VECTREN PUBLIC STAKEHOLDER MEETING

OCTOBER 10, 2019

WELCOME AND SAFETY SHARE

LYNNAE WILSON

INDIANA ELECTRIC CHIEF BUSINESS OFFICER

SAFETY SHARE

Tips to Avoid Distractions While Driving

- Make adjustments before your get underway. Address vehicle systems like your GPS, seats, mirrors, climate controls and sound systems before hitting the road. Decide on your route and check traffic conditions ahead of time.
- Snack smart. If possible, eat meals or snacks before or after your trip, not while driving. On the road, avoid messy foods that can be difficult to manage.
- Secure children and pets before getting underway. If they need your attention, pull off the road safely to care for them. Reaching into the backseat can cause you to lose control of the vehicle.
- Put aside your electronic distractions. Don't use cell phones while driving – handheld or hands-free – except in absolute emergencies. Never use text messaging, email functions, video games or the internet with a wireless device, including those built into the vehicle, while driving.
- If another activity demands your attention, instead of trying to attempt it while driving, pull off the road and stop your vehicle in a safe place. To avoid temptation, power down or stow devices before heading out.
- As a general rule, if you cannot devote your full attention to driving because of some other activity, it's a distraction. Take care of it before or after your trip, not while behind the wheel.

2019/2020 STAKEHOLDER PROCESS

August 15, 2019	October 10, 2019	December 13, 2019[1]	March 19, 2020
• 2019/2020 IRP Process • Objectives and Measures • All-Source RFP • Environmental Update • Draft Base Case Market Inputs & Scenarios	• RFP Update • Draft Resource Costs • Sales and Demand Forecast • DSM MPS/ Modeling Inputs • Scenario Modeling Inputs • Portfolio Development	• Draft Portfolios • Draft Base Case Modeling Results • All-Source RFP Results and Final Modeling Inputs • Probabilistic Modeling Approach and Assumptions	• Final Base Case Modeling • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

1 Snow date is December 19, 2019

AGENDA

Time		
9:00 a.m.	Sign-in/Refreshments	
9:30 a.m.	Welcome, Safety Message	Lynnae Wilson, CenterPoint Energy Indiana Electric Chief Business Officer
9:40 a.m.	Follow-up Information Since Our Last Stakeholder Meeting	Matt Rice, Vectren Manager of Resource Planning and Gary Vicinus, Managing Director for Utilities, Pace Global
10:10 a.m.	MISO Considerations	Justin Joiner, Vectren Director Power Supply Services
10:40 a.m.	Break	
10:50 a.m.	Scenario Modeling Inputs	Gary Vicinus, Managing Director for Utilities, Pace Global
11:30 a.m.	Lunch	
12:00 p.m.	Long-term Base Energy and Demand Forecast	Mike Russo, Senior Forecasting Analyst, Itron
12:30 p.m.	Existing Resource Overview	Wayne Games, Vectren Vice President Power Generation Operations
1:00 p.m.	Potential New Resources and MISO Accreditation	Matt Lind, Resource Planning & Market Assessments Business Lead, Burns and McDonnell
1:40 p.m.	Break	
1:50 p.m.	DSM Modeling in the IRP	Jeffrey Huber, Managing Director, GDS Associates
2:20 p.m.	Portfolio Development Workshop	Moderated by Gary Vicinus, Managing Director for Utilities, Pace Global
3: 00 p.m.	Adjourn	

MEETING GUIDELINES

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, please place your phone and computer on mute. We will open the phone lines for questions within the allotted time frame. You may also type in questions via the chat feature. Only questions sent to ‘All-Entire Audience’ will be seen and answered during the session.
3. There will be a parking lot for items to be addressed at a later time.
4. Vectren does not authorize the use of cameras or video recording devices of any kind during this meeting.
5. Questions asked at this meeting will be answered here or later.
6. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address.

FOLLOW-UP INFORMATION SINCE OUR LAST STAKEHOLDER MEETING

MATT RICE

VECTREN MANAGER OF RESOURCE PLANNING

GARY VICINUS

MANAGING DIRECTOR FOR UTILITIES, PACE GLOBAL

VECTREN COMMITMENTS FOR 2019/2020 IRP

By the end of the second stakeholder meeting Vectren will have made significant progress towards the following commitments

- ✓ Utilizing an All-Source RFP to gather market pricing & availability data
- ✓ Including a balanced, less qualitative risk score card; draft was shared at the first public stakeholder meeting
- ✓ Performing an exhaustive look at existing resource options
- ✓ Using one model for consistency in optimization, simulated dispatch, and probabilistic functions
- ✓ Working with stakeholders on portfolio development

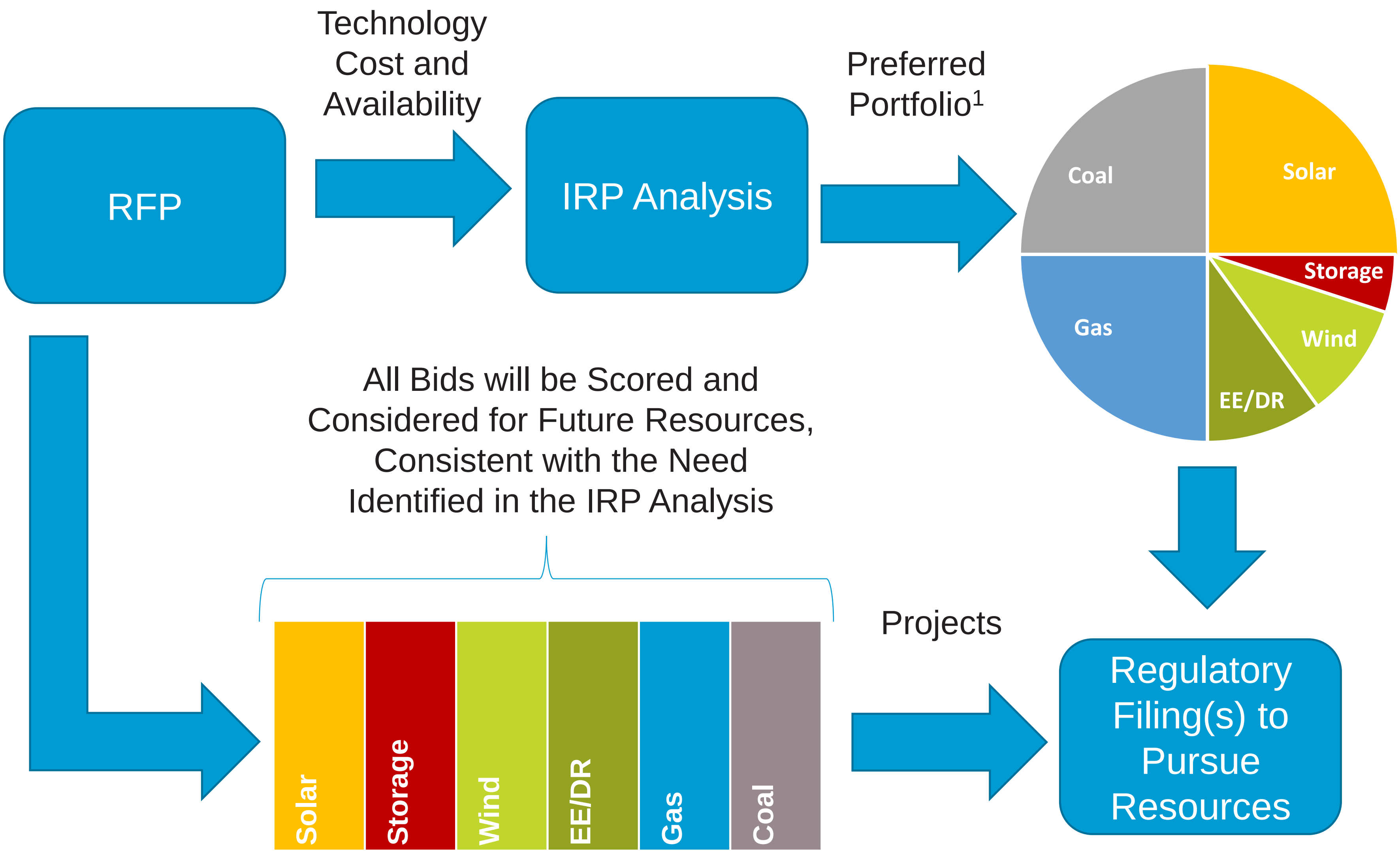
Vectren will continue to work towards the remaining commitments over the next several months

- Providing a data release schedule and provide modeling data ahead of filing for evaluation
- Striving to make every encounter meaningful for stakeholders and for us
- Ensuring the IRP process informs the selection of the preferred portfolio
- Modeling more resources simultaneously
- Testing a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- Conducting a sensitivity analysis
- Including information presented for multiple audiences (technical and non-technical)

PROPOSED 2019/2020 IRP PROCESS

1. Conduct an All Source RFP
2. Create Objectives, Risk Perspectives and Scorecard Development
3. Create Base Case Assumptions and Scenario Development
4. Portfolio Development Based on Various Strategies, Utilizing Optimization to Create a Wide Range of Portfolios and Refine with All Source RFP Data
5. Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks
6. Portfolio Testing Using Probabilistic Modeling of 200 Potential Futures
7. Utilize the Probabilistic Modeling to Conduct Sensitivity Analysis
8. Populate the Risk Scorecard that was Developed Early in the Process and Evaluate Portfolios
9. Select the Preferred Portfolio

REVIEW ROLE OF THE ALL SOURCE RFP



1 Illustrative example

STAKEHOLDER FEEDBACK

Request	Response
Scenario: Update the High Regulatory scenario to include a carbon dividend. Concern was expressed that the economic outlook would not necessarily grow worse under a high CO2 tax scenario.	Economic outlook is correlated with the load forecast. We have updated the High Regulatory scenario load forecast direction from lower than the base case forecast to equal with the base. The High Regulatory scenario includes other regulations, which we assume will net out any positive impact created from a carbon dividend.
Scenario: Update a scenario to have renewables costs lower than the base due to innovation and removal of waste from the value chain. The example provided was that the price of laptops declined as demand went up.	We have updated the 80% CO_2 Reduction and the High Regulatory scenarios to be lower cost than base.
Modeling: Options to view Aurora modeling files. Additionally, provide an understanding of "industry-supplied data" Include these modeling assumptions.	Read only copy of Aurora costs $5k and includes a help function and basic self learning slides. Additionally, we will provide Aurora release notes to those that request and sign an NDA.
Portfolio development: Fully explore the use of hydro resources, given Vectren's proximity to the Ohio River.	Vectren reviewed available materials provided to better understand/compare to our technology assessment provided by Burns and McDonnell. While we did not receive a bid and costs are high, hydro could be included within portfolio development.

STAKEHOLDER FEEDBACK CONT.

Request	Response
Scorecard: Update Environmental Risk Minimization measure to report CO_2 equivalent and consider utilizing life cycle emissions by electric generation technology	Utilize NREL Life Cycle Greenhouse Gas Emissions (upstream and downstream) from Electricity Generation by resource analysis. NREL CO_2e rates per MWh will be applied to both retail sales covered by Vectren portfolios, as well as a CO_2e emissions estimate when relying on the market.
Scorecard: Consider sunk costs in Future Flexibility measure. Change basis from MWhs of impairment by asset to $ to better reflect uneconomic asset risk	Will update this measure to reflect dollars. Will measure when costs to run an asset do not cover energy and capacity revenues in three consecutive years. Methodology will be described later in this presentation.
Scorecard: Market Risk Minimization metric bounds of 15% rational needs to be described.	We reviewed the +/-15% deadband for energy and capacity market purchases for reasonableness and feel this is a reasonable assumption. We will discuss again today.
RFP/IRP costs: Concern was expressed that we could lose opportunities to include low cost resources within Integrated Resource Plan (IRP) modeling if we only include Request for Proposals bids with a delivered cost.	For modeling, we will include firm bids on our system and those with a delivered cost. Additionally, Burns and McDonnell will review other bids and assess potential congestion costs. Such evaluated resources (including congestion estimate) may also be included within IRP modeling.

STAKEHOLDER FEEDBACK CONT.

Request	Response
Scenarios: Include an RPS standard scenario.	There are several mandates that could be imposed in the future, from renewables interests to coal interests. The primary purpose of scenarios in this IRP will be to help determine how portfolios perform in various future states. We would like your feedback on portfolio development. We can develop various portfolios utilizing an RPS, coal portfolio mandate, etc. within the model. The performance of these portfolios will be assessed within the scenarios and probabilistic modeling.
Scorecard: Include a health benefits measure.	We reviewed a recent EPA report titled "Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report[1]," which included a screening level estimate of Benefits-per-KWh value for EE, wind, and solar projects. The report noted that there are no comprehensive national studies available with data of this kind. Values from this report cannot be used for this analysis as estimates are explicitly only good through 2022.

1 Source: https://www.epa.gov/sites/production/files/2019-07/documents/bpk-report-final-508.pdf

AURORAxmp TOOL

AURORA
BY ENERGY EXEMPLAR

VECTREN
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- AURORAxmp (Aurora) is an industry standard model for electricity production costing and market simulations
- Aurora is licensed by approximately 100 clients in North America, ranging from consultants to full-scale utilities to traders to Indiana's State Utility Forecasting Group (SUFG)
- Aurora is accepted in many regulatory jurisdictions
- Vectren will use the Aurora model in the IRP to provide the following analysis:
  - Least cost optimization of different portfolios, including decisions to build, purchase, or retire plants
  - Simulation of the performance of different portfolios under a variety of market conditions
  - Production cost modeling to provide market prices for energy
  - Emissions tracking based on unit dispatch
  - A comparative analysis of various regulatory structures
- A primary output is portfolio cost performance in terms of Net Present Value

For more information: https://energyexemplar.com/solutions/aurora/

ACCESSING THE AURORA MODEL

- A one year, read-only End User License Agreement for AURORAxmp is available for $5k from Energy Exemplar; this purchase entitles access the library of modeling presentations via the web login
- The model's Help menu features material similar to a user manual
- IRP databases would include input and output tables used in the modeling and will require an NDA with Siemens
- The model database will be available for review but Siemens will not provide any review support beyond clearly-defined naming conventions (data key)

DRAFT SCENARIOS UPDATE

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Vectren has updated scenarios based on stakeholder feedback. Scenario modeling will evaluate various regulatory constructs. As a reminder, the Base Case serves as a benchmark. Alternative scenarios are shown as higher than, lower than, or the same as the Base Case

	CO_2	Gas Reg.	Water Reg.	Economy	Load	Gas Price	Coal Price	Renewables and Storage Cost	EE Cost
Base Case	ACE	none	ELG	Base	Base	Base	Base	Base	Base
Low Reg.	ACE Delay**	none	ELG Light*	Higher	Higher	Higher	Base	Base	Base
High Tech	Low CO2 Tax	none	ELG	Higher	Higher	Lower	Lower	Lower	Lower
80% CO_2 Reduction by 2050	Cap and Trade	Methane	ELG	Lower	Lower	Base	Lower	Lower	Higher
High Reg.	High CO_2 Tax w/ Dividend	Fracking Ban	ELG	Base	Base	Highest (+2 SD)	Lower	Lower	Higher

Increasing Environmental Regulation

*No bottom ash conversion required based on size of the unit and delay requirement for 2 years
**ACE Delayed for 3 years

Revised from last meeting

SCENARIO NARRATIVES

80% CO_2 Reduction by 2050 (aka 2 degrees scenario)

- This scenario assumes a carbon regulation mandating 80% reduction of CO_2 from 2005 levels by 2050 is implemented. A glide path would be set using a cap and trade system similar to the CPP, gradually ratcheting down CO_2 emissions and driving CO_2 allowance costs up.
- Load decreases as the costs for energy and backup power increase and as the energy mix transitions.
- In this scenario, regulations on methane emissions initially drive up gas prices, but are partially offset by increased supply. The price of natural gas remains on par with the Base Case.
- There is less demand for coal, driving prices lower than the Base Case; however, some large and efficient coal plants remain as large fleets are able to comply with the regulation on a fleet wide basis.
- Renewables and battery storage technology are widely implemented to help meet the mandated CO_2 reductions. Despite this demand, costs are lower than the Base Case due to subsidies or similar public support to address climate change.
- Market based solutions are implemented to lower CO_2. Innovation occurs, but is offset by more codes and standards with no incentives, energy efficiency costs rise as a result.

Revised from last meeting

SCENARIO NARRATIVES

High Regulatory (Revised)

- The social cost of carbon is implemented via a high CO_2 tax early in the scenario. Monthly rebate checks (dividend) redistribute revenues from the tax to American households based on number of people in the household.
- A fracking ban is imposed, driving up the cost of natural gas to +2 standard deviations in the long-term as supply dramatically shrinks.
- A strong decline in demand puts downward pressure on coal prices.
- The economic outlook remains at the Base Case level as any potential benefit of the CO2 dividend is offset by the drag on the economy imposed by additional regulations, including the fracking ban.
- Innovation occurs as renewables and battery storage are widely implemented to avoid paying high CO_2 prices, allowing costs to fall even as demand for these technologies increases.
- Utility-sponsored energy efficiency costs rise over time as the cost for regulatory compliance rises

Revised from last meeting

IRP OBJECTIVES & MEASURES UPDATE

For each resource portfolio, the objectives are tracked and measured to evaluate portfolio performance in the Base Case, in four alternative scenarios, and across a wide range of possible future market conditions. All measures of portfolio performance are based on probabilistic modeling of 200 futures.

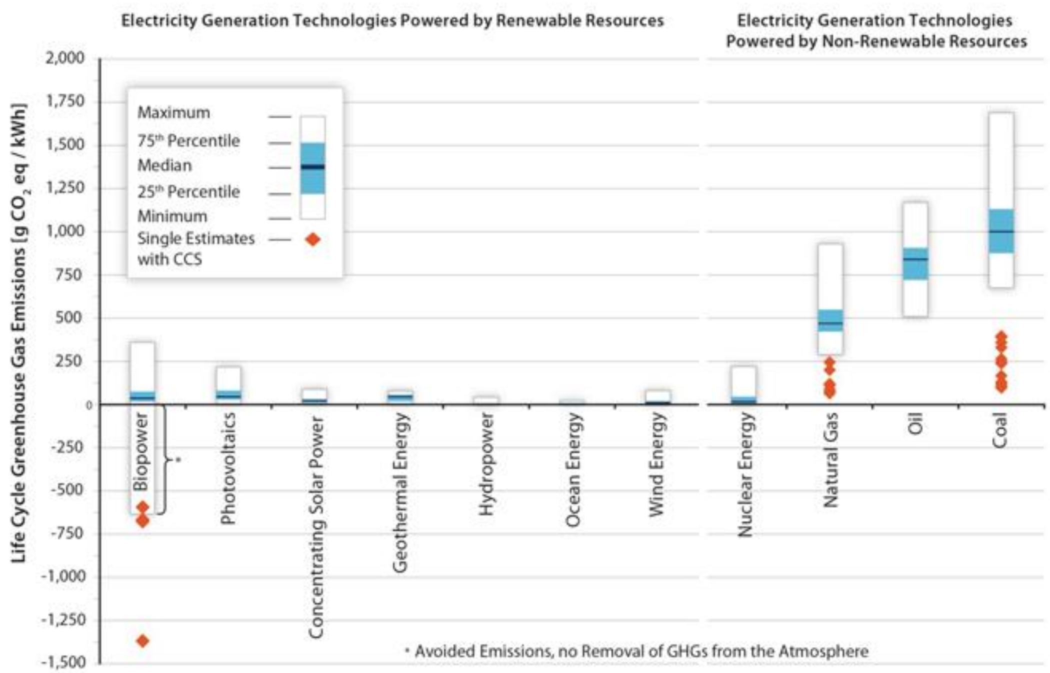
Objective	Measure	Unit
Affordability	20-Year NPVRR	$
Price Risk Minimization	95^{th} percentile value of NPVRR	$
Environmental Risk Minimization	~~CO_2 Emissions~~ Life Cycle Greenhouse Gas Emissions	Tons CO_2e
Market Risk Minimization	Energy Market Purchases or Sales outside of a +/- 15% Band	%
	Capacity Market Purchases or Sales outside of a +/- 15% Band	%
Future Flexibility	~~MWh of impairment by asset~~ Uneconomic Asset Risk	~~MWh~~ $

Revised from last meeting

ENVIRONMENTAL RISK MINIMIZATION
LIFE CYCLE GREENHOUSE GAS EMISSIONS

- Stakeholders requested a Life Cycle Analysis (LCA) and CO_2 equivalent on the scorecard
- LCA can help determine environmental burdens from “cradle to grave” and facilitate more consistent comparisons of energy technologies, including upstream, fuel cycle, operation, and downstream emissions
- NREL conducted a systematic review[1] of 2,100 life cycle greenhouse gas emissions studies for electricity generating technologies and screened down the list to about 300 credible references

Life Cycle GHG Emissions



	Biopower	Photovoltaics	Concentrating Solar Power	Geothermal Energy	Hydropower	Ocean Energy	Wind Energy	Nuclear Energy	Natural Gas	Oil	Coal
Count of Estimates	222(+4)	124	36	8	28	10	126	125	83(+7)	24	169(+12)
Count of References	52(+0)	26	10	6	11	5	49	32	36(+4)	10	50(+10)

1 Source: https://www.nrel.gov/analysis/life-cycle-assessment.html

ENVIRONMENTAL RISK MINIMIZATION
LIFE CYCLE GHG EMISSIONS CONTINUED…

- NREL utilizes median values[2] listed in the table to the right for life cycle analyses
- We plan to apply NREL rates (g CO_2e/kWh) to simulated portfolio generation emissions to serve retail load using specific technology rates
- In order to obtain a full picture of emissions, we must also estimate total emissions when customer load is being served by the market using the market rates and an average buildout of resources based on the MISO Transmission Expansion Plan (MTEP)
- Total CO_2 equivalent will be calculated for each portfolio based on emissions it generates and emissions generated from reliance on the market

Life Cycle GHG Emissions[1]

(grams of CO_2e per kWh)

	Specific Technology	Market
All Coal		1,002
Sub Critical	1,062	
Super Critical	863	
All Gas		474
Gas CT	599	
Gas CC[3]	481	
All Nuclear		16
Onshore Wind	12	12
All PV		54
Thin Film	35	
Crystalline	57	
All hydropower	7	7
Bio Power	43	43

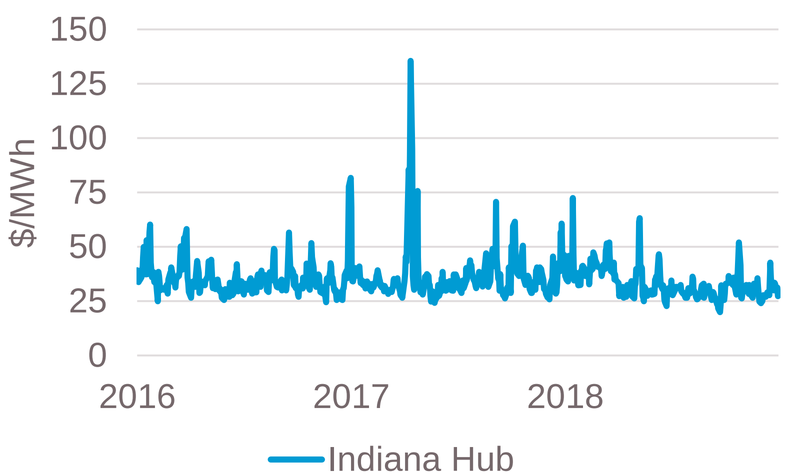
1 Battery storage was not included in the NREL report. Evaluating options for this resource.
Source: https://www.nrel.gov/analysis/life-cycle-assessment.html
2 Values derived from graphs included for each resource type.
3 Assumes 70% shale gas, 30% conventional

+/-15% ENERGY AND CAPACITY PURCHASES AND SALES BAND JUSTIFICATION

- Market transactions carry the risk for Vectren of buying when prices are high and selling when price are low.
- Vectren energy purchases are 1-2% of regional volumes* and 10-30% below regional prices for similar long-term transactions. On-peak power prices demonstrate ongoing volatility. To reduce exposure to this risk, we seek to minimize net energy sales and purchases to +/-15% of annual total sales.
- Capacity prices also fluctuate broadly in MISO and Zone 6 (Indiana). Exposure to price swings should be minimized to a range of +/-15% around forecasted demand.

Reliability First Corporation 2018 Energy Purchases by Contract Type (GWh)	
Short-Term	23,700
Intermediate-Term	14,500
Long-Term	53,100
of which Vectren	750
Other	298,000
Total	389,300

On-Peak Indiana Hub Energy Prices



Historical Zone 6, MISO Capacity Prices

* 2016-2018; Reliability First Corporation NERC Subregion

UNECONOMIC ASSET RISK ANALYSIS

- Following from stakeholder feedback, we changed the uneconomic asset risk objective measure from a MWh basis to a dollar cost basis
- Definition of an uneconomic asset: when going forward costs of the asset, which include annual variable costs (fuel + variable operations & maintenance or VOM + emissions) plus annual fixed operations & maintenance or FOM costs, are collectively greater than the total annual revenues (including both energy revenues and capacity revenues) in three successive years. By equation:

$$Going\ Forward\ Costs\ \left(\frac{\$}{kW-yr}\right) = \frac{[VOM+Fuel+Emissions+FOM]\left(\frac{\$}{yr}\right)}{Nameplate\ Capacity\ (kW)}$$

- We then identify in each stochastic model run:
  - Year when asset is deemed uneconomic
  - Undepreciated book value as of first uneconomic year
  - Revenues less going forward costs as of first uneconomic year for each year it is negative
- The resulting cost is weighted by frequency of occurrence across the iterations

FEEDBACK AND DISCUSSION

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MISO CONSIDERATIONS

JUSTIN JOINER

VECTREN DIRECTOR OF POWER SUPPLY SERVICES

MISO SUMMARY

- Based on feedback from the last stakeholder meeting we felt it necessary to go over some of the MISO principles and considerations Vectren must take into account during the IRP process.
- This section is aimed at conveying four main points:
  - 1) MISO ensures low cost and reliable energy by enforcing market and planning rules that its members must adhere to; specifically:
    - Sufficient capacity to meet peak load
    - Adequate transmission to deliver the energy
  - 2) These rules focus on generator cost and ability to reach needed load; if the generation is not cost efficient or it can not be safely delivered on the MISO transmission system, MISO will not dispatch it
  - 3) MISO is undergoing a changing resource mix that has led to an increase in emergency events and a review of accrediting resources
  - 4) Because of these principles Vectren must fully evaluate the transmission components of a project and the expected output and accreditation it will receive in order to accurately evaluate the cost and efficiency of a project

WHAT IS MISO?

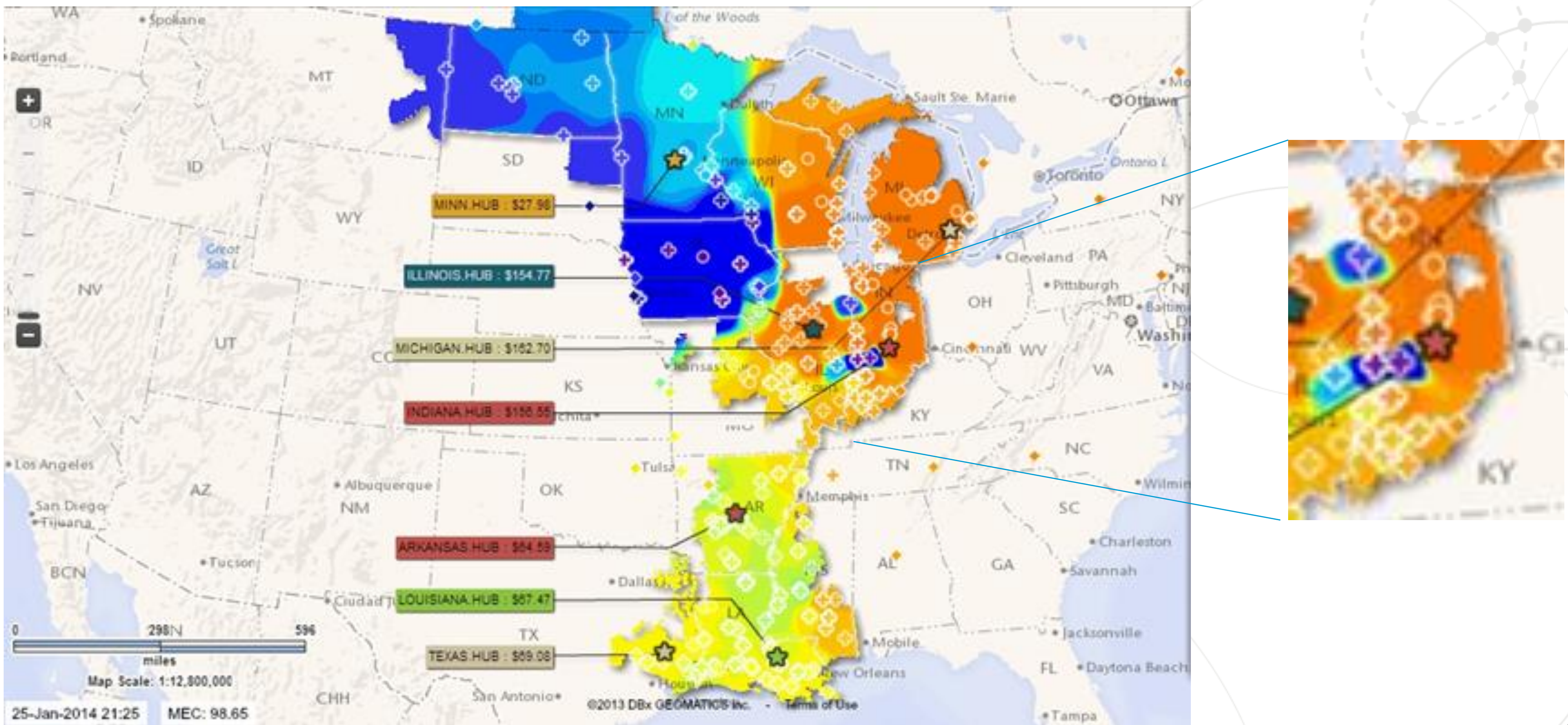
Midcontinent **I**ndependent Transmission **S**ystem **O**perator

- In 2001, MISO was approved as the first Regional Transmission Organization (RTO)
  - MISO has operational authority: the authority to control transmission facilities and coordinate security for its region to ensure reliability
  - MISO is responsible for dispatch of lowest cost generation units: MISO's energy market dispatches the most cost effective generation to meet load needs
- MISO is divided into 11 Local Resources Zones (LRZ), Indiana is part of Zone 6, which includes northwest Kentucky (Big Rivers Electric Cooperative)
- Each LRZ has its own planning requirements in regards to energy and capacity
- Each Zone's ability to rely on neighboring Zones depends largely on transmission infrastructure. Based on MISO's Local Clearing Requirement (LCR), approximately 70% of Vectren's generation must be physically located within MISO Zone 6

Source: MISO

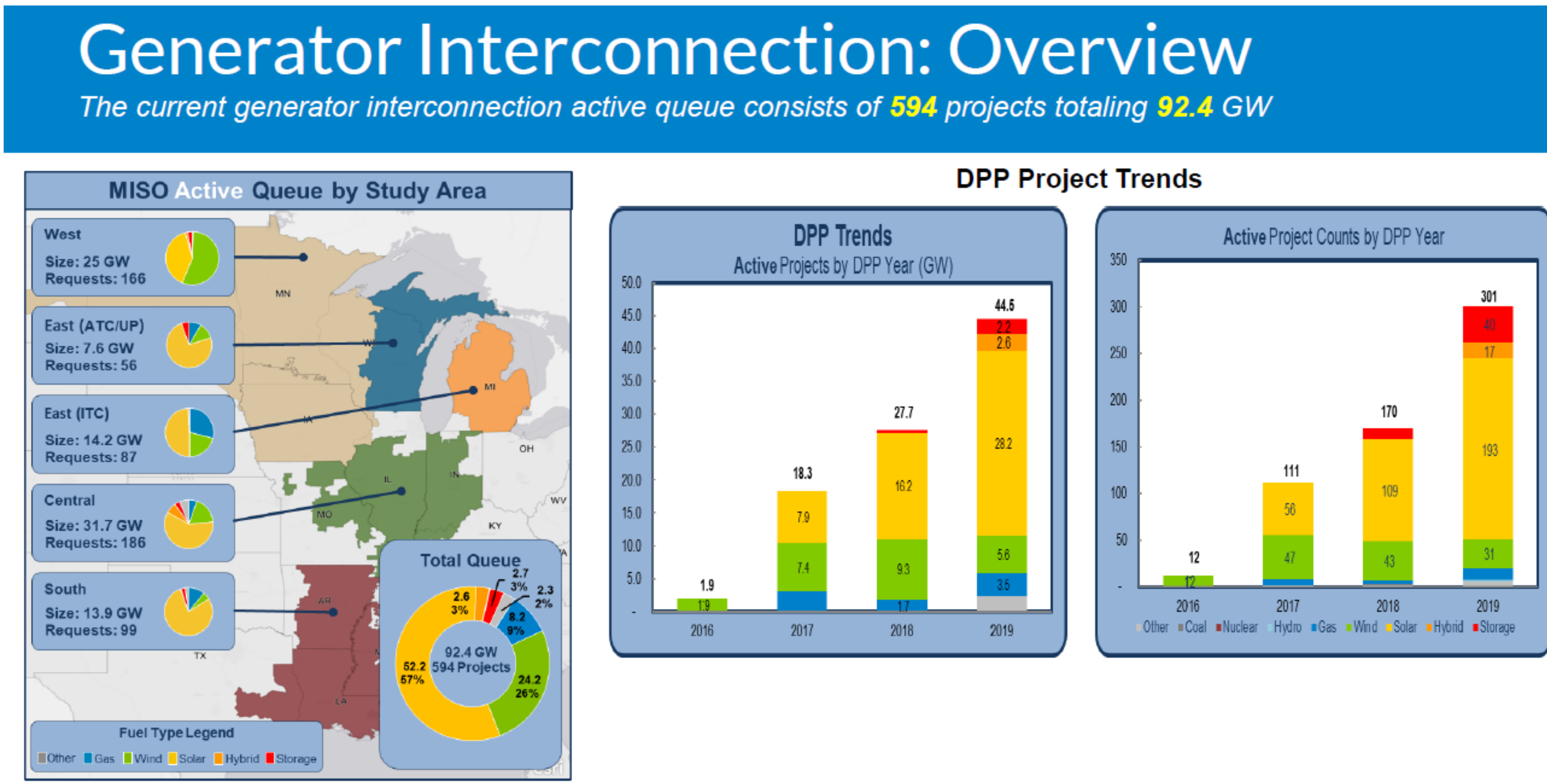
CONGESTION

- Congestion on the MISO system during a period when energy in MN was $27.98 while at that same time energy in IN was $156.55; thereby, generators in MN received $128.57 less than load was paying in IN
  - Vectren experiences price separation for wind resource power purchase agreements within IN zone 6
  - Throughout the year there is a $5 price spread that magnifies over night during periods of low load
- Important consideration for long-term energy supplies as over time and depending on transmission build-out, generation retirements and additions and congestion could change the economics and reliability of a project



MISO INTERCONNECTION SNAPSHOT

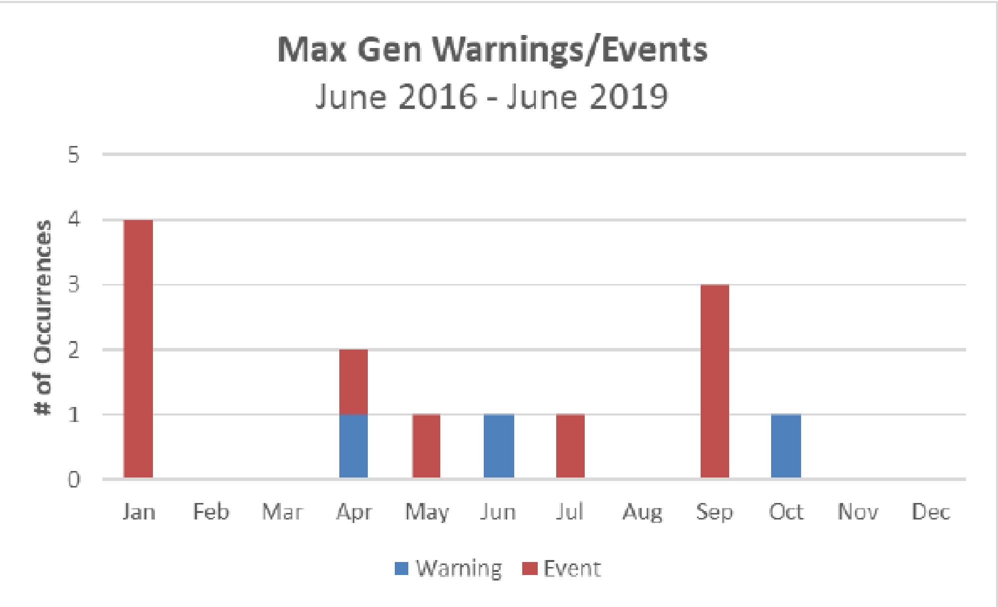
- Lengthy process that involves studies that are susceptible to many variables and cost allocation based on position in queue
- MISO Interconnection is predominantly composed of renewables (76%), followed by natural gas
- MISO's Renewable Integration Impact Assessment[1] is studying system impacts as renewables penetrate the grid and has determined that significant transmission upgrades will be necessary to reach 30% to 40% renewable penetration levels; this could lead to additional and substantial transmission investment



[1] https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment

MISO RESOURCE AVAILABILITY AND NEED (RAN) INITIATIVE

- Less capacity and lower generator availability have led to tighter operating conditions in all four seasons
- MISO has experienced 10 Max Generation Events in the last 4 years; a Max Gen Event used to occur once every couple years
- As such, the RAN Initiative is to ensure resource accreditation aligns with actual available generation throughout the year



Year	Warnings*	Events	Total
2009	0	0	0
2010	0	0	0
2011	0	1	1
2012	2	1	3
2013	0	0	0
2014	1	1	2
2015	0	0	0
2016	1	1	2
2017	1	3	4
2018	0	3	3
2019	1	3	4
Total	**6**	**13**	**19**

4

*Warnings occurring on the same day as an Event are not included

https://www.misoenergy.org/stakeholder-engagement/issue-tracking/resource-availability-and-need-ran/

ALL MISO CONSIDERATIONS NEED TO BE ACCOUNTED FOR DURING THE IRP

- Due to MISO planning requirements being based on NERC reliability standards, generator location is an important consideration
- Location is also an important consideration from a financial perspective as congestion can add or reduce considerable costs to delivered energy costs
- Furthermore, a changing resource mix in MISO has led to an increase in emergency events and a review of accrediting resources
- The IRP must review and consider actual energy sources and not simply financial representations or obligations
  - Energy must be deliverable from a congestion standpoint and must be interconnected to the MISO transmission system
  - Energy credits from projects not connected to MISO will not provide needed low-cost energy to meet our customer needs during peak conditions
  - A seasonal construct will change the expected capacity credit for generating resources and the benefit Vectren customers can receive from a project
- Due to these multiple and complex considerations, we must carefully review all RFP responses and resource mixes in order to meet MISO requirements and appropriately value the costs and benefits of projects

FEEDBACK AND DISCUSSION

SCENARIO MODELING INPUTS

GARY VICINUS

MANAGING DIRECTOR FOR UTILITIES, PACE GLOBAL

SUMMARY

- Pace Global utilized the qualitative draft scenarios discussed in the first stakeholder meeting to develop quantitative forecasts of key inputs
- Probabilistic modeling was utilized to develop higher and lower forecasts, relative to the base case for gas, CO_2, coal, load, and renewables/storage capital cost trajectories
- Coal and gas price forecasts have much wider ranges than the 2019 Energy Information Administration (EIA) Annual Energy Outlook (AEO)
- Note that capital cost forecasts will be adjusted to reflect RFP results. Final capital cost forecasts will be shared in the third public stakeholder meeting

SCENARIO MODELING

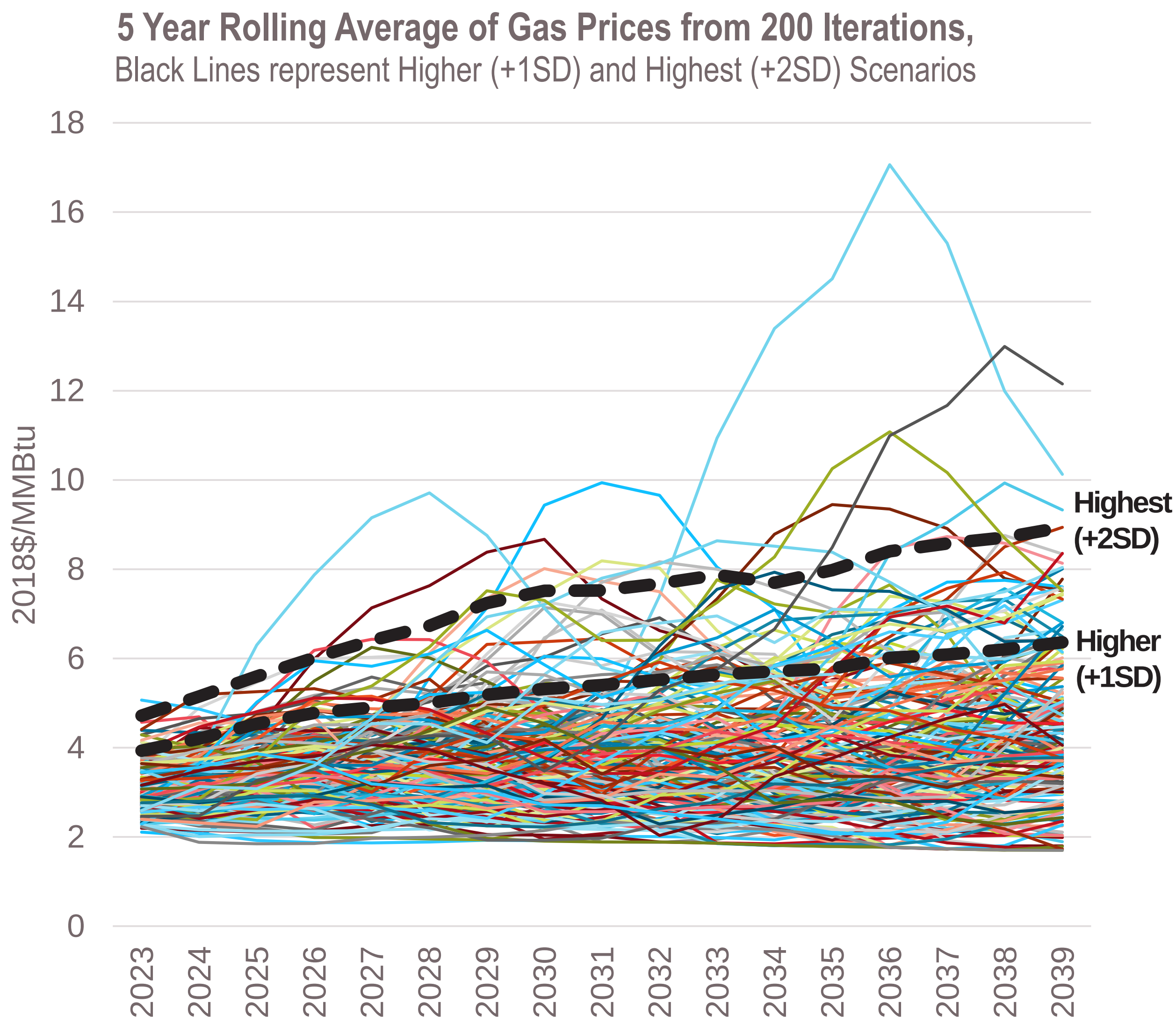
- In addition to the Base Case, four scenarios are being modeled. This will result in a least cost portfolio for each of the five cases. Additional portfolios will be developed beginning with today's stakeholder breakout session
- The Base Case inputs were shown in the first stakeholder presentation. To develop the scenario inputs, we begin with Base Case inputs and then shift into base, higher and lower ranges
- The higher and lower ranges are developed using a Monte Carlo (referred to as probabilistic or stochastic) simulation that creates 200 future paths for each variable
- A Base Case and Scenarios Assumptions Book in Excel format will be made available to intervenors
- Scenario data sheets included in the Appendix

PROBABILISTIC MODELING

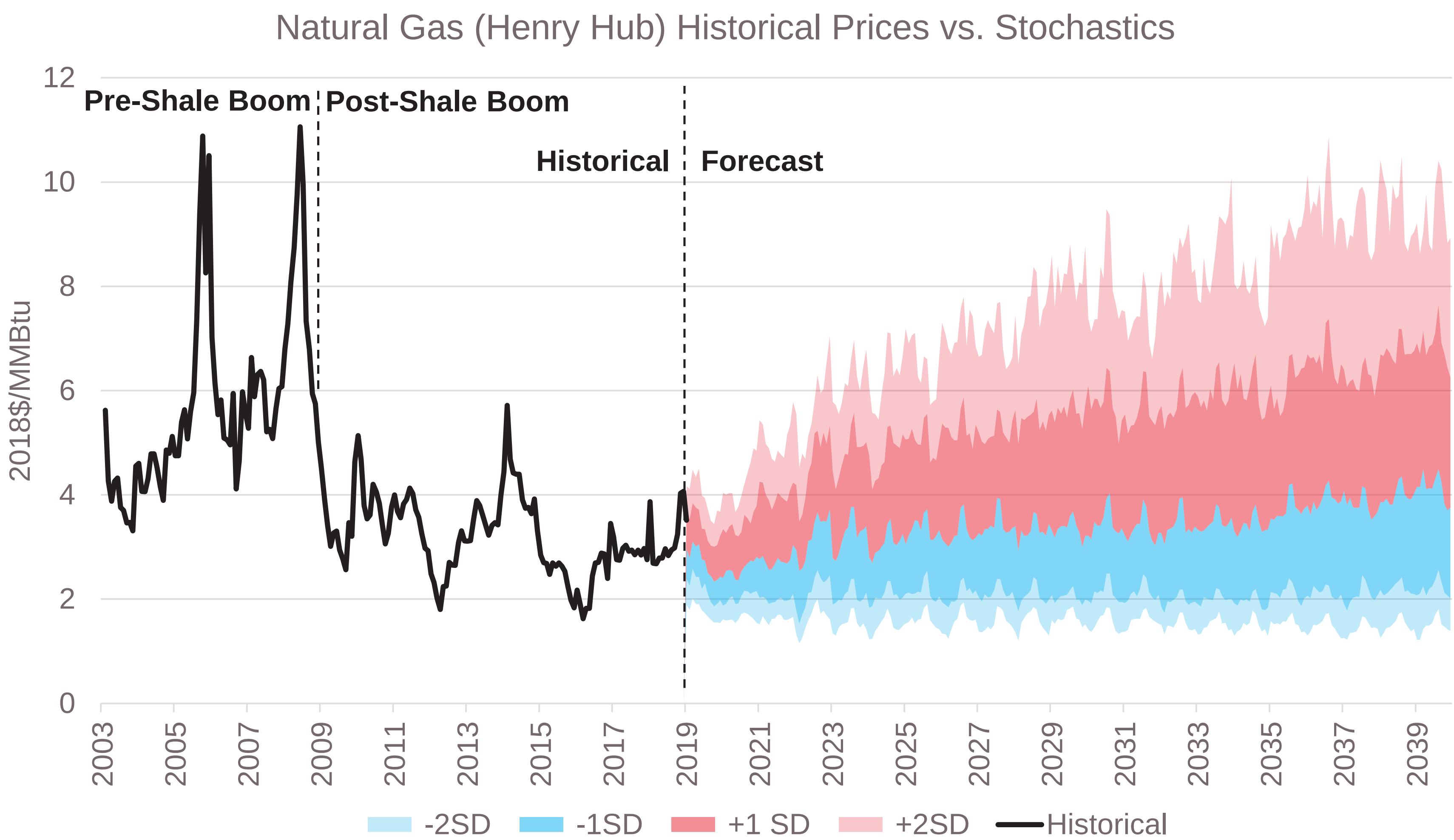
- Probabilistic modeling helps to measure risk from two hundred potential future paths for each stochastic variable
- These iterations provide percentile bands that can be used to measure the probability that a variable will be above (or below) a given percentile in a given time period and relative to the Base Case
  - For +1 Standard Deviation (+1SD) in a normal distribution, it is 84.2%
  - For -1 Standard Deviation (-1SD) in a normal distribution, it is 15.8%
  - For +2 or -2 SD, it is 97.8% and 2.2%, respectively
- Scenarios are assumed to remain the same as the Base Case in the short-term (2019-2021). In the medium-term (2022-2028), they grow or decline to +/-1SD or (+/-2SD) by 2025 (midpoint of medium-term). After 2025, the variable stays at +/-1SD (or +/-2SD) into the long-term to 2039
- Because our price path remains at the one (or two) standard deviation(s) path for the entire planning horizon, these levels have a low probability and are very conservative

PROBABILISTIC MODELING CONT.

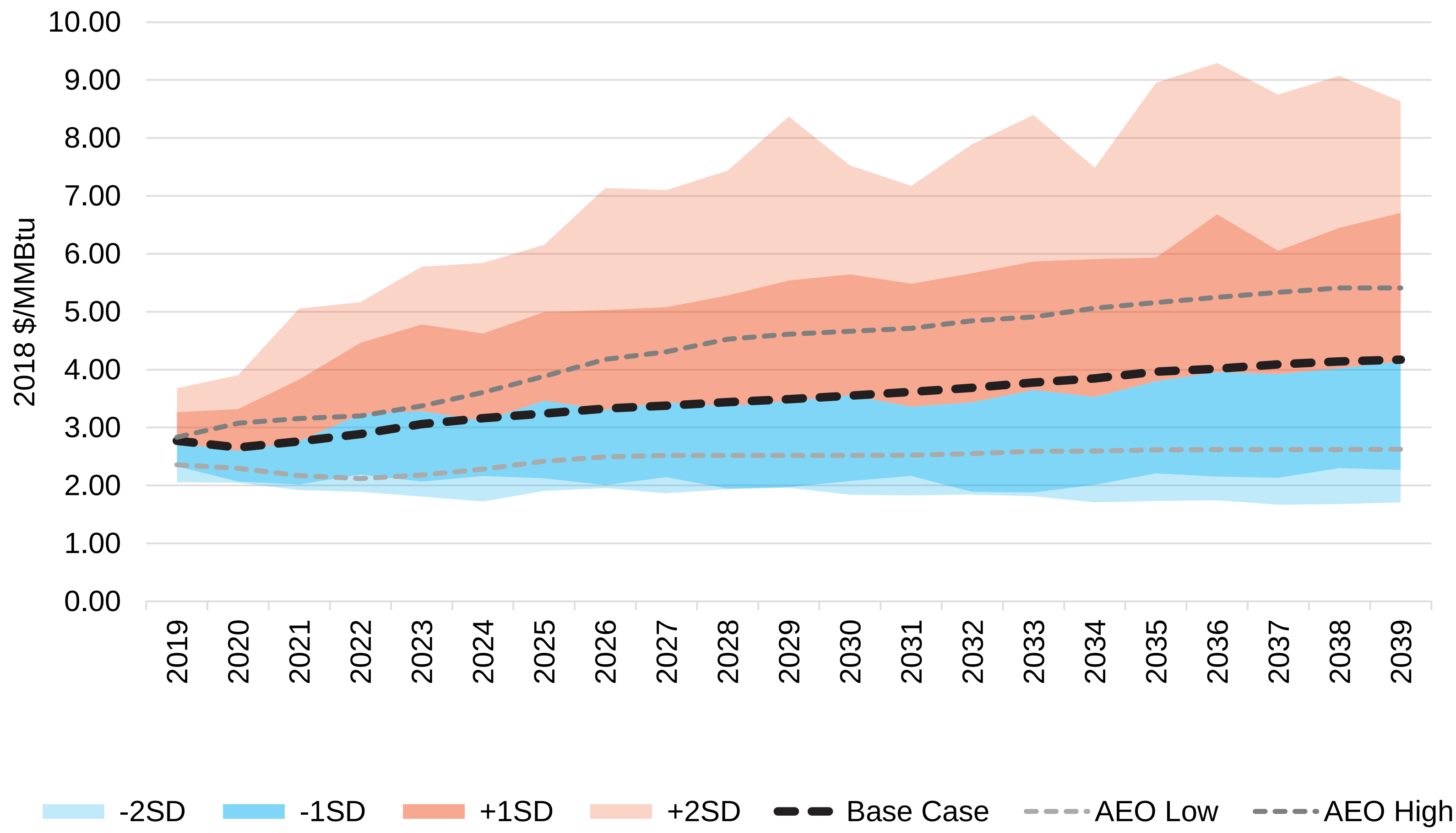
- This spaghetti diagram shows a 5-year rolling average of all 200 gas price iterations against the Higher and Highest gas price scenarios.
- In any given year, about 16% of prices are above the Higher line and about 2% are above the Highest line.
- Looking at the 20 year price average, about 7% of the 200 iterations were above the Higher line and none were above the Highest line.



HISTORICAL PRICES VS. STOCHASTICS



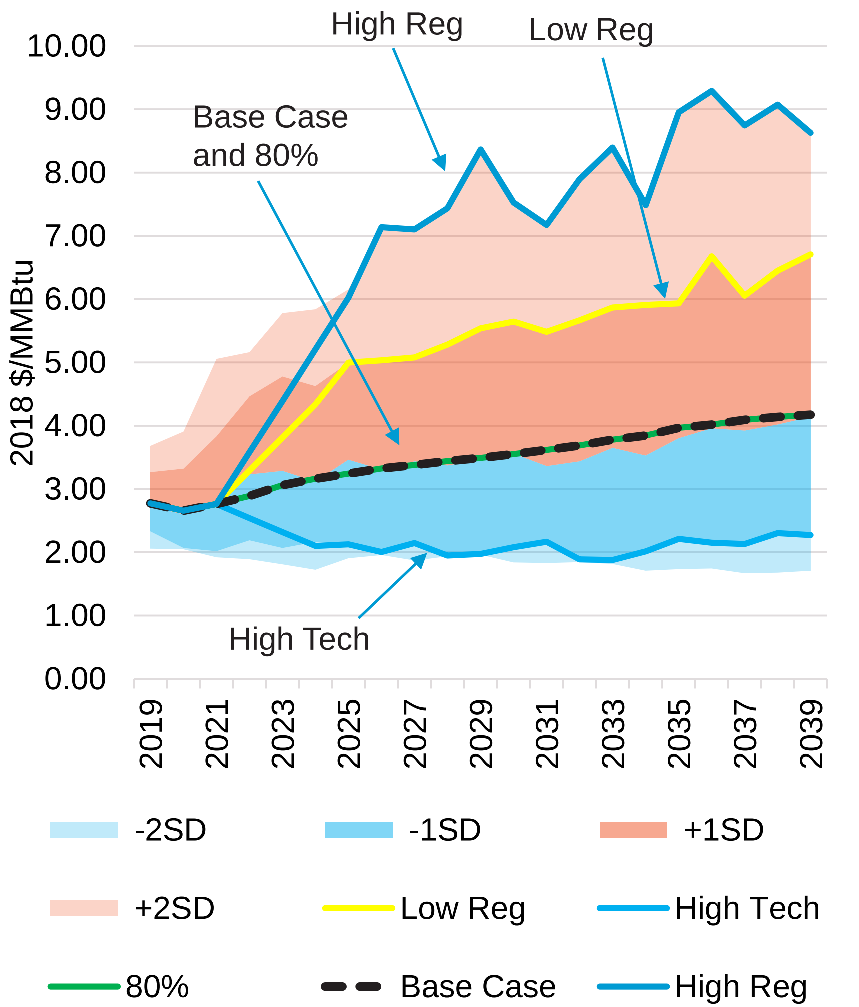
HENRY HUB GAS PRICE DISTRIBUTIONS AND: COMPARISON TO EIA AEO[1] 2019



1Source:Energy Information Administration (EIA) Annual Energy Outlook (AEO) https://www.eia.gov/outlooks/aeo/
EIA Low = AEO 2019: High Oil & Gas Resource and Technology scenario
EIA High = AEO 2019: Low Oil & Gas Resource and Technology scenario

SCENARIO INPUTS: NATURAL GAS HENRY HUB (2018$/MMBTU)[1]

	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	2.77	2.77	2.77	2.77	2.77
2020	2.66	2.66	2.66	2.66	2.66
2021	2.76	2.76	2.76	2.76	2.76
2022	2.89	3.46	3.01	2.89	3.58
2023	3.06	4.10	2.82	3.06	4.39
2024	3.16	4.75	2.64	3.16	5.21
2025	3.24	5.12	2.33	3.24	6.03
2026	3.33	5.27	2.08	3.33	7.14
2027	3.38	5.20	2.13	3.38	7.10
2028	3.44	5.45	2.06	3.44	7.43
2029	3.49	5.62	2.04	3.49	8.37
2030	3.55	5.77	2.12	3.55	7.53
2031	3.62	5.60	2.13	3.62	7.17
2032	3.69	5.76	1.97	3.69	7.89
2033	3.78	5.95	2.02	3.78	8.40
2034	3.85	6.02	1.95	3.85	7.49
2035	3.96	6.12	2.12	3.96	8.95
2036	4.02	6.64	2.12	4.02	9.29
2037	4.09	6.23	2.07	4.09	8.75
2038	4.14	6.77	2.19	4.14	9.07
2039	4.17	6.85	2.20	4.17	8.63

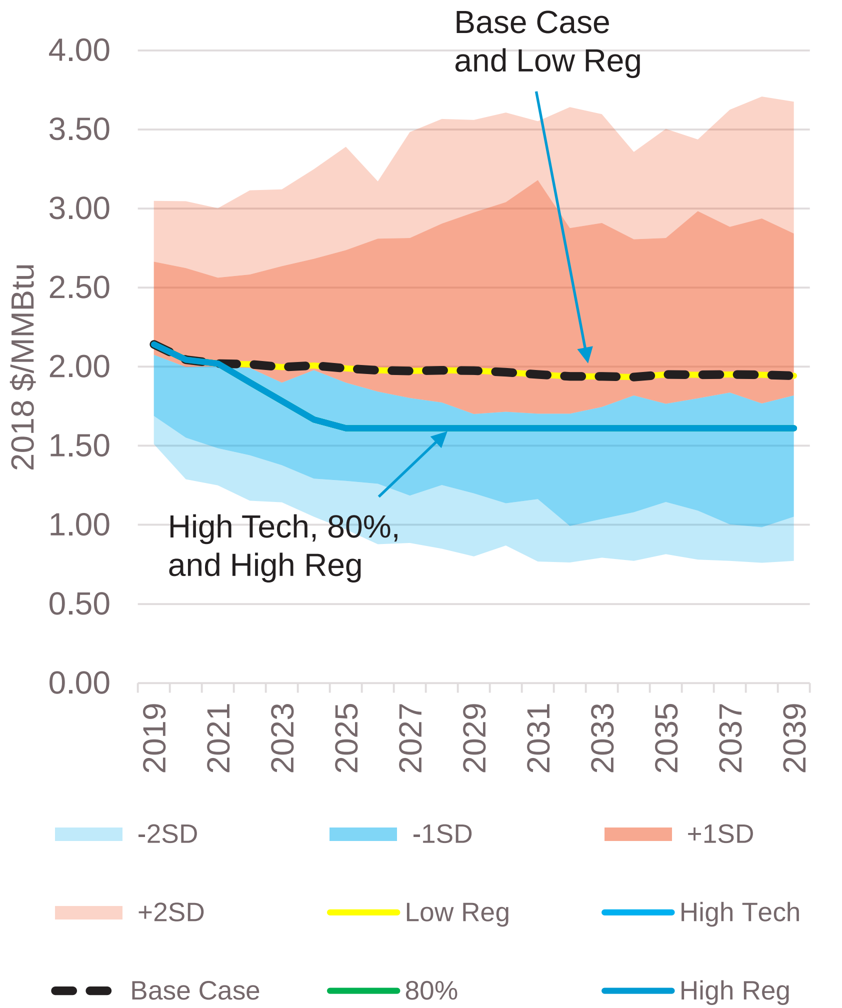


1 Modeling will include estimated inflation of 2.2% per year

SCENARIO INPUTS: ILLINOIS BASIN COAL DELIVERED TO BROWN (2018$/MMBTU) [1]

VECTREN
A CenterPoint Energy Company

	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	2.14	2.14	2.14	2.14	2.14
2020	2.04	2.04	2.04	2.04	2.04
2021	2.02	2.02	2.02	2.02	2.02
2022	2.02	2.02	1.90	1.90	1.90
2023	2.00	2.00	1.78	1.78	1.78
2024	2.01	2.01	1.67	1.67	1.67
2025	1.99	1.99	1.61	1.61	1.61
2026	1.98	1.98	1.61	1.61	1.61
2027	1.97	1.97	1.61	1.61	1.61
2028	1.98	1.98	1.61	1.61	1.61
2029	1.97	1.97	1.61	1.61	1.61
2030	1.97	1.97	1.61	1.61	1.61
2031	1.95	1.95	1.61	1.61	1.61
2032	1.94	1.94	1.61	1.61	1.61
2033	1.94	1.94	1.61	1.61	1.61
2034	1.93	1.93	1.61	1.61	1.61
2035	1.95	1.95	1.61	1.61	1.61
2036	1.95	1.95	1.61	1.61	1.61
2037	1.95	1.95	1.61	1.61	1.61
2038	1.95	1.95	1.61	1.61	1.61
2039	1.94	1.94	1.61	1.61	1.61

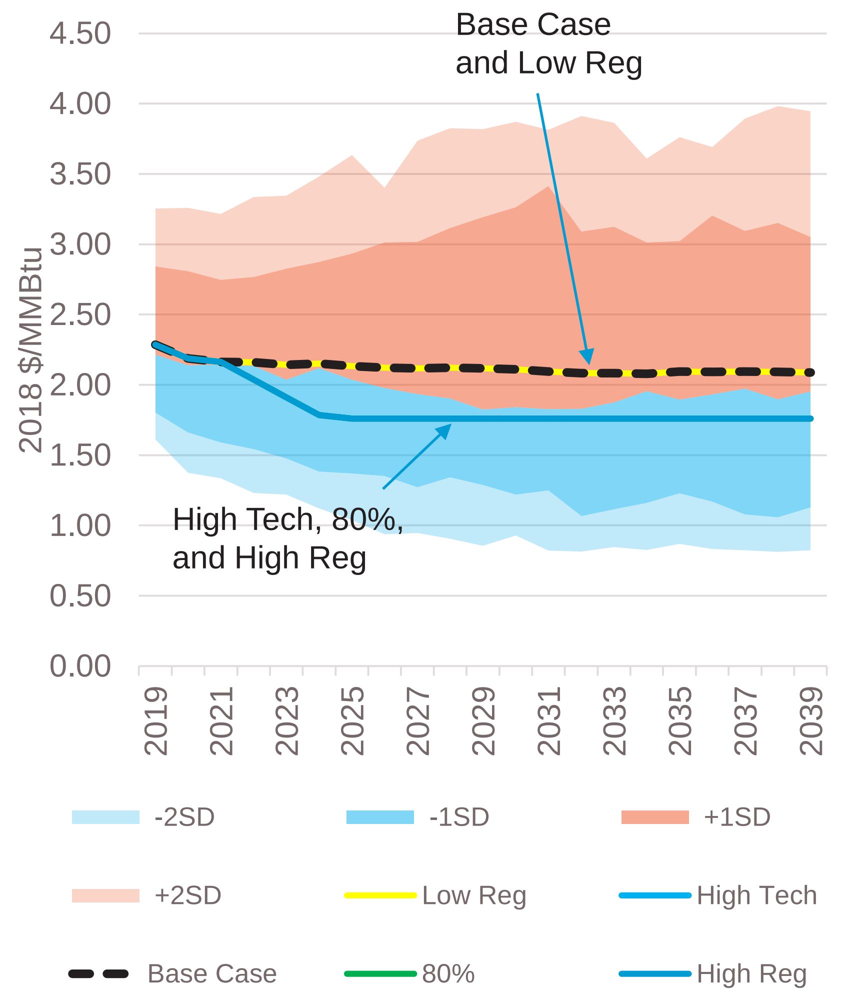


A price floor is set at $1.61/MMBtu

1 Modeling will include estimated inflation of 2.2% per year

SCENARIO INPUTS: ILLINOIS BASIN COAL DELIVERED TO CULLEY (2018$/MMBTU) [1]

	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	2.29	2.29	2.29	2.29	2.29
2020	2.19	2.19	2.19	2.19	2.19
2021	2.16	2.16	2.16	2.16	2.16
2022	2.16	2.16	2.04	2.04	2.04
2023	2.14	2.14	1.91	1.91	1.91
2024	2.15	2.15	1.78	1.78	1.78
2025	2.13	2.13	1.76	1.76	1.76
2026	2.12	2.12	1.76	1.76	1.76
2027	2.12	2.12	1.76	1.76	1.76
2028	2.12	2.12	1.76	1.76	1.76
2029	2.12	2.12	1.76	1.76	1.76
2030	2.11	2.11	1.76	1.76	1.76
2031	2.09	2.09	1.76	1.76	1.76
2032	2.08	2.08	1.76	1.76	1.76
2033	2.08	2.08	1.76	1.76	1.76
2034	2.08	2.08	1.76	1.76	1.76
2035	2.09	2.09	1.76	1.76	1.76
2036	2.09	2.09	1.76	1.76	1.76
2037	2.10	2.10	1.76	1.76	1.76
2038	2.09	2.09	1.76	1.76	1.76
2039	2.09	2.09	1.76	1.76	1.76



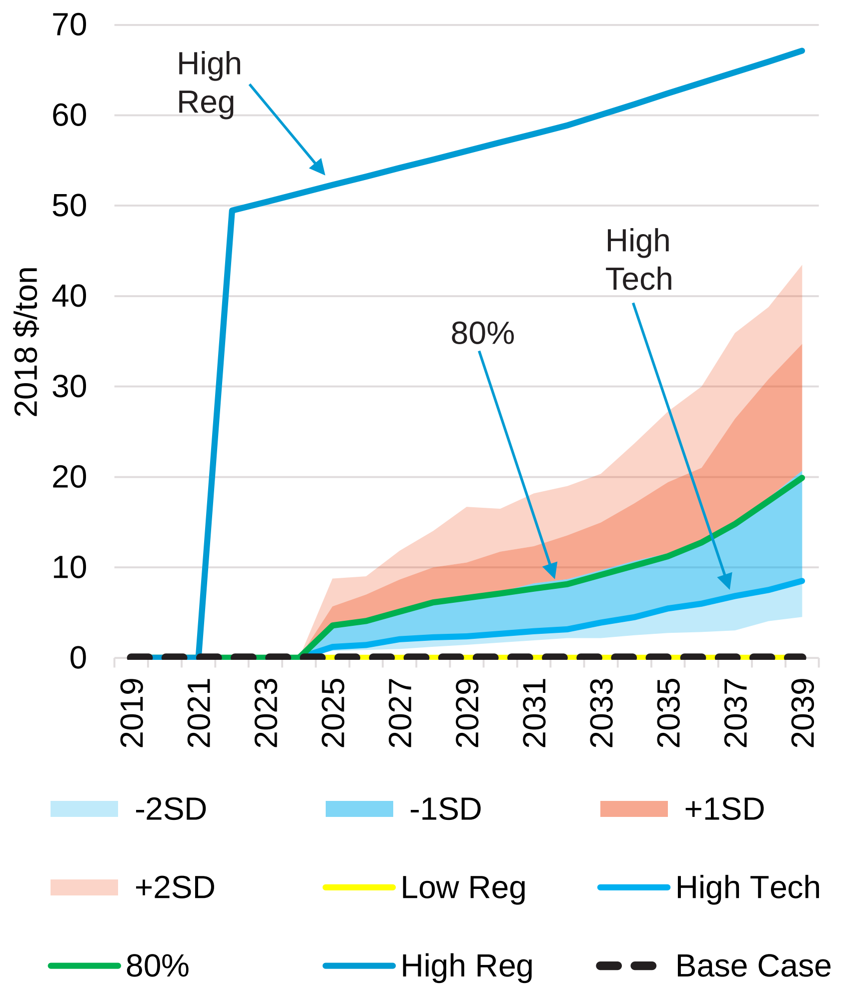
A price floor is set at $1.76/MMBtu

1 Modeling will include estimated inflation of 2.2% per year

SCENARIO INPUTS:
CO2 PRICE (2018$/TON) [1]

VECTREN
A CenterPoint Energy Company

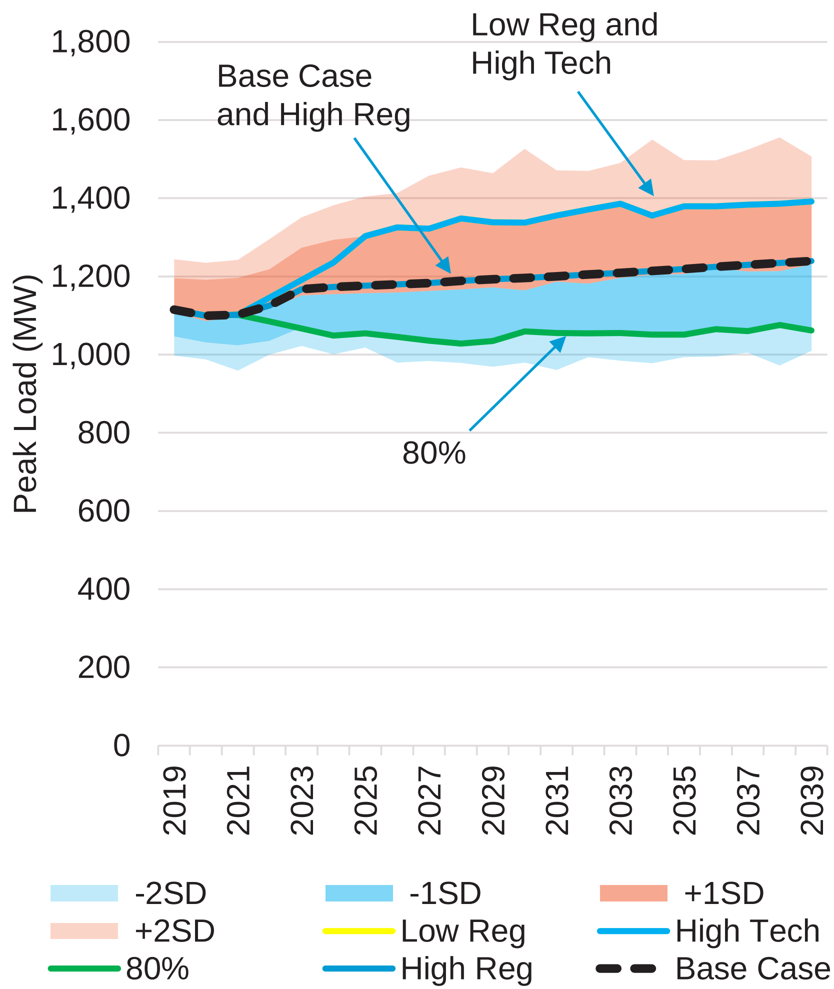
	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	49.46
2023	0	0	0	0	50.40
2024	0	0	0	0	51.34
2025	0	0	1.20	3.57	52.28
2026	0	0	1.44	4.08	53.23
2027	0	0	2.06	5.10	54.17
2028	0	0	2.28	6.12	55.11
2029	0	0	2.38	6.63	56.05
2030	0	0	2.68	7.14	56.99
2031	0	0	2.94	7.65	57.94
2032	0	0	3.17	8.16	58.88
2033	0	0	3.89	9.18	60.06
2034	0	0	4.49	10.20	61.23
2035	0	0	5.46	11.22	62.41
2036	0	0	6.01	12.75	63.59
2037	0	0	6.85	14.79	64.77
2038	0	0	7.52	17.34	65.94
2039	0	0	8.50	19.89	67.12



1 Modeling will include estimated inflation of 2.2% per year

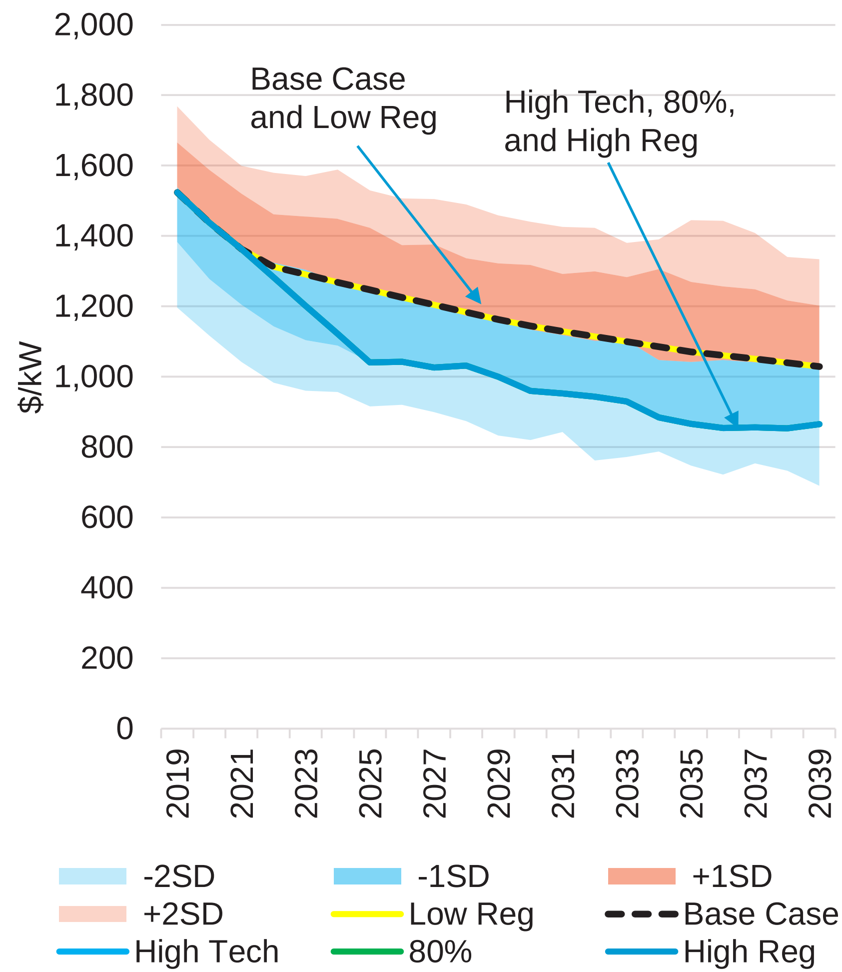
SCENARIO INPUTS:
VECTREN PEAK LOAD (MW)

	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,115	1,115	1,115	1,115	1,115
2020	1,100	1,100	1,100	1,100	1,100
2021	1,102	1,102	1,102	1,102	1,102
2022	1,126	1,146	1,146	1,084	1,126
2023	1,168	1,191	1,191	1,066	1,168
2024	1,173	1,235	1,235	1,049	1,173
2025	1,176	1,303	1,303	1,055	1,176
2026	1,179	1,325	1,325	1,045	1,179
2027	1,183	1,322	1,322	1,036	1,183
2028	1,189	1,348	1,348	1,028	1,189
2029	1,192	1,338	1,338	1,035	1,192
2030	1,196	1,337	1,337	1,059	1,196
2031	1,200	1,356	1,356	1,055	1,200
2032	1,205	1,371	1,371	1,055	1,205
2033	1,209	1,386	1,386	1,056	1,209
2034	1,214	1,356	1,356	1,051	1,214
2035	1,219	1,379	1,379	1,051	1,219
2036	1,225	1,379	1,379	1,065	1,225
2037	1,229	1,383	1,383	1,060	1,229
2038	1,234	1,386	1,386	1,076	1,234
2039	1,239	1,391	1,391	1,062	1,239



SCENARIO INPUTS: CAPITAL COST SOLAR (100 MW) (2018$/KW) [1]

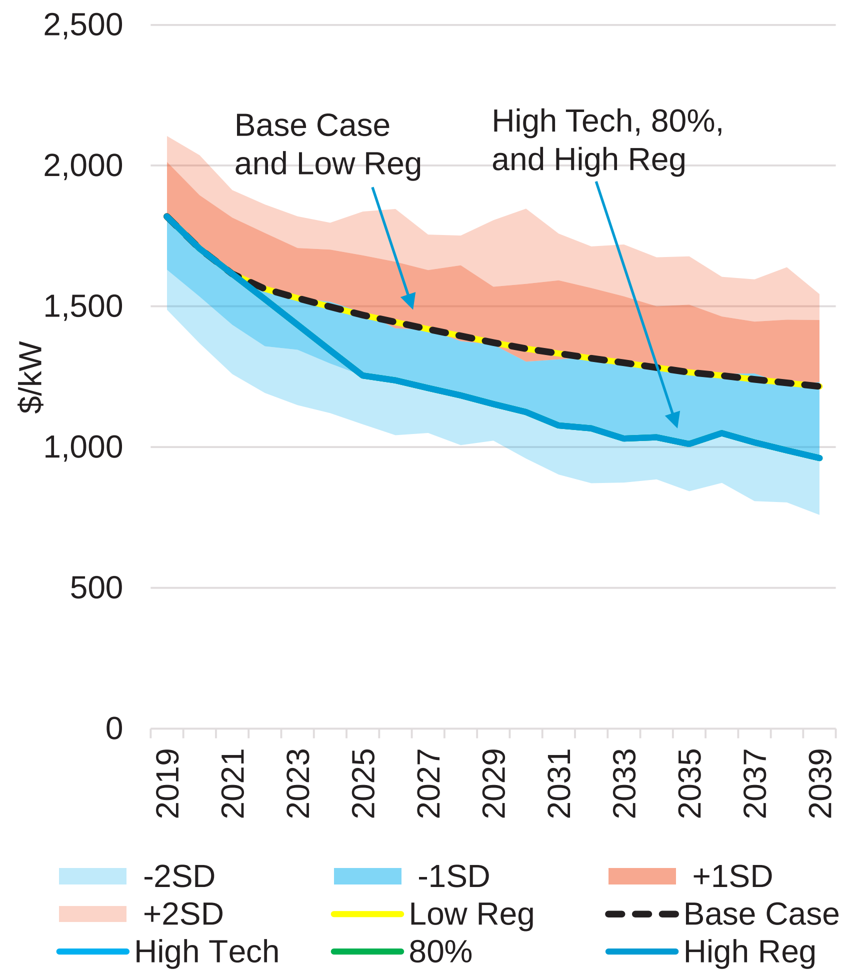
	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,524	1,524	1,524	1,524	1,524
2020	1,438	1,438	1,438	1,438	1,438
2021	1,362	1,362	1,362	1,362	1,362
2022	1,313	1,313	1,282	1,282	1,282
2023	1,290	1,290	1,202	1,202	1,202
2024	1,268	1,268	1,121	1,121	1,121
2025	1,247	1,247	1,041	1,041	1,041
2026	1,225	1,225	1,042	1,042	1,042
2027	1,204	1,204	1,026	1,026	1,026
2028	1,183	1,183	1,031	1,031	1,031
2029	1,162	1,162	999	999	999
2030	1,144	1,144	960	960	960
2031	1,129	1,129	952	952	952
2032	1,114	1,114	944	944	944
2033	1,100	1,100	929	929	929
2034	1,085	1,085	884	884	884
2035	1,070	1,070	866	866	866
2036	1,061	1,061	854	854	854
2037	1,050	1,050	856	856	856
2038	1,040	1,040	853	853	853
2039	1,029	1,029	865	865	865



1 Modeling will include estimated inflation of 2.2% per year

SCENARIO INPUTS: CAPITAL COST
SOLAR+STORAGE (50 MW PV + 10 MW/ 40 MWH STORAGE) [1]

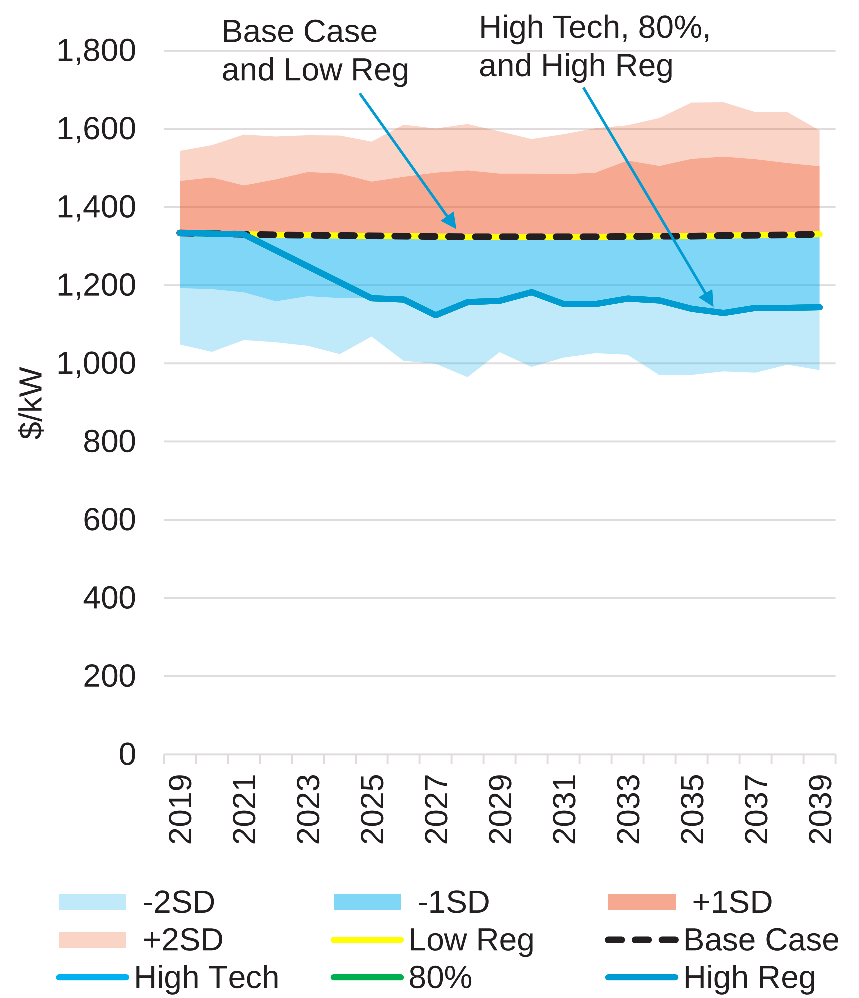
	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,820	1,820	1,820	1,820	1,820
2020	1,705	1,705	1,705	1,705	1,705
2021	1,616	1,616	1,616	1,616	1,616
2022	1,562	1,562	1,526	1,526	1,526
2023	1,529	1,529	1,435	1,435	1,435
2024	1,499	1,499	1,344	1,344	1,344
2025	1,469	1,469	1,254	1,254	1,254
2026	1,443	1,443	1,237	1,237	1,237
2027	1,419	1,419	1,210	1,210	1,210
2028	1,395	1,395	1,183	1,183	1,183
2029	1,371	1,371	1,153	1,153	1,153
2030	1,349	1,349	1,124	1,124	1,124
2031	1,332	1,332	1,077	1,077	1,077
2032	1,316	1,316	1,066	1,066	1,066
2033	1,299	1,299	1,031	1,031	1,031
2034	1,282	1,282	1,034	1,034	1,034
2035	1,266	1,266	1,011	1,011	1,011
2036	1,254	1,254	1,049	1,049	1,049
2037	1,241	1,241	1,016	1,016	1,016
2038	1,228	1,228	988	988	988
2039	1,215	1,215	961	961	961



1 Modeling will include estimated inflation of 2.2% per year

SCENARIO INPUTS: CAPITAL COST WIND (200 MW) (2018$/KW) [1]

	Base Case	Low Reg	High Tech	80% Reduction	High Reg
2019	1,334	1,334	1,334	1,334	1,334
2020	1,332	1,332	1,332	1,332	1,332
2021	1,330	1,330	1,330	1,330	1,330
2022	1,329	1,329	1,289	1,289	1,289
2023	1,328	1,328	1,249	1,249	1,249
2024	1,327	1,327	1,208	1,208	1,208
2025	1,326	1,326	1,167	1,167	1,167
2026	1,325	1,325	1,163	1,163	1,163
2027	1,324	1,324	1,123	1,123	1,123
2028	1,324	1,324	1,157	1,157	1,157
2029	1,324	1,324	1,160	1,160	1,160
2030	1,324	1,324	1,182	1,182	1,182
2031	1,324	1,324	1,152	1,152	1,152
2032	1,324	1,324	1,152	1,152	1,152
2033	1,324	1,324	1,166	1,166	1,166
2034	1,325	1,325	1,161	1,161	1,161
2035	1,326	1,326	1,139	1,139	1,139
2036	1,327	1,327	1,129	1,129	1,129
2037	1,328	1,328	1,142	1,142	1,142
2038	1,329	1,329	1,142	1,142	1,142
2039	1,330	1,330	1,143	1,143	1,143



1 Modeling will include estimated inflation of 2.2% per year

FEEDBACK AND DISCUSSION

LONG-TERM BASE ENERGY AND DEMAND FORECAST

Michael Russo, Sr. Forecast Consultant

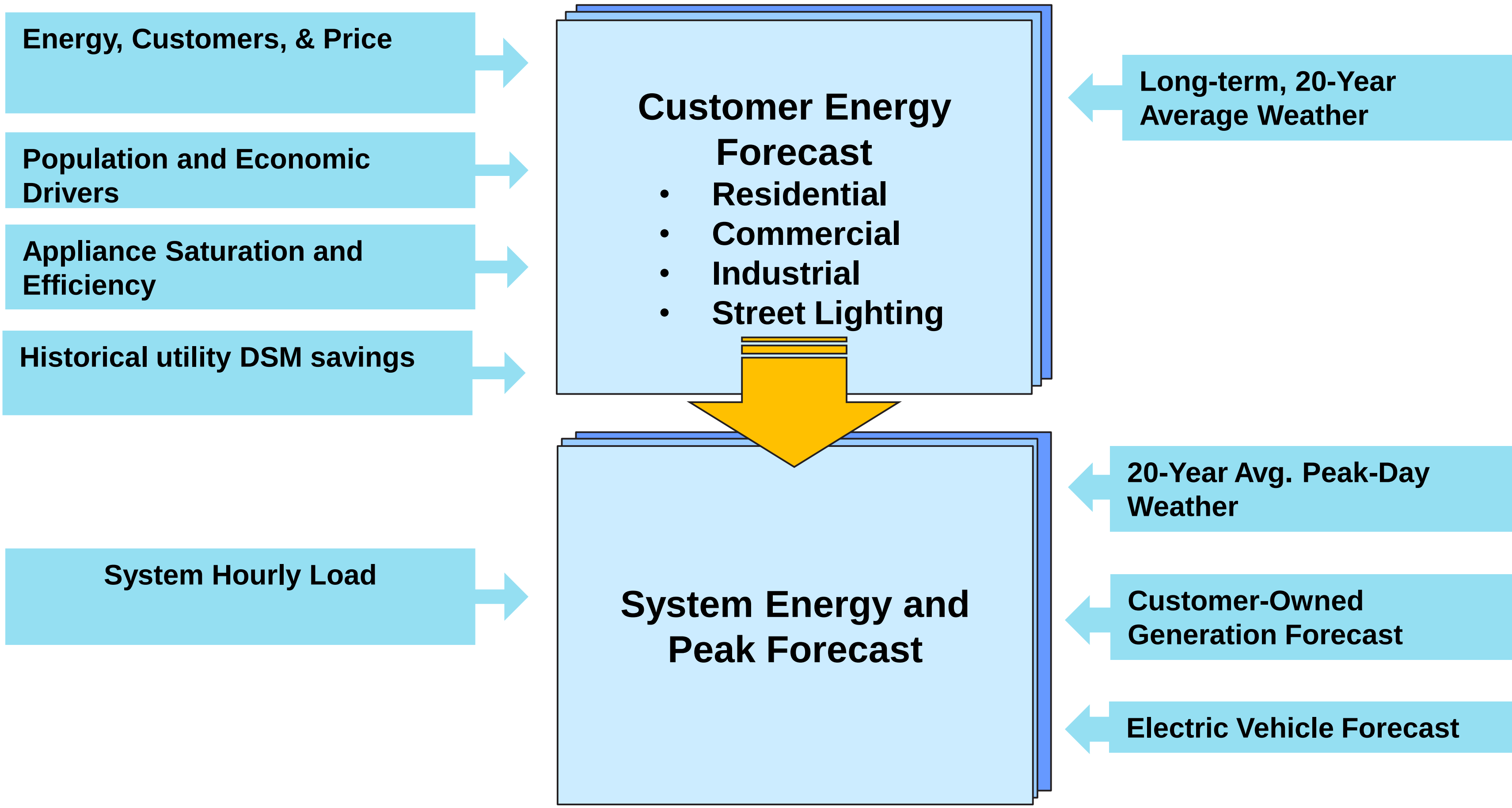
Itron

FORECAST SUMMARY

- Moderate energy growth
  - Annual energy and demand growth of 0.6%[1]
  - Slow long-term population growth (0.2% annual growth) & moderate output growth (1.7% annual growth)
  - Strong end-use efficiency gains reflecting new and existing Federal codes and standards
    - Air conditioning, heating, lighting, refrigeration, cooking, etc. are becoming more efficient over time
  - Market-driven solar adoption
  - Electric vehicle projections based on EIA 2019 Annual Energy Outlook

[1] Future energy efficiency programs are not included in the sales and demand forecast and will be considered a resource option

BOTTOM-UP FORECAST APPROACH



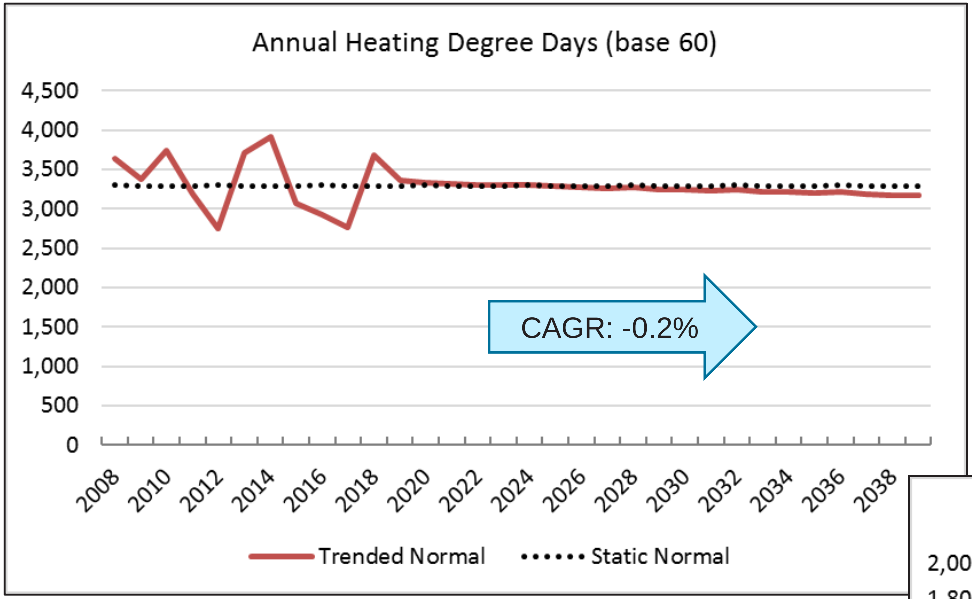
ECONOMIC DRIVERS

Moody's Analytic forecast for the Evansville MSA

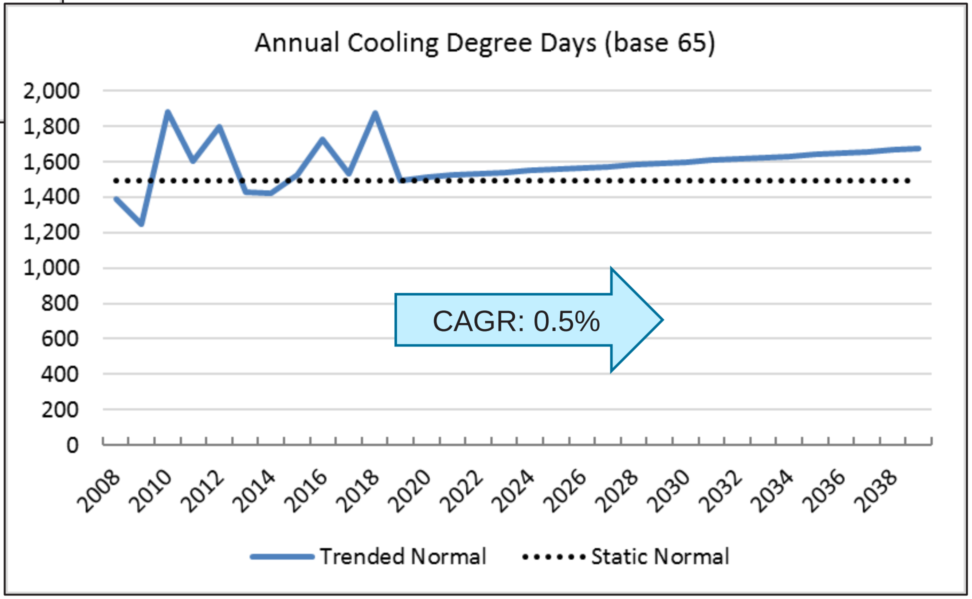
- Residential Sector
  - Households: 0.4% CAGR
  - Real Household Income: 1.6% CAGR
  - Household Size -0.3% CAGR
- Commercial Sector
  - Non-Manufacturing Output: 1.7% CAGR
  - Non-Manufacturing Employment : 0.6% CAGR
  - Population 0.2% CAGR
- Industrial Sector
  - Manufacturing Output: 1.8% CAGR
  - Manufacturing Employment: -0.5% CAGR

TRENDED NORMAL WEATHER

VECTREN
A CenterPoint Energy Company

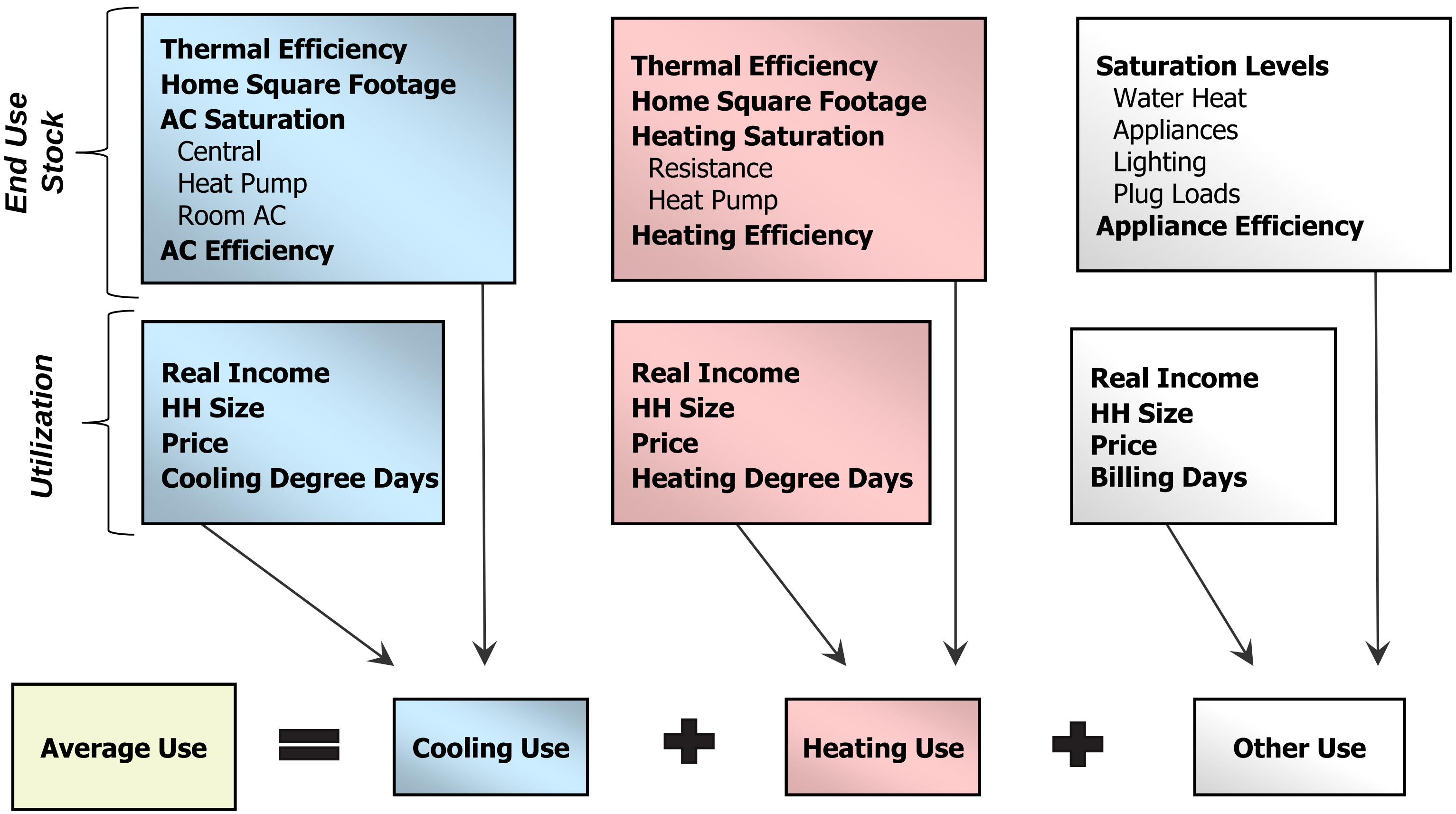


- Average temperature is increasing
  - Decline in HDD (warmer winters)
  - Increase in CDD (hotter summers)

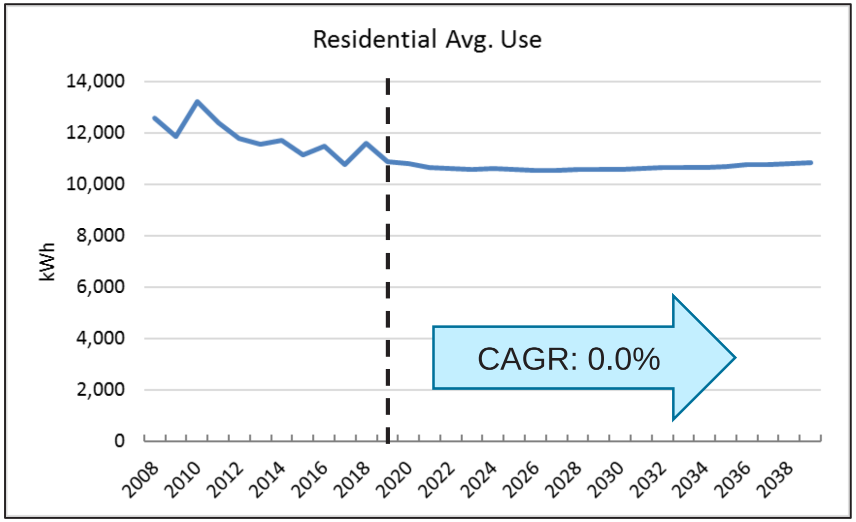


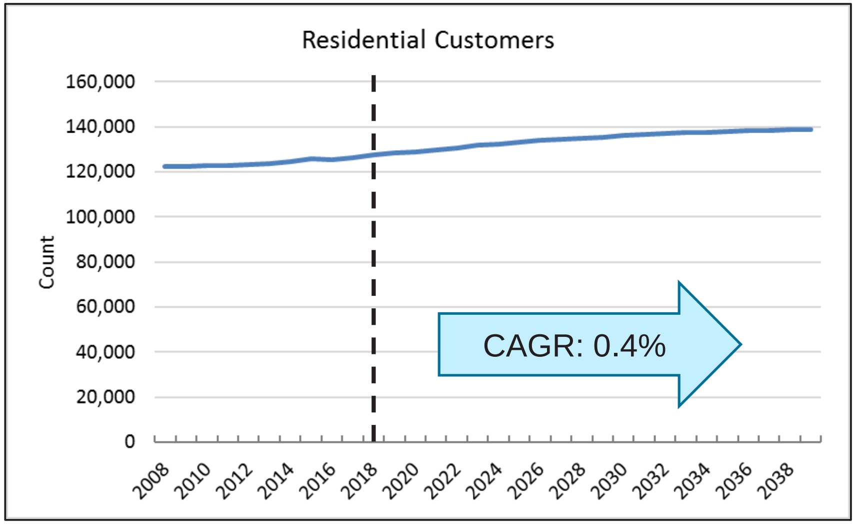
- Temperature trend based on statistical analysis of historical temperature data (1988 to 2018)

RESIDENTIAL AVERAGE USE MODEL

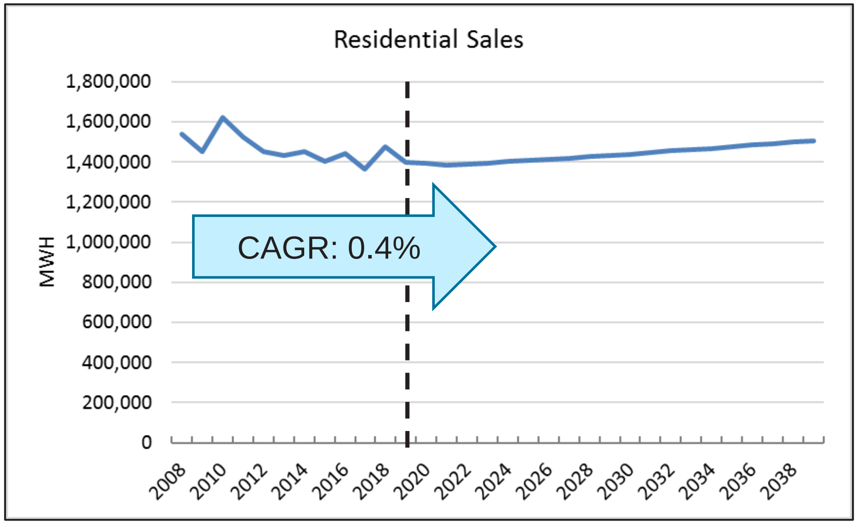


RESIDENTIAL FORECAST

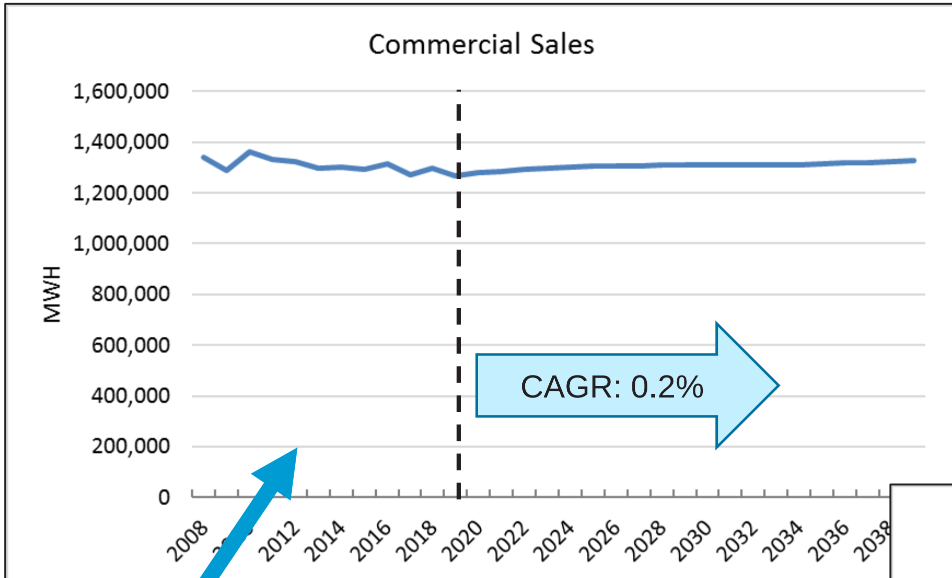


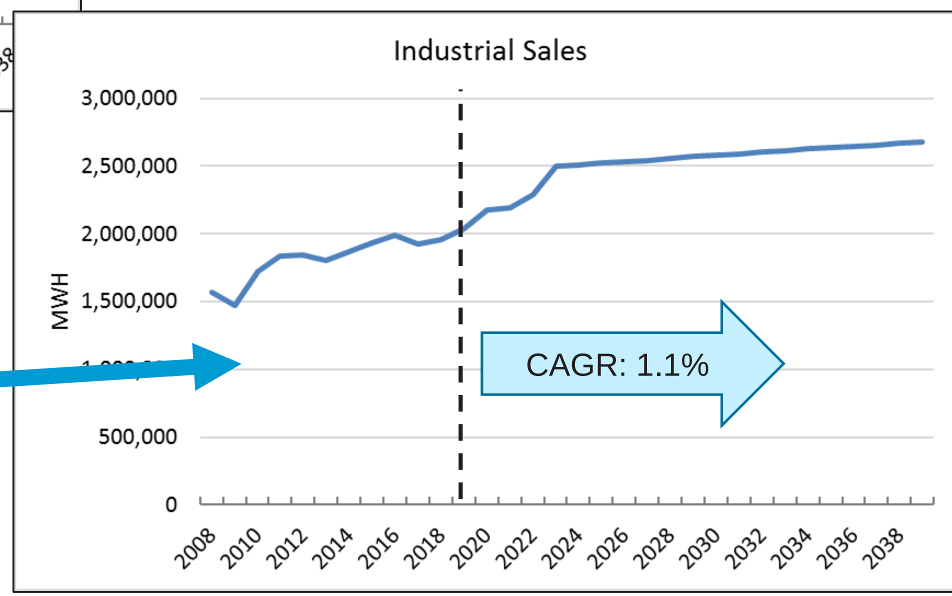


- Flat average use forecast, does not include the impact of future DSM program activity



C&I SALES FORECAST

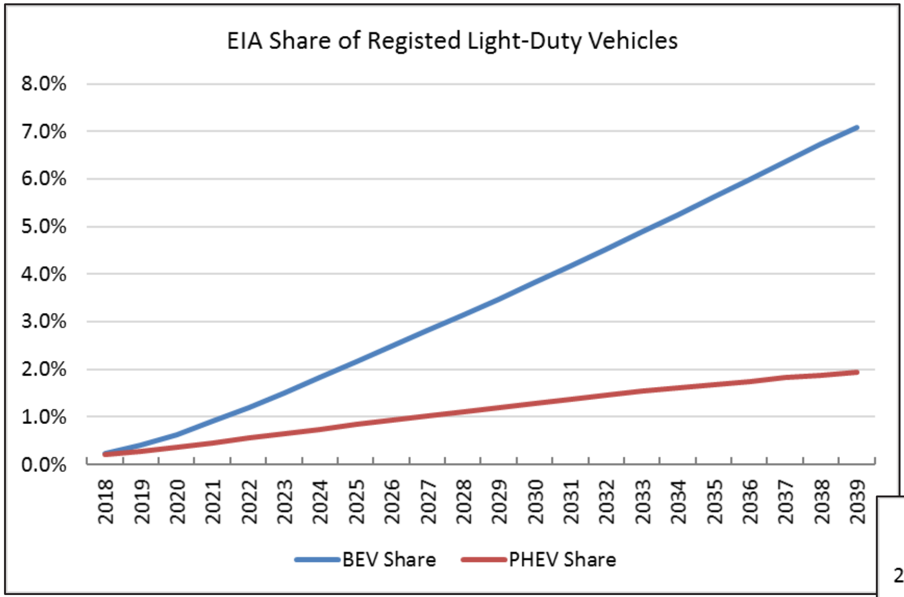




- Increase in commercial business activity countered by end-use efficiency gains
- Strong industrial sales growth related to near-term expected industrial expansion

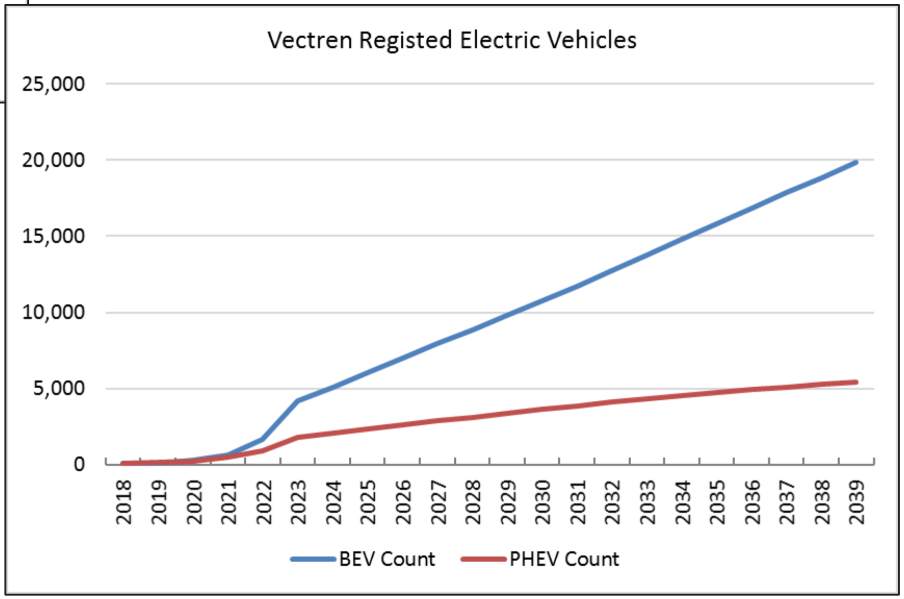
* Excludes future energy efficiency program impacts and customer-owned DG

ELECTRIC VEHICLES

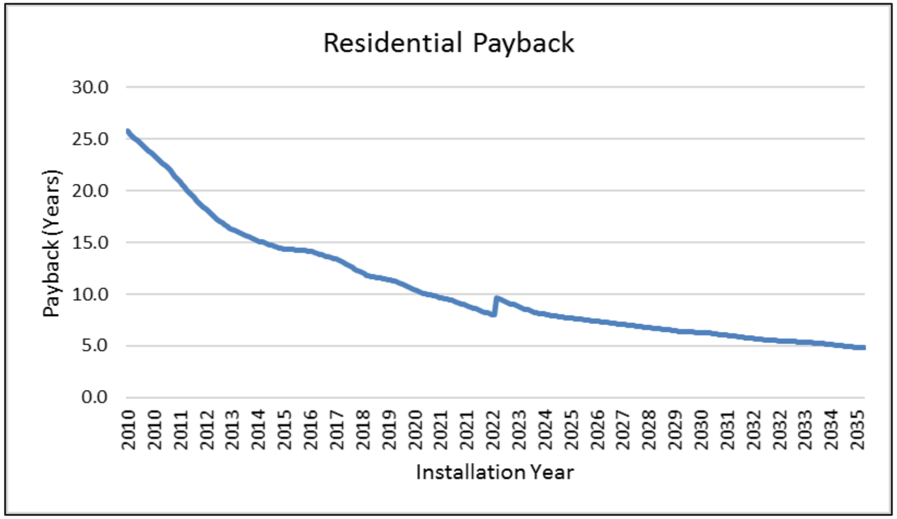


- Energy Information Administration (EIA) forecast based on share of total registered vehicles; differentiating between all electric (BEV) and plug-in hybrid electric (PHEV)

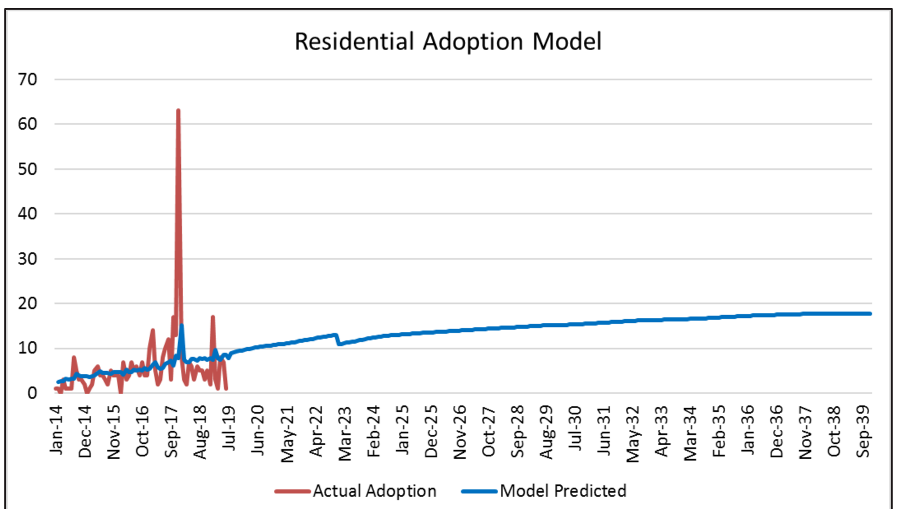
- Average annual kWh per vehicle based on weighted average of current registered BEV/PHEV
  - 3,752 kWh per BEV
  - 2,180 kWh per PHEV



CUSTOMER OWNED PV

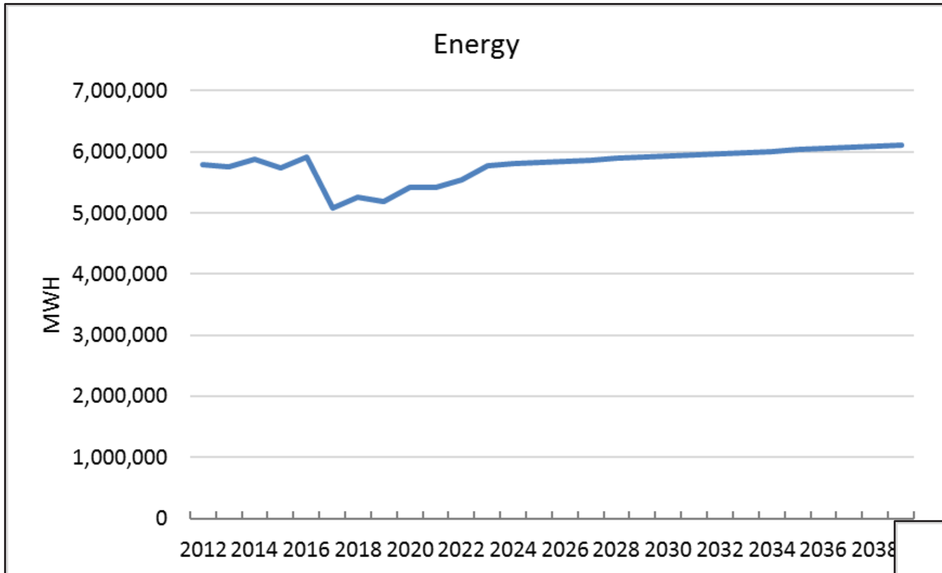


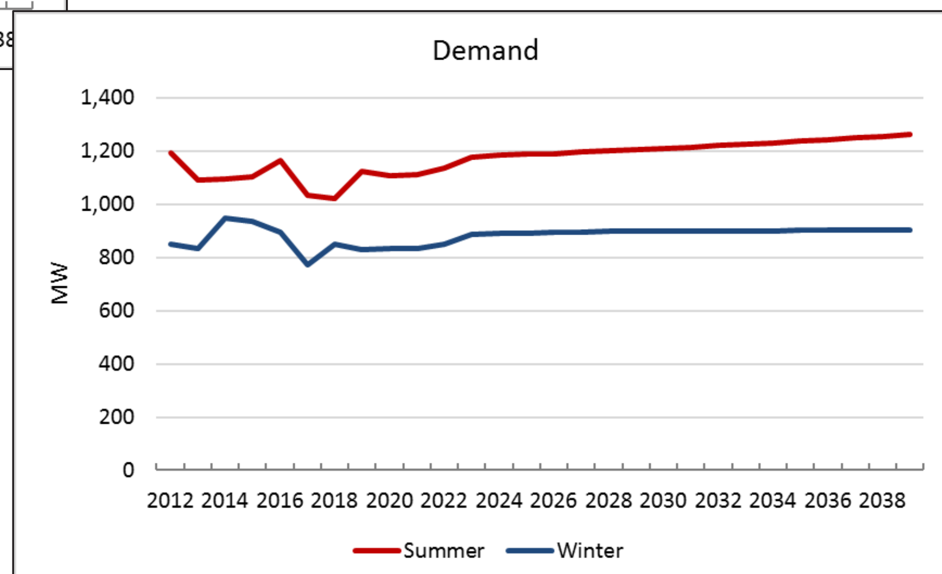
- Customer economics defined using simple payback
  - incorporates declining solar system costs, electric price projections, changes in net metering laws, and federal incentives



- Monthly adoption based on simple payback

ENERGY & DEMAND FORECAST





- Combining economic growth, end-use efficiency, and adoption of new technologies, and trended weather results in 0.6% long-term energy and summer demand CAGR (2020-2039)*

* Excludes future energy efficiency programs. Includes a forecast of customer owned solar generation and forecast for electric vehicle penetration. Excludes company owned generation on the distribution system

FEEDBACK AND DISCUSSION

EXISTING RESOURCE OVERVIEW

WAYNE GAMES

VECTREN VICE PRESIDENT POWER GENERATION OPERATIONS

EXISTING RESOURCE SUMMARY

- Vectren is doing an exhaustive look at options for existing coal resources, including continued operation, retirement and coal to gas conversion of units
- Vectren must comply with EPA regulations; as such we are performing several studies to determine compliance options
- There is risk for Vectren in continued joint operation or sole ownership options as it pertains to Warrick 4

DEFINITIONS

- ACE – Affordable Clean Energy Rule; Carbon rule that establishes emission guidelines for states to use when developing plans to limit CO_2 (improve heat rate) at their coal fired power plants
  - Heat rate improvements can be achieved through equipment upgrades or operation & maintenance practices
  - State of Indiana expected to issue requirement to comply in 2021
- Capacity Factor – The amount of energy a resource produces in a given period of time divided by the maximum amount of energy the resource is capable of producing during the same period of time
- CCR – Coal Combustion Residuals
- $EFOR_d$ – Equivalent Forced Outage Rate Demand; reliability measure used by MISO in the calculation of capacity accreditation for thermal resources
- Heat Rate – Measure of efficiency of a thermal generating resource; lower values represent better efficiency
- ICAP – Installed capacity of a resource
- MW – Megawatt
- PPA – Purchase Power Agreement
- UCAP – Unforced capacity; capacity credit a market participant receives from MISO for their resources
  - Thermal resources are based on tested unit output and 3 year historical $EFOR_d$ (Takes into account forced outages and forced derates)
  - Intermittent resources are based on historical output during peak summer hours
    - Solar resources without operating data default to a credit of 50% of installed capacity
    - Wind resources without operating default to the MISO system wide wind capacity credit from the effective load carrying capability (ELCC) study
      - Received 8% and 9.2% capacity credit for current wind PPA's in 2019-2020 planning year
- FGD – Flue gas desulfurization

SUMMARY OF CURRENT RESOURCE UCAP ACCREDITATION FOR SUMMER PEAK

Resource	Fuel \ Technology	Installed Net Capacity (MW)	2019-2020 MISO Planning Year UCAP[2] (MW)	2020-2021 MISO Planning Year UCAP[2] Projection (MW)	ICAP Conversion to UCAP (%) – 2020-2021 Planning Year Projection
A.B. Brown 1	Coal (24x7 Power)	245	209	232	Coal Fleet 92%
A.B. Brown 2	Coal (24x7 Power)	245	225	234	
F.B. Culley 2	Coal (24x7 Power)	90	86	86	
F.B. Culley 3	Coal (24x7 Power)	270	251	247	
Warrick 4	Coal (24x7 Power)	150[1]	127	118	
OVEC	Coal (24x7 Power)	32	30	30	
A.B. Brown 3	Natural Gas (Peaking)	85	71	73	Natural Gas (Peaking) 85%
A.B. Brown 4	Natural Gas (Peaking)	85	71	72	
Demand Response	N/A	62	62	62	Demand Response 100%
Benton County	Wind (Intermittent)	30	2	2	Wind 9%
Fowler Ridge	Wind (Intermittent)	50	5	5	
50 MW Solar	Solar (Intermittent)	50	0	0[3]	N/A
Total		**1,344**	**1,139**	**1,161**	

1 – Vectren Share
2 – Unforced capacity
3 – 25MW of UCAP projected for 2021-2022 MISO planning year

IRP OPTIONS FOR EXISTING COAL RESOURCES

- Continued operation of existing solely owned coal units –
  - Brown 1 & 2 and Culley 2
    - Cost to comply with CCR/ELG environmental requirements
    - Cost to comply with ACE requirements
    - AB Brown FGD replacement (Study performed to estimate cost for different technologies to identify best path forward)
  - Culley 3
    - IURC approval to install technologies to comply with CCR/ELG
    - Cost to comply with ACE requirement
- Retirement of Brown 1 & Brown 2 in 2029
    - Cost to comply with CCR/ELG environmental requirements
    - Cost to comply with ACE requirements[1]
    - Continue existing FGD operation
- Natural gas conversion for Brown 1, Brown 2, and Culley 2
- Retirement of Brown 1, Brown 2, and Culley 2 in 2023
- Extend or exit Warrick Unit 4 partnership; (agreement currently set to expire at the end of 2023)

1 - Costs are estimates pending the final IDEM implementation plan for Indiana.

RENEWABLES

- Solar (54 MW installed capacity)
  - Two 2 MW solar fields (behind the meter generation)
    - Both fields went in service late in 2018
    - 1 MW/4 MWH energy storage system connected at Volkman Road site
  - 50 MW solar field
    - Finalizing engineering & design and preparing to order materials
    - Currently scheduled for commercial operation in late 2020 to early 2021
- Wind PPA contracts (80 MW installed capacity)
  - Benton County
    - Contract for 30 MW of installed capacity expires in 2028
  - Fowler Ridge
    - Contract for 50 MW of installed capacity expires in 2030
- Blackfoot Landfill Gas (behind the meter generation)
  - Units are capable of producing 3 MW combined

COMBUSTION TURBINES (NATURAL GAS PEAKING UNITS)

- Broadway Avenue Generating Station 1; 53 MW installed capacity
  – Retired in 2018
- Northeast units 1 and 2 (10 MW installed capacity each)
  – Retired in early 2019
- Broadway Avenue Generating Station 2; 65 MW installed capacity
  – Currently in process of retirement through MISO process
    - Typical life is 30-40 years; Unit has been in service for 38 years
    - Highest heat rate (least efficient) of current generating fleet
    - Recent five year capacity factor just over 1%
    - Several millions dollars needed for known repairs
    - High probability of additional expenses in the near future given current age and condition
- Brown 3; 85 MW installed capacity
  – Black start capabilities (able to burn fuel oil)
  – No upgrades required for continued operation
- Brown 4; 85 MW installed capacity
  – No upgrades required for continued operation

F.B. CULLEY OPTIONS

- Culley 2; 90 MW installed coal capacity
  - Business as usual (continue beyond 2023)
    - Requires CCR (Coal Combustion Residuals) and Effluent Limit Guidelines (ELG) compliance
    - Compliance with ACE (Affordable Clean Energy) rule; unit upgrades & improvements
  - Natural Gas Conversion
    - Preserve existing capacity
    - High cost energy
    - Anticipate low capacity factor with high reliance on market
  - Retirement in 2023 to avoid environmental investments

Business As Usual

Regulation	Upgrade	Estimated Cost	Potential Efficiency Improvement
CCR/ELG	Dry Bottom Ash Conversion	$6 million	N/A

Business As Usual

Regulation	Potential Upgrade/Projects	Estimated Cost	Potential Efficiency Improvement
ACE	• Turbine Upgrade • Air heater • Variable Frequency Drives • Boiler program • Condenser work • O&M Practices	$30 million[1]	~4-4.5%

Natural Gas Conversion

Item	Estimated Cost
Modifications to convert unit to natural gas firing	$46 million
Gas pipeline construction	$11 million
Total	**$57 million**

1 – Costs are estimates pending the final IDEM implementation plan for Indiana

F.B. CULLEY OPTIONS (CONT.)

- Culley 3; 270 MW installed coal capacity
  - Moving forward with upgrades approved in cause 45052 to comply with CCR (Coal Combustion Residuals) and ELG (Effluent Limitations Guidelines)[1]
  - Compliance with ACE (Affordable Clean Energy) rule; requires unit upgrades to improve efficiency

Business As Usual

Regulation	Potential Upgrade/Projects	Estimated Cost	Potential Efficiency Improvement
ACE	• Turbine upgrades • Air heater Upgrade • Variable Frequency Drives • Boiler Program • Condenser Upgrade • O&M Practices	$35 million[1]	~3%

1 - Costs are estimates pending the final IDEM implementation plan for Indiana

WARRICK GENERATING STATION UNIT 4

- Warrick 4; 150 MW installed capacity (Vectren share of a 300 MW jointly owned coal fired unit)
  - Current operating agreement expires in 2023
  - Either party can exit earlier with sufficient notice
  - Alcoa currently evaluating future options. Committed to respond in 4th quarter
- Risks of continued joint operation
  - Lack of operational control
  - Environmental upgrades (cost and liability)
  - Alcoa can exit agreement after giving notice
    - Smelter future reliant on global aluminum market
- Ramifications of Alcoa exiting the operation agreement
  - Vectren takes ownership
    - 100% of environmental upgrade costs (lose benefit of industrial classification for water discharge and CCR)
    - 100% capital and O&M investment responsibility
    - Operational challenges of taking over facility
    - Future decommissioning costs
    - Increase percentage of coal capacity
  - Retire the unit
    - Procure replacement capacity

A.B. BROWN

- Brown 1 & 2; 245 MW installed coal capacity (each)
  - Natural Gas Conversion
    - Preserve existing capacity
    - High cost energy
    - Anticipate low capacity factor with high reliance on market

Item	Brown 1 Estimated Cost ($)	Brown 2 Estimated Cost ($)	Total
Modification to convert unit to gas	$89 million	$97 million	$186 million
Gas pipeline construction[1]	$50 million	$50 million	$100 million
Total	$139 million	$147 million	$286 million

1- Values shown assume both units are converted. Single unit conversion is approximately $77 million

A.B. BROWN (CONT.)

- Brown 1 & 2; 245 MW (each)
  - Business as usual
    - Requires dry bottom ash conversion and dry flyash system upgrades for CCR (Coal Combustion Residuals) and ELG (Effluent Limitations Guidelines) compliance
    - A new landfill would be needed for disposal of FGD (Flue Gas Desulphurization) by-products and fly ash
    - FGD replacement is included in continued operation plan
    - Compliance with ACE (Affordable Clean Energy) rule; requires unit upgrades & improvements based on IDEM ruling

Business As Usual

Regulation	Upgrade Projects	Brown Unit 1 Estimated Cost	Brown Unit 2 Estimated Cost	Total Estimated Cost
CCR\ELG	• Dry bottom ash conversion • Dry Fly Ash Conversion • Water treatment	$53 million	$53 million	$106 million[2]

Regulation	Potential Upgrade/Projects	Brown Unit 1 Estimated Cost	Brown Unit 2 Estimated Cost	Total Estimated Cost	Potential Efficiency Improvement	Potential Efficiency Improvement
ACE	• Air heater • Variable Frequency Drives • Boiler program • Condenser work • O&M Practices	$13 million[1]	$13 million[1]	$26 million[1]	~2.2%	~2.6%

1 - ACE costs are estimates pending the final IDEM implementation plan for Indiana
2 – Does not include landfill cost for FGD by-products and ash. New landfill required to operate beyond 2023. Size and cost to be determined based on future FGD technology

NEW FGD OPTIONS

Eight FGD technologies reviewed; four chosen for further analysis

- Market analysis being conducted for potential by-products sales
- Will perform Net Present Value (NPV) screening analysis in modeling to determine low cost option
- NPV results along with operating considerations will help determine the preferred FGD replacement technology

FGD Technology	Primary Reagent	Estimated Initial Capital Investment[1]	Estimated Landfill Capital and O&M	Estimated Variable O&M Cost/MWHr (2019$)	Marketable Fly Ash	Community Right-To-Know Emergency Action Plan	Marketable By-Product
Limestone Forced Oxidation (LSFO)	**Limestone**	**$596 million[2,4]**	**TBD Based on Gypsum and Ash Market**	**$4.44/MWHr**	**Yes**	**No**	**Gypsum**
Lime Inhibited Oxidation (LSIO)	**Lime Quicklime**	**$450 million[2,4]**	**$119 million**	**$9.39/MWHr**	**Yes (Limited)**	**No**	**No**
Ammonia Based (JET)	**Anhydrous Ammonia**	**$411 million[2,3,4,5]**	**TBD Based on Ammonium Sulfate Market**	**$11.67/MWHr**	**Yes**	**Yes**	**Ammonium Sulfate Fertilizer[6]**
Circulating Dry Scrubber (CDS)	**Lime**	**$387 million[2,3,5]**	**$125 million**	**$14.92/MWHr**	**Yes**	**No**	**No**

1 – Values represent estimated total cost for both A.B. Brown units
2 – Includes new wastewater treatment system
3 - Includes new mercury mitigation system
4 – Includes new SO_3 mitigation system
5 – Includes new particulate matter collection system
6 – Also produces unmarketable by-product (brominated powder activated carbon and mercury)

A.B. BROWN FGD OPTIONS (CONT.)

- Replacement of existing FGD’s (cont.)
  - Spray Dryer FGD and Flash Dryer FGD
    - Neither option can meet emission criteria based on 1 hour SO2 limit for Posey County and Illinois Basin Coal supply
- Conversion of existing FGD’s to limestone based technologies
  - Lime Inhibited Oxidation (LSIO) or Limestone Forced Oxidation (LSFO)
    - Neither option can meet emissions criteria based on 1 hour SO2 limit for Posey County
- Continued operation of current Brown dual alkali FGD’s through 2029

FGD Technology	Estimated 10 Year Capital	Estimated 10 Year O&M	Estimated Landfill Capital and O&M	Estimated Variable O&M Cost/MWHr (2019$)	Marketable Fly Ash	Community Right-To-Know Emergency Action Plan	Marketable By-Product
Dual Alkali	**$137 million**	**$58 million**	**$49 million**	**5.72**	**Yes**	**No**	**No**

FEEDBACK AND DISCUSSION

POTENTIAL NEW RESOURCES AND MISO ACCREDITATION

MATT LIND,

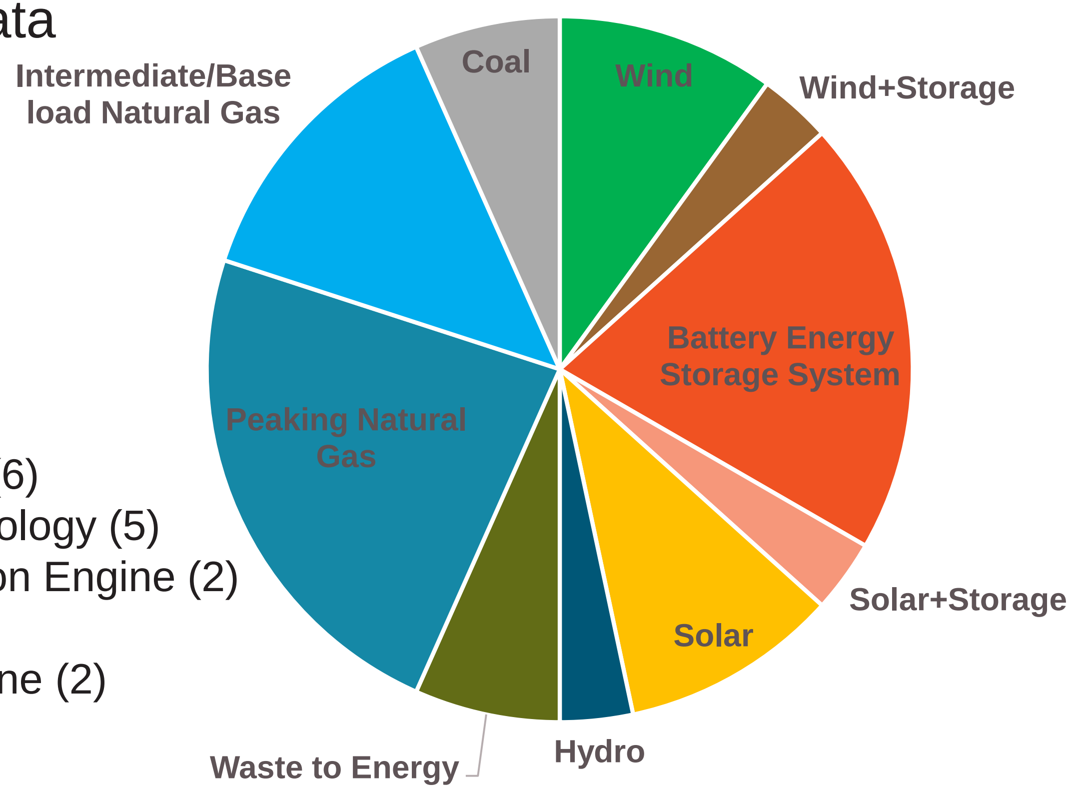
RESOURCE PLANNING & MARKET ASSESSMENTS BUSINESS LEAD, BURNS & MCDONNELL

NEW RESOURCE AND MISO ACCREDITATION SUMMARY

- Vectren initially plans to model new potential resources with draft technology assessment information as RFP modeling inputs are being completed
- Technology costs will be updated with bid information, where applicable; final modeling inputs will be shared in December
- Intermittent resources lack dispatch flexibility, as penetration increases, MISO projects lower capacity accreditation
- MISO is planning for seasonal capacity accreditation (summer/winter), some resources will receive varying levels of capacity credit depending on differences in seasonal availability

BACKGROUND

- Base Case Inputs for new power supply options
- Consensus estimates from Burns & McDonnell, Pace Global, and NREL for solar and storage resources
- Supplemental to RFP Bid data
- Resource Options (30):
  - Wind (3)
  - Wind + Storage (1)
  - Solar Photovoltaic (3)
  - Solar + Storage (1)
  - Hydro (1)
  - Landfill Gas (2)
  - Battery Energy Storage System (6)
  - Simple Cycle Gas Turbine Technology (5)
  - Reciprocating Internal Combustion Engine (2)
  - Combined Cycle Gas Turbine (2)
  - Combined Heat and Power Turbine (2)
  - Coal (2)



TECHNOLOGY DETAILS

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Examples of candidates for natural gas peaking generation:

Gas Simple Cycle (Peaking Units)	Example 1	Example 2	Example 3	Example 4
Combustion Turbine Type	LM6000	LMS100	E-Class	F-Class
Size (MW)	41.6 MW	97.2 MW	84.7 MW	236.6 MW
Fixed O&M (2019 $/kW-yr)	$36	$16	$21	$8
Total Project Costs (2019 $/kW)	~$2,400	~$1,700	~$1,500	~$800

Examples of candidates for natural gas combined cycle generation:

Gas Combined Cycle (Base / Intermediate Load Units)	Example 1	Example 2
Combustion Turbine Type	1x1 F-Class[1]	1x1 G/H-Class[1]
Size (MW)	357.2 MW	410.6 MW
Fixed O&M (2019 $/kW-yr)	$13	$12
Total Project Costs (2019 $/kW)	~$1,400	~$1,300

[1] 1x1 Combined Cycle Plant is one combustion turbine with heat recovery steam generator and one steam turbine utilizing the unused exhaust heat from the combustion turbine.

TECHNOLOGY DETAILS

Examples of candidate combined heat and power gas generation:

Gas Combined Heat and Power[1]	2 x 10 MW Recip Engines	20 MW Combustion Turbine
Net Plant Electrical Output (MW)	17.9 MW	21.7 MW
Fixed O&M (2019 $/kW-yr)	$42	$35
Total Project Costs (2019 $/kW)	~$2,800	~$4,600

[1] Utility owned and sited at a customer facility

Examples of candidates for renewable energy and energy storage:

Renewable Generation & Storage Technologies	Solar Photovoltaic	Solar + Storage	Indiana Wind Energy	Lithium Ion Battery Storage
Base Load Net Output (kW)	100 MW (Scalable Option)	50 MW + 10MW/40 MWh	200 MW	10 MW/40 MWh (Scalable Option)
Fixed O&M (2019 $/kW-yr)	$20	$27	$44	$19
Total Project Costs (2019 $/kW)[1]	~$1,600	~$1,900	~$1,700	~$2,000

[1]Total Project Costs (2019 $/kW) may change based on economies of scale. The Technology Assessment contains unique costs for the different scales of the projects.

TECHNOLOGY DETAILS

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Example of candidates for hydroelectric generation:

	Low Head Hydroelectric Generation
Base Load Net Output (kW)	50 MW
Fixed O&M (2019 $/kW-yr)	$92
Total Project Costs (2019 $/kW)	~$5,900

Potential local resources:

Dam	2012 DOE[1] Estimated Potential Capacity (MW)	2013 U.S. Army Corps of Engineers Estimated Feasible Potential Capacity (MW)	2013 U.S. Army Corps of Engineers Estimated Optimal Potential Capacity (MW)
John T. Myers (Uniontown)	395	24-115	36
Newburgh	319	15-97	22

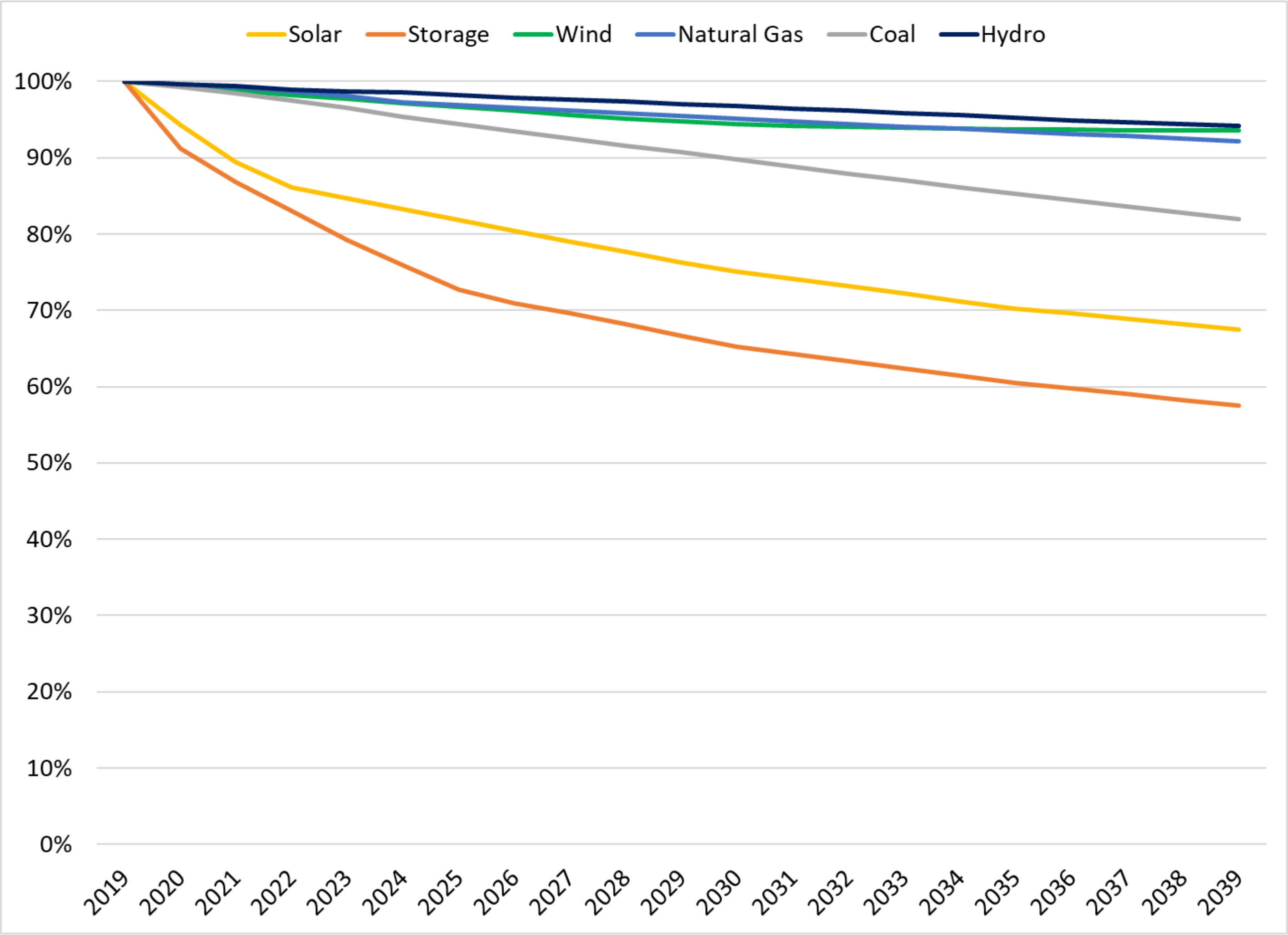
Notes:
In 2019 dollars, the Cannelton hydro project (~84 MW) total cost was approximately $5,500/kW (US Army Corps of Engineers press release)
Transmission upgrades required for the Uniontown dam are estimated at $14 million
Transmission upgrades required for the Newburgh dam are estimated at $10 million

TECHNOLOGY DETAILS

Examples of candidates for coal generation:

Coal Fired	Example 1	Example 2
Combustion Turbine Type	Supercritical Pulverized Coal with Carbon Capture	Ultra-Supercritical Pulverized Coal with Carbon Capture
Size (MW)	506 MW	747 MW
Fixed O&M (2019 $/kW-yr)	$29	$29
Total Project Costs (2019 $/kW)	~$6,100	~$5,500

FORWARD COST ESTIMATES



Technology Maturity

PROPOSAL LOCATION REVIEW

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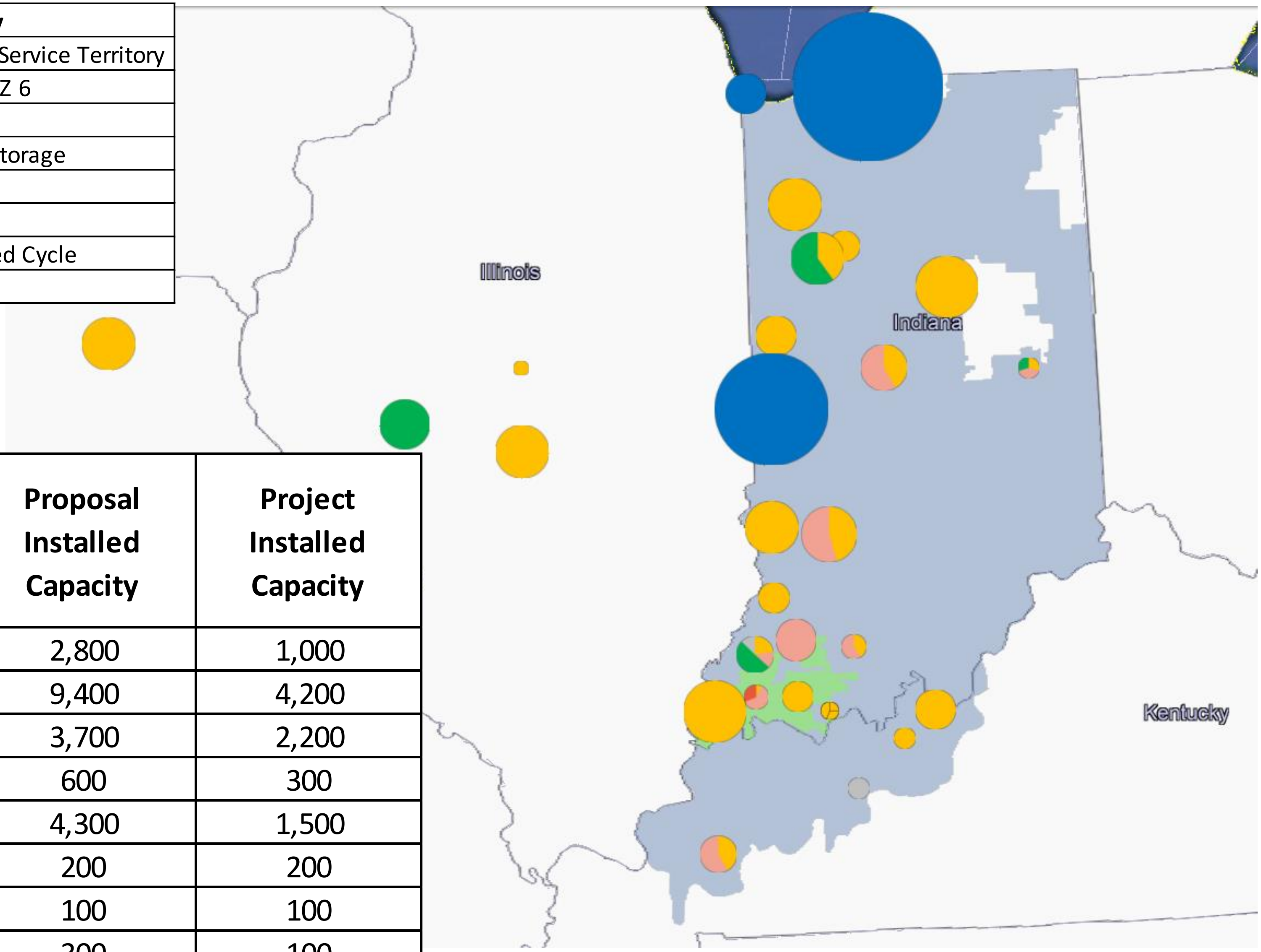
Key	
	Vectren Service Territory
	MISO LRZ 6
	Solar
	Solar + Storage
	Storage
	Wind
	Combined Cycle
	Coal



2019 RFP Responses (MW)	Proposal Installed Capacity	Project Installed Capacity
Wind	2,800	1,000
Solar	9,400	4,200
Solar + Storage	3,700	2,200
Storage	600	300
Combined Cycle	4,300	1,500
Coal	200	200
LMR/DR	100	100
System Energy	300	100
Total	**21,400**	**9,600**

PARTICIPATING COMPANIES

bp
ST. JOSEPH energy center
Origis Energy POWERING THE SOLAR REVOLUTION
S·POWER An AES and AIMCo Company

EmberClear
RANGER POWER
Constellation. An Exelon Company
APEX CLEAN ENERGY

NEXTera ENERGY RESOURCES
Clēnera
edp renewables
e·on
CALPINE

lightsource bp
DUKE ENERGY
enel x
ORION RENEWABLE ENERGY GROUP LLC
engie

Big Rivers ELECTRIC CORPORATION
res
Invenergy
Capital Dynamics TRULY INVESTED.
TENASKA

PROPOSAL GROUPING

	Potential Grouping	RFP Count	Tier 1 Proposals	Tier 2 Proposals
1	Coal PPA	2	0	2
2	LMR/DR PPA	1	1	0
3	CCGT PPA	2	0	2
4	CCGT Purchase	5	0	5
5	Wind Purchase	2	0	2
6	12-15 Year Wind PPA	9	4	5
7	20 Year Wind PPA	2	1	1
8	Storage Purchase	4	4	0
9	Storage PPA	4	4	0
10	Solar + Storage PPA	6	5	1
11	Solar + Storage Purchase	9	5	4
12	Solar + Storage Purchase/PPA	4	1	3
13	Solar Purchase/PPA	6	1	5
14	12-15 Year Solar PPA	8	3	5
15	20 Year Solar PPA	16	7	9
16	25-30 Year Solar PPA	9	3	6
17	Solar Purchase	18	4	14
N/A	Energy Only	3	0	3
	Total	**110**	**43**	**67**

- Total installed capacity of RFP bids in Tier 1 ~5X greater than Vectren's peak load
- Resource options from the technology assessment will supplement these options as needed

110 Proposals

Tier 1
- Binding Pricing
- Delivered to SIGE.SIGW OR On System

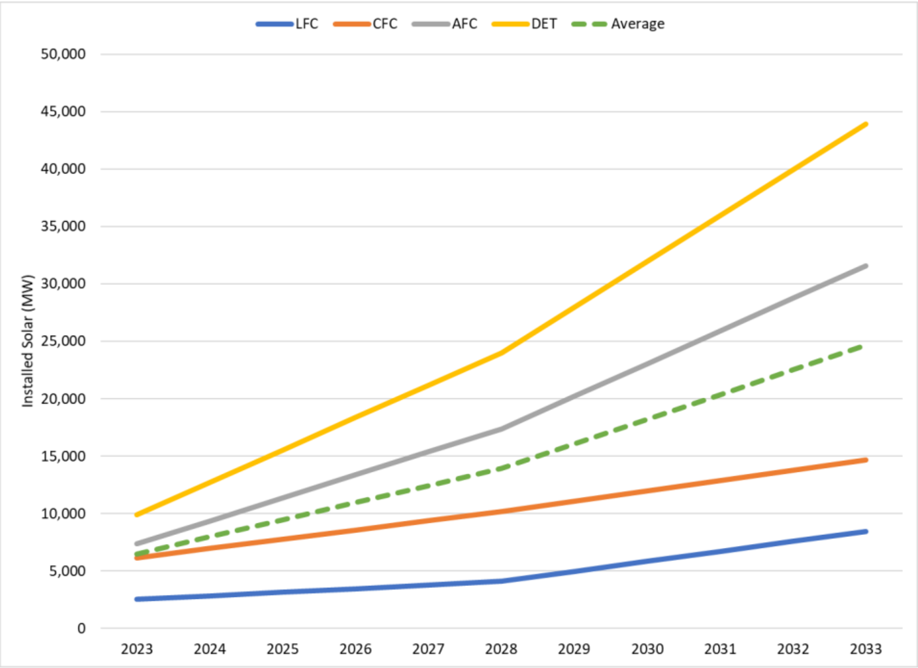
IRP Inputs

Tier 2
- Non-Binding Pricing
- Congestion / delivery risk

Potential IRP Inputs Based on Evaluation

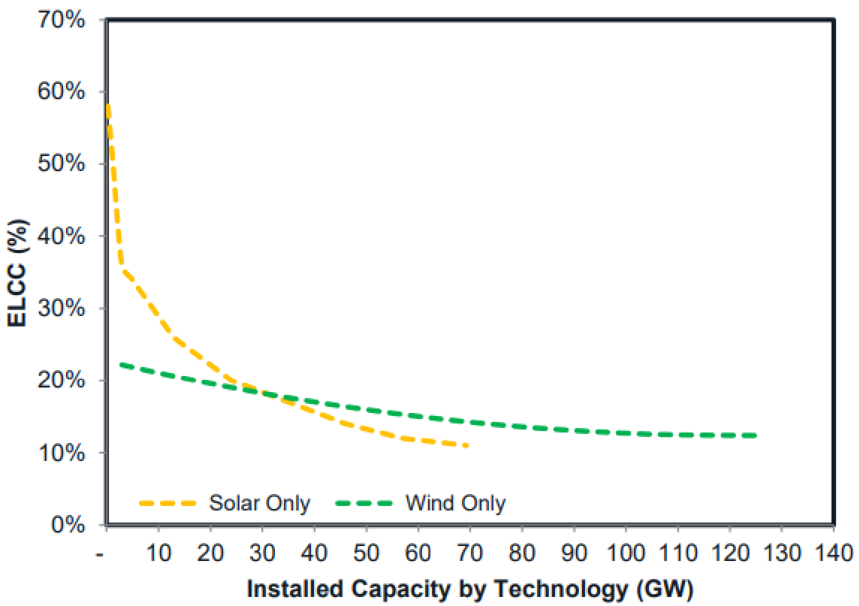
MISO RENEWABLE PENETRATION TRENDS

MTEP19 future solar capacity projections



https://cdn.misoenergy.org/MTEP19%20Futures%20Summary291183.pdf
MISO Transmission Expansion Plan (MTEP) study years 2023, 2028, and 2033. Data between study years is linearly interpolated.

Effects of increasing installations

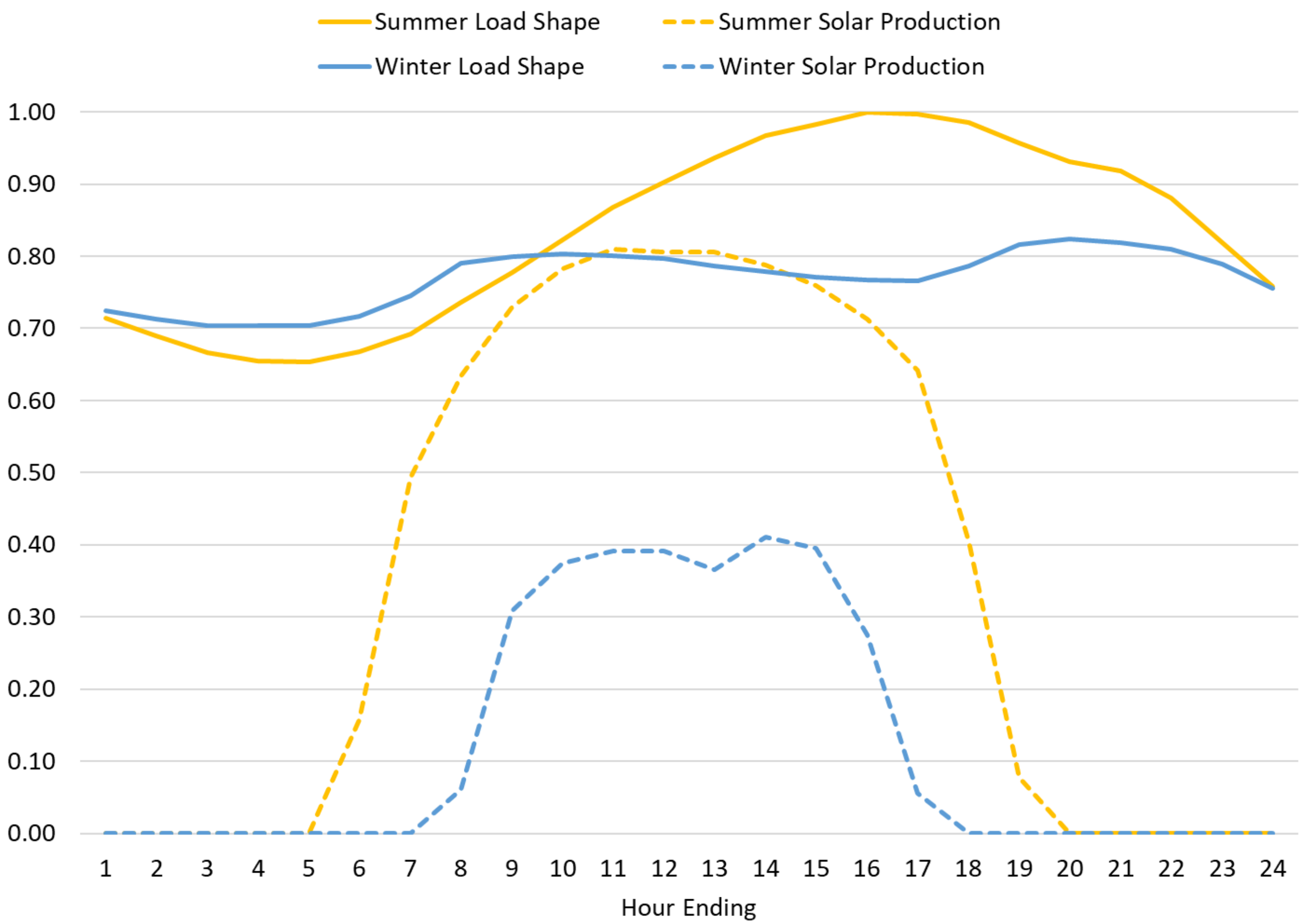


https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v7429759.pdf

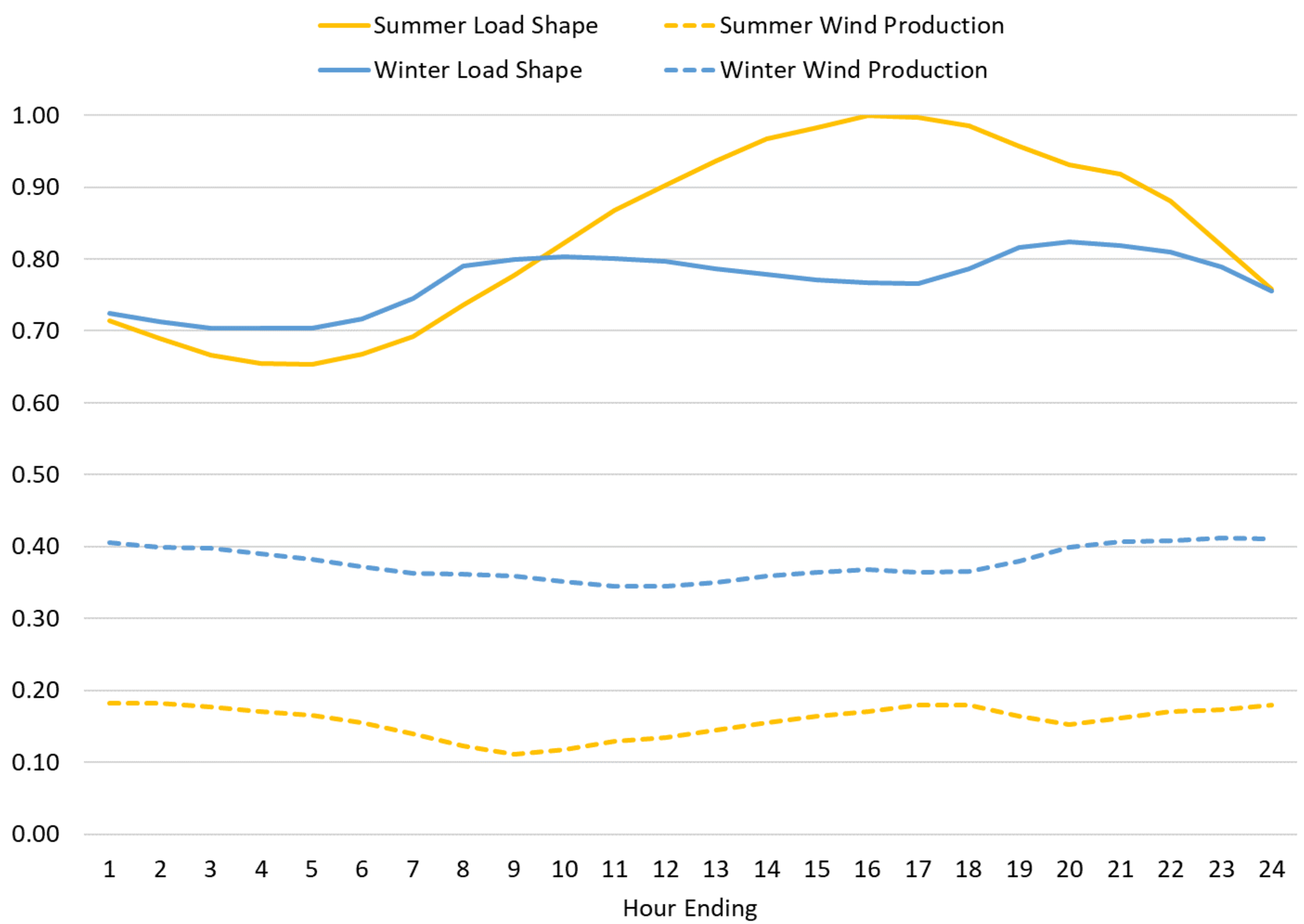
As installed capacity (ICAP) goes ⬆… Accreditable capacity (UCAP) goes ⬇

ELCC – Effective Load Carrying Capability

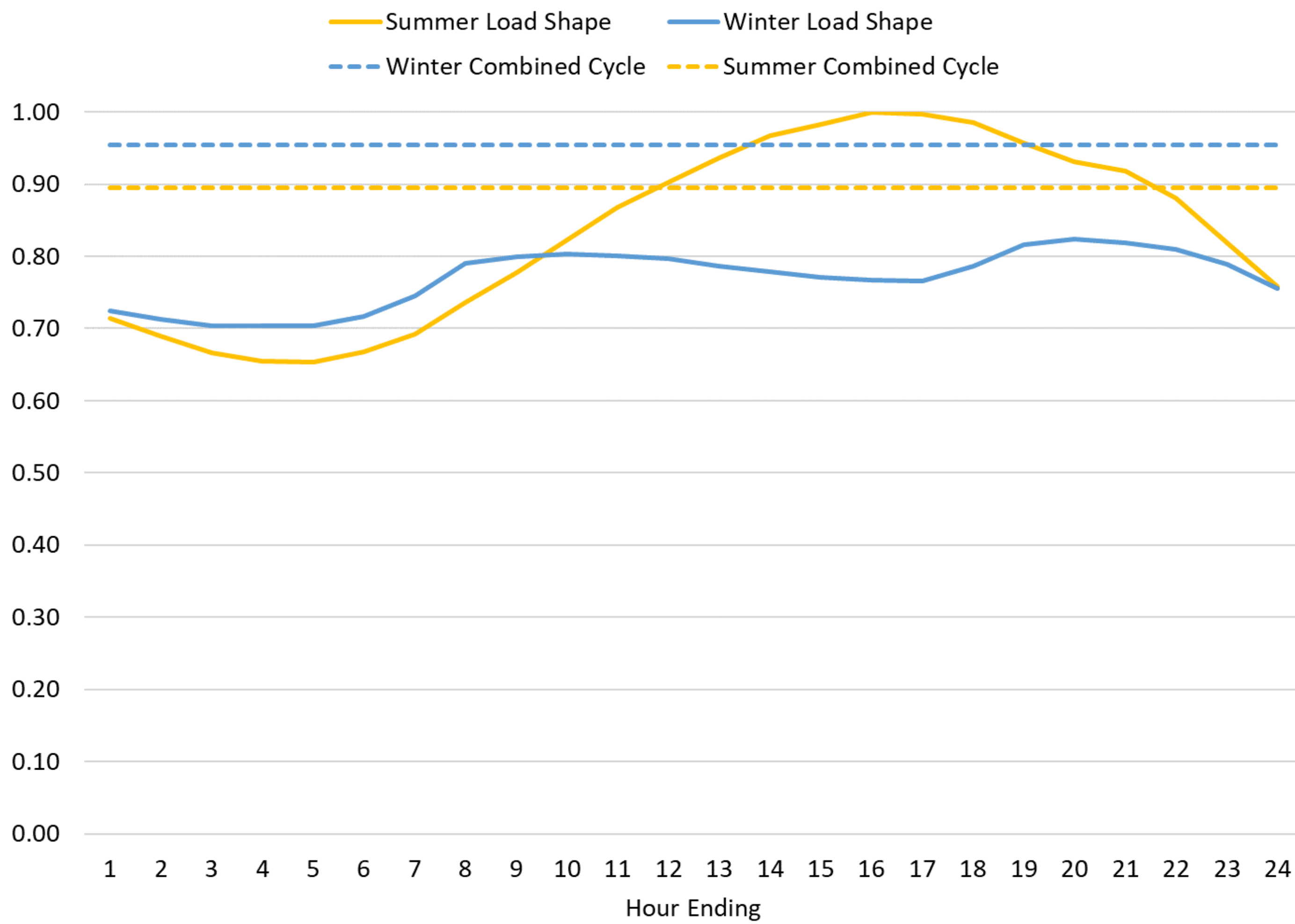
SOLAR SEASONAL DIFFERENCES



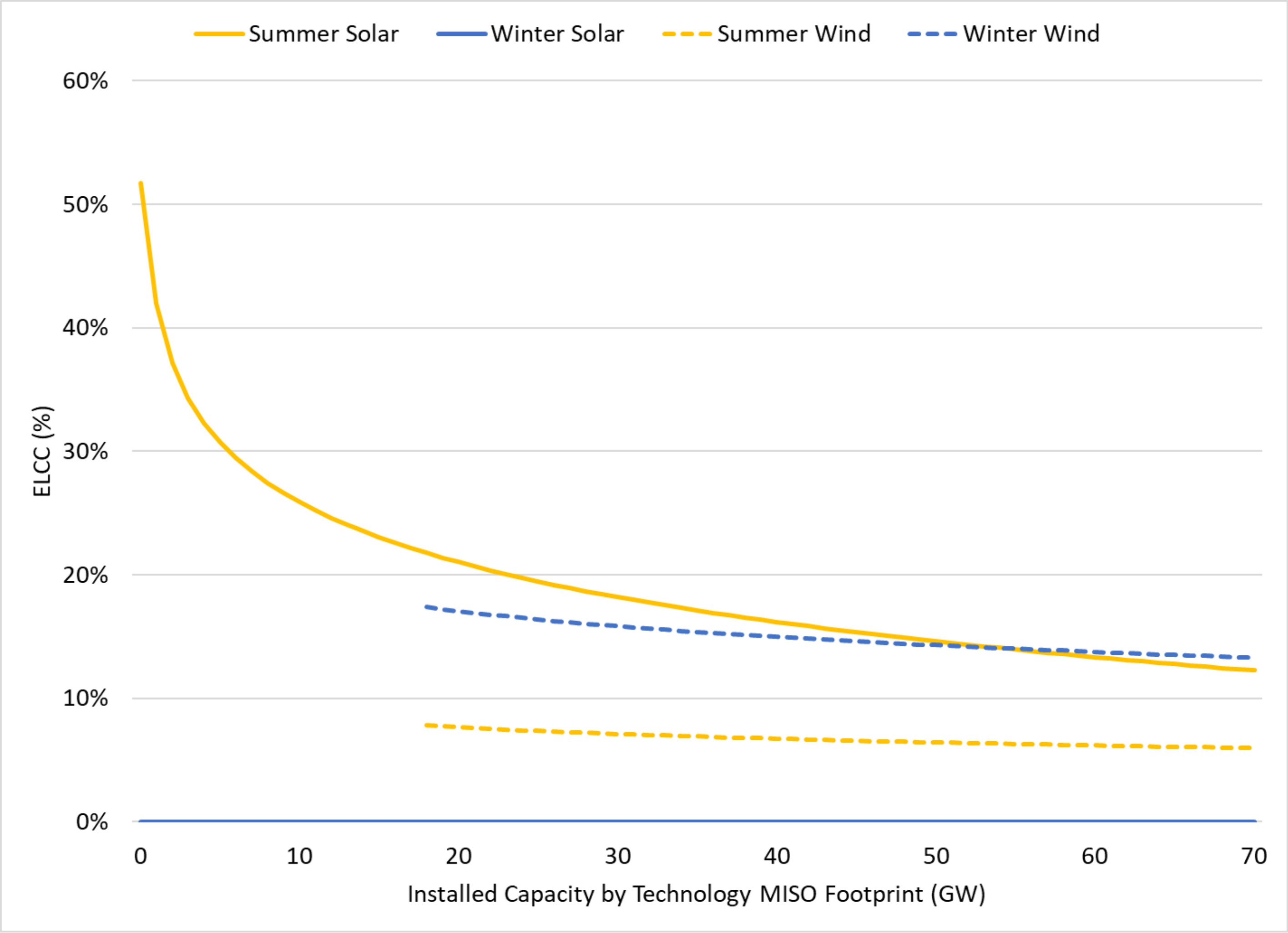
WIND SEASONAL DIFFERENCES



COMBINED CYCLE SEASONAL DIFFERENCES

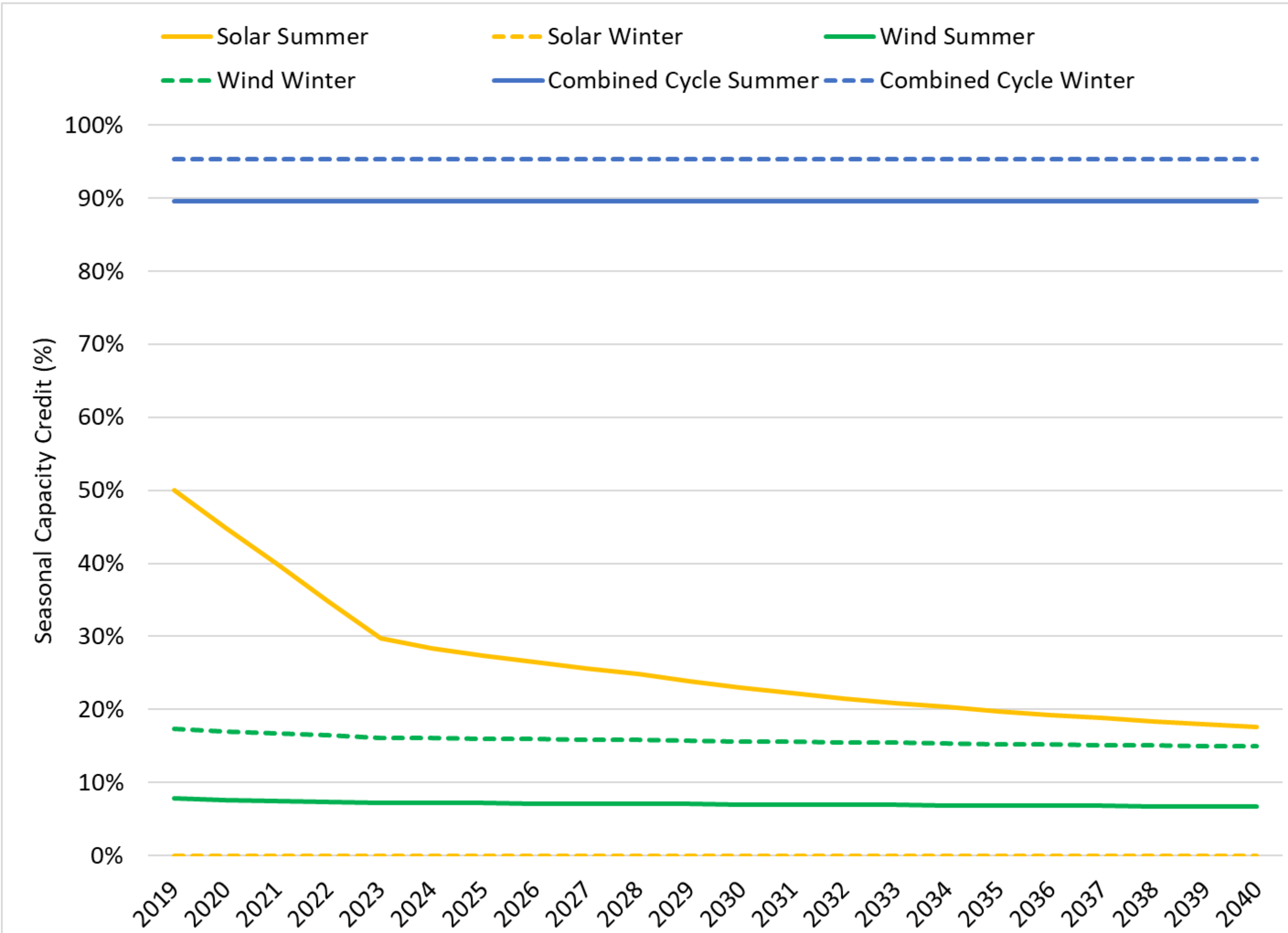


ZONE 6 SEASONAL ACCREDITATION



Winter accreditation based on similar methodology to summer

SEASONAL CAPACITY CREDIT FORECAST

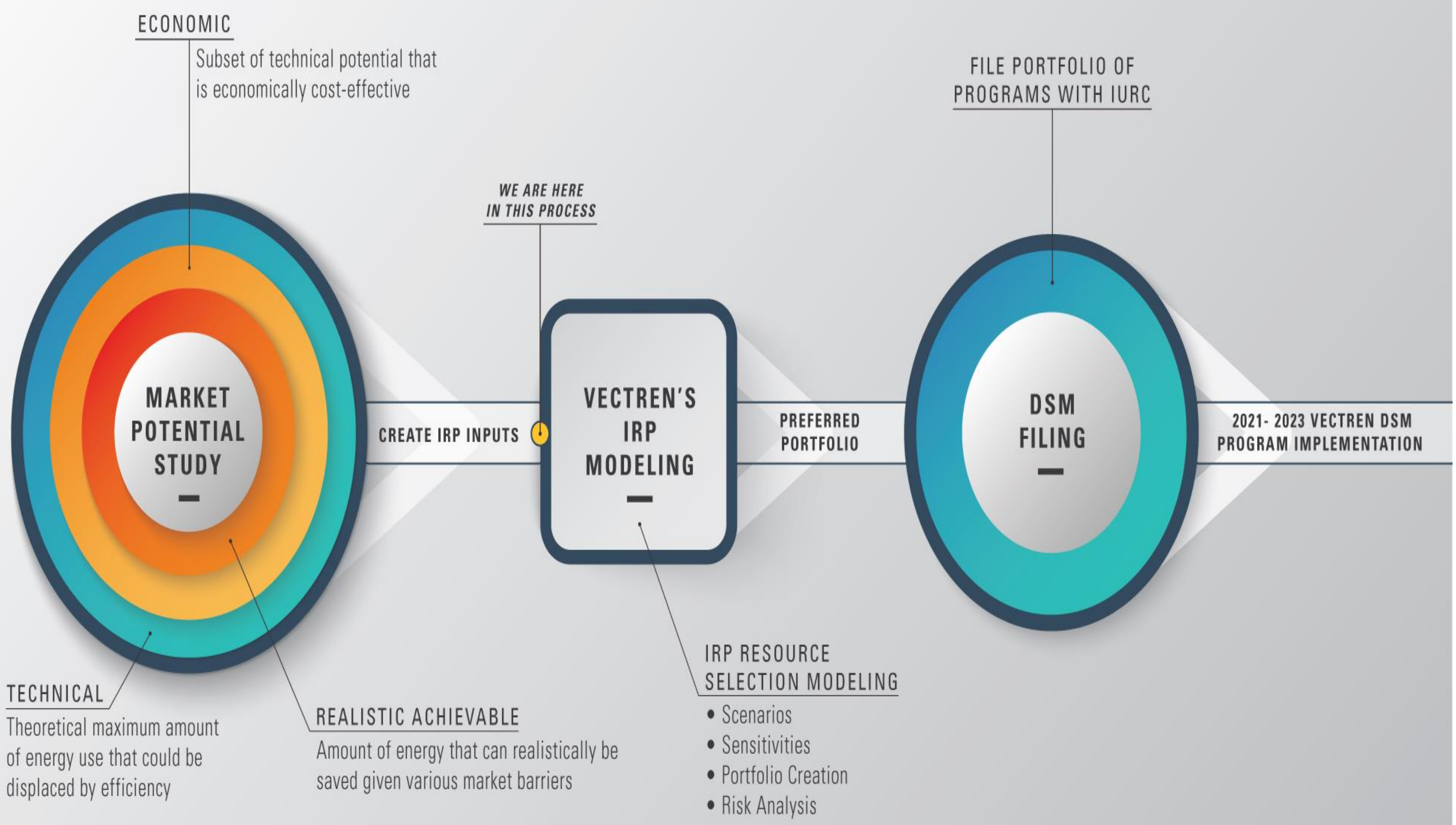


DSM MODELING IN THE IRP

JEFFREY HUBER

MANAGING DIRECTOR, GDS ASSOCIATES

Demand Side Management Process (DSM) and the Integrated Resources Plan (IRP)



ENERGY EFFICIENCY MODELING ASSUMPTIONS

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No minimum level of EE has been embedded into our sales and demand forecast

EE savings for 2018-2020 will be based on EE plan approved in Cause 44927

Total of 10 bundles, of which 8 can be selected including DR.

7 EE bundles are available at 0.25% of eligible sales

The model may select up to 1.75% of eligible sales annually. Aligns with realistic achievable potential in MPS

EE bundles represent bundle of low cost to high cost programs

For optimization runs, EE bundle selection will run for a 3 year period for the 1st 6 years

IMPROVEMENTS SUMMARY

- 2019 modeled savings and costs will tie directly to latest Market Potential Study (completed 2019)
  - MPS analysis reliant on empirical/historical data derived from DSM effects by Vectren customers
- Initial years savings disconnected from later years
- Utilize bundle specific load shapes
- Include demand response bundles
- Conduct sensitivities

DSM BUNDLES IN IRP MODELING APPROACH OVERVIEW

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BASE CASE

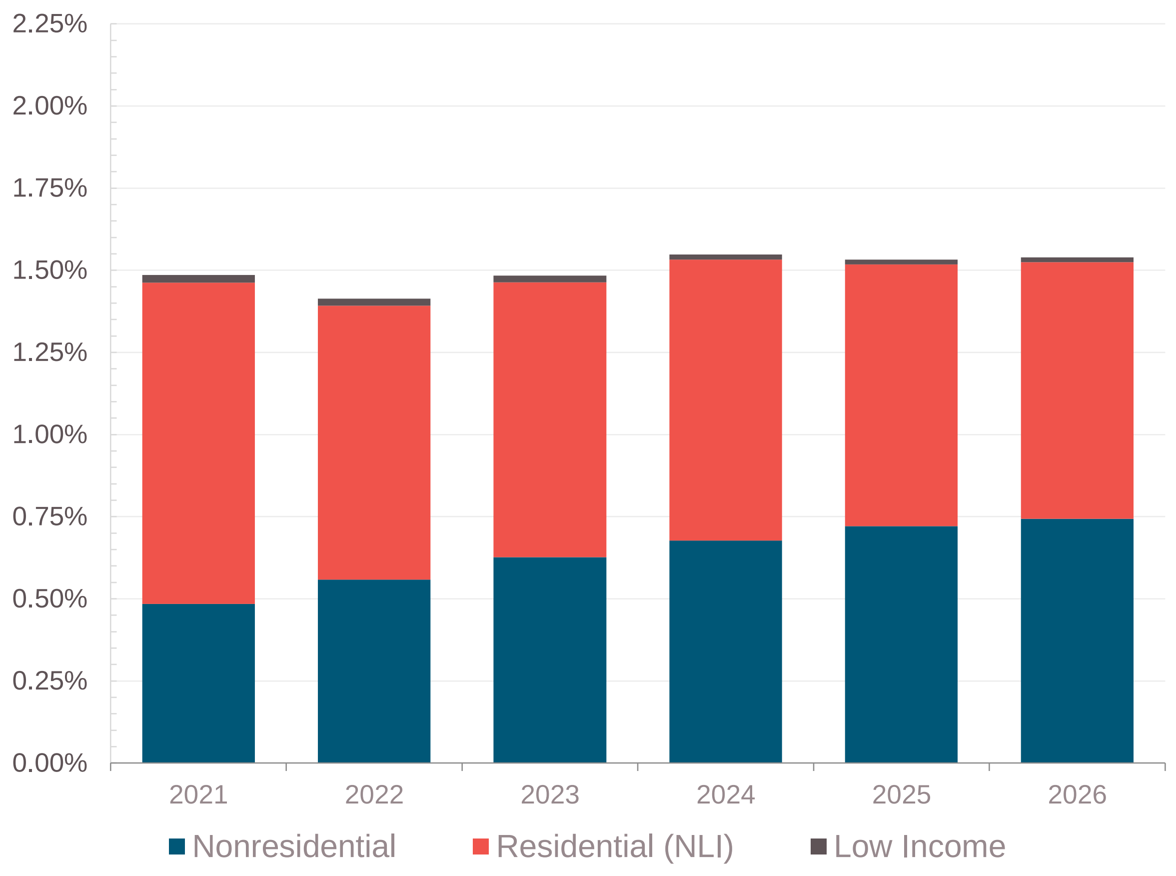
- DSM Bundles are 0.25% of annual load excluding opt-out sales
- Bundles are developed using the results from the 2018 Market Potential Study's (MPS) Realistic Achievable Potential
- Each bundle can have a mixture of residential and non-residential electric energy efficiency measures
- Each bundle has an associated loadshape and cost/MWh that serves as inputs into the IRP model
- Up to 10 bundles will be included as a selectable resource in the IRP model
    - 7 Energy Efficiency
    - 1 Low income
    - 2 Demand Response

DSM BUNDLES IN IRP MODELING INCREMENTAL SAVINGS FROM MPS

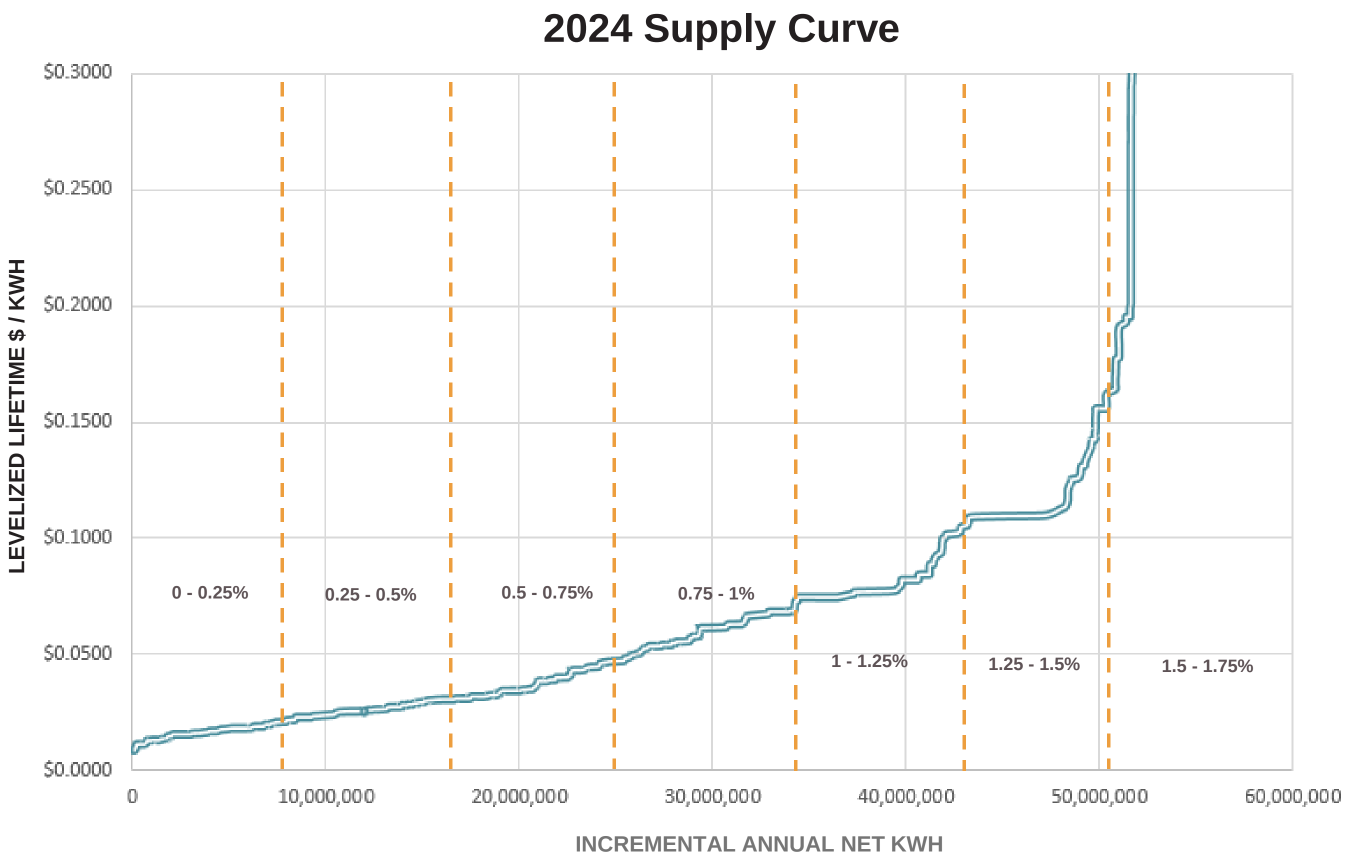
Step 1: *Initial RAP Potential Estimates from MPS*

Step 2: *Apply NTG Ratios (used latest evaluated NTG ratios)*

Step 3: *Align Low Income Savings based on Historcal Spend*



DSM BUNDLES IN IRP MODELING SUPPLY CURVE BUNDLE DEVELOPMENT



- Residential and Non-residential electric energy efficiency measures were ranked from cheapest to most expensive
- Measures were then bundled into groups of roughly 0.25% ***net*** energy savings, with each progressive bundle more expensive then the prior bundle
- Total amount of savings (and # of bundles) is dependent on the realistic achievable potential identified each year
- In 2024 example, the RAP allows for 6 complete bundles, and a partial 7th bundle

DSM BUNDLES IN IRP MODELING
BASE CASE LEVELIZED COST PER KWH

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	1	2	3	4	5	6	7	LI
	Gross Projected Cost per KWh; Cumulative by Bundle							
2021	$0.0144	$0.0189	$0.0209	$0.0240	$0.0279	$0.0328		$0.1517
2022	$0.0144	$0.0189	$0.0226	$0.0266	$0.0300	$0.0347		$0.1670
2023	$0.0147	$0.0190	$0.0226	$0.0271	$0.0314	$0.0359		$0.1839
2024	$0.0151	$0.0188	$0.0228	$0.0279	$0.0326	$0.0348	$0.0374	$0.2115
2025	$0.0156	$0.0204	$0.0244	$0.0298	$0.0346	$0.0381	$0.0390	$0.2265
2026	$0.0160	$0.0212	$0.0258	$0.0312	$0.0360	$0.0396	$0.0406	$0.2398
2027	$0.0166	$0.0223	$0.0269	$0.0329	$0.0376	$0.0411	$0.0421	$0.2583
2028	$0.0172	$0.0235	$0.0288	$0.0342	$0.0393	$0.0429	$0.0442	$0.2630
2029	$0.0181	$0.0245	$0.0306	$0.0367	$0.0410	$0.0454		$0.2648
2030	$0.0190	$0.0268	$0.0318	$0.0371	$0.0424	$0.0474		$0.2608
2031	$0.0198	$0.0277	$0.0325	$0.0390	$0.0436	$0.0482		$0.2686
2032	$0.0208	$0.0286	$0.0353	$0.0409	$0.0455	$0.0506		$0.2459
2033	$0.0220	$0.0297	$0.0373	$0.0439	$0.0470	$0.0520		$0.2494
2034	$0.0228	$0.0307	$0.0394	$0.0455	$0.0487	$0.0539		$0.2164
2035	$0.0188	$0.0243	$0.0294	$0.0366	$0.0420	$0.0441	$0.0491	$0.2411
2036	$0.0190	$0.0241	$0.0291	$0.0363	$0.0413	$0.0441	$0.0491	$0.2538
2037	$0.0190	$0.0242	$0.0291	$0.0357	$0.0412	$0.0442	$0.0490	$0.2064
2038	$0.0198	$0.0233	$0.0294	$0.0353	$0.0406	$0.0452	$0.0499	$0.2118
2039	$0.0206	$0.0238	$0.0302	$0.0354	$0.0415	$0.0459	$0.0505	$0.2175

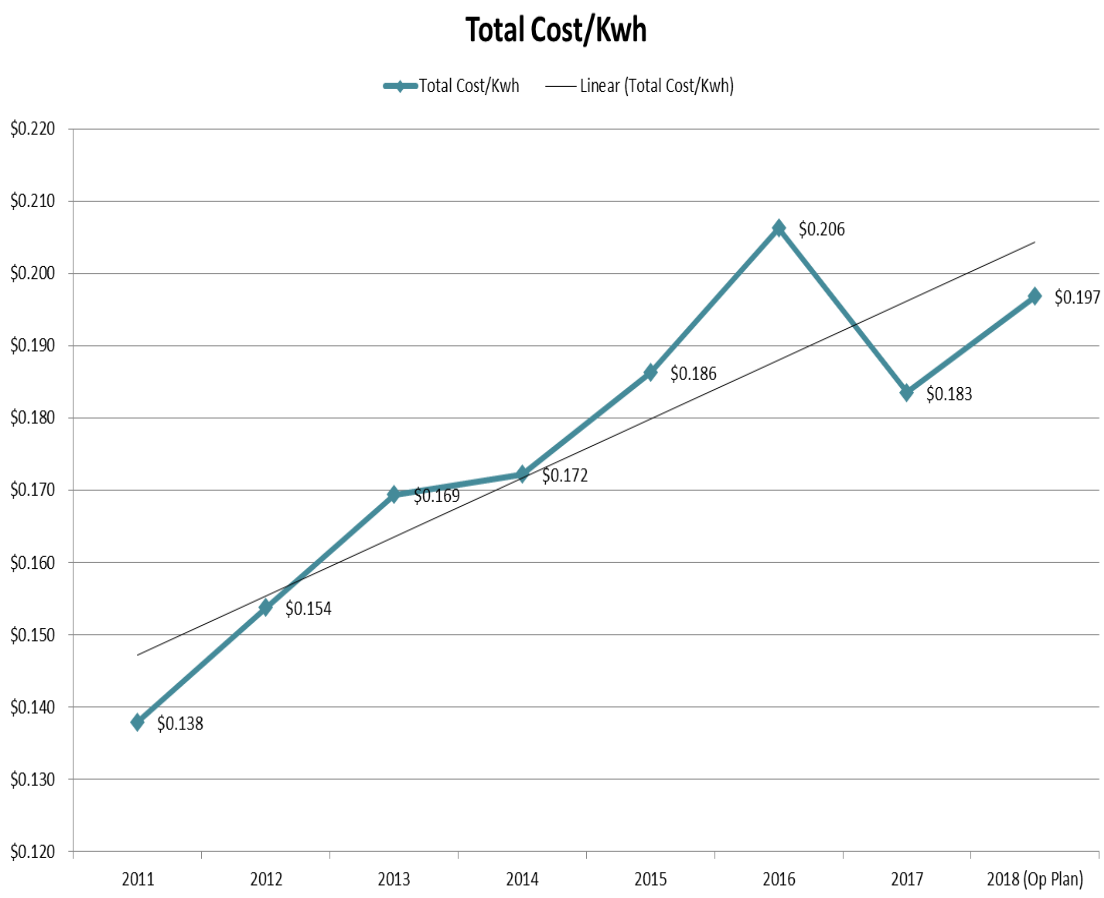
- LI Costs reflect paying 100% incentives for measures.
- Aligned to historical levels to produce an annual budget of $1.15 million per year
- Annual savings range from 457 MWh to 889 MWh

- Cost per bundle and annual costs are based on 2018 MPS costs, with two exceptions:
- IRP bundles reduced non-residential incentive costs in early years to more closely align with historical and 2019 planned Vectren data
- Non-incentive program costs were escalated at an annual estimated rate of inflation of 2.2% (in lieu of 1.6%) to be consistent with other IRP planning assumptions

DSM BUNDLES IN IRP MODELING
DSM BUNDLE SENSITIVITIES

HIGH/LOW CASE

- Sensitivity to reflect alternative DSM Costs
- Used 2011-2018 actual portfolio costs Calculated one standard deviation from the mean ($0.02097)
- Results in 11.9% increase/reduction in levelized cost
- No sensitivity performed on low-income potential



DSM BUNDLES IN IRP MODELING
DEMAND RESPONSE BUNDLES

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- Two Demand Response bundles
- First bundle includes AC DLC as well as Smart Thermostat DR (from Smart Cycle Program) (fixed)
  - Slow phase out of DLC Switch and replacement with Thermostat-controlled DR through 2039
  - Projected Summer Peak impacts range from 17.5 MW (2020) to 36.9 MW (2039)
- Second bundle include BYOT Thermostat DR (selectable)

FEEDBACK AND DISCUSSION

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STAKEHOLDER BREAKOUT SESSION: STRATEGY DEVELOPMENT

GARY VICINUS

MANAGING DIRECTOR FOR UTILITIES, PACE GLOBAL

STAKEHOLDER BREAKOUT SESSION

- The purpose of this breakout session is to allow stakeholders to discuss and develop several different strategies to meet load obligations over the next 20 years
- Specifically, stakeholders are asked to collaborate to develop alternative or additional strategies to the ones already being modeled, i.e. 80% reduction in CO_2 by 2050
- We will run a least-cost portfolio run for various strategies
- Breakout Process:

1. Separate into groups
2. Discuss potential strategies to meet load obligations over the next 20 years, i.e. least cost, minimizing CO_2, diversification, etc.
3. Designate a spokes person for each table (those on the phone are welcome to send in suggestions at irp@centerpointenergy.com)
4. In the next meeting, strategies will be defined as model structures
5. Structures will be consolidated into several portfolios for further evaluation. We will take your into consideration and ultimately develop 10-15 portfolios for modeling. Final portfolios will be discussed in the third stakeholder meeting

PORTFOLIO STRATEGY WORKSHEET

Create a set of strategies for a portfolio and the timeframe for implementation:

Strategy	Timeframe

Short-term=2019-2021; Medium-term=2022-2028; Long-term=2029-2039

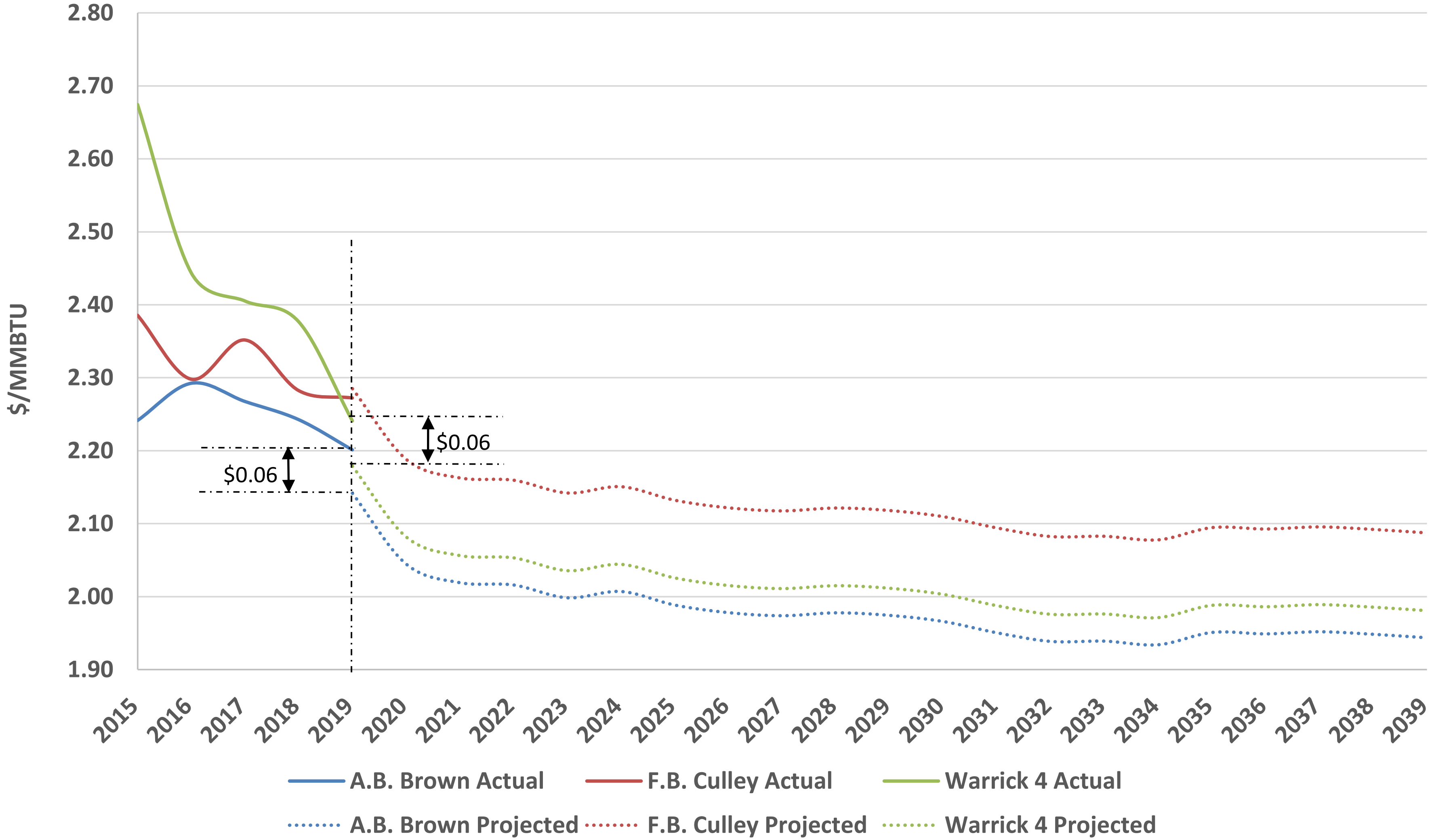
FEEDBACK AND DISCUSSION

APPENDIX

ADDITIONAL STAKEHOLDER FEEDBACK

Request	Response
Scenarios: Include the social cost of carbon.	Included in the High Regulatory scenario.
Portfolio development: Provide a list of potential portfolio strategies within the Q&A document to help groups prepare for the portfolio development workshop.	Included within meeting minutes Q&A posted to vectren.com/irp
Portfolio development: Flag portfolios that meet Intergovernmental Panel on Climate Change (IPCC) criteria.	IPCC criteria can be raised during the portfolio development discussion to ensure that we build portfolios that meet the criteria.
Listen to a local talk on Indiana Climate Change (Purdue).	Vectren attended the local meeting.
Please provide historic delivered coal prices, compared to projections	Please see the appendix for this slide.
Identify impacts on different customer groups (e.g. disadvantaged)	Price impacts are a big consideration within portfolio evaluation, captured in the scorecard. However, impacts of eventual rate making proceedings are not within scope of an IRP.
Post meeting minutes in Q&A format	Meeting minutes Q&A posted to vectren.com/irp

FOLLOW-UP QUESTION DELIVERED COAL COST



DRAFT BASE CASE INPUTS

Input	Unit	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
Coal (ILB mine)	2018$/MMBtu	1.78	1.66	1.64	1.63	1.61	1.61	1.59	1.58	1.59	1.59	1.58
CO2	2018$/ton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas (Henry Hub)	2018$/MMBtu	2.77	2.76	3.06	3.24	3.38	3.49	3.62	3.78	3.96	4.09	4.17
Vectren Peak Load	MW	1,115	1,102	1,168	1,176	1,183	1,192	1,200	1,209	1,219	1,229	1,239
Wind (200 MW)	2018$/kW	1,334	1,330	1,328	1,326	1,324	1,324	1,324	1,324	1,326	1,328	1,330
Solar (100 MW)	2018$/kW	1,524	1,362	1,290	1,247	1,204	1,162	1,129	1,100	1,070	1,050	1,029
Li-Ion Battery (50 MW, 4 hr)	2018$/kW	2,088	1,811	1,654	1,518	1,452	1,391	1,342	1,301	1,263	1,232	1,201
Flow Battery (50 MW, 6 hr)	2018$/kW	2,968	2,665	2,450	2,242	2,116	1,996	1,892	1,803	1,719	1,651	1,586
Gas CC (442 MW + DF)	2018$/kW	1,122	1,114	1,100	1,088	1,079	1,072	1,063	1,056	1,049	1,042	1,034
Gas CT (237 MW)	2018$/kW	548	544	536	529	525	521	517	513	510	506	502
USC Coal w/ CCS	2018$/kW	5,421	5,339	5,231	5,121	5,016	4,916	4,814	4,717	4,624	4,531	4,445

DRAFT LOW REGULATORY CASE INPUTS

Input	Unit	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
Coal (ILB mine)	2018$/MMBtu	1.78	1.66	1.64	1.63	1.61	1.61	1.59	1.58	1.59	1.59	1.58
CO2	2018$/ton	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas (Henry Hub)	2018$/MMBtu	2.77	2.76	4.10	5.12	5.20	5.62	5.60	5.95	6.12	6.23	6.85
Vectren Peak Load	MW	1,115	1,102	1,217	1,311	1,314	1,352	1,357	1,390	1,381	1,386	1,423
Wind (200 MW)	2018$/kW	1,334	1,330	1,328	1,326	1,324	1,324	1,324	1,324	1,326	1,328	1,330
Solar (100 MW)	2018$/kW	1,524	1,362	1,290	1,247	1,204	1,162	1,129	1,100	1,070	1,050	1,029
Li-Ion Battery (50 MW, 4 hr)	2018$/kW	2,088	1,811	1,654	1,518	1,452	1,391	1,342	1,301	1,263	1,232	1,201
Flow Battery (50 MW, 6 hr)	2018$/kW	2,968	2,665	2,450	2,242	2,116	1,996	1,892	1,803	1,719	1,651	1,586
Gas CC (442 MW + DF)	2018$/kW	1,122	1,114	1,100	1,088	1,079	1,072	1,063	1,056	1,049	1,042	1,034
Gas CT (237 MW)	2018$/kW	548	544	536	529	525	521	517	513	510	506	502
USC Coal w/ CCS	2018$/kW	5,421	5,339	5,231	5,121	5,016	4,916	4,814	4,717	4,624	4,531	4,445

DRAFT HIGH TECHNOLOGY CASE INPUTS

Input	Unit	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
Coal (ILB mine)	2018$/MMBtu	1.78	1.66	1.49	1.27	1.25	1.25	1.25	1.25	1.25	1.25	1.25
CO2	2018$/ton	0.00	0.00	0.00	1.20	2.06	2.38	2.94	3.89	5.46	6.85	8.50
Gas (Henry Hub)	2018$/MMBtu	2.77	2.76	2.82	2.33	2.13	2.04	2.13	2.02	2.12	2.07	2.20
Vectren Peak Load	MW	1,115	1,102	1,217	1,311	1,314	1,352	1,357	1,390	1,381	1,386	1,423
Wind (200 MW)	2018$/kW	1,334	1,330	1,249	1,167	1,123	1,160	1,152	1,166	1,139	1,142	1,143
Solar (100 MW)	2018$/kW	1,524	1,362	1,202	1,041	1,026	999	952	929	866	856	865
Li-Ion Battery (50 MW, 4 hr)	2018$/kW	2,088	1,811	1,513	1,214	1,156	1,096	1,042	965	928	901	894
Flow Battery (50 MW, 6 hr)	2018$/kW	2,968	2,665	2,220	1,774	1,678	1,538	1,408	1,231	1,268	1,124	1,020
Gas CC (442 MW + DF)	2018$/kW	1,122	1,114	1,100	1,088	1,079	1,072	1,063	1,056	1,049	1,042	1,034
Gas CT (237 MW)	2018$/kW	548	544	536	529	525	521	517	513	510	506	502
USC Coal w/ CCS	2018$/kW	5,421	5,339	5,231	5,121	5,016	4,916	4,814	4,717	4,624	4,531	4,445

80% REDUCTION CASE INPUTS

Input	Unit	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
Coal (ILB mine)	2018$/MMBtu	1.78	1.66	1.49	1.27	1.25	1.25	1.25	1.25	1.25	1.25	1.25
CO2	2018$/ton	0.00	0.00	0.00	3.57	5.10	6.63	7.65	9.18	11.22	14.79	19.89
Gas (Henry Hub)	2018$/MMBtu	2.77	2.76	3.06	3.24	3.38	3.49	3.62	3.78	3.96	4.09	4.17
Vectren Peak Load	MW	1,115	1,102	1,131	1,060	1,025	1,039	1,038	1,038	1,053	1,053	1,065
Wind (200 MW)	2018$/kW	1,334	1,330	1,249	1,167	1,123	1,160	1,152	1,166	1,139	1,142	1,143
Solar (100 MW)	2018$/kW	1,524	1,362	1,202	1,041	1,026	999	952	929	866	856	865
Li-Ion Battery (50 MW, 4 hr)	2018$/kW	2,088	1,811	1,513	1,214	1,156	1,096	1,042	965	928	901	894
Flow Battery (50 MW, 6 hr)	2018$/kW	2,968	2,665	2,220	1,774	1,678	1,538	1,408	1,231	1,268	1,124	1,020
Gas CC (442 MW + DF)	2018$/kW	1,122	1,114	1,100	1,088	1,079	1,072	1,063	1,056	1,049	1,042	1,034
Gas CT (237 MW)	2018$/kW	548	544	536	529	525	521	517	513	510	506	502
USC Coal w/ CCS	2018$/kW	5,421	5,339	5,231	5,121	5,016	4,916	4,814	4,717	4,624	4,531	4,445

DRAFT HIGH REGULATORY CASE INPUTS

Input	Unit	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039
Coal (ILB mine)	2018$/MMBtu	1.78	1.66	1.49	1.27	1.25	1.25	1.25	1.25	1.25	1.25	1.25
CO2	2018$/ton	0.00	0.00	50.40	52.28	54.17	56.05	57.94	60.06	62.41	64.77	67.12
Gas (Henry Hub)	2018$/MMBtu	2.77	2.76	4.39	6.03	7.10	8.37	7.17	8.40	8.95	8.75	8.63
Vectren Peak Load	MW	1,115	1,102	1,168	1,176	1,183	1,192	1,200	1,209	1,219	1,229	1,239
Wind (200 MW)	2018$/kW	1,334	1,330	1,249	1,167	1,123	1,160	1,152	1,166	1,139	1,142	1,143
Solar (100 MW)	2018$/kW	1,524	1,362	1,202	1,041	1,026	999	952	929	866	856	865
Li-Ion Battery (50 MW, 4 hr)	2018$/kW	2,088	1,811	1,513	1,214	1,156	1,096	1,042	965	928	901	894
Flow Battery (50 MW, 6 hr)	2018$/kW	2,968	2,665	2,220	1,774	1,678	1,538	1,408	1,231	1,268	1,124	1,020
Gas CC (442 MW + DF)	2018$/kW	1,122	1,114	1,100	1,088	1,079	1,072	1,063	1,056	1,049	1,042	1,034
Gas CT (237 MW)	2018$/kW	548	544	536	529	525	521	517	513	510	506	502
USC Coal w/ CCS	2018$/kW	5,421	5,339	5,231	5,121	5,016	4,916	4,814	4,717	4,624	4,531	4,445

DSM BUNDLES IN IRP MODELING
DSM BUNDLE SENSITIVITIES

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	1	2	3	4	5	6	7
	Gross Projected Cost per KWh; Cumulative by Bundle (LOW CASE)						
2021	$0.01270	$0.01668	$0.01840	$0.02112	$0.02461	$0.02891	
2022	$0.01265	$0.01660	$0.01992	$0.02346	$0.02643	$0.03053	
2023	$0.01298	$0.01676	$0.01994	$0.02385	$0.02764	$0.03165	
2024	$0.01332	$0.01654	$0.02009	$0.02460	$0.02868	$0.03064	$0.03291
2025	$0.01374	$0.01798	$0.02149	$0.02623	$0.03043	$0.03356	$0.03434
2026	$0.01408	$0.01872	$0.02274	$0.02744	$0.03172	$0.03487	$0.03578
2027	$0.01461	$0.01964	$0.02373	$0.02895	$0.03316	$0.03623	$0.03708
2028	$0.01515	$0.02067	$0.02537	$0.03010	$0.03460	$0.03783	$0.03895
2029	$0.01593	$0.02158	$0.02695	$0.03237	$0.03616	$0.03999	
2030	$0.01671	$0.02358	$0.02804	$0.03272	$0.03732	$0.04174	
2031	$0.01742	$0.02439	$0.02864	$0.03436	$0.03838	$0.04250	
2032	$0.01829	$0.02515	$0.03111	$0.03605	$0.04009	$0.04459	
2033	$0.01942	$0.02617	$0.03285	$0.03866	$0.04136	$0.04582	
2034	$0.02010	$0.02701	$0.03467	$0.04009	$0.04292	$0.04749	
2035	$0.01656	$0.02140	$0.02586	$0.03225	$0.03697	$0.03889	$0.04328
2036	$0.01674	$0.02122	$0.02561	$0.03197	$0.03641	$0.03886	$0.04329
2037	$0.01670	$0.02129	$0.02566	$0.03146	$0.03627	$0.03897	$0.04315
2038	$0.01742	$0.02048	$0.02591	$0.03110	$0.03577	$0.03984	$0.04399
2039	$0.01814	$0.02097	$0.02656	$0.03122	$0.03652	$0.04043	$0.04449

	1	2	3	4	5	6	7
	Gross Projected Cost per KWh; Cumulative by Bundle (HIGH CASE)						
2021	$0.01613	$0.02119	$0.02337	$0.02682	$0.03126	$0.03673	
2022	$0.01607	$0.02109	$0.02530	$0.02979	$0.03357	$0.03877	
2023	$0.01649	$0.02129	$0.02533	$0.03029	$0.03510	$0.04020	
2024	$0.01691	$0.02100	$0.02552	$0.03125	$0.03643	$0.03892	$0.04181
2025	$0.01745	$0.02283	$0.02730	$0.03332	$0.03866	$0.04262	$0.04362
2026	$0.01788	$0.02377	$0.02888	$0.03486	$0.04029	$0.04429	$0.04544
2027	$0.01856	$0.02495	$0.03014	$0.03677	$0.04212	$0.04601	$0.04710
2028	$0.01924	$0.02626	$0.03222	$0.03823	$0.04394	$0.04805	$0.04947
2029	$0.02023	$0.02742	$0.03423	$0.04111	$0.04593	$0.05080	
2030	$0.02122	$0.02995	$0.03561	$0.04156	$0.04740	$0.05302	
2031	$0.02212	$0.03098	$0.03638	$0.04364	$0.04875	$0.05398	
2032	$0.02323	$0.03195	$0.03951	$0.04579	$0.05092	$0.05663	
2033	$0.02466	$0.03324	$0.04173	$0.04911	$0.05253	$0.05820	
2034	$0.02553	$0.03431	$0.04404	$0.05092	$0.05452	$0.06032	
2035	$0.02103	$0.02718	$0.03284	$0.04096	$0.04696	$0.04939	$0.05498
2036	$0.02126	$0.02695	$0.03253	$0.04060	$0.04625	$0.04936	$0.05499
2037	$0.02121	$0.02704	$0.03259	$0.03996	$0.04607	$0.04949	$0.05480
2038	$0.02212	$0.02601	$0.03291	$0.03950	$0.04544	$0.05060	$0.05587
2039	$0.02304	$0.02663	$0.03374	$0.03965	$0.04638	$0.05135	$0.05650

DSM BUNDLES IN IRP MODELING
BASE CASE LEVELIZED COST PER KWH

	1	2	3	4	5	6	7
	Gross Projected Cost per KWh; Cumulative by Bundle						
2021	$0.0144	$0.0189	$0.0209	$0.0240	$0.0279	$0.0328	
2022	$0.0144	$0.0189	$0.0226	$0.0266	$0.0300	$0.0347	
2023	$0.0147	$0.0190	$0.0226	$0.0271	$0.0314	$0.0359	
2024	$0.0151	$0.0188	$0.0228	$0.0279	$0.0326	$0.0348	$0.0374
2025	$0.0156	$0.0204	$0.0244	$0.0298	$0.0346	$0.0381	$0.0390
2026	$0.0160	$0.0212	$0.0258	$0.0312	$0.0360	$0.0396	$0.0406
2027	$0.0166	$0.0223	$0.0269	$0.0329	$0.0376	$0.0411	$0.0421
2028	$0.0172	$0.0235	$0.0288	$0.0342	$0.0393	$0.0429	$0.0442
2029	$0.0181	$0.0245	$0.0306	$0.0367	$0.0410	$0.0454	
2030	$0.0190	$0.0268	$0.0318	$0.0371	$0.0424	$0.0474	
2031	$0.0198	$0.0277	$0.0325	$0.0390	$0.0436	$0.0482	
2032	$0.0208	$0.0286	$0.0353	$0.0409	$0.0455	$0.0506	
2033	$0.0220	$0.0297	$0.0373	$0.0439	$0.0470	$0.0520	
2034	$0.0228	$0.0307	$0.0394	$0.0455	$0.0487	$0.0539	
2035	$0.0188	$0.0243	$0.0294	$0.0366	$0.0420	$0.0441	$0.0491
2036	$0.0190	$0.0241	$0.0291	$0.0363	$0.0413	$0.0441	$0.0491
2037	$0.0190	$0.0242	$0.0291	$0.0357	$0.0412	$0.0442	$0.0490
2038	$0.0198	$0.0233	$0.0294	$0.0353	$0.0406	$0.0452	$0.0499
2039	$0.0206	$0.0238	$0.0302	$0.0354	$0.0415	$0.0459	$0.0505

	1	2	3	4	5	6	7	8
	2016 Projected Cost per kWh (Cumulative)							
2017	$0.03462	$0.03480	$0.03498	$0.03516	$0.04402	$0.04998	$0.05429	$0.05756
2018	$0.03607	$0.03626	$0.03645	$0.03664	$0.04547	$0.05142	$0.05572	$0.05899
2019	$0.03759	$0.03779	$0.03798	$0.03818	$0.04698	$0.05291	$0.05720	$0.06046
2020	$0.03917	$0.03938	$0.03958	$0.03979	$0.04855	$0.05446	$0.05873	$0.06197
2021	$0.04082	$0.04103	$0.04124	$0.04146	$0.05018	$0.05606	$0.06030	$0.06354
2022	$0.04254	$0.04276	$0.04298	$0.04320	$0.05187	$0.05771	$0.06193	$0.06514
2023	$0.04433	$0.04456	$0.04479	$0.04502	$0.05362	$0.05942	$0.06361	$0.06680
2024	$0.04619	$0.04643	$0.04667	$0.04691	$0.05544	$0.06118	$0.06534	$0.06851
2025	$0.04813	$0.04837	$0.04862	$0.04888	$0.05732	$0.06301	$0.06713	$0.07027
2026	$0.05016	$0.05042	$0.05068	$0.05094	$0.05928	$0.06491	$0.06898	$0.07209
2027	$0.05227	$0.05254	$0.05281	$0.05309	$0.06132	$0.06687	$0.07090	$0.07397
2028	$0.05447	$0.05475	$0.05503	$0.05532	$0.06343	$0.06890	$0.07286	$0.07589
2029	$0.05676	$0.05705	$0.05735	$0.05765	$0.06562	$0.07101	$0.07491	$0.07789
2030	$0.05914	$0.05945	$0.05976	$0.06007	$0.06789	$0.07318	$0.07702	$0.07995
2031	$0.06163	$0.06195	$0.06227	$0.06260	$0.07026	$0.07544	$0.07920	$0.08207
2032	$0.06422	$0.06456	$0.06489	$0.06523	$0.07271	$0.07777	$0.08145	$0.08426
2033	$0.06693	$0.06728	$0.06758	$0.06795	$0.07524	$0.08017	$0.08376	$0.08651
2034	$0.06974	$0.07010	$0.07046	$0.07083	$0.07790	$0.08269	$0.08618	$0.08885
2035	$0.07268	$0.07306	$0.07343	$0.07382	$0.08066	$0.08529	$0.08867	$0.09127
2036	$0.07573	$0.07613	$0.07652	$0.07692	$0.08351	$0.08798	$0.09125	$0.09375