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IMPA
INDIANA MUNICIPAL POWER AGENCY

March 31, 2014

Dr. Bradley K. Borum
Electric Division Director
Indiana Utility Regulatory Commission
PNC Center
101 West Washington Street
Suite 1500 E
Indianapolis, IN 46204

Dear Dr. Borum,

Thank you for your February 28, 2014 draft comments on Indiana Municipal Power Agency's 2013 Integrated Resource Plan. IMPA appreciates the opportunity to review your comments and provide feedback prior to the final report. Attached are responses to various questions and comments included in your report.

Once again, thank you for the opportunity to review your comments and provide clarifying information to you. We look forward to working with you and your staff as we develop future IRPs.

Thank You,

Doug Buresh P.E.
Sr. VP, Planning and Operations
Indiana Municipal Power Agency

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**<u>Indiana Municipal Power Agency Comments</u>**

**Regarding the February 28, 2014**

**DRAFT REPORT OF**
**THE INDIANA UTILITY REGULATORY COMMISSION**
**ELECTRICY DIVISION DIRECTOR**
**DR. BRADLEY K. BORUM**
**REGARDING 2013 INTEGRATED RESOURCES PLANS**

The following are Indiana Municipal Power Agency's (IMPA) comments and responses to the February 28, 204 Draft Report of the Indiana Utility Regulatory Commission (Commission) Electricity Division Director Dr. Bradley K. Borum Regarding 2013 Integrated Resources Plans (Draft IRP Report). IMPA's comments and responses are being submitted on March 31, 2014 as requested in the Draft IRP Report.

## <u>IRP Load Forecast</u>

The Draft IRP Report poses a series of questions related to IMPA's forecast. Below, each of those questions has been included in **boldface print** with IMPA's responses following each question.

**Q1. The first part of the 2013 IRP mentions that the real electricity price (measured as the average wholesale prices for each supply area) was included in the forecasting models. However, there is no mention in the text or statistics reports about the use of this variable in the "2013 Load Forecast" in Appendix D.**

R1. While a number of variables were considered in IMPA's forecast modeling process, including the real electricity price, variables that were not statistically significant predictors of load (*e.g.*, because of incorrect coefficient signs or insignificant T-statistics) were removed from the final forecast model. Specifically, real electricity price was not found to be significant in the models and was therefore excluded. IMPA will continue to evaluate real electricity price and other variables in the future as IMPA validates and refines its forecast models. In future IRPs, IMPA will expressly state if a variable referenced in the report was excluded from the final forecast model because it lacked statistical significance.

**Q2. The approach of calculating the mean temperature from the daily maximum and minimum temperatures is commonly used. However, has IMPA considered calculating the average temperature by using all the daily observations instead of only the maximum and minimum temperatures? Although this would require the use of more data, this approach could provide a better estimation of the mean temperature and improve the outcome of the model.**

R2. As noted in the question, the approach utilized by IMPA is commonly used. Specifically, IMPA utilizes the daily maximum and minimum temperatures provided in the National Oceanic and Atmospheric Administration (NOAA) database. For future

IRPs, IMPA will explore the possibility of obtaining hourly temperature data and validating it in comparison to IMPA's standard method of mean temperature calculation.

**Q3. The build-up temperature data was calculated by the summation of the coincident peak date maximum temperature times 10/17, previous day maximum temperature times 5/17 and the second day back maximum temperature times 2/17. According to IMPA, this variable had a greater statistical significance in the demand models than maximum temperature. How were the factors (10/17, 5/17, and 2/17) determined?**

R3. The use of the factors was based on IMPA staff's utility forecasting experience. The factors were obtained from an EPRI reference guide, "Nonresidential Load Forecasting for Small Utilities" (March 1987). A section on peak demand modeling in this reference guide supports using a temperature build-up variable calculated using these weighting factors. Some experts have reported using weights of 0.6, 0.3 and 0.1 for developing the weighted 3-day moving average (*See, e.g.*, "High Temperatures & Electricity Demand" a report published by the California Energy Commission Staff in July 1999, at p. 10). Converting the factors used by IMPA, 10/17, 5/17 and 2/17, into decimal form provides factors equal to 0.59, 0.29, and 0.12, which are very similar to the 0.6, 0.3 and 0.1 weights used by other utilities and forecasting groups.

**Q4. Does IMPA use one model with two different variables – one for winter and the other for summer – included in the same model for estimating peak demand. If yes, why not use one model to estimate summer peak and another model to estimate winter peak?**

R4. IMPA uses one model, but with three different temperature variables: minimum temperature for winter months, the temperature build-up variable for summer months, and the mean temperature for shoulder months. IMPA's peak demand model is based on monthly data, and using the three variables enables IMPA to utilize a single predictive model across all seasons. For the next IRP, IMPA will consider whether using two models would increase efficiency or produce a better forecast.

**Q5. Why is U.S. Real Gross Domestic Product (GDP) used as an independent variable in the forecast model instead of Indiana Real Gross State Product or a regional GDP variable? The use of a variable at a more regional level could better reflect the different characteristics of that specific region in the model.**

R5. While historical data can be obtained for both U.S. and Indiana Real GDP, it is more difficult to find reliable sources for state/regional projections. IMPA has determined that it is preferable to use a national source for the projections rather than less robust state or regional projections. Therefore, IMPA used the U.S. Real GDP variable. In addition, the largest industrial customers in IMPA's member communities have a national presence, and their production is often driven more by national influences than regional changes in GDP.

**Q6. In the 2011 IRP, IMPA mentions that future changes will include the effects of increased appliance energy efficiencies mandated by the Energy Policy Act of 2005 and higher prices from new environmental requirements. Are these effects already considered in the 2013 IRP? There are no comments about it in the current IRP.**

R6. In 2011, IMPA believed it would be able to obtain information that would allow an assessment of the effects of increased appliance energy efficiencies on IMPA's forecast. However, while preparing the 2013 IRP, IMPA found that a source for this data that is validated for the retail customers served by IMPA's members was not readily available.

**Q7. Will the current load forecast methodology be sufficient when there is a need to better understand what is happening to consumption across different customer classes and the drivers of these changes? If yes, why? Is there a need going forward for greater customer class level information if, for example, energy efficiency, DR and DG programs are to be properly modeled and considered in the resource planning process?**

R7. As recognized in the report, IMPA is a wholesale utility and as such, does not sell power directly to end-use consumers. IMPA agrees that having access to more detailed customer class data might be valuable for a number of reasons, but IMPA and its members operate independently and maintain a wholesale relationship in which end-use customer data remains in the custody and control of the member utilities.

**IMPA's Definition of Risk**

The Draft IRP Report describes IMPA's definition of risk as the "difference between the deterministic levelized rate and the average stochastic levelized rate" (p. 20) and then comments that this definition of risk "may understate the importance of extreme outcomes" (p. 21).

IMPA acknowledges that certain statements in the IRP may have resulted in confusion regarding the definition of risk utilized by IMPA, specifically a single sentence on page 12-140 of IMPA's IRP, which was intended to indicate that the difference in means between the stochastic and deterministic values identifies risk added over the deterministic case. However, as the Draft IRP Report indicates, a full reading of the balance of the report reveals that this differential was not what IMPA used as its measure of portfolio risk. Rather, IMPA measures risk as the deviation from the stochastic mean, as demonstrated in many tables and figures in the IRP report, including risk profiles and tornado charts, confidence bands, and efficient frontier graphs. IMPA will more expressly indicate the measures of portfolio risk it utilizes in future IRP reports.

**IMPA's Resource Optimization**

The Draft IRP Report indicates that IMPA's "optimization was basically limited to selecting a small number of supply-side resources" with "energy efficiency and renewables [] hardwired in the development of the 10 resource plans used in the uncertainty and risk analysis" (p. 21).

IMPA's resource optimization considered seven (7) traditional generation options, five (5) renewable options, and the retirement of all IMPA's existing resources (five coal and seven CT units). These 24 "units" over a 20+ year planning horizon combine to create millions of possible combinations in a Mixed Integer Program (MIP) solver. IMPA does not believe this quantity of

alternatives equates to "…a small number of supply side resources." Furthermore, allowing all of IMPA's existing resources the chance to retire in every year of the study opened up a potential clean slate for resource optimization. In addition, the statement that renewables were hardwired in the resource optimization is not accurate. The solar projects IMPA is reviewing for possible development were hardcoded, but the Capacity Expansion Model (*i.e.*, resource optimization) was allowed to select additional renewables for analysis in the detailed production cost model if they were cost effective. The Capacity Expansion Model did not do so because the renewable options were not economic compared to the other supply side options. Accordingly, IMPA specifically included high renewable cases to feed into the detailed production cost model to permit analysis of scenarios with higher penetrations of renewable resources.

IMPA did not model Demand Response (DR) and Distributed Generation (DG) resource options because these are both customer decisions that IMPA cannot reasonably model. IMPA has DR and DG tariffs with defined pricing and terms, but IMPA cannot make customers sign up, nor determine their own personal economics. In addition, IMPA sees no feasible or reliable way of adding a DG alternative to the resource optimization model beyond hardcoding those resources into the outcomes.

**Renewable Alternatives**

The Draft IRP Report includes the following statements regarding IMPA's renewable alternatives:

> IMPA says it included the following renewable alternatives in the resource expansion modeling:
>
> 1. Wind – Build (50 MW)
> 2. Wind – PPA (50 MW)
> 3. PV Solar (small facilities at member locations)
> 4. Bio Mass (25 MW)
> 5. Landfill Gas (2.5 MW units in sets of 10 MW)
>
> However, another section of the IRP report says a base case was developed that assumes 21 MW of solar park development over the next seven years. Additional renewable energy additions were left up to the expansion model to determine.

These statements imply that IMPA is being inconsistent by including renewables in the resource optimization, but then including hardcoded solar facilities. Renewables *were* included as available resource options in addition to the solar facilities that were hardcoded. As stated above, no renewables were selected by the model due to their economics.

**Retail Customer Data Collection**

In several places, the Draft IRP Report references IMPA's relationship with its members and their retail customers and the effect of that relationship on IMPA's forecasting and energy efficiency. As noted above, IMPA is in fact a wholesale utility with no retail customers and no ability or authority to access information regarding its members' retail sales. Those circumstances are not something IMPA can unilaterally "resolve" prior to its next IRP. Rather, IMPA's status as a wholesale electric provider is a fundamental trait. Because IMPA is not a

vertically integrated electric utility, IMPA acknowledged in its IRP that, in many cases, it is unable to conduct its planning in the manner contemplated by the Commission's IRP rules. Despite these differences, IMPA believes its wholesale forecast and its resource planning provide valuable insight into its long term resource needs, and IMPA will continue to work with the Commission on its planning efforts.