Director's Draft Report
For Indiana Municipal Power Agency's 2023 Integrated Resource Plan

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Director's Report Applicable to Indiana Municipal Power Agency's 2023 Integrated Resource Plan and Planning Process

I. PURPOSE OF IRPS

Indiana Municipal Power Agency's (IMPA's) 2023 Integrated Resource Plan (IRP) was submitted on Feb. 1, 2024. By statute[1] and rule, integrated resource planning requires each utility that owns generating facilities to prepare an IRP and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. A primary goal is a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers, the utility, and the utility's investors. At the outset, it is important to emphasize that these are the utilities' plans. The Director's report is not an endorsement of the IRP, nor does it substantiate the desirability of the utility's "preferred resource portfolio" or any proposed resource action.[2]

The essential overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible as well as support the unprecedented pace of change currently occurring in the production, delivery, and use of electricity. IRPs may also be used to inform public policies and are updated regularly.

IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum flexibility to address resource requirements. Inherently, IRPs are technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of a variety of alternative resource decisions. Because of the complexities of integrated resource planning, it is unreasonable to expect absolutely accurate resource planning 20 or more years into the future. Rather, the objective of an IRP is to bolster credibility in a utility's efforts to understand the broad range of possible risks that utilities are confronting.[3] By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their long-term resource portfolio to maintain reliable service at the lowest reasonable cost to customers.

IMPA, like every Indiana utility and stakeholder, anticipates substantial changes in the state's resource mix due to several factors[4] and, increasingly, Indiana's electric utilities are using IRPs as a foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation.

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[1] Indiana Code § 8-1-8.5-3.

[2] 170 IAC 4-7-2.2(g)(3).

[3] In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

[4] A primary driver of the change in resource mix is due to relatively low-cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies. As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

The resource portfolios emanating from the IRPs should not be regarded as being the definitive long-term plan that a utility commits to undertake. Rather, IRPs should be regarded as illustrative or an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios.

II. INTRODUCTION AND BACKGROUND

IMPA is a wholesale electric utility providing long-term electricity requirements[5] for its 61 member communities under long-term power sales contracts. IMPA's member cities and towns each own and operate an electric distribution utility. In 2022, IMPA's coincident peak demand for its communities was 1,205 MW and the annual member energy requirements during 2022 were 6,193,499 MWh. IMPA projects that its peak and energy will grow at less than 0.3% per year. These projections do not include the addition of any new members or customers beyond those currently under contract. *(See IMPA IRP, sec. 2, p. 13)*

IMPA operates in both the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM) regional transmission organizations (RTOs). IMPA has member load in five load zones and generation resources connected to six zones within the RTOs, plus two resources outside of the RTOs. IMPA's load is approximately two-thirds within MISO and one-third in PJM. Given that IMPA serves wholesale load in both the MISO and PJM *(See IMPA IRP, sec. 5, p. 23)*, IMPA must comply with the resource adequacy requirements of each RTO for its load in that RTO. *(See IMPA IRP, sec. 4, p. 19)*

III. FOUR PRIMARY AREAS OF FOCUS

The primary areas of focus of the Director's review include the interrelated topics of load forecasting; demand side management (DSM), which includes energy efficiency (EE) and demand response (DR); resource optimization and risk analysis; and the Five Pillars.

1. Load Forecast

IMPA has member load in five different load zones across MISO and PJM. IMPA's load is divided with approximately two-thirds within the MISO region and one-third in the PJM. IMPA projects average energy growth over the planning period of .21% with peak demand growing at an average rate of .2%. Modest amounts of load growth are expected to come from electric vehicle (EV) penetration.

IMPA uses regression equations to project energy consumption and peak demand on a monthly basis for each of the five zones. The explanatory variables used in each regression equation differ slightly across the zones. The explanatory variables are:

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[5] IMPA's resources include: Joint ownership interests in Gibson Station #5, Trimble County Station #1 and #2, and Prairie State Energy Campus #1 and #2; Operation and maintenance responsibility of Whitewater Valley Station #1 and #2; Five dual fuel, natural gas or No.2 fuel oil, fired combustion turbines owned and operated by IMPA; Two natural gas fired combustion turbines owned by IMPA and operated by Indianapolis Power and Light; 50 solar parks located in member communities; Long-term power purchases from Indiana Michigan Power Company, Alta Farms II Wind Farm LLC, and Ratts Solar Park LLC; Short-term contracts with market participants in MISO and/or PJM, and the IMPA Energy Efficiency Programs. (See IMP IRP, sec. 5, p. 25)

1. Sum of heating degree days (HDD) during the month.

2. Sum of cooling degree days (CDD) during the month.

3. Number of non-holiday, non-weekend days during the month.

4. Number of weekend days, plus the number of holiday-days.

5. National unemployment rate.

6. Dummy variable set to 1 for summer and 0 for other seasons.

7. Jasper dummy variable to account for unexplained loss of demand in the CenterPoint load zone.

8. Percentage change in gross domestic product from the previous year.

IMPA uses different weather stations in each load zone and uses normalized weather for forecasting.

<u>Electric Vehicle Load Evaluation</u>
IMPA made an after-the-fact adjustment to the load forecast to capture the potential impact of EVs for the first time in the 2023 IRP. IMPA makes a few simplifying assumptions in developing the EV load forecast.

1. *IMPA's member population will adopt EVs more slowly than the nation:* This is largely based on IMPA communities having lower median family household income than the national level. IMPA's EV forecast slowly increases the rate of EV adoption until it is in line with the national level in 2030, accounting for 50% of new annual car sales.

2. *Most EV charging occurs outside of on-peak hours:* Based on Idaho National Laboratory data, IMPA assumes more than 80% of EV owners will charge at home and that most will charge overnight.

3. *EV owners will allocate 100% of their charging hours to charging stations or homes located within the IMPA footprint:* IMPA recognizes this assumption is "generous" for estimating load impacts but was done for ease of modeling.

The EV sales forecast is done with several transformations. IMPA started with a national EV sales forecast from Wood-Mackenzie and combined it with data from the Alternate Fuels Data Center on EV registrations and assumed a 10% retirement rate after 10 years to create a national EV population forecast. The second transformation is to an IMPA service area forecast using ratios that capture the difference between nationwide trends and those based on IMPA demographics. IMPA assumes its service territory will mirror the national forecast by 2030. The forecast of EVs is then translated into energy usage. Annual energy usage is calculated assuming 44.6 kWh per 100 miles driven and an average annual mileage of 12,000 per vehicle. The annual energy sales are broken into monthly values and allocated across the two RTO energy forecasts.

Peak Demand Forecast Methodology

The peak demand model is a linear regression equation driven by macroeconomic and weather variables. As with the energy models, the independent variables differ slightly across the five load zones. The explanatory variables are:

1. National unemployment rate.

2. Degree day equivalents, both heating and cooling, that impute factors such as humidity and wind chill.

3. A three-day moving average of the number of adjusted cooling degree days.

4. A trinary dummy variable set to 0, 1, or 2 depending on the season and model.

5. A binary dummy variable to account for unexplained loss of demand in the CenterPoint load zone.

Alternate Load Forecasts

IMPA developed two "what if" load forecasts based on less optimistic or more optimistic economic outcomes. The two alternative load forecasts also include higher or lower levels of future EV penetration.

The status of customer-owned resources and the potential benefits are articulated in IMPA's IRP.

> As of the date of this report, IMPA has contracted with 28 customers, totaling 2.4 MW of installed renewable energy systems. IMPA has a contract with one commercial/industrial customer of an IMPA member to purchase excess generation from its onsite generation facilities. Under the current contract, the customer has been selling small amounts of energy to IMPA under a negotiated rate. IMPA does not currently have any customers on the system that operate a combined heat and power (CHP) system. While under the right circumstances CHP systems could be beneficial to both the customer and IMPA, the right mix of site-specific operating conditions and economics must be in place for both parties for a CHP project to go forward. Except for emergency back-up generators at some hospitals, factories and water treatment plants, IMPA knows of no other non-renewable retail customer generation in its members' service territories. *(See IMPA IRP, sec. 5, p. 29)*

Director's Comments – Load Forecasting

The Director understands the limitations IMPA faces when preparing load forecasts because of the wholesale nature of its business. The lack of access to uniform data on retail customer consumption imposes certain constraints on the modeling methodologies available to IMPA. Accepting this circumstance, however, there are several places where the load forecast documentation can be improved.

1. The use of the national unemployment rate is an unusual choice for a driver. As a rate statistic, it provides no indication of a change in the level of employment (e.g., if the workforce and employment both grow at the same rate, the unemployment rate is unchanged). Four of the five load zones use the unemployment rate as an explanatory variable, and three of the zones use the change in annual gross domestic product (GDP) as an explanatory variable.

2. The inclusion of the EV energy forecast is an improvement compared to previous IRPs.

3. The peak demand forecast description does not explain if and how the EV forecast impacts peak demand.

4. Comparing the energy model explanatory variables to the models in the 2020 IRP, there has been a change in the macroeconomic drivers. Real GDP growth rate and the national unemployment rate have replaced the 2020 explanatory variables Annual GDP and Energy Intensity (btu/$ of GDP). In the 2020 IRP, it was unclear how the energy intensity driver was forecasted. Perhaps that is the reason it is not used in the 2023 IRP.

5. The energy models include a peak season dummy that is 1 for summer and 0 for all other seasons. The description of this variable in Table 5 in section 6 on page 36 has an asterisk as if it has a footnote, but there is no footnote.

6. The CenterPoint energy model includes a "Jasper" dummy to account for unexplained loss in the CenterPoint load zone. It is curious that IMPA has been unable to determine the source of the loss.

7. The peak modeling appears to have changed since the 2020 IRP although the near complete lack of details in the 2020 IRP makes it difficult to determine with any degree of certainty.

8. IMPA does not cite the source for the assumptions of 44.6 kWh per 100 miles driven and an average annual mileage of 12,000 per EV.

9. In the peak load models, IMPA does not explain how the HDD equivalent and the CDD equivalent variables were constructed. It is curious that the CDD equivalent variable does not appear in the Duke Energy Ohio model.

10. The "what-if" load forecast methodology is discussed in general terms, but there is no discussion of specific assumptions about how much the economic drivers changed and how the EV forecast was modified.

11. There is no discussion of DERs in the load forecast section. The current state of DERs in the IMPA system is discussed in section 5 on pages 30-31.

2. Energy Efficiency and Demand Response

<u>Summary</u>

In the 2023 Integrated Resource Plan (IRP), IMPA considered both supply-side and demand-side resources to meet its customers' future peak demand and energy requirements. Existing demand-side resources consist of programs coordinated by IMPA as well as those implemented by its members. According to IMPA, its members have implemented a variety of programs and projects tailored to their individual systems to reduce peak demand and encourage efficient energy use. Most of these programs are rate or customer service related. Examples include coincident peak rates, off-peak rates, power factor improvement assistance, load signals to customer-owned peak reduction or energy management systems, advanced meter infrastructure/automatic meter reading, and streetlight replacement with more efficient lamps.

For the 2023 IRP, IMPA continues to include the energy efficiency (EE) program as part of the current resources. This program offers incentives in the form of rebates for the installation of dozens of items for both residential and commercial and industrial customers. According to IMPA, from 2012 through the end of 2023, IMPA's EE programs generated a cumulative savings of about 121,000 MWh and a coincident peak reduction of approximately 13.6 MW. This represents an increase of 1,000 MWh in cumulative savings and 0.1 MW in coincident peak reduction when compared with the savings reported in IMPA's 2020 IRP. IMPA mentions that the EE program will continue to be its primary method of offering EE services to member communities.

As part of the planning process, IMPA also offers a demand response (DR) tariff, an excess renewable generation program, education, and training. There are various rate structures aimed at assisting customers in lowering or controlling their energy consumption or bills. According to this IRP's action plan, IMPA is expected to continue the EE Program and implement a revised DR program.

For the current IRP, IMPA used Encompass as its planning model program in lieu of Aurora which was used in the 2020 IRP. The Encompass model was utilized to model EE and DR as selectable resources.

<u>Energy Efficiency</u>
EE programs were modeled as resources that were effectively load decrements at incrementally higher costs. The initial block of EE was modeled in one-fourth MW increments, with the initial one-fourth being modeled at IMPA's current cost of implementation ($237/Kw). Additional increments were "priced" on an increasing basis reflecting difficulty in finding additional efficiencies. In this IRP, IMPA argues that given its status as a wholesale supplier, market potential is very difficult to gauge as most EE potential lies with the retail customer.

<u>Demand Response</u>
In this IRP, DR was assumed to grow 2 MW per year in enrollments, maxing out at 10 MW. However, IMPA mentioned that currently no customers are participating in the program. As part of IMPA's preferred plan, IMPA will be enlisting the help of a DR Aggregator to assist in examining market potential and enrollment of eligible customers to a revised DR tariff.

Since the 2020 IRP, IMPA argues that the utility has engaged with leading DR aggregators to better understand how DR programs could work for the utility members who have industrial loads that may be eligible. This has led IMPA to begin the process of re-working its DR tariff to better facilitate DR enrollments. For this IRP, pricing for DR programs will ultimately be negotiated between IMPA, the member, and the load requesting to be enrolled. IMPA has assumed $700,000 in program costs per year for up to 10 MW of firm capacity. Depending on uptake, this equates to between $70/kW to $140/kW "installed" cost.

Director's Comments – Energy Efficiency and Demand Response

1. The 2023 IRP report includes a brief explanation about modeling EE and DR programs, but it does not provide sufficient details to understand how the implementation costs and one-fourth load increments were determined. A more detailed explanation about the EE and DR modeling methodology would provide more resources and information to better

analyze the whole DSM modeling process. Furthermore, in the current IRP's Action Plan, IMPA mentions that it will continue the EE programs. However, there are no quantifiable savings goals clearly stated as the potential future savings from these programs.

2. Although IMPA provided specific implementation cost for the initial increment block of EE in this current report, it is unclear how the additional increments were "priced" *(See IMPA IRP, sec. 12, p. 87)*. What factors were considered to determine the prices of the additional increments? How were prices assigned to reflect the difficulties of finding additional efficiencies? There are no details regarding the prices of the additional increment blocks of EE.

3. What aspects were considered to assume that DR will grow at 2 MW per year?

4. What is the timing of the EE blocks and DR (e.g., does the model need to select a block for the entire 20-year planning period or are smaller time periods an option)? This could affect whether a block is selected. What was the total amount available for selection?

5. What kind of rework on DR tariff was performed to facilitate DR enrollments?

3. Resource Optimization and Risk Analysis

<u>Overview of IMPA's Planning Process</u>
IMPA used Encompass for its power supply modeling by Anchor Power Solutions and MCR-FRST by MCR Performance Solutions for financial modeling. The process begins with scenario development and the underlying assumptions. IMPA used Encompass to develop portfolios against forecast market prices for commodities and environmental constraints. Encompass creates an optimal portfolio for each scenario. Supply resources at this stage are considered largely academic by IMPA and are based on a combination of the U.S. Energy Information Administration (EIA) cost estimates for new generation and other market-based observations.

Given the initial optimization results, IMPA issued an all-source Request for Proposal (RFP) seeking the resources the initial optimizations suggested. The Encompass model optimizations for each scenario were redone with the all-source RFP projects.

<u>Scenarios</u>
IMPA develops three scenarios with the stated purpose of developing "book-ends" to examine a variety of outcomes. The scenarios are a Base Case, a Voluntary Net Zero CO2 by 2040, and an Austerity Case.

<u>Base Case Scenario</u>

A. *Carbon Policy:* IMPA decided in the IRP development not to assume any national level tax or policy constraint on CO2 emissions. IMPA said that the Inflation Reduction Act of 2022 (IRA) with the treatment of Investment and Production Tax Credits (ITC and PTC) gives renewable/carbon neutral energy projects a clearer line of sight on incentives and acts as a policy carrot to curb CO2 emissions.

B. *MISO & PJM Capacity Market Reforms:* IMPA noted that the most challenging aspect of the IRP process has been dealing with the uncertainty created by the ISO/RTO market changes.

Specifically, IMPA discussed the MISO move to a four-season planning construct and the change to the resource accreditation methodology. Given this circumstance, IMPA assumed seasonal reserve margins that are the same as the Planning Year 23-24 margins and that these reserve margins are constant over the planning period.

IMPA cited that PJM is contemplating changes to how PJM sets reserve margins. Given a specific methodology has not been finalized, IMPA assumed the going forward reserve margin would stay around the 2022 Reserve Requirement Study results.

C. *Load Forecasts:* The base case load forecast has long term energy requirements growing at a compound annual growth rate (CAGR) of .21%. This accounts for EVs. Peak demand has a CAGR of .2%.

D. *Forward Prices:* IMPA utilized three different sources for arriving at forward power prices for the Indiana Hub and the AEP-Dayton Hub.
   i. First were the observed market prices via the Nodal Exchange. These prices reflect the forward curve for power out through 2033.
   ii. The second source relies on a market model develop by IMPA using the Encompass model and publicly available information on probable resources for a given RTO region. This model was used to develop only an Indiana Hub price forecast.
   iii. Third was a market price forecast supplied by Horizons Energy.

These three forward curves are blended to develop a final forward price projection.

The IMPA forward price model used the Encompass model to build a rough approximation of the MISO North Zone and the 2022 MISO Regional Resource Assessment (RRA) to develop a long-term forecast of future wholesale power prices.

Natural gas prices were developed in the same manner as was done for power prices. Market forwards were utilized, then blended with a long-term price forecast from Horizons Energy. Current market forwards for natural gas delivered to the Henry Hub end in 2033, at which point IMPA blends in Horizons gas price forecast for the remaining years.

E. *All-Source RFP:* IMPA issued an all-source RFP for capacity resources that can reliably supply 200 MW of zonal resource credits during all four seasons of MISO's Planning Resource Auction. IMPA stated that, while the RFP was capacity oriented, all submissions would be evaluated based on their contribution to IMPA's power supply portfolio.

IMPA received a variety of offers sourced from existing or yet to be built thermal resources and "other" offers. Other offers ranged from renewable/battery storage projects to financial energy only offers. IMPA received price estimates from General Electric for gas turbines in three different sizes, along with consulting estimates from Black & Veatch for balance of plant costs.

<u>Voluntary Net Zero CO2 by 2040</u>

A. *Carbon Policy:* IMPA set a self-directed target of zero emissions by 2040 which was phased in with roughly a 50% reduction by 2029.

B. *Load Forecasts:* IMPA assumed its self-directed CO2 emissions target was done in conjunction with a broader market push towards reduced CO2 emissions across both utility sector and the transportation sector. The CAGR of the Voluntary Net Zero Case energy forecast is .28% versus .21% in the base case. The difference between the two forecasts driven by higher rates of EV penetration. Demand grows at a .3% CAGR versus .2% in the base case. The higher penetration of EVs is based on the assumption that sales of EVs are 25% higher than the base scenario growth rate.

C. *Forward Prices:* IMPA states that forward price formation was done in the same general way as was done for the base scenario except that the IMPA market model projection was not used. IMPA used forward prices from the Nodal Exchange and forward prices from Horizons, with a gradual blending of the two curves beginning in 2028.

D. *All-Source RFP:* Resources from the all-source RFP were added as selectable resources.

<u>Austerity Case</u>

A. *Policy Assumptions:* IMPA assumes the Inflation Reduction Act of 2022 is eliminated. As a result, all generation is built at pre-subsidized cost under the Base Case capital expenditure assumptions. Specifically, the ITC and the PTC is eliminated.

B. *Carbon Policy:* IMPA assumes no requirement to reduce or limit carbon emissions.

C. *Load Forecasts:* The Austerity Case has overall lower loads and lower overall rates of EV penetration than either the Base Case or the Voluntary Net Zero Case. In this case, energy grows a modest .14% CAGR while demand is projected to stay flat.

D. *Forward Prices:* Forward price projection was done similar to the process for the Voluntary Net Zero Case. IMPA used the Horizons scenario pricing from their Low/Natural Gas/Low Demand case.

E. *All-Source RFP:* As was the case for the Base Case and the Voluntary Net Zero Case, those resources deemed good candidates for IMPA's portfolio requirements were added as selectable resources.

Approximately one-third of IMPA's load is in the PJM and the remaining two-thirds is in the MISO. Because the two RTOs are so different, IMPA plans for each area separately. The result is IMPA develops two separate resource portfolios.

IMPA allowed Gibson 5 to retire economically. Using preliminary capital expenditure estimates, Gibson was retired in the model in January 2028.

IMPA's PJM portfolio is long on capacity and remains so until the full requirements contract with AEP expires in Planning Year 34-35. Given this circumstance, IMPA did not issue an all-source RFP for the PJM area. The result is that the focus of the IRP for the first half of the planning period is entirely on developing resource portfolios for the MISO portion of IMPA's load.

<u>Risk Assessment for Each Optimized Portfolio</u>

In previous IRPs, IMPA used stochastic analysis to evaluate the risk profiles of candidate portfolios to capture the impact of cross commodity correlations on rates and revenue requirements. However, IMPA argues this process sometimes yields little information of value.

For this reason, IMPA chose to evaluate portfolios based on their robustness to previously seen risk events. IMPA selected two winter events, Winter Storms Uri and Elliot, and recent summer "maximum generation" events for the summers of 2022 and 2023. IMPA compiled historical loads, prices, and generator performance during each of these events and applied adjustment factors to the forecasted loads, prices, and generator capacity for those events.

Winter storm events were assumed to alternate every four years. Elliot-like events occurring in even years starting in 2024 and Uri-like events occurring in odd years beginning in 2027. Summer events were assumed to occur every summer for the entire planning period.

An additional sensitivity involved applying a 1.5 times multiplier on natural gas prices in addition to the winter stressors. Another sensitivity was run assuming no access to natural gas during the winter months.

For each scenario's candidate portfolio, IMPA presented the annual net present value of revenue requirements (NPVRR) between the cases. For example, for the Base Case portfolio results were shown for the Base Case, the Base Case with Weather Shocks, Base Case with Winter Shocks and 1.5 times natural gas prices, and the Base Case winter with No Winter Gas. IMPA also presented for each Case/Sensitivity the 20-year NPVRR, the 20-year levelized rate, the 10-year NPVRR, and the 10-year levelized rate.

The focus for each resource portfolio is on how tight the distribution of the annual NPVRRs is over the 20-year period.

Director's Comments – Resource Optimization and Risk Analysis

The use of only three optimized scenarios structured around differences in CO2 emissions restrictions and renewable energy, with each scenario also having three weather-based sensitivities seems limited.

Failure to perform a more traditional stochastic analysis limits the metrics that can be used to evaluate the performance of the portfolios under different circumstances. It is the Director's understanding that IMPA states in several places that the Aurora model requires Eastern Interconnection-wide modeling. This does not appear to be accurate as the State Utility Forecasting Group uses Aurora and only models Indiana.

In Table 18 titled "Generation Costs for New Generation Technology" in section 12 on page 85, IMPA uses a "Tech Optimism Factor" to increase the capital cost of small modular reactors but does not explain or justify the factor used.

In Figure 24 titled "New Generation – Overnight Costs ($/kW) – Unsubsidized" in section 12 on page 86, are these nominal or real dollars?

The discussion of forward price development raises several questions.

1. It is unclear whether prices shown in this section are real or nominal.

2. The natural gas price forecast in Figure 29 seems unrealistically high. The Director understands the projected price through 2033 is based on Henry Hub forward prices through 2033 and then uses a price forecast provided by Horizons Energy. The very

different price trend beyond 2033 deserves some explanation of the drivers for this trajectory.

3. IMPA states that the forward power prices rely "on an internal market model constructed by IMPA utilizing the Encompass model and publicly available information regarding probable resources stacks for a given ISO. This model is used for the Indiana Hub price forecast only." *(See IMPA IRP, sec. 12, p. 88)*

   IMPA briefly describes its use of the 2022 MISO Regional Resource Assessment to develop a long-term forecast of potential future resource mixes in the MISO footprint.

   The Director follows what IMPA did at a high level but thinks more detail would be helpful to more fully understand how the internal market model was developed and its reasonableness evaluated.

4. It is not clear if IMPA only projected energy prices or if it also projected capacity prices? If capacity prices were not projected, why? If capacity prices were projected, then how were the prices developed?

5. The prices presented in Figure 28 "Price Forecast Comparison" in section 12 on page 91 is deserving of more discussion. The figure shows significant differences between the Blended Indiana Hub On-Peak and Off-Peak compared the Horizons Indiana Hub On-Peak and Off-Peak forecasts. The differences are particularly obvious between 2025 and 2033.

The risk assessment process discussed by IMPA *(See IMPA IRP, sec. 12, p. 111)* is both interesting and different. However, the lack of detail makes it difficult to understand fully what was done and why.

1. Were the weather event adjustments made on a percentage basis or on a difference in values? Given the relatively high base natural gas price projection, this could be significant.

2. The basis for calculating the adjustments is not explained. Were these calculated adjustments adjusted over the forecast horizon or set at one value?

3. Was the 1.5 multiplier for gas prices applied year-round or only during the weather events? What was the basis for choosing to set the multiplier at 1.5?

4. It is limiting when the risk assessment only discusses the impact on the annual NPVRR, 20-year NPVRR, 20-year levelized rate, 10-year NPVRR, and 10-year levelized rate. Should not other considerations be included in the discussion when evaluating the performance of the three portfolios across the weather and fuel shock sensitivities? The Director recognizes that some other performance characteristics are discussed in the chapter on the Five Pillars and the scorecard metrics, but there are limitations that will be addressed later.

4. The Five Pillars

The Five Pillars are: reliability, resilience, stability, affordability, and environmental sustainability. IMPA notes its own mission statement contains three of the pillars: reliability, affordability, and environmental sustainability.

According to IMPA, quantifying these metrics in terms of model outputs is a challenge as most planning models do not capture certain metrics like frequency response. Despite this difficulty, IMPA selected eight metrics to capture the Five Pillars as best as possible.

IMPA's Table 27 Portfolio Metrics and the Five Pillars

Metric	***Pillar Addressed (Reliability, Affordability, Resiliency, Stability, Environmental Sustainability)***
20-Year Portfolio CO_2 Emissions – 000,000 tons	Environmental Sustainability
Market Energy as a Percent of Load	Reliability/Resiliency
Market Capacity as a Percent of Obligation (Worst Month)	Reliability/Resiliency
Potential Unserved Energy (MWh)	Reliability/Resiliency
10-Year Levelized Rate	Affordability
20-Year Levelized Rate	Affordability
Percentage Ramp Capable Generation (Up and Down) 2030	Reliability/Resiliency/Stability
Percentage Ramp Capable Generation (Up and Down) 2040	Reliability/Resiliency/ Stability

IMPA used a weighted scoring system to rank the portfolios and scenario runs. The first metric was Total CO_2 emissions over the planning period. IMPA assigned this metric a weighting of 30% because it is contained in the IMPA mission statement. The second metric was market energy as a percent of load. IMPA assigned it a weight of 5% due to the fact that the metric had minor variations across the three main cases. These small differences were driven by IMPA imposing constraints in the model on reliance on the market for energy requirements. The third metric was market capacity as a percentage of overall obligation. IMPA assigned this metric a 10% weight because IMPA deems capacity to be more important overall than energy given the difficulty of building new capacity or contracting for capacity. The fourth metric was potential unserved energy (EUE). IMPA states that generally in any optimization EUE should be zero. According to IMPA, this gives it a reliability metric to evaluate risk in portfolios that are run outside their initial assumed conditions. That the EUE that does materialize in these runs is an artifact of limits on how much the portfolios can interact with the market, resource adequacy, and unforeseen shocks to load. IMPA gives this metric a 5% weight, due to the fact that, under optimized conditions, portfolios should have zero hours of EUE.

The affordability metrics were 10-year and 20-year levelized rates, which got a 30% and 10% weighting, respectively. The 10-year levelized rate received a higher weight because of better visibility on future prices over that shorter period compared to the longer period.

The final two metrics were the percent of the portfolio that has bilateral ramp capable generation by 2030 and 2040. IMPA assigned only a 5% weight to each metric because frequency control on the grid is largely the responsibility of the grid operator.

The three main optimized portfolios were ranked against each other. The cases were the Base, Voluntary Net Zero, and Austerity Cases. Each portfolio was scored on each metric relative to the other two portfolios with points assigned for first, second, and third. First was assigned 100 points, second was 66 points, and third received 33 points. These points were then weighed and summed to arrive at a total portfolio score. This ranking of the three optimized portfolios was repeated for the weather-based sensitivities.

In order to quantify robustness of the three optimized portfolios, IMPA then modeled each resource plan under the other two scenarios. The idea was to evaluate the performance of each portfolio against a set of assumptions for which it was not optimized under. A similar process was used to develop a weighted, ranking-based scoring system. The resulting scores were used to determine the preferred portfolio.

Director's Comments – The Five Pillars

Choosing not to use any stochastic analysis limits the choice of metrics to evaluate the Five Pillars because IMPA cannot identify risk probabilities.

The use of a weighted scoring system to rank each portfolio fails to capture the degree to which portfolio metrics may vary. For example, a very large difference for one portfolio compared to another portfolio for a given metric has the same impact as a small difference given the weighted scoring system. Also, there is no information provided as to what the actual values are for most of the metrics. Only the ranked scores are provided.

The substantial overlap between the different pillars and the metrics indicates a lack of clear definition of what the pillar represents. For example, the reliability and resiliency pillars seem completely redundant. While it is true that many metrics potentially reflect multiple pillars, it seems like greater clarity is possible. For instance, IMPA could have assigned the Market Energy and Market Capacity metrics to the Reliability Pillar, the Unserved Energy metric to the Resiliency Pillar, and the Ramp metrics to the Stability Pillar.

IMPA acknowledges that the Stability Pillar is difficult to quantify in resource planning as metrics like frequency response are not properly captured, but use of ramp capability seems like a reasonable proxy.

IMPA used market energy as a percent of load as a metric. IMPA assigned this metric a weight of only 5% because all the portfolios had constraints on how much reliance could be placed on the market for energy requirements. The result was that the three portfolios had very minor differences. This raises a couple of questions:

1. Where is the specific constraint on energy purchases stated in the IRP? How was the specific constraint determined?

2. If the differences in results for this metric across the three portfolios are very minor, then what is the value of this metric in evaluating portfolio performance?

Another metric was market capacity as a percentage of IMPA's overall obligation. It is unclear if there was a limit imposed by IMPA on how much the market could be relied on for capacity, and, if there was a limit, how the appropriate limit was determined. The Director notes the conversation in section 4 on page 19, but no detail was provided.

IMPA's fourth metric was potential expected unserved energy (EUE). According to IMPA, this metric should be zero in any optimization. EUE is only non-zero when a resource portfolio is run outside its initial assumed conditions. IMPA went on to say, even then the EUE that materialized was an artifact of limits on how much the portfolios can interact with the market, resource adequacy, and unforeseen shocks to load. IMPA gave the EUE metric little weight because under optimized conditions, portfolios should have zero EUE. The Director has a few questions:

1. Did IMPA optimize its portfolios using a planning criterion based on MISO and PJM planning reserve margins?

2. If the portfolio optimization was based on reserve margins, how can EUE be zero?

3. Explain how EUE is an artifact of limits on how much portfolios can interact with the market, resource adequacy, and unforeseen shocks.

4. If EUE under the resource evaluation process utilized by IMPA has little information value, then why is this metric used to evaluate portfolio performance?

One improvement compared to the 2020 IRP involved IMPA modeling each optimized portfolio in the other scenarios for which the resource portfolio was not optimized. IMPA presented the weighted scoring for each portfolio/scenario in Figure 78 in section 15 on page 155. Unfortunately, the usefulness of this evaluation improvement compared to the 2020 IRP is reduced as there is no information provided as to what the actual values are for most of the metrics.

IV. SUMMARY

The IMPA IRP has a couple of improvements compared to the 2020 IRP. Of note is the inclusion of EVs in the load forecast and IMPA's efforts to evaluate the resilience of the three optimized resource portfolios in the face of weather and fuel shocks over the period 2024 to 2043.

Unfortunately, the IRP is lacking sufficient descriptive detail for a reasonably knowledgeable reader to understand what was done at each step of the analysis, why it was done, how it was done, and how the resulting information was used by IMPA to inform the next steps in the IRP process. This lack of discussion is particularly noticeable in the sections of the IRP covering portfolio development for the three scenarios and the section on the Five Pillars and Portfolio Comparison. As covered in more detail above, the discussion of the Five Pillars and the Portfolio Comparison is confusing and does little to help the reader understand how IMPA evaluated and considered the detailed information coming out of the IRP process.

The Director thinks the metrics included in the Scorecard need additional consideration. Not using probabilistic analysis reduced the quantitative metrics available for possible inclusion in the Scorecard. The Director does not see the analysis of weather and fuel shocks as a substitute for probabilistic analysis, rather the two forms of analysis are better seen as complements. Evaluation of weather and fuel shocks is beneficial because it helps planners and decisionmakers better understand correlated risks caused by extreme weather conditions, but it is not a substitute for alternative forms of risk and uncertainty analysis.

Scorecards are best used to evaluate metrics that can be quantified and compared across portfolios and scenarios. The quantitative metrics need to be complemented with a thorough consideration of critical qualitative factors that drive reasonable resource decisions. The discussion of the Five Pillars provides an excellent opportunity to discuss the *how* these qualitative considerations interact and affect the evaluation of near-term resource choices. IMPA has room for improvement in this area, as do all other Indiana utilities required to submit IRPs.

The Director acknowledges that writing a thorough IRP report is time-consuming and arduous. Nevertheless, in this complicated and fast-changing world, the preparation of such a report will benefit all involved in the IRP review process and associated certificate of need proceedings.