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Inquiry Into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities

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CONFERENCE COMMENCED (May 16, 2025, 9:00 a.m.)

MS. HEALY: Good morning, everyone. This is a Commission-initiated inquiry into performance-based regulation of investor-owned transmission and distribution utilities. This is docket number 2025-00107. I want to first of all thank you all for taking time out of your schedules to participate in today's workshop. Stakeholder input is very important in this process, and we're hoping that people will not be shy about speaking up and sharing their views. This workshop was noticed in an April 30, 2025 Notice of Inquiry. I'm Nora Healy. I'm the presiding officer in the case. I know that Commissioner Gilbert is on Teams and -- oh, and Commissioner Scully is on Teams as well, and Chair Bartlett may join at some point. To my right is Derek Davidson. To my left is Michael Simmons and Ethan Grumstrup who are the staff assigned to this case. And as -- today, we also have with us Christensen -- from Christensen Associates Energy Consulting on Teams, we have Nick Crowley. And, Nick, I think your camera's on. That's great. And, Nick, I think Sherry Wang is also with you today. Is that correct?

MS. WANG: Yes.

MR. CROWLEY: Yeah, we have a couple of team members on, the folks who authored the report.

MS. HEALY: Okay. So because I cannot pronounce Andi's last name, I'll let you identify Andi and your other teammate Corey.

MR. CROWLEY: Sure. So we have Sherry, Corey Goodrich, and Andi Romanovs-Malovrh. Andi, give me a thumbs up if I've got that right. All right. So that's the Christensen team.

MS. HEALY: Okay, great. And I know that Corey Goodrich was also listed as an author, but I think we've got the key -- oh, he's on great. Thanks. Apologize. I had to take a little cold medicine this morning. So as indicated in the Notice of Inquiry, the purpose of today's workshop is allow the -- to allow the Commission to collect stakeholder input regarding Christensen's draft report. In particular, the Commission is seeking input related to the goals of PBR set forth in the draft report as well as what specific PBR structures make sense for Maine. I'm not going to take appearances from everyone right now, but if you speak, I'd ask that you please state your name and the entity that you represent before you speak at least the first time. I don't -- we don't -- it doesn't look like we have a ton of people. We also have a sign-in sheet for people that have -- are in the room so that they can provide their identification as well.

We are recording and transcribing and streaming this. The transcript and the slides from Christensen's presentation will be posted in the docket. The process for today's workshop is, again, people that are here in person, please sign the sign-in sheet, and the workshop's going to begin with a presentation by Christensen related to the draft report. That draft report was attached to the Notice of Inquiry. We ask that you generally hold your questions and comments until after Christensen's gone through their presentation, and then we'll be opening up the workshop to discussion. And, again, we certainly encourage a robust discussion. We'll -- if -- we'll plan to break around 10:30. And we -- depending on where we're at, we would (indiscernible) 10:30. We will stop at noon.

Following the workshop today, we encourage people to submit written comments regarding the draft report. Those written comments are due on May 30th, 2025. Anyone can submit written comments. You don't need to have attended the workshop to submit them. Following the submission of those comments, the Commission and Christensen will review and consider them. Christensen will finalize its report and add recommendations to its report. The Commission anticipates submitting the report to the legislature, including a transcript of this workshop and any written comments as well.

A couple notes about etiquette. We're not using the meeting chat for this meeting. The transcript will capture the discussion. If you're on Teams and you want to speak, please raise your hand in Teams. If you're in the room and you'd like to speak, make sure you speak directly into the microphone. And, again, if you're going to speak, please state your name and the entity that you represent. Are there any questions before we get started? Okay, great. Michael?

MR. SIMMONS: Do you want to -- is it worth kind of going -- not doing appearances but at least mentioning the organizations that are here just for Christensen --

MS. HEALY: That --

MR. SIMMONS: -- that might be helpful.

MS. HEALY: Sure, let's do that. We'll start with David.

MR. LITTELL: Not appearances. Versant Power.

MS. HEALY: Yeah.

MR. QUALEY: And Richard Qualey also here with David Littell of Bernstein Shur on behalf of Versant Power.

MS. TUGGEY: Carly Tuggey, general Counsel, CMP, and Peter Cohen, VP regulatory.

MS. CHAMBERLIN: Susan Chamberlin, Office of the Public Advocate.

MR. MARSHALL: Yeah, and Brian Marshall for the OPA as well.

MR. BURNES: We have Becca Ferguson and Ian Burnes from Efficiency Maine Trust.

MS. HEALY: And why don't we just -- on Teams, I know we have Commissioners Gilbert and Scully. I do see the representatives of the Governor's Energy Office. Kiera, if you want to introduce yourself, you're welcome to.

MS. REARDON: Yes, thank you, Nora. This is Kiera Reardon with the Governor's Energy Office, and we have a few team members with us today learning: Sy Coffey, Lindsay Gilton, and Kelly Strait.

MS. HEALY: Okay. Is there anyone else on Teams that would like to identify themselves? Okay, then I'm going to turn it over to Nick and Christensen for the presentation. Thank you.

MR. CROWLEY: Thank you, Nora. So let me just make this a full screen. Is everyone able to see this?

MS. HEALY: Yes.

MR. CROWLEY: Great. One note, Nora. I have made a few updates to the slides since the version that I sent you. So I would ask that you hold off on posting this to the docket until after the workshop, and then I'll just send along the current version. Does that work?

MS. HEALY: Yes, it does.

MR. CROWLEY: Great. Okay. So thank you, everyone, for taking the time this morning to discuss performance-based regulation in the state of Maine. What I intend to do in this brief presentation -- the presentation itself is supposed to last about 30 minutes, and then the rest of the time can be spent in discussion. The goal is to, at a high level, present the findings of our report which we produced a few weeks ago and then provide the opportunity for stakeholders to give feedback and thoughts on next steps and things like that. So the report was authored by myself and then the other Christensen folks who are on this call, Sherry, Corey, and Andi, who were instrumental in helping put together the research and the writing of the report. Before we get too far, I would like to spend just a minute talking about our firm and the work that we do just to set the stage about what our background is. So Christensen Associates was formed -- it's a consulting firm that was formed in 1976 here in Madison, Wisconsin. The very beginning of our firm was doing work that has to do with performance-based regulation. That work was productivity analysis, total factor productivity, and we were doing that work in the 1970s and 80s for the U.S. Postal Service and then the telecommunications industry which went under a form of price cap PBR for a while in the 80s and 90s. And then our work evolved into the world of electric and gas utilities, railroads, and oil pipelines. And so the tools of PBR that we'll talk about today are tools that span not just the utility industry but many industries, and our firm has been working in those industries with those tools for many decades. Our work covers, as you can see, total factor productivity, cost benchmarking, performance incentive mechanisms, regulatory framework design. That's the kind of work that we do in the PBR sphere. There are any number of other things that we do with electric and gas utilities outside of PBR, more conventional rate design, cost of service, or cost allocation, cost of capital, things like that. So our firm is -- it's a firm that has an energy practice, and within that energy practice we do a number of different things.

My own background, I'll say briefly, is I've been with the firm for about nine years. Most of my time during that nine years has been spent doing performance-based regulation work in Massachusetts, Alberta, British Columbia, Ontario, Indiana, New Hampshire, and now Maine, as well as some kind of national work in -- before the FERC. So that's my background. Our team is a bunch of really great and smart people who are able to synthesize information from all different jurisdictions and think creatively about, you know, regulatory solutions. So that's the background.

Let's talk about the workshop outline. The first thing to do is to set the stage about why we're here, what is the project background and the purpose of the meeting. Then I'll spend a minute defining performance-based regulation and the two tools, the kind of over-arching categories of tools as we see them, of PBR. Then we'll look at Maine's existing tools and policy goals, we'll talk about PPR tools for consideration in Maine, and then finish with observations and next steps.

So let's briefly talk about the project background. I think most people who are here understand why we're here. We're here to evaluate PBR tools that may be used to regulate investor-owned utilities in the state of Maine. And there's a scope to this work which is to review what has been done elsewhere. That includes other states, but also we've spent quite a bit of time evaluating and looking at regulatory frameworks in other countries, like, for example, Canada and Great Britain and Australia. So we can bring that information to bear on what might be helpful for the state of Maine and then assist the Commission with developing goals and translate those goals into performance-based standards and metrics and then identify emerging regulatory mechanisms that would help align utility performance with these state policies.

So that's the scope of work and what we hope to convey in our report as well as in our discussion today. What we want to do is just present what we've got in that report, and then a critical part of the meeting today is to hear feedback from stakeholders. I know sometimes it can be -- you know, I've given quite a few stakeholder engagement meeting presentations, and there's -- there always seems to be hesitation with voicing opinions or giving thoughts. And I would encourage you to do away with that hesitation because this report, if you've read the report, you can see that there are placeholders which says to be finalized after stakeholder input. And if -- you know, it's incredibly helpful for us to provide recommendations that are helpful for Maine if we hear what people in Maine and the different stakeholder groups in

Maine think about what works or what is needed in the state. So please, either today in this meeting or in subsequent written feedback, it's very helpful to hear your thoughts.

So let's move into kind of the real meat of the presentation which is define -- you know, getting into performance-based regulation, defining what it is that we're really looking at. So I think, from hearing the introductions of folks around the table and also who are in various places on Teams, it sounds like there -- most of the folks here have pretty good experience with the way that regulation works in the utility industry and especially in Maine. But if there are any people on the call who are maybe less familiar, I'll take a minute just to set the table. I think the best way to talk about alternative regulation is first to define what traditional regulation is and just say at a high level what that looks like. So I'll do that briefly. Traditional regulation -- under traditional regulation, what happens is electric and gas utilities, they have occasional rate applications or rate cases where they put together an accounting of all of their costs to determine what's called a revenue requirement. That revenue requirement is then allocated across customer classes and used -- and a certain kind of mechanism called the cost of service study is used to inform rate design for all the customers on its system. Rates are set through a proceeding that is mediated by the regulator, and different stakeholder groups have the ability to provide intervening input or testimony. And then usually there's direct testimony and then rebuttal testimony, and then rates are established by the Commission at the end of that rate application. And then the utility is able to operate with those rates until it decides to file its next rate application.

So that's traditional regulation, and alternative regulation is really anything that deviates from that. And so it's a really broad umbrella. And that's what the figure on this slide is trying to depict is that there's all these different what I would call tools that deviate from alternative -- that deviate from traditional regulation. Some of these alternative regulation tools we would consider to be performance-based regulation tools and some of them wouldn't be. So if you look at this figure, the items that are in the yellow portion of the diagram are alternative regulation but not necessarily performance-based regulations. So, for example, earnings sharing mechanisms, that's something that isn't defined under traditional regulation as I just described it, but it also doesn't improve the incentives of the utility to become more, for example, efficient because it actually reduces efficiency incentives for the utility. So alternative regulation and performance regulation, they're not synonyms. What is performance-based regulation? Really it's a subset of alternative regulation that focuses on incentives, and I'll talk a little bit more about what that means in the next slide. But as a result of that, performance-based regulation is also called incentive regulation. So you can see there's a couple of tools that are almost always considered PBR. Those would be price caps, revenue caps, and performance incentive mechanisms which are also known as PIMs. Then there's some tools that you might define as PBR. It kind of depends on how you set up the plan. So multi-year rate plans, in some cases depending on how you set it up, could be a form of PBR or maybe like a light form of PBR. And that actually brings me to maybe the final point before I move on from this slide which is that PBR is not -- despite what this figure shows -- the figure makes it seem like everything is all nice and neat, well defined. There's something you can put in one category that's not in another category, but that's really not the case. PBR is a -- is really a spectrum. The incentives of any regulatory framework lies on some spectrum. And we have a figure in our report that shows that which says there are some forms of traditional regulation, depending on how you kind of set it up, that have fairly good cost efficiency incentives for a utility, for example. Or at least, you know, it could be worse. So I think that's just something to keep in mind. When we talk about PBR, we're not talking about a binary choice between is it PBR or is it not PBR because the line gets blurry.

Let's talk about the fundamental tools of PBR. We view there as -- we view there being two tools of PBR: multi-year rate plans and performance incentive mechanisms. And multi-year rate plans have two categories, kind of two over-arching categories which are forecasted multi-year rate plans where the utility forecasts its required revenues over a period of time, and the other one is index caps where the rates or the revenues are adjusted each year based on something that's not in the control or -- it's not in the control of the utility. But the fundamental principle of multi-year rate plans is that the utility is not able to come back in for a rate application at will. It has made some kind of agreement that it will stay out of a rate case for a period of time, and that could be as short as two years, it could be as long as ten years or, you know, as long as you could imagine. But the typical amount -- the typical length of a multi-year rate plan is something like three to five years depending on how it's set up.

So let's just talk a little bit more about multi-year plans before I move on to PIMs. Multi-year rate plans, the purpose of multi-year rate plans, generally speaking, is to try to incent the utility to produce outputs using the least costly combination of inputs. So if we turn our attention to the figure on this slide, you can see there's a number of inputs that any utility needs in order to produce its outputs. So those inputs include capital O&M, fuel, you can imagine other things in -- within those categories. And then the utility takes those inputs and produces outputs. Those outputs are, you know, energy, customer connections, capacity, and then a lot of other things that are often forgotten which is reliability, different rate programs. There's a huge amount of outputs that are not necessarily billed to customers that the utility provides. So the goal of a multi-year rate plan is to say if we want to get these outputs, let's incent the utility to provide those outputs at the least costly combination of inputs. So that's the goal of multi-year rate plans.

Turning to PIMs or performance incentive mechanisms, now we focus on outputs. The question is, okay, what are the outputs that we want the utility to focus on and how do we get the utility to focus on those outputs. Usually it's by some financial incentives, and we'll talk more about how PIMs work in subsequent slides. So you can see here how we kind of think about these two things. One is we're thinking about the most efficient combination of inputs, and then the other one is how do we efficiently produce outputs. But there are questions and limitations to these approaches. For example, for multi-year rate plans, a common question is, okay, you can imagine a multi-year rate plan that is -- has very strong incentives for the utility to reduce its costs, but we also need to make sure that we're providing such a framework that is feasible to the utility because, really, electric utilities are the backbone of our society and we need to make sure that they're able to produce their outputs and are not under undo stress financially. And then the question with PIMs is what are or what should be the utility's outputs and then how do you measure them. And there's any number of questions, and we'll get to that later.

Spending just one more slide on traditional versus performance-based regulation, thinking about the comparison between the two, generally speaking, traditional regulation is cost based. So the utility, because it's able to file a rate application every -- you know, whenever it deems necessary, costs and revenues end up being closely linked. And that causes there to be relatively lower incentives compared to performance-based regulation. There's also questions about, you know, administrative efficiency and whether the outputs that the consumers are looking for end up being delivered. Under performance-based regulation, the goal is to disconnect revenues and costs in order to provide incentives for the utility to find cost efficiencies. That would be under, like, the multi-year rate plan category of performance-based regulation. And as a result of that approach, you have less frequent rate cases and, ideally, depending on how you set it up, lower administrative burden over time. And then on the PIMs side, you have the incentive to provide enhanced production of certain outputs.

So I suppose -- I know that we have time at the end of the presentation for discussion, but I'll pause because I've gone through a lot here and I'll ask if there's any questions based on what I've discussed so far. Doesn't look like it. Oh.

MS. TUGGEY: This is Carly. I don't have a question, but are we able to get the slides?

MS. HEALY: We're going to file the slides in the docket.

MS. TUGGEY: That's great. They're really great. Thanks.

MS. HEALY: But if you if you want to pull them up on your laptop, you could log into Teams and mute yourself.

MS. TUGGEY: Perfect, yeah.

MS. HEALY: And then you'd at least see them.

MS. TUGGEY: And I was just thinking to share with folks on our team too to help frame things up. Thank you.

MR. CROWLEY: This slide is just depicting what we view as being the status of PBR in the United States. Now, I want to get back to something I said about five minutes ago which is that it is a fuzzy line. We're using a little bit of judgment here in what we would consider to be PBR and not PBR. So someone might look at this map and say like, oh, I disagree with, you know, North Carolina or something, I don't know. But we are aware of different PBR tools in different states that are being used. And so any state that has yellow, for example, is a state that has at least one utility that has at least one PBR tool being used. And so the -- even within the category of the yellow implementation category of states, it can be a lot different state by state. So let me just say one example. So, for example, in the state of Massachusetts National Grid and Eversource both operate under -- well, in the past, they've both operated under a revenue cap plan. Massachusetts Electric, a/k/a National Grid, currently operates under kind of a hybrid plan where their O&M expenses are under a revenue cap but capital-related revenues are more cost of service based. So even within a state you have differences in how PBR is implemented. And then, you know, in California you have these multi-year rate plans that are three or four years long. And that looks a lot different from what we see in Massachusetts. And that looks a lot different from what we see in New York, etc., etc. Now you'll see from this figure that Maine is colored yellow, and we'll talk more about why that is in a minute. But just to preview, if we think back to the two categories of PBR tools, there are multi-year rate plans and there are PIMs. And PIMs are financial incentives to produce certain outputs, and those kinds of outputs include things like reliability, customer service. And so our finding in doing our work is that, because the service quality indicators that both Versant Power and Central Maine Power have are attached to financial penalties, that is considered a PIM. And, therefore, we color Maine yellow in this in this figure.

So I just gave you the preview, but I will move on and say a few things about existing PBR tools in Maine. Actually I'm going to start with the second one because that's what I just referenced which is that both of the investor-owned utilities in Maine have service quality indicators, and in both cases, those service quality indicators are tied to financial incentives where those incentives are penalty-only incentives. So there's a few categories. I think our report has a larger table that kind of goes through the different service quality indicators that our experience -- or that the two utilities operate under. So they're not necessarily the same across both utilities, but both utilities do have SQIs that have a financial incentive tied to them. So that's the PIMs side of PBR.

On the multi-year rate plan side, the distribution utilities in Maine are allowed to file alternative ratemaking plans which span multiple years and could be either forecasted or indexed. So although I think it might be the case, if I'm recalling correctly, and Andi or anyone on in the room can correct me if I'm wrong, but my recollection is that Central Maine Power has a two-year kind of agreement at the moment which --

MR. COHEN: Yeah, this is Peter Cohen from Central Maine Power. I can confirm that.

MR. CROWLEY: Okay, yeah. So that -- it's a -- it's kind of like a mini multi-year rate plan, but it's still -- you know, like I said, it's not like a binary term where it's like, oh, we flipped the switch and suddenly we're in -- within the world of PBR. But our understanding from reading the documentation in Maine is that, you know, just to pick on Central Maine Power, if you wanted to file a rate application that had more years, you could do that. And if you wanted to do kind of an indexed cap or revenue cap or price cap approach, you -- you're allowed to do that. There's no rule as far as I know that means you can't do that. So those are the tools that are available in Maine. Service quality indicators are currently in effect. Multi-year rate plans, you know, there's an example of sort of a -- just a two-year version of a multi-year rate plan, but there's the possibility of utilities voluntarily filing different multi-year rate plans that are different from that two year.

This is the proposed policy goals in Maine, and I think it's useful to look at them because when we're making recommendations, the whole purpose of the investigation into PBR is to say do the state's current rules incent the utilities to pursue business practices that align with these policy goals. So let's just take them one by one, and I would encourage you to focus on this slide when you provide feedback because this will be kind of the basis for what the recommendations are based on. So let's start with number one, promote efficient and cost effective transmission and distribution utility operations. Just as a side note, if I was a PBR planner making a regulatory framework for a state and someone said we want to promote cost effective operations for our utilities, I would say, okay, let's go back to slide five or whatever it was where we were looking at the two tools of PBR. You've got multi-year rate plans and PIMs. I'm thinking the type of tool that does this first policy goal that aims to accomplish this goal is the first one, multi-year rate plans, developing a multi-year rate plan that provides incentives to the utility. Okay, increase planning and preparation for extreme weather events and climate hazards. Promote cost effective and comprehensive responses to outages. Those two are linked in sort of a sense because outages often come from extreme weather events. Increase affordability and customer empowerment and satisfaction. Support achievement of the state's goals for increasing consumption of electricity from renewable resources. I'll just pause here and say if I was looking at those two over-arching tools, multi-year rate plans and PIMs, I would say PIMs are a tool that could aim to achieve this goal. So if you read the report, you can look at -- the state of Hawaii, for example, has renewable connection PIMs that provide rewards for the utility to connect renewable resources to the grid. Advance the state's greenhouse gas emissions and reductions goals. I feel like that sentence is supposed to end with greenhouse gas emissions goals and maybe we need to delete the word established. And advance beneficial electrification. So a lot of these are intermingled, but these are the proposed policy goals. So think about those and whether they seem to align with what you think are the appropriate policy goals for the state of Maine because these are not set in stone and they can be -- you know, it's up for a discussion. That's the whole reason we're here today.

MS. TUGGEY: I know we're supposed to hold questions to the end, Nora, but there's just -- on that one, and you had made specific reference to it as an area to focus for commenting, you prepared that for this slide, correct?

MR. CROWLEY: When you say --

MS. HEALY: -- yeah, if you're asking who prepared that --

MS. TUGGEY: I meant that it's not in the report, correct, the --

MS. HEALY: No, I think the --

MS. TUGGEY: -- find that --

MS. HEALY: -- those goals are reflected in the report --

MS. TUGGEY: They're reflected throughout --

MS. HEALY: Right, right. Yeah. Well, I think there's a -- this same list appears in the report, doesn't it, Nick?

MR. CROWLEY: Gosh, I have to -- I can't confirm that immediately, but I don't know if -- Andi, you have got your hand up.

MR. ROMANOVS-MALOVRH: Yeah, I think they covered them in Section 7.3, and we have the regulatory goals in state of Maine. And I believe they're the exact same ones we have here.

MR. CROWLEY: You're right. Yeah, it's there at page 73, yeah.

MS. TUGGEY: There it is.

MS. HEALY: And since we're just asking a few questions about this, Nick, are these ranked in a particular order or are they sort of unranked and maybe you could just speak to that?

MR. CROWLEY: I would say it -- I would say they are unranked.

MS. HEALY: Thanks.

MR. CROWLEY: But we could rank them if there's an -- you know --

MS. HEALY: I think that's what -- I think that should be a topic of discussion after you're through your presentation but yeah.

MR. CROWLEY: I would personally not feel comfortable ranking them. I would need input from the folks on the call today in order to rank them.

Okay, so now that we know what the options are or what the current state of PBR is in the state of Maine, let's look at some PBR tools for consideration. So this first category is one that's actually not new to Maine. Central Maine Power will be familiar with price and revenue caps. And this, as I understand it, is something that could still be -- either Central Maine Power or Versant Power could currently voluntarily submit a rate application that is a price or revenue cap. How it works is it sets revenue requirement in the initial rate application just like you would under a traditional form of regulation. So there's nothing new in the in the first year of the plan, so to speak. There's a rate application. There's a revenue requirement. There's rates that are set based on that revenue requirement, and that's how rates are set in year one. But then in subsequent years, a formula based on inflation and industry productivity adjusts either prices or revenues depending on whether you have a revenue cap or a price cap. Each year of the plan -- so maybe you have a five-year price cap plan, well, then the prices that you set in year one of the plan then are adjusted by this I minus X formula for year two, year three, year four, and year five. And then at the end of year five, the utility can come back in for another rate application. And so what the reason for this approach is that it allows the utility with -- it does two things. It says the utility is not able to come in for a rate application for some set number of years, and it's not able to adjust its rates based on its own costs. So that provides the utility with really strong incentives to be cost efficient, to try to reduce its costs so that it's able to retain the return on equity that it's allowed or even exceed the return on equity that it's allowed if it's able to. And the I minus X formula is really just what we call an attrition relief mechanism that says, okay, we understand that, over those five years, the utility's costs will likely increase. They will increase according to inflation and some productivity measure. So we'll adjust the utility's rates according to that I minus X formula to allow the utility the opportunity to continue to recover its authorized ROE. So the theory is that the utility operates under this price or revenue cap. It finds cost efficiencies in order to maximize profits and then re-sets its rates. And over the long run, that way of operating or that regulatory framework is supposed to provide benefits to customers in the form of slower rate escalation over time, and it provides benefits to the utility in the form of higher -- potentially higher profits if it's able to find cost efficiencies. So the customers are protected knowing that their rates won't increase any faster than the broader industry rates are increasing, and the utility takes on some risk in making that kind of promise but is -- that risk is matched by the potential for improved profit. And the goal here is to emulate competitive markets, make everything more efficient if possible, at least provide financial incentives for finding efficiencies. And so that's the theory behind price and revenue caps. I know that they're not currently used in Maine, but that there's -- that Central Maine Power used to have a price cap for a number of years.

Another thing I'll just say about price and revenue caps is that the I minus X formula is kind of the way it's often talked about. But there, in most cases, are many other letters to the PBR alphabet here. There's a stretch factor, there's exogenous factors, there's capital factors that support capital investment, and we can talk more about that if there's interest. But I minus X usually is not sufficient to provide the utility with what it needs to survive for a five-year PBR plan.

So can indexed caps be applied in Maine? Well, that's a question that I put to you, but here's our kind of assessment. There's advantages and challenges. Indexed caps, you know, the -- if the -- if one of the goals and policy goals in the state of Maine is to improve affordability, to improve cost efficiency, indexed caps can work to -- at least the goal of indexed caps is to provide those cost efficiency incentives. Now, one reason that indexed caps might be viable or feasible in Maine is that that Maine's investor-owned utilities are lines-only utilities. And that provides a little bit more in the way of feasibility because, with distribution systems, the kind of lumpy capital investments that you see in generation and in vertically-integrated utilities is a little bit smaller. Generally speaking, if you have a vertically-integrated utility that has to put in generation -- or generation investments periodically, the kind of incremental price cap approach, it's not as well fitted for those kinds of utilities. But in the state of Maine, you have lines-only utilities that own transmission and distribution. And so it's somewhat more feasible for such utilities than it is for vertically-integrated utilities. There's also past experience with price caps in Maine, and that might help -- you know, what your experience was with that can help inform whether it's a good idea to continue to try in the future.

The challenge is, of course, that Maine's LOUs are transmission owners. That means that they have large, lumpy investments that are associated with transmission. So that lumpy capital investment issue that I talked about with generation doesn't just go away with lines-only utilities. There's still, you know, lumpy capital investments, especially on the transmission side. The other thing is that there's any number of unforeseen or -- unforeseen costs or things that are outside control of the utility management that would need to be accounted for in some kind of additional factor. So I'll talk about those maybe in -- here in the next slide which are additional elements that might be included in an indexed cap.

Exogenous factors, capital trackers, guardrails like earnings sharing mechanisms or off ramps and reopeners. What are these things? So exogenous factors are things that are costs that arise that are outside of the control of the utility. So things like fuel costs. Now, in Maine, since the utilities don't own generation, they might not have to worry about that, but there's still any number of other costs that are outside of the control of the utility. Things like pension cost changes where that's really something that is based on market interest rate changes that the utility can't control. Storm costs oftentimes, insurance costs, transmission charges, things like that that are outside of the control of the utility. Rather than putting them under this price cap, most of the time, in most jurisdictions that operate with these kinds of PBR tools have a long list of these exogenous factors. And then similarly with capital trackers, almost every -- in fact, there's no jurisdiction right now that I'm aware of that operates under a multi-year rate plan that doesn't have some way of handling capital outside of the indexed cap. So in Hawaii, they call it the exceptional project recovery mechanism. There's a subset of capital projects that, if you meet this criteria, you can collect the costs for those projects. Similar -- similarly in Ontario, they have the incremental capital module which says, okay, if you meet this criteria, you can file for cost recovery for these capital projects. In Massachusetts and Alberta, they have what's called the K-bar mechanism which is basically -- I mean, what it is is it takes historical capital spending and projects the trend in the utility's own historical capital spending into the future and says if the I minus X formula doesn't give me what the historical trend predicts I will need during my PBR plan, we can collect the difference between what we get under I minus X and what the trend suggests we actually need. So it's kind of a mechanized way of saying we need capital supplement -- we need some kind of supplemental capital revenue, but we're not going to use our own costs to determine what that amount is. It's going to be -- we're not -- it's not cost of service based, per se. It's more like a formula approach. I'll also say that the K-bar approach was just proposed by Eversource in New Hampshire in its most recent rate application which is still pending.

Guardrails, earnings sharing mechanisms, I think the utilities in Maine are familiar with earnings sharing mechanisms. Off ramps and reopeners are tools that say, okay, we need to have a -- some kind of contingency if this indexed cap plan flies off the rails and something goes terribly wrong. We need a way of handling what to do about that. So an off ramp would be, okay, maybe the -- maybe there's been an extremely poor ROE that the utility experiences, way below what it's authorized ROE is. In that case -- or way above what its authorized ROE is. An off ramp would say we need to have the utility come back in and file a new rate case to re-set its rates according to costs. Reopeners are a little bit more light handed. It's -- it says, okay, there's something -- maybe there's been an ROE trigger. Maybe the utility's ROE has been too high for too many years, and we need to look at why that is. And then there could be any number of solutions which could include an off ramp to that outcome. So those are guardrails to reduce risk under a price cap or a revenue cap plan. And what you -- if you look at price cap and revenue cap plans in British Columbia, Alberta, Ontario, Massachusetts, Hawaii, they all have some combination of these of these tools.

Okay, moving on from multi-year rate plans or from the indexed cap question to PIMs, the question is can PIMs be expanded in Maine. Now, the subtitle here is utilities in Maine already operate under penalty-only PIMs. I think that's important to stress because what you -- I think we have in our report is the term PIM is not used in every jurisdiction, but that doesn't mean that they are not there. So, for example, in Great Britain they call them output delivery incentives, ODIs. In Hawaii, they call them PIMs. In British Columbia, they called them targeted incentives, and in Maine you call them SQIs. The definition of a PIM is any -- well, it's any kind of financially -- financial incentive mechanism that provides the utility with a reason to produce certain measurable outputs, and usually that means that the financial incentive and threshold are predefined before -- you know, it's not like the regulator comes in after the fact and is able to say, well, you did badly so I'm going to make my own judgment about what kind of penalty that means. PIMs, by definition, are set in advance so that all parties know what kind of target needs to be hit and what the penalty or reward would be for hitting that target. So by that definition, Maine has what are called penalty-only PIMs, but PIMs can also be reward only. They can be symmetrical which means they have both a reward and a penalty. So, for example, both New York and Hawaii have reward-only and symmetrical PIMs. One way of thinking about whether to have penalty-only, reward-only, or symmetrical PIMs is to think about does the output that we're considering for this metric -- is it considered to be sort of a traditional output that the utility's already expected to produce and it's sort of contained within its rates. So, for example, oftentimes reliability in the form of a SAIDI PIM or a SAIFI PIM, those are oftentimes penalty only because they're sort of expected of the utility. And if the utility's expected to produce it, it should be collecting the revenue it needs to produce it. And if it doesn't, then it gets docked some amount. Whereas if you want to think about what might be a reward-only PIM, a reward-only PIM would be something that the utility hasn't in the past been expected to do. So, for example, connecting DER -- connecting distributed energy resources. That might not be something that the utility has sort of a traditional expectation of doing. And if the policy goal is to incent DER connections, then the utility would be rewarded for doing something that it's not sort of traditionally expected to do. It has a financial reward for that. Or, like, reducing greenhouse gases, for example. That might be something that would be a reward-only PIM. Or maybe, you know, you could make an argument for making it a symmetrical PIM. So that's the way that we think about deciding between whether or not to have a penalty-only or a reward-only PIM.

Other jurisdictions have introduced PIMs to encourage investment and action to meet policy objectives similar to Maine's policy goals. So our report contains a few examples of that from New York and Hawaii and maybe some other places. But it's also important to consider that Maine doesn't have -- every jurisdiction is different. Maine does not have the same control over -- or I should say the IOUs in Maine don't necessarily have control over the same outcomes such as greenhouse gas emissions as a utility like Hawaiian Electric Company which is an island utility that owns its generation. So the -- a utility that owns its generation has much more ability to control what its greenhouse gas emissions would be, whereas the distributors in Maine, maybe they don't have quite as much control over that.

Okay, let's talk about the advantages and challenges of PIMs. The advantages, of course, are that we have this set of policy goals, we have an idea of maybe what the utilities should be producing as outputs, and PIMs provide an incentive for the utilities to produce those outputs. They also -- they do that work efficiently. So it's -- it tends to be more efficient to provide a utility with a financial incentive than it is to have a mandate. And the reason is that the utility -- if the PIM is properly designed so that the reward or penalty amount is based on the value to consumers that is produced by that output, then the utility has the ability to make a judgment about whether -- essentially, whether it wants to find the efficient way to produce those outputs or whether it wants to essentially remunerate its customers for not producing that output is kind of the economic way of thinking about it. There's also -- tends to be more flexibility and transparency with PIMs. The flexibility, again, in the sense that the utility has the ability to make its own economic decisions about what is the right and appropriate level of output to produce of whatever certain output we're looking at. And then transparency, of course, is because that the utility has -- if you have a PIM, the utility is going to be publishing a metric that the -- that it either is able to meet at some threshold or it's not meeting. And so everyone's able to look at that published metric and see has the utility achieved what it set out to achieve.

Okay. So those are the advantages of PIMs. The challenges are plentiful with PIMs. And that doesn't mean that they're not, you know, a good idea in some cases, but we need to be aware of the challenges. So there -- there's a lot of design complexity. It's difficult to quantify the performance outcomes and set the appropriate rewards and penalties. Really, the appropriate reward and penalty should be based on the value to customers. So there needs -- there should be, ideally, some form of cost benefit analysis involved in the design of a PIM, and that can be expensive. And also challenging just in terms of feasibility. Limits to timely access to metrics, sometimes there's a lag between when metric is met and what the utility gets in terms of its remuneration, and that can create a potential mismatch between incentives. Accounting for external factors, of course, as we all know, there are many things that affect utilities that are outside of the control of the utility, and having its revenue based partially on things that are outside of its control is -- you know, there -- there's risk there and maybe not the best idea. Then there's unintended consequences. So whenever we think about providing financial incentives for one particular output, the utility may then have an incentive just to focus on producing that particular output, and that might be to the detriment of other outputs that are also important. And then there's finally a risk of gaming or manipulation by utilities. If the utility knows, oh, I need to answer my phone calls within 30 seconds, it'll get really good at answering these phone calls within 30 seconds. But that doesn't necessarily translate into better customer service depending on how -- you know, how subsequent action is taken. So those are the challenges. I mean, that's just a list of some challenges. We talk more at length about it in our report.

So here we are. We're on our last slide of the presentation which is observations and next steps. So observation number one, Maine IOUs face service quality indicators that meet the definition of PIM. So right now, the state of Maine has PBR tools in place as we see it. And the state's alternative regulation option allows utilities to voluntarily file multi-year rate plans. So there's a -- there's potential there already. It -- it's worth noting that other jurisdictions like Alberta and Ontario require electric utility -- electric distribution utilities to operate under some form of PBR. So in, for example, the state of Massachusetts, Eversource and National Grid, they are able to file voluntarily whatever PBR plan they want, but that's not always the case. I think it's -- you know, Australia, Alberta, Ontario, and Great Britain that we looked at, those jurisdictions require their distributors to operate under some form of PBR. So that's just worth knowing. And I'm not necessarily one to advocate for that approach, especially in a state like Maine which has only two distributors. I think the reason that those jurisdictions operate that way is that there's a lot of distributors and it's just easier for the regulator to handle. I mean, if you're familiar with Ontario, there's, like, 55 distribution utilities there and they can't handle the kind of frequent rate applications that they might have to deal with if they all weren't operating under PBR. So they all -- the jurisdictions where PBR is mandated, generally there's a lot of utilities in those jurisdictions. And then the final bullet point on this slide is Christensen Associates will provide recommendations following the stakeholder engagement meeting. And so if you look at the report, we have placeholders right now where our recommendations will go, and the goal of the presentation here is to set the stage for discussion on what will end up being in those recommendations.

So that, I think, brings us to the end. I will also say that we have substantial appendix material that we can go through and reference maybe as we discuss. A lot of it is what's going on in other jurisdictions. So Ontario, Alberta, British Columbia, Hawaii, Massachusetts, California, New York. Some things going on in the UK, Australia, New Zealand. And then we have a few slides on more detail on some of the tools that I talked about earlier with regard to indexed cap PBR. So we have what different jurisdictions do in terms of capital funding, more on K-bar because K-bar is very interesting and more complicated, and that -- I think that's it. So I flipped through these quickly, but I just wanted to show you what's there in case it's helpful for discussion. So I'll pause there, and, Nora, if you want to take the mic and facilitate discussion.

MS. HEALY: Great. And so I'll just mention again we'll -- we will have all those slides in the docket. And, Carly, just to be clear, were you looking for them to be emailed now or do you have people --

MS. TUGGEY: No, just in general. I thought the slides were helpful and it would be valuable to share with folks who are working on these.

MS. HEALY: Yeah, no, that's what we intended. I just didn't -- as I've thought about it, I thought, oh, maybe someone needs to -- needs it right now that's (indiscernible) that's not on. All right, great. And then another thing I wanted to note, there was a little discussion I think that asked where those draft sort of policy goals came from, and there is proposed legislation in L.D. 2172. And so those goals were reflective of that proposed -- the draft goals were reflective of that proposed legislation. So just wanted to let folks know that.

So I think now we can open it up for, you know, comments and questions and discussion. And as we talked about, I think the first place to start really is with those goals. And, Nick, maybe you want to flip back to the slide with the goals on them, the seven goals. And as Nick indicated, they aren't ranked. You know, one thing the Commission would like to get input on is whether those goals capture the right goals for Maine utilities, and, if so, if there are things missing from those goals or things that should not be included there. We'd like to get some input on that, you know, today and in written comments. And Pat has a question. So Commissioner Scully?

MR. SCULLY: Hi. This may be a question that you can answer, Nick, or it may be that others in the room can answer. It's more a history question, but my recollection, and I think you reference this, is that for a number of years CMP operated under a more complex alternative rate plan that was multi-year that was kind of based on a formula somewhat similar to the formula that you presented. I was not a Commissioner at the time, and at some at some point in time, either the Commission moved away from that or CMP moved away from that. And I'm wondering if anyone knows what the rationale was for moving away from that type of multi-year alternative rate plan.

MR. COHEN: This is Peter Cohen from CMP. I have the distinction of having been here when we had the ARPs and when the last ARP ended. And so the company filed a request for a third ARP, and at the time, the feeling was is that we had had two ARPs and I think one was five years and one was seven years. And the impression, as I, a utility employee, got was that it was felt that we needed to take a break from a price cap mechanism and return to, you know, the single rate year practice. And then that continued for a number of years until Central Maine Power, in its last rate case, proposed a multi-year rate plan. And that was consistent with our belief and really consistent with a lot of the messages in this document that that is the right type of rate plan for a utility. And price caps are helpful, but they're complicated and they're hard to get started. And so we felt starting off with a multi-year rate plan was, you know, getting back into the right direction without introducing something that, in relatively recent history, had gone away.

MR. SCULLY: Thanks, Peter. That's really helpful.

MR. DAVIDSON: Yeah, and maybe, Pat, I'll add a little bit to that. Like Peter, I was here as well. And I -- everything he said was right on. I think the other sort of piece to that was we, as staff, were speculating that we had gotten maybe maxed out in our efficiency improvements with the utility. And -- at that point in time, and we questioned whether we could get any further efficiency going forward.

MR. COHEN: No, I --

MR. DAVIDSON: And that's on top of --

MR. COHEN: I agree with you, Derek, because I do remember this X factor was getting smaller and smaller, and then it flipped to be a negative. And I think we changed the name to a Z factor because there was -- this was occurring at a time when there was a transaction that occurred. And so there were these benefits that could be obtained, and that was factored into the offset and the stretch factor. So the S and the formulaic on, I think, it was page 16. And that went away after they were achieved.

MS. HEALY: So the transaction you're talking about a reorganization was --

MR. COHEN: This was a transaction between Central Maine Power and the Energy East Company.

MS. HEALY: Okay.

MS. TUGGEY: Nora, I have just a high-level question for Christensen. When you include the summary tables and the finalized brackets, will those be -- I mean, obviously this is complex and there's a range of ways to do this with pros and cons depending on where you fall on the spectrum. Are you planning on making sort of a, you know, first order recommendation or an if this, then you get this but you don't get this. Like, how are you planning to approach the recommendation component of it, if you know?

MR. CROWLEY: Yeah, that's a good question. We recently did work similar to this in another state, and most of the recommendations that we provided were more on the if this, then that sort of thing. So, for example, if you go to the portion of the report that has -- it's the indexed cap portion of the report. There are many tables on -- like, Table 4 point -- 5.4 or 5.5, 5.6. It's, like, how do you set an inflation factor? How do you set an X factor? How do you set a stretch factor? All that stuff is -- the recommendation is likely to be something like if an index cap is filed, the inflation factor should be set according to, you know, this criteria. If an indexed cap is filed, the X factor should be based on a total factor productivity study, that sort of thing. So that's some of it. I think in other parts of the report, there might be more concrete recommendations. But a lot of it, I anticipate, will be, you know, something like if this PIM is adopted -- you know, if some PIM approach is adopted, these are the criteria that you should be following when designing the PIM, that sort of thing.

MS. TUGGEY: That's really helpful. Thank you. And I asked just because, as we proceed, there's a lot of work that I think is going to play out in this docket. To the extent that we can be, you know, listening and taking these recommendations into how we present things to the Commission, it can be helpful. So it's helpful to know that you might give a if this, then this. Then we can put context around any proposals we make.

MS. CHAMBERLIN: So I was looking at the customer focused one, the increased affordability and customer empowerment and satisfaction. And I was comparing it to the Ontario principle which uses slightly different language. Let's see if I can find it. A customer-centric approach, encouraging expanding opportunities for customer choice and participating in all appropriate aspects of utility system functions. I think that gives a little more definition. I think customer empowerment is kind of vague. I don't think that's specific enough to really be a goal. So I like the idea of having, you know, encouraging customer choice and participation. That gives a little more specificity in what we're looking for on the customer end of it.

MS. HEALY: And I'll just note that with Susan Chamberlin from the OPA. So -- and just a reminder to folks, just mention your name at least. Thanks.

MR. COHEN: So this is Peter Cohen from Central Maine Power. One of the things that's not on here is the word safety. And that's a very important concept for our utility. So, you know, opportunities to introduce that might be item number three, cost effective comprehensive outage restoration. But there's a lot of safety involved in that that we think is really important to get documented. Because it's one of our goals as a company when we think about --

MS. HEALY: Yeah, and I think sometimes we think of that as a given --

MR. COHEN: You think of it as a base.

MS. HEALY: -- and we don't acknowledge it as a key goal, but it's obviously fundamental, yeah.

MR. MARSHALL: Could I ask a question on the policy goals? This is Brian Marshall from the OPA. So one through four, you know, I think you could debate whether, you know, traditional cost of service or some kind of PBR or incentive mechanism makes sense. And there's really no question that those are, you know, specific goals for the regulatory tool. For five through seven, I guess there's an initial question whether this is something that the utility has direct, you know, control over or if the utility is the best positioned entity to address. I'm not questioning that they're important goals, but, you know, for example, we have a renewable portfolio standard that applies to the suppliers of electricity. We have Efficiency Maine Trust which is a separate state entity. And for something like beneficial electrification, is that something that might be better addressed through rate design rather than the specific regulatory structure? So is there some analysis needed to determine, you know, not whether the goals themselves are important but what contribution do the utilities make towards those goals? And is there actually some other entity or entities that should be tasked with addressing them? Or could they just be addressed through the design of rates themselves?

MR. CROWLEY: Yeah, I think that's a great question. And if you look at number six, that is something we mentioned also in this -- in these slides which is that in some places that have PIMs, it's easier to incent the utility to do something with regard to greenhouse gas emissions than it is maybe in the state of Maine because of the structure of the industry in Maine. So, yeah, I think maybe that's an argument for ranking the different policy goals because, you know, I could imagine that we design tools with some of these latter items in mind but that they're not necessarily the focus because of the reason that you just said which is that maybe it's not quite within -- fully within the utility's control. And I suppose I would ask the IOU representatives if they have thoughts on what tools could be used to address some of those, like, six and seven items. But I see that there's a hand up.

MS. HEALY: Yes, go ahead, Carrie, Commissioner Gilbert.

MS. GILBERT: Yeah, hi, this is Carrie Gilbert. And when I was looking at the policy goals, one additional metric that people often suggest to us is a metric around interconnection. And I was trying to figure out where interconnection would fit into the policy goals, and I guess it would be in the last three because interconnect -- mostly we're talking about interconnecting renewables or interconnecting load. So I don't know if that points to including them, but I do agree that it's a little tricky because, as you said, the RPS is the tool that, I guess, in state procurements that we're using to meet the state's goal for increasing consumption of electricity from renewable resources. And the utilities, because they don't supply, they're not really involved in that. But they are involved in the interconnection process which is -- which seems to be the one metric that people have consistently suggested we should be adding. So I don't know what that means about leaving them on, but --

MS. HEALY: Or perhaps that's suggesting more narrowly tailoring them to reflect the things that are within the utility's control.

MS. GILBERT: Yeah.

MR. MARSHALL: I could add a --

MR. CROWLEY: Yeah, I can -- oh, go ahead.

MR. MARSHALL: I was just going to add a comment that I agree, and I agree with Commissioner Gilbert's statement. And maybe rather than having five, six, seven as the sort of broad and somewhat vague articulations of policy, you have a very specific one on interconnection. And, you know, whatever your goal is related to interconnection, you want to reduce the time it takes or the expense of that, you know, make that the goal rather than something kind of vague and hard to understand and very broad, like reduce, you know, greenhouse gas emissions or advance beneficial electrification. I think the more specific the goal is, the better and the easier it will be to implement.

MR. COHEN: This is Peter Cohen, CMP. So I agree with Brian strangely enough. And when I read five, six, and seven, I -- one word came to mind which is infrastructure. And that's what I do, right? And so I need to have the infrastructure that helps our state achieve these goals. And this is one of the reasons why I believe a multi-year rate plan of duration is important because the planning for this infrastructure is time consuming and it's expensive. And then actually executing on it is kind of what our company does, right? We are less of a rate case company and more of a public utility that builds things and makes them safe and reliable.

And I do agree with Commissioner Gilbert about the interconnections that having a metric there too would help to address these. And, you know, Brian's right, we can't solely handle the achievement of climate change goals as Central Maine Power. But we can participate in them, and our ability to participate can be encouraged based on the type of regulation that we're operating under. And that's why, again, we felt it was important for a multi-year rate plan so we could focus on that. And I think -- actually I don't think, I am certain that

CMP will continue to believe that way and it'll be demonstrated in future filings.

MR. SIMMONS: Kiera has a question online if -- all right, sorry.

MS. HEALY: Go ahead, Kiera. From the Governor's Energy Office.

MS. REARDON: Thank you. Kiera Reardon. Just listening to this conversation, I think it's a really exciting moment here because all of the things that we're talking about now I feel like are coming together nicely with the climate plans that were just submitted, and CMP's presentation is on this afternoon, and the integrated grid plans that are under development and these proposed policy goals. So I'm actually wondering if there -- I would welcome feedback from the group on if there's merit on sort of zooming out and finding a way to weave the concepts we have under development in the integrated grid plans and what I've heard from the Commissioners through deliberations about using those to drive rate cases and what we're looking at here in this docket because it feels like we're just really on the cusp of having a lot of really neat, new, exciting tools at our disposal. And if we could institute them all at the same time and in a cohesive way, I think we'd be all the better for it. So not really a question, more of just a general statement for reaction.

MR. SIMMONS: David, did you want to say something?

MR. LITTELL: Just to respond to a question. David Littell for Versant Power. To respond to the question that was posed, I guess I'll respond with a question which is Brian raised the question of how much impact the utilities have on five, six, and seven which is a good question. But my question is what's sort of the envisioned outcome of this proceeding? Because those are general statements, and Brian sounded like he was diving right down into to designing a PIM. And I don't know if the outcome of this is going to be very specific PIM recommendations or if it will be a general concept with some illustrations that leaves room and invites the utilities to file and make specific suggestions with what those should be because the -- I mean, the detail here is that PIMs are designed to achieve very sort of specific outcomes. And you need to think those through and you need to think through the data, right? And what data you have to measure it. And you may very well conclude that we need better data to have that discussion. So we may do a monitoring-only sort of PIM for a while. That can be one outcome. And my last sort of related comment is not to confuse tracking and reporting with causation. Because, I mean, you could jump there if you're talking about either rewards or penalties, but sometimes you want to track things when the utilities may play an important role and Efficiency Maine Trust may play an important role and the Governor's Energy Office may play an important role. And then you -- you know, you can have a discussion on whether it's appropriate to have an incentive built in there, but you still may want to track them because they're important for the state. And the utilities are in a good position to do that tracking. So I just -- I throw out a bunch of related thoughts that I guess would come back to my point is I didn't envision, but obviously we're -- this is an initial discussion, the outcome of these being very specific PIMs that would be mandated but rather sort of goals with examples. And that -- so pose the question (indiscernible) feedback.

MS. HEALY: Well, I'll just -- and I know, Commissioner Gilbert, you have your hand up. So I certainly will let you speak, but I'll just note that this is an inquiry. It's not an adjudicatory proceeding. So I don't think we would be ordering anything out of this particular docket. But Commissioner Gilbert?

MS. GILBERT: Yeah, I actually -- I don't have a good feeling of the outcome of this docket either, but I think Nora's characterization would make sense to me. But I just wanted to echo Kiera's statement about tying some of these different dockets together. That's something I sort of hunger for. So I don't have a good idea of how we do that, but it does seem that the goals we're thinking about here should, you know, maybe tie to some of the priorities in the group plans. I think they're probably consistent, but anyway, I liked that idea. So I just wanted to say that. Thanks.

MR. DAVIDSON: And maybe I'd like to react to David's point because I think it's a good one. I was going to bring it up, is I think -- regarding specificity for the goals, I mean, I think what we're envisioning is these are going to be goals that are going to guide the Commission when it's evaluating what sort of a performance-based ratemaking plan might work for a utility, and the specificity would come in the PIMs. And I think it would be dependent on the utility as well as, you know, what we were trying to achieve. So with the goals, I think from my perspective, from a staff perspective, I want to know what are we --what is important to the state and what are we trying to achieve through this performance-based ratemaking plan. Then we can get into the specifics maybe about -- you know, as far as what sort of PIMs do we have to have in order to sort of -- to get us there. I think that's what I'm envisioning coming out of this process.

MR. SIMMONS: Yeah, and I think to add, you know, the point of this stakeholder meeting is to have this conversation, get the comments from the participants so that Christensen Associates can kind of complete the report that they've been working on. And I'll let Nick kind of talk about that recommendation part again that, you know, from what I've heard, it's going to be more if you go down this road, you want to consider these things, or if you're building a PIM, these are the considerations that you should be looking at. And I don't think, to David's point, we're getting -- the intent isn't to design the PIM, kind of do the homework to figure out what -- you know, what the target should be. And, you know, I don't know, Nick, if you need to chime in and talk about the -- kind of the report and what you see it as, but I'll give you the opportunity.

MR. CROWLEY: No, I think that is a fair characterization of the plan. So you wouldn't expect from our next draft to see PIMs that we would recommend necessarily. But we might provide guidance on how to design them, what PIMs exist in other jurisdictions that have been used to address some of the policy goals that we see here. And then I'm -- I just wanted to say on the point -- on David's point and then also -- I don't know who was talking over there on the far side of the room, but with regard to these kind of policy goals, if we look at Appendix C of the report, I have different PBR principles from different jurisdictions. And I view the policy goals as somewhat similar to what we see in Appendix C in these other jurisdictions where there's more over-arching goals that are used as guideposts for what tools then get used. And so to give a specific example, just yesterday -- I think it was just yesterday a discussion paper was published in Ontario where the Ontario Energy Board has made recommendations for what PIMs they might be introducing to the province. But each of those

PIMs is sort of categorized under -- or has a set of policy goals that it aligns with. So I think there's, like, for example, a system utilization PIM they're calling, and that system utilization PIM is aimed at, for example, addressing affordability for customers and cost efficiency for the utility. And so it's not necessarily that the policy goals are creating specific examples of what PIMs are needed but rather that the PIMs adhere -- or are aimed at addressing certain policy goals if that makes sense.

MS. TUGGEY: And maybe I'm more comfortable with this than I should be based on comments from my peers, but I'm actually very comfortable with what we're doing here in terms of talking about these ideas and the approach that it sounds like they're going to take in terms of there -- the -- there's the spectrum, and then here are the things, you do this, you get this; you do this, you get this, you might not get this. I think where I get a little uncomfortable is that the Commission is only bound by statute. So it's bound by the policy that's established in statute. So to the extent that these policy goals -- if there's an expectation here that the inquiry is going to lead to a set of policy goals that bind the Commission in terms of how it frames this, that's where I would get a little uncomfortable. I think if the point is to say, like, we're all talking about this in the same way, here are the kinds of goals that these PIMs could achieve and they're tangentially related to statute, that's great. But I just don't want to be left thinking that the policy goals here are going to bind the Commission in anyway with regard to the PIMs. That was the only thing that started to get me nervous --

MS. HEALY: No, and I can't read all the handwriting on the wall. But to be clear, I mean, these were policy goals that were reflected in proposed legislation, and there will be a report back to the legislature. So, you know, I -- again, I don't have a crystal ball, but I don't want to suggest that the legislature couldn't decide something like this that would constrain the Commission. But I think this is an opportunity for us to help inform that not in front of the legislature. So, you know, I don't -- others might have -- want to add to that, but -- and I'm just speaking for myself personally, but I think, you know, again, the topic of, you know, sort of what's missing from this -- and I know you --Peter, you mentioned safety, but if there are other important topics, I think those are the kinds of things that would be helpful to get out. And I think also the discussion about -- you know, and we've talked about this in cases, you know, for a number of years now, the goals that are less in the utility's control and less, you know -- but are important to the state need to be sort of tailored. And we do that in rate cases to some extent. But I mean, I can think -- you know, when we were talking about five, six, and seven, certainly there are limitations, and interconnection's an important one. But I've also seen, you know, utilities play a role in education. And, you know, obviously rate design is an issue that was worked on out of last CMP's last rate case and is going to continue to be worked on. And to Peter's point, there are infrastructure things associated with rate design, you know, billing systems that need to be addressed. So, you know, I think, again, just speaking for myself, but I don't want you to be left with the impression that this isn't going to go back to the legislature in some sort of form. But (indiscernible) after that I think --

MS. TUGGEY: Thank you.

MS. HEALY: -- guess about.

MR. BURNES: So I want to go in a little bit more detail of where Brian was going. This is Ian Burnes. I'm with Efficiency Maine Trust. We're the independent administrator of demand management, energy efficiency, and beneficial electrification programs in the state. And as that introduction, I think you might know where I'm going here. I think to the extent that this is a guide to future rate cases and it is a guide to the legislature on what the PUC's priorities, I would urge you to remove the elements of the report that are not within the control or the statutory authority of the utilities. And I think I'll just put three examples here. You have multiple examples of demand response programs. We're running the demand response programs. I just don't want to send the message that it's an expectation. There are a number of best practices from other utilities. We recognize we're a unique state in that there is an independent administrator of all of these things that are outside the utility. So I just hope that the final report will reflect that so that we can avoid any future confusion. This is not to say that there isn't a role of the utilities in assisting. In fact, when it comes to demand response programs, like, we rely on them for data. The prompt and accurate, you know, sharing of that data is important to us for how we run our programs. So it's not to say that there isn't a role, it's just it doesn't really lend itself to the same level of -- you know, it's not a three basis point increase like they have in Illinois as your report reflects. Like, it is a minor transaction that takes a couple of hours.

Another thing that I might say is, like, we've talked about interconnection, and Efficiency Maine Trust works on interconnection with batteries. And we had actually a real success in the level three interconnection process in which we -- actually, within a month, CMP permitted two major battery installations, and that was a real success story. But unfortunately, those battery projects sat for over a year at ISO New England, from my humble opinion, for absolutely no reason. And CMP was an advocate for us to try to figure out how to make that process go faster and probably, without their intervention, would not have gone faster. But if we -- when we get to a level of specificity, I think we need to make sure that we're reflecting that we're within a regional context for anything that's going to be interconnected over five megawatts. And these were -- actually these were over a -- these were -- it didn't even meet that. These were behind-the-meter projects, non-exporting projects under five megawatts that got swept into cluster studies. So it's just to say that it doesn't lend itself to a real clean --

MS. HEALY: (Indiscernible).

MR. BURNES: Yeah, I mean, there's just -- you get to fractals, and all of a sudden, like, I wouldn't want to hold CMP responsible for that delay and now unfortunate, ultimate demise of those two projects.

And the third one I would say is mention of the non-wires coordinator process. Again, this is an example of a place where Maine has chosen a very different policy. Not to say that there isn't a real role for the utilities to give us timely, accurate data to allow the thing to happen. But it doesn't lend itself, again, to sharing the savings of an NWA because of the policy practice that we have here. So to the extent that this could become a guide to legislators and people will be looking to this and I think that there is a lot of interest in it, I really urge you to be very careful in the way that you frame best practices from other regions and have them reflect the unique policy environment of Maine. And I don't think that the current report meets that standard. And I think there are some discrete -- there's lots of good stuff in here, but I wouldn't want to see what we have published in this docket right now as an example because it does not reflect that.

MS. HEALY: So -- and just to kind of paraphrase here, you're saying it's sort of missing the nuances of the fact of how you would actually maybe constrain to apply these in Maine because certain other entities have responsibility for things.

MR. BURNES: Yeah.

MS. HEALY: We talked about that in terms of generation, but yeah.

MR. CROWLEY: So --

MR. BURNES: Yeah, I mean, and -- yeah, go ahead.

MR. CROWLEY: Ian, appreciate that feedback. I also want to say please provide, in as much detail as you're willing to provide, written feedback because if you have specific examples, that would be helpful for us to make sure we're addressing it in the next draft.

MR. BURNES: Will do.

MS. HEALY: And, Andi, you had your -- I think you might have had your hand up at one point. I don't -- and maybe you have moved on, but if you did want to ask something or say something, please do.

MR. ROMANOVS-MALOVRH: Yeah, I just wanted to say, I know, Nora, you mentioned not to use the chat feature, but I'm just going to post a resource that Nick referenced previously when talking about Ontario if that's all right.

MS. HEALY: Yeah, that's okay. Go ahead, do that and people can share it. And then I think we'll just ask you to put that hyperlink into somewhere, maybe an appendix to the slides, and then we'll file it in the docket so that everyone has the benefit of that in the docket.

MR. ROMANOVS-MALOVRH: Sounds good.

MS. HEALY: Okay. It's about 10:38. So why don't we take a break? I assume people want to continue the discussion at least a bit more. Or maybe I should just ask. I'd like to think we could continue the discussion more. I mean, I -- there -- there's some more topics on my mind, and I think staff has some other questions. So hopefully, people will come back after the break, let's put it that way. We'll take a 15-minute break, and -- maybe we'll take a little bit more than 15 minutes. We'll come back at, what is it, 10:55, right? Is my math, right? Okay, great, we're on break.

CONFERENCE RECESSED (May 16, 2025, 10:38 a.m.)

CONFERENCE RESUMED (May 16, 2025, 10:55 a.m.)

MS. HEALY: -- 07, and I think staff has a few questions type comments.

MR. SIMMONS: Yeah, so I wanted to bring up kind of Ian mentioned, like, the interconnection experience that they had with CMP and the batteries. And, you know, with the interconnection, there are two phases, right? There's what's in Chapter 3 -- our Maine Chapter 324 which is the interconnection process, and the local utilities have timelines and requirements under that rule. And then the second part of that process is that if it's a certain FERC jurisdictional circuit interconnection, then there would be a regional process at the ISO New England. And given the example that Ian provided, you know, developing some sort of PIM associated with Chapter 324 which the local utilities have full responsibility for, you know, that seems like a way that you could do that. But you penalize the local distribution companies for the delays associated with the more regional process. Or even, like, the outcome that he referenced, the two projects didn't come online. So I guess the question would be, you know, is that kind of the best practice that you see in other jurisdictions where you develop the PIMs kind of to the limit that the utilities do have authority to act? That was directed to Nick and his team I guess, but, you know, if others want to respond, that would be fine too.

MR. CROWLEY: Well, I will just speak sort of generally to best practices for the design of PIMs is that you want to design PIMs that are associated with actions that the utility has control over or outcomes that the utility has control over. And so when -- if this particular category of outputs was something that was a priority in the state of Maine, just because it's a priority doesn't necessarily mean it's appropriate to have a PIM do the work. Because if it's outside of the control of the utility, then it's really not appropriate to be putting rewards or penalties on the outcomes. Does that answer the question that you're getting at?

MR. SIMMONS: Yeah, I think generally, and that kind of brings me up to another question. You know, just because we have these priorities that are listed, it's not the expectation that every priority has some PIM or other mechanism that would kind of get -- you know, provide outcomes that support those policies. Is that kind of your thinking?

MR. CROWLEY: Yeah. Yeah, that's just one of the -- like, the policy goals are just one guiding -- they're just one guidepost for the design of some kind of regulatory framework. It doesn't necessarily mean that we're going to be able to find a PIM that adheres to every single one of those seven different policy goals.

MR. DAVIDSON: So, Nick, this is Derek. I've got a question regarding the policy goals. Do other jurisdictions tend to prioritize those goals? And what are your specific thoughts about the helpfulness of prioritizing the goals?

MR. CROWLEY: I would say -- so I've worked -- in the jurisdictions that I've worked -- and I'll -- so let me think specifically about Alberta. Alberta is a jurisdiction that has price cap regulation for the electric distribution utilities and revenue per customer caps for the gas distribution utilities. And in the evidence that is filed by the utilities and intervenors in their rate applications and in their PBR proceedings, there is an expectation that when an argument is made, you tie it back to a PBR principle. So there is, I would say, emphasis on a to the principles that are set forth in that province. And I think that's also the case in British Columbia. And I think it's maybe a little bit less so in -- well, I see -- I feel like I'm -- I don't want to make judgements that would come back to bite me, but it's maybe a little bit less so in other places I'll just say. But usually the idea is, okay, if we're going to craft a regulatory framework, let's, at the end of each tool that we're describing or proposing, describe how it adheres to the principles or, in this case, the policy goals.

MS. HEALY: Have you seen other jurisdictions rank those goals?

MR. CROWLEY: I have not, no.

MS. HEALY: Or not? Yeah, and --

MR. ROMANOVS-MALOVRH: I can maybe --

MR. CROWLEY: Go ahead, Andi.

MR. ROMANOVS-MALOVRH: Yeah, I know one of the jurisdictions we worked in is Indiana, and they have this five-pillar approach. And in our conversations, the impression I had is that they explicitly did not want to rank those. And in this case, the five pillars -- I might not name all of them, but they're akin to reliability, resilience, affordability, and so forth. And one of them is also environmental. And they've said that they explicitly do not want to rank them because they want to make sure that, in the rate applications, utilities think about all of those goals at the same time. But that -- not saying that, you know, that's the way Maine should do it. Just as an example.

MS. HEALY: Nick and Christensen, could you talk a little bit about storm costs and storm recovery and how other jurisdictions might have treated those under performance-based regulation?

MR. CROWLEY: Yeah, so when thinking about storm costs, I think we're thinking in the category of multi-year rate plan PBR. So something like you're out -- you're not able to come back for a rate application for five years and a storm happens within that five years, how do you handle that in terms of revenue recovery. The -- it differs by jurisdiction. So in Alberta and Ontario, these are two jurisdictions where the utilities are under price cap regulation. The storm costs are recovered under the Z factor. The Z factor, I really didn't spend much time on -- in this presentation on the details of how price caps and revenue caps work. We could talk -- we could have a day-long talk about how to design a price cap and all the work that goes into each one of these different letters. But when we look at the adjustments to the price cap on this slide and we look at Y factors and Z factors, Z factors are just -- they're just cost recovery mechanisms that the utility can file on an annual basis with its annual PBR filing to say some cost occurred this year that was way outside of my control. Usually Y factors are ongoing costs like flow-through type costs. Z factors are one-time events, and storm costs could be categorized as Z factor costs. And that's how it's handled in Alberta and Ontario. In Massachusetts, they do it a little differently. They have storm -- well, I should say Eversource, I'm thinking of Eversource specifically. I don't recall offhand how National Grid does it, but Eversource has a storm fund, and that fund is collected as, like, a rate rider to customers up to a certain limit. And then once that limit -- which is, I think, 30 million, and once the utility has 30 million in the fund, then it either stops collecting or it starts returning some of the collected funds back to customers. And that fund has a bunch of different rules around it, but the idea is that they have essentially money set aside in case a storm occurs. So they don't handle storm costs through Z factors in Massachusetts, but those are two ways of doing it under these multi-year rate plan approaches. I think as -- I mean, my guess is a Z factor is the more widely used approach. It's just like if a storm happens, the utility's allowed to file information on an annual basis saying we incurred these costs as a result of the storm, now in rates over the next couple of years, we are asking for the ability to recover those costs.

MS. HEALY: Can you also talk a little bit about, you know, affordability as a goal that's reflected in those draft goals and what other jurisdictions have been doing to try and promote that goal in performance-based ratemaking?

MR. CROWLEY: Yeah. I would say going back to one of the first slides, this one, on what tools we are trying to use to incent certain outcomes, multi-year rate plans tend to be the tool that's used to try to incent cost efficiency. And cost efficiency ultimately flows through to customers in the form of improved affordability relative to traditional regulation if designed correctly. So if designed correctly, the multi-year rate plan incents cost efficiency which then ends up helping customers. How does that happen? Well, what you have is a utility that has improved efficiency to reduce its costs over time. And then when it comes in for its next rate application, the theory goes, it has a revenue requirement that is lower than what the revenue requirement would have been if it had been operating under a traditional regulation. Why is that? It's because the utility has a rate stay out period, and that rate stay out period is essentially providing the profit motive to cut costs as much as possible. And so the question is is that theory that affordability will improve over time, does that actually have any evidence in the empirical world that we live in? And we've seen empirical results that demonstrate that that theory is true.

MS. HEALY: Yes.

MR. CROWLEY: And the -- yeah, so the answer is it's very, very difficult to ever know for sure whether a certain regulatory framework is the reason for improved affordability. So that's kind of the caveat at the outset, but there have been studies. So -- and we have reviewed a number of these studies from different parts of the world, not in the U.S. because most jurisdictions in the U.S. don't really operate with what we would call, like, a pure price or revenue cap. Massachusetts and Hawaii do, but they're pretty young, whereas Ontario and Alberta have been doing it for a long time, and some countries in Europe and Australia, for example, have been doing it for a long time as well. So the data is more readily available in other countries, and what we have seen is that it does seem to be the case that jurisdictions that operate under price caps or revenue caps have slower rate escalation for customers. I authored a paper in Utilities Policy, I think it came out in 2021, looking at a comparison of Alberta and Ontario utilities that operate under price caps with a set of utilities that do not operate under price caps as, like, a sort of quasi-control group, and found that over the period of time between the year 2000 and 2018, I believe, the rate -- or I should say the revenue per customer collected by the utilities under price caps grew at a slower rate than the utilities under more traditional forms of regulation. So it does seem to be the case that there's some at least hint that maybe it does work. But, again, you can't control for everything. And as everyone in the room knows, there could be any number of reasons that that happened that are coincidental. And we did the best we could to control for the circumstances of the utilities, but we don't -- we -- I -- my paper, for example, didn't conclude that price caps were the reason. It was more like price caps are associated with slower rate escalation among customers. Now, other studies might be a little bit more definitive. And, Andi, I know you were just telling me the other day about the findings of the -- I think the Australian regulator that was reviewing their PBR mechanism, and maybe you could speak to what their finding was just briefly.

MR. ROMANOVS-MALOVRH: Sorry. Yeah, so the Australian energy regulator also has -- they have five-year multi-year rate plans. In this case, they're forecasted as opposed to having an indexed cap. They still adjust for inflation, and they have some other mechanisms in place as well. And in 2023 they conducted a review of their incentive mechanisms which included more than just the five year multi-year rate plan. But their conclusion was that the customers were better off, that the prices were lower. And they also had the service quality indicators in place which, in their case, were symmetric, like, had a reward component to it as well as a penalty component. And their conclusion was that the customers are better off. They acknowledged that there were areas of improvement which was part of what they did in that proceeding. But their over-arching conclusion was that it's successful, and they continued operating under that approach.

There was also a relatively recent study in Germany where -- so the utilities in Germany operate under revenue caps, but they have -- or I should say they operate under PBR, but they're they have a distinction between whether or not it's more -- whether or not the utilities have more incentives or less incentives depending on -- they basically have smaller utilities that are able to choose, like, an alternative regulatory approach. And, once again, the paper found that -- accounting for, you know, the various different -- differences between those groups, they found that the more restrictive or the model that you would think, in theory, has stronger incentives, also led to lower rates overall. But, once again, it's more of a -- it might have been more of an association rather than conclusive evidence that, you know, the more restrictive or more incentive-based approach actually led -- or was the cause for the reduction in rates.

MR. CROWLEY: I think it's also helpful to -- and I think it's helpful to think about who is authoring the reports sometimes because the -- for example, in Great Britain they operated under what they called RPI minus X which is essentially a price cap for many years until they transitioned to their REO (phonetic) approach. And at the end of the RPI minus X which was ended, I think, sometime in the 2014 or thereabouts era, Ofgem, the regulator, published papers proclaiming how successful -- like, it was amazingly successful. RPI minus X saved customers hundreds of millions of pounds per year. And maybe that's true and, you know, they present their argument, but also they are the ones who created the mechanism. So they have sort of an incentive to say that it worked out.

Anyway, so I tend to think that these mechanisms can be better than the sort of traditional way of regulation if designed well. It's sort of like the devil's in the details, but I also am clear eyed about the limitations and the need for certain additional tools to make sure that risk is controlled.

MR. SIMMONS: So, Nick, earlier you were talking about kind of the design of PIMs and an efficient PIM would give the utility the right signals as to whether to kind of try to attempt to meet the target or, you know, they could make the decision to take the economic hit of the penalties. And I guess I was wondering, you know, what your thought process is on that. If the targets that are set are kind of predicated on a certain level of capital investment, how would you -- you know, how should we think about that?

MR. CROWLEY: I think I need to talk through the question a little bit more to fully understand. So it sounds like you're saying how do we handle that there's capital that's required to provide the outcomes that we're looking for. Is the kind of meat of that question that it's like something that might not be -- or the investment sort of doesn't provide immediate outcomes. Is that where you're getting at?

MR. SIMMONS: So, no, I guess what I'm trying to ask is that so if the targets in a PIM are, you know, based on a certain level of investment so, you know, if it's -- you know, certain investments are made, we expect the target to be X. And, you know, the economic theory is that the utility has a decision to make as to whether, you know, they want to meet that target or pay the penalties.

MR. CROWLEY: Yeah.

MR. SIMMONS: How -- you know, if the investments are already included in -- you know, in the approved order, how do we kind of look at that going forward?

MS. HEALY: Ensure the utility actually spends the money in the way that the regulator intended the utility to spend it versus absorb the penalty. Is that right, Michael?

MR. CROWLEY: Well, now I --

MR. SIMMONS: That's a -- no, yeah.

MS. HEALY: Go ahead, Nick.

MR. CROWLEY: I'm sort of thinking about those two comments as being separate. So the first one, now, is, okay, there's embedded -- so the utility has made investments and then had a rate application where its rates have reflected investments that will then reflect -- the investments will then have an impact on the outcome of, like, the PIM essentially. So the rates already reflect costs that have been incurred in order to meet the PIM. Is that what you're saying?

MR. SIMMONS: Or if it's a future year, then --

MR. CROWLEY: Yeah. Yeah, I mean, that's a good point. And so, I mean, going back to the kind of -- I don't know if we had a -- I don't know if I put it in the slides, but at some point in here I had -- well, it probably was in this slide that I talked about it which is, like, how do you decide whether it's a reward-only or a penalty-only PIM. If my colleague Dan McLeod was here, he would say if the rates already reflect costs that have been incurred in order to meet the particular metric, then it should more likely be penalty only because the company's already collecting the -- it's collecting through rates the cost incurred to meet that goal. Now, I don't know that that's a hard and fast rule, though, because it might be the case that the company has incurred costs with the full intention of meeting the metric, and then the -- you know, it depends on -- I think it goes back to the question of are -- how in control is the outcome to the utility. So if the utility has made an -- like, let's think of a very specific example. Like, we have a -- we need to replace some poles or something to make reliability -- to improve reliability or do some -- I'm trying to think of capital investments that improve resiliency or reliability. And if the company makes those investments but then doesn't meet the reliability threshold and then has to pay a penalty, that doesn't quite seem like it's in the spirit of what we're trying to do because it's saying we're punishing the utility even though they did what they were supposed to. Something outside of their control happened and they didn't meet the PIM. So it's all kind of interconnected with the question of what's -- what is in the control of the utility. But I think it's important to consider also what's reflected already in rates. So if rates are collecting the cost of investments that are made to meet a certain threshold for a PIM, then I think we need to consider that maybe there's more likely that that's a penalty-only situation.

MR. SIMMONS: Yeah, so, Nick, that brought me kind of to my follow-up question. So if the example is, you know, they made the investments, but they didn't necessarily -- you know, they weren't on track to meet the target, would -- you know, would a symmetrical approach in that case give them the proper incentive to, you know, do more O&M or do some other actions that aren't necessarily related to the capital investments that they made?

MR. CROWLEY: Yeah, I mean, that -- I think that's possible. I think it -- it's sometimes a little bit hard to speak about these things so generally without knowing exactly what we're looking at. Having specific examples is helpful because we can assess a little bit more closely and in more detail, but I think that's an -- that's probably a good idea. I would also say just -- this is kind of a side note, but it occurred to me while we were talking about this, that -- so they have -- Duke Energy Carolinas in North Carolina has PIMs, and I was speaking with one of the regulatory folks at that company about their PIMs and how they went about designing them. And one of his comments was because there's so much that's outside of the control of the utility, I think one approach to designing PIMs is to -- specifically tying PIMs to the outcome of programs. Like, you have a program that says we will -- I mean, this is just an example, and I don't even know that this is something that they have in North Carolina. But, for example, we want to connect X number of DER customers this year, and either you do or you don't. And that's kind of, like, the threshold of whether you get the PIM reward. And so having something that's more, like, tied -- that's more -- I guess a little bit less easily defined like reliability where you have a SAIDI measure that has all these different potential impacts that are outside of the control of the utility, that makes it a lot more difficult to determine what is appropriate in terms of a reward or penalty. I'm not saying that it's not possible. Certainly, it's one of the most common PIMs that's out there, but I just think it makes it more tricky.

MR. SIMMONS: Thanks, Nick.

MR. DAVIDSON: So I have a question. This is Derek, and this is actually, I think, pointed more towards the stakeholders. So how do folks view symmetrical or reward-only PIMs? And do you think that they're appropriate? If they are, in what situations? Or are they appropriate in Maine at all?

MS. CHAMBERLIN: This is Susan of the Office of Public Advocate. I think a lot depends on whether or not it's within the normal expectation of what a utility is to provide. I don't think they should get additional incentives to provide, you know, safe, reliable utility services because that's what they're supposed to be doing. If it's something that's somewhat new or somewhat -- the path to doing it is a little uncertain, like, perhaps providing accurate and timely data for NWA, something like that, something they haven't had to do in the past, maybe there is a way to create an incentive to get them to focus on it. You know, something like that. But if it's squarely within the realm of their responsibilities, it makes more sense to me to say, look, you face a penalty if you don't do this because this is exactly what you're supposed to be doing. And I think the SQIs are along those lines. It's like, okay, this is within your realm. This is what we expect. If you're not meeting it, what's going on? I think it raises a flag.

MR. GRUMSTRUP: Susan, would you include interconnections in that category or would you see that as something utilities are already expected to --

MS. CHAMBERLIN: Well, that one -- it is in the -- kind of changing their role. It's a somewhat new thing that they're supposed to be doing. It is within their realm, but there are a lot of variables as has pointed out (sic). There's only so much within their control. So I think if it were to be the subject of a penalty, it should be very narrow, narrowly tailored. What is it they can actually do to promote it? If it sits in the ISO for a year and a half, I'm not sure that there's a lot they can do. Maybe there's some things they can do to help that.

MR. BURNES: I wonder whether -- when it comes to rewards, whether there's a way of looking at it is -- you know, as a way of -- because I very much agree with Susan. But I also feel like especially with the grid plan, we're asking the utilities to sort of be innovative, perhaps -- let's use interconnection as an example of perhaps proposing and implementing a flexible interconnection approach that would -- something along those lines that we set some goals. And the Commission might even say for something that is more innovative than their basic bread and butter utility service, that we would be open to rewards if you would take a leadership position in these kind of things. Because I think that absent a specific plan for -- from the utility to innovate, it very much could start to look like we're paying them to do exactly what they're doing. And I think that's going to be a non-starter. But to tie it to innovative behavior could help us to incent. And they know their systems better than anybody. They know how -- what that's going to look like. Because I'm also a little uncomfortable, like, you know, even leaving beneficial electrification as a potential goal. And we recognize that, you know, rate design, there are some things that could -- that fit within their purview that they could do, but I really don't want the utilities sitting there thinking about, oh, how do we get into the beneficial electrification game. Like, how do we push into that zone? Like, that's not the right policy signal for us to be thinking about. So I think we just need to be really, really careful about distorting behavior with rewards.

MS. HEALY: What about something like, you know, the utilities' conversion of customer bills to electronic billing and electronic communications? Would you view that as something that's sort of in the core, you know, bailiwick, as something that the utilities should already be doing, or would you view that as something that's more innovative? I mean, I think there are cost aspects -- you know, cost savings aspects to something like that. There are also, you know -- and I wouldn't attempt to quantify these, but things like greenhouse gas emissions benefits, you know, because you're not putting paper in the mail that's getting trucked all over the place and those types of things. Just -- I'm just throwing that out as an example to sort of test what --

MR. BURNES: I actually really don't know where they stand on that. So I -- but --

MS. HEALY: No, I'm just asking you. Like, would you consider that -- would you -- would that sound more to you like something that would be --

MR. BURNES: Yes. I mean, like, I actually -- that specific example, I'm -- I -- as a CMP customer, I think I'm already doing that. But I think that the -- I actually think there's a lot of innovation that could fit under the category of how we meter, bill, and settle energy. And coming up with new approaches on how that could overlap with beneficial electrification and interconnection of DERs could be -- that -- I would absolutely --

MS. HEALY: That would be more -- would you consider that more of a reward type situation?

MR. BURNES: Yeah.

MS. HEALY: Okay.

MR. BURNES: Yeah. You know, like, if you came up with a way of increasing the implementation time of some of the -- yeah, I think that that's a perfectly -- a perfect place to say, yeah, we would give you a higher ROI on these investments if it met these kind of criteria. Yeah, absolutely.

MS. HEALY: Do other stakeholders have thoughts on that?

MR. COHEN: I do.

MS. HEALY: Go ahead, Peter. You're a stakeholder.

MR. COHEN: So I'll give you one -- a CMP employee's opinion, not necessarily representative of the entire company. I'm not speaking for Versant. Financial incentives, but you're talking about aren't really that interesting in terms of it helping me, you know, increase my earnings because it's just they're never going to be that big and that's not really what motivates me. And I also think I can speak on behalf of CMP. Incentives motivate me more of out of fairness. So, for example, if there is a reliability metric that can be influenced by car crashes on the highway, like reliability, I have no ability to control how people are driving. But yet, if people are driving a little bit more crazy this year relative to the benchmark year, I can have a financial consequence that's completely outside my control. And I've accepted that, and Chapter 320 has enforced that. There is a negative incentive only PIM or however you want to refer to it. And that seems unfair to me because what about the year where there's less car crashes and I didn't do anything about that either? I don't get a benefit there. I just have the negative consequence. And so what I like -- and I -- I'll correct the Christensen -- we actually do have a PIM that is not just negative at CMP. We can offset negative performances for our service quality metrics with positive performances. And so, for example, if we fail to meet SAIFI, we can make it up with CAIDI. And if we fail to meet ASA 30, we can make it up in, you know, percent of meters read. That came in our last rate case, and I think people thought, oh, well, you know, who cares, they'll never use it. And we never used it. We never needed it. We met all our metrics, you know, that were harder than Chapter 320 and progressively harder through the years. But it meant a lot to the utility to know that there was a way of offsetting the uncontrollable so that it wasn't always hurting me as a company. And so I don't -- what a utility wants is a framework. We don't want a one-year plan where we have to keep coming in over and over again. I don't mind reporting. I don't mind being held accountable. I don't mind having negative revenue adjustments. I just want it to be fair, and it's not always, well, let's assume that the utility is a bad actor, let's assume that they're only motivated by sheer profit alone. Because I can tell you that we have a thousand employees at CMP that don't think of it like that. We don't look at our balance sheet and our income statements every day. We look at our customer service metrics every day, I can tell you that. We have a weekly report from Linda Ball that talks about our -- you know, how we're doing and how we're doing against plan. When -- anyways, so I just don't want folks to get the idea that if you offer me some 25 basis point incentive to do something, that that's really that interesting. But if you let me have a multi-year rate plan where we can focus on the things that will help you achieve those objectives, that's really what a utility wants. And that's what performance-based ratemaking -- we already have that. I mean, CMP already has that. And I feel as though we've done well over the past couple of years. We met all our metrics. You know, things seem to be good. We're not over earning by any stretch of the imagination. But we're not crying either about it. We're just doing our best, and I guess that's my feedback for the consultant as you think about it. We already have performance-based ratemaking as you've accurately diagnosed, a lot more than people think. And we have earnings sharing mechanism that only goes one way, for example. So it protects customers. We have downward-only reconciliation of capital spending. Only goes one way, protects the customer. We have a lot of customer protections that this utility itself proposed in its last rate case. It wasn't enforced on CMP. We proposed it when we asked for a three-year multi-year -- three-year plan. And that's kind of how at least CMP views this, and we're happy that this is occurring, this inquiry, so that we can be an active participant. But don't think, you know, you give me a ten-basis point thing if I do this right or that right. I was going to do that right either way. Just make it fair, that's all.

MR. CROWLEY: So if I might just say two things in response. First, just want to confirm the -- what you had said regarding the SQIs being not only penalty related. We -- at the top of page, I think, 72 or 71 of our report, we do talk about that. It's 72, that Central Maine Power can offset penalties within the same category for improvements in performance. Or they can use improved performance to offset poor performance. Is that the characterization that you would put it?

MR. COHEN: Yeah.

MR. CROWLEY: Okay, I agree. I still think it's penalty only because you never get a reward for that.

MR. COHEN: That's not a -- that's not how a utility looks at it, just so that you know. In fact, we were very excited to have the ability to offset with a positive.

MR. CROWLEY: Okay.

MR. COHEN: So, yeah, as far as the utility is concerned, that is a positive benefit.

MR. CROWLEY: Okay.

MS. TUGGEY: This utility anyway.

MR. COHEN: Yeah.

MR. CROWLEY: All right, well, that's helpful. The second thing I wanted to say is just to echo -- sorry, I don't your name in front of me, the person who was just talking. Peter? Peter Cohen? Yeah, so another point that you just made about the PIMs -- you know, the -- you know, you give a few basis points here and there on ROE and that doesn't affect behavior that much. I will just say from my experience speaking with the director of regulatory at Hawaiian Electric Company on this exact point, he had the same thing to say. He -- his -- so in Hawaii, how PBR went about happening in Hawaii is that they had this kind of long prolonged stakeholder engagement. They had all this collaboration, many, many years of work that went into the Hawaiian Public Utility Commission ultimately saying, okay, Hawaiian Electric Company, you now have this revenue cap and also you have these six PIMs. And I think what -- I don't know that there's any, like, documentation that I have that I can give you on this, but what they felt is that the PIMs were kind of aspirational and they ultimately didn't do that much to change any kind of behavior because of the reason that Peter was just saying which is that, you know, in the case where -- there are some cases where there are things that -- you know, there were policy goals that were being reached for, but the reward just simply wasn't sufficient to incent the behavior toward getting to those policy goals. And then in other cases, the utility already was going to do the things that it was going to do anyway under those PIMs. And so it -- the -- what would be interesting is to learn if there's -- I'm not aware of any academic research that has been done to say that PIMs do a whole lot to change utility behavior. Now, the theory would say that it would because if there's ever money on the line, the utility should be trying to minimize the loss and maximize the benefit. But sometimes there are practical limitations to that. So I'll just say that I've heard that in other jurisdictions.

MS. HEALY: (Indiscernible) about 20 minutes left. Does anyone want to respond to that topic or bring anything else up?

MR. MARSHALL: I had kind of a new question if I could.

MS. HEALY: Yeah, go ahead. Brian from the Public Advocate's office.

MR. MARSHALL: Yeah, Brian Marshall for the OPA. So in the PBR framework, the I minus X, you know, that makes sense to me as providing this strong cost control mechanism on a utility, but in a lot of the examples you pulled from, there's, you know, all these other things layered in. And especially when we start talking about things like capital trackers, it strikes me that you could really be distorting the cost control incentives there, right? So if I'm thinking, like, for any given solution or most solutions, there's, you know, conceivably an O&M solution and a capital solution. And what we want to do is encourage the utility to find the best mix of O&M and capital. But if you're only giving, like, separate specific recovery for capital spend, then aren't you really sending the incentive to the utility that they should be spending more capital? You know, just to give you some specific examples, you know, you could trim the trees more or install, you know, some capital -- covered conductor or replace the poles. Both of those solutions go at reliability. One does it through O&M, one does it through capital. So if you're allowing the utility to recover separately just those capital investments, haven't we distorted this whole analysis? Maybe you could help me out with that part of it.

MR. CROWLEY: I think the answer to that is yes. There's -- the most pure form of PBR would be just I minus X. But what we encounter in the world of distribution utilities, especially lately, is that I minus X -- so I minus X, if perfectly calibrated, would give the utility what it needs in order to survive a five-year rate stay out period. But the X factor, generally speaking, is based on historical TFP, and that historical total factor productivity is potentially reflecting conditions that are not the conditions the utility's going to experience in the next five years. So, like, in the -- so, for example, if a utility had come in for a price cap filing in the year 2020 and it had an X factor based on total factor productivity growth from the year 2005 to the year 2019, that X factor would not be giving that utility enough revenue support most likely to meet its capital needs for the next five years because, as we know, everything became incredibly expensive and in a way that wasn't necessarily reflected in the inflation measure right away. So to sort of come back to the question is it distorting utility incentives, I think the answer is yes, but also there's a practical question of, you know, what is the -- what is it -- what is the utility actually able to do? And if I minus X is insufficient, which it has been in recent years, then there needs to be some form of capital supplement.

I'll also say a lot of regulators lately have been accepting zero percent X factors which are not based on total factor productivity but are arbitrarily chosen. And if the X factor was empirically set, the need for a capital investment support would go down because the X factor is -- the empirical X factor is negative these days.

MR. COHEN: Isn't the K factor actually meant -- so the way that this formula would work is that everything is pegged on some sort of inflation less an X factor if it exists or a Z factor if it exists. And so the K is meant to suggest that there may be times like right now when capital investment needs outpace the inflation that would be supporting it in a price cap. Do you see what I'm saying? So it's not necessarily -- I think, Brian, you might be thinking it's like a targeted program. If you can, you know, focus on tin cans, then you can have this as a tracker. I actually think that a price cap, that K, is more about this differential between the underlying inflation assumption and the needs of capital investment, you know, at a macro level. Or am I thinking about that wrong?

MR. CROWLEY: It's close, but one thing that I'll say is that, like I said earlier, if the X factor could be completely accurately calculated, then that concern would go away because what the X factor is doing is saying -- the X factor is not a -- is not an optional component to the price cap. It is -- the I minus X formula is derived from economic theory where the I factor is input prices. So the price that the utility is paying for the stuff that it's buying, that includes capital and labor, like, the wage cost and the cost to buy a transformer, for example. But the X factor is how much of that stuff do we need to buy and how much output are we producing with what we buy. The X factor is productivity. So it's like the percentage change in output minus the percentage change in input. If you're needing more -- if the industry needs more and more input in order to produce the same amount of output, that X factor will be negative. And that means that the annual adjustment to rates is going to be higher than the rate of inflation which I know I'm saying that stuff kind of fast, but --

MR. COHEN: No, it's fine. It's just not the same amount of output. So I hear what you're saying, though, and I understand.

MR. CROWLEY: But -- yeah, so that's -- in summary, if you had an X factor that could be accurately reflective of what the utility's going to be experiencing over the next five years, most likely the K factor would be less important. But it's -- we really don't live in a world where that is the norm lately, is that X factors tend not to be set according to TFP and instead are sort of set arbitrarily by the regulator which is something that I would advocate against. I think if you're going to have an X factor, it should be based on the data.

One other thing on K factors that I'll mention is that they're not all the same. I think I have -- yeah, this slide here just shows an example of different types of capital funding mechanisms. And if you focus on the last one, K-bar, K-bar is one that is probably, out of these, the most -- it provides the utility with the best cost efficiency incentives with regard to capital because under the first three, it's basically some form of cost-based revenue recovery mechanism where the utility says I incurred or plan to incur these capital costs, can I please collect the revenue that I need to make those costs. K-bar says there is sort of a mechanized revenue requirement that we expect to need based on our past spending, recent past, usually, like, last three years, maybe last five years, and if I minus X doesn't give us that, then we need the rest of it. And so the utility under that kind of approach does have more incentive to reduce its capital spending than maybe under a capital tracker approach.

I had another point on this which is that I -- getting all the way back to the first point that was made, isn't it distorting incentives, and I said yes. But the thing about operating under a price cap or a revenue cap or a well-calibrated multi-year rate plan is that the utility has an incentive to reduce its costs. It's not really a concern that the utility's going to be spending more on capital under one of these approaches because the utility has an incentive to spend less generally speaking. Usually the concern is will the utility spend enough on capital. And so that's what the tracker or the kind of additional capital spending approach is trying to do is say, okay, we know that under pure I minus X with no capital supplements, the utility has an incentive to reduce its costs. But we have to make sure that the utility doesn't stop spending money on needed capital. So we're going to give this additional tool to make sure that there's not potentially damaging, like, cost reduction happening. Anyway, that's one of the theories behind capital funding.

MS. HEALY: Thank you. Anyone else on Teams have questions, comments? Okay, anyone else in the room have questions, comments? All right, well, thank you, everyone, for the discussion this morning. This was very interesting, and certainly please consider filing written comments, and we look forward to receiving those. And I think with that, we'll call it the close of the workshop, and I hope you all have a good weekend. Or a good afternoon if you're coming back here this afternoon.

MR. SIMMONS: Thanks to the Christensen folks for joining.

MS. HEALY: Yes, and thank you very much, Nick and crew. We really appreciate it. And we'll be in touch.

MR. CROWLEY: Yeah, thanks to everyone, and I look forward to seeing --

MS. HEALY: And I'll wait to receive the updated slides from you, Nick, and people can probably look for the slides on Monday.

MR. CROWLEY: All right. Well, I'll send them along this afternoon. Thank you, everyone.

CONFERENCE ADJOURNED (May 16, 2025, 11:51 a.m.)

C E R T I F I C A T E

I hereby certify that this is a true and accurate transcript of the proceedings which have been electronically recorded in this matter on the aforementioned hearing date.

D. Noelle Forrest

D. Noelle Forrest, Transcriber

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2025-00107

May 22, 2025

PUBLIC UTILITIES COMMISSION
Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities

PROCEDURAL ORDER
(Christensen's Presentation)

The Commission appreciates the thoughtful participation of those that attended the May 16, 2025 workshop. Christensen Associates Energy Consulting's slides from its workshop presentation are attached as Attachment A. Further, the Ontario Energy Board resource that Christensen posted to the meeting chat may be found at: OEB Releases Discussion Paper on Performance Incentive Mechanisms | Advancing Performance-based Rate Regulation | Engage with Us.

As described in the April 30, 2025 Notice of Inquiry written comments regarding Christensen's draft report may be filed by **Friday, May 30, 2025**. Written comments should be filed in the Commission's Case Management System under the "filings" module. For instructions how to file with the Commission, please visit https://www.maine.gov/mpuc/online-services/electronic-case-filing-consumer-complaint-system-documentation.

Dated at Hallowell, Maine, this 22nd day of May 2025.

BY ORDER OF THE PRESIDING OFFICER

Nora Healy

Nora Healy

Presiding Officer

Attachment A

Christensen ASSOCIATES

Performance-Based Regulation in the State of Maine

May 16, 2025

Nick Crowley, Xueting (Sherry) Wang,
Andi Romanovs-Malovrh,
and Corey Goodrich

Christensen Associates Energy Consulting

A wholly-owned subsidiary of Laurits R. Christensen Associates

- Costing, pricing, econometric analysis, and alternative regulation research across many industries:
  - Electric and gas utilities
  - Telecommunications
  - US Postal Service
  - Railroads
  - Oil Pipelines
- Empirical work and qualitative research:
  - Total factor productivity
  - Cost benchmarking
  - Performance incentive mechanisms
  - Regulatory framework design
- Work products include reports, testimony, presentations, and regulatory strategy

Recent PBR Work

EPCOR

New Hampshire Department of Energy

nationalgrid

ONTARIO ENERGY BOARD

EVERSOURCE ENERGY

BC Hydro

Unitil

Indiana Utility Regulatory Commission IURC

Workshop Outline

1. Project Background and the Purpose of this Meeting
2. Defining Performance-Based Regulation ("PBR")
   - Performance Incentive Mechanisms
   - Multi-Year Rate Plans
3. Maine's Existing PBR Tools and Policy Goals
4. PBR Tools for Consideration in Maine
5. Observations and Next Steps

Attachment A

Project Background and the Purpose of the Meeting

Christensen ASSOCIATES

Project Background

- **Purpose:** Evaluate PBR tools that may be used to regulate investor-owned electric utilities (IOUs) in the state of Maine
- **Scope:**
  - Review of the standards and metrics utilized in other states that have implemented PBR
  - Assist the commission in developing goals for utility performance and translate these goals into performance-based standards and metrics
  - Identify emerging regulatory mechanisms that would better align utility performance with state policies and goals when compared to other traditional forms of regulation

Stakeholder Engagement Meeting Purpose

The purpose of this meeting is to:

Present our findings on relevant PBR tools and how they may be applicable for Maine

Listen to your feedback on policy goals and the application of these regulatory tools to Maine.

Defining "Performance-Based Regulation"

Christensen ASSOCIATES

Forms of Utility Regulation

Traditional Regulation: sets rates with cost-of-service filings as frequently as required by the utility

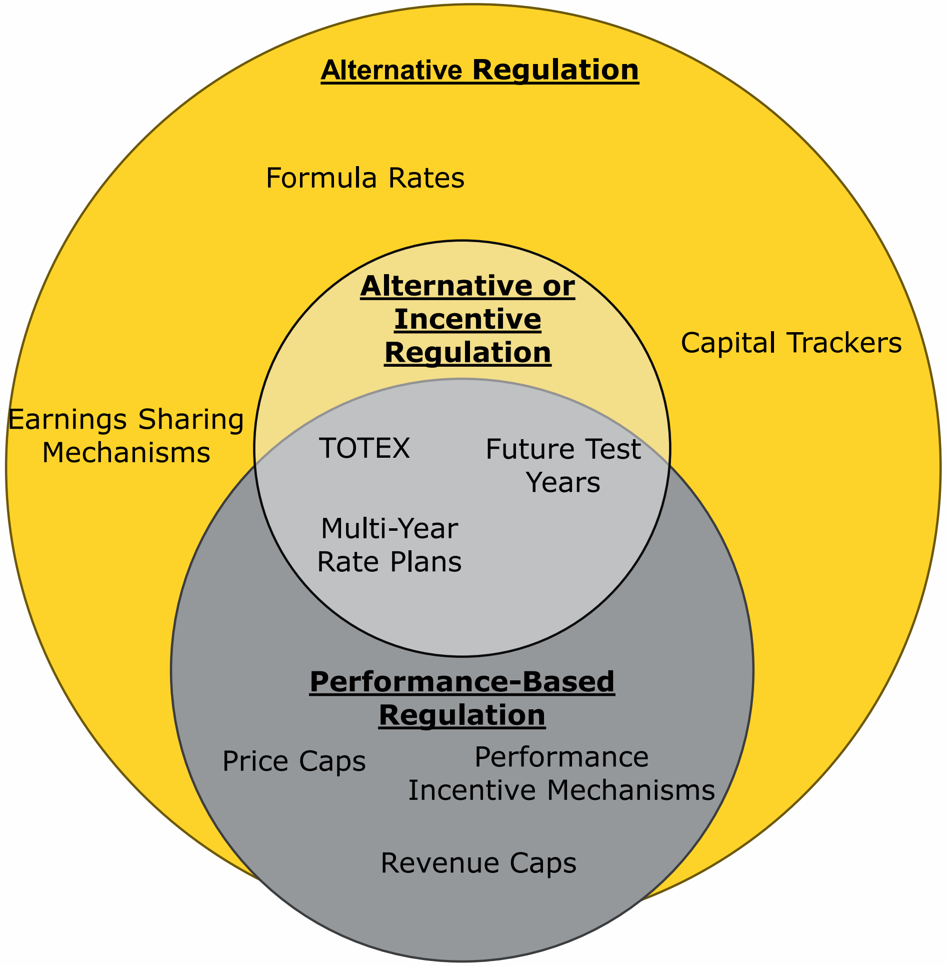
Alternative Regulation: can mean any deviation from traditional regulation.

- Does not necessarily mean improved incentive properties.

Not Synonyms!

Performance-Based Regulation: is generally considered a subset of Alternative Regulation

- By definition, focuses on incentives
- Also known as Incentive Regulation



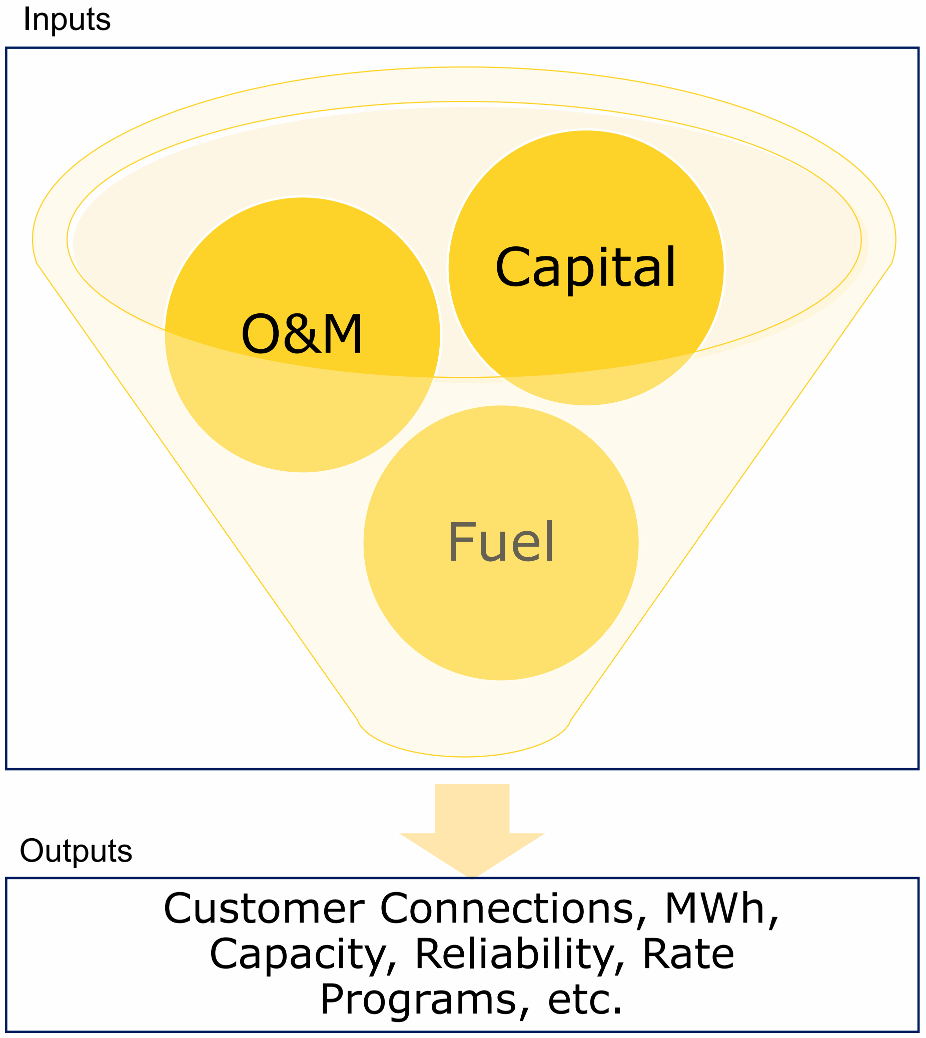
PBR – Fundamental Tools

1. MYRPs (Forecasted or Indexed Capped)

- Incent the utility to produce outputs using the least-costly combination of inputs.
- Key Question: What framework provides incentives, but is also feasible?

2. Performance Incentive Mechanisms

- Provide financial incentives for the utility to provide certain measurable outputs.
- Key Question: What are, or should be, the utility's outputs?



Traditional vs. Performance-Based Regulation

Note: Terminology is tricky!

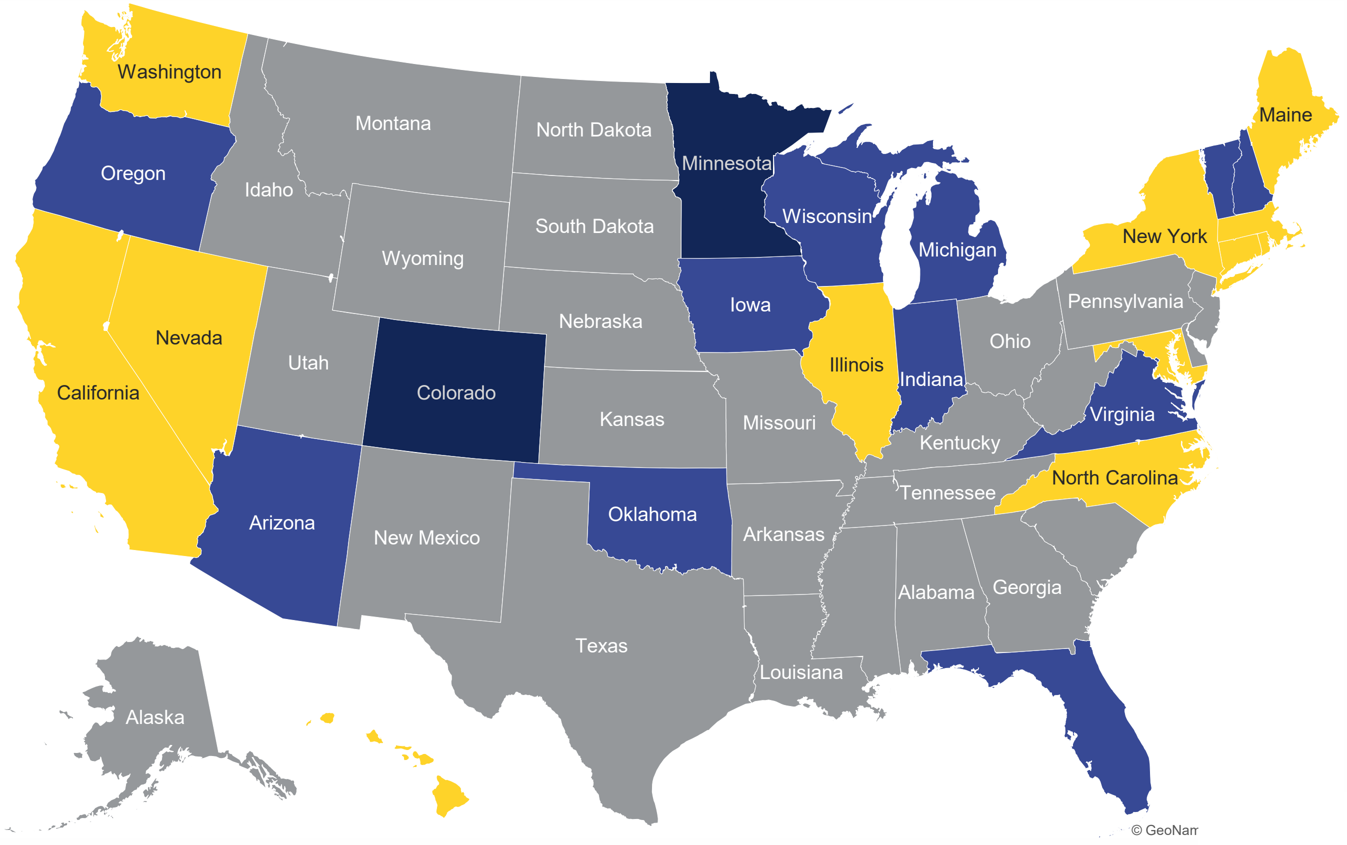
TRADITIONAL

- **Cost-based:**
  - Costs and revenues are closely linked
  - Allowed rate of return set by the regulator
- **Frequent rate applications when costs are rising and outputs falling:**
  - Rate applications could be as often as every 1-3 years
- **Relatively low incentives:**
  - Efficiency gains quickly returned to consumers; poor efficiency recovered
  - Desired outputs may not be delivered

PERFORMANCE-BASED

- **Revenues and costs could be disconnected**
  - Utility may earn above or below the cost to serve over an extended time
  - Rate of return may be more dependent upon performance
- **Less frequent rate applications:**
  - Rate stay-out periods extend the time between cost-based rate adjustments
- **Designed with enhanced incentives:**
  - May mimic competitive markets
  - Incent production of certain outputs

Status of PBR Across United States



No PBR
Exploration
Implementation
Implementation On Hold

Connecticut
Delaware
Hawaii
Maryland
Massachusetts
New Hampshire
New Jersey
Rhode Island
Vermont
Washington D.C.
West Virginia

Christensen ASSOCIATES

Attachment A

Existing PBR Tools and Policy Goals in Maine

Christensen Associates

Existing PBR tools in Maine

1 Multi-Year Rate Plans

Distribution utilities in Maine are allowed to propose plans that:

- cover multiple years
- pair with forecasted or indexed rate increases

2 Service Quality Indicators (SQIs)

- Reliability indices
- Customer service response time
- Billing accuracy

Proposed Policy Goals in Maine

1	Promote efficient and cost-effective transmission and distribution utility operations
2	Increase planning and preparation for extreme weather events and climate hazards
3	Promote cost-effective and comprehensive responses to outages
4	Increase affordability and customer empowerment and satisfaction
5	Support achievement of the State's goals for increasing consumption of electricity from renewable resources
6	Advance the State's greenhouse gas emissions reduction goals
7	Advance beneficial electrification

PBR Tools for Consideration in Maine

Christensen ASSOCIATES

Indexed Caps: Price and Revenue Caps

Price and Revenue caps emulate competitive markets

1. Revenue requirement set in initial rate application
2. Formula fixes company's price or revenue growth at the rate it would face in a competitive market.
3. Company will cut costs to maximize profit if it retains some profit for doing so.
4. Rates reset according to cost-to-serve in next rate application (typically 5 years later)

Typical Price Cap Formula:

$$\% \Delta \text{Price} = I - (X+S) + Y + Z + K$$

The core "I – X" formula:

- I: input price inflation
- X: industry productivity

Adjustments:

- S: stretch factor
- Y + Z: exogenous factors
- K: supports capital investment

Can Indexed Caps be Applied in Maine?

Advantages

- Indexed caps aim to provide cost efficiency incentives
- Maine's IOUs are "lines-only" utilities, which is similar to other jurisdictions where utilities operate under indexed caps
- Past experience with price caps in Maine

Challenges

- Maine's IOUs are transmission owners:
  - Larger and lumpier investments
  - Transmission projects are often directed by ISO-NE
- If adopted, indexed cap PBR should be accompanied by factors that allow for the recovery of costs beyond utility management's control

Making Indexed Caps Feasible

- Price cap formula forms the basis of the PBR plan
- Additional elements are often included :
  - Exogenous factors
  - Capital trackers
  - Additional guardrails
    - Earnings sharing mechanisms
    - Reopeners/Off-ramps

Fuel cost trackers
Tax changes
Storm cost recovery
Pension costs
Insurance costs
Transmission charges

E.g.,
Hawaii: Exceptional Project Recovery Mechanism;
Ontario: Incremental Capital Module
Massachusetts and Alberta: K-bar

Can PIMs be Expanded in Maine?

Utilities in Maine already operate under penalty-only PIMs

- PIMs can be reward-only; penalty-only; or symmetrical
  - Maines SQIs for basic service quality are penalty-only
  - Both New York and Hawaii have reward-only and symmetrical PIMs
- Other jurisdictions have introduced PIMs to encourage investment or action to meet policy objectives similar to Maine’s policy goals
- Distributors in Maine have less control over certain outcomes such as greenhouse gas (GHG) emissions

Advantages and Challenges of PIMs

ADVANTAGES

Alignment with Public Policy Goals

- Targeted incentives allow regulators to promote important policy goals
- Can shift the focus from capital investment to measurable outcomes

Focused on efficient outcomes

- Utility provides service demanded by customers and is rewarded according to the value of that service

Flexibility and Transparency

- Increases transparency in utility performance through measurable metrics
- Incentive mechanisms can be changed to adjust to changing market conditions

CHALLENGES

Design Complexity

- Difficult to quantify performance outcomes and set appropriate rewards/penalties
- Limits to timely access to metrics

Accounting for External Factors

- Uncontrollable external factors may impact performance metrics
- Mechanism must balance fairness with administration simplicity

Unintended Consequences

- Poor design can lead to attention toward specific goals to the detriment of service that is not rewarded/penalized
- Risk of gaming or manipulation by utilities

Observations and Next Steps

- Maine IOUs face service quality indicators that meet the definition of PIMs
- The state's Alternative Regulation option currently allows the utilities to file a MYRP
- Other jurisdictions require electric utilities to operate under some form of PBR
- Christensen Associates will provide recommendations following this stakeholder engagement meeting

Questions for Stakeholders

- Are the proposed policy goals appropriate for guiding the design of a regulatory framework in Maine?
- Are there nuances to the current regulatory framework in Maine that are not fully reflected in the Christensen report?
- Is an expansion of PIMs in the state appropriate? If so, how should they be developed?
- For the utilities: what guidance do you need from the Commission before putting together a rate application with PBR tools that are not currently used in Maine?

Appendix:
Additional Material

Christensen
ASSOCIATES

Ontario – Electric Distribution Utilities

1. The Ontario Energy Board has operated under PBR since 2000
2. Electric utilities may select a choice from a menu of options
    - Price cap
    - "Customer IR"
    - Annual IR Index
3. Each utility has a different PBR plan
    - Some with ESMs, some not
    - X factors vary
    - Stretch factors vary
    - Capital supplements are utility-specific
4. Natural Gas (e.g., Enbridge Gas Distribution) also operate under PBR in Ontario

Alberta – Electric and Gas Distribution Companies

Electricity and gas distribution currently operating under third generation PBR framework

1. Single proceeding captures all utilities, every 5 years
2. Asymmetric ESM approved in 2023
   - 200 bps deadband
3. Supplemental capital mechanism included
4. Although positive stated X factor, effective X negative once capital funding considered
5. No service quality or other PIM adjustment factors

British Columbia - FortisBC (Electric and Gas)

1. Currently operating under a five-year MYRP
2. X factor + Stretch factor of 0.5%
3. Electric and gas PBR frameworks differ in treatment of capital
   - Electric: All capital is forecast
   - Gas: "Sustainment" capital is forecast
4. Earnings sharing with no deadband
5. Flow through (Y factor) treatment of costs for many deferral accounts
6. No service quality or other PIM adjustment factors

Hawaii – Integrated Electric Utilities
Docket 2018-0088

1. Revenue cap with an X factor of zero
2. Over 60 different performance metrics
3. Symmetrical ESM
4. Capital supplement: “Exceptional Project Recovery Mechanism”
5. Reopener with three possible triggers:
   - ROE threshold
   - Credit rating downgrade
   - Commission discretion

Massachusetts Eversource (Electric Distribution)
Docket DPU 22-22

1. Second Generation plan approved November 2022
    - First generation plan had first negative X factor in U.S. electric utility regulation
2. Asymmetrical ESM: profits shared; losses not recovered
3. No PIMs
4. Added a capital supplement akin to Alberta's in PBR2
5. In the first generation, extensive stakeholder education process prior to filing

Massachusetts - Eversource (Gas)

Docket DPU 19-120

1. Revenue cap with a negative X-factor
2. 10-year rate stay-out period
3. ESM above 100 basis points
4. Consumer dividend of 15 basis points
5. Z-factor for O&M expenditures over $700K
6. Set of scorecard metrics to measure the success of PBR Plan implementation

California – Multi-Year Rate Plans

1. Four-year MYRP
2. Uses mechanisms other than "incentive" mechanisms to achieve goals
   - Example: Demand response programs
   - No PIMs!
3. The utility remuneration framework includes capital cost trackers

Distribution Regulation	
Regulated Utilities	6
Ratemaking regulator	California Public Utilities Commission
Transmission Operator	California Independent Systems Operator
UR Elements	
Multi-Year Rate Plans	✓
Revenue Decoupling	✓
Revenue Cap	
Price Cap	
PIMs	
Earnings Sharing Mechanisms	

New York – REV

"Reforming the Energy Vison"

1. Three-year MYRP based on forecasted cost to serve
2. Have seven "earnings adjustment mechanisms" (essentially, PIMs)
   - Includes "Non-Wires Alternatives" incentives
   - Additionally, NY utilities have scorecard metrics (with no financial incentive)
3. Considered TOTEX, but did not adopt it

Distribution Regulation	
Regulated Utilities	6
Ratemaking regulator	NYPSC
Transmission Operator	NYISO
UR Elements	
Multi-Year Rate Plans	✓
Revenue Decoupling	✓
Revenue Cap	
Price Cap	
PIMs	✓
Earnings Sharing Mechanisms	✓

Incentive Regulation Beyond North America

- United Kingdom
  - RPI-X (early 1990s-2013)
  - RIIO-1 (2013-2021)
  - RIIO-2 (2021-2028)
- Australia
  - Revenue caps set with building block approach
  - Both distribution and transmission
- New Zealand
  - Revenue cap on distribution utilities

RIIO: Revenue = Incentives + Innovation + Outputs

- Separate (but similar) price controls exist for:
  - Electricity distribution
  - Electricity transmission
  - Gas distribution
- Five-Year MYRP approach using both forecasts and inflation to set revenues.
- The distributor base revenues (set in 2012-13 prices) are inflated in the Retail Prices Index (RPI).
  - Plus incentive rewards or penalties for over- or under- delivery of the outputs utility must deliver.
  - Uncertainty mechanisms

Capital Funding and Indexed PBR

- Capital funding needs have often outpaced output and revenue growth
  - Electrification
  - Replacement of ageing plant
- Different jurisdictions have addressed this problem in different ways

Approach	Jurisdictions	Methodology
Forecast Capital	British Columbia; Australia	In the PBR proceeding to set initial rates, the utility establishes a forecast of capital spending costs over the PBR term and recovers these costs through rates.
Cost-of-service (capital trackers)	Massachusetts	Gas utilities in Massachusetts may recover capital expenditures beyond the PBR formula under the state's Gas Safety Enhancement Program.
Project-Specific	Ontario; Hawaii	Utilities may recover costs for projects that meet certain criteria. Known as the Exceptional Project Recovery Mechanism in Hawaii, and the Incremental Capital Module in Ontario.
K-Bar	Massachusetts; Alberta	This approach provides a capital spending envelope based on the utility's own trend in historical capital spending.

- Price cap is now

$$\%\Delta \text{Price} = I - X + Y + Z + \boldsymbol{K}$$

Capital Supplements – K-Bar

Key Features:
- Uses company-specific historical spending to set future revenue growth
- May be designed with a static time period or a rolling average

Advantages:
- Retains cost containment incentives of an effective PBR plan
- Has no forecast inflation risk

Disadvantages:
- More difficult to understand
- Obscures the meaning of the X and Stretch factors
- Hinges on the assumption that investment decisions in the past are an accurate predictor for investment decisions in the present

K-Bar Calculation Steps:

Step 1: Calculate the "going in" capital-related revenue requirement that is recovered in the base rates under the I-X mechanism for the first year of the PBR term. This is the sum of the Company's depreciation expense, the return on rate base, and property taxes.

Step 2: Establish the percentage change in revenue collected under the I-X formula, which in this case is set equal to GDP-PI minus zero.

Step 3: Determine the capital recovery supported by I-X for a given year by inflating the "going in" capital revenue requirement by GDP-PI.

Step 4: Calculate the notional revenue requirement for capital expenditures the year, based on historical capital spending.

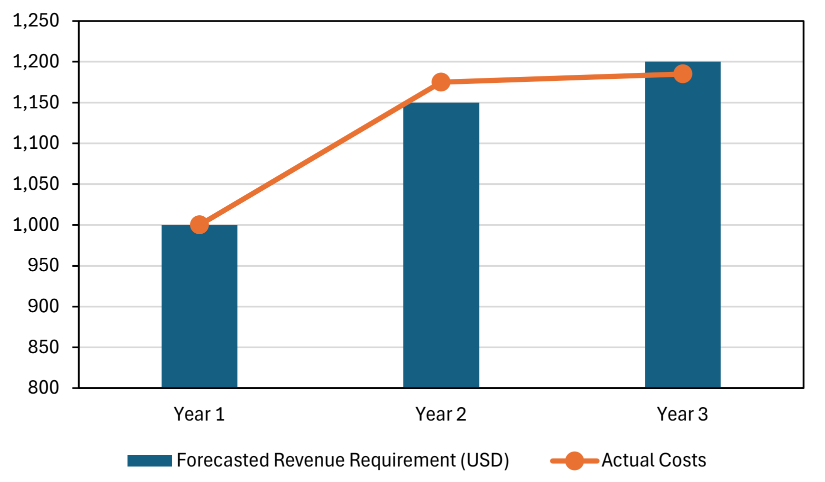
i. Obtain capital additions for each of the past three years.
ii. Inflate each of the capital additions to current dollars using the approved I-X formula, with the approved I factor for each year and the approved X factor for the prior generation PBR plan.
iii. Using the inflated capital additions, calculate the average K-bar capital additions over the historical three-year period.
iv. Inflate the average K-bar capital additions to the current year using the new approved I-X formula.
v. Calculate the amount of K-bar capital cost incurred for the current year as the sum of depreciation, return on rate base, and property taxes, based on the current year capital additions from the prior sub-step.

Step 5: Calculate the base K-bar. Calculate the difference between the current year K-bar capital-related revenue requirement required on a projected basis (from Step 4) and the current year K-bar capital-related revenue requirement recovered in the base rates (from Step 3). The result is the capital funding shortfall or surplus amount for the current year.

Capital Supplements – F-Factor

Key Features:

- Utility forecasts its required capital-related revenue for the PBR term
- Only recovers this amount—cannot recover more if spending exceeds forecast



Advantages:

- Utilities receive their expected revenue shortfall for capital expenses, while still maintaining some incentive to contain those expenses.
- Reduces regulatory burden by setting the forecast before the term begins, and leaving any variances between actual and forecasted spending to be handled mechanistically through the ESM rather than through annual cost-of-service proceedings.

Disadvantages:

- May incentivize the utility to over-forecast capital expenses if it is able to retain any savings as profit.
  - This can be mitigated through prudency reviews before and after the PBR term.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

MAINE PUBLIC UTILITIES COMMISSION	**COMMENTS**
INQUIRY INTO PERFORMANCE-BASED REGULATION OF INVESTOR-OWNED TRANSMISSION AND DISTRIBUTION UTILITIES	**EFFICIENCY MAINE TRUST**
	MAY 30, 2025
DOCKET NO. 2025-00107	

Efficiency Maine Trust (hereinafter "the Trust") offers these comments in response to the Notice of Inquiry issued on April 30, 2025. In particular, the Trust is providing here comments related to the goals of Performance Based Regulation (PBR) set forth in the Christensen's draft report as requested by the Public Utilities Commission.

I. Goals of PBR in the draft report

The Trust recommends elements of the draft report that are not fully within the control or authority of investor-owned utilities either be removed from the report or be given the level of emphasis consistent with the utilities level of control. The Efficiency Maine Trust Act grants statutory authority to the Trust to develop, plan, coordinate, and implement energy efficiency, beneficial electrification and demand management programs across Maine. The draft report provides discussion and examples of PBR that are within the purview of the Trust and other entities.

For example, section 4.6 of the report discusses the potential of Performance Incentive Mechanisms (PIMs) to "…facilitate the deployment of distributed energy resources (DERs), and promote non-wire alternatives over traditional capital investments, among other objectives."[1] There are examples provided from other jurisdictions of PIMs that include non-wire alternatives, electric vehicle adoption rates, building electrification, and DER utilization.[2] While there are discrete tasks that the investor-owned utilities undertake to assist the Trust in implementing these objectives, for the most part it falls outside of their authority and the Trust recommends that these examples and other elements of the report that are within the purview of the Trust and other entities are removed or put into the appropriate context.

Respectfully submitted,

/s/IGB

Ian Burnes
Director of Strategic Initiatives
Efficiency Maine Trust

[1] Christensen's draft report, page 21.
[2] ibid, pages 24-29, tables 4.4, 4.5, 4.6.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

PUBLIC UTILITIES COMMISSION

RE: Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities

Docket No. 2025-00107

COMMENTS OF THE OFFICE OF THE PUBLIC ADVOCATE

May 30, 2025

I. Introduction

The Office of the Public Advocate (OPA) files these comments pursuant to the Notice of Inquiry (NOI) into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities issued by the Public Utilities Commission (Commission or PUC) on April 30, 2025. Through the NOI, the Commission seeks input related to the goals of Performance Based Ratemaking (PBR), and the mechanisms by which the Commission could implement such goals. To address the implementation of PBR regulations, the OPA is submitting comments by Synapse Energy Economics, provided here as Attachment A. Below are the OPA's comments addressing the PBR policy goals as set forth in the draft Christensen Report.

II. Discussion of PBR Policy Goals

A. Review of Christensen Report Policy Goals

Section 7.3 of the draft Christensen Report identifies a version of regulatory goals for the state of Maine.[1] Most of these goals were articulated in a proposed statute, LD 2172, which did not pass, but are an indication of legislative intent.[2]

The draft regulatory goals are as follows:

1. Promote efficient and cost-effective transmission and distribution utility operations;
2. Increase planning and preparation for extreme weather events and climate hazards;
3. Promote cost-effective and comprehensive responses to outages;
4. Increase affordability and customer empowerment and satisfaction;
5. Support the achievement of the State's goals for increasing consumption of electricity from renewable resources;
6. Advance the State's greenhouse gas emissions reduction goals established; and
7. Advance beneficial electrification.

These goals encompass broad areas of policy for the state. PBR is one tool among many that may impact the state's ability to achieve these goals. It is only to the extent that utility actions can influence a policy goal cost-effectively, that they should be incentivized through a PBR mechanism.

Policy goals 1-3 address elements within a utility's current area of responsibility to provide safe and reliable utility service. Maine's existing utility Service Quality Indices (SQIs) are effectively Performance Incentive Mechanisms (PIM) that target these goals. Any additional PIMS for these goals would need to be narrowly tailored to target investment that would not otherwise take place under existing regulations.

Policy goal 4 is a fundamental goal that must be forefront in any exploration of PBRs. Borrowing language from the Hawaii PBR Guiding Principles, the goal of "customer empowerment" could be expressed more expansively as follows:

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[1] Public Utilities Commission *Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities,* Notice of Inquiry, Docket No. 2025-00107 (April 30, 2025) Attachment A, (Christensen Report) at 72.

[2] [LD 2172, HP 1391, Text and Status, 131st Legislature, Second Regular Session]

> A customer-centric approach. A PBR framework should encourage the expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions, including verifiable "day-one" savings for customers. [3]

Adding a separate goal of affordability would highlight the importance of this goal to ratepayers, such as "Increase affordability of utility rates such that arrearages and disconnections due to nonpayment are decreased as customer energy burdens are lowered."

Policy goals 5-7 are directed toward state climate policy goals. Any PBR tied to such goals must be narrowly tailored to be within the control of a wire-only utility and be a cost-effective approach toward meeting that goal. For example, ratepayers bear costs for Efficiency Maine Trust (EMT) programs which support goal #7, advancing beneficial electrification. It would be unjust for ratepayers to also pay for a utility PBR incentive program which is redundant of or possibly counter to existing EMT programs.

B. OPA Proposed Public Policy Goals

An effective PBR should strengthen the link between what utilities earn and the achievement of outcomes consumers value, such as cost effectiveness, reliability, customer service, and ensuring alignment with government policies. Borrowing language from the Ontario and Hawaii PBR principles referenced in the draft Christensen Report, a set of PBR goals for Maine that emphasize these outcomes could include the following:

1. A customer-centric approach. Encourage expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions, including verifiable "day-one" savings for customers.

2. Affordability. Increase affordability of utility rates such that arrearages and disconnections due to nonpayment are decreased as customer energy burdens are lowered.

3. Operational Effectiveness. Continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives.

4. Public Policy Responsiveness. Utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements)

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[3] *Id.* at 141.

5. Financial Performance: utility financial viability is maintained; and savings from operational effectiveness are sustainable.

III. Conclusion

It is challenging to design a PBR that incentivizes a utility to achieve identified goals without overcompensating the utility for perceived risks of moving away from cost-of-service regulation. The public policy goals expressed here are broad and may encompass objectives beyond the control of a utility. The Commission must ensure that any associated PBR targets are clearly defined and directly associated with the desired public policy goals. The Commission should ensure that the utility is in sufficient control of the variables associated with the public policy goals such that the targets create incentives for utility action. At the same time, such actions must not be considered a routine part of utility service that would be undertaken without the existence of a PBR mechanism.

While the state's public policy goals are appropriately broad, targets to incentivize utility contributions to these goals must be narrowly tailored and measurable to be effective within the confines of a PBR mechanism. As noted in the attached Synapse Report, the Commission should proceed cautiously in adopting PBR mechanisms "to ensure that the cure is not worse than the disease."

Respectfully submitted,

/s/ Susan W. Chamberlin

Susan W. Chamberlin
Senior Counsel

/s/ Brian T. Marshall

Brian T. Marshall
Senior Counsel

Performance-Based Regulatory Tools for Maine

Response to the Maine Public Utilities Commission's Request for Comments

Prepared for the Maine Office of the Public Advocate

May 29, 2025

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CONTENTS

INTRODUCTION

On April 30, 2025, the Maine Public Utilities Commission issued its *Notice of Inquiry* in Docket No. 2025-00107 requesting stakeholder input regarding the goals of Performance-Based Regulation (PBR) and potential enhancements to Maine's regulatory framework through performance-based tools such as Multi-Year Rate Plans (MYRPs) and Performance Incentive Mechanisms (PIMs).

Synapse Energy Economics, Inc. (Synapse) was retained by the Office of the Public Advocate (OPA) to respond to the draft report authored by Christensen Associates Energy Consulting (Christensen) and to generally comment on the potential for MYRPs and PIMs to promote public policy objectives while protecting consumers. Our assessment, described below, draws upon Maine's own regulatory experience, as well as our experience with PBR tools across North America.

OVERALL ASSESSMENT

Synapse has reviewed the draft Christensen report on PBR for Maine, and we find it offers a helpful description of PBR tools, as well as a useful description of some of the challenges associated with MYRPs and PIMs. We particularly agree with the report's admonition that "the introduction of new PBR tools will not guarantee improvements."[1] In theory, well-designed PBR frameworks can improve utility performance and better align utility incentives with public policy goals. However, real-world experience in Maine and elsewhere has shown that achieving these benefits in practice is far from assured.

MYRPs and PIMs are often promoted as a means of increasing efficiency and better aligning utility incentives with public interest goals. However, these mechanisms can also create perverse incentives and shift risk onto customers. MYRPs, for example, may result in unjustified revenue increases or incentivize excessive cost-cutting that undermines service quality. PIMs can lead to utilities being rewarded for actions they would have taken regardless of the incentive, or for outcomes influenced by external factors beyond their control. In these cases, customers bear the cost of incentives without receiving commensurate benefits.

Information asymmetries between utilities and regulators, combined with the complexity of designing balanced and enforceable incentives, make implementation of both PIMs and MYRPs challenging. Without careful design and oversight, PBR mechanisms can create unintended consequences that undermine regulatory outcomes and customer protections. Given these risks—particularly those

[1] Crowley, N., X. Wang, A. Romanovs-Malovrh, and C. Goodrich. Christensen Associates. Performance-Based Regulation Report for the Maine Public Utilities Commission. "Christensen Report." April 29, 2025. p. 1.

associated with MYRPs—Synapse recommends that the Commission proceed cautiously with further implementation of PBR mechanisms and ensure that strong customer protections, robust oversight, and data transparency are in place.

PIMs

Synapse agrees with the Christensen report's description of PIMs and acknowledges that additional PIMs could be designed to address various policy goals. However, we recommend that PIMs be implemented cautiously and be focused on policy goals that the utilities are most able to influence. We also concur with the report's conclusion that penalty-only PIMs are appropriate for areas within the core responsibility of the utility (e.g., providing safe and reliable service.)

Benefits of Metrics versus PIMs

As an initial matter, before implementing additional financial incentives in the form of PIMs, we recommend that the Commission focus on developing a robust set of performance tracking metrics. This approach would allow the Commission to provide the utilities with important information regarding its policy objectives, collect baseline data, evaluate the utility's performance, and identify areas in which current regulatory approaches are falling short—without introducing the risks that come with financial incentives.

Tracking metrics can also serve as a low-cost, low-risk tool to help achieve public policy goals, even where a full PIM is never established. For example, while the number of customers in arrears may not be suitable for a financial incentive (given that arrearages are also influenced by factors such as income levels and economic conditions), it remains a valuable metric. Tracking such data can help identify trends, inform utility and state program development (such as targeted assistance programs and arrearage management plans)—regardless of whether a PIM is ever applied to the metric.

To support effective use of performance metrics, we recommend that the Commission establish a standardized reporting process and centralized data repository. This would enhance transparency, reduce administrative burden, and facilitate stakeholder engagement by allowing for more efficient review and analysis of utility performance over time. It would also avoid the inefficiencies associated with ad hoc data requests and reactive analysis.

Affordability and Cost Efficiency

We also agree with the draft report's conclusion that PIMs generally do not aim to address overall utility cost efficiency,[2] but should be designed in concert with the underlying cost recovery framework (e.g.,

[2] Christensen Report, at 16.

MYRP or traditional cost of service regulation) so as to appropriately balance the incentives contained within the cost recovery framework. For example, if the utility operates under strong cost containment incentives, then higher financial incentives may be warranted for undertaking actions that the utility otherwise would not take (and which may temporarily reduce the utility's profits). Likewise, the current service quality indicators with penalties and offsets related to reliability and customer service are common across the industry and are particularly important for utilities under price-cap or revenue-cap MYRPs to guard against excessive cost cutting measures at the expense of service quality.

We also wish to note that although PIMs typically do not directly address affordability, metrics and potentially PIMs could be established to incentivize efficient operations by tracking various components of utility costs over time, such as "administrative and general expenses" per customer.

We also wish to underscore the concept that rewards and penalties should be proportionate to the value provided by the achievement of the PIM target, [3] *including the cost of achieving the PIM target*. For example, if the value of increasing performance by an increment is $500,000 and the cost of investments to achieve that incremental performance is $450,000, then the net value to customers is only $50,000. Any penalty or reward to the utility associated with achieving the additional reliability should be set below $50,000 to ensure that the achievement of the target provides benefits to customers. It may not always be possible to quantify the full cost or benefit of a PIM, but the utility and regulators should undertake the effort to understand the costs and benefits to the extent feasible.

Considerations for PIMs

To avoid over-compensating utilities and ensuring that metrics and PIMs provide value, we offer the following additional considerations for implementing PIMs:

- Are the desired public policy goals and associated metrics and targets clearly defined and measurable? It may take substantial stakeholder engagement to establish well-designed metrics and targets.
- Can these goals be achieved through existing regulatory mechanisms, or is a financial incentive necessary to spur improved performance?
- Is there a meaningful risk that utilities will not achieve these goals in the absence of a PIM? Utilities should clearly explain the barriers that prevent them from undertaking actions to achieve the goals and provide evidence regarding those barriers.

[3] Christensen Report, at 15.

MULTI-YEAR RATE PLANS

While MYRPs have the potential to create strong incentives for cost containment—thereby encouraging innovation and improving utility operating efficiency relative to traditional cost-of-service regulation—such outcomes are not guaranteed. If poorly designed, MYRPs can undermine the public interest by shifting risk to ratepayers, increasing overall costs, imposing additional regulatory burdens, or incentivizing under-investment.

Below, we examine two key challenges associated with MYRPs: accommodating capital investment and mitigating the risk of under-investment. This discussion draws on nearly two decades of experience with Central Maine Power (CMP) operating under a price-cap form of MYRP, known as an Alternative Rate Plan (ARP), from 1995 – 2013.[4] These ARPs operated as price caps, applying an "Inflation – X" formula to revenue increases.

These challenges discussed below highlight the need for the Commission to carefully evaluate the advantages and disadvantages of MYRPs relative to cost-of-service regulation before moving away from traditional approaches.

1.1. Treatment of Capital Costs

Overview

One of the most confounding problems associated with MYRPs is how to address capital costs when the traditional Inflation – X approach does not provide sufficient revenues to cover necessary investments. The Christensen report lists different approaches used by various states, including utility forecasts of capital spending, capital trackers, trends in the utility's historical capital spending, and project-specific recovery outside of the index formula.[5] The authors state that "the industry has not reached a consensus on capital recovery under PBR. Each approach to capital recovery gives rise to a certain level of complexity, risk, regulatory burden, and incentive pressure. However, the overarching similarity across PBR frameworks is that utilities have been granted means for recovering additional revenues, beyond what might be permitted under the I-X formula, in order to meet capital spending needs."[6]

Synapse generally agrees with Christensen's assessment that no mechanism offers a panacea in terms of effectively addressing capital cost recovery without introducing additional risks, distorting efficiency

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[4] Maine Public Utilities Commission. Order Approving Stipulation. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 25, 2014, at 1.

[5] Christensen Report at 44.

[6] Christensen Report at 45.

incentives, or increasing regulatory burden. We summarize below the risks to customers associated with each approach:[7]

- Capital trackers (K-Factors): These mechanisms reduce utilities' incentive to control costs, potentially leading to capital over-investment. Ironically, price cap MYRPs were originally proposed in part to end the use of cost trackers (or similar "balancing accounts"), which required regulators to rely increasingly on *ex post* prudency reviews, raising "the administrative cost of regulating the electric industry and the resources required for the Commission to perform adequately its regulatory obligations and responsibilities."[8]

- Utility forecasts: Forecasting can incentivize the utility to overstate spending needs and expected costs. Forecasts are notoriously challenging, as information asymmetry limits the ability of regulators and stakeholders to assess their accuracy and efficiency. This concern was noted by the Maine Public Utilities Commission when it rejected Central Maine Power (CMP)'s proposed forecast of capital costs, finding that CMP's proposal would "shift[] the risk of over estimation and uncertainty to the ratepayers."[9]

- Trends in historical capital spending (K-Bar): Not only does this approach rely on the assumption that past levels of investment are accurate predictors of future levels of investment,[10] it may also encourage the utility to continue increasing investment levels, as this will ensure its allowed capital revenue requirement continues to increase.

- Project-specific recovery: While potentially more targeted, this approach raises concerns about how to define and consistently apply qualification thresholds.

Additionally, treating capital costs separately from operations and maintenance (O&M) expenses overlooks the potential for capital investments to reduce O&M costs. As observed by the Maine Public Utilities Commission in 2013, "In effect, customers would be subject to increased capital costs while depriving them of the corresponding benefits of O&M savings."[11]

Experience in Maine

In May 2013, CMP proposed a new ARP, but with only operations and maintenance revenue requirements continuing to be subject to the traditional Inflation – X (I-X) formula. For capital revenue

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[7] *Ibid.*

[8] California Public Utilities Commission, Division of Strategic Planning. *California's Electric Services Industry: Perspectives on the Past, Strategies for the Future* (San Francisco, CA: California Public Utilities Commission, February 1993), at 153. Available at https://docs.cpuc.ca.gov/word_pdf/REPORT/3822.pdf.

[9] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 8.

[10] Christensen Report at 45.

[11] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 7.

requirements, CMP proposed a separate mechanism based on CMP's projections of capital costs, which would be subject to reconciliation and a sharing mechanism.[12]

The OPA filed a Motion of Partial Dismissal seeking dismissal of CMP's proposed capital reconciliation mechanism, arguing that the proposal to recover forecasted capital additions outside the traditional price index formula inappropriately shifts risk to ratepayers, while also placing unreasonable burden on the Commission and intervenors to scrutinize the forecasted capital projects and related costs.[13]

The Commission granted the OPA's motion, finding that CMP's proposal to recover capital costs based on a cost forecast would be inconsistent with the principles of both incentive regulation and cost-of-service ratemaking.[14] In dismissing the capital recovery mechanism, the Commission cited its own 1993 decision regarding the merits of including capital investments as part of the price cap formula to promote least-cost investment decisions and reduce the need for retrospective prudence reviews:

> A reason for not treating capital expenditures separately is that it would help eliminate the oft-discussed problem of ROR regulation giving firms an incentive to overcapitalize (the so-called "Averch-Johnson effect"). As an additional reason, by incorporating all capital expenditures for each category of resource … into the price cap formula, the company would have an incentive to make least-cost investment decisions. The Commission believes that such treatment of new capital expenditures should reduce the need for retrospective prudence reviews of CMP's planning activities.

The Commission found that, "By tying CMP's profits to the level of investments, the [capital recovery mechanism] removes one of the core objectives of an ARP, the elimination of the incentive to over-capitalize."[15]

Following this, CMP proposed a revised approach to incorporate its capital spending forecast into the I–X formula by introducing a K factor, which resulted in a negative productivity (X) factor. The OPA opposed this revision, instead recommending that major capital investments be addressed outside the I–X framework using traditional cost-of-service practices.[16] Ultimately, the Commission approved a stipulation in which CMP withdrew its ARP proposal and returned to cost-of-service regulation, with the

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[12] *Ibid.*

[13] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 3.

[14] *Id,* at 6.

[15] *Id,* at 7.

[16] Direct Testimony of Tim Woolf on Behalf of the Maine Office of the Public Advocate. Docket No. 2013-00168. December 12, 2013. . In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 25, 2014.

option to pursue a single-issue revenue requirement adjustment to recover costs associated with its new billing system.[17]

In summary, the inability of the traditional I–X formula to accommodate CMP's substantial capital investment plans posed a major obstacle to designing an ARP acceptable to all parties without imposing undue risk on customers. This challenge remains relevant today, particularly given similar concerns associated with capital recovery mechanisms in other MYRP frameworks.

1.2. Under-Investment

By enforcing a stay-out period and allowing utilities to keep some or all of the profit from managing costs below its revenues, multi-year rate plans increase utilities' incentives to operate efficiently. However, this incentive can result in under-investment in infrastructure in order to increase short-term profits.[18]

The Commission raised this concern in 2013 in response to Central Maine Power's request to substantially increase its capital spending after a long period of operating under a price cap MYRP. In particular, the Commission noted that a multi-year rate plan "could provide the utility with an opportunity to allow its system to degrade in order to keep profits high," and that such a possibility may need to be addressed in the rate case.[19]

In response to this concern, Commission Staff analyzed CMP's historical spending compared to its projections. Staff found that it was "difficult to assess whether more recent spending reflects a catch-up for projects that should have been done in earlier years," but that "a significant number of projects" were now necessary because many issues had been deferred or not addressed, including projects "identified in recent years that might be considered high priority."[20] In conclusion, Staff found that the substantial increases in capital spending compared to prior years "raises questions about whether projects that should have been undertaken under prior ARPs have been deferred to the benefit of CMP's shareholder[s]," and the "extent to which the prior ARPs were failing to provide the correct incentives for CMP to make plant investments."[21] These findings contributed to Staff's recommendation to take a "hiatus" from CMP's alternative regulation plan in 2013 and return to cost-of-service regulation.

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[17] Maine Public Utilities Commission. Order Approving Stipulation.

[18] Armstrong, M. and D.E.M. Sappington (2006), "Regulation, Competition and Liberalization," *Journal of Economic Literature*, 44(2), pp. 325-366.

[19] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 83.

[20] Maine Public Utilities Commission Staff. Bench Analysis. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. December 12, 2013, at 25.

[21] *Id.,* at 36.

1.3. Experience in other Jurisdictions

Synapse is aware of at least two jurisdictions currently undertaking a review of the efficacy of MYRPs: Maryland and the District of Columbia. The Maryland Office of the People's Counsel (OPC) has put forward a harsh critique of the state's foray into MYRPs, finding that the structure has resulted in average annual rate increases of more than 6 percent since the implementation of MYRPs, reflecting both accelerated capital investments as well as increased operations and maintenance spending.[22]

Notably, the Maryland MYRP construct is heavily reliant on utility cost forecasts, with provisions allowing for reconciliation to actual, prudently incurred costs. This approach significantly weakens cost-containment incentives for utilities while increasing the regulatory burden on agencies and intervenors tasked with scrutinizing forecasted expenditures.

Regarding cost containment incentives, the Maryland OPC argues that the MYRP structure:

> …drastically lower the risk to utilities posed by cost-ineffective operations through the reduction of regulatory lag and the approval of proposed capital projects for revenue requirement purposes. The very design of the [MYRP]—basing rates on utility-proposed budgets of a forecasted three-year plan—incentivizes utilities to "shoot for the moon" and pursue a greater number of capital investments than what would have been pursued under standard ratemaking, which is based on actual spending during a historic test year. The opportunity to reconcile both O&M and capital costs—and recover costs incurred above authorized budgets—substantially lowers utility risks associated with inaccurate forecasting, poor performance, mismanagement, or cost-ineffectiveness. These risks—including reduced profitability for cost-ineffectiveness and cost-disallowances for untimely and unnecessary investments—are instead shifted to customers.[23]

In terms of administrative burden, the OPC observes:

> "No evidence demonstrates that the administrative burdens imposed by MRPs are lighter than standard ratemaking burdens. Rather, experience shows that MRP cases have *increased* administrative burdens for stakeholders."

Maryland's experience provides a cautionary example of the potential pitfalls of poorly-designed MYRPs. However, as highlighted earlier in this report, it is difficult to design an efficient MYRP that provides sufficient revenues to the utility but minimizes risk to ratepayers. This underscores the importance of carefully evaluating any departure from cost-of-service regulation to ensure that the cure is not worse than the disease.

[22] Maryland Office of the People's Counsel. Initial Comments. Case No. 9618 and 9645. September 16, 2024, at 1-2.

[23] Maryland Office of the People's Counsel. Initial Comments. Case No. 9618 and 9645. September 16, 2024, at 2.

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<u>ELECTRONICALLY FILED ON MAY 30, 2025</u>

May 30, 2025

Amy Dumeny, Administrative Director
Maine Public Utilities Commission
26 Katherine Drive
Hallowell, ME 04347

Re: MAINE PUBLIC UTILITIES COMMISSION Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities, Docket No. 2025-00107.

Dear Ms. Dumeny:

On behalf of Versant Power ("Versant"), enclosed please find Versant's Initial Comments in response to the April 30, 2025 Notice of Inquiry.

If you have any questions, please do not hesitate to contact me.

Sincerely,

David P. Littell

c: Service to Active Party List via MPUC e-notification

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

May 30, 2025

Docket No. 2025-00107

PUBLIC UTILITIES COMMISSION
Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities

VERSANT POWER INITIAL COMMENTS

Versant Power ("Versant" or the "Company") submits these comments in response to the Notice of Inquiry (the "Notice") that the Maine Public Utilities Commission (the "Commission") issued on April 30, 2025. This Notice initiated the Commission's inquiry, pursuant to 35-A M.R.S. § 1301(1), to receive stakeholder input into the Commission's examination and development of performance-based regulatory tools for investor-owned transmission and distribution ("T&D") utilities.

I. <u>BACKGROUND</u>

The Notice indicates the Commission is examining and intending to develop specific regulatory tools focusing on performance-based regulation ("PBR"). Christensen Associates Energy Consulting ("Christensen") was retained to assist the Commission in its investigation of PBR for the state's electrical utilities. Christensen prepared a draft report (the "Report") that accompanied the Notice, presenting Christensen's findings and recommendations of PBR for Maine.

The Report observes that Maine already has experience with performance incentive mechanisms ("PIM") in the form of negative incentives, also known as penalties, associated with service quality standards and metrics adopted under Chapter 320 of the Commission's rules. As briefly summarized in the Notice and fully in the Report, multi-year rate plans ("MYRP") and PIMs are two different forms of PBR. MYRPs and PIMs are neither mutually exclusive nor mutually dependent forms of PBR.

II. VERSANT COMMENTS

Versant appreciates Christensen for providing a fulsome report on what advanced PBR and specifically an advanced third or fourth generation MYRP may look like in the future. Regarding the Report's recommendations on PIMs, Versant agrees with the suggestion that approaches to PIMs should be symmetric. Opportunities to receive performance rewards or offset negative PIMs with positive PIMs would be beneficial in setting up well-balanced guideposts for utility performance under a PBR plan.

Versant welcomes the opportunity to engage in discussions on the development of PIMs, including the establishment of metrics and baseline data, to ensure that resulting metrics are both measurable and meaningful. To attach a performance incentive, whether positive or negative, the performance needs to be measurable, within the control of the utility, and within reasonable reach of meeting the performance standard set by the performance metric. Versant notes the Report may underemphasize the importance of getting the metrics set to properly measure the desired outcomes and performance.

Testing metrics and evaluating them against performance is a sound scientific approach to getting the measurement performed by the metric correct. For example, if the Commission is interested in evaluating and measuring peak load reductions as a result of utility rate design or Distributed Energy Resources (two different potential goals in measurement), a peak reduction can be measured as a function of kW/MW peak(s) from the utilities prior period peak(s) for that month, or average/median peak for that month for the last two years, or seasonally, or measured as a percentage of peak reduction from a projected peak assuming load growth at a specific level or derived from peak projected by ISO New England ("ISO-NE") annually. There may be reason to adjust for heating and cooling days as well as making other conforming adjustments. Each measure can be reduced to a formula, and each is a valid measure of peak reduction, but some formulas would likely fit better to the purpose for measuring peak reductions for the intended purpose. ISO-NE, of course, has (or had) a specific measure to apply for peak reductions in the context of dispatched demand-response ("DR") that is suited to ISO-NE purposes of measuring how much activated DR operates to meet its committed peak reduction from a pre-established baseline for the DR resource. That peak reduction measure is aligned to the ISO-NE specific programmatic purpose and is probably not the right peak reduction metric for a utility if the Commission desires to measure peak reduction from utility deployed measures. Refining the purpose, the metric and the metric's formula to measure performance requires attention, analysis, and sometimes testing.

Availability of good underlying data to measure is also critical. In some instances, that underlying data may exist and in other instances that data will need to be collected. Data needs to be reliability collected, maintained, and undergo quality assurance and quality control procedures. Versant notes the Report may understate the need to identify, collect, and maintain baseline data in establishing appropriate PIMs and suggests this topic may benefit from further discussion. If data does not exist, the utilities can—assuming it is reasonably available—begin to collect it. Refining data needs similarly involves attention, analysis, and sometimes testing.

To set a PIM appropriately requires a realistic and meaningful performance standard—typically a metric expressed as a goal—which builds on a reliable set of baseline data. The Company views the use of initial report-only PIMs likely to be extremely helpful in this regard. Having T&Ds initially report only data-reporting PIMs can serve as a practical starting point for collecting and analyzing data, as well as testing certain measurement methodologies and data sets. Through the collection of data and testing of analytical methods and performance measures, baseline data and metrics can be evaluated. This process should assist the Commission, the utilities, and stakeholders in developing a shared understanding of the goals and how progress toward those goals will be measured.

Versant is interested in exploring effective approaches to measuring system resilience and greenhouse gas ("GHG") reductions—areas where performance tracking can meaningfully support both customer outcomes and state policy objectives. In the case of GHG reductions, Maine's Electric Distribution Companies ("EDC") no longer operate generation assets, which may limit direct emissions reduction opportunities compared to jurisdictions like Hawaii or Minnesota, where EDCs continue to generate electricity. That said, there may still be meaningful opportunities to assess emissions impacts associated with Versant's programs or operations. Versant looks forward to working collaboratively with the Commission and other stakeholders to examine these possibilities.

As the Report illustrates, there is a good deal of work and analysis that goes into developing a MYRP. Versant also observes that a MYRP and other PIMs serve distinct functions and use different PBR mechanisms. Neither a MYRP nor PIM regime require adopting the other. As the Report highlights through examples from Minnesota and Hawaii, developing a comprehensive PBR plan typically takes years of collaboration among regulators, utilities, and stakeholders. Versant seeks to ensure that any MYRP supports the Company's goal of enhancing distribution system reliability and overall system resiliency, including the ability to respond and recover from increasingly frequent and severe storm events and other system disruptions.

Finally, Versant emphasizes the need for efficiently-focused management attention. While large numbers of PIMs and priorities may dilute focus, a more streamlined set of MYRP and/or PIM goals and measures can be useful to focus management attention if that is the Commission's goal.

Versant is focused on delivering a more reliable and resilient power system. Versant is equally committed to achieving this in ways that support the State's GHG and other broader environmental goals. To that end, Versant favors a MYRP and PIM approach that enables a continued focus on providing reliable, resilient, and clean energy to its customers (noting that Versant does not provide electrical supply but only delivery service).

III. CONCLUSION

Versant remains committed to supporting the Commission's examination of the effectiveness of PBR goals, metrics, and PIMs in achieving its own and Maine's policy objectives. The Company advocates for a methodical approach that balances the benefits to Maine residents with the costs to customers, focusing on investments in the highest priority areas. Versant appreciates the Commission's consideration of these comments.

Dated: May 30, 2025

Respectfully submitted,

Versant Power
By its attorneys,

/s/ Arielle Silver Karsh
Arielle Silver Karsh, Esq.
Senior Regulatory Counsel
Versant Power

/s/ David P. Littell
David P. Littell, Esq.

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STATE OF MAINE | Docket No. 2025-00107

PUBLIC UTILITIES COMMISSION

May 30, 2025,

PUBLIC UTILITIES COMMISSION | **COMMENTS OF AARP MAINE**

Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities

AARP Maine is pleased to provide comments on the performance-based ratemaking (PBR) discussion.

AARP is no stranger to the issue nor to Christensen and Associates who is managing a similar endeavor for the Indiana Utility Regulatory Commission where we have also sent comments to them and to the Commission. (A report to the Legislature is being prepared. Comments are due July 16).

Nor is AARP a stranger to the PBR issue. We have helped nix similar efforts in Michigan and other states. While appealing at the 60,000-foot level, the proposal is too complex to administer, rewards utilities for things they should already be doing, and worse. This is why few U.S. states have adopted it after similar regulatory or legislative reviews.

AARP supports a few targeted performance incentives to keep rates affordable and service reliable. PIMS should be done on a pilot basis. They should be symmetrical (penalties or rewards).

Indeed, Maryland just passed a new law allowing multiyear rate plans (part of the PBR discussion) ONLY if benefits to ratepayers can be demonstrated. The state found that multiyear rate plans encouraged utilities to file 3- or 4-year wish lists of spending, causing rates to soar. Maine should heed the lessons of Maryland.

AARP is also opposing the proposal of Eversource in New Hampshire to adopt a complicated PBR scheme including the capital cost tracker affectionately known as KBAR. It is turning out to be too complex and parties to the proceeding (filed in their rate case) have numerous problems with it.

PBR means many things to different people: a rate case that spans several years and relies on speculative/forecast costs, performance incentives (rewards) for meeting things like providing excellent customer service, formula rates (or index rates) with adjustors such as capital cost trackers (KBAR) and more. The fact that one state has adopted 3-year rate cases does NOT mean it has embraced all of the other types of PBR.

In short, PBR is still an untested alternative in terms of benefits to consumers.

Our comments to Christensen and the Maine PUC are similar to those we filed in Indiana and other states and are as follows:

- Are the proposed policy goals appropriate for guiding the design of a regulatory framework in Maine? ANSWER: No. These goals should come from the legislature as proposed. The PUC should focus on maintaining affordable and reliable service.
- Are there nuances to the current regulatory framework in Maine that are not fully reflected in the Christensen report? ANSWER: Yes. PBR is a solution in search of a problem.
- The fact that California has had 3-year rate cases does not mean it uses PBR. It does not. Maine utilities can already file 3-year rate cases and propose service quality indicators. It is unclear what problem we are solving.
- Regarding formula rates, they have been a disaster for consumers as Illinois learned in its 11-year experiment. There is no reason to adopt a similar scheme (indexed rates with KBARs, etc.) in Maine.
- Is an expansion of PIMs in the state appropriate? If so, how should they be developed? ANSWER: No. AARP favors targeted use of PIMs which is already done using service quality indicators. However, they should not be easy to meet targets and penalties and rewards should be used (symmetrical). They should also be easy to measure. Oftentimes the utility alone has the data to measure meeting the target.
- For the utilities: what guidance do you need from the Commission before putting together a rate application with PBR tools that are not currently used in Maine? ANSWER: Utilities should not be allowed to pursue PBR beyond the tools they already have (multiyear rate cases, service quality indicators, and the like).

Other comments of AARP

The proposed KBAR capital cost tracker is detrimental to ratepayers. It is too complicated. It should be rejected.

The Commission should commence a study of the problems with PBR before going further. This includes why California returned to traditional regulation after briefly trying PBR in the 1990s, why Minnesota spent 3 years developing over 100 PIMs and still has not implemented it, the problems with formula rates in Illinois, Alabama, and other states that have caused rates to soar, etc. We appreciate this opportunity to comment.

Sincerely,

Noël Bonam

noël bonam

State Director
AARP Maine

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2025-00107

May 30, 2025

MAINE PUBLIC UTILITIES COMMISSION,
Inquiry into Performance Based Rates Regulation of Investor-Owned Transmission and Distribution Utilities

CENTRAL MAINE POWER COMPANY COMMENTS

I. BACKGROUND

On April 30, 2025 the Maine Public Utilities Commission ("MPUC" or "Commission") initiated an Inquiry into Performance Based Rates Regulation of Investor-Owned Transmission and Distribution Utilities ("Inquiry") pursuant to 35-A M.R.S. § 1303(1). The Inquiry seeks input from stakeholders on development of performance-based ratemaking ("PBR") tools. The MPUC held a workshop on May 14, 2025 where Christensen Associates presented their draft report, Performance-Based Regulation Report for the Maine Public Utilities Commission ("Report") and participants provided input on the goals of PBR and the draft report. CMP actively participated. The procedural schedule in this Inquiry does not provide an opportunity for stakeholders to comment on the final report; CMP suggests, such comment opportunity could be a valuable final step and would contribute comments.

Notably, the concept and application of PBR incentives and mechanisms has been available in Maine and throughout most States for more than two decades. Indeed, the MPUC's current regulations afford opportunities to implement performance metrics to drive utility accountability and performance. MPUC Rule, Chapter 320, Electric Transmission and Distribution Utility Service Standards contains both performance metrics and reporting requirements. Chapter 320 required by LD 1959, established extensive metrics to measure utility Reliability, Customer Service and Operations. Specifically, the Reliability metrics measure the length of the average customer interruption (CAIDI), the frequency of interruptions (SAlFl), the total hours an average customer was without power (SAIDI), and the Feeder Adder Interruption Frequency Index (FAIFI) for circuits that performed poorly by comparison to the rest of the system. Customer Service metrics measure how many customer calls are answered within 30 seconds (85% in 2023), how many callers hang up before being answered, how many callers cannot reach the Company when they call, how accurate and timely customer bills are issued, and how many customers have bills based on actual reads instead of estimates. Operations metrics identify how many customers had their new construction completed and energized by their Customer Guarantee Date. Each of these metrics and their associated targets were determined in a lengthy and collaborative proceeding and then approved by the Commission

In addition, CMP's current rate plan, approved in Docket No. 2022-00152 is a two-year rate plan that includes several attributes of PBR regulation including a service quality indices revenue adjustment mechanism, earning sharings, revenue decoupling and also that it is a multi-year plan. Despite this history, and active application of performance-based mechanisms, CMP strongly supports the work being done by the Commission pursuant to the law to gain further input on appropriate PBR tools and appreciates the opportunity to participate in this process.

II. CMP COMMENTS ON REPORT FROM CHRISTENSEN ASSOCIATES

The Christensen Report extensively and fairly presents fundamentals of rate regulation, fundamentals of PBR regulation, and reviews the tools and mechanisms available to regulators. Final recommendations are forthcoming in the next draft of their document. Overall, CMP views the draft report as a valuable launching off point for the next phase of PBR regulation in Maine, in particular, providing a common set of terms and definitions, and optionality for regulators as they design rates for utilities. This last point is the cornerstone of CMP's comments, namely there is no one-size-fits-all approach to PBR. Instead, common understanding on the tools and their usefulness and application, will allow regulators, stakeholders, the public advocate and the T&D utilities to work to an outcome for each IOU in Maine that achieves strong utility performance, and stronger customer outcomes. A healthy utility will lead to better outcomes for customers and PBR is an ideal way to meet those two, seemingly divergent, but actually symbiotic outcomes.

A. Comments on Christensen Report "Proposed Policy Goals in Maine"

The Report listed the following seven goals for PBR in Maine. CMP lists them and notes its view on the goal below. CMP views these goals as guiding principles and not regulatory imperatives and would oppose strict requirements in any one category. Also, CMP does not support the inclusion of goals that are outside its ability to control. Utilizing PBR mechanisms will lead to rate plans that advance each of the stated goals in a tailored manner for the utility.

1. <u>Promote efficient and cost-effective transmission and distribution utility operations</u> – CMP agrees the cost-effectiveness should be one of the top priorities as customers expect and deserve efficient delivery of safe and reliable service at reasonable rates.
2. <u>Increase planning and preparation for extreme weather events and climate hazards</u> – CMP agrees that anticipating and planning for extreme weather events is an essential goal given the increase in severity and frequency of extreme weather events causing customer outages and widespread damage to the CMP transmission and distribution system.
3. <u>Promote cost-effective and comprehensive responses to outages</u> – CMP agrees, and this goal closely aligns with #2 above – by planning for extreme whether CMP will be in a better position to respond effectively. CMP notes that inclusion of timely response as a

component of the goal could be important to customers, as customers increasingly expect rapid restoration and reduced outages.

4. Increase affordability and customer empowerment and satisfaction – CMP agrees that customer empowerment and satisfaction is a reflection of a well-run utility and an engaged customer base. Regarding affordability, this is closely aligned with goal #1 above that aims to achieve cost-effective operations. Notably, affordability is an additional consideration beyond cost-effective rates, and may be subjective. The balance between investment in the system, strong operations and affordability is a challenge, and PBR mechanisms can assist in finding the suitable balance for a particular utility at a given time.
5. Support achievement of the State's goals for increasing consumption of electricity from renewable resources – CMP supports state's renewable energy goals and does not oppose the inclusion of support for such state goals in the list of considerations. These goals are subsidiary to the threshold drivers of safe, reliability, and cost-effective service at reasonable rates, but should be included in consideration. Aspects of this goal that are strictly beyond a utility's control, should not be central to regulatory decision making.
6. Advance the State's greenhouse gas emissions reduction goals – CMP supports the reduction of greenhouse gas emissions but questions the appropriateness of including this as a goal for a utility rate plan as this may not be measurable and/or within the control of the MPUC or the utility. CMP is open to keeping this goal on the table, but notes that goals #1-#3 above should take priority for purposes of establishing rate plans that benefit customers from a performance and cost-effectiveness perspective.

7. Advance beneficial electrification – CMP supports beneficial electrification and reiterates the same points it made above, regarding measurability, utility performance and cost-effectiveness.

B. Comments on Christensen Report Recommendations

CMP agrees that the Report identifies all the key categories for designing a PBR. Rather than providing detailed suggestions in each category at this stage, CMP encourages a dynamic set of recommendations that gives some leeway to the MPUC to pick and choose different mechanism to blend together and achieve their goals. Although not established in the procedural schedule, CMP would welcome the opportunity to weigh in on the final recommendations if that would be of use to the MPUC in its process.

Respectfully Submitted,

Carlisle Tuggey
General Counsel
Central Maine Power Company

MAINE LEGISLATURE

STATE HOUSE STATION
AUGUSTA, MAINE 04333

April 18, 2024

Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018

Dear Chair Bartlett, Commissioner Gilbert and Commissioner Scully:

We are writing to urge the Public Utilities Commission to proactively implement the performance-based regulatory framework outlined in L.D. 2172, An Act to Enhance Electric Utility Regulation Based on Performance, despite the absence of legislation.

As you know, L.D. 2172 would have established a framework for the Commission to develop comprehensive regulatory reforms, based on performance, for electric utilities to better align regulation with Maine's climate and grid modernization goals. Should new legislation be proposed in the 132nd Legislature, it would only be effective in September of 2025, resulting in a proceeding beginning sometime in 2026. Any consequential results likely would not be realized until early 2028. We do not have time to wait that long.

We understand the Commission already has the authority to initiate this process under the existing statutory provisions.

We respectfully request the Commission to take the following actions:

<u>Initiate a Proceeding</u>: Commence a proceeding to examine and develop performance-based regulatory tools for investor-owned transmission and distribution utilities. This proceeding should involve robust stakeholder engagement, including workshops and public hearings to gather input from diverse perspectives.

<u>Establish Performance Goals and Standards</u>: Define clear goals for utility performance that are consistent with the objectives of the state's climate action plan and the integrated grid planning proceedings. Translate these goals into standards that might be used as the basis for metrics that could be applied in future rate cases.

<u>Report to the Legislature</u>: Provide a report to the Legislature, ideally before the end of the first session of the 132nd Legislature, on the progress of the proceeding, including recommendations

for any necessary legislative action to further enhance the effectiveness of the performance-based regulatory framework.

Voluntarily initiating a process now, with a report on any necessary legislation, will allow for the broadening of regulatory reforms that began with L.D. 1959 in the 130th Legislature to proceed without delay.

We welcome the opportunity to discuss this matter further, and to provide any additional information or support the Commission may require.

We appreciate your consideration.

Sincerely,

Gerry Runte
Maine House District 146

S. Paige Zeigler
Maine House District 40

Senator Mark Lawrence
Maine Senate District 35