# ONTARIO ENERGY BOARD

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| **FILE NO.:** | **EB-2023-0195** | **Toronto Hydro-Electric System Limited** |
| **VOLUME:** | **Evidence Presentation** | |
| **DATE:** | **May 22, 2024** | |
| **BEFORE:** | **Michael Janigan** | **Commissioner** |
| | **Allison Duff** | **Commissioner** |
| | **Anthony Zlahtic** | **Commissioner** |

**EB-2023-0195**

**THE ONTARIO ENERGY BOARD**

**Toronto Hydro-Electric System Limited**

**Application for energy distribution rates beginning January 1, 2025**

Oral Hearing held in person and by videoconference from 2300 Yonge Street, 25th Floor, Toronto, Ontario, on Wednesday, May 22, 2024, commencing at 9:34 a.m.

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EVIDENCE PRESENTATION

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BEFORE:

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| MICHAEL JANIGAN | Commissioner |
| ALLISON DUFF | Commissioner |
| ANTHONY ZLAHTIC | Commissioner |

# A P P E A R A N C E S

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| LAWREN MURRAY<br>CHARLOTTE KANYA-FORSTNER<br>JAMES GRAVELLE | Board Counsel |
| THOMAS EMINOWICZ<br>MARGARET DEFAZIO<br>DONALD LAU<br>ASHLEY SANASIE | Board Staff |
| CHARLES KEIZER | Toronto Hydro-Electric System Limited (THESL) |
| SHELLEY GRICE | Association of Major Power Consumers in Ontario (AMPCO) |
| CLEMENT LI | Building Owners and Managers Association (BOMA) |
| TOM LADANYI<br>MICHAEL LADANYI | Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC), Energy Probe Research Foundation |
| JULIE GIRVAN | Consumers Council of Canada (CCC) |
| NICK DAUBE | Distributed Resource Coalition (DRC) |
| KENT ELSON | Environmental Defence (ED) |
| MICHAEL BROPHY | Pollution Probe |
| DAN ROSENBLUTH | Power Workers' Union (PWU) |
| MARK RUBENSTEIN<br>JANE SCOTT | School Energy Coalition (SEC) |
| MARK GARNER<br>BILL HARPER | Vulnerable Energy Consumers Coalition (VECC) |

# I N D E X   O F   P R O C E E D I N G S

E X H I B I T S

## U N D E R T A K I N G S

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NO UNDERTAKINGS WERE FILED IN THIS PROCEEDING.

Wednesday, May 22, 2024

--- On commencing at 9:34 a.m.

MR. JANIGAN: Good morning. Ontario Energy Board has convened this proceeding today to provide Toronto Hydro with the opportunity to outline and discuss the components and requests in its 2025 to 2029 custom IR application for electricity distribution rates and charges. My name is Michael Janigan. I will be the presiding commissioner in a panel composed of Commissioner Allison Duff and Commissioner Anthony Zlahtic.

Toronto Hydro will be setting out a brief outline of the application request with the supporting evidence they hope to present to support those requests.

We expect that Toronto Hydro's presentation will be approximately 90 minutes in length and in addition, there may be questions by the Panel to clarify or enhance the understanding of the application.

It is expected that there will be only questions from the Panel; however, the proceeding is being transcribed and may be referenced by party in the course of the hearing or the application.

The Panel would also ask for a mercy from the presenters with respect to the use of acronyms. One notes that acronyms in regulatory evidence have proliferated faster than this commissioner, in particular, is able to commit to memory, and the use of the full wording as much as possible would be greatly appreciated.

I will now ask Lawren Murray and Charlotte Kanya-

Forstner to outline important procedural and technical aspect of the presentation today.

**PROCEDURAL MATTERS:**

MR. MURRAY: Thank you very much, Commissioner Janigan. I have a few technical reminder for parties during today's virtual -- today's event.

First, this event is being transcribed and as a result people cannot talk over one another. You have to speak clearly and into your microphone.

Second, parties appearing virtually should turn off their video and audio when they are not speaking.

Third, I will remind people that while the chat function is available in Zoom, nothing said in chat function will be recorded or appear in the transcript of today's event.

Fourth, this event is being streamed on YouTube. It is also being recorded by the OEB to assist with transcription services only and today's event should not be video recorded by any other party.

And finally, Zoom allows you to join this event by a landline or cell phone, therefore please make sure to write down the Zoom telephone numbers which are included in today's invitation.

Finally, in case you drop off the presentation and are unable to rejoin the event, please immediately inform hearing's advisor Ashley Sanasie at ashley.sanasie@oeb.ca.

And with that, I will now pass things over to Ms. Sanasie who will provide the land acknowledgment.

**LAND ACKNOWLEDGEMENT**

MR. SANASIE: The Ontario Energy Board acknowledges that our headquarters in Toronto is located on the traditional territory of many Nations, including the Mississaugas of the Credit, the Anishinaabeg, the Chippewa, the Haudenosaunee, and the Wendat peoples. This area is now home to many diverse First Nations, Inuit, and Métis Peoples. We also acknowledge that Toronto is covered by Treaty 13 with the Mississaugas of the Credit. We are grateful for the opportunity to gather and work on this land, and recognize our shared responsibility to support and be good stewards of it. Thanks.

MR. JANIGAN: Thank you very much. Despite the limits on participation, we would ask those parties in attendance, both in person and virtually to now enter an appearance. And we will start with those that are present.

**APPEARANCES**:

MR KEIZER: Charles Keizer, counsel on behalf of Toronto Hydro.

MR. JANIGAN: Okay. I was going to leave Toronto Hydro Staff to the last but that's okay. Go ahead. If you also identify any participants and presenters that might --

MR KEIZER: Well, what we would do is probably have the panel identify themselves, their role at the time of the presentation.

MR. JANIGAN: That will be fine.

MR. RUBENSTEIN: Mark Rubenstein, counsel for the School Energy Coalition.

MR. LADANYI: Good morning, Commissioners. My name is Tom Ladanyi. I am consultant representing Energy Probe and also Coalition of Concerned Manufacturers and Businesses of Canada and online listening is Michael Ladanyi, who is working with me.

MR. JANIGAN: Okay. Can we have appearances by virtual -- by those that are on for the virtual hearing?

MR. GARNER: Well, if I can start. It is Mark Garner and I appear for Vulnerable Energy Consumers Coalition, along with my colleague Mr. Harper.

MR. BROPHY: Good morning, Commissioners. Michael Brophy on behalf of Pollution Probe.

MS. GIRVAN: Good morning, Commissioners. It is Julie Girvan on behalf of the Consumers' Council of Canada.

MR. ELSON: Good morning. This is Kent Elson on behalf of Environmental Defence.

MR. DAUBE: Good morning. Nick Daube for the Distributed Resource Coalition.

MS. SCOTT: Jane Scott, I am consultant for the School Energy Coalition.

MS. GRICE: Good morning. Shelley Grice, consultant for the Association of Major Power Consumers in Ontario.

MR. ROSENBLUTH: Good morning. It is Dan Rosenbluth, counsel for the Power Workers' Union.

MR. JANIGAN: Okay, have we missed anyone that is on virtually?

MR. LI: Yes, good morning. Clement Li representing BOMA, Building Owners and Managers Association.

MR. JANIGAN: Thank you, Mr. Li. Wonder if I could turn to Board Staff to identify themselves and --

MR. MURRAY: Thank you, Commissioner Janigan. Once again, my name is Lawren Murray. I am counsel to Board Staff and with me is Charlotte Kanya-Forstner, my co-counsel. Our articling student James Gravelle. And from OEB Staff we have Thomas Eminowicz, Donald Lau and appearing virtually is Margaret DeFazio.

MR. JANIGAN: Thank you very much. I wonder if I could ask Toronto Hydro now to commence their presentation.

MR KEIZER: Yes. At first, I think, if it would be appropriate to mark the presentation, I guess, for identification, since there could be future reference. Presented to you this morning on the dais were two documents. One was a copy of the presentation. The second is, I guess, a document that's referred to as a look book, with the series of photographs which are referenced in the evidence. I will ask Mr. Murray as to what they should be marked as.

MR. MURRAY: The presentation will be marked as KP1.1.

**EXHIBIT KP1.1: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED PRESENTATION**

And the look book will be marked as Exhibit KP 1.2.

**EXHIBIT KP1.2: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED PRESENTATION LOOK BOOK**

MR KEIZER: Thank you, Mr. Murray. I understand, there may be certain -- is there technical difficulties with the presentation?

MR KEIZER:  Sorry, could I just have a moment please?

It's one of those mornings, Mr. Chair.  Apparently the presenter who was controlling the presentation was kicked out of Zoom, so we're waiting to rejoin Zoom.

I think we are now up and running.  Thank you for your patience.  I think the probably most appropriate and efficient way to proceed with respect to the presentation is ask Ms. Coban to initiate the presentation and maybe to introduce her fellow panelists, and then I will turn it over to the panel.

**TORONTO HYDRO-ELECTRIC SYSTEM LIMITED - PANEL 1**

**Daliana Coban,**

**Matthew Higgins,**

**Kirk Huntley,**

**Dan Smart,**

**Evelyn Page**

**PRESENTATION BY MS. COBAN:**

MS. COBAN:  Thank you, Mr. Keizer.  Good morning, Commissioners.  My name is Daliana Coban, and I am the director of regulatory applications at Toronto Hydro.

We are very grateful for this opportunity to provide you an overview of our investment plan and rate application.  As you know, this is Toronto Hydro's third custom IR application under the OEB's renewed regulatory framework.

What you will hear about today is how our investments over the last two custom applications have delivered benefits to customers in terms of performance and efficiency. In this next rate period, we are looking to sustain those improvements and we're also looking to invest in getting the grid and our operations ready for a future that is not like the past.

An energy transition is unfolding in the city of Toronto and is expected to accelerate in the next decade at the same time that the city continues to grow, densify, and welcome new residents and businesses to its borders. As this transition unfolds, more customers will be relying on electricity for their day-to-day needs and leveraging new technologies to generate their own electricity and to manage their consumption.

Today, my colleagues and I will tell you about our minimum investments necessary to get ready for this future state. Underneath the broad brush strokes that we're going to talk about today are thousands of pages of evidence that contain the substantiating facts and details behind our proposals, and, along with today's presentation, you have a compendium with the key evidence references, where you can find some of those details.

We also, as Mr. Keizer mentioned, have in front of you today a look book with some of the pictures that relate to the infrastructure and the aspect of our operations that we're going to be speaking about today. My colleagues will explain the what and the why of the plan, and I'm going to focus on the how we are going to get this done from a regulatory perspective.

On the right, I have Mr. Higgins and Mr. Huntley.

They are going to take us through the distribution system plan and the maintenance plan associated. And on the left, Mr. Smart and Ms. Page are going to take us through grid operations and customer service and investments.

Before I hand it over to them, I want to take you through the how, and that is the custom rate application that we've designed to enable this plan to be delivered and to enable us to achieve the outcomes that underpin this plan. We think that starting with the how is important to really [audio dropout] your role here in this process, which is to set just and reasonable rates that align with the OEB statutory objectives.

Those objectives are of course to protect customers with respect to service quality, efficiency, and price outcomes; to promote innovation in the sector; and to ensure that we have a financially viable sector by providing utilities and their shareholders an opportunity to earn a fair return on their investment.

So, starting off with the custom incentive rate framework, if we can just flip to the next slide, please. So, the investment plan and the rate framework that underpins it is responsive to a number of drivers of change and evolution that you are going to hear about today in our presentation.

So, in this application, we undertook to design a custom rate framework that works within the four corners of the OEB's RIF, the handbook, the filing requirements, with purposeful evolutions to address these needs and challenges that we face ahead. In doing so, we were guided by a number of principles which you will see summarized in the appendix.

Those principles were: 1) to deliver customer outcomes and advance public policy objectives; 2) to balance the interests of customers and utilities and their shareholders; 3) to ensure that we continue to have stability and predictability so that we can make effective multi-year plans and decisions; 4) to ensure that we have flexibility to execute those multi-year plans in more dynamic circumstances; and 5) to protect customers and the utility from structural forecasting risks that we see in times of greater uncertainty.

So, putting these principles together and looking at the needs and challenges that we face ahead, they can be distilled down into three elements that you see here, on the screen. Our framework is responsive to these elements.

The first is the funding challenge, and the funding challenge is about designing a rate formula that enables us to deliver that multi-year plan; to sustain, expand, and modernize our operations; and advance the customers' outcomes that they expect and want.

The performance challenge is about how we balance the incentives in our current framework so that we can achieve harmony between service quality, efficiency, and financial performance outcomes during this time of change and transition. And the uncertainty challenge recognizes that, although the path to net zero remains uncertain, all scenarios point to an increase in electricity demand in the next two decades, so we have to act now to get the grid ready, but we also need to remain flexible to be able to adapt if the future differs from what we expect sitting here today.

So what I want to do in this part of the presentation is take you through each of these challenges and explain how the custom rate framework that we've designed is responsive to addressing these particular needs and challenges.

So, starting off with the funding challenge, what you have here on the screen, you can see our total investment plan over our past, our current, and our future custom IR framework. And, as you can see on the slide and as you're going to hear about in more detail from my colleagues today, our plan exceeds our historical investment requirements by approximately 34 percent because we are getting ready for a future that is different than our past.

This plan contains the minimum investments that we need in assets and systems and people in order to be able to be ready for that future while we continue to maintain our table stakes of safe and reliable service. And we put this plan together, as Mr. Higgins will talk about in more detail, by taking into account customer needs and preferences.

We know that price continues to be a top priority for our customers, so striking that balance between price and the other outcomes that customers also value is at the heart of this plan and was a primary objective as we prepared this plan. My colleague Mr. Higgins will tell you a bit more about how we struck that balance and certain aspects of our plan where we held back investment in order to do our part to keep prices as reasonable as possible.

In the next slide, I also want to talk a little bit about our operational investment plans because these needs, too, stand apart from our historical expenditures, as you can see from the graph on the top left that shows our total OM&A expenditures for the past, the current, and the future rate periods.

When we look at this graph, what I want to point out is that resourcing costs are the largest component of our operational plan, with the workforce making up about 45 percent of our OM&A budget in the next rate cycle. And the reason for that is, from 2023 to 2029, we expect an increase in FTEs -- these are full-time equivalents, is how we refer to our workforce -- of approximately 25 percent. And we know that this need is consistent with trends that we're seeing in the electricity labour market more broadly.

Electricity Canada put out a report last year, their human resources. Electricity Human Resources Canada put out a report last year, indicating the labour market insights that they gleaned from a study that they performed, and, in that report, they note that the demand for labour in the electricity sector in Canada is expected to increase by approximately 23 percent from 2023 to 2028. So we know that this plan is aligned with where the rest of the sector is going in terms of workforce.

From a historical perspective, we know we have a lean workforce compared to the other large- and medium-sized distributors here, in the province, that serve the largest cities in Ontario, and you can see this from some of the key facts that we highlighted on the right-hand side of the screen in terms of our FTE benchmarking.

And, to achieve in over the last 10-years-plus, we've deployed many strategies, some of which you'll hear about today and certainly all of which are detailed in the evidence, strategies such as outsourcing, harmonizing our jobs, and automating our processes so that we can increase that throughput for FTE and do more work with less people over time.

And you can see the results of this strategy in the graph at the bottom that shows our FTE complement from 2015 to 2023. You can see that the FTE complement has declined by approximately 12 percent over that period, and, if we reach back even further in history, you would see an even bigger drop in our FTE complement.

So what I want to emphasize is that, through these productivity and accomplishments, largely focused on our workforce and getting more throughput in our workforce, we have been able to contain costs and function under a standard funding framework for our operational requirements. But it is no longer possible for us to do that going forward, so one of the key elements of our framework includes a need for multi-year funding for our operational programs as well as our capital programs.

To put that need, for you, in context, if we had to operate within a standard IRM framework in this next 5-year period, we would be looking at having to reduce the workforce plan that we put in the application by approximately 220 resources compared to what we've proposed, and that outcome is not sustainable for too two main reasons.

The first reason is that, as we have a larger capital program, we simply need more resources to be able to execute that program safely and efficiently. And the second reason, as you'll hear about today, is that we have to invest in workforce capabilities that we don't currently have today in order to be able to harness the power of technology and innovation, to drive towards long-term productivity and efficiency and performance outcomes from our -- for our customers.

So the main takeaway from this slide is that we have those prudent investments in human capital are really at the heart of why our application includes a custom funding request for OM&A as well as for capital.

So, moving on to the next slide, based on the multi-year investment plan that we put together that you are going to hear about today, we have a funding challenge in this application that is worth approximately $455 million.

This is the difference in revenue that is required to fund our plan. That's the teal green line that you see at the top of the graph, and the revenue that's available under a standard price cap framework with a full rebasing in 2025. That's the orange line at the bottom of the graph.

Given the programmatic nature of our investment plan, our investments don't fit well within the ICM-ACM project base criteria. So a custom framework continues in our view to be the most effective and efficient way for us to address this funding challenge.

And the framework that we propose is known as the custom revenue cap index, the CRCI. And what I want to do you with you in the next slide is take you through that framework and explain how we get from our current custom framework, which is known as the custom price cap index, the CPCI, how we get from that framework to this framework, by taking you through each of the coloured boxes that we have here on the slide, to try to explain how we are modifying the existing framework to get to the proposed framework.

So, starting off with the orange box on the left side, we are shifting from a price cap to a revenue cap model in this application.

In both models, the rates are set in year one based on a full cost of service rebasing methodology, using the Board's standard cost allocation model and rate design parameters.

What happens is the difference happens in years two to five. So in years two to five in a price cap, what we do is we escalate the rates themselves by a custom index, and we back out from that index the topline growth factor, which accounts for the fact that we were going to see revenue increases as a result of growth and billing determinants over the period. And that growth, of course is projected from our five-year load forecast.

In a revenue cap, the key difference is what happens in years two to five; we escalate the base revenues, rather than the rates by that approved custom index. And then we apply that expected growth and billing determinants in each class to determine the rates annually.

This shift from a revenue cap -- to a revenue cap in our view better captures the impact of growth and billing determinants over the 2026 to 2029 period, in that it allows us to look at that growth at an individual rate class level rather than assume a topline growth factor across the entire custom index.

So, by shifting to a revenue cap, the growth factor in the formula, that's the yellow box at the end of the formula that you see there, is no longer required. And that's one of the ways in which this formula becomes much simpler.

I want to move on to the green box, which describes the rate mechanism, the funding mechanism that allows us to deliver this plan.

The previous capital factor that we had in the formula is replaced by what we call the revenue growth factor, the RGF.

And that revenue growth factor is derived from the year-over-year increases in our base revenue requirement that we need to fund both the capital and the operations programs that you are going to hear about today. And this evolution of the C-factor that we have proposed really reflects the need for incremental funding above I-X for both capital and operations.

The RGF enables us to make those investments in both hard assets out in the field as well as in our people that enable this work to be executed safely.

So from the RGF, what we then do is we remove the OEB's forecasted inflation factor. So that annually, when we come in to set the rates, we can apply the actual inflation factor that has been approved by the OEB for that year, to set our rates mechanistically.

And so, with the RGF covering the entire revenue requirement and having removed that forecasted inflation factor, we no longer need to scale the funding factor by inflation. So that S-cap times inflation that you see there in the yellow box can be entirely removed from the formula, and is another way in which this formula becomes a bit simpler and more straightforward to explain.

The last box that I want to take you through is the blue box that you see here on the screen. And I think this is probably the most important element of our framework in terms of evolution; this is where the incentives in our framework are placed.

So, as you know, the current X-factor is a top-down cost control incentive through the stretch factor. It reduces the revenue that we are able to collect, creating an upfront benefit for customers and putting an incentive on the utility to deliver its plans and manage its operations within a reduced revenue envelope. And that stretch factor that we have in place today is determined by empirical total cost benchmarking. However, one of the things we have seen in recent custom IR applications is the imposition of an incremental stretch factor, over and above what the benchmarking yields.

So in this application, we are proposing an X-factor of 0.75 percent, and there are three parts to that X-factor. The first is a zero percent productivity factor. This is consistent with the OEB's current policy for all the distributors in Ontario.

The second component is a 0.15 percent efficiency factor that is supported by our custom total cost benchmarking study. And the third component is a 0.6 percent proactive incremental stretch factor that gives rise to this innovative performance incentive mechanism that we have developed as part of the framework.

I will spend a bit more time explaining that mechanism.

So, in this framework, efficiency continues to be a key outcome, but it lives alongside other outcomes that are important to us and our customers, like having a reliable and resilient system that is able to connect, expand its services in a timely manner. And so with this innovation, we believe that the X-factor that we have proposed here enables an evolution towards more comprehensive performance incentives that include both efficiency and service quality outcomes that customers value.

And so, in doing so, it is one of the ways in which we are aligning the framework and the evolution to the framework with that principle of finding balance and alignment between customer interest and utility objectives in this period. And we do find that balance by tying a portion of our financial performance in this period directly to service quality, efficiency, reliability and other outcomes that customers care about.

So, in this next slide, what I want to do is take you through a bit more detail, explaining the PIM, recognizing the novelty of this concept.

First and foremost, the PIM, in designing it, one of the things that we had in mind was the Board's guidance in our last custom IR application, where we were urged to look for better ways to improve the risk-reward balance in our framework.

We do that with the PIM providing greater accountability and protection to our customers for the outcomes and the benefits of our plan. And, through the incremental stretch factor above what the benchmarking supports. we provide customers a greater upfront rate reduction benefit, and we provide the utility an opportunity, not a guarantee, to make its full rate of return if it delivers on a number of performance objectives that we know will provide value to our customers.

So this revenue reduction that is enabled by the PIM, the $65 million that you see here on the screen, that reflects a portion of our regulated rate-of-return earnings that we would be allowed to earn under the fair return standard in the normal course.

Some may characterize this as a penalty mechanism; we don't think of it that way. We think of it as an accountability and a rate mitigation mechanism that puts more skin in the game for performance. And, in doing so, it shifts incremental performance risk to the utility and protects customers by holding us accountable to the outcomes that you see on the screen.

In terms of quantum, this PIM we believe is a significant financial commitment to performance. And I want to put that in context for you. So when we were looking at that $455 million revenue deficiency, under -- when we compare our plan to IRM, the PIM represents approximately 14 percent of that incremental revenue that gives rise to the need for custom rates in this application.

Under the PIM, we only achieve, have the opportunity to achieve our deemed ROE if we deliver the benefits on the right. And we know that these benefits provide high value to customers. Coupled with the efficiency factor, the minimum direct economic benefits that the PIM yields is approximately $90 million compared to an incentive of $65 million. So this is a net benefit of $25 million for customers, plus many other benefits that you see here on the screen which, although we cannot quantify, we know are important to customers, things such as customer satisfaction, safety performance and making progress towards our grid automation objectives.

In the appendix, we've included a slide which I don't propose to go through today unless you'd like more information about how we envision the procedural aspects of the PIM to work but we have that summarized in the appendix.

You can see all of the steps that are involved in the implementation, the review, the clearance of the PIM and set out sort of in a linear fashion so we can see how we get from where we are today to the eventual clearance of the PIM in our next rebasing application.

In the next slide dealing with challenges, this is the last aspect of our custom application is the demand-related variance account.

And we're proposing this as a flexibility mechanism, to deal with the practical challenge that we simply face greater demand uncertainty in the next period as we go through this first chapter of the energy transition, you will hear about today from my colleague, Mr. Huntley, we have a System P customer connection forecast, a DER forecast that drives investment in the grid and we also have a revenue forecast that accounts for that growth and billing determinants.

Both of these forecasts are subject to a number of external factors that create the potential for greater variability in the next five-years.

Some of these factors include customer behavior with respect to the adoption of new technologies, like EVs, and heat pumps and distributed energy resources, all of these technologies will effect where, when and how demand manifests on the grid in the next rate period.

We also have the rapid technological advancement that will affect how we decarbonize the energy system and serve our customers in the future. On top of that we have policy and regulation that could accelerate or stagnate the pace of adoption of these technologies by our customers and also could introduce other variables in the mix, such as immigration and the imperative to build housing faster here in Ontario.

And last lastly, there is macro factors like supply chains and geopolitical dynamics that could affect the pace of the energy transition at large beyond what we're seeing here in Ontario.

So, in short, you know, what I want to convey from this quick recap of the uncertainty factors that we face is that demand is more dynamic than it has been in the past and while we've got the best forecasting tools and we've done our best to anticipate how demand is going to manifest in our plan in terms of the cost and the revenues associated with this plan, there is just inherent uncertainty ahead that we cannot control.

So, the challenge is that we need to have flexibility to adapt if things change and this account here, that you see here on the screen is our proposal to build that flexibility into the plan.

The account has two main features. The first is an expenditure sub-account that's detailed on the left side. This sub-account tracks variances in actual to forecast expenditures in a number of demand-driven programs that Mr. Huntley will take us through in more detail. These are by and large the programs that make up the growth component of our plan.

And on the right side we have a revenue sub-account that reconciles variances arising from forecast to actual weather normalized billing determinants.

Together what these accounts do is protect customers units from structural unknowns in our forecasts so that neither party will profit or lose from uncertainty as we go through this first chapter of the energy transition.

To wrap up my portion of the presentation I would like to take you through the proposed rate impacts associated with our plan. Those are shown in the second column of this table where you can see the average annual monthly increase in both dollars and percentages for each major rate class and what the rest of this table does is summarize the results of our Phase 2 customer engagement and compares those results with a similar engagement that we did you to the lead up in the last application that we did in 2018.

So, across the board what we saw in our Phase 2 customer engagement when we tested these rate impacts with our customers and our plan, we saw broader and deeper engagement than we did in 2028, both in terms of the overall participation but also the mode of participation.

In 2018 we supplemented the workbook, we call it, the survey that customers complete with the telephone survey so that we can have statistically significant results.

This time around we didn't have to do that because many customers took time out of their busy day to complete the workbook and the overall participation numbers really exceeded our expectations in this most recent customer engagement, especially in the residential class where we saw nearly a threefold increase in the number of customers who completed the survey.

And in terms of social permission that's the last column, in blue. The results were also stronger than what we saw in 2018, despite the fact that we have larger increases proposed in this application. Across the board we had an average of 84 percent social permission in this application, compared to 69 percent last time.

So, when we looked at these results, at the tail end of our planning process we concluded from these results that we by and large had struck the right balance in our plan in terms of finding that balance between price and affordability and other outcomes that customers care about.

And my colleagues today will also speak to you about some of the specific choices in our plan where that balance was struck. So with that, that concludes my portion of the presentation. Thank you, panel.

I'm happy to take questions about the framework or we can reserve all of that for the end. I'm in your hands.

MR. JANIGAN: Mr. Zlahtic has a question right now.

MR. ZLAHTIC: Actually, Ms. Coban, it is on your last slide, 11. And you're showing percentage increases or dollar increases on a monthly basis. What timeframe is that? Is that by 2029 relative to today or...

MS. COBAN: That timeframe looks at the average monthly increase from 2024 to 2029. So, it takes into account the impact of the rebasing in 2025 out to the end of the rate period. But it is an annual number that you see there, an average annual number from 2024 to 2029.

MR. ZLAHTIC: Okay. I'm still trying to interpret. So, let's say for example, the residential rate class that over the period 2024 to the end of the rebasing period, 2029, on average there will be a 7 percent annual increase?

MS. COBAN: That's right.

MR. ZLAHTIC: Okay. I got it now. Thank you.

MR. JANIGAN: We'll reserve the questions until presentation is finished for the most part.

**PRESENTATION BY MR. HIGGINS:**

MR. HIGGINS: Okay. Thanks, Ms. Coban, and thank you to the commissioners for the opportunity to present our capital plan today. My name is Matthew Higgins, I'm the director of integrated planning and modernization within our planning engineering and modernization division at Toronto Hydro.

My team's sort of broad responsibility is running our integrated planning process as part of our asset management system to pull together these multi-year capital and maintenance plans so I'm going to take the opportunity today with some help from my colleague, Mr. Huntley, to describing describe the various aspects of our capital plan at a high-level.

I want to start on the first slide here, just by going back and reflecting a little bit on where we've been with our capital plan.

And on the left-hand side of the chart you -- what you are seeing here reflect the scale-up of capital investment that began with our ICM application back in 2012 and continued through our first two CIR periods.

These investments were really focused on the core needs of our system and what I mean by that is they were necessary to address a backlog of ageing, deteriorating and obsolete distribution assets, and to keep up with a rate of vertical growth in the City of Toronto that has been unparalleled in North America.

Our goal with respect to reliability specifically in this period was, first, to reverse the trend of performance deterioration that we had seen at the beginning, before the beginning of this period and then as part of our 2020 CIR plan the goal was to invest only the minimum necessary to maintain reliability while minimizing rate impacts.

And as the charts on the right show, the top one is safety related to defective equipment and the bottom one is our SAIDI for most of the other cause codes.

What these charts show is that we've largely achieved those objectives, we had a fairly steady improvement trend in reliability right up until about 2019. And then a bit of a rebound in the past period, but if we look at it as sort of a rolling average we've generally sort of been sitting and maintaining at a new plateau for those reliability statistics for the last four years or so. And so, the key takeaway from this slide that I think is important in understanding the rest of what you're going to hear today is that when it comes to asset failure risk and our system renewal investments in particular, we have successfully stabilized this part of our plan. And going-forward the planned scale-up and CAPEX that you've already seen on some of Ms. Coban's slides will be focused more so on growth and modernization with a couple of targeted exceptions that I will get in to as we [audio dropout] the statement plan.

Before I do that, just a couple of more context setting slides. So, did I want to pivot to just talk about the shift in context for growth and modernization in particular, those areas where we are seeing a bigger scale-up and, you know, rewind to where when were creating this investment plan in 2022.

We were faced at that time with an industry discussion and some open questions that were just beginning, were very fresh and very active around what the scope and the pace of electrification was going to look like, both in terms of demand as well as distributed energy resources, conservation and demand management, very open questions about what the shape of that net-zero commitment was going to look like across society and locally. And so, for the first time in a very long time, we had to grapple with the fact that the future wasn't -- we could not safely assume, at least, that the future was going to look like the past. And so, to grapple with this shift in context, what we decided to do as part of our planning process was to undertake what we call our "Future Energy Scenario Study."

And, very briefly, this study was done with support from a consultant from the UK who is a leading expert in this kind of system modelling for these purposes, and we applied their approaches, including consumer choice modelling, to our system and our customer base to essentially craft a few different scenario worlds that we thought would represent a credible range of possible transformations and paces of transformation in the energy system, and we then mapped the results of that onto our local system to assess the impacts from a demand perspective as well as looking at, for example, the rate of DER adoption and how that would impact complexity on the grid.

There were a lot of takeaways, but the real key ones that ultimately influenced this plan were these: The study did obviously, as you can see on the screen, confirm that there is in fact a significant range of potential outcomes, which are dependent upon developments in consumer behaviours, policy, technology, et cetera, things that are very difficult to predict at this stage but which we know will evolve over the next five, ten years.

The biggest drivers that really jumped off the page for us -- and you'll hear a little bit more about some of these in Mr. Huntley's presentation -- were really related to buildings, so building electrification, decarbonized heating as well as, on the inverse side of that, efficiency, particularly thermal efficiency and demand response. Those are really the drivers we're now watching in terms of what could really swing these lines between what you see on the screen, the two -- the shaded area there between the two yellow lines.

And then, finally, we also noted that, until about 2029 or 2030, all of the scenarios are relatively consistent with one another and it isn't until the early 2030s where we begin to see a really significant divergence.

So, with these factors all in mind, we set out to develop a plan that was appropriate for this level of uncertainty and this level of potential change, and I think, stepping back, regardless of the scenario, we know that in the next 15 to 25 years we're looking at significant investments in the grid on the basis of these trajectories. But, in the next five years, what we have is an opportunity to sort of ready ourselves for a number of potential different scenarios.

And so the approach that we took to that was something we have called the "least-regrets approach." You may have heard something similar, "no regrets," things like that, from other jurisdictions. Ours is a little bit more modest in terms of least regrets. But the approach in a nutshell has essentially involved committing to capacity investments where we know that we have a high degree of certainty that they are going to be required, while on the other hand making more nuanced decisions about whether to proceed or to wait and see when it comes to investments that are sort of on the margins and, in particular, where underlying drivers are less settled.

It has also meant that we are committing to expanding the use of non-wires alternatives, because this is going to be a very important part of our toolkit in managing uncertainty and risk on the demand side, and also investing in grid modernization solutions, which I'll talk about more, which are going to give us the flexibility to optimize our grid and essentially squeeze more value and capacity out of the existing assets, which again will give us flexibility to adapt should situations change quickly in the future. We are going to talk a little bit more about some of those least-regrets examples as we go.

I'll flip to the next slide now, and I just want to talk about one last thing that is kind of context-setting for the plan before we get into the details, and that is the customer engagement that we did at the beginning of the planning process. So you already heard from my colleague Ms. Coban about the second phase of customer engagement, where we brought the plan back to customers. But, at the beginning of -- yes. I apologize. I could feel myself speeding up, so I will slow down, yes. Yes, where we brought the plan back to our customers for the second phase of customer engagement.

So, talking about, just briefly about, Phase I of customer engagement, so this is -- as we've done with our previous two CIR applications, we began this planning process with an initiative to understand general needs and preferences of our customers so that we could align our planning decisions to those findings.

And, just to quickly summarize, what we heard from customers kind of boils down to three things. The first, no surprise, price and reliability continue to be top priorities for customers. What was interesting about the findings this time around is that the relative priority of reliability really moved up closer to price, almost to the point of being equivalent in terms of what our lower volume customers were certainly concerned about. And generally, when it comes to satisfaction with reliability, our customers are satisfied with their service, and for our low-volume customers, to the extent that they are seeking improvements, it would be on the duration side of interruptions. That flips when we talk about our larger key account customers, who are more sensitive to individual outages, and they were more concerned about frequency.

The second priority that emerged was around new technology. When we asked customers about their interest and support for investments in new technology, it did come up as a very close second to those other two priorities, so customers do understand the value and expect us to invest in technology that will make the system better and reduce costs over time. And that is one of the sort of bedrock inputs that went into our modernization plan.

And, last but not least, customers also do support investments in system capacity to enable development and maintain reliability in high-growth areas. It is notable that 64 percent of our key account customers that we surveyed in Phase I have their own net-zero goals, and they do expect us -- and we've heard this even just through ad hoc engagement with these customers more recently -- they do expect us to support them in meeting those objectives by ensuring that capacity is available and that we are available to provide advice in terms of the energy transition and the role of the grid.

So, with that in mind, we went through our iterative planning process, and that resulted in the plan that you see on the right-hand side of the screen, the $3.9 billion capital plan, which is expressed through these categories that ultimately reflect what we heard from customers: sustainment and stewardship, which I will talk about in a moment; investing in our assets; growth in electrification, dealing with these capacity constraints and investing in non-wires alternatives; modernization, investing in technology to improve the value of the system and our operations; and then the supporting investments in general plant.

So, with that, I will move into some of the details now. So we'll start with sustainment, and then I will kick it to Mr. Huntley to talk about growth, and then I'll come back to talk about modernization and general planning.

So, on the sustainment side, I already spoke about how we've been making significant investments in this area to improve and ultimately stabilize this part of our plan, so what I wanted to address here is just some of the drivers that are contributing to the incremental requests in this area, which we will see in the next slide, from a dollars perspective.

So, just very quickly, some key highlights: In the top left, we will start with our stations. We have many municipal stations and transformer stations across our system. These are backbone, essential, very highly critical assets that we manage with a low degree of risk tolerance in terms of failure. The best way to kind of summarize the challenges that we've got in this area -- we could look at condition; we could look at performance, but the easiest way to look at it is just asset demographics. And what you see on the screen here is 42 to 55 percent of our major stations assets are past their average expected service life, and that compares to 25 percent on average for all distribution assets together.

And this is a risk area that's been accumulating slowly over the years, as we've prioritized our investment more so on feeders and those assets that do have a direct impact on SAIDI and SAIFI statistics. But we're now at the stage where taking this more corrective, reactive, more band-aid type approach, maintenance approach, is no longer going to work just given the demographic challenges, and so stations is one area where we are asking for an increase in funding to support an acceleration of capital investment, to begin renewing this part of the asset base in the same way that we have the other parts of our asset base over the last decade.

When it comes to the overhead and underground systems that serve the Horseshoe as well as parts of Downtown, these are the areas of our system that really have the biggest direct impact on SAIDI and SAIFI statistics. This is where customers really feel the impacts of asset failure, just by virtue of the nature of the design of this part of the system. And the story here really is more grounded in 2020 to 2024 and our experience that we have had to date with our plan.

Our goal coming into this period was to sustain the condition of these assets, whether it's wood poles, underground cable, and we've made some progress on that, but we did face some challenges in the 2020-to-2024 period related to costs, and as I think everybody knows, it was a very unique inflation environment coming out of the pandemic. We had supply-chain challenges, and that resulted in some upward pressure, significant upward pressures, on unit prices.

And the only way for us to absorb that was to essentially shift priorities and do somewhat less work.

And so some of the assets that you see on the screen that are highlighted, particularly are wood poles as well as underground cables, we didn't end up being able to fund as much work as we had hoped, and some of that work has spilled into the current rate period, which we are now catching up on.

The other factor was our demand-related investments on the customer connection side and the load-demand side ended up being greater than what we forecasted at the time that we set our plan for 2020 to 2024. And that was another cost pressure that had to be absorbed somewhere. And one of those places was in our large system renewal programs. And so that would explain some of what you see on the screen here in terms of deteriorating wood pole condition, as well as some of the challenges we have had with underground cable.

So we are looking to refocus on these assets in the next rate period and ultimately sustain performance in these areas.

And then finally, on the network system, we have seen great improvements on our network system. This is the sort of downtown, very redundant, highly automated part of our system that is very reliable and serves sort of key dense areas and large significant customers.

This is an area where we have seen improvements in condition, but we do continue to have a large population of assets that are what we call non-submersible type, which means that they are essentially prone to failure risk in flooding conditions which, you know, we expect will become more frequent with climate change, and is just a risk in general. And so we are continuing at pace to sort of chip away at this legacy population in the next rate period.

So if we go to the next slide, and just quickly summarize this from a dollars perspective. And so, on the top left-hand side of the screen, you can see the programs. I am not going to go program by program. I think I have a pretty good overview of what the major drivers are and where the programs are increasing. For example, stations renewal, you can see on the screen, is increasing by more than most of the other programs for the reasons I discussed.

The bottom line is these investment plans, they manage failure risk. Defective equipment continues to be the single biggest driver of the reliability experience that our customers have, and we are looking to sustain safety related to defective equipment over this rate period.

The capital that we are asking for is $400 million above what we were spending in 2020 to 2024.

I have already mentioned some of the incremental asset management drivers. I do just want to emphasize, one more time, that by our estimation at least half and perhaps closer to 60 percent of that increase is related simply to input price inflation and the compounding effects of that over the last rate period into this rate period.

And so, less than half of that increase is really related to volumes of work, and that goes back to the drivers that I mentioned before. But this is a lean plan and, in some areas, in fact, in order to open up space for other investment priorities like modernization and growth, we are accepting actually some incremental risk over this period.

So just one quick example is we don't really expect to see an improvement in wood pole condition. Rather, we may, in fact, see continuing moderate paces of deterioration in asset health as well as in other asset categories. But it is something that we feel we can manage through prioritization and other means over the period.

One last thing before I kick it to Mr. Huntley for growth is I did want to just briefly mention our maintenance programs, because these go hand in hand with our capital sustainment programs. And the story around these, there is an increase that we are requesting.

Again, the price inflation is a major factor here, just as it is on the capital side. But the other thing that is driving increases within our predictive maintenance and our corrective maintenance programs is we are looking to rebalance a bit the relationship between OPEX and CAPEX when it comes to getting value out of our assets.

And we have been operating with very lean maintenance and operational budgets for some time. But what we found, and this is illustrated in the chart on the right at the bottom, is that we are starting to see backlogs growing in terms of corrective maintenance, which is something that we want to get on top of. And, in the preventive and predictive maintenance categories, we are looking to adjust some of our maintenance strategies to allow ourselves to actually keep some of these capital programs in place where they are, in terms of the pace of work, and still deliver reliability to customers at that level. And so it is a bit of a sort of a TOTEX view, where we are looking to rebalance a little bit. But we think that overall, in combination, these CAPEX and OPEX expenditures will give us the best result from a risk and performance perspective.

So I will leave that, at that point, and I will pass to it Mr. Huntley to talk about growth.

**PRESENTATION BY MR. HUNTLEY:**

MR. HUNTLEY: Thank you, Mr. Higgins. Good morning, Commissioners. My name is Kirk Huntley. I am the director of capacity planning and grid innovation at Toronto Hydro.

The teams that I lead are primarily responsible for managing the capacity on the Toronto Hydro grid that will facilitate connections of both a load nature in terms of customers or distributed generation.

The non-wired solutions portfolio is also managed by my team.

Now you have heard a little bit from my colleagues, Ms. Coban and Mr. Higgins, about the importance of growth and electrification to the plan that is before the Board. And I wanted to start the discussion on growth and electrification today by focusing on the tool that starts it all, and that is the peak demand forecast for Toronto Hydro.

Now, on the left of your screen, you will observe the various drivers that are components that build the peak demand forecast for Toronto Hydro.

Now historically, the peak demand forecast was developed using a combination approach to numerous drivers, but with the recognition that electrification is an important consideration going forward. The utility took a very disaggregated view to driver inputs in the development of its peak demand forecast to emphasize the importance of some unique drivers that are likely to characterize the pathway through electrification, things like electric vehicles, electrified transit and municipal energy plans.

In addition to that, we have seen in recent times the proliferation of hyper-scale data centres, which have occupied an increasing percentage of our customer connections portfolio.

As a takeaway, what has the peak demand forecast told us? Essentially the drivers that are likely to influence peak demand in the current or future rate period, meaning the 2025 to 2029 period, are dominated primarily by data centres, electric vehicles, municipal energy plans and electrified transit. Those particular drivers are serving as key components of growth going forward.

Now on the top right of your screen, you will notice some trends that we have observed. And some are forecasted over the next rate period.

For starters, the peak demand itself of the utility is expected to grow by about 14 percent over the next five years.

Now, that is driven in large part by feeder requests which have increased by a factor of 30 percent, year over year, within the last two years.

And we have also observed and forecasted a continuous increase in distributed energy resource connections which has doubled in the last two years.

Now, from a load point of view, municipal development is serving as one of the key drivers that we have considered in development of the forecast this year.

Primarily, three areas of the city are said to undergo significant development commencing in this rate period and proceeding beyond: the Downsview area secondary development plan, which is forecasted between 300 and 500 megawatts over the next 30 years; the Golden Mile secondary development plan in Scarborough, which is forecasted at 280 megawatts over the next 15 to 20 years; and the Portlands area development, which has started, and is set to continue with an initial connection of 80 megawatts, and is forecasted to increase from there.

Next slide, please. I will move on to discuss in some more detail customer connections and load demand.

Now, those components, as I mentioned earlier, shall in the case of customer connections is a key driver of near-term growth in peak demand.

Now, Toronto Hydro has seen an increase in the volume and complexity of customer connections due to ongoing growth and development in the city. The connections have become larger and more complex.

Now, if you look on the map on the right, the largest circles represent the most significant and complex connections. And as you can see, there is a significant distribution across the Toronto Hydro service territory and the City of Toronto.

However, there is an increased concentration along transit corridors, mainly Eglinton and Yonge Street north. And that indicates to us the future trend of development that is concentrated in those specific areas.

Now, there has been a significant increase in these types of connections, more than three times the connections by type have been experienced over 5MVA, more than 8 times above 10MVA.

Now, just as a matter of scale, some of the large condo complexes that you see downtown are probably in the 1 to 2MVA range, so we are talking about five or more of those complexes concentrated in one single spot. That is the kind of complexity that is involved in the growth projections that we are experiencing today.

Now, customer outcomes are closely connected to the successful execution of this program. This particular program should be thought of in a way that directly effects the customer. This is the program that interfaces, particularly closely with customers.

Now the key challenges that this program faces is where these customers show up, when they show up and what determines or the time it takes for the load to materialize, because given these types of connections it does take a while for the load to appear on the grid so investments in this program tend to show up at points in the future. Five years and more in terms of peak demand.

Now, I take you now to the right side of the screen to talk a little bit about load demand. Load demand is a complementary program to our customer connections program and it is meant to proactively manage the capacity on the grid to facilitate future conditions. It does make optimal use of the existing capacity by moving load from areas that have constraints, the areas that do not. And it is very targeted and addresses the capacity constraints in a very localized manner.

As you can see on the map, those areas of the grid are forecasted to experience constraints over the 2025 to 2029 period, primarily due to some of the growth drivers that we have discussed today. Next slide please.

MR KEIZER: Sorry, I think we may have another technical glitch at the moment. No, it is just a time lag, sorry. Sorry, I believe the presenter has to rejoin the Zoom meeting.

MR. JANIGAN: Mr. Keizer, are we near a resolution of this?

MR KEIZER: Well, based on what's on-screen I think Ms. El-hage is attempting to start the screensharing. We can either proceed on with the paper version if you want, if that's the most expeditious or maybe we can take a short five minute break and see if we can get this fixed. Or...

MR. JANIGAN:  Well, If you think that it -- may be resolved in that period we'd be happy to take a five-minute break.

MR KEIZER:  That may be the most efficient.

MR. JANIGAN:  I would add that Toronto Hydro is being assessed on the basis of utility efficiency, not audio-visual prowess.  So...

MR KEIZER:  There you go, see?  The golden rule, you leave it out, someone says it's time to take a break and it starts to work.

MR HUNTLEY:  Commissioners, I do apologize.  I'll get started again.

We were briefly transitioning our growth discussion from load connections to discuss distributed energy resources.  Now, the map on the left side of your screen demonstrates that Toronto Hydro has connected more than 2,400 distributed generation connections to date, with a cumulative capacity of more than 300 megawatts.  The utilities averaging approximately 30 connections a month, mostly of the micro generation type, less than 10 kilowatts.  These connections are primarily of the net metering type and they are solar PV type connections.

Now, in the context of the city of Toronto and Toronto Hydro, DERs are primarily solar PV and battery energy storage at this time.  They represent the largest volume of connections, but they do not represent the majority of the capacity connected to the grid.  As of today, that still remains of the nonrenewable type, CHP, that kind of thing, but that trend is expected to reverse in the next five years, with the majority of connections being of the renewable variety.

Now, the utility has maintained an on-time connection rate of greater than 92 percent for DER connections, but DER connections are expected to increase by 67 percent over the next five years, reaching a total of over 4,400 connections by the end of 2029. That is a good-news story and one that the utility is proud to continue to facilitate.

However, DER proliferation also brings with it certain unique challenges. Grids need to be considered as energy systems, so they must remain in balance; Supply must be maintained in balance with demand. As a result, if that balance is not kept, instabilities will result, and that will translate into reduced reliability, instability, poor power quality, and ultimately outages.

Now, my colleague Mr. Higgins will take you through grid modernization next, but I wanted to touch on how essential grid modernization investments are in facilitating the integration of distributed resources onto the grid. This plan emphasizes the use of technologies in that space to understand asset behaviour primarily at the edge of the grid, in the consumer space, through the use of various on-the-ground and overhead sensors, advanced metering technology, and protection and control digitization.

This plan addresses the reduction of constraints on the grid brought about by the proliferation and increase in DERs in three primary ways. We have made investments, proposed investments, in renewable battery-energy storage systems, which I'll talk about a little bit on my next slide on non-wires. We have proposed investments in station expansion at Sheppard TS, primarily to alleviate the constraints that currently our customers are undergoing into the east end of the city with respect to their inability to connect DERs. And we are investing in BUS tie reactors at additional stations to reduce the constraints that short-circuit capacity presents and serves as a hindrance to the connection of DERs.

But I wanted to leave you with a parting message when it comes to distributed energy resources in particular. You cannot control what you cannot see, so investments that enhance the visibility of distributed resources on the grid are essential in the electrification, in enabling the electrification journey. You cannot leverage what you cannot control, so you must be able to control those assets in a coordinated way to yield grid benefit. And, finally, you cannot optimize what you cannot leverage. You have to be able to leverage those resources in order to provide optimum benefit for the customers and preserve grid stability.

Next slide. Oh, excellent. I now will touch on another good-news story with respect to non-wire solutions. Now, non-wire solutions have been successfully deployed at Toronto Hydro in the form of demand response in particular over the last two rate periods. In addition, Toronto Hydro uses front-of-the-meter battery energy storage for peak shaving. That is demonstrated by its Bulwer pilot. This plan expense expands on the use of how non-wires-battery-energy storage is applied on the grid in a number of unique ways.

First of all, we are using battery-energy store -- we are planning or proposing to use battery-energy storage as a renewable-enabling investment to facilitate the connection of additional DERs on the grid. Now, part of that proliferation problem that we were discussing a while ago is the fact that the, when generation exceeds the load on the grid, the amount of generation exceeds the load on a particular feeder, that results in instability, so the use of batteries to add load at particular periods of time to maintain that balance is essential, and we are piloting that in this rate period, and we hope to deploy several such installations.

Now, Toronto Hydro has been highly successful since the launch of the CSO demand response pilot in the 2015 to 2019 rate period, culminating in the procurement of 10 megawatts in this rate period under the Etobicoke pilot.

We are increasing that procurement by a factor of three in this planned rate period, for a procurement of 30 megawatts, and that is supported by a robust benefit-cost framework that aligns with the recently published OEB framework on energy innovation.

However, for local demand response or any demand-side initiative to yield grid benefit, it must be targeted. And the use case, the best use case, targeted use case that we have found for demand response in the 2025 to 2029 rate period has been the deferral or avoidance of capital spend associated with BUS and load-feeder transfers, so this program will also complement the load demand program that I covered before.

Now, Toronto Hydro explains their rationale on how this program is proposed and applied through its response to OEB Staff IRs IB Staff 87 and 1B Staff 88 that we can refer to for additional detail on how the program functions.

Now, I will wrap this up with a discussion around the components of the growth and electrification plan. Now, as you would have been able to determine, Toronto Hydro's system and access service investments represents what is necessary to connect customers, including DERs, to build capacity on the grid. Those programs, primarily customer connections, load demand, and station expansion, all speak to the growth elements of the plan in particular. That serves as the core mandate to connect customers who want to connect to the grid while building capacity for future investments. These segments of the plan represent 25 percent of the capital spending in the proposal before the Board.

As we will observe, there are a number of factors that drive uncertainty in our planning process. Ms. Coban spoke to some of it. Mr. Higgins alluded to it, as well. But I just want to basically speak to you about how the elements on the right, right-hand side of your screen, particularly affect the planning framework going forward.

Firstly, customer connections will continue to be highly variable in size, complexity and geographical location; that is a trend we expect to continue. Customers' preferences for the decarbonization of heat, building retrofits and district energy all promise to play a role in the energy landscape, going forward. This will result in variable demand requirements on the grid.

The story around district energy is not yet fully told and it is the expectation of the utility that, at some point in the future, district energy will play a significant role in curtailing peak demand, especially around large, new municipal developments.

Customer choice and incentive structures will influence adoption rates, especially in the electric vehicle space.

We have seen the impact of economic conditions and how they challenge affordability, and its consequential impact on the adoption of electric vehicles, particularly in the last two years.

In order to meet the federal, municipal and city zero-emission vehicle goals, acceleration in this rate period, amongst those drivers, will be necessary.

Technology that empowers customers and facilitates bidirectional flow on the grid is rapidly evolving, and will continue to enhance connections, especially those of a distributed nature, and will be increasingly useful as tools to manage peak demand.

Policy evolution will play a major role in how customers and utilities respond to changes in energy use in the various aspects of their life. And we have seen the impact on DERs in particular, when we consider the transition from the FIT program in 2028 to net metering and beyond, the impact that that had on the connection of DERs for a brief period of time.

Toronto Hydro is also undergoing the third cycle of regional planning. The energy transition is playing a pivotal role in assessing the medium- and long-term needs of the transmission and bulk energy system.

This impacts distribution companies like Toronto Hydro through the need to manage energy distribution interfaces, like transformer stations, on the grid.

This can necessitate the need to build additional poles and wired assets or deploy demand-side programs to manage emerging or forecasted customer and system constraints.

Now considering various combinations of the foregoing, or in their totality, it is clear that plans must demonstrate increased flexibility to achieve the desired outcomes.

Thank you for listening, and I now pass you to Mr. Higgins to take you through the remainder of the capital presentation.

MR. HIGGINS: Thanks, Mr. Huntley. So I am going to turn our attention to the grid modernization and modernization component of our plan, generally.

This is 17 percent of our capital investment plan.

Grid modernization is one of those nebulous terms that can mean different things to different people. For us, pragmatically, grid modernization is the application of proven technologies that have a clear and obvious benefit to customers in the form of better service, reduced costs or both. And, in that way, our plan here aligns with what we have heard from customers. And that was really a key criteria in selecting the investments that we prioritized for this rate period.

Historically, our modernization efforts have been a bit smaller and really embedded within are plans, either as integrated aspects, for example, of our system renewal approach where, as we rebuild parts of the system, we are adding SCADA switches, for example. So it is just part of the routine reinvestment in the system. And in some cases, where there is a high-value opportunity, we have invested in programs like network condition monitoring and control, which my colleague, Mr. Smart, will talk about, where we retrofit a part of the system with the new technologies for certain benefits -- reliability, cost, et cetera.

If this was the status quo planning cycle, we may see more of that. But the reality with this planning cycle, as I mentioned earlier and as my colleague alluded to when talking about the need to have better observability on the system and some of the challenges that we are facing, this is not in our view a status quo planning cycle, in that we did identify a need as part of our overall integrated, least-regrets approach to planning, to accelerate some of the investment that we have been making within these proven technologies in the next rate period.

And that is in response to some accelerating challenges. I have listed a few of them on the left-hand side of the screen that I did want to highlight, really from a complexity and reliability perspective. So we haven't talked a lot about this today, but we are of course facing pressures from advancing climate change impacts. And that means more rain, more wind, more high-heat days, and that puts stress on our system and will make it more difficult to maintain the standard of reliability that we enjoy today.

On top of that, electrification of consumer energy demand is not only going to increase the actual demand pressures on the system, but it will also, just directionally, we assume, increase customer sensitivity to outages, because they will be relying on electricity as their primary fuel source more often.

And then distributed energy, the proliferation of distributed energy within our system and the expectations that customers and stakeholders will have for how we leverage that is another added complexity on the grid. And as my colleague Mr. Huntley talked about, there is that need for the ability to observe and control these resources to get the most out of them and accommodate as many as we can.

These pressures together are going to make it, A, more challenging to maintain stability and reliability on the system, and ultimately I think raise customers expectations for what we are providing to them through the electricity system.

And on top of that, we have the costs that are going to go with this, actually accommodating these challenges, but also just the costs that we have been experiencing operating in the city of Toronto, which Mr. Smart will talk about briefly in a moment.

And so, with this grid modernization strategy in the next five years, the plan that we came up with was one where we are going to be accelerating the deployment of field technology, sensors, switches, and controls, and investments in automation to create a more intelligent grid that is more flexible and adaptive to the conditions that we are facing, and ultimately more efficient.

We also have a grid readiness component of the plan, which really refers to the readiness of our grid and our operations to accommodate distributed resources and distributed energy devices in general.  So really, we are talking about DERs, but also demand-response potential as well as EVs, for example, as complex new sources of point-load on the system.

So we are looking to make investments in, again, it will leverage those observability and control investments, but also investments in better modelling, better data, and different types of digital investments and automation investments that will make it more feasible for us to operate a grid with a high penetration of these kinds of complex resources and two-way power flows.

And as part of that grid readiness strategy, we are proposing an innovation program, which is a smaller pot of funding that we are looking to set aside for investments that are more exploratory around scaling up potential technological solutions to challenges that are still somewhat sticky today, for example, alleviating hosting capacity constraints on parts of the grid for DERs. We are still exploring solutions for that challenge, and we believe there are better technologies to come. And so that is part of accelerating that.

And then finally, I don't want to give short shrift to the analytics side of things, so sort of back at the office, whether it is in our control room or in our planning areas or even just managing our administrative processes, we see huge opportunities for making better use of the data that we have through the analytics capabilities, including AI and machine learning, which are emerging very rapidly at a very opportune time. And so we are looking to make investments and breakthroughs in that area, as well.

So if we go to the next slide, this is just the program view of those expenditures that we have mapped to our modernization program.

We are looking to accelerate, albeit on a lower number of $280 million, up to $651 million.

I want to just take a quick second to focus on the big changes at the program level. And right off the bat, the one that I think jumps off the page is metering. In AMI 2.0, next generation smart meters, this is what we are considering to be one of the key elements of our observability strategy; being able to actually see what's happening at the edge of the grid is going to be very important in the years to come. And we are going to get that capability in part through AMI 2.0 for our low-volume customers.

I just want to note, however, that these are investments that are actually nondiscretionary in nature. We're making these investments, first and foremost, because our existing meter population is at the end of its life.

The second thing I just wanted to highlight is the system enhancements program. That is the other one that is going up more significantly and that is the program where we are funding some of the stuff that you see represented in the picture on the left there, switches, reclosers, essentially distributed, distribution devices that are going to give us that flexibility, observability and ultimately give us the backbone that we needed of technology to actually start automating the grid operations more often, which is something that Mr. Smart will talk about as well.

And then finally, we've carved out a portion of our IT program here that I just wanted to highlight around cyber security and software enhancements.  These are really the key modernization components of our IT investments and these investments are set aside to support, A, that cyber security elements, which is increasingly important; but also the analytics component of our plan where we do expect significant efficiency benefits to be available to us over the next decade from making use of data in automating our processes.  My colleague Dan Smart will talk to you a little bit about our investments that we're planning in this area around the ADMS or advanced distribution management system.  So I'll leave that to him.

So, that's our modernization in a nutshell and then finally I'll wrap it up with a brief discussion on general plant.  And so, this is the remainder of our operational capital investments.  And that includes facilities, fleet, IT and OT assets, and these assets are -- these operational assets are essential to enabling efficient business operations and supporting capital investment in all the areas that were previously discussed.

And starting briefly with facilities and fleet, as a mature utility we do have a diverse mix of facilities across our service territory that consists of four major work centres as well as 185 stations buildings of varying vintages.  And similarly to the actual electrical stations assets that we talked about earlier under the sustainment program, we have a demographic challenge and a condition challenge that is emerging with our stations buildings, as well.  And so, this is one of the areas where we are proposing an increase to address those key assets which ultimately protect our electrical assets and protect our workers and ultimately need to be maintained for safety and reliability purposes.

Our crews also rely on approximately 360 vehicles comprised of various light duty and heavy duty units to support operations and in that area, our plans are largely based on life cycle management of those asset, and so the plans that we've put forward are related to our asset management principles and asset condition.

I want to also mention physical security. That is another area where we are making investments that are part of the increase of the facilities management program. We have to address emerging needs to provide greater resilience against physical threats such as vandalism and sabotage through those systems, and of course physical security systems are an important part of our overall cyber security strategy as well.

And one thing I also wanted to mention was our net zero strategy. So, Toronto Hydro is committed to reducing other greenhouse gas emissions -- our scope one emissions -- to mitigate the impacts of climate change and reach net zero by 2040.

And we are planning to do this through two main things, one is increasing the complement of electric and hybrid vehicles in our fleet and the second is reducing building emissions through a combination of energy efficiency measures and the adoption of electric heating systems over natural gas.

And moving on to IT and OT. So, the investments that you see on the screen are largely related to maintaining our core information technology and operational systems in the form of hardware, software applications and systems and communication assets which are essential to our day-to-day operations, including enabling customer self serve tools managing field crews and responding to outages. And so, these costs essentially track the upkeep costs that we are seeing in those areas.

And the last thing I wanted to note was the enterprise data centre, and this is sort of a standalone project for this rate period. It is sort of a unique blend of physical facilities assets and data centre IT assets.

Our data centres, they serve as core infrastructure. Housing essential networking, telecommunication data storage, as well as servers. And they are a critical piece of infrastructure and to ensure both the reliability of our core data centre as well as the scalability of that data centre for the future, we are looking to relocate it and rebuild it at a different work centre than where it is today, and that is all part of supporting business continuity and our modernization objectives.

So, that concludes our overview of our capital plan and with that, I am going to turn it over to my colleague, Mr. Smart, to talk little about bit about the operations side of business.

MR. JANIGAN: Okay. Can we take a break? How long of a break would you need, 15 minutes? Okay. 11:30. Okay, we're going to take a break until 11:30 and resume our presentation at that time.

--- Recess taken at 11:10 a.m.

--- On resuming at 11:33 a.m.

MR. JANIGAN: Thanks very much. I want to apologize to the court reporter. I was going to request that some of the -- that there will be a slowdown in the [audio dropout] what was delivered to us and possibly that, in light of [audio dropout] and that might have been the reason for a break, but I think the break was very opportune.

Ms. Coban, the panel has discussed this, and we would like you to review the performance incentive mechanism in the appendix prior to our panel questions, if that's okay.

MS. COBAN: Sure, I would be happy to do that at the end. And, just in terms of getting us through the rest of the presentation, thanks very much for your patience. I know we had some IT connectivity challenges that resulted in a bit of a delay. We will do our best to wrap things up in about half an hour, with the remaining two presentations, without speeding up the voice and the delivery, just trying to focus on the most important points. And then we're in your hands in terms of finishing off that performance incentive slide and any questions that you may have.

MR. JANIGAN: Well, thanks very much, but don't speed it up too much. We are impressed by the complexity and the far-reaching aspects of what you've been presenting today, so we're not going to ask that we terminate it in a way which truncates part of your presentation.

MS. COBAN: That is good to know. Thank you.

**PRESENTATION BY MR. SMART:**

MR. SMART: Thanks very much, Ms. Coban, and good morning, panel. My name is Dan Smart, and, as the general manager of distribution stations and grid operations, I'm responsible for leading the team that looks after 24-7-365 operations at Toronto Hydro. So, most notably, that includes our control centre operations; our control centre support team and our trouble response crews; as well as our distribution stations design, construction, and maintenance teams.

So, what I'm going to do today is complement some of the discussions that my colleagues have gone through already today and talk about some of the operational challenges that we face at Toronto Hydro, talk about some of the ways we've been innovative and productive from an operations perspective, and then talk about some of the specific investments that we're putting forward to support operations technology and our workforce, all with the aim of addressing and overcoming some of the challenges and complexities that we've talked about already.

So, Toronto Hydro's ability to consistently deliver on customer objectives and meet customer and stakeholder expectations is really quarterbacked on a day-to-day basis by our operations teams. These fundamental objectives and outcomes that we work towards all day, every day, involve environmental and safety priorities.

So, in a typical year, we respond to over 4,100 emergency events, and I also want to note that, 89 percent of those, we have a crew on site within an hour, which is greater than the OEB-mandated target of 80 percent. We respond to and manage over 9,000 power-off events. We manage a system with over 4,000 remotely operable devices within our SCADA system, which enables reliability and efficiency improvements.

And, as stewards of the distribution system, we enable virtually all the work that takes place on or around the distribution system, and I think that's most notably represented by the figure you see on the far right of this slide here. Each year, we prepare and execute over 32,000 switch sheets and hold-offs, which are different transactions that we use to facilitate safe work on the distribution system.

As we'll discuss, Toronto Hydro operates in uniquely challenging environments, and this, coupled with the energy transition that we've talked about at length this morning, necessitates specific investments in our workforce and technology in order to meet customer expectations today and into the future.

So, in this slide, I want to talk about some of those challenges. This is not an exhaustive list of some of the complications that we deal with, but it is representative of some of the more impactful factors.

So, Toronto is a very dense city. Across our service territory, there are approximately 4,800 people per square kilometre, and, if you look specifically in the downtown core, that number balloons up to 16,000 people per square kilometre. For context, the next closest municipality is less than 3,000.

Additionally, Toronto is an old city by North American standards, so there is a significant amount of infrastructure and legacy infrastructure out in the system, and we have a fairly extensive tree canopy. And what all that means from an operations perspective is we have a different size and scale of the distribution system assets that we install and operate; the impacts of outages and emergency-type events are more significant; we have a significant volume of customer requests for new connections; and, in general, our roads are smaller, our sidewalks are smaller. I mentioned the tree canopy. It is much more challenging to locate, access, maintain, and repair a distribution system plan given those circumstances.

I think anybody who lives or works or travels through Toronto knows that it can be very, very challenging to get around with the volume of traffic that we all have to contend with. This is particularly impactful for the crews that we have that work within the city.

One data point that we have in our application is -- you know, we looked at the amount of time it takes for our crews to get to site, and the crews that are based out of our downtown work centre in the Portlands, it takes them approximately 45 percent more time to get to site as compared to the crews that are based in our suburban work centres in Etobicoke and Scarborough. And, as you can imagine, what that means is it takes us more time to get our people, our equipment, and our materials to site in order to execute our work, and it introduces challenges with respect to response times and those sorts of things because, you know, it's challenging to get around.

This challenge is something that we know is only going to grow in the future, with a number of major infrastructure projects now and in the future. For example, the Ontario line construction has begun. The city has embarked on a program to rehabilitate the Gardiner Expressway, and all of those things have a direct impact on our ability to get work done efficiently.

From a customer perspective, Toronto Hydro supplies some customers that are of unique importance at a municipal, provincial, and federal level. So, we supply the headquarters of several major banks, the Toronto Stock Exchange, the provincial legislature, as well as several hospitals that have internationally recognized research programs.

All that that's to say those types of customers have exceptionally low tolerances for service disruptions and very high expectations with respect to restoration when the lights do go out, and that impacts and necessitates additional incremental but prudent investments in terms of how we design our system in those locations to make sure that there is a sufficient level of redundancy but also our emergency response posture, to make sure we are positioned to get crews out to site as soon as we need to in order to address those types of issues.

And then, lastly, there has been a lot of discussion about the ongoing energy transition, and I want to put a bit of an operations spin on it.

So, historically with one-way power flow, the electricity flows basically consistently from the transmitter, through the distributor, down to the end customer, and, based on that simplicity, you can make some assumptions about how the distribution system operates. So you know what direction power is flowing; you know generally or you can infer what voltages are; you know, if something goes wrong, immediately what the impacts are going to be.

But, as the volume of distributed energy resources and, you know, non-wires alternatives increases and the penetration increases, those assumptions break down, and, in order to operate the distribution system in an optimal way, you need more information, more powerful tools to predict what actually is happening out there, and you can't assume that, you know, if everything is okay today, an hour from now it's going to be okay, because of the intermittent nature of some of these resources. So that results in a requirement for additional workforce development and also, as I said, additional tools in order to understand what's going on.

All right. So, despite these challenges, Toronto Hydro's grid operations are efficient and even more so when you consider the context of the environment that we operate within. Over the last period and prior, we've benefitted from innovation and realized some productivity gains through optimization of our operations. I want to just highlight a few, a few key points in this slide.

By and large over the last rate period, our workforce in the control room and the core operations area has been more or less steady, and, despite that, we have facilitated an ever-growing volume of work happening on the distribution system.

The control centre and dispatch handle over 90,000 calls each year, and, despite that, over 94 percent of those calls have a wait time of less than 10 minutes, which directly impacts the ability of crews to get going with their day and be productive in the field.

Additionally, another data point that we are particularly proud of is our improvements with respect to how long it takes to transact a hold-off. And that's basically an interaction that takes place when crews need to work adjacent to the distribution system. We have taken that interaction between the crew and the control room from 29 minutes in 2024 down to three minutes in recent years.

Another area where we have innovated and we have been productive is with respect to our operations field resources. So, in recent years, we implemented what we call Oracle Field Services Cloud, or OFSC. And really what that is, it is a modern platform that interfaces between our crews in the field, who access it through a laptop, our control centre, and our dispatch centre, who are managing our outage management system.

Through implementation of that tool, we have been able to eliminate the need for 20,000 manual work orders to be created every year. We have gained greater insight into crew travel times and been able -- it has enabled us to optimize the way that we route crews between events and between jobs. And it has also served as a catalyst to enable us to introduce new metrics and new processes around provision of estimated times of restorations for outages. So, in recent years, every single outage that happens on the Toronto Hydro system gets an estimated time of restoration.

It is updated consistently throughout the outage event by both the crew and the backend office, and it is something that we track on an ongoing basis.

The other thing we have done on the dispatch side is introduced new methods of -- or for customers to communicate system issues with Toronto Hydro. So in addition to the phone system today, we also have our IVR, we have our outage map where customers can submit issues, and we have also recently introduced a web chat feature, where customers can interact over a text box with a live agent.

On the system side, I want to briefly talk about the network condition monitoring and control program, or NCMC.

This is a program that we started several years ago, and it is aimed at automating or introducing automation and remote visibility to our downtown network system, which supplies about 10 to 15 percent of the load in the downtown core.

Through this system, we have been able to remotely identify insipient issues before they become a major problem, and without sending a crew to site. And we have also been able to automate some operations that historically would require sending a truck to a specific vault. And, for context, in the last five months of 2022, that resulted in about $78,000 of operating costs saved, where we were able to redeploy those crews to focus on more higher priority tasks.

So, to deliver on the key outcomes in terms of grid operations against some of the challenges that we have discussed throughout this morning, while also maintaining continuous improvement in productivity and efficiency, Toronto Hydro needs to invest in some technology and tools that are going to provide the foundation for more efficient operations in an ever more complex work environment.

And really, the centrepiece of that, that program and of our proposal, is introduction of an Advanced Distribution Management System, or ADMS.

The ADMS is really an umbrella term that is used to refer to a number of interconnected platforms that we use to manage our outages, to manage our distribution system model, to manage our remotely operable devices in the field and our distributed energy resource management system that we use to manage batteries and other local generation.

The platforms that we have today are all absolutely integral to what we do on a day-to-day basis, and enable us to be efficient and to process the volume of work that we need to process, day in and day out.

The systems we have today are all approaching or at the end of their vendor support period, which introduces risks with respect to future cybersecurity patches, bug fixes and are -- it constrains our ability to introduce additional enhancements and modernizations, if the vendor no longer supports the platform.

So it is absolutely imperative that we modernize those systems and we upgrade them to versions that are within vendor support.

This program and this initiative also provides the opportunity to introduce more powerful models and tools in order to address the challenges that we have talked about with respect to the energy transition, the prevalence of DERs and the deployment of non-wires alternatives.

The other thing I want to mention with respect to ADMS is the Advanced Metering Infrastructure 2.0 program.

So, in addition to the benefits from a billing perspective and the need to replace the meters due to their useful life, it will also bring significant visibility with respect to the secondary distribution system, and provide us more insight into what is going on at the edge of the grid where, today, we have no visibility whatsoever.

So that will enable us to look at what direction and how energy is flowing within the secondary system, and also provide us the ability to see in real time when there is a disruption or a service issue on the secondary side through what we call last gasp technology, which ultimately will enable us to improve our outage response.

The other technology investment that I want to talk about that is closely related to the ADMS system is the introduction of automation.

And we refer to that as the fault location isolation and service restoration module, or FLISR, F-L-I-S-R.

And in effect, what that does is it makes use of the network of smart switches, smart devices and sensors that we have installed in the distribution system. And when a fault occurs on a feeder, it automatically detects what section of the feeder that occurred.

It automatically opens the switches on either side of the damaged section of plants, and then it automatically closes switches in order to resupply power.

And all those actions happen within seconds to minutes versus, you know, 10, 15 minutes to an hour, today, when it is done manually by an operator.

If you couple that investment in automation with our plan to increase the use of SCADA devices and increase the number of smart devices like reclosers out in the system, we anticipate benefits from a reliability perspective of about 20 percent for SAIDI, so outage duration, and 25 percent for SAIFI, so significant reliability and customer benefits associated with this program.

And then the last thing I want to talk about is the workforce investments on the operations side.

I think it goes without saying that, you know, without the right people that are skilled, knowledgeable, qualified and experienced, we can't realize any of the benefits that we are talking about with modernization.  And we would be very hard-pressed to deliver the level of service that we are even delivering today.

Over the last several years, throughout the pandemic, Toronto Hydro has faced some workforce challenges that have really, you know, impacted the whole operation.

From a retirement perspective, we saw a relatively large volume, which resulted in a 7 percent reduction in our average age.

We have observed more competition for science, technology and engineering graduates who form the basis for a pool of applicants for our skilled trades.

And given the nature of work that we do, many of our positions require four and a half to six and a half years of on-the-job training before someone is fully competent.

So all that's to say it is incredibly important in order for us to be able to deliver the programs that we are talking about, but also just operate the distribution system on a day-to-day basis, that we invest sufficient money to enable us to sustain and, in certain areas, grow that workforce.

Much of our operation, the headcount will remain flat.

And one example is our complement of distribution system operators, the folks that, you know, manage the distribution system, open and close switches on a day-to-day basis. Our intention is to manage the growing volume of work with that workforce through the investments that we talked about in an advanced distribution management system, and other process automation opportunities -- sorry, process optimization opportunities. But a couple of areas where we see a need for growth, one has to do with the back-office support that underpins the automation investments and the ADMS investment. So if you introduce automation, you require a significantly more complex and powerful distribution system model. It is no longer sufficient just to know this transformer is connected to this switch; now, you need to know this transformer, which has this impedance is connected to this switch through this wire and this insulation, et cetera, et cetera, et cetera. So there is more work involved in building and maintaining the model that underpins all these investments.

And I also mentioned, we are looking to increase the number of SCADA-operable or remotely operable devices that we have on the system, which will allow us to realize more benefits from automation.

And then the secondary that is driving headcount increases in the control room operations program is the prevalence of DERs, non-wires alternatives and programs like demand response. So, in order to realize the value and the intended benefits of those programs, you need to actively monitor and manage those types of assets. And that is not something that we do at scale today. So we anticipate, as the prevalence and the penetration again of these types of solutions and assets increases, we are going to need to stand up or grow our team of people that look after and actively manage those assets on a day-to-day basis.

So, at a very high-level, those are the operational and technology investments from a -- that are most important from an operations perspective and, you know, without those types of investments we would be hard pressed to sustain or improve our operational performance in line with customer preferences around outage durations, outage frequencies, and those sorts of things.

We lack the resources to effectively implement non-wires solutions to address distribution system constraints and ultimately what we are trying to avoid is becoming an barrier to the energy transition.

So, that's the operations piece in a nutshell and I'll hand it off to my colleague Ms. Page to talk about customer care operations.

Presentation by Ms. Page:

MS. PAGE: Thank you, Mr. Smart, and good morning, Commissioners. My name is Evelyn Page and I'm the director of customer care operations. I'll be speaking about the customer OMNA programs which include customer care, key accounts and customer connections.

To provide context for our investment proposal I'd like to walk you through the core operations that these programs cover before we get to sort of our historical performance, our productivity improvements over the last several years, what's changing in the customer care area and how we plan to modernize our systems.

So, for context, our 790,000 customers include 513 key account customers, and as you've heard from Mr. Smart, some of those key account customers are fairly large, complex and have very demanding needs.

This customer account drives our meter to cash process volumes, and you can see we do -- we have 14 billion-meter reads that we need to manage on an annual basis in order to translate that into 9.5 million bills.

We process 3.6 billion in payments and this is becoming increasingly more difficult as, since the COVID pandemic and the current economic climate has made it much more difficult for customers to manage their account balances.

We respond to over 400,000 e-mails and calls in a year.  And we processed 3.6 million transactions through our serve, our various self serve technologies.

We also handled 5,400 connections, via our customer connections team and I'd like to speak a bit about the technology projects that we do in any given year.

We are usually working on 15 to 20 projects at any given time.  An example of what we've done in the last couple of years we've been upgrading our customer information system which is quite outdated.

We've implemented green button, we've implemented the ultra low overnight time of use rate, introduced live chat into our context centre area as well, introduced a mobile app that's very similar to the transactions that you can do on our website. You are now able to do that on the mobile app.

In addition, we don't always work in silos, so the field services cloud that you heard Mr. Smart speak about, that gives us the mobile ability for our field staff to do meter exchanges, to do our -- handle our disconnect and reconnect program on a much more efficient basis.

All of these projects are really driven by public policy changes, technology system upgrades that -- in order to keep other systems current, new service offerings that our customers need and efficiency projects to control costs.

And all together, you know, the reason we are working on 15 to 20 in any given year is we've got about 35 -- or over 35 technology systems that support the customer services area, so it's a fairly complex area and very dependent on technology to handle this volume of operations and ensure we're efficient and effective.

Not only is the volume increasing but the types of work behind each of these transactions is becoming more complex. So, for example, customers now have three different price plans to choose from. Net metering customers continue to grow which makes meter reading and billing more complex. In the contact centre connections and key accounts teams are handling more complex inquiries related to the energy transition.

Despite these trends the customer areas have demonstrated consistently strong performance and we are really proud of the improvements we've achieved in the last decade. As you can see on the chart we've improved performance across all of our customer performance metrics and we've done so by focusing on continuous improvement. You can see in 2022 that the customer satisfaction score was 94 percent which really reflects Toronto Hydro's commitment to excellent service.

We've also implemented productivity improvements to assist our customers and control costs. One of the things we committed to in our last rate filing was driving e-bill adoption and we exceeded our target ahead of schedule. In fact, if we stacked the paper savings from our customers on e-bills, it would actually be 10 percent higher than the CN Tower and this equates to an avoided cost of paper, printing and postage of $4.4 million annually, so it is a significant savings for our customers.

Another improvement I'd like to highlight in the two charts on our right is our success in driving self serve tools. We recently enhanced our website, we added new functionality and we added more functionality for our commercial customers as well, and this you can see how the graph has spiked up quite significantly in 2021 and 2022. As a result, this has saved us a lot in calls and e-mails, and you can see that volume in the bottom chart going down correspondingly.

These are just some of the ways that we've controlled costs while also being responsive to the needs of our customers.

As my colleagues have outlined, our rate filing is built on an extensive customer engagement process. And Toronto Hydro's objectives and our planned expenditures for customer services in the '25 to 2029 rate period are informed by what our customers have identified as their priorities through this process and through other ongoing feedback systems that we have in place.

The customer programs need to deliver on ongoing customer priorities that you see in the box on the left, so reasonable rates, finding efficiencies, reducing costs, timely and accurate bills, providing tools that our customers need so that they have the convenience to do what they need to do 24-7, and supporting our vulnerable customers.

We're also mindful that customers, in comparison to the customer service industry in general, so we need to stay current with those trends and industry norms or we risk dissatisfying our customers.

However, customers do have emerging priorities which we have gone through earlier, and so we need to layer those priorities into our services and what we've learned through this engagement, which includes assisting customers with their electrification goals, so customers are more interested in DERs, EV ownership.

Customers are also looking for more data and analytics to help them with their decision-making, so information coming out of the meter, how they're using their energy consumption, all through graphs, charts, the ability to pull with their energy management systems and pull that information out of our system. So, not only do we have to ensure that our systems are operating, they also need to be interfacing with the systems that our customers need to use and those evolving systems as well.

The customer programs have an investment plan in place that are desired designed to meet these priorities, and it is through people and technologies that we will make this shift.

So, in order to make this transition similar modernization efforts, as you have heard my colleagues speak about today, so we need to upscale our workforce, you know, to function and deliver services effectively in this complex environment. Our staff will need to have a greater depth of knowledge to help both our residential and our commercial customers to understand and navigate the new energy choices available to them, understand more complex bills with bi-directional energy flow information on them, understand government programs and incentives that might be available.

We also need to build and improve our self-serve functionalities and communication channels for customers, so these are constantly evolving. Our customers are looking to have us stay current with technologies that they wish to use, so things that we will be introducing in the near future actually are proactive notifications to customers, such as bill due dates, or your bill is overdue, thank you we've received your payment. Customers really appreciate these kinds of nudges and notifications to help them manage their accounts.

Online functionality, like customers being able to set up arrears payment arrangements online rather than having to go through an agent, that sometimes helps customers get past just the barrier of admitting that they need help if they can go things online, without through an assistant, and agent to assist them.

New payment channels are emerging that customers are interested in, like digital wallets, and we'll be introducing that shortly.

Customers are looking for us to start using text, use e-mail more frequently, so we'll be using those for proactive notifications, as well.

We also need to leverage new technologies in order to control costs for customers, such as implementing a proper knowledge-management system. Ours is completely archaic, built in-house, and it just will not support the types of information we need going forward, and it's really the foundation that we need to provide consistent data across all of our communication channels.

And it also is needed to -- as the foundation to power things like chat bots, consolidate customer information for customers, so it really works well with artificial intelligence, which we've talked about, which you've heard our other colleagues using in their areas. In the customer area, artificial intelligence is becoming very prominent, with lots of use cases, so, when you mirror your knowledge-management systems with your artificial intelligence, you can do things like pull the text of the customer conversation while it's live and pull information out of the account and provide information to the agent to help assist with the customer.

So, over the past several years, the customer programs have operated very efficiently, with our OM&A expenditures being relatively flat. We've worked very hard to drive efficiencies to offset operational pressures; however, we need to make investments in our people to meet emerging challenges. So, similar to what you've heard Mr. Smart speak about, it's really essential that we have an experienced workforce in place. We need to preserve knowledge and expertise of our core functions, and we need to add subject-matter expertise to develop the technology projects when needed.

Our Staff complement has declined over the years, and we need to rebuild our core capacity. We plan to do this by filling vacancies and transferring back in-house a portion of the functions that we currently have now with an external service provider.

We also need a newly skilled workforce to provide the capabilities to design and implement new technologies that we need. So, these skills would include workers who are very skilled in AI, machine learning, business-process automation in order to drive the innovation and efficiencies that we need and to provide staff with the ability to respond to new types and complexities of inquiries.

We need data analytic skills. As you've heard, the amount of data is just growing at an exponential rate, but, in order to really fully leverage our systems, optimize our systems, optimize the services that we can provide our customer, we really need to be taking this data, analyzing this data, allowing it to provide us the insights that we need for decision-making.

In addition, our customers are asking us for data, as well, so we need to provide the data that customers are looking for in order to help them with their electrification decisions, help them manage their usage and control costs.

We need workers to build and evolve our digital channels, which are constantly changing over time, and our self-serve tools in order to keep pace with customers' changing priorities and the customer service industry in general.

So, failure to invest in our workforce would limit our capacity to build these services that we need and keep pace with the rapidly changing technology that we know our customers are looking for us to adopt in order to contain costs and provide the services they need. Our costs would escalate as our operations would become less and less efficient over time.

It would impact our ability to meet our performance standards that we've achieved in the past and wish to, obviously, continue to achieve, and we would really frustrate our customers, who are looking for us to provide them with the services they need to meet their own energy transition goals.

So, although a period of transition is needed, we are confident that the customer plans will extract value from this investment in our workforce and achieve long-term and sustainable efficiency and performance in line with our customer performance -- sorry, in line with our customer priorities.

I think that's all we have for you today, so I would like to thank you very much for your time and attention and for listening to us go through our presentation and for your patience with our technology issues. I will turn it, I guess, to Daliana to go through the performance-incentive mechanism.

**PRESENTATION BY MS. COBAN (CONT'D.):**

MS. COBAN: Sure. If we can just turn up -- excuse me. I'm losing my voice. If we could, just turn up the appendix slide. So this is the slide that I mentioned at the outset of the presentation, that details the way that we envision this performance-incentive mechanism working from, kind of, a procedural perspective.

So what we envision in this application is that, in this first phase of the application, the Board would of course in the normal course decide the rate parameters that we are working with in terms of being able to invest our plan. And, as part of that, there may be certain decisions with respect to the pace of our investments in certain areas and what have you.

So it is really important for us when we are thinking about the performance-incentive mechanism to have the ability to reevaluate those planned targets at the end of this process so that we can reflect, in the setting of those targets, the outcomes, the funding outcomes, and other guidance that we may get from the Board in this decision and make sure that we are reflecting that back into the specific targets and measures that we will be held accountable to over this period.

In this process we envision and we've proposed as a phase 2 to this application that that would happen roughly in parallel with the draft rate order process and that would, at least in the first instance, unfold much like a settlement, where the utility and the intervenors, having the guidance of the decision and the parameters that we are working with in terms of the decision, we would come to the table together to work out what those targets and those measures would look like as part of the PIM, and only if we can't come to an agreement on that would we come back to the Board in our phase 2 to make decision submissions with respect to the finalization of that PIM.

So we see this process roughly taking place in parallel with the draft rate order, so, by the time that we are, you know, halfway through the first year of our plan, we have this part of the plan settled in terms of understanding what specific performance objectives we're working towards as part of the PIM.

We would then go through, as we do currently today, measuring our performance annually and reporting on these measures as part of our custom scorecard, through the regulatory MD&A disclosure, management discussion analysis disclosure that we do every year, with a custom scorecard. And then we could come back to the Board -- sorry.

Over this period of '25 to '29, as we are getting closer to realizing the performance objectives that we've set -- recognizing that those are 5-year objectives; they are not annual objectives, right? -- so, as we have confidence that our plan will be able to deliver the 5-year target, there would be a performance-incentive mechanism deferral account, which would be the vehicle in which those performance earnings can be recorded as we get confidence that we are going to be able to be able to hit those targets.

And then that mechanism, along with the results and the substantiating evidence around those results, would come back to the Board in the next rebasing application for a review of the results and a review of that particular account and disposition of that account.

Then, the disposition and clearance of that account would take place in the next rebasing application, and, you know, we would be able to look at that in terms of whether it is a single-year disposition or a multi-year disposition; that would be a decision that we would make in the context of all the other factors that would be affecting the rates in that next rebasing application.

So hopefully this provides you a good overview of how we see this process evolving. All of this is also set out in our evidence, where we describe this mechanism.

MR. JANIGAN: Thank you, very much, for that.

Now the Panel will have some questions, and we will start with Commissioner Duff.

MS. DUFF: Let's just stay on this page for a second.

I am thinking about what's happening in 2025 to 2029. How many regulatory proceedings are you having? Are you coming back on an annual basis, at all? And I hear you saying no.

MS. COBAN: No. So we would continue to do an annual rate update process, much like the one we have today that is handled under delegated authority, which is just a mechanistic update.

MS. DUFF: I think I actually decided your last IRM. But okay, go ahead.

MS. COBAN: Yes. We did have exceptional circumstances --

MS. DUFF: Right.

MS. COBAN: -- in the last IRM, because we were implementing the Board's directive with respect to re-evaluating our depreciation-useful lives. And as a result of that, and the timing of that study being implemented from a financial perspective, we needed a new variance account to be able to capture those variances in revenue requirement. That was really exceptional.

Typically, we don't tend to come in before the Board in those annual rebasings.

MS. DUFF: So you are here now, and then you will come back in five years. And that includes -- I guess that delegated authority could potentially be also your DBAs, your group 1s that you are trying to dispose of?

MS. COBAN: Correct. We typically deal with the group 1s in the annual process, but not the group 2s.

MS. DUFF: And I just want to make sure I have got my understanding of the significance of having a price cap versus this revenue cap, and really what the difference is.

So you have your revenue number and then it is changing every year. And is the point though where you then transcend that into actual rates that people pay, and where, if I -- and you are agreeing. Have I got that right?

MS. COBAN: Yes.

MS. DUFF: And I look at a price cap IR, I am actually taking the actual rates the customer is paying. I pay, you know, $1 per unit, and then those all increase just a little bit, based on the price cap IR percentage increase. Right? Everybody goes up the same amount.

So with this revenue cap and the way then you -- you've got a quantum of revenue. And then you are allocating it back into rates, that's where I am not really getting it. And you are not connecting that to what is actually happening in terms of the customer numbers or volume; you are doing it based on your five-year forecast. And okay, well, maybe I've got it wrong.

MS. COBAN: Yeah. So that annual allocation that happens is done in accordance with the specific growth we would expect to see in each rate class with respect to the different billing determinants in that rate class. That growth doesn't get updated annually.

MS. DUFF: Yeah.

MS. COBAN: It gets locked in at the rebasing. And then really what we are doing is just implementing those assumptions annually, as we then take that new revenue that has been escalated by the custom index and then allocate it down.

The allocation parameters don't change, so what we decide methodologically in the rebasing with respect to how the allocation works, we reproduce that year over year in the annual rate-setting process.

MS. DUFF: And hopefully you are not going to take this as a criticism, but I am just saying you are making a forecast for five years. I don't know what's going to happen with different customer groups. And is there an opportunity, did you consider updating that? Because it's an allocation process to the individual rate classes.

I could say wow, this is really changing within small businesses, or this is really changing in within industrial. And yet your, the trends, the adjustment to actual rates is going to be based on your five-year forecast. So maybe you could talk about how you made that choice and why?

MS. COBAN: Yes. So we did think about that, and that is one of the components of uncertainty that is part of this demand-related variance account that we have proposed.

So that account would allow us to track those differences between the forecasted growth and billing determinants in each rate class, and then the actual growth and billing determinants that we see in each rate class, and be able to bring those variances back to the board for disposition in the next rebasing application.

At this time, it is difficult to say what the magnitude of those balances are and typically, we don't come in for group 2 dispositions during the custom IR period. But this is something that, you know, if -- and depending on the parameters of the Board decision, if there was a certain materiality hit, that we would be able to look at that and consider whether, you know, we have reached a threshold that we have to come back in and look at that.

But, as of right now, we propose to continue with the status quo of how group 2 accounts are dealt with, which is that they are reviewed at every rebasing rather than annually.

MS. DUFF: Thank you. That makes more sense in explaining that.

Going back to the very first part of your presentations and talking about the inputs into this proposal that you have put before the OEB, am I right, and just tell me if I am wrong, one was the 2018 decision said we would like you to come back with some new ideas. And I think you have done that. That was one input.

But the other one is more just what's happening in the energy industry, this energy transition, right? And that the timing -- your five years is up, and now, it is 2024, and you are now setting it for another five years. And I think you called it the regulatory evolution; I smiled at that.

That regulatory evolution, do you think -- the proposal that you have put in front of the OEB, is it because you are Toronto Hydro, and you are so unique? You are large, you are urban.

Is that why you have come up with this custom IR? Or is it more that, just in a general sense, this is how the OEB should think about uncertainty for distributors?

I don't know if I have asked my question very well, and I am not a professional question-maker. But we regulate 60 distributors. We have got Toronto Hydro here today, kind of out front. Would you agree?

MS. COBAN: Yes.

MS. DUFF: Yes. And we have five years of this energy transition or regulatory evolution. I am not laughing; I am smiling at the term.

So what we are seeing in front of us today is something custom for Toronto Hydro, based on your needs.

Is that a better characterization than kind of a template for distributors in the province? That's what I am getting at.

MS. COBAN: Yes, as is the case with our investment plan and the rate framework, it is reflective of the particular needs and challenges that we face. And yes, we do find ourselves at the forefront of that energy transition because of the imperatives that we have here in Toronto in terms of decarbonization and the things you heard about today in terms of where our customers' priorities are with respect to decarbonization.

We did, however, in designing this framework, we didn't seek to revolutionize what's in place today because that's not our purview to do that. So we tried to work within the existing four corners of the RRF, with some adaptations that we talked about here today to deal with things like uncertainty and to deal with the balance of outcomes that we find ourselves having to deliver in this next five-year period, as we are at the forefront of that energy transition.

And we do know that, you know, being the first ones in, we have a responsibility to propose something here that is grounded in solid principles that as, you know regulatory mechanisms which work with what we have in place today and to the extent there are evolutions, there are reasoned well and they are grounded in those principles.

But we don't necessarily think of this application as being a blueprint for the rest of the sector. That would be outside of our purview. We know that the Board has plans to revisit the RRF in the near future and, you know, that will unfold in the normal course.

MS. DUFF: The timing is what it is. Your five-year term was up, and you are about to establish a new one. Right?

MS. COBAN: Yes.

MS. DUFF: Okay. I just had another area of questions. It won't take too long. It is a little bit more on customer service, I think.

I don't know what you meant by 513 key account customers. And so perhaps you could explain what a key account customer is.

MS. PAGE: Sure. Yes, a key account customer includes any customer over 5 meg. So it depends on loads. We categorize them by load or by a critical infrastructure, such as a research hospital or the Toronto Stock Exchange, like some of the ones that Mr. Smart spoke about.

MS. DUFF: In particular, one aspect about Toronto Hydro that is new to me is this, you know -- I will do the acronym first, CSMUR, these competitive multi-sub unit dwellings. So, you have 800,000 customers that you bill directly. Is that correct?

MS. PAGE: That's correct.

MS. DUFF: Do you know how many of these sub-metering end-users that you also have?

MS. PAGE: We have -- we don't have exact information on that because we don't always know what's behind a bulk meter but our best estimate is it is about 340,000.

MS. DUFF: About 50 percent of your base?

MS. PAGE: Well, that would be in addition to the 800,000.

MS. DUFF: So 340. So, is there any -- so, for those customers, what was the number you said, 340? I want to make sure I get it right. 340?

MS. PAGE: Yes.

MS. DUFF: When you are talking about -- well, what you do, your customer communication, whatever, they are not really customers of yours, though? Is that true? They are -- like, if I'm one of those end-users that I am billed by my condo owner, what when they call your customer service with questions about their bills?

MS. PAGE: They don't typically because we, you know, they get build from their sub-metre and it's got their phone number on it, so we get very few calls from those types of customers.

MS. DUFF: Okay.

MS. PAGE: But if we do, we just refer them back to their provider.

MS. DUFF: And do you think that segment of this competitive sub-metering, is it going to grow with in-fill in Toronto? I mean, right now, you know it could be an additional 340,000 customers on your 800,000 base. Do you see that increasing?

MS. PAGE: Yes, absolutely. I think with all the growth in Toronto and, you know, the number of cranes and constructions you see and a lot of it is large towers and multi-use or multi-unit type of infrastructure that's going up. Then, yes, we would see either our own suite-metered customers growing as well as sub-metered customers growing which we bulk meter.

MS. DUFF: And your focus on, you know, everything from understanding your load forecast, understanding, you know, in a power outage situation, I mean, it's a little bit different for those customers. Right? There is an intermediary party that's involved.

I'm sorry, I don't mean to just ask you, but I'm trying to understand what's -- what this -- this group of customers which I'm not really seeing in a lot of the numbers. And so, as I -- is it -- do you have line of sight and are you concerned about that? Let's just...

MR. SMART: So typically, like, the way we would look at it from an operations perspective is the load. So, bulk-metered customer would have significantly more load associated with it, and as a result, when there's an outage to that type of location or supply points, you know we he would prioritize it accordingly, so I think operationally we do have sufficient line of sight to manage the reliability of supply.

MS. DUFF: Yes, and behind the meter, I mean that condo owner they could have their own recovery, like they could have generation backfill themselves. Right? They could help their customers behind the meter. Is that true?

MR. SMART: Correct. And that does happen from time to time, where a sub-metered or suite-metered customer will have an issue and the issue is actually between their unit and the bulk-meter, in which case it is not our infrastructure.

MS. DUFF: Okay. And aside from the 340,000 customer number, do you have an associated volume, associated, like, within a rate class, can you then add it up and have the percentage of your throughput? And I'm not asking for an undertaking. I just didn't know if you've reported that on the evidence so far?

MS. PAGE: Sorry, can you clarify your question?

MS. DUFF: So associated with the 340,000 end-users --

MS. PAGE: Right.

MS. DUFF: Do we know what percentage of your load that is? And if you don't know that's fine.

MS. PAGE: Yes, I don't think we have that available. If you'd like we can take it away and get that information.

MS. DUFF: I'm not asking that. Thank you. Okay. Those are my questions.

MS. PAGE: Okay. I might add just from a, you know, with a load perspective, that we have to deal with, but it also impacts our key account team. So, when a building is being developed they're very much involved, whether we are bulk-metering it or suite-metering it, it is the same effort to get that building, you know, constructed, designed and everything in terms of the electricity that we need to provide.

MS. DUFF: Which goes back to my first question. So, those key accounts, that's one of the type of customers that's in that key account category?

MS. PAGE: That's correct, yes.

MS. DUFF: Okay, thank you.

MR. JANIGAN: Commissioner Zlahtic.

MR. ZLAHTIC: Good morning, or is it good afternoon? I'm not sure. I have a few questions. I just want to caution you that I can be a bit of a number nerd and when I see numbers that don't line up I kind of -- my head goes tilt.

So, I'm trying to remember the slide where you were talking about your general plant capital finance. One moment. There it is.

So, the number 467 and in preparation for today, you know, I was scrambling reading a bunch of evidence and the number I see is $562.6 million and I can give you an exhibit that I pulled it from. So, like, there is $100 million discrepancy from what I understand and what you presented. Can you help me?

MS. COBAN: Yes. So, I think the source of that discrepancy -- and I will take this away and confirm for some reason if there is more to it than the explanation then I will let you know -- but is that when you look at the evidence, general plant, in the distribution system plan would include all of those IT investments that Mr. Higgins talked about that form part of our modernization strategy. So, those cyber security and software enhancement investments that are part of IT have been, for the purposes of this presentation, mapped to the modernization bucket as they form a critical part of the enabling investments to deliver on those objectives. But in the distribution system plan, just following the Board's normal filing requirements, all of those IT investments are a part of general plant. That may be the source of the discrepancy that you see here.

MR. ZLAHTIC: Well, let me just give you the exhibit. My source is Exhibit 2B, section E4, updated January 29, 2024. So...

MS. COBAN: Yes.

MR. ZLAHTIC: Okay. And because I'm trying to reconcile it back to your total capital budget which is approximately $3.9 billions. So, anyways...

MR. HIGGINS: Do we want to maybe just go back one slide just to illustrate the point there. We have the IT, cyber security and software enhancements under the modernization table there for 95 million.

MR. ZLAHTIC: Okay.

MR. HIGGINS: So, that normally within the DSP that would appear as part of general plant.

MR. ZLAHTIC: Okay.

MR. HIGGINS: But we kind of broke things up in a way that this is kind of how we spoke to customers about the plan, and so this was kind of the strategic lens on the plan. So, it does get a little bit confusing, apologies for that.

MR. ZLAHTIC: Oh, no worries. It is considered reconciled.  Thank you.

I have a question, I believe it is for Mr. Huntley, and it is with respect to EVs and this is a question I ask every utility if I get one in front of me on the stand and it -- what has Toronto Hydro done to have greater visibility in just understanding what EVs are currently on your system in terms of location and the impact on load? And there's going to be a follow-up question.

MR. HUNTLEY:  Thank you for the question, Commissioner Zlahtic.  I'll start off by illustrating in a pre-filed evidence, we have -- and I would -- it would be In Exhibit 2B, section D5 where we spoke to our modernization initiatives that Toronto Hydro undertook a EV demand response pilot with Velocity to understand the impacts of EV charging in a very targeted manner on feeder loading behaviour.

We are planning a phase 2 to that project in this plan that would focus on a larger volume of EVs but also involve the use of telematics directly to the EV itself.  So in essence it is a demand response program catered specific to EVs.

Sorry, the second part of your question was?

MR. ZLAHTIC:  Oh, it's coming.  So, you know I was trying to understand it.  You know, what you understand in terms of what you have as a base, just to understand the impact on your system and then to forecast additional EV penetration and the requirements on your system in terms of upgrades, in terms systems access and system renewal because it will impact both. Right? Like, how do you do that?

MR. HUNTLEY: Okay, all right.

MR. ZLAHTIC: Sorry, was the question clear?

MR. HUNTLEY: Yes, it is. Thank you. I'll take you back to probably a little bit of the methodology behind the development of the peak-demand forecast specific to electric vehicles, themselves. The utility does have data with respect to the distribution of EVs in the Toronto Hydro territory.

The resolution at the moment, I think it is by forward sortation area, like the first three digits of your postal code. But, in essence, we have been able to map that across the grid.

Now, in terms of modelling EV-charging behaviour and its impact on the grid, we started out by working with consultants who have done research out of the state of California, that have an extensive database of the EV-charging behaviour, and modelling that particular charging behaviour and applying it in the Toronto context, especially given the additional benefits we have by implementing ultra-use overnight rates.

Those components went into the modelling of EVs, themselves, mapped to the targets developed by the city of Toronto through their EV strategy and disaggregating that with respect to light-duty vehicles, medium- and heavy-duty vehicles. Implementing additional parameters like fleet charging, TTC eBus charging behaviours, we were able to develop a robust model with respect to -charging behaviour, contextualized specifically for the City of Toronto.

MR. ZLAHTIC: Okay. Thank you, that's really helpful. It is just something that sort of nags at me every time I see an application and they are talking about the energy transition and EVs. So I have a couple of other questions, and I think it's -- this time I noted the slide, slide 18, if you can go there.

Yes. You talked about peak-demand growth forecasts for Toronto Hydro, and what was really helpful but didn't have a chance to go through it is you provided an exhibit list to go with every slide. If I were to go through this exhibits list for slide 18, would I be able to find a disaggregation of peak load by rate class?

MR. HUNTLEY: The disaggregation that you will be able to reference on the record would be by driver.

MR. ZLAHTIC: Sorry, by what?

MR. HUNTLEY: By driver.

MR. ZLAHTIC: Oh, by driver.

MR. HUNTLEY: Peak demand driver.

MR. ZLAHTIC: Okay. Sorry, I'm just being lazy here. I just want to know which of these many exhibits I have to go to see to find that information, and I can do that on my own. I am not asking for an undertaking.

MR. HUNTLEY: That would be Exhibit 2B, section D4.

MR. ZLAHTIC: Just let me make a note of that.

MR KEIZER: Sorry, again?

MR. HUNTLEY: Exhibit 2B, section D4.

MR. ZLAHTIC: Okay, I have got it.

MR. KEIZER: Commissioner Zlahtic, just to clarify, though, your question was in the realm of class load demand. Right?

MR. ZLAHTIC: Yes.

MR. KEIZER: And I think it is important that -- and maybe the witness can actually clarify -- the peak command demand here is related to stations demand, not necessarily customer demand, so there is a distinction between the two kinds of demands so to speak.

MR. ZLAHTIC: Right.

MR. KEIZER: Just so that you are not left with confusion and searching through the exhibit and not finding what you're looking for.

MR. ZLAHTIC: Okay.

MR. KEIZER: And I do believe the exhibit you've given to the Commissioner Zlahtic relates to the peak demand, which then leads into the station forecast. Correct?

MR. HUNTLEY: That's correct.

MR. ZLAHTIC: Thank you. That was helpful. I think you've helped me look for what I am looking for. Does that make sense? You have helped me look for what I was looking for, yes.

I just have a few more questions, I promise. I don't have an exhibit to point you to or a slide to point you to, but it is just a general, and it is: What percentage of Toronto Hydro's capital plan is for discrete projects?

MS. COBAN: I think we have an IR that addresses this question. It is approximately $500 million of the total that can be attributed to discrete projects.

MR. ZLAHTIC: So $500 million out of the $3.9 billion? Okay. Okay, that's a fair amount. I think I already know the answer, but I will ask it anyway. What percentage of Toronto Hydro's capital plan is covered by the proposed demand-related variance account?

MS. COBAN: Just doing quick math.

MR. ZLAHTIC: That's okay. Take your time.

MS. COBAN: To give you a sense. If we could just turn to the slide where we have the growth plan expenditures, that will help us. Apologies. So, just to give you that reference, my colleague is going to run the math, but it is essentially: The list of programs that you see here, on the slide --

MR. ZLAHTIC: Mm-hmm.

MS. COBAN: -- the only program that's, that's -- actually, it is all of the list of the programs that you see here, on the slide. These are all of our growth-related capital programs, and all of them are subject to the demand [audio dropout] So all of the programs that we see here, on the slide, relate to the demand-related variance account capital investments that would be tracked as part of that account. So we're just doing the quick math on that total and the load relative to the $3.9-billion capital plans.

MR. ZLAHTIC: All right. Can you give me the slide number reference? It is covered by the presenter's name on my screen. Which slide is that?

MR. HIGGINS: Slide 22.

MR. ZLAHTIC: Okay. Hang on a second.

MR. HIGGINS: Yes, so the answer is 24 percent.

MR. ZLAHTIC: Sorry?

MR. HIGGINS: The answer would be 24 percent, yes, because it is all of those programs.

MR. ZLAHTIC: Okay, so then it is just limited to the programs listed on this slide? Okay, that's really helpful.

MS. COBAN: Sorry, to clarify, these are the capital programs. There are also a number of operational programs that make up part of that account, so, if we can flip to the slide where we had the account, I just want to make sure you have the right information. So you see there, at the bottom, the programs in orange? Those are the operational programs that would be tracked in the account, as well. I don't have the dollars with me for those programs today, but we could provide that if you'd like.

MR. ZLAHTIC: Actually, I wouldn't mind if you would, if it is not a big ask.

MS. COBAN: It's not a problem.

MR. ZLAHTIC: Okay. I just have a few more questions and more to do with non-wires solutions. And then you folks are probably aware that the OEB published its VCE framework on May the 16th. And the question I have is that, over the term of your custom IR, will Toronto Hydro -- do they intend to notify the OEB of any projects over

$2 million that are in your capital plan?

MS. COBAN: I am pausing on your question because, given how recent that guidance was issued, we haven't had a chance to fully consider that, but, just contextually, what I can offer is that we have, you know, over a thousand projects that we would execute over this time period. So, just 2020 to 2023, we have about 1,100 capital projects that got executed, and not all of those would be above $2 million, but a significant portion of those would be above $2 million, just to give you the context.

In terms of your specific question, you know, candidly, we hadn't had the opportunity yet to consider that, so I'd have to take that back.

MR. ZLAHTIC: Yes. And again there is not an undertaking here, but just to reiterate: The number of projects you talked about, is this in the 2025 to 2029 plan or this is historic numbers? I just misheard you. I'm sorry.

MS. COBAN: It is historic, just to provide you some context as to the volume of projects that we would expect to see over a 5-year period. We don't yet have project details scoped out for the '25 to '29 period as many of our investments are of a programmatic nature.

MR. ZLAHTIC: So, ballpark, how many projects would that be, just a rough guess?

MS. COBAN: It's ballpark, if we're looking at history and we do have an increase over historicals, but historically we were looking at just under 300 projects per year.

MR. ZLAHTIC: Wow, okay. I'm just going to make a note here so I don't have the to ask again.

And I guess probably the same answer, my follow-up question was, you know, having -- once you review the May 16th guidance, the question is: Will Toronto Hydro seek OEB capital approvals over your custom IR term and I think I know the answer, is we need to take that away and think about it.

MS. COBAN: We have a plan before the Board that reflects a five-year work plan and within that plan we also have the demand-related variance account that would give us the flexibility to do more demand response work if we see opportunities for that.

And so we don't envision that we would come back for the Board if this account is approved, as we would have the necessary flexibility to adapt our plans in that regard.

MR. ZLAHTIC: Okay, thank you, thank you. Those are all my questions. Thank you very much.

MR KEIZER: Just before you move on, Commissioner Zlahtic, with respect to the discrete projects and the specific IR that Ms. Coban referenced, it is actually Exhibit 1B, Staff 12, paragraph (c) that gives you the discrete projects.

MR. ZLAHTIC: Sorry, can you just repeat. My monitor just went off.

MR KEIZER: It's okay. It's --

MR. ZLAHTIC: Hang on. I just destroyed my monitor.

MR KEIZER: It is interrogatory, Exhibit 1B, Staff 12, part (c).

MR. ZLAHTIC: Thank you. I'll just re-assemble my thing here.

MR. JANIGAN: Thank you. I only have one question and it deals with, as you know, the OEB has initiated a proceeding to establish the appropriate cost of capital and rates of return for all electric utilities, and this decision is expected to be released early in the new year, probably either in February or March. How should that decision affect Toronto Hydro and the setting of rate and charges in this application?

MS. COBAN: This proposal that we have in front of the Board of course was prepared before that cost of capital proceeding was initiated, and it does reflect an integrated proposal with respect to the cost of capital parameters that we know and understand today.

MR. JANIGAN: Mm-hmm.

MS. COBAN: We are of course in the Board's hands in terms of the eventual approval of those parameters, but our proposal to you today is that we would continue with the existing capital structure and cost of capital parameters that we have in place today.

MR. JANIGAN: Mm-hmm. Variance accounts, to my knowledge have never got gone out of style. Is that an alternative that may be acceptable?

MS. COBAN: With respect to cost of capital?

MR. JANIGAN: Yes.

MS. COBAN: We'd have to that I can that away and discuss it. I don't think I'm in a position, but we would be prepared to comment at a hearing.

MR. JANIGAN: Okay, that are -- that is all the questions that I have.

I'd like to extend our thanks to Toronto Hydro for what was an extensive and very helpful presentation that will help to guide settlement conference and, if necessary, the proceeding that follows it.

Thank you very much for the court reporter which we tested a fair amount. It is the first time I've realized that people doing presentations are a lot different than the speed at which they talk when they answer questions, and I should have intervened earlier on that score.

Thank you very much for the individuals and parties that have attended and this concludes presentation day.

--- Whereupon the presentation concluded at 12:49 p.m.