NC ENERGY POLICY TASK FORCE

Tuesday, December 2, 2025 | 1:00 – 3:30 PM
NC Museum of Natural Sciences, Nature Research Center, 4th Floor
11 West Jones St., Raleigh, NC 27601 + WebEx
Co-Chairs: NC Representative Kyle Hall & DEQ Secretary Reid Wilson

Executive Summary

The Second NC Energy Policy Task Force meeting was called to order at 1:00 PM on December 2, 2025, including opening remarks from Task Force co-chairs Secretary Reid Wilson and Representative Kyle Hall.

The Task Force heard two expert presentations from the Indiana Office of Energy Development and the Virginia State Corporation Commission (SCC).

Luke Wilson, the Chief Policy Officer of the Indiana Office of Energy Development, presented on Indiana's energy landscape and recent legislative actions for responding to load growth. Indiana has seen steady and shallow load growth over the last decade. Between now and 2050, those changes are expected to be spiky. Additionally, after a period of steep electricity price increases between 2002 and 2016, prices in Indiana have leveled off, growing slower than the national average. Prices in Indiana now sit at 0.2 cents less per kWh than North Carolina.

Indiana recently passed House Enrolled Act 1007, which represents a comprehensive approach to managing load growth. It provides two options for interconnection of new large loads: new Large Load Customer CPCNs (certificate of public convenience and necessity) and Expedited Generation Resource (EGR) Plans.

- Large Load Customer CPCNs: this creates an expedited process for connecting new large loads of 150 MW or greater and represents a way to validate interconnection requests and data to mitigate the risk of large load speculation. It pairs customers with a new generation source, with the customer having to commit to covering at least 80% of cost regardless of end service time, and where the utility may require an additional risk premium for the project. Additionally, the utility must demonstrate how ratepayers are protected and the project must meet Indiana's 5 consumer protection pillars - affordability, reliability, resiliency, stability, and environmental sustainability.
- EGR Plans: an expedited portfolio approach ("a mini Integrated Resource Plan") for new large load customers that encourages utilities to think about how they will serve their new customer base. The utility submits an EGR plan to the Indiana Utility Regulatory Commission (IURC),

which has 90 days to approve. Once they have resources, size, and cost identified, the utility must demonstrate to the Commission how all ratepayers are protected.
- The Northern Indiana Public Service Company (NIPSCO) has elected to pursue Large Load Customer CPCNs, and Indiana Michigan Power is working on an EGR Plan.
- This approach has been carried out and approved by Indiana's legislature and utilities commission without major objection from its utility companies.

Task Force Members asked Luke Wilson about Indiana's CPCN process and fairly allocating network upgrades, the context and outcomes of the local permitting waiver referenced in his presentation, Indiana's sales tax exemption for data centers, the political and legislative environment of HEA 1007 and SB 425, and the State Utility Forecasting Group. Mr. Wilson's answers laid out more details of the CPCN process including rate cases; the importance of ensuring projects would materialize; the impacts of the sales tax exemption for data centers; the bipartisan nature of HEA 1007 and relevant utility support; and the 40-year history and nonpartisan, technical expertise of the State Utility Forecasting Group. Full questions and responses can be found below.

Commissioner Kelsey Bagot from the Virginia State Corporation Commission presented on Virginia's energy landscape and their responses to load growth, with a particular focus on data centers due to their preponderance in Northern Virginia and along the I-95 corridor. Virginia's utilities are Dominion and APCo, which are vertically integrated (though the state is part of the PJM market), and a large electric cooperative NOVEC, which has significant experience with data centers of the state's cooperative utilities due to its location in data center alley. Virginia has aggressive mandatory RPS requirements: Dominion must be 100% renewable by 2045; APCo has until 2050, and there are specific build requirements for in-state resources and purchased renewable energy credits (RECs).

Electricity demand in Virginia is increasing. While Virginia has had data centers for decades now, new builds are all 100 MW or more. Load growth forecasts have increased dramatically year over year. To address this, Dominion has created a specific large load interconnection queue. Estimates for data center load growth are anywhere between 200-400 data centers that would require 30-40 GW. They are projecting 7-12 years to get online for projects in the back of the queue. By 2045-2050, Virginia needs to build the equivalent of two new Florida Power and Lights. Electricity prices are also on the rise, likely both due to specific build requirements and gas retirements from the Virginia Clean Economy Act (VCEA) and due to rapid increase in data center interconnection.

The State Corporation Commission has taken a number of steps to maintain affordability in the face of these electricity sector pressures:
- Introduced a new rate class (GS-5) for very large loads: Loads greater than 25 MW with a load factor of 75% or higher are covered. Taking into account concerns about catching manufacturers in this rate class, the Virginia SCC concluded that 25 MW with this load factor requirement captures data centers and loads with similar characteristics. According to the study the Joint Legislative Audit and Review Commission (JLARC) conducted on data centers, current rates don't

include a subsidy for very large loads, but as more large loads come on, there could be a subsidy. During their proceedings, the Commission heard that the current GS-4 (large) rate class was masking a lot of subsidization of large loads.

- Currently, the SCC does not yet have enough information to propose a new rate structure. As such, it has directed Dominion in its next transmission rider and in its next biennial case to propose alternative cost allocation methodology. The SCC expects this submission in March 2026 and expects to set a new rate structure in June 2026.
- Took action to mitigate the risk of stranded assets: In addition to the new rate class, the SCC created a minimum demand threshold and 14-year contract term for large loads. There is an 85% minimum demand charge for transmission and distribution (T&D) and 60% for generation.
- Directed Dominion to file the rules of the road for the large load interconnection queue in February 2026: This will allow actors to weed out speculative projects and improve data access and forecasting accuracy.
- Scheduled a technical conference on data center flexibility in December 2025: The SCC hopes to investigate where large load customers can be grid assets and put downward pressure on rates. For example, “flexible flexibility” may allow data centers that are not willing to make their own load flexible to purchase flexibility through demand response and virtual power plant programs in the surrounding community.

Task Force Members asked Commissioner Bagot about the scope of the VCEA, the Commission’s ability to interpret statute of the VCEA as it pertains to sustainability and the procurement process, Virginia’s data center sales tax exemption, promising alternative cost of service methodology proposals raised in Commission proceedings, data center water use, and the outcomes and implementation details of the “flexible flexibility” mechanism proposed in the state. Commissioner Bagot’s answers included clarifying that VCEA directs investor-owned utilities (IOUs); a clarification that Virginia’s sales tax exemption is for computing equipment; a mention that most data centers in Virginia conserve water through closed-loop systems; and discussion about the upcoming technical conference to include information on flexible flexibility. Full questions and responses can be found below.

After the expert presentations, subcommittee co-chairs gave updates on their activities to date. The Technical Advisory Subcommittee Co-Chair, Joshua Brooks, gave an overview of the purpose of the modeling exercises and Members’ priorities and preferences for energy system scenarios, sensitivities, and cost assumptions to consider in the models. These include consideration of multiple large load forecasts, different cost assumptions for gas and nuclear resources, whether or not certain resources like hydrogen or pumped storage will come online, and whether there will be broad, economy-wide cost shifts in energy technologies.

The Load Growth Subcommittee Co-Chairs, Senator Julie Mayfield and Kathy Moyer, updated the Task Force on their committee activity, sharing that the Subcommittee Members had heard presentations from NC experts on load growth and economic development, including all four NC major electricity providers the NC Economic Development Partnership, and multiple large load customers with operations in NC. The Co-Chairs also shared background policy research on a wide range of levers that have been proposed or explored by Task Force Members or lawmakers in other states, and shared progress on the interim report due to the Governor, NCGA, NCUC, and Rural Electrification Authority on February 15, 2026.

Task Force Members then joined breakout groups for in-depth discussion on policy approaches. Groups were asked to discuss prioritization of various approaches to load growth, focusing on categories of cost allocation, on-site energy, grid capacity, and data access. The groups had robust conversations:

- Multiple groups consistently identified ideas inspired by Indiana and Virginia in their discussion, focusing on large load tariffs and green tariffs with particular specifications to capture loads of a certain size and load factor; the large load interconnection queue, to validate forecasting and weed out speculative interconnection requests; and requirements that customers pay a certain percentage of costs associated with interconnection in order to ensure "buy-in" and affordability
- There was also interest in load flexibility and Virginia's concept of flexible flexibility
- Some members also advocated for a more concise problem statement for the Task Force before recommending that entities pursue specific actions, and highlighted the importance of further monitoring challenges to understand the best policy approaches

The meeting adjourned with reminders for the next meetings and of the due date of the report deadline.

WELCOME AND OPENING REMARKS 1:00 PM – 1:05 PM
Representative Kyle Hall
Secretary Reid Wilson

The Co-Chairs expressed excitement about the work of the Task Force and highlighted a number of key issues: North Carolina has a growing population that may face energy and electricity challenges in the future; there is concern about subsidizing the expansion of electricity infrastructure; and it is important to keep North Carolina a good place to do business. The Co-Chairs also highlighted how much work the task force has already done, pointing to efforts to develop policy approaches and design modeling scenarios that have been undertaken by the Task Force's two subcommittees. Following opening remarks, staff called the roll, and the Co-Chairs read the conflict of interest policy and public records policy.

Roll call
Present:

- Sec. Reid Wilson
- Rep. Allen Chesser
- Rep. Pricey Harrison
- Sen. Julie Mayfield - online
- Matt Abele

- Chris Ayers
- Chris Carmody
- Chris Chung
- Christina Cress
- Katharine Kollins
- Steve Levitas
- Dana Magliola
- Mark McIntire
- Kathy Moyer
- Jennifer Mundt
- David Neal
- Tim Profeta - online
- Dave Rogers
- Will Scott
- Asher Spiller
- Don Stewart
- Winnie Wade
- Steve Wall
- Markus Wilhelm
- Rachel Wilson
- Michael Youth
- Ray Fakhoury - online

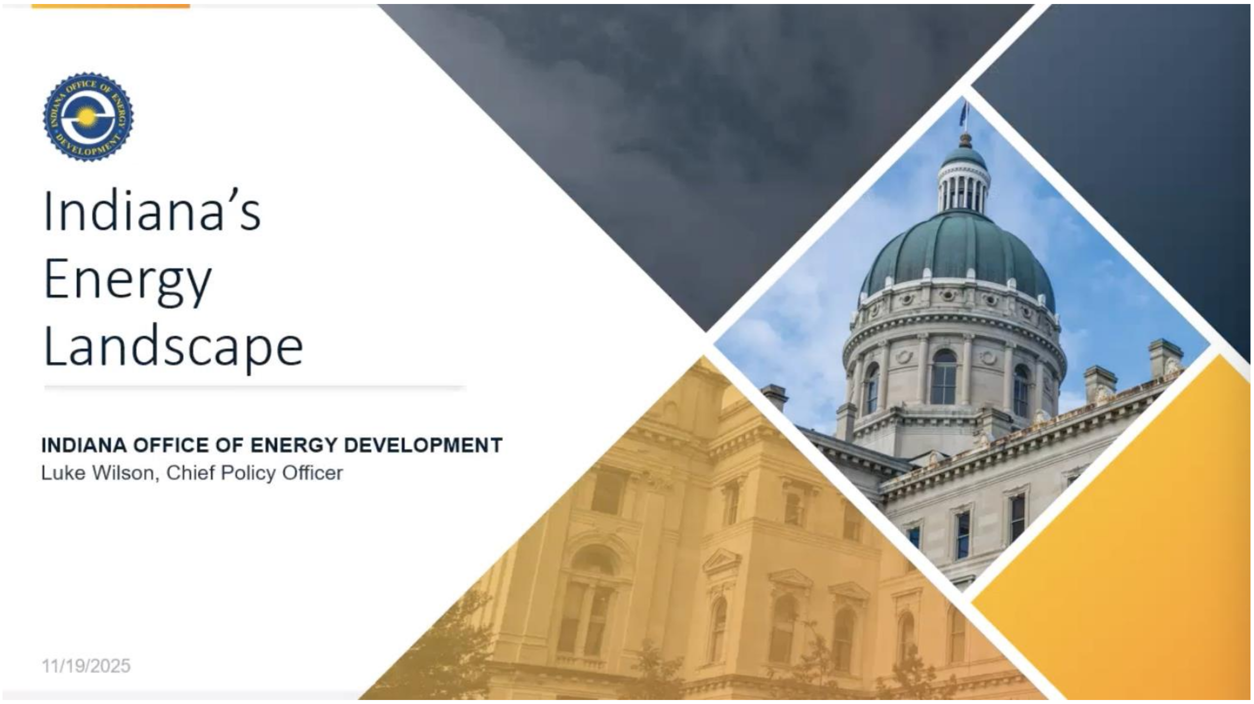
Absent:

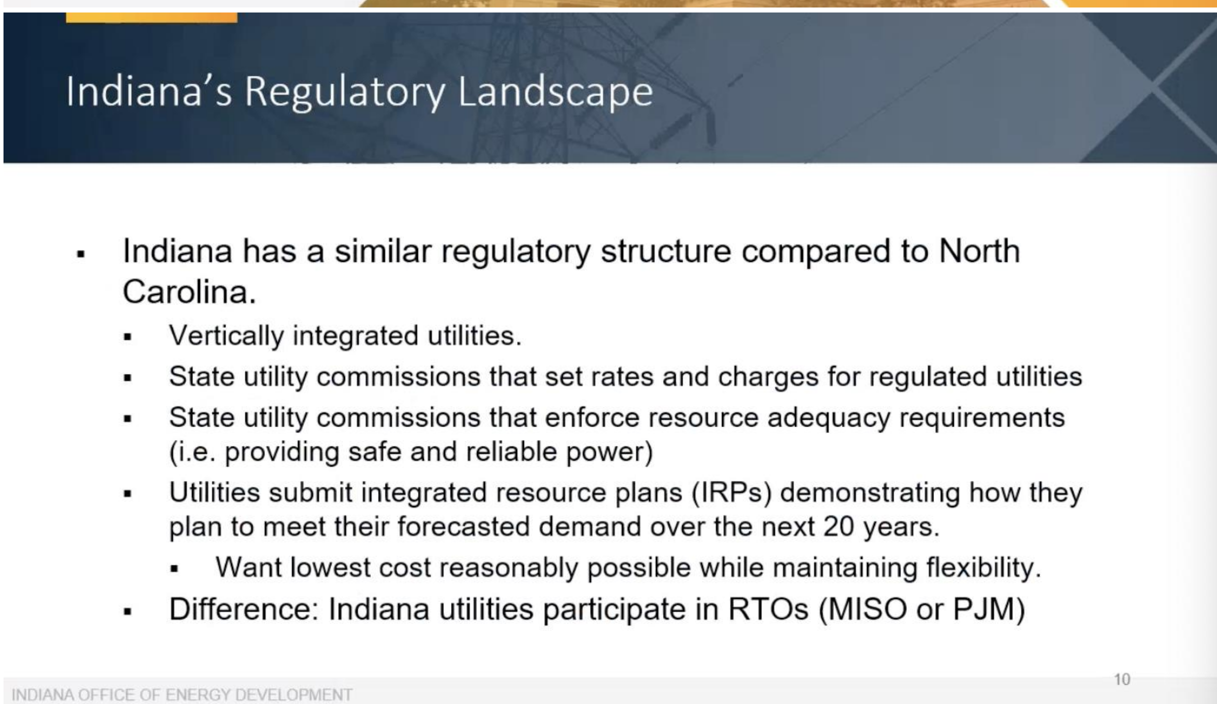
- Rep. Terry M. Brown
- Rep. Kyle Hall
- Sen. Michael Lazzara

PRESENTATIONS 1:05 PM - 2:05 PM

Luke Wilson, Chief Policy Officer,
Indiana Office of Energy Development

1:05 PM - 1:35 PM





- Verbal remarks reflected in slide

Indiana's Generation Fuel Mix

Indiana's Generation Fuel Mix

Resource	2007	2015	2024	Change
Coal	85.5%	68.5%	39.6%	-45.9%
Natural Gas	2.8%	14.2%	34.0%	31.2%
Nuclear	9.0%	9.9%	12.0%	3%
Wind	0%	4.0%	9.2%	9.2%
Solar	0%	0.1%	1.8%	1.8%
Other (e.g. hydro)	2.7%	3.3%	3.3%	0.6%

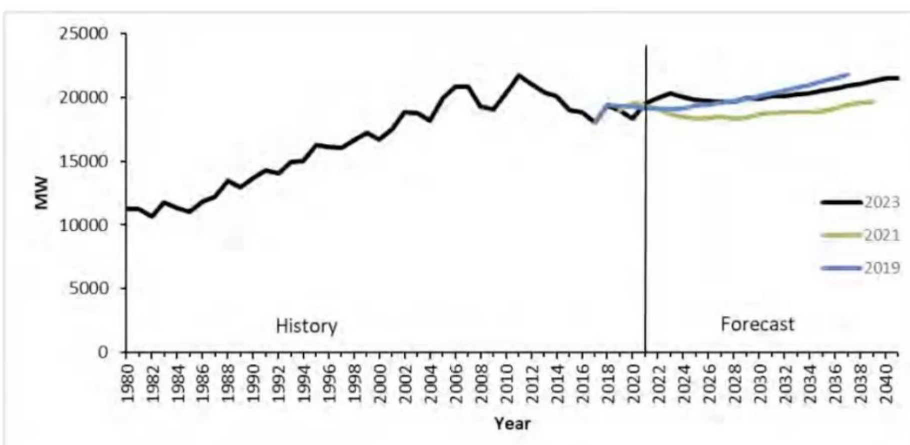
INDIANA OFFICE OF ENERGY DEVELOPMENT 11

- Slowly transitioning from coal into natural gas, solar and other resources
    - Solar has grown exponentially in the last 5 years

Energy prices and load growth:

Indiana Peak Load Growth

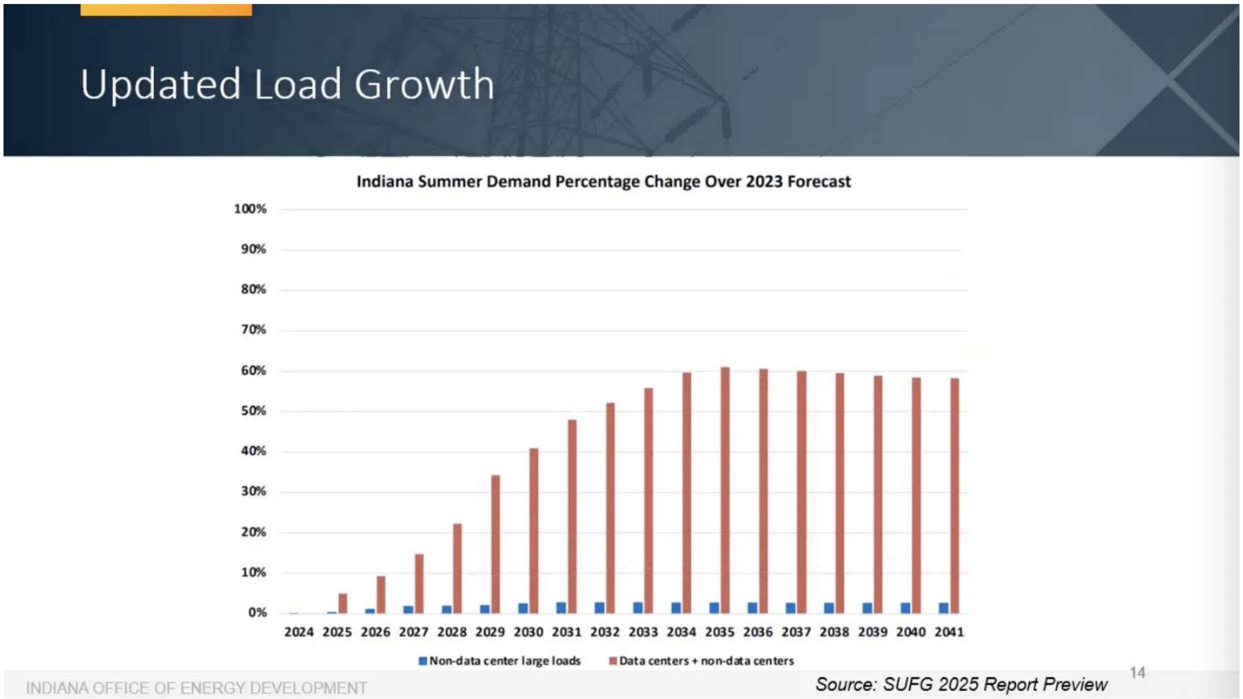
Figure 3-2. Indiana Peak Demand Requirements in MW (Historical, Current, and Previous Forecasts)



INDIANA OFFICE OF ENERGY DEVELOPMENT Source: SUFG 2023 Report 13

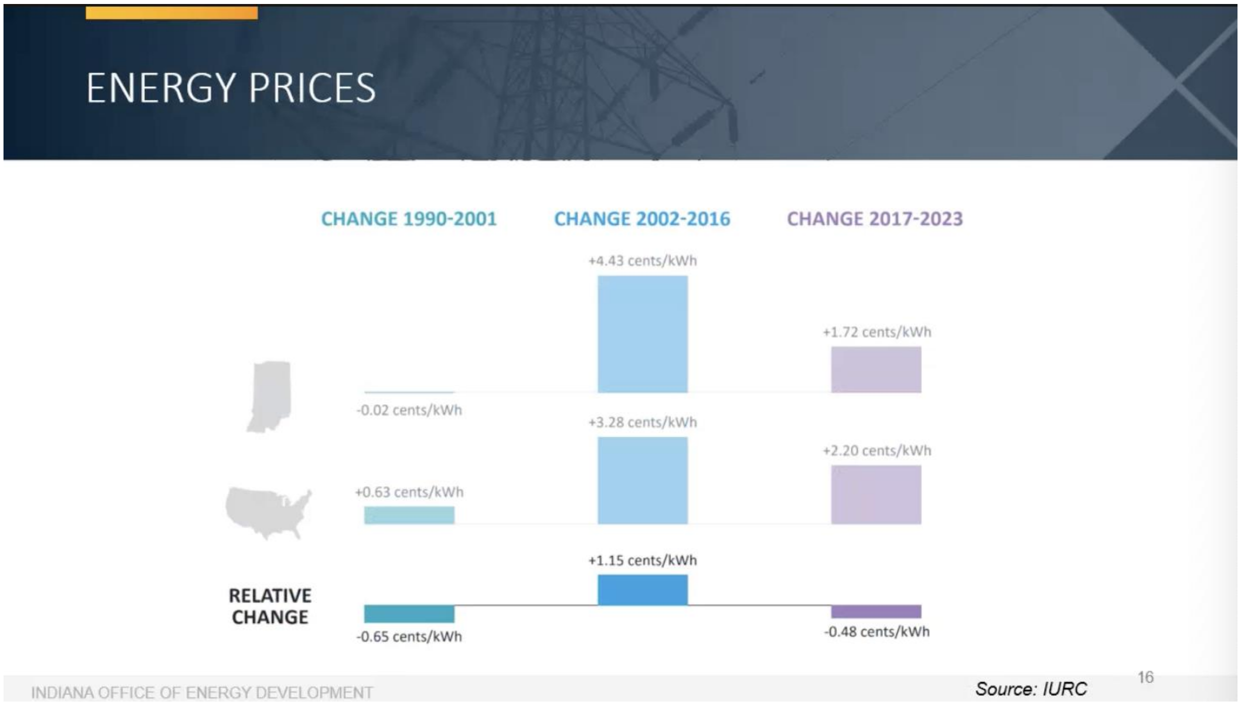
- A lot of energy efficiency measures
- Reached peak in the late 2000s/early 2010s; around the great recession
- Partner with Indiana State Utility Forecasting Group (SUFG) to project demand growth

- While high, forecasted demand is still not as high as it was during peak times around the great recession
- In the preview for the upcoming report, early 2030 is said to grow 60%

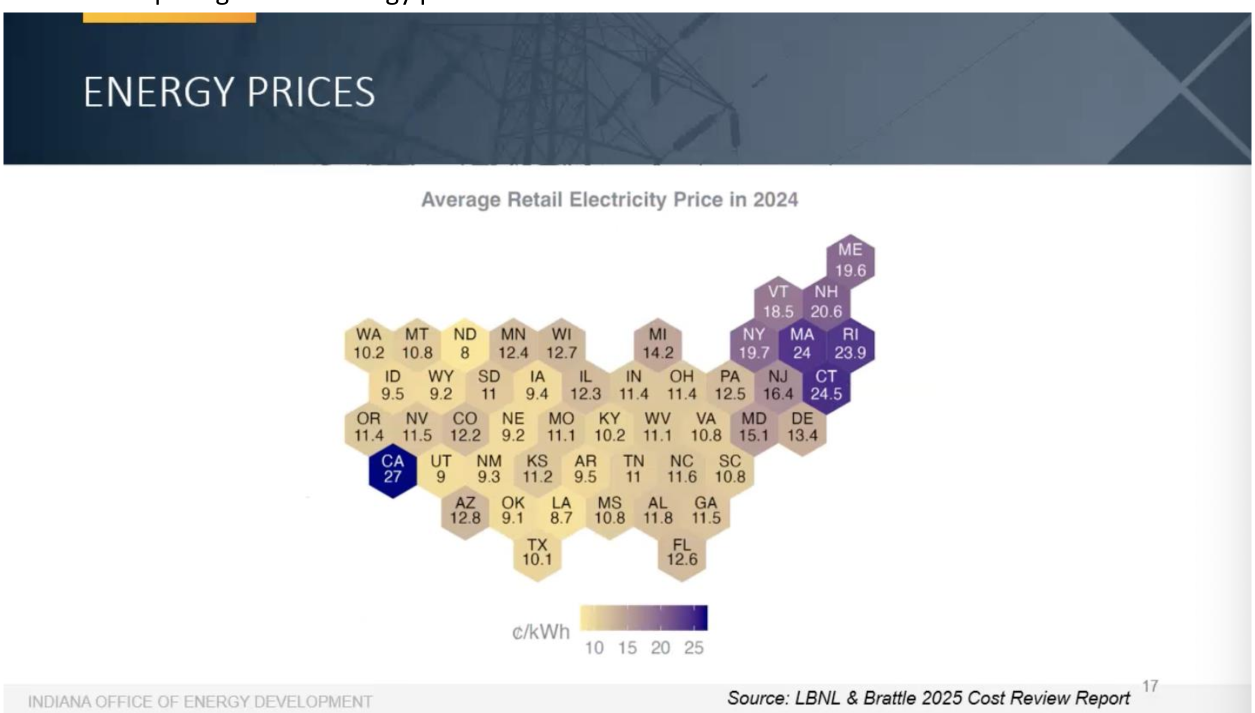


- State Utility Forecasting Group projects load growth peaking by 2035 or so

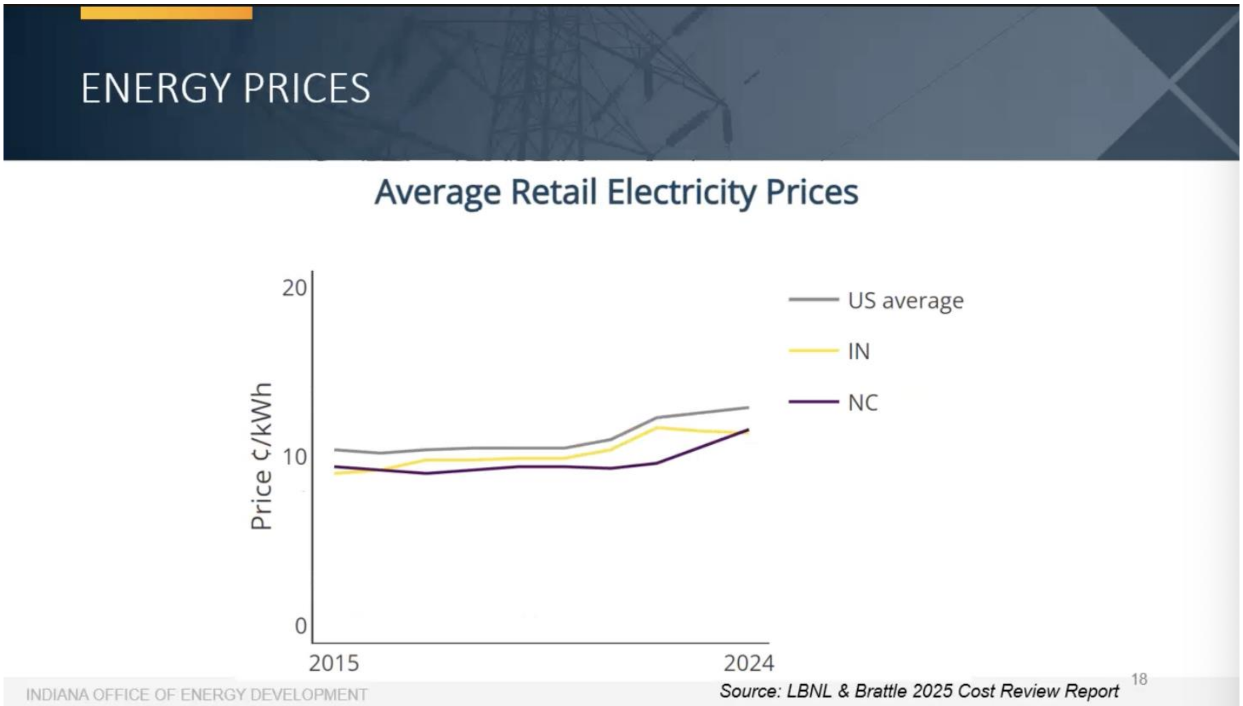
- Reporting erosion of rate competitiveness because of investing in coal units
  - Investing money to keep those plants running and recovering costs with fewer kilowatt hours of sales, so prices went up



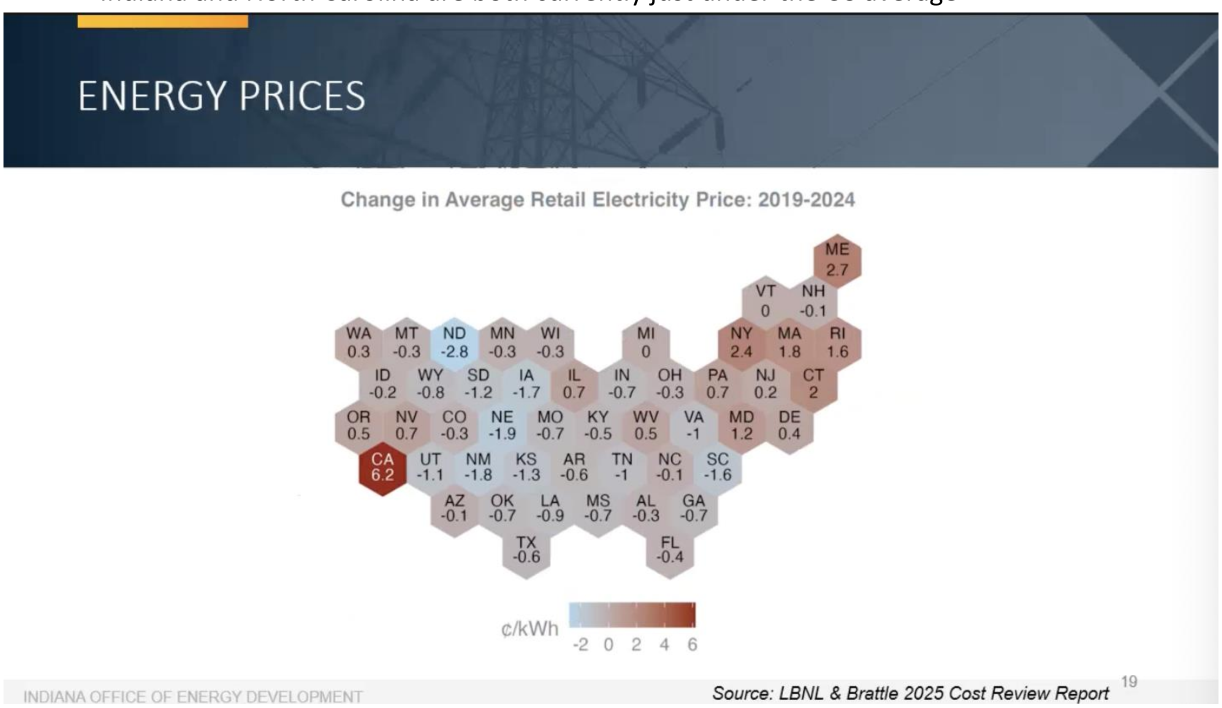
- Comparing Indiana energy prices to United States



- Overall, Indiana is competitive; 0.2 cents less per kilowatt hour than North Carolina



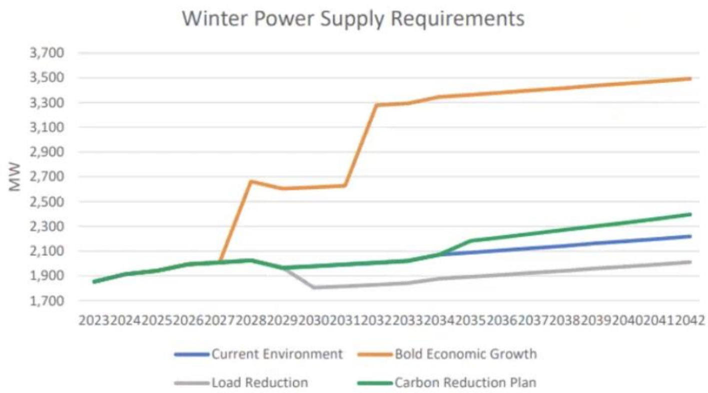
- Below US average
- North Carolina was more competitive than Indiana for a while
- Indiana and North Carolina are both currently just under the US average



- Inflation adjusted prices
- Chairman of Indiana Utility Regulatory Commission highlighted the importance of considering inflation and inflation adjusted prices

Indiana Utilities Forecasting Spiky Growth

- Wabash Valley Power Alliance (WVPA) 2023 IRP



- As much as 1.3 gigawatts of load growth projected depending on economic conditions and policy environment

Indiana Utilities Forecasting Spiky Growth

- AES Indiana 2025 IRP

2025 IRP Candidate Portfolios: Cumulative New Installed Capacity through 2035

		DR	EE	Storage	Gas CCGT	Gas Peaking	Solar	Wind
No Data Center Load	Reference Case Portfolio	223	191	100	0	0	0	0
	Gas Infrastructure Portfolio	223	191	100	0	0	0	0
	High Regulatory Portfolio	223	191	120	0	0	25	900
	Stable Markets Portfolio	87	191	0	0	0	0	0
Low Data Center Load (500 MW)	Reference Case Portfolio	218	191	420	0	480	0	0
	Gas Infrastructure Portfolio	218	191	160	700	0	0	0
	High Regulatory Portfolio	223	191	780	0	0	350	1,350
	Stable Markets Portfolio	218	191	120	0	480	50	0
Mid Data Center Load (1,500 MW)	Reference Case Portfolio	200	191	860	700	480	0	0
	Gas Infrastructure Portfolio	223	191	380	1,400	108	50	0
	High Regulatory Portfolio	223	191	1,840	0	0	1,050	2,750
	Stable Markets Portfolio	223	191	720	0	960	100	0
High Data Center Load (2,500 MW)	Reference Case Portfolio	218	191	640	2,100	294	0	0
	Gas Infrastructure Portfolio	223	191	620	2,800	0	25	0
	High Regulatory Portfolio	223	191	2,480	0	480	1,225	2,800
	Stable Markets Portfolio	218	191	960	700	1,440	100	0

- Planning for a data center
- Massive load growth

What About Indiana?

- Duke Energy Indiana 2024 IRP

Table 3-5: Key Assumptions for Alternate Load Forecast Scenarios

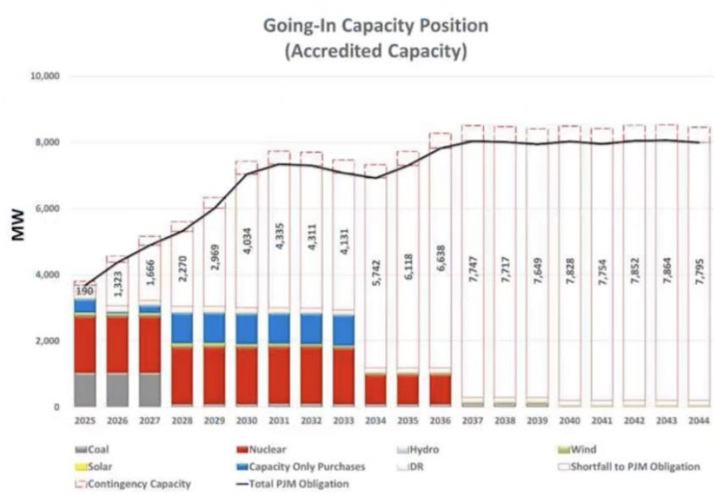
	Economics	Electric Vehicles	Behind-the-Meter Solar	Economic Development[1]
Low	90/10	Low Adoption	High Adoption	Low (25%)
Base	50/50	Base Adoption	Base Adoption	Base (~60%)
High	10/90	High Adoption	Low Adoption	Higher (75%) +500 MW data center[2]

Note 1: Economic development includes projects greater than 20 MW with plans sufficiently advanced such that some level of demand could be anticipated with a reasonable degree of certainty.
Note 2: 500 MW of data center load is assumed in the high case in addition to 75% of announced economic development projects.

- Duke Energy is also expecting a data center

Indiana Utilities Forecasting Spiky Growth

- Indiana Michigan Power (I&M) 2024 IRP
  - I&M's peak demand will almost double by 2031.



- Data centers already being built/data centers included in their IRP
- Projecting double the demand from 4 megawatts to 8 megawatts

Indiana Utilities Forecasting Spiky Growth

- NIPSCO's 2024 IRP
  - NIPSCO's peak load will more than double with confirmed data center projects.

Figure 3-42: Projected New Large Load Additions

	2028	2030	2035
IRP Peak Load – Original Reference Case	2,300 MW	2,300 MW	2,500 MW
+New Load Added to All IRP Scenarios	*600 MW*	*1,600 MW*	*2,600 MW*
IRP Peak Load – New Reference Case	**2,900 MW**	**3,900 MW**	**5,100 MW**
+Emerging Load Sensitivity	*2,600 MW*	*4,500 MW*	*6,000 MW*
Total IRP Peak Load with Emerging Load Sensitivity	**5,500 MW**	**8,400 MW**	**11,100 MW**

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- NIPSCO announced 2.1 GW for an Amazon data center
- More sensitivities with additional GW additions
- Additional 6 GW of load growth

ACCREDITED OR EFFECTIVE CAPACITY

- Morgan Stanley Annual Energy Paper (2023):
  - "…we computed the amount of natural gas that can be disconnected when adding solar and wind to meet another 10% of demand. The result: due to wind and solar intermittency and the need to meet demand and maintain system reliability, **only 10-30 MW of natural gas could be disconnected for every 100 MW of new wind and solar capacity.** These capacity credits decline as more wind and solar are added to the system..."

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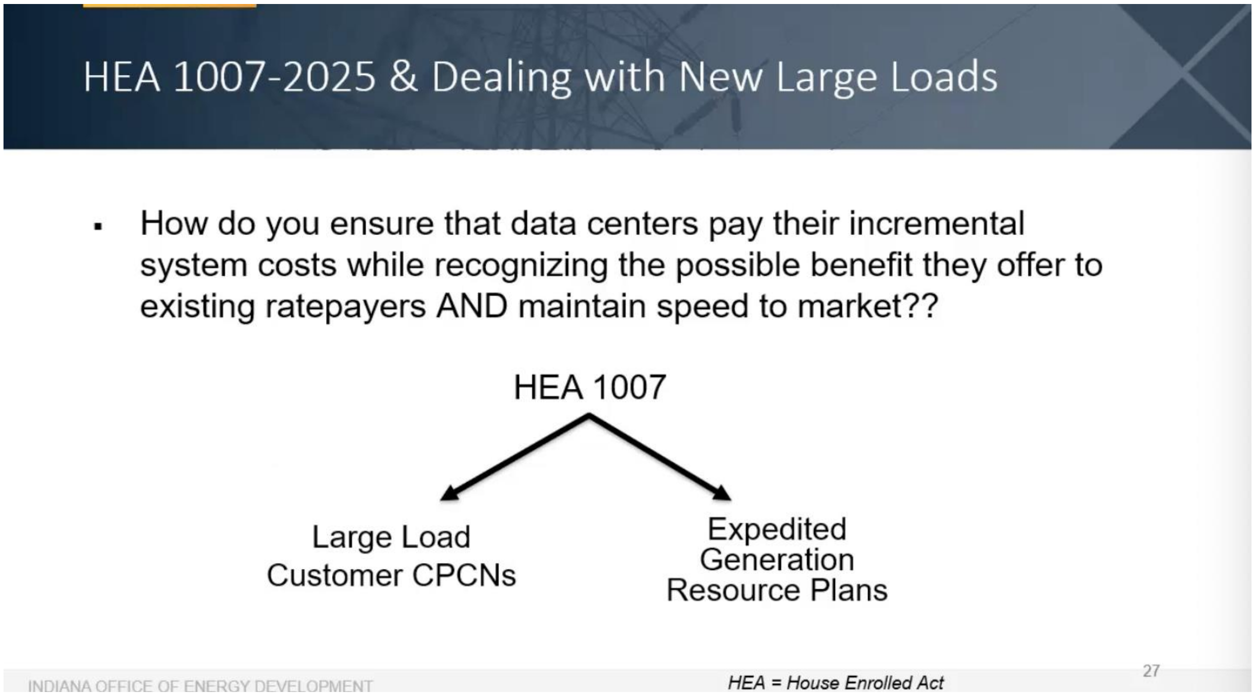
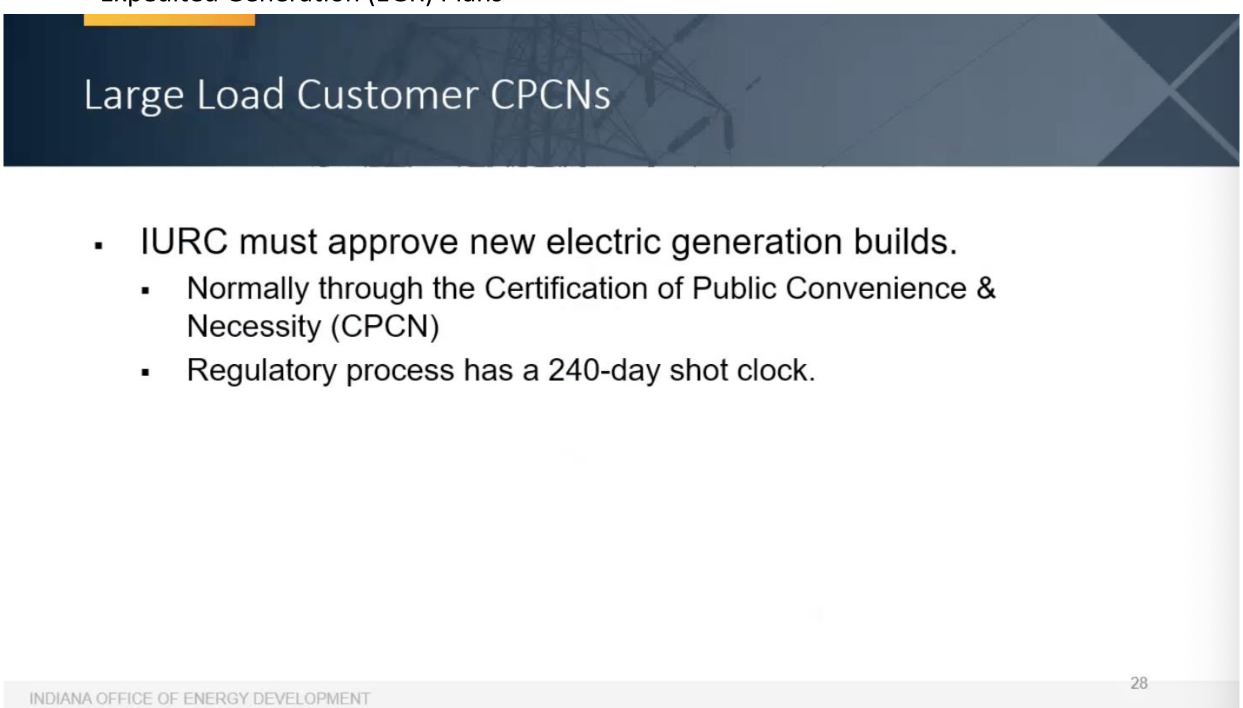
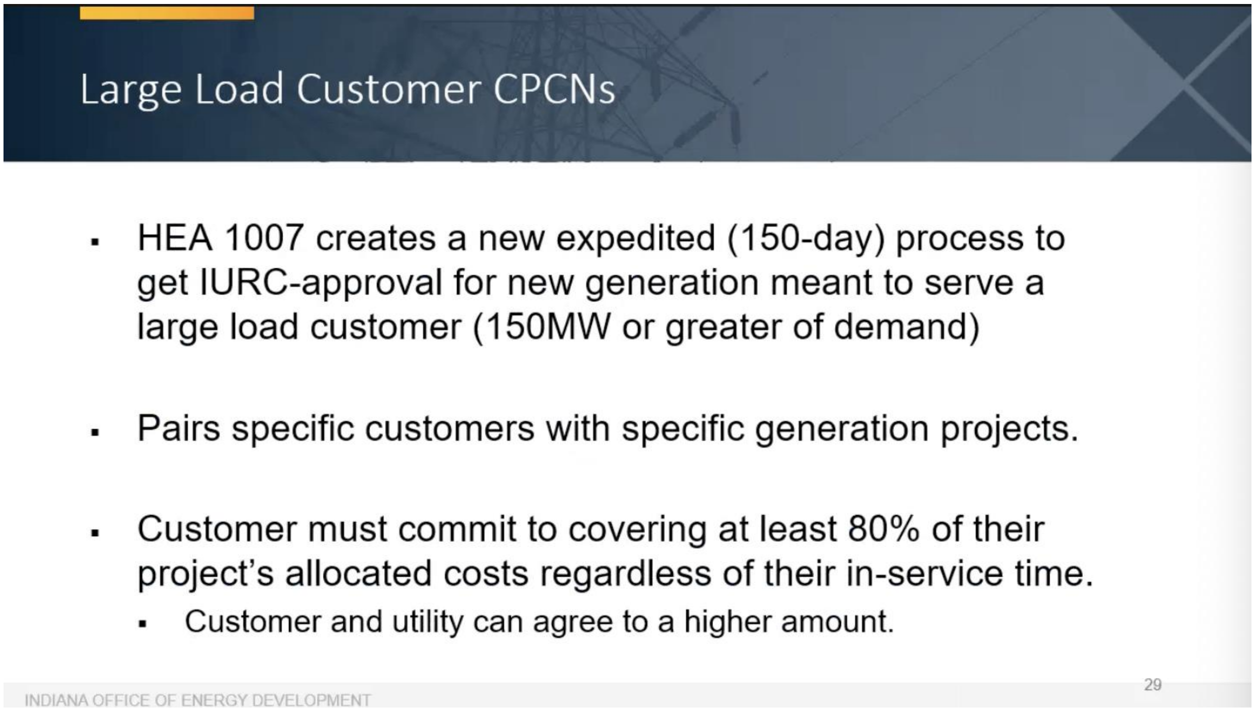
- Importance of an all of the above approach
- Making sure to meet customer demand 24/7 365



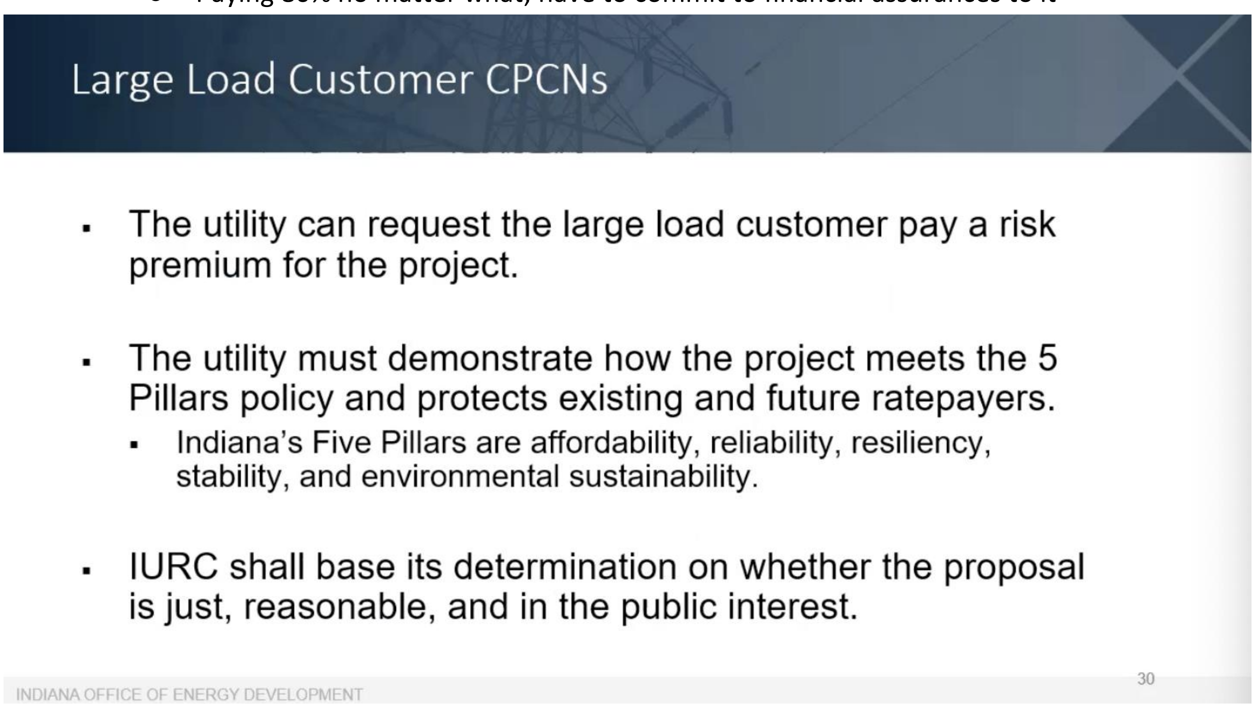
- How can data centers pay their costs and possibly benefit existing ratepayers while maintaining speed to market?
- HEA 1007 passed
- New Large Load Customer CPCNs (certificate of public convenience and necessity) and Expedited Generation (EGR) Plans



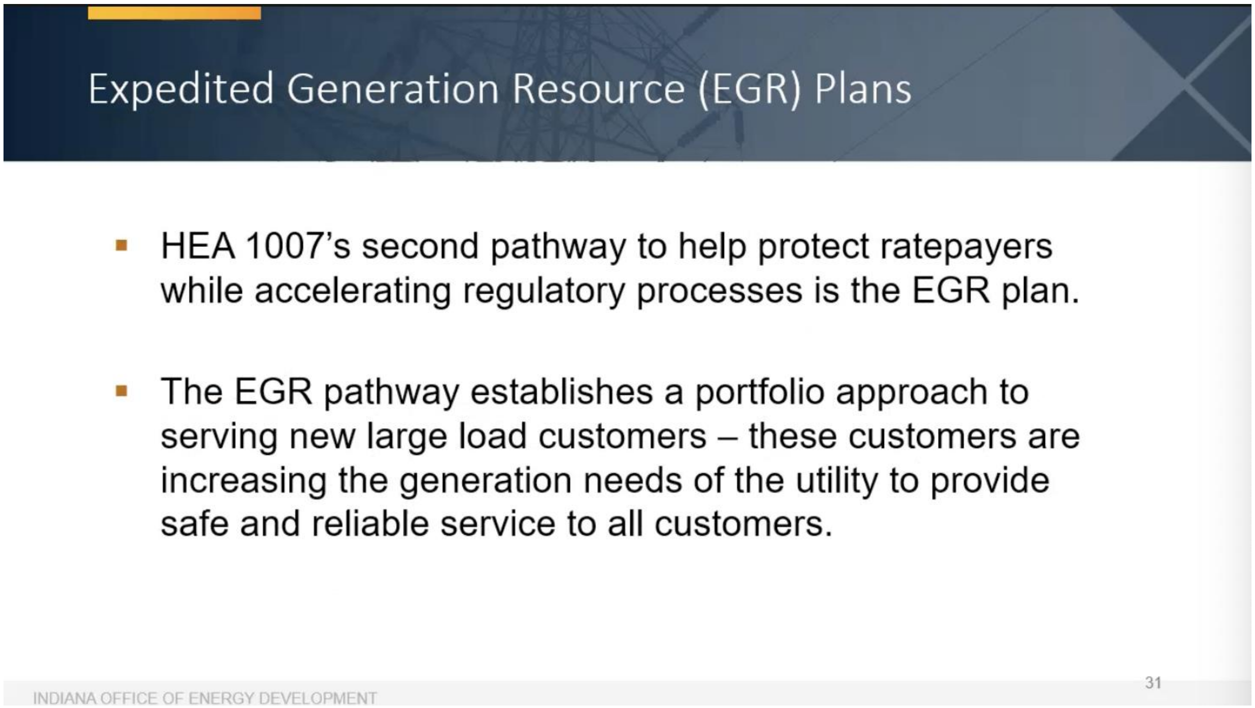
- Current CPCN process is 240 days
- A way to capture incremental costs to the system as they are being added



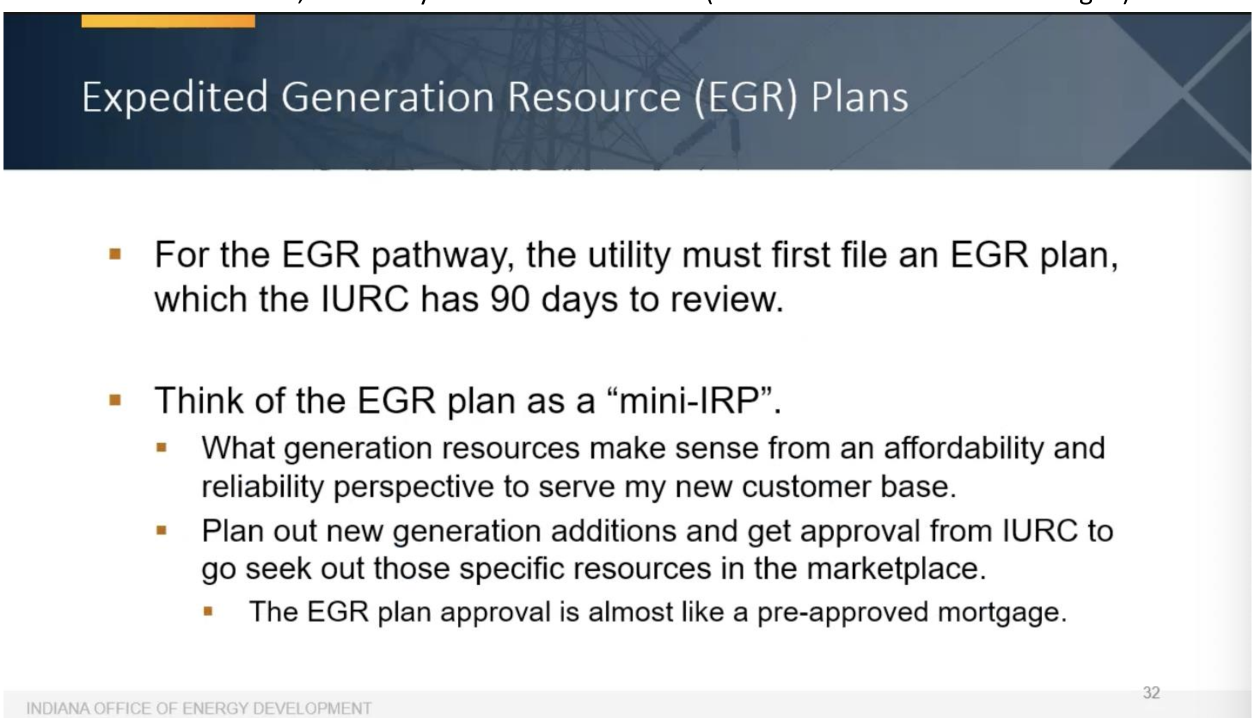
- What general assembly was thinning policy-wise
- 120 MW more and pair with new generation source; capture incremental costs to the system
- Customer has to commit to covering at least 80% of the cost regardless of end service time
    - Trying to eliminate tail risk
    - Paying 80% no matter what; have to commit to financial assurances to it



- Utility must demonstrate how ratepayers are protected
    - Pay a higher return on equity (ROE)
    - 5 pillars



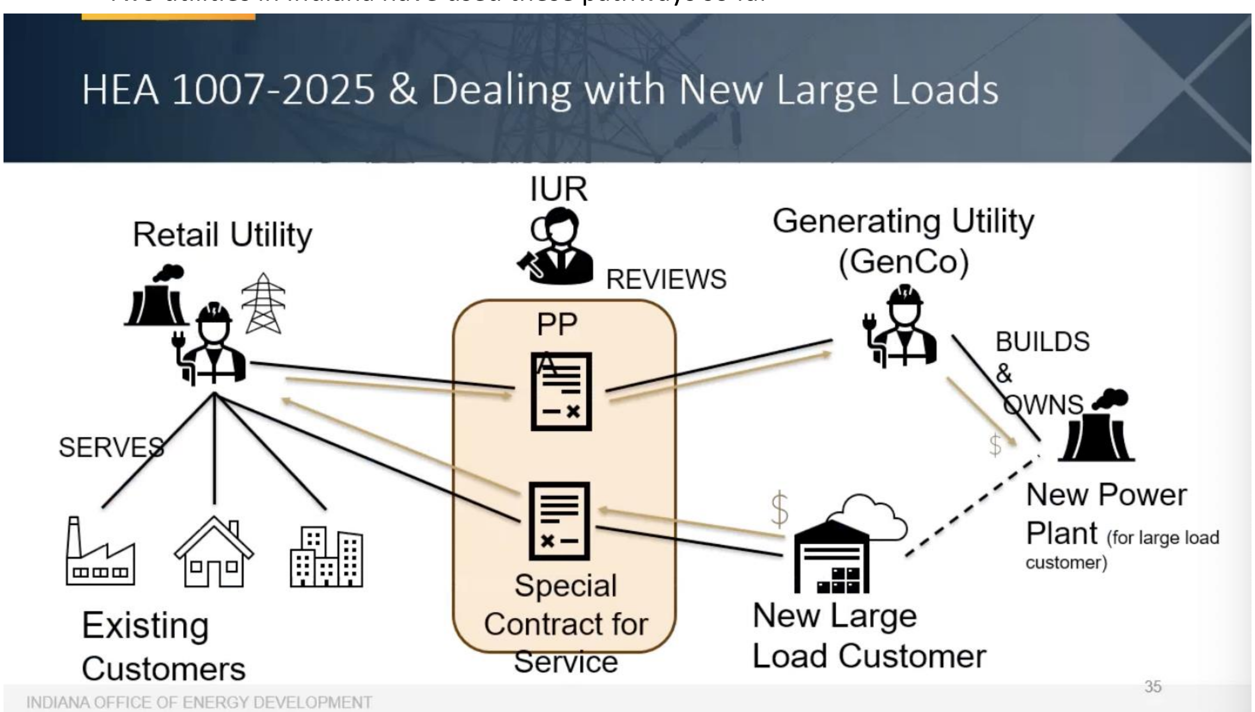
- EGR is a portfolio approach
- From an IRP lens, how will you serve all customers (several data centers are coming in)?



- Almost like a mini IRP
- Figuring out the least cost way to serve customer load
- Think of EGR like a pre-approved mortgage
    - Battery, solar, wind, gas

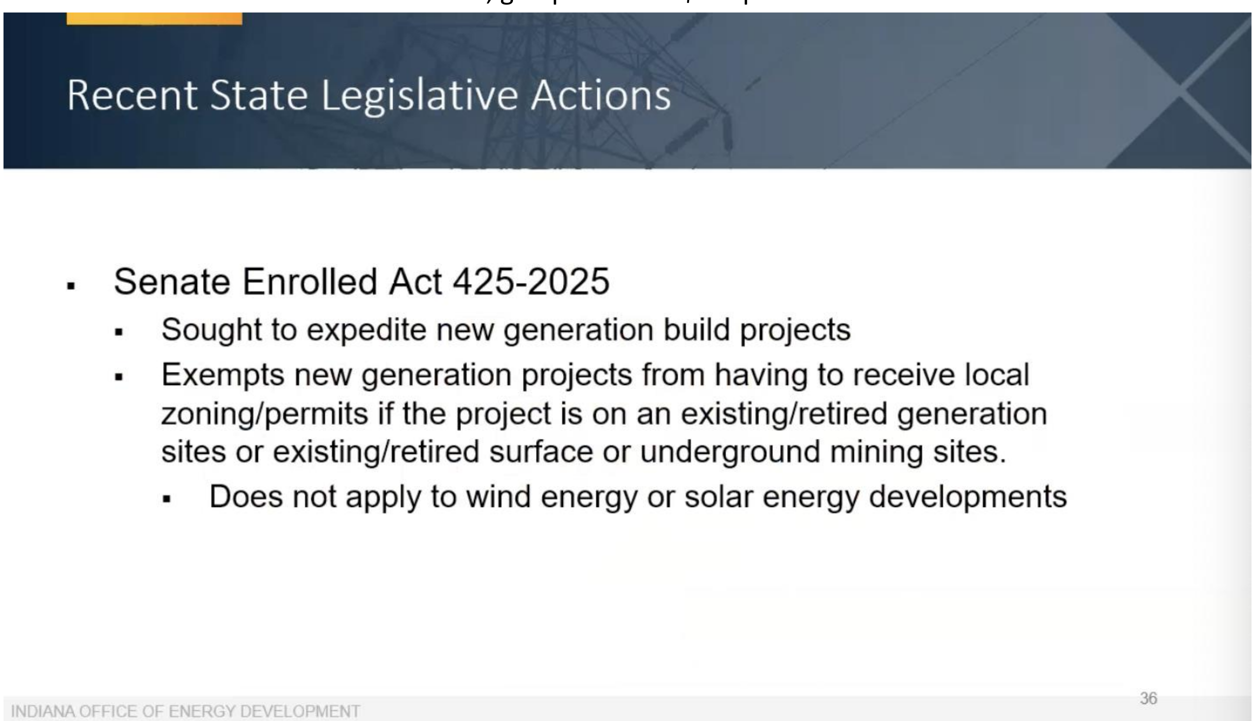
    - Go out and talk to IPPs; the commission said I need this type of resource and how do we get it onto our system to have it count towards reliability?
- Once they have identified resources, have size, estimated cost, they must demonstrate to the Commission how ratepayers are protected

- Two utilities in Indiana have used these pathways so far

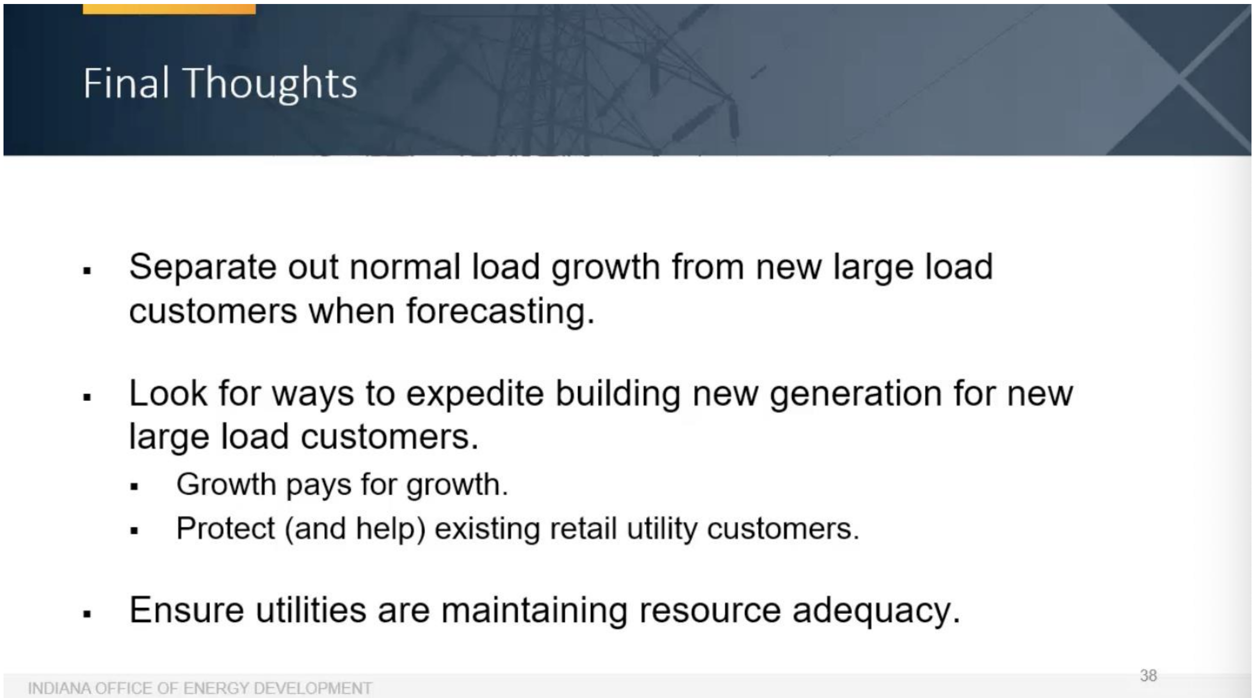


- GenCo model
- Large customer CPCN process

- 2.6 GW new load that NIPSCO will be serving
- Bottom right: new large load customer in bound
- Recent announcement with NIPSCO and Amazon
- NIPSCO has created a generating utility, or a GenCo
    - Off-system generator to serve large load customer
- Retail utility is serving traditional customers, and the new large load customer must be served by the retail utility. Thus, the retail utility has created a generation utility that is non-rate-regulated utility subsidiary that can serve the large load customer
- GenCo will have a PPA with the retail utility; NIPSCO will have special contract for service with the large load customer
- Paying off the power plant that large load customers needed
- 3 GW total because of 400 MW battery
- Amazon has a 15-year contract to pay 100% of generation and transmission costs; contribute $1 billion to the fixed cost of NIPSCO's system
    - NIPSCO crediting fixed costs back to system
    - If approved, customers will start seeing bill credits back on bill
        - Start at 10 cents, go up to about $4-5 per month over time



- In context of BANANA acronym: build absolutely nothing anywhere near anyone
- Tell locals "yes" or "no" approval
- Regulatory certainty as opposed to stringing projects along



- Separating out normal load growth from large load customers
    - 1% vs large load stepwise pattern
- Resource adequacy: checks and balances between utilities commission and the utilities

Questions:

- Q: Elaborate not on expedited resources but CPCN. How do you account for network upgrades on the transmission system and fairly allocate those costs?
    - A: Special transmission projects depend on each utility's makeup. NIPSCO is saying transmission is part of a special services contract. In some cases, it is assigned to the customer class (e.g. commercial, industrial residential). If an industrial customer is causing the upgrade, a larger chunk will be attributed to that class for the next rate case. Unless utilities are capturing that. Encouraging them to capture through incremental cost, special contract for service, or GenCo
- Q: What is the history of the policy decision, the outcome, and the pros and cons of the local permitting waiver?
    - A: It's definitely a difficult conversation because you're dealing with property rights and home rule. The tax base of this project could be a huge boon to communities while some community members don't want these projects.
    - Years ago, tried to do statewide zoning for renewable energy projects, but it failed to pass the Senate by one vote because pollinator plants weren't required. Balancing act between local communities, renewable energy/power developers, and state policy makers balancing the two objectives.
    - Have to replace thermal generation with thermal generation in Indiana
    - Local decision maker: shot clocks, just yes or no and a quicker turnaround. The aim was to stop stringing along projects.

    - Historically there would be construction work, approval, then something happens, and a local unit takes away a project that was previously approved
- Q: Most states have a sales tax exemption for data centers? Does Indiana?
    - A: Yes, we have that. Exemption on electricity sales as well as parts and components for data centers. Off top of the head, projects over $750 million get a sales tax exemption for 50 years. If they are below $750 million, they get the exemption for 25 years
- Q: Do you know how much it costs the state in tax revenue?
    - A: Not sure, I think the development corporation has to give a report by 2035?
        - But to my knowledge only one large load data center in 50MW - 100 MW range in the state
- Q: Question about the politics. Was the legislature very divided on these things? Was utility supported?
    - A: House Enrolled Act (HEA) 1007 was in the past session. Came from a working group examining large load integration while protecting ratepayers. Passed in a bipartisan manner in the house and senate. SB 425 was also, if I remember correctly, bipartisan, but different makeup/split and more no votes from people representing rural areas
- Q: The state utility forecast group does biannual load growth for the whole state? Give us a high-level view of what that is and how everyone views those forecasts? Is it considered the gospel?
    - A: The forecast group has been around for 40 years. They are a baseline technical impartial source for end grade resource plans. In the late 70s, a lot of states dealt with utilities forecasting higher load growth than was there and then they were left with excess generation, so this came about. Works with all utilities, rural cooperatives, transmission to get confidential data on the firm econ development deals, manufacturers, etc. coming that the utility knows. Use a Monte Carlo stimulation modeling software (Aurora) that is the same as what utility is using, tons of variables to run, spits out load forecasting and do price simulations as well. Also do a composite of a generation portfolio. Informing what portfolio to replace generation as load goes on.

Commissioner Kelsey Bagot, 1:35 PM - 2:05 PM
Virginia State Corporation Commission

Summary

Overview of VA Regulatory Framework & Load Growth

Recent Actions Taken by SCC and General Assembly

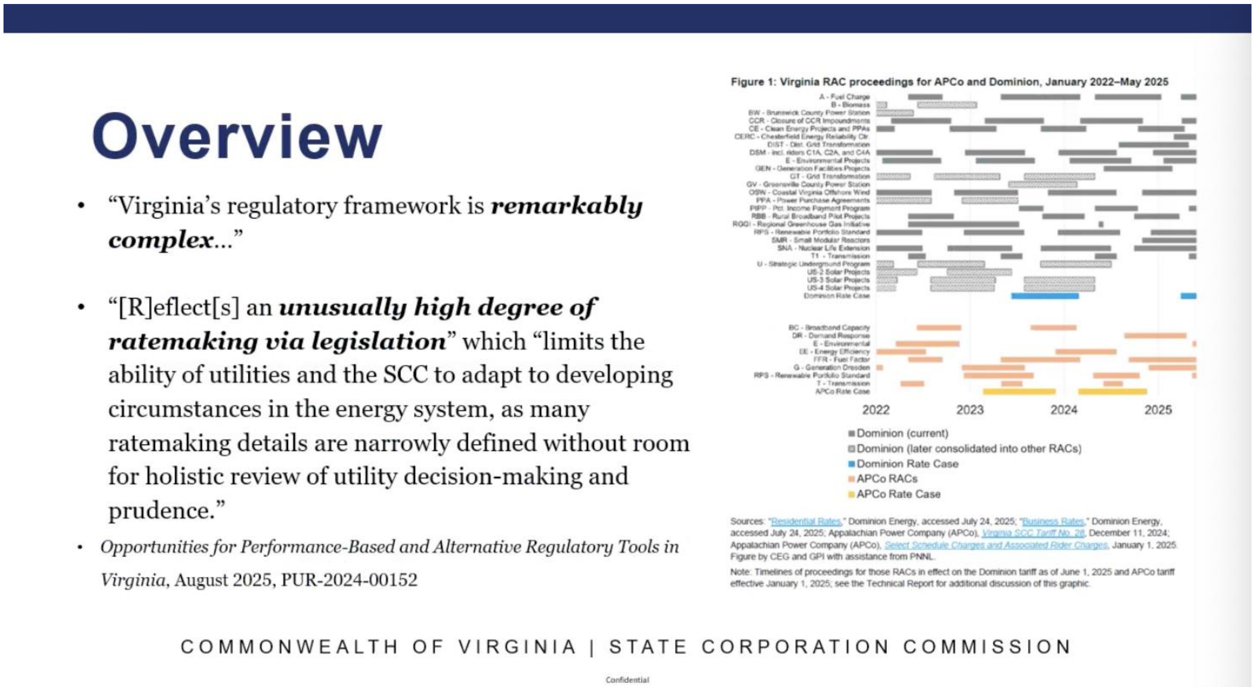
Lessons Learned

Overview

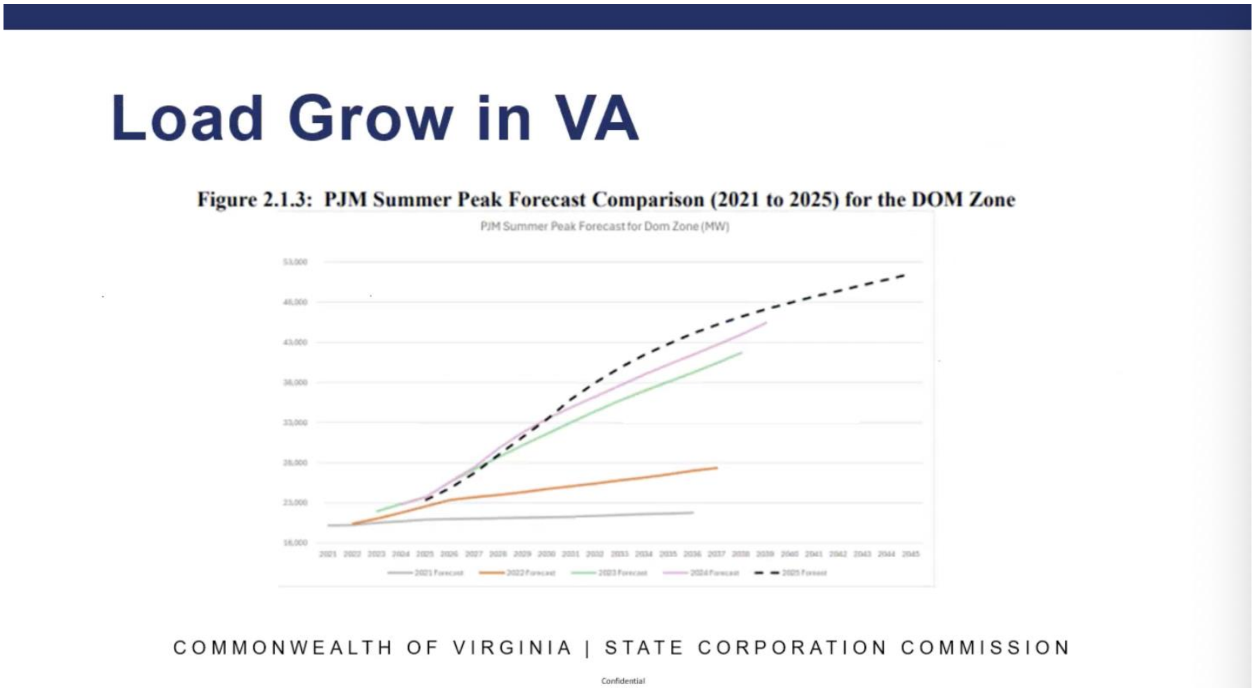
- Dominion (2.7 million customers); APCo (500,000 customers); NOVEC (180,000 non-data center customers)
- Biennial base rate reviews; IRPs; annual RPS
- Virginia Clean Economy Act (2020)
  - Mandatory RPS – 100% by 2045 Dom/2050 (APCo)
  - Mandatory EE Program – 5% (2019 baseline) by 2028

- Dominion and APCo are vertically integrated
- NOVEC is largest electric cooperative in the state
  - Has the most experience with data centers of the cooperatives; located in Loudoun County (data center alley)
- Some limited options for retail choice in Virginia
- Biennial base rate reviews and IRPs
- Annual RPS filings
- No CPCN approvals in biennial base rate reviews

- In the RPS proceedings, there are CPCNs granted as a part of the Virginia Clean Economy Act (VCEA)
- Very aggressive mandatory RPS requirements
  - Dominion must be 100% renewable by 2045; APCo has until 2050
- Act also has specific build requirements
  - Certain renewable resources; some have to be in Virginia or purchased RECs from Virginia
  - Adds a wrinkle with in-state permitting



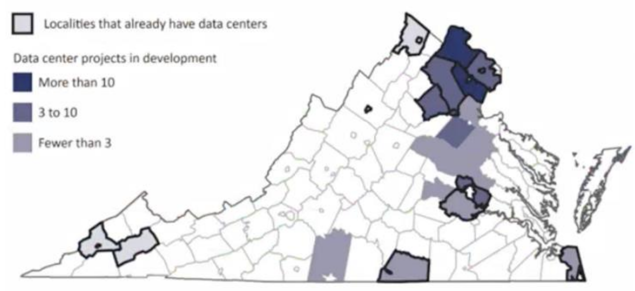
- Report: Opportunities for Performance-Based and Alternative Regulatory Tools in Virginia
- Primarily looking at performance-based rate making in period of large load growth
- Regulatory framework is remarkably complex; a lot of ratemaking via legislation
- Figure: report highlights as creating this challenge – the number of rate adjustment clauses that have been created via legislation that utilities can take advantage of
  - Outside of biennial rate review
  - Include an ROE component to them
  - Separate and apart from base rates
  - Keeping track is incredibly challenging
- Tough to engage in prudency reviews and cost allocation



- Moving target; not new to Virginia, have been around since 2010
- Has had data centers before, but they were much smaller
  - Now most are 100 MW or above
- Each line shows each progressive year's load forecast for demand growth
- Dominion's forecast has changed dramatically
- To address: Dominion has created a specific large load interconnection queue to manage how it is building for these data centers
  - Over last 4 years dominions forecast driven by data centers has changed dramatically
  - Heard anywhere between 200-400 data centers and 30-40 GW; projecting 7-12 years to get online if you are back of the queue
  - By 2045-2050, Virginia needs to build two new Florida Power and Lights (as a comparison)
  - Dominion is a little ahead of the game in terms of load forecasting since they have been doing it for a while
  - Looking at metered demand, not forecasted demand, for these loads. There is a difference of about 50%
  - Data centers that have been online many years have ramped up just to about 60% of contracted demand

Load Grow in VA

FIGURE 1-4
Data center industry still growing in established markets, but development starting to spread into new areas, such as along I-95



SOURCE: JLARC summary analysis as of September 2024.
NOTE: "In development" includes projects that are under construction, permitted, and/or have been approved through local rezoning or other approval processes (if applicable).

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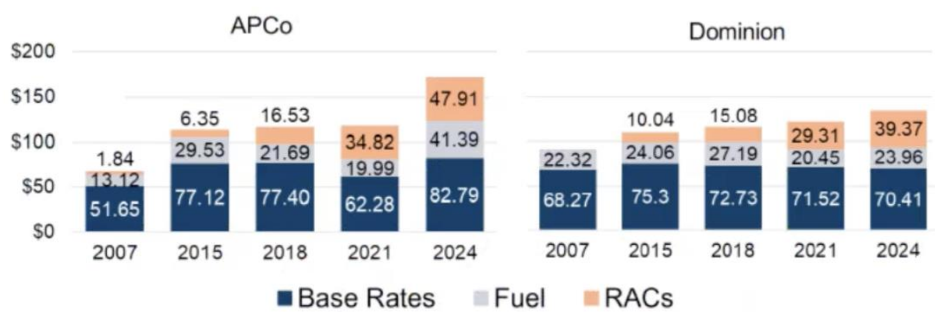
- Highest saturation of data center development in data center alley
- Seeing more come into southern Virginia, but more like AI and machine learning
    - Northern is cloud computing
        - Latency-sensitive

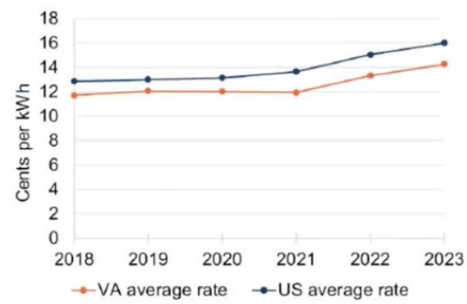
Figure 7: Historical cost components of typical monthly residential electricity bill in Virginia (1,000 kWh consumption, summer month)



- Dominion has seen steadily increasing rates; APCo does not have a lot of data centers so they are not driving rates for APCo
- National average has been about 24%, but Dominion's has been about 22%
    - About the same despite data center development
- The cost of RACs is going up

- All of renewable development generation cost is recovered through RACs and not base rates
- Just approved a gas peaker plant to be recovered by RACs; utilities can ask by right to be recovered via RAC

Figure 3: Average retail residential rate, Virginia and US (2018-2023)



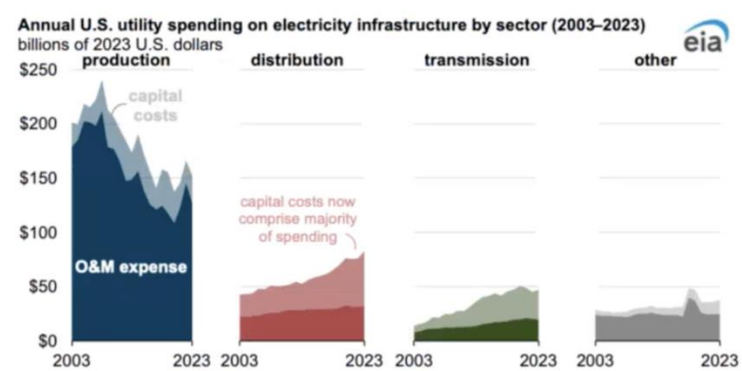
Source: "Electric Sales, Revenue, and Average Price" (Table 4, January 2018–January 2023), US Energy Information Administration, accessed July 24, 2025. Figure by CEG and GPI with assistance from PNNL.

In 2023, Virginia's average residential electricity rate was 11 percent lower than the US average. From 2018 to 2023, residential electricity rates in Virginia increased by approximately 22 percent. Over the same period, average US residential rates increased by approximately 24 percent.

Confidential

- Are seeing rate increases, but not as high as would be expected given data center development
- Not a lot of flexibility in riders

T&D capital investment represents the most significant source of long-term increased utility spending.

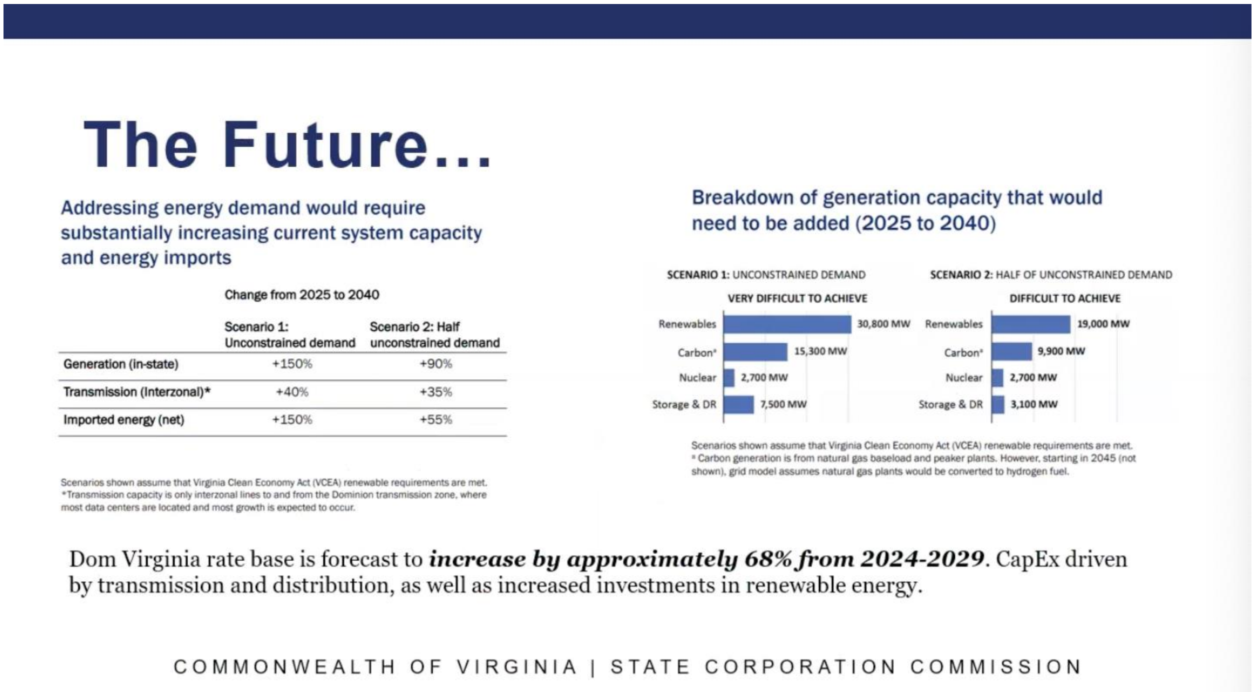


Data source: U.S. Energy Information Administration and Federal Energy Regulatory Commission (FERC) Financial Reports, as accessed by Ventyx Velocity Suite
Note: O&M=operation and maintenance

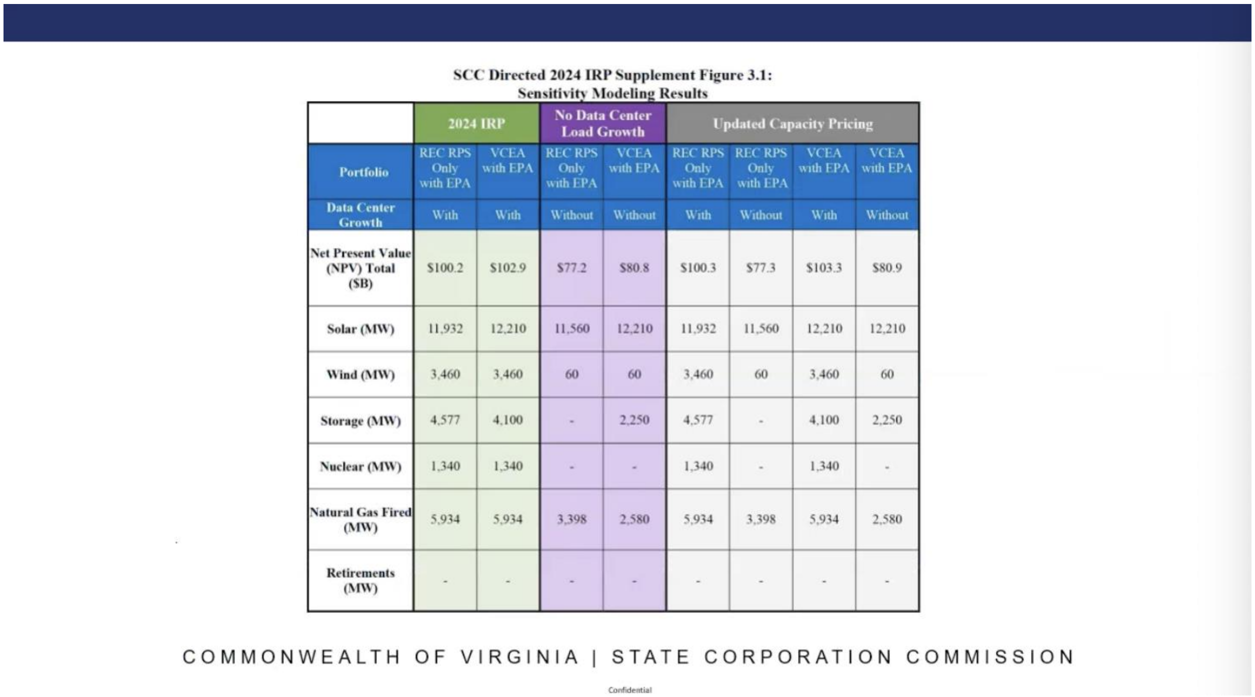
Confidential

- What is really driving rate increases? Political debate going on
  - Is it the retirement of fossil fuel resources and bringing on solar?
  - Is it data centers?

- Her opinion: probably a little bit of both
- New capital costs with building out generation resources; also seeing distribution costs go up
- Before data centers were seeing capital costs/production costs going down and rates were flat
- Now with load growth on top, everything is going up



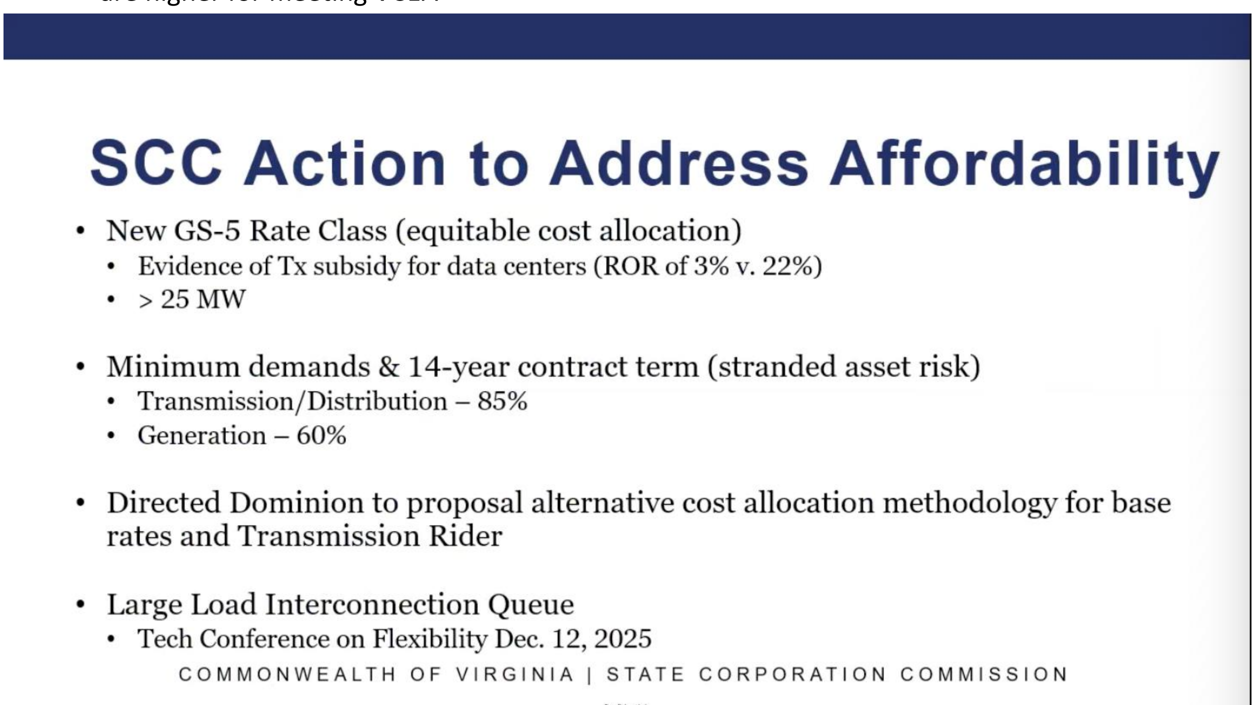
- From the JLARC study issued about a year ago
- Unconstrained demand scenario and 50% scenario
- Metered demand, not contracted for demand
- Increases to generation, transmission, and imported energy
- Relying more heavily on purchasing from PJM market than they already do
- What type of generation capacity is needed to build under 2 scenarios (unconstrained and 50%)?
- For both: meeting is very difficult
    - It is going to be incredibly difficult to do if you try to meet VCEA goals while meeting data center growth
    - Political challenge: Do we limit data center growth? Do we modify VCEA?



SCC Directed 2024 IRP Supplement Figure 3.1:
Sensitivity Modeling Results

	2024 IRP		No Data Center Load Growth		Updated Capacity Pricing			
Portfolio	REC RPS Only with EPA	VCEA with EPA	REC RPS Only with EPA	VCEA with EPA	REC RPS Only with EPA	REC RPS Only with EPA	VCEA with EPA	VCEA with EPA
Data Center Growth	With	With	Without	Without	With	Without	With	Without
Net Present Value (NPV) Total ($B)	$100.2	$102.9	$77.2	$80.8	$100.3	$77.3	$103.3	$80.9
Solar (MW)	11,932	12,210	11,560	12,210	11,932	11,560	12,210	12,210
Wind (MW)	3,460	3,460	60	60	3,460	60	3,460	60
Storage (MW)	4,577	4,100	-	2,250	4,577	-	4,100	2,250
Nuclear (MW)	1,340	1,340	-	-	1,340	-	1,340	-
Natural Gas Fired (MW)	5,934	5,934	3,398	2,580	5,934	3,398	5,934	2,580
Retirements (MW)	-	-	-	-	-	-	-	-

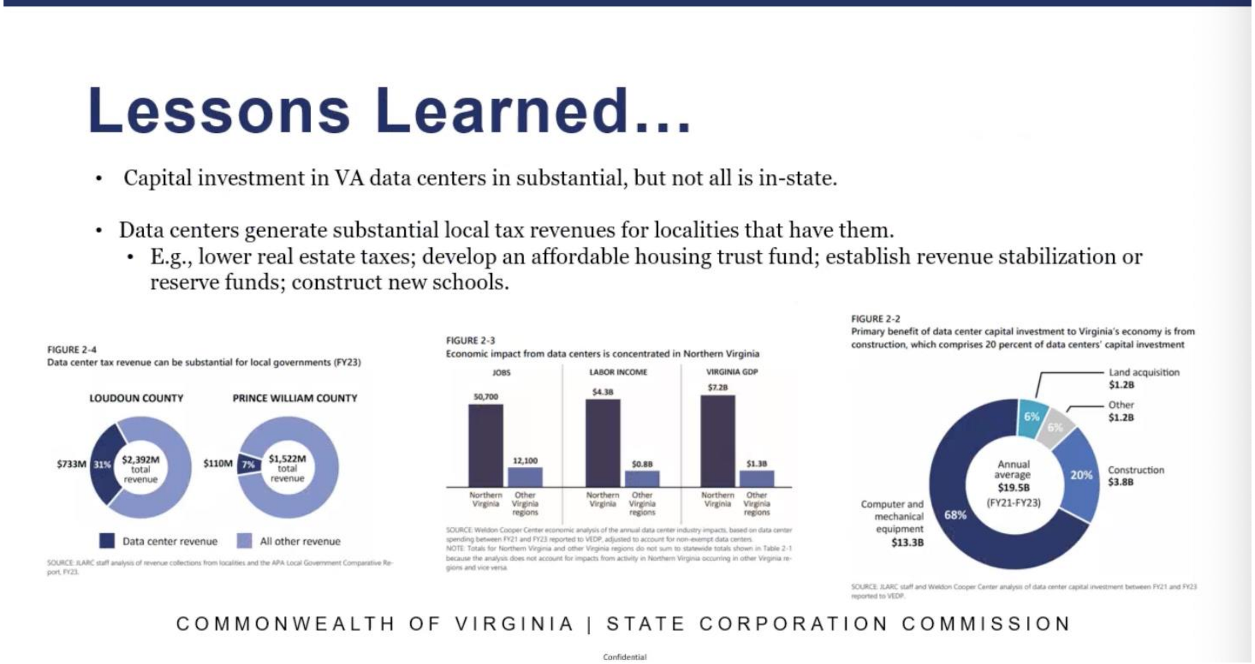
- Green: with data center load growth need to meet VCEA targets
- Purple: without data center load growth, need to meet VCEA target
- Over time low fuel costs of renewables might mean cheaper energy, but in the near term, costs are higher for meeting VCEA



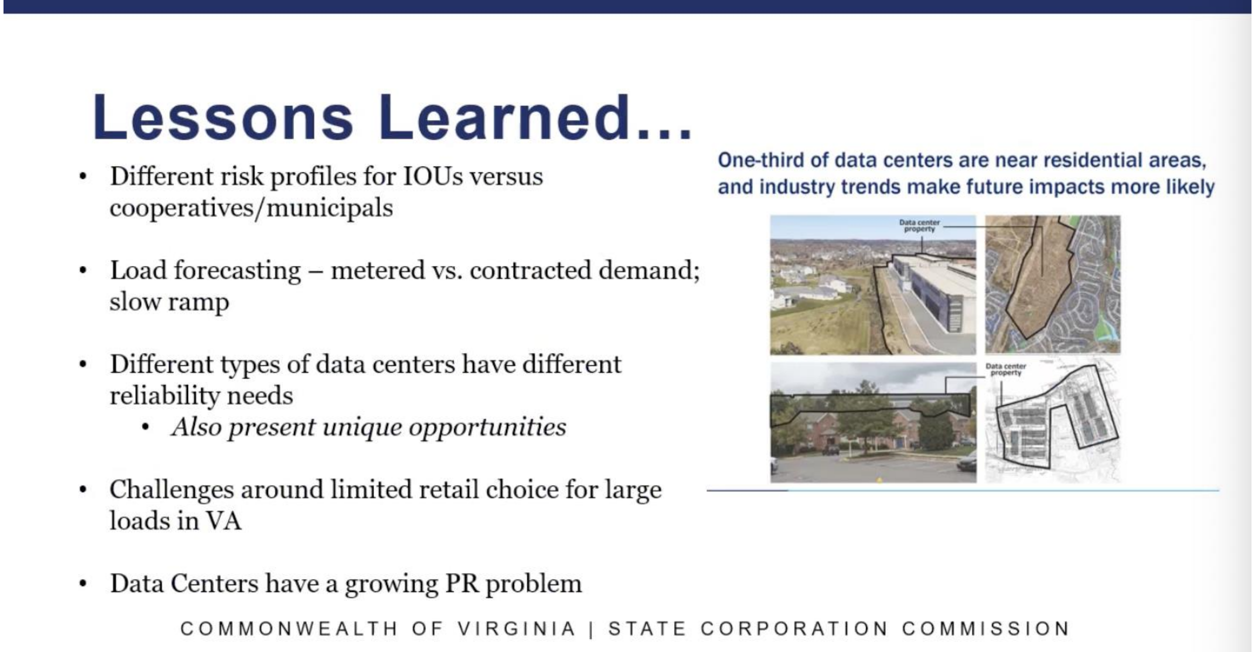
- Biennial case order
- New GS-5 rate class
    - Greater than 25 MW; 75% load factor or higher

    - A lot of debate: is 25 MW too load and would it pull in manufacturing? Went back and concluded that 25MW threshold with load factor requirement is pretty good at keeping just data centers or loads with similar characteristics
- Current GS-4 rate class
    - Looking at relative ROR: the current GS-4 rate class was masking a lot of the subsidization of large loads that was occurring
    - If you moved data centers into GS-5, there is a significant subsidy between what large load was contributing and what GS-4 was contributing
- JLARC: current rates don't include a subsidy, but as more large loads come on, there could be a subsidy
- Current rate class structure is masking some of subsidy and it is growing based on what they heard in the proceeding
- Directed Dominion in next transmission rider and in next biennial case to propose alternative cost allocation methodology for base rats and transmission rider
- Not enough evidence in that record to determine what the new cost allocation methodology would be
    - For transmission rates: new cost allocation to be submitted in March and available in June
- In addition to new rate class, create minimum demand and 14-year contract term
    - 85% minimum demand charge for transmission and distribution (T&D) and 60% for generation
    - Those were the numbers the company proposed
    - Higher for T&D because higher ability for utility to remarket generation than T&D
    - Minimum demand and contact term were stranded asset mitigation
        - Whereas GS-5 was pertaining to equal cost allocation going forward
- Directed Dominion to file the rules of the road for the large load interconnection queue
    - Given size of queue, want to weed out speculative projects
    - Make sure they have skin in the game and load actually shows up
    - Filing first week in February and acting soon due to FERC ANOPR
    - Technical Conference on data center flexibility is non-litigated and set for December 12, 2025
        - 2 tranches: First action was triage: How do we make sure that as these data centers are coming on, costs are being fairly allocated?
        - Now that we are done with triage, flexibility comes in:
            - Hopefully see where these customers can be grid assets and putting downward pressure on rates
            - Want to learn about "flexible flexibility"
            - Different data centers may not be willing to be flexible
            - If you have a requirement of flexibility to meet but they can purchase the flexibility through DR and VPP programs in the community, investments stay in community regardless of whether the data center comes online or not

- Where we might see rhetoric around data centers change and can be grid assets

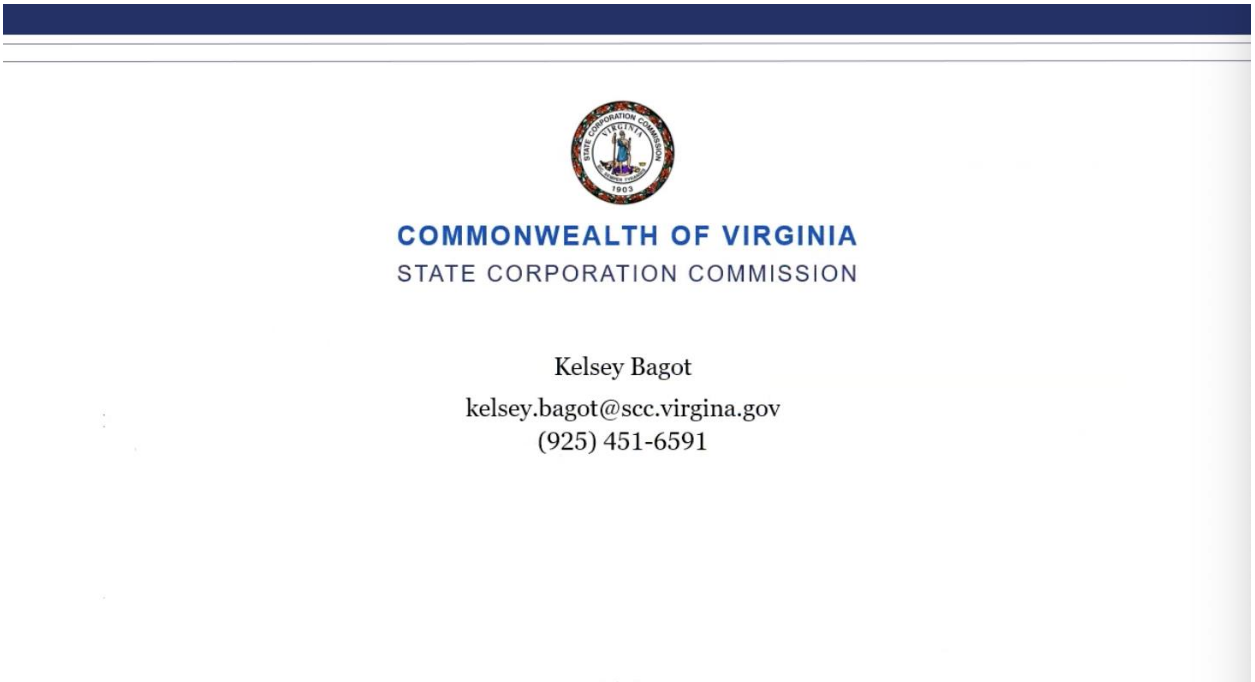


- Economic benefit, not in the form of jobs, most purchases are happening out of state, Loudoun county seeing benefits due to data centers
    - Conflict between NIMBY and officials wanting to benefit from projects



- Thinking about what kind of data centers you have and that tariffs are flexible enough for each type
- Risk costs being stranded with customers who can't jump from limited retail trust

- Different risk profiles between IOUs and cooperatives/municipal utilities
  - Smaller coops are starting to get data center interest. Given structure and small size of coop, how do you serve customers without burdening risk that all of those customers go away
  - Ring fencing those two different business models

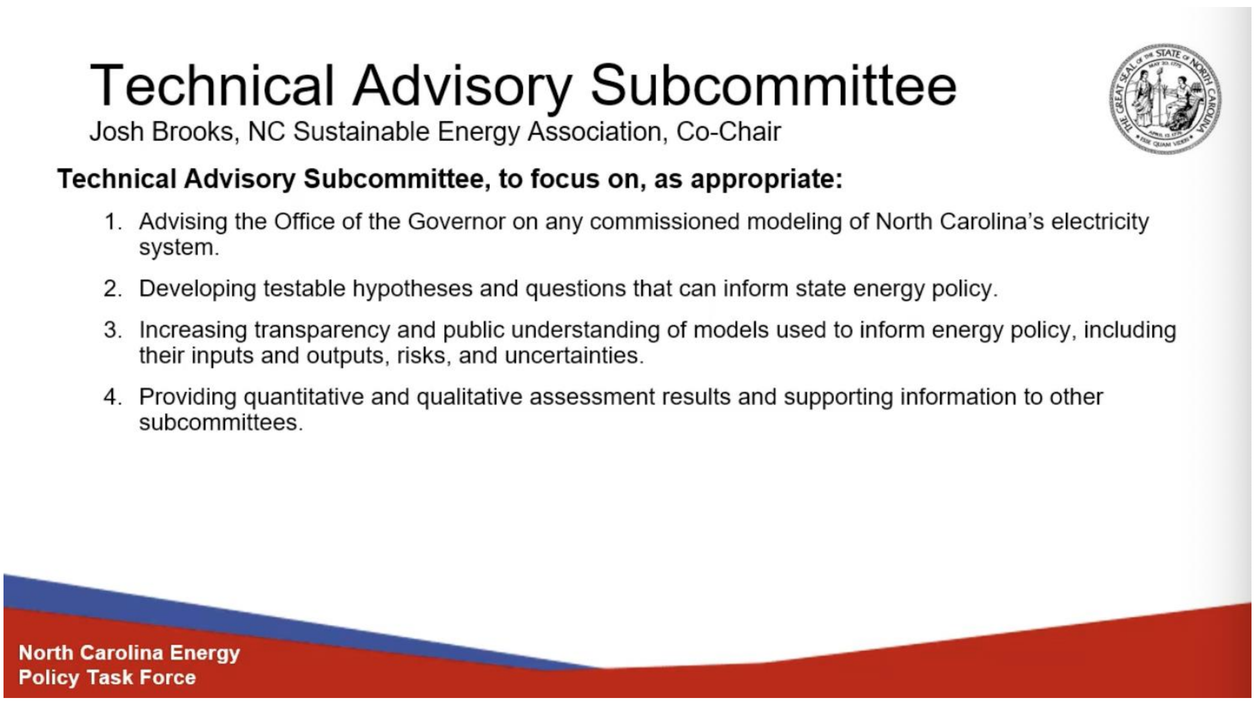


Questions

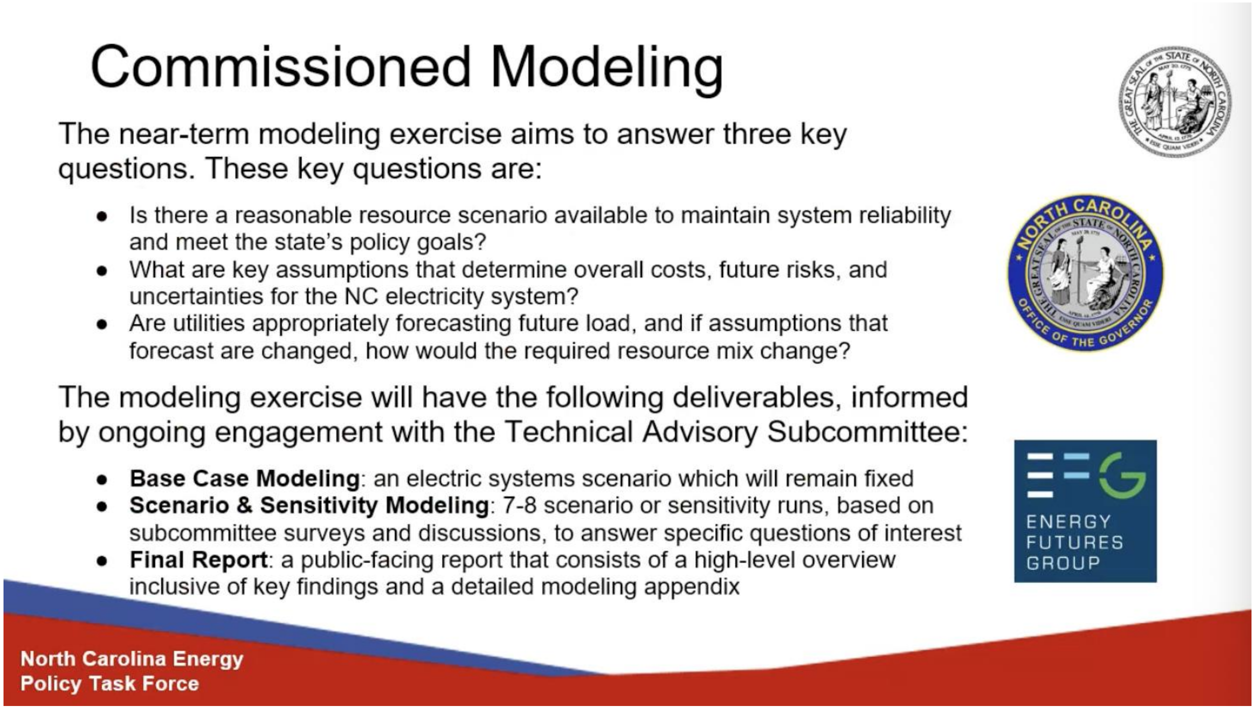
- Q: Clarifying VCEA is for data centers or IOUs?
  - A: IOUs
- Q: As a state corporation commission, are you allowed to interpret the statute?
  - A: can consider other sustainability through CPCN, but RPS is fairly prescriptive for bringing on amounts and types of new projects on 5-year bases. Do not have to approve it, but they do have to propose. Did recently deny battery and wind PPA.
- Q: Indiana's cost of the tax exemption is $1 billion a year. What are the impacts of the exemption in Virginia? Does it cover everything?
  - A: I believe it is a sales tax exemption on computing equipment. Don't believe there is an electricity sales tax exemption
- Q: There is concern in recent proceedings and proposing alternative cost of service methodologies. Any interesting cost of service methodology proposals coming out of your proceedings/state?
  - A: There has been discussion of modified average and excess. Changing CP factor. 6 or 12, make it more heavily weighted. The Commission directed them to work with Staff and come up with other options besides the modified CP. What tied our hands in this past proceeding was not enough testimony or options. Most testimony seemed to be POD, but utility was strongly opposed to this idea.

- Q: We have mostly been talking about energy, but there is also a lot of water taken. Issues with availability of water supplies? If you haven't seen it, do you anticipate it?
    - A: I haven't seen those issues yet. I think the data centers are ahead of the game there. Built or retrofitted to be closed loop. More of an issue in less concentrated areas like southern Virginia
- Q: I am interested in flexible flexibility. Can we create a secondary market? Can we share in the learning from your technical conference? Share the outputs? Second, to do flexible flexibility, do you need regulatory or legal change?
    - A: That is one of the questions we have teed up. What if any changes do we need? The other is changes related to PJM. To the PJM point, my guess is no to needing changes. Through large load tariffs and interconnection queue process, I think we have a lot of authority to put in place flexible flexibility.
    - A: Technical conference will be webcast and there will be a court reporter with a video link post conference

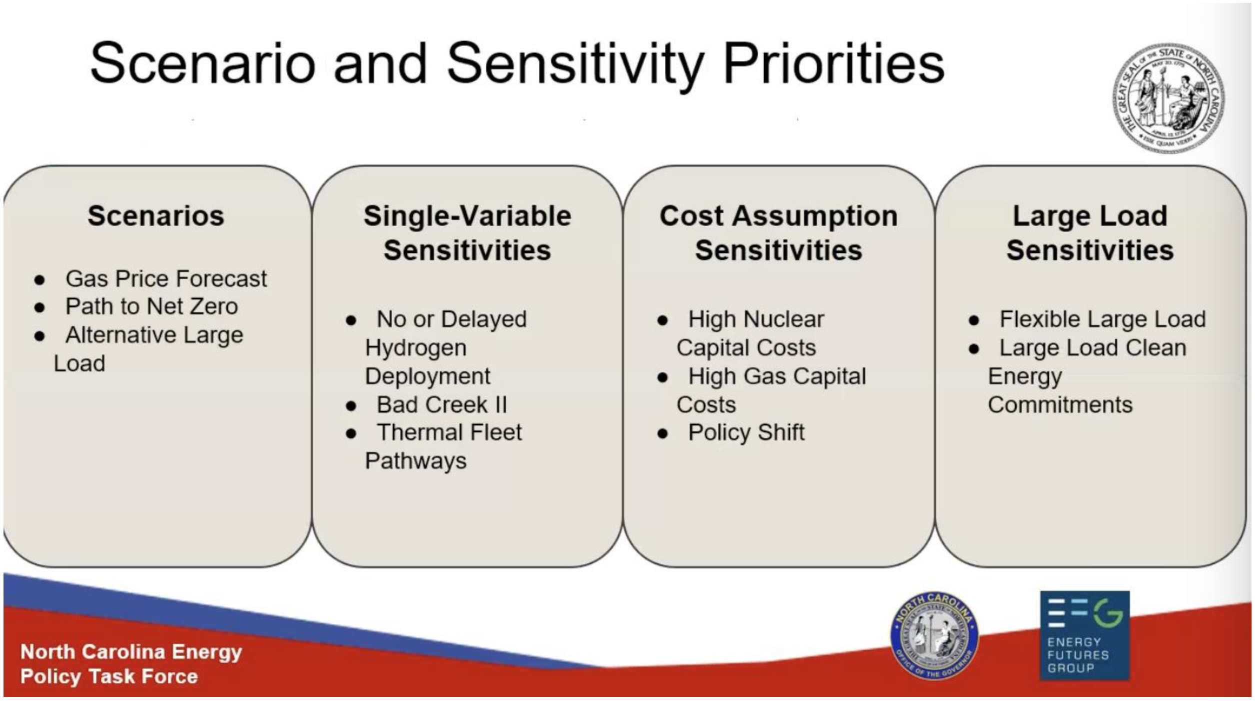
TECHNICAL ADVISORY SUBCOMMITTEE UPDATE & DISCUSSION 2:05 PM - 2:20 PM



- Specific modeling inputs and market conditions that would affect resource mix
- Advising Governor's office on modeling, testing scenario, and increasing transparency on both sides of the table



- How are we doing it?
- Using the same modeling software that duke and public staff does, EnCompass
- Pretty exhaustive inputs
  - Generation sensitivities, transmission sensitivities, fuel costs, etc.
  - Comprehensive and large model to run
  - Given its so massive we've had to reign in the questions we're being asked
- Whittling down on questions to be focused on:
  - Reference top three
- Three categories of deliverables
  - Base case
    - Business as usual/IRP filing
  - Scenario & sensitivity analysis
    - Series of scenarios and then sensitivities under those scenarios
  - Final report



- Current most viable selections
- Gas price forecast
  - Lots of pressure on gas supply costs
- Path to net zero
  - Removing 2030 mandate
- Sensitivities
  - Viability of hydrogen development
  - Bad creek
  - Prolonged operation of coal plants
- Trying to get most realistic scenarios
- Taking into account as best we can sensitivities around other costs
- But really around large load sensitivities

Questions

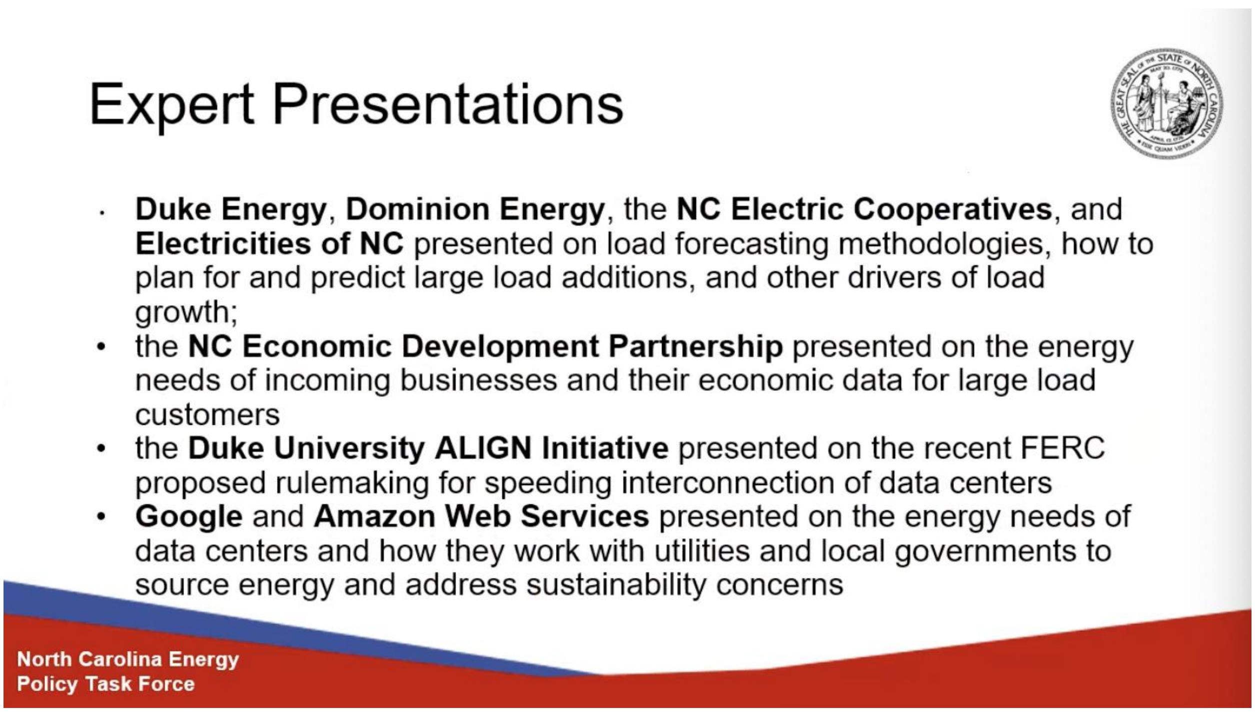
- Q: Indiana speaker referenced separating out normal load growth vs new large load growth. Is your committee talking about doing that?
  - A: Base modeling case is more typical load growth; working on input from stakeholders about anticipated load growth
  - Have had different utilities present on how they do this; trying to model in a couple of different ways

LOAD GROWTH SUBCOMMITTEE UPDATE & DISCUSSION 2:30 PM - 3:25 PM

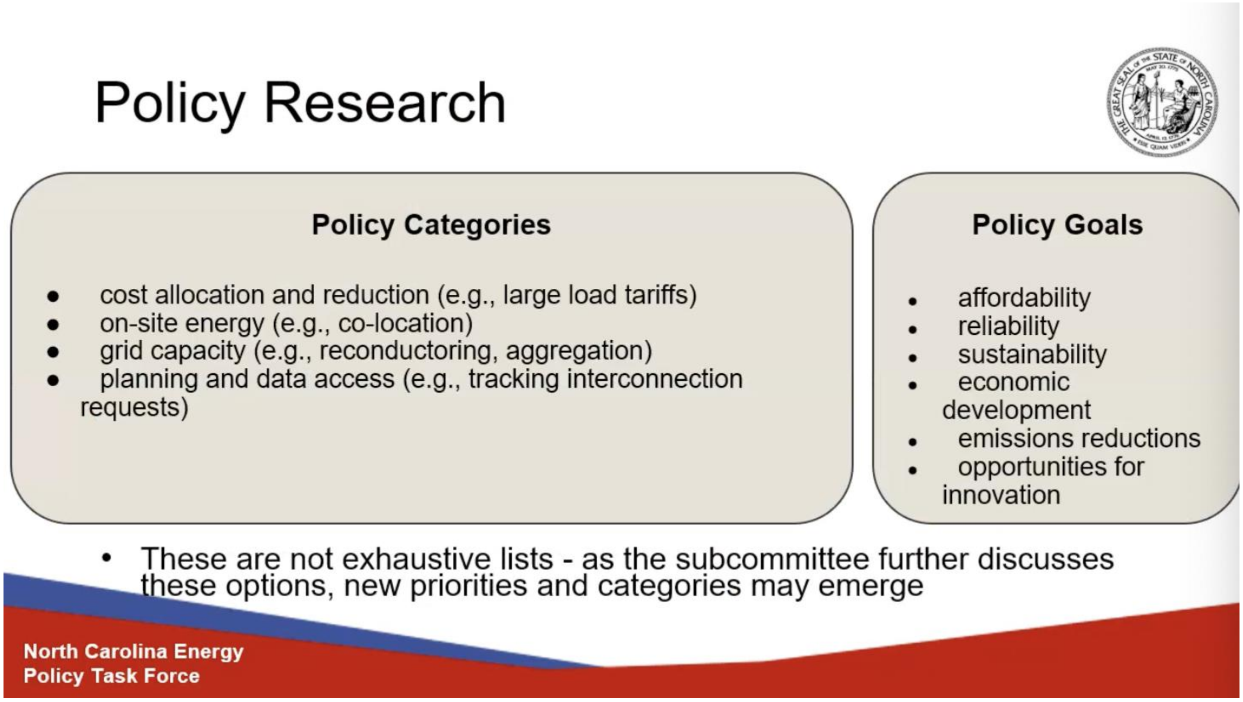
Sen. Julie Mayfield & Kathy Moyer 2:30 PM - 2:45 PM
Load Growth Subcommittee Co-Chairs

- Kathy Moyer

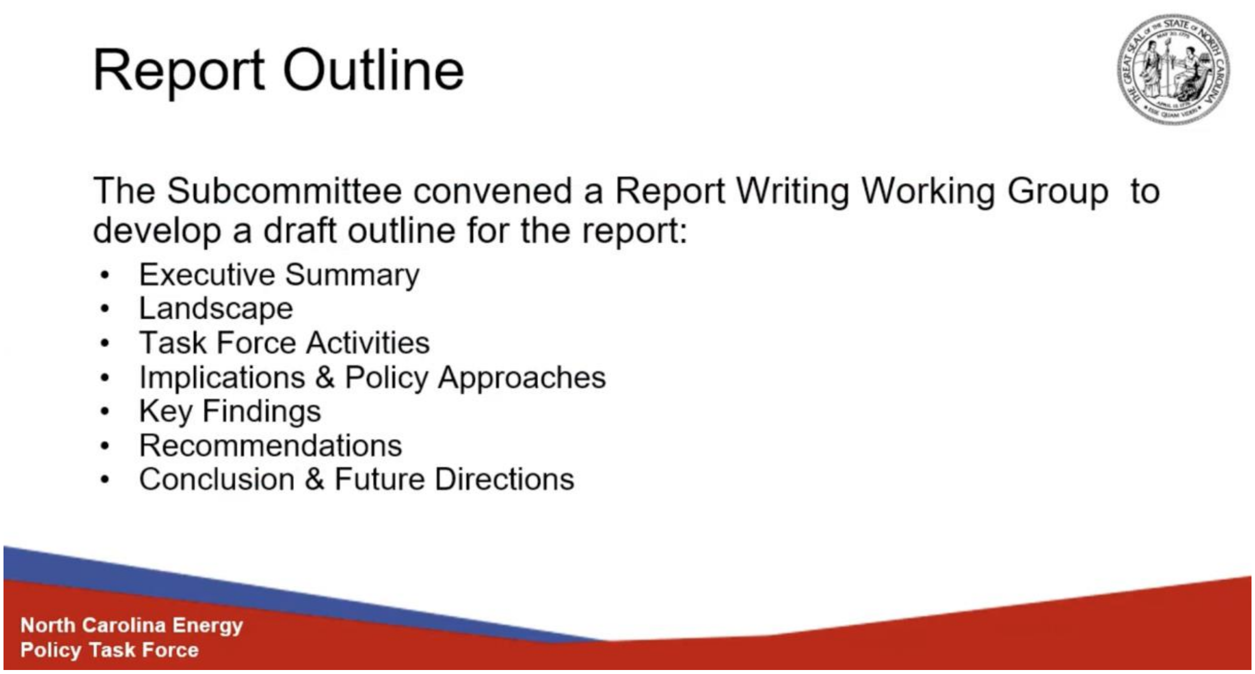
- Has met 4 times since September
- Verbal remarks reflected in slide



- Reviewing presenters we heard from
- Fifth meeting scheduled



- Reviewing the different policy categories
- Have identified the policy goals, though not an exhaustive list



- Reviewing verbally; categories may change over time
- Note subcommittee summary of activities are in member packet and feel free to reach out to task force staff

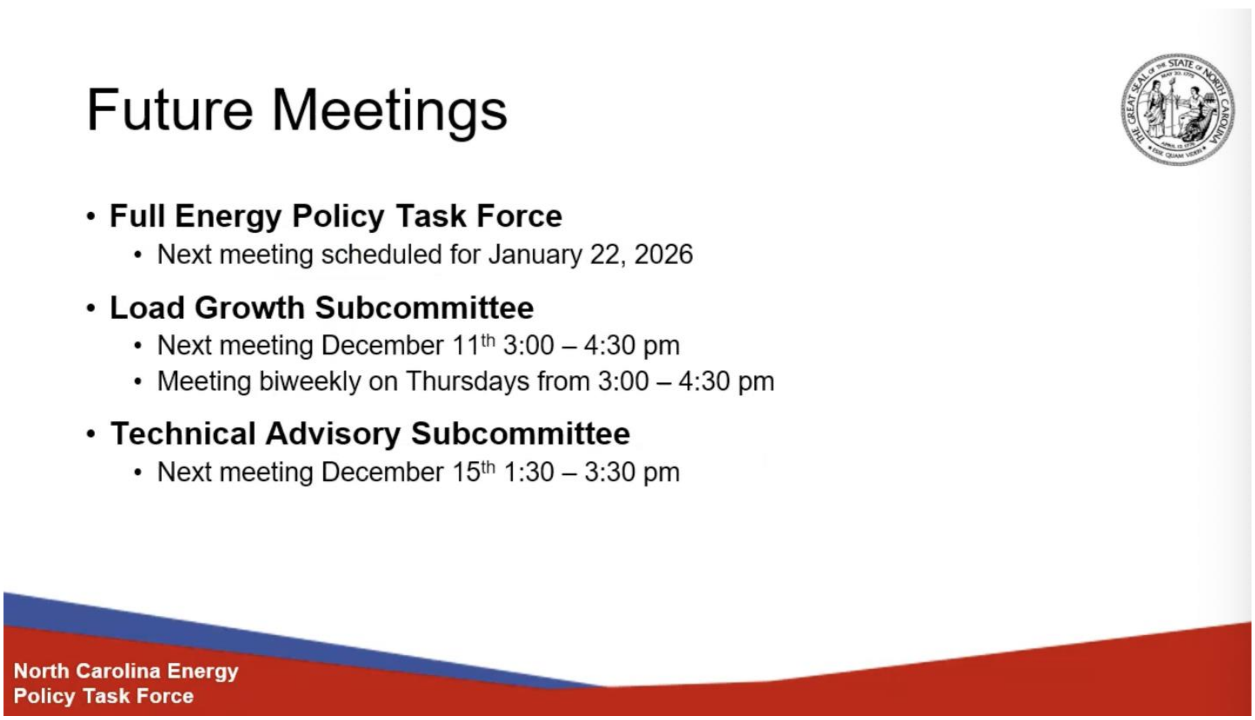
Small Group Discussion 2:45 PM - 3:25 PM

Summarized Readouts from Small Groups:

- Top priorities:
    - Addressing affordability for North Carolina ratepayers
        - Create structures that would allow us to act on what is already in the queue
        - Also a focus on storage coming online that could be quickly interconnected
    - Flexible flexibility that Virginia commission spoke about
        - Reinvest in current infrastructure
        - Grid Enhancing Technologies (GETs) items
    - Energy efficiency
        - make lasting investments in housing stock / households least able to handle an affordability crisis
    - Forecasting: what is coming through the system actually comes online
        - Intrigued by Virginia load growth forecasting
        - Take a hard look at what they are doing and see if we can learn from them
        - More certainty in queue positions
- cost / benefit of a state wanting or not wanting data centers
- Make sure there is some skin in the game/money up front
    - Large load tariffs and making sure that they adequately protect ratepayers; generation and T&D
- What are the problems that need solutions?
    - Speculative load that all customers would have to pay for
    - How do we meet this load growth while meeting statutory requirement to get to net zero
    - Barriers to large load customers bringing their own energy
    - Cost allocation issues
        - Time to take another look at cost of service methodologies
    - Speed to market issue: identified issue as large loads are looking to locate in North Carolina
- What are the approaches to focus on?
    - Large load tariffs potentially modeled after Virginia
    - Customers bringing their own energy still paying their fair share; robust process to figure out what that fair share is
    - Clean Transition Tariff or green tariff with additionality
        - Might attract those customers with clean energy goals to come do business in North Carolina
    - GETs / interconnection reform should be on the table
- the word “solution” presupposes a “problem.” What is the problem?
    - There is a perceived problem or a problem that could materialized, but has not materialized yet
        - Attorney General, Commission, and General Assembly are all strong in North Carolina and could address

        - Worthy of letting those things play out in North Carolina to see if there is a cross-subsidization issue
        - These solutions are worth existing; they are solutions to problems in other jurisdictions but unconvinced that they are happening here
- Goals to work towards: affordability, reliability, increasingly clean, encourages economic development
    - Large load tariffs – address speculation, help with forecasting, make sure that projects are actually real
    - Generation piece and BYOG: point that a lot of developers don't want to bring their own generation but would be interested in a utility-based program
    - Want to explore flexibility and the flexible flexibility idea raised in VA
    - Large load CPCN as a way to clearly ring fence around large load projects
- What needs to be done to implement some of these?
    - Flex-flex would require leg change, but a lot of these things the commission could probably change if there was interest

NEXT STEPS AND ADJOURNMENT 3:25 PM - 3:30 PM



- Not biweekly because of holidays

Questions:

Q: Are we still tracking having a report drafted by February? If so, will the next full task force review the draft iteration?

Answer: Yes and yes. Interim report and there will be a draft to review by the 22nd

MEETING ADJOURNED