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	Stakeholder	Comment	I&M Response
Questions 42 – 63 were submitted by MPSC Staff (1/04/19) in response to I&M's request for comments on its 2018-2019 IRP Inputs & Portfolios Update dated December 10, 2018.			
42.	MPSC Staff (1/4/19)	VVO - Slide 20 points out that I&M has 68 MW of demand reduction potential from VVO. How many MW of VVO potential are in Michigan vs Indiana? How many of the existing and planned VVO circuits are in Michigan vs. Indiana?	I&M estimates about 16 MW out of the 70 MW (see response to 43) total demand reduction potential are in Michigan. The remainder are in Indiana. As of 2018, I&M has 18 station busses with 46 distribution circuits enabled and operating in VVO mode in Indiana. I&M has 1 station bus and 3 distribution circuits enabled and operating in VVO mode in Michigan. I&M has an additional 6 station busses with 19 distribution circuits currently under construction in Indiana with planned in-service dates by mid-2019. I&M is currently planning the next 2 deployment of circuits for VVO in Michigan and estimates those deployments to include about 3 station busses with 9 distribution circuits in each deployment.
43.	MPSC Staff (1/4/19)	VVO - Is the 68 MW of potential for VVO circuits intended to reflect the sum of demand reduction in the "Demand Reduction (kW)" column of slide 20?	Yes, however, in checking this value the Company determined that the value is ~70MW, not 68MW as originally reported.
44.	MPSC Staff (1/4/19)	VVO - What do the capital and O&M costs consist of?	The capital costs includes the engineering and design, equipment and labor to install the necessary VVO equipment/systems. The O&M costs consist of the equipment and labor estimated to maintain the performance of the VVO system. VVO capital costs generally consistent of the cost to place assets in-service to enable VVO operation. These costs can include: station relay and control equipment costs, station communication system costs, VVO software/algorithm costs, distribution line equipment controls costs, distribution system communication equipment costs, and distribution line voltage control equipment and voltage monitoring equipment costs. O&M costs can include

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			communication system operation and maintenance costs to ensure ongoing communication and system reliability, control equipment maintenance costs, and VVO software maintenance costs.
45.	MPSC Staff (1/4/19)	VVO -How do the capital and O&M costs on slide 20 compare to the actual costs for the three pilot circuits in Niles and any other VVO circuits currently in operation?	The capital costs are based on average per circuit cost estimates multiplied by the number of circuits per tranche. Actual cost performance has improved as I&M has gained experience through several VVO deployments. Initial pilot costs were highly dependent on circumstances encountered at each station where specific stations and circuit costs varied around the average contained within slide 20 costs, with some higher and some lower. The actual costs of the Niles pilot were higher than estimated. However, as I&M has gained experience and honed planning functions, the average cost estimate used in slide 20 can be considered as reliable representations of costs for VVO deployment. I&M has also found O&M estimates as reliable, but can vary higher or lower depending upon extenuating circumstances such as communication equipment reliability, etc.
46.	MPSC Staff (1/4/19)	VVO – a. What historic data, planning information, etc. is the Company using to determine the tranche costs for Volt VAR on p. 20? b. The Company listed both a demand reduction and energy reduction for Volt VAR. Is it intended to be used as an energy savings resource or as a demand response resource during peak events? c. How is this resource modeled? d. How did the Company study Volt VAR to determine which modeling and operation approach would provide the highest ratepayer value?	a. See response to question 45 above. b. I&M operates VVO to produce both energy and peak demand reduction. c. The resource is modeled as any other resource; it has an installed cost and an ongoing cost and associated energy and demand characteristics. The energy savings are assigned the retail load shape. d. I&M undertook pilot VVO projects with independent EM&V on each pilot to determine and assess the benefit cost performance of VVO. However, within the IRP model, the analysis is based on the Cumulative Net Present Value of Revenue Requirements.
47.	MPSC Staff (1/4/19)	VVO a. How does I&M plan to obtain voltage measurements on VVO circuits? b. What physical location will the	a. I&M relies on communicating control equipment and end of line voltage sensors to measure voltage on circuits. b. As part of the automated VVO system, I&M monitors voltage at the station bus, distribution

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	Stakeholder	Comment	I&M Response
		measurements be taken in the field and how often?	equipment locations including voltage regulators, capacitors, and end of line voltage sensors on a continuous basis.
48.	MPSC Staff (1/4/19)	DR/EE/DSM a. Would like a more granular discussion about DSM and EE programs. Specifically how much is the load forecast adjusted? b. What adjustment amounts are specific to EE and by program of DSM?	The load forecast incorporates the DSM/EE programs filed with Commissions. It is assumed that impacts of the programs degrade over time. Table 48-1 provides annual energy and seasonal peak demand effects reflected in the load forecast. Tables 48-2 and 48-3 provide the estimated effects of each DSM program sponsored by the Company in its Indiana and Michigan jurisdictions. Tables 48-1, 2 and 3 provided below.

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	Stakeholder	Comment	I&M Response

Indiana Michigan and Indiana and Michigan Jurisdictions
DSM/Energy Efficiency Included in Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)

	I&M DSM/EE			I&M - Indiana DSM/EE			I&M - Michigan DSM/EE		
		Summer*	Winter*		Summer*	Winter*		Summer*	Winter*
Year	Energy	Demand	Demand	Energy	Demand	Demand	Energy	Demand	Demand
2019	181.2	48.1	50.2	152.8	43.4	44.8	28.4	4.8	5.4
2020	262.1	68.7	73.6	223.4	62.4	66.1	38.7	6.3	7.6
2021	266.5	67.0	75.3	232.9	62.4	68.2	33.5	4.7	7.1
2022	210.7	47.3	56.5	182.1	44.4	51.1	28.6	2.9	5.4
2023	154.2	27.8	37.6	129.3	26.3	33.7	24.9	1.5	3.9
2024	87.2	9.8	17.9	66.3	8.9	15.1	21.0	1.0	2.8
2025	43.1	2.1	4.8	25.8	1.2	2.9	17.3	0.8	1.9
2026	42.5	2.0	4.7	25.4	1.2	2.8	17.1	0.8	1.9
2027	42.0	2.0	4.6	25.1	1.2	2.8	16.9	0.8	1.9
2028	41.9	2.0	4.6	25.1	1.2	2.8	16.8	0.8	1.9
2029	42.2	2.0	4.7	25.4	1.2	2.8	16.9	0.8	1.9
2030	33.9	1.6	3.7	19.3	0.9	2.1	14.7	0.7	1.6
2031	17.9	0.9	2.0	7.5	0.4	0.8	10.4	0.5	1.2
2032	6.8	0.3	0.7	0.0	0.0	0.0	6.8	0.3	0.7
2033	3.7	0.2	0.4	0.0	0.0	0.0	3.7	0.2	0.4
2034	1.2	0.1	0.1	0.0	0.0	0.0	1.2	0.1	0.1
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

*Demand coincident with Company's seasonal peak demand.

Table 48-1

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	Stakeholder	Comment	I&M Response

Exhibit 2:

June 2018 Forecast - AEP Utility Operations

DSM Filed Programs - Michigan

Incremental kWh Reduction

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
R&C - Home Energy Products		690	9,670,000	5,797,473	13,028,293	14,553,201			2,782,700	4,049,765	5,311,934	5,311,934
Res - Appliance Recycling			590,000						666,484	882,678	557,840	557,840
Res - Low Income EE Assistance			1,040,000	578,415	615,560	687,609	661,790	565,975	107,792	733,131	196,778	196,778
Res - HVAC Rebates		3,623	190,000									
Res - Education			298,000				370,272	364,913	1,732,040	5,542,425	2,245,000	2,245,000
Res - Online Energy Audit			70,000						2,940,075	925,270	399,935	399,935
Res - Multi-Family			460,000									
Res - New Construction / Education	13,000		4,000							366,016		
Res - Onsite Audit			340,000									
Res - Pilot /Weatherpoofing			80,000				617,119	477,637	1,290,029	44,479	452,616	437,962
C&I - Prescriptive			7,660,000	10,375,900	17,303,847	19,329,191	17,396,489	8,432,371	7,360,903	9,741,657	6,766,700	6,770,827
C&I - Custom			4,440,000				-	11,619,760	8,867,487	7,462,637	10,321,143	10,321,143
C&I - Education			260,000				330,016	276,295	27,570	358,649	492,602	498,547
C&I Direct Install (Audit)									456,603	1,571,641		
R/C/I - IVVC Pilot			60,000									
Internal Facility / EECO / Other (VVO)		542,064	162,410					808,741	1,358,671	959,593	2,869,166	3,361,432
Residential Programs							12,138,924	12,572,861	1,303,551	6,950,823	3,691,890	3,828,153
C&I Pilot							60,296	525,460		14,311	1,402,224	1,405,691
TOTAL	**13,000**	**546,377**	**25,324,410**	**16,751,789**	**30,947,700**	**34,570,000**	**31,574,906**	**35,644,013**	**28,893,905**	**39,603,075**	**34,707,827**	**35,335,241**

Table 48-2

June 2018 Forecast - AEP Utility Operations

DSM Filed Programs - Indiana

Incremental kWh Reduction

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Res - Low/Moderate Income			467,000	591,552								
Res - Rebates			9,816,000	38,991,004	(1,411,010)							
Res - Appliance Recycling			2,469,000	3,030,422	4,260,656	3,987,730	4,029,025	3,185,144	2,343,112	3,391,002	3,348,400	3,348,40
Res - Whole House(home energy audit)				877,408	15,295	6,333,587	2,181,517					
Res - URWP Loans	18,000	9,200			779							
Res - Statewide Core Lighting	1,800,000	875,440			21,229,646	19,606,993	15,747,122		8,790,461	11,684,436	10,796,000	8,901,43
Res - Statewide Core Home Energy Assessments					4,237,391							
Res - Statewide Core Income Qualified Weatherization			90,000		1,723,888	2,119,206	1,529,696	30,132	328,281	308,497	1,129,074	1,129,07
Res - Home Energy Products					465,733		525,115	11,732,143	1,245,832	978,032	4,400,500	6,411,50
C&I - Rebates Prescriptive			4,079,000	24,910,220	38,491,566	91,826,921	23,782,606	25,386,828	25,334,528	38,223,072	22,877,500	16,665,00
C&I - Incentives					5,451,966	34,832,235	15,441,282					
R/C/I - School Energy Education			12,000	766,479	2,063,010	4,117,010	2,252,528	4,962,843	4,108,500	2,481,388	3,179,000	3,179,00
Res - Online Audit						12,257,878	2,818,382	5,135,088	3,214,949	2,627,578		
Res - New Construction						-	369,415	719,602	679,203	1,041,862	851,741	851,74
Res - Low Income Weatherization	471,000	291,000				50,919	1,395,949	205,265	125,105	472,814	734,847	744,84
Res - Home Energy Reporting			259,000		3,662,381	16,698,313	23,776,713	26,636,044	28,721,021	28,006,310	41,190,745	41,629,37
Res - Renewables & Demonstration						58,978	40,315		15,000	180,819		
C&I Custom						18,571,762	20,465,602	37,072,689	23,934,086	34,738,978	29,458,023	27,648,02
C&I HVAC Optimization /						-	12,985					
C&I Direct Install (Audit)					100,691	3,780,638	4,383,524	2,573,902	2,690,169	2,596,065	1,799,550	1,599,60
C&I Rebates					687,018							
C&I Load Management										20,125	5,911,740	5,911,74
Res - Peak Reduction			26,331			213,356	62,367	31,496	88,286	16,014		
Internal Facility / EECO / Other (VVO)		3,299,037	1,755,214	491,492	8,588,707		7,733,573	9,328,934	18,544,218	11,169,905	24,794,320	30,464,32
TOTAL	**2,289,000**	**4,474,677**	**18,973,545**	**69,658,577**	**89,567,717**	**214,455,526**	**126,547,716**	**127,000,110**	**120,162,751**	**137,936,897**	**150,471,438**	**148,484,06**

Table 48-3

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	Stakeholder	Comment	I&M Response
49.	MPSC Staff (1/4/19)	DR/EE/DSM - On page 11, what is the reason for the large decline in peaks scenarios in 2020? Is this the result of incremental EE & DSM?	This forecast decline is not the result incremental EE & DSM. This reduction in load reflects FERC Wholesale customers that have opted to select alternative energy suppliers. Therefore, these customers would no longer be a part of the Company's internal load.
50.	MPSC Staff (1/4/19)	DR/EE/DSM - Provide a view of the DR blocks that can be selected referring to P. 19 similar to the information for Volt VAR on P. 20. Identify the data, potential study, etc. that is used to determine the reasonableness of the block cost and DR potential. Confirm that the Company is considering only two programs as shown on P. 19.	The blocks are shown on page 19, and the model can select 4 blocks of each resource per year. I&M has used both direct experience of implementing similar programs including Home Energy Management smart thermostat demand response, residential AC cycling, and the September 2017 State of Michigan Demand Potential Study to inform the DR block modeling reflected on Slide 19 (Dec. 10th IRP Inputs PowerPoint Presentation). Confirmed, I&M is modeling (2) demand response measure bundles.
51.	MPSC Staff (1/4/19)	DR/EE/DSM - What resources on P. 21, if any, were screened out prior to running the resource expansion model?	Nuclear, Coal with 90% Carbon Capture and Natural Gas Combined Cycle with Carbon Capture.
52.	MPSC Staff (1/4/19)	Renewable Energy - Would the Company please provide a short explanation of the meaning of the term Tranche as it is used for wind and solar?	It is a resource block made available within the model.
53.	MPSC Staff (1/4/19)	Renewable Energy - Regarding solar LCOE, has the Company conducted a request for proposal for solar power purchase agreements? Staff is aware of solar PPA pricing available for Michigan based solar projects significantly less than the $62 to $68 per MWh pricing mentioned on slide 25. In Consumers Energy's IRP case, the Company reported that preliminary	No, the Company has not conducted a request for proposal for solar PPAs for this IRP analysis. For this IRP, the Company in confident that all of the resource assumptions are reasonable proxies for an IRP analysis. The differences between the calculated LCOE estimate and the PPA value is most likely driven by the assumptions included in each calculation. Key assumptions impacting this calculation include: cost of capital; installed cost; operating cost, asset life and asset performance to name a few.

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		analysis of solar proposals indicates an expected weighted average levelized PPA cost of $49.10/MWh for an up to 20-year contract and up to 100 MW in size.	
54.	MPSC Staff (1/4/19)	Renewable Energy - Would the Company consider a solar PPA with a potential purchase by the Company after the 5 year tax credit period ends?	Yes, but this doesn't rule out other ownership structures that the Company may consider in the future.
55.	MPSC Staff (1/4/19)	Renewable Energy - Would the Company provide some of the background for the DG Forecast on slide 27? What resulted in the increase in 2016? How many DG interconnection requests did the Company receive in 2018? Does the data include Company-owned DG	The DG forecast shown on slide 27 (Dec. 10th IRP Inputs PowerPoint Presentation) is based on PJM's November 27, 2018 Distributed Solar Forecast. The significant increase in IN DG in 2017 is likely due to the deadline established by Indiana Senate Bill 309 for net metering customers to be grandfathered under the net metering rules for 30 years. The Company observed a significant increase in Indiana DG in 2017 ~8MW, consisting of ~1MW Residential; 6MW Commercial, which includes Schools ~5MW, and 1MW Industrial. DG interconnection requests in 2018: MI – 39 interconnection requests; no company owned DG IN - 102 interconnection requests; no company owned DG
56.	MPSC Staff (1/4/19)	Storage -Please provide the information used to generate its cost estimates for energy storage.	As stated on slide 25 (Dec. 10th IRP Inputs Powerpoint Presentation), the primary data used to develop the Storage Cost estimate are from Bloomberg New Energy Finance Energy Cost Survey, September 4, 2018 and are provided to AEPSC under a subscription service.
57.	MPSC Staff (1/4/19)	Storage - Has the Company done any benchmarking of the costs of co-locating battery storage and renewable resources?	Yes, at a "desk top" or Class V estimate level and it resulted in nothing definitive or conclusive. The Company continues to monitor this resource configuration to further understand opportunities to introduce this to the model.
58.	MPSC Staff	Storage - Was energy storage considered as	Energy storage is considered a resource in the IRP. It has both energy and demand

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	(1/4/19)	a potential demand response resource for this IRP?	characteristics that are reflected in the model, in essence it has a "demand response" characteristic.
59.	MPSC Staff (1/4/19)	Storage - Please explain how the Company decided on 87% efficiency for its energy storage resources.	This is a planning assumption and the value is an estimate based on information from the DOE/EPRI 2015 Electricity Storage Handbook**.**
60.	MPSC Staff (1/4/19)	Storage - Has the Company done any energy storage pilots to inform its inputs into its model? If so, please provide information about the pilots.	As related to lithium-ion technology, no; however, AEP has extensive experience with NaS battery storage technology. From 2006 to 2008 AEP installed 5 systems: 1Mw/7MWh in Charleston, WV; 2MW/14MWh in Milton, WV; 2MW/14MWh in Churubusco, IN; 2MW/14MWh in Bluffton, OH and 4MW/28MWh in Presidio, TX. From this effort AEP has gained experience in the application, project development, installation and operations of battery storage systems. These systems were initially installed for capacity and reliability reinforcement on the Distribution System. In 2017, the installation in Milton, WV began participating in the PJM Ancillary Services/Frequency Regulation Market.
61.	MPSC Staff (1/4/19)	Storage - Please clarify what is meant by the two battery systems shown on the graph on slide 25	The red line represents the installed cost over time for energy storage and is what the Company plans to model in the IRP. The blue line was the previous energy storage cost that had been presented to the stakeholders. The lines represent the installed cost on a per unit basis in the corresponding model year.
62.	MPSC Staff (1/4/19)	Modeling - Where there any instances in which storage and solar were modelled as a combined single resource? Please explain how the model handles energy storage in conjunction with renewables. Is the model capable of handling renewable resources and energy storage in conjunction as a single resource or are the two modeled separately?	No, the Company did not include solar and storage as a single resource in the model. Currently, the resources are modeled separately. Yes, the Company would expect the model to be able to model renewables and storage as a single resource. The resource characteristics would need to be defined.
63.	MPSC Staff	Modeling - Is I&M running the Base, Low,	I&M is performing resource optimization runs for the Base, Low, High and Status Quo

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	(1/4/19)	High and status quo modeling portfolios under varying load scenarios or are these portfolios independent scenarios? If they are independent staff would suggest running additional scenarios where both the commodity prices and load are varied into new scenarios. Not all combinations would be required only ones that do not stretch the imagination. This would be particularly important if the company seeks cost recovery as this would demonstrate robustness of decisions under changing conditions.	commodity pricing scenarios under the Base load forecast assumption. These commodity price optimizations are performed under a common load forecast assumption in order to isolate the impacts of varying commodity prices on optimal resource selection. The Low and High load forecast optimization runs are performed under Base commodity pricing in order to isolate the impacts of varying load forecast assumptions on optimal resource selection. During the development of the various commodity price scenarios, the Low commodity price forecast is created under lower load growth assumptions than the Base commodity price forecast, while the High commodity price forecast is created under higher load growth assumptions than the Base commodity price forecast. In order to provide additional information to demonstrate the robustness of the Company's resource decisions, the following additional optimization runs will be performed: • High commodity prices with High load forecast assumptions, and • Low commodity prices with Low load forecast assumptions
Questions 64 – 72 were submitted by the Indiana Coal Council on January 4, 2019 in response to I&M's request for comments on its 2018-2019 IRP Inputs & Portfolios Update dated December 10, 2018.			
64.	Indiana Coal Council (1/04/19)	Slide 9 – Retail Load Growth by Class • Sensitivities on load growth should be incorporated	The slide on Page 11 (Dec. 10th IRP Inputs Powerpoint Presentation) provides the sensitives to high and low economic growth associated with the load forecast to be used in the IRP.
65.	Indiana Coal Council (1/04/19)	Slide 14 – Long Term Forecast • Why is the Base Case referred to as a "consensus case"? Consensus implies agreement among parties. • The basis for each fuel price assumption needs to be disclosed even if only on a confidential basis	The term, "Consensus Case", has been used internally to recognize that it is distributed ubiquitously to all AEP operating companies after completion and is utilized for a wide variety of applications. It is often referenced for purposes such as fixed asset impairment accounting, capital improvement analyses, resource planning, strategic planning and others. To complement the Base Case Fundamentals Forecast, three associated cases are also created; the Lower Band, Upper Band, and Status Quo cases. The associated cases were designed and generated to define a plausible range of outcomes surrounding the Base Case Fundamentals Forecast. The Lower and Upper Band forecasts consider lower and higher North American demand for electric generation and fuels and, consequently, lower and higher fuels

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			prices. Nominally, fossil fuel prices vary one standard deviation above and below Base Case values. The Status Quo case assumes there will be no regulations limiting CO_2 emissions throughout the entire forecast period. We agree that it is not intended to imply agreement among I&M Stakeholders.
66.	Indiana Coal Council (1/04/19)	Slides 16/17 – Commodity Price Forecast • Supporting detail needs to be provided even if only on a confidential basis • Additional commodity price forecasts need to be disclosed o Delivered prices of coal for both PRB and local coals o Gas prices at the relevant trading hubs o Firm Transportation cost assumptions in the analysis o Justification for the CO2 price forecast	Delivered prices of coal: Projected FOB coal prices for Powder River Basin 8,800 Btu/lb., 0.8# SO2 are provided in the attachment "2018H2_LTF_FT_Aggregated Annual Pricing_2018 IM IRP Update.xlsx" in both real and nominal dollars. Please clarify this request for delivery costs by specifying the coals, transportation methods, and delivery points (power plants) specific to the I&M IRP. Gas prices at the relevant trading hubs: Projected locational natural gas prices for the Henry Hub, TCO Pool, Dominion South Point and TCO Delivered are provided in the attachment "2018H2_LTF_FT_Aggregated Annual Pricing_2018 IM IRP Update.xlsx." Firm Transportation cost of natural gas: Please clarify this request for transportation costs utilizing Firm Transportation by identifying the transporting pipeline, receipt and delivery points specific to the I&M IRP. For modeling purposes, pipeline transportation charges are generally the 100% load factor Firm Transportation rate as published in the delivering pipeline's effective Tariff. Justification of the CO2 price forecast: The United States Environmental Protection Agency (EPA) has determined carbon dioxide to be a pollutant under the Clean Air Act which makes emissions subject to further limitation. As such, the 2018 Fundamentals Forecast employed a CO2 dispatch burden (allowance price) on all existing fossil fuel-fired generating units that escalates 5% per annum from $15 per ton in 2028. This carbon price proxy is intended to reflect the risks and costs associated with the regulation of carbon dioxide emissions from fossil fuel-fired power plants and is not intended to achieve the national mass-based emission

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	Stakeholder	Comment	I&M Response
			targets similar to those proposed in the Clean Power Plan (CPP).
67.	Indiana Coal Council (1/04/19)	Slide 21 – Supply Resource Options There is inadequate consideration of coal going forward with the sole option being CCS with PRB. While not stated on the table, it appears that the CCS assumption appears to be based upon 90% (per the table on the prior slide). If true, the actual NSPS for GHG would require 30%. Further the proposed replacement NSPS for GHG eliminates the CCS requirement.	The Company has available new coal resource configurations that exclude CCS; however, with the current estimated installed cost between $2,900 - $3,300/kW depending on the fuel type, due to the relatively high installed cost levels it is highly unlikely that the IRP model would select/optimize a pulverized coal resource.
68.	Indiana Coal Council (1/04/19)	Slide 22 – Supply Side Cost Assumptions • As noted, coal resource costs are need for the 30% CCS option and the option that corresponds to the replacement NSPS for GHG • Costs are not provided for the natural gas with CCS resource option	NGCC with CC costs and performance characteristics are provided on the bottom of page 22 (Dec. 10th IRP Inputs Powerpoint Presentation).
69.	Indiana Coal Council (1/04/19)	Slide 29- Rockport Scenarios •(a) The basis for the various retirement dates should be provided • (b) The scrubber technologies under consideration should be provided along with costs. At a minimum, the options should include wet scrubber, dry scrubber, and an ammonia sulfate	a. The basis for the retirement dates are the requirements of the Consent Decree and the end date of the Rockport U2 lease. b. The scrubber technology included in this IRP analysis is the Alstom NID FGD system with integral Pulse Jet Fabric Filter, which is a dry FGD technology. In 2011, the Company completed an evaluation of scrubber technologies for Rockport Units 1 & 2. Four technologies were evaluated for detailed comparative analysis for

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	Stakeholder	Comment	I&M Response
		scrubber. • (c)The assumption that if a scrubber is retrofit, the basis for limiting its life for 10 years should be explained along with the incremental costs of the shortened life span. • (d)A scenario in which both Rockport units are scrubbed should be included • (e) Options for retaining Rockport 2 if a lease extension cannot be negotiated with current lessors	the Rockport Unit 1 evaluation: (1) Limestone based Forced Oxidized (LSFO) Spray Tower Wet FGD with existing Dry ESP; (2) Lime based NID Dry FGD System with integral Pulse Jet Fabric Filter (PJFF); (3) Lime based Circulating Dry Fluidized Bed Scrubber (CDS) with Pulse Jet Fabric Filter (PJFF); and (4) Lime based Spray Dryer Absorber (SDA) with Pulse Jet Fabric Filter (PJFF). The evaluation recommended the Alstom NID FGD system over the other evaluated FGD technology options because it offers excellent emissions control performance based on the unit's operating parameters, best minimizes the impact to the unit's overall environmental footprint, and offers the lowest total evaluated cost. A NID FGD system at Rockport Unit 1 or Unit 2 will effectively control SO2 emissions while minimizing water usage, auxiliary power consumption, equipment footprint, and reagent usage. In addition, the NID FGD system will allow for effective co-benefit control of emissions such as mercury, SO3, and other HAPs while mitigating the risk of future NPDES permit compliance. Before this evaluation, AEP evaluated the GE-Marsulex Ammonia Based FGD System. The process produced a fertilizer grade ammonium sulfate {(NH4)2SO4 }. The storage, logistics and marketing did not fit our business model or expertise. Additionally, the process had a number of additional steps on the backend associate with drying and pelletizing. Validating our assumptions is that to-date we don't believe that any have been deployed on any US coal-fired electric power generating plants. Based on this evaluation this technology was not further considered. c. For this IRP, the Company will use a 60-year life for the Rockport units. d. The portfolios already being evaluated in the study provide sufficient information to evaluate the value of scrubbing both units so it is not necessary to evaluate a separate portfolio for this scenario.

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	Stakeholder	Comment	I&M Response
			e. Options related to Rockport 2 after the lease expires may include a power purchase that is sourced from Rockport 2.
70.	Indiana Coal Council (1/04/19)	Slide 31- Stakeholder Scenarios • ICC will recommend additional scenarios for consideration but needs to see the additional information referenced herein to fully construct, e.g., the scrubber assumptions. Generally the scenarios of interest include: o Scrubbing of both Rockport units earlier and for longer (type of scrubbing and coal TBD) o No or delayed carbon pricing o Higher load growth	The Rockport 1 and 2 material scrubber assumptions include: installed costs: (2015 $) $778/kW & $784/kW respectively ; total levelized fixed O&M costs are $13.7M and $12.5M per year respectively; variable operating costs (2015 $) $0.98/MWh and $1/MWh respectively escalating at 2%: parasitic load: 35 MW and removal efficiency: 98%. In addition, the Company will consider additional specific scenarios that may be proposed by the Indiana Coal Council.
71.	Indiana Coal Council (1/04/19)	Missing Items Complete regulatory assumptions o ELG o CCR o Other	The known costs, issues, concerns or operational constraints related to ELG and CCR are included in all scenarios and portfolios.
72.	Indiana Coal Council (1/04/19)	Missing Items Decision metrics. At a minimum, they should include: o Five and 20-year NPV calculations o Life Cycle Analysis of Carbon Emissions ☒Total carbon emissions associated with the full life of any new resource o Risk analysis of associated with irreversible decisions	The IRP process provides an informative planning document based on a snapshot in time updated every three years that evaluates resource decisions based on a number of metrics and factors. These resource decision metrics include: Identifying the resource additions that are common under optimal plans created for various commodity price and load forecast scenarios. Identifying the revenue requirement at risk impacts of selected resources by conducting stochastic risk analysis.

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	Stakeholder	Comment	I&M Response
			In addition to providing these resource selection metrics, the Company can also provide: • Annual CPW curves so that the CPWs of the various optimal plans can be compared at any point in time during the 20 year reporting horizon. • Annual CO2 emissions for the various optimal plans

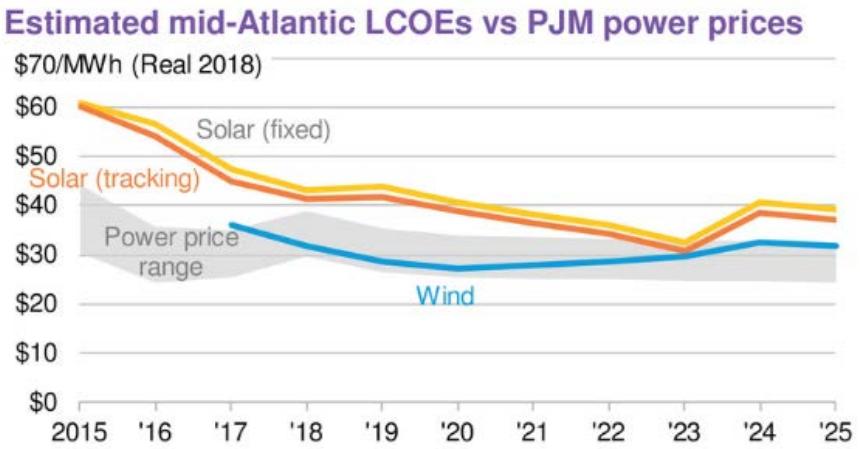
Questions 73 – 82 were submitted by the Sierra Club on January 8, 2019 in response to I&M's request for comments on its 2018-2019 IRP Inputs & Portfolios Update dated December 10, 2018

73.	Sierra Club (1/08/19)	**Request to revisit company's response to Q#40.** a. It would be helpful for council members' names who have written I&M about the 20-year energy plan to be listed in #40 so that people who wrote the utility know this is a response to their request (especially considering multiple letters were sent with different language). b. Additionally, it should be noted the number of public comments filed with the company instead of simply listing "and interested stakeholders". c. I don't feel the request for I&M to meet or exceed efficiency standards outlined by the Daniel's administration was thoroughly addressed. (i)Can some more details be provided please regarding what I&M's goals were under that program for each customer class, (ii)what performance goals I&M will be planning to meet in this 20-year energy plan; and iii)if those goals will meet or exceed the goals that were established under the statewide program? d. For the answer regarding local investments in renewable energy projects in the I&M service area it would be helpful	The following information supplements the Company's response to question #40: (a) and (b): Over 500 stakeholders provided letters or emails to I&M senior management requesting: • Replace Rockport generation with solar, wind, battery storage, and energy efficiency in a cost-effective manner. • Improve energy efficiency programs so they serve more low- and fixed-income residents. Ensure I&M meets or exceeds energy savings goals established under the former statewide Energizing Indiana program. • Invest in renewable energy projects that will transform abandoned spaces while bringing good jobs to our communities and improving the local tax base. • Ensure that this current and future 20-year planning processes are transparent and accessible to all interested customers, especially the people most impacted by I&M's decisions. Letters were submitted by Mayor Pete Buttigieg and various Ft. Wayne, South Bend and Muncie Council Members including Regiana Williams-Preston, Sharon McBride, Jo M. Broden, Jake Teshka, Karen White, Gavin Ferlic, John Voorde, Glynn Hines, Daniel Ridenour, Bradley Polk, Jerry Dishman, Nora Powell, Linda Gregory and others. Letters were also provided by the Executive Committee for People for the Common Good, including Sarah Hyndman, Shane Sullivan, Jain Young, Amanda Vance, Cortney Robbins and Meg Bloom. c. I&M's goals from the efficiency standards under the Daniel's administration were differently situated and are now not relevant according to the EE program target determination process used, and required by state law, today. Those prior targets relied heavily upon the "low hanging fruit" available at that time from low, cost high yield savings measures borne out by the programs proffered by statewide third party administrator. Today, I&M implements programs consistent with how state law now requires EE targets to be determined, as part of the optimal resource selection used in the IRP process. The "low hanging fruit" measures, costs, and savings now have different measure characteristics due to technological and efficiency baseline changes which are being modeled in this IRP. Those measures being modeled, as compared with other resource options in the IRP, will

		for you all to provide some context about how you're selecting **future** renewable energy generation sites, if any preference is given to locations in the service area/ local contractors. As well as detailing the scale of renewable investments the utility is considering in this planning time-frame.	determine I&M's future EE savings targets. The level of savings from the optimal resource selection process stemming from this IRP will determine the level of I&M's EE targets going forward. d. The IRP is a planning tool and is not meant to select any particular generation resource. The process of selecting specific new generation resources will occur after the IRP. When the time comes for I&M to select new renewable generation resources, the benefits of siting the resource within I&M's service territory is one factor among many that I&M expects to consider.
74.	Sierra Club (1/08/19)	The Rockport retirement scenarios should be made more robust to further test the going-forward value of these units to customers. In addition to the scenarios that I&M is already intending to model (Slide 29), I&M should model at least two additional Rockport scenarios: i) Retire Unit 1 in 2025 (with no FGD) and the Unit 2 lease is not extended; and ii) ii) Retire Unit 1 in 2023 (with no FGD) and the Unit 2 lease is not extended. The scenarios recommended here are to ensure that I&M can independently assess the value to ratepayers of maintaining or retiring Rockport Unit 1 independently of the economics of Rockport Unit 2. I&M must take care not to convolute the value of maintaining these units with the avoided value of deferring or avoiding FGD obligations. Finally, I&M must ensure that the full costs of maintaining either of the Rockport coal units after the analysis period (2037) are fully incorporated into	The portfolios already being evaluated in the study provide sufficient information for I&M to assess using Rockport 1 as a resource for its customers. I&M will clearly identify the assumptions forming the basis for each scenario analyzed, and provide a complete description of the costs and benefits of each, including the time period examined.

		any assessment in which either of the units continues operation.	
75.	Sierra Club (1/08/19)	I&M should model a "No OVEC" portfolio that assumes that OVEC is not retained to serve Indiana customers beyond June 1, 2019. In this portfolio, retain all other reference case assumptions and assume that at any needed energy and/or capacity is purchased on the PJM markets. For any PJM energy market purchases, use I&M's base case forecast. For any capacity market purchase, use actual PJM capacity prices through May 2022 and, after that date, use AEP's lower band PJM capacity price forecast. Assume that the costs and benefits of the OVEC contract are enjoyed by AEP shareholders for as long as AEP wishes to retain that contract, but no OVEC costs are billed to Indiana customers after June 1, 2019. I&M should compare the net present value of this "No OVEC" portfolio to that of its reference case portfolio that includes OVEC.	Under the Ohio Valley Electric Company (OVEC) Inter-Company Power Agreement (ICPA) originally entered into by I&M and the other OVEC sponsoring companies on July 10, 1953 and most recently amended on September 10, 2010 (see FERC Docket ER11-3181), I&M is contractually required to purchase a share of the output of the OVEC plants through 2040. Therefore, I&M's entitlement under the OVEC ICPA cannot be excluded from I&M's generation portfolio in this IRP.
76.	Sierra Club (1/08/19)	I&M's assumptions regarding solar and wind resources prices are unreasonably high and should be corrected. Slides 23 (wind) and 24 (solar) suggest that I&M's wind and solar price forecasts are derived from the Bloomberg New Energy Finance (BNEF) 2018 Renewable Energy Market Outlook, but the prices reflected on I&M's slides are much higher than BNEF's actual 2018 outlook prices, provided below in Chart 1. For wind, BNEF is projecting	The Company believes the renewable estimates provided are reasonable for this IRP analysis and expects to update the values before the final report based on new information from BNEF; however, an initial review of the new BNEF data has not revealed any significant differences from the company's current estimates. Additionally, the Company is open to considering a stakeholder portfolio that includes discounts to the Company estimated renewables installed costs. Regarding the comment on our current estimates versus the BNEF chart provided by the Sierra Club , the major difference between the two values is that the chart provided is in Real $s and the Company's values are in nominal $s. Furthermore, the Company's estimates

		Levelized Cost of Energy (LCOE) prices for wind between $30-$40/MWh (2018$) through 2025, not $50-$70/MWh as projected by I&M on Slide 23. For solar, BNEF is projecting LCOE prices of $30-$40/MWh, not the LCOE prices of $62-$68/MWh on Slide 24. Further, while BNEF's wind prices outlook is generally flat through 2025, I&M's price outlook shows substantially increasing prices throughout the forecast period. *Chart 1 shown in I&M response column.* Not only are I&M's solar and wind price projections high compared to BNEF's 2018 Outlook prices, I&M's prices are much higher than actual bids received by I&M's neighboring utility NIPSCO in its recent "all source" RFP. In response to its RFP, NIPSCO received 26 solar bids for 2023 (or earlier) delivery with an average price of $35.67/MWh. And, in response to its RFP, NIPSCO received six wind bids for 2023 (or earlier) delivery with an average price of $26.97/MWh I&M must dramatically reduce its forecasted wind and solar prices to reflect these market realities.	include, its cost of capital and expected performance levels and ongoing costs, which are most likely different than BNEF's assumptions. If we take the 2021 value from the chart, ~$28/MWh and assume 2% inflation in nominal $s this is equivalent to $30/MWh, the Company is modeling a $34.11/MWh resource or the Company's resource is ~15% higher, without knowing all of the details that produced the BNEF LCOE, the Company is confident that the modeled cost for its resources are a reasonable proxy for wind resources for this IRP. Regarding the comparisons to NIPSCO's bids the Company compares favorably to the values in Table 4-16 of the NIPSCO IRP from our perspective. The solar installed cost range from ~5% less or up to 15% higher, this is without knowing many key design considerations that impact this price; such as, expected capacity factor and DC to AC ratio, etc. For the wind resource our estimate is ~1% higher, again without knowing any key design characteristics of the NIPSCO resource. The major differences identified are between a "PPA" resource cost and an owned resource cost. The Company's current assumption is to own generating resources. **Chart 1: BNEF 2018 Renewable Energy Market Outlook (Provided by Sierra Club)**

			
77.	Sierra Club (1/08/19)	I&M should remove its arbitrary caps on the amount of renewable energy that its model can select. As noted in slides 23 and 24, I&M has included arbitrary constraints on its model for the amount of wind and solar that the model can select per year and total over the planning period. I&M should remove these constraints entirely or, at a minimum, dramatically raise these caps. I&M appears to have included these caps due to some notion of what would be pragmatically achievable in terms of time needed for construction. But these arbitrary caps prevent I&M's model from selecting the lowest-cost portfolio to serve customers. Instead of these arbitrary caps, I&M should allow the model to select renewable projects without constraint. If the model selects renewables at levels that	The Company will consider a Portfolio with higher annual build levels. Please see slide 31, 4b (Dec. 10th IRP Inputs Powerpoint Presentation).

		I&M considers administratively difficult to execute, it should explain that cost-versus-administration risk tradeoff after the modeling is completed.	
78.	Sierra Club (1/08/19)	I&M should revise downward its projections of storage costs to reflect better data. On Slide 25, I&M shows projected storage prices starting in 2018 at $450/MWh. But Lazard data shows that a four-hour Lithium Ion battery project has a dramatically lower LCOE of $200-$300/MWh today. I&M should either incorporate Lazard's lower price or explain its choice not to do so. In addition, I&M should consider incorporating the storage prices received by NIPSCO in response to its RFP, or explain its choice not to do so.	The Company is confident that the storage cost and performance characteristics are reasonable for this IRP. The Company may consider lowering the storage cost curve for specific stakeholder Portfolios. While on the surface the NIPSCO storage cost appear to be lower, it is not clear the assumed life or duration of the storage NIPSCO modeled.
79.	Sierra Club (1/08/19)	I&M should completely remove its arbitrary inclusion of new gas plants in its Company Scenarios. The pre-determined "assumed" new gas capacity in the Company scenarios are completely antithetical to any reasonable definition of an optimized or least-cost seeking resource plan. In fact, this pre-determined "assumed" gas capacity violates the Commission's Proposed IRP Rule that requires a utility to demonstrate how a preferred portfolio balances "cost minimization" against other defined criteria. In the Company Scenarios (Slide 30), I&M should not arbitrarily assume construction of a combustion turbine gas plant in 2022 or any future	The Company believes there is a misunderstanding here. The wording on slide 30 where we stated "Add"… was not meant to imply that we "pre-determined" to add a CT or NGCC. What should be understood is for Company Scenarios 1 "Conventional Portfolio", the Company is not allowing a NGCC to be selected until 2028, this basically allows for other resources to fill any need other than an NGCC. So in the "12-Year Peaking Plan", NGCCs are not allowed to be selected until 2034 & 2037 again to allow the model to pick other available resources. The Company is adding a short term market resource and plans to present the initial modeling results at the next stakeholder meeting.

		assumed gas plants in 2028, 2034, or 2037. For the 2022 timeframe, I&M should instead issue an all-source RFP for delivery year 2022 and use the results of such RFP to inform its modeling. If I&M believes there is insufficient time to engage in such prudent planning, then it should instead model the NIPSCO average bid results from that company's RFP to fill any capacity need in 2022. In no event, should I&M just assume by proclamation that a combustion turbine should be built in 2022. In addition, I&M should remove the construction of an NGCC in 2028, 2034, and 2037 from its Company Scenarios. Instead, the Company should seek least cost replacement or capacity market purchases for the purposes of this IRP, and state that any capacity shortfalls in those years will be met with an I&M all-source RFP. For the purposes of this modeling exercise, I&M should assume capacity additions are made in those years at the price of AEP's lower band PJM capacity price.	
80.	Sierra Club (1/08/19)	Sierra Club defines the "No New Fossil Generation" portfolio as one that meets any capacity shortfall with construction of renewable resources, storage, energy efficiency, or interruptible load. In this portfolio, I&M should prevent the model from selecting any new natural gas or coal-burning generation. This Portfolio should use average bid data from the NIPSCO RFP for wind, solar, and storage prices, and	The Company plans to run this Portfolio with the Company's resource assumptions. See slide 31, 4c.

		retain all other reference case assumptions. If necessary to meet capacity needs, the model could be allowed to choose to purchase capacity on the market at the "lower band" forecast price, but not the "status quo" or "higher band" forecasts, for the reasons stated in our eighth point below.	
81.	Sierra Club (1/08/19)	I&M should reject inclusion in its modeling of AEP's base and high band PJM capacity prices. For years, utilities have wrongly projected a dramatic escalation of PJM capacity prices, approaching the Cost of New Entry (CONE). As I&M is well-aware, these forecasts have always been wrong and always in the same direction—too high. I&M should recognize the reality that PJM capacity prices are never going to reach CONE and should stop relying on assumptions that it knows are incorrect. Assuming these implausibly high capacity prices, could, for example, cause I&M to retain uneconomic generation that should instead be retired.	Please recognize that the reported capacity values across all the scenarios of AEP's Fundamentals Forecast and are a discrete output of the Aurora energy market model. Capacity prices represent the non-energy revenue necessary for the least-dispatched units to remain economically viable and for the entire fleet to meet required reserve margins. It would be reasonable to infer that low capacity prices mean that the modeled fleet is long in generation and that new generation is not required to maintain reserve margins. Similarly, an increase in capacity prices would indicate that new generation is required to meet reserve margins.
82.	Sierra Club (1/08/19)	I&M should cease using its "high band" and "low band" characterizations of uncertainty, and independently test key uncertain variables. For years, AEP Companies have used a reference case, and "high band" and "low band" for commodity prices, energy prices, capacity prices, and carbon uncertainty. AEP then clusters the highest cost outcomes into a "high band" scenario and the lowest cost outcomes into	Please recognize that I&M is willing to consider the inclusion of reasonably formulated scenarios and/or sensitivities in order to support robust Stakeholder involvement in the IRP process. Also recognize that the consideration of additional scenarios and/or sensitivities should not result in the "rejected inclusion" of previously modeled scenarios.

		a “low band” scenario. This clustering obscures the true range of risk, and denies the Company, regulators, and stakeholders the opportunity to assess outcomes decoupled from the inappropriately clustered assumptions. While the ranges of individual commodities can and should be rigorously reviewed and debated (see comment seven, above), the combination of assumptions simply obscures reasonable risk. For example, AEP typically clusters into a “high band” the highest gas price, coal price, and carbon price assumptions, while clustering into the “low band” the lowest fuel prices, no carbon price, and the lowest projection of capacity market outcomes. While these clusters can be illustrative to demonstrate the highest and lowest cost to consumers of a chosen portfolio, they are nearly useless for the selection of a reasonable range of portfolios and do not represent bookends, and misrepresent real outcomes. For example, in a world with a mass-based carbon constraint, fuel prices might be anti-correlated with carbon prices, as higher carbon prices are needed to drive investments towards non-emitting resources in the presence of low fuel prices. In another key example, as gas prices have fallen, coal volumes have fallen, increasing the fixed cost burden on production and keeping solid fuel prices relatively high. Key commodity price projections – coal, gas, carbon, and	

		capacity price – must be disentangled and assessed both separately and in concert.	
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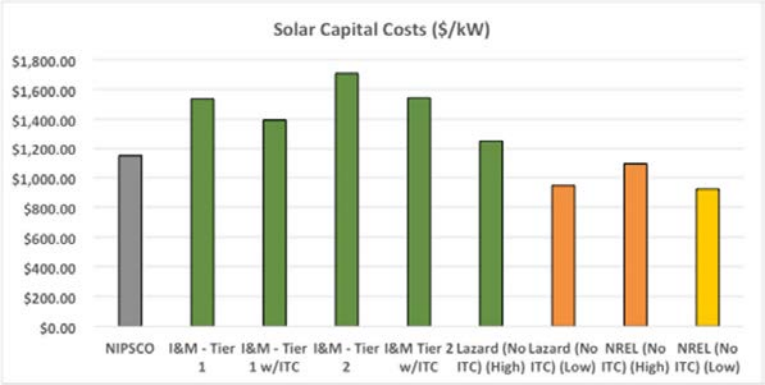
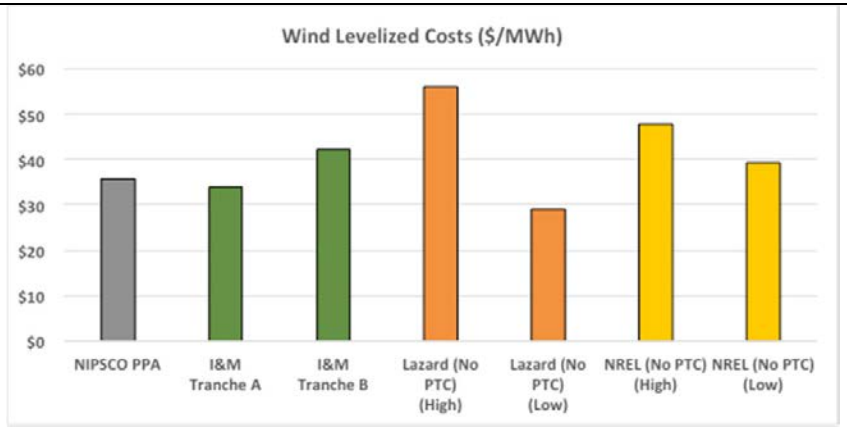
	Stakeholder	Comment	I&M Response
Questions 83-92 were submitted by the CAC on 1/11/19. In addition to the specific questions, the CAC noted that as we always do in cases like this, we would encourage I&M to provide this data in spreadsheet format in the future with as much background information and formulae underlying that data as possible. Doing so permits stakeholders to conduct a more thorough review and to understand key details, e.g. whether costs are in nominal or real dollars.			
83.	Citizens Action Coalition of Indiana, Inc. (01/11/19)	Load Forecast – While I&M notes that it's 10-year historical compound average growth rate has been -0.1% in the peak, its forecast is assuming growth in peak demand once load drops in 2020 and 2021. This growth begins with an unexplained increase in peak demand in 2022 and then what appears to be a steady rate of growth through the rest of the planning period. We would encourage I&M to use a peak demand forecast that includes flat to declining peak demand throughout the planning period and not just in the initial years.	While the 2008 through 2017 CAGR was -0.1%, if one looks at the most recent 10 year period of 2009 through 2018, which is the 10-year historical period that will provided in Company's forthcoming IRP, the CAGR for peak demand is 0.3%. Between 2018 and 2020, the Company will experience some FERC wholesale customers opting to buy energy services from an alternative supplier and therefore the Company's peak demand and energy requirements will experience declines, with the energy requirements decline being also felt in the 2021 annual data. The CAGR for peak demand during 20-year period of the load forecast is projected to be 0.0%. For the last 15 years of the forecast, the CAGR for peak demand is projected to be 0.4%. Based on the economic forecast from Moody's Analytics, and the Company's analysis of energy and peak demand, the Company believes the forecast is reasonable with the modest growth projection. Also, the Company bounds this expectation with high and low forecast scenarios.
84.	CAC (1/11/19)	Commodity Price Forecasts – The wholesale energy and capacity prices shown on slides 16 and 17 appear to show that in all scenarios real price growth is anticipated. This means that none of these forecasts would extend the price trends seen at AEP hubs of sub $40 and, recently, sub $30 per MWh power (with the exception during cold snap events like the polar vortex), i.e., real declining prices. At a minimum, a scenario without real price escalation in commodity prices ought to be added. Further, the projected PJM AEP Capacity prices grow significantly to what appears to be market equilibrium or CONE values. This does not make sense as a base case scenario since	Please recognize that I&M is willing to consider the inclusion of additional reasonably formulated scenarios and/or sensitivities in order to support robust Stakeholder involvement in the IRP process. The reported capacity values across all the scenarios of AEP's Fundamentals Forecast are a discrete output of the Aurora energy market model. Capacity prices represent the non-energy revenue necessary for the least-dispatched units to remain economically viable and for the entire fleet to meet required reserve margins.

		capacity prices in the RTO zone have typically fallen well short of CONE even when faced with retirement of significant capacity. It is good IRP practice to test a wide arrange of realistic values and such a range ought to include the trends currently faced by the utility. I&M is lacking the data that would allow it to assess its fleet under the conditions it currently faces.	
85.	CAC (1/11/19)	Scenario and Sensitivity Construction – We concur with the Sierra Club in its comments that combining "low" forecasts together in one scenario and "high" forecasts together in another is not necessarily logical. If scenario beyond the reference case are intended to capture a range of possible outcomes, then those scenarios ought to be driven by a narrative of a possible external event that could have significant impact on I&M's system, e.g., additional loss of wholesale requirements customers, the imposition of a meaningful carbon reduction policy, financial crisis in the natural gas industry, etc. These types of scenarios can be more meaningful than merely bundling high forecasts together or low forecasts together since they convey more meaningful information about the risk that is being considered.	Please recognize that I&M is willing to consider the inclusion of additional reasonably formulated scenarios and/or sensitivities in order to support robust Stakeholder involvement in the IRP process. Also recognize that the consideration of additional scenarios and/or sensitivities should not preclude inclusion of previously modeled scenarios.
86.	CAC (1/11/19)	Energy Efficiency Costs and Savings – We are disappointed to see that I&M intends to replicate key portions of its approach to modeling EE from its 2015 IRP. That IRP resulted in the nonsensical conclusion that residential lighting was the only cost-effective measure. In its 2016 DSM filing, rather than acknowledging the flaws in its approach, I&M argued that	For current IRP DSM/EE measure bundle modeling, I&M is relying on its 2016 Market Potential Study (MPS) performed by Applied Energy Group (AEG). Different from the 2015 IRP bundle attributes modeled, I&M's 2016 MPS specifically modeled the I&M system and service territory demographics, DSM/EE measure saturation and program history, and each state jurisdiction's energy and cost attributes for measure bundles and programs. During MPS development, I&M's DSM/EE Oversight Board stakeholders were engaged and afforded final review of the MPS before completion. As such, current IRP measure bundle costs and savings are directly tied to I&M's 2016 MPS

		"While it is true that the IRP model and Preferred Plan only included the Residential Lighting bundle in 2018 and 2019, this does not imply that a DSM Plan would only include residential lighting." We hope that I&M does not intend to extend this illogic to the 2019 IRP modeling. Though bundle costs have generally moderated in the Commercial sector, the Residential bundles are still wildly overpriced. And the potential for savings has been dramatically reduced. For example, the so-called Achievable Shell bundle in the 2015 IRP contained 7,585 and 13,699 MWh of savings in 2019 and 2024, respectively. I&M now proposes to reduce savings available for the model to choose from this bundle to just 1,516 MWh per year over a similar period. The levelized cost of this bundle is now much higher as well, $162.66 per MWh rather than the $40.27 per MWh assumed in the 2015 IRP. Indeed, it does not appear that it would even be possible to select the same level of savings on an annual basis that are contained in I&M's current DSM plan. This is a radical revision to an already fatally flawed dataset and will ensure that I&M continues to overstate EE costs and understate EE savings potential. To continue to use this dataset would completely undermine I&M's selection of a least cost, preferred plan.	for cost and savings potential and reflect I&M's cost of DSM/EE programming (LCOE, or first year annual). I&M worked directly with AEG to ensure consistent and accurate modeling in the IRP using MPS measure bundle attributes. Any specific measure bundle attribute variations between the 2015 IRP and the current IRP modeling are the result of actions taken by I&M to refine DSM/EE modeling based on feedback and lessons learned from the 2015 IRP process.
87.	CAC (1/11/19)	Demand Response – It's not clear if slide 19 refers to existing DR programs or is the characterization of what I&M believes to be its additional potential. If the former, then these numbers understate what we understand to be I&M current	Demand response (DR) resources shown on slide 19 are consistent with participant targets set forth in I&M's current programs, other similar program experience (to the extent applicable) and with the State of Michigan Demand Response Potential Study dated September 2017 which included a survey of DR programs nationwide by program type and technology. For the total of the 4 blocks of each DR resource, the amount of demand savings is consistent with participation levels experienced by I&M.

		program offerings by a wide margin. If the latter, then the C&I potential, in particular, seems extremely limited. Indeed, it is limited just to commercial customers and does not include industrial customers.	
88.	CAC (1/11/19)	Wind, Solar, and Battery Costs – Most wind, all solar, and battery costs appear to be overstated as shown in the charts below. We would recommend adjusting these costs to approximately the values received in response to NIPSCO's all-source RFP, assuming I&M will not be performing its own all-source RFP for this IRP as requested by stakeholders in a letter dated December 4, 2018. We recommend that the NIPSCO values be the starting place for capital costs and NREL ATB escalation rates be applied going forward.  Figure 1. I&M's Estimated Solar Costs are Much Higher than NIPSCO RFP Responses, Lazard,1 or NREL2 Estimates Both With and Without the ITC	Please see the Company's response to Sierra Club question #76. As stated in the Sierra Club Question #76 response the Company is open to considering a stakeholder scenario with lower renewable and storage cost.

		 Figure 2. I&M's Tranche B Estimated Wind Costs are Much Higher than NIPSCO RFP Responses, Lazard, and NREL3 Estimates if PTC were included.	
89.	CAC (1/11/19)	Limitations on Resource Selection – In the past I&M has argued that limitations on wind, in particular, were necessary to prevent the model from building wind resources purely for arbitrage purposes. While we agree that this is not a desirable outcome, the limitations on resource selection are so narrow as to prevent the model from choosing a cost-effective portfolio that does not contain a fossil-fuel based resource. As I&M itself, states, it will be in a capacity deficit position with the retirement of the Rockport units. It is good modeling practice to allow the model to consider a wide arrange of portfolio options to meet this deficit. It would therefore be preferable to allow the model to pick unlimited amounts of as many resource options as possible, evaluate that	Please see the Company's response to Sierra Club question #77. The Company will consider modifying the annual and total build constraints for both wind and solar resources within a stakeholder defined portfolio.	

		result in a transparent fashion, and then decide whether further resource selection limitations make sense.[4] *[4] Note that we are also not clear what size increments these resources are modeled. Making the resource options large enough to leverage economies of scale but small enough not to burden ratepayers with overbuilt capacity is very important.*	
90.	CAC (1/11/19)	Rockport and OVEC Retirements – CAC believes additional portfolios modeling Rockport and OVEC retirements are warranted. Namely, I&M should model the retirement of Rockport 1 in 2025 with no lease extension of Rockport 2 and model the retirement of Rockport 1 in 2023 with no lease extension of Rockport 2. I&M should also consider whether its OVEC contract ought not to be renewed and should model a portfolio where the OVEC contract is not extended. Based on the results of the 2015 IRP, we believe there is a strong likelihood that either of these portfolios would be cost-effective for customers and therefore ought to be included in I&M's modeling.	**P**lease refer to the response to Sierra Club question # 74 for the Company's response to the proposed Rockport scenarios. **P**lease refer to the response to Sierra Club question # 75 for the Company's response to the OVEC comment.
91.	CAC (1/11/19)	Portfolios – As we alluded to above in #7, Limitations on Resource Selection, the portfolios proposed by I&M, are overly limited. We'd like to see portfolios created by using Plexos' optimization capabilities as much as possible before additional portfolios with fixed resources are created. There is no mention in the slides of creating unconstrained portfolios, but we believe doing so can help inform the development of the constrained portfolios so that they are as	The base, high, low and status quo optimizations are all unconstrained as defined by the Company's inputs. Please see the company's response to Question #89.

		cost-effective as possible.	
92.	CAC (1/11/19)	EE Decrement Approach – In order for this analysis to be meaningful, a much wider level of annual EE savings reduction needs to be assessed, i.e., up to a 2% annual reduction and the limitations on resource selection need to be removed. If they are not, then I&M is putting CAC and its consultants in the frustrating position of doing analysis that it will attribute to CAC and/or its consultants but which is nothing like what we are proposing. Further, it is critical to provide CAC and its consultants an opportunity to review this analysis and make adjustments to the modeling if necessary, before it is published. This is an essential step to help ensure that the modeling comports with our recommendation.	The Company will consider modifying or creating an additional "Decrement" portfolio. The Company plans on making this portfolio and all portfolios as transparent as needed so all stakeholders can understand the results.
93.	Philip Sakimoto, University of Notre Dame (2/19/19)	I commend IMP for planning to phase out coal-sourced electricity production and replace it with renewables. I urge you to do this as quickly as possible because the need to reduce emissions of greenhouse gases is urgent. I also urge you to consider similarly replacing natural gas with renewables. Although, as many people point out, that combustion of natural gas produces less carbon dioxide than does combustion of coal (for the same heat output), leakage of natural gas--particularly at the point of extraction--poses a climate risk that may be even worse that that posed by coal. Natural gas leakage of only	I&M appreciates your comments and thanks you for providing input to this important process.

		about 3 percent of the amount used places enough methane in the atmosphere to make a greenhouse effect as large as that of coal. Preliminary studies indicate leakages of much more than 3 percent (perhaps as much as 9 percent). Thus moving off of natural gas, as well as off of coal, in favor of renewables is imperative. For further details on this crucial point, please see: R. A. Alvarez, et.al., "Greater focus needed on methane leakage from natural gas infrastructure," Proc. Natl. Acad. Sci., 109, no. 17 (April 2012):6435–6440); J. Tollefson, "Methane leaks erode green credentials of natural gas," Nature 493, no. 7430 (January 2, 2013): 12; L.M., Cathles, et.al., "A commentary on 'The greenhouse gas footprint of natural gas in shale formations' by R.W. Howarth, R. Santoro, and A. Ingraffea," Climatic Change, 113, no. 2 (July 2012): 525–535; R.W. Howarth, et. al., "Methane emissions from natural gas systems," Background paper prepared for the National Climate Assessment, reference number 2011-0003 (2012); G. Petron, et.al., "Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study," J. Geophys. Res. Atmospheres, 117, no. D4 (February 27, 2012): D04304; T. Skone, "Role of alternative energy sources: Natural gas power technology assessment," National Energy Technology Laboratory, DOE/NETL-	

		2011/1536 (2012)).	
Questions 94 -107 were submitted by the Indiana Coal Council on February 27, 2019 in follow up to the February 21, 2019 IRP Stakeholder Meeting.			
94.	Indiana Coal Council (2/27/19)	There are material differences in the February 21st presentation with the New Generation Technologies table in testimony of John F. Torpey filed on September 19, 2018 on behalf of AEP Ohio. Of particular interest are the different assumptions related to the combined cycle options, i.e., fuel cost, VOM, FOM, capacity factor, and LCOE. Please provide a full explanation of the differences including the basis for each (Table not shown here).	The New Generation Technology Option Table contains data that is updated on an annual basis or if relevant assumptions change. The September Table was prepared in early 2018. The February Table has more current assumptions from vendors and AEPSC Generation for the various technology options, including installed costs, which are lower, and fixed costs, which are higher. Note that the September Table's fuel costs are based on levelized values over a 40-year period, while the February Table shows year 1 fuel costs. The February Tables capacity factors are based on recent model experience and are higher than the September Table. The capacity factor, and using a more recent gas price estimate, produced a lower LCOE in the February Table. For the final IRP, I&M plans to provide another update to this table in the meeting material for the March 22, 2019 Stakeholder meeting. This update is driven by AEPSC Generation providing updated information as well as updated commodity forecasts from AEPSC Fundamentals.
95.	Indiana Coal Council (2/27/19)	It is not obvious how Firm Transportation costs are included in these numbers. Please provide I&M's assumption regarding Firm Transportation costs and where those costs are included.	For the new natural gas fired configurations, estimated reservation costs for firm transportation are embedded in the Installed Cost ($/kW) shown in the table of IRP Inputs and Assumptions. The cost estimate includes the pipeline extension to serve the new facility and other considerations such as upstream pipeline improvements, potential capacity reservation charges, metering facilities and others.
96.	Indiana Coal Council (2/27/19)	Please explain why the use of a Base Load coal plant assuming 90% carbon capture is the only coal option when the NSPS for GHG requires only 30% CCS and a replacement NSPS for GHG has been proposed based on high-efficiency, low-emitting plants with no carbon capture.	Please see Company's previous response to #67. In addition, according to USEPA's website, "On December 6, 2018, EPA proposed to revise the New Source Performance Standards (NSPS) for greenhouse gas emissions from new, modified, and reconstructed fossil fuel-fired power plants." The Fact Sheet accompanying that information, found at https://www.epa.gov/sites/production/files/2018-12/documents/fs-111b_proposal_12-6-2018f.pdf, states that the agency is proposing changes which would limit CO2 for newly constructed super-critical steam units to 1,900 lbs CO2/MW-hour. As a result of the partial government shutdown in early 2019, the comment deadline has been extended until mid-March. AEP is reviewing the proposal and potential impacts. As

			this is a proposed change that was not issued until December, AEP did not model this potential scenario. The Company will take it under consideration once the proposed standards impacts are more fully understood.
97.	Indiana Coal Council (2/27/19)	It appears that I&M correlates its coal and natural gas price forecasts. Historically, coal and natural gas prices are not correlated. Please provide the basis for the correlated assumptions going forward.	Four distinct long-term commodity pricing scenarios were developed; the Base Case, Lower Band, Upper Band, and Status Quo (No Carbon) scenarios. The Base, Low Band, and High Band scenarios each consider the potential impact of carbon regulations. The modeling associated with each of these scenarios assumed a CO2 dispatch burden, or allowance value, equal to $15/ton commencing in 2028 and escalating at 5% per annum thereafter on a nominal dollar basis. The associated cases were designed and generated to define a plausible range of outcomes surrounding the Base Case. The Lower and Upper Band forecasts consider lower and higher North American demand for electric generation and fuels and, consequently, lower and higher fuels prices. Generally, Lower and Upper Band fossil fuel prices vary one standard deviation above and below Base Case values. The Status Quo Scenario assumes there will be no regulations limiting CO2 emissions throughout the entire forecast period.
98.	Indiana Coal Council (2/27/19)	Did any cases consider a low coal price with a high gas price? If so, which ones? Please provide those forecasts.	Although we did not run a low coal price, high gas price scenario, the other scenarios modeled allow for an extrapolation under that circumstance, which would generally suggest that coal generation would be somewhat more economic than it would be otherwise, all other things being equal.
99.	Indiana Coal Council (2/27/19)	Please provide the key assumptions behind the natural gas price forecasts, including the forecasts for LNG exports, the forecasts for pipeline exports to Mexico, and the forecasts for residential and commercial demand.	The Fundamentals Forecast recognizes the balance between long-term increase in demand (the expanding role of natural gas for electric generation, the prospect of liquefied natural gas exports, natural gas for use as a transportation fuel, and others) and the likelihood of cost-effective advances in shale-directed drilling and completion techniques (longer laterals, increased fracturing stages, proppant delivery, and others). Abundant, relatively low-cost natural gas reserves and productive capacity will continue to grow domestically and globally as shale gas extraction technology becomes more widespread. Despite negative reaction in some regions of the country, the long-term environmental impacts of shale gas development ultimately will be manageable. Natural gas pipeline capacity is expected to keep pace with the evolving locations of supply and consumption as the extensive domestic natural gas transportation infrastructure is sufficiently robust to overcome constraints through existing capacity expansions, flow reversals, and new construction. Forecasts for LNG exports, pipeline exports to Mexico, and forecasts of residential and commercial natural gas demand are not explicit deliverables of the Company's Fundamentals Forecast. However, the Company's projected view of these natural gas demands are in line with those presented in

<table>
<tr><td></td><td></td><td></td><td>the 2018 Energy Information Administration's Annual Energy Outlook.</td></tr>
<tr><td>100</td><td>Indiana Coal Council (2/27/19)</td><td>Please provide the delivered price forecasts for all coal to Rockport. The price forecast should be per year for each coal type burned in these units. Rail/barge and commodity price forecasts should be broken out.</td><td>
<table>
<tr><td colspan="5">Indiana Michigan Power Company</td></tr>
<tr><td colspan="5">Annual Coal Cost Forecast</td></tr>
<tr><td colspan="5">For the Years of 2019 Through 2022</td></tr>
<tr><td></td><td>2019</td><td>2020</td><td>2021</td><td>2022</td></tr>
<tr><td>Rockport</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Tons (000)</td><td>7,142</td><td>6,100</td><td>5,606</td><td>5,144</td></tr>
<tr><td>¢/MMBTU (PSCR)</td><td>195.42</td><td>203.15</td><td>209.11</td><td>201.32</td></tr>
</table>

Although the transportation component of the delivered coal price for the years 2019 through 2022 is confidential it would be reasonable to assume an average value of approximately $28/ton for this time period.</td></tr>
<tr><td>101</td><td>Indiana Coal Council (2/27/19)</td><td>Please provide the delivered natural gas price assumptions for the “new” CCGT. The prices should provide the Henry Hub forecast and the basis differential.</td><td>The “new” CCGT’s modeled delivered natural gas price is TCO Pool. See the TCO and Henry Hub prices in the table below:</td></tr>
</table>

<table>
<tr><td></td><td></td><td></td><td>
<table>
<tr><th colspan="6">I&M 2018 IRP
2018H1 Base Nominal Gas Prices</th></tr>
<tr><th rowspan="2">Year</th><th colspan="2">$/mmbtu</th><th rowspan="2">Year</th><th colspan="2">$/mmbtu</th></tr>
<tr><th>TCO Pool</th><th>Henry Hub</th><th>TCO Pool</th><th>Henry Hub</th></tr>
<tr><td>2018</td><td>2.94</td><td>3.22</td><td>2034</td><td>6.83</td><td>7.33</td></tr>
<tr><td>2019</td><td>3.59</td><td>3.88</td><td>2035</td><td>7.04</td><td>7.55</td></tr>
<tr><td>2020</td><td>4.26</td><td>4.59</td><td>2036</td><td>7.25</td><td>7.78</td></tr>
<tr><td>2021</td><td>4.31</td><td>4.69</td><td>2037</td><td>7.47</td><td>8.01</td></tr>
<tr><td>2022</td><td>4.41</td><td>4.82</td><td>2038</td><td>7.63</td><td>8.24</td></tr>
<tr><td>2023</td><td>4.56</td><td>4.96</td><td>2039</td><td>7.86</td><td>8.47</td></tr>
<tr><td>2024</td><td>4.68</td><td>5.12</td><td>2040</td><td>8.08</td><td>8.71</td></tr>
<tr><td>2025</td><td>4.82</td><td>5.22</td><td>2041</td><td>8.31</td><td>8.93</td></tr>
<tr><td>2026</td><td>4.93</td><td>5.32</td><td>2042</td><td>8.54</td><td>9.16</td></tr>
<tr><td>2027</td><td>5.02</td><td>5.41</td><td>2043</td><td>8.78</td><td>9.4</td></tr>
<tr><td>2028</td><td>5.58</td><td>5.99</td><td>2044</td><td>9.02</td><td>9.64</td></tr>
<tr><td>2029</td><td>5.69</td><td>6.15</td><td>2045</td><td>9.26</td><td>9.88</td></tr>
<tr><td>2030</td><td>5.99</td><td>6.48</td><td>2046</td><td>9.5</td><td>10.12</td></tr>
<tr><td>2031</td><td>6.29</td><td>6.71</td><td>2047</td><td>9.76</td><td>10.38</td></tr>
<tr><td>2032</td><td>6.43</td><td>6.91</td><td>2048</td><td>9.99</td><td>10.6</td></tr>
<tr><td>2033</td><td>6.62</td><td>7.12</td><td></td><td></td><td></td></tr>
</table>
</td></tr>
<tr><td>102</td><td>Indiana Coal Council (2/27/19)</td><td>Please provide all legal filings related to the dispute over the Rockport 2 lease.</td><td>All filings are publically available on the electronic docket of the United States District Court for the Southern District of Ohio (Case No. 2:13-cv-01213-EAS-CMV) and the electronic docket of the United States Court of Appeals for the Sixth Circuit (Case No. 16-3496).</td></tr>
<tr><td>103</td><td>Indiana Coal Council</td><td>Please provide a discussion of all scrubber options considered. If a wet scrubber with high sulfur coal was not considered, please</td><td>Please see I&M’s response to #69.</td></tr>
</table>

	(2/27/19)	explain why.	
104	Indiana Coal Council (2/27/19)	The question related to Life Cycle Analysis of emissions was not answered. Please explain whether I&M proposes to provide such an analysis.	I&M did not prepare a Life Cycle Analysis of emissions and does not have the data to perform the analysis.
105	Indiana Coal Council (2/27/19)	Please explain why the forecast period goes beyond 20 years. Please provide NPV's (CPW's) for the first five years and through 2038.	The forecast period goes beyond a 20-year period in order to capture the full economics of long lived assets (e.g. 30 year operating life) when making resource selection decisions. Shortening the duration of the analysis period may create a bias against the addition of long-term resource additions in favor of shorter-term resources over the planning period. The Company is planning to include 10-year, 20-year and total life CPWs in the final analysis and may also provide the information at the 4th Stakeholder meeting if the data are available. A 5-year CPW would be of limited value since most of the identified resource additions occur after this period.
106	Indiana Coal Council (2/27/19)	Please provide I&M's forecast of residential customer rate impacts for each year of the plan.	I&M plans to provide an indicative, average cost/kwh metric as part of final stakeholder presentation and in the final IRP report.
107	Indiana Coal Council (2/27/19)	Are any of I&M's industrial customers requesting alternative tariffs that would allow them greater access to market-priced power? If yes, please provide the status of such discussions.	While discussions with some industrial customers suggest they are aware of and interested in market conditions, the discussions have not focused on "alternative tariffs" at this time.
108	CAC 3/6/2019	CAC's IRP Team was able to debrief regarding the issues we raised about I&M's latest market potential study and the use of such in I&M's IRP. We tried to figure out how I&M could model EE cost and potential in the IRP in a way that would address these data quality issues we've identified in the latest MPS and the prior MPS. We tried to also keep in mind your concerns about timing and the resources that would be required to resolve this in time for a 5/1 IRP	As presented in the stakeholder meetings, I&M included an IRP scenario using the CAC's decrement approach. From that scenario, while the costs of the decrement approach can be inferred relative to how much each decrement should ultimately cost, that type of derivation is not consistent with the IRP modeling approach performed across all other resources. Since the IRP assesses each resource modeled according to each resource's specific direct cost and load shape (energy and capacity requirement) solution, use of the decrement solution does not yield a solution that satisfies economic treatment for a system resource. From this perspective, and when factoring in the 10 factors that the Commission must consider in the approval of a DSM Plan, I&M will not seek use of the decrement method in

		submission if we did a piecemeal approach of updating your MPS with agreeable costs and savings figures, as well as other assumptions. By and large, we think it will be nearly impossible to find a sort of "proxy" MPS that could fit the I&M characteristics perfectly for use in your IRP. There would be some major work that would need to be done to translate data from any MPS that was not specifically constructed for I&M's system. (That said, I&M could look at, for example, this MPS from Minnesota to try and characterize bundles differently than the AEG MPS does and then figure out a resolution on savings and cost totals with us; but you'd still have to make some assumptions about how much of that potential is on your system and what cost and resource availability look like after 2029). Thus, we suggest that it makes much more sense to simply use our proposed decrement analysis as part of your base case, and we can help you work through that. We think this makes much more sense to have good information about the impact of a wide range of EE savings than sink all of our and your time into updating the MPS when the results of the prior MPS were much different than your current one.	the IRP to determine the appropriate level of EE. Regarding EE bundle cost, this IRP's EE cost profiles were developed from what it costs for I&M to implement the programs and to offer EE measure rebates to customers. From the prior IRP, I&M took responsive action to make adjustments based on I&M specific program costs, savings, and potential instead of using regional based estimates in the 2015 IRP. While these costs are modeled in the 2016 I&M MPS, AEG did not create or develop these costs in isolation from I&M's service territory and program performance history. Furthermore, I&M is satisfied that AEG is a reputable firm for DSM/EE MPS'. AEG has performed MPS' for other AEP Operating Companies as well as other state regulatory commissions that I&M works with, namely Michigan where AEG performed their most recent State of Michigan Demand Response MPS. As such, I&M's position is that the MPS performed by AEG in 2016 for the I&M system, using I&M specific data, information, and measure history, is the appropriate EE planning resource to rely on for this IRP.

Questions 109 – 114 were submitted by the CAC on March 29, 2019. The CAC provided the questions to help them better understand how energy efficiency is proposed to be characterized in order to provide the best possible feedback and to prepare for the April 11, 2019 conference call. I&M provided draft responses just prior to the April 11, 2019 conference call and discussed its answers on the call with the CAC, Bran Borum, Bob Pauley and others. **I&M provides the following responses as part of its IRP public advisory process under 170 IAC 4-7-2.6.**			
109	CAC (3/29/19)	109 (CAC 1.1) To put some of the energy efficiency savings bundle assumptions into context, we are trying to understand I&M's forecast and have several questions. a. Is the second graph on slide 6 of the December 10, 2018 presentation intended to show GWH sales (the y-axis is labeled MW)? b. The sum of the residential, commercial and industrial sales shown on slide 9 appear to be on the order of 18,000 GWh in 2019. However, that is significantly lower than the 24,000 to 25,000 shown for total sales on slide 6. What is the difference? c. The peak demand growth shown in the "base forecast" on slide 11 (rising from about 4000 MW in 2019 to about 4400 or 4500 MWh in 2030 suggests a level of growth that is very different from the flat peak demand growth shown in the first graph on slide 6. What is the difference? d. Can I&M please provide graphs (and underlying values) like those on slides 6, 9 and 11 but separately for its Indiana and Michigan service territories?	109 a (CAC 1.1a): The bottom chart on slide 6 shows I&M total energy (GWh). 109b (CAC 1.1b): The sales on slide 9 are for the IN jurisdiction only. The GWh on slide 6 are for the entire I&M system including MI and wholesale. 109c (CAC 1.1c): The scale is different on slide 11 (zoomed in) to try to show the distinction between the various scenarios. The CAGR for the base forecast on slide 11 from 2019 – 2039is essentially flat (-0.03%). 109d (CAC 1.1d): The load forecast that will go into the final IRP analysis is not completed. However, I&M will provide the sales by jurisdiction (contained on slide 9) in the final report. The charts on slide 6 & 11 show total I&M system peak and energy. The company doesn't report peak and energy on a jurisdictional level but does report it on a total system level. Since the Company does not report weather normalized peak and energy at the jurisdictional levels, this request would require additional estimations that are not critical or supportive of the IRP process. However, after the load forecast is finished, the total system peak and energy data will be included in the final report.

110	CAC (3/29/19)	110 (CAC 1.2) In response to a CAC comment regarding energy efficiency resources on 1/11/19, I&M stated that it is relying on its 2016 Market Potential Study (MPS) for the characterization of the efficiency bundles it is modeling in its IRP. This raises several questions: a. Can I&M please provide an Excel spreadsheet that shows how all of the LCOE ($/MWh)", "installed cost ($/kWh)", "yearly potential savings" (for various time periods) and "Bundle life" values on slide 18 of its December 10, 2018 presentation were computed? b. Are the total achievable Residential and Commercial/Industrial MWh savings per year shown on slide 18 for the entire I&M service territory, or just for the Indiana portion? c. Slide 18 suggests that the achievable potential for the residential sector averages 49,634 MWh per year and for the commercial/industrial sector averages 49,656 MWh for each year from 2020 to 2024, for a total of a little over 99,290 MWh. The "high achievable potential" adds another 22,440 MWh, for a grand total of 121,730 MWh. Are these values expressed as incremental annual savings (that is, the amount of new savings produced in a given year)?	110a (CAC 1.2a): The cost data summary was provided to the CAC as a confidential attachment. 110b (CAC 1.2b): The total achievable Residential and Commercial/Industrial MWh savings per year shown on slide 18 are for I&M, total Company. 110c (CAC 1.2c): Yes, the values are expressed as incremental annual savings. 110d (CAC 1.2d): It is not valid to directly compare the program design portion of the MPS to the IRP efficiency bundles. The IRP efficiency bundles are derivatives of the measure-level MAP and RAP potential scenarios based on specific measures included in the IRP efficiency bundles. The program design portion of the MPS is also a derivative of the measure-level MAP and RAP potential scenarios, but the measures included in the program design portion of the MPS and IRP efficiency bundles are not equivalent. Therefore, comparing the program design portion of the MPS to the IRP efficiency bundles is incomplete due to the measure-level differences and overlap of measures. 110e (CAC 1.2e): Based on the question being asked and the footnote included below we need further clarification on the comparison being made.

		d. The MPS suggests that incremental annual savings are on the order of 130,000 MWh per year under the "mid scenario" (Table 7-9) and 150,000 MWh per year under a "high scenario" (Table 7-12) in the first half of the 2020s. In other words, it seems that the MPS mid scenario has savings that are about 30% higher than the "achievable potential" efficiency bundles in I&M's IRP and MPS high scenario savings are about 25% higher than the high achievable potential values in the measure bundles on Slide 18. Is that the case? If so, why would that be the case? e. Just for the C&I sectors, the MPS suggests that the average growth in cumulative annual savings from 2019 through 2026 is about 70 GWh under "realistic achievable potential" and 96 GWh per year under the maximum achievable potential (Table 5-6). That's growth in cumulative potential, so less than incremental annual savings potential. In contrast, slide 18 suggests that the C&I achievable potential is only about 50 GWh and the high achievable potential is only 67 GWh per year from 2020-2024. In other words, the C&I MPS values appear to be more than 40% higher than the savings bundles on slide 18. Why is that the case?	

111	CAC (3/29/19)	111 (CAC 1.3) Can I&M please provide detailed calculations showing how the values provided in slide 18 were derived from the MPS? As suggested in subsequent questions, it is not clear how that would have been the case. For example: a. The sum of costs in the Indiana MPS for the "mid scenario" for the Home Weatherproofing and Income Qualified Weatherproofing programs in 2019 is $907,000 (Table 7-9) and the sum of the incremental electric savings is 1568 MWh (Table 7-11), for an average cost per first year kWh of $0.58, which is 65% less than the $1.65 installed cost assumed for the Achievable Potential scenario for the building shell bundle. b. All told, the sum of program costs per first year kWh for the all residential programs excluding Home Energy Reports in the Indiana MPS' mid scenario appears on the order of $0.31. In contrast, the weighted average installed cost for residential programs other than Behavior for the achievable potential level of savings is $0.49 (weighted by 2020-2024 savings).	111a (CAC 1.3a): Because the IRP evaluates measure bundles, and not DSM/EE programs, it is not an appropriate or valid comparison where programs contain different measures than IRP measure bundles. 111b (CAC 1.3b): Because the IRP evaluates measure bundles, and not DSM/EE programs, it is not an appropriate or valid comparison where programs contain different measures than IRP measure bundles.
112	CAC (3/29/19)	112 (CAC 1.4) According to Attachment JCW-2 (Cause No. 44841), I&M was planning to achieve	112 (CAC 1.4): It is reasonable to use levels of efficiency from the 2016 MPS in this IRP because the 2016 MPS was developed for use in this IRP, specific for I&M. The Cause No. 44841 DSM Plan approved by the Commission was based on a different MPS and the 2015

		incremental annual savings in 2019 of 148,484 MWh in its Indiana service territory. That is on the order of 20% more than the sum of the efficiency bundles for "high achievable potential" on slide 18, even though the plan covers only the Indiana portion of the I&M territory and the plan is not spending at levels associated with "high achievable potential". Why is it reasonable to use levels of efficiency in the IRP that are so much lower than what the Company is currently actually achieving or planning to achieve?	IRP. Efficiency levels authorized in Cause No. 44841 were approved as reasonable but exceeded the levels selected in the 2015 IRP for 2019, the extent of which was described by I&M in that Cause.
113	CAC (3/29/19)	113 (CAC 1.5) We are confused about the DSM/EE "degradation" approach used by I&M. a. Could you please explain how the degradation factors by year are developed? From slide 24 of the April 11, 2018 Stakeholder Workshop #2 presentation, they don't appear to be linear over the measure life. b. On slide 23 of its April 11, 2018 Stakeholder Workshop #2 presentation, the Company explains that degradation is needed because "'actual' DSM/EE program savings are measured against a historical base, and the SAE forecast models already account for the changing saturations and appliance efficiencies that are likely to occur in the market…" However, that is not our understanding of how most efficiency program savings are measured. For example, when a customer takes a rebate	113a (CAC 1.5 a): The degradation factors were developed in consideration of the expected life, declining effectiveness, and market efficiencies of the various end-use programs and in consideration of the saturation trends in energy efficiency already embedded in the load forecast models. The observed impacts were not linear over time so I&M utilizes a non-linear estimation algorithm to degrade the program savings that are ultimately subtracted from the load forecast. 113b (CAC 1.5 b): We agree there is a lack of consistency with how DSM program savings are measured across the industry. The degradation discussion for the IRP is relative to how things are modeled in the load forecast, not how they are measured in the EM&V process or described in the Technical Reference Manual. In the example provided in the CAC question, the savings are measured against whatever efficiency they could have otherwise purchased in the market (SEER 13).From the load forecast perspective, that is the "historical base" level. Now assume 2years after the purchase was made, only SEER 15 ac units are available in the market, it would be inappropriate to continue to subtract savings that were measured off of the historical base (SEER 13) when someone who is not participating in the DSM program would be able to install the same efficiency (SEER 15) without that incentive, unless the load forecast model is assuming efficiencies are held constant(SEER 13) throughout the forecast horizon.

		for a SEER 15 Central A/C, the savings are measured relative to the SEER 13 that they otherwise would have purchased, not the old SEER 10 that they replaced (i.e. not to a historic base efficiency). Furthermore, once they make a purchase decision, the efficiency results of that decision are "locked in" for the 18 year life of the Central A/C they purchased. That is the case for all efficiency programs targeting "time-of-sale" or new construction purchasing decisions, which is made clear in the Indiana Technical Reference Manual. Why would any degradation of energy savings make sense in such cases? c. The only measures for which the "historic" level of consumption is the baseline from which efficiency savings are measured are true retrofit measures – i.e. measures added to an existing building such as insulation added to residential attics or controls added to existing commercial ventilation systems. However, it also is unclear why degradation factors would be applied to these measures. While it is possible that some homes which get attic insulation through an I&M efficiency program would have eventually installed such insulation on their own, that effect is typically captured in estimates of net-to-gross adjustments. If that is the case, a degradation adjustment would "double-count" the same effect. Also, in our	113c (CAC 1.5 c): See response to part b above. It appears CAC is applying a different definition to 'historic baseline' than is used in the load forecast process. If the Company's degradation approach used in its load forecast was "double counting" as CAC alleges, one would expect the actual loads to consistently come in above the forecasted amounts. That is simply not the case. 113d (CAC 1.5 d): There is no double counting of the degradation factors. The baseline projection from the market potential study does include some estimate for the impact of existing and approved changes to building codes and appliance standards but does not account for free ridership and spillover that result from I&M programs. The market potential study does, however, apply a net-to-gross ratio (similar in concept to the degradation factor) when translating from a measure-level to a program level. The IRP inputs are at the measure level which have not been adjusted for free riders and spillover. Therefore the measure level inputs from the MPS are degraded in the IRP modeling so that the output from the IRP can be consistent with the program level outputs, both at a net savings level.

		experience it is likely that only a modest fraction of customers would ultimately install additional attic insulation (and many other pure retrofit measures) on their own over the next couple of decades, not 100% of customers as the degradation factors seem to imply. Why would it make sense to assume that such savings eventually degrade to zero? d.It does seem important that forecasts of future demand take into account savings that will result "naturally" – that is, absent efficiency programs. That would include savings resulting from new federal product efficiency standards. However, it is our understanding that the MPS account for such naturally occurring conservation, including the effects of new building codes and product efficiency standards. In other words, it seems as if the MPS savings estimates, which I&M has degraded, were already "degraded" to adjust for what would have happened absent the programs. Is that not right? If not, it would be helpful to have a discussion to understand why not.	
114	CAC (3/29/19)	114 (CAC 1.6) Please see the attached Indiana-specific Market Potential Study for I&M performed by AEG and the Executive Summary of the entire MPS linked here on I&M's website. Please provide the Michigan-specific Market Potential Study for I&M performed	R114 (CAC 1.6): The company provided of the I&M Report- Michigan Final 6.2.16 as Attachment 2.

		by AEG	
115	Anne Beasly – Customer 4/2/19	Comments/Questions: My letter to the editor of the South Bend Tribune: As a former student of ecology and a mother, I worry constantly about the world I will leave to my two little boys. My husband and I have spent the last decade learning and making incremental changes to reduce our impact on the environment. We have adopted a more plant-based diet, joined a food co-op and begun raising backyard chickens. But without systemic change, our individual actions are meaningless. Our utility Indiana Michigan Power can turn the tide on climate change by releasing a 20-year energy plan that moves us away from fossil fuels to 100 percent renewable energy in upcoming decades. It is crucial that this plan create environmentally friendly investments that will benefit our local community both now and over the long term. Customers benefit when utility companies move to renewable energy. In October 2018 NIPSCO announced plans to retire all of its coal plants by 2028 and replace that power exclusively with efficient renewable energy sources. The company projects this move will save their customers $4 billion.	I&M appreciates your input and participation in this process.

		Moving away from coal and gas power is the best way for us to have a healthier community that is prepared for the future.	
Questions 116 parts a, b, c and d were submitted by the CAC on April 26, 2019. I&M hosted on conference call with the Jennifer Washburn (CAC), Chris Neme (Energy Futures) and Anna Sommer (Sommer Energy, LLC) on May 9, 2019 to discuss Q116 (CAC 2.1). I&M provides the following responses as part of its IRP public advisory process under 170 IAC 4-7-2.6.			
116	CAC (4.26.19)	116 (CAC 2.1) After our recent call to discuss I&M's EE modeling assumptions in its upcoming IRP, we want to be clear that we have serious concerns with the way in which EE is being modeled by I&M and respectfully request the following as a sensitivity to I&M's base case: a) Please use AEG's "high savings" scenario to characterize the EE bundles. b) Please model those bundles so that they are consistent with their representations in the AEG study which I&M characterized as more representative of its program delivery than bundles it is currently modeling. That means modeling program bundles with mixes of different measure types where that is appropriate, rather than end use bundles of measures that may or may not be expected to be delivered together. It also means using both AEG estimated program costs and AEG estimate program savings. As with I&M's current EE bundles, a weighted average savings life can be computed for each program bundle. Similarly, weighted average load shapes (to	R 116 a: I&M worked with AEG to use data output from AEG's realistic achievable and the maximum achievable potential scenarios to develop the efficiency bundles used in the IRP modeling, These correspond to the achievable and high achievable efficiency bundle line items within the IRP bundle table presented in December. The Company continues to evaluate the High Achievable Potential from the MPS and will discuss at the May 23rd stakeholder meeting. R116 b: I&M's IRP models EE measure bundles according to the respective load shape used in I&M's load forecast that each measure bundle impacts. I&M's MPS also evaluated EE measure bundle according to those same load shapes, although some measures impact more than one load shape (e.g. a heat pump that provides both air conditioning and heating impacts both the cooling load shape and the heating load shape). For those type of measures, I&M and AEG worked together in measure bundle development for the IRP, ensuring the appropriate EE measure impacts were reflected according to their allocated load shape impact and consistent with aggregate usage patterns for the I&M service territory. Accordingly, the MPS and the IRP both model EE measures, not EE programs, and it is not practicable or reasonable to change modeling according to EE program designs as EE program designs are based on the output of the MPS and the IRP. Furthermore, changing how measure bundles are aligned to well-developed Company load shapes would only serve to undermine the integrity of process through alteration of those load shapes without well-informed data and the means of doing so.

		address the reality of different measure types included in some programs) could also be computed and used. c) Please remove any net to gross adjustments made outside of the AEG savings estimates. d) Please do not use any "degradation" adjustments for the bundles. We do not believe the AEG study actually characterizes the maximum achievable potential for EE savings on I&M's system. However, making these changes will address some of our most egregious concerns with I&M's current characterization of energy efficiency.	R116 c: There were no specific net to gross adjustments made outside of the AEG savings estimates. R116d: The degradation adjustments are necessary to prevent the overstatement of efficiency savings impacts with the Company's load forecast models. Please see the presentation from the 2nd Stakeholder, slides 12 – 26 for the Company's rationalization for the use of degradation. <u>Supplemental response (May 22, 2019)</u> In response to an email request from the CAC to clarify I&M's plan for completing the requested additional modeling, I&M provided the following supplemental response: To clarify, I&M intends to accept several of CAC's recent suggestions on modeling EE. In particular, as suggested in CAC question 116, we will use AEG's "high savings" scenario from the Market Potential Study and AEG's estimated measure savings; we will compute a weighted average savings life for each measure bundle; and we will not make any "gross adjustment" outside of the AEG savings estimates. We intend to re-run all of our IRP scenarios incorporating these CAC suggestions. Many of CAC's remaining suggestions (e.g., modeling other "program bundles with mixes of different measure types," using AEG's program costs instead of costs based on I&M's own data, computing other unspecified average load shapes) would be unnecessarily time-consuming at this juncture and/or are unlikely to lead to materially different modeling results. We also disagree with certain CAC-proposed modeling methodologies, as we have explained in our responses to CAC's questions (e.g., we believe our rationale for degradation, which we have explained many times, is sound). Over the course of the IRP process, CAC has made numerous suggestions on EE modeling, and we appreciate CAC's input and have incorporated many of those suggestions. At this point, we are going forward with finalizing the IRP.
The Indiana Coal Council submitted Questions 117 - 119 by email on May 23, 2019 after the close of I&M's stakeholder meeting #4.			

117	Indiana Coal Council (5/23/19)	Where are the fuel assumptions by fuel type? In reference to Slides 38, 41, 47, 54, 60	R 117: Please refer to ICC Q 117 Attachment 1 2019H1_LTF_Base_Nominal_2019-04-23 and ICC Q 117 Attachment 2_2019H1LTF_Base_Real_2019-04-23 for fuel price and other commodity assumptions used in the development of slides 38, 41, 47, 54 and 60. Additional fuel cost data related to the development of the graphs shown on slides 38, 41,47, 54 and 60 are confidential and will be provided subject to the execution of a non-disclosure agreement.
118	Indiana Coal Council (5/23/19)	Did I&M perform an NPV analysis of the scenarios on a 20-year basis rather than a 30-year basis? If yes, please provide. If no, please perform an NPV analysis on a 20-year basis, which is consistent with the IRP planning horizon.	R 118: I&M provided 10-year, 20-year and 40-year Cumulative Present Worth (CPW) data for Group 1, Group 2, Group 2A and Group 3 Scenarios (as defined on slide 25). Please refer to I&M Stakeholder Workshop #4 slides 40. 46, 53, 59 for requested data.
119	Indiana Coal Council (5/23/19)	Did I&M analyze the customer rate impacts by year for each scenario? If yes, please provide the analysis. If no, please perform an analysis of customer rate impacts by year for each scenario.	R 119: I&M plans to provide annual indicative average cost/kwh data in the final IRP report.
120	Michael Kagan, Concentric Energy Advisors	Thank you for holding the May 23rd Stakeholder Presentation. I have the following questions regarding the materials that were presented: 1. Please explain how the forward capacity prices shown on Slide 30 of the May 23rd IRP Stakeholder Presentation were developed.	R 120: The reported Capacity Values are a discrete output of the Aurora model used to project fundamental power prices. Capacity prices represent the non-energy revenue necessary for the least-dispatched units to remain economically viable and for the entire fleet to meet required reserve margins. It would be reasonable to infer that low capacity prices mean that the model is long in generation and that new generation is not required to maintain reserve margins. Similarly, an increase in capacity prices would indicate that new generation is required to meet reserve margins.
121	Michael Kagan, Concentric Energy Advisors	2. How do the forward capacity prices shown on Slide 30 of the May 23rd IRP Stakeholder Presentation compare with forecasted cost of new entry in PJM, and to the extent they differ, please explain why?	R 121: The forecasted Capacity Values are capped at the cost of new entry (CONE), currently defined as the cost of a new combustion turbine. Also, please refer to the Company's response to question 120.

122	Michael Kagan, Concentric Energy Advisors	3. Regarding Slide 30, under I&M's preferred plan, what quantities of short-term capacity does I&M plan to purchase from the market starting in 2020 and when will I&M make commitments for such purchases?	R 122: At this point in time I&M has not determined whether it will participate in the 2022/2023 PJM capacity market as an FRR entity or as an RPM auction participant. Considering the IRP assumptions related to the Rockport plant, if I&M participates as an FRR entity it will likely need to enter into a short-term bi-lateral agreement with existing resources that can provide the required capacity for I&M to meet its load obligation. I&M anticipates making this determination later this year.
123	Michael Kagan, Concentric Energy Advisors	4. Slides 13 and 14 indicate that I&M's preferred plan for new capacity additions starting in 2022 (to replace in part the shortfall created by the expiration of the Rockport 2 lease) includes a substantial amount of wind. Has I&M already procured such capacity/has it issued an RFP for such procurement, and if not, when does it expect to begin that process?	R 123: The preferred plan shows that wind resources would be economic in 2022. I&M will continue to monitor the renewable energy market and if it determines that there are viable projects in the market may consider issuing a solicitation later this year.
Questions 124- 138 were submitted by the CAC (referred to by CAC as DR set 3 on June 14, 2019.			
124	CAC (6.14.19)	(CAC 3.1) Please identify and provide instructions on where in Plexos reduced costs can be found. If reduced costs cannot be accessed with the read-only license, please provide the reduced costs for Case 9, Case 12, and Case 12A.	R 124: This information is available in the respective "2-pager" files for each case located on the Citrix server in the PLEX_IN_OUT folder. Please see the summary tab for the major cost components for each case.
125	CAC (6.14.19)	(CAC 3.2) Please provide, in spreadsheet format with all formulas and links intact, I&M's demand and energy forecasts.	R 125: The material available in spreadsheet format is located on the Citrix server in IRP Appendix Vol. 1, Exhibit A.
126	CAC (6.14.19)	(CAC 3.3) Please provide, in spreadsheet format, the economic, weather, and other forecast variables used to develop I&M's load forecast.	R 126: The Company does not use spreadsheets to prepare its load forecasts. Please refer to IRP Appendix Vol. 2 and Vol. 3, Exhibits H, K, L and M for load forecast model inputs, assumptions and output.

127	CAC (6.14.19)	(CAC 3.4) Please provide, in spreadsheet format, the input and output files produced in the development of I&M's load forecast.	R 127: Please refer to the Company's response to Q 126.
128	CAC (6.14.19)	(CAC 3.5) Please provide definitions for all variables included in the regression models to determine the load forecast across all customer classes and/or end-uses.	R 128: Please refer to the Company's response to Q 126.
129	CAC (6.14.19)	(CAC 3.6) Please specify which variables were in the regression model for determining load forecasts across each customer class.	R 129: Please refer to the Company's response to Q 126.
130	CAC (6.14.19)	(CAC 3.7) Please provide the variable coefficients and model statistics for each regression model used to determine the load forecast for each customer class.	R 130: Please refer to the Company's response to Q 126.
131	CAC (6.14.19)	(CAC 3.8) Please provide a spreadsheet showing the specific post estimation adjustments, if any, made to I&M's load forecast.	R 131: Please refer to the Company's response to Q 126.
132	CAC (6.14.19)	(CAC 3.9) Please provide any economic datasets purchased (from Moody's, IHS Markit, etc.) by I&M since April 1, 2018.	R 132: Please see IRP Appendix Vol. 1, Exhibit A -11 and the Company's response to Q 126.
133	CAC (6.14.19)	(CAC 3.10) Please break out the specific Effluent Limitation Guideline (ELG) and Coal Combustion Residuals (CCR) compliance costs assumed in the fixed operations and maintenance (O&M) costs for each of I&M's coal units, if applicable. If those	R 133: This information is available in the respective "2-pager" files for each case. The CCR and ELG costs for Rockport are included in the on-going capital costs of the units. The OGC costs can be found in the RP Costs tab of the 2 pagers. The specific CCR and ELG costs for Rockport can be found in the Citrix server PLEX_IN_OUT/Inputs/Existing System fixed costs/2018 I&M IRP Existing Unit Fixed Costs.xlsx, in the OGC Data tab, rows 160 and 161.

		costs are not embedded in the fixed O&M field, please indicate where they can be found and break them out from other capitalized maintenance, etc.	
134	CAC (6.14.19)	(CAC 3.11) Please provide, in spreadsheet format, all forecasts used for commodity prices.	R 134: This is available in the PLEX_IN_OUT>Inputs>Commodity Prices folder on the Citrix server.
135	CAC (6.14.19)	(CAC 3.12) Please provide, in spreadsheet format, the costs and operating characteristics for potential supply-side resources.	R 135: This is available in the Appendix Vol. 1, Exhibit D and IRP Section 4. The information is also available in the Citrix server PLEX_IN_OUT>Inputs>Generic Units.
136	CAC (6.14.19)	(CAC 3.13) Please provide, in spreadsheet format, the hourly production profile for solar and wind.	R 136: This is available in the PLEX_IN_OUT>Inputs>Solar> Solar Bundles R10 Redo.xlsx file and PLEX_IN_OUT>Inputs>Wind> Headwaters 35.0% (40.5) Forecast For 2018 I&M IRP 09-12-2018_xz.xlsx and on the Citrix server.
137	CAC (6.14.19)	(CAC 3.14) Please provide I&M's two most recent MISO-OMS survey responses.	R 137: I&M is in the PJM RTO and doesn't prepare MISO-OMS survey responses.
138	CAC (6.14.19)	(CAC 3.15) Please provide any identified benefits from the addition of the RICE units as a microgrid/mini-grid.	R 138: See Section 4.7.4.3, page 100, of the IRP for the discussion of RICE units, the specific economic benefits are shown in each "2-pager" file. Please also refer to the Company's response to Q 124.
139	CAC (6.14.19)	(CAC 3.16) Please explain how I&M will own and operate the microgrids/mini-grids and how this is different from the RICE units serving as peaking resources.	R 139: I&M intends to own and operate the micro grid resources. Each micro-grid will include uniquely configured generation resource(s) and distribution investments to allow the sectionalizing of the distribution system. In addition, the IRP micro grid generation resources are different in its proposed size in MWs than the traditional RICE plant the Company models. Although not modeled in the IRP, there may likely be different cost and performance characteristics based on the final location and design of each Mini-grid deployment (for example, location-specific, interconnection requirements).

Question 140 was submitted by the CAC (referred to by CAC as DR set 4) on June 25, 2019.

140 | CAC (6.25.19)

(CAC 4.1) Please refer to Ind. Code § 8-1-8.5-9 and provide the following information in the table below for each year from 2014 to 2019 according to each range of electric demand shown in the first column. If this information is not readily available or aggregated in such a way so as to cause undue burden to provide the requested information in the table below, then please provide the same raw, disaggregated data in electronic spreadsheet format with all formulae and links intact.

Response to Q-140: I&M doesn't track the requested granularity of > 1 MW increments as requested but does track total # of customers within the single increment of > 1 MW. The following table provides the requested data for the "> 1MW increment":

Year	Number of customers eligible to opt out under IC § 8-1-8.5-9	Total kWh and kW of customers eligible to opt out under IC § 8-1-8.5-9		Number of customers who opt out pursuant to Ind. Code § 8-1-8.5-9	Total electric demand of those customers who opted out pursuant to Ind. Code § 8-1-8.5-9	Percentage of total kWh and kW opting out pursuant to Ind. Code § 8-1-8.5-9
2014, > 1MW	271	4,356,467,540	914,010	52	135,990	20%
2015, > 1MW	294	4,533,245,500	936,599	53	136,998	19%
2016, > 1MW	294	4,533,245,500	936,599	44	122,466	17%
2017, > 1MW	286	4,312,445,609	1,000,354	44	122,466	17%
2018, > 1MW	286	4,312,445,609	1,000,354	42	126,335	18%
2019, > 1MW	295	4,492,356,465	944,111	42	126,335	18%