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SURREBUTTAL TESTIMONY

OF

GEOFF MARKE

Submitted on Behalf of the Office of the Public Counsel

RAYTOWN WATER COMPANY

CASE NO. WR-2023-0344

November 8, 2023

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SURREBUTTAL TESTIMONY

OF

GEOFF MARKE

THE RAYTOWN WATER COMPANY

CASE NO. WR-2023-0344

I. INTRODUCTION

Q. Please state your name, title and business address.

A. Geoff Marke, PhD, Chief Economist, Office of the Public Counsel (OPC or Public Counsel), P.O. Box 2230, Jefferson City, Missouri 65102.

Q. Are you the same Geoff Marke that filed direct and rebuttal testimony in WR-2023-0344?

A. I am.

Q. What is the purpose of your rebuttal testimony?

A. I am responding to the rebuttal testimony of other parties' witnesses on select topics. The following is a list of those topics and the witnesses:

- Advanced Metering Infrastructure ("AMI")
  - Staff witnesses David A. Spratt and Daronn A. Williams
  - Raytown Water Company ("RWC") witness Chiki Thompson;
- Accounting Timing and Treatment of Meters
  - Staff witness Angela Niemeier; and
- Late Fees
  - Staff witness Melanie Clark
  - RWC witness Chiki Thompson

My silence regarding any issue should not be construed as an endorsement of, agreement with, or consent to any party's filed position.

II. ADVANCED METERING INFRASTRUCTURE

Response to Staff witness Daronn A. Williams

Q. What issues did Staff witness Williams have with your AMI testimony?

A. Mr. Williams's rebuttal touched on four points where he disagreed with the analysis put forth in my direct testimony and was silent on the rest of my objections. Mr. Williams's rebuttal has been paraphrased as follows:

1. Raytown's small, densely located customer base is a good setting for AMI meters;
2. Despite the Company's AMI, its meter readers also have other tasks, such as taking monthly water testing samples for MO DNR;
3. RWC will continue to notify customers at the end of the month for high/low usage; and
4. Even though the AMI investment does not contain leak detection valves, the Company still has to conduct a third-party annual leak loss survey.

I will respond to his counter-arguments in turn now.

Q. Is Raytown a good setting for AMI meters?

A. No.

I am operating under the assumption that Mr. Williams misunderstood my argument here. Raytown is a small water utility that is not geographically dispersed. If it was, then there would be a greater argument for operational efficiencies gained from the elimination of expensive meter readers or potential weather-related water usage variation. As such, there are no stated operational savings (in fact there is at least a two-fold increase in O&M costs) and utility rates are not going to be set based on persistent drought-like conditions that may only be present for some customers that might justify this high of an expenditure.

Historically, RWC has been operating for ninety-eight years without AMI and a couple of meter readers who make a little over $40K a year.

Now, the Company is seeking to charge $3.8M for AMI (including a healthy profit margin on top of this expenditure), retain its meter readers, *and* add an additional $100K annual AMI maintenance fee. Mr. Williams seems to believe that these meters will result in cost savings for customers, but his testimony is silent on the savings' derivation.

Simply put, the small, dense size of Raytown's service area means that the O&M savings that RWC could, theoretically, gain through AMI were already very small because there were only a couple of meter readers and they did not have to travel as far as other utility meter readers.[1] RWC's less than 7,000 service connections underscores how important identifying and verifying savings are when the investment will cost ratepayers over $5M within the first ten years of the AMI.

Q. Why is that?

A. With such a small customer base there is very little room for managerial error in accessing the prudency of capital investments without inducing a "rate shock" like scenario. If savings don't materialize then costs will increase unnecessarily. Which is exactly what RWC's customers are now facing.

Contrast Raytown's situation with a large utility like Missouri American Water Company ("MAWC") who has many more customers to absorb high fixed capital investments. MAWC can induce cost savings from economies of scale, competitive bidding, and operational efficiencies that are absent from RWC's case.

Now consider, for a moment, that the meter investment (and ancillary supporting hardware/software) is largely driving the double-digit rate increase in this case *and,*

[1] Again, it is worth stressing that no O&M savings materialized as the $100K additional annual maintenance costs and failure to eliminate meter readers ensures that costs will outweigh benefits.

depending on how the Commission rules, may very well drive the double-digit rate increase request that will shortly follow this case.

The fact that RWC neither conducted a cost-benefit study nor solicited any competitive bids further underscores this managerial imprudence.

Q. Mr. Williams suggests that the requirement for water utility companies to take monthly water samples negates any O&M savings from reduced personnel due to the AMI investment. Do you agree?

A. I reject the premise of his argument. Water testing and meter reading are not mutually exclusive. Nor are RWC's water testing requirements labor or time intensive.

Based on my discussions with the Missouri Department of Natural Resources ("DNR"), RWC is required to take fifteen routine bacteriological samples every month, two disinfection byproduct samples every quarter and thirty lead and copper samples every three years. No additional testing is currently required.[2]

More importantly, water testing would continue to occur with or without AMI. It should not factor into whether or not the AMI investments were a prudent expenditure. If anything, Mr. Williams' argument directly refutes one area where Staff has claimed AMI will create cost savings. Mr. Williams appears to believe that meter readers are still required in order to take monthly water samples for DNR; therefore, cost savings from reduced O&M would not materialize.

Q. Mr. Williams argues that Raytown is going to still manually alert customers of high/low monthly usage even after the AMI investment. Do you agree?

A. After speaking with the Company it appears as though it *may* continue that practice. This belief is based on the Company's response to OPC DR-2054:

[2] See GM-1.

Question: Please confirm whether Raytown Water expects to issue its exception list for the Company, or, is that feature now dependent on the customer affirming it on the individual customer portal.

Answer: Company will continue to review the exception list at time of billing. Customers will have the opportunity to sign-up if they want to receive automatic alerts from Aclara between billings.[3]

The Company can confirm in the evidentiary hearing whether or not its promise to "continue to review the exception list" equates to actively contacting customers and informing them of their high/low usage on a monthly basis with written communication.

Q. Is that practice a benefit for customers?

A. If true, it is now a redundant benefit. To clarify the difference between customers notice around high/low water usage before and after Raytown implemented this AMI technology:

<u>Pre-AMI</u>

- Company notified customers of high or low usage on a monthly basis

<u>Post-AMI</u> ($3.8M in initial capital costs)

- Company continues to notify customers of high or low usage on a monthly basis (just like before)
- At some point in the future, a customer can set their customer portal to receive daily high/low usage; and
- At some point in the future, a customer could ask the utility of copies of historic hourly usage.

The Number of customers who contacted RWC about <u>metering issues</u> (January 2018- June 2023)

- 1,299 meter related inquiries; or
- Slightly fewer than 20 calls a month on average over a five-and-half-year period

Importantly, what we don't know is how many of these calls were reoccurring (same account and thus double-counted) or were actually about water usage let alone leakage.

[3] See GM-2.

Regardless, even if we assume that each and every call was a unique account with a leakage issue it would still result in a very small amount of monthly inquires.

Q. What is your response to Mr. Williams's assertion that this $3.8M AMI investment will still benefit customers, despite not having leak-detection valves, because the Company still has to conduct annual third-party leak loss surveys?

A. I fail to see how these two issues are connected other than more costs for customers. Mr. Williams appears to insinuate the annual leak loss survey and the AMI's leak detection valve are equal or measure the same things. They're not. Despite Mr. William's belief, that is not the case. The annual third-party leak loss survey assesses the quality of the communal distribution and transmission lines. Alternatively, a leak detection valve provides an automatic water shut-off either by monitoring flows in the pipe or by detecting water on the floor of a given domicile. Therefore, despite Mr. Williams assertion otherwise, these methods of leak detection are not the same.

Further, as Mr. Williams should be aware, the Company is required to conduct the third-party leak loss surveys and post the results on its website annually, due to a stipulation and agreement from a past rate case.[4] More to the point, this survey does not have any bearing on the Company's choice of AMI investment.

To be clear, according to Staff and RWC, the $3.8M AMI investment and $100K annual reoccurring fee:

- Cannot remotely disconnect or reconnect customers;
- Will not eliminate meter readers (in fact, it will be increasing its maintenance costs for its meters by over $100K annually);
- Cannot tell the Company or regulators about leaks on its distribution system;
- Was chosen without the due diligence of a cost-benefit analysis;

[4] It should not be lost on the Commission that RWC was not in compliance with this stipulation because they were not posting the results of its leak loss surveys for several years on its website until it was brought to their attention through discovery issued by OPC in mid-October of this year.

- Was chosen without the benefit of any cost competitive solicitation from other vendors;
- Results in *at least* one double-digit rate increase; and
- Adds a layer of operational complexity by introducing 3rd party cyber security threats;

The espoused benefits include:

- Water usage data on a daily basis on a customer web portal with hourly usage available upon request for a Company with a customer base that has at most, a little less than twenty calls a month related to meters.

Q. Can you summarize Mr. Williams's rationale for supporting the $3.8M investment in AMI?

A. Yes. Mr. Williams effectively argues:

- Raytown is a better location to invest in AMI, generally, because the customer base is smaller and densely located;
- RWC's meter readers (or somebody at the Company) will still have to take periodic water samples;
- RWC will continue to notify customers about high/low water usage at the end of the month (just like they have been doing); and
- Ratepayers will still pay for the annual one-week leak detection survey by a third-party.

That's it. To refute the OPC's legitimate concerns surrounding the AMI technology Raytown chose, and the method through which the Company chose this technology, Mr. Williams presents these four counter-arguments. Importantly, each of his last three points would occur regardless of the Company's AMI investment.

That leaves the first argument, which directly conflicts with Commission's findings in the Report and Order for Case No WR-2023-0006:

> OPC's analysis fails to consider the unique geographical locations of the Confluence Rivers' water systems. The Indian Hills and Hillcrest systems are both the only system that Confluence Rivers operates in their respective counties. The location of these two systems relative to each other and other Confluence Rivers systems would likely indicate that operational savings would not only include a meter reader salary, which OPC acknowledged, but would also include additional operation cost saving and saving worker travel time between systems.

The Commission correctly asserts that geographic location has an impact on cost savings assumptions. Raytown, contrasted with Confluence, is a small, densely populated utility that does not have the cost burden of servicing customers in remote locations. Additionally, unlike Confluence, Raytown's service area is not growing so the customer impact over managerial imprudence is magnified when costs grossly outweigh benefits.

However, Mr. Williams is not the only Staff witness to file rebuttal testimony addressing my concerns. I will now turn my attention to MO PSC witness Mr. David A. Spratt.

Response to Staff witness David A. Spratt

Q. What issues did Staff witness Spratt have with your AMI testimony?

A. Mr. Spratt raised the following counter-arguments, paraphrased below:

1. AMI meters are superior at helping customers detect leaks;
2. Are more accurate than conventional meters;
3. Customers can see daily usage that could empower them;
4. Water leaks within a domicile can be expensive;
5. Remote shut-off options were not selected because of excessive costs;
6. "Staff would suggest that more customers means more investment at probably about the same cost per customer."[5]
7. Small utility companies do not always have the capability to conduct internal cost benefit analysis or issue request for proposals;

[5] Case No. WR-2023-0344 Rebuttal Testimony of David A. Spratt p. 5, 15-16.

I will respond to his counter-arguments in turn.

Q. Does Staff present any evidence that these AMI meters are "far superior" at helping customers detect leaks?

A. No. At least not directly. Mr. Spratt's evidence is purely anecdotal without context.

No meter is going to tell you where a leak is coming from. AMI merely tells you how much water usage you are going to be billed at a more finite temporal level. If a customer is proactive in checking their water usage on their phone (after the software application is presumably up and running), they may be able to see patterns over a long enough period that could help identify that an internal leak is occurring but not where.[6]

Q. Are these AMI meters more accurate than conventional meters?

A. A new meter will be more accurate than an old meter whether it is an AMI or not. The only variable AMI minimizes within the accuracy department is the potential for meter reader (human) error. To the best of my knowledge human error has not been a reported problem for RWC. Of course, this unknown benefit would be offset by the increased liability from cybersecurity threats, 3rd party suppliers going out of business, or technological obsolesce.

Q. Are customers more empowered by these AMI water meters?

A. I do not believe so. Affordable and just water rates will result in more empowerment for customers than the ability to check daily water usage data.

Additionally, it has been my professional experience that a certain segment of the population is entirely against AMI due to perceived health and/or safety concerns. So, it stands to reason that at least some customers are not going to want to have anything to do with a smart meter. It has also been my experience that very few customers take advantage of the

[6] It may apply this same argument to electric customers. Theoretically, the same "benefit" could occur from someone monitoring their electric usage if they have an electric AMI. But we never hear utilities claim that the potential to identify energy leakage as a benefit for electric AMI investment. Nobody would take that benefit seriously or be able to assign a value to that analysis because a costly blow-door test would need to be employed to find out exactly where the energy leakage was occurring. Again, the meter only shows your consumption usage.

customer portals that utility companies have enabled. Even in more pronounced situations where customers can choose their electric rate (see Evergy TOU), most are passive recipients of their utility service. If you factor in the assumed costs of the meters and supporting ancillary hardware/software, the Company is effectively asking each of its account holders to make a $600+ investment in a meter that may someday show daily water usage. If customer empowerment was the goal of this AMI choice, Raytown missed the mark.

Q. Are water leaks expensive?

A. They can be. A leaky pipe within a home should be detected relatively quickly if those account holders live in the location (e.g. a busted pipe splashing water on the ground). A more likely out-of-sight, out-of-mind scenario would involve a toilet whose flush valve ("flapper") was not properly seated. Of course, if this was the main argument (benefit) for consumers a thorough analysis would also look at all available options to address the issue.

Q. Are there other, inexpensive alternatives to the $600 AMI investment for detecting leaks in a toilet?

A. Of course. One cost-effective option would be to put 10-15 drops of food coloring or a dye tablet in the toilet tank and wait thirty minutes without flushing. Figure 1 provides an illustrative example of three colored dye that cost $2.99 at Hobby Lobby, which is approximately a 99.5% cheaper than the cost of the AMI. I have no doubt a more comprehensive cost review of food dye options could bring those costs down further.

Figure 1: $2.99 Hobby Lobby Colored Dye

Q. Do you agree with Mr. Spratt that the remote shut-off function should not have been secured because it cost too much money?

A. My position is that this entire AMI investment costs too much money. Mr. Spratt's testimony is unfortunately silent on how much more money a remote shut-off function would cost as it appears as though he's just repeating the Company's testimony at this point. Regardless, it is yet another benefit that has failed to materialize.

Q. Mr. Spratt states, "Staff would suggest that more customers means more investment at probably about the same cost per customer."[7] Do you agree?

A. No.

This statement is of course false, as economies of scale should drive cost advantages that a business obtains due to its size. As a business grows, it can spread its fixed costs over a larger number of units of output, which reduces the average cost per unit.

[7] Case No. WR-2023-0344 Rebuttal Testimony of David A. Spratt p. 5, 15-16.

The economies of scale argument is a central concept of utility regulation and natural monopolies. It is also literally one of American Water's primary propositions for investors and why issues like single-tariff pricing never go away despite that concept conflicting with the principles of cost causation.

It is also one of the primary reasons why consolidation is taking place across all industries at such a rapid clip. More customers allows for more market and negotiating power.

It's why Ford can buy steel in bulk at a lower price per unit than small machine shop. Why Wal-Mart can negotiate lower prices from its suppliers because it buys in bulk. It is also why it is incumbent that regulated utilities are held accountable when they make imprudent investments. Public utility regulation should not be a risk free world. At least, it is not supposed to be if economic regulation is truly operating as a proxy for the market and looking out for the best interest of our captive Missouri customers when we review our utilities who have no competition. This leads into Mr. Spratt's next argument that RWC is somehow incapable of conducting a cost benefit analysis or issuing a competitive bid for multi-million dollar AMI investments because it is "less sophisticated".

Q. In his rebuttal testimony, Mr. Spratt states:

> **"While Dr. Marke might like to see thorough calculations, oftentimes small companies are conducting much less sophisticated analysis using the information that is available to them when determining what investments are prudent."[8]**

What is your response?

A. I believe Mr. Spratt is arguing that math and facts are not necessary in making multi-million dollar capital investment decisions and that RWC (and similarly non-sophisticated utilities) can apparently operate prudently based on pure intuition. This belief is dangerous. Further, Mr. Spratt's argument ignores the fact that this Commission recommended that the

[8] Ibid. p. 6, 9-11.

Company conduct this exact analysis for all large equipment purchases in its Managerial Audit that took place in 1994.

Mr. Spratt's statement elicits many more questions for me surrounding the Staff's small water rate case process, Staff's clear preferential treatment for certain utilities, and even what Mr. Spratt's threshold is for "sophisticated" versus "non-sophisticated" analysis. I can assure the Commission my objection to RWC's AMI investment is not based on a complicated mathematical computation but common sense and simple arithmetic with the Company's own numbers taken at face value (and arguably to a fault). Mr. Spratt, in contrast, is perpetuating a moral hazard[9] and shifting risks onto captive customers when he makes declarative statements that excuse utilities of the consequences of their poor managerial decisions.

The Raytown Water Company has operated for ninety-eight years. This Company has a multi-million dollar rate base and the blessing from the Missouri Public Service Commission to provide service to over 6,541 accounts for well over 10,000 captive ratepayers. However, according to Mr. Spratt, we shouldn't expect the Company to have the wherewithal to issue a competitive bid or check the cost/benefit assumptions surrounding its investments.

RWC did not have any information around AMI-provider options outside of Utility Service Group ("USG") because it was uninterested in obtaining any information around AMI-provider options outside of the first sales pitch. It's as simple as that. The first and only sales pitch was good enough for the Company.[10]

To be completely up front, I believe both Staff *and* OPC are continuing a trend of treating RWC with "kid gloves" in this case. For example, my recommendation around AMI does

[9] "Moral hazard" refers to the risks that someone or something becomes more inclined to take because they have reason to believe that an insurer (or ratepayer in this case) will cover the costs of any damages. The concept describes financial recklessness.
[10] This of course raises all sorts of other questions about RWC's operations.

not disallow any costs related to the actual investment itself. I am merely recommending that the Company should not profit off of its managerial imprudence. If the Commission elects to disallow more than a return on investment—I believe that choice would be appropriate and that any Report and Order issued in that vein would adhere to the regulatory principles that should guide this administrative process. Simply put, RWC operates in the coveted realm of a competition-free business, and unlike a competitive industry where imprudent decisions are imperative to survival of the business, utility companies regulated by this Commission will continue to make imprudent public-impacting decisions unless the Commission holds utilities to a heightened standard.

Response to RWC witness Chiki Thompson

Q. What issues did RWC witness Thompson have with your AMI testimony?

A. Ms. Thompson offered rebuttal to six points where she disagreed with my analysis and was silent on the rest of my objections. Ms. Thompson's rebuttal has been paraphrased as follows:

1. Raytown does not have a fully exclusive service territory;
2. Meter readers will have to take fewer trips to houses;
3. OPC should include the annual maintenance fee;
4. OPC analysis did not take into account leaks found during the billing process;
5. Safety benefits extend to meter readers not having to read meters; and
6. Meters still needed to be replaced per Commission rule

I will respond to her counter-arguments in turn now.

Q. Does Raytown experience competition for water customers?

A. No. This was confirmed in the response to OPC DR-2050:

<u>Question</u>: The rebuttal testimony of Chiki Thompson p. 2, 8-11 states:

> *Q. Does Raytown have a fully "exclusive" service territory?*
>
> *A. No. The Raytown Water service territory overlaps in places with the Jackson County Water District No. 2 and the City of Independence.*

Are Raytown customers able to switch their water service provider to Jackson County Water District No. 2 or the City of Independence? If so, are there any additional costs for a customer who elects to switch provider?

Answer: We do not believe so. Only new construction customers have a choice of water provider where there are other water providers available. We assume the Customer would need to pay for tapping fees and expenses at the rate of the entity chosen.

Q. Will meter readers have to make fewer trips to homes?

A. Yes. Meter readers are no longer reading meters.

Since the meter readers do not need to drive to each location to check each meter, that should result in some gasoline savings. However, the meter readers will shift to field technician positions and Raytown is seeking to add a $100K maintenance fee. For these reasons and more, the costs outweigh the benefits.

Q. Should the annual maintenance fee be included in the revenue requirement if the Commission supports your recommendations?

A. Yes. I believe that would be appropriate.

Q. Did you take into account leaks found as a result of the Company's monthly billing process?

A. No. I do not believe the Company can legitimately claim that leaks are occurring at any of those premises outside of on-site verification or affirmation from the customer. Ms. Thompson, for her part, is silent on how many customers are affected by such leaks. Again, all the Company should know from the billing process is that water usage is higher or lower than average, not what is causing the usage variation or where it is coming from.

Q. Are meter readers safer now that they don't have to read meters?

A. I am not aware of any attacks on meter readers or imminent threats. The Company has been reading meters for ninety-eight years. But I will concede that, yes, not physically reading a meter would minimize risk to a meter reader.

Again, as it pertains to meter readers, no positions have been eliminated and a maintenance fee for an additional $100K annually will be added. The costs still outweigh the benefits.

Q. What is your response that the meters needed to be replaced anyway?

A. I am not recommending disallowance of the AMI meters, annual maintenance fee, or ancillary software/hardware necessary for this investment even though the Commission would be justified in disallowing more. I am simply recommending a disallowance of the "return on" the AMI investment and recommending that all meters be placed into the rate base. This recommendation results in a small overall increase from the Staff and the Company's stipulated position.

Ms. Thompson's own testimony acknowledges that the Company would benefit from more than $1M in cost savings if it had elected to go to AMR instead of AMI. No doubt these costs savings would be even greater if a competitive bid were issued or the Company chose a direct-read meter.

As it stands, the investment has effectively been gold-plated and will result in financial harm to ratepayers.

Q. What is gold-plating?

A. In the context of utility regulation, "gold-plated" refers to utility investments or expenses that are excessive or unnecessary, and that are likely to lead to higher rates for consumers. A non-exhaustive list of examples include the following:

- Over-engineering infrastructure projects;
- Using more expensive materials or construction methods than necessary;
- Duplicating existing infrastructure;
- Investing in projects that are not cost-effective or that do not meet the needs of consumers;
- Hiring more staff than necessary or paying higher salaries than necessary; and
- Engaging in wasteful or inefficient practices

Q. Why would RWC want to gold plate?

A. To make more money.

Under rate-of-return regulation, a utility company's profits are capped at a certain percentage of its rate base, which is the value of its assets. This means that the Company has a perverse incentive to increase its rate base by investing in more capital assets, such as AMI meters.

This is also known as the Averch-Johnson effect in economics and explains why a regulated company will tend to over-invest in capital in order to expand the volume of their profits.[11]

If regulators do not hold utilities accountable, a utility's perverse incentive to overspend on capital can be like a bottomless pit of cost inefficiencies that gradually and then suddenly increase the cost of service to captive customers.

Q. Do you have any final comments to make on this topic?

A. Yes, I have two. First, neither this case nor RWC's financing case (Case No. WF-2021-0427) did the MO PSC Staff issue any discovery surrounding the prudency of the AMI investment. No issued discovery for a cost benefit analysis, competitive bids, explicit benefits, or other related inquires. This is extremely concerning and raises additional questions above and beyond this filing.

Second, on the off chance that the Commission feels compelled to support the AMI investment because of the financing order I would remind the Commission of several things.

1.) I am not recommending a disallowance on the "return of" the meters. Only the "return on."

2.) Missouri is not a pre-approval state;

[11] Per the New Palgrave Dictionary of Economics: "The Averch–Johnson effect is produced when fair rate of return regulation encourages a firm to invest more than is consistent with the minimization of its costs. This can happen when the allowed rate of return exceeds the cost of capital, since the difference between the two represents pure profit." See also Averch, H.A., and L.L. Johnson. 1962. Behavior of the firm under regulatory constraint. *American Economic Review* 52: 1052–1069.

3.) Page 4A of the Commission's Order approving the Finance Authority in Case No. WF-2021-0427 states:

"Nothing in this Order shall be considered a finding by the Commission of the prudency of this transaction for rate making purposes, and the Commission reserves the right to consider the rate making treatment to be afforded the financing transaction, and its impact on the cost of capital, in any later rate proceeding."

4.) Prudency issues are largely reserved for rate cases or in statutorily approved single-issue ratemaking adjustments (e.g., fuel adjustment clause, energy efficiency, etc…); and

5.) Finally, the National Regulatory Research Institute ("NRRI") produced a white paper in 2008 by Scott Hempling titled "Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Sponsored Capital Projects?" That white paper contains a fair amount of useful information and guidelines including the following excerpt from the first hypothetical pre-approval scenario that involves a small water utility seeking pre-approval in connection with a relatively large—but otherwise routine—investment:

> **Each of these questions have a common theme: cost-benefit analysis**. The Commission should be satisfied that the risks associated with providing approvals in advance—including the constraints on the Commission's ability to take actions after the fact because of approvals granted before-the-fact—are outweighed by the benefits derived from the timely implementation of the infrastructure upgrade. **Then the Commission should ensure that those benefits arrive** (emphasis added).[12]

Based on NRRI's guidelines, conditions necessary for appropriate pre-approval were not in place nor were they met at any point during their deployment. Benefits were not assured

[12] See GM-3A and GM-3B. The former includes the specific case study with the excerpt highlighted. The latter includes the entire white paper.

and ratepayers are being financially harmed which results in my recommendation for partial cost disallowance.

III. ACCOUNTING TIMING AND TREATMENT OF METERS

Q. What is the matching principle in utility regulation?

A. The matching principle is a concept that states that revenues should be matched to the costs that were incurred to generate those revenues. This principle is used to ensure that utilities are earning a fair return on their investment, while also protecting consumers from paying excessive rates.

When setting rates, regulators will consider the utility's total costs in providing service and regulators will then match these costs to the utility's expected revenues. In Missouri, the Commission utilizes a historic test year with adjustments or "true ups" made to test year data to account for known and measurable changes that are expected in the future.

Q. Staff witness Angela Niemeier argues that the matching principle prevents Staff from including the rest of the AMI investment. Do you agree with Ms. Niemeier's argument?

A. No. This is a case where a known and measureable cost is being incurred. RWC currently has all but a couple hundred meters in operation with the remainder to be deployed by the end of the year. The Company's maintenance fee went into effect in September.

My recommendation to include the rest of the meters is an attempt to defer another immediate rate case and yet more costs to ratepayers. This recommendation is a unique departure from how OPC historically approaches this issue due to expected rate shock of another rate case. As such, my recommendation is more than reasonable given the circumstances. I would add that this Commission has included known and measurable capital investments immediately outside of a test year in the past on a case-by-case basis under unique and/or pragmatic situations.

My additional recommendation to disallow the profit margin on this imprudent investment of AMI meters, which minimizes the cost impact to ratepayers and leaves the Company very close to the already agreed-to language of the stipulation that the Staff and the Company entered into. It also means that these meters can begin depreciating sooner which will result in a long-term cost benefits to consumers.

If the Commission decides to support Staff's position of not including the known and measurable meters currently in operation the end result will most certainly be a new immediately filed rate case with more needless cost increases.

That being said, I would not support including all of the known and measurable meters and annual maintenance fee if the Commission also elects to rewards RWC for its gold-plated investment with a return on that investment. The public has not been made adequately aware of the rate increase that would occur as a result and is already in a position to receive approximately a 60% increase from what the Company filed if the Commission adopts the Staff and the Company's position in it entirety.

IV LATE FEES

Q. What was Staff's response to your request to remove late fees?

A. Staff witness Melanie Clark argues that Raytown's customers are not financially struggling. She states:

> Staff is cognizant that there are many customers who struggle to pay their bill on time and adding a small late charge adds to that burden. However, generally speaking, the City of RWC has a median household income of $59,049 RWC. Based on this, Staff does not believe a $5 fee will be a burden to the majority of RWC customers.[13]

[13] Case No. WR-2023-02344 Rebuttal Testimony of Melanie Clark p. 2, 14-17.

Q. What is your response?

A. Raytown is not an affluent suburb. Raytown's median household income is 3% less than that of the median household income in Missouri at $61,043.

As stated in my direct testimony, the rationale behind late fees is being called into question in many domains and has, at best, questionable empirical support to substantiate their existence. Context matters as well. Late fees may be more acceptable in a competitive market or tied to an obligation that does not result in immediate health and safety concerns. That is not the case here. RWC customers are captive and cannot choose their provider and water is an essential service whose absence would quickly have a detrimental impact on one's health. I maintain that late fees are needlessly punitive, regressive in nature, and do not reflect actual cost causation. The reality of the situation is that many of RWC's customers are economically unstable, on fixed incomes, and will struggle at greater levels if any sort of rate increase is granted. They have every incentive to pay their bills or run the risk that their service be disconnected.

Q. What was RWC's response to your request to remove late fees?

A. RWC witness Chiki Thompson believes costs for a variety of customer service related ancillary functions will increase as a result. She states:

> I believe the number of delinquent accounts would increase, therefore, we would need to hire additional help to handle the calls for payments, payment arrangements, and complete the disconnect/reconnect process. Of course, this may also increase our printing and posting expense because these processes require additional customer notifications.

A. There is no factual basis for this discourse.

Nor does it reflect the lived experience of any water utility that has removed their late fees in Missouri. Importantly, neither Staff nor RWC address my observation that RWC's current practice of charging delinquent customers $5 or 1% of the customer's bill is an arbitrary amount and does not reflect cost causative principles.

Q. What do you mean?

A. To answer that question, I would direct the Commission to the following discovery responses.

OPC DR-2071 asks and received the following:

Question: What is the cost basis for setting late fees at either $5 or 1% of a monthly bill (whichever is greater)?

Answer: It is our memory that the $5 or 1% provision was implemented in Case No. WR-2009-0098 based on a Staff proposal. We believe costs will not have been reduced during that time. Also see the response to DR 2072 below.[14]

OPC DR-2072 asked and received the following:

Question: Would the Company be opposed to setting late fees at just 1%? If not, why not?

Answer: Yes, the Company would be opposed. Late fees at 1% of a monthly bill, would not cover our current costs just to issue the late notices. The average bill is around $45. 1% of $45 is only $0.45. 1% would not cover the cost of the first delinquent notice expense, let alone the cost of a second notice.

Estimated Cost of 1 delinquent notice = $1.14 each, which does not include Overhead or taxes, or any impact of delayed cash flow on RWC's operations.

- Billing stock - $0.02 ea
- Envelopes - $0.14 ea
- Postage - $0.68 ea
- Printing - $ .04 ea

[14] See GM-2.

- Labor: min 2 hr. @ $52.28/hr for a batch of such notices (includes taking to post office) $0.26 ea[15]

At a minimum, the actual cost of the late fee is $1.14. If I give Ms. Thompson the benefit of the doubt that a second delinquent notice will always be issued then the total cost is $2.28. Which is still 54% less than what customers are being charged.

Regardless of the amount, it still does not get at the underlying premise of my argument which is that the threat of disconnection is a greater motivator for timely payments than a punitive late fee.

Q. Has your position changed at all in light of this information?

A. My primary recommendation remains. As an alternative, I would recommend a $2.50 late fee that would at least align with cost causative principles and cover the mailing notice expense. I believe this is a suboptimal outcome for ratepayers but it would at least be a step in the correct direction as there is no basis for charging customers $5 for a late fee.

Q. Does this conclude your testimony?

A. Yes.

[15] *Ibid*.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of a Rate	)	
Increase of Raytown Water Company	)	Case No. WR-2023-0344

AFFIDAVIT OF GEOFF MARKE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Geoff Marke, of lawful age and being first duly sworn, deposes and states:

1. My name is Geoff Marke. I am a Chief Economist for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Geoff Marke
Chief Economist

Subscribed and sworn to me this 8th day of November 2023.

TIFFANY HILDEBRAND
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES AUGUST 8, 2027
COLE COUNTY
COMMISSION #15637121

Tiffany Hildebrand
Notary Public

My commission expires August 8, 2027.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of a Rate Increase of Raytown Water Company	)))	Case No.WR-2023-0344

PUBLIC COUNSEL DATA REQUEST NO. 2050-2074

The Office of Public Counsel (Public Counsel), in accordance with its authority to "represent and protect the interests of the public in any proceeding" before the Commission (§ 386.710(2) RSMo) submits the following Data Requests to Raytown Water Company ("Raytown" or "Company") pursuant to Commission Rule 20 CSR 4240-2.090. Please provide electronic responses within five (5) days to opcservice@opc.mo.gov, geoff.marke@opc.mo.gov, and anna.martin@opc.mo.gov. These data requests are continuing in nature and require supplemental responses as each recipient obtains further or different responsive information.

RWC RESPONSES TO DATA REQUESTS

2050. The rebuttal testimony of Chiki Thompson p. 2, 8-11 states:

Q. Does Raytown have a fully "exclusive" service territory?

A. No. The Raytown Water service territory overlaps in places with the Jackson County Water District No. 2 and the City of Independence.

Are Raytown customers able to switch their water service provider to Jackson County Water District No. 2 or the City of Independence? If so, are there any additional costs for a customer who elects to switch provider?

We do not believe so. Only new construction customers have a choice of water provider where there are other water providers available. We assume the Customer would need to pay for tapping fees and expenses at the rate of the entity chosen.

2051. Referencing OPC DR-2050 above, if customers may switch water providers, how many customers have elected to be served by Jackson County District No. 2 and/or the City of Independence in each of the past five years? **N/A**

2052. Referencing OPC DR-2050 above, if customers may switch water providers, how many previous customers have elected to switch to Raytown Water that were formerly served by Jackson County District No. 2 and the City of Independence in each of the past five years? **N/A**

2053. The rebuttal testimony of Chiki Thompson p. 4, 10-12 states:

> *As I will discuss later, the annual maintenance fee associated with these meters that was referenced by Dr. Marke (Dir., p. 11) did not start until September of 2023.*

Please provide a copy of the contract, terms, and/or warranty surrounding the AMI maintenance fee.

The employee with possession of this document is out of the office as of this date. RWC expects to provide this document on Monday, November 6, 2023.

2054. Please confirm whether Raytown Water expects to issue its exception list for the Company, or, is that feature now dependent on the customer affirming it on the individual customer portal.

Company will continue to review the exception list at time of billing. Customers will have the opportunity to sign-up if they want to receive automatic alerts from Aclara between billings.

2055. The rebuttal testimony of Chiki Thompson p. 7, 19-22 states:

> *The Company last installed meters during the 2009-2015 timeframe as part of the meter replacement program (approximately 1/10th of the system each year). After 2015, meters were changed only as needed due to damage.*

Please provide an excel spreadsheet of the meter replacements by year for the years 2009-2015 as well as after 2015.

Please see attached spreadsheet for all meters in the system prior to the new installations which began after March 15, 2023.

2056. Regarding OPC DR-2055, what types of meters were utilized in Raytown Water's last meter installment and how many of these meters were AMR capable?

All were **Neptune T-10 Direct read meters, with the exception of 46 AMR Mueller HotRod meters.**

2057. How many years has Raytown Water utilized meter readers in its history?

Since 1925, 98 years.

2058. Does Raytown water plan on seeking a waiver of the Commission rules for 20 CSR-4240-10.030(38)? If yes, when? If no, why not?

No. Company intends to continue with recommended meter testing and change out schedule to ensure accuracy of water consumption, as long as the Commissions still believes those time periods to be appropriate.

2059. The rebuttal testimony of Chiki Thompson p. 8 lines 9-12 state:

Q. As of 2023, approximately what percentage and number of Raytown Water meters were due to be removed and replaced?

A. Approximately 80% of the 5/8 x 3/4 meters and 100% of meters 1 inch and larger.

Please provide any and all documentation that substantiates the claim that 80% of 5/8 inch and 100% of 1 inch meters had to be removed or replaced in 2023.

See Excel spreadsheet provided in response to DR 2055.

2060. Regarding OPC DR-2059, please provide a narrative explanation as to why these meters needed to be replaced in 2023.

Please see Commission Rule 20 CSR-4240-10.030(38).

2061. Regarding OPC DR-2059, please provide a copy of the request for proposal Raytown issued to water meters vendors "in anticipation of the AMI 2020 project" as stated in the rebuttal testimony of Chiki Thompson p. 8, 2.

The Company did not separately seek bids for meters. Meters were purchased thru Aclara as part of their bid package.

2062. The rebuttal testimony of Chiki Thompson p. 8, 13-19 states:

Q. Given your experience in the industry, what would be an approximate cost per meter for the Company to replace that number of meters with non-AMI meters?

A. Manufacturers have generally moved beyond read meters. The new meters are AMR/AMI. As an example, attached as Schedule CT-1-R is an email I received from our manufacturer representative as to this matter.

Ms. Thompson did not answer the question posed. What would be the cost (or cost range) of a non-AMI water meter? Please provide any supporting documentation for this conclusion.

As indicated in Ms. Thompson's Rebuttal Testimony, we are not able to obtain a current price for direct read Neptune meters as they are no longer being manufactured. The Company has tested several other meters such as Zenner, Master Meter, ABB, Octave, Sensus and Badger in our system over the past 10 years and found that Neptune has been the most reliable meter we have used for the price.

The estimated cost was calculated based upon current information and products available from the vendor.

2063. Referencing OPC DR-2062, does Ms. Thompson believe that the only water meters available for sale are AMI in nature?

Yes, only AMR or AMI for Neptune meters.

2064. Referencing OPC DR-2062, has Ms. Thompson made any other inquiries into water meter availability and cost beyond the phone/email conversation that occurred on October 19, 2023? If yes, please provide documentation to substantiate the claim. If no documentation exists, please provide names of individuals and/or companies and the approximate time these discussions occurred.

No. Schulte is the approved local Vendor for Neptune meters.

2065. Please clarify what Ms. Thompson means by "direct read meters" as referenced on page 8, 19-21.

Direct read meters do not transmit readings. Readings can only be obtained by physically/directly looking at the meter register.

2066. Does RWC believe that its meters would have to have AMR technology if it did not select the AMI option? **Yes, because of meter availability/unavailability.**

2067. Based on Ms. Thompson's professional experience, what is the cost per meter difference between regular diaphragm meter (meter reader required to visually see the output number), an AMR meter (meter reader drives a vehicle within signal distance to obtain meter reading number) and an AMI meter (meter reads sent directly to the Company). Please include all assumed hardware and software costs in an excel spreadsheet.

Cost difference between regular diaphragm meter (direct read) and AMI/AMR cannot be calculated as we are not able to obtain current prices for direct read meters.

2068. What sources did Ms. Thompson rely on for her Schedule CT-2-R)? Please provide citations and/or explanations for each of her inputs.

Water Loss Calculation completed by Leslie Smart, Sr. Accountant.

Calculation: Kansas City Water Dept bill Gallons purchased – Gallons sold to customers during same time period = Water Loss.

2069. The rebuttal testimony of Chiki Thompson p. 9, 1-7 states:

I have estimated the costs of completing the needed meter replacement with non-AMI meters. It is my belief that such a replacement would have cost at least $2,685,495.48 (See Schedule CT-2-R). The meters acquired at this price would be for radio read (AMR) but would not have any additional wiring or equipment necessary to be read by radio. The Company would still be required to direct read. If Raytown Water later tried to go to AMI with these meters, they would have to be retro-fit, which would likely be significant additional expense down the road.

Why would RWC purchase radio read (AMR) meters without the radio equipment necessary for it be functional?

Pricing for direct read meters is not available. Thus, the only way to come up with an estimated cost was to use pricing for AMR meters without all of the wiring and equipment.

Having said this, it was the Company experiment/experience with AMR meters that helped direct it to AMI.

Among other things, AMI offers more benefits and features than AMR such as availability of daily and hourly reads at Company to assist customer inquiries, thus reducing the research time needed to help resolve customer.

EXAMPLE: Customer calls stating they think they fixed a leak after receiving a high usage notice from the Company but wanted to make sure.

AMR -Company issues a work order to have meter read and check leak detector on meter. This is a minimum delay of 24 hours (72 hours if work order is issued on a Friday) before a new reading can be obtained and leak detector checked.

- **Issue work order to have meter read and check leak detector**
- **Meter Reader drives to location**
- **Meter Reader completes work order and returns to Customer Service Tech to close out with results.**
- **Customer Service Tech returns call to customer with results and may need to leave message for customer call office back for further discussion.**

AMI – result can be obtained in minutes by looking on Aclara 1 portal.

- **Save 24-72 hours of lost time to resolve issue.**
- **Help customer reduce water loss by shortening the time to verify meter reads.**
- **Eliminate need for Customer and Company on return call with results.**
- **Save time for both customer and company.**
- **Reduces risk of Company personnel being exposed to hazardous conditions.**
- **Reduce vehicle expense.**

2070. Regarding OPC DR-2069, has Ms. Thompson conducted any estimate of what the cost would be for traditional non-AMR or non-AMI water meter? If not, why not?

Pricing for traditional non-AMR or non-AMI water meter is not available.

2071. What is the cost basis for setting late fees at either $5 or 1% of a monthly bill (whichever is greater)?

It is our memory that t**he $5 or 1% provision was implemented in Case No. WR-2009-0098 based on a Staff proposal. We believe costs will not have been reduced during that time. Also, see the response to DR 2072 below.**

2072. Would the Company be opposed to setting late fees at just 1%? If not, why not?

Yes, the Company would be opposed. Late fees at 1% of a monthly bill, would not cover our current costs just to issue the late notices. The average bill is around $45. 1% of $45 is only $0.45. 1% would not cover the cost of the first delinquent notice expense, let alone the cost of a second notice.

Estimated Cost of 1 delinquent notice = $1.14 each, which does not include Overhead or taxes, or any impact of delayed cash flow on RWC's operations.

- **Billing stock - $0.02 ea**
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- **Printing - $ .04 ea**
- **Labor: min 2 hr. @ $52.28/hr for a batch of such notices (includes taking to post office) $0.26 ea**

2073. The rebuttal testimony of Chiki Thompson p. 10 18-21 & p. 11, 1-2 states:

Q. Are there any costs that will increase as a result of an elimination of the late fees?

A. The cost of printing, envelopes and postage would increase along with cost associated with a new employee, if one can be hired, or additional overtime, in the alternative. The costs associated with actual disconnection and reconnection would also increase?

Please provide, in detail, the reasoning behind Ms. Thompson's assertion.

It is our opinion that some number of Customers pay to avoid additional costs like a $5 late fee, which helps keep our revenue stream more constant. Those who are late and on the disconnect list are almost the same people each month. With no incentive to pay timely, more customers will be delinquent therefore, the number of late notices would increase.

The weekly collection process currently takes approximately 2 full working days for minimum 2-3 employees. See the attached collection/disconnection procedures. I anticipate this time to increase as the number of customers on the disconnect list increases.

2074. Regarding OPC DR-2075, please provide any documentation, internal cost study or secondary empirical research for any utility (anywhere or at anytime) that substantiates this assumption.

We are unsure what assumption will be referenced in OPC DR 2075.

Submitted by Geoff Marke October 26, 2023

Answers provided November 3, 2023

Responsible Person: Chiki Thompson

Marke, Geoff

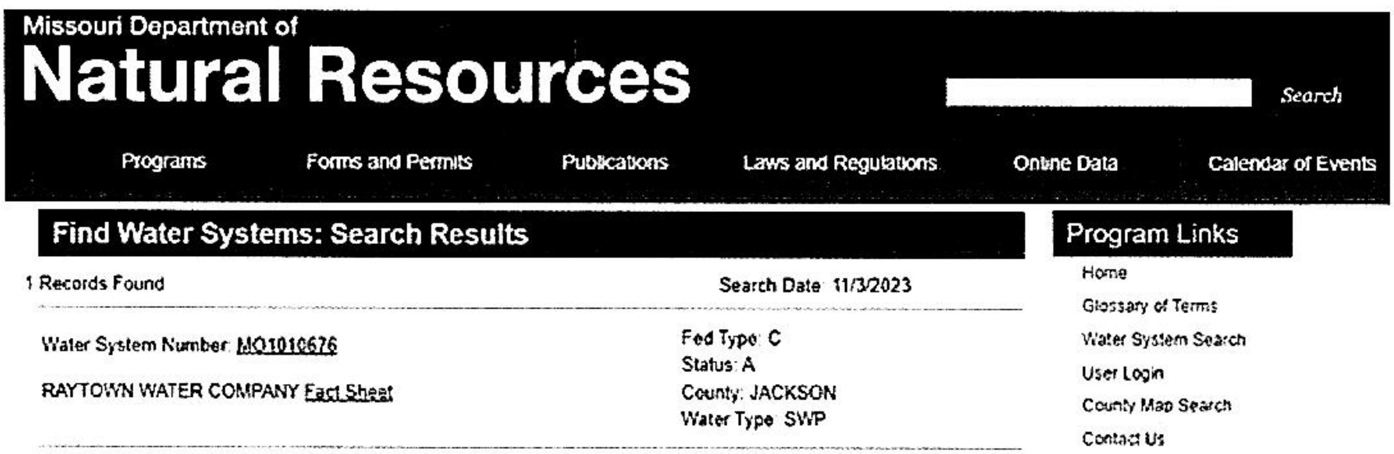
From: Weckenborg, Scott
Sent: Friday, November 3, 2023 12:25 PM
To: Marke, Geoff
Subject: RE: question on monthly water testing

Good afternoon Geoff,

Even though Raytown Water Company purchases water from Kansas City PWS, Raytown Water Company also meets the definition of a public water system. Since Raytown Water Company is a consecutive system and does not treat drinking water, they are responsible for meeting the following distribution system monitoring requirements:

15 Routine bacteriological (Total Coliform/E. coli) samples every month.
2 Routine disinfection byproducts [total trihalomethanes (TTHM) and haloacetic acids (HAA5)] samples every quarter.
30 Lead and Copper samples every 3 years.

These schedules can be accessed along with more information about Raytown Water Company on Missouri Drinking Water Watch. https://www.dnr.mo.gov/DWW/JSP/SearchDispatch
Then type in the water system name or PWS ID number you are interested in searching. Then click on the Water System number like highlighted yellow below.



Then click on Sample Schedules/FANLs/Plans link in yellow font on the top left of the Water System Detail Page to view the active sample schedules for Raytown.

I hope this helps and if you have any more questions, please let me know.

Thanks,

Scott Weckenborg
Missouri Department of Natural Resources
Public Drinking Water Monitoring Section
Bacteriological & Chemical Monitoring Unit
P.O. Box 176, Jefferson City, MO 65102-0176
Phone: 573-526-1124 Fax: 573-751-3110
scott.weckenborg@dnr.mo.gov

We'd like your feedback on the service you received from the Missouri Department of Natural Resources. Please consider taking a few minutes to complete the department's Customer Satisfaction Survey at https://www.surveymonkey.com/r/MoDNRsurvey. Thank you.

From: Marke, Geoff <Geoff.Marke@opc.mo.gov>
Sent: Thursday, November 2, 2023 3:22 PM
To: Weckenborg, Scott <scott.weckenborg@dnr.mo.gov>
Subject: question on monthly water testing

Scott,

Your name has been forwarded to me as somebody who could answer some questions I have about DNR's requirements regarding water testing. The specific question I have has to do with the Raytown Water Company, a distribution only company that buys its water from the City of Kansas City. In this example, who tests the water? Is it Raytown, KC, or both? Any insight would be greatly appreciated.

Best regards,

Geoff Marke
Chief Economist
Missouri Office of the Public Counsel
(314) 956-4487 cell
(573 751-5563 office

National Regulatory
Research Institute

Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?

Scott Hempling, Esq.
Scott H. Strauss, Esq.

November 2008

08-12

A. **Example #1: A relatively small water utility seeks pre-approvals in connection with a relatively large — but otherwise routine — investment**

Assume that a small water utility is required by statute or regulation to undertake a relatively large capital investment. The investment concerns a program that, while substantial for the utility, is routine for the industry. An example could be the development of a leak detection and mitigation program, which may include the removal and repair or replacement of a large portion of the utility's underground plant. The utility asserts that it needs upfront assurances that would not be available under the traditional approach of cost recovery after-the-fact.

The small utility might request two kinds of pre-approvals: one involving cost recovery and one involving approval without addressing cost recovery. An example of the former would be the utility arguing that it has no access to the level of financing required to complete the project, and that it cannot proceed absent assurance of contemporaneous cost recovery. An example of the latter would be seeking the regulator's blessing of the proposed program as a prudent course of action. Given the commission's statutory obligation to support any decision with substantial evidence, it must require that the utility document the specific challenges. If a utility wants advance approval, it must demonstrate that the program is the best option available. Identifying a statutory mandate, state or federal, would serve this purpose if the mandate specifies the solution.

The commission will need to consider whether conditions should be imposed on pre-approval, including these questions:

- Should the pre-approval, if granted, be contingent on the receipt of periodic progress reports?

- Should any cost recovery be capped at no more than the estimated price tag for the program? Should that cap be a hard cap, or one that the commission can raise or lower depending on future facts?

- Does the small utility have the technical resources sufficient to undertake a major capital project? If not, should the commission condition pre-approval on the utility procuring engineering and project management assistance? To what extent should or must the commission become involved in monitoring project progress?[50]

- Will a pre-approval aimed at shifting regulatory risks involve other associated adjustments? For example, should the utility's return on equity be adjusted if assurances are provided that result in changes in the utility's risk profile?

Each of these questions have a common theme: cost-benefit analysis. The commission should be satisfied that the risks associated with providing approvals in advance — including the constraints on the commission's ability to take action after the fact because of approvals granted

[50] To the extent the commission is involved in monitoring progress, the commission staff or an outside consultant will have to examine the progress of the project, measure it against whatever standards are available, and help the commission render a judgment as to whether the job is being done adequately.

before-the-fact — are outweighed by the benefits derived from the timely implementation of the infrastructure upgrade. Then the commission should ensure that those benefits arrive.

B. Example # 2: A utility with reasonable access to capital seeks pre-approvals in connection with a routine investment

In this example, the utility has ready access to capital on reasonable terms, and the needed capital project presents few new or unusual challenges. Unlike the first example, there is no reasonable claim that, absent pre-approvals, the project cannot be financed. As in the first example, the project will provide substantial benefits for customers, assuming efficient implementation.

The utility here seeks the same two types of pre-approvals: one that directly involves cost recovery and one that does not. For the pre-approval that does not directly involve cost recovery, the utility must demonstrate that its selected project is the best feasible option.

As to pre-approval of cost recovery, the utility's access to capital requires assessment of at least the following issues:

- The utility can make the investment without a pre-approval commitment. One question is whether pre-approval of cost recovery will lower the cost of capital while having no effect on management's incentive to act efficiently.
- The commission can address the efficiency issue directly by considering whether any advance authorization should be capped at the estimated cost of the project and, if so, whether the cap is hard (no later adjustments) or soft (later adjustments, up or down, possible based on fact changes). If the authorization is entirely "upside" for the utility, it may lack sufficient incentive to manage the project efficiently.
- As in the first example, the commission might consider conditioning cost recovery commitments on the submission of periodic project status reports. Continued regulatory supervision should encourage management to conduct construction of the project in a cost-efficient manner. Moreover, regulatory oversight can readily catch and prevent glaring inefficiencies and errors, especially as concerns routine infrastructure repair and replacement projects.
- The commission should consider why a utility with access to capital needs pre-approval of cost recovery. Is the utility seeking pre-approval to rectify prior management neglect? Was this project, for example, something that should have been pursued several years ago? Is early approval and cost recovery in such situations merely a reward to a utility that may have unreasonably delayed making necessary repairs and improvements to its system? To the extent there is evidence of management imprudence, the commission might consider combining early approval and cost recovery with reductions to the allowed return on equity to reflect (a) the lower risk to the utility where its costs are approved or recovered before project completion, as well as (b) management imprudence in delaying necessary investments.

National Regulatory
Research Institute

Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?

Scott Hempling, Esq.
Scott H. Strauss, Esq.

November 2008

08-12

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Executive Summary

Until the last quarter of the 20th century, utility regulators commonly made cost recovery decisions concerning new capital projects only after construction was completed and the facility had entered commercial operation. The key aspect of this traditional approach is timing -- *i.e.*, that whatever regulatory decision is made with respect to the rate-making treatment of construction costs occurs "after-the-fact," *i.e.*, after the utility has incurred the costs at issue. Deciding only after a project is completed whether to allow rate recovery means that (1) cost recovery does not begin until the utility seeks and obtains a rate increase; and (2) during construction, the utility has to obtain outside (*i.e.*, non-ratepayer) sources of funds to finance the project.

Some state commissions, based on traditional statutes or recent amendments, are breaking from this traditional approach, thereby providing some level or form of cost recovery assurance prior to commercial operation (and sometimes prior to commencement of construction). Stimulating these new approaches are multiple factors: growing demand, aging infrastructure, environmental requirements, an increasing call for the construction of renewable projects, and shrinking credit markets. These considerations have led utilities to seek upfront regulatory commitments before expressing a willingness to pursue even much needed major capital projects.

This paper addresses the many and conflicting considerations raised when a utility asks a commission to commit to cost recovery in advance of the regulated utility's completion -- or, perhaps, even the initiation -- of construction of a major capital project. For shorthand purposes, we term these commitments as "pre-approvals," and define them as:

> ***An official government declaration that constrains future government decision-making, issued (a) by the commission pursuant to state statute, or (b) by statute directly. The declaration is issued at some point in time before (a) the utility obligates itself to incur project costs, or (b) the project enters commercial operation. The declaration provides that the utility (a) will receive, or (b) will have an opportunity to assert that it should receive, at some point or points in time, dollars from ratepayers, with some level of certainty, to cover some or all of the project costs.***

In evaluating whether to make a pre-approval commitment, there are many potential options and real-life examples to consider. These include state commission determinations that a specific capital project is a prudent choice, that pre-construction costs can be recovered in rates, or that some of the costs to be incurred in constructing a project can be included in rates, on either a contemporaneous or post-completion basis. Any of these approaches involves some upfront shifting, from regulated utilities to ratepayers, of the economic and timing risks associated with implementing a major capital project.

Examples of these mechanisms, which are not mutually exclusive, include:

- Recovery of construction costs during, rather than only after, construction;

- Approval of specific projects in advance of completion (sometimes, though not always, subject to conditions such as meeting scheduled milestones or imposing cost recovery caps);

- "Adjustment clauses" (allowing for recovery of specified costs as incurred, *e.g.*, on a monthly or annual basis);

- Approval of "formula" rate structures, which allow for automatic recovery of certain types of costs, including capital costs;

- Single issue rate increases (*e.g.*, involving consideration of only a capital improvement) rather than general rate cases (involving consideration of all of a utility's costs, whether increased or decreased since the last general rate case);

- Riders and surcharges, allowing for the recovery of pre-approved, specific cost increases without the need for a general rate case; and

- "Securitization" (a rock-solid, often statute-based, government guarantee of cost recovery, which is intended to reduce financing costs by eliminating the risk of non-recovery).

While the paper contains a review of these and other possibilities, its larger purpose is to identify the considerations that the regulator should take into account before moving forward with any form of an in-advance -- rather than after-the-fact -- approval of utility actions or costs. Consideration of advance commitments requires that the commission determine the terms on which risks may be shifted as between a utility's shareholders and its customers, and the benefits provided in response to any approved risk-shifting. In addressing these issues, the regulator must weigh multiple, and occasionally conflicting, concerns, including those involving management effectiveness, regulatory effectiveness, and rates. Some of the considerations involved in addressing pre-approval issues are arrayed sequentially in Figures 1 and 2 to this paper.

While the issues are, of course, fact-specific, the paper presents certain general guidelines that the regulator can apply in evaluating potential pre-approval opportunities. In general, the regulator should ensure that:

- Any pre-approvals are granted only upon a supported showing that regulatory action will benefit customers.

- Regulatory actions are based on full review of the relevant facts, and are supported by evidentiary showings.

- Whatever regulatory action is taken is appropriately limited or conditioned. Approval of an option as a "prudent" choice is not the same thing as approving the inclusion in rates of whatever dollars are expended to pursue it. Approving the recovery of "preliminary" or "planning" costs should not construed as approving the recovery of later-incurred dollars. The key is to be certain that regulator flexibility and discretion are retained to the greatest extent possible.

- The regulator has adequate resources to conduct appropriate reviews of whatever is requested. The commission will need assured access to sufficient technical resources if it is inclined to consider the request of a utility seeking, for example, a determination that building a new nuclear plant is a "prudent" response to the need for new capacity.

- The roles of the regulator and the utility remain properly defined. While it may be appropriate to require that a utility provide periodic reports on the progress of a construction project, the regulator's oversight should not leave it as the party with responsibility for managing the project.

Consideration is given to offsetting adjustments. If pre-approval will reduce the utility's going-forward risk profile, consider whether an adjustment to the utility's return on equity should be ordered in connection with whatever pre-approval is granted.

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Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?

I. Introduction

Every regulated public utility has a statutory obligation to satisfy its customers' needs, reliably and cost effectively. To meet that obligation, the utility must, among other things, forecast demand accurately and commit to appropriate capital projects. Those projects must then be completed on time and constructed in a prudent and cost-effective manner. [1]

Achieving these public interest objectives — accurate forecasts, prudent capital project commitments, cost-effective and timely project implementation — requires a number of decisions by both the regulated utility and the regulatory commission. Common to these decisions is the commitment of dollars. Using its legal powers to approve projects, sites, and rates, the regulatory commission commits ratepayer dollars to the project. Using its legal powers to enter contracts, the regulated utility condemns land, borrows money, issues stock, and commits corporate resources — and ultimately shareholder dollars — to the project.

Taken together, these corresponding commitments present a multi-billion dollar, multi-part question: When a public utility proposes to undertake a major capital project, at what point in time should a commission provide assurance that the utility will recover its investment? What conditions, if any, should be placed on whatever assurance is provided? Phrased differently, how much ratepayer money should regulators commit, when should regulators commit it, and under what conditions should such commitments be made?

This paper focuses on commitments made by regulatory commissions in advance of the regulated utility's completion — or, perhaps, even the initiation — of construction of a major capital project. When faced with a request for approval of a project-related regulatory commitment in advance of project completion, a commission will face several basic questions:

a. What types of regulatory commitments should be considered?

b. At what point in the construction process should the regulator make a commitment to a new capital project?

[1] In this paper, "public utility" or "utility" refers to an entity having a legal obligation to serve. This obligation can arise from legislative or commission mandate. The policy origins of such a mandate are normally a determination that (a) the service is essential to the public welfare and (b) the provider is a monopoly or near-monopoly, such that customers have few alternatives and thus need regulation to ensure high-quality service. The application of this term will vary across states and across industries. At the state level, a regulated utility's obligation to serve typically amounts to a responsibility to provide a defined product (*e.g.*, reliable electric, gas, or water service) in a quantity sufficient to satisfy all demand within an assigned service territory. We do not address the more complex issue of utility obligations where there is competition for the right to supply customers.

c. Assuming the commitment involves cost recovery, should the commitment be bounded through the imposition of conditions, and, if so, how should those conditions be structured?

Consideration of advance commitments requires that the commission determine the terms on which risks may be shifted as between a utility's shareholders and its customers, and the benefits provided in response to any approved risk-shifting. In answering the questions presented above, the regulator must weigh multiple, and occasionally conflicting, concerns, including those involving management effectiveness, regulatory effectiveness, and rates.

While these questions can be considered sequentially, real-world decision-making is not so orderly. In a given set of circumstances, the answers to each of the questions posed will be interrelated and interdependent. For this reason, it is important for a regulator to observe the entire array of choices systematically, before making commitments at any particular stage.

Some of the considerations that may be posed by a request for a regulatory commitment are reviewed in this paper, are displayed in Figures 1 and 2 to this paper, and are applied in the "examples" presented below in Section III.

A. The Situation: Needed New Investment in Capital Projects Poses Challenges for Utilities and Regulators

Facing a combination of growing demand, aging infrastructure, environmental requirements, an increasing call for the construction of renewable resources, and shrinking credit markets, utilities are seeking upfront regulatory commitments before expressing a willingness to pursue even much needed major capital projects.

Consider the situation currently facing service providers in the electricity, gas and water industries:

a. Electricity

Infrastructure needs are growing for electric utilities. Some utilities are seeing capacity margins shrink as demand continues to grow in the face of plant retirements. Others have deferred investments in aging transmission and distribution systems. Utilities are voluntarily (or by mandate) investing in advanced metering and data management systems while facing the need to comply with new renewable energy and energy efficiency directives. Some utilities are considering investing in a new generation of nuclear plants, while others are proposing to meet customer needs by entering into long-term purchase power agreements. Those involved in construction projects have seen increases in the cost of raw materials used as project inputs. Licensing remains a challenge for any major project in an era of NIMBY (not in my backyard) and NIMTOO (not in my term of office). Utility financial capabilities and the availability of capital in today's markets also constrain capital investment projects.

b. Gas

During the past five years, gas utilities spent roughly $5 billion per year on capital investments. This spending trend is on the upswing. The American Gas Association (AGA) estimates that during the next twenty years, annual capital expenditures will increase to $6.5-$9 billion,[2] with funds expended on new main and service pipes, replacement pipes, and compliance with new federal safety regulations.[3]

In some states, gas utilities are petitioning their state commissions to approve accelerated recovery of capital expenditures.[4] As of the end of 2007, eleven state commissions allow gas utilities to "use expense trackers or accounting deferrals to recover costs expended to replace infrastructure in a timely manner."[5] Similar mechanisms are pending before other state commissions.

c. Water

In the years immediately following World War II, the unprecedented industrial, business, commercial and residential development experienced in the U.S. was accompanied by water and wastewater infrastructure to support that development. Many of the water and wastewater facilities constructed during that period are now at the point where they must be upgraded or replaced. Absent action, communities risk adverse economic consequences, such as unplanned system failures, increased maintenance costs, and unbudgeted repair and replacement costs. Water and wastewater utilities are also facing increasingly stringent water quality regulations, which will require large capital investments in water treatment facilities and processes. United States Environmental Protection Agency surveys indicate that over the next two decades, the level of needed investment in water and wastewater infrastructure improvement and replacement is between $500 billion and $1 trillion.[6]

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[2] Cynthia J. Marple, Facilitating Energy Efficiency and Conservation: Non-Volumetric Rate Designs, Presentation Before the Virginia SCC and LDC Conference (Oct. 1, 2008).

[3] For example, the Pipeline Safety Improvement Act of 2002 (Pub. L. No. 107-355, 116 Stat. 2985 (codified as amended in scattered sections of 49 U.S.C.)) and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (Pub. L. No. 109-468, 120 Stat. 3486 (codified as amended in scattered sections of 49 U.S.C.)) require gas utilities to increase their pipeline maintenance and safety investments. The latter legislation requires gas utilities to spend additional money on excavation damage prevention, distribution integrity management, excess flow valves and pipeline control room operations. In addition, state regulators can impose standards that are more stringent than federal safety mandate minimums.

[4] In general, state public utility commissions approve the construction of distribution facilities and intrastate pipelines, which include main distribution lines and service lines, metering systems, and storage facilities located within a utility's service area. Commissions review the economics and need (*e.g.*, requirement for meeting federal safety regulations) for these facilities before issuing a certificate. Moreover, state commissions may require that gas utilities under their jurisdiction provide reliable and safe service, which can include, for example, imposition of the obligation that a utility replace some of its existing pipes to comply with safety standards or construct new service lines to accommodate new customers.

[5] American Gas Association, "Infrastructure Cost Recovery Mechanisms," *Natural Gas Rate Round-Up*, December 2007. Commissions have approved trackers for pipeline integrity management programs and pipeline replacement costs.

[6] David Denig-Chakroff, Nat'l Regulatory Research Inst., The Water Industry at a Glance (2001), http://nrri.org/pubs/water/Water_industry_at_a_glance.pdf.

B. The Traditional Approach: Determine Cost Recovery at Project Completion

Until the last quarter of the 20th century, regulators commonly made cost recovery decisions concerning new capital projects when construction was completed and the facility had entered commercial operation.[7] Under this traditional approach, referred to as the "prudent investment rule," cost recovery was available only on satisfaction of two conditions: costs were prudently incurred, and the project was "used and useful," *i.e.*, providing actual benefits to the public.[8]

The mechanics of the traditional approach are straightforward: once the plant enters commercial operation, the utility, for accounting purposes, puts its construction and associated financing costs into its rate base and books associated depreciation. The utility then seeks a rate increase to pay for the plant. In computing its proposed new rates, the utility includes the net book value (*i.e.*, original investment less booked depreciation) in its proposed rate base and includes annual depreciation of the investment in its proposed annual expenses. The depreciation expense gives the utility the return <u>of</u> its investment, while the cost of capital applied to the rate base gives the utility a return <u>on</u> its investment.[9]

In connection with the proposed rate increase, the regulator engages in several assessments, the aim of which is to determine whether the costs proposed for inclusion in rates were prudently incurred and whether the resulting utility plant is used and useful for serving the public. Those assessments include: (1) examining the utility forecasts that supported the decision to build the project, thereby satisfying itself that the project was, in fact, needed; (2) assessing the project choice, including reviewing whether potentially less expensive alternatives were considered and, if so, why they were not pursued; (3) evaluating whether the methods and sources of plant financing reflect prudent decision-making; and (4) conducting a review of the reasonableness of construction costs and the timeliness of completion. Upon completing this review, the regulator disallows costs that it finds were caused by the utility's imprudence.

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[7] In setting utility rates, Commissions typically do not guarantee cost recovery, but rather provide a reasonable opportunity for recovery. That reasonable opportunity exists when the regulator includes the designated costs in the utility's revenue requirement when setting rates. Whether the utility actually collects that full revenue requirement depends on the extent to which its actual expenses and sales volumes match the levels assumed in the Commission-approved revenue requirement. Guaranteed cost recovery, which is the exception but not unprecedented, requires a distinct device, such as a fixed line item amount on each customer's bill, or a "pass through clause" that allows for periodic true-ups, or, most formally, a statutorily-defined "securitization" mechanism in which the state government promises full payment.

[8] For background on this concept, see Justice Brandeis's dissenting opinion in *Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission*., 262 U.S. 276 (1923); and James Bonbright, <u>Principles of Public Utility Rates</u> 159-61 (1961).

[9] In a state which defers cost recovery until construction is complete, the technical accounting works like this: While construction is ongoing, the utility records its construction costs as Construction Work in Progress, or CWIP. It also records an Allowance for Funds Used During Construction, or AFUDC, which represented the cost of financing the outstanding CWIP. The AFUDC rate varies: it may be the utility's weighted average cost of capital, or it may be the cost of debt, or the cost of short-term debt. When the plant is complete, the utility stops recording CWIP and AFUDC, moves the CWIP to plant-in-service accounts, and begins depreciating the plant and including it in rate base. For purposes of this discussion, the important point is that during construction the utility does not obtain a cash return of or on the investment, but books the costs for later recovery in rates.

For purposes of this discussion, the key aspect of the traditional approach is *timing — i.e.*, that whatever regulatory decision is made with respect to the rate-making treatment of construction costs occurs "after-the-fact," i.e., after the utility has incurred the costs at issue. Deciding only after a project is completed whether to allow rate recovery means that (1) cost recovery does not begin until the utility seeks and obtains a rate increase;[10] and (2) during construction, the utility has to obtain outside (*i.e.*, non-ratepayer) sources of funds to finance the project.

Supporters of the traditional approach assert that it offers customers important benefits, including encouraging utility management to complete the project on schedule and on budget (if not sooner than forecast and less expensively). Moreover, in an after-the-fact cost recovery review, regulators have access to all relevant construction facts before making prudence and rate recovery decisions.

C. Is the Traditional Approach Optional Where Needed Financing is Difficult to Obtain?

Beginning in the 1970s, the factual bases for the traditional approach began to change. In the electric industry, for example, until the 1970s, the combination of economies of scale and increasing demand growth permitted utilities to size facilities to a level that would both meet expected demand and reduce unit costs, while also allowing for additional sales. However, the combination of inflation and fuel cost increases meant that internal utility funds were less available for use on construction projects. Moreover, access to needed capital became more difficult as construction projects grew larger, employed new technologies, required longer construction periods, and had to meet new and uncertain regulatory requirements (such as those emanating from the Nuclear Regulatory Commission for electric utilities and the Environmental Protection Agency for water utilities). These facts made capital markets less optimistic about whether, and when, ratepayers would pay up. In response, capital — both shareholder capital and debt capital — became more expensive and less available.

State law and practices concerning the timing and processing of rate increase requests subjected utilities to additional financial stress. Some states had statutory "stay-out" provisions, limiting the frequency of the utility's general rate increase requests. Regulators also had a non-statutory preference for infrequent rate cases, due to resource limits and public relations challenges. For small utilities, the transaction costs of a full rate case could compare unfavorably to the size of the revenue increase associated with the likely outcome.

Critics of the traditional approach have asserted that this combination of circumstances has had negative effects, including: delays in needed utility investments (thereby increasing the risk of shortages, blackouts, brownouts and other service concerns); decreasing the frequency of rate filings (and conditioning customers to unchanging (meaning below-cost) utility rates even as other costs of

[10] One clarification of the phrase "seeks and obtains": some states allow the utility to institute some or all of its proposed rate increase before the commission has decided the case. Practitioners label such rates "interim subject to refund." If the Commission ultimately approves rates lower than those placed into effect, the utility must refund the excess amounts.

living rose)[11]; and deferring projects until "crisis" conditions prevailed (leaving insufficient time for commission examination of potential alternatives).

Regulators have responded to these concerns by considering certain modifications to the traditional approach, many of which are short-term and project-specific. Examples of these mechanisms, which are not mutually exclusive, include:

1. Recovery of construction costs during, rather than only after, construction (known as recovery of Construction Work in Progress or "CWIP");

2. Approval of specific projects in advance of completion (sometimes, though not always, subject to conditions such as meeting scheduled milestones or imposing cost recovery caps);

3. "Adjustment clauses" (allowing for recovery of specified costs as incurred, *e.g.*, on a monthly or annual basis);

4. Approval of "formula" rate structures which allow for automatic recovery of certain types of costs, including capital costs;

5. Single issue rate increases (*e.g.*, involving consideration of only a capital improvement) rather than general rate cases (involving consideration of all of a utility's costs, whether increased or decreased since the last general rate case);

6. Riders and surcharges, allowing for the recovery of pre-approved, specific cost increases without the need for a general rate case; and

7. "Securitization" (a rock-solid, often statute-based, government guarantee of cost recovery, which is intended to reduce financing costs by eliminating the risk of non-recovery).

Some of these mechanisms were mandated by legislative action, which might single out a particular technology or cost category for favorable (*i.e.*, certainty-enhancing) treatment. However, approval of any of these cost recovery mechanisms could unreasonably shift risk from shareholders to ratepayers if not limited (*e.g.*, by imposing a cap on cost recovery, which could be exceeded if certain showings were made).

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[11] Eventual – and generally substantial – rate cases could engender customer and media attention that undermined public trust in both the commission and the utility. Bonbright, in his *Principles of Public Utility Rates*, *supra*, at 291 (bullet point 5), emphasizes the value of rate stability (including gradual rate increases) over sudden, large rate increases.

D. The Framework for a New Approach

The present regulatory landscape at the state commission level features an apparent mismatch between (a) the magnitude of investment dollars necessary for essential infrastructure expansion and replacement essential to the nation's well-being, and (b) the clarity and predictability of the regulatory treatment of those investment dollars. These concerns are present regardless of the perspective from which the situation is viewed. For example:

Regulators and utility executives are unclear about largely the same things: what decisions are theirs to make, which decisions will be mandated or guided by legislators, what risks they incur in taking particular actions, and, therefore, how best to identify and balance the managerial, financial, technical, economic, and political factors that affect construction of needed large capital projects.

Investors are unclear about when regulatory commitments will be made, how those regulatory actions will allocate responsibility for project costs and risks, when dollars will flow, through what ratemaking mechanism, and how regulatory commitments might change with unanticipated events.

Customers are unclear about (a) what to expect in terms of the cost consequences of utility investments on their behalf; and (b) whom to hold accountable — legislators, regulators, utility executives, capital markets, or all of the above — for outcomes that vary from these expectations.

In short, there is a need for clarity and predictability, in the form of systematic, but not rigid, decision-making. Systematic decision-making seeks clarity and predictability, the prerequisites for which include alertness to all relevant facts, identification of all legitimate values, attention to both long-term and short-term consequences, and analytic transparency. A framework embodying these features will allow for improvisations, changes of heart and mind, and creative modifications.

In considering how and when to approve the recovery of the costs associated with large capital projects, achievement of the public interest requires at least three ingredients:

- First, whatever regulatory commitments are made should be well-founded, *i.e.*, based on a substantial evidentiary record.

- Second, the commission must have the capacity (including skills, experience and resources) to evaluate anticipated utility performance, to monitor performance throughout the course of the project (including a review of utility rationales for schedule slips and cost overruns), and to take actions in response to unanticipated events.

- Third, whatever regulatory action is taken must be designed to both motivate the utility to excel (*i.e.*, operate efficiently) and to penalize the utility for poor performance.

In regulatory dialogue, these concepts can be captured in the term "pre-approval." This term has been given multiple meanings. Here is a suggested definition that covers many of them:

> ***An official government declaration that constrains future government decision-making, issued (a) by the commission pursuant to state statute, or (b) by statute directly. The declaration is issued at some point in time before (a) the utility obligates itself to incur project costs, or (b) the project enters commercial operation. The declaration provides that the utility (a) will receive, or (b) will have an opportunity to assert that it should receive, at some point or points in time, dollars from ratepayers, with some level of certainty, to cover some or all of the project costs.***

The concept can be viewed with more clarity when the description's separate components are parsed:

> ***a. An official government declaration that constrains future government decision-making, issued (a) by the commission pursuant to state statute or (b) by statute directly,***

Whether the commission issues an order or the legislature enacts a statute, the action is "official" because it declares rights and obligations. The declaration, the content of which is addressed below, can issue from the commission, acting pursuant to statutory authority, or directly from the legislature (which can either direct or authorize a result). However, unless the declaration constrains future government decision-making, it is legally meaningless.

> ***b. at some point in time before (a) the utility obligates itself to incur project costs, or (b) the project enters commercial operation,***

Utilities seek "pre-approval" to reduce the risk non-recovery of costs, and also to reduce the time lag between expenditure and cost recovery. "Pre-approval" can address one or both of these goals. Risk reduction occurs if a government makes a cost recovery commitment before the utility incurs a cost. Time lag reduction occurs if cost recovery under a pre-approval structure occurs sooner than would be the case if the utility has to file an after-the-fact rate case.

> ***c. that the utility (a) will receive, or (b) will have an opportunity to assert that it should receive,***

This phrase goes to the heart of what the government is, in fact, approving. If the government approves cost recovery, then it is promising that the utility "will receive" some amount of dollars at some point, predicated on the fulfillment of certain conditions (such as prudent conduct, timely completion of construction, or completion within a specified budget).

Another, and more limited type of "approval" does not commit to cost recovery specifically, but somewhat constrains future commission decisions on cost recovery. Assume, for example, that a commission determines that a utility's demand forecasts are accurate and that new capacity is necessary to meet those forecasts. If action is taken by the utility based on that finding, then the commission presumably cannot — absent a material change in factual circumstances — find later that the capacity addition was unnecessary. This type of pre-approval constrains the regulator to stick to its original "need" finding. However, depending on the scope of the action, the regulator remains free to question (a) the utility's choice of a particular project as the means of meeting the acknowledged need; (b) the reasonableness of the costs incurred in constructing the additional capacity; and (c) the utility's continuation of the project despite material changes in underlying facts.

d. at some point or points in time

In the context of pre-approvals, the point in time when the utility receives ratepayer dollars can vary widely. Dollars can flow either as or after the utility incurs costs, and each of these options themselves involve multiple choices. "As incurred" can mean in each monthly bill or pursuant to an annual true-up. "After incurred" could be at the next rate case if the costs were "deferred" (meaning that the commission has allowed the utility to preserve the right to argue later for recovery of costs incurred in the past).

e. dollars from ratepayers,

This portion of the description reflects that the main purpose of "pre-approval" is either to (a) create a government-authorized flow of dollars from ratepayers to the utility as compensation for utility service, or (b) have the commission bless a particular option (thus precluding a later finding that the option was imprudent), while leaving the specific dollar amount for subsequent determination.

f. with some level of certainty,

A regulatory approval granted prior to project completion may shift, but does not necessarily eliminate, cost recovery risk. Cost recovery certainty depends on several factors, including the scope of the regulator's decision. The regulator might determine that a particular project selection is prudent, but remain silent on the prudence of particular project costs. Such a decision creates certainty, in that prudent costs associated with the decision will be recoverable, but leaves uncertain what level of costs is prudent. The regulator might find that the utility's forecast of future needs is accurate but not address the type of project (*e.g.*, power plant vs. demand-side management) that will meet that need prudently, leaving that important question for later determination.

g. to cover some or all of the project costs.

The certainty of cost recovery is distinct from the amount of that recovery. A regulator could find, in advance, that all costs up to a stated amount are deemed prudent and therefore recoverable. On the other hand, as concerns additional costs, the regulator may find that costs above that limit (a) are not recoverable (making the stated amount a ceiling), or (b) the utility may argue later that the costs should be recovered because they were prudently incurred (making the stated amount a floor).

Having now set forth, in conceptual terms, the parameters of a pre-approval approach, we turn to a review of how various state commissions are putting these concepts into action.

II. Pre-Approval Mechanisms in Action: Examples from across the Nation

Pre-approval opportunities are typically triggered by a specific action taken by the utility, which results in a request for some type of imprimatur from a regulator. We begin by reviewing potential pre-approval triggers and then move into a discussion of specific regulatory actions that might be taken. This discussion will address the considerations that may be weighed in reviewing a specific request and provide examples of how regulators and state legislatures across the country are dealing with these issues.

A. Triggering Actions

1. Forecast customer requirements

The utility forecasts customer peak demand and annual consumption requirements. In order to do so, the utility measures economic trends and customer behavior (including price responsiveness and propensity to adopt efficiency opportunities). The utility may ask the regulator to "approve" the forecast or to bless actions to be taken in response to it.

2. Incur specific pre-commitment costs

Prior to committing to a capital project, a utility may incur costs necessary to preserve the option. Examples are paying a fee to an equipment supplier to reserve a place in its queue, initiating site development or seeking a construction license from the NRC. Such steps are time consuming and involve cost incurrence; their purpose is not to initiate a project, but to ensure that if the utility subsequently selects that option, it can move forward without undue delay. The utility might seek approval, in advance of the commencement or completion of a project, to recover such "pre-commitment" costs in rates.

3. Commit to a project and initiating construction

After assessing supply and demand options, the utility might ask the commission to approve the utility's commitment to an option that it asserts best matches the forecasted customer requirements (whether from the perspective of size, timing, reliability, environmental or siting effects) and cost (whether construction cost, running cost over its useful life, or decommissioning cost). In this context, "commitment" means that the utility binds itself contractually to the contractors and suppliers of the equipment, technology and other cost drivers required to construct the project.[12]

[12] For a detailed discussion of the multiplicity of generation choices, organized according to their characteristics, *see* J. McGarvey et al., Nat'l Regulatory Research Inst., *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria* 3 (2007), http://nrri.org/pubs/electricity/07-03.pdf.

4. Continue construction

While a utility's commitment to a project may create some unavoidable cost obligations, there will always be avoidable costs as the project moves through various stages of development. Before committing to each stage of cost commitment, a prudent utility will compare the project's prospective costs and benefits, taking into account factors like cost escalations beyond those assumed in original projections, changes in forecasted customer requirements, and alternate options. The utility may ask the commission to approve continued (or modified) efforts.

5. Change in project plans

During construction, changes in circumstances may warrant project changes. Examples include: downsizing or upsizing to reflect changes in forecasted customer requirements, design changes to comply with new regulatory requirements, and modifications to fuel supply arrangements due to changes in availability or price. Any such change might shift the project's cost-benefit ratio, and may lead to the utility seeking commission approval of associated project modifications.

6. Abandon a project

Prior to completion, circumstances may change the cost-benefit ratio so drastically as to justify project abandonment.[13] Abandonment itself may cause the incurrence of new costs (*e.g.*, decommissioning, attorney fees to renegotiate supplier costs, payment of liquidated damages to shed contract commitments). The utility could seek authorization to recover abandoned plant costs before any such decision is made, or seek abandonment cost protection in advance of a decision whether to pursue a particular project.

B. Pre-Approval Regulatory Commitments that Constrain Future Decisions but Do Not Commit Ratepayer Dollars to Immediate Cost Recovery

For major capital projects, cost recovery is not the only regulatory decision. Under most state statutory schemes, a utility must obtain approvals relating to need, suitability, and environmental effects — often before incurring projects costs. Examples of these approvals include obtaining:

(1) A Certificate of Public Convenience and Necessity ("CPCN"), demonstrating that the proposed project is necessary to serve the public;

(2) A determination that a proposed project is consistent with an integrated resource plan;

[13] Factors leading to an abandonment decision may include: decline in forecasted customer requirements; emergence of new alternatives; unanticipated cost increases relating to fuel supply or regulatory requirements; and unavailability of key equipment components.

(3) Permission to exercise the power of eminent domain (*i.e.*, the taking of private property for utility purposes);

(4) Permission to site utility facilities in particular locations, including (in some states) permission to preempt local zoning restrictions;

(5) Approval of compliance with federal or state environmental restrictions, such as installation of pollution control equipment or other actions associated with electric generating plants, transmission lines, gas and oil pipelines;

(6) Approval of a plan to address reliability problems arising from insufficient resources;

(7) Approval of critical infrastructure protection plans in response to national security challenges;

(8) Approval of plans for repair and replacement of aging facilities;

(9) Approval of bidding or procurement programs; and

(10) Permission to issue debt and equity securities.

Consideration of any of these actions raises at least two questions: (a) What purposes does the approval action serve?, and (b) Does the action constrain future regulatory decision-making, including cost recovery decisions?

1. What are the purposes of an approval that does not directly involve cost recovery?

Any of the above-listed approvals may serve several purposes.

Action at an early stage may provide the regulator with an opportunity to better match the utility's private interest with the public interest. There are plenty of opportunities for mismatch. A utility may prefer to build its own facilities (so as to earn a return on the investment), rather than relying on purchases from others (which might be lower cost, but will not produce a profit for the utility). A utility may seek to maximize sales of its product, even if promoting actions to reduce consumption would be a better choice for the public. Considering regulatory action at an early, pre-cost stage may identify areas in which private and public interest diverge and create opportunities for interest matching – identified through the development of an evidentiary record and implemented through, for example, conditional approvals.

Similarly, consideration of pre-approval actions that do not directly involve cost recovery give the regulator the opportunity to balance multiple factors besides cost. In the specific context of integrated resource planning, project choices involve multiple options with varied possible impacts on the consuming public – including cost, environmental, and economic development impacts — all on both a short-term and potentially longer-term basis. An early open planning process, culminating in some type of regulatory commitment, facilitates a public investigation of these effects and a weighing of the many public preferences and values.

Even where the issue before the regulator does not involve cost recovery, a pre-approval process can create a useful template for future consideration of cost recovery issues. In the case of pollution control infrastructure, some state statutes authorize their jurisdictional electric utilities to file compliance plans for meeting with state or federal emissions requirements. By approving the plan, the commission may effectively be committing to cost recovery of utility funds spent carrying out the plan, assuming a subsequent showing by the utility that such funds were prudently incurred.

Consider Indiana Code 8-1-27-8(1)(A), which directs the Indiana Utility Regulatory Commission to consider an electric utility's Clean Air Act Amendment compliance plan in terms of whether it is efficient, reliable, economic, and constitutes a reasonable least cost strategy over the life of the investment. The electric utility can seek recovery of its original cost estimate for the plan, an approved revised cost estimate, or additional costs, if it can show that they were necessary and prudent. The commission also has authority to modify or withdraw its original pre-approval if there have been substantial changes in the need for, or estimated cost of, an approved environmental compliance plan.[14] A similar arrangement is in place in Pennsylvania.[15]

2. To what extent does approval of a non-cost mechanism constrain a commission's future cost recovery decisions?

The short answer to this question is that it depends on what the commission says in its approval order. Some utilities have sought, prior to the incurrence of major costs, commission or legislative findings that the construction of a specific project is prudent. Such findings can vary in their degree of regulatory commitment to eventual cost recovery. At one end, a ruling on a specific project might not promise cost recovery at any particular cost level, but would insulate the utility from a subsequent finding that its project selection was imprudent. The North Carolina Commission has ruled, for example, that it has authority to issue a declaratory, pre-expenditure ruling regarding the prudence of a proposal.[16] However, some commission orders state expressly that approval of a project choice is not an approval of any cost recovery.[17]

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[14] Ind. Code §§ 8-1-27-18,-19. *See, e.g.*, *In re Indianapolis Power & Light Co.*, 145 P.U.R.4th 513 (Ind. Util. Regulatory Comm'n 1993); *In re S. Ind. Gas & Elec. Co.*, 137 P.U.R.4th 231 (Ind. Util. Regulatory Comm'n 1992). *See, e.g.*, *In re Indianapolis Power & Light Co.*,145 P.U.R.4th 513 (Ind. Util. Regulatory Comm'n 1993); *In re S. Ind. Gas & Elec. Co.*, 137 P.U.R.4th 231 (Ind. Util. Regulatory Comm'n 1992).

[15] *See* Pennsylvania statutes, Pa. Stat. Ann. § 530(d)(2) (requiring utility to show that amounts spent to fulfill the plan were reasonable in amount and prudently incurred as determined in an appropriate rate or other proceeding, for costs to be reflected in rates).

[16] *In re Duke Power Co.*, 256 P.U.R.4th 215, 232 (Commission finds authority to issue declaratory ruling providing "general assurance" concerning nuclear plant assessment activities), *clarified*, No. E-7, Sub 819, 2007 WL 2790658, *clarified*, No. ID 153282, E-7, Sub 819, 2007 WL 3273546 (N.C. Utils. Comm'n 2007); and *In re Duke Energy Carolinas LLC*, No. E-7,

That said, the initial "approval" may constrain later regulatory decisions to the extent that actions the utility takes on the basis of that approval. In other words, the regulator can criticize a utility's implementation of an approved plan, but cannot simply announce after-the-fact that it is reversing that approval absent finding that the relevant facts have materially changed and that the utility should have taken the fact changes into account.[18] However, the commission's approval does not authorize the utility to take imprudent and unnecessarily costly actions to obtain the needed capacity, or to ignore changes in facts that undermine the basis for the original approval. The utility has a continuing obligation to act in a cost-effective manner, and the commission should remain free to enforce that obligation. For this reason, some states require utilities to file periodic updates of demand forecasts and project progress, allowing for a continuous reassessment of project premises.

C. Moves toward Pre-Approved Cost Recovery: "Deferral" of Costs for Later Consideration

Under traditional, embedded cost ratemaking, commissions use a "test year" to match utility cost and revenue increases and decreases. A "historic test year" is a 12-month period experienced by the utility, in which test year costs and revenues are those actually incurred by the utility during that period. Along with adjustments for inflation and other predictable changes (called "known and measurable changes"), these costs and revenues become the basis for the utility's new rates. A "future test year" approach bases rates on expected costs and revenues, rather than adjusted historic costs and revenues. The extent of any difference between the historic test year and future test year approaches depends on the nature of the predictions and adjustments.

After rates are set, if the utility incurs costs not anticipated in the test year, some commissions will permit the utility to "defer" these costs, meaning the utility records them on its books and thereby preserves the opportunity to request recovery in future rates. By definition, such cost deferrals are

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Sub 819 (N.C. Utils. Comm'n 2008), *available at* http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=EAAAAA36180B&parm3=000125794.

[17] Consider this 1999 Idaho PUC ruling:

> The Commission further finds that the general purposes to which the proceeds will be put are lawful purposes under the Public Utility Law of the State of Idaho and are compatible with the public interest. However, the Commission finds that this general approval of the general purposes to which the proceeds will be put is neither a finding of fact nor a conclusion of law that any particular program of Rockland which may be benefited by the approval of this Application has been considered or approved by this Order, and this Order shall not be construed to that effect.
>
> Further, the issuance of an Order authorizing the proposed loans does not constitute agency determination/approval of the type of financing or the related costs for ratemaking purposes, which determination the Commission expressly reserves until the appropriate proceeding.

In re Direct Commc'ns Rockland, Inc., Order No. 27914, No. ROK-T-99-1, 1999 Ida. PUC LEXIS 36, at *6-*7 (Idaho Pub. Utils. Comm'n 1999).

[18] For example, if the regulator finds that the utility needs to install or otherwise procure 500 MW of new capacity, then utility actions taken to obtain that capacity cannot be imprudent on the sole ground that the utility does not need the capacity. On other hand, the utility does not get a "free pass" if it continues to pursue the 500 MW in the face of later evidence that it no longer needs the capacity.

deviations from the typical test year approach; deferral preserves the utility's option to argue for later recovery, even though costs were incurred prior to the test year. In permitting the deferral, the commission order makes no promise about cost recovery.[19]

Some state commissions are authorized to permit cost recovery deferrals for capital projects, but only where the project meets certain identified criteria. For example, under Nevada regulations, Nev. Admin. Code § 704.9484, the Commission may designate a "critical facility," thus making the utility eligible for special incentives for its construction, operation and maintenance, including authority to "defer" construction costs in a regulatory asset account for possible later cost recovery.[20] During the deferral period, the utility also can include put into rates "construction work in progress" (which is addressed separately below) associated with the designated facility.[21]

D. Options for Implementing Pre-Approved Cost Recovery

The most immediate, certain form of cost recovery is to permit a utility to include costs in rates contemporaneous with expenditure incurrence. Regulatory options are reviewed below.

1. Construction Work In Progress ("CWIP")

Under the traditional approach, a commission addresses cost recovery of a capital project in the utility's general rate case, submitted when the project enters commercial operation. If the costs are prudent, the commission allows them in rate base and establishes a depreciation rate, allowing for the gradual recovery of the investment.[22] Thus, cost recovery commences only when the plant enters

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[19] *See*, for example, *In re Idaho Power Co.*, Order No. 29904, No. IPC-E-05-21, 2005 Ida. PUC LEXIS 225 (Idaho Pub. Utils. Comm'n 2005) (clarifying the conditions under which a utility can treat preliminary survey and investigation costs as construction work in progress); *Phila. Elec. Co*., 57 Pa. P.U.C. 114 (Pa. Pub. Util. Comm'n 1983). Similarly, in approving a Settlement that provided for a cost recovery deferral, the Pennsylvania Commission noted that in exchange for this treatment, the Settlement provided for early flow-through to consumers of the benefits derived from certain off-system transactions. *See In re Metro. Edison Co*., Nos. G-900240, P-900485, P-910502, C-913373, P-910502C001, 1992 Pa. PUC LEXIS 87, at *73 (Pa. Pub. Util. Comm'n 1992) ("Affiliated Interest Agreements").

[20] The recovery would occur pursuant to subsection 3 of Nev. Admin. Code § 704.9523 (costs may be deferred between rate cases, and must include application of a carrying charge at the rate of 1/12 the authorized overall rate of return; account balances may be recovered via amortization over a period determined by the Commission in a general rate case, with a return at the authorized return plus 5 percent). Nev. Admin. Code § 704.9484(3)(cross-reference explanation supplied).

[21] In order to be eligible for these special cost recovery protections, the Commission (under Nev. Admin. Code § 704.9484(2)) must find that the facility will

1. protect reliability,
2. promote diversity of supply and demand side sources,
3. develop renewable energy resources,
4. fulfill specific statutory mandates,
5. promote retail price stability, or
6. fulfill any combination of the above.

[22] For example, if the plant cost $900 million and has an expected useful life of 30 years, and if the commission uses a straight line depreciation rate, the rates will recover a depreciation expense of $30 million, as well as a return on the

commercial operation. By contrast, some states allow rate recovery of construction costs during the construction process. Known as "construction work in progress," the technique involves a commission finding that the utility's project selection decision, and the costs incurred to date, are prudent. This regulatory action eliminates the risk of non-recovery, and allows for recovery earlier. The technique both reduces non-recovery risk and aids in cash flow during construction. Providing CWIP may also reduce a utility's finance costs, as construction financing will be provided by ratepayers rather than lenders or shareholders.

Until the investment is moved from CWIP to a plant-in-service account, the utility is permitted to apply a rate of return to the investment amount (which covers its financing costs, *i.e.*, a return on investment). The utility is not permitted, however, to apply a depreciation rate to the investment amount, meaning that the shareholders will not start to see a return of their investment until the plant enters service and satisfies the commission's prudence review.[23] When a utility completes construction and the plant enters operation, accounting rules require the utility to (a) cease accruing an AFUDC on the investment; (b) place the CWIP associated with the plant into a plant-in-service account; and (c) begin amortizing (*i.e.*, reducing) that plant-in-service account by treating a portion of it as depreciation expense. Of course, there are limits to the impact of a decision to allow CWIP in rate base. While the action provides a current return during construction, it does not necessarily preclude the regulator from reviewing the prudence of the underlying investment once the project begins operation.

Proponents have argued, and some commissions have found, that permitting a utility to recover CWIP funding can reduce a project's total net present value cost, compared to booking construction costs as AFUDC and then placing those costs in rate base upon commercial operation.[24] CWIP has been justified on the ground that it removes any utility incentive to rush completion of a nuclear plant imprudently (so as to get its costs into rates) and in doing so risks errors and safety lapses.[25] On the other hand, including CWIP means that customers pay for a plant before it provides benefits, raising intergenerational inequity issues. Some states ban it. *See, e.g.*, *Barasch v. Pa. Pub. Util. Comm'n*, 532 A.2d 325 (Pa.1987), *aff'd sub nom. Duquesne Light Co. v. Barasch*, 488 U.S.

undepreciated $870 million.

[23] In other words, putting CWIP in rate base does not allow the utility to recover the CWIP costs themselves. The utility instead recovers only the financing costs associated with the CWIP. The CWIP amount earns a return at the utility's Weighted Average Cost of Capital ("WACC"). Further, where CWIP is put in rate base with an AFUDC offset, the only dollar cost recovery created is CWIP times the excess of the allowed return over the AFUDC rate. This amount is substantial only where the AFUDC rate is based primarily on debt, particularly short-term debt, rather than a measure of the utility's WACC.

[24] *See* also the Oklahoma Commission's recitation of the competing views of witnesses in the Red Rock pre-approval case. *In re Okla. Gas & Elec. Co.*, Order No. 545240, No. PUD 200700012, 2007 Okla. PUC LEXIS 249 (Okla. Corp. Comm'n 2007) (utility's early approval request denied on other grounds).

[25] *See, e.g., Phila. Elec. Co.*, 103 P.U.R.4th 430 (Pa. Pub. Util. Comm'n 1989)("early window" treatment allowed when the Company filed for rate increase just before fuel was loaded into the Limerick 2 Nuclear Unit); and *Pa. Power & Light Co.*, 47 P.U.R.4th 274 (Pa. Pub. Util. Comm'n 1982)("early window" treatment allowed where the Company filed two months before receiving an operating license for Susquehanna Nuclear Unit I).

299 (1989).[26] Similarly, the Pennsylvania Commission denied "early window" treatment in a case in which the utility sought such authority three years before it acquired its proposed ownership interest in one plant and five years before it began construction of a related transmission line.[27]

2. Riders, surcharges and "single issue" rate increases

A commission's inclusion of costs in the utility's revenue requirement rates does not *guarantee* recovery (because other cost increases, or declines in sales, can leave the utility earning less than its authorized return on equity). One method for increasing the probability of cost recovery is the use of a rider or surcharge, added to each customer's bill on top the "normal" charges (*i.e.*, charges based on the revenue requirement). These riders or surcharges are typically applied to the quantity consumed; thus, as actual consumption may vary from estimates, the utility is still subject to some revenue recovery uncertainty. The probability of full cost recovery is greater if the charge is a fixed, per customer charge (meaning, it does not vary with the customer's consumption). While the typical forum for addressing surcharges is the utility's general rate case, some commissions have established them in so-called "single-issue" rate proceedings, in which recovery of a particular investment is the sole issue.

Certain surcharges are designed to increase over time through automatic "step increases" according to a pre-determined schedule or, as the utility's project costs rise, with periodic adjustments to avoid under- or over-recovery. For example, since 1997 Pennsylvania's water utilities have been allowed by statute to recover the costs of certain system improvements through a "Distribution System Infrastructure Charge" or "DSIC."[28]

The New Hampshire Commission has, in specific circumstances, granted step increase pre-approvals to gas and water utilities to recover the costs of infrastructure remediation, while providing certain safeguards to limit cost recovery. The gas utility filed a plan for gas main replacement under which the utility, operating under an approved schedule, would replace bare steel

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[26] Alternatively, some state commissions developed standards for inclusion of CWIP in rate base. *See*, *e.g.*, Nev. Admin. Code § 704.9484(3). In allowing CWIP for a portion of the construction costs associated with the North Valmy coal-fired plant, the Nevada Commission supported its decision by citing to intangible benefits associated with higher quality earnings, a federal policy of promoting coal over oil and natural gas, and the assertion that completion of the plant would advance the goal of fuel diversity. *In re Nev. Power Co.*, No. 06-06051, 2007 Nev. PUC LEXIS 22, at *114-15 n.11 (Nev. Pub. Serv. Comm'n 2007).

[27] *See* earlier discussion of Affiliated Interest Agreements. The Commission also denied "early window" treatment where neither size nor safety were important considerations. *Re W. Penn Power Co.*, 66 P.U.R.4th 337 (Pa. Pub. Util. Comm'n 1985) and *Re Pa. Power Co.*, 68 P.U.R.4th 357, 361 (Pa. Pub. Util. Comm'n 1985).

[28] *See* Section 1307(g) (66 Pa. Stat. Ann. § 1307(g)) to the Pennsylvania utility code, which states:

> **[Q]uality, fire protection reliability and long-term system viability**.—Water utilities may file tariffs establishing a sliding scale of rates or other method for the automatic adjustment of the rates of the water utility as shall provide for recovery of the fixed costs (depreciation and pretax return) of certain distribution system improvement projects, as approved by the commission, that are completed and placed in service between base rate proceedings. The commission, by regulation or order, shall prescribe the specific procedures to be followed in establishing the sliding scale or other automatic adjustment method.

gas mains (bare steel pipes lacking cathodic protection) with either cathodically-protected steel pipes or PVC piping. The purpose was to avert ongoing corrosion and gas main leaks associated with the unprotected bare steel pipe.[29] Similarly, the New Hampshire Commission awarded step increase treatment to address local water utilities' difficulties in financing improvements needed to address long-developing infrastructure deficiencies.[30] At the same time, the Commission, in each instance, provided for review and audit of construction costs incurred under the plan and review of the prudence of such costs, before the step increases would take effect.[31]

California has allowed water utilities to obtain step increases pursuant to an approved water infrastructure development plan. Once the plan is approved, the utility implements related annual rate increases by filing so-called "advice letters." In each letter, the utility notifies the Commission that investments that are required as preconditions for the step increase have been made and files the resulting new rates for application in the next year.[32]

In Washington State, the Commission gave Puget Sound Energy, Inc. authority to recover the costs of new power sources in the utility's reconciling Power Cost Adjustment, upon the approval of the new source in a so called Power Cost Only Rate Case (or PCOCR).[33]

Similarly, a Florida statute encouraging construction of new nuclear and Integrated Gasification Combined Cycle ("IGCC") plants, and the Commission regulations implementing the statute provide for annual construction cost recovery based on estimates of upcoming construction activities, together with a reconciliation of the most recent year's expenditures against the estimates upon which the earlier charges were based.[34]

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[29] *See*, *e.g.*, *Re N. Utils., Inc.*, Order No. 20,546, No. DR 91-081 (N. H. Pub. Utils. Comm'n 1992) and *Re N. Utils., Inc.*, Order No. 23, 052, No. DR 98-169 (N.H. Pub. Utils. Comm'n 1998) (approving the sixth step increase under Northern Utilities' bare steel main replacement plan).

[30] In that case, the Commission found that the deficiencies at issue

> pose a threat of backflow and cross-contamination to the drinking water supply. [The utility's witness] explained that this threat exists because much of the infrastructure is greater than 100 years old and consists of unlined cast-iron pipe which is subject to corrosion and failure. In addition, over 78% of the system has no post-treated storage. Also, increased traffic on the roadways, under which much of the distribution system is located, exerts additional pressure on these already weak pipes.

In re Hanover Water Works Co. Order No. 23,007, No. DF 98-076 (N.H. Pub. Utils. Comm'n 1998). Hanover Water Works serves approximately 8500 customers. Citydata.com, http://www.city-data.com/city/Hanover-New-Hampshire.html (last visited Oct. 3, 2008).

[31] The review proceedings differ from full rate cases in that they do not look at any other potential changes in revenues, costs and rates of return.

[32] *See*, *e.g.*, *In re San Gabriel Valley Water Co.*, 258 P.U.R.4th 65 (Cal. Pub. Utils. Comm'n 2007).

[33] Twelfth Supplemental Order, *Wa. Utils. & Transp. Comm'n v. Puget Sound Energy* , Nos. UE 011570, UG 011571, (Wa. Utils. & Transp. Comm'n 2002), *available at* http://www.wutc.wa.gov/rms2.nsf/vw2005OpenDocket/CB033A64A4C98B5688256BDE007D6AAE?OpenDocument.

[34] *See* Div. of Policy Analysis & Intergovernmental Liaison, Fla. Pub. Serv. Comm'n, Distribution System Improvement Charges for the Florida Water and Wastewater Industry 1 (2001), http://www.psc.state.fl.us/publications/pdf/pai/dsic4ww.pdf.

3. Formula rates

The traditional test year approach to determining a utility's revenue requirement allows for a consideration of all cost increases and decreases. Regulators have designed a method for preserving the integrity of the test year while expediting analysis of a proposed rate increase necessitated by a capital addition. The approach allows the utility to update its rate base with increments of completed capital investment by filing an annual update of the inputs to a rate formula. The utility supplies the new cost data in accordance with the accounts of costs and revenues filed with the Federal Energy Regulatory Commission on the annual FERC Form 1, with (perhaps) some particular pre-approved adjustments. Because the regulator has approved the formula (and the input form) in advance, the regulatory review is confined to scrutiny of the prudence of particular input items or to arguments that the utility has misapplied the formula (*e.g.*, by including inaccurate or erroneous formula inputs).

4. Securitization

Securitization attaches a statutory commitment to cost recovery, thereby eliminating all risk of non-recovery. Reducing risk reduces the cost of capital to the customer.

E. Conditions That Can Accompany Pre-Approval Mechanisms to Ensure Consistency with the Public Interest

To ensure that risk-shifting pre-approval regulatory commitments promote the public interest, regulators have conditioned such commitments, including through the application of screening mechanisms. We review examples of such conditions below.

1. Consistency with regulator-approved resource plans

An integrated resource planning process identifies the public's needs and the investment options that may satisfy them cost-effectively. Once the plan has been approved, a commission will be more inclined to grant some form of pre-approval to projects that are consistent with the terms of the plan. Conversely, denying pre-approval to projects that are inconsistent with the plan properly leaves project risk with the utility.

2. Cost cap

Imposing a cost cap on the pre-approved amount limits the economic risk to ratepayers and shifts that risk to the utility. Similarly, some states have permitted the inclusion of CWIP or accelerated cost recovery only up to a defined dollar cap.[35] A cap can be set as a dollar amount or as a percentage of forecasted costs.

[35] *See*, *e.g.*, *Ariz. Pub. Serv. Co.*, Decision No. 54247, at 19-20 (Ariz. Corp. Comm'n 1984). In this case, the utility was rapidly accruing CWIP because of its construction of the Palo Verde nuclear power plant. The Commission allowed

While a cap encourages utility cost-control measures, it can also have unintended and potentially adverse consequences. For example, a strict cap can induce the utility to cut corners or even abandon a project prematurely. Some regulators avoid this problem by making the cap a floor — *i.e.*, approving a cost level as prudent and leaving the utility free to argue for recovery of additional expenditures, if prudent. To protect ratepayers, the regulator might subject above-cap costs to some form of heightened scrutiny or require an enhanced demonstration of need and prudence before approving recovery.

3. Project must be near completion

Since pre-approval provides some cost recovery certainty, commissions may seek to ensure ratepayer benefits by implementing corresponding performance conditions. One approach is to limit pre-approval to projects that have a high probability of completion. An indicator of likely success is whether the project has met certain milestones.

The Oklahoma Commission authorized a rider for early recovery of the costs of a wind farm, providing a completion condition was met.[36] Similarly, a rider might be authorized only where the project will likely enter service within a short period of time (*e.g.*, six months). Or the commission (or the legislature) could require that a specified percentage of the costs of the project be incurred before the early recovery mechanism takes effect.[37]

4. Regulatory "oversight" of project activities

Where early cost recovery is authorized, the commission can keep track of the course of construction by requiring the utility to provide detailed status reports. The Florida Commission, by rule, requires utilities seeking current cost recovery for nuclear or IGCC plants to submit periodic reports on:

(a) the feasibility of finishing the plant;

(b) the technology selected by the utility including, but not limited to, a review of the technology and the factors leading to its selection;

(c) contracts executed in excess of $1 million, including the nature and scope of the work, the dollar value and term of the contract, the method of vendor

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approximately $200 million of the utility's $600 million CWIP balance to go into rate base, before the plant was complete, to address the utility's cash-flow deficiency, and also to soften the rate increases that would occur if the entirety of the nuclear plant entered in rate base at one time.

[36] The condition was that at least 73 of the 80 contemplated required turbines had to be operational. *See In re Chermac Energy Corp.*, Order No. 524078, Nos. PUD 2005-00059, PUD 2005-00177 (Okla. Corp. Comm'n 2006).

[37] *See, e.g.*, Ohio Rev. Code. Ann. § 4909.15 (allowing the commission to approve CWIP in rate base if the plant is at least 75 percent complete, and the investment represents a defined percentage of the rate base).

selection, the identity and affiliation of the vendor, and current status of the contract;

(d) monthly expenditures incurred for major tasks performed within site selection, pre-construction and construction categories, and annual variance explanations, comparing the current and prior period to the most recent projections for those periods filed with the Commission; and

(e) monthly expenditures for major tasks performed within site selection, preconstruction and construction categories.[38]

5. Limit approval to specified investments

Some capital investments, such as pollution control equipment, are mandated by law. Where required by statute, and where no additional evidentiary showing is needed, the commission might grant pre-approval of cost recovery (at least up to a cap) or take other actions to reduce the risk of non-recovery.[39]

For example, Indiana's Environmental Compliance Plan Pre-Approval Act, Ind. Code § 8-1-27, allows the Commission to limit challenges to Commission-approved environmental compliance costs to issues of fraud, concealment or gross mismanagement. The Commission will grant pre-approval for these costs if they are part of an Environmental Compliance Plan that will "constitute[] a reasonable and least cost strategy over the life of the investment consistent with providing reliable, efficient and economical electric service."[40]

6. Preliminary project investments only

A commission (or legislature) may wish to encourage preliminary steps towards undertaking a capital project, while declining to commit ratepayer dollars to the full cost of the project before the completion of needed planning, investigation or engineering activities.

In 2008, the North Carolina Legislature enacted a statute providing for early recovery of so-called "project development" costs for potential nuclear power plants.[41] The legislation includes

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[38] Fla. Admin. Code Ann. r. 25-6.0423(5)(c)(5), (8)(b)-(e).

[39] These cases arise most frequently where a state requires the utility to file a pollution control or environmental compliance plan for commission review and approval. Such plans may include additions to infrastructure, as well as retrofits to existing infrastructure. Other examples are scrubbers on generators, leak detection programs for gas utilities, and treatment plants for water utilities, and post-9/11 security enhancements.

[40] The Florida Legislature enacted Section 366.93, Fla. Stat. § 366.93, providing early cost recovery for the siting, design, licensing, and construction of nuclear and integrated gasification combined cycle power plants.

[41] N.C. Gen. Stat. § 62-110.7 (effective January 2, 2008) states:

> § 62-110.7. Project development cost review for a nuclear facility.
>
> (a) For purposes of this section, "project development costs" mean all capital costs associated with a potential nuclear electric generating facility incurred before (i) issuance of a certificate under G.S. 62-110.1 for a facility

two conditions on recovery. First, the costs must be for preliminary activities in connection with a nuclear generating plant. Second, the costs must be incurred before certain dates or events have occurred. The statute also contains a non-exclusive list of examples of the types of activities that are included in the term "preliminary activities."[42]

The North Carolina Commission has approved Duke Power Company's requests for early approval of nuclear power development costs. The Commission approved a cost cap consistent with Duke's estimate of the costs it would incur in the relevant year for development efforts recoverable under the statute.[43] The Commission found that if Duke did not incur those expenses now, then long-lead time items needed to build the facility might not be available to Duke in a timely manner.[44]

7. Reduced ROE to reflect risk reduction

Some commissions have allowed early recovery where the utility's weakened financial condition would otherwise preclude projected completion or trigger certain specific adverse financial events, such as a bond rating reduction below investment grade, reduction in interest coverage ratios below a specified level, or insufficient cash flow to ensure adequate service.[45] In other cases, early recovery has been denied.[46] Any approval based on claimed financial weaknesses should be based on specific evidentiary showings, including the likelihood that the requested relief will alleviate the utility's financial problems.

Because pre-approvals reduce utility risk, commissions awarding some form of pre-approval cost recovery should consider whether a corresponding reduction in the utility's authorized return on equity is appropriate.

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located in North Carolina or (ii) issuance of a certificate by the host state for an out-of-state facility to serve North Carolina retail customers, including, without limitation, the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs.

[42] As set out in the North Carolina statute, these can include the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, and initial site preparation costs, among others.

[43] These include: review by, and responses to, the NRC, purchases of land and rights-of-way, site preparations, project planning and engineering, and payments to fabricators to hold the utility's place in line for obtaining long-lead-time material and equipment such as reactor coolant pumps, containment vessel, reactor pressure vessel, steam generators, control rod drive mechanisms, and condenser circulating water piping.

[44] *In re Duke Power Co*., 256 P.U.R.4th 215 (N.C. Utils. Comm'n 2007).

[45] In *Sierra Pacific Power Co.,* Docket No. 959, Order issued July 21, 1977, the Nevada Commission allowed SPCC to include CWIP associated with the Valmy generation project in rate base once the capital costs exceeded $27.7 million, in part on the theory that cash earnings would be higher quality earnings for the utility. In 1979, the Nevada Commission authorized SPPC to include $ 31.966 million of Valmy 1 and any common facilities CWIP in to rate base. *In re Nev. Power Co.*, No. 06-06051, 2007 Nev. PUC LEXIS 22, at *114-15 n.12 (Nev. Pub. Serv. Comm'n 2007).

[46] See Affiliated Interest Agreements (Pennsylvania Commission denies request for early approval and cost recovery where the estimated expenditure was no more than 15% of the total capital expenditures of the utility applicants over the next ten years).

F. Criteria for Selecting among Pre-Approval Mechanism Options

As shown, a regulator considering some form of pre-approval commitment has many options. Indeed, even where the state legislature has already made certain choices, there will likely remain room for commission discretion.[47] We here offer criteria that a regulator may consider applying in making choices among competing options. The application of these criteria requires the regulator to match subjective concepts to the facts at hand.[48]

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[47] *E.g.*, Fla. Stat. § 366.93 (providing for cost recovery for certain changes relating to nuclear or IGCC plants, but leaving PSC free to "establish … cost recovery mechanisms.")

[48] The criteria are an outgrowth of questions developed by James Bonbright, and set forth in Principles of Public Utility Rates. Bonbright, *supra*, at 152-58, articulated five criteria for judging the appropriateness of a utility's rate:

1. The capital-attraction criterion: "[P]rinciples of rate control are best designed to permit well-managed, soundly financed public utility companies to attract needed capital."
2. The management-efficiency criterion: "[D]esigned, not just to enable a company to attract capital but also to reward efficiency and discourage inefficiency of management.
3. The rate-level stability criterion: "[W]hether or not an attempt to secure cyclical flexibility in the right direction is desirable and feasible remains a highly controversial question."
4. The consumer-rationing criterion: "[E]ach rate should be designed to encourage all consumption for which consumers are ready to pay escapable, marginal costs, and so as to deter any consumption for which consumers are not prepared to pay these costs."
5. The fairness-to-investors criterion: "Market acceptability may thus be thought to become, at one and the same time, the test of fairness and of corporate financial need….But…the principle is subject to serious qualifications…."

Bonbright (*supra*, at viii) noted the impossibility of meeting all five criteria at one time with any on rate-making approach:

> Reasonable public utility rates, like reasonable prices in general, are rates designed to perform with reasonable effectiveness multiple functions as instruments of social control. But a system of rates that would be best designed to perform any one of these functions is unlikely also to be the best that could be designed to perform any of the others. Hence, to a substantial extent, sound ratemaking policy is a policy of reasonable compromise among partly conflicting objectives.

Commissions and legislatures have added to Bonbright's list. *See, e.g.*, Michael Dworkin et al., *The Environmental Duties of Public Utility Commissions*, 18 Pace Envtl. L. Rev. 325 (2001). And *see* 2 Alfred E. Kahn, The Economics of Regulation xii (1971) (stating a regulatory goal of encouraging a utility to "engage in product or service innovation with an intensity" the same as its pursuit of efficiency).

1. Utility effectiveness criteria

(a) **Alignment of public and private interest:** The regulator should assess whether a proposed commitment will align the utility's commercial interest with the public interest. The utility must satisfy the multiple customer needs of reliable, safe and timely service at reasonable cost, while earning a reasonable return. Whatever pre-approvals are granted by the Commission should provide clear signals, in the form of both rewards and penalties, and should avoid conflicting messages. The regulator should consider whether pre-approval will promote broader objectives, such as construction of renewable resources.

(b) **Efficient utility management:** The regulator should consider whether granting the incentive will promote efficient utility management and discourage inefficient management. Will regulatory reduction of shareholder risk, through advance approval, reduce management's incentive to act cost-effectively? Conversely, if the regulator refrains from commitment, will the utility choose shorter-term, smaller, or more conventional projects over possibly more efficient but larger projects that involve greater risk?

(c) **Alignment of responsibility and risk:** Does the regulatory decision allocate responsibilities, risks, and benefits logically? Does it align decisional responsibility with management knowledge? Does the decision involve regulatory approval of a detailed, technical solution where the detailed regulatory knowledge is locked within utility management? Do the regulatory conditions involve the regulators so deeply in project management as to relieve the utility's project management experts of responsibility and risk? To the extent regulatory approval is conditioned on the commission oversight of the construction process, does the commission have the requisite technical expertise?

(d) **Sound planning and timely investment:** Will the decision encourage sound planning and timely investment? Some argue that the traditional regulatory practice of giving the utility no cost assurance until a plant is complete causes conservatism, lack of innovation, reliance on "what everyone else is doing." Others argue that the traditional practice, which includes not only no cost assurance but also no cost expectations, encourages a utility to overspend, because if the project cost is large enough, a "too big to fail" situation will pressure regulators to disallow no costs. Still others argue that without cost assurance upfront, the utility will tend to "wait until the last minute" to propose a project, in the hopes that the surrounding urgency will induce the regulator to approve the project for cost recovery without examining alternatives. All these tendencies, if the facts support them, deserve attention as regulators design approval methods. A useful approach is the integrated resource plan, approved well in advance of a project request, containing general guidelines about need, appropriate resources, and timing. A process allowing pre-authorization of a project consistent with a plan ensures two opportunities – the first one conceptual, the second one practical, to ensure utility effectiveness.

(e) **Access to capital:** How does the regulatory decision affect the utility's ability to attract necessary capital on reasonable terms? If the regulatory has refrained from promising cost recovery, will capital be available on reasonable terms? Conversely, if the commission has promised cost recovery, has the commission accurately reflected that risk reduction in the authorized return on equity?

(f) **Pre-approvals versus utility errors:** Is the request for a pre-construction commitment the result of utility errors or inappropriate delays? In other words, to what extent is the utility itself at fault for the need to consider a pre-approval commitment? Would granting the approval create a "moral dilemma" by rewarding (and encouraging for the future) sub-optimal practices?

2. Regulatory effectiveness criteria

(a) **Clarity:** "Pre-approval" encompasses a range of regulatory commitments. Choose your metaphor – palette of colors, symphony of sounds, tool chest of tools, algebraic equations with multiple variables – the regulator has choices about the level of certainty, the timing of decision, the depth of detail, and the intensity of oversight. Common to all the options is clarity: A regulatory commitment should be express as to its limits, thereby avoiding any later claim that the commission has "implicitly" approved recovery of subsequently-incurred costs.

(b) **Information and expertise:** A regulatory commitment can be no more detailed than the regulator's mastery of the details. In reaching a decision, the regulator should have access to information and expertise, including delaying or qualifying a decision, where feasible, until needed facts are available. Data concerns are increasingly prevalent as utilities operating in competitive markers have sought protection from public disclosure of cost data and other key information concerning proposed capital projects.

(c) **Timing affects information:** Pre-approvals are, by definition, approvals that precede knowledge about outcomes. In response to that informational gap, the regulator must focus its limited resources on a myriad of hypothetical concerns. Opponents of pre-approval object that this focus on hypotheticals produces less informed decisions than after-the-fact reviews: knowing the events that precipitated excess costs, the regulator can better assess management's handling of those facts. An argument against after-the-fact review is the risk that the regulator improperly imputes to utility management knowledge of facts that were not known when management made decisions.

(d) **Do precedents and consistency matter?** Regulatory statutes do not require identical, or even comparable, treatment of different projects. Provided the commission has a rational, evidentiary basis for each decision, treatments can vary, generally in accordance with material factual differences. But in sending signals to an investment community considering financing utility projects across four industries (electricity, gas, telecommunications, water), consistency has a value. The importance of consistency should be weighed against the need to address individual projects on the basis of the specific facts that are presented. Amplifying this tendency are legislative enactments that single out a particular industry, or even a particular expenditure, for pre-approval opportunity.[49]

(e) **Post-approval oversight:** How deeply does the regulatory commitment involve the commission in project oversight? Is the commitment an efficient use of commission resources? Does

[49] *See* earlier discussions of Fla. Admin. Code Ann. r. 25-6.0423; and N.C. Gen. Stat. § 62-110.7.

the commission possess the technical resources to monitor and enforce its conditions? Will the commission need to curtail other regulatory activities to free up the necessary resources? Will the utility cooperate in the commission's efforts to obtain the necessary resources?

3. Rates criteria

(a) **Economic efficiency:** Prices that reflect the cost of consumption induce consumer and producer behavior that maximizes benefits for the economy. In choosing the timing and type of pre-approval, and the method of cost recovery, regulators should seek rate solutions that send proper price signals.

(b) **Gradualism:** Sudden jumps in rates for a commodity product produced through large fixed costs with long lives make customers skeptical of the sellers and the regulators. Methods of pre-approval and cost recovery that give weight to gradualism without distorting economic efficiency deserve regulatory attention.

(c) **Investor risk:** As discussed throughout this paper, pre-approval is about identifying and allocating risk of uneconomic results. More sophisticated but clearer methods and procedures for calibrating the proper debt-equity ratios and authorized returns on equity for various types of pre-approvals may be necessary. This is an area deserving additional research.

(d) **Intergenerational equity:** Will the regulatory decision create a cost-benefit mismatch among generations of ratepayers? Early cost recovery requires customers taking service during the period of construction work in progress to pay for plant investments, the use of which they may never enjoy, or will enjoy for only part of the project's life. It also means that customers paying towards the investment during the construction period may pay more for the plant than customers who paid nothing during the construction, even if they are on the system for the same length of time. Yet this problem is not unique. A city collects taxes from today's parents for buildings that will benefit future students. Taxpayers pay today for mass transit projects that will benefit tomorrow's riders. Intergenerational equity need not be a requirement for each project if there is intergenerational sharing overall.

III. Application of the Framework to Hypothetical Examples

The criteria and other considerations addressed in Sections I and II are summarized in a chart entitled, "Pre-Approval: Options and Considerations," which is appended to this paper.

Here we illustrate how these criteria/considerations can be applied in the context of three hypothetical situations that may come before a state commission. We do not examine these examples to explain how they should be resolved. Our purpose is to identify the types of questions and considerations that may be weighed in deciding whether to provide some form of pre-approval, including cost recovery authorization. Specific answers will depend on the specific facts at issue and the weight commissions give to different considerations in the particular circumstances.

A. Example #1: A relatively small water utility seeks pre-approvals in connection with a relatively large — but otherwise routine — investment

Assume that a small water utility is required by statute or regulation to undertake a relatively large capital investment. The investment concerns a program that, while substantial for the utility, is routine for the industry. An example could be the development of a leak detection and mitigation program, which may include the removal and repair or replacement of a large portion of the utility's underground plant. The utility asserts that it needs upfront assurances that would not be available under the traditional approach of cost recovery after-the-fact.

The small utility might request two kinds of pre-approvals: one involving cost recovery and one involving approval without addressing cost recovery. An example of the former would be the utility arguing that it has no access to the level of financing required to complete the project, and that it cannot proceed absent assurance of contemporaneous cost recovery. An example of the latter would be seeking the regulator's blessing of the proposed program as a prudent course of action. Given the commission's statutory obligation to support any decision with substantial evidence, it must require that the utility document the specific challenges. If a utility wants advance approval, it must demonstrate that the program is the best option available. Identifying a statutory mandate, state or federal, would serve this purpose if the mandate specifies the solution.

The commission will need to consider whether conditions should be imposed on pre-approval, including these questions:

- Should the pre-approval, if granted, be contingent on the receipt of periodic progress reports?
- Should any cost recovery be capped at no more than the estimated price tag for the program? Should that cap be a hard cap, or one that the commission can raise or lower depending on future facts?
- Does the small utility have the technical resources sufficient to undertake a major capital project? If not, should the commission condition pre-approval on the utility procuring engineering and project management assistance? To what extent should or must the commission become involved in monitoring project progress? [50]
- Will a pre-approval aimed at shifting regulatory risks involve other associated adjustments? For example, should the utility's return on equity be adjusted if assurances are provided that result in changes in the utility's risk profile?

Each of these questions have a common theme: cost-benefit analysis. The commission should be satisfied that the risks associated with providing approvals in advance — including the constraints on the commission's ability to take action after the fact because of approvals granted

[50] To the extent the commission is involved in monitoring progress, the commission staff or an outside consultant will have to examine the progress of the project, measure it against whatever standards are available, and help the commission render a judgment as to whether the job is being done adequately.

before-the-fact — are outweighed by the benefits derived from the timely implementation of the infrastructure upgrade. Then the commission should ensure that those benefits arrive.

B. Example # 2: A utility with reasonable access to capital seeks pre-approvals in connection with a routine investment

In this example, the utility has ready access to capital on reasonable terms, and the needed capital project presents few new or unusual challenges. Unlike the first example, there is no reasonable claim that, absent pre-approvals, the project cannot be financed. As in the first example, the project will provide substantial benefits for customers, assuming efficient implementation.

The utility here seeks the same two types of pre-approvals: one that directly involves cost recovery and one that does not. For the pre-approval that does not directly involve cost recovery, the utility must demonstrate that its selected project is the best feasible option.

As to pre-approval of cost recovery, the utility's access to capital requires assessment of at least the following issues:

- The utility can make the investment without a pre-approval commitment. One question is whether pre-approval of cost recovery will lower the cost of capital while having no effect on management's incentive to act efficiently.

- The commission can address the efficiency issue directly by considering whether any advance authorization should be capped at the estimated cost of the project and, if so, whether the cap is hard (no later adjustments) or soft (later adjustments, up or down, possible based on fact changes). If the authorization is entirely "upside" for the utility, it may lack sufficient incentive to manage the project efficiently.

- As in the first example, the commission might consider conditioning cost recovery commitments on the submission of periodic project status reports. Continued regulatory supervision should encourage management to conduct construction of the project in a cost-efficient manner. Moreover, regulatory oversight can readily catch and prevent glaring inefficiencies and errors, especially as concerns routine infrastructure repair and replacement projects.

- The commission should consider why a utility with access to capital needs pre-approval of cost recovery. Is the utility seeking pre-approval to rectify prior management neglect? Was this project, for example, something that should have been pursued several years ago? Is early approval and cost recovery in such situations merely a reward to a utility that may have unreasonably delayed making necessary repairs and improvements to its system? To the extent there is evidence of management imprudence, the commission might consider combining early approval and cost recovery with reductions to the allowed return on equity to reflect (a) the lower risk to the utility where its costs are approved or recovered before project completion, as well as (b) management imprudence in delaying necessary investments.

C. Example #3: A utility seeks pre-approvals in connection with a risky and discretionary investment intended to serve its customers

In this example, a utility seeks pre-approvals in connection with a potentially risky capital project, such as a nuclear plant or "clean coal" facility that is needed to meet load (but for which there are other more conventional, proven technology options). The utility might be pursuing this option in a partnership, thereby spreading the risk.[51] Given the uncertain nature of project costs and timelines, it will be difficult for the commission to marshal sufficient facts to support upfront cost recovery. And the request for approval might not involve cost recovery directly, but might still have substantial cost recovery implications (*e.g.*, a determination that the decision to build a nuclear plant instead of pursuing other options is "prudent"), as well as daunting cost recovery requests (*e.g.*, recovery of planning costs, or costs to maintain the project as an option that could be pursued on a timely basis).

If the commission believes the utility would pursue this risky investment absent some form of pre-approval, there is not a clear basis for commission assistance. But if the project could benefit ratepayers yet is too uncertain for the utility to bet its own money, the commission faces a hard question: To what extent should it devote ratepayer money to experiments where, in the absence of ratepayer commitment, the experiments will not occur? To insist on never betting ratepayer money is to risk continued dependence on yesterday's technology. While new technologies can receive stimuli from Congressional authorizations, universities and ratepayer-funded joint research organizations like the Electric Power Research Institute, the involvement of local utilities and their state commissions can also influence technological development. Still, in these situations, the commission can insist that the utility first seek private sources.[52]

A commission may be asked to bless a potentially risky option as a "prudent" choice under the circumstances. This determination will involve both evidentiary showings and policy considerations. The resources identified as potential means to meet forecasted electricity needs for electricity, including energy efficiency, are all characterized by some level of uncertainty. The public may or may not prefer to take on the uncertainties of future carbon mitigation costs, generation construction cost overruns, safety and health consequences, and other risks affecting nuclear and IGCC generation, rather than the uncertainties as to the extent of achievable energy efficiency, or cost-competitive renewable power. Either way, and absent express intervention by the legislature, in addressing a pre-approval proposal, the commission will have the responsibility to make a policy call.[53]

[51] On the regulatory treatment of joint venture investments in demonstration projects, see S. Hempling, *Joint Demonstration Projects: Options for Regulatory Treatment*, 21 Electricity J. 30, 30-40 (2008).

[52] The mere fact that such projects are estimated to have very high costs does not necessarily render them incapable of attracting private capital. Paul D. Phillips et al., *Financing the Alaskan Project: The Experience at SOHIO*, 8 Fin. Mgmt. 7, 7-16 (1979).

[53] Analysts have observed the somewhat symbiotic relationship at issue in the context of large and risky capital projects, highlighting the need for ratepayer support of such projects in order for the financial markets to make investments in such technologies. *See, e.g.*, Ellen Lapson, Managing Director, Utilities, Power & Gas, FitchRatings, Construction of Coal-Fired Generation: Evaluating the Utility Credit Implications, Presentation Before the National Association of Regulatory Utility Commissioners (July 17, 2007) (presentation available at

Depending upon the evidence, a regulator could determine that the decision to go forward with an expensive and risky generation option was not the product of sound planning, and that the plant was not needed to serve the public. Utilities proposing nuclear, IGCC, and similar plants will presumably have the expertise, staff, and external resources needed to carry out forecasting, construction management, commissioning, and operation of the plants. Compared to the huge firms involved in nuclear and IGCC plant development, regulators will lack sufficient resources to make the myriad decisions involved in the development process. Thus, additional (internal and external) resources may be needed to conduct extensive reviews of such utility proposals. Of course, this concern is not unique to pre-approvals and would be equally applicable present under the traditional approach.

Even where the commission restricts early approval and cost recovery to pre-construction costs, or to costs incurred within a single year, such decisions must be drafted carefully to avoid to constraining subsequent decision-making flexibility. If, for example, the commission is limiting recovery to "preliminary" or "pre-construction" costs, it must define these terms tightly. For emphasis, the commission could consider including in its approval order a specific definition and/or an express dollar amount.

Unlike routine infrastructure replacements, nuclear and IGCC projects (for example) are enormously complicated undertakings, dealing with technologies that may still be in experimental phases. In such circumstances, the commission must retain the flexibility to address changing conditions. This can be accomplished in part by requiring periodic reports from the utility and by retaining staff with sufficient technical expertise to review them and to advise the regulator. However, and as mentioned earlier, care should be taken to make clear that the provision and review of reports does not leave the commission in the role of supervising day-to-day project construction activities.

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http://www.narucmeetings.org/Presentations/Construction%20of%20Coal-Fired%20Generation.ppt); Michael Degernes, Aberdeen Asset Management, Integrated Gasification Combined Cycle: Financing the Next Generation of Coal Plants, Presentation Before the Oregon Advanced Coal Workshop (May 24, 2006) (presentation available at http://www.oregon.gov/PUC/meetings/pmemos/2006/052406/Degernes.pdf); Kevin Genieser, Managing Director, Morgan Stanley, Putting Capital to Work to Achieve CO_2 Reduction¸ Presentation before the Electric Power Research Institute (Aug. 7, 2007) (presentation available at http://mydocs.epri.com/docs/SummerSeminar07/Presentations/EPRI_Summer_Seminar_07_Geneiser.pdf); and Ari Kagan, Director, Global Power Group, FitchRatings, Presentation Before the National Association of Regulatory Utility Commissioners Energy Resources and the Environment Committee: Credit Rating: Issues Associated with Nuclear Investment (July 27, 2005) (presentation available at http://www.narucmeetings.org/Presentations/ERE_Kagan_s05.pdf).

IV. Conclusions: Recommendations for Regulators

This paper has examined options a regulator can consider when faced with a "pre-approval" request — *i.e.*, an upfront request for approval of a utility's proposed course of conduct or for rate recovery of the costs that it plans to incur. The purpose of the paper has not simply been to provide a catalogue or description of potential options, though such a listing can be quite useful. The larger purpose has been to identify the considerations that the regulator should take into account before moving forward with any form of in-advance – rather than after-the-fact — approval of utility actions or costs.

The advice presented in this paper can be summarized as follows:

Where empowered to do so, the regulator can consider breaking from the traditional approach to rate recovery and shifting toward the provision of some in-advance security to the utility. That security can take many forms, including rulings that an option is prudent, that pre-construction costs can be recovered in rates, or that some of the costs to be incurred in constructing a project can be included in rates, on either a contemporaneous or post-completion basis. Any of these approaches involve some upfront shifting, from regulated utilities to ratepayers, of the risks associated with implementing a major capital project. Thus, in considering such approaches, the regulator should ensure that:

- Any pre-approvals are granted only upon a supported showing that regulatory action will benefit customers.

- Regulatory actions are based on full review of the relevant facts. For example, if a utility seeks the commission's blessing that a particular project is "prudent," require the applicant to explain why other options were rejected (and not simply why the applicant's option is appropriate).

- Whatever regulatory action is taken is appropriately limited or conditioned. Approval of an option as a "prudent" choice is not the same thing as approving the inclusion in rates of whatever dollars are expended to pursue it. Approving the recovery of "preliminary" or "planning" costs should not construed as approving the recovery of later-incurred dollars. The key is to be certain that regulator flexibility and discretion are retained to the greatest extent possible.

- The regulator has adequate resources to conduct appropriate reviews of whatever is requested. The commission will need assured access to sufficient technical resources if it is inclined to consider the request of a utility seeking, for example, a determination that building a new nuclear plant is a "prudent" response to the need for new capacity.

- Roles remain properly defined. For example, while it may be appropriate to require that a utility provide periodic reports on the progress of a construction project, the regulator's oversight should not leave it as the party with responsibility for managing the project.

- Consideration is given to offsetting adjustments. If pre-approval will reduce the utility's going-forward risk profile, consider whether an adjustment to the utility's return on equity should be ordered in connection with whatever pre-approval is granted.

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Pre-Approval: Options and Considerations

For each proposed action:

What utility action is being proposed?

- Forecast customer requirements
- Incur specific pre-commitment costs
- Commit to a project and initiate construction
- Continue construction
- Change project plan
- Abandon project

What are possible regulatory commitments?

- Approve for purposes other than cost recovery (e.g., financing, siting)
  - What are the purposes of these regulatory actions?
  - Does an approval action constrain the commission's future recovery decisions?
- Approve for purposes of cost recovery, with varying certainty
- Approve deferral of costs for later consideration

When might a regulator make a commitment?

- Before utility commits to any costs
- At one or more points in time during construction
- After the project has entered commercial operation

At what points in time, and over what time period, might cost recovery occur?

- As incurred (monthly)
- As incurred (annually)
- Upon commercial operation

What cost recovery devices are available?

- CWIP
- Riders, surcharges, and "single-issue" rate increases
- Formula rates
- Securitization

What conditions might the commission impose?

- Consistency with regulator-approved resource plan
- Cost cap
- Project must be near completion
- Regulatory oversight of project activities
- Limit approval to specified investments
- Preliminary project investments only
- Reduced ROE to reflect risk reduction

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Figure 2

Pre-Approval: Options and Considerations

Utility Effectiveness

- Alignment of public and private interest: Is the utility's interest aligned with the public interest in all relevant respects?
- Efficient utility management: Will the proposed regulatory action (or inaction) add (or subtract) certainty; to what extent, if any, will the utility have less incentive to act cost- effectively?
- Alignment of responsibility and risk: Does the approval allocate responsibilities, risks and benefits logically?
- Sound planning and timely investment: Will the decision encourage sound planning and timely investment?
- Access to capital: Will the decision allow the utility to attract necessary capital on reasonable terms?
- Pre-approvals versus utility errors: Would granting the approval create a "moral dilemma" by rewarding (and encouraging for the future) suboptimal practices?

Regulatory Effectiveness

- Clarity: Is the regulatory commitment express as to its limits, thereby avoiding any later claim that the commission has implicitly approved recovery of subsequently-incurred costs?
- Information and expertise: Does the regulator have effective access to the information and expertise necessary to make an appropriate decision?
- Timing affects information: To what extent does a pre-approval require the regulator to focus on hypotheticals and produce decisions based on imperfect information?
- Precedents and consistency: Will the regulatory decision create a precedent favoring a particular type of action and disfavoring others?
- Post-approval oversight: Does the regulatory action make efficient use of commission resources?

Rates

- Economic efficiency: What rate solutions will send proper price signals?
- Gradualism: Does the decision avoid unnecessary jumps in rate levels?
- Intergenerational equity: Will the regulatory decision create a cost- benefit mismatch among generations of ratepayers?

General Concerns

- Has the utility demonstrated that a pre-approval will benefit customers?
- Is the decision based on a full review of relevant facts?
- Is the regulatory action appropriately limited or conditioned?
- Does the regulator have adequate resources to conduct appropriate reviews of whatever is requested?
- Are the roles of the utilities and the regulator properly defined?
- Are there any offsetting adjustments that should be made?

-