Post-Award Indexed REC Process Third Workshop:

Comparing Other States' Mechanisms for REC contracts

September 30, 2024 Workshop Notes

1. Introduction

    a. People (IPA, NERA, Others)

    Attendance: Ameren Illinois, ComEd, Earthrise Energy, REV Renewables, EDF Renewables, EDP Renewables, Clean Grid Alliance, Apex Clean Energy, NYSERDA, Mercura, Energy, Emeren, NextEra Energy, ICC, Clean Capital, Invenergy,

    b. Recap on Indexed REC and Workshop Process

        i. Why is the IPA holding these workshops?

        ii. What will the IPA do with the information shared during the workshop?

IPA wants to improve the Indexed REC procurement process for all parties involved through this workshop process. IPA wants to be aligned on what we're seeing in the market with the players in the market while maintaining the integrity of the competitive procurement process.

        iii. Option to submit confidential information or public feedback

2. Workshop Logistics

    a. Workshop Format

IPA wants these workshops to be conversational so we can gather information for any process improvements. IPA will hold 2 more workshops after today and will post recording and notes of each workshop with a goal that a proposal will be included in a compliance filing with the ICC in February 2025.

3. Follow-up from Last Workshop

    a. RPS Budget

        i. Overview of the structure of the Illinois RPS Budget

ANTHONY: What I'm going to spend a few minutes doing is going through what the RPS budget in Illinois is, sort of a bit of the history of it how it's structured, some of the issues and challenges we have around setting the budget, and then a little bit of discussion around possible things and levers we have for adjusting assumptions.

I suspect for some of you on the call you'll see a lot of information that you've seen before, but we wanted to make sure to have a basic baseline of understanding of how the budget system in Illinois works for supporting Renewables and use that as one of the touch points for the subsequent conversations. There really are three major phases of the RPS budget. The RPS in Illinois was initially established in in 2007, so it was a period through 2016 where we had an initial structure that was revised by the Future Energy Jobs Act, which passed late 2016, and took effect in 2017, that had its set of issues which were then adjusted through the Climate and Equitable Job Act of 2021, which is the applicable law right now. I suspect we will see in the future subsequent legislation making further changes.

So when the RPS was first established in 2007 it only applied to default service customers. Those are the residential and small commercial customers in Illinois who didn't switch to other suppliers, and it was set with a rate cap of a little bit over 2% of what the rates were in May 2007. For customers of alternative suppliers who serve the larger customers and those residential small commercial customers who chose to switch to other suppliers, they started having an RPS obligation in 2009—or the legislation was enacted in 2009 for that. And that was done through a combination of the alternative suppliers procuring RECs and then also making payments into a state fund called the Renewable Energy Resources Fund. This model had a variety of challenges to it: first and foremost, the rise of municipal aggregation meant that the number of default service customers shrank significantly and therefore there was less funding available. And that could change year to year, so it created this great budget uncertainty. This was a period of time when the finances of the state of Illinois were not as strong as they are today and that some of that money was diverted to other uses by the State during some of our more difficult financial times, so this created a real budget uncertainty because year to year there was not any certainty of how much money would be available to support renewable efforts.

As a result, the IPA, in our procurement plans, basically was only able to propose annual procurements of renewable energy credits from spot markets. The one exception was a procurement we did in 2010 for some long-term power purchase agreements. The initial model of the RPS was very convoluted because there were different buckets of money that could be used for renewables and they would change year to year—there was no way to do proper planning.

One of the many things FEJA did was change the focus of the RPS to spurring development of new projects and renewable energy credits would be the tool we would use to support those projects. This was also when the IPA was given the legislative authority to have specific procurements for new utility scale wind, solar, brownfield projects, as well as the creation of our incentive programs, Illinois Shines and Illinois Solar For All, for distributed generation and community solar. FEJA also consolidated funding. It phased out over a period of a couple years the alternative suppliers having their own requirements and created a consolidated budget of about $230 million a year collected from customers. One thing FEJA did not do is it didn't create specific funding buckets—it was an amount of money that was collected from rate payers but then how that money was budgeted for various types of procurements, whether it was utility scale projects which at the time were supported through fixed REC price contracts, or for renewable energy credits from smaller scale projects, that was set out in a long-term plan but there was not specific buckets or line items for any given type of project. We would have to look at and forecast things.

A challenge we then faced was the way FEJA structured the budget was that for the first four years money collected in a given year, if it wasn't spent, could be rolled over to the next year but after four years any unspent money would be refunded back to customers, and then there would be annual collections and expenditures. This didn't work in large part because of COVID, where a large amount of money that was allocated to community solar projects in 2019, which was expected to be completed by 2021 and starting to receive payments for their renewable energy credits, that obviously did not happen because development came to a halt in 2020. And so, we were faced in the fall of 2021with a scenario where there was money that under the law was due to be refunded back to customers, even though there were large contractual obligations looming in the future which was sort of an artifact of how the law was written in a sort of nonsensical way to approach these things.

CEJA did several things again to update and refine the RPS in Illinois. Key among those was first it increased the amount of funding that was available by increasing the rate cap, and also resetting it to a different test year for what that amount was based upon. This increased the amount of money being collected from customers to up to about $580 million a year, it also replaced that model I described with a new model of a five-year first in, first out accounting system where money was collected from ratepayers and was available for use for five years, and then any money from year one and year six that was unspent would be refunded to customers. However, any refunds would be reduced if there were existing contractual obligations yet to be paid. This means that the money will be collected and as long as the expenditure is going on, all is available to be spent. Only if things were to really come to a halt would you ever see a scenario where refunds to ratepayers would be made.

We also switched to the competitive procurement model of index RECs where the REC price is not set like it was during the procurements we did after FEJA passed, but instead the REC price is based on the difference between the strike price that the winning bidder received and whatever the wholesale market price of electricity in they given month is. So this created revenue certainty for projects that the combination of the REC price and energy price would add up to their strike price, but it created uncertainty for us in terms of budgeting because at any given moment in time we can look at forecasts of future energy prices but as I'll get to in a few slides those are constantly changing.

If you want to delve into all the details of this, chapter three of our Long-Term Plan has a detailed discussion of the RPS budget and then we have a spreadsheet available as Appendix B that lets you really look at all the numbers, look at the formulas, you can make changes if you like, all those sorts of fun things—those are available on our website and they reflect the long-term plan that was published in April 2024. We're currently working on an update to the RPS budget, hoping to release it in mid-October and then quarterly updates coming after that.

ii. Current and planned RPS Expenditures

ANTHONY: Some preliminary data on some of the following slides shows what you'll see in that update. The key changes from what we released in April are 1.) we've updated the volumes of RECs under contract. There are various activities going on since the spring, such as a procurement we held for utility scale RECs over the summer, those numbers are now in the budget. Now this doesn't change things much because we already had forecasts of those and now they're moving basically from the projected or forecast REC quantities into our RECs under contract; 2.) A very significant change is the change in the forward price curve. This is what we use to estimate future costs of indexed RECs; 3.) We also are going to do a better job explaining or showing what exists in terms of obligations from contracts that already exist or what's going to be planned from the current Plan, and what would have to be approved through future plans.

A quick overview of where the RECs are coming from: ABP- the RECs for small scale distributed generation and community solar, RECs from the procurements under FEJA which are 15 year contracts that begin to end in around 2035, and you can see the impact of the procurements we've conducted to date for RECs and under the index REC procurement, but we also have a large shortfall that does not meet the RPS targets that the State has.

What do we do to address that issue? We have a set of activities that were approved in the 2024 Plan.

iii. Options and issues for managing the RPS Budget

1. Under the 2024 Long-Term Plan

ANTHONY: The IPA has an Indexed REC procurement coming up later this year, we have two REC procurements planned for next year, and we have blocks of capacity for the Illinois Shines program. The IPA will also have future plans, such as a 2026 Long-Term Plan that will cover activities in 2026 and 2027, another plan would be approved in 2028, one approved in 2030, and so on. So there's a lot of things that are kind of anticipated we'll need to meet our RPS targets, but are still going to have to go through a future ICC approval of one of our Long-Term Plans.

I want to differentiate between what's known today, which is we have a set of things that we expect over the next two years, and then there's the further out things that we expect will happen in the future through Long-Term Plans, but there's going to be a lot of discussion, debate, consideration before those future plans are approved.

So how do we develop our budget estimate? We start with the RECs that are under contract, these are obviously the things that are most knowable. So we look at the REC prices from procurements that have already taken place where we know what the REC price is, we make assumptions for projects that are not yet energized of how long they will take between when their contract is approved and when they come under contract. For Indexed REC procurements, we make an assumption that projects will be energized three years after the contract. We use the forward price curve where we use data from EOX and Argus to look at futures prices going out to 20 years, and we use those against the strike price to come up with an estimate of what we expect the expenditures for Index RECs will be.

We also have a statutory set-aside of $50 million for the Illinois Solar for All Program to support income-eligible solar. There's some money set aside every year for job training, and then we also have an estimate of our ongoing administrative expenses, so those are the most known numbers, although with Indexed REC procurements, there still is an assumption at this time about the price that will change in the future based upon how forward market prices change. For the 2024 Plan, we assume that we will successfully procure everything up to our targets for Indexed REC projects and that we'll fill all the blocks of capacity for the Illinois Shines Program. We have some assumptions for the Illinois Shines Program, which has REC prices that are administratively determined rather than set through competitive bidding, that those will decline 4% year to year. For future plans, we assume levels of activity similar to what we have in the 2024 Plan. In 2030, we begin scaling down some of those volumes a bit so that the overall number of RECs procured meets the RPS target. So things go from more certain and to less certain as we go along.

Some of the key unknowns for our budgeting model: the first is the forward price curve. One of our observations,' for the update we'll be releasing in a few weeks, is that the forward price curve has been falling. It's falling about $4 a megawatt hour on average over the next 20 years since we released the Long-Term Plan in April 2024. This has a huge impact because if you look at what's under contract, what we expect to do in the 2024 Plan, and what we plan to do in the subsequent Plan to carry on at our planned level of activity, we would have about 340 million RECs delivered through 2040. So a $4 a megawatt hour decrease in the forward price of electricity is basically adding another $1.2 billion of spending compared to what we had in the Long-Term Plan.

If the forward price curve goes up again, that number will decrease, but at least at this point in time our snapshot is that REC prices look quite different than we thought they would in April. We also have the unknown that projects may take longer to energize because of any number of reasons why projects take a long time to develop. So, our assumptions about when expenditures will start may be off. There could also be projects that get done faster than we expected but probably by and large we're more likely to see delays than projects getting done early. We don't know what the future REC prices are for the Illinois Shines Program. There's a lot of things changing in the distributed generation market: Shifts for residential customers on net metering values, a smart inverter rebate that's going to be updated at some point in the next year, and ongoing trends with equipment costs. The overall assumption we use for modeling is probably ripe for revisiting and that's something we'll be looking into over the next year.

There's also a large customer Self-Direct Program that allows very large customers to self-procure RECs in exchange for receiving a reduction in their RPS charge. That program is slowly growing and right now the methodology for studying the reduction results in a fairly small reduction rate, so the impact on the RPS budget is not significant, but as the program grows or if that methodology were to change in the future through statutory changes, the impact on the RPS budget from the Self-Direct Program could change. We also don't know future load growth. This has certainly been the hot topic for the last six to nine months that load growth is maybe higher than people had forecast, that will increase REC RPS collections. That's good. On the other hand, our RPS targets will go up as well if we need to offset a larger portion of load. So certainly, something that's very much in play is understanding what the future will look like and what forecasts we've made that need to be revisited.

So this slide has two different views of future expenditures: the graph on the right is similar to the one that is in the April 2024 Long-Term Plan that shows that if we continue on the path we are right now with the level of activities in future plans at the level we had forecast of what we need to do to meet the RPS, we would end up hitting a $3 billion deficit in 2039. This is about a billion dollars higher than we had when we published the Long-Term Plan, and that is almost entirely due to the decrease in the forward price curve. Some of the other update of volumes and a few small formulas had small increases and small changes to this forecast, but the key thing is the ongoing uncertainty about the forward price curve.

But there's another way to look at that—and that's the graph on the lower left. This is what if we only looked at what is currently under contract today, and what if we only did the activities that have been authorized through the 2024 Long-Term Plan. If you do that instead, and basically saying let's take off the table anything that happened after the current Plan is over, because that's subject to the next plan development process, then we have a much better view of the future and in fact the year-end balance (because in any given year money is collected from ratepayers and then goes out to pay for contracts) never goes below $290 million. So, in terms of what we know is authorized today, the outlook is much rosier then if you build in assumptions about future plans that have not been developed yet, let alone approved.

The difference and contrast between these two graphs I think is really important. So going forward we plan to include both versions of these projections in our RPS budget updates, and we'll continue to update how we portray these numbers in our future Plans.

So, what are some of the options for issues around managing the RPS budget? In terms of the short-term, we can continue to look at what our targets are for our competitive procurements we're going to be holding next year. Similarly, we'll be updating REC prices for the Illinois Shines Program in the spring and that's following methodology that was approved in our current Plan, but we'll be updating cost inputs. So those are two things that will have an impact on the budget based upon the Plan as we know today.

2. Through the 2026 Long-Term Plan update (including stakeholder feedback in summer 2025)

ANTHONY: Then you go into the 2026 Long-Term Plan, there is going to be stakeholder feedback that we'll be soliciting starting next spring and into the summer, releasing that plan next summer for comment. So, we can consider a variety of changes to competitive procurements. This workshop obviously being front and center in how we're looking at what sort of things we could do to consider changes in the model for the future.

There are also adjustments to the Illinois Shines Program in terms of the size of the program and how we approach REC pricing that we can look at, so much bigger levers are going to be available in the Long-Term Plan. And then finally there's legislative changes. The IPA is not endorsing or suggesting any of these changes at this time, but based upon conversations that we understand are happening among stakeholders around possible legislative solutions these are just a few that I would flag for consideration. One is ability to adjust RPS collections to ensure there's sufficient annual funding. Some of the challenges we have, as I was saying, from the changes in the forward price curve, are that we have this year-to-year uncertainty that as electricity prices change, the amount we'd have to pay for Indexed RECs will change. So the ability to have some sort of adjustment mechanism to ensure that year to year there is sufficient funding would be useful. Right now the rate at which customers are charged for the RPS is fixed at a number based upon 2009 rates: it does not adjust for inflation. The buying power of the RPS will decline over time. That could be recalibrated as well.

I mentioned that there are not separate funding sources for utility scale and smaller scale renewables projects. Separate funding streams to create more certainty could be something that's under consideration. We've raised at some hearings the idea of thinking about different incentive mechanisms for distributed generation and community solar. Residential customers are finding 15-year REC delivery contracts very confusing. This may not be the best way to support distributed generation. So we're definitely interested in changes that could come in the future that might change the incentive mechanism and therefore the funding stream for support of those sorts of projects.

3. Through legislative changes

ANTHONY: Additional changes to utility scale project procurement: the items we're discussing in these workshops, some can be addressed through our Plan, but some will ultimately lead to things that would need consideration through legislation. The large customer Self-Direct Program is something that I know there's been a real interest in and some desire to recalibrate how that program works to bring additional value to large customers, but we want to make sure that that's done in the context of ensuring sufficient RPS funding for projects that are participating in the Illinois RPS, and I'm sure there are many other ideas above and beyond what I've suggested that could be considered as well.

CHANDRIKA: I know in the past there were a lot of concerns about budget or potential projected budget shortfalls so this would be a good time, when we just talked about how the budget works, what goes into under-contract budget items versus projected budget items. So if there are any questions about the budget how it works or what possibly we could be doing or what we're not looking at, if there's any feedback or questions about what Anthony just shared this would be a great time to bring those forward.

QUESTIONER: Can we go back to the slide with the two different future outcomes on funding surplus versus shortfall? Just to make sure we're listening well, it sounds like the chart on the left assumes a forecast on energy price curves given indexed contract prices and assumes a volume of PPAs or indexed REC contracts through the current cycle that's covered by the 2024 Long-Term Plan, which means that you get full subscriptions and hit your volume targets for fall of this year and two more procurements next year. And then you pause and there's no more new deals after 2025. Is that right?

ANTHONY: That's correct. So yes, if we do not hit our procurement volume then expenditures would be lower. This is also based upon an update of the forward price curve and so if electricity prices continue to fall, then that would also impact this as well. On the other hand if electricity prices were to rise, the estimated expenditures would then go down. But at any given point in time we have to take a snapshot of what the futures markets are. Futures markets are the best tool we have to predict future electricity prices. We use EOX and Argus as I mentioned, obviously there's other data sources out there as well and so different people have different models of what future electricity prices look like.

QUESTIONER: Understood and that's great clarity. And then the chart on the right which obviously shows a potential significant shortfall, it sounds like that assumes that you continue to procure into the future to continue to hit at full volume what the RPS goals are over the longer term, and just given that that's many more megawatt hours, then that puts more strain on the budget, and given the way the legislation, the state policy is set up now—and again given the forward curve assumptions could be right or could be wrong, that if you continue long term to hit your goals—then you dive into potentially three billion negative?

ANTHONY: Correct. There's many layers of uncertainty. We may, as we continue to refine the Illinois Shines Program, if REC prices there were to go down, those contracts pay off much faster than the 20-year Indexed REC contract, so that could have a significant change in expenditures as well. But based upon what we know today and what we forecast from the future, this is what a full successful participation would look like and what it would require if future energy prices were not to change, which we know obviously is not the case.

QUESTIONER: Right, understood, this is super helpful. I'm sorry if some of these are newcomer questions to the mechanism, but it sounds like that the broad directional opportunity to address potential budget shortfalls is either at a state policy level to change the funding mechanism which sounds like it would require higher costs for ratepayers, or to end up working with some of these different levers within the Program, although the scope of these levers to make changes are not, probably not, dramatic for any given lever. Everything would have to go the right way and energy forward curves would have to, in reality, rise to allow you to come anywhere close to hitting your targets if you're not going to impose higher costs at a policy level on ratepayers. Is that a fair takeaway?

ANTHONY: Generally, although, I would add the caveat that one opportunity especially through statutory change, and maybe to a lesser extent through changing our plans, is that there may be ways of figuring out how to lower the cost. So for example when we look at the REC prices for the Illinois Shines Program, maybe we'll look at what's the appropriate level of support for those sorts of projects and determine a lower REC price makes sense. So that could be a scenario. De-risking the Indexed REC procurement should in theory lead to lower bid prices that would also reduce costs. But those are all very speculative ideas. I think the challenge we face is that there's the things we can control, there's the things we can't control, and the things we can't control dominate the different outlooks we have here.

QUESTIONER: Understood, that's awesome clarity, thank you so much.

CHANDRIKA: Thanks Dom. I just want to highlight two things that Dom, you touched on. Number one, the future projections, the graph on the right, assumes that not only we keep procuring every two years which is how we do the procurement and they keep getting approved. So at some point, if let's say we are forecasting budget shortfall, the only way to enter into a shortfall is for us internally, and when we publish this, everyone can see that we're hitting a shortfall and then the idea is we truly hit a shortfall and everyone says yes let's keep procuring—add this weight, add this price—and then keep hitting that shortfall, which seems very unrealistic and is probably not going to happen. So that's the point I want to highlight is that we do this every two years and now we're going to be updating these RPS budget figures quarterly which means that we're looking at it very regularly to show what's truly under contract and what the budget looks like versus what we're projecting and wanting to do and what the budget would look like—keeping all of these factors under consideration: the forward price curves, the different ways that we're structuring our different programs, and the fact that we're continuing to procure at the same level given all these other factors what we're looking at today is what it looks like. I just want to highlight that for it to reach a shortfall level, that means collectively, a lot of people are potentially ignoring in that particular Long-Term Plan, that there is a shortfall that everyone can see and we're still going ahead and conducting procurements to truly reach our shortfall which, again, probably not going to happen and seems very unrealistic.

ANTHONY: Yeah, that's one of the points that I want to make with graph on the left is that there's still time to address these issues before that scenario plays out because if you look at the activities we have planned through next year, we look in much better shape. Then we have some hard choices coming down the road.

QUESTIONER: Yeah, totally understand. I don't mean to imply this is an uncontrolled Freight Train by any means it's just helpful to see the different directional Pathways that things could go to highlight what the variables are, so appreciate that.

ANTHONY: Yeah one thing I want to highlight is if you want to really dig into this in the Appendix B to our Long-Term Plan, which is a spreadsheet available on IPA's website, you can go into that and there's a there's a line on one of the tabs that's a forward price curve you could put in a different forward price curve and then what and then go to the tab that shows the expenditures and see the impact—that's a really interesting way of to understanding the sensitivities. We'll be publishing an updated version of that spreadsheet as well when we release some updates later in October.

QUESTIONER: I believe the IPA is saying in the 2024 Long-Term Plan, the IPA is committed to sort of managing to 95% of the projected RPS budget in future procurements. My question is whether there is any plan to reduce that target percentage of budget to something less than 95% and or what the level of forward prices would need to be reduced by if you did manage to 95% of the Plan to trigger a shortfall?

ANTHONY: So the 95% of the current Long-Term Plan, that's sort of the policy we have in place until the next Long-Term Plan is approved and that's one of the things that I hope the graph on the left illustrates, is that right now, what we're looking at is that we're far away from hitting that threshold. If we're collecting about $580 million a year and we don't expect our year-end balance to fall below, $290 million, we're a long way away from having 95% of the funds committed. In terms of your question of how far would electricity prices have to fall, I don't know that off the top of my head. I'd have to go into the spreadsheet and put in numbers until we hit that scenario.

QUESTIONER: Okay thanks. Yeah understood that we're not at the 95% threshold yet but the plan would be to keep procuring until you get there, right?

ANTHONY: Right. Right now based upon current expected volumes and based on current forward electricity prices, we're not going to get close to 95% because we're never falling below more than almost half a year of collections.

QUESTIONER: I'm just trying to understand that the truth is somewhere between the two graphs on the screen because while it's comforting to sort of look at the graph on the lower left and say we still have room, the plan for the IPA is to keep procuring over and above that in the in the future plans.

ANTHONY: But to the point Chandrika is making, the next Plan would have to be approved by the

Illinois Commerce Commission. I can't speak for them but I would imagine they would take into consideration our budget estimate contained in that Plan before approving future procurements let alone the results of the procurements themselves.

CHANDRIKA: Just to add, Anthony, that will be only for the two years following that plan. So we're cumulatively talking about potentially three years into the future. If we don't look at what we'll be procuring through the 2026 Plan, just to address the first part of your question, if you're just looking at what we're procuring through the 2024 Plan given where the price curves are today, we are not even close to reaching that 95% number and if we were to continue procuring at the same level through the 2026 Plan that gets approved, at which point we will look at the refreshed forward price numbers. I think currently the way we're projecting even through that plan we're not seeing anything concerning until after the 2026 Plan.

ANTHONY: I would have to double check like which Plan would create the pinch point, but one of the reasons I so wanted to start with talking about the history of how the RPS has evolved is, though we can't speak for the Illinois General Assembly, we do have a history in Illinois of updating the RPS every few years as we learn what the drivers and challenges of it are. So I know there's a lot of interest right now on a variety of different legislative topics that hopefully will lead to some structural changes to how the Illinois approaches our energy goals and, part of our goal of getting this information out is to help inform those discussions. So, we can't guarantee that in the next year legislation will pass that will impact this, but certainly our hope is that this will be something that will be taken under consideration during the legislative discussion.

QUESTIONER: Can I just ask if we end up with a situation where you dip a bit negative, what happens under the Indexed REC contracts? Do payments to the projects just get delayed for a few months until further rate payer fund funds came in and then payments resume and everybody's just a couple months behind or what happens?

ANTHONY: We have a variety of different contracts and I don't want to speak generically to all of them because I think different contracts have slightly different provisions in them. It might be best for us to follow up on that as I don't want to say something incorrect.

QUESTIONER: Understood.

CHANDRIKA: Any other questions on the RPS budget topic before we move over?

QUESTIONER: I'm wondering if there is a sense, just from a macro level, that the participation that the IPA anticipates receiving from developers for these procurements, is that in alignment with what you would expect to see or is it just sort of concerns about the RPS being able to satisfy the contracts impacting the interest in your solicitation?

ANTHONY: One challenge is we don't know why bidders bid what they bid or don't bid, we only see certain inputs so that sometimes makes it hard to answer a question like that. In terms of our recent procurements, we've been hitting our solar targets so that sector feels alive and well. It's no secret we are not hitting we haven't hit our wind targets in several procurements. We had slightly better luck in our spring procurement than the one previously, but there's so many factors impacting development. To what extent is this budget concern the issue, is it the interconnection delays, are there other financing concerns? It's hard for us to always sort of know for sure which of those factors is the tipping point or how they fully add up but the extent to which we can find ways to address and remove problems that's the goal of these workshops as well as our ongoing discussions about budgeting reform.

CHANDRIKA: Like Anthony mentioned, we will be putting out a memo in mid-October with a snapshot of what's happening with the RPS budget, what are we projecting, where the forward price curves are, and where we stand from a contractual standpoint.

4. Discussion Topic: Comparing Other States' Mechanisms for REC contracts

a. Comparing other states' models for rebidding/renegotiating REC contracts and current mechanisms for REC procurement: Please see slides from the workshop to see a visual representation of formulas used by other states

i. New York

ii. New Jersey

iii. Connecticut

iv. Massachusetts

v. Rhode Island

b. Current mechanism for procuring REC contracts for both onshore and offshore

renewable projects in the above states

QUESTIONER: With all of those other states, was it automatically included in the contract, or was it optional, like the land-based resources in New York?

CHANDRIKA: Yes, optional. For all those other states, it's optional based on what I understand. And it's optional for land-based in New York, but not offshore wind. But in all the other states, they are free to choose.

DOM: It seems like there's a lot of precedent for not negotiating post-award, but how much pain is there for bidders in these programs vs what's the structure of the process right now? Like in the fall with the IPA if you awarded and doing everything you can to make it work, but can't sign the contract because you'll lose money and it's not viable for your business. How much pain is there for bidders in the IPA process? Are they losing deposits?

CHANDRIKA: I think you might be misunderstanding two things. We're talking about is once you've been award the contract, and signed the contract and executed it, between the time when you've executed the contract and when the project starts construction, if there's significant economic conditions which change the bid price you were awarded and contracted at, there's no mechanism to renegotiate. As far as between the time of when you're awarded to when you execute, that's not what we're talking about here. We're talking about all these states when projects have been awarded, contracts were executed, and then between the time when the projects were building, there were requests to renegotiate the price post-execution. Ben, do you know what happens right now between award and execution?

BEN: In general, in most other states, after the selection of a winner, there's a somewhat lengthy negotiation process. In Illinois there's not such a lengthy negotiation process, by design, to give suppliers certainty quickly that if you're selected as a winner and it's approved by the ICC, you will have the contract signed and executed within no more than two weeks from the approval date, so around 10 days or so from the bid submission you should get a contract executed. What this workshop is about adjustments after contract execution.

DOM: I was asking about the time between award and execution—if it doesn't work out to execute the contract because market conditions have changed, are there penalties imposed in that period prior to signing?

BEN: We have a pretty standard process. Bidders put up pre-bid security. And if you bid and do not sign the contract within 10 days or so after the bid date, then you will lose the pre-bid security.

DOM: So the assumption is that if you're awarded, you're moving right to signing and getting that done?

BEN: Right. We'll put a link to more information about pre-bid security amounts in the chat.

CHANDRIKA: If you're awarded the contract and choose not to execute, the amount you lose is your pre-bid security, which changes by procurement. Are there other states the IPA should be looking at that are not included above?

d. Renegotiation versus rebidding models

   i. Rules of engagement for other states that allow renegotiation or rebidding

   ii. Do stakeholders prefer renegotiation over rebidding?

   iii. Would advancing maturity requirements alter the need for renegotiation or rebidding? Pros and cons of advancing maturity requirements?

   iv. Should projects that are rebidding be fast tracked or should there be a penalty for rebidding in subsequent procurement events?

CHANDRIKA: The way that some other states have handled rebidding or future procurements when factors have shifted is to make it go faster to fast-track applications. Is having advanced maturity requirements in order to participate (such as in NY) something that folks like?

QUESTIONER: I can jump in here, I've participated in the NYSERDA process previously. I think overall, stepping back, the whole rebidding process at least in NY was both beneficial to developers and also NYSERDA and ratepayers, because you're rebidding these projects against the current market rates and against other projects. Overall, it's something I know we would be okay with. Like you mentioned, it works a little differently with more frequent procurements, and then I know one of the big questions with the NYSERDA process was the contract security, and lot of projects had contract security out there. Some projects had not signed a contract yet, so there is some grey area with obtaining it or rolling it over to the next solicitation. Regarding the advanced maturity requirements, I think it makes sense. From a very basic view, the more mature projects are going to have the closest outlook on pricing and the least amount of risk of changes to pricing. It was a certain scenario that they were able to pick a threshold with the interconnection queue with NY ISO specifically. That was a big point. You had to have one of your agreements in hand, which limits the playing field but it makes it a lot less risky for that group of projects because it means they'll have a more accurate outlook on interconnection pricing. And they're also closer to procurement. On the other hand, bidding a couple years ago you kind of just are making estimates. Like we've seen in IL and NY, and across the entire industry, things have just changed in the last couple years that it wasn't really possible to forecast. I think we're generally open to that, it's just figuring out mechanisms and thresholds are the main questions. We worked with NYSERDA to figure out what makes the most sense and what is fair while keeping their competitive procurement process.

CHANDRIKA: Thank you so much for sharing. Now for the wider group: what I'm hearing right now is that having some sort of ability to capture this market shift through inflation adjustment overall is seen positively. I want to see if that's something our audience today feels as well. If IL were to pursue some sort of inflation adjustment, would that solve some of the challenges we're talking about in this process? That seems to be the approach a lot of other states have adopted. The renegotiation piece was primarily not adopted given the concerns around the ability to maintain the procurements' competitive integrity. And applying this accelerated timeline and inflation adjustment was seen as a good equivalent to that. Is that how this audience is feeling? If Illinois were to explore something like this, would that address the challenges we've heard? I'd especially appreciate feedback from wind developers (on inflation adjustment compared to renegotiation), given that more of these concerns have come from wind projects given the longer timeline for wind project development compared to that of solar projects.

ELIZABETH: I don't know if I have a good sense about our members' opinion yet. But it did make me wonder about the possibility for renegotiation of other contract terms and whether other states have run into any complications with delivery of RECs as a part of the contract, or other terms that might be presenting challenges.

CHANDRIKA: From what I understand, the other contract terms don't significantly change between contract execution and construction start. But we are open to all other feedback on other contract terms. As far as other contract terms, it might be more helpful if we explored through our Long-Term Plan because it's a significant shift from our current contract structure. I understand that a lot of folks prefer a more generation-based REC delivery outcome as opposed to a very strict REC delivery outcome, which is the mechanism we currently use to meet our RPS goals. While I'm completely open to that feedback, I don't think that's something that significantly shifts between execution and construction, so I don't think it's right for renegotiation. But as we explore improving our Indexed REC process, that feedback is valuable for us to consider in thinking about changing the structure of our procurements. I don't personally see it as a renegotiation piece.

ELIZABETH: Yes, I'm not sure what the specific solution should be for it yet.

BEN CHEE, NERA: We made some significant changes in our last round of Indexed REC contract adjustments. First, we've provided more leeway in terms of the shortfall before a termination occurs. Prior to this round, the default event occurred if you miss your delivery year requirements 5 times, and on top of that, the amount of the shortfall exceeds one year of annual quantity. We've since moved that to two years of annual quantity of shortfall required. The second thing we've done, in the event of structural shifts impacting your ability to deliver, there is now a last resort waiver process to address this with the IPA. Such as, the shortfall is out of your control, you may appeal to the IPA, and on a case-by-case basis the IPA has the ability to look into this and give a waiver to those shortfall amounts. Those adjustments were made pursuant to some of the comments we have received from stakeholders.

e. Inflation indexing in lieu of renegotiation

i. Inflation indices used by other states

BRAM: NY's inflation adjustment formula is generally working for the folks that are interested in it, with some key areas of improvement, such as making them more technology specific and revisiting the actual adjustment date. But the data and mechanics are well understood by the bidders and the people who are helping finance these projects.

ii. Do stakeholders prefer certain indices that better capture the market?

iii. Should the change in price from indexing adjustment be limited to a certain percentage increase and decrease?

5. Questions Submitted in Advance of the Workshop

IPA has posted these on the Downstream Negotiation for Indexed REC Contracts site.

6. Future Workshop Topics and Workshop Dates

CHANDRIKA: The next workshop will be on Monday, October 21, 2024. We will capture what we have discussed in the first three workshops to explore what we apply to Illinois, such as rebidding or inflation indexing formulas.

7. Next Steps After the Third Workshop

a. Posting of Workshop Summary

b. Fourth Workshop Details – Topic, Agenda, and Date

CHANDRIKA: This will be more focused on solutions that could potentially work in Illinois. Hopefully taking a deeper dive into indices that other states use, how people feel about capping these adjustments, and how we can apply some of this to Illinois.