# Critical Gaps in the 2014 Big Rivers Integrated Resource Plan

## How better planning could be a key to the long term fiscal health of BREC

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# 1. SUMMARY

The primary purpose of integrated resource planning (IRP) is to reduce the long term costs to customers by identifying least-cost options and mitigating risks associated with an uncertain future.[1] Big Rivers has misused the IRP process, modeling only minor, often asymmetric sensitivity analyses on its preferred future resource plan. It has assumed success of its greatest hopes, rather than modeling and evaluating a range of realistic alternatives. By doing so it has denied ratepayers and stakeholders the opportunity to understand and evaluate decisions being made by Big Rivers' management.

The Big Rivers 2014 IRP is a credible answer only to the wrong question: Is there any possible scenario under which all of Big Rivers' current capacity would be useful and profitable? The IRP demonstrates at length that there may be one such scenario, and that minor variations on it would produce only minor variations in rates. If everything breaks entirely in Big Rivers' hoped-for direction, then the IRP could be a decent plan for ratepayers. But Big Rivers has tried this approach before, forecasting a favorable future as a way of validating its decision to retain all of its existing capacity, which has resulted in significant and unexpected rate increases and an idled coal plant.

An IRP is supposed to help avoid such situation by openly and transparently evaluating a range of scenarios that assess the impact to ratepayers of potential future conditions and resource options in order to identify a least cost/least risk resource plan. But Big Rivers has not presented such an evaluation; instead, the company has presented its desired resource plan and assessed only minor variations that do not take into account any of the major load and cost risks that Big Rivers faces. The narrowly limited range of sensitivity analyses in the IRP misunderstands the purpose of scenario analysis. Previous analyses which should inform future decisions, namely [redacted] were ignored by BREC in the IRP, and provided only in response to data requests. In addition, capacity prices in the IRP are forecast to [redacted] and energy prices appear to vary widely with each updated BREC calculation.

In short, nothing is said in the IRP to answer the right questions: What are the principal risks and uncertainties facing Big Rivers, and how do they affect the Company's plan for serving its customers? If prices, load growth, and/or environmental regulations turn out less favorably than the company now hopes, would a different resource plan be preferable? Are there circumstances under which the Company's customers would be better off if Big Rivers shed some of its capacity? The IRP provides no basis for evaluating such questions.

In fact, Big Rivers own actions indicate that it does not believe its own IRP. Just a few months after finishing the IRP, the Company adopted a financial forecast built on a scenario that is distinctly more

[1] "Integrated Resource Planning, The Basics and Beyond." James W. Gardner. October, 2013, at p. 6. Available at http://www.naruc.org/international/Documents/GARDNER-%20NARUC%20LMI%20ppt%20IRP%20Gardner.pdf

pessimistic than anything in the IRP.  In other words, Big Rivers appears to be undertaking internally at least some of the resource planning evaluations that should have been included as part of an open and transparent IRP process.

Big River's inability to appropriately conduct long term planning will impose unnecessary costs on its members and will only hurt the long-term financial health of the Company. For this reason, it is crucial for the independent management audit to do a thorough and careful evaluation of Big Rivers' resource strategy.

# 2. OBJECTIVES OF LONG TERM PLANNING

In the 1950s and 60s, the utility industry enjoyed a relatively low-risk environment with reasonably stable load growth and fuel prices. By the 1980s, this was no longer the case. The oil price spikes of the 1970s and nuclear cost overruns from the 1970s and 1980s led many states to call for development of long-term, integrated resource plans (IRP) to help protect consumers and the utility companies.

> The combination of higher oil prices and skyrocketing nuclear construction costs were felt most strongly in New England, and led to the bankruptcy of several utilities – Public Service of New Hampshire, Eastern Utilities, New Hampshire Electric Coop, Eastern Maine Electric Coop, and Vermont Electric Utility Coop. These crises of the 1970s and 1980s caused both utility planners and consumers to examine energy demand and use, resource selection, and risk.[2]

According to the Regulatory Assistance Project, a group of former regulators who provide assistance to policymakers and regulators on energy issues, the primary objective of an IRP is to "minimize the total societal cost of energy production and use over the long-term."[3] PacificCorp (one of the largest utilities in the United States, with service territory in Colorado, Utah, Wyoming, Idaho, Washington, and Oregon) notes that an IRP is not just a document used to fulfill a regulatory obligation but should provide meaningful information to both the company and stakeholders:

> As a business planning tool, [the IRP] supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources. The emphasis of the IRP is to determine the most robust resource plan under a

[2] "A Brief Survey of State Integrated Resource Planning Rules and Requirements." Rachel Wilson and Paul Peterson. April, 2011. Available here: http://www.cleanskies.org/wp-content/uploads/2011/05/ACSF_IRP-Survey_Final_2011-04-28.pdf

[3] "Integrated Resource Planning: History and Principles." Frederick Weston. May 2009. Available here: http://raponline.org/document/download/id/419

reasonably wide range of potential futures as opposed to the optimal plan for some expected view of the future.[4]

Because the future is always uncertain, it is critically important for the long-term planning in IRPs to address a wide range of risks through scenario and sensitivity analysis that evaluate how resource decisions should change in response to such risks. Risks that should be evaluated include changes in fuel prices (coal, oil, and natural gas), future load, electricity market prices, and carbon dioxide and other environmental regulations. And resource decisions that should be considered in response to such risks include not only the pursuit of new generation, but also the potential retirement or sale of existing resource and implementation of energy efficiency and demand response programs that can help mitigate such risks. The IRP process is typically done in the public sphere with opportunities for comment from the public and a review from the Commission. Generally, Commissions can accept or reject the resource plan, and often identify concerns regarding the plan. Commissions have in some cases rejected entire IRPs, or only portions thereof.[5] ().

In Kentucky, the IRP process is established by 807 KAR 5:058. It mandates that utilities evaluate improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.[6] When done properly, long-term planning by Kentucky utilities and cooperatives will help these companies maintain a strong financial outlook and serve their customers. As the PSC Staff explain in its Report on the 2010 Big Rivers IRP: "The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electricity were being examined and pursued and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost."[7] Unfortunately, as described below, Big Rivers' IRP entirely fails to achieve that goal.

# 3. THE USE OF FORECASTING

Developing load and price forecasts is one of the most important parts of the IRP process. Utilities in Kentucky are required to include a base load forecast that is "most likely to occur and, to the extent

[4] "2007 Integrated Resource Plan: Pacific Power, Rocky Mountain Power, PacifiCorp Energy" ParcifiCorp. 2007. Available here: http://www.psc.state.ky.us/PSCSCF/2007%20cases/2007-00477/OCI%20Workpapers%20II/Pacificorp%20IRP.pdf

[5] In re: Public Utilities Comm. Integrated Resource Planning, Docket No., 2012-0036, Order No. 32052 avaialbe at http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A14D29A91612I8285218+A14D29B10740E600721+14+1960

[6] Kentucky Administrative Regulation 807 KAR 5:058: Integrated resource planning by electric utilities. Available at: http://www.lrc.ky.gov/kar/807/005/058.htm

[7] "Staff Report on the 2010 Integrated Resource Plan of Big Rivers Electric Corporation." Case No. 2010-00443. December 2011. Available here: http://psc.ky.gov/agencies/psc/industry/electric/irp/201000443_122011.pdf

available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system."[8] The use of unrealistic forecasts was a major issue in Big Rivers' two recent rate cases. In this IRP, the forecasts used as modeling inputs are not only unrealistic, but appear to be developed primarily on the basis of an overly optimistic future – on what the company hopes will come to fruition, rather than careful evaluation of what is likely to come about.

## 3.1. 800 MW of replacement load

Replacement load of 800 MW is roughly what is needed to support all of Big Rivers' capacity, in the absence of the smelters. In the IRP base case, Big Rivers assumes that 800 MW of replacement load will be available by 2021. This represents a near doubling of the Company's current load. Sensitivity analyses explore only the possibilities that the 800 MW target will be reached two years earlier or later, either by 2019 or not until 2023 (IRP, p.54). The IRP does not include an evaluation of any scenario in which less than 800MW of replacement load is obtained. In other words, the IRP assumes that Big Rivers' load mitigation plan will succeed in replacing virtually all the load lost when the two smelters left the system, rather than also evaluating the risks and impacts if the Company can only achieve a lower level of replacement load.

Explaining the scenario process, the IRP says that:

> In addition to the base case forecast, Big Rivers prepared forecast scenarios to evaluate the impacts of varying economic conditions, market price sensitivities, fuel price sensitivities, weather conditions, and potential environmental regulations. Key model inputs were adjusted in developing the economy, market, fuel, weather, and environmental regulation scenarios and were set to values that Big Rivers believes would be similar to the 95% and 5% points of their respective probability distributions. (IRP Appendix C, p.C-2)

Taken literally, this suggests that the company has 90 percent confidence that it will reach 800 MW of replacement load at some point between 2019 and 2023 – and that there is only a 5 percent chance of failing to reach the 800 MW level by 2023. Figure 1 shows the narrow range of assumptions about future load growth in the IRP load forecasts. Every one of the 18 scenarios in the IRP assumes 800MW of replacement load will be achieved between 2019 and 2023 and as a result, the company has only investigated a limited range of possible outcomes. While other utilities are investigating the impacts of no load growth, or even load reduction, Big Rivers seems stuck in the past, relying on a future with a near doubling of load in every single model run.

[8] 807 K.A.R. 5:058 Section 7(3)

[redacted]

Replacement load of 800 MW is roughly what is needed to support all of Big Rivers' capacity, in the absence of the smelters. But is it plausible, in a market environment in which many other utilities are also scrambling to find new load for their excess capacity? According to Big Rivers' limited analysis, the answer is, in effect, trust us, we'll find it. The 2014 IRP states that, "With current market price projections, Big Rivers currently anticipates it may be cost effective to return idled plants [to service] in 2016 or 2017."[9] But the expectation of securing long term contracts for large amounts of additional load runs counter to BREC's experience and to current market trends. Recently, "[n]ine municipal power providers… have threatened to bolt from Kentucky Utilities Co., saying they believe they can get a more flexible electricity contract and save money on the open market."[10] Utilities in the region are not just losing customers to the market; some customers are vanishing entirely, including the large industrial load from the USEC uranium enrichment facility in Paducah, KY which shut down last year.[11]

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9 Big Rivers Electric Corporation Integrated Resource Plan. May 15, 2014. Page 113

10 "Nine Cities threaten defection from Kentucky Utilities." James Bruggers. *The Courier-Journal*. May 14, 2014. Available at: http://www.courier-journal.com/story/tech/science/environment/2014/05/14/lge-ku-energy-munciple-power-contracts/2140012/

11 "Kentucky Operator to Cease Enrichment of Uranium." Mathew L. Wald. *The New York Times*. May 24, 2013. Available at: http://www.nytimes.com/2013/05/25/business/usec-to-shut-uranium-enrichment-plant-in-kentucky.html?_r=0

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] By failing to include a 400MW replacement load scenario (or any other meaningfully different load scenario) in the IRP, Big Rivers has foreclosed the Staff and Intervenors from evaluating whether such scenario is more likely and whether it would be better for ratepayers for Big Rivers to pursue a resource plan that assumed such lower level of replacement load. As such, it is critically important that the independent management audit carefully evaluate a 400MW replacement load forecast and other reasonable load forecast scenarios that Big Rivers failed to include in its IRP.

Even if one were to accept Big Rivers' optimistic load forecasts, the rates being charged to different customer classes should be carefully examined. Figure 2 contrasts Big Rivers' projected rates that will be charged to rural, large industrial, and replacement load customers. If these projections come true, [redacted]

**Figure 2.** [redacted]

[redacted]

## 3.2. Capacity market

Big Rivers is forecasting capacity prices that appear to exceed reasonable expectations for the MISO capacity market. MISO operates a one-year-ahead capacity auction that determines capacity payments. MISO also calculates a “cost of new entry” (CONE) price for each of the nine Local Resource Zones (LRZs). CONE is the price that the system operator expects that new capacity resources would need in order to remain financially solvent based on capacity market revenues alone. MISO LRZ 4, which includes the three states that border Big Rivers’ territory, is the most representative locational resource zone for Big Rivers. MISO has estimated that the LRZ 4 cost of new entry (CONE) is roughly $89,000/MW-yr.[12] Net CONE, the amount a new resource would need minus the revenues that that resource could expect in the energy market, is generally 15-20% less than gross CONE.[13] Based on a 16% mark down of gross CONE, Synapse estimates that net CONE in LRZ 4 is just shy of $75,000/MW-yr. [14]

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[12] “Re: Filing of Midcontinent Independent System Operator, Inc. Regarding LRZ CONE Calculation; FERC Docket No. ER13-____-000” Michael L. Kessler. Septermber, 2013. Available here: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/LRZ%20CONE%20Filing_3%20Sept%202013.pdf

[13] PJM Planning Period Parameters 2017-2018 Available here: http://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-planning-period-parameters.ashx

[14] Based on the average ratio of gross to net CONE in the PJM Planning Period Parameters 2017-2018. Available here: http://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-planning-period-parameters.ashx

Historically, the MISO capacity market price has been held down by excess existing capacity; until the 2015/2016 auction it remained below $1,000/MW-yr. The 2015/2016 clearing price "skyrocketed" to $6,000/MW-yr (still far below net CONE). Capacity prices have consistently been higher in the market run by MISO's eastern neighbor, PJM – but the PJM capacity market clears at an average price of 55% of PJM's CONE.[15]

[redacted] Figure 3 compares 55% of MISO LRZ 4 Net CONE to the Big Rivers Forecast.

[15] Direct Testimony of R. Hornby, Case No. 11-1775-E-P PSC of West Virginia. July, 2013. Pg 21. Available at http://www.synapse-energy.com/sites/default/files/SynapseTestimony.2013-07.WV-CAD.APCo-WPCo-Generation-Transaction.13-030.pdf

[16] Fine, S., A. Saraf, K. Kumarawamy, A. Anich. "The True Value of Solar." ICF White Paper. October, 2014. Available at http://www.icfi.com/insights/white-papers/2014/true-value-of-solar

**Figure 3** [redacted]

[redacted]

[redacted]

Based on historic data and economic theory, the Big Rivers forecast is above and beyond a reasonable upper bound. Yet the IRP presents this forecast as a "base case" and suggests that there is even a possibility of capacity revenues exceeding the base case by [redacted][17] That scenario implies a capacity price that is consistently higher than gross CONE, an unrealistic expectation. For the purposes of planning, it would be far more reasonable to use 55% of net CONE as a base case estimate for the capacity price.

Big Rivers uses the capacity market forecast to adjust the costs of each of the scenarios. They do so by multiplying the Company's available capacity in each year by the forecasted market price, resulting in a projected revenue stream from capacity sales. The Net Present Value (NPV) of this revenue stream is calculated using a [redacted] discount rate (see the spreadsheet attachment to the BREC Response to SC 1-15c). Changing the capacity price forecast to 55% of net CONE would reduce the NPV of capacity market revenues by roughly half. For the base case, this adjustment reduces capacity market revenues from [redacted] million to [redacted] million.

Big Rivers' basis for its capacity price assumption is that large amounts of coal capacity will soon retire due to the costs of compliance with MATS, 111(d) and other EPA regulations. If this happens, and if no one else were to adopt the same strategy, then Big Rivers might indeed enjoy increased capacity revenues. It seems reasonable to assume, however, that other owners of coal plants will pursue the

[17] Big Rivers Electric Corporation Integrated Resource Plan. May 15, 2014. Appendix H

same strategy, hanging onto otherwise unprofitable plants in hopes of a capacity market windfall. If that happens, the price for capacity will be lower than every utility had hoped. The result could be a multi-state game of chicken, as every utility waits for others to retire their uneconomic units, finally allowing the price to rise for the remaining plants. Big Rivers does not have the financial resources to win such a game, outwaiting other utilities; some of its competitors have much stronger balance sheets, and have already invested more in compliance with CSAPR and other environmental regulations.

## 3.3. Coal Prices

The Big Rivers IRP not only relies on unrealistically favorable market prices for revenue calculations, it also uses unrealistically favorable market prices for fuel costs, mainly coal. In real terms, Big Rivers is [redacted] Meanwhile, EIA's Annual Energy Outlook (AEO) 2014, has both minemouth and delivered coal prices steadily increasing over the BREC planning horizon; see Figure 4. If Big Rivers had utilized a more realistic coal price forecast, the IRP modeling and analysis would have shown higher rates for the members, lower off-system sales, and a reduction in the dispatch of BREC's coal plants. Or, the use of a more realistic coal price forecast could have led to the identification of different resource plans that would help avoid those impacts.

**Figure 4.** [redacted]

[redacted]

## 3.4. Energy market

Big River's forecast for energy market prices seems to change with every inquiry. The IRP provides the Wood Mackenzie equilibrium price forecast. In response to data request SC 1-25, BREC provides a PCM run with a different forecast. A third and altogether different forecast was presented in the PCM run provided in response to data request AG 1-7, which was used to develop the latest financial forecast as provided in response to data request AG 2-2. Although these price forecasts are not comparable in absolute terms because they represent weighted averages of either sales, purchases, or the overall market, one would expect them to display similar overall trends over time. That is not the case; the significant differences among these forecasts, shown in Figure 5, are a challenge to explain.

**Figure 5.** [redacted]

[redacted]

It is also troubling that the Wood Mackenzie energy price forecast which Big Rivers is relying on may in fact result in a double counting of capacity price revenues. According to BREC response to SC 1-31, BREC uses Wood Mackenzie equilibrium prices, which are calculated by a model which

> …produces three layers of prices: short run marginal cost prices which represent the production cost of the marginal MW, the scarcity premium above short run marginal cost that generators can expect to receive in the energy market that covers fixed costs and bid mark-ups, and the capacity price required for new market entry.

This suggests that the Wood Mackenzie long term price may already include capacity prices, which BREC calculates and adds in separately. If BREC revenues are based on a long term energy price forecast plus capacity revenues, then BREC may be double counting capacity market payments. Without access to the three layers of prices and an explanation of how they are used to generate the equilibrium price, it is impossible to be sure about this.

## 3.5. Carbon Price

There are several co-existing meanings for the term “carbon price” or “$CO_2$ price”: it might be describing carbon allowances, a carbon tax, the social cost of carbon, a carbon shadow price, or some other carbon cost. Each of these terms is appropriate in its own context. Complex models that are used for long-term planning, including the model used by BREC, are capable of modeling carbon allowances or a carbon tax;

more simplistic financial models cannot easily represent carbon allowances, so a carbon tax or shadow price is more appropriate to use. In either case, there are a number of regulations that mandate a reduction in greenhouse gas emissions in the power sector, either directly or indirectly.[18] And with EPA having proposed its Clean Power Plan (a development that was well advertised in advance, before the completion of the Big Rivers IRP), it is imprudent to omit a carbon price in long-term modeling.

Big Rivers does not completely ignore the fact that a carbon price of some sort is likely to be adopted at some point in the future. Big Rivers does use the model to cost out the impact of carbon regulation; however, the company fails to appropriately use a carbon forecast in several ways.

Big Rivers' most egregious failure with respect to carbon prices is that it did not use the IRP to evaluate resource plans that could mitigate the costs of carbon regulations to BREC customers. Since Big Rivers did not allow its model to choose the retirement of any existing resource, and did not assume any retirement scenarios, there has not been any evaluation of options for reducing future carbon costs.[19] With the same amount of coal capacity operating in every scenario, there is almost no variation between scenarios in the amount of carbon emissions.

Another apparent failure is the use of a base case energy price forecast that [redacted] It is difficult to evaluate this error in any detail due to the extreme lack of transparency regarding forecasts: when projections from consulting firms are presented as confidential information, without supporting documentation or detailed explanation, PSC staff, auditors and intervenors are forced to take the Company's word for the reasonableness of the forecasts. However, in the response to data request SC 2-14, Big Rivers said that [redacted] – although no information was provided that allows independent confirmation of this potential error.

Moreover, the company fails to include a carbon forecast in the majority of its analyses. The 2013 Synapse paper that the Company cites is one of many sources suggesting that at this point, companies should be including a carbon price in all of their forecasts. U.S. electric utilities and other entities are increasingly incorporating $CO_2$ price projections into long-term planning and decision making process. In the words of another commentator:

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[18] CO2 Price Report, Spring 2014. Patrick Luckow et. al. May 2014. Available here: http://www.synapse-energy.com/sites/default/files/SynapseReport.2014-05.0.CO2-Price-Report-Spring-2014.14-039.pdf

[19] BREC Response to SC 1-16(a),(g) and SC 1-34 Case No. 2014-00166

> The utility Integrated Resource Plans (IRPs) required by many states make it necessary to project future prices for fuel and electricity. The substantial uncertainties in these price forecasts are understood, and are accepted as part of the process of making the best possible predictions given current information. Forecasting a $CO_2$ price is a similar exercise. Given the current regulatory environment, many utilities have come to recognize that making the assumption that there will be no $CO_2$ price is unrealistic and may lead to significant unexpected future costs.[20]

An ongoing review by Synapse of recent IRPs found that 39 utilities, representing 42 states and a substantial fraction of total U.S. generation, use $CO_2$ forecasts in their reference case (also sometimes called a base case or business as usual case).[21] Big Rivers' decision not to include a $CO_2$ price in the Company's base case prevents them from being able to properly mitigate risk. This type of planning can lead to unnecessary, unanticipated costs which its rural customers cannot afford, and its industrial customers will not willingly accept. The carbon prices incorporated in selected utility forecasts, over the same time frame covered in the Big Rivers 2014 IRP, are shown in Figure 6. These are forecasts used in utility base cases, where Big Rivers is assuming that there will be no cost of carbon emissions.

The Company's decision to neither allow the model to reduce carbon emissions by retiring coal plants nor to include a reasonable $CO_2$ price in most of their modeling runs will ultimately result in endorsement of resource choices that are not in the best interest of its members or in the interest of the long term financial health of the company. Delaying action to reduce $CO_2$ emissions only makes future emissions mitigation more costly.[22]

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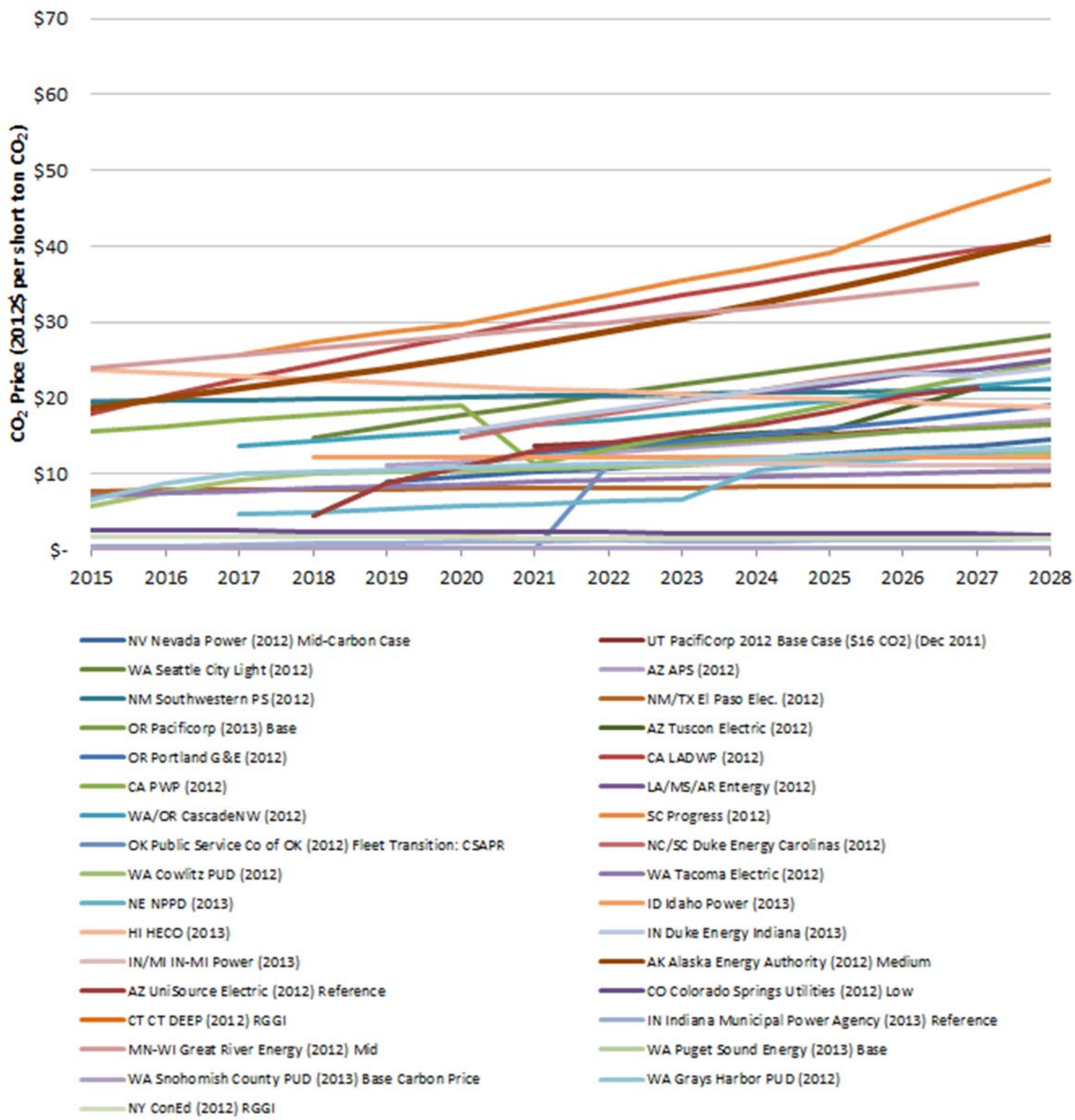
[20] Luckow, P., J. Daniel, S. Fields, E. A. Stanton, B. Biewald. 2014. "CO2 Price Forecast: Planning for Future Environmental Regulations." EM Magazine, June 2014, 57-59.

[21] Biewald, B. Written Statement of Bruce Biewald. Submitted as part of the February 27, 2014, U.S. Subcommittee on Energy and Power hearing: "Benefits of and Challenges to Energy Access in the 21st Century: Electricity;" February 2014

[22] Clarke, L.; Edmonds, J.; Krey, V.; Richels, R.; Rose, S.; Tavoni, M. International Climate Policy Architectures: Overview of the EMF 22 International Scenarios; Energy Economics 2009, 31 (Suppl. 2), S64-S81.

**Figure 6. Sampling of $CO_2$ Price Forecasts used in Base Case IRP scenarios**




*Source: Various. Assembled by Synapse Energy Economics.*

*Note: Dates shown are from 2015-20028 to reflect the same time horizon as the Big Rivers IRP, many of these forecast extend beyond this date range.*

# 4. USING SCENARIOS AND SENSITIVITIES

Developing scenarios and testing how a resource plan performs under various sensitivities is a basic part of long term planning. Ideally, multiple potential plans should be developed and tested under a range of sensitivities. The plans that perform best under multiple likely scenarios should be selected for additional sensitivity analysis. While utilities select plans on a wide range of metrics, generally the preferred plan performs well under numerous different sensitivity analyses. Most importantly, each of the scenarios developed should be realistic, and reflect reasonable assumptions about load, market prices, and environmental regulations in a plausible future.

Big Rivers, however, decided on its resource plan before starting the IRP process, rather than evaluating a range of resource options under a reasonable range of projected future conditions. The Company did not present any scenario in which it evaluated retiring one or more coal units, and did not allow the model to select retirement as an option.[23] And while BREC is actively seeking to sell or idle some of the Company's generating units, any analyses that reflect those courses of actions are omitted from the IRP. The result of this omission is that every resource portfolio discussed in the IRP is nearly identical; at most, a few have minor changes or additions in the later years. (The sole exception is the renewable energy mandate scenario, in which significant new renewable capacity is assumed to be required by law.) Nearly every one of the 18 scenarios presented in the IRP is deeply flawed; individually and collectively, these scenarios fail to represent what the future may hold for Big Rivers and its members, under any but the most optimistic assumptions.

Of the 18 scenarios only two include the costs associated with known environmental regulations which Big Rivers has assessed, while two others include a cost of carbon emissions (resulting from regulations such as the proposed Clean Power Plan); none of the scenarios include both compliance with known environmental regulations and a price on carbon emissions. Omitting or fragmenting these costs, which total in the [redacted], makes it impossible to draw meaningful conclusions by comparing scenarios. The IRP identifies [redacted] This should lead to questions and analysis about the merits of retirement versus retrofitting of these aging plants. Meanwhile, all 18 scenarios achieve exactly 800 MW of replacement load, differing only slightly in timing; this makes the IRP useless in determining the costs associated with not meeting the replacement load target, developing a plan to mitigate those costs, or evaluating whether attempting to replace all of the lost smelter load in order to keep all of Big Rivers' coal capacity operating is in the best interest of ratepayers.

In the IRP process, Big Rivers modeled several scenarios, most defined as sensitivity analyses varying a single assumption in the base case. The scenarios are largely presented as things that might happen to

[23] BREC Response to SC 1-16(a),(g) and SC 1-34 Case No. 2014-00166

BREC (better or worse weather, economic growth, market prices, etc.), not different cost mitigation strategies that BREC might choose to explore. The scenarios are examined only one at a time, as if multiple deviations from the company's base case are not conceivable. Essentially nothing is said about why these particular scenarios represent the 5th and 95th percentiles on the relevant probability distribution (see above). In the case of load forecasts, capacity price forecasts, and perhaps others, it is very difficult to believe that Big Rivers has correctly identified the 5th and 95th percentiles of possible outcomes, since it has excluded any consideration of partial success in finding replacement load, or capacity prices that remain in line with historical experience.

# 5. VALUE OF ASSETS

The IRP process is a powerful tool that can help guide utilities to take appropriate actions. This process is aided when utilities use previous reports and analysis to inform the new, long term planning. However, it is apparent that BREC has ignored an important prior analysis that they themselves had commissioned.

Big Rivers has [redacted]. According to the Company, Big Rivers has not performed any net present value revenue requirement analysis of potential future operation of Coleman Station.[24] [redacted]

In 2013, at Big Rivers' request, [redacted]

[redacted]

[redacted]

[24] BREC Response to SC 1-12 Case No. 2014-00166

[redacted]

[redacted]

[redacted] As in other aspects of the IRP, BREC's plans look reasonable only under the most optimistic assumptions. [redacted]

[redacted] These analyses, which were carried out before the IRP was filed, demonstrate even further why Big Rivers should have openly and transparently evaluated in its IRP scenarios in which one or more of its coal units is retired, rather than assuming that all of its coal units would continue for the entire planning period no matter what the future may hold.

# 6. Disconnects Between Planning and Plan

At the end of an IRP, utilities should have a clear path forward that includes a list of action items that the company plans on pursuing. This would include short-term, mid-term, and long-term plans, like increasing the budget of the following year's energy efficiency program, signing a Power Purchase Agreement with a wind developer, construction of a new plant, or decommissioning an old plant that is no longer necessary. While these plans are not set in stone, significant changes in market conditions or regulations may mean that the action plan varies from the previous IRP. However, the action plan (sometimes referred to as the preferred plan) should reflect a portfolio that was chosen because it was tested under a range of scenarios, and performed well enough that it is not likely to require significant changes in the short term.

Big Rivers seems to have used the IRP to analyze options they have no plan to pursue (such as increased energy efficiency, explained below), while simultaneously not analyzing options they may plan on pursing [redacted] This prevents the long-term "integrated resource plan" from being either integrated or a plan. The IRP focused on a single portfolio that BREC management predetermined to be optimal, and tested it under a myriad of unlikely futures. It is no surprise that the Company's current plans do not match up with the IRP results.

## 6.1. Energy Efficiency Plan

The company's action plan in the IRP states that, "The proposed actions over the next 3 years are in line with continued efforts to implement the Mitigation Plan filed in Big Rivers' 2012 Environmental Compliance Plan case, Case No. 2012-0063, as well as a continued focus on DSM programs."[25] This statement runs counter to the Company's declared actions since the release of the IRP in May. As shown above, the Company has already significantly deviated from the "Mitigation Plan" with its most recent long term financial plan. And despite a claim that it is focusing on demand side management (DSM) programs, they are forgoing opportunities for additional member savings by not pursuing the more aggressive energy efficiency (EE) plan it modeled during the IRP process. Big Rivers commissioned an Energy Efficiency Potential study which identified the potential for $270 million in net benefits, which Big Rivers is not pursuing. The study also identified a "$2 million" energy efficiency program that would yield $63 million in net benefits, which the Company is choosing to not pursue. Instead, the Company has chosen to pursue the energy efficiency program with the least amount of net benefits among the options it considered. At less than $32 million in net benefits, the "$1 million" program is expected to yield half the net benefits of the $2 million program.

**Table 1. Energy Efficiency Potential Study Results**

***Benefit-Cost Ratios by Scenario Estimated by the Energy Efficiency Potential Study***

| *Scenarios* | *NPV $ Benefits* | *NPV $ Costs* | *Benefit/Cost Ratio* | *Net Benefits* |
|---|---|---|---|---|
| ***Achievable Potential*** | *$506,791,256* | *$236,486,056* | *2.14* | *$270,305,200* |
| ***Program ($ 2 million)*** | *$114,112,784* | *$50,901,486* | *2.24* | *$63,211,298* |
| ***Program ($ 1 million)*** | *$56,970,960* | *$25,432,384* | *2.24* | *$31,538,576* |

*Source: Big Rivers Electric Corporation Integrated Resource Plan. May 15, 2014. Table 5.2*

[25] Big Rivers Electric Corporation Integrated Resource Plan. May 15, 2014. Page 113

## 6.2. Resource Portfolios

All of the resource portfolios analyzed are nearly identical. While some of the plans would require small additions of capacity (50 MW) in future years, the plans all include massive amounts of replacement load, so that BREC can supply both members and the market with coal-fired electricity. The problem with this approach is that it fails to address or analyze options for a lower cost, risk resilient portfolio that may (or may not) include retiring, idling, or fuel switching various coal units. The company claims that it decided not to model any of the Company's generating units being retired "because there are no plans to retire any generating units in the term of the IRP."[26] However, the purpose of an IRP should be (among other things) to determine whether the Company should plan on retiring any units. Modeling scenarios with and without different generating units is how a prudent utility would determine if a generating resource should be kept on line. However, BREC management circumvented this entire critical step by predetermining to not retire any of their current generating units.

As discussed above, the Company has apparently been considering [redacted] yet this possibility is never mentioned in the IRP. The Company has also been considering [redacted] The IRP would have been the appropriate forum to analyze whether [redacted] would benefit ratepayers. Gas conversion analysis is omitted from the IRP, with only a passing mention (on p. 92 of the IRP) that the company is considering some unspecified amount of conversion to natural gas [redacted] Apparently this analysis of natural gas conversion [redacted] took place in a separate conversation about real resource plans for Big Rivers, not in the "everything's coming up roses" version presented in the IRP.

# 7. RECOMMENDATIONS

In general, the company constrained its scenario modeling in a manner that prevents the company, the Commission, and other stakeholders from gleaning any meaningful information from the model runs. In responses to inquires about options it chose not to model, Big Rivers repeatedly responded that it did not model options it did not plan to pursue. Inconsistencies between the IRP and other Company documents regarding [redacted] represent significant gaps between the Company's stated plans and the planning process. All of these items are examples of paths the Company is actually exploring but chose not to model or discuss in the IRP.

Alternatively, the Company should have allowed the IRP process and modeling results to inform its Company plans; however that was not the case. In at least one case, the Company chose to analyze a

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[26] BREC response to SC1-16 in case 2014-00166

planning option it had no plan to pursue: an energy efficiency plan costing more than $1 million. The Company's decision to not pursue a $2 million EE program (despite the fact that it results in a greater increase in savings than in costs) confirms that the IRP did not serve the purpose of long-term planning. This is indicative of extremely poor planning because the modeling results should inform and support the Company's resource planning process – not the other way around.

There is a stark disconnect between the modeling results and data responses on the one hand, and the IRP text and the path that BREC is pursuing on the other hand. Modeling the impacts of [redacted] as BREC apparently now does for financial forecasting purposes, could provide valuable insights to not only BREC itself, but also its customers, the PSC and other stakeholders. So, too, could modeling of more realistic energy and capacity prices, [redacted]. Even taking seriously its own results on EE – showing that a more ambitious EE scenario creates greater savings – would have led to improvements in Company resource planning.

This IRP sheds surprisingly little light on the risks and opportunities facing Big Rivers. Once again, the Company has merely shown that all of its assets may be needed if everything goes its way in energy, capacity, fuel, and replacement load markets. Useful planning requires facing the music, admitting that utilities have to make decisions in a complex, risky economic environment, under conditions not of their own choosing. Prior to the IRP process, BREC had completed significant and important analyses that never made its way into the IRP. Furthermore, the Company seemed to ignore the analysis of its own consultants and failed to model many of the Company's own stated plans. Not only did the Company decide not to make plans to react to the results of prior analysis; responses during the IRP process suggest that even considering any such plans (like not meeting replacement load goals) would be ridiculous. However, in analysis done after the initial IRP modeling, the Company appears to be considering many of those previously inconceivable plans – though not all, since more ambitious EE plans with their greater savings are still ruled out. These issues should all be addressed carefully in the independent management audit.

In the past, Big Rivers has argued that it must keep all its plants in service because they are pledged as collateral on its loans; retiring any one of them would allegedly risk default. The constraint of Big Rivers' substantial debt burden should be recognized and analyzed explicitly; what is the minimum revenue requirement compatible with repayment of debts and provision of service to the members? It seems entirely possible, as was suggested in the latest rate case, that retirement of one or more plants, combined with a clear statement from the Commission that Big Rivers will be allowed sufficient revenue to meet its interest payments, would be the least-cost path forward under many future scenarios. But we will not know for sure until a more reasonable long-range planning exercise occurs.