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By electronic mail

Dr. Brad Borum
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RE: Indiana Coal Council comments to IPL Integrated Resource Plan

Dear Brad,

Please accept the following comments on the IPL Integrated Resource Plan which are being filed on behalf of the Indiana Coal Council. The ICC appreciates the opportunity to participate in the IRP process and to submit comments related to the various utility IRPs for Commission consideration. Please contact me if you have any questions about the ICC's comments or would like to request further information or clarification.

All the best,

Jeffery A. Earl

A. CONCLUSIONS AND RECOMMENDATIONS

The Indiana Coal Council (ICC) conducted a review of the Integrated Resource Plan (IRP) that Indianapolis Power & Light (IPL) prepared and submitted to the Indiana Utility Regulatory Commission (IURC) on December 19, 2019. Although the following comments describe the ICC's differing views on several issues and methodologies used in the IRP, the ICC wishes to express its gratitude to IPL and to compliment IPL on its IRP stakeholder meetings and process. IPL's stakeholder meetings were conducted in a clear, concise, and professional manner, providing meaningful and relevant information in an efficient meeting. In addition, IPL responded quickly and fully to all ICC requests for additional information

Upon review of the IPL IRP, the ICC reached the following conclusions:

1. In the IRP, IPL identifies its Preferred Resource Portfolio to include the retirement of Petersburg Units 1 and 2 by 2023, the addition of new capacity in 2023 obtained through an all source RFP, load reductions through demand side management (DSM) and energy efficiency (EE), and the preservation of Petersburg Units 3 and 4 for the foreseeable future.

2. IPL considered five scenarios with multiple portfolios in each. The Preferred Resource Portfolio was close in cost to the Reference Case in the first five years. IPL did not include costs related to the incremental transmission and distribution revenue requirements in the Preferred Resource Portfolio, which is often significant for renewables.

3. IPL concluded that carbon price assumptions were the major determinant for the model analysis. IPL used a single carbon forecast in all the carbon cases with stochastic modeling. The forecast was applied to both coal and gas but only within the fence-line of the power plant. For example, the base gas price did not reflect any carbon cost for methane emissions at the wellhead. While IPL acknowledged the carbon prices were used as a proxy for a carbon regime, IPL made no attempt to model the potentially more likely scenario of a future Federal Renewable Portfolio Standard, or its equivalent, with and without carbon offsets.

4. IPL used three metrics to evaluate the portfolios: cost, risk, and environment.

5. IPL performed three separate cost analyses. In addition to the standard 20-year Present Value of Revenue Requirements (PVRR), IPL looked at annual revenue requirements and levelized rate impacts. The PVRR suffered from the same issues that have occurred in the other Indiana utility IRPs. The results for the first five years are very close. It is only projected savings from future years (which are highly theoretical) that swing the results. In addition, the failure to include incremental transmission and distribution costs makes the results less dispositive. The annual revenue requirements, which also suffer from the omission of incremental transmission and distribution costs, show that results are very

similar in the early years. The levelized costs per kilowatt-hour are meaningless because rates are based on undepreciated capital, not levelized capital.

6. The risk analysis concluded that the Reference Case had the lowest risk, which IPL attributed to the lower volatility of coal prices relative to power and gas prices.

7. The environmental analysis looked at carbon emissions (total tons and intensity), NOx, and SO_2. The analysis was limited to inside the fence emissions and did not recognize carbon emissions associated with the production and transportation of fuels to the power plants. Not surprisingly, the higher the renewable share, the lower the emissions.

8. Any IRP is "a snapshot in time" analysis. While there are always modest changes from any snapshot analysis, in this case monumental changes have occurred since IPL filed its IRP. The Coronavirus Pandemic has altered the U.S. and world societies and economies in just a few months. The Federal Reserve predicts the unemployment rate will exceed 30 percent and has concluded that the U.S. is already in a recession. With likely months remaining before recovery can begin and probably a full year or more to go before a vaccine will be available, it will be a rocky road for the U.S. While the full impacts are indeterminable at this time, what is known is that COVID-19 will have a severe impact on the economy, which in turn will affect energy markets, including level of demand, availability and cost of capital, and concerns about the affordability of power.

9. The obvious consequences for IPL (and the other utilities in the state of Indiana) are a loss of load, increased collection losses related to non-payment and reduced disconnects, financial pressures as a result of both higher labor and supply costs, and higher cost of capital. There is an industry expectation that renewable projects may suffer in the short-term due to supply chain disruptions and reduced availability of tax equity financing, which is the primary source of capital for renewable projects.

10. The decisions that do not need to be made immediately should be deferred until the full consequences of COVID-19 are better understood with an eye to making steps to minimize rate impacts during these difficult and uncertain times.

11. IPL did not discuss or even acknowledge the Indiana Legislature's 21st Century Tax Force study that is currently underway. The results of the task force's study could be significant in the formulation of future state policy affecting Indiana utilities.

B. <u>IPL's COAL ASSETS</u>

1. IPL has diversified it generating fleet over the last decade with the closure of the Eagle Valley plant and the repowering of the Harding coal plants. IPL's only remaining coal plant is the four-unit Petersburg station.[1]

[1] All tables are taken from the IPL IRP, Volume 1, unless otherwise noted.

Figure 5.4 | IPL's Existing Coal Assets

Unit	Name	Type	ICAP MW	UCAP MW	In-Service Year	Estimated Last Year In-Service
Petersburg						
PETE ST1	Pete 1	Coal	235	225	1967	2032
PETE ST2	Pete 2	Coal	401	366	1969	2034
PETE ST3	Pete 3	Coal	518	486	1977	2042
PETE ST4	Pete 4	Coal	536	523	1986	2042
Total Coal:			1,690	1,600		

Figure 5.5 | IPL's Existing Gas and Oil Assets

Unit	Name	Type	ICAP MW	UCAP MW	In-Service Year	Estimated Last Year In-Service
Eagle Valley						
EV CCGT	Eagle Valley	CCGT	671	617	2018	2055
Harding Street						
HS 5G	Harding Street 5	Gas ST	100	95	1958	2030
HS 6G	Harding Street 6	Gas ST	99	94	1961	2030
HS 7G	Harding Street 7	Gas ST	415	394	1973	2033
HS GT4	Harding Street GT4	Gas CT	74	70	1994	2044
HS GT5	Harding Street GT5	Gas CT	74	70	1995	2045
HS GT6	Harding Street GT6	Gas CT	154	143	2002	2052
HS GT1 & GT2	Harding Street GT1&2	Oil	38	37	1973	2023
Georgetown						
GTOWN GT1	Georgetown 1	Gas CT	79	75	2000	2050
GTOWN GT4	Georgetown 4	Gas CT	79	76	2001	2052
Total Natural Gas:			1,746	1,634		
Total Oil:			38	37		

2. IPL currently owns no renewable facilities. It has Power Purchase Agreements (PPA) for 396 MW of renewable energy, which collectively provide only 54 MW of UCAP[2]. The wind PPAs are 20-year commitments and are significantly higher in cost than IPL's coal generation.[3]

Figure 5.6 | IPL's Existing Renewable PPAs

Unit	Type	ICAP MW	UCAP MW	PPA Start	PPA Expiration
Wind and Solar					
Hoosier Wind Park (IN)	PPA	100	6.6	Nov-09	Nov-29
Lakefield Wind (MN)	PPA	200	0	Oct-11	Oct-31
Solar (Rate REP) *	PPA	96	47.5	varies	2021-2030
Total Renewables:		396	54		

*IPL is using 47.5 MW for 2020, but this value decreases over time.

3. The Petersburg coal units are equipped with pollution control equipment and are generally compliant with all current regulations including Effluent Limitation Guidelines (ELG). In addition, the estimated costs of potential environmental regulations are relatively modest.

Figure 6.3 | Estimated Cost of Potential Environmental Regulations

Rule	Expected Implementation Year	Capital Cost Range Estimate ($MM)	Assumed Technology
CWIS 316(b)*	2022	$13.8	Modified traveling screens
ELG	2018	$0	None
ACE Rule	2024	$8-27	Varies across portfolio

4. As shown below, Petersburg had the third highest capacity factor for in-state coal plants in the two-year period 2017 and 2018. Petersburg ranked number four in 2018 on efficiency as measured by Btu per kilowatt-hour (kwh).

[2] UCAP represents the MW's the utility can credit towards its reserve obligations.
[3] In its most recent FAC filing, the average cost of the wind PPA's was $93.108 per MWh, while the average cost of coal was $20.379 per MWh (Cause 38703 FAC 127).

INDIANA UTILITY COAL-FIRED PLANTS

Operator	Plant	MW	2017 Generation	2017 CF	2018 Generation	2018 CF	Average 2017 and 2018 CF
DEI	Cayuga	985	5,734,487	66%	6,082,109	70%	68%
DEI	Gibson	3,144	17,996,759	65%	17,631,801	64%	65%
IPL	AES Petersburg	1,664	9,341,524	64%	9,101,208	62%	63%
Hoosier	Merom	1,008	4,909,662	56%	5,870,298	66%	61%
Vectren South	F B Culley	360	1,843,436	58%	1,912,244	61%	60%
OVEC	Clifty Creek	1,231	6,037,635	56%	6,369,305	59%	58%
I&M	Rockport	2,600	10,923,442	48%	11,894,109	52%	50%
Vectren South	A.B. Brown	500	1,919,347	44%	2,409,437	55%	49%
NIPSCO	R M Schahfer	1,625	4,948,283	35%	6,755,808	47%	41%
NIPSCO	Michigan City	469	1,280,833	31%	2,040,518	50%	40%
DEI	Edwardsport	630	1,933,355	35%	1,828,443	33%	34%
DEI	R Gallagher	280	194,215	8%	285,152	12%	10%
Total		**14,496**	**67,062,978**	**53%**	**72,180,432**	**57%**	**55%**
DEI		**5,039**	**25,858,816**	**59%**	**25,827,505**	**59%**	**59%**
DEI excluding Gallagher		**4,759**	**25,664,601**	**62%**	**25,542,353**	**61%**	**61%**

5. Petersburg was the fourth most efficient coal plant in 2018. Not surprisingly, the rankings for capacity factor and heat rate are similar, which demonstrates how the capacity factor affects plant efficiency. Simply put, the higher the capacity factor, the more efficient the power plant.

Company	Plant	2018 Elec Fuel Consumption (MMBtu)	2018 Net Generation (MWH)	Calculated 2018 Heat Rate (MMBtu/KWH)
DEI	Cayuga	60,910,976	6,082,242	10,015
I&M	Rockport	120,066,241	11,894,109	10,095
Hoosier	Merom	61,286,582	5,870,298	10,440
IPL	AES Petersburg	96,550,893	9,101,269	10,609
OVEC	Clifty Creek	68,520,782	6,369,305	10,758
DEI	Gibson	189,741,687	17,631,801	10,761
DEI	Edwardsport	42,850,594	3,962,018	10,815
Alcoa	Warrick	47,326,406	4,336,582	10,913
NIPSCO	Michigan City	22,361,452	2,040,518	10,959
Vectren South	F B Culley	20,972,594	1,912,244	10,968
Vectren South	A B Brown	27,137,491	2,444,520	11,101
NIPSCO	R M Schahfer	76,971,291	6,771,610	11,367
DEI	R Gallagher	3,804,474	285,152	13,342

Source: 2018 EIA Form 923

C. <u>PREFERRED RESOURCE PORTFOLIO</u>

1. Retirement of Petersburg units 1 and 2 by 2023.

2. Competitively procure replacement capacity by June 1, 2023, through an all-source RFP.

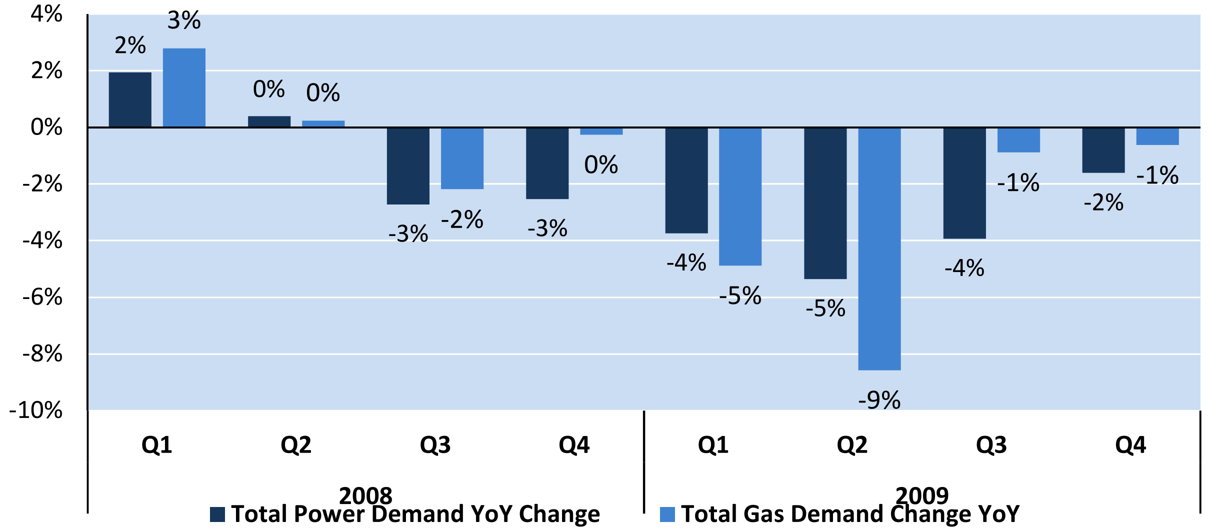
3. Target approximately 130,000 MWh per year of demand side management (DSM) and energy efficiency (EE) programs.

4. Maintain generation at Petersburg units 3 and 4 for the next five years.

D. CORONAVIRUS PANDEMIC

1. The 2019–20 coronavirus pandemic is an ongoing pandemic of coronavirus disease that started in 2019 (COVID-19). The outbreak was first identified in Wuhan, Hubei Province, China, in December 2019. The World Health Organization (WHO) declared the outbreak to be a Public Health Emergency of International Concern on January 30, 2020, and recognized it as a pandemic on March 11, 2020. As of the end of March 2020, more than 850,000 cases of COVID-19 have been reported in over 200 countries and territories, resulting in almost 50,000 deaths.
2. The virus is mainly spread during close contact and by respiratory droplets produced when people cough or sneeze. There is currently no vaccine or specific antiviral treatment. Efforts to prevent the spreading of the virus include closure of non-essential businesses, quarantines, workplace hazard controls, social distancing, and cancellations.
3. The pandemic is leading to severe global economic disruptions. In the United States (and, specifically, in Indiana), non-essential businesses and schools have closed. Public and private gatherings of large groups are prohibited or have been cancelled. Unemployment in the U.S. is expected to rise above 30 percent. The Federal Reserve believes the U.S. is already in a recession. There is speculation that the recession will turn into a depression. Several stimulus bills are expected to increase the deficit by trillions of dollars. There is universal agreement that the U.S. is in unchartered territory.
4. The closest parallel is the Global Financial Crisis of 2008/2009. As shown below, there were material declines in both the demand for power and natural gas. The impact of COVID-19 could be larger and of a greater duration.

Exhibit 1: Total Electricity and Natural Gas Demand YoY Change



Source: Energy Ventures Analysis, Inc.

5. According to EPRI[4], peak and power demand in Italy declined by 18 to 22 percent during days five to 10 of its COVID-19 shutdown, compared to the prior year.
6. The New York Independent System Operator reported load and demand in New York City declined by 12 percent during the third week of March compared to the prior year.
7. Members of the White House Coronavirus Task Force believe it could be months before recovery can begin. On March 31st, the Task Force reported assuming compliance with social distancing and stay at home guidelines, deaths in the U.S. are likely to be between 100,000 and 240,000. While the full impacts are indeterminable at this time, it is clear that COVID-19 will have a severe impact on the economy which in turn will affect energy markets including fuel prices, the level of electricity demand, and availability and cost of capital for investments in electric generation.
8. The energy investments in Indiana most likely to be directly affected by the economic downturn are the projects reliant on tax equity investment. Tax equity investments are transactions that pair tax credits generated by a qualifying physical investment with the capital financing associated with that investment. These transactions involve one party agreeing to assign the rights to claim the tax credits to another party in exchange for an equity investment (i.e., cash financing). Tax equity financing is commonly used to take advantage of renewable electricity production tax credits (PTC) and energy investment tax credits (ITC). COVID-19 is expected to adversely affect the availability of tax equity financing because of lower or negative earnings.
9. Wind developers are also experiencing both immediate supply chain disruptions and potentially dramatic impacts of delay on construction timelines and financings. Delays can reduce the tax credit amount due to scheduled declines in the tax credits. Wind turbine suppliers have provided force majeure notices to utility-scale wind developers.

[4] EPRI Transmission Operations and Planning, EPRI Product ID: 3002018602.

These supply chain disruptions are in addition to delays in construction equipment availability and worker availability at the project sites due to the effects of COVID-19.

10. Another related affect is the extent of short- and long-term demand reduction as a result of the prolonged recovery from COVID-19. While some speculate that recovery will be quick and robust, this is no longer the consensus. The debate now focuses on the size of demand reduction.
11. Finally, an oil price war between Russia and Saudi Arabia has caused a free fall in the price of oil as a result of increased production and lower demand. While there appears to be a partial resolution, it is unclear whether the relatively small curtailments in oil production will have much impact in part because the demand impact of COVID-19 is so devastating. Global storage capacity limits are being tested. Further, the typical demand response to lower prices is not being realized. The U.S. is affected by the impact of lower prices on its shale oil production which some argue is the ultimate objective of the oil price war.
12. The net effect of the market impacts is considerable uncertainty as to demand and alternative resource options. Further, the economic devastation caused by COVID-19 makes clear that the highest priority for ratepayers is not a 20-year Net Present Value but rather how power rates and reliability will be affected in the short-term, i.e., three to five years. In this context, it is critical that utilities defer unnecessary capital expenditures, maintain existing generation infrastructure, and strongly consider the short-term rate impacts of each alternative.
13. Other states are recognizing COVID-19 impacts on near-term development. In Virginia, the economic crisis is reportedly raising new concerns about the expense of wind and solar projects. According to Virginia Delegate Sullivan, "(t)he current economic crisis may well affect the timeline …"[5] There is concern that Dominion, the largest state utility, may have a difficult time raising the needed capital.
14. Utilities are expected to experience numerous adverse economic impacts as a result of COVID-19. First, the utilities are likely to incur higher labor costs as a result of workforce absences due to quarantines and illness, which will require replacements with temporary employees and/or contractors with costs not part of budgeted amounts. Similarly, the cost of replacement equipment is expected to be materially higher as a result of disruptions to the existing supply chains. With a moratorium on service disconnections by many utilities, including IPL, utilities may be forced to absorb additional costs that may or may not be recovered from customers. Finally, lower sales will reduce recovery of costs. If or when utilities are allowed to recover these additional costs in rates, it could adversely affect customer rates.

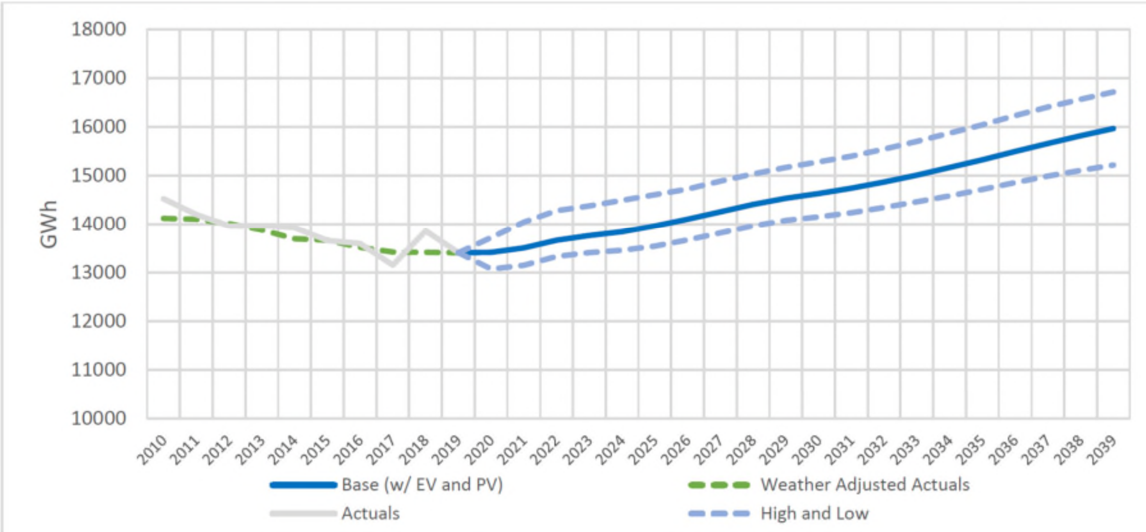
E. LOAD MODELING CONCERNS

1. The load forecasts IPL used in the IRP fall in a relatively narrow range. The base forecast calls for 0.4 percent annual growth, which appears counter to what has occurred in recent

[5] https://www.wvtf.org/post/should-northam-reconsider-renewable-energy-legislation-light-pandemic#stream/0

history. While the low case calls for a slight dip in 2020, the cases do not capture the likely effect of the global recession that has already occurred.

Figure 4.8 | IPL Base, High & Low Load Forecast (2020-2039)



F. ELECTRIC VEHICLES

1. IPL, reliant on a third party, has understated the potential impact of electric vehicles on future load.

2. IPL stated that "(w)ith respect to medium- and heavy-duty trucks, [its consultant] concluded that these technologies and the deployment of them are at too early a stage to attempt to include them in a forecast." [6]

3. This is inconsistent with IPL's own position that the "market for Electric Vehicles . . . is expected to grow rapidly driven by declining battery costs and improved performance."[7]

4. In 2019, many industry participants painted a more certain future for such deployment.[8]

5. The incomplete consideration of the growth in EV's is important in two specific respects. First, IPL is potentially understating its resource requirements. Second, IPL is potentially mischaracterizing the shape of its load curve.

6. Understating resource requirements given the proposed coal plant retirements results in understating future capital requirements for new resources.

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[6] 2019 IPL Integrated Resource Plan, page 48

[7] 2019 IPL Integrated Resource Plan, page 44.

[8] Provide cites

7. The change in the load curve, which IPL acknowledged in the IRP, would increase the value of its coal generating assets, which need to operate at minimum loads throughout the night.

G. WIND AND SOLAR DISPATCH

1. A potentially significant cost associated with wind and solar can be incurred as a result of MISO's decision to dispatch intermittent resources.

2. Many initial wind PPA's did not contemplate this could occur, and following litigation, utilities found themselves obligated not only for costs but for the production tax credits when the units were dispatched.

3. MISO has proposed to dispatch solar in a similar manner.

4. The dispatching of wind and solar affects the economic considerations of these resources in two way—it increases per unit costs and it increases the need for capital investment in transmission for the resources to be accommodated.

H. MODELING SCENARIOS

1. IPL developed five scenarios for the IRP. As shown below, the scenarios varied only with respect to natural gas prices, carbon pricing, and load growth.

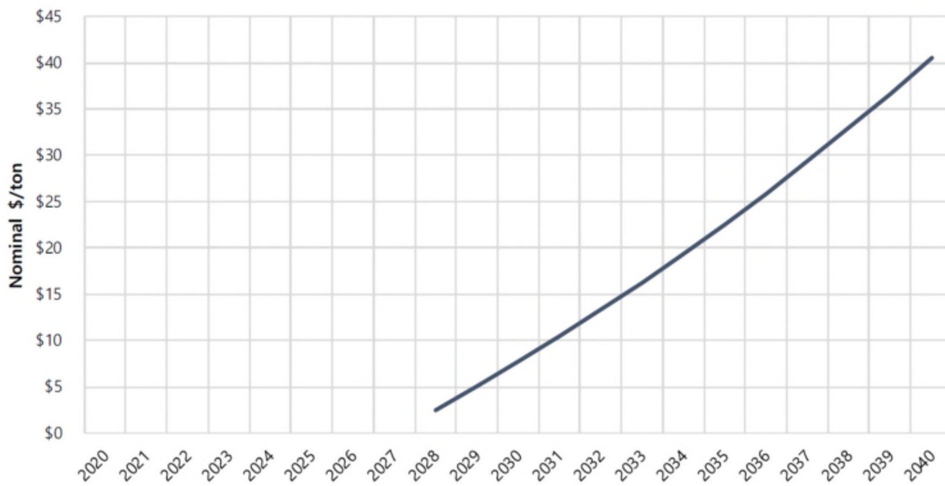
Figure 7.3 | IPL 2019 IRP Scenarios and Drivers

	Reference Case	Scenario A: Carbon Tax	Scenario B: Carbon Tax + High Gas	Scenario C: Carbon Tax + Low Gas	Scenario D: No Carbon Tax + High Gas
Natural Gas Prices	Base	Base	**HIGH ↑**	**LOW ↓**	**HIGH ↑**
Carbon Tax	No Carbon Price	**Carbon Tax (2028+)**	**Carbon Tax (2028+)**	**Carbon Tax (2028+)**	No Carbon Price
Coal Prices	Base	Base	Base	Base	Base
IPL Load	Base	Base	Base	**LOW ↓**	**HIGH ↑**
Capital Costs for Wind, Solar, and Storage	Base	Base	Base	Base	Base

2. Under the scenario construct, IPL found that the single biggest determinant of relative NPV was the carbon assumptions.

3. IPL used a single curve for carbon starting in 2028 with stochastic analysis

Figure 7.11 | Federal U.S. Carbon Price in Carbon Scenarios



5. IPL included a relatively nuanced discussion of carbon in its IRP, stating:

> IPL recognizes that the uncertainty surrounding any assumption for future carbon legislation. The timing, the scale, and structure of any price on carbon is difficult to forecast. At the time this report was developed seven different carbon tax legislative proposals have been introduced to Congress in 2019. … Each bill has a different structure and timeline, and there are significant political headwinds facing these bills until after the 2020 Federal Election.

Despite such recognition, IPL then argues that "including a federal price on carbon in scenarios is a prudent planning exercise considering the national and global efforts for carbon reduction." It is useful to consider what the presumptive Democratic nominee for President includes in his Climate Change platform.[9] Former Vice President Biden proposes to include in his year one legislative agenda a plan to achieve net zero emissions no later than 2050 and states that the economy must achieve ambitious reductions in emissions economy-wide instead of having just a few sectors carry the burden of change. Carbon taxes are not mentioned in his emission-reduction proposal. Rather the focus is effectively on a renewable portfolio standard[10] approach akin to what many states are embracing. Further, it acknowledges that any plan will not be limited to the power sector.

6. The failure over more than a decade to obtain legislative agreement on a carbon tax does not support an argument that prudent planning should be based on a carbon price, even if it is just a proxy for other carbon regulation. Rather, given the tools

[9] https://joebiden.com/climate/
[10] A renewable portfolio standard also goes under the name of a clean energy portfolio.

available to it, IPL would have been well advised to consider a scenario based on a renewable portfolio standard approach in it is modeling.

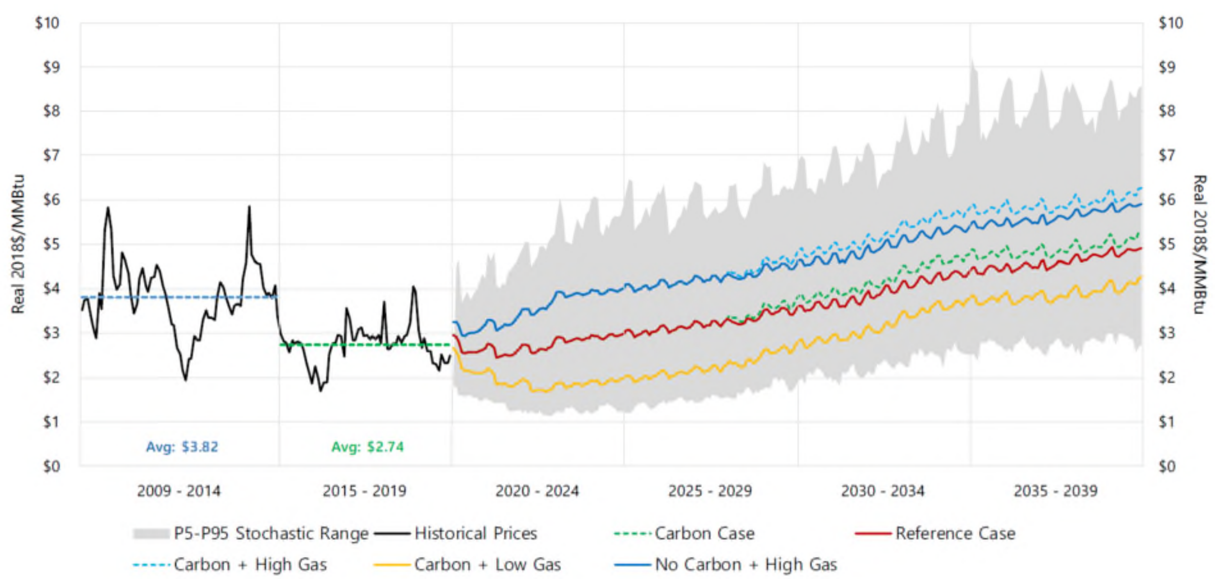
7. The Biden plan also calls for "requiring aggressive methane pollution limits for new and existing oil and gas operations." While carbon taxes at the power plant level are assumed in all carbon cases, it is not clear that carbon taxes or limits on methane emission during natural gas extraction are reflected, even in the high gas price case.[11] For consistency, consideration of carbon taxes and methane limits on natural gas, which would result in higher prices, should be considered in all carbon cases.

8. IPL acknowledges the single most important determinant of the IRP is the carbon price. In addition to looking at alternative scenarios, it is unclear why IPL did not consider a range in carbon prices and a range in implementation dates.

I. <u>FUEL PRICES</u>

1. IPL modeled three natural gas prices.

Figure 7.9 | Henry Hub Natural Gas Prices



2. While the associated modeling of the low, base, and high gas price forecasts was stochastic, the specific forecasts themselves were deterministic.

3. According to IPL, the high gas price forecast included factors that **could** lead to such a result. The factors included increased regulation on fracking and natural gas production, which **could** include regulations on methane and/or water, a carbon tax driving higher

[11] According to IPL, the high gas price sensitivity case **could** include regulations on methane. (Volume I page 127)

demand for gas as a bridge fuel, and higher than expected natural gas exports. In other words, the actual basis for the higher price forecast was not specific.

4. IPL uses a single coal price forecast with stochastics in this IRP.

5. IPL appears to justify this based upon "the low correlation between coal and natural gas prices".

6. While ICC agrees with the lack of a coal-gas price correlation, IPL appears to ignore the relationship between pricing and the level of coal demand. As with natural gas, it is ultimately the supply/demand balance that determines coal pricing. Stochastic analysis will not capture the basic differences in a low, medium and high price case.

J. METRICS

1. IPL used three metrics to evaluate its analyses: costs, risks, and environmental.

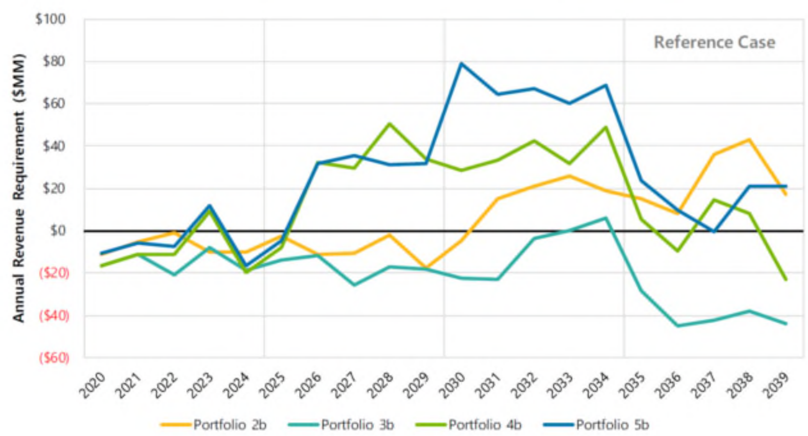
2. IPL used three different cost metrics:

   a. 20-year Present Value of Revenue Requirements
   b. Annual revenue requirement
   c. Levelized $/kwh rate

3. IPL notes that the 20-year PVRR is the standard in IRPs. IPL notes its PVRR does not include transmission and distribution revenue requirements even though transmission and distribution revenue requirements are higher under a heavy renewables strategy.

4. IPL calculated an annual revenue requirement presumably in order to address a frequent criticism of a 20-year PVRR, which often relies on future savings to offset higher short-term costs. IPL notes that its Preferred Resource Portfolio (Portfolio 3B) is almost always lower in cost than the Reference Case. In the early years, however the difference is small, well within the margin of error, and does not include the incremental transmission and distribution revenue requirements, which can be significant for renewables. The meaningful savings with the Preferred Portfolio do not occur until after 2034.

Figure 8.17 | Annual Difference from Portfolio 1b (Nominal $MM)



5. IPL also calculated a levelized $/kwh rate impact. The purpose of this is unclear. The most relevant issue in a cost comparison is the annual customer rate impact, which is not determined on a levelized basis. Capital is depreciated over time and the utility earnings/rates are based on the undepreciated capital, not levelized capital. The irrelevance of this metric is shown by the minimal attention IPL has provided to it in the IRP. IPL even provides a qualifier that "(a)ny potential rate impacts of decisions stemming from this IRP will be considered in future regulatory filings." In other words, it has not calculated any meaningful rate impacts.

6. IPL defines risk as a model-calculated premium based on the assumed cost distributions, such that the risk premium is larger for wider cost distributions. According to IPL, the "risk premium metric evaluates the probability weighted average of high cost outcomes less the media."

7. The analysis shows the Reference Case (no coal retirements) to be lower in risk. This recognizes that coal prices are relatively stable compared to power and natural gas prices.

Figure 8.33 | Net Present Value of Annual Risk Premium ($MM)

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1A	$329	$383	$406	$353	$400
Portfolio 2A	$370	$425	$465	$384	$452
Portfolio 3A	$367	$419	$464	$370	$448
Portfolio 4A	$466	$537	$611	$466	$554
Portfolio 5A	$441	$498	$574	$431	$539
Portfolio 1B	$358	$420	$447	$385	$430
Portfolio 2B	$354	$407	$442	$363	$431
Portfolio 3B	$408	$468	$532	$415	$495
Portfolio 4B	$461	$534	$609	$467	$554
Portfolio 5B	$493	$565	$649	$481	$595
Portfolio 1C	$348	$406	$430	$374	$416
Portfolio 2C	$360	$412	$449	$368	$438
Portfolio 3C	$372	$424	$476	$378	$448
Portfolio 4C	$457	$534	$612	$464	$554
Portfolio 5C	$442	$507	$584	$448	$543

8. That coal is lower in risk is no surprise. One simply needs to look at IPL's latest FAC filing[12] to reach this conclusion. In Cause 38703 FAC 127, IPL reports its estimated costs for coal and oil generation was $20.379 per MWh while its costs for wind PPA's was $93.108 per MWh.[13]

[12] Cause 38703 FAC 127

[13] Coal/oil generation costs of $55.155 million and 2706.4 kwh (1000); wind PPA costs of $11.697 million and 125.624 kwh (1000). Gas generation costs are not comparable because Firm Transportation is recovered in base rates.

INDIANAPOLIS POWER & LIGHT COMPANY
Determination of Fuel Cost Adjustment
Beginning with August 2020 Based on the Estimated
Three Months Average of June, July, and August 2020

Line No.	Description	(A) Estimated Month of: June	(B) July	(C) August	(D) Total	(E) Estimated Three Month Average	Line No.
	kWh Source (000's)						
1	Coal and Oil Generation	839,181	974,731	892,511	2,706,423	902,141	1
2	Nuclear Generation	-	-	-	-	-	2
3	Hydro Generation	-	-	-	-	-	3
4	Other Generation - Internal Combustion	-	-	-	-	-	4
5	Gas Generation	562,149	744,554	625,120	1,931,823	643,941	5
	Purchases through MISO:						
6	Wind Purchase Power Agreement Purchases	47,700	37,091	40,833	125,624	41,875	6
7	Non-Wind PPA Market Purchases	64,381	28,176	87,614	180,171	60,057	7
8	Other	-	-	-	-	-	8
9	Purchased Power other than MISO	17,855	16,690	16,231	50,776	16,925	9
	LESS:						
10	Energy Losses and Company Use	57,491	65,723	64,191	187,405	62,468	10
11	Inter-System Sales through MISO	334,496	433,088	326,050	1,093,634	364,545	11
12	Inter-System Sales other than MISO	-	-	-	-	-	12
13	Non-Jurisdictional Retail Sales	-	-	-	-	-	13
14	**Sales (S)**	1,139,279	1,302,431	1,272,068	3,713,778	1,237,926	14
	Fuel Cost ($)						
15	Coal and Oil Generation	17,386,641	19,601,656	18,166,268	55,154,565	18,384,855	15
16	Nuclear Generation	-	-	-	-	-	16
17	Hydro Generation	-	-	-	-	-	17
18	Other Generation - Internal Combustion	-	-	-	-	-	18
19	Gas Generation	9,875,606	13,779,382	11,589,649	35,244,637	11,748,212	19
	Purchases through MISO:						
20	Wind Purchase Power Agreement Purchases	4,709,422	3,651,771	3,335,492	11,696,685	3,898,895	20
21	Non-Wind PPA Market Purchases	1,100,245	696,427	1,850,084	3,646,756	1,215,585	21
22	Other	-	-	-	-	-	22
23	MISO Components of Cost of Fuel	1,080,038	1,234,704	1,205,920	3,520,662	1,173,554	23
24	Purchased Power other than MISO	3,010,839	2,819,645	2,728,627	8,559,111	2,853,037	24
	Less:						
25	Inter-System Sales through MISO	5,998,778	7,928,745	5,983,254	19,910,777	6,636,926	25
26	Inter-System Sales other than MISO	-	-	-	-	-	26
27	Non-Jurisdictional Retail Sales	-	-	-	-	-	27
28	Transmission Losses	294,215	343,357	336,144	973,716	324,572	28
29	Lakefield PPA Adjustment	87,754	90,147	77,384	255,285	85,095	29
30	**Total Fuel Cost (F)**	$ 30,782,044	$ 33,421,336	$ 32,479,258	$ 96,682,638	$ 32,227,545	30
31	**F ÷ S (Line 30 ÷ Line 14) (Mills/kWh)**					26.033	31

Line No.	Description	Months to be Reconciled: November	December	January	Total		Line No.
32	Fuel Cost Variance	$ (126,673)	$ (2,308,581)	$ (3,627,020)	$ (6,062,273)		32
	(Mills/kWh)						
33	Variance Charge (Line 32 Total divided by estimated Indiana jurisdictional sales of		3,713,778	kWh (000's)		(1.632)	33
34	Adjusted Fuel Cost Charge (Line 31 + Line 33)					24.401	34
35	Less: Base Cost of Fuel Included in Rates					32.938	35
36	Fuel Cost Charge					(8.537)	36
37	Fuel Cost Charge Adjusted for Indiana Utility Receipts Tax (1)					(8.665)	37

(1) Line 36 Divided By (1-(1.4% URT Rate/(1-0.05375)))

9. The environmental analysis looked at carbon emissions (total tons and intensity), NOx, and SO_2. The analysis was limited to inside-the-fence emissions and did not recognize carbon emissions associated with the production and transport of fuels to the power plants. Not surprisingly, the higher the renewable share, the lower the emissions.

10. Given the concern about carbon, it is inappropriate to ignore upstream carbon emissions. The upstream portion includes the emissions on a CO_2 equivalent basis related to production and transport.

K. 21st CENTURY ENERGY DEVELOPMENT TASK FORCE

1. Ind. Code ch. 2-5-45, effective July 1, 2019, created the 21st Century Energy Policy Development Task Force (Task Force) whose mandate is to deliver to the Indiana General Assembly and others, by December 1, 2020, its report and recommendations concerning:

    a. Outcomes that must be achieved in order to overcome any identified challenges concerning Indiana's electric generation portfolios, along with a timeline for achieving those outcomes.

    b. Whether existing state policy and statutes enable state regulators to properly consider the statewide impacts of changing electric generation portfolios and, if not, the best approaches to enable state regulators to consider those impacts.

    c. How to maintain reliable, resilient, and affordable electric service for all electric utility consumers, while encouraging the adoption and deployment of advanced energy technologies.

2. The results of this very important and relevant Task Force could provide useful information and guidelines that affect the future construction of IRPs. Therefore, the schedule for IPL's next IRP should allow for such consideration.

3. In the IRP, IPL did not acknowledge this pending report nor the potential impact of its findings on its resource planning.