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North American Utility Regulatory Jurisdictions: Some Notable Developments

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Key Takeaways

- Since our last report in July 2023, we have examined developments in numerous North American utility regulatory jurisdictions.
- We are also monitoring several changes across North America that, at some point, could help or hinder the business risk of various utility companies.

S&P Global Ratings has been monitoring recent developments in various U.S. and Canadian utility regulatory jurisdictions in which the utilities we rate operate. Since our last report, published in July 2023, key regulatory developments across North America include securitization and increasing pending rate cases to support weather risk mitigation efforts and initiatives on energy transition. Other important developments include updates on gas bans (Oregon and District of Columbia), increased scrutiny in rate cases (Connecticut and Florida), large pending rate cases (California), and possible formula rate plan revisions (Arkansas, Illinois, and Louisiana).

Our periodic assessments of regulatory jurisdictions provide a reference for determining a utility's regulatory advantage or risk. Regulatory advantage is incorporated into our analysis of a regulated utility's business risk profile. Our analysis covers quantitative and qualitative factors, focusing on regulatory stability, tariff-procedures and design, financial stability, and regulatory independence and insulation.(See **Key Credit Factors For the Regulated Utilities Industry**, published Nov. 19, 2013, for more details on each category.)

Utility Regulatory Jurisdiction Assessment

- S&P Global Ratings periodically assesses every regulatory jurisdiction in the U.S. and Canada with a rated utility or where a rated entity operates. Our last full assessment was in July 2023, in which we examined developments in numerous jurisdictions.
- These assessments, with categories from credit supportive to most credit supportive, provide a reference when determining the regulatory risk of a regulated utility or a holding company with more than one utility.
- We base our jurisdictional analyses on quantitative and qualitative factors, focusing on regulatory stability, tariff-setting procedures and design, financial stability, and regulatory independence and insulation.
- Utility regulation, no matter where on the continuum of our assessments, strengthens a utility's business risk profile, and generally underpins our ratings.

U.S. And Canadian Regulatory Utility Jurisdiction Developments

We group jurisdictions by quantitative and qualitative factors that comprise the regulatory advantage determinations we make in rating committees in approximately 220 U.S. and 30 Canadian utilities we rate.

The categories are an important starting point for assessing utility regulation and its effects on ratings. They are all credit-supportive to one degree or another because all utility regulation tends to sustain credit quality. We believe the presence of regulation, regardless of where it falls on the credit-supportive spectrum, reduces business risk and generally supports utility ratings. We therefore designate all these jurisdictions on a continuum from credit supportive to most credit supportive. These descriptions vary only in degree.

The following is a current snapshot of our assessment of each regulatory jurisdiction.

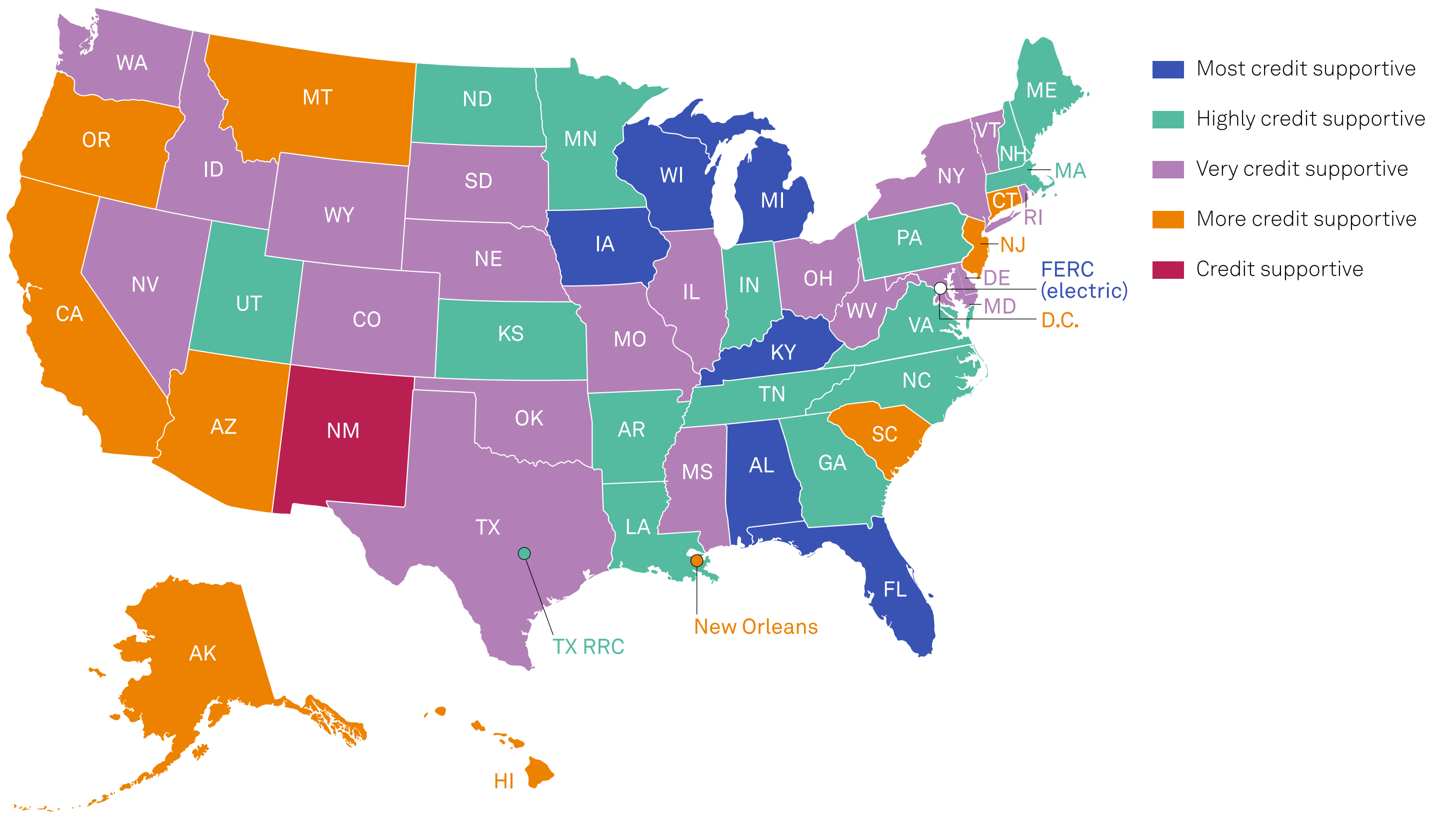
Utility regulatory jurisdictions among U.S. states and Canadian provinces

Credit supportive (adequate)	More credit supportive (strong/adequate)	Very credit supportive (strong/adequate)	Highly credit supportive (strong/adequate)	Most credit supportive (strong)
New Mexico	Alaska	Colorado	Alberta	Alabama
Nova Scotia	Arizona	Delaware	Arkansas	British Columbia
Prince Edward Island	California	Idaho	Georgia	Federal Energy Regulatory Commission (electric)
	Connecticut	Illinois	Indiana	Florida
	District of Columbia	Maryland	Kansas	Iowa
	Hawaii	Missouri	Louisiana	Kentucky
	Montana	Mississippi	Maine	Michigan
	New Jersey	Nebraska	Massachusetts	Ontario
	New Orleans	Nevada	Minnesota	Quebec
	Oregon	New York	North Carolina	Wisconsin
	South Carolina	Ohio	New Hampshire	
		Oklahoma	Newfoundland & Labrador	
		Rhode Island	North Dakota	
		South Dakota	Pennsylvania	

Texas	Tennessee
Vermont	Texas RRC
Washington	Utah
West Virginia	Virginia
Wyoming	

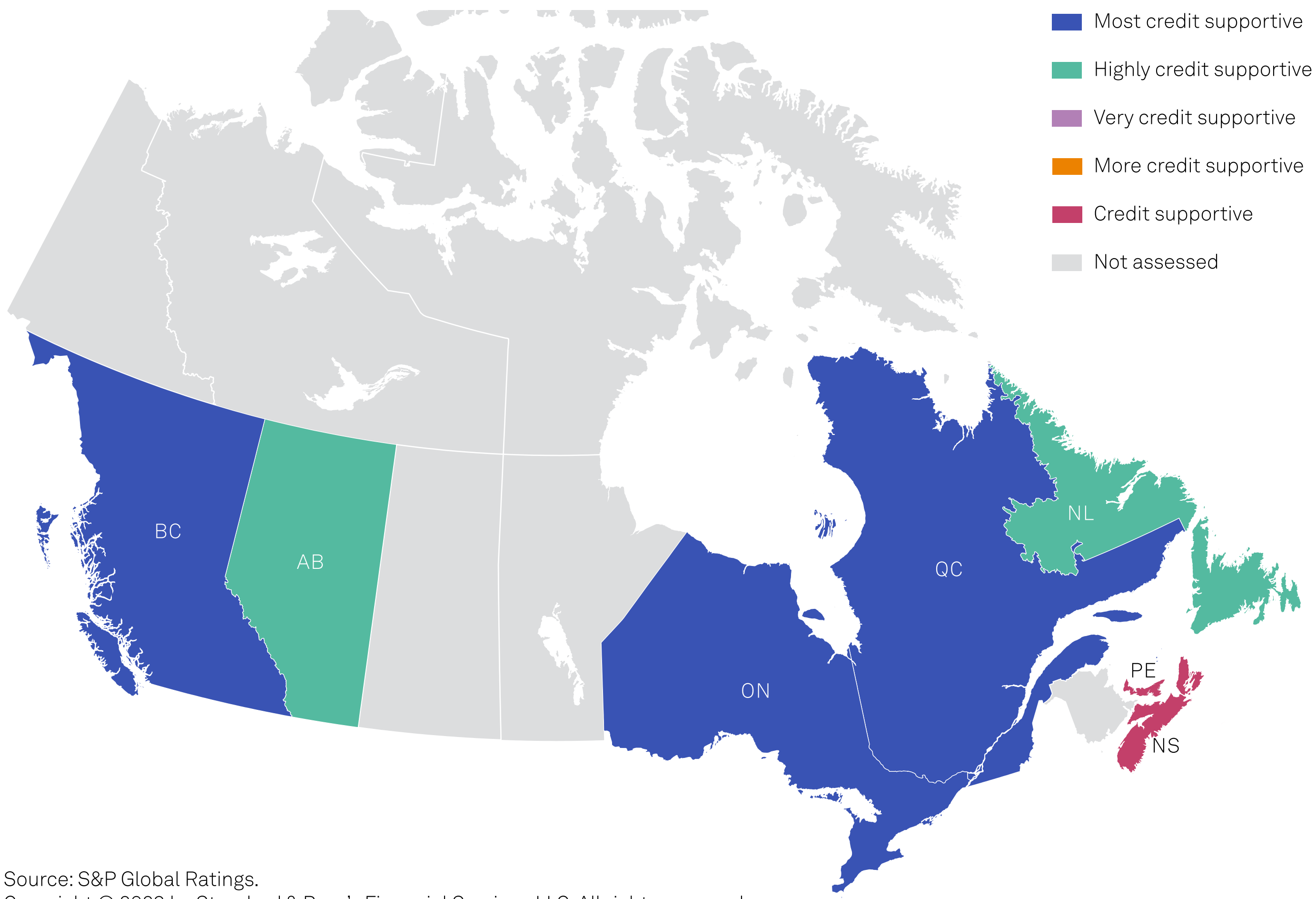
RRC--Railroad Commission of Texas. Source: S&P Global Ratings.

Regulatory assessment by state
As of November 2023



Source: S&P Global Ratings.

Regulatory assessment by Canadian province/territory
As of November 2023



Source: S&P Global Ratings.

No Revised Assessments, But Notable Developments

Alberta

The Alberta Utilities Commission (AUC) recently announced a decision in the generic cost of capital proceedings. The AUC authorized a formula-based approach in calculating the return on equity (ROE) for utilities, which becomes effective in 2024. The formula consists of a base ROE of 9% which is adjusted for the Government of Canada long-term bond yield spread and the utility bond yield spread to their base calculations. ROEs will be calculated based on this formula in November each year and will become effective in January of the next year. We view this as slightly positive, given that the base ROE is higher by a modest amount than the previously authorized ROE of 8.5%. In addition, we expect that the formulaic approach to establishing ROEs will result in more predictability in the tariff-setting process, supporting credit quality.

Arizona

Recent regulatory outcomes appear to be constructive for credit quality. In August 2023, the Arizona Corporation Commission (ACC) issued an order in Tucson Electric Power Co.'s (TEP) rate case authorizing about $100 million electric base rate increase premised upon a 9.55% ROE, which we view as supportive of the company's credit quality since the ROE is in line with industry averages. The company had requested a rate increase of about $123 million premised upon a 9.75% ROE. TEP previously had a 9.15% ROE. Separately, in June 2023, the ACC approved a resolution reversing a 20-basis-point reduction in ROE from Arizona Public Service Co.'s (APS) 2019 rate case (revising the company's ROE up to 8.9% from 8.7%) and allowed the recovery of $215.5 million related to APS's previously disallowed selective catalytic reduction (SCR) costs at the Four Corners coal power plant, which is being collected through a rate surcharge effective July 2023.

In addition, we are closely monitoring APS's pending rate case. In the pending case, APS is seeking about $378 million rate increase and a 10.25% ROE (the company's current ROE is 8.90%). A final order is expected before year-end 2023.

Arkansas

A settlement between Entergy Corp. subsidiaries, System Energy Resources Inc. (SERI) and Entergy Arkansas LLC, and the Arkansas Public Service Commission would resolve actual and potential claims against SERI related to proceedings before the Federal Energy Regulatory Commission (FERC). Although the settlement has yet to be filed with FERC, if approved, SERI would refund about $142 million to Entergy Arkansas that includes $50 million already refunded. SERI's authorized ROE would be 9.65% and the equity ratio would be no more 52%, both in line with what FERC authorized for SERI in affiliate Entergy Mississippi LLC's proceeding. We consider the settlement as credit supportive since, if adopted by the FERC, it would reduce uncertainty and regulatory risk at Entergy.

Additionally, we continue to monitor capital spending by utilities in Arkansas. Rising capital spending could mean that some utilities may decide to stop using formula rate plans (FRPs). Under Arkansas state law, utilities are allowed to operate under an FRP but are subject to a 4% annual cap in rate increases. Although we generally consider FRPs as constructive for credit quality, the 4% cap may limit the necessary rate increases for a utility to fully recover all costs, particularly with increasing capital spending.

California

Edison International subsidiary Southern California Edison Co. (SCE), Sempra subsidiary San Diego Gas & Electric Co. (SDG&E), and PG&E Corp. subsidiary Pacific Gas & Electric Co. (PacGas), have pending rate increase requests with the California Public Utilities Commission (CPUC) totaling approximately $6 billion for the 2023–2028 period. We think the sizable nature of the requests and its impact to customer bills create uncertainty regarding the rate hikes. This reflects our base case for financial improvement given the elevated capital spending and negative discretionary cash flow for the respective parent companies. We assume constructive regulatory outcomes on the pending rate cases as originally filed.

In May 2023, SCE filed for its 2025 general rate case (GRC) with the CPUC, requesting a rate increase of approximately $1.9 billion effective Jan. 1, 2025. As part of this GRC, the company is also requesting increases of $619 million for 2026, $664 million for 2027, and $705 million for 2028. We expect the CPUC to issue a decision by year-end 2024.

Separately, SCE recently reached a settlement on Track 4 of its 2021 GRC that if approved, will result in a rate increase of $758 million, compared to its initial Track 4 rate increase request of $972 million, effective in 2024.

In July 2023, SDG&E filed updated testimony to its pending GRC, requesting a revenue increase of $141 million for gas and $333 million for electric, with rates effective Jan. 1, 2024. The company's request also includes post-test-year, step-up increases, designed to take effect in 2025, 2026, and 2027.

Recently, an administrative law judge in PacGas's rate case proposed that the company underground 200 miles of its system and install covered conductors on 1,800 miles at a cost of about $2 billion over the same period, compared to the company's request to underground about 2,000 miles in its rate case filing at a capital cost of close to $6 billion for 2023-2026. At the same time, an alternate proposed decision was also put forward by a CPUC commissioner, proposing that the company underground 973 such miles, while installing covered conductors on approximately 1,027 miles at a cost of about $4.3 billion over the same period. A final decision on this rate case is expected by year-end 2023.

In October, PacGas, SCE, SDG&E, and Southern California Gas Co. filed letters with the CPUC to increase their ROEs by 70 basis points (bps) under the state's cost-of-capital mechanism. The companies indicate that the utility bond yield increased 100 bps in the current 12-months; October through September, therefore triggering the mechanism to adjust ROEs. If approved, the increase would be effective in January 2024.

Overall, we believe these regulatory developments are indicative of regulatory risk that the companies have to navigate effectively as they seek to recover costs including those for mitigating wildfire risk.

Colorado

We are following developments in Colorado where the natural gas local distribution companies (LDC) filed their "clean heat plans". In August, Xcel Energy Inc.'s subsidiary, Public Service Co. of Colorado (PSCo), filed its plan that lays out multiple paths to achieving the state-mandated targets, which include greenhouse gas emissions reductions of 4% by 2025 and 22% by 2030 (compared to a 2015 baseline). Notably, PSCo incorporates significantly higher capital spending requirements than allotted in the statute's annual budget of $34 million. PSCo also proposed to utilize certified natural gas purchases and carbon offsets to comply with the targets, but compliance using this indirect approach has yet to be approved by the state commission.

Although we expect investor-owned utility (IOU) capital spending related to the clean heat plans to be significant, the potential impact to credit quality is unclear at the moment given the nascency of the conversation with the state commission. However, we believe the inclusion of the state's LDCs in the decarbonization conversation is credit supportive. We expect the state's other IOUs, including Atmos Energy Corp. and Black Hills Corp., to file their clean heat plans in the coming months.

Connecticut

Following notices of intent by Avangrid Inc. subsidiaries Connecticut Natural Gas Corp. and Southern Connecticut Gas Co., the state's attorney general made a public statement indicating that the rate case applications would be thoroughly scrutinized, signaling the potential for regulatory lag. In general, we expect utilities in regulatory jurisdictions that we assess as more credit supportive to receive timely and full recovery of all operating and capital costs and to operate under a consistent framework that supports credit quality with limited political intervention. We will continue to monitor these pending rate cases along with the recently filed Connecticut Water Co. rate case to determine if support for utilities' credit quality is unchanged, or has worsened.

Florida

In early October 2023, the Florida Supreme Court remanded a Florida Public Service Commission (PSC) 2021 ruling that authorized a $4.8 billion multi-year rate increase for Florida Power & Light Co. (FPL). The court has requested that the PSC provide further justification and documentation regarding specific decisions around certain components of the rate increase. Although the remand does not change the already implemented multi-year rate increase, and does not prevent FPL from seeking additional rate increases while the remand review is ongoing, we will continue to monitor further developments regarding the review. Once ready, the PSC's justification and documentation will need to be submitted to the court, which will review and provide its final ruling.

Georgia

In August 2023, Georgia Power Co. (GPC), a Southern Co. subsidiary, announced the beginning of commercial operations of Unit 3 at the Vogtle Nuclear Power Plant. Simultaneously GPC also received clearance from the U.S. Nuclear Regulatory Commission (NRC) to load fuel and begin the startup process at Unit 4. GPC filed a stipulation with the Georgia Public Service Commission (GPSC) on all outstanding issues, including the reasonableness, prudency, and recovery of the remaining construction and capital costs for Unit 3 and Unit 4, set at about $7.6 billion. Other parties to the stipulation include the GPSC Public Interest Advocacy Staff, the Georgia Association of Manufacturers, the Georgia Watch, the Georgia Interfaith Power & Light, and the Partnership for Southern Equity. We view these developments as positive for credit quality and consistent with the positive outlook on Southern and its subsidiaries. Should the stipulation be approved as filed, new rates would take effect in the month following Unit 4's commercial operations, which we expect during the first quarter of 2024.

Illinois

Natural gas LDCs in Illinois are primarily seeking to roll into base rates amounts currently being recovered through the Qualified Infrastructure Plant (QIP) surcharge before it expires Dec. 31, 2023. This includes subsidiaries of WEC Energy Group Inc. (Peoples Gas Light & Coke Co. (The) and North Shore Gas Co.), Ameren Corp. (Ameren Illinois Co.), and The Southern Co. (Northern Illinois Gas Co.). We do not anticipate a replacement for the QIP, and therefore expect natural gas utilities to seek cost recovery through traditional rate proceedings after 2023 that will likely take longer to complete. This may pressure the LDCs' financial measures since the utilities will have less cash flow to support financial measures and heightens the need for the utilities to effectively manage regulatory risk. We anticipate completion of these proceedings by year–end 2023.

The electric utility subsidiaries of Exelon Corp. (Commonwealth Edison Co.) and Ameren Corp. (Ameren Illinois Co.) also have proceedings nearing resolution with the Illinois commission. Each utility is currently seeking four-year multi-year rate plans based on future test periods. The ability to file multi-year rate plans succeeds the formulaic ratemaking approach that has been used to set rates and ends at year-end 2023. We believe the use of a future test period minimizes regulatory lag and offers added predictability of rate recovery, which lowers uncertainty for a utility and helps reduces business risk.

Kansas

In April 2023, Evergy Inc. subsidiaries Evergy Kansas Central Inc. (EKC) and Evergy Metro Inc. (Metro) filed rate cases in Kansas seeking net increases of $204 million and $14 million, respectively. These are the first rate cases filed in Kansas since Evergy was formed following the 2018 merger of Great Plains Energy Inc. and Westar Energy. In the rate case proceeding, the Kansas Corporation Commission (KCC) staff recommended a net increase of $109.5 million for EKC and a net decrease of $42.3 million for Metro, a combined $150 million below the company's requested amounts. In late September 2023, the Evergy subsidiaries along with other parties to Kansas rate proceedings filed a unanimous settlement with the KCC, supporting a net rate increase of $74 million for EKC and a net decrease of about $33 million for Metro. If the settlement is adopted as filed, the rate changes could weaken Evergy's financial measures. We expect a KCC order by December 2023. We continue to have a negative outlook on Evergy and its subsidiaries, primarily reflecting our expectation of weaker financial measures, particularly if the KCC adopts the settlement as filed.

Louisiana

Entergy Louisiana LLC (ELL) has filed with the Louisiana Public Service Commission (LPSC) for regulatory treatment for 2025, 2026, and 2027. ELL currently operates under a formula rate plan (FRP) which will expire in 2024 (2022 test year). ELL has proposed to either file a full general rate case or to extend the current FRP for another three years. If extended, ELL has requested for the first year $173 million premised on a 10% ROE. Under the base rate option, ELL is requesting a $430 million rate increase and a 10.5% ROE. The request reflects investments necessary for reliability of the grid where ELL seeks to change rates to align with current costs, as ELL has been under earning for the last three years. We expect a decision in 2024.

We are also monitoring ELL's resiliency filing with the LPSC. The filing is intended to accelerate power restoration and reduce costs following major storms. ELL proposes to spend about $9.6 billion over the next 10 years. ELL is proposing to recover costs through a rider. We expect a decision in late 2023 or early 2024.

Maine

The Maine legislature has allowed a ballot measure to proceed that could result in a public acquisition of investor-owned utility transmission and distribution assets in the state. The Maine citizens will vote on whether Maine creates a new power company governed by an elected board to acquire and operate existing for-profit electricity transmission and distribution facilities in Maine. The state's two largest utilities, Central Maine Power Co., a subsidiary of Avangrid Inc., and Versant Power, indirectly owned by Enmax Corp., have campaigned against the referendum. If approved by voters, legal challenges could delay the process and lead to litigation costs that could result in utilities focusing less on investing in strengthening infrastructure and potentially lead to regulatory lag that could weaken the companies' cash flows. Furthermore, it is uncertain if the utilities would be compensated for the full value of assets. Current estimates by various parties are far apart. We continue to monitor the developments on the referendum and its impact on the utilities.

Maryland

We continue to monitor the various major rate cases before the Maryland Public Service Commission (PSC), specifically for AltaGas Ltd. utility Washington Gas Light Co. (WGL) and Exelon Corp. utility subsidiaries Baltimore Gas & Electric Co. (BGE) and Potomac Electric Power Co. (PEPCO).

Various aspects of WGL's Strategic Infrastructure Development and Enhancement (STRIDE) program are being scrutinized by intervenors in the utility's two pending rate cases. Regarding its rate case for the third installment of STRIDE, the public utility judge recommended a scaled-back version of the program prospectively, citing that the third installment does not coincide with state emission standards. Regarding WGL's rate case including investments made under STRIDE from January to August 2023, intervenors have proposed alternatives, including the recommendation by the Office of People's Counsel (OPC) to reduce rates. We continue to monitor the proceedings.

In BGE's electric and natural gas rate cases, intervenor OPC requested that the utility's proposed electrification program be removed from the utility's electric rate case, citing it is a premature filing as the state develops a plan for its greenhouse gas emission goals. The removal of the electrification program would reduce the requested revenue requirement by about $44 million. We expect final decisions in mid-November 2023 for BGE's rate cases.

Separately, the PSC asked for PEPCO's rate case to be delayed given the currently large caseload before the commission. PEPCO and the PSC agreed to extend the schedule of the utility's rate case by 90 days to help manage commission capacity.

Michigan

On July 26, 2023, the Michigan Public Service Commission (MPSC) approved an integrated resources plan (IRP) for DTE Energy Co. (DTE) subsidiary DTE Electric Co. (DTEE). Provisions include:

- Converting the Belle River coal generation facility to natural gas by 2026.
- Retiring two coal units at the Monroe generating facility by 2028, with the remaining two units retired by 2032.
- Developing 6,500 megawatts (MW) of solar power and 8,900 MW of wind power by 2042.
- Accelerating the development of energy storge, with a target of 780 MW through 2030 and 1,830 MW through 2042.

The MPSC's approval is constructive because it indicates a possible path for DTEE to transition away from coal-fired generation in a manner that supports credit quality. Key reasons include preapproval of $125 million of capital to convert the Belle River coal generation facility to gas and supportive regulatory treatment for the remaining net-book value of affected coal-fired assets to be retired. Specifically, MPSC authorizes DTEE to securitize approximately $1 billion in certain investments related to its Belle River and Monroe assets after these plants are closed. Furthermore, we expect DTEE to receive recovery of the remaining net book value of its Monroe generation assets over 15 years, with an authorized return on equity of 9%, beginning with the utility's next rate order.

On the gas side, we continue to monitor energy transition risk given recent trends such as the City of Ann Arbor's recent push to replace gas distribution with a lower-emissions method of heating buildings. DTE subsidiary DTE Gas Co. currently provides natural gas in the city of Ann Arbor under a franchise that expires in 2027.

New Hampshire

In August 2022, the New Hampshire Public Utilities Commission (PUC) initiated an investigation to review the methods used by the state's electric and gas utilities for calculating step adjustments as part of previously authorized multi-year rate plans. This investigation was prompted by the high volume of step adjustment filings received by PUC, along with the different methodologies used for the calculation. As a part of this investigation, PUC is evaluating the necessity of these step adjustments and scrutinizing the calculation and accounting methodologies. We think the investigation suggests a focus by the PUC on managing the rate impact on customer bills and indicates potential for an increase in regulatory risk. As such, we continue to monitor related developments.

New Jersey

After the unexpected president vacancy at the New Jersey Board of Public Utilities (BPU) in September 2023, Governor Murphy appointed commissioner Christine Guhl-Sadovy to serve as the president until a permanent appointment is made. At the same time, there continues to be a vacancy in the BPU, leaving the commission with an even number of commissioners. With pending rate cases at Atlantic City Electric Co. and Jersey Central Power & Light Co., we continue to monitor developments as the proceedings advance. Additionally, a vacancy could be further impactful as other utilities in the state are expected to file rate cases in the next few months and the BPU has a key role in the state meeting its energy transition goals.

New Mexico

The New Mexico Public Regulation Commission (NMPRC) approved a settlement regarding Public Service Co. of New Mexico's (PSNM) abandonment of the San Juan Generating Station coal plant. Under the terms of the settlement, PSNM will issue up to $360 million in Energy Transition Act (ETA) bonds for the costs associated with the abandonment. We view these aspects of the approved settlement as supportive of credit quality, reducing regulatory risk and uncertainty. We also view securitizations to recover undepreciated plant balances as positive for credit quality in the state given coal units may be retired early due to energy transition goals.

We are monitoring PSNM's and New Mexico Gas Co. Inc.'s (NMG) current rate cases to gauge credit supportiveness of the newly formed commission. Hearings in PSNM's rate case have concluded and an order is expected in December 2023. NMG filed its rate case in September and rates are expected to be effective by the fourth quarter of 2024.

New Orleans

We continue to monitor Entergy New Orleans LLC's (ENO) resilience filing with the New Orleans City Council (NOCC). We currently expect a decision by the end of the year. If approved, the plan will benefit ENO by enhancing its ability to protect against severe storms while recovering costs through a rate rider. However, recent comments by a NOCC member indicated that affordability of ENO's plan could be a hurdle. This highlights our view on ongoing regulatory risks in New Orleans as ENO needs to strike a fine balance between necessary capital spending while minimizing customer bill increases.

Ontario

In September 2023, the Ontario Energy Board (OEB) approved preliminary Uniform Transmission Rates (UTRs) that can be implemented by electric local distribution utilities (LDCs) in their respective annual rate adjustment applications for 2024. When setting final transmission rates, the preliminary rates will be adjusted. Until recently, UTRs were typically issued by the OEB in December or January, limiting the LDCs from using the most current UTRs until their next annual rate applications. This resulted in material under-recovery of retail transmission service rates (RTSR) of which UTR is a significant component. We consider this revised timeline as supportive of the credit quality of Ontario LDCs. We continue to monitor further OEB regulatory developments that we would consider supportive of credit quality, including the upcoming decision on final UTRs.

Oregon

In Oregon, several developments occurred since our last regulatory review that were supportive of Oregon utilities' credit quality. In June 2023, the City of Eugene's city council repealed a previously passed ordinance that prohibited natural gas appliances in new residential construction. This followed a federal appeals court ruling that overturned a similar ban in Berkeley, California. We view this repeal as supportive of natural gas local distribution companies' (LDC) credit quality in Oregon since the repeal removes a legal barrier against their future growth. We continue to monitor how policymakers enact upcoming legislation regarding energy transition and its implications for the gas LDCs in the state.

In August 2023, legislation was enacted that enables Oregon's electric and gas utilities to securitize costs and expenditures associated with declared emergencies that have been deemed as reasonable and prudent and approved for recovery in rates. Such events include severe storms, pandemics, or wildfires. We consider this new law as a credit-supportive way for utilities to mitigate and recover extraordinary costs.

Washington

In our March 2023 publication of this report, we commented that the state's regulated IOUs including Puget Sound Energy Inc. (PSE), Avista Corp., Cascade Natural Gas Corp., and Northwest Natural Gas Co. (NNG), filed for deferral accounting treatment of the expenses and revenues relating to compliance with the Climate Commitment Act (CCA), which requires businesses emitting greater than 25,000 metric tons of carbon dioxide per year to participate in a cap and trade program. In August 2023, the Washington commission issued an order authorizing PSE to implement a nearly $17 million natural gas rate increase to recover the projected costs of emissions allowances needed to comply with the CCA. The tariff, the first one approved in Washington, reflects a new revenue requirement for the increase in emissions allowance costs of $104.8 million and a new revenue requirement decrease of $87.9 million related to projected emissions sale proceeds, resulting in a net revenue requirement increase of $16.8 million. In October 2023, NNG similarly requested a nearly $18 million natural gas rate increase related to the impact it anticipates in complying with the CCA.

These filings follow a February 2023 commission order authorizing the utilities to defer costs and revenues tied to compliance. We believe the approach taken by the commission in approving PSE's natural gas compliance costs is credit supportive as it facilitates financial stability, specifically as it pertains to the timeliness of cost recovery and the flexibility of the regulatory construct to recover infrequent costs tied to the new cap and trade program. We anticipate a similar approach to cost recovery could be taken for PSE's electric costs and other IOUs.

Washington, D.C.

The push to ban natural gas was met with resistance in Washington, D.C., as the Construction Codes Coordinating Board (CCCB) recently struck down a natural gas ban in new commercial buildings. Parties that supported the electrification initiative stated that their proposal would have aligned with the district's climate goals: reducing greenhouse gas emissions by 50% by 2032 from 2006 levels and achieve carbon neutrality by 2050. The failure of the proposed ban reduces the risks of gas utilities possibly experiencing lower growth in their businesses in the medium term. However, the CCCB must develop construction codes that require commercial buildings to achieve a net-zero standard by 2027. This could affect the credit quality of gas utilities operating in the district, particularly if there is a ban on gas operations to achieve the net-zero standard.

West Virginia

In August 2023, the Public Service Commission of West Virginia (PSC) staff filed testimony seeking a disallowance of $262 million in the requests filed by American Electric Power Co. Inc. subsidiaries Appalachian Power Co.and Wheeling Power Co. to recover about $552 million of unrecovered purchased power, fuel, and transmission costs incurred between March 1, 2021, and February 28, 2023. The accrued costs arose primarily due to larger wholesale power purchases than anticipated due to limited availability of coal that constrained the companies' ability to use their coal-fired generation. Overall, we view the timely recovery of costs such as purchased power, fuel, and transmission investments as essential for utilities' credit quality. We will continue to monitor these developments for potential credit implications.

Wisconsin

In April 2023, Madison Gas & Electric Co. (MG&E), a subsidiary of MGE Energy Inc., filed for a multi-year electric rate increase of $18 million (3.75%) in 2024 and $16.9 million (3.41%) in 2025. In addition, MG&E requested a multi-year natural gas rate increase of $6 million (2.56%) in 2024 and $4 million (1.66%) in 2025. The proposed increases include a requested 9.8% ROE and equity ratio of about 56%. The proposed increases reflect higher labor costs and investments in the natural-gas-fired West Riverside Energy Center, local solar generation, and grid modernization. If authorized, the increases in rates will bolster MG&E's financial measures. We continue to monitor developments around the rate cases with Wisconsin commission rulings expected by year-end 2023.

Offshore wind—Connecticut, Massachusetts, and Rhode Island

To help ameliorate rising costs for offshore wind developers, which have led to project cancellations and other uncertainties, the states of Connecticut, Massachusetts, and Rhode Island agreed to coordinate procurement of offshore wind capacity to meet their cumulative procurement goals. The states would like to enable developers to bid larger projects, have greater economies of scale, and lower costs, while also using all three states to take advantage of local supply chain benefits. We consider this development as supportive of utilities' credit quality since the states would like to limit customer rate impacts from higher-priced offshore wind energy. This could lead to lower bid prices as compared to smaller single-state projects.

Related Research

- Credit FAQ: **What's Behind Our Recent Actions on Investor-Owned Utilities in Connecticut?**, Sept. 28, 2023
- **Key Credit Factors For The Regulated Utilities Industry**, Nov. 19, 2013

This report does not constitute a rating action.

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