Lindsay Hunter: My name is Lindsay Hunter and I am the project manager for our IRP Development Process.

As mentioned earlier, we are using the IRP to help shift how we engage with our customers and interested parties, and ensure your feedback and perspectives inform our analysis in the IRP report. We also want to improve the visibility of how we approach our analysis and how we interpret what the modeling is communicating. Talking to you now before we finalize our modeling and analysis allows an opportunity to get feedback to inform the remainder of our modeling. Because we are still in the middle of our modeling phase, the results that we are sharing are very much preliminary at this point. They may be revised once the modeling is finalized. Like many things, our modeling process is iterative. As we continue the modeling process with different model runs, the outputs allow us an opportunity to learn new things in the results that were not evident before.

The first step in generating the outputs in our initial modeling results is developing the two scenario specific inputs within our IRP modeling process. The customer electric and gas demand projections.

Returning again to this chart presented earlier, we can see the different pace of change for each key input and for each scenario assumed for the IRP analysis. Scenario four is of particular importance in our initial results, given the assumptions around our customers electricity and natural gas needs that accelerate decarbonization as compared to the other scenarios. The scenarios were developed to be bookends for potential energy features. Based on the research and feedback gathered in our last round of engagement, we associate specific values to each of the key inputs for each scenario. We use these to generate electric and natural gas demand projections that are the basis of our IRP modeling. The scenarios assume that the type of energy customers use may change, but that they will continue using energy like they do today. For example, customers will continue charging EVs like they do today as there is nothing in place to influence when they will charge. Sensitivities are where we start to introduce interventions and other constraints for each scenario to explore their effects on our outputs and initial modeling results. We will discuss these in more detail later in the presentation.

We use the key inputs as well as other data to develop the demand projection for each scenario. The left hand graph shows the electric energy needs over the study period for each scenario. While the right hand graph shows the demand for each scenario. In all scenarios, it is anticipated that our customers will use more electricity in the future as they adopt electric vehicles and start to use more electricity to heat their homes and businesses. This is most pronounced in scenario four.

Demand does increase between scenarios one, two, and three, but there is a significant step change to scenario four. This step change is because scenario four represents accelerated decarbonization and a pathway towards net zero through electrification. As you can see on the graphs, these assumptions for scenario four in 2042 result in our customers needing double the energy as today. More importantly, they also result in a peak demand in 2042 that is two and a half times the current demand. This has significant impacts on our system's capacity requirements. One thing specifically impacting this peak demand is converting natural gas space heating to electricity. We explore that further on our next slide.

This graph shows the impact to peak demand for each scenario over a calendar year. Today and into the future, the greatest amount of electricity is needed in January and February. Manitoba's current winter peaking load is shown by the lower light blue line. The four scenarios assume customers will switch from natural gas to electric heating at different rates, which results in the corresponding increase in winter peak demand. We can see that with the bumps that form on the right hand side of the graph between October and April. Scenarios one, two, and three have relatively minor differences in the rate of change for the various electrification assumptions. While scenario four has a significant change. Again, this is shown by the step change increase to winter peak demand as shown by the top line.

In addition to electricity, we also consider how we can meet our customers future natural gas needs. These needs could change, particularly if there is greater focus on decarbonization. Natural gas is primarily used for space heating in Manitoba, so as we study futures where customers switch to heat their homes and businesses with electricity, there is a corresponding decrease in natural gas usage. In all scenarios, our initial modeling results anticipate Manitobans will still be using natural gas in 2042. In scenario four, natural gas in 2042 is used in industrial applications such as for a process input or feed stock, with some natural gas still being used for space heating.

To summarize our observations with the outputs of the load projections, all scenarios have an increased peak demand driven by the assumptions around space heating electrification. Scenario four experiences the biggest impact, as this includes assumptions around the greatest pace of change. And from scenario four, we can see that those assumptions leading to accelerated decarbonization results in significant increases in our system for both energy and capacity needs, while also seeing a reduction in natural gas usage.

Now that we have our demand projections, we pair these with other projections such as wholesale market prices and fuel prices and run them through the resource optimization model. The model is a cost optimization model, which means that it finds the lowest cost way to meet customers future capacity and energy needs based on the provided assumptions and constraints. We use the outputs of the model to find commonalities between the initial results to identify least regret decisions and to see where differences may need further exploration. We compare things like energy requirements, capacity requirements, relative costs, and GHG emissions.

Here we are showing graphs of the model outputs for each scenario's new supply mix that represents the lowest net system costs at the end of the 20 year study period. We need to consider both energy and capacity when planning the system, so we are showing the capacity resources to meet custom demand on the right and the energy produced by those same resources on the left.

There is a lot of information we can understand from these two graphs, but there are two key points. First, that energy needs in 2042 for each scenario shown on the left hand graph are still predominantly provided through hydropower. Existing hydropower is supplemented with wind and imports. The biggest differences between scenario results are the amounts of the new energy sources. And secondly, scenario four has a significant step change as compared to the other scenarios. Understanding the step change for scenario four is important. The peak load increase in winter due to assumptions, the space heating electrification, is driving the need for increased capacity resources for scenario four in 2042 as shown on the right hand graph. Within the capacity outputs for scenario four, there's a significant amount of thermal generation. This is the yellow portion that is about 50% of all capacity resource outputs.

However, when we look at the left hand energy graph, we can see that this thermal generation contributes to only about 10% of the total average energy used throughout the year. This tells us that for the most of the year, energy is supplied through clean electricity such as variable renewable resources like wind. However, as these resources cannot always be counted on when we have significant winter peak capacity needs, we need to pair these variable renewable resources with a dispatchable resource.

In our results, this is thermal generation fueled by natural gas because it is one of the most cost competitive resources for providing capacity. We also see, or in some cases don't see, other notable information on other resources. For example, there is no new hydro generation selected. What is selected in every scenario is an upgrade to an existing hydro generation station. This is the skinny dark blue line in the right hand capacity graph. While this may seem insignificant as compared to other resources, it does come into each of the scenario outputs and before other resources are brought in. Indicating that it is a very cost effective resource. There's also no solar generation selected. And finally, energy efficiency through demand side management, labeled DSM on this slide, is very similar for all scenarios.

Again, to summarize some of the observations in the initial modeling results for the energy and capacity supply mix is first, our existing hydro generation will still make up a significant portion of the system for meeting both energy and capacity needs. In addition, improving existing generating stations can be an economic choice to add capacity. Further study will help understand the true potential of expanding this resource option. What is also evident is that no new hydropower resources are included in the initial results. Next, wind generation is cost effective resource that provides significant energy. Due to its capacity limitation, other resources are needed to add capacity to the system to meet winter peak demand.

That leads to thermal generation. Thermal generation is an economic capacity resource that can produce energy when needed. It also provides energy during a drought when other less costly resources do not provide enough energy. Imported electricity from outside Manitoba can also provide energy during a drought or other extreme events such as a weather disruption. Such imports may also provide a low cost source of energy. Additional solar beyond that included in efficiency Manitoba's plan is not selected by the model. Solar cannot meet winter peak demand because it does not provide the capacity needed in Manitoba's winters when we need it the most. Finally, additional energy efficiency programming helps to meet some future energy needs, but more study is needed to understand its potential role. We understand this is an area of interest for many people and we are working on that now.

With the increase in thermal resources in the scenario outputs, we can expect that Manitoba's hydro generation specific emissions would increase even though new thermal generation would be mostly limited to peak demand. But we also want to know if within these initial results do they support a reduction in GHG emissions across the province, particularly in other sectors like transportation and space heating. To answer this question, we first need to understand the sources of GHG emissions in Manitoba. Generally, they are separated into four categories, three of which are directly impacted by our customers energy choices. These three categories are stationary combustion as shown in purple. Which represents just under 19% of all provincial emissions and includes energy used for space heating as well as industrial processes.

Transportation as shown in light blue, represents about 40% of all provincial emissions. Moving from internal combustion engines to electric vehicles will directly impact electricity needs and future emissions. An electricity generation as shown in pink, which is at the very top of the column, represents about 0.1% of all provincial emissions. Differences in generation fuel sources may impact future emissions. The other category as shown in gray are the emissions that are not energy dependent. These are generally GHG emissions from agriculture because they are not impacted by different energy choices, they are not discussed further.

The left hand chart shows the impact to the emissions in Manitoba from the initial modeling outputs for the three categories of GHG emissions that are energy dependent. As you can see, GHG emissions decline over time in every scenario, with scenario four representing the largest changes in energy use to reduce emissions. While all scenarios use natural gas to generate electricity through thermal resources, overall, provincial emissions still decrease. This is because emissions are reduced in other categories like transportation and stationary combustion, of which a significant portion is space heating. Again, while you may have more thermal resources, they are running infrequently to help meet peak electricity demand. The majority of the time when demand is lower, the electrification of transportation and space heating is served through clean electricity generations such as hydropower and wind.

To recap our observations on GHG emissions within the future scenarios, first total provincial energy related emissions drop in all scenarios, even with the fact that the resource outputs include thermal generation fueled by natural gas. Second, a measured increase in emissions in electric generation along with new renewable energy resources can enable significant decreases in emissions from transportation and heating through electrification.

Now, let's look at one other output from the model net system cost. Costs shown are the present value of the net system costs to provide electricity and natural gas service over the 20-year IRP study. The net system costs include both capital costs as well as maintenance and operating costs, natural gas costs, transmission and distribution infrastructure costs, fuel costs, and finally import costs and export revenue. These costs are generated from very high level estimates for the purposes of comparing model outputs between the scenarios to help inform decisions on developing the roadmap and near term actions. These are not intended to be interpreted to support specific project decisions. We see from this graph that the costs associated with meeting energy needs in scenarios one, two, and three are similar. While significantly more investment is needed for scenario four. These numbers give a sense of what is needed to get to 2042 for each scenario.

Understanding how our different metrics interact between the scenarios helps to inform the decisions needed to draft our roadmap and near term actions. One way is to look at the cost outputs and compare them to our energy in green and capacity in teal. Unlike previously, energy is shown here as a combination of electric and gas energy needs. As well, the costs do not include impacts due to inflation.

We are showing all values as of 2042 as a percentage of the value as of 2022. This provides a sense of the ongoing needs past our study period. We can pull a few very key pieces of information from these graphs. One, as we've seen before, scenarios one, two, and three all have very similar results with a step change to scenario four. We can also see that the initial modeling results are showing that all scenarios will require some level investment to meet future demand. And secondly, the step change also helps to illustrate that costs in yellow are driven by firm capacity needs. This is because of the more proportional increases between capacity and cost in all scenarios as compared to the energy increases.

We've also added in a metric for the unit cost of energy, which is the dark teal column. Here we take the energy in each scenario for both electric and gas supplied and divide that into the net system cost. Even though in scenario four we can expect to sell more electricity, we can see from this result that the cost to serve that electricity is higher than in the other scenarios.

Another way to understand how metrics interact is through this graph that demonstrates how different customer energy choices in each scenario can impact system costs and GHG emissions. While there is a steady decline in GHG emissions over the four scenarios, the change from scenario three to scenario four is important. There is minimal change in GHG emissions, but the net system cost increases significantly. This indicates that greater levels of electrification will be more expensive to support and alternative ways to reduce emissions at lower costs are needed. We'll talk about this more shortly.

From our initial modeling outputs, we can see that financial investment is needed in all scenarios. However, the different levels of electrification we have studied within the scenarios result in very different impacts to the overall net system costs. These costs are fundamentally tied to these increasing levels of electrification that are directly increasing our winter peak demand and a corresponding need for capacity resources.

So far, the results have been focused on the end of our 20 year study period in 2042. There can be important observations relating to the pace of change over time to help understand the initial modeling results. To show this pace of change, we've plotted the dependable energy on the left hand side and capacity on the right hand side, both over the study period. The blue area curves are what must be available for the four scenarios, and the red line is what is available from our existing system. When the red line crosses the blue curves is when new resources are needed to serve the required load.

For scenario four, we can see in the capacity graph that new resources would be needed in only a few years from today. This poses a challenge because many of the new resource options being studied would require a longer time to plan, construct, and put into service. Other solutions may be needed to be investigated. For scenarios one, two, and three, the existing system continues to meet most of the energy and capacity needs. Some new resources would start to be required for these scenarios in the early 2030s timeframe.

Again, to summarize what we just discussed, the existing system continues to meet earlier demand for scenarios one, two, and three. Meeting the demand due to high levels of electrification in scenario four, especially for heating, will be a particular challenge in the next 10 years due to the time required for approval and construction or purchase of new resources. Beyond 10 years, all scenarios will need continued investment to meet demand, with a much greater requirement for scenario four.

If you have any questions, please do email us at IRP@hydro.mb.ca.