REINHOLD ENVIRONMENTAL ®

2023 Reinhold/PCUG Round Table Presentation

Cohosted by Duke Energy and Vistra in The Westin Hotel, Cincinnati, OH on June 26-27, 2023

Continuing Evolution of Environmental Performance in the Electric Generating Industry

J. Michael Geers, P.E.

Reinhold Environmental Round Table Conference – June 27, 2023

Duke Energy At A Glance

One of the **LARGEST** energy holding companies in the U.S.

8.2 MILLION
Retail electric customers in **six** states

1.6 MILLION
Natural gas customers in **five** states

27k* EMPLOYEES

Headquarters: *Charlotte, N.C.*

We own and operate diverse power generation assets in North America, including a portfolio of **natural gas, coal, renewable wind, solar, energy storage, nuclear, hydro and microgrid projects.**

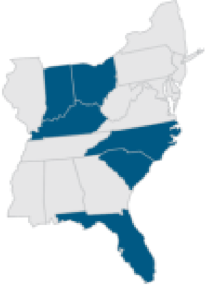
11,900 megawatts (MW) including 6,651 MW regulated and 5,279 MW commercial wind and solar owned, operated or contracted with an updated goal of **30,000 MW** wind and solar by 2035.**

$145+ BILLION
CAPITAL PLAN

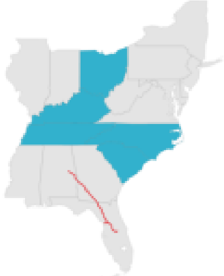
85% ($123 billion) funding investments in the grid and our clean energy transition.

* 27,859 employees as of December 31, 2022.
** Includes owned and contracted within our regulated jurisdictions.

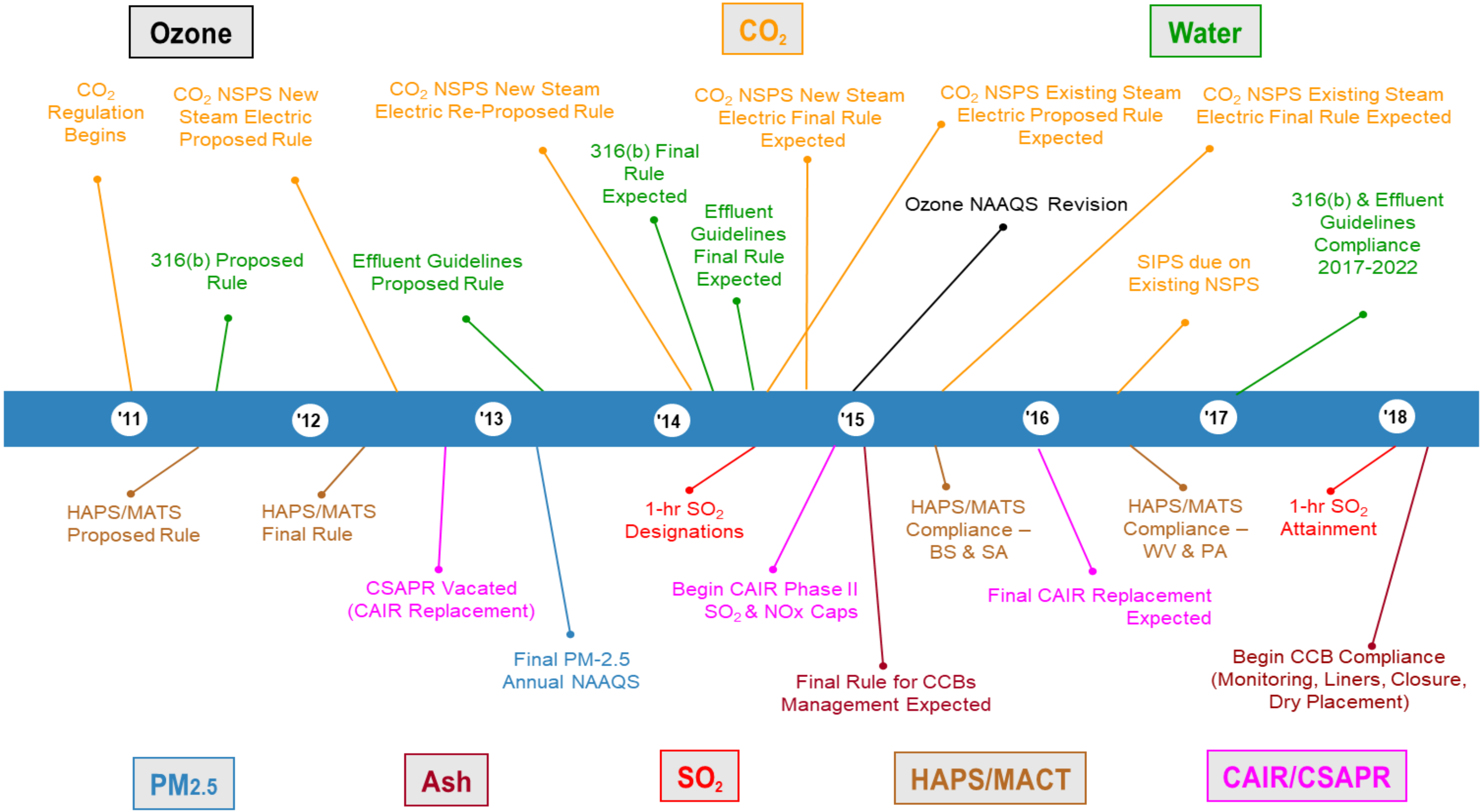
ELECTRIC UTILITIES & INFRASTRUCTURE



GAS UTILITIES & INFRASTRUCTURE

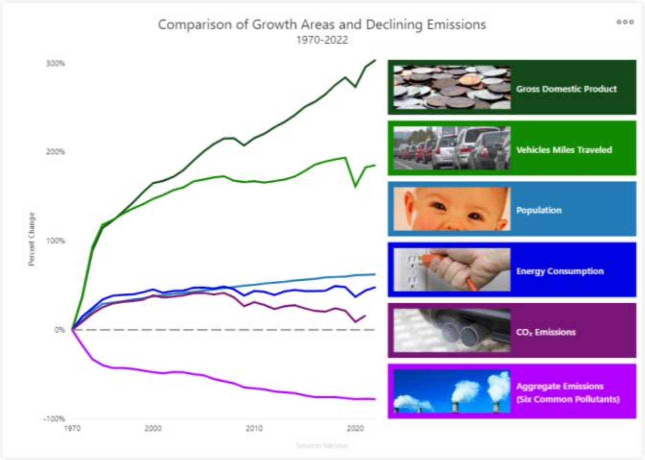


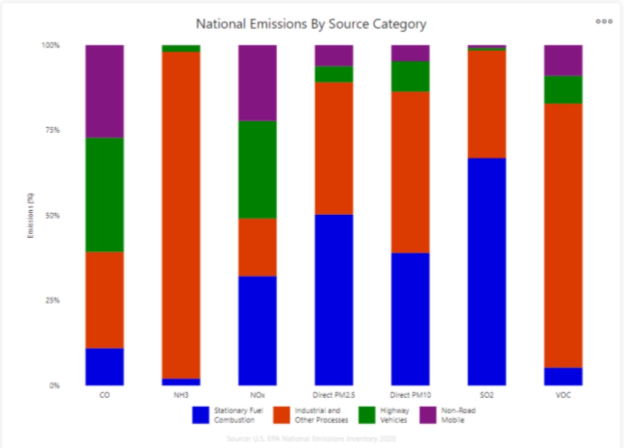
Past Industry Challenges – Environmental Regulatory Timeline

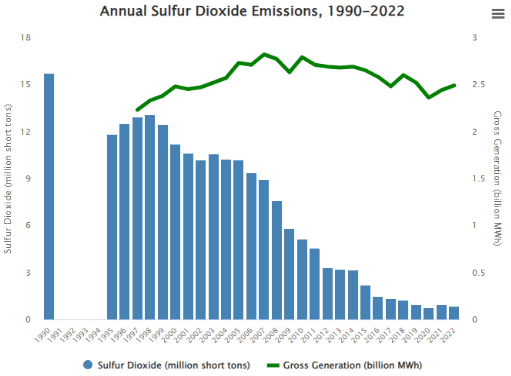


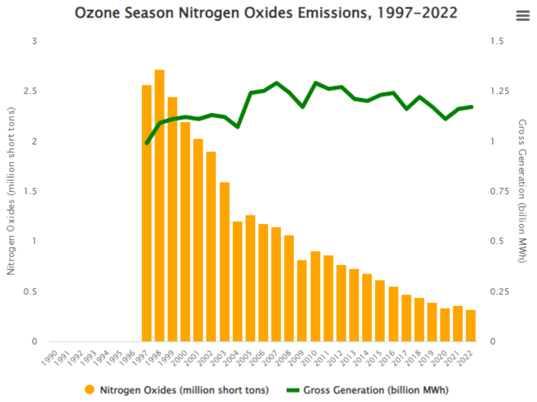
Adapted from Wegman (EPA 2003) 2013.7.1

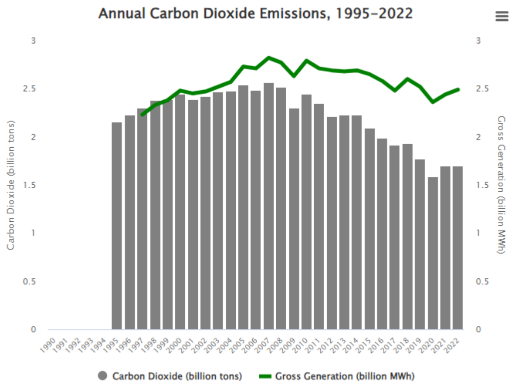
Air Quality and Emissions Trends











Duke Energy's View on Climate & Resiliency

SUSTAINABLE DEVELOPMENT GOALS
17 GOALS TO TRANSFORM OUR WORLD
7 AFFORDABLE AND CLEAN ENERGY
9 INDUSTRY, INNOVATION AND INFRASTRUCTURE

NET-ZERO BY 2050

The energy sector must transition for tomorrow in a way that also benefits society today. For our part, we're committed to achieving net-zero emissions by 2050. Our net-zero goal for electricity generation by 2050 and net-zero goal for methane emissions by 2030 serve as our north star, guiding our actions.

GHG TARGETS

We are leading our industry by addressing 95% of our Scope 1, 2 and 3 calculated greenhouse gas footprint. And we have interim targets - 80% reduction in our Scope 1 emissions by 2040 and 50% reduction for Scope 2 and certain Scope 3 by 2035.

TRANSFORMATION & COLLABORATION

We will achieve these transformative goals by expanding new and existing energy technologies and by collaborating with policy makers, industry peers and external partners on how best to meet this challenge.

Breakdown of Scope 1, 2, and 3 Targets

	Scope 1	Scope 2	Scope 3
Goals	**2030** • Reduce Scope 1 CO_2 emissions by 50% from 2005 • Achieve Scope 1 net-zero methane emissions from our natural gas distribution business • Coal to represent 5% of our generation mix **2035** • Exit coal generation **2040** • Reduce Scope 1 CO_2 emissions by 80% from 2005	**2035** • Reduce Scope 2 CO_2 emissions by 50% from 2005	**2035** • Reduce certain Scope 3 CO_2 emissions by 50% from 2005
What's Included	**Direct emissions from company facilities:** • Electricity generation • LDC pipelines • Company vehicles, etc.	**Purchased power for Duke Energy facilities that are not served by Duke Energy itself** • Electricity • Steam • Heating and cooling	**Category 3** • Fuel and energy-related activities not included in Scope 1 or 2 – upstream emissions from natural gas suppliers for natural gas distribution business • Upstream emissions (extraction, production, transportation) from purchased fossil fuels for electricity generation • Emissions associated with power purchased for resale **Category 11 – Use of Sold Products** • Emissions from the use of natural gas sold to customers

95% of our calculated greenhouse gas emissions – Net-Zero by 2050

Duke Energy's Road to Net-Zero

Where we've been
(2005 – 2022)

Where we're going
(2023 & beyond)

7,500 MW coal retired

6,000 MW regulated renewables[3]

44% CO_2 reduction by 2021[1]

2030
On track to exceed 50% Scope 1 reduction target[1]

Net-zero methane for LDC

2035
Interim target 50% Scope 2 & 3 reduction[2]

Out of coal[4] and **30,000 MW regulated renewables**[3]

2040
Interim target 80% Scope 1 reduction[1]

2050
Affirming net-zero Scope 1,2,3 target

(1) Off 2005 levels
(2) Off 2021 levels. Certain Scope 3 emissions include: upstream fossil fuel procurement, production of power purchased for resale, and downstream use of sold products in our natural gas LDCs
(3) Includes utility-owned and purchase power agreements
(4) Subject to regulatory approvals. Contemplates retiring Edwardsport coal gasifiers by 2035 or adding carbon capture utilization and storage to reduce carbon emissions

Emissions From Electric Generation

Scope 1 Emissions
Emissions From Electric Generation[1]

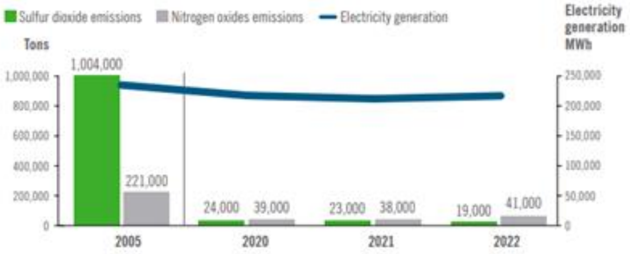
	2005	2020	2021	2022
CO_2 emissions (thousand metric/short tons)	139,000/ 153,000	74,000/ 82,000	77,000/ 85,000	**77,000/ 85,000**
CO_2 emissions intensity (pounds per net kWh)	1.29	0.78	0.79	**0.78**
SO_2 emissions (metric/short tons)	1,004,000/ 1,107,000	24,000/ 27,000	23,000/ 25,000	**19,000/ 21,000**
SO_2 emissions intensity (pounds per net MWh)	9.3	0.3	0.2	**0.2**
NO_x emissions (metric/short tons)	221,000/ 244,000	39,000/ 43,000	38,000/ 42,000	**41,000/ 45,000**
NO_x emissions intensity (pounds per net MWh)	2.1	0.4	0.4	**0.4**
CH_4 emissions (CO_2 equivalent) (thousand metric/short tons)	381/420	142/157	151/166	**123/135**
N_2O emissions (CO_2 equivalent) (thousand metric/short tons)	663/731	272/300	289/318	**231/254**

1 All data based on Duke Energy's ownership share of generating assets as of the end of each calendar year. Fuels used by Ohio Valley Electric Corporation (OVEC) are excluded because power from OVEC and associated emissions are accounted as purchased power and Scope 3 emissions.

Emissions From Electric Generation

Many factors influence emissions levels and intensities, including demand for electricity, generation diversity and efficiency, weather, fuel and purchased power prices, and emissions controls deployed. Since 2005, our carbon dioxide (CO_2) emissions decreased by 44%, sulfur dioxide (SO_2) emissions decreased by 98% and nitrogen oxides (NO_x) emissions decreased by over 82%. These decreases are primarily due to the addition of pollution control equipment for SO_2 and NO_x in previous years, replacement of coal generation with natural gas and renewables and increased dispatch of cleaner, more efficient plants. In 2021 and 2022, CO_2 emissions were somewhat higher than in 2020 due to increased generation as the economy began to rebound from the pandemic.

Sulfur Dioxide and Nitrogen Oxides Emissions (metric tons)[1] and Electricity Generation (thousand net megawatt-hours)



1 SO_2 and NO_x reported from Duke Energy's electric generation based on ownership share of generating assets.

Methane, Sulfur Hexafluoride and Power Purchase Emissions

Methane Emissions from Natural Gas Distribution (thousand metric/short tons)[1]				
	2019	2020	2021	2022
CH_4 emissions (CO_2 equivalent)	308/340	327/361	333/367	**322/355**

1 Methane emissions are calculated using a combination of EPA's Subpart W reporting and the NGSI protocol.

Sulfur Hexafluoride Emissions from Electric Transmission and Distribution (thousand metric/short tons)[1]				
	2019	2020	2021	2022
SF_6 emissions (CO_2 equivalent)	477/526	384/423	363/400	**230/254**

1 SF_6 emissions vary year to year due to maintenance, replacement and storm repair needs.

Scope 2 Greenhouse Gas Emissions (thousand metric/short tons)[1]			
	2020	2021	2022
Power purchases Estimated from power purchases for Duke Energy facilities that are not served by Duke Energy itself (CO_2 equivalent).	5.7/6.3	5.4/5.9	**4.4/4.8**

1 2020 and 2021 values have been updated to include purchased power for the commercial business, the same approach used to calculate the 2022 values.

Methane Emissions From Natural Gas Distribution

Methane (CH4) is the primary component of natural gas and is a greenhouse gas. Duke Energy announced in October 2020 its goal of reducing methane emissions in its natural gas distribution companies to net-zero by 2030. The emissions reported here are estimates pursuant to EPA's Subpart W reporting and the Natural Gas Sustainability Initiative (NGSI). Subpart W has a prescribed methodology for capturing emissions from facility counts such as miles of pipe, customer meters, and numbers of services using standardized emissions factors and the NGSI accounts for other data points that are not included by EPA such as emissions from meters, blowdowns and third-party damages.

Sulfur Hexafluoride Emissions

Sulfur hexafluoride (SF6) is a greenhouse gas that is used as an insulating gas in high-voltage electric transmission and distribution switchgear. We work to minimize SF6 emissions, but some are released during operations and maintenance. We continue to work with leading industry research institutes on improved SF6 leak detection technology. Duke Energy monitors equipment health, leveraging business intelligence reporting to support system reliability programs. The significant reduction of SF6 emissions in 2022 represents improved line of sight on data completeness and inventory validation, in conjunction with proactive equipment repair. We have identified and scheduled several projects for completion in 2023 to help mitigate SF6 emissions from equipment.

Scope 3 and Toxic Release Inventory Emissions

Scope 3 Greenhouse Gas Emissions

We have determined the emissions and identified the relevant Scope 3 categories in which we have adopted goals. We continue to share best practices and encourage peer utilities to decarbonize as we share reliance on Scope 3 progress. We also continue to work with customers on energy efficiency programs and strategies.

Scope 3 Greenhouse Gas Emissions (thousand metric/short tons)

	2020	2021	2022
Purchased goods and services: includes emissions from all purchased goods and services not otherwise included in the other upstream Scope 3 emissions.	Not calculated.	2,800/ 3,100	**3,800/ 4,100**
Fuel and energy-related activities[1]**:** (not reported in Scope 1 or 2). This is an estimate of CO_2 emissions associated with electricity Duke Energy purchased for resale (CO_2 equivalent).	13,300/ 14,600	15,600/ 17,200	**18,700/ 20,600**
Upstream emissions: (extraction, production, & transportation) from purchased fossil fuels for electricity generation	Not calculated.	5,500/ 6,100	**6,800/ 7,500**
Upstream emissions from natural gas suppliers for natural gas distribution business	Not calculated.	1,000/ 1,100	**900/ 1,000**
Use of sold products: CO_2 emissions from the use of natural gas that Duke Energy sold to its end use customers (CO_2 equivalent).	Not calculated.	6,600/ 7,200	**7,900/ 8,700**
Emissions: associated with other fuel purchases	Not calculated.	280/ 310	**280/ 310**
Waste: includes emissions from treatment and disposal of both solid waste and wastewater.	Not calculated.	51/56	**30/33**
Employee travel: estimate of CO_2 emissions associated with employee travel (CO_2 equivalent) including air travel and hotel stays.	4.9/5.4	4.2/4.7	**7.9/8.7**

1 2021 values have been updated to include purchased power from PJM into DEO, the same approach used to calculate the 2022 values.

Toxic Release Inventory (TRI)

Duke Energy's TRI releases for 2021 were down 91% from 2007, primarily due to the significant investments we've made in environmental controls for our power plants, and decreased coal generation. (Data for 2022 will be available in August 2023.)

Toxic Release Inventory (thousand pounds)[1]

	2007	2019	2020	2021
Releases to air	97,969	4,259	3,210	**3,145**
Releases to water	257	162	159	**167**
Releases to land	22,052	8,290	7,000	**7,743**
Off-site transfers	155	3,122	508	**573**
Total	**120,434**	**15,832**	**10,876**	**11,629**

1 Data pertain to electric generation facilities Duke Energy owns or operates and where Duke Energy is the responsible reporting party. Totals do not add up exactly due to rounding.

Electricity Generated and Generation Capacity

Environmental Metrics

2022 Electricity Generated and Generation Capacity[1]	Electricity Generated (net megawatt-hours)		Generation Capacity (megawatts)	
	MWh (thousands)	Percent	MW	Percent
Total Carbon-Free	**89,613**	**40.8%**	**15,942**	**29.2%**
Nuclear	73,110	33.3%	8,907	16.3%
Wind	8,597	3.9%	3,194	5.9%
Conventional Hydro[2]	2,554	1.1%	1,338	2.5%
Solar[2]	5,352	2.4%	2,502	4.6%
Total Low-Carbon	**93,514**	**42.6%**	**19,686**	**36.1%**
Natural Gas	93,172	42.4%	19,642	36.0%
Fuel Cell	342	0.2%	44	0.1%
Total Higher-Carbon	**37,150**	**16.9%**	**16,647**	**30.5%**
Coal	36,792	16.7%	15,652	29.0%
Oil	358	0.2%	995	1.8%
Pumped-Storage Hydro	**(698)**	**-0.3%**	**2,300**	**4.2%**
Total	**219,579**	**100%**	**54,575**	**100%**
Purchased Carbon-free Generation (Includes PPAs)[2]	**11,301**	**5%**	**3,930**	**7%**

2022 Electricity Generated and Generation Capacity

Duke Energy has a diverse, increasingly clean generation portfolio. Over 40% of the electricity we generated in 2022 was from carbon-free sources, including nuclear, wind, hydro and solar. Forty-two percent was from lower-carbon natural gas, which emits about half as much carbon dioxide as coal when combusted. Approximately 17% was from higher-carbon coal and oil. Taken together, owned and purchased renewables are equivalent to almost 11% of our electricity generation.

Regulated and Commercial Businesses Combined: 2022 Electricity Generated and Generation Capacity

2022 Electricity Generated*

2022 Generation Capacity*

*Excludes pumped-storage hydro.

1 All regulated data is based on the firm summer capacity of Duke Energy's ownership share of generating plants as of December 31, 2022. Commercial wind and solar is based on the nameplate capacity, with majority-owned assets presented at 100% capacity. Purchased carbon-free generation includes connected renewables (wind, solar, hydro) in Duke Energy's regulated service territories. It does not include purchased biomass or net-metered generation. Reduced capacity is used for plants with transmission capacity limitations. Totals do not add up exactly because of rounding.

2 See "Statement Regarding Renewable Energy Certificates" on page 74.

3 Pumped-storage hydro helps meet peak demand and, like other storage technologies, consumes more energy than it produces.

Fuels and Water Used For Electric Generation

Fuels Consumed for Electric Generation[1]	2008	2020	2021	2022
Coal (million tons)	63.1	19.7	19.9	**17.0**
Oil (million gallons)	231	19.4	27.3	**43.4**
Natural gas (billion cubic feet)	163	585	631	**737.1**

1 All data based on Duke Energy's ownership share of generating assets as of the end of each calendar year. Fuels used by Ohio Valley Electric Corporation (OVEC) are excluded because power from OVEC and associated emissions are accounted as purchased power and Scope 3 emissions.

Fuels Consumed for Electric Generation

Since 2008, the use of coal and oil as generation fuels has significantly decreased. These fuels are being replaced by cleaner natural gas and renewables.

Water Withdrawn and Consumed for Electric Generation (billion gallons)	2016	2020	2021	2022
Withdrawn	5,341	4,696	4,924	**5,059**
Consumed	74	125	111	**79**
Consumption intensity (gallons per MWh generated)	337	594	516	**403**

Data for 2021 and 2022 were developed using processes aligned with the CDP Water methodology. Data are not consistently available at time of publication to apply this methodology to earlier years.

Water Withdrawn and Consumed for Electric Generation

Water withdrawn is the total volume removed from a water source, such as a lake or a river. Because of the once-through cooling systems on many of our coal-fired and nuclear plants, almost 98% of this water is returned to the source and available for other uses. *Water consumed* is the amount of water removed for use and not returned to the source.

Waste, Oil Spills and Regulatory Citations

Waste

Duke Energy nearly met its goal to recycle 80% of solid waste. We are working on strategies to minimize landfilled waste and continually improve performance on this goal. These strategies include planning to avoid waste generation, reuse and repurposing of generated materials, identifying reuse and recycling technologies and partners, and benchmarking with other companies to identify best practices. (This goal excludes Duke Energy Sustainable Solutions, which has a relatively small waste stream.)

Waste

	2019	2020	2021	2022
Solid waste				
▪ **Total generated** (thousand short tons)	118	108	110	**112**
▪ **Percent recycled**	77%	80%	79%	**75%**
Hazardous waste generated (short tons)	232	2,536	709	**730**
Low-level radioactive waste (Class A, B and C) generated (cubic feet)	140,331	128,739	102,382	**—**

1 Weights are estimated based on volumes where necessary. Excludes Duke Energy Renewables, which has smaller volumes, and large nonreplicable projects such as plant demolitions.

2 Hazardous waste generation fluctuates mainly due to maintenance projects. For example, in 2020, a very large maintenance project was completed at one of our power plants.

3 Total of Class A, B and C waste disposal as reported to the Nuclear Regulatory Commission. Crystal River Unit 3 is not included in these statistics because it is not part of the operating fleet and is retired. Data for 2022 will be available later in 2023.

Reportable Oil Spills

Oil spills include releases of lubricating oil from generating stations, leaks from transformers, or damage caused by weather or by third parties (typically because of auto accidents).

Reportable Oil Spills to Water[1]

	2019	2020	2021	2022
Spills	17	18	16	**10**
Gallons	140	208	124	**514**

Environmental Regulatory Citations

Citations in 2019-2021 are mostly due to discharge reporting and compliance issues, which have been resolved with regulatory authorities.

Environmental Regulatory Citations[1]

	2019	2020	2021	2022
Citations	25	13	8	**11**
Fines/ penalties (dollars)	$97,558	$581	$18,399	**$7,975**

1 Includes U.S. federal, state and local citations and fines/penalties.

Emerging Technologies Will Complement Existing Generation Mix

Hydrogen and biofuel capable gas turbines

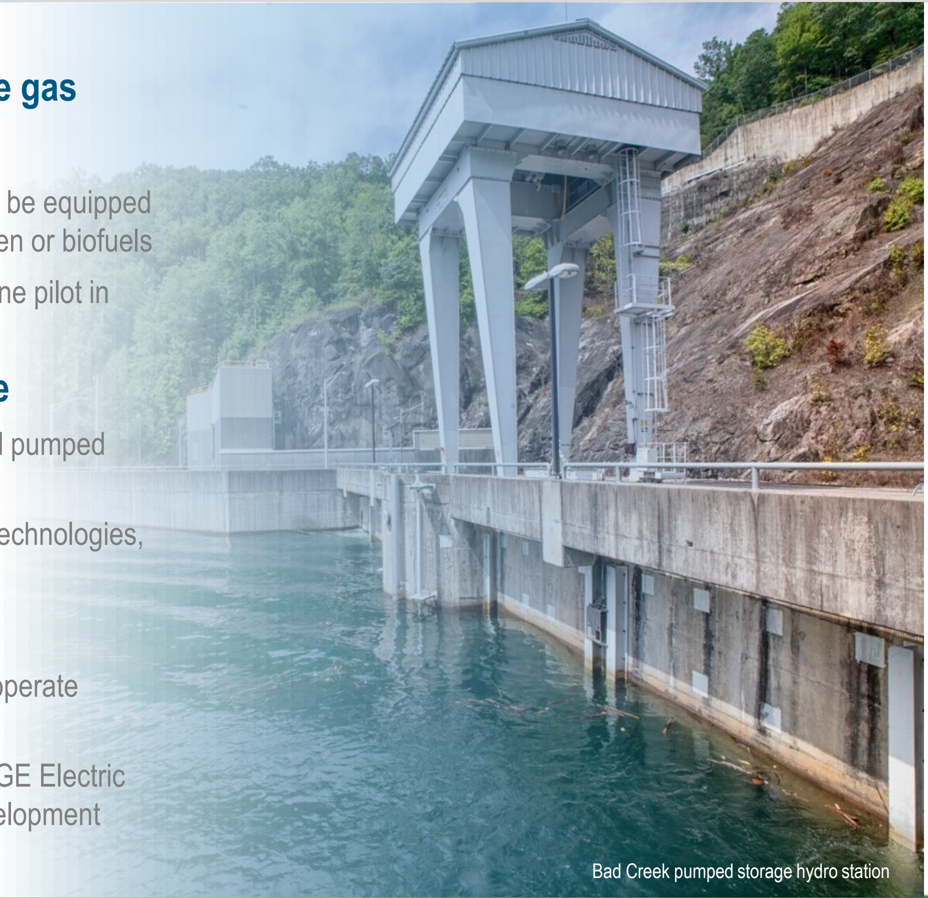
- Current and future gas plants will be equipped to run off alternatives like hydrogen or biofuels
- First solar-to-hydrogen-fired turbine pilot in Florida

Long-duration energy storage

- Evaluating potential for increased pumped storage capacity
- Piloting multiple battery storage technologies, such as flow batteries

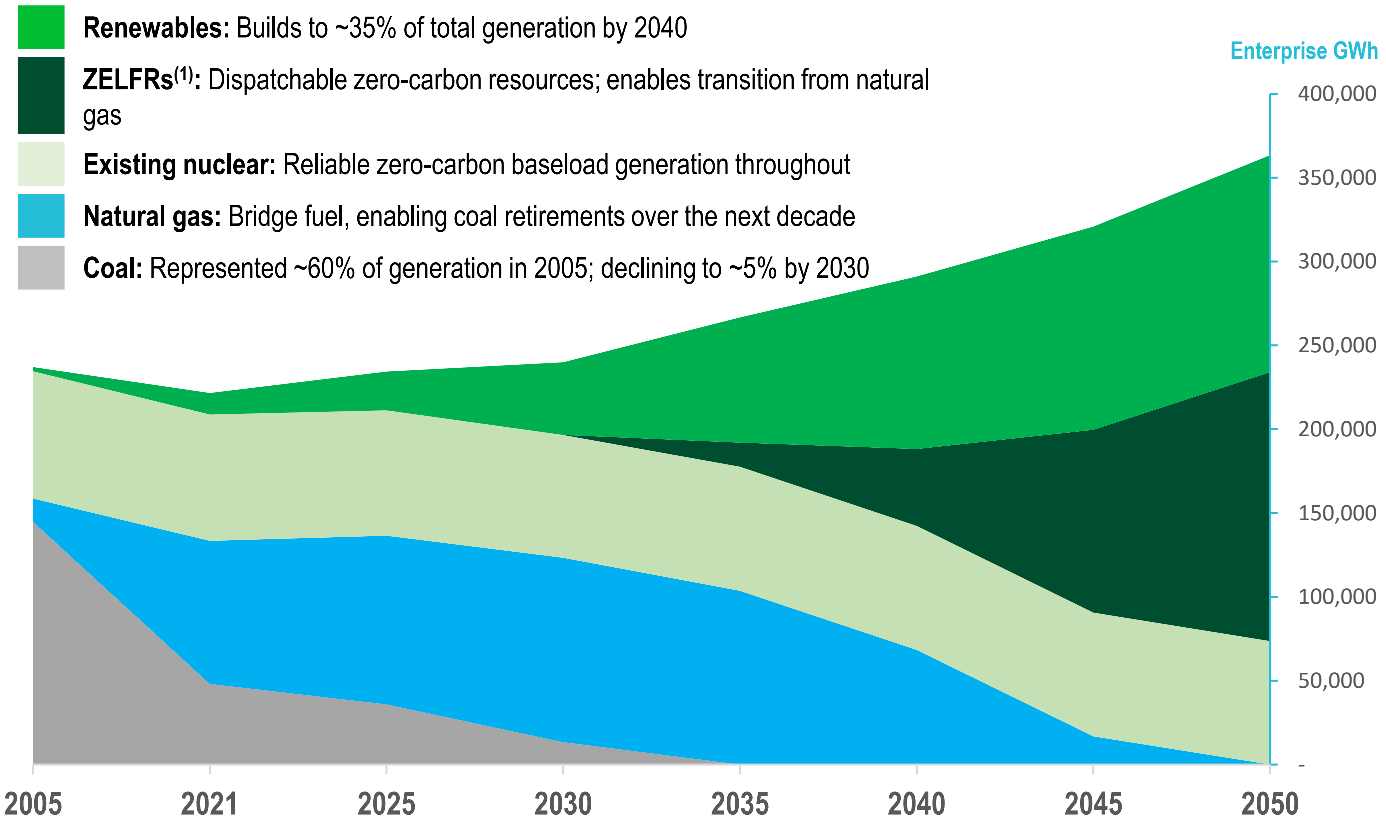
Nuclear

- Small modular reactors (SMRs) operate similar to current nuclear fleet
- Partnering with TerraPower and GE Electric Hitachi on advanced reactor development



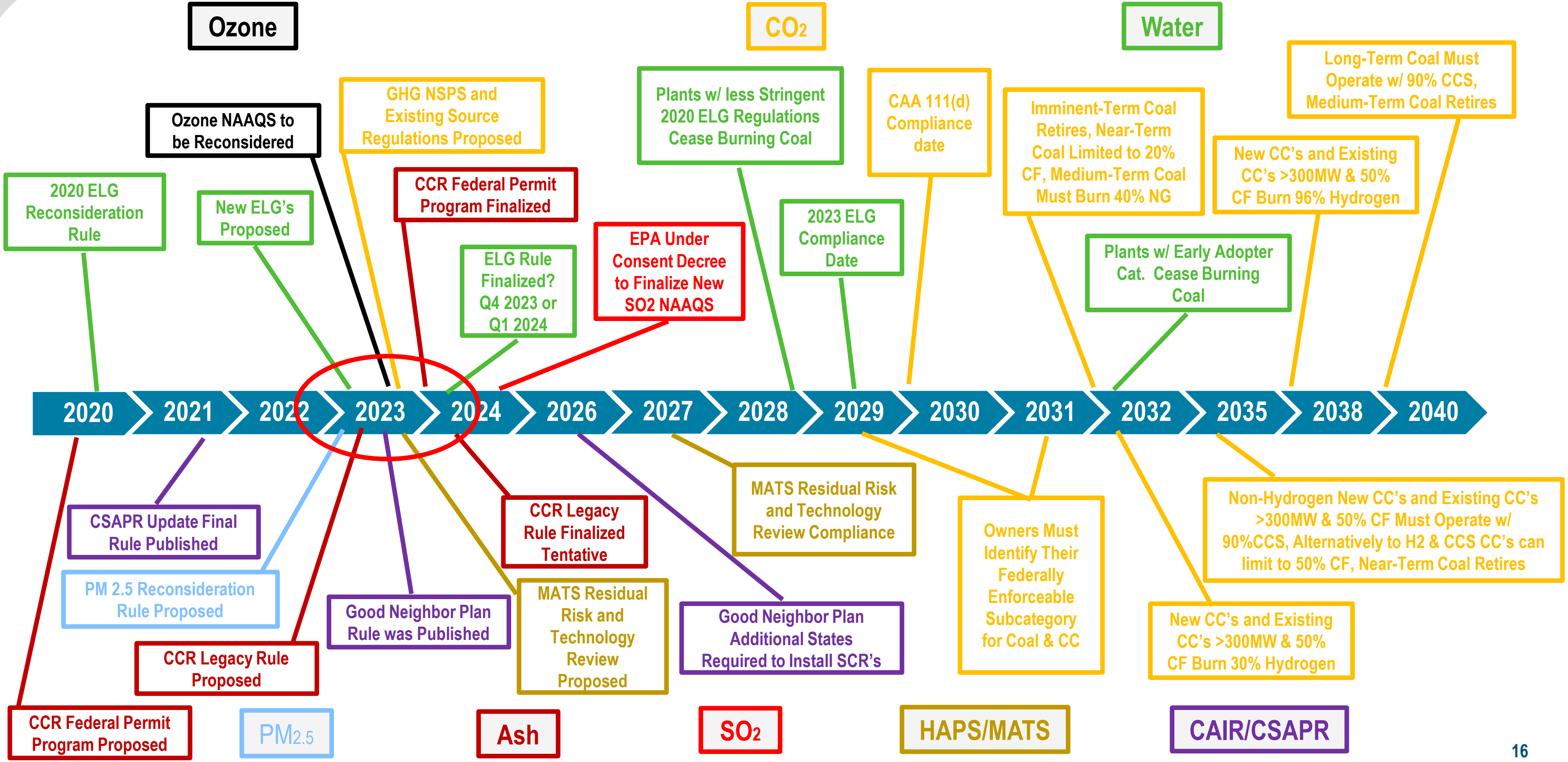
Bad Creek pumped storage hydro station

Diverse Generation Mix is Key to Reliability and Rate Stability



(1) Zero-emission load following resources (ZELFRs) include small modular reactors and turbines run-off of hydrogen or biofuels

Updated – Environmental Regulatory Timeline



EPA's Proposed CO_2 Standards for Electric Generating Units

Proposed EPA GHG Performance Standards for Fossil-Based Electric Generating Units – DRAFT (05/19/023)

	Proposed Best System of Emissions Reduction (BSER) and Resulting Performance Standards[1]				
	Through Dec. 31, 2029	Jan. 1, 2030 – Dec. 31, 2031	Jan. 1, 2032 – Dec. 31, 2034	Jan. 1, 2035 – Jan.1, 2039	2040 and beyond
111(d) – Existing Steam EGUs (coal-fired)*					
• Retire by 12/31/2031	No applicable standard	Routine operations/no emissions increases***	**Unit retired**		
• Retire 2032-2034	No applicable standard	20% annual capacity factor (CF) restriction***		**Unit retired**	
• Retire 2035-2039	No applicable standard	40% natural gas co-firing***			**Unit retired**
• Retire after 1/1/2040	No applicable standard	CCS at 90% capture rate***			
111(d) – Existing Steam EGUs (gas-fired)*					
• ≥45% Capacity Factor	No applicable standard	Routine efficient operations; 1,300 lb CO_2/MWh			
• <45% Capacity Factor[2]	No applicable standard	Routine efficient operations; 1,500 lb CO_2/MWh			
111(d) – Existing NGCC**					
• CCS option	1000 lb CO_2/MWh or current permit standard			CCS at 90% capture rate***	
• Hydrogen (H_2) option			30% hydrogen blending by volume (from 1/1/2032 until 1/1/2038)***	96% hydrogen blending by volume (after 1/1/2038)***	
111(b) – New NGCC*[3]					
• Base load > 45-55%*** (CCS option)	Highly efficient generation/best O&M practices 770 lb CO_2/MWh for > 2,000 MMBTU/h Units 770-900 lb CO_2/MWh for < 2,000 MMBTU/h Units			CCS at 90% capture rate 90 lb CO_2/MWh	
• Base load > 45-55%*** (H_2 option)	Highly efficient generation/best O&M 770 lb CO_2/MWh for > 2,000 MMBTU/h Units 770-900 lb CO_2/MWh for < 2,000 MMBTU/h Units		30% hydrogen blending by volume 680 lb CO_2/MWh (until 1/1/2038)	96% hydrogen blending by volume 90 lb CO_2/MWh (after 1/1/2038)	
111(b) – New CT*[2]					
• Intermediate – NGCC < 45-55% CF CT < 33-40% CF	Efficient operations 1,150 lb CO_2/MWh		30% hydrogen blending by volume 1,000 lb CO_2/MWh		
• Low Utilization (CT)***	Use of clean fuels (NG, Nos. 1 & 2 fuel oil); 20% annual CF restriction; 120-160 lb CO_2/MMBTU				

* States set emissions limits for existing units under Clean Air Act §111(d) that reflect EPA"s BSER. Under Clean Air Act §111(b), EPA sets emissions limits based on its BSER determination for new units.
** Only applies to NGCC units that are >300 MW with a capacity factor of ≥50%.
*** Actual CF restriction will be a unit-specific inquiry, based on design efficiency. States will set resulting performance standards using a unit-specific baseline emissions rate.

[1] A covered EGU is not required to use the technology identified as BSER, but instead to achieve an emissions rate equivalent to using the BSER. For existing units, the proposed regulations would allow states to authorize the use of various compliance flexibility tools to meet the standards (e.g., averaging, trading, banking, etc.).
[2] EPA does not propose a BSER or presumptive emissions rate for natural gas steam boilers that operate at capacity factors of less than 8%.
[3] New source standards are effective upon proposal, which is the date of *Federal Register* publication.

Proposed CO_2 Standards for Existing Steam Units

Proposed EPA GHG Performance Standards for Fossil-Based Electric Generating Units – DRAFT (05/19/023)					
	Proposed Best System of Emissions Reduction (BSER) and Resulting Performance Standards[1]				
	Through Dec. 31, 2029	Jan. 1, 2030 – Dec. 31, 2031	Jan. 1, 2032 – Dec. 31, 2034	Jan. 1, 2035 – Jan.1, 2039	2040 and beyond
111(d) – Existing Steam EGUs (coal-fired)*					
• Retire by 12/31/2031	No applicable standard	Routine operations/no emissions increases***	**Unit retired**		
• Retire 2032-2034	No applicable standard	20% annual capacity factor (CF) restriction***		**Unit retired**	
• Retire 2035-2039	No applicable standard	40% natural gas co-firing***			**Unit retired**
• Retire after 1/1/2040	No applicable standard	CCS at 90% capture rate***			
111(d) – Existing Steam EGUs (gas-fired)*					
• ≥45% Capacity Factor	No applicable standard	Routine efficient operations; 1,300 lb CO_2/MWh			
• <45% Capacity Factor[2]	No applicable standard	Routine efficient operations; 1,500 lb CO_2/MWh			

* States set emissions limits for existing units under Clean Air Act §111(d) that reflect EPA"s BSER. Under Clean Air Act §111(b), EPA sets emissions limits based on its BSER determination for new units.

Proposed CO_2 Standards for Combustion Turbines

111(d) – Existing NGCC**			
• CCS option	1000 lb CO_2/MWh or current permit standard		CCS at 90% capture rate***
• Hydrogen (H_2) option		30% hydrogen blending by volume (from 1/1/2032 until 1/1/2038)***	96% hydrogen blending by volume (after 1/1/2038)***
111(b) – New NGCC*[3]			
• Base load > 45-55%*** (CCS option)	Highly efficient generation/best O&M practices 770 lb CO_2/MWh for > 2,000 MMBTU/h Units 770-900 lb CO_2/MWh for < 2,000 MMBTU/h Units		CCS at 90% capture rate 90 lb CO_2/MWh
• Base load > 45-55%*** (H_2 option)	Highly efficient generation/best O&M 770 lb CO_2/MWh for > 2,000 MMBTU/h Units 770-900 lb CO_2/MWh for < 2,000 MMBTU/h Units	30% hydrogen blending by volume 680 lb CO_2/MWh (until 1/1/2038)	96% hydrogen blending by volume 90 lb CO_2/MWh (after 1/1/2038)
111(b) – New CT*[2]			
• Intermediate – NGCC < 45-55% CF CT < 33-40% CF	Efficient operations 1,150 lb CO_2/MWh	30% hydrogen blending by volume 1,000 lb CO_2/MWh	
• Low Utilization (CT)***	Use of clean fuels (NG, Nos. 1 & 2 fuel oil); 20% annual CF restriction; 120-160 lb CO_2/MMBTU		

* States set emissions limits for existing units under Clean Air Act §111(d) that reflect EPA"s BSER. Under Clean Air Act §111(b), EPA sets emissions limits based on its BSER determination for new units.

** Only applies to NGCC units that are >300 MW with a capacity factor of ≥50%.

*** Actual CF restriction will be a unit-specific inquiry, based on design efficiency. States will set resulting performance standards using a unit-specific baseline emissions rate.

[1] A covered EGU is not required to use the technology identified as BSER, but instead to achieve an emissions rate equivalent to using the BSER. For existing units, the proposed regulations would allow states to authorize the use of various compliance flexibility tools to meet the standards (e.g., averaging, trading, banking, etc.).

[2] EPA does not propose a BSER or presumptive emissions rate for natural gas steam boilers that operate at capacity factors of less than 8%.

[3] New source standards are effective upon proposal, which is the date of *Federal Register* publication.

Continuing Evolution of Environmental Performance in the Electric Generating Industry

Questions

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