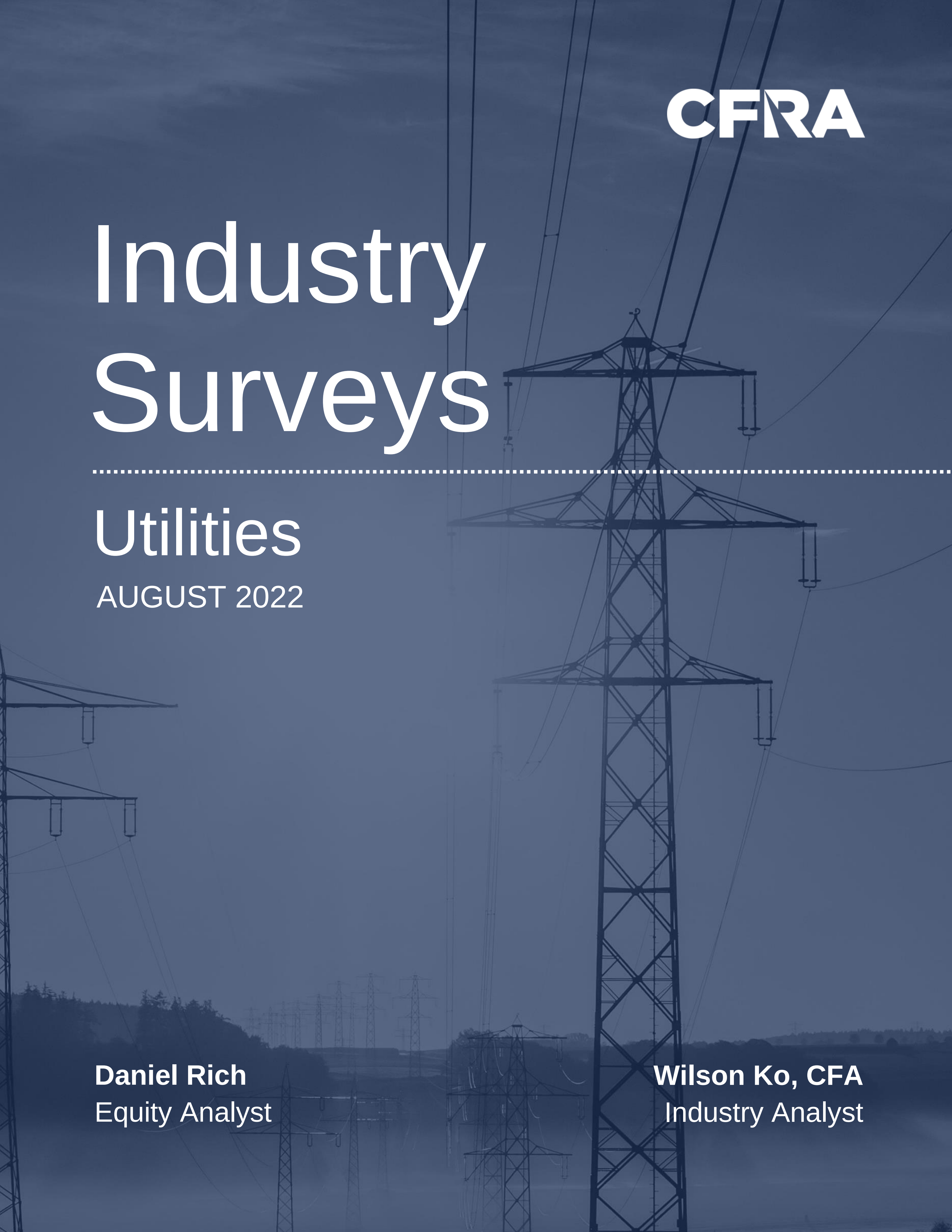

Industry Surveys

Utilities

AUGUST 2022

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NEW THEMES

What's Changed: In 2022, we expect a revenue decline for electric utilities on moderation of residential electric demand growth. Check out our Financial Metrics on pages 6-8.

What's Changed: While higher utility capital spending levels make sense for the long term, we think some utilities may slow capital spending in the near term as recession risk looms. See pages 13-14.

EXECUTIVE SUMMARY

Our 12-month fundamental outlook for the electric utilities sub-industry is neutral, balancing the negative impact of several near-term operating headwinds against projected record levels of capital spending (capex) that should support earnings growth, in our view. Below is a discussion of the key trends underpinning our outlook.

Industry Facing Headwinds from Slowing Electric Demand, Rising Rates, and Inflation

Given the recent inflationary effects on labor and equipment costs, we expect operations and maintenance expenses to remain high for electric and gas utilities. With the Federal Reserve aggressively increasing interest rates in an effort to combat inflation, utilities and other debt-heavy industries also face higher borrowing costs to issue new debt, which can be a consistent headwind against earnings. We see U.S. retail electric demand growing slowly in the near term, with potential downside if U.S. economic conditions, such housing starts and unemployment, begin to deteriorate in a recessionary environment. The U.S. Energy Information Administration (EIA) currently forecasts annual residential electricity sales to grow around 1.0%-1.5% in 2022, while commercial and industrial sales are expected to grow around 3.5% and 3.2%, respectively. In 2023, the EIA expects a 1.0%-1.5% decline in residential sales, flat to negative 0.5% growth in commercial sales, and 1.0%-1.5% growth in industrial sales.

Utility Commissions Grappling with Inflation, Rising Interest Rates in Upcoming Rate Cases

Spurred by higher natural gas prices, a key input for non-renewable power generation, we expect retail electricity rates to continue rising in the near term, with the residential average reaching 14.56 cents per kilowatt-hour (kwh) in 2022, followed by 14.93 cents/kwh in 2023, up from 13.72 cents/kwh in 2021 and 13.16 cents/kwh in 2020. With consumers dealing with higher energy bills, particularly in a midterm election year, we think utilities could face strong opposition in upcoming rate cases. For utilities without interim rate relief mechanisms, this situation can increase “regulatory lag” – the delay in time between when utilities make needed expenditures and when their regulators authorize new rates to recover the costs. Despite higher interest rates, electric utility authorized ROEs have not trended upward through the first half of 2022. Authorized ROEs trended downward in recent decades as interest rates declined, and we assumed authorized ROEs would begin to trend upward in a rising rate environment. However, as of August 9, 2022, the average electric utility authorized ROE in rate cases tracked by Regulatory Research Associates (RRA), part of S&P Global Market Intelligence, was 9.37%, flat with the full-year 2021 average of 9.38%, while average gas utility authorized ROE was 9.41%, below the full-year 2021 average of 9.56%. In our view, these trends suggest a lack of support at the regulatory level for granting higher utility returns at this time.

Capital Spending, Including Investments in Clean and Renewable Energy, at Record Highs

One factor that could sustain utility earnings through tough economic times is projected record levels of capex, including electric grid and gas main repairs and upgrades, investment in electric transmission infrastructure, and new clean power generation. Growing capex expands utility rate bases, provides opportunity for new rate increases, and can allow utilities to tap into tax incentives for clean energy investments. In 2022, we expect an approximately 9.1% increase in the electric sub-industry capex, a 24.5% increase for multi-utilities, and a 17.2% increase for gas utilities. Our overall estimate for 2022 capital expenditures is $139.5 billion, which would set a new record. Spending levels for 2023 are expected to grow 4.2% to $145.3 billion, with electric utilities showing 1.3% capex growth and multi- and gas utilities showing 10.2% and 2.9% growth, respectively, from 2022 levels. In a recessionary economic environment, however, current projected capex levels could prove to be too aggressive.

Industry Snapshot

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UTILITIES

Outlook: Neutral

MARKET CAP BREAKDOWN*

RANK NO.	COMPANY NAME	MARKET CAP ($ billion)
1	NextEra Energy	166.0
2	Duke Energy	84.6
3	Dominion	66.6
4	Sempra	52.1
5	American Electric Power Co	50.6
6	Exelon	45.6
7	Consolidated Edison	35.2
8	Public Service Enterprise	32.8
9	WEC Energy	32.7
10	Eversource Energy	30.6
	Others†	489.8

Source: CFRA, S&P Global Market Intelligence
*Companies included in the S&P Composite 1500 Electric, Gas, and Multi-Utilities indices; as of July 31, 2022.
†Refer to the Comparative Company Analysis section of this survey for other companies in both industries.

ETF FOCUS

ETF	AUM ($M)	Expense Ratio
XLU Utilities Select Sector SPDR	15,365.9	0.12
VPU Vanguard Utilities	5,519.8	0.10
FUTY Fidelity MSCI Utilities	1,760.9	0.08
IDU iShares U.S. Utilities	977.8	0.43

BY THE NUMBERS

2.5% Projected growth in U.S. retail electricity sales in 2022

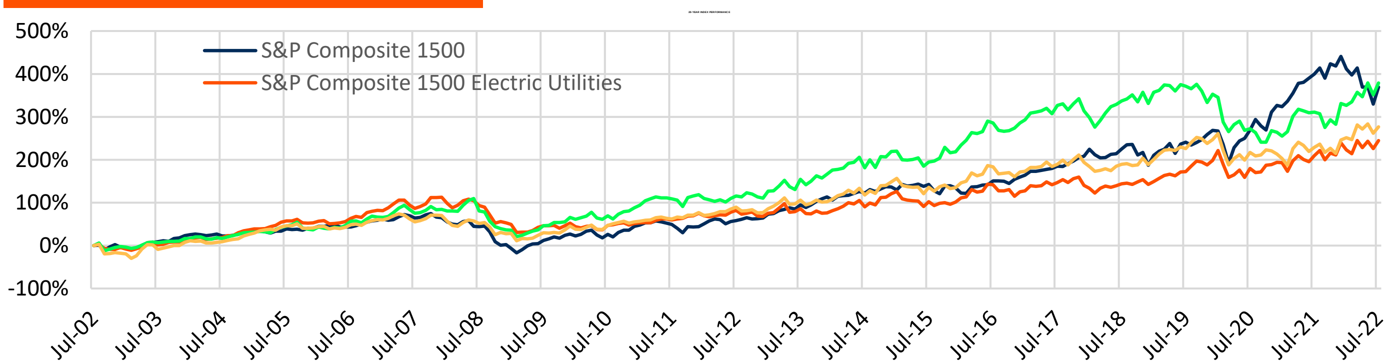
6.9% Consensus forecast utility sector EPS growth in 2022

$6.80 vs. $4.06 Expected Henry Hub natural gas spot price in 2022 vs 2021

$139.5 billion Projected capital spending by utilities in 2022

11.6% Electric utility P/E premium over 10-year average

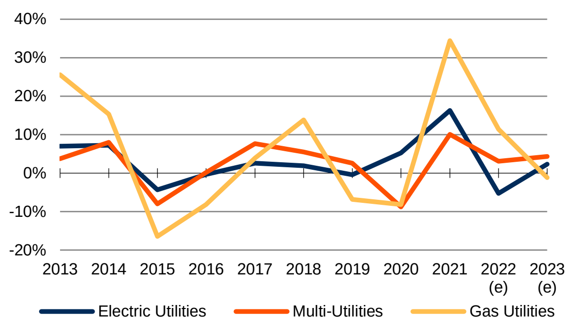
3.2% Average electric utility dividend yield



FINANCIAL METRICS

Revenue Growth

(percent)

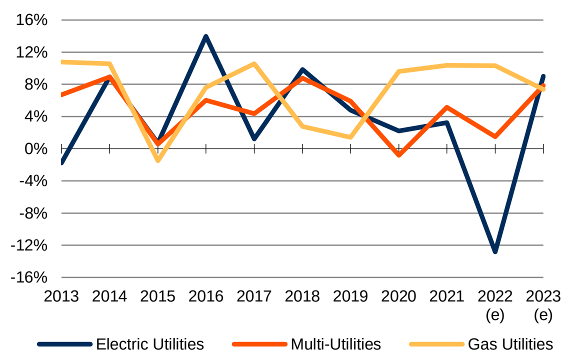


Source: CFRA, S&P Global Market Intelligence.

- Fueled by economic recovery, new rates, and stronger power prices, electric utilities booked 16.3% revenue growth in 2021, while multi-utilities and gas utilities grew revenue by 10.1% and 34.4%, respectively.
- Consensus forecasts suggest a 2022 revenue decline of 8.7% for electric utilities, while revenues for multi and gas utilities are expected to grow 5.8% and 13.6%, respectively. We feel these trends reflect a higher natural gas price environment as well as moderation of residential electric demand growth.
- With new rates and rising electric prices, we expect moderate (1.0%-1.5% electric; 2.5%-3.0% multi) revenue growth in 2023, while we think moderation in natural gas prices causes a small decline (around 2%) in gas utility revenue.

Earnings Per Share (EPS) Growth

(percent)

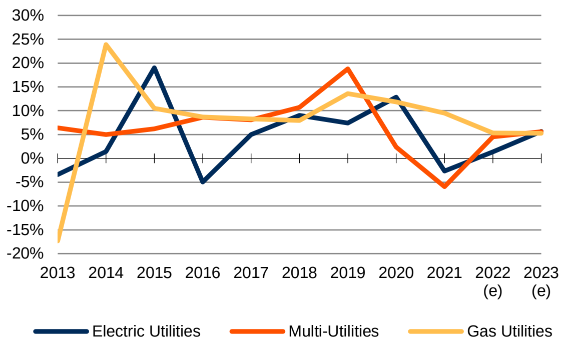


Source: CFRA, S&P Global Market Intelligence.

- In 2021, we saw EPS growth of 3.2% (electric), 5.1% (multi), and 10.4% (gas), bolstered by returns on transmission, pipeline, and other infrastructure investments.
- Consensus forecasts suggest average 2022 EPS growth of -12.8% for electric utilities, 1.7% for multi-utilities, and 9.6% for gas utilities. The outlook for 2023 is better, with forecasted average EPS growth of 9.5% for electric utilities, 7.6% for multi-utilities, and 7.4% for gas utilities.
- We think new new rate case decisions and increased capital spending will support utility earnings in the near term, though we think consensus forecasts could prove too aggressive if persistent inflation or an economic recession limits capital spending or new rate increases.

Annual Dividend Growth

(percent)

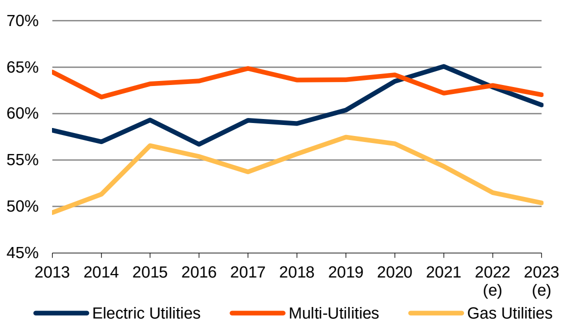


Source: CFRA, S&P Global Market Intelligence.

- Dividend growth plays a key role in the value proposition for utility investors. We saw lower dividend growth across the utility landscape in 2021, with many companies experiencing lower operating cash flows.
- In 2022, we expect dividend growth of 1.8% (electric), 4.4% (multi), and 5.6% (gas), marking a small recovery for electric and multi-utilities though continuing a multi-year trend of declining dividend growth for gas utilities. We see more consistent growth in 2023, between 5%-6%, across the sector.
- From 2016-2021, dividends grew at a compound annual growth rate of 4.4% for electric utilities, 7.1% for multi-utilities, and 10.0% for gas utilities, despite fluctuating net income.

Dividend Payout Ratios

(percent)

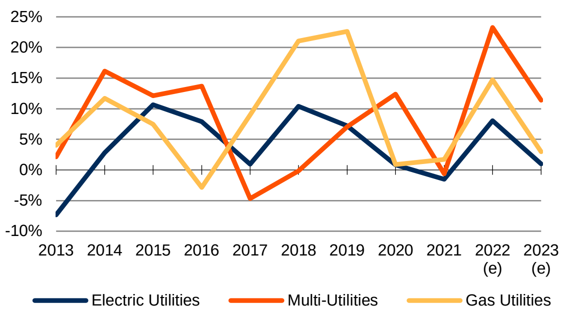


Source: CFRA, S&P Global Market Intelligence.

- Despite earnings fluctuations, consensus forecasts see little annual change in average dividend payout ratios of 63.2% (electric) and 62.9% (multi) in 2022. With EPS growing faster than dividends, we expect average dividend payout ratios to decline across the sector in 2023.
- For electric utilities, this would represent the fourth consecutive year of payout ratios exceeding 60%, while multi-utilities have seen payout ratios between 60% and 65% for several years now.

Capital Expenditures Growth

(percent)

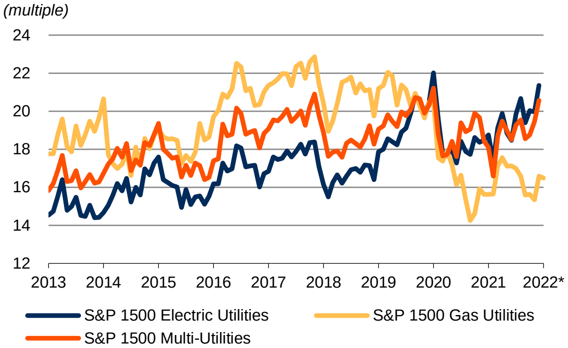


Source: CFRA, S&P Global Market Intelligence.

- In 2022, we expect increasing capital spending across all three sub-industries (electric +9.1%; multi +24.5%; gas +17.2%) and see sector capex reaching an all-time high of $139.5 billion (+14.1% vs. 2021). We currently expect capex of $145.3 billion in 2023 (+4.2%) with the assumptions that inflation will guadually ease in 2023, while unemployment rate remains low.
- In general, capital spending is driven by system modernization and upgrades, storm hardening, and new power generation, including wind, solar, battery, and other clean energy resources.

P/E Ratios

(multiple)



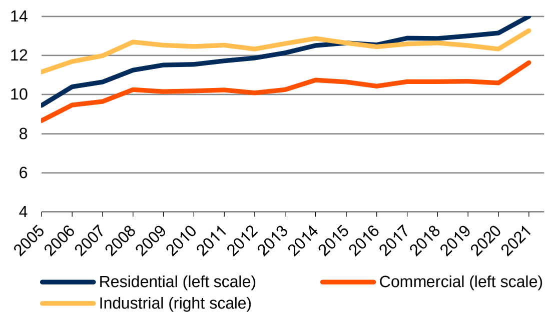
*Data through June 30.
Source: CFRA, S&P Global Market Intelligence.

- As of June 30, 2022, the forward P/E multiple was 20.8x for electric, 20.3x for multi-utilities, and 16.4x for gas utilities.
- Against their 5-year forward P/E averages, electric utilities were trading at an 11.6% premium, multi-utilities at a 5.4% premium, and gas utilities at a 13.2% discount.
- Given the environment of inflation, rising rates, and fear of recession, we think investor “flight to safety” to defensive industries helps explain the current premium valuation for electric and multi-utilities.

KEY INDUSTRY DRIVERS

Customer Electric Rates

(cents per kilowatthour)

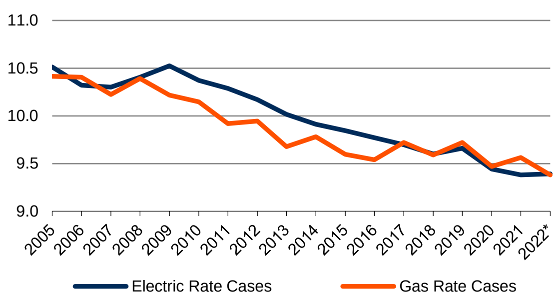


*Data through March.
Source: U.S. Energy Information Administration.

- Utilities' rate base is a key indicator of how the local government determines the price the utility company is allowed to charge its customers; therefore, it is a key component in determining customer rates.
- High and growing capital expenditure levels over the last few years have driven the rate base higher, leading to growth in customer rates (generally, more utility spending means higher bills for customers).
- As natural gas prices (key electricity input) remain high, we expect retail electricity rates to continue rising in the near term, with residential averages reaching 14.56 cents per kilowatt-hour (kwh) in 2022, followed by 14.93 cents/kwh in 2023, up from 13.72 cents/kwh in 2021 and 13.16 cents/kwh in 2020.

Allowed Return on Equity

(percent)

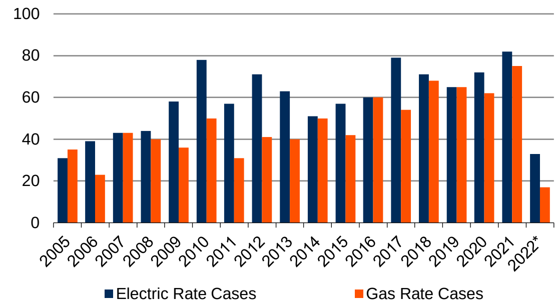


*Data extracted on July 13, 2022.
Source: S&P Global Market Intelligence.

- Return on equity (ROE) permitted by regulators for both electric and gas rate cases has dropped in the past couple of decades due to falling interest rates. In a rising rate environment, we expect there will be pressure from utilities to see increasing ROEs in their upcoming rate cases, which could a boon for earnings growth.
- However, in an environment of high inflation and potential recession, we think utility commissions may limit or delay new rate increases to protect consumer interests, which could be a drag on allowed ROEs.
- Overall, we expect average allowed ROE to remain flat or slightly increase in 2022, with better probability for rising ROEs in rate cases decided during 2023, in our view.

Number of Rate Cases

(numbers)



*Data extracted on July 13, 2022.

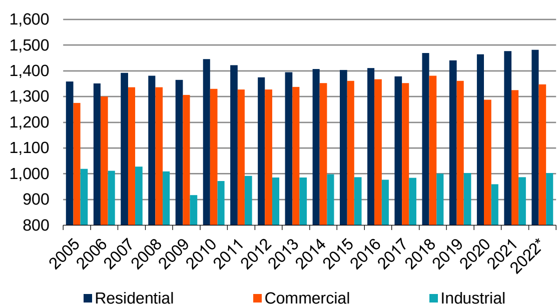
Source: S&P Global Market Intelligence.

◆ During the period immediately after several states deregulated their electric and gas markets in the late 1990s, rate case activity fell to exceptionally low levels.

◆ As rate freezes imposed by regulators began to roll off, utilities began to file additional rate cases. Going forward, we expect rate case activity to remain high as utilities regularly file new cases to reflect rising rate bases, especially given the need to invest in aging infrastructure.

Electric Usage by Customer Class

(billion kilowatt-hour)



*Last twelve months ended April 2022.

Source: U.S. Energy Information Administration

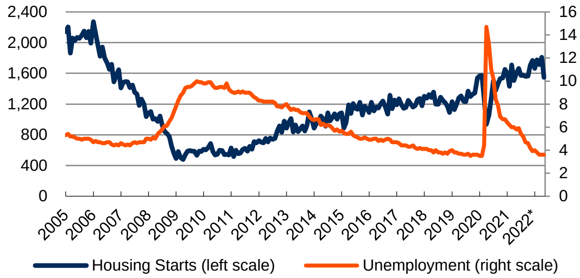
◆ Due to the pandemic, electric demand by commercial and industrial customers significantly declined in 2020, though we saw usage trends begin to normalize in 2021 as businesses reopened and many people left the home for work and travel.

◆ Based on EIA projections, we expect residential electric usage to grow 1.0%-1.5% in 2022, while we expect electric consumption growth by commercial and industrial customers to grow 3.5% and 3.2%, respectively.

◆ Recent EIA projections for 2023 indicate weaker electric demand ahead, with small expected declines in residential electric usage, flat commercial usage, and slight growth in industrial usage.

Housing Starts and Unemployment

(seasonally adjusted annual rate, in thousands) *(percent)*

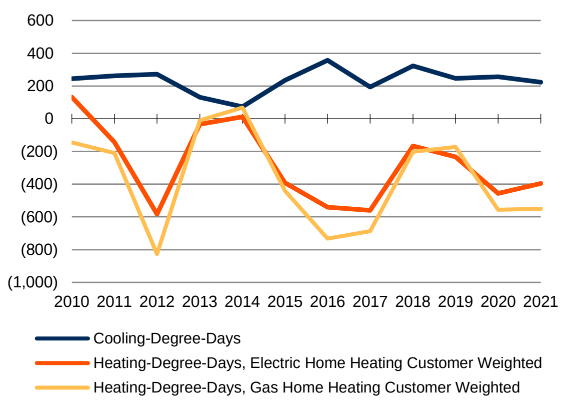


* Data through May.

Source: U.S. Department of Commerce.

Degree-Day Statistics

(Degree-day deviation from normal)



Source: CFRA calculations, National Oceanic and Atmospheric Administration's National Weather Service and Climate Prediction Center.

- Housing market growth can be an indicator of growth for residential electric and gas demand.
- The housing market had been in an extended upcycle that lasted roughly 15 years and ended in 2006. Starting 2009, after the financial crisis, housing started another upcycle. While the pandemic brought about a crash in housing starts in the first half of 2020, the market is enjoying a V-shaped recovery, with housing starts back to their pre-pandemic levels.
- In July 2022, the U.S. unemployment rate was 3.5%, well below recent high of 14.8% in April 2020. The recent unemployment rate is equal with the 3.5% rate in February 2020, before the pandemic hit the U.S., versus an average of 3.7% in 2019.
- U.S. housing starts are forecasted to grow 4.0% in 2022, while the unemployment rate is expected to average 3.6% in 2022, down from 5.4% in 2021, according to Action Economics.

- Degree days are measures of how cold or warm a location is. A degree day compares the mean (the average of the high and low) outdoor temperatures recorded for a location to a standard temperature, usually 65 degrees Fahrenheit in the U.S. The more extreme the outside temperature, the higher the number of degree days. A high number of degree days generally results in higher levels of energy use for space heating or cooling.
- Since around 1980, the number of heating degree days has decreased, and the number of cooling degree days has increased relative to the 20th century average. The recent increase in cooling days is driven by more frequent days above 65 degrees Fahrenheit and more frequent extreme high temperatures.
- We expect a continuation of higher degree days in the near term, but at a slower pace given the likeliness of efforts to reduce the effects of global warming.

INDUSTRY TRENDS

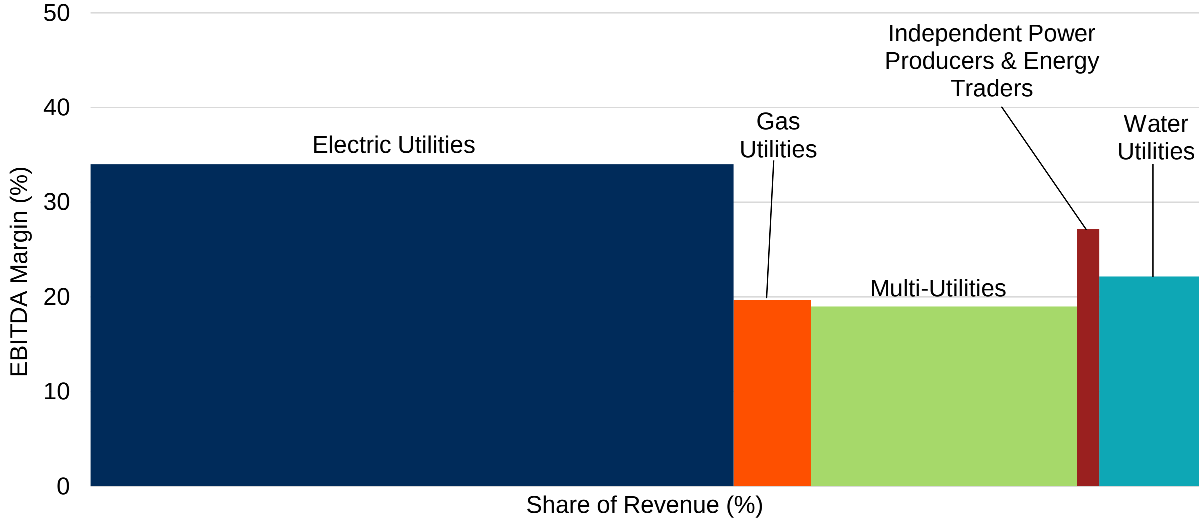
Competitive Environment

Below is a Porter's Five Forces Analysis, which highlights key aspects of the competitive environment we see for the Utilities sector.

Porter's Five Forces Analysis	
Degree of Rivalry/ Competition *(Very Low)*	The U.S. regulated generation industry is dominated by a handful of utilities in each state. Since utilities are granted franchises to be the sole providers by the states and cities that they serve, there is no competition for customers within their service area; still, the states and cities protect consumer interests through regulation. Utilities with competitive rates can attract businesses to their service area if other operating conditions are favorable.
Bargaining Power of Customers *(Low)*	Bargaining power of customers is low as electric and gas rates are set by regulators, although customer advocacy groups try to have an impact on the ratemaking process. Consumption by industrial users tends to be more sensitive to changes in economic activity and price than commercial or residential demand because industrial customers have greater ability and incentive to alter their consumption according to market forces. Industrial users have the highest customer bargaining power, while residential customers have the lowest.
Bargaining Power of Suppliers *(High)*	Bargaining power of suppliers is high as commodity fuels, such as natural gas, are the main inputs for power generators. Fuel costs routinely change based on fuel supply and demand patterns, and utilities often enter purchase-contracts and hedge-contracts to reduce risks of price swings that may not be captured by customer rate mechanisms. Utilities have some power to switch to plants with another fuel if the cost of a certain fuel increases relative to the others. For regulated gas distribution, utilities purchase natural gas from suppliers through purchase contracts and hedge contracts to reduce the volatility of gas cost pass-throughs to their customers. Both electric and gas utilities may be forced to purchase electricity, fuel, and natural gas from the wholesale markets if they need to supplement contracted resources.
Threat of Substitutes *(Very Low for Electric, Low for Gas)*	The threat of substitutes is low. Electricity and natural gas can sometimes be substituted for each other, but switching is rarely done. Additionally, for a vast majority of the demand for either product, there is low switching as doing so requires significant capital investment, especially for residential customers. However, energy efficiency policies and standards (such as improved appliance efficiency, utility energy efficiency rebates, etc.) are likely to hurt the electric, gas, and multi-utilities sub-industries since revenues are tied to delivered volumes. For gas utilities, we see the impact of increasing generation from renewable resources initially occurring slowly enough to maintain gas demand. However, over time, renewable resources could reduce gas demand from natural gas-fired generation units. As battery storage is introduced, gas-fired peaking plants could also start to be phased out, but we see this evolution taking many years.

Threat of New Entrants or New Entry *(Very Low)*	Barriers to entry are high as the U.S. electric, gas, and multi-utilities sub-industries are dominated by state or local government-sanctioned monopoly businesses that have exclusive rights and obligations to deliver power and natural gas to homes and businesses. Huge capital investments are required to build large electric and gas distribution networks, as well as to maintain and operate the systems.

PROFIT-POOL MAP OF S&P 1500 UTILITIES SECTOR
(for the last twelve months ended first quarter of 2022)



Source: CFRA estimates, S&P Global Market Intelligence.

Operating Environment

Electricity Consumption Trends
Following significant economic disruption for the U.S. Utilities industry due to the Covid-19 pandemic in 2020, electric volumes in the commercial and industrial sectors recovered in 2021 as the economy reopened and vaccinations were distributed nationwide. Residential electric demand reached higher levels in 2021 as work-from-home trends continued across many settings. Year-to-date EIA data through Q2 2022 (latest available) shows electric sales to residential customers were up 3.3% vs. the same point in 2021, while commercial sales were up 4.7% and industrial sales up 3.2%, respectively. We see U.S. retail electric demand growing slowly in the near term as U.S. economic conditions, such as housing starts and unemployment, could begin to deteriorate in a potential recessionary environment. The EIA currently forecasts annual residential electricity sales to grow around 1.0%-1.5% in 2022, while commercial and industrial sales are expected to around 3.5% and 3.2%, respectively. In 2023, the EIA expects a 1.0%-1.5% decline in residential sales, flat to negative 0.5% growth in commercial sales, and 1.0%-1.5% growth in industrial sales.

Capital Spending Updates and Projections
Constituents of the S&P Composite 1500 electric, multi, and gas utilities sub-industries saw capital spending decrease by around 1.1% in 2021 after increasing capex by 3.9% in 2020. Capital expenditures by electric, gas, and multi-utilities in the S&P Composite 1500 during 2021 totalled $122.3 billion, just below the $123.6 billion capex level in 2020, which was the highest annual level recorded for the industry. In 2022, we expect an approximately 9.1% increase in the electric sub-industry capex, a 24.5% increase for multi-utilities, and a

17.2% increase for gas utilities. Our overall estimate for 2022 capital expenditures is $139.5 billion, which would set a new record. Spending levels for 2023 are expected to grow 4.2% to $145.3 billion, with electric utilities showing 1.3% capex growth and multi- and gas utilities showing 10.2% and 2.9% growth, respectively, from 2022 levels. Considering the need to upgrade aging infrastructure, expand the nation's electric transmission systems, strengthen the power grid against severe weather events, and develop cleaner power generation sources amid the broader green energy transition, higher utility spending levels make sense for the long term. However, as the U.S. enters a possible recession in the near term, we could see some utilities start to slow capital spending or potentially delay certain investments to future years, especially if regulators grow stricter on permitting new rates or higher authorized ROEs due to inflation, a weakening economic environment, or other factors that may tip the scales towards consumer protection rather than utility interests at this time.

Natural Gas and Electricity Prices

The EIA projects average residential electricity prices will rise 6.1% in 2022, marking a nearly 11% rise in average residential prices from 2020, with higher natural gas prices (an input for nonrenewable electric generation) explaining much of the price increase, in our view. With lower gas inventories, strong export demand for liquified natural gas (LNG), and scarcity-driven demand from the Russia-Ukraine conflict, natural gas prices remain elevated above recent years. Rising gas prices mean higher expenses for gas utilities, though the higher price is generally passed through to customers via bill increases. Based on EIA data, the Henry Hub natural gas spot price averaged $4.06 per million British thermal units (MMBtu) in 2021 vs. $2.11 in 2020 and $2.67 in 2019. The price averaged $6.25/MMBtu in the first half of 2022. The EIA expects prices to remain high in 2022, with a forecasted average Henry Hub price of $6.80/MMBtu. In 2023, the EIA sees Henry Hub prices moderating to $5.10/MMBtu.

Weather

The National Oceanic and Atmospheric Administration (NOAA) recently forecasted a season of above-average hurricane activity, assigning a 60% chance of above-average hurricane levels between June 1 and November 30. NOAA also sees a continuation of La Niña, a climate phenomenon that makes hurricanes more likely near the Caribbean and Atlantic Ocean and less likely near the U.S. West Coast and Pacific Ocean. Utilities operating near the Gulf of Mexico or in the Southeast, as well as those with operations in Central America, could see more damage and outages due to hurricanes, leading to higher expenditures for grid response and repair, as well as potentially raising prices of fuel if electric or gas markets are disrupted. For the second quarter of 2022, EIA data shows that average U.S. cooling degree days were 12.9% higher relative to the prior-year quarter, indicating warmer temperatures. Recent sweltering weather could continue through the third quarter, as NOAA's recent three-month (August-October) temperature outlook assigned no region of the U.S. greater than equal chances of below normal temperatures. Large swaths of the Southeast, Midwest, and Pacific Northwest appeared to be have somewhat above equal odds of above normal temperatures, while parts of the Southwest and virtually all of the Mid-Atlantic and New England skewed towards even higher odds of experiencing above normal temperatures. Electric utilities rely on summer volumes driven by cooling demand, so a warmer summer could have a positive effect on electric utility revenues and earnings, while cooler temperates would likely have a negative effect. We note that many utilities have revenue decoupling mechanisms that insulate them from the effects of abnormal weather in their service territories.

The Continued Shift Toward Clean Energy

Renewables Continue Displacing Coal

According to the International Renewable Energy Agency (IRENA), out of the total renewable power generation capacity installed globally in 2021, 257 GW (or 81%) of the renewable power generation capacity added had electricity costs lower than the cheapest source of new fossil fuel-fired capacity, bolstering the economic case for transitioning to cleaner energy resources. Continued declining costs for wind and solar projects helped to make renewables the dominant source of new power generation, with the global renewable share of total generation capacity rose to 38.3% in 2021 from 36.6% in 2020, according to IRENA. With further cost reductions projected in the long term, wind and solar farms will increasingly threaten existing coal-fired plants, creating opportunities to lower power system costs and reduce carbon emissions by retiring uneconomic fossil fuel assets, in our view. Providing additional momentum for renewable energy, major utilities in the country have already pledged to slash their emissions by the mid-century. The tables below highlight some of the planned capacity retirements as well as additions.

U.S. PLANNED CAPACITY ADDITIONS AS PER FUEL GROUP

	Owned Planned Capacity (Megawatts)			
	Advanced Development	Early Development	Under Construction	Grand Total
Biomass	169	2,029	1,119	3,317
Coal		470	72	542
Gas	21,978	69,650	25,237	116,864
Geothermal	360	913	185	1,458
Nuclear	2,205	10,485	2,728	15,418
Oil		252	286	538
Other Nonrenewable	1,264	16,909	2,531	20,704
Solar	11,001	135,951	27,280	174,233
Water	2,512	15,492	2,851	20,855
Wind	20,808	104,185	21,024	146,016
Grand Total	60,296	356,336	83,313	499,945

*Includes all projects that are completed or expected to complete in 2022 and onwards

Source: CFRA, S&P Global Market Intelligence

U.S. APPROVED CAPACITY RETIREMENTS AS PER FUEL GROUP

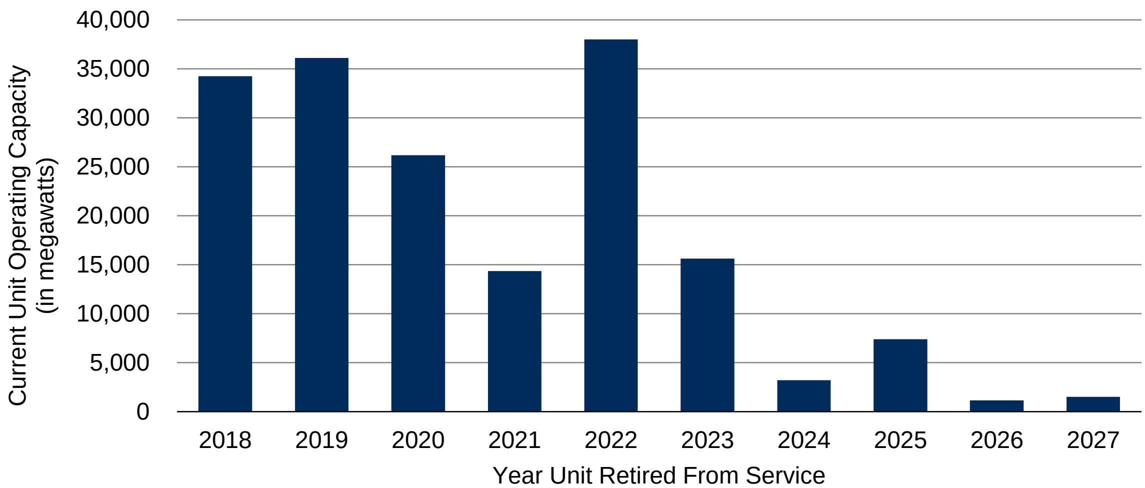
	Owned Planned Capacity (Megawatts)					
Year	Coal	Gas	Geothermal	Nuclear	Oil	Water
2022	9,696	1,889	31	816	290.8	188
2023	5,759	4,524			19	3
2024	1,478	4,499		2,154	32.4	
2025	5,873			6,698	7.5	
2026	1,149	481		1,268	3.3	
2027	755	522		1,078		
2028	7,225			6,260		
2029	448			2,122		
2030	2,540			2,628		
2031	766	1,213		903		
2032				3,338		

Source: CFRA, S&P Global Market Intelligence

Recent trends in the electric utilities industry—such as lower natural gas prices, slower growth of electric demand, and environmental regulations—have resulted in declining revenues and increased operating costs for coal plants. The decline in natural gas prices since 2008 has driven down electricity prices and payments received by generators for the electricity they produce. Lower natural gas prices also strengthen the competitiveness of natural gas combined-cycle (NGCC) power plants, lowering the cost of generating electricity from an NGCC plant to less than the cost of a nearby coal-fired plant. As a result, the coal plant is operated less often, thus earning less revenue and making it a candidate for retirement.

However, we saw a short-term turnaround of the declining coal trend as natural gas prices rose sharply in 2021, leading more power producers turning to coal for favorable economics. Natural gas prices averaged $2.11/MMBtu in 2020, but the price rose to an average of $4.06/MMBtu in 2021. As a result, U.S. coal production increased about 8% to 579 million short tons in 2021, and the EIA sees an increase of 21 million short tons (about 3.5%) in 2022, for a total of 599 million short tons. Despite this, the EIA expects that U.S. coal consumption will decline in 2022 and 2023 due to limited coal supplies and moderating natural gas prices. We also think more renewable power sources coming online will reduce the near-term and long-term demand for coal consumption.

COAL RETIREMENT SUMMARY



Source: CFRA, S&P Global Market Intelligence.

Wind and Solar Continue Upward Trajectory

Over the past decade (2012 to 2021), coal generation capacity shrank by 81,740 MW, while most of the new power plant capacity additions came from wind (75,299 MW), solar (59,237 MW), and natural gas (47,885 MW), according to S&P Global Market Intelligence (SPGMI), which expects solar additions (166,989 MW) to outpace wind additions (92,222 MW) from 2022 to 2031, while gas is expected to add additions of 35,444 MW during the period.

One reason why renewable additions should outpace gas additions relates to capacity utilization issues. Wind and solar generation capacity have low rates of capacity utilization—only one-third to one-fifth as much as fossil fuel technologies, according to *Public Utilities Fortnightly*, a trade publication. Because of this, 3 to 5 times as many megawatts of renewables capacity must be installed, compared to the megawatts of fossil fuel capacity being replaced, to produce equivalent megawatt-hours of electrical energy. Luckily, getting new wind and solar plants from concept to operations is much faster than that of large, combined cycle natural gas plants, meaning many more renewable projects can be added in each period, thereby addressing some of the excess capacity needs.

Aside from the declines in coal capacity and nuclear capacity, petroleum capacity is also expected to decline in the coming years, contributing to the market's increased reliance on natural gas, solar, and wind. Below are projected power plants capacity additions (broken down by fuel source) as well as the status of power plants currently under construction.

U.S. POWER PLANT CAPACITY PROJECTIONS

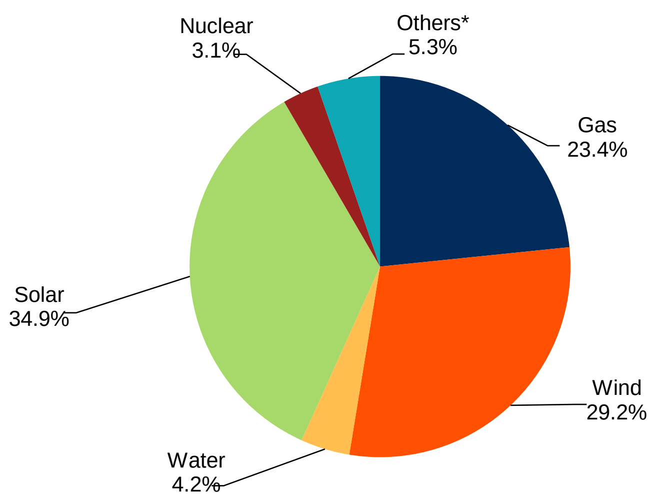
(all regions, in megawatts, arranged by 2021 capacity)

Fuel	2021	SHARE (%)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	SHARE (%)	10-YEAR CAGR *(in percent)*	TOTAL CHANGE 2021-2031
Gas	534,148	44.5	545,894	552,803	557,446	565,845	569,569	570,125	570,805	570,805	570,805	569,592	38.1	0.6	35,444
Coal	212,192	17.7	202,648	197,318	196,270	190,397	189,248	188,493	181,268	180,820	178,280	177,514	11.9	(1.8)	(34,677)
Wind	135,379	11.3	152,647	169,848	186,584	201,558	212,044	219,353	221,753	222,901	227,601	227,601	15.2	5.3	92,222
Water	104,225	8.7	104,117	105,021	105,086	105,277	106,586	107,924	113,940	115,341	118,840	121,090	8.1	1.5	16,865
Nuclear	98,555	8.2	97,739	99,967	98,845	97,727	96,459	96,181	96,501	94,939	95,256	95,453	6.4	(0.3)	(3,101)
Solar	62,928	5.2	96,250	169,353	210,372	226,053	229,066	229,861	229,916	229,916	229,916	229,916	15.4	13.8	166,989
Oil	29,063	2.4	28,808	28,795	28,763	28,763	28,763	28,763	28,763	28,763	28,763	28,763	1.9	(0.1)	(300)
Biomass	13,437	1.1	13,458	13,545	13,574	13,599	13,599	13,599	13,599	13,599	13,599	13,599	0.9	0.1	163
Other Nonrenewable	6,747	0.6	11,174	19,899	24,079	25,787	26,729	26,729	26,729	26,729	26,729	26,729	1.8	14.8	19,982
Geothermal	3,120	0.3	3,180	3,260	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	0.2	1.1	370
TOTAL	1,199,792		1,255,914	1,359,810	1,424,510	1,458,495	1,475,553	1,484,518	1,486,763	1,487,302	1,493,279	1,493,747		2.2	293,955

Note: Future capacity is based on actual planned and under construction projects, and not based on any projections of unreported new developments or retirements.

Source: CFRA, S&P Global Market Intelligence

POWER PLANTS UNDER CONSTRUCTION AND IN EARLY OR ADVANCED DEVELOPMENT BY PRIMARY FUEL TYPE
(for units slated to enter service through 2035)



Total: 499,945 MW

*Others include:

Coal	0.2%
Geothermal	0.1%
Other Nonrenewable	2.0%
Biomass	0.3%

Source: CFRA, S&P Global Market Intelligence.

NUCLEAR CAPACITY TO BE PERMANENTLY SHUT DOWN BETWEEN 2020 AND 2026						
PLANT NAME	ULTIMATE PARENT	YEAR UNIT(S) IN SERVICE	RETIREMENT/ LICENSE EXPIRATION YEAR	RETIRING CAPACITY (MW)	ISO/RTO	COUNTY, STATE
India Point	Entergy Corp.	1974, 1976	2020, 2021	2,066	NYISO	Westchester, NY
DAEC	Multi-owned	1975	2020	622	MISO	Linn, IA
Palisades	Entergy Corp.	1971	2022	817	MISO	Van Buren, MI
Diablo Canyon	PG&E Corp.	1985, 1986	2024, 2025	2,240	CAISO	San Luis Obispo, CA
Perry†	Energy Harbor	1987	2026	1,268	PJM	Lake, OH
TOTAL				7,013		

† Record from the U.S. Nuclear Regulatory Commission does not show pending review of a license renewal application for the facility

*Data compiled on July 16, 2022

Source: CFRA, S&P Global Market Intelligence

Battery Storage Could Transform the Power Sector

Natural-gas fired peaker plants—typically brought into service when demand for power rises and regular supplies are insufficient—could potentially be phased out gradually by the utility-scale battery storage powered by renewable energy. Peaker plants tend to retire after 40 years in service, and instead of reinvesting in those plants, batteries will probably replace them, in CFRA's opinion. While peaker plants are expensive to run, lithium-ion batteries, which have gotten cheaper over the recent years, are emerging as a competitive alternative to inject power into the grid, according to the *Wall Street Journal* (WSJ). The dollar value of the global battery energy storage market is expected to reach $31.2 billion by 2029, from $9.2 billion in 2018, according to *Fortune Business Insights*, a global research firm. CFRA thinks that the adoption of renewable energy powered battery storage will negatively impact the pure-play gas utilities, as renewables are a substitute for natural gas and reduce demand for natural gas distribution.

Battery storage can be built as a standalone installation, but the utilities pair lithium-ion batteries with nearby solar plants in what is known as "solar plus storage", with the solar power helping to charge the batteries which can serve as a store of power.

In December 2018, the New York Public Service Commission passed an initiative to double its state-wide energy storage target to 3.0 gigawatts (GW) by 2030, with an interim target of 1.5 GW by 2025. Other states such as New Jersey (2.0 GW by 2030), California (1.3 GW by 2020), Massachusetts (1.0 GW by 2025), and Oregon (5 MWh by 2020) also developed similar storage mandates, albeit at a smaller scale. In January 2018, Arizona regulators proposed a 3.0 GW energy storage target by 2030. In the same month, the Colorado Public Utilities Commission adopted an order requiring utilities to consider energy storage in their utility planning processes.

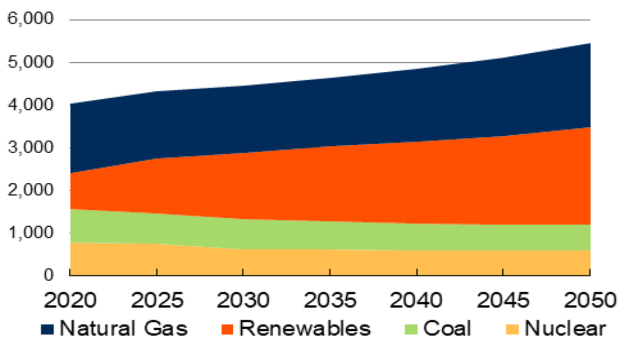
In July 2020, a federal appeals court upheld a major Federal Energy Regulatory Commission order (Order 841) designed to direct regional grid operators to remove barriers to energy storage participation in wholesale electricity markets. Order 841 creates a clear legal framework for storage resources to operate in all wholesale electric markets and expands the universe of solutions that can compete to meet electric system needs.

2021 saw the introduction of new battery storage infrastructure across the U.S., with 40 utility-scale installations combining for around 1.7 GW of storage capacity through the first three quarters, according to S&P Global Market Intelligence (SPGMI), which expected nearly 3.6 GW of additional battery storage to come online during the fourth quarter alone. Looking ahead, more storage projects are expected in the next two years, with 9 GW of additional capacity expected in 2022 and 10 GW expected in 2023, per SPGMI data.

Critical Need for R&D and Other Innovation Efforts to Achieve Emission Goals
Despite renewables gaining market share (see graphs below), countries and companies around the world will be unable to fulfill their pledges of net-zero emissions by 2050 without a critical acceleration in R&D and other innovation, according to a special report by the International Energy Agency (IEA). A significant part of the challenge comes from major sectors where there are currently few technologies available for reducing emissions to zero, such as shipping, trucking, aviation, and heavy industries like steel, cement, and chemicals.

ELECTRICITY GENERATION FROM SELECTED FUELS

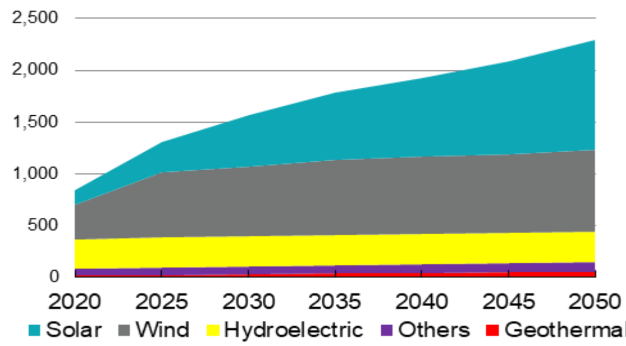
(gigawatts)



Source: EIA

RENEWABLE ENERGY GENERATING CAPACITY AND GENERATION

(gigawatts)



Source: EIA

Natural Gas Review

A Bull Case and a Bear Case
CFRA thinks there is potential for the share of natural gas in energy demand to rise even further than EIA estimates suggest, predicated on two concepts. First, burgeoning supplies, courtesy of the shale gas revolution. Second, potential fuel substitution by customers, and specifically switching away from coal, which we see as hampered by a litany of environmental woes. The healthy development of shale gas and the subsequent development of shale oil (which brings with it associated gas) have generated a deluge of production in the natural gas market.

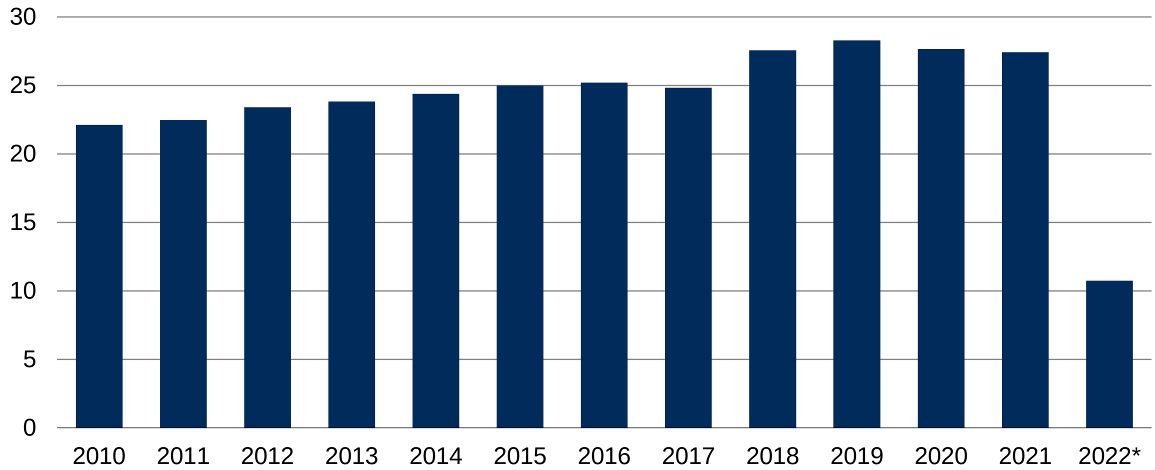
As of July 29, 2022, 20 states, including Arizona, Ohio, Texas, and Florida, have passed legislation against local measures to ban the use of natural gas in buildings, while several states introduced similar legislation which failed to advance in the most recent legislative session, according to S&P Global Commodity Insights. We think these trends signal political support in some jurisdictions for the continued usage of natural gas as a so-called "bridge fuel" in the medium term as the renewable power industry continues to expand supplies, lower costs, and develop nascent technologies like hydrogen and carbon-capture.

However, some recent developments also present a bear case possibility for natural gas. Some states, such as California, New York, and Washington, have adopted local building gas bans and electrification mandates, while other states have similar measures in development, according to S&P Global Commodity Insights. Longer term, we think the rapid expansion of renewable energy capabilities across the country, spanning solar, wind, battery storage, and other methods, theatens to reduce the nation's reliance on natural gas, putting some multi and gas utilities at risk for what is known as "stranded assets" or investments in gas infrastructure for which the utility is unable to recoup some or all of its costs due to social and regulatory shifts.

In 2021, total retail gas sales declined to 27.4 trillion cubic feet (Tcf), down 0.8% from 2020. In the first four months of 2022, total retail gas sales were 10.7 Tcf, up from 10.2 Tcf (5.0%) during the first four months of 2021.

TOTAL RETAIL GAS SALES VOLUME

(in trillion cubic feet)

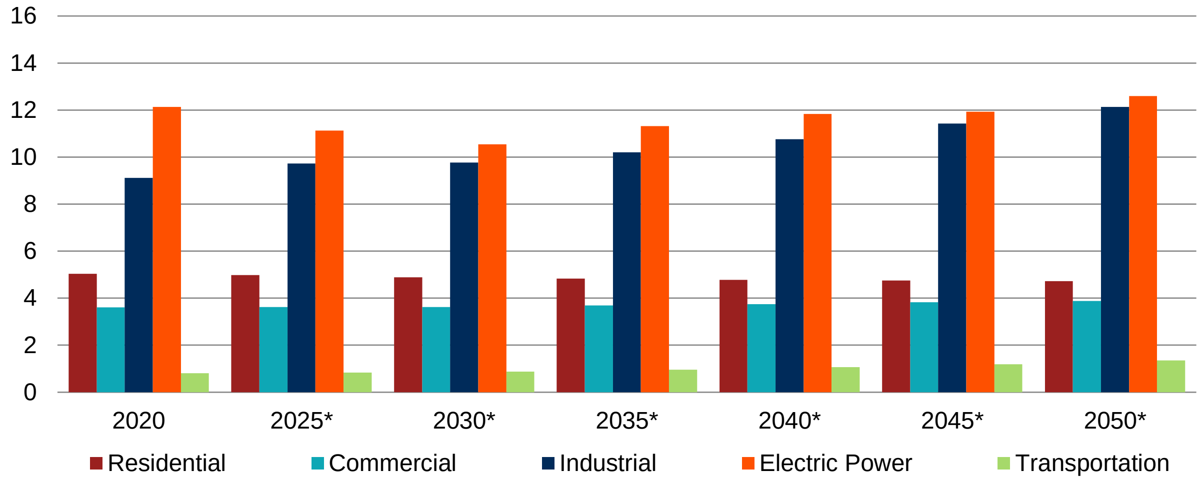


*Data through April.

Source: U.S. Energy Information Administration

Residential, commercial, and industrial customers, as well as electric power plants, use natural gas for a variety of purposes, including heat, power generation, and as the raw material for products such as chemicals and fertilizers. Each group displays markedly different responses to changing weather patterns, price levels, and economic activity. In the first four months of 2022, roughly 12.4 billion cubic feet (Bcf) of natural gas was consumed in the U.S.; 86.8% reached the various end-users, and 5.0% was used as lease and plant fuel in gas processing plants. Also, before the gas even reaches these customers, some of it is used for other purposes; 8.1% is used by pipelines to power compressors used to move the gas. See the chart below for long-term projections of consumption by segment.

NATURAL GAS CONSUMPTION BY SECTOR
(in trillion cubic feet)



*Projections.

Source: U.S. Energy Information Administration's "Annual Energy Outlook 2021".

Development of Natural Gas Pipeline Networks
There is a flurry of investments in new and expanding pipeline networks, despite some environmental pushback. As of July 18, 2022, there are 70 natural gas pipeline projects longer than 10 miles (either announced or under development/construction) in North America, according to the EIA.

Attached to the pipeline systems are many natural gas storage facilities, which store gas during periods of nonpeak demand to be able to maintain supply during peak demand times. There are 12 storage projects as of July 18, 2022, according to SPGMI, each with a capacity of more than 0.1 Bcf. As of April 2022, there were 412 active and inactive storage facilities, with total storage capacity of about 9.3 Tcf and total working gas capacity, defined as the total gas minus base gas capacity, of about 4.8 Tcf. Base gas capacity is the amount of gas needed to maintain adequate pressure in a storage reservoir during the withdraw season.

Numerous gas storage projects are in the works to accommodate increased gas usage and to improve reliability. The added storage capacity is likely to result in additional gas purchases during off-peak months to refill the storage fields in advance of the winter season, helping to smooth seasonal price fluctuations by increasing nonpeak demand and decreasing peak demand. The table below highlights some of the current projects in development as well as their respective operators.

GAS DEVELOPMENT PROJECTS FOR NATURAL GAS PIPELINES WITH CAPACITY ABOVE 500 MMcf/d
(arranged by estimated construction cost, in $, millions; year in service through 2025)

PROJECT NAME	OPERATOR	YEAR IN SERVICE	CAPACITY (MMcf/d)	ESTIMATED CONSTRUCTION COST ($, MILLION)
Mountain Valley Pipeline	Mountain Valley Pipeline, LLC	2023	2,000	6,200
Permian Pass Pipeline Project	Kinder Morgan Energy Partners	2023	2,000	-
Pecos Trail Pipeline	Namerico	2022	1,850	-
Gemini Gulf Coast Pipeline	Trace Midstream, Quantum Midstream	2022	1,500	-
Supply Header Project	Dominion Energy Transmission Co	2022	1,500	500
Regional Energy Access Project (Phase I and II)	Transcontinental Gas Pipeline	2023	1,050	-
Greene Interconnect Project	Mountain Valley Pipeline, LLC	2022	1,000	28
Tioga to Emerson Project	WBI Energy Transmission	2023	600	-

*Excludes cancelled, on-hold, pre-applied projects.
Source: CFRA, EIA

A Burgeoning Liquified Natural Gas (LNG) Industry

The secular drivers in favor of rising natural gas demand, with potential for further gains from fuel switching, have also led to the expansion of LNG markets. Previously a development only in Asia and Europe, many former U.S. regasification plants have been converted to liquefaction plants, enabling them to participate in the LNG markets by harnessing cheap U.S.-based natural gas, shipping it overseas, and selling it into gas-needy markets in Asia or Europe.

The U.S. is now to the world leader in LNG exports, with a peak capacity potential of 13.9 billion cubic feet per day. By year-end, the country is expected to operate seven major LNG export facilities and expects an eighth to come online in 2024.

LNG trade has burgeoned in recent years, and we expect upcoming reports to confirm a continued uptrend. In 2021, global LNG trade grew 4.5% to 372.3 mt, setting a record for eight straight years, according to the "2022 World LNG Report" published by the International Gas Union (IGU).

Consulting firm McKinsey expects global LNG demand to grow at a CAGR of 0.9% from 2020 to 2035, according to its "Global Gas & LNG Outlook to 2050" report released in February 2021. The share of LNG in global gas consumption is likely to expand from 13% in 2020 to 23% by 2050. Between 2020 and 2035, McKinsey expects both the global demand and supply of natural gas to increase at a CAGR of 0.4%.

GAS DEVELOPMENT PROJECTS FOR LNG WITH CAPACITY ABOVE 500 MMcf/d*
(arranged by year in service through 2026 and capacity, in $, millions)

PROJECT NAME	OWNER	YEAR IN SERVICE	CAPACITY (MMcf/d)	ESTIMATED CONSTRUCTION COST ($, MILLION)
Driftwood LNG Pipeline	Driftwood LNG Pipeline	2024	5,700	-
Rio Bravo Pipeline Project	Rio Bravo Pipeline Company	2023	4,500	2,173
Golden Pass LNG Bidirectional Pipeline	Golden Pass Pipeline LLC	2022	2,500	383
Louisiana Connector- Port Arthur Pipeline	Port Arthur Pipeline LLC	2023	2,000	1,207
Texas Connector-Port Arthur Pipeline	Port Arthur Pipeline LLC	2023	2,000	-
Gator Express Pipeline (Phase 1)	Venture Global Gator Express LLC	2022	1,970	-
Gator Express Pipeline (Phase 2)	Venture Global Gator Express LLC	2023	1,970	-
Gulf Run Pipeline	Enable Gas Transmission	2023	1,650	540
Corpus Christi Stage III Pipeline	Cheniere Energy Corpus Christi	2022	1,530	-
Evangeline Pass Expansion Project	Tennessee Gas Pipeline Co	2023	1,100	262
Acadiana Project	Kinder Morgan Energy Partners	2022	894	143

*Excludes cancelled, on-hold, pre-applied projects.
Source: CFRA, EIA

Reserve Margins, Transmission Projects, and Rate Cases

Power Supply/Demand and Reserve Margin Forecasts

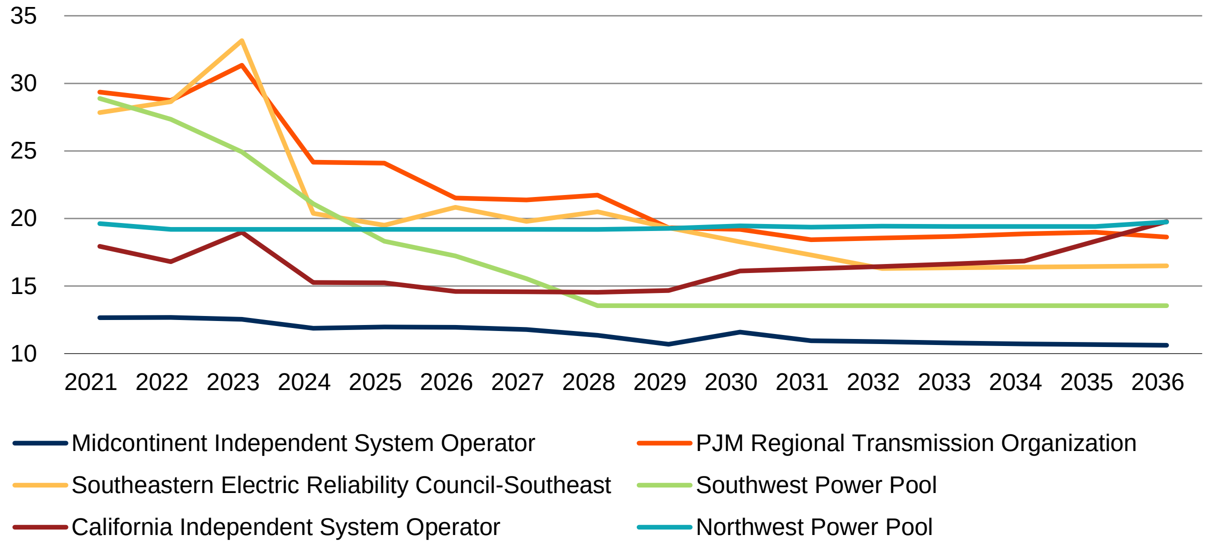
CFRA thinks that reserve margin forecasts are tied to the reduction in overall plant capacity from retiring coal and nuclear plants, and that the declining reserve margins will likely lead to higher power prices for the industry.

The anticipated reserve margin considers the amount of anticipated resources (capacity to generate) relative to net internal electricity demand. A reserve margin of 15% means that 15% of a region's electric generating capacity would be available as a buffer to supply the summer's peak hourly load. Anticipated reserve margins in most assessment areas are expected to meet or exceed corresponding reference margin levels until 2026 (each region aims to have their anticipated reserve margins surpass their planning reference margins), according to the "2021 Long-Term Reliability Assessment" published by the North American Electric Reliability Corporation (NERC).

In Texas, a large amount of new wind and solar generation was added, providing on-peak capacity to lift reserve margins for summer peak demand. However, extreme weather can affect both generation and demand and cause energy shortages that lead to energy emergencies in the Electric Reliability Council of Texas (ERCOT).

The retirements of conventional generating units and rapid addition of variable resources (primarily wind and solar) are changing the operating characteristics of the electricity business in certain areas, as well as presenting new challenges and opportunities for reliability. The NERC deemed that with the large additions of solar and wind generation, additional flexible resources are required to offset ramping and variability.

FORECAST RESERVE MARGIN
(in percent, as of Q3 2021)



Source: CFRA, S&P Global Market Intelligence.

New Major Transmission Projects
Electric utilities invest in their systems to provide reliable and economic electric service—addressing system needs, including meeting reliability requirements, modernizing, and replacing infrastructure, accommodating new and retiring electricity generation sources, and meeting public policy requirements. A total of 180 transmission projects in the U.S. that have been announced or are under development/construction stage will be completed from 2022 through 2031, according to SPGMI. These projects are at least 115 kilovolt (kV) and longer than 10 miles, and comprise new facilities as well as rebuilds and upgrades.

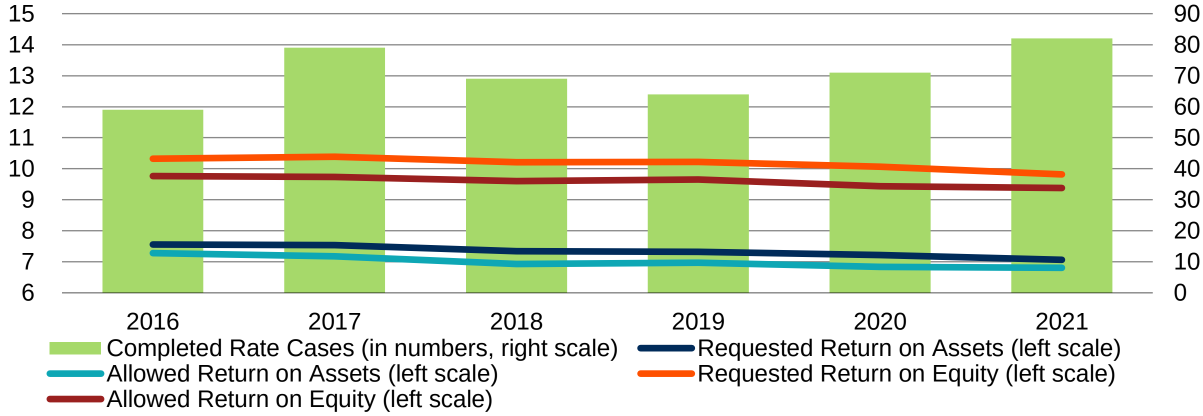
SPGMI estimates that all the transmission projects from 2022-2031 would record a total maximum construction cost of about $21.4 billion. Investments in transmission projects generate a wide range of benefits, such as providing reliable electricity service, relieving congestion, facilitating wholesale market competition, supporting a diverse and changing generation portfolio, mitigating damage and limiting customer outages in extreme weather, as well as deploying advanced monitoring systems and other new technologies designed to ensure a more flexible and resilient grid, according to the Edison Electric Institute (EEI).

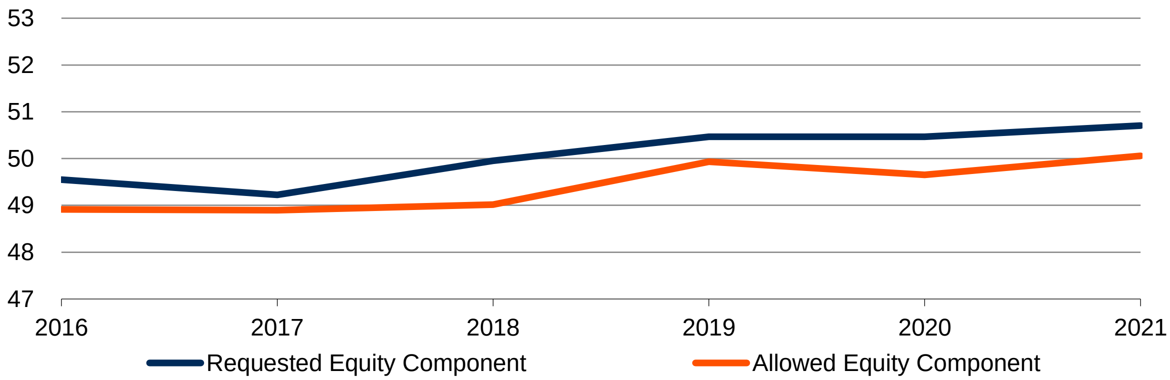
Electric Utilities Rate Cases
In 2021, a total of 82 rate cases were completed, with an average allowed return on equity (ROE) of 9.8%, allowed return on original cost rate of 6.8%, and allowed common equity to total capital of 50.1%,

according to SPGMI. In 2020, there were 71 rate cases completed with an average allowed ROE of 10.1%, allowed return on original cost rate of 6.8%, and allowed common equity to total capital of 49.7%.

Despite higher interest rates, electric utility authorized ROEs have not trended upward through the first half of 2022. Authorized ROEs trended downward in recent decades as interest rates declined, and we assumed authorized ROEs would begin to trend upward in a rising rate environment. However, as of August 9, 2022, the average electric utility authorized ROE in rate cases tracked by RRA was 9.37%, flat with the full-year 2021 average of 9.38%, suggesting a lack of support at the regulatory level for granting higher utility returns at this time, in our view.

ELECTRIC RATE CASE METRICS
(all values are in percent except as noted)





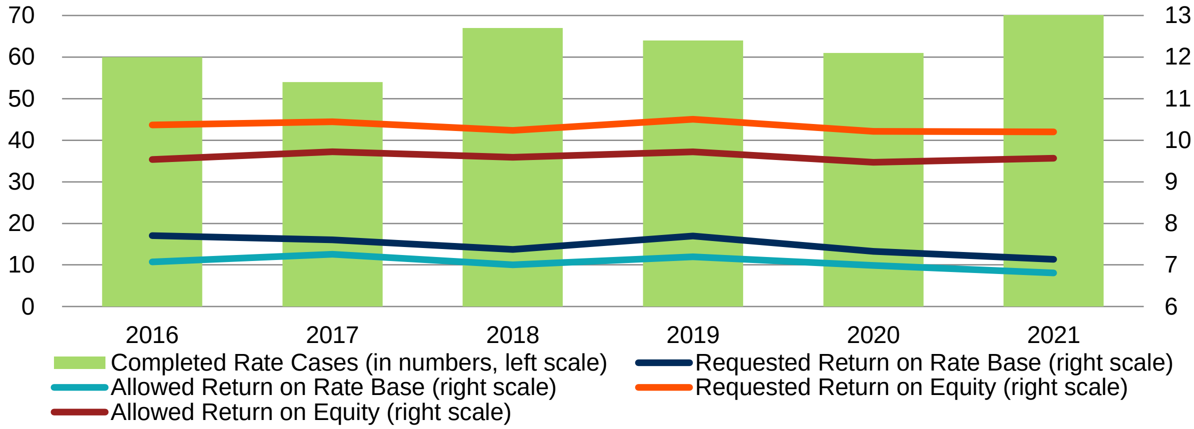
Source: CFRA, S&P Global Market Intelligence.

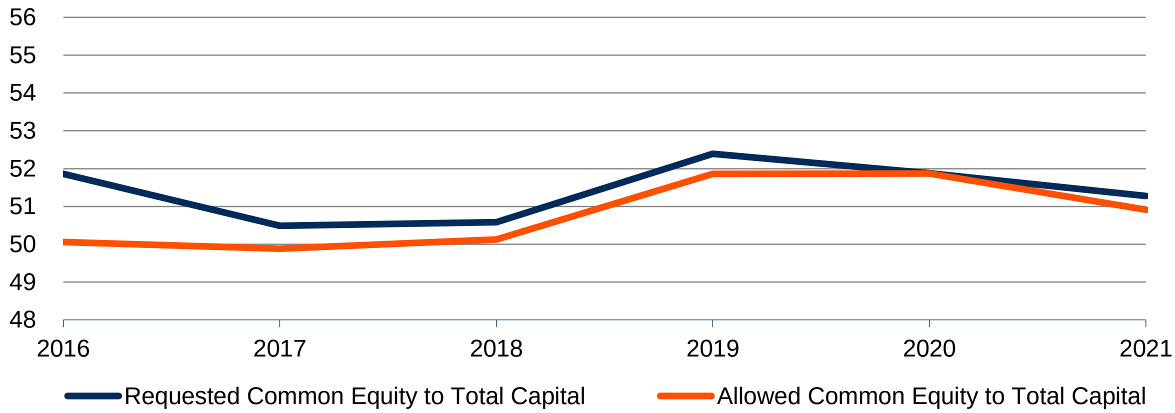
Gas Utilities Rate Cases

In 2021, 70 gas rate cases were completed, with an average authorized ROE of 9.6%, allowed return on original cost rate of 6.8%, and allowed common equity to total capital of 50.7%. In 2020, there were 61 rate cases completed with an average allowed ROE of 9.5%, allowed return on original cost rate of 7.0%, and allowed common equity to total capital of 51.9%. Similarly to electric utilities, gas utility authorized ROEs have not trended upward despite rising interest rates. As of August 9, 2022, the average gas utility authorized ROE in rate cases tracked by RRA was 9.41%, below the full-year 2021 average of 9.56%.

GAS RATE CASE METRICS

(all values are in percent except as noted)





Source: CFRA, S&P Global Market Intelligence.

M&A Environment

Renewed Focus on Core Business: Utilities Divest Unregulated Operations

Several utilities have recently reduced their risk profile by divesting non-regulated energy operations and non-core businesses. The primary purposes of these transactions are reinvesting in core utility operations, building clean-energy infrastructure, reducing debt, and increasing share repurchases.

In June 2021, CMS Energy agreed to sell EnerBank, an industrial bank providing unsecured consumer installment loans, to Regions Financial Corporation. The merger closed in October 2021, and CMS received $1.019 billion in proceeds. In August 2021, PSEG announced it reached an agreement to sell its 6,750 MW unregulated fossil generating portfolio to subsidiaries of ArcLight Energy Partners Fund VII, L.P for roughly $1.92 billion.

In December 2021, CenterPoint Energy Inc.'s equity interests in Enable Midstream Partners were converted into shares of Energy Transfer LP, which announced it acquired Enable for $7.2 billion. The move follows CenterPoint's plan to fully eliminate its midstream exposure by the end of 2022. In December 2021, Dominion Energy announced the closing of its sale of Questar Pipeline Co. to Southwest Gas Holdings Inc., in a deal worth $1.975 billion, including $430 million in debt. Questar operates natural gas transmission and storage services in the Rocky Mountains region of the U.S.

In February 2022, Exelon formally completed the tax-free spin-off of its power generation and competitive energy business, which now trades as an independent public company known as Constellation Energy Corporation (CEG). Following the spin-off, Exelon will continue to operate as a fully regulated transmission and distribution utility.

One Merger Fails and Another Succeeds

In December 2021, the New Mexico Public Regulation Commission rejected the proposed $4.3 billion acquisition of PNM Resources Inc. by Avangrid Inc., a subsidiary of Iberdrola SA. The merger was originally announced in October 2020, and the transaction had received approvals from state regulators in Texas, the U.S. Committee on Foreign Investment in the U.S., the Federal Communications Commission, FERC, NRC, and PNM shareholders. The New Mexico PRC cited concerns over Avangrid's utility service reliability in other regions and stated that the risks of the transaction outweighed the benefits. In January 2022, Avangrid and PNM agreed to extend the merger deadline to 2023, providing more time for a potential approval.

On March 17, 2021, PPL WPD Limited (Western Power Distribution) entered into a share purchase agreement to sell PPL's U.K. utility business to a subsidiary of National Grid plc for GBP7.8 billion. The transaction closed in June 2021, resulting in net cash proceeds of $10.4 billion. Concurrently with the U.K utility transaction, PPL announced it will purchase The Narragansett Electric Company from National Grid for approximately $3.8 billion cash (GBP2.7 billion). Narragansett Electric is the largest electricity transmission and distribution service provider to Rhode Island, as well as a natural gas distributor in the state, serving approximately 780,000 customers. PPL received regulatory approval for the acquisition in February 2022. However, the Rhode Island attorney-general appealed the decision, which was then granted a stay by the Massachusetts Supreme Judicial Court in March 2022. In May 2022, PPL reached a settlement with the Rhode Island attorney-general and agreed to, among other provisions, $50 million in bill credits for Narragansett utility customers and a three-year "stay out" following the closing of the acquisition, during which time the company will not request customer rate increases. PPL formally closed the acquisition in May 2022.

Regulatory Updates: Federal Spending, Clean Energy, and More

Biden's Clean Energy Plan

President Biden pledged to cut electricity-sector carbon emissions to zero by 2035 during his presidential campaign. In January 2021, he signed a set of executive orders, ordering federal agencies to procure carbon-free energy and electric vehicles, spur commercialization of clean energy technologies, and accelerate clean energy generation and transmission projects. This move provided some early indications of how he will seek to use the spending power of the federal government to bolster his pledges.

The U.S. power plant future capacity based on actual planned and under construction projects as of July 15, 2022 shows that the shares of gas-type power plants are expected to reduce to 38% in 2031 from 45% in 2021. Similarly, the share of coal type plants is expected to reduce to 12% in 2031 (versus 18% in 2021), while shares of solar and wind type plants are expected to both grow about 15% in 2030 (versus 5% and 11% in 2021), according to SPGMI. With Biden's strong political stand on clean energy and cutting carbon emissions, we believe we are likely to see more renewable projects replacing existing non-renewable plants over the president's term in the White House.

In November 2021, President Biden signed the Infrastructure Investment and Jobs Act, which includes government funding for research and investment in both hydrogen and carbon capture technologies, which many utilities are considering adding to their array of strategies to reduce carbon emissions and provide affordable power in the coming decades. The bill contains $65 billion in funding for power infrastructure. Of this total, approximately $29 billion will go towards transmission and other improvements to the nation’s electric grid, according to SPGMI. Between 2022 and 2026, the bill allocates $8 billion for the creation of four regional “clean hydrogen hubs” intended to promote research and development of clean hydrogen energy technologies. Importantly, SPGMI reports that the bill also gives FERC the authority to provide permits for transmission infrastructure spending even if state utility commissions deny the projects, easing the process for continued transmission buildout in the coming years.

The Build Back Better Act, which proposed to extend tax credits for both production of and investment in solar, wind, nuclear, and other clean energy sources, had stalled in Congress for several months, creating uncertainty for the next five to ten years of clean energy investment by utilities. As of this survey’s publication date, the legislation, now dubbed the Inflation Reduction Act, had officially passed the Senate, giving new hope to the Biden administration’s clean energy agenda, assuming passage in the House of Representatives. The proposed bill allocates $369 billion towards U.S. energy security and climate change initiatives, including an extension of the nuclear production tax credit (PTC), starting in 2024 and running through 2032. The bill also proposes a “zero emissions” credit for solar, wind, battery storage, and other clean technologies starting in 2025.

HOW THE INDUSTRY OPERATES

Since electricity was first harnessed more than a century ago, technological advances have altered the landscape of the electric utilities industry. Nevertheless, the physics of electricity generation has not changed: electricity is produced when a magnet is rotated inside a coil of wire. The spinning of the magnet may be caused by steam (as in coal, oil, and nuclear power plants), by falling water (as in hydroelectric plants), or by hot expanding gases (as in gas turbines and diesel generators).

Electrical energy cannot be stored economically, so it must be generated and instantaneously delivered, based on customer demand. Consequently, a company in the electric utilities industry must own production facilities capable of meeting the maximum demand on its system, as well as transmission and distribution systems that can manage the load. Each utility must also have a reserve margin of extra production capability to allow for maintenance, equipment outages, and unexpected variations in usage.

In general, the Utilities sector's peak earnings come with the warm weather in the second and third quarters, when customers are running air conditioners. By contrast, cold weather tends to have a marginal impact on earnings; most customers use electricity simply to start their heaters, while fuel (oil or gas) provides the heat. Thus, electric utilities' lowest earnings typically occur in the first and fourth quarters, although actual results may vary by region, and depend on weather conditions and other factors.

Generating Power

The Utilities sector relies on various fuel sources to generate electricity. Some utilities also purchase power to meet peak demand.

Fuel Sources
Fuel sources used by the Utilities sector include coal, natural gas, nuclear power, renewable sources (including hydroelectric and wind), oil, and other gases.

◆ **Natural gas.** Natural gas surpassed coal in 2016 as the most significant fuel source for electricity in the U.S. Based on preliminary 2021 data from the EIA, natural gas accounted for 38.3% of U.S. electricity production, down from 40.5% in 2020. We think the recent surge in natural gas prices explains the year-over-year decline, as electricity producers temporarily utilized more coal and continued their adoption of renewable sources like solar and wind, a trend we expect will continue.

◆ **Coal.** Coal accounted for 21.8% of U.S. electricity production in 2021, up from 19.3% in 2020 and 23.4% in 2019. Expect for what we see as a temporary uptick in 2021 due to spiking natural gas prices, coal's share of total production has been on a general decline since 2007.

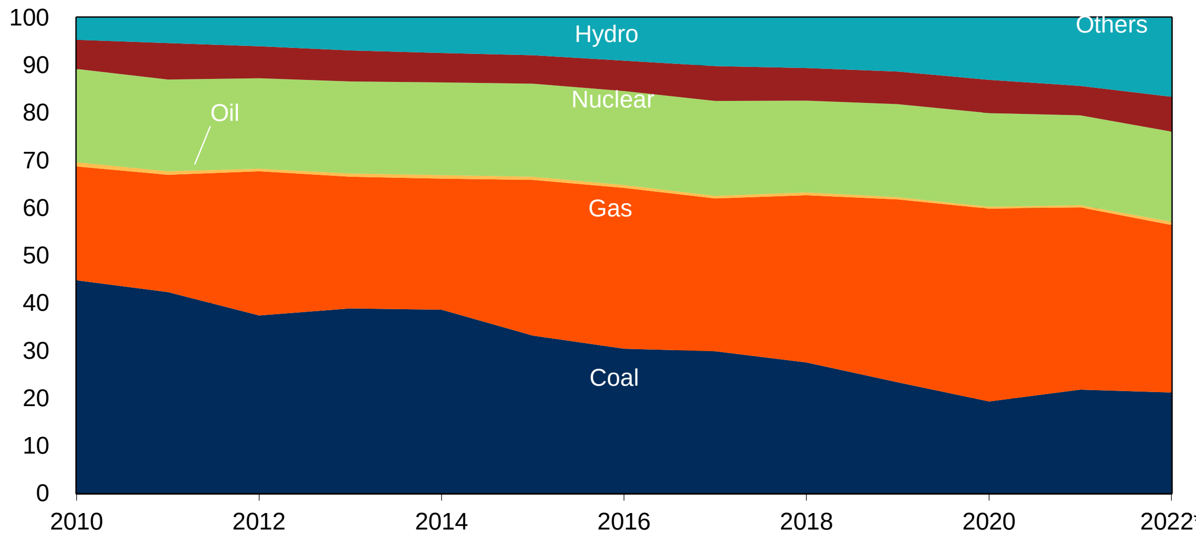
◆ **Nuclear power.** In 2021, nuclear power accounted for 18.9% of U.S. electricity production, down from 19.7% in 2020 and 19.6% in 2019. Nuclear's clean emissions and relatively low cost of production have made it compelling for power production. However, even before the crisis at Fukushima, it was felt that the development of nuclear plants in the U.S. was unlikely to occur quickly, due to the expense associated with new plant construction and the length of time involved in the regulatory approval process. In addition to the increased costs pertaining to the heightened scrutiny of existing nuclear plants in the U.S., there are costs related to the decommissioning of a plant, which involves reducing radioactivity, disposing of nuclear waste, and dismantling certain machinery. Utilities are required to prefund decommissioning costs over each plant's 40-year operating life. These costs are substantial, generally in the hundreds of millions of dollars.

◆ **Renewable sources.** The share of renewable generation accounted for 20.1% in 2021, up from 19.5% in 2020 and 17.7% in 2019. Non-hydro renewable generation, which includes wind, solar, geothermal, and biomass sources of power, accounted for 13.8% of U.S. electricity production in 2021, up from 12.4% in 2020 and 10.7% in 2019.

◆ **Petroleum.** Power production from petroleum accounted for about 0.4% of total electricity generation in each of the last three years. Electric energy production using petroleum occurs chiefly in the Northeastern and the Southeastern regions of the U.S.

◆ **Other gases.** Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels accounted for 0.3% of U.S. electric power supply in the last three years.

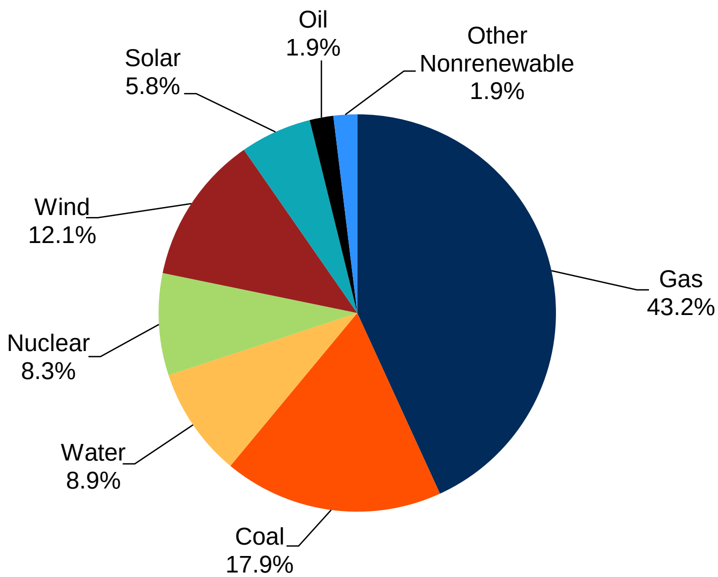
ELECTRIC GENERATION BY ENERGY SOURCE
(percentage of U.S. total)



*Aveage based on January to March data.

Source: U.S. Energy Information Administration.

U.S. OPERATING PLANT CAPACITY BY FUEL TYPE
(based on summer peak capacity, data extracted on July 14, 2022)



Source: CFRA, S&P Global Market Intelligence.

AVERAGE COST OF FOSSIL FUELS DELIVERED TO ELECTRIC GENERATING PLANTS
($ per million Btu, including taxes)

YEAR	COAL	PETROLEUM*	NATURAL GAS	ALL FOSSIL FUELS†
2011	2.39	12.48	4.72	3.29
2012	2.38	12.48	3.42	2.83
2013	2.34	11.57	4.33	3.09
2014	2.37	11.60	5.00	3.31
2015	2.22	6.74	3.23	2.65
2016	2.11	5.24	2.87	2.47
2017	2.06	7.10	3.37	2.65
2018	2.06	9.68	3.55	2.83
2019	2.02	9.07	2.89	2.50
2020	1.92	5.98	2.40	2.22
2021	1.98	9.60	4.98	3.64
2022‡	2.18	13.94	5.66	4.10

‡Data through June.
*Includes residual fuel oil, distillate fuel oil and petroleum coke.
†Weighted average of costs shown under "Coal", "Petroleum" and "Natural Gas".
Source: U.S. Energy Information Administration

Purchased Power Fills the Gap

Wholesale wheeling—the buying and selling of power by different utility-related companies—has significantly increased utilities' use of purchased power. Urban utilities, with their high daytime peak loads, have found that purchased power contracts let them meet peak demand and boost their load factors without building additional capacity.

A purchased power contract generally has two components: a capacity charge and an energy charge. The capacity charge is usually considered a rate base item; in other words, it is incorporated into the end-customer's base rates, whether the power is used or not. Energy charges are regarded as fuel costs and are passed along to the end-customer on a dollar-for-dollar basis, according to usage.

Getting Power to the User

A combination of generators is used by a utility to accommodate various levels of demand. Baseload generating units can supply substantial amounts of power; they ordinarily operate at or near full capacity for extended periods. While baseload generating units are the most expensive units to build in terms of capital investment, they are also the most efficient—and thus the most economical, in terms of operating expenses.

In contrast, peaking units are designed to operate exclusively during periods of high demand, and may run for as little as a few hours at a time. These generators—usually oil or gas combustion turbines—are the least costly in terms of capital investment, but they are usually the most expensive to run.

The cycling unit, an intermediate class of generator, runs when demand is above the capacity of the baseload generators but below the level necessary to use the peaking units. In terms of capital investment and operating costs, cycling units normally fall between baseload generators and peaking units.

Transmission and distribution facilities are the arteries through which power is delivered to customers. To transmit electricity effectively over long distances while minimizing power losses, utility companies use high-voltage transmission lines. Although such lines commonly cost considerably more to build than low-voltage wires, they can carry much more power.

Transformers reduce the voltage of electricity as it moves from transmission lines to distribution lines. At a customer's site, meters attached to the distribution lines measure the amount of electricity used during a period so that the utility may charge the appropriate sum to each account.

Some electricity-generating plants are members of regional "power pools," which generally are made up of several investor-owned utilities in a geographic area. The participating power plants dispatch electricity to all member utilities from a central control point.

Peak Load and Energy Rates

A utility's customer profile (the proportion of its sales that go to large industrial and wholesale customers versus smaller retail customers) can have a considerable influence on both its expenditures and its rates. Utilities forecast their peak loads—the average amount of energy required to serve customers at times of greatest usage—based on the average total demand from all customers at peak periods. Peak loads can differ significantly from utility to utility. The loads of some companies are relatively uniform throughout the day, whereas others are heavily concentrated during certain hours.

Capacity and Load Factors

A utility's capacity factor is the relationship between demand and capacity. It is the measure of actual output versus a generator's rated capacity.

Load factor is a related but somewhat different concept: the ratio of actual electric energy consumption during a given time relative to the consumption that would have occurred if usage had been fully sustained at the peak capacity level. Thus, it measures the variability of load (or demand) over a given time. A high load factor means that a utility operates near capacity most of the time.

The Natural Gas Supply Chain

The natural gas supply chain comprises three distinct segments: upstream, midstream, and distribution. Gas utilities, also known as Local Distribution Companies (LDC), build, maintain, and operate distribution pipelines.

- ◆ Upstream companies explore and drill for natural gas.
- ◆ Midstream companies move the natural gas to end consumers through a system of interstate and intrastate pipelines.
  - Gathering pipelines gather raw natural gas from production wells and transport it to processing facilities (to remove impurities and separate out liquids like propane and butane).
  - Transmission pipelines transport natural gas thousands of miles from processing facilities across many parts of the U.S.
- ◆ Downstream companies
  - Distribution pipelines distribute natural gas to homes and businesses through large distribution lines mains and service lines.

Local Distribution Companies (LDCs)
LDCs perform two related, but distinct, services: the delivery of gas, as well as the procurement and sale of gas to the customer. LDCs deliver gas to customers through pipeline networks they build and maintain and attempt to earn a profit for providing that service. In addition, they procure gas and sell it to customers at cost, a service for which no profit is earned. In both cases, state officials regulate the rates that LDCs can charge, and they have no guarantee that state regulators will allow them to fully recover the cost of gas sold to customers.

How Rates Are Set

State commissions are responsible for determining utilities' proper rate bases and allowable operating expenses. The rulings of individual states often differ regarding these determinations. They also differ in allowed accounting treatments for depreciation accruals and investment tax credits. Although rulings are often presumed to be based solely on the public interest, commissions seek to provide a balance between investor and consumer interests.

Shareholder risk is a component of a utility's allowed rate of return. To determine risk levels, state utility commissions consider the percentage of common equity versus debt in a utility's capitalization. The higher the equity component, the lower the assumed risk; a lower assumed risk generally results in a lower allowed rate of return. In contrast, shareholders that assume higher risk usually will be allowed a higher potential return.

Utilities that engage in significant cost-cutting tactics, such as work force downsizing and refinancing (both prevalent in recent years), often attempt to delay the next rate review for as long as possible. This strategy lets its investors benefit from the savings until the next rate case.

The greatest power that state utility commissions hold over LDCs is the ability to set the rates that LDCs charge for delivery and for gas supply. As a practical matter, the delivery charge is the more complex to set, since it must allow the LDC to earn a profit. Gas supply charges, while not free of controversy, are more an issue of reimbursement, though disputes can and often do arise over whether a gas supply charge was prudently incurred. To summarize, LDCs earn profits from managing the infrastructure and providing the service of natural gas transport. They are largely agnostic to the cost of natural gas, as this is just a pass-through cost absorbed by the end-user (though large swings can make alternative electricity producers gain market share).

In general, the ratemaking process begins with a regulated utility's request for a change in rates when the current rate schedule expires. The process of deciding a utility's allowed rates is known as a "rate case." In addition to the change in rates requested, there may be simultaneous negotiations between the company and the commission on any other issues that one or both sides want to address, such as customer complaints, infrastructure investment, environmental issues, or reliability problems.

Consumer Safeguards
Electric utilities companies are required to charge what the regulatory bodies deem "just and reasonable rates" to protect consumers against potential pricing abuses while allowing utilities to attract capital and provide adequate service.

Establishing a utility's rates on an individual cost-of-service basis typically involves two steps. The first is to determine the rate level that will cover the utility's operating costs and give it an opportunity to earn a reasonable return on its investment. The utility's required revenue is often referred to as the "revenue requirement" or "cost of service." The second step designs specific rates that will eliminate discrimination against, and unfairness toward, affected classes of customers.

Government Guides Rates, Construction
Regulators once encouraged utilities to construct ample generating plants to satisfy vigorously growing electric demand. During the late 1970s, however, electric demand slowed significantly as that decade's energy crises sparked large increases in electric rates. Meanwhile, the cost of nuclear plant construction skyrocketed because of the Three Mile Island nuclear accident in Pennsylvania in 1979.

In response to those developments, regulators often disallowed or delayed cost recovery for plant investments deemed imprudent or unnecessary. In the wake of those disallowances, utilities became hesitant to undertake major capacity-related construction projects, and many chose to rely on power purchased from other generators.

When generating capacity appears unable to meet the levels of power required during periods of great demand (such as during "above-normal" heat waves), resulting in significant power shortages, utilities or independent power generators have found themselves compelled to increase their generating capacity. This was the case with the California power crisis in 2000, which resulted from the state's insufficient power supplies; it led to an accelerated approval process for new plants. A nationwide expansion of power plants ensued, resulting in an excess of power-generating capacity. Meanwhile, demand was greatly reduced due to a longer-than-expected weakness in the economy.

Rate Structures That Motivate

It has been argued that traditional utilities regulation—in which rates are based on the cost of service, plus a risk component—does not give utilities an incentive to become efficient. Hence, many states are examining the need to reform the cost-based framework.

Incentive Regulation Mechanisms
An alternative to cost-of-service ratemaking exists in the form of "incentive regulation mechanisms," which, at one point, were prevalent in the telecommunications industry. Through incentive mechanisms, utility managements are given performance targets. If the utility exceeds its target, it will share part of the

resulting benefits through incremental increases in its allowed return on equity (ROE). Examples of incentive-based ratemaking include performance-based pricing, revenue sharing, and price-cap regulation.

◆ **Performance-based pricing.** Utilities that have settlement agreements on new nuclear plants or nuclear plants that have suffered prolonged outages use this ratemaking mechanism. It entails removing the plant from the rate base and extracting related operating expenses from those included in the utility's cost of service. Instead of earning a rate of return based on assets specified by regulators, a utility using performance-based pricing earns a preset price per kilowatt-hour (kWh) that the plant produces, making recovery dependent on plant performance. The most notable example is Pacific Gas & Electric Co.'s Diablo Canyon nuclear plant in California; the company announced on June 21, 2016, that it plans to close the plant by 2025.

◆ **Earnings sharing.** Another kind of incentive-based rate that has gained popularity in recent years is "earnings sharing." When regulators determine a utility's rate of return for a given period, the specified return is a target return that the rate schedule is designed to produce.

Because actual events may lead to a different return, regulators may designate an "allowed rate of return" band that includes an acceptable variation from the target. If actual returns fall below that band, the utility may be allowed to petition for a rate change. If returns are above the target band, companies share the "excess" earnings, in part or in whole, with customers in the form of future rebates. This protects the utility from unexpectedly low returns and lets customers benefit from improved efficiency.

◆ **Regulatory lag.** One of the simplest ways to create more incentives for improved performance is known as "regulatory lag," or the extension of the minimum time between rate changes. This produces a strong incentive to cut costs, because utilities would keep 100% of any cost savings made during the period; they would also bear 100% of any additional costs incurred.

◆ **Price-cap regulation.** Common in the telecommunications industry, this regulation sets a ceiling for consumer prices. The price cap is intended to cover a reasonable cost of service, while letting utilities choose the most efficient way to provide that service. The choice of services that a utility may offer a specific customer currently is subject to state regulatory review.

The Laws That Shape the Industry

Several pieces of federal legislation have shaped the U.S. electric utilities industry over time. Below are brief descriptions of some of these laws and their immediate and ongoing impact.

◆ **The Federal Power Act.** Enacted in 1935, this law created the Federal Power Commission (later renamed the Federal Energy Regulatory Commission, or FERC) to regulate the interstate transmission and sale of electric power, and to license hydroelectric plants.

◆ **The Public Utility Regulatory Policies Act (PURPA) of 1978.** By the 1970s, the regulatory framework that had been in place for some 40 years needed change. That decade's energy crises generated widespread support for reducing U.S. dependence on nonrenewable sources of energy in general and on foreign oil.

To promote national self-sufficiency in energy consumption, Congress enacted PURPA in 1978. As part of this legislation, the FERC was ordered to develop rules to encourage alternative energy sources and cogeneration by creating qualifying facilities (QFs), a special class of independent power producers (IPPs).

The small generators that QFs owned were exempt from Public Utility Holding Company Act of 1935 (PUHCA) restrictions. Utilities were required to purchase the firms' electricity at prices mandated by state regulators, typically set at the utility's "avoided cost," or the cost that a company in the electric utilities industry would incur to produce or otherwise procure electric power. Although PURPA did not exempt the larger IPPs from PUHCA, it nonetheless had a significant impact on the growth of non-utility generation.

◆ **The National Energy Policy Act (NEPA) of 1992.** By reforming PUHCA, this law greatly increased competition within the electric utilities industry at the level of both production and sale of wholesale power; the latter having become the industry's most lucrative business when demand is high. Under NEPA, the FERC was empowered to direct an electric utility to provide wholesale wheeling, or transmission service, at cost from any electricity-generating entity to another utility, regardless of whether the transmitting entity is another utility or an IPP.

Under NEPA's terms, transmitting utilities must receive compensation for providing wholesale wheeling services. The FERC sets rates for transmission service at a level that lets a company fully recover the "legitimate and verifiable" costs of providing the service.

NEPA created an additional class of IPP—the exempt wholesale generator, or EWG—that was free from regulation under PUHCA provisions. Unlike IPPs of the past, however, EWG projects could have investor-owned utilities as majority interests. Affiliated EWGs can produce and sell electric power at the wholesale level; state commissions regulate these transactions. NEPA also allowed EWGs to operate outside the U.S. and to compete in foreign markets at the retail level.

Enactment of Electricity Legislation

In August 2005, President George W. Bush signed into law a comprehensive energy bill called the Energy Policy Act of 2005 (EPAct 2005). The electricity portion of the new legislation—called the Electric Reliability Act of 2005—made grid-reliability standards mandatory, repealed the PUHCA, and authorized federal permits for transmission lines. The main electricity provisions contained in the new law are outlined below.

Public Utility Holding Company Act Repealed

The legislation repealed the PUHCA of 1935. PUHCA was enacted to eliminate the abuses committed by the holding companies of that period, such as excessive charges for "services" provided to the operating utilities that were then passed on to the consuming public. PUHCA restricted the non-utility activities of holding companies and required that the service territories of the utility operating companies be contiguous.

The law required that holding companies maintain and make available (to both the FERC and the appropriate state commissions) any books and records deemed relevant to the costs incurred by a utility within a holding company. In addition, both the FERC and the state commissions would maintain their authority to ensure that jurisdictional rates were just and reasonable, to prevent cross-subsidization, and to determine whether a utility would be allowed to recover, via rates, costs related to another company within the holding company.

While new mergers still require approval by the FERC and state utility commissions, the legislation required the U.S. Department of Energy (DOE) to review the extent to which the FERC's merger authority was duplicative of other federal and state merger authorities, and imposed statutory deadlines intended to accelerate the merger review process.

Establishment of Electric Reliability Organizations

To address reliability issues highlighted by the power blackout of August 2003, the new law made several amendments to the Federal Power Act of 1935. It created a new section in the law, Section 215, which calls for the establishment of a self-regulating, electric reliability organization (ERO) under the jurisdiction of the FERC. The law also authorized the FERC to establish ERO requirements, including regulations allowing the ERO to delegate authority to a regional entity for the purpose of proposing and enforcing standards that would ensure the reliability of the bulk power system.

Although the EROs and any regional entities given enforcement authority would not be considered departments or agencies of the U.S. government, the FERC was authorized to take whatever actions it considered necessary to ensure compliance with reliability standards or related commission orders. The law does not preclude individual states from taking actions aimed at ensuring the reliability of the bulk power systems situated in those states, if those actions are consistent with the reliability standards.

Final FERC Rule for Transmission Facilities Aims to Spur Investment

The “not in my backyard” attitude that has hindered the construction of new transmission facilities was effectively countered by legislation. In any geographic area where transmission capacity constraints or congestion affect consumers, the U.S. Department of Energy (DOE) was given the authority to designate a “national interest electric transmission corridor,” after consulting with the appropriate states and regional reliability entities. The Federal Energy Regulatory Commission (FERC) had the authority to issue permits for the construction or modification of transmission facilities in such areas and under specified conditions. Permit holders could acquire the rights-of-way for the project by exercising eminent domain in the federal district court with jurisdiction over the area where the property is located.

The FERC issued its Final Rule in July 2006, promoting transmission-pricing reforms that were designed to promote needed investment in the U.S. energy infrastructure. The Energy Policy Act (EPAct) of 2005 had directed the FERC to develop incentive-based rate treatments for the interstate transmission of electric power. The Final Rule was intended to implement those incentives, provide regulatory certainty, and ensure that transmission rates remain just and reasonable.

The rate incentives identified in the Final Rule were intended for both traditional utilities and stand-alone transmission companies (known as “transcos”). The incentives include providing a ROE sufficient to attract new investment. This enables the recovery at a rate base of 100% of prudent transmission-related construction work in progress, accelerates the recovery of depreciation expense, enables the recovery of deferred costs, and provides a higher rate of ROE for utilities that join transmission organizations. In addition to enhancing the reliability of the national grid, the Final Rule aims to expedite the procedures for the approval of incentives and to facilitate the financing of transmission projects.

The Regulator’s Role

The FERC, a division of the DOE, exercises jurisdiction over wholesale utility sales and certain transactions between affiliated companies. It also oversees utilities’ issuance of certain stock and debt securities, the assumption of obligations and liabilities, and mergers.

State public utility commissions regulate electricity sales to end-use customers, such as homeowners and businesses. Regulation seeks to ensure that consumers receive reliable service at a fair price. It gives each utility the opportunity—not a guarantee—to earn an adequate return so that it can attract new capital to develop and expand plants to meet customer demand. Regulation also aims to ensure public safety and to prevent unreasonable prices, excessive earnings, and discrimination against customers.

Regulated Monopolies Move Toward Competition

In the past, individual companies operated as natural monopolies. In theory, a natural monopoly should provide economies of scale, efficient service, and lower prices. However, if the owners of such a monopoly control an essential resource, they can profit excessively. The federal government regards the supply of electricity as a necessity; thus, federal and state governments have long supervised the industry through close regulation.

“Regulatory compacts” have enabled states to grant investor-owned utilities exclusive service territories in exchange for the utility’s “obligation to serve” all consumers in that territory on demand. This obligation requires utilities to build, operate, and maintain generating plants and transmission and distribution systems that would service all present and future customers. Such franchise agreements allow the highly capital-intensive utility companies to raise the necessary financing, recover their fixed costs over time from a stable customer base, and enjoy increased efficiency through economies of scale.

The pricing process is the most significant difference between regulated utilities and competitive enterprises. Whereas market forces and competition determine how much an unregulated company can charge for its products or services, a state regulatory commission establishes a utility’s rates in a rate-case proceeding. Once set, rates generally do not change without another rate case.

While the wholesale power market has been opened to competition in many states, the scandals related to Enron and other power marketing operations have helped many state regulatory commissions decide not to pursue deregulation of generation assets. CFRA also expects interstate electric transmission to remain regulated by FERC in the U.S., and electric distribution to remain completely regulated by the localities and states in which they provide service due to the local monopolies granted to them by the regulators.

FERC Rulings Pulled the Plug on Monopolies

In March 1995, the FERC released a watershed Notice of Proposed Rulemaking (NOPR), alerting the industry that it had targeted the wholesale power market for deregulation and was about to issue new rulings on open access transmission. (A NOPR is a notice to the industry that the FERC is revising its regulations and will release an official ruling later.)

On April 24, 1996, the FERC issued the expected rulings, which consisted of two separate orders. The first, Order 888, addressed both open access and stranded-cost issues. The second, Order 889, required electric utilities to establish electronic systems to share information about available transmission capacity.

The FERC rulings initially targeted the wholesale power market, where electric power is provided to utilities, which then distribute it to the retail market. The agency believed that, in the long term, the rulings would reduce the need to regulate bulk power sales. It expected the opening of the transmission system to increase competition and lower prices by eliminating the power generation monopoly at the electric plant level.

◆ **Order 888.** This order addressed two principal issues: transmission service and “stranded costs.”

Transmission service. Order 888 required public utilities that own, control, or operate transmission lines to provide transmission service for wholesale transactions on an open, nondiscriminatory basis. The order set guidelines for efficient operation of the transmission system, and for terms and conditions of service. It required utilities to file open access transmission tariffs stating the minimum conditions under which they can provide both network and point-to-point service. Order 888 did not mandate either corporate unbundling or divestiture of assets, but it did establish standards of conduct to ensure this functional unbundling.

In issuing this order, the FERC supported the concept of independent system operators (ISOs), although it did not require utility companies to join them. Each ISO controls the operation of interconnected transmission facilities within a certain region. It also is responsible for ensuring nondiscriminatory, open access transmission, as well as the planning and security of the utilities' combined bulk transmission systems.

Stranded costs. This term refers to the money a utility could lose if it were unable to recover its investment in generating plants, and/or other deferred costs, such as those incurred when a wholesale customer switches providers or types of service. In Order 888, the FERC endorsed the principle of full recovery of prudently incurred wholesale stranded costs. The FERC thus reaffirmed its view that utilities should be able to recover these costs from departing customers by negotiating remedies before the end of the contract.

◆ **Order 889.** Also known as the Open Access Same-Time Information System (OASIS) rule, Order 889 required electric utilities to do two things. First, each utility must make available electronically, to other utilities and electricity providers, certain information about its transmission systems—the information that it would use for its own wholesale power transactions. Second, each utility's wholesale power marketing must be administered and accounted for separately from its transmission operation functions, enabling customers to compare prices for these services—a change from past practices, when the services were bundled.

◆ **Order 2000.** Although orders 888 and 889 encouraged the formation of ISOs, they still left management of the transmission grid to the vertically integrated electric utilities. The FERC eventually concluded that this structure was not efficient or reliable enough to support the development of genuinely competitive electricity markets.

To promote efficiency in wholesale electricity markets and to ensure that consumers pay the lowest possible price for reliable service, the FERC issued Order 2000 in December 1999. Its objective was to encourage all public and nonpublic electric utilities to place their transmission facilities under the independent control of a regional transmission organization (RTO). The function of an RTO is to control the transmission grid in each regional territory, thus assuring nondiscriminatory access while increasing efficiency and reliability. Although similar in concept to the ISO, the RTO would have more authority to eliminate discrimination.

Order 2000 established the minimum characteristics and functions for an RTO: independence from market participants, enough geographical scope and regional configuration, a clear operational responsibility and authority, and the ability to assure short-term reliability. The order encouraged a collaborative process whereby all utilities that own, operate, or control interstate transmission facilities could consider and develop RTOs in consultation with state officials.

◆ **Order 890.** The EPAct 2005 authorized the FERC to prescribe rules to provide for the dissemination of information about the availability and price of wholesale electric power and transmission service. The FERC strongly believed that, more than 10 years after Order 888, the open access transmission tariffs (OATTs) contained flaws that undermined its core objective of preventing undue discrimination by transmission owners. To change this, the FERC issued Order 890 on February 16, 2007—authorizing several reforms.

First, it eliminated the wide discretion that transmission providers have in calculating available transfer capacity. Second, it required an open, transparent, and coordinated transmission-planning process. Third, it increased the efficient utilization of transmission by eliminating artificial barriers (such as denying a request for long-term, point-to-point service if the request cannot be granted in an hour). Fourth, it facilitated the use of clean energy resources, such as wind power, through reforming generator imbalance charges (since these resources have limited ability to control their output). Last, Order 890 increased the clarity of OATT requirements and strengthened compliance and enforcement efforts by adopting penalties for clear violations of an OATT.

Industry Accounting Quirks

The industry's regulated nature has given rise to unique accounting practices. In particular, several significant "noncash" items can dramatically alter a utility's earnings. Historically, the most notable noncash component in accounting has been the allowance for funds used during construction (AFUDC). If state regulators do not include a utility's construction work in progress (CWIP) in the calculation of its rate base (upon which the utility is allowed to earn an actual return), the utility records an AFUDC on its income statement. This is an income credit representing construction financing costs. Once the facility is placed into operation, a return will be earned on the portion of those costs included in the rate base. The costs not included in the rate base will be recovered over the life of the facility through depreciation charges.

AFUDC amounts are added to a plant's costs. Like other construction expenditures, they are depreciated over time. During periods of heavy construction, AFUDC could represent a substantial portion of utility earnings, but are of much less significance during periods of limited construction spending.

Another source of noncash earnings is multi-year phase-ins of rate hikes given to utilities to cover costs for new generating plants. This practice generates noncash earnings in that the reported "earnings" do not include the related expense that has been recorded as an asset on the balance sheet under deferred charges. By phasing in these large rate increases, regulators lessen the "rate shock" to customers. To avoid the negative earnings impact from enormously expensive projects, utilities can defer the recording of these costs while new rates are phased in. Such deferred amounts are then amortized and recovered over time.

Many state commissions require or allow utilities to create "regulatory assets" by deferring the recording of some costs—such as those related to damages from severe storms, clean air expenditures, and demand-side management energy-efficiency programs—until the next general rate increase. For some utilities, the next expected general rate increase might be years away, so reported earnings would be affected only in the long term. However, the deferred costs hurt the quality of near-term earnings, because the earnings do not fully reflect the costs of that period. Suppose, for example, that a company incurs a $100 million expense for repairing storm damage. The company's current reported earnings would not be affected because the expense has been deferred, but this compromises the quality of those earnings. Regulatory assets are only appropriate if it is probable that they will be amortized and recovered once the next rate increase becomes effective.

HOW TO ANALYZE A COMPANY IN THIS INDUSTRY

We recommend that investors look at earnings per share (EPS) and dividend growth prospects, as well as relative valuations of individual companies versus peers, when valuing electric, multi, and gas utilities. Investors should be aware of valuations of other sectors and the broader market when performing their analysis. An examination of the industry drivers outlined on pages 9 to 11—customer electric rates, allowed return on equity, number of rate cases, degree day statistics, electric usage per customer class, and housing starts—is a good starting point.

Industry Drivers

◆ **Allowed ROE, allowed ROA, and equity ratio.** These statistics are relatively common inputs for setting regulated utility electricity rates. The higher the allowed return on assets (ROA), and the lower the allowed equity-to-total-capitalization ratio, then the higher the allowed return on equity (ROE) will be.

◆ **Cooling- and heating-degree-days.** Cooling- and heating-degree-days are measures of the average temperature for a given period. Mean temperatures below a reference temperature, usually 65 degrees Fahrenheit, result in heating-degree-days; those above the reference temperature result in cooling-degree-days. Reported by both the Edison Electric Institute (EEI) and the Climate Prediction Center of the National Weather Service, these statistics have an important bearing on utility earnings, in that electricity delivered typically increases when it is hotter than normal in the summer or, to a much lesser extent, when it is colder than normal in the winter.

◆ **Electricity rates.** These rates, generally set by regulatory authorities, are the price charged by electric utilities for the electricity that they deliver. Rates at vertically integrated utilities incorporate both the production and distribution of electricity.

◆ **Generating capacity total and capacity by fuel source.** Most electric utilities are still vertically integrated. Those that are integrated have power plants that generate electricity to be sold to their own customers or into wholesale electric markets. Hydro, nuclear, and coal plants, as well as some combined-cycle natural gas plants, tend to run 24/7, while smaller peaking plants tend to run only when electric demand is highest and intermittent power sources, such as solar and wind, tend to run whenever they are available.

◆ **Interest rates.** The regulated and capital-intensive nature of the utilities industry makes the financial performance of these companies overly sensitive to the level of interest rates and available returns. Utility rates are based on operating costs, capital investments, and the cost of capital. Changes in overall market rates affect utility rates via the cost of debt and the allowed ROE. When market rates drop substantially, utility rate increases can be pressured as more of the financing cost savings can theoretically be passed on to customers.

In addition, income-oriented investors are sensitive to interest rates when evaluating a utility company's shares. If interest rates are rising, these investors may be able to receive comparable returns elsewhere and, consequently, may be less likely to purchase a utility stock that did not provide a comparable yield.

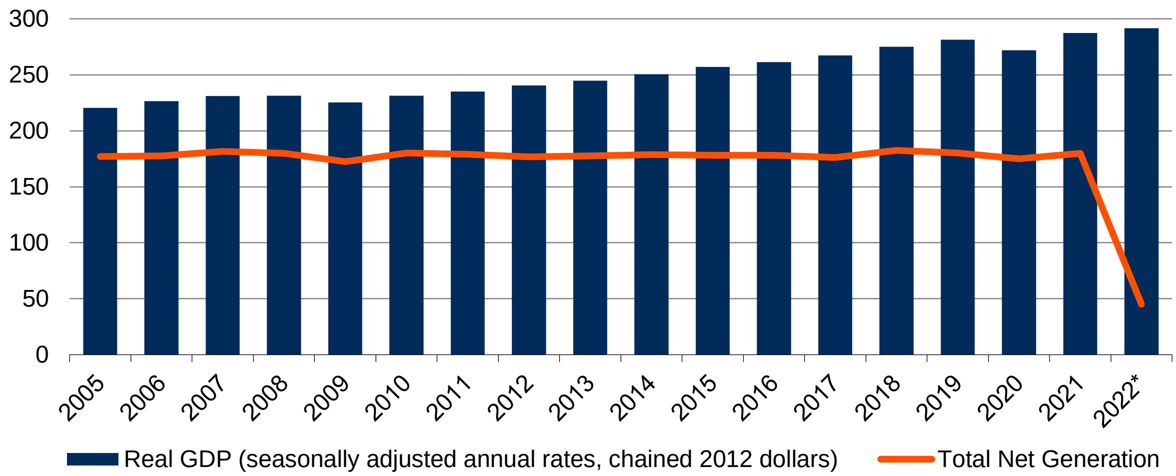
◆ **Key demographic and housing statistics.** Demographic trends can influence the customer base of a company in the utilities industry. New household formations and the rate of new housing construction are the key sources of residential customer growth. The U.S. Census Bureau reports household formations, while the U.S. Department of Commerce (DOC) reports housing starts monthly.

◆ **Total electricity delivered, and electricity delivered by customer class.** Electric deliveries are ultimately the main volume driver of utility revenues. Rates charged (prices) for electricity delivered also help to determine electric utilities revenues. Each customer class typically has a certain rate for electricity, with residential users typically paying the most and large industrial users paying the least.

◆ **U.S. gross domestic product.** Reported quarterly by DOC, GDP is a broad measure of aggregate economic activity. It is the market value of goods and services produced by labor and capital in the U.S. Growth in the economy is measured by changes in inflation-adjusted (or real) GDP.

Changes in demand for electricity and gas closely mirror the rate of economic growth. However, weather patterns can cause swings in electric and gas consumption. In addition, demand growth for an individual utility company depends heavily on economic trends within its geographic region.

REAL GDP AND TOTAL KILOWATT-HOUR SALES
(1980=100)



*Net generation data through Q1.

Source: U.S. Bureau of Economic Analysis, U.S. Energy Information Administration.

Company Analysis

The job of analyzing a company in the utilities industry is becoming increasingly complex as the industry moves toward a deregulated, competitive marketplace. A fair assessment now requires much more than a look at the dividend yield (the annual dividend divided by the stock price). When evaluating a company in this industry, it is as important to assess the utility's underlying business position as it is to determine its current financial health.

Qualitative Factors

Major factors that affect a company's business position in the utilities industry include the following:

Location
The ideal environment for a utility is one in which a robust economy attracts new businesses that, in turn, contribute to above-average population growth. Is economic activity in the utility's service region healthy

and growing? What is the area's outlook for population growth and new housing starts? What are the forecasts for future regional demand?

Customer Mix

A utility's customer base has an important bearing on its profitability level. A utility with a large industrial and commercial load should be viewed with caution, because these customer classes expose the utility to competition. A large residential customer base, in contrast, provides a more stable and predictable earnings stream. (The introduction of residential competition is not likely to affect this situation any time soon; most residential customers are expected to remain with their current utility.)

If any single wholesale or retail customer accounts for a sizable portion of a utility's sales, the analysis must focus on the stability of that customer and on the utility's competitive position—its prospects for retaining that company's business.

Competitive Position

A company's rates and its ability to lower production costs generally determine its position relative to competitors. A high-volume customer could choose to relocate to a different service area with lower rates or to buy power from an independent producer. A large industrial customer could turn to self-generation or nontraditional energy sources.

How do the utility's production costs and rates compare with those of other utilities in the same region and with the national average? Examine the utility's plans for capital additions. How much is it expecting to spend? How will its plans be funded? As competition increases, utilities must become even more careful about capital additions, questioning whether the future customer base will support the additional costs.

Fuel Mix and Supply

A utility company's ability to alter its generating sources (such as coal, nuclear power, hydroelectric power, gas, and oil) defends it against supply disruptions or price spikes in a commodity. It also lets the company take advantage of changes in fuel costs. Conversely, a lack of flexibility in fuel supply restricts a company's options if the environment changes.

Plant Operations

Areas for analysts to consider include the various costs to run the plants, the reliability of the operations, and the quality of the service. Have there been any unscheduled outages? What are the current estimates of remaining plant life and decommissioning costs? Will it be profitable to run the plant(s) in a competitive market? Does the company have idled or excess capacity? If so, what are its plans?

In addition, look at the utility's transmission access. Is it adequate for current demand? Is the company locked into any long-term purchase power contracts with high-price non-utility generators? If competition drives down the industry's production costs and market prices, the utility would suffer from contractual obligations to purchase power at above-market rates.

Business Strategy

The electric utilities industry offers little in the way of domestic growth prospects, given its maturity. For that reason, many utilities had attempted to achieve growth through investments in wholesale energy marketing and trading operations, and/or other energy-related businesses, as well as in utilities in foreign countries. Such ventures, however, added a significant risk component to their operations, and often resulted in serious economic losses and even bankrupt businesses. One must determine whether the utility's business strategy and management are conservative or aggressive, and whether they are appropriate considering the company's strengths and culture, and the opportunities available to it.

The Regulatory Environment

Utilities' activities remain subject to extensive state and federal regulation, despite the eventual arrival of retail competition. Regulated areas include consumer rates, allowed rates of return, the safety and adequacy of service, the purchase and sale of assets, accounting systems, and the issuance of securities.

Therefore, it is important to study the trends at the regulatory commissions that have jurisdiction over a utility. Compare the recent average return on equity (ROE) that the commission authorized for the utility with the amount the utility requested. Was the ruling favorable? If not, why? Is there a possibility of a rate decrease? When will the next rate increase (or decrease) be filed? What other key issues will be addressed?

What are the local commission's views on retail competition and regulatory reform? On stranded-cost recovery, demand-side management programs, and clean air compliance? All these factors can affect a utility's ultimate revenues.

Evaluating the Income Statement

At this point, one should have a good understanding of how well the utility being analyzed is positioned to compete in the current changing environment and its own markets. Now it is time to look at the financial statements, beginning with the income statement.

Revenue Growth

Revenue growth for utilities is somewhat predictable because of regulatory constraints on price increases. Nevertheless, it is still important to study past sales trends and expectations for the future. Did growth come from a rate hike or from increased weather-related demand? Is the economy improving and is the population growing in the utility's service area?

Operating Expenses

Fuel is the largest and most variable item on a utility's list of operating expenses, and it is often the least controllable. Note whether the company has been able to pass along higher fuel costs to customers. Pay close attention to nonfuel expenses, and particularly to how they compare with revenues. An improving trend in operating and maintenance costs usually indicates that a company is focusing on streamlining its operations and controlling costs.

Noncash Items

Unique to the analysis of utility companies are certain noncash items that can make a notable difference in the quality of reported earnings. These items include the treatment of deferred income taxes, deferred expenses, phase-ins, depreciation and amortization, and the allowance for funds used during construction (AFUDC). If any of these items constitutes a sizable portion of reported earnings, the results may be overstated or unsustainable.

Study the trends in depreciation and amortization charges. Given the current competitive environment and the possibility of stranded investments, many utilities are accelerating the write-down of at-risk assets. A higher depreciation rate depresses a utility's current net earnings, but analysts view the tactic as a positive step, because accelerated depreciation helps a utility recover the costs of its investments more quickly.

Watch Out! *Companies can boost earnings by extending the depreciable lives of property, plant and equipment (PP&E) beyond their reasonable useful lives or increasing salvage values associated with fixed assets. Therefore, it is important to refer to the notes to the financial statements to ensure that a change in depreciable life has not occurred. Additionally, analyzing the trend in depreciation expense relative to gross PP&E and comparing the depreciable lives used by competitors with those used by the company may detect potential manipulation. Finally, be wary of companies where capital expenditures consistently exceed depreciation as these companies may be understating depreciation expense or may experience an increase in depreciation expense in future periods.*

STATEMENT OF INCOME—INVESTOR-OWNED UTILITIES*

(in millions of dollars, except as noted)

ITEM	-- CALENDER YEAR -- 2021	2020	% CHG.
Total electric operating revenues	385,500	347,934	10.8
Electric operating expenses			
Energy expenses	115,014	92,589	24.2
Operations & maintenance	95,741	91,549	4.6
Depreciation & amortization	60,424	56,547	6.9
Taxes (other than income)	22,156	20,895	6.0
Other operating expenses	21,126	15,320	37.9
Total operating expenses	314,461	276,900	13.6
Total utility operating income	71,039	71,034	0.0
Total other recurring revenue	12,941	13,660	(5.3)
Non-recurring revenue	(2,046)	(398)	414.1
Interest expense	26,469	26,636	(0.6)
Other expenses	385	486	(20.8)
Asset writedowns	2,012	6,704	(70.0)
Other non-recurring expenses	7,875	8,504	(7.4)
Net income before taxes	45,193	41,966	7.7
Net income before extraordinary items	41,547	38,610	7.6
Total extraordinary items	731	17	4,200.0
NET INCOME	42,278	38,627	9.5

*The financial data covering 40 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges, and 5 additional companies that provide regulated electric service in the United States but are not listed.

Source: S&P Global Market Intelligence, Edison Electric Institute Finance Department

Non-Operating Expenses

Because the utilities industry is extremely capital-intensive, interest payments are its most significant non-operating expense. Since the mid-1980s, however, interest costs have trended downward, largely because industry overcapacity has resulted in reduced capital expenditures and construction. If interest expenses are increasing, find out why.

Watch Out! *Companies can boost current earnings by capitalizing a greater amount of interest expense that would otherwise be expensed. To detect potential manipulation of capitalized interest, investors can analyze trends in capitalized interest relative to total interest costs as well as capitalized interest relative to total capital expenditures. If these ratios are increasing, a company may be manipulating earnings by capitalizing interest costs that are normally expensed.*

Balance Sheet and Cash Flow Measures

The capitalization ratio, debt ratings, cash flow, and ROE are all measures of a company's financial strength and performance.

BALANCE SHEET DATA—INVESTOR-OWNED UTILITIES*
(in millions of dollars)

ITEM	--- CALENDER YEAR --- 2021	2020	% CHG.
ASSETS			
Utility plant			
Gross property & equipment	1,746,509	1,677,413	4.1
Accumulated depreciation	502,863	481,097	4.5
Net property in service	1,243,646	1,196,316	4.0
Construction work in progress	86,365	81,559	5.9
Net nuclear fuel	15,358	15,252	0.7
Other property	16,786	16,354	2.6
Net property & equipment	1,362,155	1,309,481	4.0
Current assets	157,857	153,620	2.8
Investments	136,761	129,344	5.7
Other assets	283,880	274,860	3.3
Total assets	1,940,653	1,867,305	3.9
CAPITALIZATION & LIABILITIES			
Common equity	526,146	494,872	6.3
Preferred equity	10,870	14,566	(25.4)
Noncontrolling interests	25,939	27,502	(5.7)
Total shareholders' equity	562,955	536,940	4.8
Short-term debt	41,836	35,951	16.4
Current portion of long-term debt	37,380	39,208	(4.7)
Short-term and current long-term debt	79,216	75,159	5.4
Accounts payable	79,979	72,654	10.1
Other current liabilities	54,400	63,311	(14.1)
Current liabilities	134,379	135,965	(1.2)
Deferred taxes	112,686	106,328	6.0
Non-current portion of long-term debt	699,441	656,153	6.6
Other liabilities	349,363	356,000	(1.9)
Total liabilities	1,375,085	1,329,605	3.4
Total mezzanine level	2,613	757	245.2
Total Liabilities and Equity	1,940,653	1,867,302	3.9

*The financial data covering 40 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges, and 5 additional companies that provide regulated electric service in the United States but are not listed.
Source: S&P Global Market Intelligence, Edison Electric Institute Finance Department

Capitalization Ratios

When analyzing a utility's balance sheet, pay close attention to the capitalization ratio, which measures long-term debt as a percentage of capital. Historically, utilities have been highly leveraged. The main factors influencing the level of debt are the level of capital expenditures, particularly construction expenditures, and the cost of debt compared with the value of the company's common stock. (A company will not issue new shares if its stock price is relatively low.) Companies with strong balance sheets will have more flexibility to further reduce their debt, invest in their non-regulated businesses, and/or increase their dividends.

> ***Watch Out!*** *Investors may be misled by the items on the face of a company's financial statements if the company is involved in significant off-balance sheet entities and/or activities. In this way, an investor may not be able to ascertain the true risks and obligations, including cash outflows, associated with all of a company's activities.*

Debt Ratings

A debt rating measures a company's financial position and its ability to repay debt. The Standard & Poor's ratings for a utility's debt securities are a good indication of a company's financial security. Analysts should look for any trends in these ratings over time. Have they changed for the better or the worse?

Although a high debt rating is usually desirable, it is not always the best news for shareholders. For example, a company that focuses on using earnings (cash) to pay off debt may do so at the expense of common stock dividend payments. As a rule, however, low debt ratings are not desirable. Companies with low ratings often find it hard to raise capital; they also incur high interest payments to finance capital improvements. If the stock price is low enough, however, the utility's shares may be attractive to investors.

Cash Flow

A review of cash flow trends helps to reveal the health of an electric utility. For an investor, it is important to look at free cash flow—what is left after interest and dividend payments have been made. A company struggling with cash flow problems may have to consider cutting dividends or freezing dividends at current levels to preserve funds.

> ***Watch Out!*** *Companies can remove accounts receivable from the balance sheet and boost cash flow from operations through securitization activities. To the extent the off-balance sheet receivables remain outstanding at the reporting date, these activities have the potential to distort trends in accounts receivable, cash flow, and cash flow growth.*

> ***Watch Out!*** *Supplier financing arrangements (also known as reverse factoring) can delay a* ***company's payments to its suppliers****. There are several variations of these programs, but basically, a company arranges for a financial institution to pay its suppliers and the company repays the financial institution later. This effectively lengthens the supplier payment terms and thus improves working capital. However, operating cash flows can be overstated if the cash payment to the financial institution is presented as financing outflows rather than operating cash flows, which would be the case if the company pays the supplier directly. Furthermore, companies may not reclassify accounts payable under reverse factoring programs into financial liabilities, which may understate leverage ratios.*

CASH FLOW STATEMENT—INVESTOR-OWNED UTILITIES*
(in millions of dollars)

ITEM	-- CALENDER YEAR -- 2021	2020	% CHG.
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	42,278	38,627	9.5
Depreciation and amortization	62,928	59,766	5.3
Deferred taxes and investment credits	5,278	4,196	25.8
Operating changes in AFUDC	(1,453)	(1,432)	1.5
Change in working capital	(8,354)	(20,478)	(59.2)
Other operating changes in cash	(18,277)	(13,029)	40.3
Net cash provided by operating activities	82,400	67,650	21.8
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(134,056)	(132,733)	1.0
Net non-operating asset sales and purchases	17,686	2,854	519.7
Change in nuclear decommissioning trust	(314)	(408)	(23.0)
Investing changes in AFUDC	49	102	(52.0)
Other investing changes in cash	754	2,081	NA
Net cash used in (provided by) investing activities	(115,881)	(128,104)	(9.5)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net change in short-term debt	5,043	3,182	NA
Net change in long-term debt	45,444	68,220	(33.4)
Proceeds from issuance of preferred equity	3,783	5,364	(29.5)
Preferred share repurchases	(2,100)	0	NA
Net change in preferred issues	1,683	5,364	(68.6)
Proceeds from issuance of common equity	9,432	17,938	(47.4)
Common share repurchases	(1,531)	(3,933)	(61.1)
Net change in common issues	7,901	14,005	(43.6)
Dividends paid to shareholders	(30,754)	(29,716)	3.5
Other financing changes in cash	5,112	4,219	21.2
Cash flows from financing activities	34,429	65,274	(47.3)
Other changes in cash	12	9	33.3
Net increase (decrease) in cash and cash equivalents	960	4,829	NM
Cash and cash equivalents at beginning of period	16,881	11,574	45.9
Cash and cash equivalents at end of period	17,841	16,403	8.8

*The financial data covering 40 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges, and 5 additional companies that provide regulated electric service in the United States but are not listed.
Source: S&P Global Market Intelligence, Edison Electric Institute Finance Department

Return on Equity

If a utility's ROE is too low, the analyst must determine if it was caused by mild weather or the absence of a needed rate hike—or if the utility is poorly operated. Conversely, a ROE that is too high could cause regulators to seek a rate cut. In recent years, average ROE generally ranged between 7% and 11% across electric, multi, and gas utilities.

Valuation Measures

Stock price figures as a variable in the measures described below, as they indicate the market's valuation of a company's current and potential future performance.

Market-To-Book Ratio
The market-to-book (or price-to-book) ratio is used to measure shareholder confidence in a company's prospects. It is calculated by dividing the company's current market price per share by the company's book value per share. A low market-to-book ratio could mean that a company has assets, such as nuclear generation facilities, that are no longer economically viable. For firms in the S&P Composite 1500 electric utilities and S&P Composite 1500 gas utilities indices, shares normally trade between one and three times the company's book value per share.

P/E Ratio and Dividend Yield
To evaluate the current market price of the utility's shares, look at the price-to-earnings (P/E) ratio and the dividend yield. Is the P/E ratio greater or less than the expected sustainable growth rate of the company's earnings? How does the P/E compare with the industry average? Investors tend to pay a higher P/E and to accept a lower dividend yield from the shares of a company with earnings that are expected to rise rapidly.

Since June 2011, firms in the S&P Composite 1500 electric utilities index have normally traded between 14x and 20x the company's projected earnings per share (EPS), with an average of 16.9x. Over the same period, firms in the S&P Composite 1500 multi-utilities index normally traded at a P/E ratio of between 15x and 21x, with an average of 17.9x, while firms in the S&P Composite 1500 gas utilities index normally traded at P/E ratios between 16x and 22x, with an average of 18.6x. Dividend yields normally range from 3% to 6%. Because of these higher-than-average dividend yields, dividend income is an important component of investors' total return on utilities stocks.

Given the importance of the dividend (especially for income-oriented investors), utilities stocks are often seen as interest-rate sensitive, with falling rates making dividend yields more attractive, and vice versa. However, several recent examples indicate that the correlation is less than perfect. For example, the value of utilities stocks declined in both 2001 and 2002, despite a significant decline in interest rates. We think this may reflect the perception that higher growth industries may benefit more from falling rates. In 2007, although there was correlation between the decline in interest rates and the rise in utility stocks, we think the latter was more affected by the weakness of the overall market. Utility stocks appear to benefit the most when the broader market is facing uncertainty and investors are looking for a "safe haven" for their investments, particularly in the lead-up to recessions and bear-markets. However, history illustrates that during the course of severe financial downturns, such as the Dot-Com Bubble of 2000 and the Great Recession of 2007-2009, utilities often decline significantly along with the broader market.

GLOSSARY

Allowance for funds used during construction (AFUDC)—On the income statement, this noncash item represents the estimated composite interest costs of debt and the allowed return on equity (ROE) used to finance a utility's construction. AFUDC is capitalized in the property accounts.

Avoided cost—The cost that an electric utility would normally incur to produce or procure electric power, but which it does not incur because it has purchased that power from a qualifying facility.

Baseload unit—An electricity-generating plant, or a generating unit within a plant, that normally is operated continuously to meet the system's minimum constant level of electric demand.

British thermal unit (Btu)—The amount of heat required to increase the temperature of a pound of water by one degree Fahrenheit; about equal to the energy of a kitchen match. Used as a common measure of heating value for different fuels; one Btu equals 252 calories or 0.293 watt hours. A commonly used multiple is MMBtu (one million British thermal units).

Construction work in progress (CWIP)—A balance sheet account that shows all costs associated with the construction of new utility facilities until these facilities are placed in service. These costs may or may not be included in the rate base.

Cost of capital—The sum of the weighted cost of capital for each funding source: long-term debt, preferred stock equity, and common stock equity.

Cost of service—In public utility regulation, the total costs incurred to supply utility service; it is the chief determinant of the rate of return allowed a utility.

Decommissioning costs—Expenses incurred in the removal and disposal of components of a nuclear power plant that has permanently stopped producing electricity.

Decoupling—A rate adjustment mechanism that breaks the link between the amount of energy a utility sells and the revenue it collects to recover the fixed costs of providing service to customers. This ensures that a utility's revenue from fixed costs remains at the level regulators determine to be fair and reasonable, including a fair return on investment and that customers pay a fair amount for services rendered.

Degree-day—A unit of measure expressing the extent to which temperatures vary from a specific reference temperature (usually 65 degrees Fahrenheit) during a given period; each degree above or below the benchmark equals one degree-day. Thus, a given day during which the mean temperature is 55 degrees would be considered as 10 heating-degree-days. This usually would be compared with the prior period and the historical average.

Demand-side management—The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage.

Deregulation—The process of decreasing or eliminating government regulatory control over industries in the expectation that competitive forces will drive the market.

Disallowance—A regulatory body's determination that certain costs a utility incurred are not recoverable from the utility's customers through rates. Such costs could include those that regulators find to be unwise, excessive, unaccounted for, or caused by lack of proper foresight.

Firm power—Power or power-producing capacity always intended to be available during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

Gigawatt—A unit of power or capacity equal to one billion watts.

Hedging—The process of using physical resources or contracts to mitigate financial exposure. For example, utilities may hedge commitments to deliver gas through storage, bilateral contracts, and derivative instruments.

Hub—A pipeline interchange used as a standard delivery point for figuring natural gas futures contracts. There are four major hubs: the Henry Hub in Southern Louisiana, the Katy Hub near Houston, the Waha Hub in West Texas, and the Midwest Exchange Hub near Chicago.

Independent power producers (IPPs)—Non-utility power-producing entities that are not qualifying facilities (QFs); they typically sell the power they generate to electric utilities at prevailing wholesale prices. The utilities then resell this power to their customers.

Independent system operators (ISOs)—An entity formed to control and operate a regional transmission system; the individual parts of the system have different owners. Commissions in each state determine the rules for ISOs.

Interruptible service—Program activities that can interrupt consumer load during seasonal peak times, in accordance with contractual arrangements.

Kilowatt—A unit of power or capacity equal to one thousand watts.

Load—The amount of power carried by a utility system or subsystem, or the amount of power consumed by an electric device at a specified time; also referred to as demand.

Load factor—The ratio of the actual electric energy consumed during a given period to the consumption that would have occurred at the peak demand level.

Megawatt—A unit of power or capacity equal to one million watts.

Midstream—The gathering of natural gas after exploration and production (E&P)—that is, its processing and storage for later transmission and distribution. The term is sometimes meant to include pipeline transmission services, which supply LDCs and large industrial customers.

Multi-utilities—Utility companies that are comprised of both electric utilities and gas utilities.

Natural monopoly—Businesses that are monopolies because of underlying industry attributes. Natural monopolies typically occur in industries in which a large capital investment is required to produce a single unit of output, making it difficult for new businesses to enter the market.

Peaking unit—An electricity-generating plant (or a generating unit within a plant) designed to produce electric energy on short notice and for relatively brief periods. Peaking units are used when all other units and energy sources are operating at their maximum capability.

Power pool—An association of two or more interconnected electric systems that have agreed to coordinate operations, and to plan for improved reliability and efficiencies.

Rate base—The valuation of a utility's assets for the purpose of determining the rates the utility is permitted to charge its customers as established by a regulatory authority. The rate base helps the local government determine the price the utility company is allowed to charge its customers. It determines prices because it helps to ensure a reasonable profit for the utility company while keeping utilities (which are perceived as necessary) affordable for customers.

Rate case—The major regulatory proceeding during which regulators examine in depth a utility’s costs and operations, as part of the overall process of determining utility rates.

Rate of return (ROR)—The return earned by or allowed a utility enterprise, calculated as a percentage of the utility’s rate base.

Rate structure—The combined rate components and designs a utility uses to bill its various classes of customers.

Regulated plants—Contains utilities that own and operate all electricity. From the generation to the meter, the utility has complete control. The utility company owns the infrastructure and transmission lines then sells it directly to the customers.

Reserve margin—The difference between an electric utility's system capability and anticipated peak load during a specified period, measured either in megawatts or as a percentage of peak load.

Revenue requirement—The total amount of money a utility must collect from customers to pay all operating and capital costs, and to receive a fair return on investment.

Scheduled outage—The shutdown of a generating unit, transmission line, or other facility for inspection or maintenance, in accordance with an advance schedule.

Tariff—Public schedules detailing utility rates, rules, service territories, and terms of service, filed for official approval with a regulatory agency.

Test year—The 12-month base period selected for presenting data in a case or hearing before a regulatory agency.

Regulated plants— Allows for the entrance of competitors to buy and sell electricity by permitting market participants to invest in power plants and transmission lines. Generation owners then sell this wholesale electricity to retail suppliers. Retail electricity suppliers set prices for consumers, which are often referred to as the "supply" portion of the electricity bill. It often benefits consumers by allowing them to compare rates and services of different third-party supply companies (ESCOs) and provides different contract structures (*e.g.,* fixed, indexed, hybrid).

Watt—The basic unit for measuring electric power.

Wholesale sales—Energy supplied by a utility or independent power producer to other electric utilities, cooperatives, municipals, and federal and state electric agencies for resale to the ultimate customers.

Wholesale wheeling—The provision of transmission service for any electricity-generating entity that sends power to another utility.

INDUSTRY REFERENCES

PERIODICALS

Energy Intelligence
energyintel.com
Covers industry news.

Public Utilities Fortnightly
fortnightly.com
Covers the electric and gas utilities industries.

Waterborne Commodity Intelligence: LNG
ihs.com/products/waterborne-commodity-intelligence.html
Provides data and estimates of global liquefied natural gas (LNG) import and export volumes.

TRADE ASSOCIATIONS

Edison Electric Institute (EEI)
eei.org
Supplies industry statistics and information on electric utilities industry issues.

International Gas Union (IGU)
igu.org
An international non-profit organization consisting of 152 associations and corporations of the gas utilities industry, spread across 90 countries. Aims to promote the technical and economic progress of the industry.

North American Electric Reliability Corp. (NERC)
nerc.com
Not-for-profit organization formed in 1968 by the electric utilities industry to promote the reliability and adequacy of North America's bulk power supply.

INDUSTRY CONSULTANTS

Baker Hughes Inc.
bakerhughes.com
Firm providing various oil & gas industry consulting services to its clients. It is also considered the authority on rig count data, and it publishes weekly and monthly rig count information.

Fortune Business Insights
fortunebusinessinsights.com
Firm offering end-to-end solutions beyond flagship research technologies to help senior leaders across enterprises achieve their mission-critical goals.

IHS Markit
ihs.com
Research firm providing economic data, forecasts, analysis, and consulting. Among its many publications is the *Monthly Natural Gas Price Outlook*.

McKinsey Energy Insights
mckinseyenergyinsights.com
Segment within management consulting company McKinsey & Co. that provides forecasting and market analytics on global crude, refined product, natural gas markets, and oilfield services.

S&P Global Market Intelligence
spglobal.com/marketintelligence
Research firm providing regulatory, financial, market, and M&A data on several industries, including energy.

GOVERNMENT AND REGULATORY AGENCIES

Federal Energy Regulatory Commission (FERC)
www.ferc.gov
Independent five-member commission within the U.S. Department of Energy (DOE) that regulates interstate and wholesale electric power rates (tariffs) and transactions, as well as hydroelectric licensing and interstate natural gas pipeline companies.

National Oceanic and Atmospheric Administration (NOAA)
National Weather Service (NWS)
noaa.gov
weather.gov
NOAA is a scientific agency within the U.S. Department of Commerce (DOC) that focuses on the conditions of the oceans and the atmosphere. The NWS, an agency within the NOAA, is tasked with providing weather forecasts, warnings of hazardous weather, and other weather-related products.

U.S. Department of Energy (DOE)
energy.gov
A department in the U.S. Cabinet comprising the Office of the Secretary of Energy and the FERC.

U.S. Energy Information Administration (EIA)
eia.gov
Agency within the DOE; supplies publications and statistics on the electricity industry.

U.S. Environmental Protection Agency (EPA)
epa.gov
Independent federal agency that formulates and enforces policies and regulations aimed at the protection of human health and the environment.

U.S. Nuclear Regulatory Commission (NRC)
nrc.gov
Independent federal agency that regulates civilian uses of nuclear materials in the U.S. The NRC's main functions include inspecting plant operations, reviewing and issuing construction and operating licenses, and researching regulatory and standards development.

COMPARATIVE COMPANY ANALYSIS

				Operating Revenues																
				Million $							CAGR(%)			Index Basis (2008=100)						
Ticker		Company	Yr. End	2021	2020	2019	2018	2017	2016	2015	10-Yr.	5-Yr.	1-Yr.	2021	2020	2019	2018	2017	2016
ELECTRIC UTILITIES																			
ALE	†	ALLETE, INC.	DEC	1,419.2	1,169.1	1,240.5	1,498.6	1,419.3	1,339.7	1,486.4	4.3	1.2	21.4	95	79	83	101	95	90
LNT	[]	ALLIANT ENERGY CORPORATION	DEC	3,669.0	3,416.0	3,648.0	3,534.0	3,382.2	3,320.0	3,253.6	1.3	2.0	7.4	113	105	112	109	104	102
AEP	[]	AMERICAN ELECTRIC POWER COMPANY, INC.	DEC	16,792.0	14,918.5	15,561.4	16,195.7	15,424.9	16,380.1	16,453.2	1.1	0.5	12.6	102	91	95	98	94	100
CEG	[]	CONSTELLATION ENERGY CORPORATION	DEC	19,649.0	17,603.0	18,924.0	20,437.0	18,500.0	17,757.0	19,135.0	6.5	2.0	11.6	103	92	99	107	97	93
DUK	[]	DUKE ENERGY CORPORATION	DEC	24,677.0	23,453.0	24,658.0	24,116.0	23,189.0	22,381.0	21,975.0	5.7	2.0	5.2	112	107	112	110	106	102
EIX	[]	EDISON INTERNATIONAL	DEC	14,905.0	13,578.0	12,347.0	12,657.0	12,320.0	11,869.0	11,524.0	3.5	4.7	9.8	129	118	107	110	107	103
ETR	[]	ENTERGY CORPORATION	DEC	11,742.9	10,113.6	10,878.7	11,009.5	11,074.5	10,845.6	11,513.3	0.4	1.6	16.1	102	88	94	96	96	94
EVRG	[]	EVERGY, INC.	DEC	5,586.7	4,913.4	5,147.8	4,275.9	2,571.0	2,562.1	2,459.2	9.9	16.9	13.7	227	200	209	174	105	104
ES	[]	EVERSOURCE ENERGY	DEC	9,863.1	8,904.4	8,526.5	8,448.2	7,752.0	7,639.1	7,954.8	8.2	5.2	10.8	124	112	107	106	97	96
EXC	[]	EXELON CORPORATION	DEC	36,347.0	33,039.0	34,438.0	35,978.0	33,558.0	31,366.0	29,447.0	6.7	3.0	10.0	123	112	117	122	114	107
FE	[]	FIRSTENERGY CORP.	DEC	10,943.0	10,607.0	10,844.0	11,063.0	10,740.0	10,504.0	14,610.0	(3.5)	0.8	3.2	75	73	74	76	74	72
HE	†	HAWAIIAN ELECTRIC INDUSTRIES, INC.	DEC	2,850.4	2,579.8	2,873.9	2,860.8	2,555.6	2,380.7	2,603.0	(1.3)	3.7	10.5	110	99	110	110	98	91
IDA	†	IDACORP, INC.	DEC	1,458.1	1,350.7	1,346.4	1,370.8	1,349.5	1,262.0	1,270.3	3.6	2.9	7.9	115	106	106	108	106	99
NEE	[]	NEXTERA ENERGY, INC.	DEC	17,069.0	17,997.0	19,204.0	16,727.0	17,173.0	16,138.0	17,486.0	1.1	1.1	(5.2)	98	103	110	96	98	92
NRG	†	NRG ENERGY, INC.	DEC	26,989.0	9,093.0	9,821.0	9,478.0	9,074.0	8,915.0	12,328.0	11.5	24.8	196.8	219	74	80	77	74	72
OGE	[]	OGE ENERGY CORP.	DEC	3,653.7	2,122.3	2,231.6	2,270.3	2,261.1	2,259.2	2,196.9	(0.7)	10.1	72.2	166	97	102	103	103	103
PNW	†	PINNACLE WEST CAPITAL CORPORATION	DEC	3,803.8	3,587.0	3,471.2	3,691.2	3,565.3	3,498.7	3,495.4	1.6	1.7	6.0	109	103	99	106	102	100
PNM	†	PNM RESOURCES, INC.	DEC	1,779.9	1,523.0	1,457.6	1,436.6	1,445.0	1,363.0	1,439.1	0.5	5.5	16.9	124	106	101	100	100	95
POR	[]	PORTLAND GENERAL ELECTRIC COMPANY	DEC	2,396.0	2,145.0	2,123.0	1,991.0	2,009.0	1,923.0	1,898.0	2.8	4.5	11.7	126	113	112	105	106	101
SO		PPL CORPORATION	DEC	5,783.0	5,474.0	5,602.0	7,785.0	7,447.0	7,517.0	7,669.0	(7.6)	(5.1)	5.6	75	71	73	102	97	98
SO	[]	THE SOUTHERN COMPANY	DEC	23,113.0	20,375.0	21,419.0	23,495.0	23,031.0	19,896.0	17,489.0	2.7	3.0	13.4	132	117	122	134	132	114
XEL	§	XCEL ENERGY INC.	DEC	13,431.0	11,526.0	11,529.0	11,537.0	11,404.0	11,107.0	11,024.0	2.3	3.9	16.5	122	105	105	105	103	101
GAS UTILITIES																			
ATO	[]	ATMOS ENERGY CORPORATION	SEP	3,407.5	2,821.1	2,901.8	3,115.5	2,759.7	2,454.6	2,927.0	(2.3)	6.8	20.8	116	96	99	106	94	84
CPK	§	CHESAPEAKE UTILITIES CORPORATION	DEC	570.0	488.2	479.6	490.3	449.6	498.9	459.2	3.1	2.7	16.7	124	106	104	107	98	109
NFG	†	NATIONAL FUEL GAS COMPANY	SEP	1,742.7	1,546.3	1,693.3	1,592.7	1,579.9	1,452.4	1,760.9	(0.2)	3.7	12.7	99	88	96	90	90	82
NJR	†	NEW JERSEY RESOURCES CORPORATION	SEP	2,156.6	1,953.7	2,592.0	2,915.1	2,268.6	1,880.9	2,734.0	(3.3)	2.8	10.4	79	71	95	107	83	69
NWN	§	NORTHWEST NATURAL HOLDING COMPANY	DEC	860.4	773.7	746.4	706.1	755.0	668.2	723.8	0.4	5.2	11.2	119	107	103	98	104	92
OGS	†	ONE GAS, INC.	DEC	1,808.6	1,530.3	1,652.7	1,633.7	1,539.6	1,427.2	1,547.7	1.1	4.9	18.2	117	99	107	106	99	92
SJI	§	SOUTH JERSEY INDUSTRIES, INC.	DEC	1,992.0	1,541.4	1,628.6	1,641.3	1,243.1	1,036.5	959.6	9.2	14.0	29.2	208	161	170	171	130	108
SWX	†	SOUTHWEST GAS HOLDINGS, INC.	DEC	3,680.5	3,298.9	3,119.9	2,880.0	2,548.8	2,460.5	2,463.6	6.9	8.4	11.6	149	134	127	117	103	100
SR	†	SPIRE INC.	SEP	2,235.5	1,855.4	1,952.4	1,965.0	1,740.7	1,537.3	1,976.4	3.4	7.8	20.5	113	94	99	99	88	78
UGI	†	UGI CORPORATION	SEP	7,447.0	6,559.0	7,320.0	7,651.0	6,120.7	5,685.7	6,691.1	2.0	5.5	13.5	111	98	109	114	91	85
MULTI-UTILITIES																			
AEE	[]	AMEREN CORPORATION	DEC	6,119.0	5,540.0	5,646.0	6,009.0	5,909.0	5,817.0	5,885.0	0.3	1.0	10.5	104	94	96	102	100	99
AVA	§	AVISTA CORPORATION	DEC	1,438.9	1,321.9	1,345.6	1,396.9	1,445.9	1,442.5	1,484.8	(1.2)	(0.0)	8.9	97	89	91	94	97	97
BKH	†	BLACK HILLS CORPORATION	DEC	1,949.1	1,696.9	1,734.9	1,754.3	1,680.3	1,538.9	1,261.3	4.4	4.8	14.9	155	135	138	139	133	122
CNP	[]	CENTERPOINT ENERGY, INC.	DEC	8,352.0	7,418.0	7,564.0	6,277.0	9,614.0	7,528.0	7,386.0	(0.1)	2.1	12.6	113	100	102	85	130	102
CMS	[]	CMS ENERGY CORPORATION	DEC	7,329.0	6,418.0	6,624.0	6,873.0	6,583.0	6,399.0	6,456.0	1.2	2.8	14.2	114	99	103	106	102	99
ED	[]	CONSOLIDATED EDISON, INC.	DEC	13,676.0	12,246.0	12,574.0	12,337.0	12,033.0	12,075.0	12,554.0	0.6	2.5	11.7	109	98	100	98	96	96
D	[]	DOMINION ENERGY, INC.	DEC	13,964.0	14,172.0	14,401.0	11,199.0	12,586.0	11,737.0	11,683.0	0.1	3.5	(1.5)	120	121	123	96	108	100
DTE	[]	DTE ENERGY COMPANY	DEC	14,964.0	11,423.0	12,168.0	14,212.0	12,607.0	10,630.0	10,337.0	5.4	7.1	31.0	145	111	118	137	122	103
NI	[]	NISOURCE INC.	DEC	4,899.6	4,681.7	5,208.9	5,114.5	4,874.6	4,492.5	4,651.8	(1.6)	1.8	4.7	105	101	112	110	105	97
NEW		NORTHWESTERN CORPORATION	DEC	1,372.3	1,198.7	1,257.9	1,192.0	1,305.7	1,257.2	1,214.3	2.1	1.8	14.5	113	99	104	98	108	104
PEG	[]	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATEI	DEC	9,722.0	9,603.0	10,076.0	9,696.0	9,094.0	8,966.0	10,415.0	(1.3)	1.6	1.2	93	92	97	93	87	86
SRE	[]	SEMPRA	DEC	12,857.0	11,370.0	10,829.0	10,102.0	9,640.0	10,183.0	10,231.0	2.5	4.8	13.1	126	111	106	99	94	100
UTL	§	UNITIL CORPORATION	DEC	473.3	418.6	438.2	444.1	406.2	383.4	426.8	3.0	4.3	13.1	111	98	103	104	95	90
WEC	[]	WEC ENERGY GROUP, INC.	DEC	8,316.0	7,241.7	7,523.1	7,679.5	7,648.5	7,472.3	5,926.1	6.4	2.2	14.8	140	122	127	130	129	126

Note: Data as originally reported. CAGR-Compound annual growth rate. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
Souce: S&P Capital IQ.

			Net Income																
			Million $							CAGR(%)			Index Basis (2008=100)						
Ticker	Company	Yr. End	2021	2020	2019	2018	2017	2016	2015	10-Yr.	5-Yr.	1-Yr.	2021	2020	2019	2018	2017	2016
ELECTRIC UTILITIES																			
ALE	† ALLETE, INC.	DEC	169.2	174.2	185.6	174.1	172.2	155.3	141.1	6.1	1.7	(2.9)	120	123	132	123	122	110
LNT	[] ALLIANT ENERGY CORPORATION	DEC	659.0	614.0	557.0	512.0	457.3	371.5	378.2	8.1	12.1	7.3	174	162	147	135	121	98
AEP	[] AMERICAN ELECTRIC POWER COMPANY, INC.	DEC	2,488.1	2,200.1	1,921.1	1,923.8	1,912.6	610.9	2,047.1	2.5	32.4	13.1	122	107	94	94	93	30
CEG	[] CONSTELLATION ENERGY CORPORATION	DEC	(205.0)	589.0	1,125.0	370.0	2,710.0	483.0	1,372.0	NA	NM	NM	(15)	43	82	27	198	35
DUK	[] DUKE ENERGY CORPORATION	DEC	3,908.0	1,377.0	3,748.0	2,666.0	3,059.0	2,152.0	2,816.0	8.6	12.7	183.8	139	49	133	95	109	76
EIX	[] EDISON INTERNATIONAL	DEC	759.0	739.0	1,284.0	(423.0)	565.0	1,311.0	1,020.0	NA	(10.4)	2.7	74	72	126	(41)	55	129
ETR	[] ENTERGY CORPORATION	DEC	1,118.5	1,388.3	1,241.2	848.7	411.6	(583.6)	(176.6)	(1.8)	NM	(19.4)	(633)	(786)	(703)	(481)	(233)	331
EVRG	[] EVERGY, INC.	DEC	879.7	618.3	669.9	535.8	323.9	346.6	291.9	14.3	20.5	42.3	301	212	229	184	111	119
ES	[] EVERSOURCE ENERGY	DEC	1,220.5	1,205.2	909.1	1,033.0	988.0	942.3	878.5	12.0	5.3	1.3	139	137	103	118	112	107
EXC	[] EXELON CORPORATION	DEC	1,706.0	1,963.0	2,936.0	2,005.0	3,779.0	1,121.0	2,269.0	(3.7)	8.8	(13.1)	75	87	129	88	167	49
FE	[] FIRSTENERGY CORP.	DEC	1,283.0	1,079.0	912.0	1,348.0	(1,724.0)	(6,177.0)	578.0	3.8	NM	18.9	222	187	158	233	(298)	NM
HE	† HAWAIIAN ELECTRIC INDUSTRIES, INC.	DEC	246.2	197.8	217.9	201.8	165.3	248.3	159.9	5.9	(0.2)	24.4	154	124	136	126	103	155
IDA	† IDACORP, INC.	DEC	245.6	237.4	232.9	226.8	212.4	198.3	194.7	3.7	4.4	3.4	126	122	120	116	109	102
NEE	[] NEXTERA ENERGY, INC.	DEC	3,573.0	2,919.0	3,769.0	6,638.0	5,380.0	2,906.0	2,752.0	6.4	4.2	22.4	130	106	137	241	195	106
NRG	[] NRG ENERGY, INC.	DEC	2,187.0	510.0	4,438.0	268.0	(2,153.0)	(774.0)	(6,382.0)	27.2	NM	328.8	(34)	(8)	(70)	(4)	34	12
OGE	† OGE ENERGY CORP.	DEC	737.3	(173.7)	433.6	425.5	619.0	338.2	271.3	8.0	16.9	NM	272	(64)	160	157	228	125
PNW	[] PINNACLE WEST CAPITAL CORPORATION	DEC	618.7	550.6	538.3	511.0	488.5	442.0	437.3	6.2	7.0	12.4	142	126	123	117	112	101
PNM	† PNM RESOURCES, INC.	DEC	195.8	172.8	77.4	85.6	79.9	116.8	15.6	1.1	10.9	13.3	1,252	1,105	495	548	511	747
POR	† PORTLAND GENERAL ELECTRIC COMPANY	DEC	244.0	155.0	214.0	212.0	187.0	193.0	172.0	5.2	4.8	57.4	142	90	124	123	109	112
SO	[] PPL CORPORATION	DEC	(1,480.0)	1,469.0	1,746.0	1,827.0	1,128.0	1,902.0	682.0	NA	NM	NM	(217)	215	256	268	165	279
SO	[] THE SOUTHERN COMPANY	DEC	2,393.0	3,119.0	4,739.0	2,226.0	842.0	2,448.0	2,367.0	0.8	(0.5)	(23.3)	101	132	200	94	36	103
XEL	[] XCEL ENERGY INC.	DEC	1,597.0	1,473.0	1,372.0	1,261.0	1,148.0	1,123.0	984.0	6.6	7.3	8.4	162	150	139	128	117	114
GAS UTILITIES																			
ATO	[] ATMOS ENERGY CORPORATION	SEP	665.6	601.4	511.4	603.1	396.4	350.1	315.1	12.4	13.7	10.7	211	191	162	191	126	111
CPK	§ CHESAPEAKE UTILITIES CORPORATION	DEC	83.5	71.5	65.2	56.6	58.1	44.7	41.1	11.7	13.3	16.7	203	174	158	138	141	109
NFG	† NATIONAL FUEL GAS COMPANY	SEP	363.6	(123.8)	304.3	391.5	283.5	(291.0)	(379.4)	3.5	NM	NM	(96)	33	(80)	(103)	(75)	77
NJR	† NEW JERSEY RESOURCES CORPORATION	SEP	117.9	163.0	123.9	233.4	132.1	131.7	181.0	1.5	(2.2)	(27.7)	65	90	68	129	73	73
NWN	§ NORTHWEST NATURAL HOLDING COMPANY	DEC	78.7	76.8	61.7	64.6	(55.6)	58.9	53.7	2.2	6.0	2.5	146	143	115	120	(104)	110
OGS	† ONE GAS, INC.	DEC	206.4	196.4	186.7	172.2	163.0	140.1	119.0	9.1	8.1	5.1	173	165	157	145	137	118
SJI	§ SOUTH JERSEY INDUSTRIES, INC.	DEC	88.1	157.1	76.9	17.7	(3.5)	118.8	105.1	(0.1)	(5.8)	(43.9)	84	149	73	17	(3)	113
SWX	† SOUTHWEST GAS HOLDINGS, INC.	DEC	200.8	232.3	213.9	182.3	193.8	152.0	138.3	6.0	5.7	(13.6)	145	168	155	132	140	110
SR	† SPIRE INC.	SEP	271.7	88.6	184.6	214.2	161.6	144.2	136.9	15.6	13.5	206.7	198	65	135	156	118	105
UGI																		
MULTI-UTILITIES																			
AEE	[] AMEREN CORPORATION	DEC	990.0	871.0	828.0	815.0	523.0	653.0	630.0	6.7	8.7	13.7	157	138	131	129	83	104
AVA	§ AVISTA CORPORATION	DEC	147.3	129.5	197.0	136.4	115.9	137.2	123.2	3.9	1.4	13.8	120	105	160	111	94	111
BKH	† BLACK HILLS CORPORATION	DEC	236.7	227.6	199.3	258.4	177.0	73.0	(32.1)	16.9	26.5	4.0	(737)	(709)	(621)	(805)	(551)	(227)
CNP	[] CENTERPOINT ENERGY, INC.	DEC	1,486.0	(773.0)	791.0	368.0	1,792.0	432.0	(692.0)	0.9	28.0	NM	(215)	112	(114)	(53)	(259)	(62)
CMS	[] CMS ENERGY CORPORATION	DEC	1,353.0	755.0	680.0	657.0	460.0	551.0	523.0	12.5	19.7	79.2	259	144	130	126	88	105
ED	[] CONSOLIDATED EDISON, INC.	DEC	1,346.0	1,101.0	1,343.0	1,382.0	1,525.0	1,245.0	1,193.0	2.5	1.6	22.3	113	92	113	116	128	104
D	[] DOMINION ENERGY, INC.	DEC	3,288.0	(401.0)	1,358.0	2,447.0	2,999.0	2,123.0	1,899.0	8.9	9.1	NM	173	(21)	72	129	158	112
DTE	[] DTE ENERGY COMPANY	DEC	907.0	1,368.0	1,169.0	1,120.0	1,134.0	868.0	727.0	2.5	0.9	(33.7)	125	188	161	154	156	119
NI	[] NISOURCE INC.	DEC	584.9	(17.6)	383.1	(50.6)	128.5	331.5	286.5	6.9	12.0	NM	204	(6)	134	(18)	45	116
NEW	NORTHWESTERN CORPORATION	DEC	186.8	155.2	202.1	197.0	162.7	164.2	151.2	7.3	2.6	20.4	124	103	134	130	108	109
PEG	[] PUBLIC SERVICE ENTERPRISE GROUP INCORPORATEI	DEC	(648.0)	1,905.0	1,693.0	1,438.0	1,574.0	887.0	1,679.0	NA	NM	NM	(39)	113	101	86	94	53
SRE	[] SEMPRA	DEC	1,317.0	3,932.0	2,197.0	1,049.0	256.0	1,370.0	1,349.0	(0.1)	(0.8)	(66.5)	98	291	163	78	19	102
UTL	§ UNITIL CORPORATION	DEC	36.1	32.2	44.2	33.0	29.0	27.1	26.3	8.2	5.9	12.1	137	122	168	125	110	103
WEC	[] WEC ENERGY GROUP, INC.	DEC	1,300.3	1,199.9	1,134.0	1,059.3	1,203.7	939.0	638.5	9.5	6.7	8.4	204	188	178	166	189	147

Note: Data as originally reported. CAGR-Compound annual growth rate. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
Souce: S&P Capital IQ.

Ticker		Company	Yr. End	Return on Revenues (%) 2021	2020	2019	2018	2017	2016	Return on Assets (%) 2021	2020	2019	2018	2017	2016	Return on Equity (%) 2021	2020	2019	2018	2017	2016
ELECTRIC UTILITIES																					
ALE	†	ALLETE, INC.	DEC	11.9	14.9	15.0	11.6	12.1	11.6	2.6	2.9	3.4	3.4	3.4	3.2	4.8	6.3	8.3	8.2	8.7	8.4
LNT	[]	ALLIANT ENERGY CORPORATION	DEC	18.0	18.0	15.3	14.5	13.5	11.2	3.6	3.5	3.3	3.3	3.2	2.8	11.1	10.9	10.9	11.2	10.8	9.4
AEP	[]	AMERICAN ELECTRIC POWER COMPANY, INC.	DEC	14.8	14.7	12.3	11.9	12.4	3.7	2.8	2.7	2.5	2.8	3.0	1.0	11.5	10.8	9.8	10.3	10.8	3.5
CEG	[]	CONSTELLATION ENERGY CORPORATION	DEC	NM	3.3	5.9	1.8	14.6	2.7	NM	1.2	2.3	0.8	5.6	1.0	NM	3.8	7.8	2.8	19.2	4.2
DUK	[]	DUKE ENERGY CORPORATION	DEC	15.8	5.9	15.2	11.1	13.2	9.6	2.3	0.8	2.4	1.8	2.2	1.6	7.1	2.2	7.8	6.1	7.4	6.4
EIX	[]	EDISON INTERNATIONAL	DEC	5.1	5.4	10.4	NM	4.6	11.0	1.0	1.1	2.0	NM	1.1	2.6	4.5	4.7	9.1	NM	3.9	9.4
ETR	[]	ENTERGY CORPORATION	DEC	9.5	13.7	11.4	7.7	3.7	NM	1.9	2.4	2.4	1.8	0.9	NM	9.7	12.8	12.7	9.8	5.0	NM
EVRG	[]	EVERGY, INC.	DEC	15.7	12.6	13.0	12.5	12.6	13.5	3.1	2.3	2.6	2.1	2.8	3.0	9.9	7.3	7.4	7.9	8.7	9.6
ES	[]	EVERSOURCE ENERGY	DEC	12.4	13.5	10.7	12.2	12.7	12.3	2.5	2.6	2.2	2.7	2.7	2.9	8.5	9.0	7.5	9.1	9.0	8.9
EXC	[]	EXELON CORPORATION	DEC	4.7	5.9	8.5	5.6	11.3	3.6	1.3	1.5	2.3	1.7	3.2	1.0	5.3	5.6	9.0	6.4	12.9	4.4
FE	[]	FIRSTENERGY CORP.	DEC	11.7	10.2	8.4	12.2	NM	NM	2.8	2.4	2.2	3.4	NM	NM	15.6	14.1	13.1	19.0	NM	5.9
HE	†	HAWAIIAN ELECTRIC INDUSTRIES, INC.	DEC	8.6	7.7	7.6	7.1	6.5	10.4	1.6	1.3	1.6	1.5	1.3	2.0	10.3	8.4	9.7	9.3	7.8	12.2
IDA	†	IDACORP, INC.	DEC	16.8	17.6	17.3	16.5	15.7	15.7	3.4	3.3	3.5	3.6	3.5	3.2	9.4	9.4	9.6	9.8	9.7	9.4
NEE	[]	NEXTERA ENERGY, INC.	DEC	20.9	16.2	19.6	39.7	31.3	18.0	2.5	2.3	3.2	6.4	5.5	3.2	6.2	5.5	8.5	17.1	19.4	12.4
NRG	[]	NRG ENERGY, INC.	DEC	8.1	5.6	45.2	2.8	NM	NM	9.4	3.4	35.4	2.5	NM	NM	82.8	30.4	1779.7	110.7	NM	NM
OGE	†	OGE ENERGY CORP.	DEC	20.2	NM	19.4	18.7	27.4	15.0	5.8	NM	3.9	4.0	5.9	3.4	19.2	NM	10.6	10.8	17.0	10.0
PNW	[]	PINNACLE WEST CAPITAL CORPORATION	DEC	16.3	15.3	15.5	13.8	13.7	12.6	2.8	2.7	2.9	2.9	2.9	2.8	10.8	10.1	10.2	10.1	10.1	9.6
PNM	†	PNM RESOURCES, INC.	DEC	11.0	11.3	5.3	6.0	5.5	8.6	2.3	2.2	1.1	1.2	1.2	1.8	9.7	9.6	5.2	5.7	5.4	7.5
POR	†	PORTLAND GENERAL ELECTRIC COMPANY	DEC	10.2	7.2	10.1	10.6	9.3	10.0	2.6	1.7	2.5	2.6	2.4	2.6	9.2	6.0	8.4	8.6	7.9	8.4
SO	[]	PPL CORPORATION	DEC	NM	26.8	31.2	23.5	15.1	25.3	NM	3.1	3.8	4.2	2.7	5.0	0.1	4.9	6.0	16.3	10.9	19.2
SO	[]	THE SOUTHERN COMPANY	DEC	10.4	15.3	22.1	9.5	3.7	12.3												
XEL	[]	XCEL ENERGY INC.	DEC	11.9	12.8	11.9	10.9	10.1	10.1												
GAS UTILITIES																					
ATO	[]	ATMOS ENERGY CORPORATION	SEP	19.5	21.3	17.6	19.4	14.4	14.3	3.4	3.9	3.8	5.1	3.7	3.5	9.1	9.6	9.7	13.9	10.4	10.4
CPK	§	CHESAPEAKE UTILITIES CORPORATION	DEC	14.6	14.6	13.6	11.5	12.9	9.0	3.9	3.7	3.7	3.3	4.1	3.6	11.3	11.2	11.3	11.3	12.9	11.1
NFG	†	NATIONAL FUEL GAS COMPANY	SEP	20.9	NM	18.0	24.6	17.9	NM	4.9	NM	4.7	6.5	4.6	NM	19.4	NM	14.9	21.5	17.5	NM
NJR	†	NEW JERSEY RESOURCES CORPORATION	SEP	5.5	8.3	4.8	8.0	5.8	7.0	2.1	3.1	2.8	5.6	3.4	3.5	7.2	10.2	8.3	17.6	11.0	11.6
NWN	§	NORTHWEST NATURAL HOLDING COMPANY	DEC	9.1	9.9	8.3	9.1	NM	8.8	1.9	2.0	1.8	2.0	NM	1.9	8.6	8.0	8.0	8.9	9.0	7.7
OGS	†	ONE GAS, INC.	DEC	11.4	12.8	11.3	10.5	10.6	9.8	2.5	3.3	3.3	3.1	3.1	2.8	9.0	9.0	9.0	8.6	8.5	7.5
SJI	§	SOUTH JERSEY INDUSTRIES, INC.	DEC	4.4	10.2	4.7	1.1	NM	11.5	1.2	2.3	1.2	0.3	NM	3.2	4.8	10.2	5.7	1.5	NM	10.2
SWX	†	SOUTHWEST GAS HOLDINGS, INC.	DEC	5.5	7.0	6.9	6.3	7.6	6.2	1.6	2.7	2.6	2.5	3.1	2.7	6.9	8.8	8.8	8.8	11.1	9.3
SR	†	SPIRE INC.	SEP	12.2	4.8	9.5	10.9	9.3	9.4	2.9	1.1	2.4	3.1	2.5	2.4	10.5	3.5	7.7	10.1	8.6	8.6
MULTI-UTILITIES																					
AEE	[]	AMEREN CORPORATION	DEC	16.2	15.7	14.7	13.6	8.9	11.2	2.8	2.7	2.9	3.0	2.0	2.6	10.5	10.1	10.4	10.9	7.3	9.2
AVA	§	AVISTA CORPORATION	DEC	10.2	9.8	14.6	9.8	8.0	9.5	2.1	2.0	3.2	2.4	2.1	2.6	7.0	6.5	10.6	7.8	6.9	8.6
BKH	†	BLACK HILLS CORPORATION	DEC	12.1	13.4	11.5	14.7	10.5	4.7	2.6	2.8	2.6	3.7	2.7	1.1	9.1	9.5	9.0	13.6	11.7	9.2
CNP	[]	CENTERPOINT ENERGY, INC.	DEC	17.8	NM	10.5	5.9	18.6	5.7	3.9	NM	2.2	1.4	7.9	2.0	7.5	5.8	6.3	6.2	44.0	12.5
CMS	[]	CMS ENERGY CORPORATION	DEC	18.5	11.8	10.3	9.6	7.0	8.6	4.7	2.5	2.5	2.7	2.0	2.5	11.0	12.5	12.9	14.2	10.5	13.4
ED	[]	CONSOLIDATED EDISON, INC.	DEC	9.8	9.0	10.7	11.2	12.7	10.3	2.1	1.8	2.3	2.6	3.2	2.6	6.1	6.1	8.2	8.6	10.3	9.1
D	[]	DOMINION ENERGY, INC.	DEC	23.5	NM	9.4	21.9	23.8	18.1	3.3	NM	1.3	3.1	3.9	3.0	9.9	4.4	2.4	10.1	17.2	14.5
DTE	[]	DTE ENERGY COMPANY	DEC	6.1	12.0	9.6	7.9	9.0	8.2	2.3	3.0	2.8	3.1	3.4	2.7	7.4	8.6	8.4	10.8	11.4	9.1
NI	[]	NISOURCE INC.	DEC	11.9	NM	7.4	NM	2.6	7.4	2.4	NM	1.7	NM	0.6	1.8	9.0	NM	6.5	NM	3.1	8.4
NEW		NORTHWESTERN CORPORATION	DEC	13.6	12.9	16.1	16.5	12.5	13.1	2.8	2.4	3.3	3.5	3.0	3.0	8.5	7.5	10.2	10.5	9.4	10.0
PEG	[]	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATEI	DEC	NM	19.8	16.8	14.8	17.3	9.9	NM	3.8	3.5	3.2	3.7	2.2	NM	12.3	11.5	10.2	11.7	6.8
SRE	[]	SEMPRA	DEC	10.2	34.6	20.3	10.4	2.7	13.5	1.8	5.9	3.3	1.7	0.5	2.9	5.6	9.6	9.7	5.4	2.5	10.9
UTL	§	UNITIL CORPORATION	DEC	7.6	7.7	10.1	7.4	7.1	7.1	2.3	2.2	3.2	2.5	2.3	2.4	8.6	8.4	12.1	9.6	9.2	9.4
WEC	[]	WEC ENERGY GROUP, INC.	DEC	15.6	16.6	15.1	13.8	15.7	12.6	3.3	3.2	3.2	3.2	3.8	3.1	11.9	11.5	11.3	11.0	13.0	10.6

Note: Data as originally reported. CAGR-Compound annual growth rate. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
Souce: S&P Capital IQ.

Ticker	Company	Yr. End	Current Ratio						Debt/Capital Ratio (%)						Debt as a % of Net Working Capital					
			2021	2020	2019	2018	2017	2016	2021	2020	2019	2018	2017	2016	2021	2020	2019	2018	2017	2016
ELECTRIC UTILITIES																				
ALE	† ALLETE, INC.	DEC	0.5	0.6	0.5	0.8	1.0	0.7	37.4	36.3	37.5	39.9	41.0	42.0	NM	NM	NM	NM	8829.4	NM
LNT	[] ALLIANT ENERGY CORPORATION	DEC	0.5	0.7	0.4	0.5	0.4	0.8	57.0	56.6	53.7	56.7	52.7	54.4	NM	NM	NM	NM	NM	NM
AEP	[] AMERICAN ELECTRIC POWER COMPANY, INC.	DEC	0.6	0.4	0.4	0.5	0.5	0.6	62.8	63.2	62.0	57.8	55.8	54.9	NM	NM	NM	NM	NM	NM
CEG	[] CONSTELLATION ENERGY CORPORATION	DEC	1.0	1.3	1.0	1.5	1.6	1.1	42.3	34.1	24.8	34.1	35.4	41.5	NM	406.0	NM	299.8	323.3	1050.7
DUK	[] DUKE ENERGY CORPORATION	DEC	0.6	0.5	0.6	0.6	0.7	0.7	56.8	55.5	56.1	57.1	56.4	55.5	NM	NM	NM	NM	NM	NM
EIX	[] EDISON INTERNATIONAL	DEC	0.6	0.5	0.6	0.6	0.5	0.4	63.2	61.9	55.2	56.3	55.0	47.1	NM	NM	NM	NM	NM	NM
ETR	[] ENTERGY CORPORATION	DEC	0.6	0.6	0.5	0.5	0.7	1.2	70.8	70.5	69.0	71.0	70.6	65.4	NM	NM	NM	NM	NM	3073.8
EVRG	[] EVERGY, INC.	DEC	0.6	0.7	0.6	0.6	0.9	0.7	58.1	55.1	55.8	46.7	53.0	52.7	NM	NM	NM	NM	NM	NM
ES	[] EVERSOURCE ENERGY	DEC	0.6	0.6	0.7	0.6	0.7	0.7	58.9	56.5	56.1	56.1	55.9	50.7	NM	NM	NM	NM	NM	NM
EXC	[] EXELON CORPORATION	DEC	0.9	1.0	0.8	1.2	1.1	0.9	55.4	53.3	49.9	52.1	51.7	56.0	NM	NM	NM	1828.4	3050.5	NM
FE	[] FIRSTENERGY CORP.	DEC	0.7	0.7	0.5	0.5	0.8	0.4	71.9	82.8	77.5	77.3	84.0	85.4	NM	NM	NM	NM	NM	NM
HE	† HAWAIIAN ELECTRIC INDUSTRIES, INC.	DEC	1.1	1.3	1.4	1.4	1.4	1.9	51.9	52.1	52.9	49.5	50.9	47.1	430.9	172.6	130.6	121.4	121.2	72.1
IDA	† IDACORP, INC.	DEC	1.8	2.2	1.5	2.3	2.2	1.8	42.8	43.8	41.3	43.6	43.6	45.3	740.3	563.8	912.7	541.2	719.0	926.8
NEE	[] NEXTERA ENERGY, INC.	DEC	0.5	0.5	0.5	0.4	0.6	0.7	54.9	50.6	51.0	54.1	54.7	53.1	NM	NM	NM	NM	NM	NM
NRG	[] NRG ENERGY, INC.	DEC	1.4	3.1	1.3	1.5	1.3	1.4	68.9	83.8	77.6	123.2	81.8	78.1	271.9	211.2	796.0	536.4	848.1	795.7
OGE	† OGE ENERGY CORP.	DEC	0.6	0.6	0.7	0.6	0.5	0.5	58.3	50.4	45.1	42.0	44.2	45.2	NM	NM	NM	NM	NM	NM
PNW	[] PINNACLE WEST CAPITAL CORPORATION	DEC	0.9	0.9	0.5	0.6	0.8	0.6	55.7	53.7	47.6	47.2	49.2	46.9	NM	NM	NM	NM	NM	NM
PNM	† PNM RESOURCES, INC.	DEC	0.5	0.4	0.3	0.6	0.4	0.5	62.3	56.9	63.3	65.5	62.9	62.1	NM	NM	NM	NM	NM	NM
POR	† PORTLAND GENERAL ELECTRIC COMPANY	DEC	0.9	0.9	1.0	0.8	1.2	0.8	54.8	55.2	50.1	46.5	50.1	48.4	NM	NM	NM	NM	2580.9	NM
SO	[] PPL CORPORATION	DEC	2.2	1.4	0.6	0.5	0.6	0.5	44.2	54.9	65.0	67.9	68.5	67.7	402.9	254.4	NM	NM	NM	NM
SO	[] THE SOUTHERN COMPANY	DEC	0.8	0.7	0.8	0.7	0.7	0.8	62.3	58.8	59.3	62.2	66.6	64.5	NM	NM	NM	NM	NM	NM
XEL	[] XCEL ENERGY INC.	DEC	0.8	0.8	0.7	0.7	0.7	0.9	60.9	59.1	58.7	60.0	59.0	57.8	NM	NM	NM	NM	NM	NM
GAS UTILITIES																				
ATO	[] ATMOS ENERGY CORPORATION	SEP	0.8	0.6	0.4	0.3	0.5	0.4	38.3	40.0	43.0	42.3	51.2	54.9	NM	NM	NM	NM	NM	NM
CPK	§ CHESAPEAKE UTILITIES CORPORATION	DEC	0.5	0.4	0.3	0.4	0.4	0.4	58.3	56.7	68.6	73.2	65.6	59.5	NM	NM	NM	NM	NM	NM
NFG	† NATIONAL FUEL GAS COMPANY	SEP	0.4	0.7	0.9	1.2	1.3	1.4	63.1	57.8	51.2	52.4	55.0	57.7	NM	NM	NM	2039.0	1209.7	1908.8
NJR	† NEW JERSEY RESOURCES CORPORATION	SEP	0.6	1.2	1.1	1.0	0.7	1.1	66.8	60.5	50.2	50.6	56.5	53.5	NM	2619.4	2359.3	6787.2	NM	3365.0
NWN	§ NORTHWEST NATURAL HOLDING COMPANY	DEC	0.6	0.5	0.6	0.6	0.7	1.0	72.4	66.6	57.1	62.9	51.7	47.9	NM	NM	NM	NM	NM	5412.5
OGS	† ONE GAS, INC.	DEC	2.3	0.7	0.6	0.8	0.9	1.3	69.2	52.4	52.8	47.6	49.2	43.4	335.8	NM	NM	NM	NM	1070.0
SJI	§ SOUTH JERSEY INDUSTRIES, INC.	DEC	0.7	0.4	0.4	0.4	0.5	0.5	67.9	75.9	83.6	70.5	63.6	52.9	NM	NM	NM	NM	NM	NM
SWX	† SOUTHWEST GAS HOLDINGS, INC.	DEC	0.5	1.0	0.8	0.9	0.8	0.8	82.9	50.9	51.3	50.9	55.7	47.9	NM	NM	NM	NM	NM	NM
SR	† SPIRE INC.	SEP	0.8	0.4	0.4	0.5	0.7	0.5	64.5	62.1	61.1	59.0	62.0	61.8	NM	NM	NM	NM	NM	NM
UGI	† UGI CORPORATION	SEP	1.4	0.9	0.8	1.1	1.0	1.0	56.3	62.4	68.5	55.4	56.4	55.1	685.0	NM	NM	2930.4	58939.2	NM
MULTI-UTILITIES																				
AEE	[] AMEREN CORPORATION	DEC	0.7	0.8	0.6	0.6	0.5	0.6	58.5	57.4	54.7	54.1	52.6	51.7	NM	NM	NM	NM	NM	NM
AVA	§ AVISTA CORPORATION	DEC	0.5	0.7	0.6	0.5	0.5	0.9	54.6	55.8	54.7	55.6	50.7	55.1	NM	NM	NM	NM	NM	NM
BKH	† BLACK HILLS CORPORATION	DEC	0.9	0.7	0.6	0.8	0.9	0.9	64.8	60.8	62.3	59.9	67.4	66.9	NM	NM	NM	NM	NM	NM
CNP	[] CENTERPOINT ENERGY, INC.	DEC	1.7	0.6	1.0	2.1	1.1	0.9	62.3	58.1	63.0	51.9	63.9	68.8	507.7	NM	NM	233.2	2525.8	NM
CMS	[] CMS ENERGY CORPORATION	DEC	1.2	0.8	0.9	0.9	0.9	0.9	62.6	65.9	70.8	69.5	68.3	69.9	2847.8	NM	NM	NM	NM	NM
ED	[] CONSOLIDATED EDISON, INC.	DEC	1.0	0.7	0.7	0.6	0.7	0.9	56.2	56.5	55.1	58.4	50.8	54.4	19495.2	NM	NM	NM	NM	NM
D	[] DOMINION ENERGY, INC.	DEC	0.8	0.6	0.6	0.7	0.4	0.5	61.5	58.0	47.3	59.4	68.1	70.9	NM	NM	NM	NM	NM	NM
DTE	[] DTE ENERGY COMPANY	DEC	0.5	1.3	0.8	0.7	1.1	1.1	65.7	60.2	60.3	55.8	57.7	56.6	NM	2356.3	NM	NM	4760.2	3618.8
NI	[] NISOURCE INC.	DEC	0.7	0.7	0.5	0.5	0.6	0.5	58.8	64.4	69.3	70.2	73.3	74.6	NM	NM	NM	NM	NM	NM
NEW	NORTHWESTERN CORPORATION	DEC	1.2	0.7	0.9	0.8	0.5	0.5	52.1	55.0	52.3	52.0	58.8	60.4	4370.3	NM	NM	NM	NM	NM
PEG	[] PUBLIC SERVICE ENTERPRISE GROUP INCORPORATEI	DEC	0.9	0.7	0.6	0.7	0.8	1.0	63.2	51.0	51.5	51.5	48.7	47.0	NM	NM	NM	NM	NM	NM
SRE	[] SEMPRA	DEC	0.4	0.7	0.4	0.5	0.5	0.5	49.7	47.5	56.1	55.7	56.0	55.0	NM	NM	NM	NM	NM	NM
UTL	§ UNITIL CORPORATION	DEC	0.9	1.0	0.8	0.8	1.0	0.7	59.4	63.3	60.9	63.7	58.1	65.4	NM	18056.2	NM	NM	138200.0	NM
WEC	[] WEC ENERGY GROUP, INC.	DEC	0.7	0.5	0.7	0.7	0.6	0.9	62.5	60.2	56.0	57.6	55.9	55.3	NM	NM	NM	NM	NM	NM

Note: Data as originally reported. CAGR-Compound annual growth rate. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
Souce: S&P Capital IQ.

			Price/Earnings Ratio (High-Low)						Dividend Payout Ratio (%)						Dividend Yield (High-Low, %)					
Ticker	**Company**	**Yr. End**	**2021**	**2020**	**2019**	**2018**	**2017**	**2016**	**2021**	**2020**	**2019**	**2018**	**2017**	**2016**	**2021**	**2020**	**2019**	**2018**	**2017**	**2016**
ELECTRIC UTILITIES																				
ALE	† ALLETE, INC.	DEC	22 - 18	25 - 15	25 - 20	24 - 20	24 - 18	21 - 15	78	74	65	66	63	66	4.6 - 3.7	4.3 - 3.5	5.0 - 2.8	3.1 - 2.7	3.3 - 2.7	3.4 - 2.7
LNT	[] ALLIANT ENERGY CORPORATION	DEC	24 - 18	24 - 16	24 - 18	21 - 17	23 - 19	25 - 19	61	61	61	61	63	72	3.1 - 2.6	3.3 - 2.6	3.8 - 2.5	3.4 - 2.6	3.6 - 2.8	3.4 - 2.8
AEP	[] AMERICAN ELECTRIC POWER COMPANY, INC.	DEC	18 - 15	24 - 16	25 - 19	21 - 16	20 - 16	57 - 46	61	64	70	65	62	183	3.9 - 3.0	4.0 - 3.2	4.0 - 2.7	3.7 - 2.8	3.9 - 3.2	4.1 - 3.2
CEG	[] CONSTELLATION ENERGY CORPORATION	DEC							NM	294	80	271	24	191	1.3 - 0.8	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0	0.0 - 0.0
DUK	[] DUKE ENERGY CORPORATION	DEC	22 - 17	59 - 37	19 - 17	24 - 19	21 - 18	28 - 23	80	204	71	93	80	108	4.1 - 3.4	4.5 - 3.7	5.9 - 3.7	4.4 - 3.9	4.9 - 4.0	4.7 - 3.9
EIX	[] EDISON INTERNATIONAL	DEC	34 - 27	39 - 22	20 - 14	NM - NM	48 - 37	20 - 14	135	126	63	NM	125	48	4.8 - 3.8	4.9 - 4.0	5.7 - 3.3	4.6 - 3.2	5.1 - 2.7	3.1 - 2.6
ETR	[] ENTERGY CORPORATION	DEC	21 - 16	19 - 11	19 - 13	19 - 15	38 - 31	NM - NM	69	54	57	76	153	NM	4.0 - 3.2	4.4 - 3.3	4.8 - 2.8	4.4 - 3.0	4.9 - 4.2	5.1 - 4.0
EVRG	[] EVERGY, INC.	DEC	18 - 14	27 - 17	24 - 20	24 - 19	25 - 22	24 - 17	57	75	69	54	69	59	3.8 - 3.2	4.1 - 3.1	4.5 - 2.7	3.5 - 2.8	3.4 - 2.8	3.2 - 2.6
ES	[] EVERSOURCE ENERGY	DEC	26 - 22	28 - 17	30 - 22	22 - 16	21 - 17	20 - 17	66	62	73	62	61	60	3.3 - 2.6	3.1 - 2.5	3.6 - 2.3	3.2 - 2.5	3.8 - 2.9	3.5 - 2.9
EXC	[] EXELON CORPORATION	DEC	31 - 22	25 - 15	17 - 15	23 - 17	11 - 8	31 - 22	88	76	48	66	33	104	3.6 - 2.6	4.0 - 2.8	5.1 - 3.0	3.3 - 2.8	3.8 - 3.0	4.0 - 3.1
FE	[] FIRSTENERGY CORP.	DEC	17 - 13	26 - 13	29 - 22	20 - 15	NM - NM	NM - NM	66	78	90	57	NM	NM	4.3 - 3.2	5.7 - 3.9	5.9 - 3.0	4.2 - 3.1	4.9 - 3.7	5.1 - 4.1
HE	† HAWAIIAN ELECTRIC INDUSTRIES, INC.	DEC	20 - 15	29 - 18	24 - 18	21 - 17	25 - 21	15 - 12	60	73	64	67	82	47	3.6 - 3.1	4.0 - 3.0	4.1 - 2.5	3.5 - 2.8	3.9 - 3.2	4.0 - 3.2
IDA	† IDACORP, INC.	DEC	23 - 18	24 - 16	25 - 20	23 - 18	23 - 18	21 - 17	60	58	56	54	53	53	3.1 - 2.5	3.3 - 2.6	3.6 - 2.4	2.8 - 2.3	2.9 - 2.3	2.9 - 2.4
NEE	[] NEXTERA ENERGY, INC.	DEC	51 - 39	52 - 30	31 - 22	13 - 10	14 - 10	21 - 17	85	94	64	32	34	55	2.5 - 1.6	2.2 - 1.6	3.1 - 1.8	2.7 - 2.1	2.9 - 2.4	3.1 - 2.5
NRG	[] NRG ENERGY, INC.	DEC	5 - 4	19 - 11	3 - 2	48 - 27	NM - NM	NM - NM	15	58	1	14	NM	NM	3.9 - 3.0	4.0 - 2.8	5.5 - 0.3	0.4 - 0.3	0.5 - 0.3	1.1 - 0.4
OGE	† OGE ENERGY CORP.	DEC	10 - 8	NM - NM	21 - 18	20 - 14	12 - 11	20 - 14	44	NM	69	64	40	67	4.8 - 3.9	5.5 - 4.4	6.5 - 3.3	3.8 - 3.2	4.5 - 3.5	3.8 - 3.3
PNW	[] PINNACLE WEST CAPITAL CORPORATION	DEC	16 - 12	21 - 13	21 - 17	20 - 16	21 - 18	21 - 16	60	64	61	60	59	62	5.3 - 4.2	5.4 - 3.8	5.0 - 3.0	3.7 - 3.0	3.8 - 3.0	3.6 - 2.9
PNM	† PNM RESOURCES, INC.	DEC	22 - 20	26 - 14	55 - 41	42 - 32	46 - 33	25 - 20	57	57	119	99	97	60	3.1 - 2.7	2.8 - 2.5	4.1 - 2.2	2.9 - 2.2	3.1 - 2.3	2.8 - 2.1
POR	† PORTLAND GENERAL ELECTRIC COMPANY	DEC	19 - 15	36 - 19	24 - 19	21 - 16	24 - 20	21 - 16	61	90	63	59	63	57	4.0 - 3.0	4.0 - 3.2	4.8 - 2.5	3.3 - 2.7	3.7 - 2.7	3.1 - 2.7
SO	[] PPL CORPORATION	DEC	NM - NM	19 - 10	15 - 12	12 - 10	24 - 19	14 - 12	NM	87	68	62	95	54	6.0 - 2.6	6.3 - 5.4	8.9 - 4.5	5.9 - 4.8	6.4 - 4.4	4.6 - 3.9
SO	[] THE SOUTHERN COMPANY	DEC	30 - 25	24 - 15	14 - 10	22 - 20	63 - 56	21 - 18	116	86	54	109	273	86	4.3 - 3.5	4.5 - 3.9	5.7 - 3.5	5.6 - 3.9	5.6 - 4.5	5.0 - 4.4
XEL	[] XCEL ENERGY INC.	DEC	24 - 20	27 - 18	25 - 18	22 - 17	23 - 18	21 - 16	59	58	58	58	63	61	3.1 - 2.6	3.2 - 2.5	3.4 - 2.3	3.2 - 2.5	3.6 - 2.8	3.5 - 2.8
GAS UTILITIES																				
ATO	[] ATMOS ENERGY CORPORATION	SEP	20 - 17	25 - 16	26 - 20	17 - 14	24 - 18	24 - 17	49	47	48	36	48	50	3.0 - 2.2	3.0 - 2.2	2.9 - 1.8	2.4 - 1.9	2.5 - 2.0	2.6 - 2.0
CPK	§ CHESAPEAKE UTILITIES CORPORATION	DEC	30 - 21	26 - 17	25 - 20	27 - 19	24 - 18	24 - 19	38	38	38	39	34	39	1.8 - 1.3	1.7 - 1.4	2.4 - 1.6	1.9 - 1.6	2.0 - 1.5	1.9 - 1.5
NFG	† NATIONAL FUEL GAS COMPANY	SEP	14 - 10	NM - NM	17 - 13	13 - 11	18 - 15	NM - NM	45	NM	48	37	49	NM	3.6 - 2.4	4.7 - 3.2	5.3 - 3.5	3.8 - 2.8	3.4 - 2.8	3.2 - 2.7
NJR	† NEW JERSEY RESOURCES CORPORATION	SEP	36 - 22	26 - 14	37 - 32	18 - 14	29 - 20	25 - 18	99	72	84	41	67	63	4.2 - 3.1	5.1 - 3.0	5.1 - 2.7	2.8 - 2.3	3.0 - 2.3	3.3 - 2.4
NWN	§ NORTHWEST NATURAL HOLDING COMPANY	DEC	22 - 17	31 - 17	36 - 28	32 - 23	NM - NM	31 - 23	71	72	86	79	NM	87	4.5 - 3.4	4.5 - 3.4	4.4 - 2.5	3.3 - 2.6	3.6 - 2.7	3.4 - 2.7
OGS	† ONE GAS, INC.	DEC	21 - 16	26 - 18	27 - 22	27 - 19	26 - 20	25 - 18	60	58	56	56	54	52	3.6 - 2.7	3.7 - 2.6	3.2 - 2.1	2.6 - 2.1	2.9 - 2.1	2.7 - 2.1
SJI	§ SOUTH JERSEY INDUSTRIES, INC.	DEC	36 - 26	20 - 11	41 - 32	171 - 124	NM - NM	22 - 15	151	73	139	536	NM	69	5.3 - 3.5	5.8 - 4.2	6.4 - 3.5	4.3 - 3.4	4.3 - 3.1	3.5 - 2.9
SWX	† SOUTHWEST GAS HOLDINGS, INC.	DEC	21 - 17	19 - 13	23 - 19	23 - 17	21 - 18	25 - 17	69	54	54	55	48	55	3.7 - 2.6	4.0 - 3.3	4.4 - 2.7	2.9 - 2.4	3.2 - 2.3	2.7 - 2.1
SR	† SPIRE INC.	SEP	16 - 11	61 - 36	25 - 20	19 - 14	23 - 17	22 - 16	54	161	66	51	60	59	4.6 - 3.5	4.8 - 3.4	4.4 - 2.7	3.3 - 2.8	3.7 - 2.7	3.4 - 2.7
UGI	† UGI CORPORATION	SEP	7 - 5	20 - 9	41 - 32	13 - 10	21 - 17	23 - 15	19	51	78	25	39	44	4.2 - 2.9	4.1 - 2.9	5.7 - 2.6	2.8 - 1.8	2.4 - 1.9	2.3 - 1.9
MULTI-UTILITIES																				
AEE	[] AMEREN CORPORATION	DEC	23 - 18	25 - 17	24 - 19	21 - 16	30 - 24	20 - 16	57	57	57	55	82	64	2.9 - 2.4	3.1 - 2.4	3.2 - 2.3	3.0 - 2.4	3.5 - 2.7	3.6 - 2.8
AVA	§ AVISTA CORPORATION	DEC	23 - 18	28 - 17	17 - 13	25 - 21	29 - 21	21 - 16	80	85	52	72	80	64	4.4 - 3.8	4.5 - 3.5	4.9 - 3.0	3.9 - 2.9	3.1 - 2.8	3.7 - 2.7
BKH	† BLACK HILLS CORPORATION	DEC	19 - 16	23 - 14	25 - 19	14 - 11	22 - 17	46 - 32	61	60	63	41	55	120	3.7 - 3.0	3.9 - 3.1	4.2 - 2.5	3.3 - 2.5	3.8 - 3.0	3.3 - 2.5
CNP	[] CENTERPOINT ENERGY, INC.	DEC	12 - 8	NM - NM	23 - 18	40 - 34	7 - 6	25 - 17	33	NM	88	139	26	103	2.6 - 2.1	3.3 - 2.4	9.6 - 2.4	4.7 - 3.7	4.5 - 3.6	4.3 - 3.5
CMS	[] CMS ENERGY CORPORATION	DEC	14 - 12	26 - 18	27 - 20	23 - 18	31 - 25	23 - 18	37	62	64	62	82	63	3.0 - 2.5	3.2 - 2.6	3.4 - 2.4	3.0 - 2.4	3.4 - 2.7	3.2 - 2.6
ED	[] CONSOLIDATED EDISON, INC.	DEC	22 - 17	29 - 20	23 - 18	19 - 16	18 - 15	20 - 16	77	89	69	61	53	61	4.0 - 3.1	4.7 - 3.9	4.7 - 3.2	3.9 - 3.1	4.0 - 3.1	3.9 - 3.1
D	[] DOMINION ENERGY, INC.	DEC	20 - 17	NM - NM	50 - 41	22 - 17	18 - 15	23 - 20	62	NM	220	89	64	81	3.6 - 2.9	3.7 - 3.1	6.3 - 2.9	5.4 - 4.4	5.4 - 3.6	4.2 - 3.6
DTE	[] DTE ENERGY COMPANY	DEC	31 - 23	19 - 11	21 - 17	19 - 15	18 - 15	21 - 16	87	56	59	55	52	61	3.2 - 2.5	3.9 - 3.0	5.3 - 3.0	3.5 - 2.8	3.7 - 3.0	3.5 - 2.9
NI	[] NISOURCE INC.	DEC	20 - 16	NM - NM	35 - 29	NM - NM	71 - 56	26 - 19	68	NM	93	NM	178	62	3.6 - 2.9	4.1 - 3.3	4.0 - 2.7	3.1 - 2.6	3.5 - 2.6	3.2 - 2.5
NEW	NORTHWESTERN CORPORATION	DEC	19 - 15	26 - 16	19 - 14	16 - 13	19 - 17	19 - 15	69	78	57	55	62	58	4.6 - 4.0	4.5 - 3.5	5.0 - 3.0	3.8 - 3.0	4.3 - 3.3	3.7 - 3.3
PEG	[] PUBLIC SERVICE ENTERPRISE GROUP INCORPORATEI	DEC	NM - NM	16 - 10	19 - 15	20 - 16	17 - 13	27 - 22	NM	52	56	63	55	94	3.7 - 2.9	3.8 - 3.1	5.3 - 3.0	3.6 - 3.0	3.9 - 3.2	4.1 - 3.2
SRE	[] SEMPRA	DEC	36 - 29	12 - 7	21 - 14	34 - 29	120 - 98	21 - 16	109	34	52	92	295	50	3.7 - 2.7	3.8 - 3.1	4.7 - 2.4	3.4 - 2.6	3.6 - 2.7	3.1 - 2.7
UTL	§ UNITIL CORPORATION	DEC	25 - 17	30 - 15	22 - 16	24 - 19	26 - 21	23 - 18	65	70	50	66	70	74	3.7 - 2.6	3.9 - 2.6	4.6 - 2.3	3.1 - 2.3	3.5 - 2.8	3.3 - 2.7
WEC	[] WEC ENERGY GROUP, INC.	DEC	24 - 20	28 - 19	27 - 19	22 - 17	18 - 15	22 - 17	66	67	66	66	55	67	3.3 - 2.7	3.4 - 2.6	3.6 - 2.4	3.3 - 2.4	3.8 - 3.0	3.8 - 3.0

Note: Data as originally reported. CAGR-Compound annual growth rate. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
Souce: S&P Capital IQ.

			Earnings per Share ($)						Tangible Book Value per Share ($)						Share Price (High-Low, $)					
Ticker	Company	Yr. End	2021	2020	2019	2018	2017	2016	2021	2020	2019	2018	2017	2016	2021	2020	2019	2018	2017	2016
ELECTRIC UTILITIES																				
ALE	† ALLETE, INC.	DEC	3.23	3.35	3.59	3.38	3.38	3.14	45.36	44.04	43.19	37.52	36.04	33.86	73.10 - 56.84	84.71 - 48.22	88.60 - 72.50	82.82 - 66.64	81.24 - 61.64	66.92 - 48.26
LNT	[] ALLIANT ENERGY CORPORATION	DEC	2.63	2.47	2.33	2.19	1.99	1.64	23.91	22.76	21.24	19.43	18.08	16.96	62.35 - 45.99	60.28 - 37.66	55.40 - 40.75	46.58 - 36.84	45.55 - 36.56	40.99 - 30.38
AEP	[] AMERICAN ELECTRIC POWER COMPANY, INC.	DEC	4.96	4.42	3.88	3.90	3.88	1.24	44.39	41.28	39.62	38.47	37.06	35.27	91.49 - 74.80	104.97 - 65.14	96.22 - 72.26	81.05 - 62.71	78.07 - 61.82	71.32 - 56.75
CEG	[] CONSTELLATION ENERGY CORPORATION	DEC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00 - 0.00	0.00 - 0.00	0.00 - 0.00	0.00 - 0.00	0.00 - 0.00	0.00 - 0.00
DUK	[] DUKE ENERGY CORPORATION	DEC	4.94	1.72	5.06	3.76	4.36	3.12	36.06	34.34	34.53	33.38	31.59	30.55	108.38 - 85.56	103.79 - 62.13	97.37 - 82.46	91.35 - 71.96	91.80 - 76.14	87.75 - 70.16
EIX	[] EDISON INTERNATIONAL	DEC	2.00	1.98	3.77	(1.30)	1.72	3.98	36.57	37.08	36.75	32.10	35.82	36.82	68.62 - 53.92	78.93 - 43.63	76.45 - 53.40	71.00 - 45.50	83.38 - 62.67	78.72 - 57.97
ETR	[] ENTERGY CORPORATION	DEC	5.54	6.90	6.30	4.63	2.28	(3.26)	55.56	52.68	49.44	44.79	42.19	43.01	115.02 - 85.78	135.55 - 75.20	122.09 - 83.24	90.79 - 71.95	87.95 - 69.63	82.09 - 65.38
EVRG	[] EVERGY, INC.	DEC	3.83	2.72	2.79	2.50	2.27	2.43	30.13	28.20	27.51	30.12	27.50	26.84	69.45 - 51.92	76.57 - 42.01	67.81 - 54.57	61.10 - 47.06	57.32 - 49.20	57.50 - 40.01
ES	[] EVERSOURCE ENERGY	DEC	3.54	3.55	2.81	3.25	3.11	2.96	29.39	28.04	24.87	22.28	21.01	22.70	92.66 - 76.64	99.42 - 60.69	86.55 - 63.10	70.53 - 52.76	66.15 - 54.08	60.44 - 50.01
EXC	[] EXELON CORPORATION	DEC	1.74	2.01	3.01	2.07	3.98	1.21	28.31	26.55	26.26	24.85	24.10	20.74	58.01 - 38.36	50.54 - 29.28	51.18 - 43.42	47.40 - 35.57	42.67 - 33.30	37.70 - 26.26
FE	[] FIRSTENERGY CORP.	DEC	2.35	1.99	1.68	1.99	(3.88)	(14.50)	5.36	2.98	2.51	2.20	(3.80)	1.41	41.75 - 29.25	52.52 - 22.85	49.07 - 36.29	39.88 - 29.34	35.22 - 27.93	36.60 - 29.33
HE	† HAWAIIAN ELECTRIC INDUSTRIES, INC.	DEC	2.25	1.81	1.99	1.85	1.52	2.29	21.12	20.66	20.17	19.10	18.52	18.28	45.97 - 32.96	55.15 - 31.83	47.64 - 35.06	39.35 - 31.72	38.72 - 31.71	34.98 - 27.30
IDA	† IDACORP, INC.	DEC	4.85	4.69	4.61	4.49	4.21	3.94	52.82	50.73	48.90	47.04	44.68	42.55	113.75 - 85.30	113.58 - 69.05	114.01 - 89.31	102.44 - 79.59	100.04 - 77.49	83.40 - 65.03
NEE	[] NEXTERA ENERGY, INC.	DEC	1.81	1.48	1.94	3.47	2.85	1.56	16.11	16.11	16.49	17.02	13.90	11.92	93.73 - 68.33	83.34 - 43.70	61.25 - 42.17	46.05 - 36.28	39.85 - 29.33	33.00 - 25.55
NRG	[] NRG ENERGY, INC.	DEC	8.93	2.07	16.81	0.87	(6.79)	(2.22)	(2.90)	1.77	1.16	(8.45)	(4.39)	(1.88)	46.10 - 31.94	40.25 - 19.54	43.66 - 32.63	43.08 - 23.75	29.78 - 12.19	18.32 - 8.92
OGE	† OGE ENERGY CORP.	DEC	3.68	(0.87)	2.16	2.12	3.10	1.69	19.62	17.66	20.29	19.79	19.05	17.04	38.57 - 29.18	46.43 - 23.01	45.77 - 38.04	41.80 - 29.59	37.41 - 32.60	34.23 - 23.37
PNW	[] PINNACLE WEST CAPITAL CORPORATION	DEC	5.47	4.87	4.77	4.54	4.35	3.95	49.88	47.48	45.72	44.25	42.50	42.34	88.54 - 62.78	105.51 - 60.05	99.81 - 81.63	92.64 - 73.41	92.48 - 75.79	82.78 - 62.51
PNM	† PNM RESOURCES, INC.	DEC	2.27	2.15	0.97	1.07	1.00	1.46	22.01	20.63	17.58	17.70	17.79	17.55	50.11 - 43.84	56.14 - 27.08	52.98 - 39.71	45.35 - 33.75	46.00 - 33.35	36.15 - 29.22
POR	† PORTLAND GENERAL ELECTRIC COMPANY	DEC	2.72	1.72	2.39	2.37	2.10	2.16	26.38	25.11	24.60	23.45	23.62	22.81	53.12 - 40.83	63.08 - 31.96	58.43 - 44.03	50.40 - 39.02	50.11 - 42.41	45.21 - 35.27
SO	[] PPL CORPORATION	DEC	(1.94)	1.91	2.37	2.58	1.64	2.79	17.23	16.00	11.80	10.80	9.82	9.03	30.72 - 26.15	36.83 - 18.12	36.28 - 27.80	32.46 - 25.30	40.20 - 30.74	39.92 - 32.08
SO	[] THE SOUTHERN COMPANY	DEC	2.24	2.93	4.50	2.17	0.84	2.55	20.90	21.02	20.59	18.18	16.90	17.71	68.88 - 56.69	71.10 - 41.96	64.26 - 43.26	49.43 - 42.38	53.51 - 46.71	54.64 - 46.00
XEL	[] XCEL ENERGY INC.	DEC	2.96	2.79	2.64	2.47	2.25	2.21	28.70	27.14	25.24	23.78	22.56	21.73	72.94 - 57.23	76.44 - 46.58	66.05 - 47.70	54.11 - 41.51	52.22 - 40.04	45.42 - 35.19
GAS UTILITIES																				
ATO	[] ATMOS ENERGY CORPORATION	SEP	5.12	4.89	4.35	5.43	3.73	3.37	54.19	48.14	42.06	36.30	29.86	26.33	105.30 - 84.59	121.08 - 77.92	115.19 - 89.19	100.76 - 76.46	93.56 - 72.54	81.97 - 60.00
CPK	§ CHESAPEAKE UTILITIES CORPORATION	DEC	4.73	4.26	3.97	3.45	3.55	2.86	40.57	37.23	31.75	30.10	28.27	26.32	146.07 - 99.64	111.40 - 69.47	98.55 - 77.59	93.40 - 66.35	86.35 - 63.00	70.00 - 52.25
NFG	† NATIONAL FUEL GAS COMPANY	SEP	3.97	(1.41)	3.51	4.53	3.30	(3.43)	19.53	21.62	24.72	22.47	19.85	17.88	64.72 - 39.80	46.67 - 31.58	61.71 - 42.98	59.15 - 48.31	61.25 - 53.03	59.62 - 39.79
NJR	† NEW JERSEY RESOURCES CORPORATION	SEP	1.22	1.71	1.38	2.64	1.52	1.52	16.93	16.98	17.06	15.81	13.81	13.55	44.41 - 33.32	44.67 - 21.14	51.20 - 40.32	51.83 - 35.55	45.45 - 33.70	38.92 - 30.46
NWN	§ NORTHWEST NATURAL HOLDING COMPANY	DEC	2.56	2.51	2.07	2.24	(1.93)	2.12	27.77	26.79	26.78	26.10	25.85	29.71	56.75 - 41.71	77.26 - 42.33	74.13 - 57.20	71.81 - 51.50	69.50 - 56.53	66.17 - 48.90
OGS	† ONE GAS, INC.	DEC	3.85	3.68	3.51	3.25	3.08	2.65	40.86	39.03	37.36	35.85	34.45	33.10	81.90 - 62.52	96.97 - 63.67	96.66 - 75.82	87.75 - 62.20	79.51 - 61.42	67.35 - 48.01
SJI	§ SOUTH JERSEY INDUSTRIES, INC.	DEC	0.80	1.62	0.83	0.21	(0.04)	1.56	10.83	9.34	7.68	5.91	14.83	16.00	29.24 - 20.75	33.43 - 18.24	34.48 - 26.64	36.72 - 25.96	38.40 - 30.75	34.85 - 22.06
SWX	† SOUTHWEST GAS HOLDINGS, INC.	DEC	3.39	4.14	3.94	3.68	4.04	3.18	19.40	40.74	39.32	35.70	34.01	32.09	73.54 - 57.00	81.62 - 45.68	92.94 - 73.27	85.97 - 62.54	86.87 - 72.32	79.58 - 53.51
SR	† SPIRE INC.	SEP	4.96	1.44	3.52	4.33	3.43	3.24	24.08	21.48	22.16	21.39	16.98	13.22	77.95 - 59.29	87.96 - 50.58	88.00 - 71.67	81.13 - 60.09	82.85 - 62.33	71.21 - 57.10
UGI	† UGI CORPORATION	SEP	6.92	2.54	1.41	4.06	2.46	2.08	4.57	(0.32)	(1.67)	0.04	(3.21)	(4.19)	48.55 - 34.37	45.26 - 21.75	57.28 - 40.52	59.31 - 42.51	52.00 - 45.03	48.13 - 31.59
MULTI-UTILITIES																				
AEE	[] AMEREN CORPORATION	DEC	3.84	3.50	3.35	3.32	2.14	2.68	36.04	33.66	31.06	29.53	27.92	27.58	90.77 - 69.79	87.66 - 58.74	80.85 - 63.13	70.95 - 51.89	64.89 - 51.35	54.08 - 41.50
AVA	§ AVISTA CORPORATION	DEC	2.10	1.90	2.97	2.07	1.79	2.15	29.40	28.56	28.09	26.12	25.53	24.79	49.14 - 36.68	53.00 - 32.09	49.47 - 39.75	52.91 - 41.92	52.83 - 37.78	45.22 - 34.31
BKH	† BLACK HILLS CORPORATION	DEC	3.74	3.65	3.28	4.66	3.21	1.37	22.81	19.91	17.07	14.46	7.51	5.75	72.78 - 58.22	87.12 - 48.07	82.01 - 60.82	68.23 - 50.49	72.02 - 57.01	64.58 - 44.65
CNP	[] CENTERPOINT ENERGY, INC.	DEC	2.28	(1.79)	1.34	0.74	4.13	1.00	6.82	2.25	3.34	10.75	8.69	6.03	28.37 - 19.31	27.53 - 11.58	31.42 - 24.25	29.63 - 24.81	30.45 - 24.45	24.98 - 16.38
CMS	[] CMS ENERGY CORPORATION	DEC	4.66	2.64	2.39	2.32	1.64	1.98	22.11	19.02	17.68	16.78	15.77	15.23	65.79 - 53.19	69.17 - 46.03	65.31 - 47.97	53.82 - 40.48	50.85 - 41.12	46.25 - 34.96
ED	[] CONSOLIDATED EDISON, INC.	DEC	3.85	3.28	4.08	4.42	4.94	4.12	51.71	49.54	48.16	45.58	47.93	45.07	85.60 - 65.56	95.10 - 62.03	94.97 - 73.30	84.94 - 71.12	89.70 - 72.13	81.88 - 63.47
D	[] DOMINION ENERGY, INC.	DEC	3.98	(0.57)	1.62	3.74	4.72	3.44	21.40	19.33	25.69	19.13	15.58	12.08	81.08 - 67.85	90.89 - 57.79	83.93 - 67.41	81.67 - 61.53	85.30 - 70.87	78.97 - 66.25
DTE	[] DTE ENERGY COMPANY	DEC	4.67	7.08	6.31	6.17	6.32	4.83	33.73	52.81	35.46	39.00	35.41	32.79	145.43 - 108.22	135.67 - 71.21	134.37 - 107.33	121.00 - 94.25	116.74 - 96.56	100.45 - 78.01
NI	[] NISOURCE INC.	DEC	1.27	(0.19)	0.87	(0.18)	0.39	1.02	9.66	8.64	9.48	7.95	7.11	6.62	27.85 - 21.09	30.46 - 19.56	30.67 - 24.69	28.11 - 22.44	27.76 - 21.65	26.94 - 19.05
NEW	NORTHWESTERN CORPORATION	DEC	3.60	3.06	3.98	3.92	3.34	3.39	36.67	34.03	33.33	31.49	29.19	27.28	70.80 - 53.16	80.52 - 45.06	76.72 - 57.33	65.74 - 50.01	64.47 - 55.65	63.75 - 52.16
PEG	[] PUBLIC SERVICE ENTERPRISE GROUP INCORPORATEI	DEC	(1.29)	3.76	3.33	2.83	3.10	1.75	28.61	31.40	29.64	28.21	27.16	25.78	67.05 - 53.77	62.15 - 34.75	63.88 - 49.97	56.68 - 46.19	53.28 - 41.67	47.41 - 37.85
SRE	[] SEMPRA	DEC	4.01	12.88	7.29	3.42	1.01	5.46	72.93	63.86	54.35	47.68	38.50	40.13	144.93 - 114.66	161.87 - 88.00	154.47 - 106.09	127.22 - 100.49	122.98 - 99.71	114.66 - 86.72
UTL	§ UNITIL CORPORATION	DEC	2.35	2.15	2.97	2.23	2.06	1.94	28.06	25.91	25.22	23.60	22.72	20.82	59.32 - 38.02	65.76 - 32.80	64.53 - 47.05	53.07 - 40.92	52.84 - 43.03	46.00 - 34.70
WEC	[] WEC ENERGY GROUP, INC.	DEC	4.11	3.79	3.58	3.34	3.79	2.96	24.90	23.51	22.38	21.35	20.31	18.64	99.86 - 80.55	109.53 - 68.01	98.19 - 67.21	75.48 - 58.48	70.09 - 56.05	66.10 - 50.44

Note: Data as originally reported. CAGR-Compound annual growth rate. []Company included in the S&P 500. †Company included in the S&P MidCap 400. §Company included in the S&P SmallCap 600. #Of the following calendar year.
Souce: S&P Capital IQ.

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