Indiana Municipal Power Agency response to Director's Draft Report

Introduction

On April 29, 2021, the Indiana Utility Regulatory Commission issued its "Draft Director's Report Applicable to Indiana Municipal Power Agency's 2020 Integrated Resource Plan and Planning Process." IMPA appreciates the Director's thorough review of its 2020 IRP. IMPA also appreciates having the opportunity to address and respond to the Director's concerns and questions. IMPA's core mission has always been to provide low cost, reliable and environmentally responsible power supply to our member utilities. As we continually balance these three pillars, one of the main objectives in IMPA's resource planning process is that of retail customer affordability for each of our member utilities. It is imperative that IMPA's resource planning process continue to be flexible and allow thorough investigation of the clear transition that is taking place within the electric utility industry regarding generation resources.

The draft report was broken into four main sections of comments: Load Forecasting, Energy Efficiency, Resource Optimization and Risk Analysis, and Future Enhancements. The following sections contain IMPA's discussion of certain of the Director's comments. Where possible, the page reference of the Director's report is listed.

A. Load Forecasting

IMPA appreciates the Director's introductory comments on IMPA's load forecasting process and written discussion within the IRP. For additional context, IMPA was well into the process of working on the IRP when COVID-19 went from what appeared to be a regional issue to a global pandemic. IMPA hopes the Director understands that, without the benefit of hindsight, IMPA staff and leadership were highly concerned about potentially high levels of demand destruction as a result of permanent business closures and a fundamental shift in the way people conducted business. These were events and risks that were unfolding in real time. Consequently, IMPA felt it imperative to try to quantify risks to the downside so as not to overestimate planning requirements and subsequently burden IMPA members with potential over-investment.

With respect to the Director's comments regarding confusion in the load forecast write-up (page 8), IMPA apologizes for the lack of clarity. Ultimately, IMPA was attempting to convey that its priority was to quantify any permanent loss of load from the COVID-19 pandemic. Once that proved to be difficult, IMPA then audited the old forecast for performance and decided to maintain the basic load forecast methodology (*i.e.*, top down), tweaking the approach to try to find variables that work for each of the five load zones. In essence, IMPA was trying to retain the independent forecasts for each of the five load zones but with as many common variables as statistically possible. Ultimately, this is what IMPA tried to convey in Table 5 of the IRP; five load zones using the same variables but each with their own regression statistics. Annual real GDP was excluded from the DUK-OH zone due to poor regression statistics, as the Director surmises.

Regarding the NIPSCO load zone forecast (page 9), IMPA noted that on a going forward basis, either stripping the load out or utilizing a dummy should correct the overestimation. At the time of writing, IMPA was also seeing some declines in specific wholesale meters but had not tracked down root causes for the declines. Since filing, IMPA has revised the NIPSCO load forecast utilizing a dummy variable, to account for both the closure of St. Joseph's College and the additional, potentially COVID-related declines seen in some locations.

Source data and summary descriptions (page 9) for each data point are:

Peak Days: the number of days in a month with On-peak hours of use (as defined by NERC).

Off-Peak Days: is the number of days in a month defined as being solely Off-Peak hours (as defined by NERC)

HDD: Heating Degree Days for the load zone's relevant weather station using a 65-degree base temperature. *Source: ABB Energy Velocity Database*

CDD: Cooling Degree Days for the load zone's relevant weather station using a 65-degree base temperature. *Source: ABB Energy Velocity Database*

Weather Stations: Indianapolis, IN (DUK-IN); Valparaiso, IN (NIPSCO); Evansville, IN (Vectren); Muncie, IN (AEP); Cincinnati, OH (DUK-OH)

When using the term "Peak Season Dummy" IMPA uses either a 2 or a 1 for summer/winter months to pull load into the appropriate peak season. All IMPA load zones except DUK-OH utilize a 2 for June-August and a 1 for December through February. DUK-OH, because it is a winter peak, reverses these dummy variables.

Energy Intensity (btu/$ of GDP) is defined as total energy consumption as published by the EIA divided by US Real GDP in $ as published by the St. Louis Federal Reserve FRED database.

Source BTU: https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T02.01#/?f=M

Source Real GDP: https://fred.stlouisfed.org/series/GDPC1

IMPA uses this data to construct the btu/$ of GDP, then utilizes long term forecasts for Real GDP from a basket of forecasts such as IMF, World Bank, OECD, etc. Long term energy consumption estimates from oil majors such as Exxon Mobil and BP are utilized to place a trajectory on energy consumption patterns.

With respect to peak load forecasting, IMPA uses a seasonal peak forecast model with the following variables used:

Season/Area	DUK-IN	Vectren	NIPSCO	AEP	DUK-OH
Spring	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	Daily Peak MWh, High Temp	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	DUK-OH Load, HDD/CDD for Cincinnati
Summer	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	Daily Peak MWh, Difference between High and Low Temp, Average Wind Speed	Peak Dummy, Daily Peak MWh, High Temp	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	DUK-OH Load, HDD/CDD for Cincinnati
Fall	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	Daily Peak MWh, High Temp	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	DUK-OH Load, HDD/CDD for Cincinnati
Winter	Peak Dummy, Daily Peak MWh, Low Temp, Maximum Wind Speed	Daily Peak MWh, Average Barometric Pressure	Peak Dummy, Daily Peak MWh, Low Temp, Maximum Wind Speed	Peak Dummy, Daily Peak MWh, Low Temp, Maximum Wind Speed	DUK-OH Load, HDD/CDD for Cincinnati

From a methodology standpoint, these are unchanged from the previous IRP. The regression statistics for each season of DUK-IN are as follows:

Spring Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.957412	Intercept	-360.7256896	26.6779846	-13.52147454	1.62637E-25
R Square	0.916639	Peak Day in Month Dummy	5.893783041	2.171000692	2.714777137	0.007654179
Adjusted R Square	0.913739	Daily Load	0.048100359	0.001728924	27.82098594	6.73361E-53
Standard Error	8.118987	Hi Temp In Kelvin	1.259853061	0.061589326	20.45570458	4.02957E-40
Observations	168	Wind (mph) avg	-0.489696755	0.196244322	-2.495342292	0.014002607

Summer Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.924962	Intercept	-519.7393618	116.1955629	-4.472970817	1.82204E-05
R Square	0.855554	Peak Day in Month Dummy	2.944792761	1.874151832	1.571266912	0.118868039
Adjusted R Square	0.85053	Daily MWh	0.033081647	0.001667235	19.84222256	6.21033E-39
Standard Error	8.230051	Temp Hi Kelvin	2.374795298	0.401802571	5.910353658	3.56175E-08
Observations	168	Wind (mph) avg	-0.550008201	0.268027285	-2.052060488	0.042434233

Fall Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.965027	Intercept	-458.7824122	53.05783005	-8.64683708	3.83525E-14
R Square	0.931277	Peak Day in Month Dummy	3.423052621	3.277433617	1.044430802	0.298495761
Adjusted R Square	0.928866	Daily MWh	0.0513319	0.001545945	33.20422513	1.92878E-60
Standard Error	11.99111	Temp Hi Kelvin	1.54017007	0.176524525	8.724963702	2.53626E-14
Observations	168	Wind (mph) avg	-1.627523825	0.369998784	-4.398727491	2.46084E-05

Winter Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.906287	Intercept	487.5764877	69.20472473	7.045421965	1.59328E-10
R Square	0.821356	Peak Day in Month Dummy	3.262672217	1.604201234	2.033829764	0.044332044
Adjusted R Square	0.814976	Daily MWh	0.025703414	0.001990547	12.91273726	6.46508E-24
Standard Error	6.727253	Low Temp degrees Kelvin	-1.079999667	0.209522908	-5.154566033	1.10409E-06
Observations	168	Max Wind	0.165068595	0.065815452	2.5080523	0.01357266

For NIPSCO:

Spring Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.888326	Intercept	-18.37928951	4.369437479	-4.206328527	5.25153E-05
R Square	0.789123	Peak Day in Month Dummy	1.201170708	0.390021234	3.07975721	0.002606442
Adjusted R Square	0.781592	Daily MWh	0.040476667	0.002763117	14.64891731	8.66127E-28
Standard Error	1.510991	High Temp (Kelvin)	0.099107301	0.010765826	9.205731076	2.24853E-15
Observations	168	Wind Avg	-0.00258935	0.039714581	-0.065198985	0.948131802

Summer Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.920132	Intercept	-42.60975717	15.12261333	-2.817618638	0.005712522
R Square	0.846643	Peak Day in Month Dummy	0.90090451	0.258855469	3.480337945	0.000712581
Adjusted R Square	0.842571	Daily MWh	0.032798817	0.001646758	19.9172043	9.19797E-39
Standard Error	1.184312	High Temp (Kelvin)	0.226572201	0.052356919	4.327454792	3.27317E-05
Observations	168					

Fall Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.953047	Intercept	-39.91917655	6.440306215	-6.198335176	9.76014E-09
R Square	0.908298	Peak Day in Month Dummy	0.897487525	0.453168444	1.980472242	0.050102334
Adjusted R Square	0.905023	Daily MWh	0.049544658	0.001824589	27.15387313	4.30862E-51
Standard Error	1.710976	Hi Temp K	0.133676315	0.021801313	6.131571649	1.33725E-08
Observations	168	Wind Avg	-0.052703865	0.053954241	-0.976825244	0.330760857

Winter Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.840386	Intercept	31.55133354	6.259229023	5.040769945	1.79776E-06
R Square	0.706249	Peak Day in Month Dummy	0.57466009	0.184164296	3.120366455	0.002297558
Adjusted R Square	0.695758	Daily MWh	0.02557742	0.002252159	11.35684452	2.3677E-20
Standard Error	0.740302	Low Temp K	-0.010870232	0.015280146	-0.711395821	0.478318028
Observations	168	Max Wind	0.02823174	0.01037135	2.72208931	0.00752499

For Vectren:

Spring Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.988373	Intercept	-44.2511221	4.812313912	-9.195393915	2.90994E-18
R Square	0.976881	Daily MWh	0.06231651	0.000502277	124.0680209	1.5874E-300
Adjusted R Square	0.976754	High Temp (K)	0.09795531	0.016244248	6.030153724	4.0152E-09
Standard Error	2.383924					
Observations	168					

Summer Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.98439	Intercept	-15.5923852	0.808999529	-19.27366419	9.4953E-70
R Square	0.969024	Daily MWh	0.05991336	0.00035993	166.4581833	0
Adjusted R Square	0.968923	High Temp -Lo Te	0.24877926	0.036398161	6.834940424	1.496E-11
Standard Error	3.190737	Avg Wind	-0.1236475	0.046291038	-2.671089429	0.007694645
Observations	168					

Fall Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.991462	Intercept	-44.8004901	4.358779522	-10.27821891	6.60646E-22
R Square	0.982996	Daily MWh	0.06011464	0.00045039	133.472287	0
Adjusted R Square	0.982902	High Temp (K)	0.10937513	0.015421981	7.092158306	7.00864E-12
Standard Error	2.268615					
Observations	168					

Winter Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.984702	Intercept	44.6709168	12.18766517	3.665256317	0.000261552
R Square	0.969637	Daily MWh	0.05758546	0.000345761	166.5472001	0
Adjusted R Square	0.96957	Pressure - avg	-1.86628495	0.408010543	-4.574109619	5.45208E-06
Standard Error	2.749236					
Observations	168					

For AEP:

Spring Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.926678608	Intercept	-204.4295073	26.6779846	-13.52147454	1.62637E-25
R Square	0.858733242	Peak Day in Month Dummy	4.721838433	2.171000692	2.714777137	0.007654179
Adjusted R Square	0.853776514	Daily MWh	0.043913666	0.001728924	27.82098594	6.73361E-53
Standard Error	5.248943598	Hi Temp	0.78803392	0.061589326	20.45570458	4.02957E-40
Observations	168	Wind Avg	-0.204368029	0.196244322	-2.495342292	0.014002607

Summer Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.897250964	Intercept	-334.9858976	116.1955629	-4.472970817	1.82204E-05
R Square	0.805059293	Peak Day in Month Dummy	1.523887938	1.874151832	1.571266912	0.118868039
Adjusted R Square	0.798219268	Daily MWh	0.034409498	0.001667235	19.84222256	6.21033E-39
Standard Error	6.136993841	Hi Temp	1.474868789	0.401802571	5.910353658	3.56175E-08
Observations	168	Wind Avg	-0.281467685	0.268027285	-2.052060488	0.042434233

Fall Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.961558571	Intercept	-280.06478	53.05783005	-8.64683708	3.83525E-14
R Square	0.924594885	Peak Day in Month Dummy	2.754377611	3.277433617	1.044430802	0.298495761
Adjusted R Square	0.921949091	Daily MWh	0.050560684	0.001545945	33.20422513	1.92878E-60
Standard Error	7.542510588	Hi Temp	0.931130667	0.176524525	8.724963702	2.53626E-14
Observations	168	Wind Avg	-0.467018807	0.369998784	-4.398727491	2.46084E-05

Winter Peak Demand						
SUMMARY OUTPUT						
Regression Statistics			*Coefficients*	*Standard Error*	*t Stat*	*P-value*
Multiple R	0.796678578	Intercept	276.8250631	69.20472473	7.045421965	1.59328E-10
R Square	0.634696756	Peak Day in Month Dummy	2.506692946	1.604201234	2.033829764	0.044332044
Adjusted R Square	0.621765668	Daily MWh	0.018973868	0.001990547	12.91273726	6.46508E-24
Standard Error	5.001850917	Low Temp K	-0.398319435	0.209522908	-5.154566033	1.10409E-06
Observations	168	Max Wind	0.181934038	0.065815452	2.5080523	0.01357266

With respect to risk banding the load forecasts (page 9), IMPA believes the most appropriate method of doing this is through the extensive Monte Carlo work it does on each of the candidate portfolios. These Monte Carlo simulations account not only for risks in commodity prices, but also loads while capturing the correlation between all interrelated variables. IMPA believes constructing risk bands around load forecasts, while instructive, does not fully capture the portfolio risk associated with the uncertainty around the load.

With respect to state law and constrained service territory (page 9), IMPA is referring to Indiana Code 8-1-2.3-6 which was changed in 2015 to disallow municipal electric utilities from expanding their assigned service territory when the city or town annexes new land into the city/town boundaries. This law states:

After May 19, 2015, a municipality that:

> **(1) owns and operates an electric utility system furnishing retail electric service to the public; and**
>
> **(2) annexes an area beyond the assigned service area of its municipally owned electric utility;**

may not petition the commission to change the assigned service area of the municipally owned electric utility to include the annexed area according to the procedures set forth in subsection (a)(1). After May 19, 2015, the boundaries of the assigned service areas of electricity suppliers may be changed only according to the procedures set forth in subsection (a)(2) or (a)(3), as applicable. This subsection does not affect a petition that is filed with the commission under subsection (a)(1) before May 20, 2015, and pending before the commission on May 20, 2015.

While all utilities in the state have fixed territories, municipal utility territories are generally much more constrained. Although some members have existing electric service territory boundaries that allow for continued growth, many have essentially used the territory they have. These members cannot extend their electric service even if the town/city extends its municipal boundaries and provides all other municipal services. All the electric load growth generated by the municipal annexation and taxpayer funded provision of infrastructure and city services in the annexed land is served by a different utility. This constraint is having some effect on IMPA load growth and could explain why certain economic variables work better in some areas than others.

IMPA agrees with the director that, long term, electric vehicle (EV) penetration could become a factor driving load growth (page 9). IMPA communities have demographic and economic trends that may not support as rapid of near-term EV penetration as other areas of the state. Except for the handful of communities located in the “donut” counties around Indianapolis, most IMPA communities are seeing somewhat negative population growth. Compare these declines with areas such as Hamilton County where growth is almost 2%. Furthermore, from an economic perspective, the per capita and household income of member communities generally lags the state averages. At a time when EVs exceed the price of internal combustion engine (ICE) vehicles, rapid deployment in these communities does not seem likely. IMPA does believe that ICE/EV parity will reflect a “tipping point” which will lead IMPA to a greater penetration of EVs in member communities.

IMPA did not explicitly model increased EV load not because it does not believe EV will influence future loads, but due to a lack of information on how large or how fast expansion of EV use will occur in the member communities. Before planning for EV load, IMPA thought it better to understand the potential growth from a time and volume perspective. IMPA will continue to analyze EV impacts in member communities and its effect on IMPA’s load and load shapes.

B. Energy Efficiency

To date, the energy efficiency (EE) programs implemented by IMPA have largely been rebates to incentivize the installation of more energy-efficient HVAC systems, lighting, refrigeration, etc. This is the primary method in which IMPA can implement EE programs with its members given the wholesale nature of IMPA's business. Measures that focus more on end-user behavior modification, such as using AMI to implement time-of-use rates or manage device consumption during periods of high demand, are very difficult for IMPA to implement due to a vast array of rate schedules and metering systems among the membership. More importantly, however, is the fact that IMPA does not have a direct relationship between the end user and the utility, the local municipal utility does. Ultimately, the decision to implement more advanced EE programs lies between the municipal utility and the end user.

From a planning perspective, IMPA's solution to this was to create, as mentioned, EE load decrements in tranches. The first tranche was intended to represent IMPA's existing program based on IMPA's historical annual cost of implementation per MWh saved per year. IMPA's initial EE load decrement tranche was priced accordingly, while the next tranches were priced at increasingly higher costs. The goal of having increasing costs for the subsequent tranches was to reflect the increasing cost, difficulty and diminishing returns of more complex solutions. IMPA acknowledges that these later tranches were not well defined in the IRP text and did not represent any specific EE programs. IMPA will attempt to improve the data flow between member utilities in an effort to expand the EE modeling and future program delivery.

Regarding the director's comments about borrowing AMI and load research data (page 9-10), IMPA's engineering subsidiary, IMPA Service Corporation, is currently assisting some members with the installation of AMI systems. At this time, the program is in its early stage with only a few thousand meters installed. IMPA's planning staff hopes to be able to work with some of the members to utilize some of the AMI data to assist in load forecasting and EE. IMPA will endeavor to more thoroughly review EE and demand side programs over the coming years.

C. Resource Optimization and Risk Analysis

Modeling

To clarify the Director's comment regarding whether IMPA studied the Base Case Portfolio in the other two cases (page 10), IMPA did not. The reason for this is because within Aurora you first must begin with a given set of deterministic assumptions that results in a market build plan that is optimized for that deterministic world view. Challenges arise when build plans vary greatly between cases. In this year's IRP, there were no CTs built in the Green Case, which would have ruled out their selection for a "base case" plan in the Green Case market expansion. In other words, if the base plan built a CT and the optimization selected the CT for the portfolio, that same portfolio could not be replicated in the Green Case as the CT needed was never constructed. In summary, the ability to run scenario-specific portfolios across different world views in Aurora is not always forward and backward compatible due to limitations of optimized market expansion in each world view. In theory, IMPA could have introduced the needed supply to the Aurora optimized footprint, but this would potentially yield disconnects between market prices for energy and capacity. In future IRPs, IMPA will enhance and improve this aspect of its modeling portfolios across different world views.

Regarding the IRP comment that IMPA plans for the best expectation of future events as being "concerning" (page 12), we believe the Director misunderstands the intent of the comment. In this statement, IMPA is explaining that we take a market-based view whenever possible and IMPA will take readily observable forward prices as the best proxy for the expectation for future prices/market conditions. IMPA believes that to take a view that is wildly different from market expectation is imprudent. This is not to say we ignore any "non-consensus" viewpoints or potential outcomes. While forward prices for IMPA's commodity exposures move daily, policy measures move much more slowly and IMPA closely monitors those events as part of its planning process. Policy risks, whether coming from a federal or state level or even ISO stakeholder process, are probably the biggest risk facing most utilities. There is no forward market for policy actions (other than perhaps predictit.org), but policy actions move at a much slower pace and utilities can shape policy actions through stakeholder processes. Finally, that statement was written in the context of being mindful about not overcommitting to a particular long-term plan given all the short-term uncertainty unfolding as the IRP was in progress (COVID-19, elections, etc). The ultimate intent was to convey that while the IRP set forth a short-term action plan, the level of uncertainty in the world might lead the plan to change depending on events unfolding concurrently with the publishing of our IRP. For example, the IRP was due on November 2nd and elections were held on November 3rd.

Finally, IMPA believes it has a robust framework for evaluating candidate portfolios through its stochastic modeling. This allows IMPA to take a market-based view while simultaneously accounting for risks to that view, whether it be changes to load (Figure 44), market prices (Figures 40 and 41), or, to a degree, CO2 policy changes (Figure 43). Risk profiles of each of the plans (and cross scenario plans) presented in Figure 103 implied a lower potential risk to Average System Rate ("ASR") in the Green Portfolio under a Base Case world. However, by fusing stochastic analysis and analyzing portfolio impacts, IMPA illustrated that the Green Portfolio in the Base Case was overly reliant on off-system sales, thus creating an artificially low ASR for that portfolio. In this manner, IMPA gauges the relative value of portfolios that may benefit from taking a significantly different view than the market-based view.

On retirements (page 10), the Director seems to be most concerned with the Green Case. To begin, all resources with publicly announced retirement dates were manually retired in Aurora (IRP 11-75). Second, any resource that has not announced a retirement date is nevertheless treated as retired when it reaches 60 years of age. Beyond these entered retirement dates, IMPA allowed Aurora to retire resources based on economics. Those units with slated retirement dates can be retired earlier by the model. The model determines retirements and additions by a rolling NPV of the resources.

Aurora converts overnight construction costs, local labor adders by region, and financing costs into an amortized fixed cost over the life of the asset. Aurora also carries default fixed costs for existing units based on their market research and IMPA staff updates these fixed costs for IMPA specific information and to account for additional capital investment in order to make the evaluation between existing assets and new assets more "apples to apples."

IMPA agrees the Green Case was somewhat curious. In 2026, the second year of an aggressive CO_2 tax in the Green Case, Aurora selected to keep some coal-fired resources open while building a handful of combined cycle ("CC") units and building vast amounts of solar and wind. Solar and wind facilities do not receive the capacity credit of a coal or gas facility (or perhaps batteries in the future), so something must provide that capacity. At this point it becomes a question of whether it is more economical to leave an existing unit to act solely as a capacity resource or build an entirely new unit. These coal facilities that were left online had fairly low run times but were providing the needed capacity for the regions. An analysis of Aurora proformas shows that these facilities combined O&M, ongoing capital, fuel and CO_2 expenses were less than the new build cost, O&M, ongoing capital, fuel and CO_2 expenses of CC plants.

Furthermore, IMPA notes the "false economy" of replacing a coal unit with a 52% net capacity factor ("NCF") with a CC that has a 92% NCF. It is popular to claim 50% CO_2 savings by replacing coal with gas, but that neglects how unit performance in a heavily renewable energy portfolio may impact total emissions.

Ultimately, Aurora's optimization of market expansion under the Green Case seems to suggest that certain coal assets can have a place even in a very punitive CO_2 tax regime. IMPA has anecdotally seen this result in CO_2 analyses by other entities as well. Of course, different cost assumption regarding the prices of commodities 7 or 10 years from now could very well have produced different results.

Since the publication of the IRP and Presidential election/transition however, IMPA allows that perhaps a better path forward, given some of the climate proposals being put forth in the new administration would be to model climate policy from a CO_2 emission cap, versus an outright tax.

Storage

To expand on the analysis of storage assets on 11-68, Aurora models new resources strictly from their value to the RTO markets (i.e., energy and capacity value). Based on IMPA's internal analysis for a small battery of around 2 MW, the fixed annual energy revenue requirement far exceeds the revenue requirements for other energy market resources.

In its internal analysis of battery storage, IMPA concluded that the economics of storage could potentially be beneficial in transmission applications or behind the meter applications, neither of which are explicitly handled in Aurora's market expansions.

IMPA fully anticipates expanding the modeling of battery storage systems in ongoing analysis and future IRPs.

D. Future Enhancements to IMPA's IRP Process

IMPA appreciates the Director's comments on IMPA's lack of proposed improvements. To begin, with a modeling resource such as Aurora, IMPA strives to strike a balance between supplying data and narrative. For example, IMPA can create a pro forma income statement with Aurora for every existing generator in the Eastern Interconnect in addition to any new resource added for capacity expansion. Using the Green Case, for MISO Load Resource Zones 4 and 6, this totals roughly 400 generating stations and 86 reportable variables for each time interval modeled, be it annual, monthly, by time of use, or even hourly. This is almost 35,000 data points per reported interval.

This is a double-edged sword as it gives IMPA staff reams and reams of data with which to support the planning process, but also complicates matters in terms of what information the Director will find most useful or relevant. In an effort to make this year's IRP more readable, IMPA attempted to be judicious in its presentation of supplemental information. Going forward, IMPA will err on the side of more information rather than less as well as improve the analysis and discission of certain technologies.

Also, as a note for future reference, IMPA has begun the early phases of evaluating power supply modeling platforms to determine if we should stay with Aurora of move to something else. IMPA undertakes these evaluations as means to not only improve our internal analyses, but to improve the robustness of the IRP process.

Summary

The Director also offered several summary observations of the IRP (Page 14). IMPA offers the following comment and goals for future IRPs.

DERs and EVs: The director commented that the effects of DER and EVs were small at this time but could be large in the future. IMPA acknowledges that analysis of expanded customer generation was lacking. Customer generation is a customer choice and it is difficult for a utility to model customer decisions that may be based on much different factors than utility decisions. Going forward, IMPA will include more analysis and discussions of the effects of DER, EVs and their effect on IMPA's long term load forecast(s) and member distribution systems.

Organizational constraints: The director acknowledged the organizational relationship and difficulties in data sharing between IMPA and its members but encouraged a greater coordination of data between IMPA and its member systems. Data acquisition between IMPA and its members always has and continues to be a challenge. IMPA will work on ways to educate and work with member communities to increase the flow of information between IMPA and the members.

Existing resources: The director suggested that IMPA's discussion of existing resources and future decisions was too limited. Going forward, IMPA will include greater discussions of such decisions and include any internal reports regarding such decisions in the Appendix.

Stakeholder Comments of the Sierra Club

Whitewater Valley Station

The Sierra Club's evaluation of Whitewater Valley Station grossly underestimates the station's benefits to IMPA members and overstates the costs of keeping the units operational. While the Sierra Club is correct that the resource is used in a peaking fashion, the LMP revenues from the plant make up less than 20% of the gross benefits IMPA and its members receive. Major sources of revenue ignored in the Sierra Club analysis were equivalent PJM capacity value and various savings on PJM transmission charges and fees.

In addition to the revenues being grossly understated, the ongoing capital expenses were overstated as well. At this time, this unit is used as a capacity resource only. Capital maintenance is performed to maintain compliance and for reliability and safety for the limited days of operation per season. While the station does have certain NOx, Hg, HCl, and PM reduction equipment, neither unit is equipped with a flue gas desulfurization ("FGD") scrubber as stated in the Sierra Club analysis. This error overstates the requirements by 15% even assuming the rest of the cap-ex formula is proper for the station. However, comparing the capital requirements of a seldom used peaking-only facility to a baseload resource is not a proper comparison.

In summary, contrary to the Sierra Club's analysis that the plant costs IMPA and its members ($96)/kW-yr, the plant benefits IMPA and its members with significant positive net revenues. The station is not an integral part of IMPA's energy supply as it provides virtually no energy to the portfolio and shutting it down would not change IMPA's energy supply portfolio at all.

Going forward, barring unforeseen issues at the plant or significant changes in revenue streams, IMPA continues to see the facility offering benefits to IMPA and its members. IMPA will continue to operate this facility until the combination of plant expenditures and market revenues no long provided benefits.

Clean Energy Portfolio Replacement

IMPA has been rapidly expanding its renewable power supply portfolio. Since 2018, IMPA has executed power purchase agreements for 75 MW of wind and 150 MW of solar, while actively expanding its solar park program that interconnects solar to its members' distribution systems to over 120 MW and growing. IMPA is also negotiating additional solar power purchase agreements.

One area where Sierra Club's analysis diverges from IMPA's experience, however, are the rapidly shifting costs in the renewable space. During negotiations with renewable developers, IMPA has found them unwilling or unable to hold pricing due to cost increases in raw materials, labor, equipment and EPC contracting. In addition, MISO's interconnection queue is experiencing delays in study timelines, casting doubt on stated commercial online dates. Lastly, there is the increasing scarcity of available projects in areas where zoning battles or community opposition have the potential to significantly delay or kill a project. This risk is acute with wind and is burgeoning with solar.

Ultimately, Sierra Club's analysis suggests IMPA can achieve near immediate huge savings by implementing a portfolio plan that is solar, wind, storage, and DSM. This, however, ignores some of the very real constraints being experienced in the marketplace at the time of writing.

Storage

Sierra Club notes that the EIA is tracking 4,300 MW of storage in a wide range of geographic locales. Fifty percent of these locales have high levels of solar penetration and investment in storage is being spurred by the ability to pair storage systems with solar PV facilities to qualify the entire system for the investment tax credit. New York, Florida and Montana have systems where storage can be deployed as a transmission asset in order to delay/defer upgrade costs to the transmission system. In discussions with storage developers, IMPA believes there is a compelling case to be made for storage as a "non-wires" alternative. At this time, IMPA has not found any non-wires alternatives among its membership.

Commercially, IMPA has solicited quotes for pilot projects to better educate itself on the pros and cons of storage. NDAs prevent IMPA from sharing specific costs, but quoted costs were significantly higher than the NREL study price used by the Sierra Club.