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September 2013

Putting Down a Coal Plant: Retiring a Utility Asset

As electric utilities prepare for what many anticipate will be a regime of more stringent state and federal regulations on greenhouse gasses and other coal-fired power plant pollutants, many of these utilities are concluding that it's in their company's best interest, and that of their customers, to evaluate the merits of keeping their coal plants, and if so for how long.

Many power plant owners are concluding it makes more sense to shut down a coal-fired power plant than to try to bring it into compliance with known regulations or keep up with new and increasingly tighter regulations on power plant owner-operators. Utilities that reach that determination then face another thicket of questions that must be addressed: How to explain the decision to customers, to regulators, and to their shareholders? What are the rate implications of accelerating the depreciation of the coal plant and then the costs of decommissioning them, as opposed to the cost of replacing the lost power from retired coal plants? Are there conditions in which an early plant retirement can be justified for environmental or economic reasons, or both? And if a utility decides to pull the trigger on a coal unit that still has book value, can that utility still make the case that closing a still-operating power plant makes economic and regulatory sense?

The Snake River Alliance began asking these questions with its August 2012 report, "Kicking Idaho's Coal Habit, Charting a Cleaner Energy Future," which explored the extent of the reliance on coal-fired power generation by Idaho electric utilities and the resultant health and environmental impacts of those energy choices. Subsequent to that report, the Alliance was asked to explore some of the ways utilities retire coal units ahead of schedule as a strategy to minimize the looming economic risks associated with burning coal in what is becoming, for the electric utility sector at least, a carbon-constrained regulatory world. Unless utilities can see a clear path to transitioning off coal – a path that can be supported by utility regulators, customers, and investors – these utilities are more likely to delay the inevitable decision of plant retirement until the full weight of environmental and health regulations compels them to act, exposing the utilities to even more costs down the road.

For those advocating early retirement of coal-fired generating plants, then, the idea is to work with the utility to find a way in which a plant is retired before its time, while keeping the utility whole and not costing its shareholders and while minimizing costs to customers.

Such mechanisms already exist in various forms, notably accounting changes such as accelerated depreciation in cases where a plant will be retired before the end of its useful life, but before it has been fully depreciated. Many of the utilities that are currently retiring coal plants around the country are taking advantage of similar mechanisms, which we discuss in more detail below.

The economic case for replacing coal with cleaner alternatives that are also cost-competitive has been made and has withstood regulatory scrutiny in multiple state jurisdictions. Utility executives, who consider themselves stewards of company assets, are searching for a coal plant off-ramp that minimizes financial impacts to their companies while they retire these assets in response to demands by their customers and also to scrutiny by Wall Street investors leery of utilities that are long on coal and its associated risks. Many utilities outside of Idaho, including American Electric Power, Duke, Dominion, and FirstEnergy, have embarked on that path and have landed on their feet. The situation in Idaho is complicated by the reality that investor-owned utilities serving Idaho load for the most part do not hold a 100 percent ownership of these coal assets, so efforts to divest the assets, if they are going to be made at all, must be done along with one or sometimes multiple utility partners.

The shift away from coal and toward demand-side or less-risky supply-side resources is already having a profound impact on the electricity sector, and the impacts will likely grow as more utilities react to the coming regulatory wave that threatens to make continued coal generation less economic or out of the money altogether. The trend is well under way: Gigawatts of U.S. coal-fired power production are being shed each year. The question confronting electric utilities is whether to be a part of it, or more precisely *when* they will be a part of this trend.

In some cases, utilities are attempting to accelerate the timetable for environmental control retrofits so they can obtain regulatory approval for the investments before the anti-pollution and climate change regulatory environment squeezes such investments out of the money so much that retrofits lose any competitive edge with other alternatives such as natural gas plants, renewables, and energy efficiency. But rushing to invest more in coal plants before the weight of greenhouse gas regulations hits carries a huge risk because a utility could end up with a stranded asset and without full cost recovery.

One of the West's most noted examples of a utility foregoing coal is NV Energy, which surprised the western electricity sector when it announced in early 2013 that it planned to go coal-free, signaling its departure from the Reid-Gardner coal plant near Las Vegas and eventually other coal units as well by 2025. The utility said its decision was prompted by a combination of current and expected environmental regulations and persistently low natural gas prices. A big part of its coal replacement will be natural gas.

The reasons for retiring coal assets vary from utility to utility. Most replace coal with what for now at least are more attractive natural gas prices and to hedge against anticipated regulations on greenhouse gas emissions. Some make the move because their customers or their shareholders [or both] demand a cleaner electricity product. Some are responding to tightening renewable energy portfolio standards that require portfolios containing more clean energy. Most are motivated by a combination of business and environmental considerations.

As utilities respond to today's economic and environmental realities by backing off of coal, the proportion of the nation's electricity portfolio that comes from coal continues to decline. Not only do utilities need to deal with replacing the power from retired coal plants, they must also deal with reclaiming the sites from decades of toxic pollution, which as it turns out is no small matter.

The U.S. Energy Information Administration [EIA] reported in its March 2013 Short-Term Energy Outlook that in 2012 total domestic consumption of coal for electricity declined 11.6 percent, and while coal consumption may rise slightly due to higher demand, the trend has been established, and is most likely irreversible:

> *"Preliminary data from the EIA Electric Power Monthly indicate that 7.9 gigawatts of coal-fired generation capacity was retired in the electric industry during 2012, which represents 2.5 percent of installed coal capacity at the beginning of the year [and about 0.8 percent of total generating unit capacity]. Two-thirds of the coal capacity retired in 2012 was located in the Midwest and Southeast regions of the United States. In comparison, the U.S. electric industry retired 2.6GW of coal capacity in 2011 and retired an average of 1.0 GW each year between 2006 and 2010. The coal-fired capacity retired during 2012 was offset somewhat by the addition of five new coal-fired generating units with a combined capacity of 3.6GW."*

U.S. EIA Short-Term Energy Outlook March 2013

Depending on the forecast used in terms of high, reference or low natural gas prices and also on varying economic growth scenarios, EIA projects coal plant retirements to range from 40GW to 70GW by 2020. As would be expected, the *number* of coal units that will soon be retired seems unusually high given the amount of *generation* being replaced. That's because many of the power plant candidates for decommissioning are decades old, and consequently their capacity is far less than the much larger power plants of more recent vintage – such as 1970 and beyond.

Coal plants have an average life span of 40-50 years, at least for purposes of depreciation, and even that time frame may be shortened as environmental regulations and climate change concerns threaten long-term continued plant operation. So with such a high percentage of the U.S. fleet now eclipsing their expected longevity, it stands to reason the wave of plant retirements will only accelerate, depending on whether plant owners try to nurse their generators along by retrofitting them with pollution-control equipment in hopes of complying with state and federal health and environmental laws and regulations. Adding such equipment, as most U.S. coal plants require and will continue to require for an indefinite period of time, however, means adding significant new costs to operate a plant – something that must be considered if a utility is on the fence between retiring or retrofitting. The age of the plant is often, but not always, an indicator of a plant's life span. Some older plants lack many of the anti-pollution controls that are common today, so bringing them into compliance with existing or anticipated environmental laws may not make economic sense. Some plants are not bound by certain environmental regulations due to their age. Some plants will be shut down because one of their owners pulled the plug regardless of the desires of their minority partners, as was the case in majority owner Portland General Electric's decision to retire the plant in Boardman, Oregon, in response to rising environmental compliance costs that made continued operation of the plant beyond 2020 economically impractical.

The decision is incredibly complex on the one hand, but it can often be distilled to the overarching consideration of whether it will cost more to make repeated investments in coal units to keep them operating, or whether it will be cheaper over time to either replace the plant entirely with other resources such as natural gas, renewable energy, energy efficiency, or to convert them to another fuel such as natural gas, or to buy the energy elsewhere. Some coal plants readily lend themselves to a conversion from coal to gas; others do not. One thing that will force the hands of many utility coal plant owners is if the federal government, whether Congress or more likely the executive branch and the U.S. EPA, places a price or penalty on carbon emissions such as a carbon tax or a carbon trading mechanism. If that happens, and with President Obama announcing his Climate Action Plan on June 25, 2013, to adopt by 2015 emissions restrictions from *existing* plants it likely will, then the pace of coal plant retirements can be expected to increase.

Coal's Declining Share of the Generation Mix

The Northwest Power and Conservation Council, the four-state Northwest region's leading source on power planning, notes the region's two coal plants in Oregon and Washington are set for early retirement (a third plant, Colstrip in Montana, is not). The Council's Sixth Power Plan Mid-Term Assessment Report it gave a few reasons why:

"Increasingly, natural gas-fired generation is displacing coal-fired generation. Coal to gas fuel switching is partly the result of environmental concerns, but it also reflects changed economics. In particular, it appears that lower market prices for natural gas are combining with higher market prices for coal to make natural gas-fired generating facilities more cost-effective…

Several factors magnify the impacts of air emissions regulations on coal-fired generation. These factors include:

- *Burning coal produces larger quantities of toxic air pollutants than other fossil fuels such as natural gas;*
- *The quantity of carbon dioxide emitted per megawatt-hour of power generated at an existing coal-fired power plant is roughly two and one half times as much as the emissions from a modern combined-cycle natural gas-fired combustion turbine power plant;*
- *Coal-fired generation represents about one-third of the nation's generating capacity, and until recently met nearly half of annual power supply needs;*
- *A significant portion of the nation's fleet of coal-fired generating facilities is more than 30 years old; many of these units would require refurbishment to continue operating over the long term."*

The Power Council's report re-enforces the current thinking that natural gas as a power generating resource is pushing coal to the economic and environmental margins:

"Many utilities are comparing go-forward costs for their existing coal plants with the cost of new natural-gas-fired combustion turbines, and are concluding that replacing older coal-fired generation with new gas-fired generation makes sense. The prospect of future (greenhouse gas) regulations, with the costs and risks they pose, further tip the analysis in favor of retiring certain older coal-fired units."

A U.S. Department of Energy-funded report by ICF Incorporated for the Eastern Interconnection States Planning Council similarly drove the point home:

"Both new and existing coal-fired power plants face an array of regulations that, together with low natural gas prices, will fundamentally alter the role of coal-fired generation going forward. With 40GW of coal-fired capacity retirements already announced, and more expected by the 2015 compliance deadline, existing coal-fired capacity are likely to be reduced nationally from approximately 315GW to 250GW. Beyond that, another 50GW of coal-fired capacity is "on the margin" and will have some tough decisions regarding whether to retrofit to meet new rules in light of low gas and power prices, or to retire."

"Current State and Future Direction of Coal-fired Power in the Eastern Interconnection" Final Study Report, June 2013.

The EIA reported July 31, 2012, that with an estimated 50GW of coal generation expected to be retired by 2020, that accounts for approximately one-sixth of U.S. coal-fired power generation and 5 percent of the total U.S. electricity generation.

It is impossible to take such a large amount of generation out of play investing in replacement resources. There will also be costs associated with physically dismantling power plants and remediating the plant sites. Those costs are often identified in a comprehensive demolition or dismantling study.

According to an analysis by the Brattle Group, a Selective Catalytic Reduction (SCR) system to reduce nitrogen oxides (NOx) and mercury emissions can cost between $50 million and $60 million for a modestly sized 300-megawatt coal plant. Addition of a scrubber to reduce sulfur dioxide (SO2) and mercury can cost between $100 million and $120 million for a similarly sized power plant. A baghouse to capture particulate matter and mercury costs about $30 million. Those are for known environmental improvements to aging power plants – the kind that exist in each of our utilities' energy resource portfolio.

The above improvements do nothing to contain climate warming carbon dioxide (CO2) emissions, which currently cannot be controlled on the scale of an electric generating station.

An October 2012 discussion paper by the Brattle Group identified the costs of anti-pollution retrofits in 2012 dollars at between $98 billion and $115 billion in a base case gas scenario, while the cost of replacement capacity would be between $14 billion and $24 billion. The estimates range from a lenient to strict regulatory scenario. Further, the cost of replacing coal-fired generation can be determined with more precision than the unknown costs of regulation-driven retrofits.

Pulling The Trigger

For purposes of this paper, we assume a decision has been made to shut down a coal-fired power plant regardless of the circumstances. Beyond the obvious environmental considerations described above, it involves such things as an electric utility's overall generation, or supply-side, resource portfolio. It entails the utility's integrated resource planning process, which takes into account everything from expected electricity load growth to natural gas prices and the utility's energy-saving efficiency and conservation programs. It entails state standards on such things as setting renewable energy and emissions performance targets. And, of course, it entails things less quantifiable such as whether a utility is attempting to "green up" its portfolio either voluntarily or from pressure by its customers. Finally, it entails a calculation as to whether it's cheaper to keep the plant and keep it going or whether to pull the trigger and figure out how to put the plant down.

In some cases, such as with the Boardman plant mentioned above, utilities may commit to closing a plant that still has a book value that has not been fully depreciated.

The last thing a regulated electric utility, or any other similarly situated enterprise, wants is to have to deal with a "stranded asset," or an asset that's worth less on the market than what its owner still has invested in it. That's potentially what happens with a coal plant targeted for retirement due to high costs to meet new regulations as many coal plants are today. The plant's market value is extremely low, or zero if the plant is now obsolete while its owner has not fully recovered the funds it invested in the plant. Not unlike some automobile or homeowners, it is not unheard of for a utility to be upside-down on a power plant.

So long as the utility's state regulators are on board with an investment such as a coal plant scrubber, the utility might be inclined to make that investment on behalf of its shareholders. It's Utility Accounting 101: Utilities can earn more money for shareholders if the utility has more money invested. So a utility may be more inclined to make additional investments in something like a coal plant – including hundreds of millions of dollars for environmental upgrades and avoid the risk of having the plant become a stranded asset.

Other Utilities Have Blazed the Trail

How difficult is it to retire a coal plant before the end of its alleged useful life? Not so difficult that the only two such plants in the Pacific Northwest are now scheduled to shut down in 2020-2025 rather than 2040 or beyond. When that happens, the Pacific Northwest will be the only region in the United States without utility coal plants despite the fact some of its utilities still draw considerable amounts of power from coal plants elsewhere.

Idaho has no coal plants, but it has three major utilities that, combined, import about 1,500 megawatts of electricity into the state from other western states. That's about half of the electricity consumed by Idaho customers. Idaho Power, the state's largest utility and serving the southern portion of Idaho, is the biggest coal generation importer with an ownership share in about 1,100 megawatts of power, or slightly less than half its generation. PacifiCorp, which does business in southeast Idaho as Rocky Mountain Power, relies on coal for more than 60 percent of its energy. Spokane-based Avista Utilities is the Idaho investor-owned utility least reliant on coal, drawing about 15 percent of its energy needs from its share of the huge Colstrip plant in eastern Montana.

A regulated utility cannot simply walk away from a power plant and replace the energy from another resource. It must satisfy state utility regulators where it operates that the decision makes financial sense, and often that coal plant replacement with other options is the least-cost and least-risk alternative to keeping it operating. For Idaho's regulated electric utilities, it has been done before and it will be done again.

Idaho Power applied to the Idaho Public Utilities Commission for special accounting procedures after the Boardman coal plant in which it had a 10 percent interest was scheduled for early retirement.

Idaho Power's share of the Boardman coal plant decommissioning costs is slightly above $6 million in 2020 dollars, although that could increase significantly once more is known about the company's responsibility for disposing of waste ash and other environmental requirements. Had PGE decided to run the plant through 2040, Idaho Power's share of the additional required environmental upgrades that would have been borne by customers would have been an estimated $50 million to $70 million, or 10 percent of the $500 million to $700 million that would have been required in environmental upgrades.

Rocky Mountain Power is doing somewhat the same thing with its 55-year-old Carbon power plant in Utah. Carbon's two boilers are near the end of their lifespans, and the company plans an early retirement of the plant in 2015. Carbon still has a net book value of about $55 million and according to company filings with the Idaho PUC its depreciable life would run through 2020. We'll talk more about how that early retirement worked.

There are many methods utilities use when deciding whether it's time to retire a power plant rather than trying to extend its life with expensive retrofits. PacifiCorp, one of the nation's largest coal plant owners, serves customers from Utah and Wyoming to Idaho and Oregon, Washington, and California. It does business in southeastern Idaho as Rocky Mountain Power and in Oregon as Pacific Power. It owns or partly owns a stake in 26 coal plant units in Wyoming, Utah, Arizona, Colorado and Montana. It has a two-thirds ownership of the four-unit Bridger coal complex in Wyoming. Idaho Power owns the other third, so those plants are among those sending electricity into Idaho.

PacifiCorp recently completed a protracted regulatory case before the Oregon Public Utilities Commission in which the company sought to recover part of the $661 million spent on environmental improvements to seven of the 19 plants that it owns and operates. The case was contentious in large part because clean-energy and consumer advocates questioned the validity of the utility's analysis of whether it's cheaper to keep the plants going or retire them.

Idaho Power recently completed its cost-benefit analysis required by regulators to determine whether it made more sense to end its participation in plants in Wyoming and in Nevada, where it holds a 50 percent interest in the North Valmy plant with NV Energy, the utility planning to abandon coal.

In Idaho as in most states, if electric utilities want to recover capital investments such as power plants or transmission lines through customer rates, state regulators must determine that those investments were "prudent" – or defensible as necessary to serve customers with reliable, affordable energy.

Ultimately, utilities must show that the environmental upgrades they want to install will keep a power plant operating long enough to generate enough revenue to offset the cost of those upgrades through the rest of its expected useful life. It's no small task. In the case of PacifiCorp, the company has testified before Congress that its coal fleet has an estimated value of about $3.38 billion of net depreciation, yet it estimates the needed environmental improvements to keep the plants running will cost about $4.2 billion.

PacifiCorp sought to justify its investments in its coal fleet with the findings of its "present value revenue requirement differential (PVRR(d))" analysis that compares the costs of installing such things as scrubbers to the keep the plants operating to the cost of closing the plant and going to the markets to replace the power that used to come from coal. PacifiCorp defines the PVRR as the amount derived by subtracting the operating and capital revenue requirement from the market value of generation.

The problem with such studies has been that utilities such as PacifiCorp and Idaho Power have so far confined their analysis to just a handful of options: Close the plants and replace the power with natural gas or market purchases, or keep them open with huge retrofit investments to comply with state and federal environmental rules.

In their October 2011 report, "Incorporating Environmental Costs in Electric Rates," Jim Lazar and David Farnsworth of the Regulatory Assistance Project said utility regulators have a major role to play in determining whether plants should be retired, since they're the ones who will determine whether the utility made a "prudent" decision and just as important who should bear how much of the costs of retrofitting a plant or decommissioning it:

> *"Retrofit costs to control pollution and carbon emissions can be extremely expensive, often far more than the current investment in the plants, and in some cases, more than the cost of replacing the units with energy efficiency or new generation. Utility regulators should take a comprehensive view – evaluating long-term resource alternatives for meeting environmental and reliability requirement – when they consider requests fro regulated utilities for investment in and cost recovery for retrofit measures, or for approval to dispose of these units."*

Far from simply weighing the costs of retiring a plant and replacing with a gas plant against those of running it for its useful life, Lazar and Farnsworth say regulators should insist on a "comprehensive" analysis. Their list includes such things as the operating history of the power plant; remaining life of the plant's major components; a range of estimates of costs of carbon emissions; available renewable generation resources and energy efficiency resources in the utility's service areas; and available demand response measures to help deal with peak loads.

As the Alliance pointed out in its 2012 coal report, utility regulators and advocates for utility consumers (Idaho is the only state in the West without a consumer advocate to represent consumers in cases before the PUC) must be on guard against utilities coming in for approval of individual, piecemeal power plant retrofits or other improvements. Those may seem to make sense taken by themselves, but combined they can total hundreds of millions of dollars – sometimes more than the original cost of the plant itself. That is why the Alliance proposed in its report and reiterated here that the PUC should require more stringent review, such as for a "certificate of public convenience and necessity" (CPCN) for each significant power plant improvement before a utility can spend the money and expect to recover those costs from customers. In June 2013, Idaho Power applied for such a CPCN review by the Idaho PUC.

Paying for Early Plant Retirements

It's important for the utility and its regulators to guard against "rate shock" to customers in the event the costs of retiring a plant are extraordinary. Otherwise, public sentiment will grow against retiring a power plant regardless of the health and environmental urgency to do so. It's also possible that regulators may not allow all of the costs a utility claims if regulators aren't convinced the investments were not prudent.

From the utility's standpoint, it makes sense to balance its need for a return on equity from coal plant investments against a similar return in cases where the utility opts to develop its own non-coal generation assets, such as solar or wind. Utilities can reduce the impacts on their shareholders by developing clean energy projects, and capitalizing energy efficiency investments, for example, as opposed to replacing power from retired plants with market purchases.

In many cases, the utility applies to regulators for ratemaking treatment to allow the utility to speed up the depreciation of its asset so the utility and its customers [and shareholders] are not left with a stranded cost of the asset once it is retired.

It's an unusual but not an extraordinary procedure, and as mentioned above it has been employed in Idaho by two of our utilities in recent years. One of the most recent cases involved the Idaho Power application referenced above to recover the costs associated with its share of the 33-year-old Boardman plant, in which Idaho Power has a 10 percent share. Because the plant is still worth something but because Portland General Electric chose to shut it down in 2020 rather than 2040 and avoid major new environmental retrofits, Idaho Power needed the PUC's approval to accelerate the depreciation of its share of the coal plant.

In this case, the Idaho PUC authorized Idaho Power's request for an "incremental revenue requirement increase," or rate hike, by .181 percent, to recover $1.5 million that will be spread across all customer classes annually at the early stage of the decommissioning process. The total cost projected by the company as its share of the plant's retirement is $53.8 million, most of which is attributed to the plant's accelerated depreciation.

The PUC also approved creation of an Idaho Power "balancing account" to track the various costs associated with closing Boardman so they can be recovered later; as well as company revenues from its share of the plant's energy output. The account is needed in part because the coal plant's value must be written off ahead of schedule. Rather than pay off Idaho Power's share of the plant's worth over more years, ratepayers will pay slightly more so the value of the plant can be written off earlier than it otherwise might be. PUC approval is required for the Boardman decommissioning costs as an "Asset Retirement Obligation" so the utility can begin collecting revenues to cover its share of the decommissioning costs. The Idaho Commission's May 17, 2012, order in the Boardman decommissioning rate recovery case described it this way:

> *"With this Application, the Company asks to recover the levelized revenue requirement, which includes 1) the return associated with Boardman capital investments net of accumulated depreciation forecasted through Boardman's remaining life, 2) the cost of accelerating the Boardman depreciation and 3) the decommissioning costs associated with the Boardman shutdown."*

And:

> *"The Company is replacing the base rate revenue recovery associated with the Company's existing investment in Boardman with a levelized revenue requirement to be tracked in the balancing account."*

This procedure also involves creation of what's known as a "regulatory asset," a common tool used in such cases in which the utility records the financial impacts related to the early plant closure. Creation of a regulatory asset allows tracking of costs and revenues that are kept off the utility's income statement for tax purposes until the plant is actually retired. The costs will still be collected from customers, but in a subsequent rate case to be filed later.

While calculating the depreciation expenses for the early retirement of the plant is straightforward and based on the new target closure date, it is more difficult to know what the final decommissioning costs and required environmental upgrades and salvage proceeds will be, and that's one reason the new balancing account for the power plant is needed.

It also matters how long a utility is given to depreciate a plant that will be abandoned. Compressing that recovery period too much may result in a substantially higher depreciation rate to be borne by customers since the total amount will be recouped in a shorter time but in bigger annual amounts. Conversely, stretching out the depreciation period too long – such as beyond the time a plant is retired and instead to its original target lifespan – may spread the amount collected over a longer time, but it may also lead to additional debt interest costs, equity costs, and other components of the power plant's financial carrying charge.

In a 2008 Oregon PUC case, PacifiCorp sought to increase the depreciable lives of its coal plants in part to ensure that the plants will be fully depreciated by the time they are taken out of service. But Oregon regulators balked, reasoning that increasing likelihoods of greenhouse emission reduction requirements and the probability of EPA anti-pollution regulations are prompting utilities to decrease their use of fossil fuels. Extending the depreciable life of a coal plant, Oregon regulators said, could expose ratepayers to added costs if the utility needs to add even more environmental controls to the plants to keep them in compliance with ever-tightening environmental standards:

> *"We believe that it is probable that future environmental regulations will significantly increase the costs of maintaining and operating a coal-fired generation plant. This raises the possibility that continued operation of one or more of Pacific Power's coal-fired generating plants would no longer be consistent with integrated resource planning principles or the long-run public interest. In that case, questions could arise regarding Pacific Power's ability to recover the costs of the carbon emission controls in customer rates if the early retirement of a coal-fired generating plant is in the public interest…*
>
> *It is inappropriate to ignore the possibility that increased environmental regulations could reduce the economic lives of coal-fired generation plants."*

In addition to the accounting changes that must be approved by the PUC, the utility retiring its interest in a coal plant must conduct a "decommissioning study" that estimates the various costs associated with the plant shutdown. Those costs include such things as dismantling the primary plant infrastructure (boiler, turbine, etc.), as well as assorted support buildings, lagoons and ponds, railroad and transmission facilities, and environmental cleanup costs. The study also projects expected salvage value that will help offset some of the decommissioning costs. That salvage value helps reduce the possibility of stranded costs from the plant retirement.

In the PacifiCorp Carbon coal plant retirement case, PacifiCorp received PUC approval in December 2012 to transfer the remaining balances of its plant near Helper, Utah, into a regulatory asset account to recover the costs when the plant is retired early in 2015. Built in 1954 and 1956, the two-unit Carbon plant also faced tougher EPA environmental standards, and PacifiCorp determined it is not cost effective to refit the coal units with the scrubbers, baghouses, and other equipment needed to comply with EPA regulations. The company also determined it is not practical to convert the plants to natural gas, making early retirement the most cost effective option.

PacifiCorp will now amortize the plant's remaining value through 2020, its scheduled retirement year. The plant had a book value of about $55 million at the end of 2011, and PacifiCorp estimated the cost of decommissioning and reclaiming the plant site to be about $57 million.

Conclusion: Plant Retirement is Becoming a Well-Worn Path

As the risk to utilities, customers, and shareholders grows with continued coal plant operations, and as utilities opt for early plant retirements in greater numbers, the path toward plant decommissioning with reduced sticker shock for customers is becoming clear.

Early plant retirement is no longer considered revolutionary or bad business sense, particularly given the alternative of maintaining plant operations, but to make that decision utilities must have a regulatory mechanism in place to ensure cost recovery in the event a plant is shut down early. Fortunately, such options exist, helping to remove one of the largest barriers to plant retirement.