision would provide utilities with a degree of certainty that they will be entitled to recover the value of investments in least-risk resources through the ratemaking process. It should also provide an additional incentive for utilities to engage in diligent resource planning. However, this presumption of prudence should not act as a substitute for comprehensive ratemaking proceedings, which allow for more thorough evaluations of specific investment decisions.

Regulators should therefore establish both least-risk planning and least-risk procurement policies that together incentivize investments in least-risk resources. These policies should include provisions establishing a presumption of prudence and necessity for investments in identified least-risk resources. Once a utility obtains a CCN to invest in a least-risk resource, the least-risk procurement policy should preserve the utility's ability to recover a portion of its costs in the event that the resource never enters into service.

In addition to incentivizing least-risk investments, least-risk procurement policies should also discourage investments in least-cost resources that expose ratepayers to excess risk or uncertainty. Procurement policies should therefore establish a rebuttable presumption that proposed investments in non-least-risk resources are not prudent or necessary. A utility could rebut this presumption by demonstrating that the resource would not disproportionately expose ratepayers to risk. However, the utility would then be subject to a strict used and useful requirement limiting cost recovery if the resource never entered into service or incurred additional costs over time.

Some state IRP rules already include provisions creating a presumption of prudence and necessity for investments that are consistent with an approved IRP. New Mexico's IRP rules, for example, establish that when a utility seeks a CCN for a new resource, it must provide evidence that the resource is consistent with a commission-accepted IRP.[298] New Mexico's utilities therefore receive some assurance that when they invest in resources identified through the planning process, they will be entitled to recover their investment costs.

Other states consider IRP approval as a relevant factor in ratemaking proceedings, but stop short of allowing IRP approval to create a rebuttable presumption of prudence and necessity. For example, the Oregon PUC has consistently held that IRP acknowledgment does not constitute ratemaking, though it does believe that IRP acknowledgment is a relevant factor to consider when making prudence determinations.[299] According to the PUC, "[c]onsistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment."[300] Similarly, a utility resource investment that is inconsistent with an acknowledged IRP will not necessarily be denied cost recovery, though the utility must provide additional justification for the investment.[301]

The Oregon PUC's hesitation in allowing IRP approval to dictate ratemaking determinations is based in part on fundamental differences between the IRP and ratemaking processes, particularly in regards to access to information. In rate proceedings, prudence determinations are "based on an evaluation of what was known and knowable to the utility at the time when the decision was made."[302] If an IRP served as evidence in favor of prudence, then ratemaking prudence review could be based on what was known and knowable at the time the IRP was created, rather than at the time the investment decision was made.[303] Moreover, interested parties have more access to information regarding what was "knowable" to a utility during ratemaking proceedings than they do during the IRP process.[304] During ratemaking proceedings, interested parties have the opportunity to conduct discovery and obtain information on what was "known and knowable" to the utility at the time it made the decision to invest in a specific resource.[305] Public participants in an IRP proceeding do not have access to the same depth of information. This is because an IRP only outlines a utility's anticipated resource investments over the course of the planning horizon, but it does not include specific investment proposals for individual resource acquisitions.[306]

As in Oregon, resource plan approvals should not act as a substitute for prudence determinations conducted through full ratemaking proceedings. Nevertheless, regulators should mandate that proposed resource investments must be consistent with an approved resource plan. In addition, regulators should presume that proposed investments in least-risk resources identified through an approved IRP are prudent and necessary. This presumption would provide utilities with a degree of certainty that they may recover the value of lower-risk investments. In other words, regulators should not require utilities to engage in least-risk planning without also providing some assurance that investments in least-risk resources will be entitled to cost recovery.

Utilities should have some assurance that investments in least-risk resources will be eligible for cost recovery.

Conclusion

The electricity sector is currently undergoing a period of substantial change, and future conditions will almost certainly differ dramatically from the conditions that investor-owned utilities are accustomed to. Though future conditions are highly uncertain and difficult to predict, it appears inevitable that future fuel price volatility and impending efforts to limit greenhouse gas emissions will make it increasingly difficult for fossil fuels to compete in the 21st Century electricity market. We now understand that utility investments in fossil fuel generating resources disproportionately expose ratepayers to unreasonable risk, yet entrenched least-cost planning requirements impede the transition to a more stable, predictable energy system. Regulators throughout the country should therefore develop and implement least-risk planning policies to reduce investor and ratepayer vulnerability to risk and incentivize renewable energy development. Utilities that engage in least-risk planning should be better able to adjust their procurement plans in response to regulatory shifts and other changes in circumstances. Perhaps more importantly, these utilities should be better equipped to transition from the fossil fuel-based electricity system of today to the renewable energy system of tomorrow.

ENDNOTES

[1] *See* JOHN STERLING, ET AL., NREL, TREATMENT OF SOLAR GENERATION IN ELECTRIC UTILITY RESOURCE PLANNING 4 (2013), *available at* http://www.nrel.gov/docs/fy14osti/60047.pdf.
[2] *See, e.g.*, FORREST SMALL & LISA FRANTZIS, THE 21ST CENTURY ELECTRIC UTILITY: POSITIONING FOR A LOW-CARBON FUTURE, A CERES REPORT 9 (2010), *available at* http://www.ceres.org/resources/reports/the- 21st-century-electric-utility-positioning-for-a-low-carbon-future-1.
[3] MELISSA POWERS, ENERGY LAW 42–43 (2012).
[4] *Id.*
[5] STERLING, ET AL., *supra* note 1, at 4.
[6] *Id.* at 44.
[7] *See* So. Cal. Edison Co. v. Pub. Util. Comm'n, 576 P.2d 945 (Cal. 1978).
[8] *Id.*
[9] *Id.*
[10] *See* Duquesne Light Co. v. Barasch, 488 U.S. 299, 310–316 (1989).
[11] *See* Melissa Powers, *The Cost of Coal: Climate Change and the End of Coal as a Source of "Cheap" Electricity*, 12 U. PA. J. BUS. L. 407, 426–27 (2010).
[12] Order Conditionally Approving Application of Sw. Elec. Power Co. for a Coal-Fired Power Plant in Ark. at 8, PUC Docket No. 33891 (Tex. Pub. Util. Comm'n Aug. 12, 2008).
[13] *Id.*
[14] THE REGULATORY ASSISTANCE PROJECT, ELECTRICITY REGULATION IN THE US: A GUIDE 73 (2011), *available at* http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CCgQFjAA&url=http%3A%2F%2Fwww.raponline.org%2Fdocs%2FRAP_Lazar_ElectricityRegulationInTheUS_Guide_2011_03.pdf&ei=tq9NU_mCDYiy2wW954GoDw&usg=AFQjCNGQmJpx6o94LjxdGMzSmrsBiezsFQ&bvm=bv.64764171,d.b2I [hereinafter RAP GUIDE].
[15] CAL. ENERGY COMM'N, COST OF GENERATION MODEL USER'S GUIDE VERSION 2 at 1–2 (2010), *available at* http://www.energy.ca.gov/2010publications/CEC-200-2010-002/CEC-200-2010-002.PDF.
[16] *Id.*
[17] The revenue requirement represents the total revenue a utility must recover from consumers to recover its costs and earn a rate of return. *See* Ron Davis, Group Exercise I: Calculating the Revenue Requirement, *available at* http://www.naruc.org/international/Documents/Calculating%20Revenue%20Requirement_Davis.pdf.
[18] *See* RON BINZ, ET AL., PRACTICING RISK-AWARE ELECTRICITY REGULATION: WHAT EVERY STATE REGULATOR NEEDS TO KNOW, A CERES REPORT 28 (April 2012), *available at* http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation.
[19] *See* Powers, *supra* note 11, at 411–13.
[20] Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776, § 111(d)(19) (Oct. 24, 1992).
[21] *See* RACHEL WILSON & PAUL PETERSON, SYNAPSE ENERGY ECONOMICS, A BRIEF SURVEY OF STATE INTEGRATED RESOURCE PLANNING RULES AND REQUIREMENTS 7 (2011), *available at* http://www.cleanskies.org/wp-content/uploads/2011/05/ACSF_IRP-Survey_Final_2011-04-28.pdf.
[22] *See, e.g.*, In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon, Order No. 89-507 (Or. Pub. Util. Comm'n Apr. 20, 1989).
[23] RAP GUIDE, *supra* note 14, at 73.
[24] *See* BINZ, ET AL., supra note 18, at 28.
[25] POWERS, *supra* note 3, at 42–43.
[26] *Id.*
[27] *Id.* at 43.
[28] *Id.* at 45.
[29] *Id.* at 46.
[30] *Id.*
[31] Powers, *supra* note 11, at 413.

[32] For example, during the nuclear power boom and bust of the 1970s and 1980s, many PUCs allowed utilities to recover the costs of failed nuclear plants through electricity rates. *Id.* at 418–18.
[33] POWERS, *supra* note 3, at 86.
[34] *See id.*
[35] *Id.* at 44.
[36] Powers, *supra* note 11, at 417–18.
[37] *Id.* at 418–19.
[38] *Id.*
[39] RACHEL WILSON & BRUCE BIEWALD, BEST PRACTICES IN ELECTRIC UTILITY INTEGRATED RESOURCE PLANNING 3 (2013), *available at* http://www.synapse-energy.com/Downloads/SynapseReport.2013-06.RAP.Best-Practices-in-IRP.13-038.pdf.
[40] *Id.* at 3; STERLING, ET AL., *supra* note 1, at 1.
[41] *See, e.g.,* In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon, Order No. 89-507 (Or. Pub. Util. Comm'n Apr. 20, 1989).
[42] STERLING, ET AL., *supra* note 1, at 5–6.
[43] *See* U.S. ENERGY INFO. ADMIN., LEVELIZED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 2013, 1–5 (Jan. 2013), *available at* http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf.
[44] Scenario analysis entails evaluating how a resource portfolio performs under a variety of potential future conditions. Stochatic analysis tests portfolio performance under multiple variables that randomly change hundreds or thousands of times. Stochastic analysis is also known as Monte Carlo simulation. Both analytical methods aim to determine a portfolio's sensitivity to uncertain conditions. STERLING, ET AL., *supra* note 1, at vi n.4, 13.
[45] MARK BOLINGER & RYAN WISER, BALANCING COST AND RISK: THE TREATMENT OF RENEWABLE ENERGY IN WESTERN UTILITY RESOURCE PLANS 42 (2005), *available at* http://emp.lbl.gov/sites/all/files/REPORT%20lbnl%20-%2058450_0.pdf.
[46] *See id.*
[47] *Id.* at 45.
[48] RAP GUIDE, *supra* note 14, at 26.
[49] POWERS, *supra* note 3, at 384.
[50] SMALL & FRANTZIS, *supra* note 2, at 28.
[51] *Id.* at 1.
[52] For example, EPA recently proposed rules to regulate GHG emissions from new and existing electric generating units. *See* Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, Notice of Proposed Rulemaking, 79 FED. REG. 1,432 (Jan. 8, 2014) [hereinafter NSPS Rule]; Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 FED. REG. 34,830 (June 18, 2014) [hereinafter Clean Power Plan].
[53] SMALL & FRANTZIS, *supra* note 2, at 1.
[54] Draft Survey of Utility Resource Planning and Procurement Practices for Application to Long-term Procurement Planning in California, report prepared for the California Public Utility Commission by Aspen Envtl. Group and Energy & Envtl. Econ., at 72 (2008), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/029611EA-D7C7-4ACC-84D6-D6BA8515723A/0/ConsultantsReportonUtilityPlanningPracticesandAppendices09172008.pdf [hereinafter Cal. PUC IRP Survey].
[55] *Id.* at 73.
[56] *Id.*
[57] *See id.* at 85–88.
[58] SMALL & FRANTZIS, *supra* note 2, at 17.
[59] NSPS Rule, *supra* note 52, at 1,433.
[60] ENVTL. PROTECTION AGENCY, REGULATORY IMPACT ANALYSIS FOR THE PROPOSED STANDARDS OF PERFORMANCE FOR GREENHOUSE GAS EMISSIONS FOR NEW STATIONARY ELECTRIC UTILITY GENERATING UNITS 5-12 (2013), *available at* http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposalria.pdf [hereinafter NSPS RIA].

[61] *See id.* 4-31, 5-13; *see, e.g.*, PACIFICORP, 2013 INTEGRATED RESOURCE PLAN VOL. I at 178 (2013), *available at* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol1-Main_4-30-13.pdf [hereinafter PACIFICORP 2013 IRP].
[62] Jay Warmke, *Frac-Onomics: Why Fracking Makes Little Economic Sense*, ECOWATCH.COM, Jan. 30, 2012, http://ecowatch.com/2012/01/30/frac-onomics-why-fracking-makes-little-economic-sense/.
[63] *Id.*
[64] U.S. Energy Info. Admin., *Natural Gas Weekly Update*, Nov. 20, 2014, http://www.eia.gov/naturalgas/weekly/.
[65] For example, the Energy Information Administration (EIA) anticipates that the U.S. natural gas exports will increase substantially in the near future, exceeding eight trillion cubic feet in 2040, and predicts that natural gas prices will increase over the coming decade due to elevated natural gas consumption and export demands. *See* U.S. ENERGY INFO. ADMIN., AEO2014 EARLY RELEASE OVERVIEW 2, 7 (2014), *available at* http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf.
[66] *See* NSPS Rule, *supra* note 52, at 1,487.
[67] *See* Ian Urbina, *Behind Veneer, Doubt on Future of Natural Gas*, NYTIMES.COM, June 26, 2011, http://www.nytimes.com/2011/06/27/us/27gas.html.
[68] Cal. PUC IRP Survey, *supra* note 54, at 68.
[69] *Id.*
[70] SMALL & FRANTZIS, *supra* note 2, at 5.
[71] CARBON TRACKER INITIATIVE, UNBURNABLE CARBON 2013: WASTED CAPITAL AND STRANDED ASSETS 4 (2013), *available at* http://carbontracker.live.kiln.it/Unburnable-Carbon-2-Web-Version.pdf.
[72] *Id.*
[73] SMALL & FRANTZIS, *supra* note 2, at 7.
[74] *Id.* at 25.
[75] *Id.*
[76] *See* BINZ, ET AL., *supra* note 18, at 5.
[77] Kenneth Colburn, et al., *Least-Risk Planning*, 150 NO. 11 PUB. UTIL. FORT. 38 (2012); Herman K. Trabish, *Can Decision-Makers Learn to Embrace Change in the Energy Risk Lab?*, GREENTECHMEDIA.COM, Aug. 17, 2012, http://www.greentechmedia.com/articles/read/can-decision-makers-learn-to-embrace-change-in-the-energy-risk-lab.
[78] Trabish, *supra* note 77.
[79] Colburn, et al., *supra* note 77, at 39.
[80] *Id.*
[81] *Id.*
[82] Trabish, *supra* note 77.
[83] *See* BOLINGER & WISER, *supra* note 45, at 1.
[84] *See* STERLING, ET AL., *supra* note 1, at 4.
[85] *See* PACIFICORP 2013 IRP, *supra* note 61, at 201.
[86] *See* BOLINGER & WISER, *supra* note 45, at 1–20.
[87] *See id.* at 1, 14, 23.
[88] *See* Patrick Bean & David Hoppcock, *Least-Risk Planning for Electric Utilities*, Nicholas Institute for Environmental Policy Solutions Working Paper 14 (2013), *available at* http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_13-05.pdf.
[89] SMALL & FRANTZIS, *supra* note 2, at 5 (citing MARC CHUPKA ET AL., THE BRATTLE GROUP, TRANSFORMING AMERICA'S POWER INDUSTRY: THE INVESTMENT CHALLENGE 2010-2030 vi (2008), *available at* http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf).
[90] *See* Bean & Hoppcock, *supra* note 88, at 4.
[91] *See, e.g.*, In the Matter of Pub. Util. Comm'n of Or.: Investigation into Integrated Resource Planning, Order No. 07-002 at 5, n. 6 (Or. Pub. Util. Comm'n Jan. 8, 2007) (adopting integrated resource planning guidelines directing utilities to select the "best cost/risk portfolio").
[92] BINZ, ET AL., *supra* note 18, at 11.
[93] *See* WILSON & BIEWALD, *supra* note 39, at 5; *see, e.g.*, PORTLAND GENERAL ELECTRIC CO., 2013 INTEGRATED RESOURCE PLAN 187–88 (March 2014), *available at*

http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp.pdf [hereinafter PGE 2013 IRP].
[94] Bean & Hoppcock, *supra* note 88, at 3.
[95] PGE, for example, models five different carbon dioxide compliance scenarios that impose costs ranging from no carbon cost to $136 per short ton of CO_2 emitted. PGE 2013 IRP, *supra* note 93, at 185.
[96] STERLING, ET AL., *supra* note 1, at 16.
[97] *Id.* at 17.
[98] Bean & Hoppcock, *supra* note 88, at 5.
[99] STERLING, ET AL., *supra* note 1, at 16.
[100] *Id.* at 16–17.
[101] Bean & Hoppcock, *supra* note 88.
[102] *Id.* at 8.
[103] *Id.*
[104] Investigation into the Treatment of CO_2 Risk in the Integrated Resource Planning Process, Adopted Guideline 8, Order No. 08-339, UM 1302, app. C at 8(a) (Or. P.U.C. June 30, 2008).
[105] WILSON & BIEWALD, *supra* note 39, at 2.
[106] *Id.* at 4; *see also* STERLING, ET AL., *supra* note 1, at 4, 16.
[107] WILSON & BIEWALD, *supra* note 39, at 10.
[108] *Id.*
[109] *Id.* at 12.
[110] *Id.* at 13.
[111] In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon, Order No. 89-507 (Or. Pub. Util. Comm'n Apr. 20, 1989).
[112] *Id.* at 2.
[113] Or. Pub. Util. Comm'n, Adopted IRP Guidelines, Order No. 07-047, UM 1056, app. at 2 (Or. P.U.C. Feb. 9, 2007) [hereinafter Oregon IRP Guidelines].
[114] *See id.* Guideline 4: Plan Components.
[115] *Id.* Guideline 4(i), (k).
[116] *Id.* Guideline 4(g), (m).
[117] *See* PACIFICORP 2013 IRP, *supra* note 61; PGE 2013 IRP, *supra* note 93.
[118] Oregon IRP Guidelines, *supra* note 113, Guideline 1(b).
[119] *Id.* Guideline 4(i).
[120] PGE 2013 IRP, *supra* note 93, at 187.
[121] *Id.* at 184.
[122] *Id.* at 188.
[123] Oregon IRP Guidelines, *supra* note 113, Guideline 1(c)(1).
[124] PGE 2013 IRP, *supra* note 93, at 203.
[125] *Id.*
[126] *Id.*
[127] *Id.* at 204.
[128] Oregon IRP Guidelines, *supra* note 113, Guideline 1(c).
[129] PGE 2013 IRP, *supra* note 93, at 207.
[130] *Id.* at 176, 178. PGE ultimately determined not to recommend adding any major new supply-side resources as part of its proposed four-year action plan, so it will reevaluate these candidate portfolios in its next IRP. *Id.*
[131] PACIFICORP 2013 IRP, *supra* note 61, at 156–57, 171.
[132] *Id.* at 185, 187. "System Optimizer" is PacifiCorp's IRP modeling software. *Id.* at 159.
[133] *Id.* at 187.
[134] *Id.*
[135] *Id.* at 196.
[136] *Id.*
[137] *Id.*
[138] *Id.* at 199.

[139] *Id.*
[140] *Id.* at 200.
[141] *Id.* at 201
[142] *Id.*
[143] PGE 2013 IRP, *supra* note 93, at 172.
[144] *Id.* at 184–85. It should be noted that PGE assigns differing meanings to the terms "future" and "scenario": A "future" is an input variable, such as a high fuel price, while a "scenario" is a future applied to a portfolio. *Id.* at 172.
[145] *Id.* at 186.
[146] PACIFICORP 2013 IRP, *supra* note 61, at 173–74.
[147] *Id.* at 185, 187.
[148] PGE 2013 IRP, *supra* note 93, at 103, 183.
[149] *Id.* at 176, 178.
[150] PACIFICORP 2013 IRP, *supra* note 61, at 167.
[151] *Id.* at 215–216.
[152] *Id.* at 205.
[153] *Id.* at 201, 215–216.
[154] *Id.* at 201.
[155] *Id.* at 230.
[156] *Id.* at 11.
[157] *Id.* at 201.
[158] *Id.* at 205.
[159] *Id.* at 164.
[160] *Id.* at 11; PGE 2013 IRP, *supra* note 93, at 176, 178.
[161] PacifiCorp's 2014 net generating capacity is 10,595 MW. PACIFICORP, PacifiCorp Facts (2014), *available at* http://www.pacificorp.com/content/dam/pacificorp/doc/About_Us/Company_Overview/PC-FactSheet-Final_Web.pdf. PGE's 2014 generating capacity is 3,376 MW. PGE 2013 IRP, *supra* note 93, at 20.
[162] Oregon IRP Guidelines, *supra* note 113, Guideline 4(g).
[163] BINZ, ET AL., *supra* note 18, at 9.
[164] *See* BOLINGER & WISER, *supra* note 45, at 56.
[165] *Id.* at 1.
[166] SMALL & FRANTZIS, *supra* note 2, at 17.
[167] BOLINGER & WISER, *supra* note 45, at 8.
[168] SMALL & FRANTZIS, *supra* note 2, at 2.
[169] BOLINGER & WISER, *supra* note 45, at 23.
[170] NSPS RIA, *supra* note 60, at 5-12.
[171] PACIFICORP, 2003 INTEGRATED RESOURCE PLAN 48 (2003), *available at* http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2003IRP/2003IRP_Brochure_Jan2003.pdf.
[172] PACIFICORP 2013 IRP, *supra* note 61, at 186.
[173] *Id.* at 11.
[174] U.S. ENERGY INFO. ADMIN., LEVELIZED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 2013 4 (Jan. 2013), *available at* http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf.
[175] NSPS Rule, *supra* note 52, at 1,436.
[176] PACIFICORP 2013 IRP, *supra* note 61, at 11.
[177] *See, e.g.*, *id.* at 186.
[178] *See* STERLING, ET AL., *supra* note 1, at vii; BOLINGER & WISER, *supra* note 45, at 23.
[179] STERLING, ET AL., *supra* note 1, at 19; *see, e.g.*, DUKE ENERGY PROGRESS, 2013 INTEGRATED RESOURCE PLAN 89 (2013), *available at* http://www.duke-energy.com/pdfs/dep-2013-annual-plan-public-final-r2.pdf [hereinafter DEP 2013 IRP] (noting that energy storage technologies were eliminated from review during the IRP's technical screening stage).
[180] PACIFICORP 2013 IRP, *supra* note 61, at 29.

[181] *See* NSPS Rule, *supra* note 52, at 1,487.
[182] MELISSA WHITED, FRANK ACKERMAN, & SARAH JACKSON, SYNAPSE ENERGY ECONOMICS, WATER CONSTRAINTS ON ENERGY PRODUCTION: ALTERING OUR COLLISION COURSE 19, 29 (2013), *available at* http://www.synapse-energy.com/Downloads/SynapseReport.2013-06.CSI.Water-Constraints.13-010.pdf.
[183] *See* Stephen Stock, et al., *Waste Water from Oil Fracking Injected into Clean Aquifers*, NBCBAYAREA.COM, Nov. 14, 2014, http://www.nbcbayarea.com/investigations/Waste-Water-from-Oil-Fracking-Injected-into-Clean-Aquifers-282733051.html.
[184] *Id.*
[185] BOLINGER & WISER, *supra* note 45, at 65.
[186] *See, e.g.*, Oregon IRP Guidelines, *supra* note 113, Guideline 1(B)1; N.M. Pub. Reg. Comm'n, Integrated Resource Plans for Electric Utilities, N.M. Admin. Code § 17.7.3.9(G) (2007); N.C. Util. Comm'n, Integrated Resource Planning and Filings, N.C.U.C. Rule R8-60(g).
[187] *See* BOLINGER & WISER, *supra* note 45, at 44.
[188] *See, e.g.*, PACIFICORP 2013 IRP, *supra* note 61, at 178.
[189] BOLINGER & WISER, *supra* note 45, at 48.
[190] *Id.*
[191] *Id.* at 54.
[192] N.C. Util. Comm'n, Integrated Resource Planning and Filings, N.C.U.C. Rule R8-60(g).
[193] DEP 2013 IRP, *supra* note 179, app. A at 42.
[194] *Id.*, app. F at 92.
[195] PATRICK LUCKOW, ET AL., 2013 CARBON DIOXIDE PRICE FORECAST 17 (2013), *available at* http://www.synapse-energy.com/Downloads/SynapseReport.2013-11.0.2013-Carbon-Forecast.13-098.pdf.
[196] BOLINGER & WISER, supra note 45, at 62.
[197] WILSON & BIEWALD, supra note 39, at 30.
[198] DEP 2013 IRP, *supra* note 179, at 32.
[199] *Id.* at 101.
[200] *See* Union of Concerned Scientists, How it Works: Water for Natural Gas, July 15, 2013, http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-natural-gas.html.
[201] WHITED, ACKERMAN, & JACKSON, *supra* note 182, at 22–23.
[202] *See id.* at 30–32.
[203] PNM, INTEGRATED RESOURCE PLAN: 2014–2033 at 79 (July 2014), *available at* https://www.pnm.com/documents/396023/396193/PNM+2014+IRP/bdccdd52-b0bc-480b-b1d6-cf76c408fdfc [hereinafter PNM 2014 IRP].
[204] *Id.* at 71.
[205] *Id.* at 74.
[206] *Id.*
[207] *See* BOLINGER & WISER, *supra* note 45, at 1.
[208] *See id.* at 23.
[209] STERLING, ET AL., *supra* note 1, at 2.
[210] BOLINGER & WISER, *supra* note 45, at 14.
[211] *Id.* at 1, 42.
[212] *Id.* at 42.
[213] Bean & Hoppcock, *supra* note 88, at 5.
[214] *See* Oregon IRP Guidelines, *supra* note 113.
[215] PGE 2013 IRP, *supra* note 93, at 103, 183.
[216] *Id.* at 176, 178.
[217] N.C. GEN. STAT. § 62-2(3a); N.C. Util. Comm'n, Integrated Resource Planning and Filings, N.C.U.C. Rule R8-60.
[218] DEP 2013 IRP, *supra* note 179, at 92.
[219] *Id.* at 5, 19–20.

[220] CHRISTOPHER E. VAN ATTEN, ET AL., BENCHMARKING AIR EMISSIONS OF THE 100 LARGEST ELECTRIC POWER PRODUCERS IN THE UNITED STATES 34 (May 2014), *available at* http://www.nrdc.org/air/pollution/benchmarking/files/benchmarking-2014.pdf.
[221] The U.S. Environmental Protection Agency (EPA) recently proposed two rules that would regulate carbon emissions from new and existing stationary electricity generating units. NSPS Rule, *supra* note 52; Clean Power Plan, *supra* note 52.
[222] DEP 2013 IRP, *supra* note 179, at 18.
[223] *Id.* at 17.
[224] N.C. Gen. Stat. § 62-2(3a).
[225] N.C. Util. Comm'n, Integrated Resource Planning and Filings, N.C.U.C. Rule R8-60(g) (emphasis added).
[226] Oregon IRP Guidelines, *supra* note 113, Guideline 1(c).
[227] For example, North Carolina's general statute states that it is "the policy of the State of North Carolina . . . to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable." N.C. Gen. Stat. § 62-2(3a).
[228] In Oregon, for example, the PUC's IRP Guidelines states that the primary goal of resource planning "must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers." Oregon IRP Guidelines, *supra* note 113, Guideline 1(c).
[229] N.C. Util. Comm'n, Integrated Resource Planning and Filings, N.C.U.C. Rule R8-60(g) (emphasis added).
[230] N.M. Pub. Reg. Comm'n, Integrated Resource Plans for Electric Utilities, N.M. Admin. Code § 17.7.3.6 (2007) (emphasis added).
[231] Haw. Pub. Util. Comm'n, A Framework for Integrated Resource Planning § II.A (March 14, 2011) [hereinafter Haw. IRP Framework].
[232] Oregon IRP Guidelines, *supra* note 113, Guideline 1(c).
[233] *Id.* Guideline 1(d).
[234] *See, e.g.*, N.C.U.C. Rule R8-60(e); N.M. ADMIN. CODE § 17.7.3.9(G)(1); Oregon IRP Guidelines, *supra* note 113, Guideline 1(b).
[235] Oregon IRP Guidelines, *supra* note 113, Guideline 1(b).
[236] Investigation into the Treatment of CO_2 Risk in the Integrated Resource Planning Process, Adopted Guideline 8, Order No. 08-339, UM 1302, app. C (Or. P.U.C. June 30, 2008).
[237] N.M. ADMIN. CODE § 17.7.3.9(G)(2).
[238] *Id.* § 17.7.3.9(G)(1).
[239] Haw. IRP Framework, *supra* note 231, § II.B.4.
[240] N.M. ADMIN. CODE § 17.7.3.9(C)(12).
[241] Haw. IRP Framework, *supra* note 231, § V.C.8(a).
[242] Oregon IRP Guidelines, *supra* note 113, Guideline 4(h).
[243] *Id.* Guideline 4(i).
[244] *Id.* Guideline 1(c).
[245] *Id.* Guideline 4(g).
[246] Haw. IRP Framework, *supra* note 231, § IV.D.1(a)(3).
[247] N.M. ADMIN. CODE § 17.7.3.9(F)(1).
[248] BOLINGER & WISER, *supra* note 45, at 44.
[249] *Id.*
[250] *See* U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2014 (2014), *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.
[251] *See* U.S. ENERGY INFO. ADMIN., AN ASSESSMENT OF PRICES OF NATURAL GAS FUTURES CONTRACTS AS A PREDICTOR OF REALIZED SPOT PRICES AT THE HENRY HUB (2005), *available at* http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2005/futures/futures.pdf.
[252] BOLINGER & WISER, *supra* note 45, at 47.
[253] *Id.* at 48.
[254] U.S. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2014 MT-21, MT-22 (2014), *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

[255] GALEN BARBOSE, ET AL., MANAGING CARBON REGULATORY RISK IN UTILITY RESOURCE PLANNING: CURRENT PRACTICES IN THE WESTERN UNITED STATES (2009), *available at* http://emp.lbl.gov/sites/all/files/Managing%20Carbon%20Regulatory%20Risk%20in%20Utility%20Resource%20Planning%20Current%20Practices%20in%20the%20Western%20United%20States.pdf.
[256] *Id.* at 16; *see also* SMALL & FRANTZIS, *supra* note 2, at 8–9.
[257] *See* BOLINGER & WISER, *supra* note 45, at 62–63.
[258] *See* SMALL & FRANTZIS, *supra* note 2, at 10.
[259] Oregon IRP Guidelines, *supra* note 113, Guideline 8.
[260] *Id.* Guideline 8(a).
[261] *Id.*
[262] *Id.* Guideline 8(c).
[263] *Id.*
[264] *Id.* Guideline 4(j).
[265] *Id.* Guideline 4(l).
[266] *Id.* Guideline 2.
[267] N.M. ADMIN. CODE § 17.7.3.9.H.
[268] Haw. IRP Framework, *supra* note 231, § III.F.1.
[269] *Id.* § III.F.3.
[270] *Id.* § III.G.2.
[271] PNM 2014 IRP, *supra* note 203, at 112.
[272] *Id.*
[273] *Id.*
[274] DEP 2013 IRP, *supra* note 179, at 93–95, 150–153.
[275] *See discussion supra* section IV.D.
[276] In the Matter of PacifiCorp, dba Pacific Power, 2013 Integrated Resource Plan, Order No. 14-252 (Or. P.U.C. Jul. 8, 2014).
[277] *Id.*
[278] *Id.* at 7.
[279] *Id.* at 4–5.
[280] *Id.* at 5.
[281] *Id.* at 3.
[282] In re Pub. Util. Comm'n: Instituting a Proceeding to Investigate Proposed Amendments to the Framework for Integrated Resource Planning, Docket No. 2009-0108 at 2 (Haw. P.U.C. March 14, 2011).
[283] Haw. IRP Framework, *supra* note 231, § III.A (2011).
[284] *Id.*
[285] In re Pub. Util. Comm'n: Regarding Integrated Resource Planning, Order No. 32052 (Haw. P.U.C. April 28, 2014).
[286] *Id.* at 22.
[287] *Id.* at 27.
[288] *Id.* at 33.
[289] *Id.* at 36.
[290] *Id.*
[291] *Id.* at 39.
[292] *Id.* at Exhibit A.
[293] *Id.* at 1.
[294] *See id.* at 2.
[295] *See* POWERS, *supra* note 3, at 115–16.
[296] *See* In re PacifiCorp, dba Pacific Power, 2013 Integrated Resource Plan, Order No. 14-252 at 1 (Or. P.U.C. Jul. 8, 2014).
[297] *See* POWERS, *supra* note 3, at 45.
[298] Integrated Resource Plans for Electric Utilities, N.M. ADMIN. CODE § 17.7.3.12 (2007).

[299] *See* In re Pub. Util. Comm'n of Or.: Investigation into Integrated Resource Planning, Order No. 07-002 at 24 (Or. P.U.C. Jan. 8, 2007); In re Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon, Order No. 89-507 at 7 (Or. P.U.C. Apr. 20, 1989).
[300] Or. P.U.C. Order 07-002 at 24 (Jan. 8, 2007) (quoting Or. P.U.C. Order No. 89-507 at 7 (Apr. 20, 1989)).
[301] *Id.*
[302] *Id.* at 25.
[303] *Id.*
[304] *Id.*
[305] *Id.*
[306] *Id.*