Indianapolis Power & Light Company
2016 IRP Public Advisory Meeting #4
September 16, 2016

Meeting Summary

Welcome & Safety Message
Bill Henley, IPL Vice President of Regulatory & Government Affairs

Bill Henley introduced himself and welcomed participants. He thanked everyone for attending Indianapolis Power & Light Company's (IPL) fourth and last public advisory committee meeting for the 2016 Integrated Resource Plan (IRP).Mr. Henley also thanked Barnes and Thornburg for hosting the meeting. IPL's intentions for this meeting are to share final modeling results, listen to participants, and foster trust and confidence. Mr. Henley expressed appreciation for all the feedback that stakeholders have offered throughout the process and acknowledged people's deep commitment to these issues and to the process.

He introduced Teri Tillery to give a safety message. Ms. Tillery noted that September is National Preparedness Month, for which the message is "Don't Wait, Communicate – Make Your Emergency Plan Today". She suggested that people make their own plans and talk with their neighbors as well. In the event of any problems in the room today, she outlined emergency exit procedures.

Mr. Rafael Sanchez, President of IPL, also thanked staff and participants for their time and effort in preparing materials for this year's stakeholder workshops and for the engaged attendance.

Introductions & Meeting Objectives, Agenda Review, Guidelines
Dr. Marty Rozelle, The Rozelle Group Ltd.
(slides 3-6)

Dr. Rozelle welcomed participants. She reminded those in the room to use the microphones so that phone participants can hear. She asked everyone to introduce themselves. The agenda is quite full today, as always. She provided an overview of the agenda and described the group discussions that will occur after lunch. She encouraged participants to take notes and write down their questions as we go along. Those on the phone should use the webinar chat feature to ask questions. She asked stakeholders to please send any additional comments they might have after this meeting to IPL by September 23. The summary of this meeting will be posted to the website by October 7.

Summary & Feedback from IRP Public Advisory Meeting #3
Joan Soller, IPL Director of Resource Planning
(slides 7 - 12)

Joan Soller introduced herself by saying that she's been with IPL for seven years and has worked on resource planning for two years. She reviewed the topics to be discussed today. She showed a slide indicating the six scenarios studied and how the main drivers were used in each.

The drivers include load forecasts, natural gas and market price, Clean Power Plan and environment, and distributed generation.

Ms. Soller told participants that the Quick Transition scenario has been modified in response to stakeholder comments at the August meeting. The original Quick Transition scenario was presented in Meeting 3 which included retiring Petersburg coal units in 2030. Modifications to the Quick Transition portfolio included retiring Petersburg Unit 1 and refueling Units 2, 3, and 4 in 2022, the maximum achievable demand side management (DSM), and supplemented remaining capacity requirements with solar, wind, and batteries in 2030. These modifications increased the cost of the portfolio by about $600 million. The greatest changes in the generating resource portfolio occurred between the initial Quick Transition portfolio and final Quick Transition portfolio in 2022 as displayed in the meeting materials.

Guiding Principles and Assumptions
Joan Soller
(slides 13 - 18)

Ms. Soller reviewed IPL's guiding principles and assumptions for the 2016 IRP. The company will always comply with the Indiana Utility Regulatory Commission's (IURC) rules and orders as well as other regulatory and reliability requirements. Cost estimates for demand and supply side resources are based on local economics and recent market experiences. IPL is agnostic to the resource mix in the portfolio plans, and the model is also agnostic to resource ownership.

Regarding demand side management principles, DSM is modeled as a selectable resource, which is a change from previous years. IPL will offer DSM programs that are inclusive for customers in all classes.

Assumptions that are considered consistent for the entire study period are that the regulatory framework will stay the same in Indiana, and that the MISO (Midcontinent Independent System Operator) capacity construct will stay the same. She noted that MISO will file changes for the 2018-19 planning year. MISO's changes are uncertain at this time, therefore IPL assumed that the capacity construct stays the same within the study period. IPL will continue to participate in the MISO stakeholder process as changes are discussed. Additionally, natural gas and market price correlation trends are assumed to be the same at 80-90% historically, and distributed generation (DG) is synchronized with the distribution system and does not need to be curtailed, e.g. for transmission congestion.

She noted that some changes may affect future portfolios. These include future technology enhancements such as combustion turbine design. The upcoming national election could affect pending environmental regulation, public policy, and tax credits. Stakeholder sustainability interests may also evolve in the future.

Participant questions and comments included the following:

- What does "agnostic to resource ownership" mean? Differences in resource ownership can have effects on generation, so how does the model account for this? For example, the participant noted differences in how purchase power agreements (PPAs) are handled. She thinks there are market differences between owning the asset and using a PPA.

  - PPAs are based on foundational costs, which would be similar in terms of construction and operating & maintenance costs, so purchase power agreements aren't modeled separately due to model limitation especially with all the DSM that's included as a selectable resource. IPL applies the known economics of existing resources to future resources. This does not mean that IPL expects to own every resource, and RFPs are issued for new resources as well. (IPL is in the process of scheduling a follow up meeting with this meeting participant).

- Does slide 9 summarize all the modeling changes that were made in all the scenarios?
  - Yes. Resources are the same for all scenarios, so they are inclusive and the model can choose any of them.

Final Model Results
Diane Crockett, Principal Consultant, ABB
(Slides 19 – 41)

Diane Crockett introduced herself as IPL's consultant who performed the modeling for the 2016 IRP. She has worked for ABB for 15 years and Kansas City Power and Light before that. She reviewed the portfolio development process that included using sequential model results for load forecasts, DSM MPS, and the ABB Reference Case as inputs to the *Capacity Expansion* module to develop portfolios, the *Strategic Planning* module to perform sensitivity analysis, and the *Risk* module to evaluate performance metrics.

The six scenarios modeled were:

- Base Case
  - With Sensitivity: Base Case with Delayed Clean Power Plan
  - With Sensitivity: Base Case with High Carbon Tax
- Robust Economy
- Recession Economy
- Strengthened Environmental Regulations
- Distributed Generation
- Quick Transition

The resource technology options included are simple cycle gas turbine, combined cycle gas turbine, nuclear, wind, solar, community solar, energy storage, combined heat and power, demand side management, and market purchases. Fuel sources are natural gas, oil, and coal. Ms. Crockett showed scenario capacity mix for the six scenarios in 2036.

She reviewed the megawatt (MW) operating capacity and planning capacity of various resource options, e.g. new wind receives 10% planning capacity credit. Most resources are dispatched based on operating costs resulting in specific capacity factors for each resource. Wind (35% capacity factor) and solar (17% capacity factor) are inputs to the model with hourly energy profiles developed to represent those technologies for the Indiana area based on existing experience. Current legislation that provides for production tax credits and investment tax credits were also modeled.

The stakeholder group had several questions:

- Are these the capacity factors MISO uses? It would be helpful to have this information for each resource.
    - Joan answered: These are factors, not ratings. MISO gives 0% capacity rating for planning purposes right now if the wind does not have firm transmission service. The 35% capacity factor is an industry average, and IPL is assuming that transmission facilities will be built to accommodate additional wind generation.
- Why is there no coal in the Recession Economy scenario?
    - More detail will be provided later. There are low load forecasts and low gas prices in this scenario, so it's more economical to refuel coal units than to keep them as coal.
- Do you mean you can't count any planned resources in MISO? It's typical to use 15.6% in an IRP assuming wind will have capacity value when it comes on line.
    - Joan answered: There may be some confusion here. MISO has a planning reserve margin requirement of about 15%. Wind only receives credit toward that total capacity requirement if there is firm transmission available, which we don't have now. MISO uses 10-12% for future years, but IPL uses more assuming transmission will be available.
- Which ABB models did you use? Are you combining the results of both models to get PVRR? Why was wind accredited at 10%?
    - We used *ABB Capacity Expansion* module to do optimization. We input all resources, DSM, and assumptions about scenarios and this gave us the optimal resource plan. The *Strategic Planning* model uses expansion plans run on an hourly basis. The *Strategic Planning* model has all capital costs and operating costs. No, we don't combine the models.
    - Joan answered: The MISO wind capacity number is interesting but it's not the best assumption to use for Indiana assets, since there are existing and future resources available in Indiana and Minnesota. The Equivalent Load Carrying Capacity (ELCC) Indiana zone is 9.6% and we don't have transmission capacity; this may change.
- On Slide 21, community solar is a resource alternative – is that an alternative from a policy and legislative perspective? She thought community solar was not permitted in Indiana.
    - Joan answered: IPL modeling used the production output curves based on IPL's existing Solar REP PPAs. We assume the community solar asset would be based on Indiana assets. A 1-MW site is typically connected to the distribution system, so it's Indiana-specific. The model does not look at ownership, but selects resources based on economics, not who owns the asset. But you're correct that customers owning an asset together and producing their own power is not permissible in Indiana. . But there could be a short-term offering that is IPL owned or we could work with a third party to offer this service to IPL customers. This community solar resource alternative is modeled more broadly.
- Why is there a limit of 200 MW on nuclear? This should be explained a bit more. Can you test this based on IPL's history?
    - We looked at the smallest amount of capacity IPL could buy (capacity of simple cycle, which is about 180 MWs), so we used 200 MW as the limit on all

resources that would be over that. If it's more economic to buy market resources (set at 50 MW limit), it's cheaper than installing new capacity. IPL has a lot of capacity now, so there is not a short term need to buy capacity. However, historically, IPL has purchased capacity (300 MW this year) to bridge the gap between Eagle Valley unit retirements and construction of the new Eagle Valley unit but we don't intend to rely on the market heavily in future.

Ms. Crockett showed the estimated costs in present value of revenue requirement (PVRR) for the six plans and two sensitivities. Present value revenue requirements are the annual revenue requirements that the system needs which includes annual operating costs, plus a return on rate base for new assets and upgrades to coal units, but no ongoing capital maintenance – these are incremental costs. She explained that each portfolio developed in the *Capacity Expansion* model was modeled against the Base Case assumptions for this particular analysis, which is important to remember. So, for example, the answer to the previous question about why there is no coal in the Recession Economy scenario is there was a low load forecast combined with low gas and low market prices; when the model saw this it chose to refuel the units rather than keep them as coal.

Questions included:

- Please clarify that these PVRR are only future capital costs.
    - No, these include operating costs and capital costs plus some fixed costs. Some costs of doing business are not included such as administrative and general or transmission & distribution.
- A participant suggested that using a baseline of $6 billion instead of zero on this graphic is misleading.

<u>Post Meeting Follow Up</u>:
IPL intends to represent the results in the IRP narrative based on this participant's suggestion.

- Regarding adoption of distributed generation, it was noted that DG costs are borne by the owners, not by IPL customers, so that it seems logical that the cost to customers should be least in the Adoption of DG scenario. Given this, wouldn't IPL be encouraging use of DG?
    - We're showing all costs related to serving base load requirements. This scenario embedded DG, but the model did not select it based on economics. Remember the model doesn't care who owns DG.

Ms. Crockett provided details of model inputs, assumptions, and results of the modeling for each scenario. She explained how to interpret the energy mix graphics shown for each. The discussions and stakeholder questions are summarized below.

<u>Base Case:</u>
The sensitivity variable in the Base Case was carbon price. Sensitivities included delayed CPP to 2030 along with higher gas prices, and the high carbon tax starting in 2022 with correlated gas prices.

The base case capacity was illustrated. In this case there are no additions until 2033 except for DSM. Petersburg Units 1 and 2 are retired in 2032 and 2034. No wind capacity rating until 2030. Combined cycle is added in 2034. Regarding the energy mix, on average IPL is "long" on energy production and sells to the market in the Base Case.

- On Slide 25 and others, please explain the purple band for battery.
    - Future maximum wind capacity was 1000 MW in the Base Case scenario, which was intentionally limited for reliability purposes. The model selected more batteries as a least cost future resource in this scenario to meet the reserve margin compared to the Robust Economy scenario, for example, where wind was not constrained, so not as much battery was needed.

<u>Robust Economy:</u>
In the Robust Economy scenario, market purchases are needed in later periods, and until then IPL is over its needed capacity. Significantly more wind is added (3500 MWs), as reflected in the energy mix illustration.

<u>Recession Economy:</u>
In this scenario there is a low load forecast and low gas and market prices. Petersburg 1 - 4 would be refueled. IPL will be short on capacity towards the end of the period, and will not meet reserve requirements starting in 2033. When this portfolio is modeled against the base assumptions, the refueled units do not run as much as they did with the low gas/market prices. This plan is more expensive because more market purchases are needed to account for energy deficit situations at times.

- What are the characteristics of power plants that cause you to have an energy shortfall constraint?
    - The power plant characteristics do not create the energy shortfall. Market conditions affect unit dispatch. The capacity factors of refueled Pete units are a lot lower than a new CCGT due to higher production cost to run the units, so it is cheaper to buy from the market.
- So, why wouldn't converting Pete units to gas not be a reliable way to provide energy?
    - The Pete units are reliability, just less economic in this scenario. It's just cheaper to make market purchases in this scenario, if gas prices go up. Capacity factors will be explained in more detail later.
- Why would DSM not be included in a peak load scenario?
    - DSM is a direct reduction to load. We're showing it as a selectable resource, so don't want to double count.
- A participant noted that at NIPSCO's recent workshop they showed each unit and associated costs, and costs at which they became uneconomical. At what gas price would the model choose to refuel? She suggested including this in the final IRP.
    - The "low" gas price would be the operative variable. We haven't done an analysis on specific prices.

> **<u>Post Meeting Follow Up</u>**:
> IPL intends to represent the results in the IRP narrative based on this participant's suggestion.

- When you have excess capacity today, why would you refuel all 4 Petersburg units rather than retiring some?
    - The cost of capital to replace them later is outweighed by the cost of keeping these units in the system.
- Do you scale up DSM impacts to account for the fact it doesn't need to be covered by a reserve margin?
    - Yes

<u>Strengthened Environmental:</u>
In this scenario 20% of energy requirements will be met by renewables by 2022. We assumed higher upgrade costs, so the model selected retirements. Wind and solar were selected prior to 2020 to take advantage of tax credits because of the need to meet a renewable portfolio standard (RPS) early. Consequently, PVRR went up. For energy, market purchases were required mainly because of high carbon tax that also drives retirements.

<u>High Customer Adoption of DG:</u>
This portfolio looks a lot like the base except the DG resources were not economically added by the Capacity Expansion Model. This scenario meets capacity needs at all times.

> **<u>Post Meeting Follow Up</u>**:
> After the meeting, IPL noticed an error on the High Customer Adoption of DG Capacity Factor Appendix slide.
> Slide 114 shows revised results.

<u>Quick Transition:</u>
This scenario shows no coal by 2030. This leaves a 51% capacity deficit which was filled by equal parts photovoltaic solar (PV), battery, and wind. The energy graph shows market purchases starting in 2022. All DSM that passed the market potential study (42 groups) were included to help meet the energy requirement.

The reserve margins for all six portfolios were shown. Capacity factors for scenarios were illustrated. For the Base Case coal units are not refueled. Coal unit and Eagle Valley capacity factors drop thru time as a result of the carbon tax. CO_2 tax was developed to meet the 32 percent reduction by 2030. In addition, it was further refined to reflect the CO_2 tax that would be required to meet the interim targets. There is a step change between 2024-2025, 2027-2028 and 2029-2030. That is why you see the Eagle Valley & coal units responding to the changes in CO_2 tax and market prices. Ms. Crockett explained that the green line in the charts is the capacity factor for existing wind, which is assumed to be replaced by units with a 35%-capacity factor around 2029. Petersburg Units 2 and 4 are refueled to gas in Strengthened Environmental scenario because the carbon tax is much higher.

The stakeholders' questions and comments included the following:

- Are you losing opportunity sales by declining Petersburg capacity factors?
    - Yes
- Please explain the Harding Street 5-7 capacity factor. Why is it below 10%?
    - The Harding Street units provide peak energy resulting in low capacity factors. They also provide planning capacity value in MISO.
- The capacity factor for the coal plants shown here are much higher than today's operation – why? What changes in the market prompt this?
    - Recent natural gas prices have been lower in some months than the forecasted natural gas prices. Actual experience may always be different from historical operation.
- Petersburg had 60% capacity factor in 2015 – why is it so much less here?
    - The model looks at dispatch cost on an hourly basis. If the dispatch cost is less than the market price, the unit will be dispatched and will sell energy into the market. The capacity is sold into the market also at a price. Load is bought back from the market at that same capacity price plus the 15% reserve margin requirement.

Preferred Resource Portfolio
Joan Soller
(Slides 42 – 46)

Ms. Soller pointed out that some of the reasoning behind the preferred portfolio selection is based on the metrics and sensitivities that will be presented later. IPL evaluated the most likely inputs and most probable risks known at this time. The primary selection criterion is least cost to customers as reflected in the PVRR. Other metrics included environmental impacts, rate impacts, market reliance, and risk exposure. She pointed out that IPL does not use a "scorecard" but considers all these factors qualitatively.

She told the group that the Base Case is the preferred portfolio, as it has the lowest PVRR and most favorable risk tradeoff. The Base Case portfolio includes the following components:

- Upgrade Petersburg units for NAAQs-SO2 and CCR compliance (1700 MW)
- Implement 206 MW of DSM
- Retire oil-fired units at Harding Street (32 MW)
- Retire Harding Street natural gas Units 5, 6, and 7 (628 MW)
- Retire Petersburg coal-fired Units 1 and 2 (651 MW)
- Purchase 200 MW capacity
- Add 1000 MW of wind
- Add 100 MW of solar
- Add 500 MW of battery storage for peaking capacity
- Add 450 MW of combined cycle gas turbines

A reliability concern in this scenario is transmission capacity, which IPL will continue to analyze in the future to determine what can be done to upgrade the system. IPL transmission planners state that this resource mix can't be sustained, since there is a 2000 MW import limitation and this scenario included a 3000 MW import capacity.

Stakeholders asked:

- Regarding transmission constraints, what do costs look like for handling DG on the distribution system rather than the transmission system? DG might eliminate some of the transmission constraints.
  - DG does reduce the requirement to import energy on the transmission system. The IRP will describe this in more detail.
- For energy storage, will there be batteries in different locations? They are all at Harding Street now.
  - The batteries assumed in this portfolio can be charged by any unit on the138kV system, so they can be located anywhere.

Metrics and Sensitivity Analysis Results
Megan Ottesen, IPL Regulatory Analyst
Patrick Maguire, Director, Corporate Planning & Analysis
(Slides 48 – 84)

Megan Ottesen reminded participants about the metrics exercise that was conducted at the June workshop, and said that the results were used in this analysis. She showed "scores" for the top metrics of interest to stakeholders. There were 10 metrics across 4 categories.

Patrick Maguire explained the process used to evaluate metrics. A deterministic capacity expansion model was run, and a production cost model was run with the base assumptions for all portfolios. Then stochastic modeling and risk analyses were conducted. He explained that deterministic models will select a single variable changed by a fixed amount. Environmental variables for delayed CPP and high carbon costs were the deterministic sensitivities modeled. This results in a deterministic PVRR for each environmental sensitivity. Stochastic models change multiple variables randomly, with ranges bound by estimated probability. This approach resulted in 50 model iterations for each portfolio.

PVRR is the traditional metric relied upon. The PVRR for each scenario over a 5-year period divided by total generation over the period provides the cost per megawatt hour. This provides a basis for estimating rate impacts, which were illustrated for each scenario over the planning period. The Base Case, with the sensitivity of delayed Clean Power Plan implementation is the lowest cost, and the Base Case is the next lowest.

Financial risk exposure shows the range of risk across portfolios. The Recession Economy scenario has the greatest range of potential risk, or most uncertainty, for example. The Strengthened Environmental case eliminates some risks by converting units under high carbon prices, but overall costs of the portfolio are higher because of that.

- How do you define mitigation costs for these risks?

- We'll talk about those more later. Although we assume equal probability of risks across the board, mitigation costs can be figured out but are not included here. We assume correlations of variables, such as gas price, coal price and load.

- Stochastic modeling needs to define distribution of the variables, so do you agree that the accuracy of this modeling depends on the distribution you use?
  - Yes, we worked on this with ABB, to look at 10 different variables for risk, e.g. coal/gas price, availability, capital costs.

<u>Post Meeting Follow Up</u>:
The ten variables considered are –
- resource technology cost
- coal prices
- oil prices
- coal unit availability
- gas unit availability
- natural gas prices
- energy load forecast
- peak load forecast
- carbon prices

IPL stochastic modeling also looked at –
- long-term combined cycle capital cost
- long-term wind and solar capital cost
- long-term utility scale and community solar capital cost
- long-term battery storage capital cost

- Will your IRP report include all modeling data?
  - No, but you can sign a non-disclosure agreement if you would like to see it.

Mr. Maguire showed a series of "tornado charts" that show impacts of drivers – or specific variables – across the scenarios. He explained that the vertical lines show the expected value in PVRR, broken into each driver; drivers are energy (megawatt hours), gas price, coal price, peak load, and carbon price. The charts illustrated the biggest drivers that contribute to costs in each scenario in the 2017-26 and 2027-36 planning horizons.

<u>Post Meeting Follow Up</u>:
After the meeting, an error was noticed on Slide 64.
Independent and Dependent labels were switched.
This is now corrected in the deck.

A participant noted that rate impacts from customer adoption of DG are not comparable since customers bear these costs individually. He shares other stakeholders' concerns about how DG is addressed and would like more information for a better understanding.

Ms. Ottesen discussed the environmental metrics, including average annual carbon dioxide (CO_2) emissions, sulfur dioxide (SO_2) emissions, and nitrogen oxides (NO_x) emissions over the period, showing emissions profiles estimated for the various scenarios. The Strengthened Environmental and Recession Economy scenarios have the lowest overall emissions.

Planning reserves included base assumptions for each scenario. An illustration showed how the scenarios would meet the reserve requirement over the planning horizon, which all but the Recession Economy scenario would do.

- Why is the reserve margin so high for portfolios that include refueling?
  - This estimate is based upon capacity expansion model results, which refuel 3 to 4 units.

For the DG penetration metric, Ms. Ottesen said that the model selected DG when economical for each scenario in all timeframes. She showed a chart indicating what this penetration would be, ranging from 1% to 10%.

<u>Post Meeting Follow Up</u>:
The calculation presented at the meeting included IPL's existing solar DG, but not additional solar. Since Public Advisory Meeting 4, IPL has changed the calculation to also include all new solar additions, as they will likely be added to IPL's distribution system.

The metric category of Resiliency looks at the need to make energy purchases from the market. She explained how this was calculated. The Base, Robust Economy, and Adoption of DG scenarios have the lowest reliance on market purchases. The Base Case has about 4% market reliance.

- Would IPL realistically purchase such high levels of energy from the market as shown on some of these options?
  - No, probably not.
- This stakeholder thought, therefore, that these scenarios are not realistic, and the portfolios are not useful in comparison to the Base Case.

Ms. Ottesen summarized the analysis by saying that the Base Case has the lowest cost; the risk exposure is similar for all scenarios; environmental stewardship is enhanced when peak units convert to natural gas or retire; the Recession Economy results in the lowest planning reserves; DG was not selected as an economic resource but was added to the Adoption of DG scenario; and there is little market reliance for capacity purchases across scenarios.

Participants had the following questions and observations:

- How was social equity accounted for in this metrics analysis? Was it included? How?

    - It was not defined, nor was it included in the analysis because of the difficulty of defining measures for it. It will be included in the narrative for the IRP. Ms. Soller invited further discussion and participation by stakeholders in defining this for the future.
- What interest rate was used?
    - 5.61% discount rate, or the current cost of capital.
- When IPL comes forward with a request for a specific project, will it be consistent with what was included in the IRP? This is a question for all IRP planning. This may end up with "uncomfortable" discussions.

LUNCH

Analysis Observations
Joan Soller
(Slides 86 - 90)

Joan Soller provided some observations about the IRP analysis to date. She thanked everyone again for the engaged discussion this morning. The expansion plan creates these portfolios based on a set of assumptions, but the operation of the portfolio uses the base case assumptions (where gas prices are lower and market prices are lower).

In the first meeting IPL proposed some changes to the way the scenarios are evaluated by adding metrics other than cost. For this IRP, the risk analysis was more robust, DSM was included more fully, more probabilistic methods were used, and the stakeholder process was enhanced with more interactive exercises.

Ms. Soller emphasized that stakeholder input has really shaped the modeling process. Metrics have informed the discussions. She reminded participants that the ultimate resource portfolio could differ from the model results if assumptions are different from the Base Case. The variety of capacity factors is due to the way resources perform under different scenarios. Wholesale energy and capacity sales offset revenue requirements. IPL will continue to evaluate the use of batteries with renewable resources. The blackstart units at Harding Street (32 MW) are retired in all scenarios. She noted that energy requirements and gas prices tend to be the most influential drivers of the scenario results.

Participants asked:

- Where do fuel prices come from?
    - Natural gas prices are from the ABB model, and coal prices reflect short term contracts enhanced with IPL/ABB forecasts.
- What battery technology are you assuming?
    - Lithium ion batteries. The assumed costs are proprietary.
- A stakeholder observed that a limitation on market purchases is a sensible approach. The stakeholder asked that IPL be aware that scenarios need to be realistic.

Discussion of Results
Marty Rozelle

Marty Rozelle introduced the small group discussions to talk about the information that has been presented today. She asked participants to move to tables based on the colored dots on their name tags. Participants should complete the worksheets individually and then discuss them in your groups. There will be a report from each of the three tables at the end.

Discussion points from the stakeholder groups are summarized below. Several individual comment sheets were also submitted and will be considered by IPL in finalizing the IRP.

1. What is your opinion of the preferred resource portfolio?

Meeting Participants Responded:

Regarding coal retirements, consider how the Base Case complies with the Clean Power Plan including the clean energy incentive program, and how it could be a model option in future, including community solar as an option. NIPSCO has tried to address this issue in its workshops this year. There should be a societal metric for the societal cost test. If results vary significantly, how might this affect the choice of a preferred plan? Evaluate more fully how to look at rate impacts from DG.

There was a question about whether this IRP is a continuation of prior IRPs. IPL responded that it is not, and they are starting from a clean slate.

It was suggested that the way in which DSM information is presented should be comparable to IURC filings, e.g. incremental DSM, to compare “apples to apples”.

This approach to the preferred portfolio is too much status quo, given that it is not until 2023 that the generation mix is changed. To be a modern city we need to take a fresh look at how we generate electricity. On the other hand, we need to consider that lower electric rates help to keep and attract jobs and economic development. Several participants mentioned health benefits and impacts.

Some participants thought that it has been difficult to understand how the preferred plan was decided; more or clearer information is needed.

It was observed that the Adoption of DG scenario having higher emissions than the Base Case doesn’t make any sense.

Energy should apply to solar and other technologies and not just to wind.

There was discussion on types of batteries modeled and used as well as discussion about CCGT technology types.

Clarification was requested about how regional trends fit into model assumptions, e.g. development and prices.

2. Did the portfolios vary as much as you expected? If not, how might scenario assumptions be modified to produce more varied results?

Meeting Participants responded:

Groups did not offer any observation on this question.

3. What is your opinion of the metrics results? Please refer to the metrics handout for more information.

Meeting Participants responded:

There was a request to provide more information about how emissions vary over time.

Post Meeting Follow Up:

Emissions information will be presented in the IRP report.

4. Do any specific metric results surprise you?

It was suggested that metering rules as currently implemented might not apply to future DG efforts.

The difference in cost of less than $.01 per kilowatt hour between the Base Case and Quick Transition scenarios was surprising.

Short Term Action Plan
Joan Soller
(Slides 92 - 97)

Joan Soller told the group that the short term action plan is a requirement of the IURC. She reported the items that IPL has completed from the 2014 short term action plan include:
Eagle Valley coals Units 3-6 have been retired.
Harding Street Units 5-6 have been converted from coal to gas.
Petersburg units have been retrofitted to comply with mercury and air toxics regulations.
IPL has secured market capacity purchases for 2015 to 2017.
A 20-MW battery storage system has been installed at Harding Street.

Items that are in progress from 2014 include:
Implement DSM for 2015-17.
Construct a CCGT at Eagle Valley.
Complete transmission projects for the Eagle Valley CCGT.
Retrofit Petersburg and Harding Street for NPDES water quality compliance.
Support Blue Indy electric car sharing program. 74 of 200 locations are complete.

In coming years, IPL plans to continue implementing DSM programs, complete Eagle Valley CCGT and NAAQs-SO_2 and CCR compliance at Petersburg. For the 2016 short-term action plan, between now and the next 2019 IRP, IPL would like to:

Analyze smart meter data for more granular load forecasting.
Refine DSM modeling.
Research MISO transmission congestion forecasts.
Assess 138 kV voltage stability options.
Refine frequency and reactive support requirements of new wind assets.
Conduct a study confirming benefits of batteries with renewables.

IRP Public Advisory Process Feedback
Joan Soller & Marty Rozelle
(Slides 99 - 101)

Marty Rozelle referred participants to a handout of questions to prompt thoughts and suggestions from stakeholders about the current public consultation process. Their responses are summarized below.

Large group discussion

1. Did you find the stakeholder presentations helpful?
   - Stakeholder presentations were excellent. But CAC probably won't offer any in the future since they are involved in rate cases.
   - NAACP appreciated being able to possibly influence the process and offer thoughts and ideas.

2. Do you recommend IPL continue them in the future?
   - Yes

3. What topics can IPL expand on in future?
   - Laurel Mountain wind/battery project in WV, highlight, use as example.
   - AMI Smart meters, costs, advantages, disadvantages – IPL also has experience with this.

4. What have you learned about other utility IRPs that you would like IPL to consider?
   - Consider doing something similar to NIPSCO unit-by-unit cost analysis, and social evaluation included in analysis (matrix including jobs, community economics, low income customers, pollution burdens, etc. by portfolio) – several people agreed with this recommendation.
   - Continue to do more outreach to get larger and more diverse stakeholder participation, e.g. bargaining units, employees. Perhaps ask stakeholders who have been part of this process to advocate for this as well.

- Appreciate these workshops, welcomes further discussion about modeling methodologies and helping develop modeling runs.

5. Was the additional August meeting helpful to review initial results?
   - Yes, but it probably could have been a webinar only meeting.

6. Were the group exercises helpful, and do you have any suggestions for additional exercises? How can we make group exercises more effective?
   - Small group discussions were the most beneficial aspect of these workshops, even if the conversations didn't always pertain to the discussion. But we need more time for them since it takes a little while to "warm up"

7. Was IPL responsive to stakeholder feedback?
   - Yes, very responsive and receptive, and as transparent as they can be. What have they done with the feedback, what difference did it make, what is IPL finally going to file, what impact did stakeholders have on the company?
   - Appreciated that IPL talked to stakeholders ahead of time. Has input changed results? Seems the preferred plan is pretty status quo.

Ms. Soller noted that IPL has tried to respond to all comments and let stakeholders know how their input was addressed at every meeting. Also, lots of changes have been made in the IPL system recently, so perhaps there is not that much else to be done. All slides will be included the IRP filing.

8. What can IPL do to improve the IRP public meetings?
   - No suggestions on this.

9. How might IPL continue to engage stakeholders in resource planning efforts with the change in the IRP cycle from 2 years to 3 years?
   - Recognizing that a lot hinges on the election, perhaps an annual meeting or webinar to update on things that have changed since the last filing.
   - We know you have made adjustments based on stakeholder comments, so thank you. One participant gave an example of a boy who lived near Harding Street saying that he no longer wanted to move, due to improved air quality.
   - A first step in getting ready for the next one could be an "IRP 101" evening session, and invite elected and appointed officials to help them understand the importance of this; discussion should not be limited just to 'geeks' and special interest groups. Have some enticements to attend.
   - If anything major changes, you could let stakeholders know about things that might change the IRP, as well as any legislative changes that occur.

Concluding Remarks and Next Steps
Joan Soller & Marty Rozelle
(Slides 102 - 104)

Ms. Soller pointed participants to a draft table of contents of the IRP report and asked for comments and suggestions by September 23. She asked attendees to please submit comments within the next week, and IPL will respond by October 7. The IRP filing deadline is November 1. Interested parties can file comments for 90 days afterward. She invited everyone to let IPL know their feedback directly and thanked everyone very much for their continued participation.