2022 Integrated Resource Plan ("IRP")

Public Advisory Meeting #2 Minutes

Date: Tuesday, April 12, 2022
Time: 10:00 a.m. to 3:00 p.m. (EDT)
Location: Virtual via Microsoft Teams

Agenda:

Time	Topic	Speakers
Morning Starting at 10:00 AM	Virtual Meeting Protocols and Safety, Schedule	Chad Rogers, Senior Manager, Regulatory Affairs, AES Indiana
	Meeting #1 Recap	Erik Miller, Manager, Resource Planning, AES Indiana
	Load Scenarios	Mike Russo, Forecast Consultant, Itron Eric Fox, Director, Forecasting Solutions, Itron
	MPS Results & DSM Resources	Jeffrey Huber, Overall Project Manager and MPS Lead, GDS Associates
Break 12:00 PM – 12:30 PM	Lunch	
Afternoon Starting at 12:30 PM	Current Generation Portfolio Overview	Kristina Lund, President & CEO, AES Indiana
	Replacement Resource Assumptions	Erik Miller, Manager, Resource Planning, AES Indiana
	IRP Portfolio Matrix & Scenario Framework	Erik Miller, Manager, Resource Planning, AES Indiana
	Final Q&A and Next Steps	

Meeting Summary

Agenda and Introductions

Stewart Ramsay, Managing Executive, Vanry & Associates
(Slides 1 – 3)

Moderator Stewart Ramsay began Public Advisory Meeting #2 by introducing himself and walking through the meeting agenda.

Virtual Meeting Protocols and Safety

Chad Rogers, Senior Manager, Regulatory Affairs, AES Indiana
Stewart Ramsay, Managing Executive, Vanry & Associates
(Slides 4 – 9)

Chad Rogers welcomed stakeholders to Public Advisory Meeting #2 and thanked them for their participation. He introduced the internal and external members of AES Indiana's IRP team. He then introduced the various stakeholder groups that registered to attend Public Advisory Meeting #2, which included the Indiana Utility Regulatory Commission ("IURC" or "Commission"), the Office of Utility Consumer Counselor ("OUCC"), various commercial and industrial customers, local agencies and advocacy groups, and individual residential customers. He thanked these groups for their interest and participation in AES Indiana's planning to address the future needs of the community.

Moderator Stewart Ramsay then described the best practices for virtual meetings. He noted a benefit of virtual meetings the AES Indiana IRP Team has noticed is the attendance and volume of questions are significantly greater compared to in-person meetings. He stressed AES Indiana wants candid feedback and input from its stakeholders and noted the different options available to stakeholders to participate via Microsoft Teams, which includes utilizing the chat function or clicking on the "raise your hand" feature and asking questions live via audio. Stewart stated he and the AES Indiana IRP Team will monitor questions in the chat throughout the meeting, and he will select questions that pertain to the subject matter being discussed to address live during the meeting. All other questions will be answered via the Microsoft Teams chat function. He concluded this discussion by reiterating AES Indiana encourages stakeholders to ask questions and make comments throughout the meeting because the purpose of the public advisory meetings is to receive stakeholder feedback and incorporate it into AES Indiana's IRP process.

Chad Rogers then explained AES's purpose and values reflect its dedication to improving lives and making a lasting difference in its communities. He explained the IRP process is completed together with its stakeholders to ultimately determine the future of energy. He explained AES Indiana places equal importance on how it completes its work as the work itself, which its people embody through living out the values of safety first, highest standards, and all together. Chad then described each value, starting with safety, as it is as the core of everything AES Indiana does and is a foundation to measure success against. He explained highest standards represents AES Indiana's commitment to act with the utmost integrity and hold the solutions it delivers to a standard of excellence. He described the value of all together as embodying AES Indiana's commitment to working as one team across its business and with its stakeholders to meet the changing needs of its customer with agility in a meaningful way.

Chad Rogers then presented safety reminders for conducting business in a virtual environment, which included using secure, unique, and complex passwords and enabling two-factor authentication when available, thinking before clicking on a link, file, or attachment, knowing your network and using a Virtual Private Network, protecting your device, sharing data responsibly, and being prepared through threat identification.

Meeting #1 Recap

Erik Miller, Manager, Resource Planning, AES Indiana
(Slides 10 – 13)

Erik Miller thanked stakeholders for their attendance and participation in Public Advisory Meeting #2. He began the recap of Public Advisory Meeting #1 by acknowledging there were several new attendees for Public Advisory Meeting #2 and discussing AES Indiana's updated 2022 IRP timeline. He explained AES Indiana conducts technical meetings with interested stakeholders who have entered into non-disclosure agreements with AES Indiana, in which the AES Indiana

IRP Team and its stakeholders discuss finer details related to the materials, and one week following these technical meetings, AES Indiana conducts the larger public advisory meetings. He stated AES Indiana's Public Advisory Meeting #3 is expected to occur in the second half of June, Public Advisory Meeting #4 is expected to occur in August, and Public Advisory Meeting #5 is expected to occur in October. He explained following the public advisory meeting process, AES Indiana will file the IRP with the IURC on November 1, 2022.

Erik Miller then previewed the main goal of Public Advisory Meeting #2 will be to discuss the assumptions that will be included in the planning model, which will utilize EnCompass's modeling software. He explained AES Indiana and its IRP Team gathered these inputs and assumptions but do not yet have modeling results, so AES Indiana welcomes stakeholder feedback on these assumptions. Erik then previewed AES Indiana would be releasing a generation Request for Proposals ("RFP") later in the week.

Erik Miller then discussed the topics for the first two public advisory meetings. He recapped Public Advisory Meeting #1 focused on the fundamental concepts of the IRP process, which included Itron explaining the base load forecast, Bright Line Group and GDS presenting the electric vehicle ("EV") and distributed generation ("DG") forecasts, and GDS presenting the market potential study ("MPS") overview. Erik then explained in Public Advisory Meeting #2, Itron will discuss the high and low load scenarios for the load forecast, while GDS will cover the MPS and the demand side management ("DSM") inputs. He reminded stakeholders DSM will serve as resource inputs that will feed into the planning model for selection alongside other supply side resources. Erik then previewed he will be discussing replacement resource assumptions, which are the assumptions used for supply side resources that are offered as selectable in the model, and he will then discuss the IRP portfolio matrix and scenario framework.

Erik Miller next presented the planned discussion items for the future public advisory meetings. He stated in Public Advisory Meeting #3 in June the AES Indiana IRP Team plans to evaluate the portfolios, provide an overview of reliability in Indiana, discuss its reliability analysis, and discuss distribution system planning ("DSP"). He stated AES Indiana has contracted with Quanta, which is a consultant agency specializing in reliability analysis previously utilized by the Northern Indiana Public Service Company ("NIPSCO"), for its IRP reliability analysis. Erik stated the Citizens Action Coalition ("CAC") shared its comments to NIPSCO's reliability analysis that utilized Quanta's services with AES Indiana in a technical meeting, and Erik thanked Jennifer Washburn with the CAC for sharing the information as it will be helpful to inform AES Indiana's IRP. Erik stated AES Indiana plans to discuss distribution system planning and stressed while reliability has always been a large focus of IRPs, due to the current influx of renewables coming into the Midcontinent Independent System Operator ("MISO") footprint and coal retirements, there is a renewed focus around ensuring AES Indiana provides reliable service through its IRP planning. Erik stated, AES Indiana should have preliminary modeling results to review and portfolio metrics and scorecard results to assess by Public Advisory Meeting #4, which will likely drive most of the discussion in that meeting. He concluded the public advisory meeting preview by stating AES Indiana will present its Preferred Resource Portfolio and Short-Term Action Plan in Public Advisory Meeting #5.

Erik Miller then provided an overview of the IRP process to demonstrate how all the different items in the IRP process come together. He explained the items on the left side of slide 13 are the core assumptions the AES Indiana IRP Team has been developing, which are inputs for the planning model. He stated GDS will assist with developing the DSM MPS, Conrad Technical services will be assisting with the Distribution System Plan, Itron will be assisting with the Load Forecast, and Concentric will assist with present value revenue requirement ("PVRR") calculations, all of which will be input into the capacity expansion model. He expounded on the capacity expansion model stating it also includes replacement resource assumptions, including assumptions for different resource types, including solar, wind, and combined cycle gas. He explained once all the assumptions are entered into the capacity expansion model, the AES Indiana IRP Team completes a retirement and replacement analysis of its portfolio matrix, which will utilize expertise from ACES and Patrick Maguire, who was instrumental in AES Indiana's 2019 IRP, to develop the EnCompass model. He previewed the portfolio matrix is expected to consider four strategies across four scenarios that will be assessed using a PVRR for each portfolio across the various scenarios calculated using the Production Cost Model to understand the costs of each portfolio to AES Indiana's customers. He explained AES Indiana will then assess the portfolio against other metrics, including environmental, reliability, and risk factors. Once these items are completed, Erik explained AES Indiana will score the portfolios and select the portfolio that proves the reasonable least cost for customers to become its preferred resource portfolio and develop a short-term action plan to illustrate AES Indiana's path forward, which will be covered in Public Advisory Meeting #5. Erik detailed AES Indiana would then file the IRP report on November 1, 2022.

Erik Miller then described the filings that will be driven by the IRP, which include the DSM Plan filing for the subsequent three years (2024 through 2026) and certificate of public convenience and necessity ("CPCN") filings to receive approval from the IURC for any resource replacement identified in AES Indiana's IRP process. Erik explained CPCN filings are largely driven by resources identified in the RFP, which will be led by Sargent & Lundy.

Stakeholder Laura Ann Arnold, a representative of the Indiana Distributed Energy Alliance, asked AES Indiana when it expects to issue the All-Source Generation RFP. AES Indiana responded it expects to issue its 2022 All-Source Generation RFP later in the week. Laura followed up by asking how to get on the distribution list to receive the All-Source RFP announcement. AES Indiana informed Laura there is not a distribution list for the 2022 All-Source RFP; rather, the RFP will be posted publicly to the AES Indiana RFP website (https://www.aesindiana.com/request-proposals-rfp) later in the week.

Load Scenarios

Mike Russo, Forecast Consultant, Itron
(Slides 14 – 22)

Mike Russo began his presentation by introducing himself and explaining Itron will be working with the AES Indiana IRP Team to develop the Load Forecast that will be used as an input into the IRP modeling. He reviewed he discussed the Baseline Load Forecast in Public Advisory Meeting #1 and previewed he will be presenting the High and Low Load Forecast inputs in Public

Advisory Meeting #2. He provided an overview of the modeling approach that was previously discussed and reiterated the modeling approach will consist of a bottom-up model, which starts with the rate class level model using monthly sales and customers for residential, commercial, industrial, and a few other classes disaggregated to differentiate between certain characteristics in each class (e.g., residential heating versus residential non-heating). He explained Itron utilizes monthly estimations at those rate class levels, and to estimate monthly residential customer sales, Itron utilizes the product of models to determine monthly residential average use and the number of customers. For the other rate classes (e.g., commercial, industrial, etc.), Itron models total sales. He expounded the monthly sales models will utilize economic drivers, end-use standards, weather conditions, electric prices, and energy efficiency ("EE") program savings. He then provided greater detail on each of the inputs:

- Economic drivers utilize the population, the number of households, employment numbers, gross domestic product ("GDP") values, and manufacturing GDP values depending on the rate class being modeled.
- End use standards vary by rate class. Residential customers primarily use electricity to heat their houses, cool their houses, and for other activities. Itron then considers whether customers have central air conditioning, room air conditioners, or heat pumps, which can be impacted by new construction. The efficiencies of these technologies change over time, especially as federal codes and standards change (e.g., transition from incandescent light bulbs to LEDs). Itron provides similar end-use comparisons for commercial and industrial customers that considers efficiency improvements.
- Weather conditions utilize the number of heating or cooling degree days in each month assuming a normal heating or cooling degree day.
- Itron utilizes historical performance to forecast energy efficiency program savings and energy prices.

Mike Russo explained these inputs allow Itron to forecast the rate class level sales, aggregate the sales to determine total sales, and apply a line loss factor to develop an energy forecast. He explained to forecast peaks, Itron pulls the end-use sales for all the rate classes (e.g., heating sales, cooling sales, and other sales), and interacts the end-use sales with the heating and cooling degree days on the day of the peak to forecast peaks. He stated this ensures sales, energy, and peaks are tied together and the peaks are driven by the underlying heating, cooling, and base use requirements from the different rate classes. He also prefaced his presentation by stating all load values exclude future DG, EVs, DSM, or EE savings.

Mike Russo explained Itron will use alternative economic drivers as inputs and run those through the rate class models to determine the high and low load forecasts. He reminded stakeholders the baseline load forecast will use Moody's Analytics Baseline Forecast, which establishes a threshold where there is a 50% probability the economy will perform either better or worse. Mike explained Itron uses Moody's Scenario 3 for the low load forecast scenario, which is a 90th percentile estimate, meaning Moody's estimates there is a 90% probability the economy will perform better than the scenario. He stated Itron uses Moody's Scenario 1 for the high load forecast, which is a 10th percentile estimate, meaning Moody's estimates there is a 90% chance the economy will perform worst than the forecasted scenario.

Mike Russo explained Itron uses the baseline economic variables as initial inputs and applies growth rates from Moody's low and high scenarios beginning in January 2022 to ensure the historical values are the same across scenarios. He explained Itron then constructs the variables in a manner to ensure the growth rates are appropriate relative to the baseline scenario (i.e., the low case uses growth rates less than or equal to baseline and the high case uses growth rates that are greater than or equal to the baseline case), which is done because the scenarios tend to differ significantly for the first three to five years then tend to converge to the baseline in later years, but imposing this rule ensures there will be a separation between the high and low load scenarios. He explained the charts on slides 18,19, and 20 demonstrate the convergence of the low and high scenarios to the baseline scenario over time.

Mike Russo clarified the charts on slides 19 and 20 depict the drivers used in the residential, commercial, and industrial models, with the drivers being the graphs on the left and the growth rates of the drivers on the right. He stated population levels do not tend to be correlated to economic conditions, which causes little variation in population levels among the high, low, and baseline scenarios. He explained Marion County household income is used in the residential average use models and reiterated while there tends to be convergence among the scenarios around 2024, Itron has manually overridden the inputs to ensure the low case scenario growth rates are lower than the high case scenario and the high case scenario growth rates are higher than the low case scenario. He stated the primary economic drivers used for commercial and industrial classes are Indianapolis employment and gross regional product, which tend to converge around 2028.

Mike Russo explained he would address the alternative economic scenario model results. He presented the energy and peak forecasts and noted the average annual growth rates for both energy and peaks are relatively similar, but are compounded over 20 years, which causes variation among the scenarios. He stated the low case resulted in a reduction of roughly 460,000 megawatt hours ("MWh") and 84 megawatts compared to the baseline forecast, while the high case resulted in an increase of roughly 140,000 MWh and 26 MW, not including DG, EVs, DSM, or EE savings. He contextualized the economic load drivers by stating EV and DG saturation, discussed later in the presentation by Erik Miller, has a far greater impact on load than the economic factors.

Stakeholder Anna Sommer, a representative of Energy Futures Group, asked Mike Russo why the Decarbonized Economy scenario, discussed later in the presentation, uses a high economic case and not a case specifically tied to electrification. She clarified she asked out of curiosity and had not yet formed an opinion on the issue. Mike explained the high load economic forecast is used in the Decarbonized Economy scenario because it is logical to assume the associated increases in sales across various industries, including the solar and EV industries, could cause the economy to grow at a slightly elevated rate. Anna stated it made sense the load would increase in total across a given year but was curious about the shape of the load as it did not seem to change much in the high case. Erik Miller explained the shape of load will likely not change much due to economic drivers and explained they use the load forecast into the model that has a load shape based on load shapes from EV, DG, and other factors. Erik stated the EV and DG load shapes will drive the aggregate load shape. Anna stated she was curious about the impact of electrification on load shapes as well, especially related to water heaters and other devices. Erik stated the AES Indiana worked with GDS and Brightline to complete a potential analysis on electrification and found EV electrification was the only item that had a significant impact on load. Jeffery Huber added the electrification evaluated was naturally occurring without intervention and reiterated the impact is expected to be relatively minimal. Anna responded the responses made sense and thanked the presenters.

MPS Results & DSM Resources

Erik Miller, Manager, Resource Planning, AES Indiana
Jeffrey Huber, Overall Project Manager & MPS Lead, GDS Associates, Inc.
(Slides 23 – 63)

Erik Miller started the conversation on the MPS by contextualizing the MPS within the IRP process. He explained the MPS, conducted by GDS, starts by evaluating the technical potential of measures, which represents the universal set of DSM measures that are technologically viable, and the set is then reduced further based on the economic potential of the measures, which evaluates the cost effectiveness of a measure. Erik elaborated GDS will then further reduce the set of DSM measures by what is achievable within AES Indiana's service territory. Erik explained AES Indiana would then load the achievable potential into the Capacity Expansion Model, which AES Indiana is currently working to accomplish. Erik further detailed the capacity expansion model will then consider the DSM resources alongside other supply side resources based on AES Indiana's capacity need. Once the DSM measures are selected in the model, AES Indiana can issue an RFP for vendors to deliver the DSM programs for the next three years, which is described in the DSM Plan filed with the Commission, and upon approval, AES Indiana works to implement the DSM Plan.

To clarify the discussion, Moderator Stewart Ramsay summarized technical potential includes all measures where there is a technology that reduces load or demand, economic potential is the subset that is theoretically possible and can be cost justified, and achievable potential is the subset further refined to estimate the actual number of customers that will participate. Erik Miller agreed and stated Jeffrey Huber will discuss the finer details of Maximum Achievable Potential, which assumes AES Indiana will cover 100% of the incremental measure costs and Realistic Achievable Potential, which essentially utilizes lower incentives compared to the maximum achievable potential.

Jeffrey Huber went through the agenda and items he will discuss, including a MPS recap from Public Advisory Meeting #1, Energy Efficiency Potential, Demand Response Potential, and Developing DSM IRP inputs. He explained conducting MPSs can be time and resource intensive and require a lot of preparation in the beginning. He explained all the square boxes in the chart on slide 28 were initial setup items that had to be completed prior to conducting the MPS, and these startup items begin by evaluating the sales forecast by sector that Itron and AES Indiana provided. He explained they then consider how the information could be segmented to fit the analysis for the MPS and developed assumptions for EE measures and demand response programs using new and existing primary research as well as secondary research. He noted the primary research is especially useful to inform the transition from economic potential to achievable potential as the achievable potential gauges how customers will react to economic incentives by estimating of the percentage of customers that will adopt a measure at varying incentive levels. Jeffrey explained once the data is finalized, GDS places the inputs into its model, which is represented by the triangles in the chart on slide 28.

Jeffrey Huber further described the achievable potential by breaking it into two categories, Maximum Achievable Potential (“MAP”) and Realistic Achievable Potential (“RAP”). He stated RAP accounts for various market barriers and detailed RAP is developed using current or proxy (if the measure or technology is new) incentives levels offered for measures. He specified RAP does not necessarily reflect what will actually occur as there is often room for growth over the long-term from what is currently occurring in the market. He explained MAP estimates adoption if incentives increase to up to 100% of the incremental measure cost. He stated GDS will not increase a measure’s incremental cost to the point the measure is no longer economically feasible, meaning if increasing a measure’s incentives to 100% of the incremental costs causes the measure to no longer be cost effective, GDS will not raise incentives to that level. Jeffrey noted GDS will not reduce a measure’s incentives below the current incentive levels to make the measure cost effective.

Stakeholder Shannon Anderson, a representative of Earth Charter Indiana, asked Jeffrey Huber how cost effective is defined and if cost effective means cost effective for customers. Jeffrey explained in Indiana, the economic potential is screened using the utility cost test, which compares the avoided cost of the utility to the cost of the measure to determine whether the cost is effective, which is more generous than other tests that are used in other states that require the full measure cost to be used. Erik Miller added if a measure is considered cost effective, implementing it would reduce the PVRR, which would ultimately result in a reduced cost for customers.

Jeffrey Huber described the methodological assumptions for MAP and RAP in greater detail. He stated the Willingness to Participate survey (“WTP”) informs the short- and long-term adoption rates used in MAP and RAP. He reiterated historical incentives are a key driver for RAP. He stated GDS considers non-incentive utility costs, including costs to operate the program to maximize the effectiveness of measures and is developed using historical or proxy data. He explained the economic potential does not consider these non-incentive utility costs because these costs vary based on how the programs are run, so it is beneficial to assess non-incentive utility costs later in the process so non-incentive utility costs can be optimized to maximize the benefits of the measures. He explained GDS then considers an estimate of net-to-gross ratio (“NTG”), which removes free riders (i.e., customers that participate in a program that would have completed the same actions in the absence of the program) from consideration as the IRP’s focus is on the net impact of measures.

Jeffrey Huber further explained the WTP asks customers their likelihood to participate in measures based on various incentive levels (0%, 25%, 50%, 75%, and 100%). He expounded the WTP also includes questions meant to gauge non-incentive motivational factors for various end-uses that impact participation levels. He described the WTP also calibrates EV and solar inputs used in the IRP model outside of the MPS. He noted the WTP considers adoption rates based on incentive levels for residential customers, while C&I customers’ adoption rates are evaluated by payback periods to capture the differing financial motivations between the classes of customers, as C&I customers tend to be less deterred by initial costs if there is a relatively short payback period, thus C&I customer participation is primarily driven by payback period rather than incentive levels that reduce marginal cost. He summarized the MPS process by reiterating all savings are at the gross level until the program potential is evaluated, meaning the savings include the net savings as well as free riders and the economic potential screening utilizes the utility cost test savings with current incentive levels.

Jeffrey Huber then provided an overview of the results starting with the overall cumulative results with residential and C&I customer classes combined. He explained the chart on slide 34 represents the cumulative savings over three years, 10 years, and 19 years. He detailed as time progresses, the results capture the expected cumulative impact of new measures, technologies, and participants. He stated by the 19th year, the technical potential of all measures is expected to be 42% savings relative to eligible sales; the economic potential reduces this down to 34% of savings relative to eligible sales; MAP reduces the value to 24% of eligible sales; and RAP further reduces the value to 19% of eligible sales.

Jeffrey Huber then provided the results of the MPS by customer class. He detailed after 19 years, residential customer technical potential is expected to be 47% of residential sales, economic potential is expected to be 33% of residential sales, MAP is expected to be 23% of residential sales, and RAP is expected to be 19% of residential sales. He then provided the residential cumulative MAP 19 years out (2042) and noted heating, ventilation, and air-conditioning ("HVAC") measures created the largest amount of savings. He noted lighting measures only account for 6% of MAP, which is a reduction from studies conducted roughly four or five years ago prior to widespread LED adoption. He compared the 23% 19-year cumulative MAP to the 19-year MAP provided in AES Indiana's 2019 IRP, which was 35%, and noted the difference is largely attributable to the updated definition of MAP as the MAP used for the current IRP only set incentives to 100% of marginal costs if the measures remained cost effective at that level, whereas the 2019 IRP's MAP methodology set all measures to 100% of marginal costs regardless of the cost effectiveness of the measure at that level. He also differentiated the MAP used in the current MPS to the MAP value used in AES Indiana's 2019 IRP stating the current MAP is based on a new set of WTP criteria and application methodology.

Stakeholder Shannon Anderson asked a follow-up question to her previous question by stating she believes EE participation among customers will be influenced by the amount shown on their bills – not a distant theoretical rate decrease. Moderator Stewart Ramsay asked Jeffrey Huber and Erik Miller to correct him if he was wrong but stated the MAP represents programs that would reduce the energy consumption and presumably the cost of the bill for any participating customers. Erik Miller stated Stewart was correct. Stewart then asked to confirm his understanding further by stating the economic potential evaluates whether a measure is cost effective for the customer (i.e., saves the customer money), but does not consider the costs of the utility to implement the program (e.g., incentive and non-incentive costs). Stewart expounded on this by stating MAP then considers whether it is cost effective for the utility to offer a measure to ensure non-participating customers are not subsidizing the measure for participating customers, which ensures a win-win scenario for the participating and non-participating customers by reducing the overall costs to the utility. Erik confirmed Stewart's understanding and explanation of the various components of the MPS. Erik stated AES Indiana further evaluates program cost effectiveness at the program level once the IRP is completed as a component of the DSM Plan filings by looking at the benefit of certain measures (e.g., equipment rebate programs) using both the utility cost test, which looks at the benefit to all customers, and the participant cost test, which evaluates the payback periods for participating customers.

Stakeholder Laura Arnold asked what residential incentives are being proposed for HVAC systems, especially related to air-conditioning. AES Indiana replied by stating it currently offers a variety of rebates for residential customers to help with efficient HVAC system upgrades, and current program offerings can be found online at https://www.aesindiana.com/home-improvement-rebates. Laura followed up by asking if the evaluation breaks out heating from air-conditioning. Jeffrey Huber responded GDS distinguishes between heating and cooling, specifically by technology (e.g., air-conditioning, heat pump electric furnace, etc.) and this level of detail will be available in the appendix of the MPS report when that is completed.

Stakeholder Joey Myles stated he has attempted to register for AES Indiana's CoolCents program but was told his system is "too advanced" for CoolCents to regulate. He detailed he has a Bryant Evolution system and asked if AES Indiana could confirm this. AES Indiana replied customers can participate in CoolCents by installing a smart-thermostat or by having the program install an auxiliary control switch connected to their HVAC unit. AES Indiana further detailed to determine if either of these options are compatible with a customer's system, please call 866-908-4915 or visit the program website, https://www.aesindiana.com/coolcentsr-air-conditioning-management, for more information.

Jeffrey Huber then described the results from the residential RAP in further detail, which produced 18% savings relative to total residential sales in 2042. He noted the relative impacts by end-use are largely the same as the RAP values. He then presented the residential incremental annual savings by end use, which represents the impacts of new savings and participants each year. He noted while behavioral factors were a relatively small component of the overall impact, when evaluated on an annual basis, the behavioral factors had a relatively strong impact on incremental savings. He explained the difference between the cumulative impact and annual incremental impact of behavioral end-uses is due to the continual nature of behavioral measures as utilities must offer the program continuously to achieve savings compared to equipment rebates, which tend to be one-time costs for utilities. He noted transitions to more energy efficient lighting options impacts residential incremental annual savings, but behavioral and HVAC end uses are the primary drivers of residential incremental annual savings.

Jeffrey Huber then detailed the MPS results for C&I customers. He started the conversation by reminding stakeholders a subset of C&I customers that are eligible to opt-out of demand response and energy efficiency measures may select to do so, which requires GDS to exclude these customers from the analysis. He explained opt-out customers are a significant subset of customers as 28% of commercial sales and 76% of industrial sales were from opt-out customers in 2022. He then provided the cumulative annual demand savings as a percentage of C&I sales. He noted the 19-year cumulative technical potential for C&I customers is 36% of C&I sales, which is slightly lower than the residential technical potential. He stated the 19-year cumulative economic potential for C&I customers is 35%, meaning most measures offered and technically feasible are cost effective. He stated the 19-year cumulative MAP is 25% of C&I sales, and the 19-year cumulative RAP is 20% of C&I sales.

Jeffrey Huber then explained the drivers of C&I MAP by end-use and noted the differences in outcomes compared to the MPS used in AES Indiana's 2019 IRP are driven by the fact GDS is not increasing the incentives to 100% of marginal costs if that would cause the measure to no longer be cost effective and differences in the calculation of achievable potential based on the WTP. He noted MAP adoption rates are now calculated using the change in the MAP adoption rate from the current adoption level to the maximum adoption level. He noted there is a fair amount of lighting end uses for eligible achievable potential over the long term and the whole building end use is a large contributing factor to 19-year cumulative MAP and consists of a mixture of several technology types (e.g., cooking, compressed air, behavioral, elevators, vending machines, and other miscellaneous technologies).

Jeffrey Huber then detailed the long-term C&I RAP by end use and noted while long-term C&I cumulative MAP is slightly lower than the value used in AES Indiana's last IRP, the long-term cumulative RAP increased slightly compared to AES Indiana's 2019 IRP. He then detailed the C&I incremental annual savings by end use and noted there is a slight downward trend over the long-term, primarily driven by the lighting end-uses as incremental opportunities for demand savings due to lighting measures are expected to decline as C&I customers adopt lighting measures.

Jeffrey Huber then discussed the process of transitioning from an estimate of RAP to an estimate of Program Potential. He explained some studies may be more nuanced if Program Potential is defined by a budget or predetermined savings level, but in this case, GDS is simply applying a NTG ratio to the RAP to calculate Program Potential. He stated GDS is using the latest evaluated results as its proxy for the NTG impacts and explained it is possible these NTG ratios change over time, but GDS is using the most recent data available and holding that constant to convert from gross to net. He then explained the sole difference between the RAP and program potential is the application of the NTG ratio, which has a greater impact on a cumulative basis in later years due to the compounding impact of the NTG ratio.

Jeffrey Huber then presented the annual residential program potential by program on slide 46. He stated GDS included 2021 using historical data as well as 2022 and 2023 using planned values based on AES Indiana's most recent DSM Plan filing. He explained the Program Potential is slightly higher than the historical and planned values for 2021 through 2023, largely because GDS has included EE technologies or additional tiers of efficiency that may not currently be offered. He then shared the Annual C&I Program Potential on an incremental annual basis at the program level segmenting lighting versus non-lighting again to demonstrate the impact of the decrease in lighting measures particularly in the prescriptive program. He explained GDS did not have the detail needed to break out the historical and planned years (2021 through 2023), but the decrease in prescriptive programs is expected to be driven by the continued decrease in prescriptive lighting. He explained there is a slight annual increase in custom program potential, but the decline in lighting is the primary driving factor for the overall annual C&I program potential reduction in later years.

Jeffrey Huber then described the layering of program potential non-incentive costs, which include implementation costs, utility administrative costs, indirect costs, marketing costs, and other costs that are non-incentive program costs. He explained the charts on slide 48 illustrate the implementation costs of the programs is the primary driver of non-incentive costs. He then presented the residential program potential annual costs segmented by incentive and non-incentive costs. He explained the residential program costs are expected to increase over time as participation is expected to increase and transition to some slightly more costly technologies, until 2035 when residential program costs are expected to decrease slightly. He explained GDS did not assume any changes in incentives over time on a nominal basis, which causes the incentives to decrease slightly over time on a real basis. He stated GDS increased the administrative costs over time by the rate of inflation, but not using the current inflation rate, rather GDS used an inflation rate of 2%. He then presented the C&I program potential annual costs and used the chart on slide 50 to illustrate budgets are relatively flat while the incremental impacts are decreasing, which is due to the shift away from lighting EE improvements to measures with more costly incentive and administrative costs.

Jeffrey Huber then provided an overview of demand response and stated demand response is assessed at the program level. He described different demand response tools, including load control devices, time of use rates ("TOU") that incentivize demand peak savings, and load control devices were evaluated. He explained the residential sector has load control using air-conditioning, space heating, water heating, smart appliances, and pool pumps, while non-residential direct load control is primary air, space heating, lighting, and water heating. He explained it is important to recognize the interactive impacts between typical load control and rate options as customers are unlikely to be able to take advantage of both programs because they might save the same load, which causes the need to create a hierarchy for participation in programs. He stated the hierarchy starts with existing programs to identify the programs individuals will utilize first. He elaborated for residential customers, direct load control is the first in the hierarchy, followed by behavior demand response, then lastly TOU. He explained the hierarchy for small C&I is direct load control, capacity bidding, and then TOU. He stated the hierarchy for large C&I is similar to small C&I, except rather than direct load control, interruptible agreements are the first item, then capacity bidding, and lastly TOU.

Jeffrey Huber then presented the residential demand response MAP and RAP results for savings in 2042. He noted the peak impact for MAP is roughly 398 MW, which is reduced down to 241 MW for RAP. He reiterated the MAP and RAP values include existing and incremental participants and opportunities. He explained the existing programs had high levels in the WTP, which led to existing programs driving most of the savings, and as a result, there is less potential from the incremental offerings. He then presented the C&I demand response MAP and RAP results for 2042, and noted the MAP is 157 MW and RAP is 78 MW, with the primary driver being the interruptible agreements. He then explained slide 56 illustrates the incremental annual impact of demand response using RAP by sector. He explained the maximum expected adoption is essentially reached within the first five years, and subsequent incremental growth is driven by lower new customer growth and incremental opportunities. He then described the annual demand response budgets by sector, which he sated are increasing over time largely driven by increasing incentive levels.

Jeffrey Huber then discussed the process utilizing the MPS results in the IRP. He started with EE IRP inputs and stated there is a reference case of EE inputs that align with the Program Potential. He explained GDS will break the inputs into three different vintages, the first vintage being 2024 through 2025, which is the starting year of the MPS and the subsequent two years. He stated the next vintage will be 2026 through 2028 and the third vintage will be a 13-year block from 2029 through 2042. He explained the first two vintages are three-year blocks to model the DSM Program Plan and the last vintage is broader because there will be an opportunity in later IRPs to refine the approach and utilizing more granular vintages for the later years could create a sense of false precision as well as increase the runtime of the model. He further detailed the first vintage will align with the current programs being offered, which will allow the selection process to understand what is cost effective and which programs are the best candidates for the IRP. He stated for remaining vintages, EE inputs will be aggregated at the sector level to understand the levels of DSM resources that are selected at the different sector levels. He noted segmenting at the sector level also allows AES Indiana and GDS to evaluate Income Qualified Weatherization (“IQW”) programs for low-income customers, which is often not cost effective, but segmenting allows AES Indiana to force IQW into the IRP. He explained EE costs include utility costs, which include incentive and non-incentive costs, and will be adjusted to reflect the net present value (“NPV”) of transmission and distribution (“T&D”) benefits, which aligns with the MPS apart from the adjustment for T&D benefits. He stated the capacity expansion model does not account for the T&D benefits, so the T&D benefits must be quantified outside of the capacity expansion model and then the costs reduced based on the T&D benefits, which is an item the AES Indiana IRP Team has worked with stakeholders and the oversight board in the past to improve upon. He noted since the IRP modeling starts in 2023 and the MPS starts in 2024, DSM for 2023 will be “hard coded” into the model based on the currently approved savings and cost DSM totals for 2023. He stated the chart on slide 60 illustrates the impact of the three vintages as well as the cumulative annual impacts. He detailed the first three years represent the different programs and how they will be analyzed, and starting in 2027, there is a bigger block of residential and nonresidential. He stated IQW will appear in the second vintage and EE begins to grow significantly in 2030. He explained while the IRP timeline ends in 2042, the EE savings extend roughly another decade, which highlights the importance of evaluating the benefits and costs. He stated the costs for the measures are assessed on a levelized cost basis, meaning there is a cost per lifetime MW, which will allow the savings that occur outside of the IRP timeframe to be considered and ensures consistency with other resources.

Jeffrey Huber explained the EE IRP inputs need to be provided on an hourly level to ensure compatibility with the IRP model. He stated GDS assigns each measure an end use and uses end use load shapes, which primarily come from the National Renewable Energy Lab (“NREL”) and Lawrence Berkely National Lab (“LBNL”). He detailed the residential sector includes 33 end-uses and the nonresidential sector includes 11 end-uses. He stated AES Indiana contributed to the research NREL completed by providing its own hourly savings shapes, so the model captures the timing of savings relative to the AES Indiana system and peak periods. He described the chart on slide 62 illustrates the EE measures for the nonresidential sector throughout the year and noted cooling measures are dominant on an hourly basis in during the summer months of the year.

Jeffrey Huber then described the IRP inputs for demand response. He stated the same vintages used for EE will be used for demand response. He explained the first residential bundle will be the traditional demand response measures, including direct load control technologies and a rate module. He stated the same is true for C&I as C&I will consider existing demand response offerings as well as the additional rate options. He expounded there will be both summer and winter impacts in the bundles, but summer will have the larger peak impacts.

Stakeholder Anna Sommer noted a conversation with Jeffrey Huber in the last technical meeting where they discussed how or if there was a method to capture inflationary and supply chain pressures on supply side resources, which could also affect DSM as the avoided costs could increase due to the cost of energy increasing. Anna noted this could impact the willingness to pay and customer participation. Anna recognized it is difficult to capture these items but asked how Jeffrey would rank those items and whether there would be a method to capture the biggest impacts in the IRP. Jeffrey stated GDS will note Anna's recommendation and stated inflation and supply chain issues could impact payback performance, which could impact results since payback performance is a primary driver. He stated it may be relatively conservative to not recognize additional measure costs are increasing due to supply chain pressures, but in large part, GDS commonly sees short-term impacts not continue into the long term, which influenced GDS to not include various short-term impacts into the long-term. He explained if GDS were to extend some short-term costs into the long term, the costs would not be met. Anna replied even if the economy goes from 8% inflation to 2% inflation the next year, there would still be an 8% increase in overall consumer costs. Anna noted she does not believe inflation would be the same for energy generators and consumer products and agrees using an 8% inflation rate year over year would imply a radically different, unstable economy, but she is curious whether a short-term reordering of resources is in order because of the cost pressures. Erik Miller stated that is an item to consider and proposed the 8% inflation number could be a starting point and then assume 2% inflation from there. Anna replied that is one way to think about the concept and is an interesting thought. Moderator Stewart Ramsay asked Anna if the effect that Anna would anticipate seeing is a higher short-term increase in EE and DSM program participation. Anna replied yes. Stewart stated over the long term one would expect the same levels of saturation perhaps with a different curve. Anna replied yes, potentially. Erik stated this is something AES Indiana and GDS will consider. Anna then thanked Erik for the response.

Current Generation Portfolio

Kristina Lund, President & CEO, AES Indiana
(Slides 65 – 68)

Kristina Lund began her presentation by thanking stakeholders for their attendance and participation. She previewed most of the remaining conversation in Public Advisory Meeting #2 will be focused on scenarios and portfolio strategies. She stated prior to delving into those topics, she will be discussing AES Indiana's current generation portfolio and detailing how AES Indiana and its stakeholders arrived at the current portfolio over the last several IRPs. She stated AES Indiana owns and operates 36 gigawatts ("GW") of capacity in Indiana, with the three largest generation cites being: the Petersburg site, which currently consists of three units totaling 14 GW of energy from coal; the Harding Street plant, which is located in southwestern Indianapolis and contributes over one GW of capacity and operates using natural gas; and Eagle Valley, which is located roughly 40 miles south of Indianapolis and uses combined cycle gas turbine ("CCGT") technology and contributes 671 MW of capacity. Kristina stated AES Indiana has wind, solar, and battery storage resources located throughout Indiana. She detailed AES Indiana has announced the acquisition of two solar projects, the Hardy Hills Solar Project in Clinton County and the Petersburg Energy Center, which is a combined solar and battery storage project in Pike County that will interconnect through the Petersburg interconnection, which also serves the Petersburg coal plant.

Stakeholder Ben Inskeep, a representative of the Citizens Action Coalition, asked Kristina Lund if she could provide an update on the status of the solar and battery projects. He further asked if AES Indiana has experienced any recent delays with the supply chain issues or with perspective tariffs that are currently being discussed. Kristina thanked Ben for the question and stated Hardy Hills is expected to come online in 2023, and AES Indiana is working with the developer to ensure the project is on track and did not have any updates at this time for Hardy Hills. Kristina stated the Petersburg Energy Center is slated for operation in 2024, so it has more time prior to commercial operation, but there are also no updates or changes on the timeline for that project.

Stakeholder Laura Arnold asked AES Indiana what it is projecting to do when current Rate REP 15-year contracts expire. AES Indiana replied it will work with Rate REP customers to determine the appropriate and most customer beneficial rate after the expiration of their contract, and those customers may be eligible for Rate CGS or Rate EDG. Laura followed up her question by asking if the future solar power available from Rate REP is reflected anywhere in the IRP. AES Indiana replied yes, the energy generated from existing Rate REP solar projects is forecasted to continue through the IRP study period.

Kristina Lund presented the figures on slide 67 and stated this represents the history of AES Indiana's current portfolio. She explained the changes to the portfolio described on slide 67, from 2015 to 2025, AES Indiana will have reduced the portfolio carbon intensity by more than 40%, which is a proud accomplishment AES Indiana has worked very hard to achieve. She noted AES Indiana has accomplished this gradually through the IRP process and other agreements over the past decade or more. Kristina detailed AES Indiana was an early adopter of wind energy when it signed a power purchase agreement ("PPA") in the 2010 timeframe, and AES Indiana still has the same energy from the wind PPA in its portfolio today. She noted AES Indiana purchases energy from solar projects located in and around its service territory under the incentives it has in place through Rate REP. She stated AES Indiana has evaluated each of its plants through the IRP process and has incorporated new technologies over time. She elaborated AES Indiana retired coal at Eagle Valley in 2016, and through the IRP process, AES Indiana replaced the coal generation with the 671 MW CCGT that is currently located at Eagle Valley. Kristina further detailed AES Indiana retired the coal firing plant at Harding Street, AES Indiana's largest generation site in Indianapolis, and refueled it with natural gas. She stated Harding Street now operates on natural gas and is especially valuable during peak demand times. Kristina then focused on AES Indiana's actions in 2021 through 2023 when AES Indiana's short-term action plan from its 2019 IRP began and noted as a result of the short-term action plan and preferred resource portfolio, AES Indiana retired Petersburg Unit 1 in 2021 and plans to retire Petersburg Unit 2 in 2023. She explained the solar projects Hardy Hills and the Petersburg Energy Center are expected to come online in 2023 and 2024, respectively. She recognized AES Indiana has made rapid progress on carbon intensity and is dedicated to using different technologies in the evolution of its portfolio to increase its value to customers.

Kristina Lund then discussed the capabilities and infrastructure at its generation sites and noted as AES Indiana and its stakeholders assess the portfolio moving forward, it is important to consider the highest value of these capabilities and infrastructures. She first discussed the capabilities and infrastructure at Petersburg, which includes a very experienced and skilled labor force, a large amount of land in Pike County, an interconnection of more than one GW, water rights, water treatment facilities, and natural gas pipelines that are already present at the site. She then described the capabilities and infrastructure at Harding Street, including the large output capabilities of the plant, the location inside AES Indiana's service territory close to its load, interconnection rights, an experienced and skilled labor force, and rail and water rights. She noted AES Indiana seeks to optimize the infrastructure for the future of its customers, the community, and the City of Indianapolis, especially considering priorities such as the White River Project. Kristina then discussed the capabilities and infrastructure at Eagle Valley, which includes a new plant that is highly efficient and flexible for future grid changes. She summarized this analysis by stating AES Indiana is considering all these capabilities and infrastructures when considering the energy transition, and AES Indiana is seeking to partner with its customers, the City of Indianapolis, Pike County, and all its stakeholders to not only drive customer value, but also develop the best method to transition these sites for the future.

Replacement Resource Assumptions

Erik Miller, Manager, Resource Planning, AES Indiana
(Slides 69 – 90)

Erik Miller previewed he will be discussing replacement resources assumption and how they fit into the IRP process. He explained AES Indiana is completing a capacity expansion analysis of its generation portfolio to determine if retirements are needed and assess AES Indiana's need for capacity. He explained the replacement resource assumptions are ultimately what feeds into the model for the capacity expansion analysis. He stated the key replacement resources AES Indiana is considering are DSM and EE, which use inputs from the MPS previously discussed by Jeffrey Huber; wind; solar; battery storage, including both utility-scale standalone storage as well as solar coupled with storage; and natural gas, including CCGTs, combustion turbines ("CT"), reciprocating engines, and refueling Petersburg to natural gas.

Erik Miller then provided an overview of the key replacement resource assumption the planning model uses for selecting the replacement resources when energy or capacity is needed. He specified the key resource assumption components consist of both costs and operating characteristics. He explained a large portion of the costs include the overnight capital cost to construct, which include the cost associated with the development and construction of the resource. He stated another assumption is the operating costs, which consist of fixed operation and maintenance ("O&M") and variable O&M costs. He detailed fixed O&M costs are the costs incurred regardless of the operation status of the plant, whereas the variable O&M costs are the costs associated with electricity reduction. He then explained operating characteristics vary based on the technology of the resource and differentiated solar and wind from the other technology types as they are non-dispatchable, meaning when the sun is out or the wind is blowing, these resources are generating electricity, which requires the use of generation profiles to understand when solar and wind will produce energy. Erik elaborated 8,760 hourly shapes are created for wind and solar resources, which get loaded into the model. He explained effective load carrying capability ("ELCC") is a measure of a resource's capacity value when the system is at its peak and is used to assess wind and solar resources' capacity values. He noted as renewable penetration in the MISO system increases, AES Indiana expects the loss of load probability to shift to later hours in the day, which is currently being seen in California. Erik explained MW limits and asset useful lives are also consideration for solar and wind resources. Erik next detailed the operating characteristics of storage resources, which include round trip efficiency ("RTE") (i.e., the efficiency of charging the battery then discharging the batter to the system), capacity accreditation using ELCC, MW and MWh limitations, and asset useful life. Erik described the operating characteristics of CTs and CCGTs, which include heat rates (i.e., the efficiency of the unit at converting its energy source to heat, measured in terms of MMBtus per MWh or Btus per kWh), ramp rates (i.e., how quickly the resource can come online and respond to load), capacity accreditation (i.e., the capacity value of the resource during the peak), and asset useful life.

Stakeholder Bhawramaett Broehm, a representative of Wärtsilä, asked if AES Indiana considers the starting costs for CTs and CCGTs and noted this will be important to capture as the share of variable energy grows. Erik Miller confirmed AES Indiana is including the startup costs in its analysis.

Stakeholder Bruce Russell-Jayne, a representative of Unitarian Universalist Church of Muncie, asked AES Indiana why climate change is not considered in its modeling. AES Indiana replied it discussed it will capture climate change using increased temperature trends for the calculation of normal weather in Public Advisory Meeting #1. Bruce followed up by asking why climate change is not considered in AES Indiana's RFP, considering the weather is only a small part of climate change. AES Indiana replied the IRP considers climate change using increased temperature trends. AES Indiana further explained the RFP is intended to fill a generation need based on the results of the IRP, and the RFP results are evaluated based on quantitative and qualitative factors, which do include costs and effects of environmental impacts.

Erik Miller then discussed the methodology used to create the replacement resource cost assumptions. He stated the average of three secondary data sources from Bloomberg New Energy Finance ("BNEF"), NREL, and Wood Mackenzie were used to benchmark the starting year assumptions for the capital cost forecast using AES Indiana's 2019 IRP results as an initial benchmark. Erik detailed AES Indiana contracted Sargent and Lundy ("S&L") to administer its 2019 All-Source RFP for generation, and as a follow up to that work, S&L summarized the cost and operating components of the resources included in AES Indiana's All-Source RFP to inform AES Indiana's 2022 IRP. Erik noted S&L supplemented the review by researching their internal databases and a comprehensive list of public data sources to review several resource types and cost component, as further detailed on slide 72.

Erik Miller then discussed AES Indiana's 2022 All-Source Generation RFP ("2022 RFP"), which AES Indiana released the week of Public Advisory Meeting #2. Erik explained AES Indiana initially wanted to issue the RFP in fall 2021, but the initial onslaught of supply constraints and solar tariffs caused AES Indiana to delay the RFP. He stated AES Indiana decided to release the 2022 RFP for two primary reasons: (1) to allow AES Indiana to be in a position to quickly execute generation contracts once the preferred resource portfolio and action plan are developed and the IRP process is complete and (2) to inform the sensitivities in the IRP to ensure the preferred resource portfolio is able to adapt to potential changes in the market and understand the impact to PVRR and cost to customers. He explained the 2022 RFP will also allow AES Indiana to assess the impact of solar tariffs issued by the US Department of Commerce for southeast Asian manufacturers that have evaded Chinese tariffs, which could cause solar prices to increase. Erik explained AES Indiana and the industry expects a preliminary decision from the Department of Commerce on the direction of their tariffs in roughly 150 days.

Stakeholder Ray Wilson, a representative of Faith in Place, asked AES Indiana where possible residential solar fits into the picture and if AES Indiana is considering community solar. Erik Miller explained AES Indiana conducted a solar forecast based on behind the meter solar (i.e., customer driven solar), which AES Indiana reviewed in Public Advisory Meeting #1. Erik added AES Indiana models solar in its Capacity Expansion Model, and if community solar-scale resources are selected in the planning model, a portion of the solar could be community solar or AES Indiana could position it that way.

Erik Miller then further detailed the sources used for the replacement resource cost assumptions, as seen on slide 74. He explained data from BNEF, NREL, and Wood Mackenzie is benchmarked against AES Indiana's 2019 RFP and considers AES Indiana-owned resources when possible. He noted primary data is used to estimate grid connection/interconnection costs and tax equity costs, which are costs AES Indiana has found to be extremely important to accurately anticipate in its 2019 RFP. He noted the grid connection and tax equity costs are difficult to evaluate as they are project-specific, but it is important to understand and evaluate as part of the IRP. He described grid connection costs are the costs associated with interconnecting to MISO. He then detailed tax equity costs are costs a utility incurs when entering into a partnership for a build-transfer agreement ("BTA"), which allows utilities to utilize the investment tax credit ("ITC") and the production tax credit ("PTC") associated with the construction of solar or wind resources, despite lacking the tax position to directly monetize the ITC. He noted S&L provides the assumptions for the tax equity component as S&L has a database of several proposals and projects for which they were administrators, which allowed S&L to pull together estimations for grid connection and tax equity costs.

Erik Miller then detailed the wind capital and operating costs on slide 75. He explained the blue line on the chart is the average of the BNEF, NREL, and Wood Mackenzie data and noted the capital cost forecast starts relatively flat and escalates with inflation. He also noted the wind capital cost forecast on slide 75 does not include the PTC as this will be evaluated later. He explained AES Indiana will also consider subsidies for wind projects, but the subsidies vary by scenario, with some scenarios having more aggressive ITC/PTC credits. He explained the purple triangle in the chart on slide 75 represents the capital cost forecast from AES Indiana's 2019 IRP.

Erik Miller then detailed the wind parameters used, which were developed by modeling wind generation in northern and southern Indiana using the NREL System Advisory Model in addition to capacity factor, which allowed AES Indiana to generate its shape and 8,760-hour input data that is an input for the IRP planning model. Erik explained it is more difficult to acquire wind projects in northern Indiana, so AES Indiana modeled wind resources in southern Indiana near the Petersburg area, which created a range of capacity factors (ranging from 33.6% to 40.4%). Erik stated AES Indiana assumes a project size of 50 MW of installed capacity ("ICAP") and noted it was a relatively small size, but AES Indiana can build up capacity from wind as needed using a modular structure. He also noted the useful life of wind resources is assumed to be 30 years. Erik then explained Horizon Energy provided the ELCC data, which estimates an ELCC of 7.1% during summer and 20% during winter. Erik described the primary driver for the difference in wind resource ELCC in winter compared to summer is more wind naturally occurs in the winter compared to summer.

Stakeholder Ben Inskeep asked if the capital cost of wind is declining in AES Indiana's model when evaluating on a real basis. Erik Miller stated AES Indiana is noticing that and elaborated Bloomberg, Wood Mackenzie, and NREL assume a learning curve with wind and solar, and in the near term, costs are reduced on a real basis due to learning curve improvements.

Erik Miller then presented the solar capital and operating costs and noted the same trend identified for wind resources is present for solar as the solar capital cost forecast is declining due to experience gained with the resources. Erik explained the experience/learning curve assumes as solar technology becomes more ubiquitous in the market, there will be advances in technology that ultimately produce lower costs for the technology, which drove the capital cost forecast to decline in the future. Erik noted inflation is included in the capital cost forecast, but incentives are not included in the capital cost forecasts as the incentive levels will be addressed during the scenario evaluation. He noted the capital cost of Hardy Hills was provided in the chart on slide 77 for comparison.

Erik Miller then detailed the solar resource parameters, which were developed using the NREL System Advisory Model and Petersburg, Indiana as the location. Erik explained AES Indiana could have selected anywhere in Indiana to locate the project for the purpose of developing resource parameters. He detailed the NREL System Advisory Model calculated a capacity factor of 24.5%, useful life of 35 years, and a project size of 25 MW ICAP, which lends itself to be modular in nature. Erik explained Horizon Energy provided the ELCC forecast based on the customer reference case, which is expected to be 58.7% in summer. Erik noted solar ELCC is forecasted to decline over time, which is expected to occur because as renewables achieve higher penetration rates across MISO, the loss of load probability hour would shift and negatively impact solar ELCC. Erik stated the ELCC forecast from Horizon Energy utilizes the base, Reference Case scenario, and the solar ELCC values could differ based on the different fundamentals resulting from the different scenarios.

Stakeholder Ray Wilson asked AES Indiana how large of a solar system would be possible to install at the Petersburg site. Erik Miller stated AES Indiana currently will have 200 MW of injection rights at the Petersburg interconnection following the planned retirement of Petersburg Unit 2 and operation of the Petersburg Energy Center. Erik previewed AES Indiana will specifically request projects that utilize the interconnection in its 2022 RFP. Moderator Stewart Ramsay asked Erik if using the injection rights allows projects to "move to the front of the line," meaning projects that utilize existing injection rights do not have to wait in the MISO queue for transmission capacity. Erik stated Stewart was correct. Stewart then followed up by stating if projects were submitted that made use of the Petersburg interconnection, it would allow the projects to bypass one step in the process related to obtaining transmission capacity. Erik agreed with Stewart and noted utilizing the Petersburg interconnection could also potentially reduce costs. Erik added AES Indiana will have 200 MW of injection rights and any projects that utilize the injection rights could account for more or less than 200 MW. Stewart clarified 200 MW of injection rights are available, and AES Indiana will consider projects that are larger, but moving forward with a project larger than 200 MW would require additional steps to secure additional injection rights. Erik agreed with Stewart.

Erik Miller next discussed storage capital and operating costs. He explained the blue line on slide 79 represents the average of the values obtained from Wood Mackenzie and Bloomberg. Erik noted AES Indiana removed the NREL data from the storage capital cost forecast because it was an outlier as the costs were much higher than the costs from Wood Mackenzie and Bloomberg as well as the proposals AES Indiana received during its 2019 RFP. He noted storage currently does not receive ITC, but storage subsidies will be evaluated in the scenario analysis.

Stakeholder Anna Sommer asked AES Indiana if it plans to discuss resource adequacy assumptions at some point and noted AES Indiana is using seasonal ELCCs. Erik Miller responded AES Indiana plans to model resource accreditation using MISO's seasonal construct. Erik stated Public Advisory Meeting #3 will focus on reliability and resource adequacy. Anna thanked Erik for his response.

Erik Miller then discussed the storage parameters and explained while the location is listed as Indianapolis, it could exist anywhere in the state. He detailed AES Indiana assumes a project size of 20 MW ICAP and 80 MWh four-hour discharge as well as a RTE of 85%. Erik further noted the useful life is expected to be 20 years with a capacity accreditation of 95%, which would cause a 20 MW battery to receive 19 MW of capacity accreditation. Erik also stated AES Indiana plans to model six-hour storage, which will be modeled and scaled using AES Indiana's four-hour assumptions.

Stakeholder Ben Inskeep asked if storage durations other than four hours will be considered and why AES Indiana used four hours as a parameter as two-hour storage, which could produce a lower dollar per kW capital cost. Erik Miller explained MISO's capacity accreditation for storage resources uses a four-hour discharge requirement. Ben then thanked Erik for his response. Stakeholder Anna Sommer then added two-hour storage is treated as getting half the four-hour storage capacity value. AES Indiana replied Anna is correct and added AES Indiana models four-hour storage due to the MISO capacity requirements and storage that is designed to dispatch for four hours is optimized for that type of dispatch. AES Indiana elaborated, as Erik mentioned, AES Indiana will also model 6-hour storage as an option.

Erik Miller then discussed the solar direct current ("DC") coupled with storage capital and operating costs. He explained AES Indiana assumes a 2:1 solar to storage ratio or weighted average to calculate the capital costs for the capital cost forecast. Erik noted AES Indiana included a comparison to the Petersburg Energy Center, which is a DC coupled solar plus storage project. He clarified subsidies are not considered in this capital cost forecast. Erik Miller then discussed the solar plus storage parameters and noted the size of the solar component is

25 MW ICAP at the interconnection paired with a 12.5 MW ICAP storage component and 50 MWh, 4-hour battery. Erik mentioned AES Indiana is capturing synergies around costs, including cost efficiencies associated with DC coupling as this produces reduced inverter costs by removing the need to convert from DC to alternating current ("AC") then back to DC, which reduces capital costs by 4.3% and improves RTE by 2%. Erik noted AES Indiana is assuming 100% summer capacity credit in 2025, which is expected to decline in later years and a 48% winter capacity credit that is held flat throughout the period.

Erik Miller then provided the CCGT capital and operating costs. He explained the capital cost forecast was created using the average of the BNEF, NREL, and Wood Mackenzie data. Erik explained the starting capital cost essentially escalates with inflation over time. Erik described the CCGT parameters, which include a size of 325 MW ICAP and a heat rate of 6,700 Btus per kWh, which is derived from the heat rate of the Eagle Valley CCGT. He stated the useful life is expected to be 30 years and receive 94.2% of capacity for both summer and winter, which is the MISO class average for a CCGT.

Stakeholder Ray Wilson asked AES Indiana if it is considering EV battery storage possibilities during the 20-year timeframe. AES Indiana replied it is not at this time, but that is something it can consider in future IRPs.

Stakeholder Anna Sommer asked what configuration and turbine class AES Indiana is assuming for the CCGT. AES Indiana replied Erik Miller addressed this question in his presentation as AES Indiana is using Eagle Valley as its benchmark for the operating parameters of the selectable generic CCGT. Anna replied she missed that in the conversation and asked if that means AES Indiana is using a 2x1 F Class. AES Indiana replied yes, Eagle Valley is a 2x1 F Class and AES Indiana models the generic CCGT at half the size of Eagle Valley.

Erik Miller next provided the frame combustion turbine capital and operating costs. He explained the capital cost forecast was created using the average of the BNEF, NREL, and Wood Mackenzie data. Erik explained the starting capital cost essentially escalates with inflation over the planning period. Erik then described the frame combustion turbine parameters, including a project size of 100 MW ICAP; a heat rate of 10,000 Btus per kWh, which was developed using the combustion turbine Harding Street Unit 6 as the benchmark; a useful life of 20 years; and a winter and summer capacity credit of 95.6%, which is the MISO class average.

Erik Miller presented aero-derivative combustion turbine ("aero CT") and reciprocating engine capital and operating costs and explained these tend to be smaller in size and can ramp quicker compared to frame combustion turbines but are more costly. He stated S&L provided the cost forecast. Erik described the parameters of the aero CT and reciprocating engine, including a project size of 90 MW ICAP for the aero CT and 54 MW ICAP for the reciprocating engine. Erik stated the heat rate for the aero CT is 8,200 Btu/kWh versus 7,400 Btu/kWh for the reciprocating engine. Erik stated both the aero CT and the reciprocating engine have useful lives of 20 years and summer/winter capacity credits of 95.6%.

Erik Miller then detailed the Petersburg Refuel capital and operating costs. He explained this option would be on a one-for-one MW basis to refuel Petersburg Units 3 and 4, which represents roughly 1,000 MW of capacity. He noted the cost of refueling would be similar to the cost to refuel Harding Street Units 5, 6, and 7 that occurred in 2016, as discussed earlier in the presentation by Kristina Lund. Erik stated while the cost to refuel Harding Street was considered, AES Indiana and its IRP team also conducted further engineering analysis on other costs, including the gas infrastructure upgrade, which ultimately results in a relatively low capital cost of roughly $100 per kW, which does not include the cost associated with the gas infrastructure upgrade. He noted benefits of refueling from coal to gas, including decreased carbon emissions by roughly half. He noted AES Indiana would expect Petersburg to have a reduced capacity factor following a refuel, similar to the reduction Harding Street experienced after its refuel, which means Petersburg would produce less energy after the refuel. He explained Petersburg would mainly exist for its capacity value and for its value when load is high and the system is peaking. He added since it would be dispatchable, it would position AES Indiana well with the new MISO seasonal capacity construct.

Erik lastly provided the parameters for the refuel of Petersburg Units 3 and 4. He stated since the replacement would be on a one-for-one MW basis, each unit would remain around 526 MW ICAP. He explained AES Indiana would expect a heat rate of 10,800 Btu/kWh whereas the current heat rate at Petersburg is 10,500 Btu/kWh meaning the refuel would make Units 3 and 4 slightly less efficient than they are currently while running on coal. He added AES Indiana expects a fixed O&M reduction of 65% through its potential refuel. He stated the Petersburg Units 3 and 4 refuel would have a useful life of 20 years and capacity credit between 90 and 95%.

Stakeholder Devi Glick, a representative of Synapse Energy, asked AES Indiana if it could confirm it plans to calculate and include gas infrastructure costs in its model. Erik Miller replied yes, AES Indiana plans to evaluate all costs associated with gas infrastructure upgrades in the model.

Stakeholder Bhawramaett Broehm asked AES Indiana if its IRP would explore either green H_2 combustion resources or refueling of existing gas resources to operate on H_2. AES Indiana replied in Public Advisory Meeting #1, AES Indiana discussed its desire to be open to developing emerging technologies like H_2, but those technologies will not be considered in its 2022 IRP.

Stakeholder Ben Inskeep asked AES Indiana if it had additional insight into what the rough gas infrastructure upgrade costs would be or if it has developed a levelized cost of energy (“LCOE”) for this option. Erik Miller stated AES Indiana has not included an LCOE for this option, but it is something they will consider.

Stakeholder Anna Sommer stated in a technical meeting, AES Indiana stated it would allow bidders to submit offers using the remaining injection rights and asked if the injection rights correspond to the sizes of the remaining two units. Erik Miller explained as a result of AES Indiana’s 2019 IRP, it retired Petersburg Unit 1 and will retire Petersburg Unit 2, but AES Indiana is also adding the Petersburg Energy Center, which is 500 MW. He stated AES Indiana would be seeking to fill the injection rights left over from these events, which is roughly 200 MW.

IRP Portfolio Matrix and Framework

Erik Miller, Manager, Resource Planning, AES Indiana
(Slides 91 – 119)

Erik Miller explained AES Indiana's portfolio matrix considers four generation portfolio strategies across four scenarios to arrive at a cost to customers for each strategy in each scenario. He explained AES Indiana will then evaluate all the portfolios against other metrics, including cost, environmental, reliability, and risk metrics. He stated after these processes are completed, AES Indiana will be able to develop a preferred resource portfolio that makes the most sense for its customers.

Erik Miler reiterated AES Indiana is considering four strategies AES Indiana views as potential future strategies for the generation portfolio. Erik explained this requires AES Indiana to predefine retirement dates, capital expenditures, and cost treatments in its planning model for each strategy. Erik stated AES Indiana is also considering scenarios, which are views of the future defined by external influences, such as political outcomes, economics, and regulations, that have driving assumptions that support each of the scenarios and are ultimately put into the model for evaluation. He added AES Indiana will able be conducting stochastic sensitivities, which will be addressed in greater detail in Public Advisory Meeting #3.

Erik explained the first of the four strategies AES Indiana is considering is the No Changes to the Portfolio strategy, which would keep Petersburg Units 3 and 4 online through 2042. Erik stated the next strategy is the Petersburg Refuel, which would occur in 2025. He described the next scenario is One Petersburg Unit Retires Early, where one unit would retire in 2026 (either Unit 3 or 4) and the other unit remains in service through its useful life of 2042, and replacement capacity for the retired unit starts in 2026. He detailed the final strategy, which is where both units retire early, one in 2026 and the other in 2028.

Erik explained slide 95 is especially important because it provides the rationale for AES Indiana predefining these portfolio strategies and explains the ideas behind each strategy. Erik explained AES Indiana allows the EnCompass model to optimize on its own, which allows the EnCompass model to inform AES Indiana when the optimal time to retire Petersburg units is rather than AES Indiana determining that on its own, but Erik noted the issue with allowing the EnCompass model to determine items such as the retirement of Petersburg is that EnCompass could produce a result that is not feasible, such as a decision to retire all Petersburg units in 2023 and build 1,000 MW of renewables to replace it. Erik explained the problem with that is it is not feasible for AES Indiana to execute on items that quickly as AES Indiana would need time to phase Petersburg out and retire it as well as time to procure replacement resources. Erik illustrated this point by referencing lessons learned from the 2019 IRP as AES Indiana learned it takes a significant amount of time to replace resources. He noted a strategical consideration behind staggering the potential retirements of Petersburg Units 3 and 4 to 2026 and 2028 is it would be difficult to procure 1,000 MW of capacity in 2026 all at once, whereas staggering the retirement dates can aid in the procurement process. Erik further explained the Petersburg refuel suggested date is 2025 because that is the earliest year it can feasibly be completed.

Stakeholder Ben Inskeep asked Erik Miller why AES Indiana is not evaluating a portfolio of exclusively clean energy resources. Ben stated one strategy is to continue coal, one strategy is explicitly geared toward natural gas, and the other two strategies select resources based on the modeling and asked Erik if he had any thoughts on the evaluation of an exclusively clean energy portfolio. Erik stated this will be addressed in AES Indiana's scenarios as it has a Decarbonized Economy scenario that assumes a clean energy standard that will likely replace Petersburg's capacity with roughly all renewables, meaning a portfolio will exist that replaces all of Petersburg's capacity with renewables. Erik asked Ben if Erik's explaination made sense, and Ben responded yes and thanked Erik for his response.

Stakeholder Zachary Harbin, an employee at AES Indiana's Petersburg Generating Station, asked AES Indiana how it could replace Petersburg with dispatchable energy and not refuel to natural gas. AES Indiana responded the purpose of the IRP process is to evaluate the best generation resource mix to reliably serve its customers considering a variety of alternatives in varying scenarios. AES Indiana explained gas conversion is one of the alternatives that will be considered in this process, and it is not predetermining gas conversion or any other resource outcome ahead of going through the full evaluation. Zachary followed up by stating he understands but asked AES Indiana how that loss of generation under the Petersburg retirement scenario will be covered if renewables are not dispatchable. AES Indiana replied Zachary's question goes to the heart of reliability, which will be evaluated as part of the IRP process.

Stakeholder Bhawramaett Broehm asked AES Indiana how imports and exports with MISO are being modeled. AES Indiana replied this is an important modeling constraint that is still being worked out, and AES Indiana plans to share this type of modeling assumption in Public Advisory Meeting #3.

Erik Miller previewed he will walk through how the portfolio looks in EnCompass. He explained the chart on slide 97 represents the strategy of making no changes to the existing portfolio, meaning Petersburg will not be retired until their age-based retirements in 2042. He detailed the black line is AES Indiana's load with a reserve margin. He noted Harding Street Units 5, 6, and 7 would retire in 2031 and 2034, which would create a gap in capacity, and AES Indiana would use the EnCompass capacity expansion model to fill the gap with resources. He explained the capacity gap would be filled based on the replacement resource assumptions and DSM inputs discussed earlier in the meeting. He also noted Hardy Hills and the Petersburg Energy Center come online in 2023 and 2024.

Erik Miller then discussed the Petersburg Refuel in 2025 strategy. Erik explains this strategy looks almost identical to the No Changes to Existing Portfolio strategy as Petersburg would continue to run on natural gas rather than coal, which would lead to the same capacity expansion needs in the future.

Erik Miller then analyzed the One Petersburg Unit Retires strategy, which has Petersburg Unit 3 retiring in 2026. He explained this creates a capacity need of roughly 400 MW starting in the 2027 to 2028 timeframe. Erik recognized this creates a capacity need much sooner, so the EnCompass capacity expansion model will fill that with the most cost-effective resource(s). He noted the retirement of Harding Street Units 5, 6, and 7 in the 2030s creates a relatively large capacity need of roughly 1,000 MW over that period as well. Erik Miller next examined the Both Petersburg Units Retire scenario, which would create a need for roughly 1,000 MW of replacement capacity by 2028. He explained using certain assumptions, such as certain environmental policy assumptions, the capacity expansion model would likely select renewable energy to fill the capacity gap.

Erik Miller then discussed scenarios and driving assumptions in greater detail. He noted AES Indiana will take the four strategies he just discussed and run them through the four scenarios, which will ultimately allow AES Indiana to create its portfolio matrix. Erik explained AES Indiana will utilize the four scenarios listed on slide 101, which are in order from least environmentally aggressive to most environmentally aggressive, starting with No Environmental Action, then Current Trends (i.e., reference/base case), then Aggressive Environmental, and the most environmentally aggressive is the Decarbonized Economy scenario.

Erik next discussed the commodity assumptions AES Indiana works with Horizons Energy to develop. Erik explained each scenario will have its own set of fundamental curves or set of power prices that must be generated. Erik provided background on Horizons Energy stating they are a relatively new vendor in terms of commodities as they have been around since 2016. Erik stated Horizons has worked on several IRPs, including Duke's most recent IRP. Erik stated AES Indiana is using Horizons Energy to run the entire MISO system, conduct a fundamental analysis to calculate commodity prices, and to provide consulting services. Erik explained AES Indiana will provide Horizons Energy the policy assumptions developed in its scenarios, and Horizons will load that information into their EnCompass model and run capacity expansion for all of MISO in order to develop fundamental curves, including around the clock, on-peak, and off-peak energy prices as well as capacity prices that AES Indiana will ultimately use for each of its scenarios to ensure each scenario has its own set of fundamental curves to place into its EnCompass model. Erik stated the fundamental curves are currently in production and review internally, and AES Indiana plans to share them in Public Advisory Meeting #3.

Stakeholder Ben Inskeep asked AES Indiana if it can commit to making the commodity assumptions publicly available, particularly the natural gas price assumptions will be important inputs in this IRP and some other utilities have redacted this important set of assumptions in other examples. AES Indiana responded does not make these commodity assumptions publicly available as it is confidential, proprietary, competitively sensitive, and/or trade secret information; furthermore, those participating in technical conferences have or will receive this information.

Erik Miller then previewed he will further describe each of the four scenarios. Erik first described the is the No Environmental Action scenario. Erik stated this future is defined by relaxed environmental regulation, expanded fracking, and low demand from low electrification. Erik stated AES Indiana expects high inflation, low GDP, and low customer growth under this scenario. Erik stated AES Indiana expects coal to continue to operate under this scenario, which combined with expanded gas production, causes gas prices to decrease. Erik noted the power price is currently listed as TBD because it is in production with Horizon Energy, and AES Indiana will provide that information and discuss further in the next meeting. Erik then detailed the load assumptions for the No Environmental Action scenario. He explained the solid blue line in the chart on slide 105 is the relevant load forecast and the other lines are present to provide context.

He stated Mike Russo explained the different load forecasts earlier in the presentation, and the No Environmental Action scenario will use the low case load forecast, low case EV forecast, and low case distributed solar forecast. Erik noted these forecasts do not include future DSM, which are considered supply side resources selected in the capacity expansion model. Erik then discussed the No Environmental Action environmental policy assumptions, which assumes ITC and PTC will not get extended, which means ITC will decline to 10% by 2028 and remain at 10% through the analysis period, while the PTC with Safe Harbor stay at 60% through 2027. Erik explained while the PTC expires at the end of 2022, Safe Harbor allows developers who completed even minor construction by the end of 2022 for a qualifying project to take advantage of the PTC. Erik stated AES Indiana assumes no carbon tax and no additional coal fired production costs for the No Environmental Action scenario.

Erik next described the Reference Scenario/Current Trends scenario in greater detail. He stated in this scenario, it is assumed congressional gridlock persists and any effort to pass sweeping environmental legislation is stalled (i.e., the Build Back Better Act does not pass). He explained five-year ITC and PTC extensions are assumed and a modest carbon price starting at $6.49/ton in the late 2020s, which is consistent with 1/3 of the value of the Social Cost of Carbon as calculated by the US Government Interagency Working Group on Social Cost of Greenhouse Gasses. He stated the Current Trends scenario uses the base case load forecast with base Moody's economic assumptions, base case EV market share of 22% in 2042, and base case distributed solar forecast market adoption of 15% in 2042. He next detailed the Current Trends environmental policy assumptions, which assumes a five-year extension of ITC and PTC, with ITC staying at 26% until declining to 10% by 2032 and remining at 10% through the analysis period, while PTC safe harbor period expires in 2032.

Stakeholder Ben Inskeep asked Erik to reconsider the carbon price option because the US Government Interagency Working Group on Social Cost of Greenhouse Gasses cautions against using a single estimate, particularly the lowest of the four values they estimate as Ben is concerned that value may not be indicative of the actual cost of carbon calculated in that report. Ben also added it would be worthwhile to model the initial starting price, whatever AES Indiana determines is appropriate and having that rate increasing at a rate above the inflation rate because carbon pricing mechanisms tend to escalate the price across time as it ratches up in terms of the carbon pricing mechanism. Erik Miller stated AES Indiana appreciates Ben's comments. Erik stated for this scenario, he believes there should be some carbon available in the late 2020s, and considering the trends in the market, Erik believes the carbon estimates using the Current Trends scenario is modest. However, Erik stated he would be willing to take Ben's concern offline to better understand his perspective and his thoughts on the issue. Erik noted there are more aggressive environmental scenarios that he has not yet addressed, but Erik would certainly appreciate to hear Ben's input. Ben thanked Erik for his response.

Erik Miller next detailed the Aggressive Environmental scenario, which assumes Congress passes sweeping environmental legislation (i.e., the Build Back Better Act) that incorporates key components of the Build Back Better Act, including adding a carbon tax and granting a 10-year extension of ITC and PTC. Erik explained the short-term transition from coal to gas is a result of the legislation would cause the demand for gas to increase, so AES Indiana used a high natural gas price for this scenario. Erik explained the load forecast for the Aggressive Environmental scenario will use the high economic forecast, the high EV forecast, and the high distributed solar forecast and noted the dip in load seen in the chart on slide 109 is due to the bass diffusion model for distributed solar participation leveling off in the mid-2030s. Erik also noted the Aggressive Environmental scenario adds a $26.64/ton carbon tax in 2035 and escalating at 5% per year through the planning period, as well as imposes additional costs for coal ash disposal.

Stakeholder Ben Inskeep stated he is happy to discuss offline, but he does not believe a $26.64/ton carbon tax beginning in 2035 is a particularly “aggressive” environmental policy, and he requests some additional consideration of this modeling input. AES Indiana thanked Ben for his feedback.

Erik then detailed the final scenario, the Decarbonized Economy scenario, which assumes Congress passes aggressive decarbonization mandate on power sector with explicit renewable energy targets, high ITC/PTC through planning horizon, carbon targets achieved through a Renewable Portfolio Standard that targets Net Zero (not a market mechanism like a carbon tax or cap and trade), high load driven by electrification, and base gas prices driven by low demand due to reduced gas generation. Erik detailed the load forecast for the Decarbonized Economy uses the high economic case, the very high EV market share case at 85% adoption in 2042, and the high distributed solar forecast with adoption of 29% in 2042. Erik then discussed the environmental policy assumptions, which assumes 30% ITC through the planning period; 100% PTC through the entire period; no carbon tax, rather a Renewable Portfolio Standard similar to the Clean Energy Performance Program the Biden Administration proposed last year (i.e., 85% clean energy by 2042 with penalty if not met); and additional coal-fired production costs, including additional costs for coal ash disposal and high ozone season NO_x price forecast.

Erik Miller then presented a summary of the scenario driving assumption on slide 116. He noted the base case for coal was used for all scenarios and explained the difference between the base and low cases for coal were minimal and the low forecast was actually higher than the base forecast in some years, so AES Indiana believes the base scenario captures coal is near its demand floor and does not believe it is necessary to change it for the different scenarios.

Erik Miller next described the IRP Portfolio Matrix takes the four strategies (No Early Retirement, Petersburg Refuel, One Petersburg Unit Retires in 2026, and Bother Petersburg Units Retire in 2026 and 2028) and evaluates them across the four scenarios (No Environmental Action, Current Trends/Reference Case, Aggressive Environmental, and Decarbonized Economy) to arrive at the Portfolio Matrix. Erik noted AES Indiana will run the capacity expansion model across each of these scenarios so each portfolio will have a PVRR. Erik further elaborated AES Indiana will then evaluate each of the portfolios against a scorecard that includes cost, environmental, reliability, and risk metrics. Erik noted AES Indiana will work with Quanta to develop reliability metrics. Erik explained once the portfolios have been evaluated against the scorecard, AES Indiana will select its preferred resource portfolio.

Stakeholder Bruce Russell-Jayne asked AES Indiana if it could not include its own desire to reduce its carbon output in this matrix. AES Indiana replied it, like all utilities in the state, is legally required to engage in a rigorous stakeholder engagement process when determining future plans for generation resources. AES Corporation and AES Indiana take this responsibility seriously and will meet all obligations in this IRP process, which is currently under way for 2022, and the IRP outcome is subject to approval by Indiana regulators. Through a combination of asset sales, fuel conversions, and retirements, this plan is conditioned upon maintaining reliability and affordability for customers and is subject to regulations and approvals on the local, regional, and national levels; the conditions and necessary approvals may impact the pace of meeting this decarbonization goal.

Erik Miller then provided a preview for the risk analysis around sensitivities and stochastics, which will be discussed in greater detail in Public Advisory Meeting #3. He explained AES Indiana plans to model sensitivities for key variables to understand how the PVRR may change in a future where the variable looks very different from the IRP assumption (e.g., renewable capital cost sensitivity). Erik then stated AES Indiana will run portfolio sensitives, which allows AES Indiana to assess the changes to the PVRR of portfolios based on changes to the policy future. He then explained AES Indiana will run a stochastic analysis on fuel prices, energy prices, and load to understand the risk to PVRR in the Reference Case from these key IRP variables.

Final Q&A and Next Steps

Erik Miller, Manager, Resource Planning, AES Indiana
(Slides 120 – 122)

Stakeholder Bruce Russell-Jayne stated AES Indiana's IRP matrix does not mention AES's desire to reduce its carbon footprint and the matrix seems to be policy and externally driven. Bruce asked Erik Miller why AES Indiana does not include its own desire to reduce the carbon its emitting. Erik stated the AES Corporation has certain global objectives, but AES Indiana operates in the state of Indiana and is required to engage in a regulatory process through its IRP where it engages with stakeholders to work through the process. Several stakeholders requested to hear AES Indiana's response to Bruce's question, so Moderator Stewart Ramsay read AES Indiana's response that came through the Microsoft Teams chat function noted in the meeting minutes above.

Stakeholder Bhawramaett Broehm asked Erik Miller if AES Indiana will perform any sub-hourly dispatch modeling to quantify the value/need for flexible and responsive resources. Bhawramaett noted the EnCompass model is being solved on an hourly basis and asked if there would be any attempt to do model on a sub-hourly basis to understand price volatility risks that come from variable renewables resources' ability to provide sub-hourly ancillary service benefits. Erik responded the EnCompass model uses hourly data, so AES Indiana only has plans to do hourly analysis. Erik noted he has seen other utilities use sub-hourly modeling to capture the ancillary service value of batteries and other resources, but AES Indiana does not currently have plans to do that; however, it is an item AES Indiana is willing to consider. Bhawramaett thanked Erik for his response.

Stakeholder Bhawramaett Broehm asked AES Indiana if there is an email address that stakeholders can use to contact to ask additional questions after the Public Advisory Meeting. AES Indiana provided its IRP email address, aesindianairp@aes.com.

Erik Miller lastly guided stakeholders through a timeline of AES Indiana's Public Advisory Meeting process. He noted Public Advisory Meeting #3 is expected to occur in June, Public Advisory Meeting #4 is expected to occur in August, and Public Advisory Meeting #5 is expected to occur in October. Erik mentioned there have been questions around in-person meetings and shared he hopes to meet in-person, but AES Indiana will continue to monitor COVID-19 and will assess the situation closer to the meetings. He reminded stakeholders AES Indiana's IRP materials can be accessed online at https://www.aesindiana.com/request-proposals-rfp.

Stakeholder Anna Sommer asked AES Indiana when it expects to have a schedule for sharing modeling files. Erik Miller replied AES Indiana will send assumption files and a lot of the items that have been covered in the Public Advisory meetings so far within a week of Public Advisory Meeting #3. Erik noted AES Indiana is still working on the modeling files, which will probably be ready in the next few months, but AES Indiana communicate with stakeholders on the availability of modeling files.

Erik Miller concluded the meeting by thanking stakeholders for their time and participation.