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WITNESS: ERIC M. MARKELL

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Joint Application of **PUGET HOLDINGS LLC** **And** **PUGET SOUND ENERGY, INC.** **For an Order Authorizing Proposed Transaction**	**Docket No. U-072375**

THIRD EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED REBUTTAL TESTIMONY OF ERIC M. MARKELL ON BEHALF OF PUGET SOUND ENERGY, INC.

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THE CAPEX CYCLE

The last big build-out changed the industry, which wonders whether it will undergo traumatic times again as it aproaches the next capital expenditure boom.

BY JULIE M. CANNELL

REMEMBER when people said that electricity generated by nuclear power would be too cheap to meter? When announcements of new nuclear plants were commonplace, followed by cancellations of most of those plants? When electric utilities were in a seemingly unending rate relief cycle and many faced acute financial distress? Well, many folks still do recall the bad old days of the late 1970s and 1980s. And they fear that Mark Twain was right when he said, "History doesn't repeat itself, but it does rhyme."

It was not so apparent at the time, but in retrospect, the events and circumstances that brought the electric utility industry to the brink of financial disaster are fairly clear. As we ramp up to another cycle of major capital expenditure, we find that the traumatic past

yields many lessons that can help prevent its recurrence—and several beneficial circumstances and policies currently in place will help the current capex cycle avoid the pitfalls of the last.

Key among the lessons of the 1970s and 1980s is the need for supportive regulation. Violation of the fundamental regulatory compact—which provides a reasonable return on the investment required for the reliable provision of electricity—increases the cost of capital and serves to harm every stakeholder. The necessity of a diverse generation portfolio is another lesson, as is the necessity to be acutely aware of the costs (for nuclear, coal, natural gas, renewables, and energy efficiency) to build it. Finally, utilities and regulators must meet investor needs for returns commensurate with the risks in a major construction cycle.

Still, there are rhymes between this cycle and the last. How utilities and regulators hear them and react to them will be critical to this cycle's success.

An Industry Used to Growth

In the post-World War II years, a healthy American economy hummed along at a 7-percent annual clip, inflation was benign, and electricity sales kept pace with economic growth. Demand outstripped usage two-to-one, prompting utilities to begin aggressive construction programs.

Another motivator for new construction was the fact that the industry operated under a declining marginal cost structure. Technological improvements and economies of scale yielded larger, more efficient thermal generating plants, fueled by fossil supplies whose cost was declining in real terms. Transmission, distribution, and other generating infrastructure were also added cheaply. The price of electricity declined on both a real and an absolute basis. Customers used more power, utilities built more plants.

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Dinner by candlelight at the automat. The 1965 Northeast Blackout raised costs for utilities, which then poured money into nonrevenue-producing upgrades. It also fueled public distrust of the industry, exposing it to criticism on environmental, consumer, and other issues.

To secure a franchise, utilities assumed an iron-clad obligation to serve the customer. Both because demand for power was so strong and because demand forecasting methodology was far from perfect, utilities frequently overbuilt to ensure that sufficient supply would exist, particularly should demand prove stronger than anticipated.

The basic premise of ratebase regulation also led to additional construction. With utilities permitted a return on their rate base, they had incentive to increase the size of that base and thus added new infrastructure as a way to boost earnings power.

This idyllic set of circumstances for the industry didn't last.

The Road to Troubled Times

Costs, which had largely been in the black for utilities during the 1960s, began to appear in red ink as the 1970s ensued. Inflation and interest rates rose, having a particularly negative impact on capital-intensive electric companies. Utilities saw higher expenses at every turn—for fuels, construction, operations and maintenance, and financing. Further, the technological innovation that had once boosted generating plant economies of scale and efficiencies began to abate. Finally, the economic slowdown beginning in the mid-1970s encouraged customer conservation efforts, thereby lowering utility sales (that is, revenue) growth.

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Several events exacerbated the effects of cost pressures. A massive 13-hour blackout over the Northeast and Ontario in November 1965 led utility managements to spend on upgrades of a hitherto smooth-running system, upgrades that neither produced revenue nor were absorbed by demand growth. The blackout lowered the public's esteem of the utility industry, and higher customer rates deepened the mistrust.

In the early 1960s, a focus on industry's environmental impacts gave rise to environmental activism across the country and intense scrutiny of the polluting electric utility industry. Public opposition to rate increases and new power plant construction mounted. The nation saw the first Earth Day, President Nixon created the Environmental Protection Agency, and many environmental laws were enacted. Compliance with new emissions regulations required additional expenditures and also served to increase rates.

The oil embargo by the Organization of Petroleum Exporting Countries in 1973 increased the price of fuel—utilities reflected this in fuel adjustment clauses, which passed the higher costs on to consumers, who reacted by cutting power consumption (thereby slowing utility sales growth). In fact, 1974 saw the first year-over-year decline in electricity sales since 1946. Utility managements initially viewed the drop as an anomaly and continued to build. But this new construction, in addition to being unnecessary, was also undertaken with higher financing costs, which added to the industry's mounting financial pressures.

In April 1974, due to severe financial straits, Consolidated Edison omitted its quarterly dividend—one of the hallowed aspects of utility stocks. The action decimated confidence in investments in the industry as a whole. This also caused a credit squeeze, making it at best expensive, if not impossible, for companies with weak credit to tap into capital markets. By 1975, the industry's capital expenditures declined for the first time since 1962. In 1978, Congress passed the Public Utility Regulatory Policies Act, wherein "qualifying facilities" (QFs) could generate power that utilities had to buy at their own avoided cost. Over time, the QF purchase obligation proved to be an expensive burden on the back of numerous electric utilities. But the financial pressures were only just beginning.

Nuclear Trepidation

In March 1979, the cooling equipment in unit 2 of General Public Utilities'

Three Mile Island shifted public perceptions in the 1970s and 1980s: safe and reliable became risky and expensive.

Three Mile Island plant malfunctioned, leading to a meltdown of the reactor core. The event initially caused widespread (but subsequently unfounded) fear of radiation release, and this had far-reaching ramifications. A reliable, safe, and inexpensive energy source was now thrown into question. An anti-nuclear movement gained momentum rapidly and hampered the efficacy of existing units and especially those plants under construction or still on the drawing boards. Investors now began to turn their backs on the technology, and funding a new nuclear plant became prohibitively expensive, if not impossible.

Governmental actions and regulations further exacerbated the cost associated with a new nuclear build. New safety regulations requiring extensive and expensive retrofits to both operating plants and those under construction became *de rigueur*. The avalanche of new requirements was complicated by the lack of standardized plant design throughout the industry. The Nuclear Regulatory Commission declared a moratorium on new nuclear construction, which prompted numerous cancellations or deferrals, with severe impacts for investors. (See the sidebar, "Nuclear Plants.") All utilities involved in the nuclear construction business suffered financially, losing both massive amounts of previously expended investment dollars as well as current market value in their securities. Dividend reductions and omissions became more commonplace.

Another phenomenon the industry had not experienced prior to the nuclear crisis was the b-word. In early 1988, Public Service Company of New Hampshire declared bankruptcy due to problems in efforts to build a nuclear plant (Seabrook) with a huge financial requirement. In addition to construction problems and runaway costs, the utility encountered numerous political difficulties and inadequate regulatory support to see the project through—attributable, in part, to the astronomical rate increases that would have been involved in bringing the facility into rate base.

In short, the nuclear industry hit the wall.

An Altered Regulatory Paradigm

The utility industry and its regulators enjoyed a compatible relationship from the end of World War II until the 1960s. In a declining-cost industry, the addition of new plants did not require rate increases, so regulators were able to keep all constituencies happy. But in the 1970s, as costs incurred by the industry began to rise across the board, companies had to seek rate increases. Regulators found themselves in the middle, with utilities (on one side) whose financial conditions were deteriorating, consumers (on another) who were balking at paying higher rates, and politicians (on yet another) who pressured regulators not to raise those rates. In response, many state commissions granted inadequate amounts of rate relief. (See Table 1.) At the same

Nuclear Plants

Halting nuclear plant construction was expensive. Cincinnati Gas & Electric pulled the plug on its Zimmer Nuclear Station in 1983, when the plant was 97 percent complete, because finishing the facility would require an additional $2.8 billion-$3.5 billion in investment spending and another two to three years of work. Other large cancellations included Public Service of Indiana's Marble Hill, Long Island Lighting's Shoreham, and Consumer Power's Midland stations. Nuclear units that were eventually built overcame huge delays and a final price tag that was often multiples of the original cost estimates. One of the last nuclear plants completed in this country, the South Texas Nuclear Project, was finished in 1989 at a cost of just under $5 billion. The station's original estimate was $974 million.

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time, inflation was climbing, and the result was that utilities were in a perpetual state of earnings attrition.

Under these circumstances, the quality of these hampered earnings suffered. By the end of the 1980s, companies in only 15 states could include "construction work in progress" (CWIP) in rate base with a full or at least partial cash return on investment as utilities incurred it. To bolster earnings levels, companies used accounting mechanisms like "allowance for funds used during construction" (AFUDC), which effectively deferred interest charges during the building cycle. When the nuclear construction situation began to spiral out of control, many utilities had AFUDC as a percentage of earnings for common stock ratios of over 100 percent. In other words, the earnings were there on paper, but their quality was abysmal. With earnings deferred to a future time, this at some point would translate into massive rate increases. At the same time, poor earnings quality led investors to require higher returns on equity as compensation—returns that regulators were not providing. The price of utility securities began to reflect this in stock prices significantly below book value and the high yields on fixed-income investments.

Also, many states did not provide for full recovery of fuel costs. Some addressed those expenses on a lagged basis, adding to earnings attrition. And other states had provisions for prudence oversight—regulators could scrutinize fuel purchases and conclude that, in retrospect, management decisions were unreasonable and thus not allowed to be recovered.

Prudence disallowances became a hallmark of the post-Three Mile Island years. Indeed, by the end of the 1980s, utility commissions in 26 states required imprudence adjustments. When utilities began to cancel nuclear plants or delay commercial operation dates in earnest, the second-guessing began. Full recovery of already expended funds became a thing of the past, as regula-

TABLE 1

AUTHORIZED VS. EARNED RETURN ON EQUITY FOR SHAREHOLDER-OWNED ELECTRIC UTIITIES 1972-1991

Year	Authorized ROE	Earned ROE	Difference (Basis Points)	Market as % of Book Value (Moody's)
1972	12.01	11.72	29	117
1973	11.87	11.29	58	100
1974	12.50	10.45	205	67
1975	12.90	11.19	171	69
1976	12.80	11.46	134	79
1977	13.10	11.40	170	87
1978	13.20	11.37	183	80
1979	13.40	11.17	223	75
1980	14.23	11.41	282	66
1981	15.22	12.60	262	67
1982	15.78	13.50	228	77
1983	15.36	14.35	101	89
1984	15.32	14.43	89	85
1985	15.20	13.73	147	101
1986	13.93	13.29	64	125
1987	12.99	13.50	(51)	118
1988	12.79	13.00	(21)	110
1989	12.97	12.00	97	124
1990	12.70	11.60	110	130
1991	12.55	11.60	95	145

Source: Edison Electric Institute, Regulatory Research Associates, Energy Information Administration, Moody's Investors Service tors had to contend with plant price tags that were exponentially higher than original estimates. Regulators accused managements of having made "imprudent" decisions to build nuclear plants and therefore disallowed large amounts of funds recovery.

The industry, already reeling, began to teeter on the brink, with many companies facing massive write-offs and financial disaster. (A solution for some utilities came in the form of securitization, wherein the disallowed construction costs were recoverable over time via an AAA-rated bond backed by a specific asset.)

In essence, the 1970s and 1980s saw the fundamental underpinning of the utility industry begin to come apart. The regulatory compact—fair return for reliable electricity—began to unravel. Utility companies could not count on fair regulatory treatment, and neither could their investors.

The industry made it through the 1970s and 1980s, but with deep scars. After the construction binge abated, companies looked elsewhere for earnings—largely through diversification into nonutility areas and overseas expansion, strategies that withered in the late 1990s. Mergers and acquisitions characterized the next wave of growth and met with varying levels of success.

But none of these vehicles required investor capital in the same measure or even the same involvement of regulators as did the major construction cycle. It is only now, as the industry once again finds itself with massive building needs, that the nation will test those requirements again.

Lessons Learned—Or Not?

Right now, with electricity demand absorbing the excess supply generated from the overbuilding of the 1970s and 1980s, the industry now finds itself again needing new power plants—258 gigawatts' worth by 2030, along with new transmission and distribution infrastructure, emissions compliance-related construction, and the potential large impacts of carbon constraints.

So: Will history repeat itself?

Four factors present today may help prevent the kind of near disaster of the last major industry build.

First, a relatively new phenomenon in the industry is integrated resource planning (IRP), a formalized process in many states requiring utilities to submit long-range plans that spell out prospective resource needs and the underlying assumptions. IRP imposes a discipline on the construction process not universally practiced during the last cycle, when utility managements continued to build despite a clear decline in electricity demand. Such a decline would be more difficult to ignore under today's IRP process.

Also, the economic dislocations and high interest rates of the 1970s and 1980s are not at work today. Though there are debates about the U.S. economy's future strength, the last several years have seen a solid economy and quite low interest rates—a far cry from the double-digit phenomenon experienced in the 1980s.

Of course, though a strong economy argues for more supply to meet expected demand, that was also the case in the years preceding the earlier construction cycle; and the possibility exists that an overbuilding echo could occur today. Mitigating that prospect is the number of other factors that drive the industry's infrastructure requirements. These include complying with environmental regulations and legislation, replacing aging assets, and building transmission to support generating facilities mandated by renewable portfolio standards (RPS) in many states.


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Finally, in recent years, energy efficiency has gone from being a "soft" concept to one of material importance in utility plans to temper demand. A heightened national awareness of climate change, high commodity prices (for fuels, construction materials, etc.), and a desire to avoid at least some construction of hard assets have led to this. (See the sidebar, "The Street's View.")

Arguing against a 1970s repeat are a solid economy, mature efficiency programs, and greater public awareness of power needs.

The Regulatory Compact

One of the lingering doubts about the new construction cycle has to do with the tone of regulation. Frankly, the jury is still out on how supportive state regulators will be this time around. Evidence is present on both sides of the argument.

On the plus side, the industry generally has adopted a constructive approach toward regulation. During the 1970s and 1980s, utility-regulatory relationships were frequently adversarial and combative. In light of the role state commissions will play in the sizeable construction programs that lie ahead, many utility managements have sought

New regulatory, utility staffs. Both are working to fill the gaps in institutional memory that have appeared since the last buildout.

to build positive regulatory relationships. Over the years, companies have come to a better appreciation for the many constituencies whose interests commissions must serve. At the same time, utilities have worked to help regulators understand how utility needs fit into the broader context of ratepayer, investor, political, and economic interests. This outreach is particularly important right now because of the turnover at most state commissions since the last major rate relief cycle.

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A similar lack of institutional memory exists among utility companies and institutional investors.

But a positive regulatory experience has not been universal. Several states, notably Illinois and Maryland, saw major rate increase petitions filed in 2006 by utilities that were coming off multi-year rate freezes, which the state had adopted as part of a move to deregulation. Because the companies filed the cases at the same time commodity prices were rising dramatically, the increases sought were politically unpalatable, and a major upheaval ensued. To avoid a repeat of the Illinois and Maryland rate shock experience, other deregulated states, such as Pennsylvania, are already seeking a solution to mitigate the rate impact from a move to market-based rates.

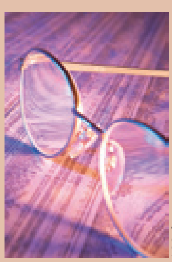
Recovery of Construction Costs

Not yet tested in this period of major capital expenditures is the ratebase treatment for a major generating unit. In the instances of prudence disallowances in the 1980s, the regulatory compact was clearly broken: Utilities undertook a construction project in good faith, expecting to be granted full recovery of the costs as well as a reasonable return on investment, but many companies received neither. How should we protect against this now?

The concept of CWIP in rate base has recently returned, though there has been little progress in expanding its adoption more broadly than in the 1970s and 1980s, despite CWIP's salutary financial impact during a construction program. Investors certainly would support a broader presence of the concept. In a 2005 study of financial community views on state utility regulation, 97 percent of respondents supported CWIP as helping to improve cash flow (and thus credit quality), decrease costs, and minimize regulatory lag (and thus risk).

In the same study, respondents also strongly endorsed the concept of "in-

The Street's View



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Companies are considering several business models for energy efficiency programs. To the extent that the industry is still in the early stages of doing this, the investors who will fund such endeavors view the topic from a conceptual rather than analytical perspective. The investment community understands the potential that energy efficiency holds for curbing demand but also is cognizant of the risks of underestimating the need for future infrastructure. They are aware that efficiency is only one component of a portfolio solution, one that includes renewables as well as nuclear, coal, and natural gas. Analysts also stress the need to balance near-term political expediency with long-term program viability. While the prospect of using less power is appealing, along with it comes an associated decline in revenue and earnings growth; accordingly, utilities will need some form of incentives to undertake programs.

And for energy efficiency to be an investable utility platform, the support of investors will require assurance of a return on any investment they make.

Rising costs for labor, materials, and construction management require assurances of cost recovery that can withstand the strain.

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vestment pre-approval," which they see as providing considerable certainty and decreasing investment risk. Many utility managements agree and have publicly declared that their companies will not put the first spade in the ground until they have assurance from regulators that the investment dollars will be recoverable. Some states have passed statutes to offer such assurances; others have adopted supportive rulemakings; and industry stakeholders seek to broaden the trend. Without the certainty, some utilities may choose not to spend the capital.

Despite the promise of cost-recovery provisions, rising costs in general have fueled concerns about future construction. In a recent study, the Brattle Group analyzed the rapid escalation in costs associated with all utility infrastructure expansion. [See "The Upward Climb" in the September/October *Electric Perspectives.*] The report noted that these price increases—not expected to abate any time soon—have been due to factors beyond the industry's control. Prices for raw materials and manufactured products common in utility construction projects have climbed due to global demand, higher production and transportation costs, and a weak U.S. dollar. Labor costs have also risen. Engineering, procurement, and construction firms are in high demand, and so construction management bids have been heading upward.

The study spelled out some chilling numbers in terms of the cost of new generation construction. The installation cost of new combined cycle gas units between 2000 and 2006 cumulatively increased by 95 percent, with most of the boost coming in the last year. Wind projects' price tag climbed 50-70 percent over the last two years. For several coal plants, just two years after the first plant construction estimate, some companies are reporting new estimates that approach a doubling of the initial price.

Moody's Investors Service noted recently the concerns that arise "from the sector's sizeable infrastructure investment plans in the face of an environment of steadily rising operating costs," which can create a continuous need for rate relief. As well, higher costs will put pressure on ratepayer pocketbooks. So, on the one hand, regulators must maintain the financial integrity of the companies they oversee; on the other, they must struggle with the fact that raising customer rates is never popular or politically expedient.

Generation Options

Generation choices that utilities make in coming years not only will have long-lasting ramifications, but also will factor into how much of a reprise there might be of the 1970s and 1980s construction-related woes.

In addition to nuclear being back in favor now, many see it as a logical choice (in addition to coal and natural gas) as a fuel for future baseload generation. The pro-nuclear argument is that some important things have changed. In the first place, a key problem 40 years ago (in retrospect) was the lack of standardization of nuclear reactors, which both increased the ultimate cost of the facilities and created delays in construction timetables. The licensing process exacerbated the problem: NRC and its predecessor, the Atomic Energy Commission, issued two separate licenses: one for construction and another for operation. In some cases, complete plants sat idle as they waited

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Yucca Mountain work continues, but politics will hold up permanent nuclear waste storage for another decade.

for the operating license. In other cases, construction took much longer than expected. The result, however, was the same: significantly higher costs than initially estimated.

The Energy Policy Act of 1992 took steps to change this. First, NRC now can issue a combined construction and operating license (COL) under which all regulatory reviews are completed prior to spending significant capital. Another advantage of the COL is that it limits the extent to which intervening parties can protract the licensing process. Also, in terms of standardization, NRC has precertified two of five possible reactor designs.

Second, the Energy Policy Act of 2005 provided: a production tax credit (PTC) for the first eight years of a new nuclear plant's operation; standby support, whereby the federal government would cover debt service for the first six reactors built if licensing or litigation problems delay commercial operation; and federal loan guarantees.

Finally, the focus on the environment and climate change has improved the perception of nuclear, which does not emit criteria air pollutants or greenhouse gases (GHGs). As such, the technology will not incur any of the estimated billions of dollars of spending for emission or GHG controls to meet federal regulations.

Still, not all the concerns have disappeared. Even though the industry has greatly tightened its safety oversight and practices and has an excellent record, safety worries persist in the public mind. In addition, the threat of terrorism has concerned some people.

Moreover, the nuclear waste issue remains unresolved. Litigation and politics have pushed out the timeline for permanent storage at Yucca Mountain for at least another decade. The prospect for recycling nuclear fuel also does not appear to be a near-term option. Thus, the industry continues to rely on interim storage solutions.

Another point of debate is cost. Moody's Investors Service recently published an estimate range of $5 billion-$6 billion for a new plant. The rating agency acknowledged that "its estimate is only marginally better than a guess," but noted its conservative slant compared to current market forecasts of $3 billion-$4 billion. With escalating costs associated with all utility infrastructure projects, the possibility exists that even Moody's conservative estimates could turn out not to be conservative enough.

But it comes down to these questions: Are investors willing to provide the capital for nuclear plant construction? do companies have sufficient scale and capitalization to take on such a huge project? Will regulators provide adequate reassurance on investment recovery? Billions of investment dollars were lost during the 1980s. For companies and investors to step back up to the nuclear plate, they first will have to have solid assurance that they would receive a reasonable return in the face of high risk. Second, the company would have to define the potential escalation of construction costs, and regulators would need to provide a guarantee of cost recovery. Third, regulated utilities and investors would need assurance that the regulatory compact will now remain solidly in place.

Coal and Natural Gas

Several recent analyses have addressed the significant rate of coal-fired plant cancellations. One Bernstein Research analysis pointed to some 16,000 MW of coal-fired projects canceled since March 2007. This largely reflects the intervention of state regulators and legislators or utilities concerned about the climate issue; sobering construction cost escalations; or the looming future cost of carbon compliance. Bernstein noted that the capacity canceled in 2007 is equivalent to nearly half the coal-fired capacity under development in this country and exceeds the capacity currently under construction.

Coal's rapid fall from grace has serious ramifications for long-term capacity planning. According to Edison Electric Institute, of the nearly 61,000 megawatts of capacity projected to be added by 2017, coal comprises almost one-third. (Another third for new nuclear plants; 36 percent for gas-fired; and the balance for wind and other sources.) With the most optimistic in-service date for a nuclear plant slated for 2015 or 2016, the only other fuel available to power a sizeable plant is natural gas. Currently, the price of natural gas is more than double its highest levels in the 1990s, with higher spikes over the years. The supply of natural gas is limited and subject to disruption from both natural (hurricanes) and political (Middle East turmoil) events. We face international competition for relatively new sources, like liquefied natural gas; and untapped reservoirs (on the Outer Continental Shelf, for example) remain closed, at least for now. So, while natural gas can provide the fuel for new plants, which are less expensive and faster to build, both price and supply risk offset its benefits.

Eventually, the pendulum should swing back to coal. At that point, new plant designs could take greater advantage of advanced coal technologies—integrated gasification combined cycle, circulating fluidized bed, and supercritical and ultrasupercritical

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The pendulum should swing back to coal. But full acceptance requires carbon sequestration on a commercial level.

pulverized coal—in light of environmental considerations. But for coal to be fully embraced as a future generation source, carbon sequestration must be addressed on a commercial level.

Renewables

Just as climate issues have put coal backstage, they have thrust renewables into the limelight.

In recent years, 26 states have moved to adopt an RPS, requiring a certain percentage of electricity from renewable power sources. Several bills under review by Congress also contain a federal RPS.

Another force that has spurred the development of more renewable generation is the availability of a federal PTC and other financial incentives. Even with this assistance, however, renewables remain an expensive supply source. Renewable assets located in remote locations will need new transmission to support them, as well. Utilities must factor in the costs for that new infrastructure, as well as for whatever backup capacity is needed.

Most estimates maintain the category at a relatively low level of the total U.S. generation mix. EIA forecasts (which assume that state RPSs will not be met) place renewables by 2030 at 30 GW—3 percent of total power sector generation. The Electric Power Research Institute (which assumes that all RPSs will be met by 2017, with an addition of 2 GW afterward) estimates renewable energy at 70 GW by that date, or 5.2 percent of total generation.

Follow the Free Cash Flow

Whatever the fuel mix, it will have a heavy price tag. Lehman Brothers' estimates show roughly $50 billion in annual capital expenditures for the regulated industry through 2010. The firm notes that its construction estimates are likely conservative, given increasing cost pressures, evolving announcements of new transmission projects, and potential imposition of carbon restrictions.

Lehman's analysis shows that free cash flow is heading into negative territory over the next several years, a trend that likely will persist over the next decade. The firm also estimates that $60 billion of total capital spending will come from external sources, so that the utility can maintain the leverage ratios and dividend levels it wants. At this point, says Lehman, most companies are focusing on debt financing, but equity spending will probably follow in later years.

This scenario has three major implications. First, reviewing the 1970s-80s cycle, Lehman found that equity risk premiums marked that era, as companies faced mounting risks related to financing, regulation, and execution. The firm expects higher risk premium demands to return in this cycle.

Second, as investors in the last cycle sought higher returns as compensation for increased risk, pressure rose for additional rate relief—but the amount granted was rarely enough to allow companies to earn at authorized levels. A trend toward more robust rate case activity is already underway and should persist throughout the capex cycle. While regulatory and legislative measures in a number of jurisdictions will help minimize attrition and regulatory lag, increased financial pressures remain a looming risk for many companies. Ensuring that state commissions understand, respect, and maintain the regulatory compact with the utilities they oversee will be critical to preventing a recurrence of the historical experience.

The third and perhaps largest implication concerns investor willingness. The character of investors and the financial markets has changed drastically since the previous construction cycle. In general, the market today has a much shorter investment horizon than it did several decades ago; indeed, volatility is one of the market's hallmarks. This largely reflects the presence of institutional investors, in contrast to the individuals who typically have a longer-term holding period. Utility companies will need institutional investors (which currently own 60 percent of the industry's outstanding common stock and most of its debt) to supply most of the external financing for the next construction cycle. And one of the key metrics these investors use in assessing a potential investment is a company's free cash flow. The industry's expected negative free cash flow position over the next few years may well serve as a deterrent for institutional investors to making their capital available or providing it at a reasonable cost.

Interesting Times

Are we heading down a path similar to the one we traveled during the capex cycle of the 1970s and 1980s? On one side of the argument, there's more discipline in the construction process; the economy is on firmer ground; energy efficiency has traction; relations between state commissions and utilities have improved; and many things that hampered nuclear plant planning and construction are gone. On the other side, the costs of infrastructure construction have risen; the regulatory and legislative assurance of investment recovery has not gained much strength; all options for new baseload generation have drawbacks; and it is unclear whether the industry can meet investors' needs for returns commensurate with investment risk.

Many of those factors are beyond the industry's control. But the issues with which utilities can deal will require consideration and decisive action. Most important, utilities and their regulators must come to a successful resolution of how they approach the complexities that lie ahead, particularly those having to do with combined resources. At the heart of each of those issues lies a critical need for regulatory support and renewed integrity of the regulatory compact.

"May you live in interesting times" is an old adage, meant to be both a blessing and a curse. The industry's current capex cycle is certainly a most interesting period and promises to remain so in the years ahead. ◆