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Assessing the Risk of Utility Investments in a Least-Cost-Planning Framework

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ABSTRACT

Unprecedented uncertainty in the electricity sector makes it difficult to estimate the cost or likely range of costs for new capital investments. Different assumptions about the future can make an investment that is least cost in one future or scenario high cost (relative to other investments) in another. In many states, utility commissions use a least-cost framework to evaluate different investment options, but determining what is least cost is difficult and can depend on the range of potential futures that utilities and regulators consider. In this environment, critical questions for utilities and utility regulators are (1) what is the realistic range of cost estimates and (2) what risk do different options create for customers. This paper reviews risk metrics that utilities and utility regulators can use to evaluate investment options as well as methods to incorporate these metrics in a least-cost-planning framework.

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INTRODUCTION

The electricity sector faces significant, if not unprecedented, uncertainty. Recent reports from the Edison Electric Institute, Deloitte Consulting, Citi bank, and others have focused the public, regulators, and utility shareholders on the uncertainty related to disruptive technology, stagnant demand, aging infrastructure, regulation, and other factors.[1] This uncertainty creates risk for electricity customers—especially in states where utilities are guaranteed cost recovery for prudently incurred investments—because utility investments that appear to be least cost today may in fact lead to high future costs relative to other investment options. Electric utility investments have always entailed uncertainty, but current conditions may warrant additional assessment of risk to protect customers and shareholders. An important question for utility regulators and policy makers is how to assess this risk, which is defined here as the potential for negative outcomes due to uncertainty.

In many states, utility commissions are required or assumed to adopt a least-cost framework for approving new electricity sector capital investments.[2] Identifying the least-cost investment option amid significant uncertainty regarding future electricity demand, technology development, environmental regulation, relative fuel prices, and even the electric utility business model is difficult, given the wide range of potential futures. An investment alternative that is least cost under one potential future may be high cost in another, and as a result it may be impossible to choose an alternative that performs well under all possible futures. For utility commissions with a least-cost-planning framework, the key questions become (1) how uncertain cost estimates are for future investments (degree of uncertainty) and (2) what risk do different options create for customers.

Some experts have suggested that utilities and utility commissions move from a least-cost decision framework to a risk-based framework that seeks to minimize "bad" decisions rather than attempt to make an optimal decision under uncertainty.[3] This approach has merits but may not be feasible in the near term for some commissions due to legislative constraints.[4] However, given broad uncertainty in the electricity sector, utility commissions have a strong interest in incorporating risk into a least-cost-planning decision analysis.

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[1] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electricity Business,* Energy Infrastructure Advocates on behalf of the Edison Electric Institute, January 2013; Gregory Aliff, *The Math Does Not Lie: Factoring the Future of the U.S. Electric Power Industry,* Deloitte Center for Energy Solutions (2012); Jason Channell, Heath Jansen, Alastair Syme, Sofia Savvantidou, Edward Morse, and Anthony Yuen, *Energy Darwinism: The Evolution of the Energy Industry*, Citi GPS, October 2013; Ron Binz, Richard Sedano, Denise Furey, and Dan Mullen, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (Boston: CERES, 2012).

[2] See appendix for example statutory requirements.

[3] David M. Boonin, *Utility Scenario Planning: Always Acceptable vs. the Optimal Solution,* National Regulatory Research Institute (March 2011), http://www.nrri.org/pubs/multiutility/NRRI_utility_scenario_planning_mar11-07.pdf; Patrick Bean and David Hoppock, *Least-Risk-Planning for Electric Utilities,* Nicholas Institute for Environmental Policy Solutions Working Paper 13-05, August 2013.

[4] As shown in the appendix, statutes governing utility commissions often require commissions to use cost minimization (least cost) or cost *and* risk minimization as criteria for approving utility investments. This can prevent commissions from making decisions on the basis of minimizing risk if options that minimize risk have higher expected cost.

The goal of this paper is to provide a brief introduction to concepts and methods that utility regulators and utilities can use to incorporate risk assessment into a least-cost-planning framework.

UNCERTAINTY AND UTILITY PLANNING DECISIONS

Estimates of the long-term cost of investment alternatives in the electricity sector are based on assumptions about multiple variables (fuel cost, load, wholesale market prices, cost of construction and operations, regulations, financing costs and so on) that are volatile and difficult to predict. Most of these estimates are based on calculations of the costs' net present value assuming a single, known future (or scenario) for all variables. For example, historical natural gas and coal spot prices have displayed significant volatility, whereas cost projections from the Energy Information Administration have tended to change gradually over time (Figure 1).

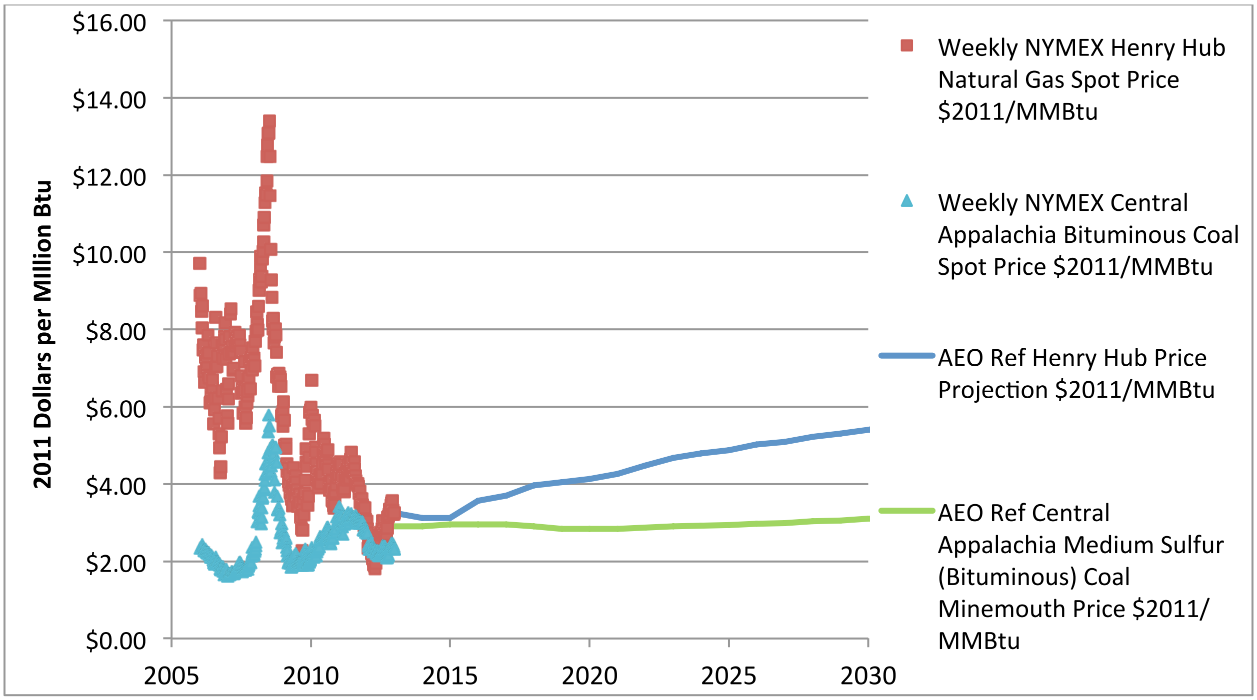

Figure 1. Historical 2006 to 2012 NYMEX spot prices for natural gas and coal and EIA AEO 2013 Reference case projections for Henry Hub natural gas prices and Central Appalachia coal minemouth prices. *Sources:* NYMEX historical natural gas and coal prices available from http://www.eia.gov/coal/nymex/html/nymex_archive.cfm and http://www.eia.gov/dnav/ng/hist/rngwhhdw.htm; AEO projection data from http://www.eia.gov/oiaf/aeo/tablebrowser/.

Estimating future costs in the electricity sector is further complicated by the long financing life (20-plus years) and lead times of capital investment. Moreover, the further into the future forecasts of variables, like fuel prices, are made, the more likely they are to be incorrect (Figure 2). Given that estimates of future costs in the electricity sector are dependent on multiple uncertain variables that have exhibited significant volatility in the past, experts generally acknowledge that almost all cost estimates will prove to be incorrect.

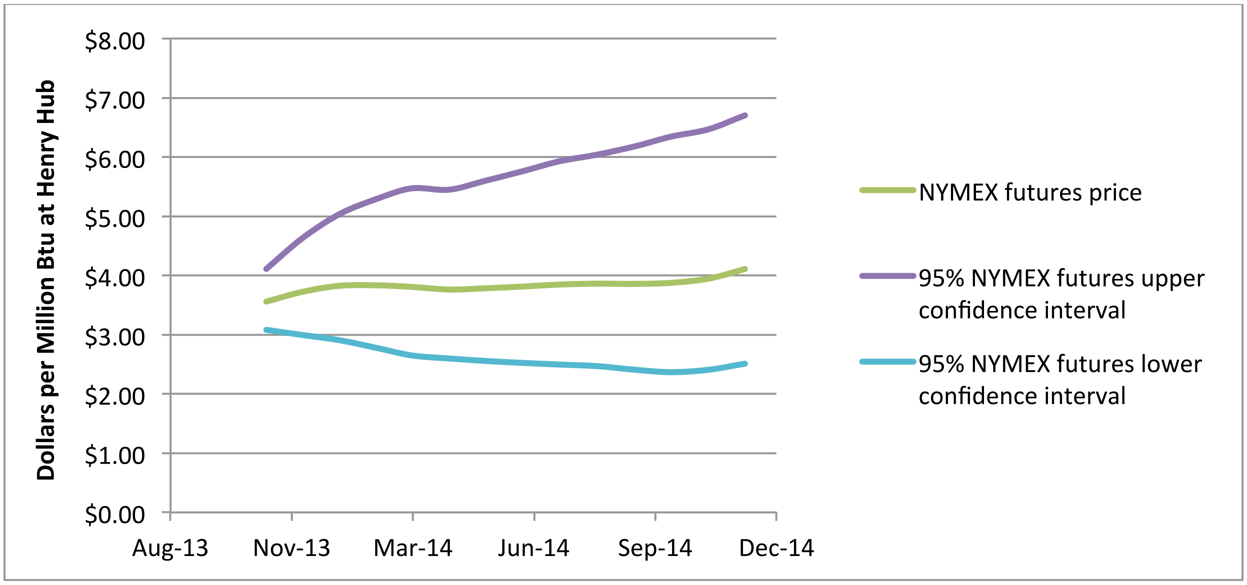

Figure 2. NYMEX Henry Hub natural gas futures prices and 95% confidence intervals. *Source:* EIA Short-Term Energy and Winter Fuels Outlook, October 8, 2013 (http://www.eia.gov/forecasts/steo/report/natgas.cfm).

SCENARIO ANALYSIS

To account for the uncertainty of key input variables and cost estimates, electric utilities often analyze investment options and portfolios under a range of scenarios. Each scenario represents different assumptions about the future, with varying forecasts for key uncertain variables. Within each scenario, or "bundle of assumptions," each uncertain variable has a single path (or trajectory).[5] With a wide range of potential futures, results tend to vary significantly across scenarios; an investment that is least cost in one scenario is high cost in another. For example, in the Progress Energy Carolinas' 2012 Integrated Resource Plan, three investment options were optimal across four scenarios (Table 1).[6] If the least-cost investment option varies across scenarios, utilities and utility commissions must adopt additional criteria to determine which least-cost option is "best." Decision makers can give more weight to individual scenarios they believe are more likely to be realized or look for options that perform well across multiple scenarios. In either case, they need to justify why they are discounting the results for scenarios in which the investment option performs poorly. If the decision maker is risk averse, she or he can pick an option that performs poorly in no scenario, effectively choosing to avoid risk rather than attempting to optimize a decision based on cost.

[5] Traditional scenario analysis, using a single, known cost path for each uncertain variable, is deterministic, meaning the result of the analysis is constant, despite the uncertain inputs.
[6] Progress Energy Carolinas, 2012 Integrated Resource Plan, September 4, 2012, NCUC Docket No. E-100 Sub 137.

Table 1. Progress Energy Carolinas' 2012 Integrated Resource Plan Scenario Analysis Results

	Scenario Rankings[a]			
	Low Stress: low carbon price, low natural gas price, low construction costs	Stringent Environmental: high carbon prices, high demand for natural gas leading to high natural gas prices	Current Trends: mid carbon price, mid natural gas price forecast	Economic Revival: high demand leading to high construction cost and natural gas prices, mid carbon prices
Plan A: natural gas and regional nuclear	**2**	**2**	**2**	**2**
Plan B: natural gas only	**1**	**4**	**3**	**4**
Plan C: regional nuclear with less NGCC[b]	**4**	**3**	**4**	**1**
Plan D: regional nuclear with more NGCC	**3**	**1**	**1**	**3**

[a] Rankings are based on the net present value of utility in each plan. Utility is a function of costs and emissions.
[b] NGCC = natural gas combined cycle.

ASSESSING RISK

Risk assessment provides additional information about a given option's potential for negative outcomes due to uncertainty. It can be combined with cost estimates to aid decision-making when the least-cost strategy is unclear and to indicate the range of possible outcomes. Below is a description of some common risk assessment methods—qualitative and quantitative—and examples of their use in utility planning.[7]

Qualitative Methods

Decision makers can perform a qualitative analysis of risk by contemplating how each investment option could create negative outcomes due to uncertainty. For example, a decision maker can identify the uncertainties that could cause a negative outcome for a decision option relative to a baseline and then think about the potential range and likelihood of these uncertainties, their interactions, and their impacts on the investment option. This process can be used to create a narrative describing the relative risks of available options (see Appendix for an example narrative).

In a scenario analysis context, the decision maker can examine the range of costs for each investment option across all scenarios, rather than focusing on which option performs best in each scenario. Utility regulators and planners generally look for the "robustness" of results across scenarios. Thinking through the negative outcomes for all investment options across all scenarios and creating a narrative may offer additional insight into the likely range of cost outcomes. However, as described below, any attempt to estimate risk using scenario analysis results is dependent on including a range of scenarios that capture all plausible sources of risk.

[7] There are numerous risk assessment methods available to decision makers. This paper does not attempt or pretend to be an exhaustive review of all methods.

Quantitative Methods Using Scenario Analysis

There are a number of methods to characterize risk using traditional scenario analysis. Three of these methods—cost distributions, regret scores, and sensitivity analysis—are described below. As noted above, methods for calculating quantitative risk metrics using traditional scenario analysis only have value if the decision maker believes the analyzed scenarios include all the plausible sources of risks due to uncertainty. For example, if the decision maker is concerned about natural gas price risk but the scenario analysis only includes a scenario with moderately higher natural gas prices and the decision maker believes prices could be considerably higher, any risk metric calculated from the scenario analysis would not reflect the extent of natural gas price risk from the decision maker's perspective.

Neglecting a source of risk will bias a risk assessment toward options that primarily face underrepresented risks. However, this consideration does not imply that utilities and utility commissions should analyze an endless number of scenarios in traditional scenario analysis.

Selecting and Generating Scenarios

When selecting scenarios, analysts must consider the tradeoff between the convenience of having a relatively small number of scenarios versus the higher accuracy and insight that a larger number of scenarios may provide. Analyzing too many scenarios makes it difficult to interpret and communicate results in a manner that is informative and useful to decision makers. Selecting too few scenarios may exclude important risks that should be accounted for. Given this tradeoff, a sensible approach may be to select scenarios in an iterative process whereby scenarios are removed and replaced according to the insight they provide in the results. Some authors advocate generating very large number of scenarios and then using scenario reduction techniques to identify the most meaningful scenarios.[8]

When generating scenarios, all of the assumptions included in the scenario should be internally consistent. For example, in a scenario with low natural gas prices, coal prices should be depressed due to decreased demand for coal.[9] Ideally, cost projections for scenarios should be created using models that relate all factors in the electricity sector.[10] If a model is not available, elasticities among key variables should be reflected in the scenario.

Cost Distributions

A simple way to analyze results from a scenario analysis (Table 2) is to plot the distribution of results for each investment option across all scenarios (Figure 3). A risk-averse decision maker should look at the "negative" side of this distribution, which in a utility planning context means the highest-cost outputs.

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[8] Robert J. Lempert, David G. Groves, Steven W. Popper, and Steve C. Bankes, "A General, Analytic Method for Generating Robust Strategies and Narrative Scenarios," *Management Science* 52(4): 514–528; http://dx.doi.org/10.1287/mnsc.1050.0472; Antonio J. Conejo, Miguel Carrion, and Juan M. Morales, *Decision Making Under Uncertainty in Electricity Markets* (Ciudad Real, Spain: Springer, 2010).

[9] Unless the scenario includes assumptions that would increase demand for coal, for example through increased exports, or that would restrict coal supply.

[10] For example using general equilibrium models such as the National Energy Modeling System (NEMS) maintained by the Energy Information Administration.

Table 2. Example Scenario Analysis Net Present Value Revenue Requirement (PVRR) Results

	Net Present Value Revenue Requirement[a]			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Investment A	*$ 100 B*	*$120 B*	*$125 B*	*$140 B*
Investment B	*$103 B*	*$123 B*	*$127 B*	*$131 B*
Investment C	*$110 B*	*$125 B*	*$128 B*	*$130 B*

[a] Present Value Revenue Require is the net present value of revenues required to cover all system costs (operating, fuel, capital, etc.), including returns on capital investments.

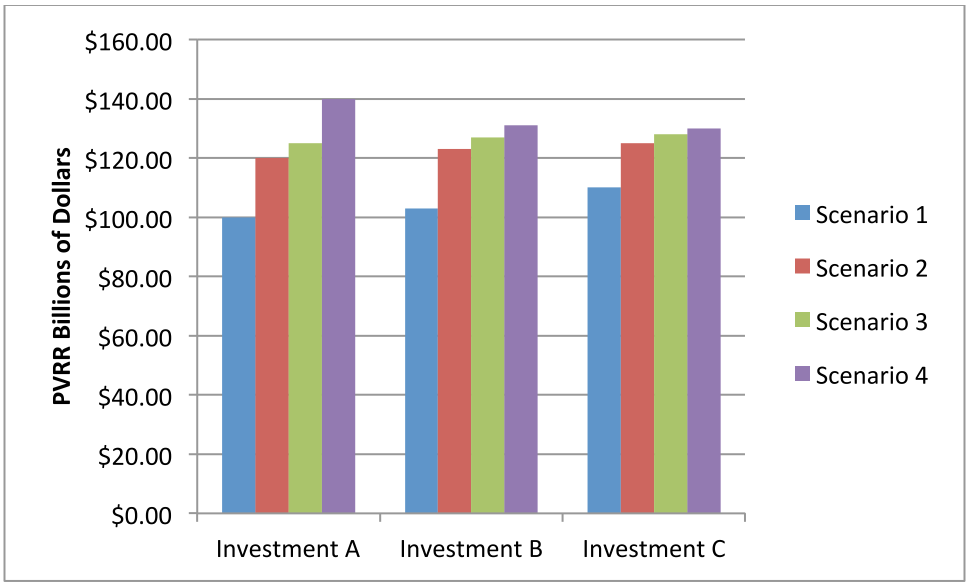

Figure 3. Distribution of scenario analysis results by investment option.

Another way to examine the risk associated with a particular investment strategy is to look at the spread of results across scenarios. This spread can be plotted as cost bands (Figure 4), providing a useful visual comparison. The highest-cost value for each option can be used as a metric for the worst possible outcome given the scenarios analyzed. For example, in Figure 4 below, the highest-cost value for Investment A is $140 billion.

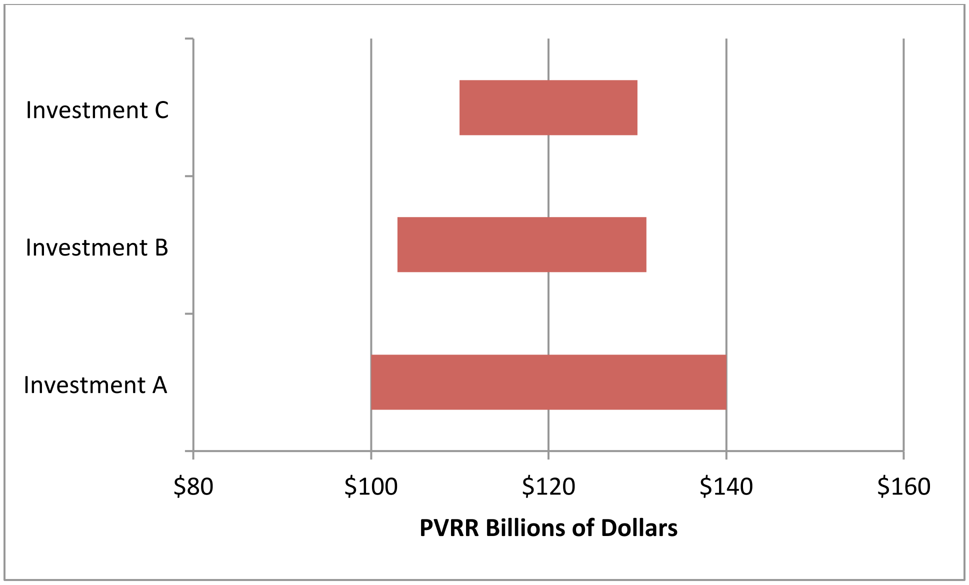

Figure 4. Cost bands of scenario analysis results by investment option.

Regret Scores

Regret scores are another risk metric decision makers can calculate using scenario analysis outputs. Regret scores measure the difference in cost between the optimal solution for each scenario and the other investment options. By calculating regret scores for all investment options across all scenarios, decision makers can estimate the maximum potential regret for each investment option for each scenario.

To calculate regret scores, the analyst determines the most positive or "best" outcome for each scenario (Table 3). (In the context of utility planning, this outcome is the net present value of the least-cost option that meets all relevant constraints, e.g. reliability.) She or he then subtracts this value from the net present value of cost for all options (Table 4). The resulting quantity is the regret score.[11]

Table 3. Least-Cost Option for Each Scenario

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Investment A	*$ 100 B*	*$120 B*	*$125 B*	*$140 B*
Investment B	*$103 B*	*$123 B*	*$127 B*	*$131 B*
Investment C	*$110 B*	*$125 B*	*$128 B*	*$130 B*

[11] For an in-depth discussion of regret scores, see Patrick Bean and David Hoppock, *Least-Risk Planning for Electric Utilities,* Nicholas Institute for Environmental Policy Solutions Working Paper 13-05, August 2013.

Table 4. Example Calculation of Regret Scores

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Maximum Regret of Each Investment
Investment A	$100 – 100 *$ 0 B*	$120 – 120 *$0 B*	$125 – 125 *$0 B*	$140 – 130 *$10 B*	*$10 B*
Investment B	$103 – 100 *$3 B*	$123 – 120 *$3 B*	$127 – 125 *$2 B*	$131 – 130 *$1 B*	*$3 B*
Investment C	$110 – 100 *$10 B*	$125 – 120 *$5 B*	$128 – 125 *$3 B*	$130 – 130 *$0 B*	*$10 B*

Sensitivity Analysis

Sensitivity analysis using scenario analysis is another option to determine the conditions that cause investment options to become least cost.[12] One way to conduct sensitivity analysis is by selecting an investment option that is least cost for a set of scenarios (one or more) and then adjusting the value of a key uncertain variable until that option is no longer least cost. For example, the decision to build a natural gas plant may be least cost for scenarios with a reference gas price and a moderately higher natural gas price. To test the decision's sensitivity to natural gas prices, increase the cost of the natural gas until investing in the natural gas plant is no longer the least-cost option. The point at which the natural gas plant is no longer least cost represents the tipping point at which different assumptions about the future lead to different optimization outcomes (Figure 5). Sensitivity analyses can also be conducted by changing two uncertain variables to create a range of tipping points (Figure 6).

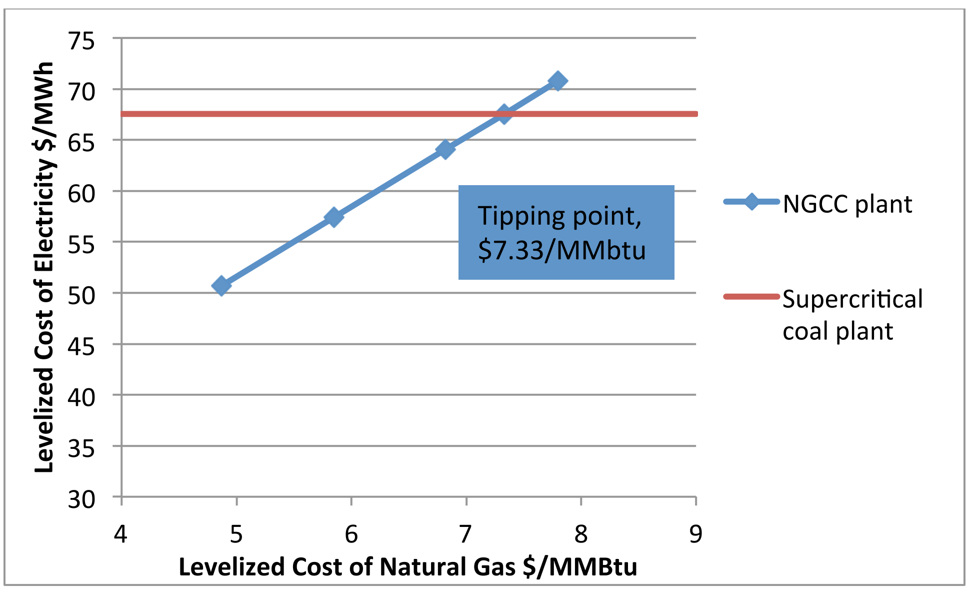

Figure 5. Sensitivity analysis to determine the point at which a new natural gas plant becomes more expensive than a new coal plant, assuming a levelized coal price of $2/MMBtu. Analysis uses the Carnegie Mellon University Center for Energy and Environmental Studies' Integrated Environmental Control Model (IECM), version 8.0.2. NGCC: wet cooling tower, 2 GE 7FB turbines, 526.6 MW net output. Supercritical coal: wet cooling tower, in-furnace NOx controls, SCR, wet FGD, chemical treatment wastewater, Illinois #6 coal, 526.6 MW net output.

[12] Sensitivity analysis is sometimes referred to as break-even analysis.

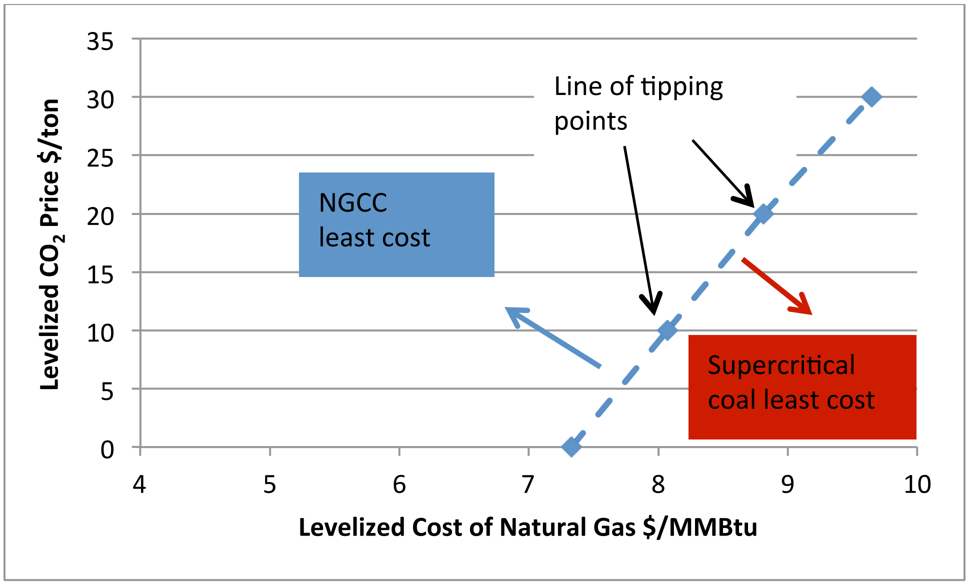

Figure 6. Sensitivity analysis to determine natural gas and CO_2 price tipping points between investing in a new natural gas plant and a new coal plant assuming a levelized coal price of $2/MMBtu. Analysis uses IECM, version 8.0.2. NGCC: wet cooling tower, 2 GE 7FB turbines, 526.6 MW net output. Supercritical coal: wet cooling tower, in furnace NOx controls, SCR, wet FGD, chemical treatment wastewater, Illinois #6 coal, 526.6 MW net output.

Once a tipping point or series of tipping points are known, the decision maker can reflect on the probability of occurrence. This probability represents the probability of the decision maker making a decision that is not least cost if the original option is adopted. Additionally, decision makers can ask subject matter experts for their opinion on the probability of reaching a tipping point, a process known as *expert elicitation*.[13] The probability of reaching the tipping point, combined with the cost saving from the lower-cost option beyond the tipping point, gives the decision maker an estimate of the risk of making a higher-cost investment. Because sensitivity analysis is an iterative process, it requires additional modeling runs beyond those presented to utility commissions under traditional scenario analysis.[14]

Risk Assessment and Modeling Alternatives to Scenario Analysis

Utilities and utility regulators can use multiple alternatives to traditional scenario analysis to account for uncertainty in their decision-making process and to quantify risk. One alternative is Monte Carlo analysis, a stochastic modeling technique for estimating outcomes that are dependent on uncertain variables through repeated modeling runs.[15] Uncertain variables are represented as probability distributions, and for

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[13] For additional information about expert elicitation, see M. Granger Morgan and M. Henrion. *Uncertainty: A Guide to Dealing with Uncertainty in Quantitative Risk and Policy Analysis* (New York, NY: Cambridge University Press, 1990). For examples of expert elicitation, see M. Granger Morgan and David W. Keith, "Subjective Judgments by Climate Experts," *Environmental Science and Technology* 29 (1995): 468A–476A; Will Usher and Neil Strachan, "An Expert Elicitation of Climate, Energy and Economic Uncertainties," *Energy Policy* 61 (2013): 811–821.

[14] For additional information about sensitivity analysis and determining tipping points, see Robert T. Clemen and Terence Reilly, *Making Hard Decisions* (Pacific Grove, CA: Duxbury, 2001).

[15] Stochastic modeling processes differ from traditional scenario analysis because the precise outcome of an individual model run is unknown. By contrast, traditional scenario analysis is deterministic, meaning that if the same inputs are used in every model run, the model will produce the same output every time. Monte Carlo is typically used for outcomes dependent on at least two random variables. If an outcome is dependent on only one

each model run, a random number generator is used to select a value along the distributions. By running the model many times, a distribution of outcomes is created. The distribution of outcomes, assuming there are sufficient modeling runs, approximates the full range and probability of outcomes, including low-probability, high-cost (or other negative) outcomes given assumptions about probability distribution for uncertain variables.[16] The Tennessee Valley Authority (TVA) and Northwest Power and Conservation Council (NWPCC) both use a form of Monte Carlo analysis for their integrated resource planning process. Monte Carlo analysis is often conducted with specialized software packages like @Risk™ but can be performed without specialized software using a random number generator.

Because the distribution of outcomes from a Monte Carlo analysis represents the range and probabilities of outcomes, it can be used to characterize the cost and probability of negative outcomes. Figures 7 and 8 show example distributions of Monte Carlo outputs from the NWPCC Sixth Northwest Electric Power and Conservation Plan and TVA's 2011 Integrated Resource Plan (IRP) as well as the risk metrics calculated using these distributions.[17] Note that the NWPCC and TVA cost distributions are both skewed to the left with infrequent, but very high cost outcomes on the right of the distribution. This phenomenon reflects the fact that, regardless of how favorable conditions are, most utilities have baseline capital and operating costs that create a lower bound on costs. These costs can increase significantly in low-probability, unfavorable futures.

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random variable, creating a distribution of outcomes without a Monte Carlo simulation is relatively straightforward.

[16] See *Making Hard Decisions* for a further explanation of the application and the strengths and weaknesses of Monte Carlo analysis.

[17] Northwest Power and Conservation Council, Sixth Northwest Electric Power and Conservation Plan, February 2010, Council Document 2010-09; Tennessee Valley Authority, Integrated Resource Plan TVA's Environmental and Energy Future, March 2011.

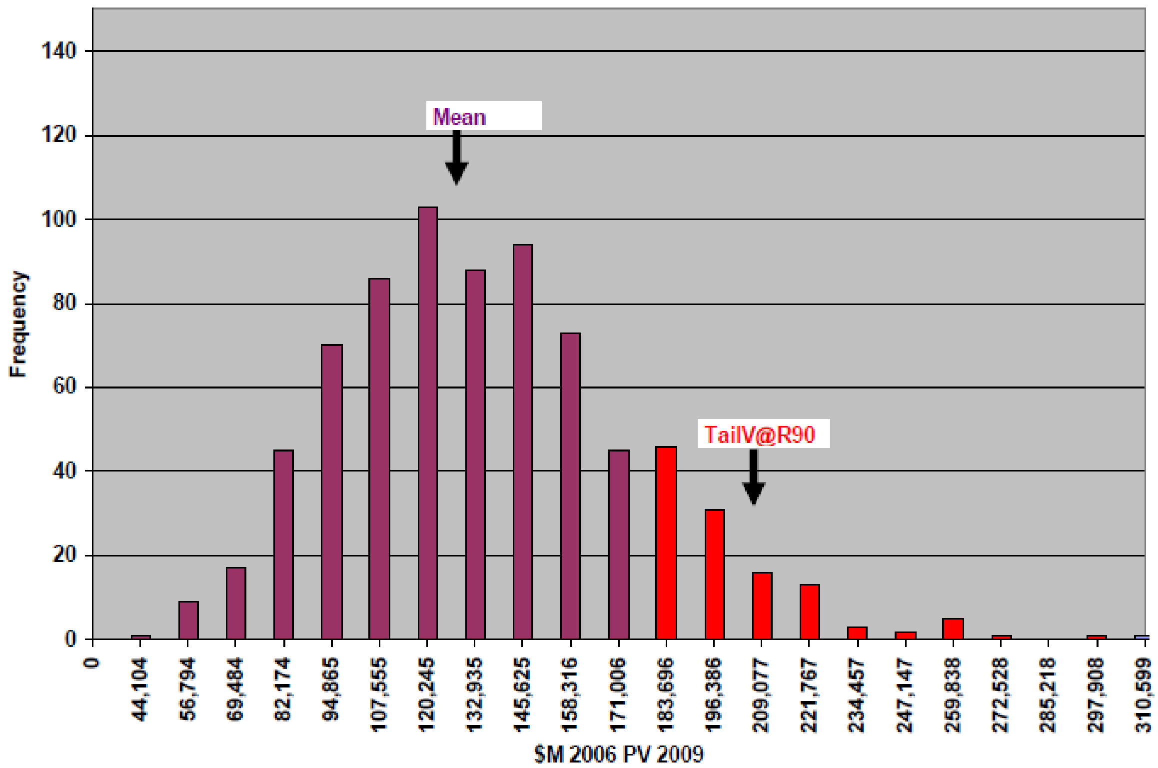

Figure 7. Example output of Monte Carlo analysis for an individual investment plan. *Source:* Figure 9-1 in NWPCC Sixth Northwest Electric Power and Conservation Plan.

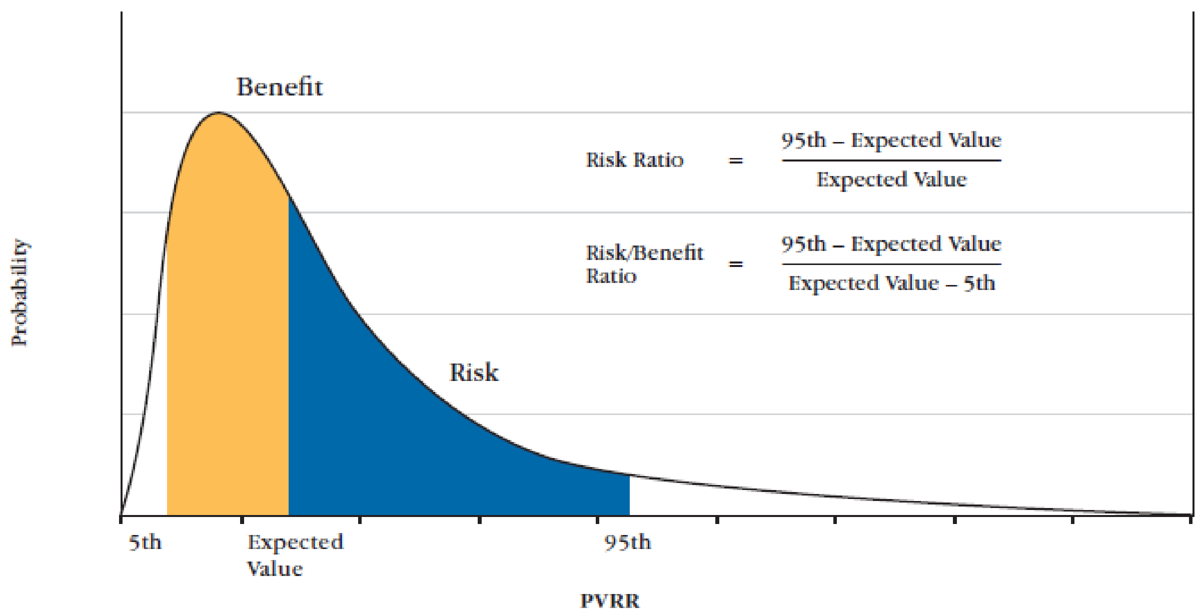

Figure 8. Example Monte Carlo analysis output. *Source:* Figure 6-8 in TVA 2011 IRP.

Risk metrics calculated from the distribution of Monte Carlo modeling outcomes tend to focus on the highest-cost, lowest-probability outcomes and on the spread between high-cost and mean outcomes. The

NWPCC uses TailVar90 as a risk metric. TailVar90 is the average of the 10% highest-cost outcomes—in other words, the average of all the values between the 90th and 100th percentile.[18]

TailVar90 = Sum of 10% highest cost outcomes/(1/10 * total number outputs)

TVA calculates two risk metrics: a risk ratio and a risk-benefit ratio. The risk ratio calculates the size of the spread between 95th percentile output and the mean output (expected value) relative to the mean value. The risk-benefit ratio calculates the ratio of the spread between the 95th percentile output and the mean output (50th percentile), and the spread between the mean output and the 5th percentile output.[19]

Risk Ratio = (95th percentile – mean value)/mean value

Risk/Benefit Ratio = (95th percentile – mean value)/(mean value – 5th percentile)

Other risk metrics include percentile metrics, CVaR and Value-at-Risk. Percentile metrics simply note the value (cost in utility planning) at some high percentile such as the 90th or 95th percentile. A percentile estimates the value below which the outcome is likely to occur at that percentile. Thus, if the 90th percentile is $183 billion dollars, the chance that the outcome will fall below that value is 90%. CVaR is similar to TailVar90, but rather than calculating the average of all values above the 90th percentile, CVaR calculates the average of all outputs above some predetermined value.[20] CVaR is generally written as CVar2000 or some other number showing the cutoff value.[21]

Value at Risk (VaR) is a risk metric frequently used in the financial sector. VaR estimates a potential loss on an asset or portfolio over a specified time period based on a distribution of potential outcomes.[22] For electricity sector planning, the potential loss is generally the potential increase in total system cost versus the mean total system cost over the planning period.[23] For example, if the mean present value revenue requirement (PVRR) is $17,500 million, and PVRR is $27,500 million at the 90th percentile, VaR90 is $10,000 million, meaning the chance that PVRR will be $10,000 million greater than the mean PVRR is 10%.[24]

The risk metrics summarized above measure different things. TailVar90 and CVaR measure the average of the highest-cost values in a distribution. Percentile metrics simply note the cost at select (generally high percentile) locations on a distribution. Risk ratio and risk-benefit ratio measure the spread between

[18] Northwest Power and Conservation Council, Sixth Northwest Electric Power and Conservation Plan, February 2010, Council Document 2010-09.
[19] Tennessee Valley Authority, Integrated Resource Plan TVA's Environmental and Energy Plan, March 2011.
[20] The predetermined value used with CVaR is generally set at a cost threshold that represents the lower bound of what the decision maker considers a negative or very negative outcome.
[21] Northwest Power and Conservation Council, Fifth Northwest Electric Power and Conservation Plan, Appendix P, September 2006.
[22] NYU Stern Business School, Value at Risk (VAR), www.stern.nyu.edu/~adamodar/pdfiles/papers/VAR.pdf.
[23] Northwest Power and Conservation Council, Fifth Northwest Electric Power and Conservation Plan, Appendix P, September 2006.
[24] For additional information about Value at Risk and its application, see Richard A. Brealey and Stewart Meyers, *Financing and Risk Management* (New York: McGraw Hill, 2002).

the mean value and outlier values. Utilities and utility regulators may want to select one or more risk metrics that are the most meaningful to them. Regardless of the risk metric used, the same metric or metrics should be used across all investment options to provide a consistent set of information for the decision maker.

Issues with Perfect Foresight Models in the Context of Risk Assessment

Many electricity sector planning models used to present scenario analyses to utility commissions assume perfect foresight—that is, assume that the decision maker can foresee the exact value that all relevant variables will take in the future at each period in the planning process. Electricity planning models assuming perfect foresight optimize investment decisions for a specific, known future. As a result, these models provide a point estimate of the cost of implementing an investment alternative. Point estimates can provide a false sense of certainty because decision makers can only foresee with relative accuracy the possible range that important variables, such as fuel prices, will take in the immediate future. Distant variable values, for example fuel prices in 20 years, are very difficult to forecast but are assumed to take a set of specific values in planning models assuming perfect foresight.[25]

Monte Carlo analysis can be used to develop risk metrics, but individual runs within it often assume perfect foresight once a random location along the distribution of variables is selected. In utility planning, conventional MonteCarlo analysis draws a single path for uncertain variables from a probability distribution or time-varying stochastic process and simulates investment and operating decisions for that perfectly foreseen scenario.[26] Both Monte Carlo analysis and scenario analysis with perfect foresight provide optimized decisions for a range of conditions like high or low natural gas prices but do not provide information about what happens if a sudden, unanticipated shift in conditions occurs.[27] Given past volatility in fuel prices and sudden shocks like the 2008 financial crisis, such shifts are likely. These shifts create risk for consumers, but perfect foresight analysis does not do a good job of incorporating this risk.

Electric utility capacity expansion and dispatch models are computationally intensive and may be hard to adjust to a modeling framework without perfect foresight. Despite this complexity, there are methods utilities and others can use to assess the risk of unexpected shifts in conditions. The NWPCC IRP analysis uses a Monte Carlo model that incorporates bounded random changes in conditions over time as well as between model runs.[28] This model facilitates capture of the risk of large-lead-time investments that face changing conditions as well as the hedging value of investment options that delay major capital investments[29] and that reduce exposure to volatile inputs like fuel costs.[30] In many cases, utilities may be able use traditional utility modeling tools to simulate abrupt changes by subjecting a model run's initial results to new conditions. If, for example, a capacity expansion model determines that the least-cost investment in a low-gas-price scenario is a new natural gas plant that becomes operational in 2016, a

[25] All perfect foresight analysis is deterministic.

[26] It is possible to run a more sophisticated version of Monte Carlo analysis wherein the conditions (values of important uncertain variables) change within each run over the modeling period.

[27] Perfect foresight models can model scenarios with sudden changes, but they anticipate these changes and optimize for them assuming a single path for the variable (or variables) that changes suddenly.

[28] Bounded random changes are random changes limited by inputs into the model.

[29] The ability to delay an investment decision is referred to as a real options analysis.

[30] Northwest Power and Conservation Council, Appendix P Fifth Northwest Electric Power and Conservation Plan, September 2006.

decision maker can explore the effect of a sudden shift in conditions by starting the capacity expansion model after the plant's capital costs are sunk, for example in 2018, and run the model in a scenario with high natural gas prices.

Real Options and Probabilistic Models

Some modeling frameworks do not assume perfect foresight and therefore make explicit the value of managerial flexibility in adapting to changing conditions as well as facilitate identification of hedging investments. For example, techniques for real options valuation allow decision makers to model the cost impacts of sudden changes, capturing not only the value of flexibility but also the risk of inflexible investments.

Real options models seek to capture the value of managerial flexibility that may be present in investment decisions, such as the ability to delay construction of an asset, abandon it before completion, build it in phases, or mothball (continue to own but not use) it. By contrast, perfect foresight models often do not include all real options—for example, the ability to build in stages—and do not capture the value of flexibility, because there is certainty within each optimization.[31] Very often they ignore the ability to defer an investment and by doing so fail to account for the investment's opportunity cost.[32]

Probabilistic models optimize expected values for different futures or scenarios on the basis of the futures' probability. Given assumptions about the probabilities of different futures, these models capture the uncertainty that exists from the decision point and determine the optimal hedging investment. One probabilistic model that includes real options is the PowerOptInvest model. PowerOptInvest allows the user to set scenario probabilities over an uncertainty period and to define investment options as well as to delay, stagger, mothball, and abandon investments. By setting scenario probabilities over an uncertainty period, the PowerOptInvest user can select probabilities that mimic sudden changes (Table 5).[33] This flexibility allows the user to compare the resiliency of investment options and strategies to cope with sudden changes.[34]

[31] For example, utilities often include a set amount of renewable capacity in a perfect foresight capacity expansion model rather than allow the model to invest in the full range of incremental investments.

[32] The opportunity cost of making an investment decision is the lost ability to make that decision later and the foregone opportunity to use the capital invested in the decision in some other manner. For additional information about real options models, see Avinosh K. Dixit and Robert S. Pindyck, *Investment under Uncertainty* (Princeton, NJ: Princeton University Press, 1994).

[33] PowerOptInvest is a publically available utility model that optimizes operations and investment decisions over multiple scenarios using user-defined probability matrixes. See http://nicholasinstitute.duke.edu/special-projects/state-utility-regulartion#.UlcWx9Lkstq to access the model, download model documentation, and review example analyses.

[34] For additional information about modeling under uncertainty using probabilities, see *Investment Under Uncertainty* and *Making Hard Decisions*.

Table 5. Example Scenario Probabilities Input for Modeling a Sudden Shift in Natural Gas Prices in PowerOptInvest

	Scenario Probabilities					
	2013	2014	2015	2016	2017	2018
Reference Scenario	0	0	0	100%	0	0
Low NG Price	100%	100%	100%	0	0	0
High NG Price	0	0	0	0	100%	100%

INTEGRATING RISK ASSESSMENT INTO LEAST-COST DECISION MAKING

Regardless of method, one key to successfully assessing risk is integrating risk measures and metrics with other decision criteria. In an environment in which investments are least cost in one scenario but often higher cost in other scenarios, utilities and utility commissions commonly justify decisions on the basis of fuel diversity or performance robustness, effectively merging these considerations with cost.[35] Combining risk assessment with cost or expected cost data is effectively the same as including criteria like fuel diversity or performance robustness with cost when making an investment decision—a strategy that works best when deployed systematically. Displaying cost and risk data in the same table or figure helps decision makers understand cost and risk tradeoffs. Figure 9 shows PVRR cost bands and maximum regret for the example scenario analysis shown in Table 2 above.

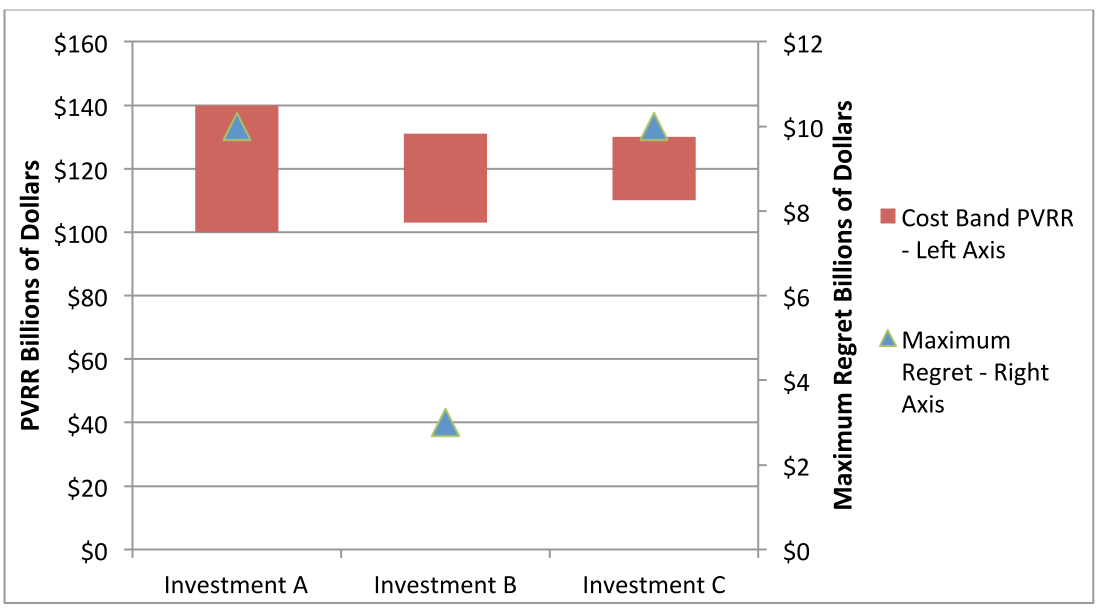

Figure 9. Cost bands and maximum regret scores in billions of dollars.

[35] For example, the 2012 Duke Energy Carolinas IRP preferred plan calls for new nuclear units largely to maintain fuel diversity. In Duke's scenario analysis, a natural gas portfolio was least cost in approximately half of the analyzed scenarios; nuclear was low cost in the other scenarios. See Duke Energy Carolinas, 2012 Integrated Resource Plan, September 4, 2012, NCUC Docket No. E-100 Sub 137.

In some cases, risk metrics such as risk ratios have no unit of measurement, making comparisons of scale more difficult than comparisons of cost metrics. One option for comparing metrics with different units or different scales is to convert outputs into a unitless scale. TVA uses this approach with its cost and risk metrics. It gives the best-performing outcome a score of 100 and all other outcomes lower scores on the basis of their percent difference from the top-performing outcome (Figure 10).

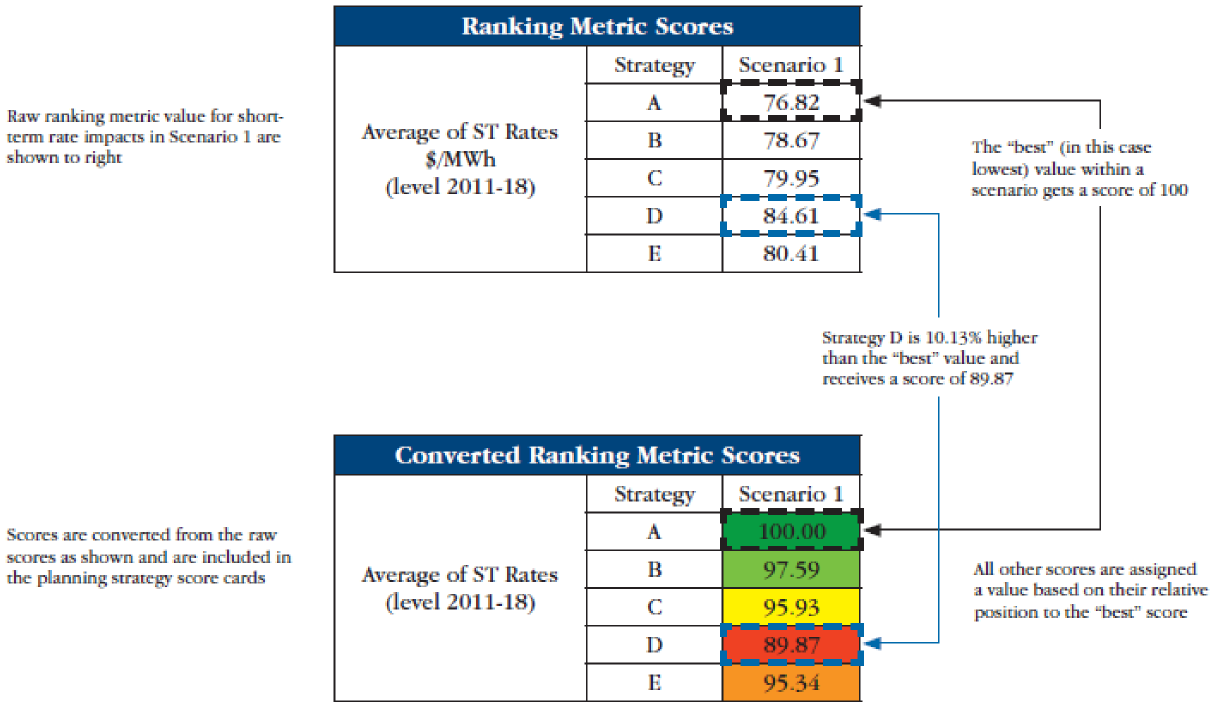

Figure 10. Conversion of short-term cost values to a unitless ranking system, with the best performing output set equal to 100. *Source:* Figure 6-9 in TVA 2011 IRP.

Once different metrics are converted into unitless scores, they can be combined into a total score. TVA uses unitless metrics to create cost and risk scores, which it combines into a single ranking metric score.[36]

Cost = 0.65*PVRR + 0.35*short-term rates

Risk = 0.65*risk ratio + 0.35*risk/benefit ration

Ranking metrics score = 0.65*cost + 0.35*risk

Another way to merge risk and cost metrics in a decision-making process is to use one of the metrics as a boundary and make a decision on the basis of the best-performing option within the boundary. The NWPCC uses a risk-constrained optimization that effectively accomplishes this task. It plots risk and cost for all investment options to allow NWPCC Council members to choose a least-cost option according to their risk tolerance (Figure 11). Similarly, a decision maker could set a boundary on expected cost and select the lowest-risk option within that boundary.

[36] Tennessee Valley Authority, Integrated Resource Plan TVA's Environmental and Energy Plan, March 2011.

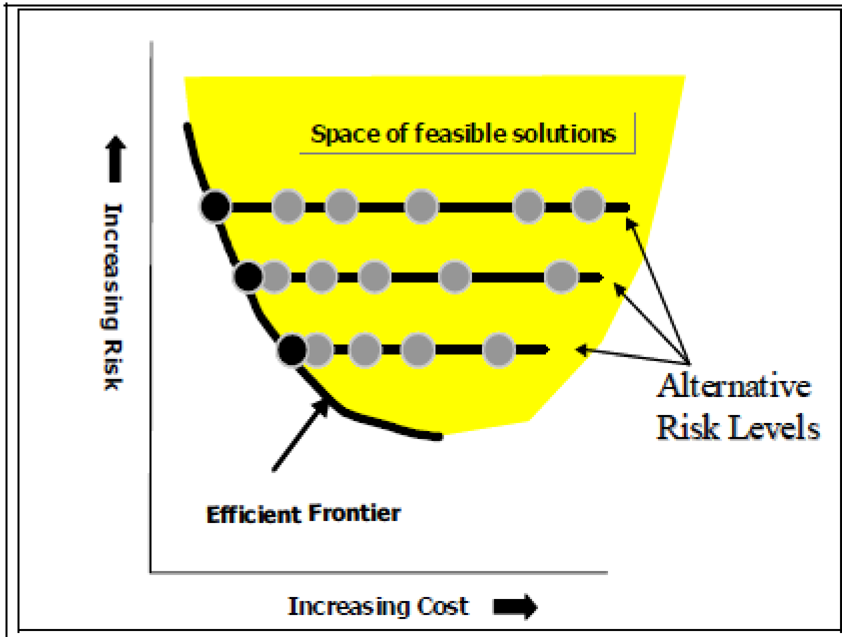

Figure P-2: Feasibility Space

Figure 11. Risk and cost of options. *Source:* NWPCC Sixth Power Plan, Appendix P, Figure P-91.

CONCLUSION

Given the long project and financing lifetimes and multiple uncertain input variables of electric utility investments, almost all, if not all, cost projections for decisions about these investments will prove incorrect. This reality, coupled with the fact that the least-cost investment option depends on the scenarios considered, makes investment decision making in the electricity sector tremendously challenging. Risk assessment can help decision makers understand the likely ranges of undesirable outcomes and risks for consumers and utilities. Risk assessment methods are well established in many sectors of the economy and have been effectively demonstrated in the electricity sector by many integrated resource plans. Introducing a formal risk assessment method into a least-cost planning framework should offer decision makers additional insights and help with difficult investment decisions during this period of significant uncertainty and change in the electricity sector.

APPENDIX

Example Narrative

In this example, a utility and a utility commission are deciding whether to retire an old, high-heat-rate coal plant. If the coal plant is retired, the capacity must be replaced with new generation capacity or a power purchase agreement. Building a new natural gas combined cycle (NGCC) plant is one option for new generation capacity.

Example risk narratives for building a new NGCC plant and continuing to operate the coal plant are given below. Additional options would likely exist; therefore, any decision maker using a narrative to qualitatively assess risk should create a narrative for all options.

Risk Narrative for Construction of an NGCC Plant

The decision to build a NGCC plant is based on current, low-natural-gas-price forecasts and on assumptions about reduced price volatility, relative to the past decade, due to the large supply of domestic natural gas resources. Higher natural gas prices and volatility could increase fuel costs significantly and lead to volatile electricity prices. High prices would reduce the operation of the NGCC plant, placing stress on other generation assets. If natural gas prices are sufficiently high, the NGCC plant would be a regrettable decision—one creating political risk for the utility and utility commission—because other options—such as natural gas turbines, renewable generation, continuing operation of the coal plant, and power purchase agreements—would lead to lower costs for consumers. Relying on base-load natural gas generation during winter months could lead to shortages of natural gas pipeline capacity and, in a worse-case scenario, load shedding. Investment in a NGCC plant could also create an opportunity cost (loss of the option to delay a major capital investment) if load remains stagnant or decreases or lower-cost technology is developed.

Risk Narrative for Continued Coal Plant Operation

Continuing to operate an older plant creates operational risks because of the increased likelihood of outages, creating stress on other generating units and, in a worst case scenario, leading to load shedding. Relative to new generation options, the existing coal plant reduces the system's capacity to ramp up and down due to changing load conditions, again creating stress on other units. Continued low natural gas prices could make the decision to continue operating the plant a regrettable decision—creating political risk for the utility and the utility commission—because a natural gas plant would be lower cost for consumers. The high emissions rate of the coal plant may force significant emissions reductions from other generation sources, depending on Clean Air Act requirements. Similarly, delaying a switch to a lower emissions generation portfolio could require the utility to make multiple large capital emissions reduction investments over a short period, creating a price shock for consumers. The potential for coal price rises due to increased regulation of coal mining or international demand also creates risk for consumers.

Example Legislative Statutes and Commission Rules Governing Least-Cost Planning

State	Statutory	Regulatory	Authority
Colorado	Yes	Yes	C.R.S.A. § 40-3.2-104(1): "It is the policy of the state of Colorado that a primary goal of electric utility least-cost resource planning is to minimize the net present value of revenue requirements. The commission may adopt rules as necessary to implement this policy." 4 CCR 723: Rules Regulating Electric Utilities. See specifically 723-3:3002 (least-cost resource plan outlined in 3603, 3618, 3619); 3601 (goal of electric planning is to minimize net present value of revenue requirements), 3618 (cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities), 3619.
Hawaii	Yes	No	It is the policy of the state to "ensure, to the extent that new supply-side resources are needed, that the development or expansion of energy systems uses the least-cost energy supply option and maximizes efficient technologies." HRS § 226-18(c)(3), (5).

Indiana	No	Yes	170 IAC 4-7-8: Commission must assure that a utility's proposal is consistent with acquisition of the least-cost mix of demand-side and supply-side resources to reliably meet the long-term electric service requirements of the utility's customers. 170 IAC 4-8-3: A utility shall identify in an integrated resource plan the variables, standards of reliability, and other assumptions expected to have the greatest effect on the least-cost mix of resources.
Montana	Yes	Yes	§§ 69-3-1201-1206: Integrated Least-Cost Resource Planning and Acquisition Act. Specifically, § 1204 states that the utility may have to file a plan that meets customer needs in the most cost-effective manner. Mont. Admin. R. 38.5.2001-2016 further defines and sets guidelines for least-cost planning for electric utilities.
Nebraska	Yes	No	66-1060: The public utilities in Nebraska shall practice integrated resource planning and include least-cost options when evaluating alternatives for providing energy supply and managing energy demand in Nebraska. (integrated resource planning)
Nevada	No	Yes	NAC 704.9494 (c): The utility must demonstrate that the energy supply plan balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of the plan.
North Carolina	Yes	Yes	N.C. Gen. Stat. § 62-2: The policy of the State of North Carolina is "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." 4 NCAC 11.R8-60 implements N.C. Gen. Stat. 62-2 (with respect to least-cost integrated resource planning by the utilities)
North Dakota	No	Yes	69-09-02-33: Principle of Least Cost. It shall be the duty of utilities [...] to adopt, after a full consideration of all factors, the most practicable method which provides the greatest present and future economy and convenience in rendering the services involved [...]
Oklahoma	No	Yes	165: 35-34-3: “The evaluation of the responses to the RFP [Request for Proposal] will proceed as follows: (A) The soliciting utility will evaluate all timely submitted bids to determine the lowest reasonable cost for long-term reliable power or reliable long-term fuel sought that minimizes ratepayer cost”
Tennessee	Yes	No	831m-1: “The Tennessee Valley Authority shall conduct a least-cost planning program in accordance with this section.”
Utah	Yes	No	U.C.A. § 54-17-201: “[T]he commission shall determine whether the significant energy resource decision [...] will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers”
Vermont	Yes	No	§ 218-2-1d: “Each regulated electric or gas company shall prepare and implement a least cost integrated plan for the provision of energy services to its Vermont customers.”

Washington	No	Yes	480-100-238: "At a minimum, integrated resource plans must [describe] the mix of resources that is designated to meet current and projected future needs at the lowest reasonable cost to the utility and its ratepayers."
Wisconsin	No	Yes	PSC 113.1002: "The utility shall provide safe, reliable service with extensions that conform, to the extent possible, to each of the following standards: [...] Design. The utility shall design and install facilities to deliver service to the customer and the area at the lowest reasonable cost."