Concept Paper 2: Assessment of the Nevada Electric Utility Regulatory Framework

Nevada Alternative Ratemaking Proceeding
Docket No. 19-06008

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In consultation with
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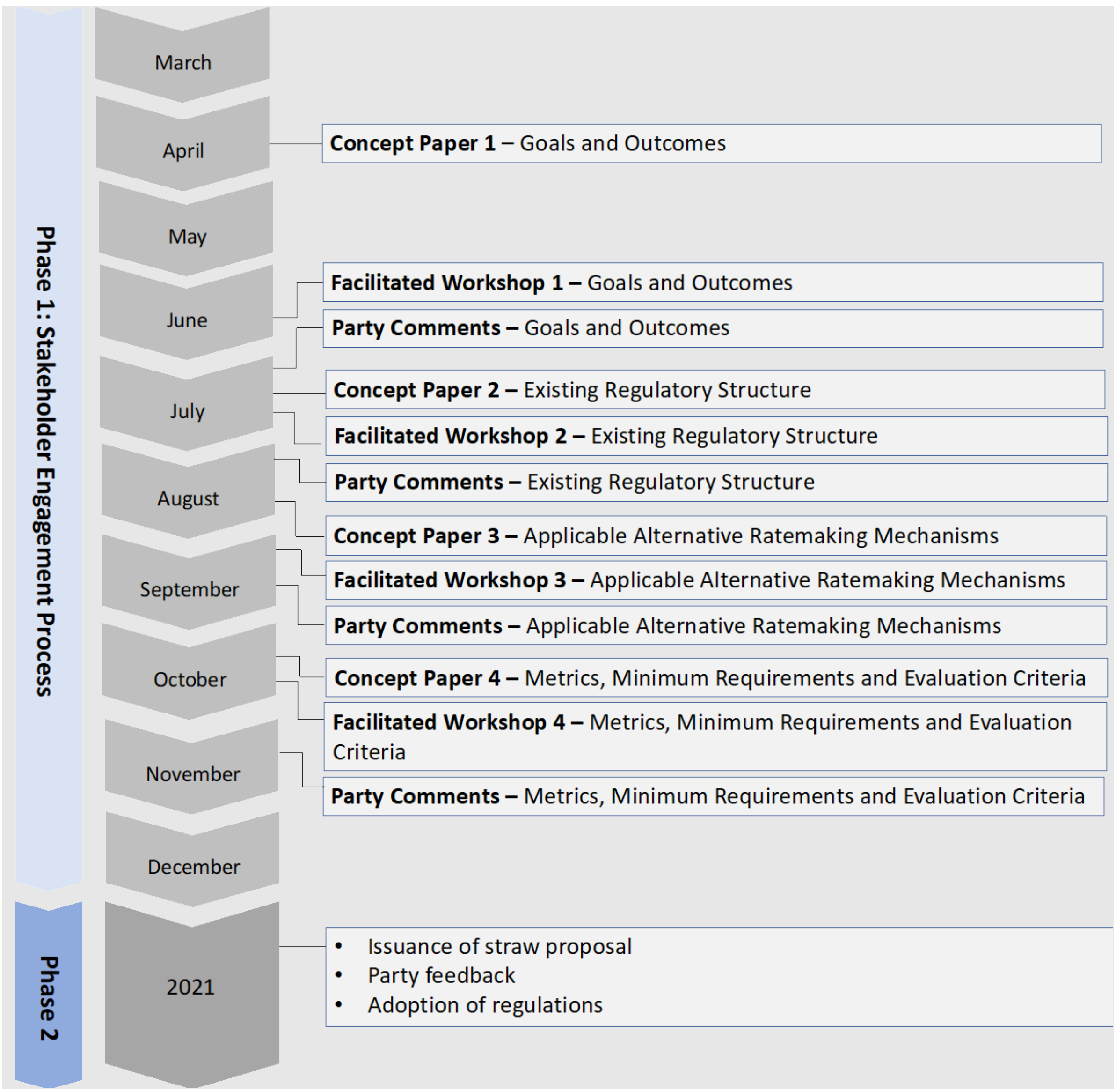
Section I: Introduction and Overview

Docket No. 19-06008 before the Public Utilities Commission of Nevada (PUCN or Commission) is now in the midst of a facilitated stakeholder review process requested by the PUCN and guided by Rocky Mountain Institute (RMI) and the Regulatory Assistance Project (RAP). On April 24, 2020, the PUCN in consultation with RMI and RAP released Concept Paper 1 in Docket No. 19-06008. Concept Paper 1 described the facilitated stakeholder process that is envisioned to occur through 2020 and into 2021. The PUCN has provided some updates to this facilitated stakeholder process in Figure 1 below.

Figure 1: Updated Stakeholder Process Timeline and Activities



The primary focus of Concept Paper 1 was to establish a framework for the development of goals and outcomes by stakeholders. Following the stakeholder workshop held June 25-26 to further discuss goals and outcomes, the Presiding Officer issued Procedural Order No. 6 in Docket No. 19-06008 on July 8, 2020, seeking comments from stakeholders on refining goals and outcomes. The PUCN intends to identify a working set of goals and outcomes that will serve to constructively guide continued progress in this proceeding after evaluating these comments. The PUCN, in consultation with RMI and RAP, will release this working set of goals and outcomes prior to the next stakeholder workshop on July 23 and 24. As discussed below, these goals and outcomes will be used in the upcoming workshop to assist in evaluating and assessing the existing Nevada regulatory structure to determine whether current regulatory mechanisms align with a set of working goals and outcomes.

The goals and outcomes the PUCN will release in consultation with RMI and RAP prior to Workshop 2 should be construed as a working set that may still be refined as the stakeholder process continues. Both stakeholders and the PUCN may seek to clarify or improve the working set of goals and outcomes, as further discussions about how to achieve outcomes may reveal where refinements are necessary.

This Concept Paper 2 provides an inventory of existing regulatory mechanisms, practices and associated statutes and regulations in Nevada. This review is intended to provide stakeholders with a common understanding of the regulatory landscape in Nevada upon which regulatory improvements might be considered. Some improvements may be adjustments to traditional, existing regulatory mechanisms, while others might use the alternative ratemaking mechanisms identified in SB 300. In either case, this paper provides a foundation that stakeholders can reference as they consider which traditional regulatory mechanisms and alternative ratemaking mechanisms offer a way to facilitate achievement of identified goals and outcomes. Concept Paper 3, which concerns applicable alternative ratemaking mechanisms, will delve further and examine whether alternative ratemaking mechanisms can better achieve identified goal and outcomes.

Concept Paper 2 has three objectives:

1) Describe the existing regulatory framework and mechanisms in Nevada;

2) Describe how the existing practices, mechanisms and policy provisions will be evaluated using a regulatory assessment tool; and

3) Prepare stakeholders for Workshop 2.

Concept Paper 2 outlines the information needed to successfully participate in Workshop 2. Section II introduces the basic electricity regulation foundations in Nevada. Section III summarizes the existing regulatory mechanisms in Nevada and is broken into categories as follows:

- Category 1 – Rate Setting Mechanisms.
- Category 2 – Practices and Mechanisms that Adjust Rates between Rate Cases
- Category 3 – Practices and Mechanisms that Affect Utility Investment and Supply Decisions

- Category 4 – Policy Provisions that Inform Utility Investment Decisions
- Category 5 – Existing Alternative Ratemaking Mechanisms

To start the discussion of how each mechanism addressed in Concept Paper 2 relates to goals and outcomes, the paper highlights how an existing regulatory mechanism might be related to various areas of interest that have been raised in the goals and outcomes discussion.[1] While RMI, RAP and the stakeholders may more directly link the mechanisms discussed in this paper to specific goals and outcomes during Workshop 2, the references in this paper are meant only to start a high-level discussion on how existing ratemaking mechanisms might relate to the themes raised in the goals and outcomes discussion.

After discussing Nevada's existing regulatory mechanisms, this paper in Section IV offers a regulatory mechanism assessment approach to assist stakeholders in evaluating whether a given mechanism is positively or negatively affecting certain outcomes. Stakeholders will be more equipped to fully review and addresses Section IV when the PUCN issues a working set of goals and outcomes prior to the upcoming Workshop 2.

Section V describes how the information provided in this Concept Paper 2 will be used in Workshop 2. Workshop 2 will offer stakeholders the opportunity to evaluate selected mechanisms and to consider whether the mechanism is working well, whether it needs a tune-up with existing tools or whether an alternative ratemaking approach deserves further consideration.

In Workshop 2, stakeholders will be asked to consider how the existing practices, mechanisms, and policy provisions affect goals and desirable outcomes. To the extent an existing mechanism advances attainment of an outcome, can the mechanism be improved to further advance the outcome? To the extent an existing mechanism impedes the attainment of an outcome, should the mechanism be refined with traditional tools, or is the consideration of an alternative ratemaking mechanism more appropriate?

Section II: Electricity Regulation Basics

Regulation of investor-owned electric utilities in the United States is not uniform across every jurisdiction, but two fundamental features of utility service justify government oversight of the electric utility sector in all states. First, because a utility provides essential services for the well-being of society — both for individuals and businesses — it is an industry "affected with a public interest."[2] Second, because the technological and economic features of the electric utility industry lead to some electric services being

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[1] The goals or outcomes that are noted in this paper are consistent with those provided to stakeholders as Attachment 1 to Procedural Order. No. 6, issued on June 30, 2020. As stated previously, the PUCN is still refining the goals and outcomes and will take time to evaluate the comments filed by stakeholders on July 8, 2020, before releasing a complete set of working goals and outcomes.

[2] *Southwest Gas Corp. v. Pub. Serv. Comm'n*, 86 Nev. 662, 668 (1970) ("The rule governing the duty of public utilities or companies to serve the public is well stated in the case of *Birmingham Railway, Light & Power Co. v. Littleton*, 201 Ala. 141, 77 So. 565, 569 (1917): 'This duty to serve the public exists independent of statutes regulating the manner in which public service corporations or companies shall do business. It is imposed upon the public service corporation because it is organized to do a business affected with a public interest, and because the corporation has held itself out to the public as being willing to serve all members thereof.' *Messer v. Southern Airways Sales Co.*, 245 Ala. 462, 17 So.2d 679 (Ala.1944); *Gibbs v. Baltimore Gas Co.*, 130 U.S. 396, 9 S.Ct. 553, 32 L.Ed. 979 (1889)).

provided most economically by a monopoly provider, regulatory oversight of electric utility rates is essential. While the level of regulatory oversight of utility rates varies from state to state depending on whether the state has mandated a "retail choice" model or vertically integrated utilities continue to serve customers, the fact remains that there is an important role for state public utility commissions to provide regarding regulatory oversight of monopoly services.

The fundamental approach to the economic regulation of investor-owned electric utilities is also founded on a common basis: cost of service (COS) regulation. COS was established and has evolved to ensure that adequate investment flows to electric utilities and electric service is available to all at just and reasonable rates. Important steps along the way to establishing just and reasonable electric rates include determining those costs that should be incurred to ensure adequate and reliable electric service and allowing recovery of those costs, while establishing an allowed return on equity that fairly compensates investors for their capital investments that support provision of electric service.

Rather than discuss the many different variations of how electric service is regulated in the United States today, we will focus on how regulation works in Nevada. Because we expect this facilitated stakeholder process to invite participation of some stakeholders who may be less familiar with how electricity regulation works around the country, we have provided a short primer in the appendix that attempts to summarize electricity regulation at a high level. You may also find useful a document that is available for free from RAP's website entitled "Electricity Regulation in the United States: A Guide."

Roles and Obligations of Regulators, Utilities and Customers in Nevada

To protect the public interest, various roles and obligations are imposed on regulators, on the utilities and even on the customers themselves. These duties and obligations are established under law and are detailed primarily in Chapters 703 and 704 of the Nevada Revised Statues (NRS). Key provisions in the NRS that address these duties and obligations are identified below.

- NRS 703.151 requires the PUCN to:

  1. Protect, further and serve the public interest;

  2. Provide effective protection for customers who depend upon electric service;

  3. Provide for stability in rates and for the availability and reliability of electric service;

  4. Encourage the development and use of renewable energy resources; and

  5. Require providers of electric service to engage in prudent business management, effective long-term planning, responsible decision making, sound fiscal strategies and efficient operations.

- NRS 703.025(2)(c) provides that if customers are authorized by a specific statute to obtain a competitive, discretionary or potentially competitive utility service, the PUCN shall take any actions which are consistent with the statute and which are necessary to encourage and enhance:

(1) A competitive market for the provision of that utility service to customers in this State; and

(2) The reliability and safety of the provision of that utility service within that competitive market.

- NRS 703.025(2)(d) requires the PUCN to adopt such regulations consistent with law as it deems necessary for the operation and the enforcement of all laws administered by the PUCN.
- NRS 704.001 addresses powers and duties of both the PUCN and utilities, stating that the purpose and policy of the Legislature in enacting NRS Chapter 704 is:
    - to confer upon the PUCN the power, and to make it the duty of the PUCN, to regulate public utilities to the extent of its jurisdiction;
    - to provide for fair and impartial regulation of public utilities;
    - to provide for the safe, economic, efficient, prudent and reliable operation and service of public utilities; and
    - to balance the interests of customers and shareholders of public utilities by providing public utilities with the opportunity to earn a fair return on their investments while providing customers with just and reasonable rates.
- In addition, NRS 704.040 and 704.120 establish a duty on the PUCN and the utilities to:
    - provide for just and reasonable rates;
    - after a hearing, if any rates, tolls, charges or schedules are found to be unjust, unreasonable, unjustly discriminatory, preferential, or in violation of statute, substitute those rates, tolls, charges or schedules with just and reasonable rates, tolls, charges or schedules; and
    - if any regulation, measurement, practice, act or service complained of is unjust, unreasonable, insufficient, preferential, unjustly discriminatory or otherwise in violation of statute, or if service is found to be inadequate, or that any reasonable service cannot be obtained, substitute just and reasonable regulations, measurements, practices, service or acts.
- NRS 704.210 establishes the powers of the PUCN to:
    - adopt necessary and reasonable regulations governing the procedure, administration and enforcement of the provisions of NRS Chapter 704; and

- prescribe classifications of the service of all public utilities, and fix and regulate rates of public utilities, subject to limited exceptions.

The primary electric utilities in Nevada subject to PUCN oversight are Nevada Power Company (NPC) and Sierra Pacific Power Company (SPPC). NPC and SPPC are both wholly owned subsidiaries of NV Energy, Inc., an energy holding company that is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company. NPC and SPPC do business under the d/b/a "NV Energy," which is a service mark registered with the Nevada Secretary of State. NPC and SPPC are vertically integrated, investor-owned utilities. SPPC is the northern Nevada utility serving approximately 353,000 electric customers, and NPC is the southern Nevada utility operating primarily in the Las Vegas area, serving approximately 956,000 customers. NPC and SPPC serve more than 90 percent of the electricity customers in Nevada and, as monopoly franchise holders, accept certain obligations that flow from the PUCN regulatory responsibilities enumerated above. Specifically, these utility companies are expected to:

- Provide service to anyone within their franchised service territory who requests it and pays for it at the PUCN-approved prices. The utility can impose a connection charge if providing service involves a significant expense by the utility.

- Adhere to strict State and Federal government safety standards, because the public can be adversely affected by infrastructure problems, such as downed utility lines.

- Provide adequate service, because utility consumers cannot generally "shop around" for utility distribution service among multiple providers, though Nevada has provisions available to some larger customers that permit those customers to access the competitive market for the supply of energy.

- Be responsive to consumer needs in transactions like new service orders and billing questions.

- Adhere to service reliability standards that are set based on industry standards and focused on reducing the frequency and duration of outages.

In exchange for accepting the obligation to serve that comes with a monopoly franchise, utilities are permitted to charge customers rates approved by the PUCN that compensate the utility for the costs it incurs to meet that obligation to serve, while also allowing the utility an opportunity, which is not a guarantee, to earn a fair return on investments. From this allowed return, the utility pays dividends to shareholders and reinvests in the company.

The regulatory practices, mechanisms and policies in effect in Nevada today are described in the next section.

Section III: Characterization of the Existing Nevada Regulatory Framework

The purpose of this section is to provide a description of the key elements and mechanisms of Nevada's current framework that is specific enough to support an assessment of how well current practices align with the goals and outcomes identified through this stakeholder process. For the purposes of this paper, the practices, mechanisms and policy provisions in use today are grouped into five categories, as noted above and detailed in Table 1 below.

The first two categories describe the predominant rate setting practices and mechanisms in place today. The next two categories describe how planning and policy affect or inform utility capital investment and supply decisions, which then flow into utility cost recovery and revenue requirements. The final section describes alternative ratemaking practices that have been tried or that are currently in place in Nevada. A summary of the mechanisms covered is included in Table 1 below for reference.

Table 1: Summary of Existing Regulatory Mechanisms in Nevada

Category	Existing Mechanisms
Category 1: Rate Setting Practices or Mechanisms	1. General Rate Case 2. Modifications to Cost of Service Study 3. Deferred Energy Accounting Adjustment
Category 2: Mechanisms That Adjust Rates Between Rate Cases	4. Quarterly Adjustments for Fuel and Purchased Power Costs 5. Lost Revenue Adjustment
Category 3: Practices and Mechanisms that Affect Utility Investment and Supply Decisions	6. Integrated Resource Plan a. Distributed Resource Plan b. Supply Plan, including Transmission Plan c. Energy Supply Plan 7. Emissions Reduction and Capacity Replacement Plan
Category 4: Policy Provisions That Inform Utility Investment Decisions	8. Renewable Portfolio Standard 9. Energy Efficiency and Conservation Goals 10. Clean Energy Incentive Programs a. Low-Income Solar Energy Program b. Electric Vehicle Infrastructure Demonstration Incentives c. Electric School Bus Incentive Program d. Small Energy Storage Program e. Large Energy Storage Program f. Solar Energy Systems Incentive Program g. Waterpower and Wind Energy Systems Demonstration Programs 11. Biennial Energy Storage Targets 12. Temporary Renewable Energy Development Program 13. Net Energy Metering 14. SB 358 Renewable PPA Pricing and Ownership Options 15. Expanded Solar Access Program 16. Natural Disaster Protection Plan

Category	Existing Mechanisms
	17. Provisions in Law that Permit Commercial Customers to Take Service from a Provider Other than the Monopoly Utility 18. Application, Interconnection, Service Connections, Meters and Customer Facilities
Category 5: Existing Alternative Ratemaking Mechanisms	19. Tariffs and Mechanisms for Commercial or Industrial Customers a. Special Tariffs for Certain Commercial Customers b. Electric Vehicle Commercial Charging Rider c. Economic Development Rate Rider d. Green Rider Rate Calculation 20. Time-of-Use Tariffs for Residential and Business Customers 21. Earnings Sharing Mechanism 22. Investment Support Mechanisms a. Incentives for Critical Facilities b. Construction Work in Progress in Rate Base c. Regulatory Assets and Liabilities 23. Electric Utility Alternative Ratemaking Mechanisms Not Presently in Use a. Authority to Implement Decoupling b. Imputed Debt for Renewable PPAs and Energy Efficiency Contracts c. Additional Incentives for Specific Energy Efficiency and Conservation Programs d. Variable Interest on Debt Recovery

Category 1: Rate Setting Practices and Mechanisms

General Rate Case

The general rate case is the regulatory proceeding that establishes the rates charged to utility customers to produce revenues required to ensure reliable service. General rate case proceedings focus primarily on establishing just and reasonable rates, but some elements of the general rate case relate to customer engagement and satisfaction. For example, the creation of a new rate class could increase the services and options available to customers, as well as increase customer participation.

The existing regulatory framework in Nevada is anchored on cost of service (COS), rate-of-return regulation. In fact, COS, rate-of-return regulation is a fundamental tenet in the filing and resolution of general rate cases (GRCs). GRCs are the vehicle in Nevada used to adjust the base tariff general rate, which provides for recovery of the capital costs of the utility, such as infrastructure, as well as operations, maintenance and tax expense. The GRC has many specific filing requirements, but the primary determinations made in a GRC are the revenue requirement (including the determination of the cost of capital and the return on equity that each utility has the opportunity to collect for its investment in the system), the allocation of costs to the respective classes of customers and the design of rates for each customer class represented in separate tariffs of the utility.

GRCs are required by statute to be filed every three years, with NPC and SPPC filing in different years.[3] The submission of a GRC starts a 210-day clock for the PUCN to make a final decision. While most elements of the GRC are filed and decided concurrently, a depreciation study may be filed separately. At a minimum, depreciation studies must be filed every six years and can be approved or rejected separately from or in parallel to the GRC.[4]

The GRC filing is based on an historical test year of data. The historical test year is the recorded revenues, expenses, investments and costs of capital for the most recent 12-month period for which all necessary data is available.[5] Electric utilities may update actual historical costs by making a certification filing. If certification is filed, the PUCN is required to consider evidence in support of increased rates based upon actual recorded results of operations adjusted for increases in revenues, increased investment in facilities, increased expenses for depreciation, certain other operating expenses and changes in the cost of securities that are known and measurable with reasonable accuracy at the time of initial GRC filing and will become effective within six months after the 12-month historical test period. A limitation on certification is that the utility cannot place the increased rates into effect until changes have been experienced and certified.[6]

An electric utility has some flexibility to include additional data to update its historical costs by filing a statement of expected changes in circumstances (ECIC).[7] ECIC statements are meant only for specific and identifiable events or programs rather than general trends, patterns or developments.[8] At the time of the GRC filing, a utility submitting an ECIC statement must clearly and separately identify each specific event or program proposed as an ECIC.[9] ECIC statements must include all increases and decreases in revenue and expenses which may occur within 210 days (seven months) after the date on which its general rate application is filed for the events or programs listed in the ECIC statement. Where a utility opts to submit such a statement, it has the burden of proving that the proposed ECICs are reasonably known and measurable with reasonable accuracy. The utility also is obligated to include all reasonable projected or forecasted offsets in revenue and expenses that are directly attributable to ECICs for PUCN consideration.[10]

As such, in Nevada's current GRC paradigm, the electric utility provides information based on the 12-month historical test year (with adjustments), which may then be updated for actual experienced changes

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[3] NRS 704.110(3)(a)-(b).

[4] NAC 703.276.

[5] NRS 704.110(3).

[6] The full set of requirements are described in NAC 703.2201 to NAC 703.2481.

[7] NRS 704.110(4).

[8] NRS 704.110(4). According to the statute, ECICs must have an objectively high probability of occurring to the degree, in the amount and at the time expected, be primarily measurable by recorded or verifiable revenues and expenses, and be easily and objectively calculated, with the calculation of the expected changes relying only secondarily on estimates, forecasts, projections or budgets.

[9] NAC 703.2791. While utilities that file ECICs must submit a statement of updated revenue and expense data for each ECIC program or event within 90 days of the application filing, the updated data cannot be used to meet the applicant's burden of proof as required by NRS 704.110(4). As such, while certification permits updated numbers to be filed for purposes of implementing rates, any updated data filed for ECICs is meant only to "examine the reasonableness of monetary and other values provided" to the Commission when the ECIC statement was originally filed with the initial application. NAC 703.2793.

[10] ECIC filing requirements are outlined in NAC 703.279 - NAC 703.2794.

for up to the following six months (certification) and may separately include adjustments for ECICs for the seven months after its rate case filing. This effectively allows material adjustments to better reflect the utility's revenue requirement 13 months after the historical test year closes and up to the date rates become effective for the next three-year rate cycle.[11]

The GRC process in Nevada has yielded fairly consistent results for NPC and SPPC over the last five years in terms of the amount of rate base each utility has, each utility's total operating expenses and their resulting net income. Similarly, while the authorized return on equity (ROE) has been modified by the PUCN by approximately 50 basis points for each utility (60 basis points for NPC and 40 basis points for SPPC), each utility's earned ROE has consistently stayed above the authorized amount over the most recent five-year period, with limited exception.

- Rate Base: As of December 31, 2014, NPC had $4.9 billion in rate base. That rate base has only trended downward slightly to $4.6 billion as of December 31, 2017, and $4.5 billion as of March 31, 2020. The trend is reversed for SPPC, which had $1.5 billion in rate base as of December 31, 2014, $1.6 billion as of December 31, 2017, and $1.8 billion as of March 31, 2020.

- Total Operating Expenses: As of December 31, 2014, NPC had approximately $2.0 billion in total operating expenses, $1.9 billion as of December 31, 2017, and $1.8 billion as of March 31, 2020. SPPC had approximately $621 million in total operating expenses as of December 31, 2014, approximately $560 million as of December 31, 2017, and $627 million as of March 31, 2020.

- Net Income: NPC had approximately $284 million in net income as of December 31, 2014, $276 million in net income as of December 31, 2017 and $272 million as of March 31, 2020. SPPC had $84 million in net income as of December 31, 2014, $89 million in net income as of December 31, 2017 and $92 million as of March 31, 2020.

- Authorized ROE: NPC's authorized ROE was 10.0 percent in 2014, changed to 9.8 percent in 2015 and 9.4 percent as of 2018, where it remains today. SPPC's authorized ROE in 2014 was 9.8 percent in 2014, changed to 9.6 percent in 2017 and went down to 9.5 percent in 2020.

- Earned ROE: NPC earned an ROE of 12.07 percent as of December 31, 2014, 12.14 percent as of December 31, 2017 and 11.52 percent as of March 31, 2020. SPPC earned an ROE of 12.49 percent as of December 31, 2014, 10.77 percent as of December 31, 2017 and went down to 9.27 percent as of March 31, 2020.[12]

[11] Pursuant to NAC 703.2794, adjustments that are certified cannot be included as an ECIC, so while the utility is permitted to make adjustments for up to 13 months after its historical test period closes, the adjustments cannot be for the same events, programs, projects or costs.

[12] All of the data put forth in the above-listed bullet points was gathered from filings in the following dockets: 13-07021, 19-08001 and 20-01011.

Modifications to Cost of Service Studies

Cost of service studies assign costs to customer classes and thus are an integral part of the rate-setting process. Modifications to cost of service studies most directly relate to the establishment of just and reasonable rates, but rate-setting could affect, for example, a customer's willingness to take service pursuant to a new rate class or adoption of distributed energy resources.

Utilities use COS studies to determine allocation of customer costs. Traditionally, Nevada electric utilities have allocated revenues to customers based upon a marginal cost of service study (MCSS) rather than an embedded cost of service study (ECSS).[13] The allocation of costs to customer classes and the design of rates that flows from the allocation of costs has two functions:

- to fairly allocate costs so that one class of customers is not unfairly subsidizing or subsidized by others, and
- to establish price signals that align the cost impact of customer choices with cost causation on the electric system to promote economically efficient customer choices.

While Nevada has used an MCSS to assist in setting rates for over three decades, the PUCN in 2017 declared that it was reviewing shifting away from a using only an MCSS to allocate costs among different rate classes. In the PUCN's order in Docket Nos. 17-06003 and 17-06004, it found that there was doubt and disagreement about the validity and accuracy of NPC's MCSS filed in those dockets, as well as in SPPC's general rate case in Docket Nos. 16-06006 through 16-06009.[14] The PUCN found in the order for consolidated Docket Nos. 17-06003 and 17-06004 that "[a]s Nevada modernizes its electric system, with advancements in NEM, battery storage, and electric vehicle usage ongoing, old ways and methodologies *must* be challenged and thoughtfully reviewed to ensure they still work in a changing world."[15] As such, the PUCN ordered NPC and SPPC to file an ECSS along with an MCSS in each utility's next general rate case.[16]

In SPPC's 2019 rate case in Docket No. 19-06002, the PUCN again acknowledged its concerns regarding reliance on the filed MCSS. For example, concerns were raised about how certain methodological changes might have affected the MCSS, including the effect of joint dispatch on cost allocations in the residential customer class.[17] In that docket, the PUCN found that while SPPC filed an ECSS in accordance with the

[13] The MCSS is a cost allocation study that apportions costs among customer classes using estimates of how costs change over time in response to changes in customer usage. An ECSS apportions the actual historic test year or projected future rate year system costs among customer classes, typically using customer usage patterns in a single year-long period to divide up the costs.

[14] Consolidated Docket Nos. 17-06003 and 17-06004, Modified Final Order, at ¶ 569 (Dec. 19, 2018).

[15] *Id.* at ¶ 570 (emphasis in original).

[16] *Id.*

[17] Docket No. 19-06002, Modified Final Order, at ¶ 113 (Apr. 2, 2020).

order from Docket Nos. 17-06003 and 17-06004, the ECSS was incomplete.[18] The PUCN directed SPPC to complete both its ECSS and a hybrid cost of service study presented by Staff in its next GRC. The PUCN also directed NPC to include similar studies in its next GRC (filed in June 2020).

Additionally, in rulemaking Docket No. 19-12026, the PUCN has proposed changes to NAC 704.660 and NAC 704.662 to permit PUCN consideration of cost of service studies other than those focused on marginal or incremental costs for supplying or delivering electricity to customers. The Legislative Counsel Bureau has examined and returned the proposed changes to PUCN regulations that reflect the PUCN's intent to have flexibility to consider different types of cost of service studies.

Deferred Energy Accounting Adjustment

Deferred energy accounting allows the utility to adjust its base tariff energy rate and deferred energy accounting adjustment rate to reflect changes in fuel and purchased power costs. Deferred energy accounting provides rate and earnings stability during periods where fuel and electricity costs are volatile; thus, it primarily supports just and reasonable rates ensuring utility financial strength and customer rate stability.

Deferred energy accounting allows electric utilities in Nevada to recover their fuel and purchased power costs on a dollar-for-dollar basis (no mark-up). There are two key rate components related to fuel and purchased power costs: the base tariff energy rate (BTER) and the deferred energy accounting adjustment (DEAA). The BTER is a flat charge per kilowatt-hour (kWh) that is set based on the 12-month rolling total of energy and purchased power costs. The DEAA recovers the difference between the costs collected through the BTER and the actual cost of fuel and purchased power as experienced by the electric utility. In other words, the DEAA rate compensates or charges a utility if fuel and purchased power costs are under or over collected.

The BTER must be adjusted on a quarterly basis pursuant to statute, and the electric utility may file for approval to adjust its DEAA rates on a quarterly basis based on changes in the electric utility's recorded costs of fuel and purchased power.[19] Quarterly adjustments to the BTER and DEAA rates are reviewed annually in the deferred energy applications. These annual applications are filed on or before March 1 of each year. There is no presumption of reasonableness or prudence for any quarterly rate adjustment or for any transactions or recorded costs of purchased fuel and purchased power included in quarterly rate adjustments. As such, the electric utility has the burden of proving reasonableness and prudence in the annual deferred energy accounting proceeding for all aspects of fuel and purchased power.[20]

[18] *Id.* at ¶ 108.

[19] NRS 704.110(10). Both NPC and SPPC have filed for approval of and adjust their DEAA rate on a quarterly basis.

[20] NRS 704.110(11).

CATEGORY 2: Mechanisms that Adjust Revenue between Rate Cases

This section describes mechanisms that permit some deviation in revenue collected between rate case cycles.

Quarterly Adjustments for Fuel and Purchased Power Costs

Deferred energy accounting includes quarterly adjustments to rates to reflect short-term changes in fuel and purchased power costs, but the magnitude of the adjustment is limited. These quarterly adjustments provide rate and earnings stability during periods where fuel and purchased power costs are volatile; thus, they primarily affect the goal of just and reasonable rates by supporting outcomes related to utility financial strength and customer rate stability.

As noted above, the cost of fuel and purchased power captured in the BTER and DEAA rates are permitted to deviate on a quarterly basis between annual rate case cycles. Of particular importance to these quarterly adjustments, the DEAA charge has a deadband limitation to modulate rate volatility, and any charges (payments) in a rate adjustment not made due to deadband limits are rolled into the deferred account balance for recovery in a subsequent quarterly DEAA adjustment.

Specifically, any quarterly adjustment to the DEAA rate must not exceed 0.25 cents per kWh of electricity. Moreover, if the balance of the electric utility's deferred account varies by less than 5 percent from the electric utility's annual recorded costs for purchased fuel or purchased power that are used to calculate quarterly rate adjustments, the DEAA must be set to zero cents per kWh of electricity.[21]

Lost Revenue Adjustment Mechanism

The lost revenue adjustment mechanism is intended to compensate the utility for the financial disincentive it incurs as a result of the implementation of energy efficiency and conservation programs. Effective demand side management programs have the potential to help customers control their bills, affect the contribution of demand side resources to meeting system reliability standards, affect how energy resources are optimized and affect certain public policy directives related to distributed energy resource use and customer engagement.

Demand side management (DSM) programs are programs implemented by Nevada electric utilities to reduce electricity sales via energy efficiency and conservation.[22] If the programs are effective, reduced sales will lead to under recovery of a utility's total revenue requirement, and thus may harm utility

[21] NRS 704.110(10).

[22] DSM programs may include more than energy efficiency and conservation programs, such as load shifting programs. Load shifting programs may have no impact on utility revenues and, in some cases, may increase electricity sales.

shareholder earnings. In effect, this translates to "lost revenues" (e.g., financial disincentives) associated with the implementation of DSM programs.

In Nevada, the PUCN has implemented a lost revenue adjustment mechanism to allow electric utilities to recover these lost revenues. Recovery of lost revenues can help ensure that the utility is encouraged to continue implementing and promoting customer participation in cost-effective energy efficiency and conservation programs. Notably, Nevada's lost revenue adjustment mechanism has evolved over time. As discussed below in Category 5, the PUCN appears to have legislative authority to further modify the methodology through which electric utilities recover the financial disincentives that utilities incur as a result of implementing energy efficiency and conservation programs.

In 2009, the Nevada Legislature passed Senate Bill (SB) 359, a law providing for the adoption of regulations authorizing electric utilities to recover an amount based on the effects of implementing energy efficiency and conservation programs.[23] The law is codified as NRS 704.785. NRS 704.785 provides that:

> 1. The Commission shall adopt regulations authorizing an electric utility to recover an amount based on the measurable and verifiable effects of the implementation by the electric utility of energy efficiency and conservation programs approved by the Commission, which:
>
> (a) Must include: ... ... (2) Any financial disincentives relating to other supply alternatives caused or created by the reasonable implementation of the energy efficiency and conservation programs.

In response to the passage of NRS 704.785, the PUCN adopted NAC 704.9524, allowing for recovery of amounts based on measurable and verifiable effects on revenues caused or created by implementation of programs for energy efficiency and conservation. NAC 704.9524 put in place the lost revenue adjustment mechanism (LRAM), which permitted an electric utility to recover revenue lost due to implementation of PUCN-approved DSM programs. The mechanism required the utility to support claimed lost revenue by providing specific and detailed measurement and verification reports.

In 2013, the PUCN opened rulemaking Docket No. 13-04014 to amend NAC 704.9524 to determine whether an application filed for lost revenue pursuant to NRS 704.785 was required to present evidence regarding the electric utility's rate of return. At that time, NRS 704.785 had a provision that stated that the "regulations adopted pursuant to this section must not ... authorize the electric utility to earn more than the rate of return authorized by the Commission in the most recently completed rate case of the electric utility."[24] Based on that rulemaking, the current regulations limit the amount of lost revenues so that such revenues do not contribute to an electric utility earning more than the rate of return authorized by the PUCN in the mostly recently completed rate case of the electric utility. The current mechanism allows recovery of lost revenues associated with DSM programs through a simplified method wherein energy efficiency program costs are multiplied by the utility's current authorized rate of return grossed up

[23] Prior to the passage of this law, NV Energy used a return on equity adder for its approved DSM investments. This adder provided a return on equity for DSM investments of five percent higher than the return on equity for other capital investments.

[24] NRS 704.785(3)(b) (2013). The statute has since been modified by SB 150 in 2017, eliminating this language.

for taxes applicable to the utility's equity portion of the authorized rate of return.[25] However, if "overearning" is demonstrated pursuant to regulation, the "amount of revenue [collected] which caused the electric utility to exceed the rate of return authorized by the Commission" must be adjusted and credited back to customers along with carrying charges.[26]

Table 2: Lost Revenue Adjustment Mechanism Returns

YEAR	AMOUNT OF LOST REVENUE NPC EXPECTED TO RETURN TO CUSTOMERS[27]	AMOUNT OF LOST REVENUE SPPC EXPECTED TO RETURN TO CUSTOMERS[28]
2015	$10.7 million[29]	$2.1 million[30]
2016	$9.4 million[31]	$2.0 million[32]
2017	$5.4 million[33]	n/a
2018	$4.5 million[34]	$1.4 million[35]
2019	$4.8 million[36]	$1.2 million[37]
2020	$3.8 million[38]	$1.1 million[39]

In terms of the rates charged to customers, the lost revenue adjustment mechanism is captured in the energy efficiency implementation rate (EEIR).[40] The EEIR is set annually in the deferred energy accounting application, which is described above. If it is determined in the annual deferred energy accounting application that the utility has over-earned during the prior program year, the revenue

[25] NAC 704.9523(2)(b).

[26] NAC 704.9523(4).

[27] This amount includes carrying charges.

[28] This amount includes carrying charge.

[29] Application, Docket No. 15-02039, at Exhibit L.

[30] Application, Docket No. 15-02040, at Exhibit L.

[31] Application, Docket No. 16-03003, at Exhibit L.

[32] Application, Docket No. 16-03004, at Exhibit L.

[33] Application, Docket No. 17-03001, at Exhibit L.

[34] Application, Docket No. 18-03002, at Exhibit L.

[35] Application, Docket No. 18-03003, at Exhibit L.

[36] Application, Docket No. 19-03001, at Exhibit L. The EEIR Adjustment rate was adjusted pursuant to Exhibit A to the Stipulation attached as Attachment A to the Order issued in Docket Nos. 19-03001, 19-03002 and 19-03003 on August 1, 2019.

[37] Application, Docket No. 19-03002, at Exhibit L.

[38] Application, Docket No. 20-02026, at Exhibit L.

[39] Application, Docket No. 20-02027, at Exhibit L.

[40] There are in effect three different EEIR rates. The EEIR Base rate is an amount calculated based upon the expected financial disincentives resulting from the annual energy efficiency and conservation programs. This rate is set as a per-kWh rate by rate class. The EEIR Amortization rate is set as a true-up to the EEIR Base rate and is shown as one per kWh rate for all rate classes. True-up may be necessary if the energy efficiency and conservation savings were lower or higher than expected or kWh sales were higher or lower than expected in any given year. Finally, the EEIR Adjustment rate is used to return EEIR Base rates collected from the prior program year if utility has over-earned. The EEIR adjustment rate is also set as a per kWh rate by rate class.

collected from customers via the EEIR Base rate must be returned to customers in an EEIR Adjustment rate. Since 2015, both SPPC and NPC have been required to return lost revenues collected from customers in the EEIR Base rate via the EEIR Adjustment rate. The table above demonstrates the amount of lost revenues returned to customers from 2015 through 2020.

CATEGORY 3: Practices and Mechanisms that Affect Utility Investment or Supply Decisions

The Integrated Resource Plan

Integrated Resource Plans require an electric utility, interested stakeholders and the PUCN to examine the electric utility's current system, anticipated resource needs, and how those needs might be met over the short- and long-term. The integrated resource plan is primarily focused on ensuring the demand- and supply-side resources are in place to provide for reliable electric service, but resource plan proceedings also affect various public policy objectives in Nevada.

Nevada requires electric utilities to file an Integrated Resource Plan (IRP) with the PUCN on or before June 1 every three years.[41] The IRP must set forth a three-year action plan to meet demand for electric service in an efficient, reliable, and sustainable manner over a 20-year planning period. In effect, the IRP requires an electric utility in Nevada to present its plan for investments to the PUCN that will permit the utility to provide reliable service to customers in a manner consistent with state public policies, such as NRS 704.746(5). Among other requirements, NRS 704.746(5) states that the PUCN must give preference to the measures and sources of supply that provide the greatest economic and environmental benefits to the State; provide levels of service that are adequate and reliable; provide the greatest opportunity for the creation of new jobs in this State; and provide for diverse electricity supply portfolios that reduce customer exposure to the price volatility of fossil fuels and the potential costs of carbon. Affiliated utilities with common ownership and that have an interconnected system for the transmission of electricity are required to submit a joint plan. NPC and SPPC jointly file their IRPs. The next IRP is due June 1, 2021.

An electric utility's resource plan must include several different components, including a forecast of future load, a demand side plan, the best combination of sources of supply to meet demand or the best method to reduce demand, a financial plan, an energy supply plan, and an action plan for next steps in the utility's resource procurement or demand-side resources. Specifically, a utility's IRP shall include the elements that follow. As some of the components of the IRP, including the distributed resources plan, the supply plan and the energy supply plan are significant parts of planning in their own right, those components are discussed in more detail below the overall outline of the IRP.

- Load Forecasts: Load forecasts must include energy consumption and peak demand for the 20-year planning period, including assessments of the impacts of energy efficiency and conservation, the

[41] NRS 704.736-704.754; NAC 704.9005-704.9525. NAC 704.9208 still states that NPC and SPPC will file IRPs on July 1 of every third year. This regulation is out of date, given that NRS 704.741(1) now provides that the utilities will file IRPs on June 1 of every third year.

impact of distributed generation, and the impact of applicable new technologies and governmental programs and regulations. The load forecast must include a range of future peak demand and energy consumption based on and consistent with the upper and lower limits of expected economic and demographic change in the utility's service territory in the next 20 years, commencing with the year following the year in which the resource plan is filed, as follows: a forecast of high growth; a forecast of base growth; and a forecast of low growth.[42]

- Demand Side Plan: The demand side plan includes the programs proposed by the electric utility to promote energy efficiency and conservation. The plan must include an identification of end-uses for programs for energy efficiency and conservation, an assessment of savings attributable to technically feasible programs, and an assessment of which programs will produce benefits in peak demand or energy consumption. The plan is required to include a list of programs for which the utility is requesting PUCN approval, and a report on the status of existing programs. The plan also will consider the impact of new technology on future energy efficiency and conservation options. The plan must include an energy efficiency program for residential customers that reduces the consumption of electricity or any fossil fuel, as well as a life-cycle analysis of the costs and benefits of the program.[43]

- Supply Plan: The supply plan means an electric utility's plan for using existing and proposed resources to meet its forecasted demand requirements. Given that some of the components of the supply plan may be significant in future IRPs, the supply plan is detailed in a separate section below.

- Distributed Resources Plan (DRP): Recent amendments require utilities to include a DRP to efficiently integrate distributed renewable energy resources and demand side technologies into the utility's distribution system. The DRP is discussed in more detail below.

- Financial Plan: The financial plan is a plan that demonstrates the financial impact of the utility's preferred plan on the utility and its customers. The financial plan must include information on the financial and economic characteristics of planned facilities, and the assumptions and methodologies used to develop the financial plan must be described.[44]

- Energy Supply Plan: The energy supply plan establishes the parameters of an energy supply portfolio for the three-year action plan period. Given that the energy supply plan can be updated separately from the IRP and is a key component of the IRP, specific information on the energy supply plan is detailed below.

- Emissions Reduction and Capacity Replacement (ERCR) Plan: The ERCR plan is a comprehensive plan for the reduction of emissions from coal-fired electric generating plants and the replacement of the capacity of such plants with increased capacity from renewable energy facilities and other

[42] NAC 704.9225, NAC 704.925 and NAC 704.9281.

[43] NAC 704.9057 and NAC 704.934.

[44] NAC 704.9069, NAC 704.9395 and NAC 704.9401.

electric generating plants. The ERCR is filed with the IRP. This plan has several specific requirements discussed in more detail below.

- Action Plan: The action plan specifies the actions that an electric utility intends to take to meet its demand and energy requirements during the three years following the year in which the resource plan is filed. The action plan must present an integrated analysis of the demand side plan and supply plan of the utility, including:

  - an introduction explaining how the plan fits into the utility's long-term strategic plan;
  - a list of actions for which the utility is seeking PUCN approval;
  - a schedule for the acquisition of data, including planned activities to update and refine the quality of the data used in forecasting;
  - a timetable for acquisition of supply-side options and energy efficiency and conservation programs;
  - any changes to methodologies used by the utility;
  - any utility plans to acquire additional modeling instruments;
  - a section for the utility's program for acquisition of resources for supply;
  - an energy supply plan;
  - a budget for planned expenditures, organized into separate categories for forecasting of loads, energy efficiency and conservation, plans for supply and financial planning;
  - schedules to compare planned and actual activities and accomplishments; and
  - a renewable energy zone transmission plan for serving one or more of the PUCN-designated renewable energy zones.[45]

- Summary: The IRP summary must include a brief introduction describing the electric utility and the plan; load forecasts; a summary of the demand side plan; a summary of the preferred plan showing each planned addition to the system; a summary of renewable energy; a summary of the energy supply plan, risk management strategy, fuel procurement plan, and the purchased power procurement plan; a summary of the action plan; and an evaluation of the preferred plan in relation to the strategic objectives of the utility.[46]

- Technical Appendix: The IRP must include a technical appendix that contains sufficient detail to

[45] NAC 704.9006 and NAC 704.9489.

[46] NAC 704.9215.

enable a technically proficient reader to understand how the resource plan and its forecasts were prepared and to evaluate the validity of the assumptions and accuracy of the data used. The appendix must also contain sufficient information to enable a technically proficient reader to reproduce the results from the computations shown, including specific information outlined in the IRP regulations.

All information used by an electric utility in its resource plan must be based on substantially accurate data, adequately demonstrated and defended, and adequately documented and justified.[47]

After a hearing on an IRP, the PUCN must issue an order accepting or modifying the plan, or specifying any portions of the plan it deems to be inadequate. If the PUCN issues an order modifying the plan, the utility may file a notice with the PUCN consenting to or rejecting the modifications. PUCN approval of an action plan constitutes a finding that the programs and projects contained in the action plan, other than the energy supply plan, are prudent. If the PUCN also determines, at the time it approves the action plan, that the elements of the energy supply plan are prudent, it will specifically note in its action plan determination that the elements in the energy supply plan are prudent. The electric utility may recover all prudent and reasonable expenditures made to develop the electric utility's plan in a separate rate proceeding.[48]

Between 15 and 21 months after the date on which the electric utility files its action plan, it must file a progress report on the action plan. The progress report must include:

- the status of planned facilities approved by the PUCN;
- the status of all energy efficiency and conservation programs;
- a comparison of budgeted and actual costs for the entire action plan;
- identification and justification for any deviations from the action plan;
- an updated forecast of energy consumption and peak demand; and
- an updated table for loads and resources for the remaining years covered by the 20-year plan.[49]

The PUCN will assign a new docket number to the progress report, and the utility or any party of record may request a hearing on the report. Upon a finding of good cause, the PUCN will order a hearing.

An electric utility is required to continually monitor its action plan. A utility must amend the plan before submitting a new action plan if: the utility is moving forward with resources not previously approved as part of the plan; the utility is unable to place an anticipated resource into service; the utility makes a commitment for an option that was not available at the time the plan was approved; or there is a material

[47] NAC 704.9321.

[48] NRS 704.746, NRS 704.751 and NAC 704.9494.

[49] NAC 704.9498.

change in the basic data used in the formation of the plan that affects the choice of resource that was approved as part of the action plan.[50]

NPC and SPPC jointly filed an IRP on June 1, 2018 (2018 IRP).[51] In that IRP, the PUCN approved 1,001 MW of solar energy power purchase agreements (PPAs). Three of the PPAs, all located in northern Nevada, include battery storage systems, which will provide capacity and flexibility to the northern Nevada system. The approved PPAs are as follows:

- Dodge Flat Solar – a PPA for a 200 megawatt (MW) solar photovoltaic (PV) facility with a 50 MW, 200 megawatt-hour (MWh) battery energy storage system located in Washoe County, Nevada. The project is on schedule to be in service by August 2021.

- Fish Springs Ranch Solar – a PPA for a 100 MW solar PV facility with a 25 MW, 100 MWh battery energy storage system located in Washoe County, Nevada. This project is on schedule to be in service by December 1, 2021.

- Battle Mountain Solar – a PPA for a 101 MW solar PV facility with a 25 MW, 100 MWh battery energy storage system located in Humboldt County, Nevada. The project remains on schedule to meet the July 1, 2021, commercial operation date.

- Eagle Shadow Mountain Solar Farm – a PPA for a 300 MW solar PV facility located in Clark County, Nevada. This project remains on schedule to meet the December 31, 2021, commercial operation date.

- Copper Mountain Solar 5 – a PPA for a 250 MW solar PV facility located in Clark County, Nevada. The project is on schedule to meet the January 1, 2022, commercial operation date.

- Techren Solar V – a PPA for a 50 MW solar PV facility located in Clark County, Nevada.[52]

In addition to approval of the above-referenced PPAs, the PUCN also adopted NV Energy's conditional early retirement of Valmy Unit 1 as of December 31, 2021.[53] Valmy Unit 1 is coal-fired generating unit. The conditions for retirement of the unit relate to reliability and cost concerns.

NPC and SPPC filed an amendment to their 2018 IRP on June 24, 2019. The parties to that proceeding filed a stipulation that was accepted by the PUCN. The stipulation permitted NV Energy to enter into three renewable PPAs, as follows:

- A PPA between NPC and Southern Bighorn Solar Farm for 300 MW of solar PV. The PPA also will provide an additional 135 MW of capacity from co-located battery storage. Forty percent of the

[50] NAC 704.9503 and NAC 704.9516.

[51] Docket No. 18-06003.

[52] Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy Action Plan Progress Report Pursuant to NAC § 704.9498 for the Action Plan Period 2019-2021, Docket No. 20-02025 (Feb. 27, 2020).

[53] *Id.* at 4-5 (noting the conditions for retirement of Valmy Unit 1).

portfolio energy credits, energy, capacity and costs will be allocated to SPPC, and the remaining 60 percent will be allocated to NPC. The expected commercial operation of the Southern Bighorn Solar Farm is September 1, 2023.

- A PPA between NPC and Moapa Solar for 200 MW of solar PV generation. The PPA also will provide an additional 75 MW of capacity of co-located battery storage. Seventy percent of the portfolio energy credits, energy, capacity and costs will be allocated to SPPC, and the remaining 30 percent will be allocated to NPC. The expected commercial operation of the Moapa Solar project is December 1, 2022.

- A PPA between NPC and Gemini Solar for 690 MW of solar PV generation. The PPA also will provide an additional 380 MW of capacity from co-located battery storage. Forty percent of the portfolio energy credits will be credited to SPPC, and the remaining 60 percent will be allocated to NPC. The expected commercial operation of the Gemini Solar project is December 1, 2023.

Distributed Resources Plan

Distributed resource planning provides an opportunity for a utility and interested parties to consider how the distribution system can be used to optimize resource integration and system flexibility. A distributed resources plan can assist with grid optimization and enhancing system reliability.

In addition to an IRP, pursuant to amendments to statutes in 2017, Nevada electric utilities also are required to prepare and file a distributed resources plan (DRP).[54] The term "distributed resources" includes "distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies."[55] Within the DRP, the electric utility must do several things, including:

- evaluate the locational benefits and costs of distributed resources, based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other costs or benefits;

- propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources that satisfy the objectives for distribution planning;

- propose cost-effective methods of effectively coordinating existing programs approved by the PUCN, incentives and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources;

- identify any additional spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding a net benefit to the customers of the

[54] NRS 704.741(5).

[55] NRS 704.741(8)(c).

electric utility or utilities; and

- identify barriers to the deployment of distributed resources, including without limitation, safety standards related to technology or operation of the distribution system in a manner that ensures reliable service.[56]

NPC and SPPC filed their first DRP in 2019 as an amendment to their 2018 IRP, and the PUCN approved a joint stipulation to accept the plan.[57] In addition to accepting the terms of the stipulation that satisfied the bulleted items above, the approved stipulation also identified several commitments for NPC and SPPC as follows:

- provide users the ability to download data from the publicly accessible DRP web portal as of December 31, 2019;
- develop a DRP web portal user guide;
- continue to work with stakeholders to clarify "real-time" hosting capacity analysis;
- continue to complete Non-Wires Alternative analysis for transmission projects;
- provide a status update on the use of Volt-VAR optimization/conservation voltage reduction technologies in the SPPC's and NPC's Non-Wires Alternative analyses;
- provide a status update on the demand response demonstration project for Village Substation;
- investigate and implement where possible or practicable several recommended improvements to the publicly accessible DRP web portal by June 30, 2020; and
- perform Non-Wires Alternative analysis for substations and feeders that are forecasted to have constraints in years four through six of the forecast for those facilities, ensuring that geo-targeted demand-side management and demand response programs are considered in developing Non-Wires Alternative solutions.[58]

Although the timing required that the first joint DRP be filed as an amendment to the IRP, the statute anticipates that the DRP will be filed as part of the IRP for all future filings. As noted above, NPC and SPPC are expected to jointly file their next IRP in June 2021.

[56] NRS 704.741(5).

[57] Docket No. 19-04003, Final Order (Aug. 1, 2019).

[58] Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy Action Plan Progress Report Pursuant to NAC § 704.9498 for the Action Plan Period 2019-2021, Docket No. 20-02025, at 8.

Supply Plan, including Transmission Plan

A utility's supply plan, which includes a transmission plan, sets forth the various options for supplying energy to meet demand. Because it examines the sources of generation and how that energy will be transported to meet demand, the supply and transmission plan primarily relates to reliability and grid optimization, while also touching on promotion of state public policy goals.

At a high level, the electric utility's supply plan represents all of the options for supplying electric service to its customers based on expected future demand and energy requirements. In an IRP, the electric utility must develop a set of analyses of its options for supply, and those analyses must include an examination of the impact of each option, taking into account best available technologies and the environmental benefit of renewable resources. The utility then must evaluate the economics and financial impacts of each option over a 20-year planning period and identify a preferred option.

The options to be considered in a supply plan must include:

- construction of new generation or upgrades to existing generation facilities;
- construction of new transmission facilities or upgrades to existing transmission facilities;
- purchases of long-term transmission rights;
- improvements in the efficiency of operations and scheduling;
- options of low carbon intensity; and
- transactions with other utilities, independent power producers and utility customers for:
    - pooling of power;
    - purchases of power; or
    - exchanges of power.[59]

The supply plan also must include:

- information regarding assumptions, data, and projections used by the utility to develop options;
- a table of all existing generation facilities that it expects to be operating in each of the 20 years covered by the forecast;

[59] NAC 704.9355.

- a list of all sources from which the utility has contracted to buy, or has plans or potential opportunities to buy, electric power during the 20-year plan;

- a transmission plan that includes a conceptual renewable energy zone transmission plan for the 20 years covered by the forecast;[60] and

- a proposal for annual limits on the total amount of energy and capacity that customers may be authorized to purchase from providers of new electric resources.[61]

For each component of the supply plan, the PUCN's regulations provide specific details that must be provided by the electric utility. For example, the supply plan must include a transmission plan for 20 years that includes the following information, among other items listed in the regulations:

- A summary of the capabilities of the transmission system, including import, export and the rating of significant transmission paths within the system of the utility, and of the existing and planned transmission system of the utility for each year in the period covered by the resource plan.

- A description of the transmission projects the utility is considering for expanding or upgrading the capabilities of its transmission system, the anticipated timing of those projects, and the impact of the projects on the transmission capabilities of the existing and planned transmission system of the utility.

- A description of the participation of the utility in regional planning organizations and an explanation of the role of those organizations in the transmission planning process of the utility.[62]

A list of NPC's and SPPC's most recent transmission projects approved by the PUCN can be found in its Action Plan Progress Report, which was filed in Docket No. 20-02025.

Energy Supply Plan

The Energy Supply Plan sets forth how energy will be supplied during the three-year action period, taking into consideration cost, impact on rates, and reliability. The Energy Supply Plan thus primarily addresses reliability, safety and resiliency issues, as well as the implementation of just and reasonable rates.

The energy supply plan establishes the parameters of an energy supply portfolio for the three-year action plan period. PUCN regulations mandate that, on or before September 1 of the first and second years after the action plan is filed, the utility is required to file an update to the energy supply plan that is applicable

[60] NAC 704.9385.

[61] New electric resources are energy, capacity or ancillary services, which are able to be delivered to an eligible customer from an asset that is not owned by an electric utility or subject to contractual commitments from an electric utility or are market purchases from a provider of such resources. NRS 704.741(6), NRS 704B.110 and NRS 704B.080.

[62] NAC 704.9385(3).

for the remaining period of that action plan.[63] NV Energy states that prudent planning is embodied in IRPs, energy supply plans and the energy supply plan update process. The planning that is detailed in each of these filings represents the essential elements to manage risk.[64]

The energy supply plan must balance the objectives of minimizing the costs of supply; minimizing retail price volatility; and maximizing the reliability of energy supply over the term of the plan. The energy supply plan is made up of a purchased power procurement plan, fuel procurement plan and a risk management strategy.[65]

In the last energy supply plan update filed in August of 2019, NPC noted an open position of 870 MW and 1,341 MW for 2020 and 2021, respectively, and SPPC noted an open position of 231 and 259 MW for 2020 and 2021, respectively.[66] NPC and SPPC jointly proposed a staggered power procurement approach to close its open positions, noting the availability of excess capacity in wholesale markets that minimized the costs and risks for filling these open positions.[67]

Emissions Reduction and Capacity Replacement Plan

The Emissions Reduction and Capacity Replacement plan created a means by which NPC was to retire coal plants and replace that generation capacity with renewable energy or non-coal fired generation. This plan primarily relates to advancing public policy goals within Nevada, while also maintaining reliability on the system.

The ERCR plan originates from SB 123, which was signed into law on June 11, 2013. SB 123, subsequently codified as NRS 704.7311 through NRS 704.7322, provides for the retirement or elimination of not less than 800 MWs of coal-fired electric generating capacity and replacement of such capacity with renewable or non-coal conventional generation. The ERCR plan, which was only applicable to NPC, includes requirements for increased capacity from renewable energy facilities and other electric generating plants. More specifically, SB 123 required the utility to include a plan for the retirement or elimination of: not less than 300 MW of coal-fired generation capacity on or before December 31, 2014; an additional 250 MW on or before December 31, 2017; and an additional 250 MW on or before December 31, 2019. As part of its ERCR plan, the utility was required to have a plan for tracking and specifying the accounting treatment for all costs associated with the decommissioning of the coal plants.[68] The last coal retirement was NPC's share of the Navajo Generating Station in 2019.

The ERCR plan also addressed replacement resources for the coal plant retirements. NPC was required to issue requests for proposals (RFPs) for electric generating capacity from new renewable energy facilities,

[63] NAC 704.9506.

[64] Docket No. 19-08034, Ex. 1 at 28.

[65] NAC 704.9061, NAC 704.9504, NAC 704.9506 and NAC 704.9508.

[66] Docket No. 19-08034, Ex. 1 at 1.

[67] *Id.*

[68] NRS 704.7311-7322 and NAC 704.9453-9525.

including: an RFP for 100 MW on or before December 31, 2014; an RFP for an additional 100 MW on or before December 31, 2015; and not more than an additional 100 MW if the PUCN determined a need for such electric generating capacity. The utility was required to review each proposal received pursuant to its RFPs to identify those renewable energy facilities that would provide: (1) the greatest economic benefit to Nevada; (2) the greatest opportunity for the creation of new jobs in Nevada; and (3) the best value to customers of the electric utility. In addition to renewable replacement resources, the utility was required to include plans in the ERCR filing to construct or acquire and own plants to replace the coal-fired resources that were retired or eliminated, totaling 496 MW. If the plan included construction or acquisition of natural gas plants, the utility was required to include a strategy for the commercially reasonable physical procurement of fixed-price natural gas.[69]

The ERCR plan also could include additional utility facilities, generating plants, and elements or programs necessary to carry out the plan, including the construction of new natural gas pipelines needed for the operation of any new natural gas plants, entering into contracts for the transportation of natural gas necessary for the operation of any natural gas plants included in the plan, and the construction of transmission lines and related infrastructure needed for the operation of any plants included in the plan. For all plants constructed or acquired pursuant to an ERCR plan, the utility was required to begin recording, in a regulatory asset with carrying charges, an amount that reflects a return on the utility's investment in the facility, depreciation of the investment, and the cost of operating and maintaining the facility, all of which is a deviation from traditional utility ratemaking.[70]

While all of the required retirements and eliminations of coal-fired generating capacity have occurred pursuant to SB 123, not all of the replacement capacity has been filled. SB 123 permitted the utility to have at least 50 MW of replacement capacity in the form of utility-owned renewable generation.[71] There is still 35 MW of this utility-owned renewable generation that has not been fulfilled. As such, NPC is still authorized to construct or acquire an additional 35 MWs of utility-owned electric generating capacity from new renewable energy facilities upon a determination that the utility has satisfactorily demonstrated a need for such capacity.[72]

[69] NRS 704.7311-7322, NAC 704.90595, NAC 704.90597 and NAC 704.9453-9525.

[70] *Id.*

[71] NRS 704.7316(2)(b)(6)-(7).

[72] NRS 704.7316(2)(b)(7); Consolidated Docket Nos. 14-05003 and 14-06022, at 75, n.15 (Oct. 28, 2014).

CATEGORY 4: Policy and Regulatory Provisions that Further Inform Investment Decisions

In addition to the revenue and existing alternative ratemaking mechanisms discussed below, there are several additional mechanisms and requirements that inform utility investment choices.

Renewable Portfolio Standard

The Renewable Portfolio Standard requires utilities and others in the state to supply a specified percentage of retail sales via renewable energy. This percentage of renewables supplied to customers increases over a period of time. The Renewable Portfolio Standard largely relates to supporting state public policy goals, but may also affect customer engagement and satisfaction.

The Renewable Portfolio Standard (RPS)[73] sets the percentage of electricity sold each year by providers of electric service to Nevada customers that must come from renewable energy.[74] Renewable energy is defined as being biomass, geothermal energy, solar energy, waterpower and wind.[75] Until 2025, energy efficiency measures can be used to comply with the annual RPS requirement.[76] If a provider of electric service fails to meet the standards, the PUCN may impose an administrative fine on the provider or take other administrative action against the provider, or both. SB 358, passed by the Nevada Legislature in 2019, accelerated the amount of energy that a provider of electric service is required to generate, acquire or save from renewable energy or efficiency measures. SB 358's requirements are as follows:[77]

Table 3: SB 358 Requirements

YEAR	MINIMUM RENEWABLE ENERGY REQUIREMENT
2020	22%
2021	24%
2022-23	29%
2024-26	34%
2027-29	42%
2030	50%

[73] In Nevada, the RPS is called the "Portfolio Standard." NRS 704.7805. For purposes of this paper, however, we will refer to it as the RPS.

[74] The Nevada RPS is stated in terms of the number of portfolio credits required for compliance. A portfolio credit is equal to one kilowatt-hour of renewable energy generated or one kilowatt-hour of energy saved through an efficiency program.

[75] NRS 704.7715. The statute provides that "renewable energy" does not include coal, natural gas, oil, propane or any other fossil fuel, or nuclear energy. The statute also adds additional clarification as to what "waterpower" means, generally limiting the facilities that can be deemed as providing "waterpower" via renewable energy to those facilities that provide not more than 30 MWs of generation.

[76] NRS 704.7821.

[77] *Id.*

As part of SB 358, the Legislature also declared it the policy of the state to:

1. Encourage and accelerate the development of new renewable energy projects for the economic, health and environmental benefits provided to the people of this State.

2. Become a leading producer and consumer of clean and renewable energy, with a goal of achieving by 2050 an amount of energy production from zero carbon dioxide emissions resources equal to the total amount of electricity sold by providers of electric service in this State.

3. Ensure that the benefits of the increased use of portfolio energy systems and energy efficiency measures are received by the residents of this State. Such benefits include, without limitation, improved air quality, reduced water use, a more diverse portfolio of resources for generating electricity, reduced fossil fuel consumption and more stable rates for retail customers of electric service.[78]

Other changes made to the RPS compliance in SB 358 are as follows:

- Subject to certain limitations, the bill expanded resource eligibility by including the generation from certain large hydro facilities, such as Hoover Dam. More specifically, only energy produced from large hydro facilities greater than 30 MW after the effective date of SB 358, which was April 22, 2019, and placed into service prior to July 1, 1997, can be counted toward RPS compliance.

- SB 358 also adjusted the RPS calculation by permitting retail providers to exclude from retail sales subject to the RPS compliance, those retail sales made pursuant to PUCN-approved optional pricing programs, such as sales agreements under the NV GreenEnergy Rider tariff, where the provider either transfers portfolio credits to the customer or retires portfolio credits above the renewable energy standard on behalf of the customer.

- By eliminating the minimum solar credit requirement in SB 358, the annual RPS requirement is now agnostic, permitting providers to satisfy the RPS requirement using PUCN-approved portfolio credits from any type of Nevada eligible renewable generating resource.

- SB 358 eliminated, in part, a provision that permitted certain providers of new electric resources that provide retail service to customers of NV Energy who have exited their system pursuant to NRS Chapter 704B, to maintain an RPS requirement that is different from the public utility, namely NV Energy.

- As is discussed below in Category 4, NV Energy also was given authority in SB 358 to acquire an existing renewable facility without getting specific approval from the PUCN for such acquisition if specific terms have been met or, with PUCN approval, construct a renewable facility without including that facility in its utility rate base. The statute also permits a utility or utilities under

[78] NRS 704.7820.

common ownership in an IRP application or an amendment to the IRP application to file a request that the PUCN establish a just and reasonable price by means of reference to a competitive market rate for energy produced by a renewable energy facility owned by the utility or utilities.

On or before April 15 of every year, providers of electric service must file an annual report of compliance with the portfolio standard for the previous year.[79] For calendar year 2019, not less than 20 percent of electricity sold to Nevada retail customers was required to come from renewable energy resources. Additionally, of the total amount that the provider is required to generate, acquire or save from portfolio energy system or efficiency measures during 2019, not more than 20 percent of that amount can be based on energy efficiency measures. Of the energy efficiency measures relied upon by a utility, at least 50 percent of that amount must be saved from energy efficiency measures installed at service locations of residential customers, unless a different percentage is approved by the PUCN.

The following is the information that relevant providers of electric service filed as to compliance with the RPS in 2019:

- NPC states in its filing that 29.1 percent of its total retail sales are from renewable energy or efficiency measures; SPPC states in its filing that 24.1 percent of its retail sales of energy are from renewable energy or efficiency measures.[80]

- Tenaska Power Services Co., which is a provider of new electric resources pursuant to NRS Chapter 704B, claims to have met the 20-percent RPS standard for 2019.[81]

- Shell Energy North America (US), L.P., which is a provider of new electric resources pursuant to NRS Chapter 704B, claims to have met the 20-percent RPS standard for 2019.[82]

- Macquarie Energy LLC, which is a provider of new electric resources pursuant to NRS Chapter 704B, claims to have met the 20-percent RPS standard for 2019.[83]

- Exelon Generation Company, LLC (“Constellation”), which is a provider of new electric resources pursuant to NRS Chapter 704B, claims to have met the 20-percent RPS standard for 2019.[84]

- Switch Ltd., which is an eligible customer that has exited NV Energy’s system and receives services from Morgan Stanley Capital Group Inc. pursuant to NRS Chapter 704B, claims to have met and exceeded the 20-percent RPS standard for 2019.[85]

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[79] NAC 704.8877 and NAC 704.8879.

[80] Docket No. 20-04018, Annual Report at 8.

[81] Docket No. 20-04013, Annual Report at 4.

[82] Docket No. 20-04019, Annual Report at 7.

[83] Docket No. 20-04020, Annual Report at 1.

[84] Docket No. 20-04021, Annual Report at 1.

[85] Docket No. 20-04022, Annual Report at 1.

Energy Efficiency and Conservation

Establishment of energy savings targets and related requirements on utilities for energy efficiency and conservation serves the purpose of ensuring utilities will pursue energy efficiency and conservation measures, which otherwise might be in conflict with their inherent incentive to sell more energy to customers. Energy efficiency and conservation targets likely affect customer engagement and satisfaction, and support state public policy goals and grid optimization.

The PUCN is required to establish goals for each utility for energy savings from energy efficiency programs implemented each year. Each utility is then required to develop and include in its most recent resource plan a demand side plan that is designed to meet or exceed those goals, including identification of the programs to be implemented for energy efficiency and conservation. The annual budgets for energy efficiency and conservation programs are approved through the demand side plan. The PUCN has generally used the Total Resource Cost Test to determine cost effectiveness of the plan. In Docket No. 16-09004, the PUCN clarified in a Report that its regulations offer sufficient flexibility to permit consideration of other inputs beyond the Total Resource Cost Test. Specifically, the PUCN found that parties to contested cases may offer the results of other tests, such as the Utility Cost Test, the Societal Cost Test and the Ratepayer Impact Measure test, as further evidence to aid in the evaluation of energy efficiency and conservation programs. These tests are defined in the glossary included at the end of this paper. In addition, in consolidated Docket Nos. 17-07011 and 17-08023, the regulations were revised to require that the utility include a cost and benefits analysis of the programs using at least one standard test of cost effectiveness that accounts for the non-energy benefits of the program.

SB 150 and Assembly Bill (AB) 223 enacted by the 2017 Nevada Legislature revised requirements related to energy efficiency and conservation programs, including that energy savings goals be established and that not less than 5 percent of the expenditures related to energy efficiency and conservation programs in the demand side plan must be directed to energy efficiency and conservation programs for low-income customers of the electric utility. The regulations adopted in consolidated Docket Nos. 17-07011 and 17-08023 established an average reduction of 1.1% of the forecasted weather normalized sales of the electric utility for the period beginning January 1, 2020 and ending December 31, 2024, as the goal.

The PUCN may approve an energy efficiency plan that consists of energy efficiency and conservation programs that are not cost-effective if the PUCN determines that the plan as a whole is cost-effective. The demand side plan also must include a report on the status of all programs for energy efficiency and conservation that have been approved by the PUCN, including the planned and achieved reductions in energy and capacity by year, and the cost of the programs.

Costs for the energy efficiency and conservation programs are recovered through rates, which are calculated during the annual DEAA filing. To facilitate recovery of energy efficiency and conservation costs, the regulations set up a balancing account system. The energy efficiency program rate (EEPR) is designed to recover the utility's direct costs to deliver energy efficiency and conservation programs to customers; in other words, this rate reflects the program costs. These costs include, among other things, cost for labor, overhead, materials, incentives paid to customers, advertising, marketing, monitoring and evaluation. As discussed above, the energy efficiency implementation rate, or EEIR, is meant to eliminate the financial disincentive associated with energy efficiency and conservation programs. Both the EEPR and EEIR have balancing rates (called the Amortization EEPR and the Amortization EEIR) that reflect program costs or lost sales during a deferral period that is not reflected in the base rates collected from customers.[86] Energy efficiency costs are recovered through a single line item on customer's bills.

By July 1 of the year following the filing of a resource plan, utilities are required to file an updated analysis with the PUCN including results of the prior program year and any modifications requested to be made for the upcoming program year. For calendar 2019, this information was filed in Docket No. 20-07004. NPC expended $33,197,277 in program costs in 2019 and reported achieved savings of 232,653,028 kWh, 1.15% of weather normalized retail sales. SPPC expended $11,360,730 in program costs and reported achieved savings of 94,562,194 kWh, 1.04% of weather normalized retail sales.

Clean Energy Incentive Programs

Offering incentives for customers to deploy specific types of technologies serves the purpose of increasing adoption of those technologies within the state and often is intended to jump-start a particular market by encouraging early adoption. From a high level, these types of programs foster the achievement of state public policy goals around technology adoption and emission reductions, and also likely affect customer engagement and satisfaction.

A variety of clean energy incentive programs, totaling $295,270,000 of incentives, have been established by various Nevada statutes and implemented by the PUCN to promote the installation of distributed renewable energy systems with a nameplate size less than 1 MW.[87] Generally speaking, these incentive programs are aimed at smaller customers. In other words, the incentives listed in this sub-category are not directed at utility-sized projects.

Each year the electric utility files an annual plan regarding these incentive programs. The plan is filed on February 1 for a program year that runs from July 1 through June 30. Costs are recovered through rates that are calculated in the annual DEAA proceeding and are reset annually. Rates are a flat per-kWh charge and are listed as a separate line item on the customer's bill.

[86] More explanation of each of these rates can be found in NPC's and SPPC's most recent annual DEAA filing. *See* Consolidated Docket Nos. 20-02026, 20-02027 and 20-02028, at Ex. 1-2 (Feb. 27, 2020).

[87] NRS 701B.005(1).

Low-Income Solar Energy Program

Solar PV installation incentives do not typically reach low-income populations and this program seeks to remedy that by offering incentives to businesses that serve low-income populations. This program engages customers who would otherwise not have the opportunity to share in solar PV programs and contributes to state public policy goals related to solar energy adoption and low-income customer support.

The Low Income Solar Energy Program (LISEP) was created in 2013 as a pilot program and was made permanent in 2017 through SB 145. Incentives are available for solar PV installation for businesses that serve a significant population of low-income individuals, or low-income housing and multi-family housing that qualifies for the Federal Low-Income Housing Tax Credits. NV Energy has proposed to continue this program in 2020-2021 with $1,000,000 in incentives per program year allocated to the program through SB 145, supplemented with funding from amounts made available from cancellations, withdrawals and forfeitures in other clean energy programs (except the Electric Vehicle Infrastructure Demonstration program). From July 1, 2018, through June 30, 2019, a total of 33 LISEP projects were completed, representing 634,519 kW of installed capacity. From July 1, 2019, through December 31, 2019, an additional 9 projects were completed representing 1,029,145 kW in installed capacity.

Electric Vehicle Infrastructure Demonstration

Electric vehicle infrastructure programs offer incentives that are intended to expand electric vehicle charging infrastructure and promote adoption of electric vehicles across Nevada. These programs support state electric vehicle public policy goals.

The Electric Vehicle Infrastructure Demonstration (EVID) programs launched in September 2018 and continued during the 2019-2020 program year. The EVID program was created as a result of SB 145 (2017), meant to expand and accelerate the deployment of electric vehicles and supporting infrastructure throughout Nevada. The PUCN allotted $15 million in incentive funds for EVID programs via regulations adopted in Docket No. 17-08021. While money was set aside in the 2017 docket, the initial programs for EVID were approved in Docket Nos. 18-02002 and 19-02001. The approved programs are detailed below and were strategically designed to expand the electric vehicle charging infrastructure and promote adoption of electric vehicles across Nevada by providing incentives to offset the cost of engineering, procurement and installation of electric vehicle charging stations. Additionally, the regulations adopted in Docket No. 17-08021 permitted NV Energy to own electric vehicle charging infrastructure, but NV Energy has not undertaken to own any of its own infrastructure.

- The Nevada Electric Highway – This began as a partnership between the Governor's Office of Energy, NV Energy and other electric co-ops to expand the state's electric vehicle charging infrastructure by placing charging stations at cost-effective and strategic locations, initially along U.S. 95 between Reno and Las Vegas. A subsequent RFP was issued to ensure chargers were placed along I-15, I-80 and U.S. 50. The site locations can be found at the Governor's Office of Energy website: http://energy.nv.gov/Programs/Nevada_Electric_Highway/.

- EV Charging Station Incentives – These incentives were offered to NV Energy's commercial customers under the categories of multi-family residential, fleet electrification, workplace, and public charging. The goal of the program was to support installation of electric vehicle charging infrastructure at locations throughout NV Energy's service territories and promote adoption of electric vehicles within Nevada. From July 1, 2018, through June 30, 2019, NV Energy completed installations for 4 applications for 12 DC fast chargers and eight level 2 connectors (representing the fleet and workplace categories). From July 1, 2019, through December 31, 2019, NV Energy completed installations for 11 applications for two DC fast chargers and 45 level 2 connectors (in the workplace and multi-family category).

- Electric Vehicle Custom Grant Program – This custom grant program, first approved in Docket No. 18-02002, provides financial support to help offset the costs of installing non-residential electric vehicle charging infrastructure in NV Energy's service territories. More specifically, the program is meant to support charging infrastructure development that may not be identified in, or eligible for, other incentive programs offered in the EVID program. In the 2018-2019 program year, NV Energy awarded a total of three grants to the following programs: (1) the Town of Gardnerville Electric Vehicle station; (2) the Washoe County 9th Street Administration Complex; and (3) McCarren Airport Electric Ground Support Equipment.[88] In 2019, the PUCN ordered in Docket No. 19-02001 that the custom program be used to provide financial support to assist school districts in NV Energy's areas to deploy electric school busses and related charging infrastructure.

- Technical Advisory Services – Through this program, NV Energy offers technology advisory and consulting services that help customers better understand, select, implement and optimize deployments of electric charging infrastructure projects. The primary focus of the Technical Advisory Services team is to support fleet electrification initiatives, but the team also provides assistance to customers pursuing participation in the Energy Storage Incentives program and/or the Solar Incentives program. NV Energy EVID Proposals -- NV Energy has put forth new proposals related to EVID in their latest annual plan filing in Docket No. 20-01040. The new proposals approved by the PUCN are:

    - In addition to the incentives previously offered to multi-family residential, fleet electrification, workplace, and public charging (now called public convenience charging), NV Energy proposed to add a governmental and lower-income, multi-family housing charging program. The lower-income program is being offered by NV Energy in conjunction with the Governor's Office of Energy. This program will offer incentive funding up to 100 percent of the total project cost for level 2 charging stations up to a maximum of $10,000 per port. NV Energy will contribute 75 percent of the total project cost, up to $7,500 per port, while the Governor's Office of Energy will contribute 25 percent of the total

[88] For more information, *see* Docket No. 20-01040, Ex. 1 at 117-18.

project cost, up to $2,500 per port. Regarding the governmental charging program, NV Energy and the Governor's Office of Energy identified that various government agencies have shown a particular interest in the installation of electric vehicle charging infrastructure, but do not typically have the same level of capital available for these installations. NV Energy and the Governor's Office of Energy proposed an incentive program for funding up to 100 percent of the total project cost in line with the parameters note above for the lower-income program.

- Increase the minimum charging capacity for eligible direct current fast charges (DCFC) to 50 kilowatts for all EVID programs.

- Electric vehicle charging stations with plug types that can only charge one vehicle make are eligible for an incentive for the non-public charging station incentive programs, including the workplace, fleet and multi-family charging programs. The specifics for each of these programs are:

  - For chargers deployed in multi-family dwellings, up to 50 percent of the connectors incentivized at any one site may be of a type that can charge only one vehicle make. Connectors that can only charge one vehicle make are not eligible for the programs DCFC incentive of $400 per kW if deployed at multi-family dwellings.

  - For chargers deployed at workplaces, up to 50 percent of the first four connectors may be of a type that can only charge one vehicle make. For any additional connectors incentivized above four, only 25 percent may be of a type that can only charge one vehicle make. Connectors that can only charge one vehicle make are not eligible for the programs DCFC incentive of $400 per kW if deployed at a workplace.

  - There is no restriction on the type of connector for chargers funded through the program and deployed to serve fleets.[89]

- NV Energy Required to File Charging Station Data – The PUCN also has issued a directive to NV Energy that it is required to use information and data available and work with the owners of charging stations to develop a report on how the charging stations are being used. NV Energy will be required to file that report in 2021 regarding the approval of its 2021-2022 annual plan, with the data broken down by SPPC's and NPC's service territory.

[89] Docket No. 20-01040, Order, at 3-4 (June 11, 2020).

Electric School Bus Incentive Program

Electric school bus incentives support the acquisition of electric school busses and charging infrastructure by Nevada school districts. This program engages school districts as customers of NV Energy and supports state electric vehicle adoption public policy goals.

The Electric School Bus Incentive program, brought about by SB 299 (2019), is a first-come, first-serve incentive program that provides financial support to assist school districts in NV Energy's service area to replace diesel-engine school buses with battery-electric versions and to install related charging infrastructure. This program will provide incentives up to 75 percent of the expected costs to purchase the electric school bus and/or install the charging infrastructure necessary for the buses. The applicant must be a public school.

Small Energy Storage Program

Residential and non-residential storage incentives support the adoption of storage systems less than 100 kW that are charged at least 75 percent by renewable energy resources. These incentives promote customer engagement by supporting customers who wish to adopt storage, as well as support state public policy goals that encourage increased use of storage and renewable energy.

The Small Energy Storage program was established pursuant to SB 145 in 2017. This program provides for up to $5 million in incentive funding for residential and non-residential customers pursuing energy storage systems with a nameplate capacity of up to 100 kWs. Residential customers eligible for the small energy storage program may receive a larger incentive by electing to enroll in a time-of-use rate. Residential customer eligibility requires solar generation to be installed on the customer premises. More specifically, 75 percent of the energy to charge the storage system must be from renewable energy. The storage system also must have a total power capacity between 4 and 100 kW. From July 1, 2018, through June 30, 2019, six projects were completed under this program, representing 95 kWh of installed capacity. From July 1, 2019, through December 31, 2019, there were 108 completed projects, representing 2,285 kWh of installed capacity.[90] All of the completed projects were residential.

For the program year beginning July 1, 2020, the non-residential component of the Small Energy Storage program consists of incentives for installations with solar generation and for standalone storage systems. The non-residential Small Energy Storage program plus solar incentives are slightly higher for systems that do not qualify for the federal Incentive Tax Credit. The non-residential Small Energy Storage program standalone incentives are differentiated by profit and non-profit/government designations, with the latter receiving slightly higher incentive amounts. Non-residential customers receiving incentives for

[90] Docket No. 20-01040, Ex. 1.

a standalone small energy system must take service under time-of-use rates for a minimum of five years.

Large Energy Storage Program

Non-residential storage incentives support the adoption of storage systems between 100 and 1,000 kW that are charged at least 75 percent by renewable energy resources. These incentives support customer engagement on larger storage systems and support adoption of state public policy goals that encourage the adoption of storage and renewable energy.

The Large Energy Storage program was also established via SB 145 (2017). This program provides for up to $5 million in incentive funding for non-residential customers pursuing an energy storage system with a nameplate capacity of at least 100 kW but not more than 1,000 kW. This program is intended to prioritize installations that serve critical infrastructure facilities. The incentive structure is different for critical and non-critical infrastructure facilities, and further differs by whether the facilities are eligible for the federal Investment Tax Credit. As with the Small Energy Storage program, the energy storage system must be capable of being charged at least 75 percent by a renewable energy source. Based on the latest information from NV Energy, it appears no projects have been completed under this program, although the forecast for incentive payments for this program is nearly $960,000 for the current program year.[91]

Solar Energy Systems Incentive Program

Nevada electric utilities have been required to offer rebates to customers who install certain solar energy systems on their property since 2004. The program supports engagement with customers who wish to install solar and supports state public policy goals encouraging the adoption of solar energy.

The Solar Energy Systems Incentive Program requires electric utilities to develop and administer programs that offer rebates to customers who install qualifying solar energy on their property. The program is funded by ratepayers through a monthly charge on their bills. As of June 5, 2019, this program became fully subscribed and the program was closed to new applications. As of December 31, 2019, there were just over 2,813 solar incentive projects in various stages of the pipeline for completion. From July 1, 2018 through June 30, 2019, 8,993 projects representing 63,043 kW of installed capacity were completed under this incentive program for residential customers. From July 1, 2019 through December 31, 2019, another 5,099 residential projects were completed representing 35,287 kW of installed capacity. During that time frame, 12 low-income or nonprofit projects were completed, representing 68 kW of installed capacity. In total, since 2004, this incentive program has paid approximately $254 million in incentives, representing 299,379 kW of installed capacity.

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[91] *Id.*

Waterpower and Wind Energy Systems Demonstration Programs

Nevada electric utilities are required to offer rebates to customers who wish to install certain water and wind systems on their property. The program supports engagement with customers who wish to adopt these systems and supports state public policy goals encouraging the adoption of water and wind energy systems.

The Nevada Legislature also created the Waterpower Energy Systems Demonstration Program and the Wind Energy Systems Demonstration Program in 2007 to encourage the development of renewable energy. The programs require utilities to develop programs that offer rebates to customers who install eligible energy systems on their property. Both programs were closed to new applicants on June 5, 2019, and there are no remaining pending applications. For the Waterpower Energy Systems Demonstration Program, a total of 1,345 kW was installed, with incentives totaling $2,097,500 over the program life. For the Wind Energy Systems Demonstration Program, a total of 10,129 kW was installed, with incentives totaling $25,646,208 over the program life.

Biennial Energy Storage Targets

Targets for the deployment of certain types of resources have the effect of pushing utilities to make those resources a priority in planning and procurement. An energy storage target affects the state's ability to meet public policy goals, as well as encourages grid optimization.

In Docket No. 17-07014, the PUCN adopted regulations that reflect an energy storage deployment target of 1,000 MWs by 2030 and required the utilities to include energy storage in IRPs. The biennial targets start at 100 MWs by December 31, 2020 and increase 100 MWs every two years until reaching the ultimate goal of 1,000 MWs by December 31, 2030. The targets can be reached by either centralized or distributed energy storage systems. Moreover, the energy storage systems can be connected to either the transmission or distribution system. The biennial storage targets are cumulative and include energy storage system resources approved by the PUCN and procured by the utilities via contract even before the effective date of the regulation.

Temporary Renewable Energy Development Program

The Temporary Renewable Energy Development Program provides an incentive payment to complete renewable energy projects and has the effect of encouraging development of large-scale renewable energy in the State. This program furthers Nevada’s interest in meeting public policy goals.

To help facilitate the development of renewable energy projects necessary to meet the state’s renewable portfolio standard, the Nevada Legislature created the Temporary Renewable Energy Development or

TRED program in 2005. The program was meant to ensure prompt payment to renewable energy providers to encourage completion of projects. A "TRED" charge is collected from electricity customers as a separate line item on their bill, and this charge is determined annually in the DEAA application. Only one TRED-eligible project delivers renewable energy or portfolio credits to NPC and SPPC currently. Specifically, NPC contracted with Solargenic Energy, LLC (now known as Nevada Solar One) to purchase a portion of the output of a concentrating solar thermal power plant. Under the current PUCN-approved agreement, NPC receives 68 percent of the output of this facility, and SPPC receives 32 percent of the output of this facility.[92] The TRED program is now closed to new applicants.[93]

Net Energy Metering

Net energy metering is intended to encourage customer-sited adoption of renewable energy generation by allowing customers to export excess power to the grid and be compensated for that exported energy through their electric bills. Net energy metering addresses issues concerning customer engagement, grid optimization and achievement of state public policy goals.

The most recent updates to Nevada's approach to net energy metering came about in AB 405 (2017), which established a tiered rate structure for providing net metering customers of not more than 25 kilowatts with bill credits for the net excess energy their renewable energy system produces.[94] This tiered rate structure decreases over time as the amount of electricity produced by net metering systems hits 80 MW benchmarks. Specifically, the compensation structure for net metering customers is such that they receive a one-for-one credit for all production up to the amount that they receive from the utility over a billing period, and they are reimbursed at 95 percent of the retail rate for all net excess generation (meaning production that exceeds the amount of electricity delivered to the customer by the utility over the billing period). The compensation for net excess generation declines by 7 percent with every 80 MW of cumulative installed capacity of net metered systems to a floor of 75 percent of the retail rate. The progression through the tiered rate structure is available on the PUCN's website at: http://puc.nv.gov/Renewable_Energy/Net_Metering/.

Net metering customers remain in the same customer class as non-net metering customers and cannot be charged any fee or charge that is different than that charged to non-net metering customers. Net metering customers will pay the same basic service charge and other fees as non-net metering customers.

While the tiered rate structure described above is available only to those systems of not more than 25 kilowatts, NRS 704.741(1)(a) defines net metering systems more broadly as systems that use renewable energy as their primary energy source, are not larger than a capacity of 1 MW, are located on the customer-generator's premises, operate in parallel with the utility's transmission and distribution

[92] Consolidated Docket Nos. 20-02026, 20-02027, and 20-02028, Ex. 2 at 14-15.

[93] Docket No. 10-02020, Order, at Attachment A at 2 (July 30, 2010).

[94] The PUCN's regulations use "net metering" rather than "net energy metering," but the terms are synonymous.

facilities, and are intended primarily to offset part or all of the customer's requirements for electricity.

SB 358 Renewable PPA Pricing and Ownership Options

Mechanisms and programs that allow utilities to more easily invest in renewable energy projects are intended to accelerate deployment of renewable energy, which primarily supports the achievement of state public policy goals.

SB 358, which was passed by the Nevada legislature in 2019, increased the renewable portfolio standard, as described above. It also added provisions to statutes related to resource planning and ratemaking that authorize electric utilities to acquire an existing renewable facility without getting specific approval from the PUCN for such acquisition if specific terms have been met or, with PUCN approval, construct a new renewable facility without placing that facility within its rate base.

SB 358 permits a utility or utilities under common ownership in an IRP application or an amendment to the IRP application to file a request that the PUCN establish a just and reasonable price by means of reference to a competitive market rate for energy produced by a renewable energy facility owned by the utility or utilities. If the PUCN grants the request, any capital investment made by the utility or utilities on the renewable energy facility must be excluded from rate base and all expenses associated with the facility must be excluded from the revenue requirement of the utility or utilities. The just and reasonable price for the electricity generated by the renewable energy facility must be established by reference to a competitive market price for the electricity, without regard or reference to the principles of cost of service or rate of return price setting. The PUCN may determine a competitive market price based on the results of a reasonably contemporaneous competitive RFP for a substantially similar product with substantially similar terms and conditions, including duration of the proposal. In other words, the utility or utilities would charge customers based on a competitive market price established by the PUCN, rather than recovering the costs through traditional ratemaking. Also, in an IRP or IRP amendment that includes a provision for acquisition by the utility of a renewable energy facility, the PUCN may establish reasonable performance terms and conditions for the generation and sale of the electricity.

If, pursuant to SB 358, the PUCN establishes a just and reasonable price for the electricity generated by a renewable energy facility by reference to a competitive market price for the electricity, the PUCN must establish regulations whereby a utility can recover that just and reasonable price through the deferred accounting mechanisms for fuel and purchased power set forth in NRS 704.187.

The regulations to implement these provisions are currently being drafted in Docket No. 19-06010.

Expanded Solar Access Program

Renewable access programs targeted at specific groups of customers, such as low-income customers, serve to improve equitable access to clean energy. This program supports just and reasonable rates, customer engagement and satisfaction, and achievement of state public policy goals.

AB 465, which passed the Nevada legislature in 2019, created an expanded solar access program that requires NV Energy to develop between 3 and 10 community-based solar resources to expand solar access to low-income, disadvantaged businesses and nonprofit organizations, and to residential customers who are unable to install rooftop solar. The expanded solar access program provides communities within the utility's service territory the ability to participate in the siting and naming of the community-based solar resources, as well as a workforce training program for the construction of the resources. An electric utility must consider and provide greater weight for a location sited in a disadvantaged or low-income community. Draft regulations implementing AB 465 propose that the utility's plan must include information regarding a solar workforce innovations and opportunities program. The solar workforce innovations and opportunities program is to be developed by the Department of Employment, Training, and Rehabilitation in conjunction with potential employers and the International Brotherhood of Electrical Workers, to provide workforce education, training and job placement.

AB 465 requires a reasonable mixture of community-based solar and utility-scale solar to be made available through the program. The capacity of the program is divided up to be reserved for low-income customers (25 percent), disadvantaged businesses and nonprofit organizations (25 percent), and residential customers who are unable to install rooftop solar (50 percent). The total amount of energy available for SPPC's service territory under these percentages is 40,000 MWh, 40,000 MWh and 80,000 MWh, respectively; for NPC, 60,000 MWh, 60,000 MWh and 120,000 MWh, respectively. The expanded solar access rate will replace the BTER and DEAA. For low-income customers, the program must provide for a lower overall energy rate. The program also must provide the other eligible customers of the program who are not low income stability and predictability and the opportunity for a lower energy rate. The regulations to implement the program are currently being drafted in Docket No. 19-06028.

Natural Disaster Protection Plan

> *Planning for natural disasters supports enhancing the reliability and resiliency of the electrical grid, while also promoting state public policy goals. Proactive prevention of catastrophic loss to customer life and property also promotes utility financial stability by reducing liability for such catastrophic loss.*

SB 329 (2019) requires electric utilities to submit natural disaster protection plans to the PUCN on or before June 1 of every third year. The bill requires the plans to contain procedures and protocols relating to the efforts of the utility to prevent or respond to natural disasters, such as wildfires. The bill authorizes electric utilities to recover all prudent and reasonable expenditures made by the public utility to develop and implement the plan as a separate monthly rate on customer bills. Regulations that implement the requirements of SB 329 were adopted in Docket No. 19-06009. NPC and SPPC jointly filed their natural disaster protection plan in Docket No. 20-02031. The plan's effective period would be from 2021-2023. In Docket No. 20-02032, NPC and SPPC jointly filed for approval of cost recovery of a regulatory asset account established in 2019 related to natural disaster protection.

The natural disaster protection plan has important implications for regulation of Nevada utilities, as risk of natural disasters like wildfires are expected to play an ongoing and significant role in how NV Energy directs the focus of its capital spending. As such, much like an IRP, the natural disaster protection plans will determine significant investment decisions for NV Energy in the future. For example, in NV Energy's first natural disaster protection plan, it requested approval of 24 capital projects and 11 operations and management programs (including public safety outage management). The total requested budget to implement the natural disaster protection plan includes budgets for capital projects and operations and maintenance programs in the range of $237 million to $346 million dollars. These projects, programs and amounts may change pending the outcome of consolidated Docket Nos. 20-02031 and 20-02032.

Provisions in Law that Permit Commercial Customers to Take Service from a Provider Other than the Monopoly Utility

Provisions in statute and regulation that allow certain customers to exit the vertically owned utility system and purchase power from a different provider are intended to increase customer choice and access to low cost power, as well as to enhance competition. These provisions in law relate primarily to customer engagement and satisfaction.

Pursuant to Chapter 704B of the NRS, certain non-residential customers may exit NV Energy's system and purchase electricity and capacity from a different provider. These non-residential customers still take distribution-only service from the monopoly utility, but acquire energy, capacity and ancillary services from "a provider of new electric resources" to meet their electricity needs. In choosing the 704B option, certain costs incurred while the customer was a fully bundled customer of the utility must be paid to ensure that the remaining full requirements customers do not absorb costs incurred on behalf of the departing customer. Some of these costs are recovered from the exiting customer with a calculated "impact fee" that is determined as a condition of exiting as a full requirements customer. SB 547, adopted during the 2019 legislative session, provided clarity to the costs that exiting customers must pay in an impact fee to ensure that the remaining fully bundled customers are not negatively impacted, in addition to other changes.[95]

SB 547 requires the PUCN to set annual limits on the amount of energy and capacity that may exit NV Energy's system. To determine the appropriate annual limits pursuant to SB 547, the utility must present a sensitivity analysis that addresses load growth, import capacity, system constraints and the effect of eligible customers purchasing less energy and capacity. SB 547 clarified that the impact fee charged to the

[95] In SB 547, the Nevada Legislature modified existing statutes to require that any application for an eligible customer to exit NV Energy's system must be in the public interest. As part of this public interest finding, the PUCN is required to consider:

(a) Whether the electric utility that has been providing electric service to the eligible customer will experience increased costs as a result of the proposed transaction;

(b) Whether any remaining customer of the electric utility will pay increased costs for electric service or forgo the benefit of a reduction of costs for electric service as a result of the proposed transaction; and

(c) Whether the proposed transaction will impair system reliability or the ability of the electric utility to provide electric service to its remaining customers.

NRS 704B.310(6).

exiting customer must ensure that the customer pays their load-ratio share of the costs associated with the electric utility's obligations that were incurred as deviations from least-cost resource planning. SB 547 provides a list of statutes and legislative bills that are deemed to be deviations from least-cost planning.[96]

Docket No. 19-06029 is the rulemaking docket wherein the PUCN is considering new regulations to implement the requirements of SB 547. The regulations being considered in Docket No. 19-06029 provide additional detail regarding the impact fee calculation, determining certain charges that will be paid by those customers who are approved to exit NV Energy's system pursuant to NRS Chapter 704B. In particular, the regulations propose a means to calculate the impact of the customer leaving on both the base tariff general rate (BTGR) developed in a GRC and the BTER. Also, the proposed regulations state that the exiting customer must pay a non-bypassable charge monthly in an amount at least equal to the customer's share of the ongoing out-of-the money portion of the costs of long-term renewable energy contracts entered into by the utility, other public policy programs the utility was required to participate in while the customer was served by the utility, and decommissioning and remediation costs of any generation resource previously used to provide service to the customers.[97]

NRS 704B customers retain the obligation to meet certain state public policy requirements, like the RPS, thus helping Nevada to approach its carbon emission reduction goals.

Application, Interconnection, Service Connections, Meters, and Customer Facilities

> *Rules and regulations in tariffs related to interconnection, service connection, meters and other similar issues serve the purpose of dictating aspects of the customer experience when interacting with the utility's system. Generally speaking, the terms of tariffs govern customer engagement and satisfaction, reliability and grid optimization.*

NPC and SPPC each have rules governing bundled and unbundled retail electric service.

Rule 3 details how eligible customers can choose to receive distribution-only or bundled service from the utility, and the conditions under which customers can return to the utility for their energy, capacity, or ancillary services if they have opted to receive those services from a provider other than the utility in the past.

The line extension rule in Rule 9 details how line extension projects are invested in by the utility on behalf of ratepayers. This rule governs how the total cost and construction responsibilities are allocated between the utility and the applicant for the line extension.

The generating facility interconnection rule (Rule 15) describes the interconnection, operating, and

[96] NRS 704B.310(7)(b)(4).

[97] Letter to Legislative Counsel Bureau from the Utilities Hearing Officer, Docket No. 19-06029 (May 27, 2020).

metering requirements for generating facilities that wish to be interconnected to the utility's distribution system. It applies to facilities with a net capacity of 20,000 kilowatts or less that will operate in parallel with the utility's distribution system.

Rule 16 details a number of provisions related to the extension of service and how utility-owned metering equipment is to be treated. It also lays out the conditions under which the utility will allow for the installation of non-utility-owned equipment within its metering compartments or enclosures. This allows customers to install certain equipment that will help reduce energy demand or total energy usage when that equipment cannot be installed elsewhere on the customer premises. The utility will install this equipment for customers if the conditions in this rule are met.

CATEGORY 5: Existing Alternative Ratemaking Mechanisms

Category 4 incentives and programs could be viewed as a step away from traditional ratemaking and a step toward forward-looking alternative ratemaking because they support emerging technologies, policies and customer preferences. Category 5 mechanisms take one step further away from traditional regulation and toward alternative regulation by introducing new tariffs and utility incentive mechanisms.

The mechanisms in this section are grouped into five subcategories. The first subcategory includes non-traditional tariffs or mechanisms offered to commercial or industrial customers to support public policy or customer engagement. The second subcategory are time-of-use tariffs for residential and commercial and industrial customers. The third subcategory concerns Nevada's adoption of an earnings sharing mechanism that requires certain utility surplus earnings to be shared by customers and shareholders. The fourth subcategory is for investment support mechanisms. In addition to these four subcategories of active tariffs or mechanisms set forth in statute and/or regulation, there are several mechanisms that are rightly considered alternative ratemaking that are not currently in use but are permitted under Nevada law, and these tariffs and mechanisms are presented together in a fifth subcategory.

Tariffs and Mechanisms for Commercial or Industrial Customers

Special Tariffs for Certain Commercial Customers

Commercial customers may be interested in self-provisioning their energy resources to potentially save money, to meet corporate sustainability goals or for other reasons. Tariffs that enable customer self-provisioning (in whole or in part) without requiring the filing of an application pursuant to NRS Chapter 704B may be desirable for some customers and may serve to protect remaining full-service customers. The terms of the tariff may advance public policy, enhance customer engagement, and ensure just and reasonable rates.

In Docket Number 19-10011, the PUCN approved a stipulation establishing a Market Price Energy Tariff (MPE) that allows large commercial customers to become a bundled retail customer of NPC, but have their rate reflect a market price for energy rather than charging the otherwise applicable tariff rate for that customer. The MPE tariff is potentially available to all non-residential customers demonstrating that they have an average annual load of 1 MW or more, and are not already a fully bundled retail customer of NPC but have been approved by the PUCN to purchase energy, capacity and ancillary services from an alternative provider through NRS Chapter 704B without the imposition of an impact fee.[98] The rates and charges the customer is subject to are set forth in the MPE tariff. Specifically, customers taking service under the MPE tariff pay:

- The BTGR with the cost of generation capacity and energy supply removed through bill credits;
- A demand charge (if applicable) and a facility charge (if applicable);
- The Basic Service Charge (BSC);
- The Universal Energy Charge (UEC), franchise fees, taxes and mill assessment;
- Public Program Costs pursuant to any applicable law or order of the PUCN; and
- The energy charge applicable to that customer is based on an energy supply agreement (ESA) between NPC and its customer, which must be approved by the PUCN

A customer taking service under the MPE tariff will not pay, unless otherwise ordered by the PUCN:

- The Net-BTER and DEAA; and
- The renewable energy program rate (REPR), TRED, energy efficiency rates and any other public policy costs if the customer had an order from the PUCN exempting the customer from paying these costs

The tariff also requires that the ESA shall:

- Be in the public interest;
- Provide for payment by the customer of NPC's incremental cost in procuring the energy;
- Provide a contribution to NPC's fixed transmission and distribution costs;
- Not impair the reliability of NPC's system or NPC's ability to provide electric service to its other customers;
- Include other terms and conditions related to the respective rights and obligations of NPC and the customer to take service under the tariff;
- Identify the basis for the calculation of the price of energy; and

[98] Given the conditions of the MPE, it would apply to a very small number of customers.

- Be the same term as the underlying renewable resource unless otherwise specified and explained in the ESA.

One customer so far has been approved to take service pursuant to the MPE tariff. The PUCN approved the stipulation of the parties regarding the ESA in Docket 19-10012. The parties to the docket stipulated that the PUCN should find the ESA is in the public interest because it is consistent with the legislative and policy objectives of the state in supporting the development of renewable resources and the reduction of carbon emissions, and it provides for a "Customer Margin Benefit" (CMB) that provides monetary benefit to other customers as a result of the transactions. The CMB is stipulated to be split 80 percent benefit to NPC's other bundled customers and the remaining 20 percent benefit to NPC. NPC's 20 percent share of the CMB is subject to the earning sharing mechanism approved in Docket No. 17-06003 and discussed above.[99]

In a separate proceeding, the PUCN was asked to consider a Large Customer Market Price Energy (LCMPE) tariff schedule filed by NPC with different applicability conditions than the MPE. The LCMPE tariff is potentially applicable to all non-residential customers demonstrating that they will have an average annual hourly load of 10 MW or more, are not a fully bundled retail customer of NPC, and have not been approved by the PUCN to purchase energy, capacity and ancillary services from an alternative provider pursuant to NRS Chapter 704B. The PUCN approved the stipulation by the parties regarding the requested tariff in Docket No. 19-12016. The tariff rates and charges, and the ESA requirements, largely mirror those of the MPE tariff with one addition: Unless otherwise described in the ESA, a customer receiving service under the tariff that subsequently falls below the 10MW threshold, based on a twelve-month rolling average, will pay the otherwise applicable rate schedule of the customer until the twelve month rolling average once again achieves the 10MW load threshold. An ESA must be approved by the PUCN in order for a customer to take service pursuant to the LCMPE. One customer has applied to have its ESA approved under the LCMPE tariff.[100] That application is pending in Docket No. 19-12017.

Both the MPE and LCMPE tariffs were filed by NPC. SPPC recently filed for approval of its MPE and LCMPE tariffs in Docket Nos. 20-06031 and 20-06032, respectively. Those tariff advice letters are pending review and a PUCN order.

Finally, NPC and SPPC recently filed a "Customer Price Stability Tariff" (CPST) with the PUCN in Docket Nos. 20-05003 and 20-05004, respectively. According to the utilities, they proposed this tariff to respond to customer requests for price stability and cost savings in meeting customer-specific business needs, as well as to assist with economic recovery associated with the COVID-19 pandemic. A non-governmental, fully-bundled customer with an average consumption of 8,760 MWh per year and a load factor of at least 50 percent, or a governmental customer with an average consumption of 8,760 MWh per year, would be eligible for the proposed program. This applies to both NPC and SPPC service territories. The PUCN would review and issue an order on each individual customer agreement. The overall program allotment is proposed to be 2.84 million MWh for NPC and 0.26 million MWh for SPPC, based upon the results of a

[99] *See* Docket Nos. 19-10011 and 19-10012, Final Order, at ¶ 3, Attachment 2 at 4 (Jan. 30, 2020).

[100] The ESA application for use of the LCMPE tariff was for Google's Henderson Data Center. Docket No. 19-12017, Final Order at¶ 4, Attachment 1 (Feb. 14, 2020).

solicitation of interest in March 2019 for a previous iteration of the program.

The proposal requires customers to pay an Energy Resource Rate, as well as a fixed Program Participation Rate.[101] These would substitute for the BTER and DEAA rates. The Energy Resource Rate represents a fixed energy price, aimed at providing an increased measure of price certainty to customers who take service pursuant to the tariff. The basis of the Energy Resource Rate is the solar production costs of the three most recently approved power purchase agreements for the output of renewable energy facilities executed by NV Energy in Docket No. 19-06039. The fixed Program Participation Rate is designed to offset system costs that should be shared by all customers, such as for battery energy storage procurement, wholesale market capacity purchases and natural gas transportation charges.

NV Energy requests that the program proposed for the CPST lasts five years starting in 2022 when the Program Participation Rate would be in effect for all subscribing customers. In addition to the Energy Resource Rate and the Program Participation Rate, subscribing customers would continue to be responsible for other costs under the otherwise applicable tariff, such as:

- The BSC;
- The BTGR recovering the embedded cost of distribution, transmission and generation;
- The REPR;
- The UEC;
- The TRED charge;
- Energy efficiency rates;
- Demand charge(s);
- A facilities charge; and
- An additional meter charge as applicable.

Given that these dockets addressing the proposed CPST are still pending, the PUCN is providing limited discussion of the tariff in this concept paper.

[101] These terms are explained in the White Paper filed in Docket No. 20-05003.

Electric Vehicle Commercial Charging Rider

Special riders that make electric vehicle charging more economic, such as demand charge discounts for commercial charging, act to incentivize more widespread adoption of EVs. These mechanisms are designed to achieve specific state public policy goals and also may affect grid optimization and customer satisfaction.

Both NPC and SPPC have riders in tariffs that discount demand charges for eligible customers related to electric vehicle commercial charging.[102] Participation in this rider is limited to 225 installed meters within NPC's and, separately, SPPC's service territory and will be applied on a first-come, first-served basis. Eligible commercial customers have a 10-year transition period before a full-priced demand rate is charged. More specifically, in 2019, eligible commercial customers can receive a 100-percent discount on demand charges, with that discount ratcheting down by 10 percent each year until a full demand rate is charged as of April 1, 2029.

As of December 31, 2019, NPC had approximately three customers/meters in one rate class taking service under this tariff. For SPPC, there were approximately eight customers/meters in two rate classes. Seven applicable rate classes for NPC and five applicable rate classes for SPPC have no customers taking service under the respective tariffs.

Economic Development Rate Rider

An economic development rate rider has the goal of attracting businesses to Nevada by providing discounted rates to certain qualifying new customers, and typically recovers the cost of providing that discount from all other ratepayers. This mechanism is primarily used to advance state public policy goals.

The Economic Development Rate Rider Program, established in NRS 704.7871 through 704.7882, was meant to attract new commercial and industrial businesses to Nevada. The PUCN administers the program in consultation with the Office of Economic Development. The program required electric utilities to set aside an amount of capacity determined by the PUCN for allocation to new customers. The total amount of capacity set aside from all electric utilities must not exceed 50 MW. The utility tariffs within the program describe how the kWh energy sales applicable to the discounted charge will be determined for each billing period.

For eligible customers, the rider is a discount to the BTER that is otherwise applicable. The BTER is discounted by the following percentages every month beginning with the first billing period after the customer commences service under the rider:

a) 30 percent in the first and second years of the effective rate period;

[102] *See* Schedule No. EVCCR-TOU.

b) 20 percent in the third, fourth, fifth, and sixth years; and

c) 10 percent in the seventh and eighth years

The discount reverts to zero percent in the ninth and tenth years, and the customer will resume paying the otherwise applicable BTER charge. The cost of the discount flows through the quarterly BTER filing to the other ratepayers.

Two eligible customers applied and are currently receiving the discount. Tesla Motors was approved for the maximum 25 MW in SPPC's service territory in Docket No. 17-02045, and began taking service effective January 1, 2018. Xtreme Manufacturing, LLC was approved for an estimated 1 MW in NPC's service territory in Docket No. 17-10009, and began taking service in June 2018. The discount provided to Xtreme Manufacturing, LLC pursuant to this rider totaled $34,530 in 2018 and $52,713 in 2019, and flowed in to the deferred energy balances to be collected from all other customers. No discount amounts are publicly available for Tesla Motors.

Green Rider Rate Calculation

Green power tariff programs allow customers to purchase or contract for renewable energy through their utility directly and pay for that power through a rider or other subscription fee. These types of programs relate to just and reasonable rates, customer engagement and satisfaction, and achievement of state public policy goals.

Non-residential customers of NV Energy have options to participate in green energy programs through the utility. Depending on whether they are customers of SPPC or NPC, the options are slightly different. Customers who participate in this program pay either NPC's or SPPC's NV GreenEnergy Rider (NGR) schedules, as appropriate.

NPC customers that are LGS-1 or larger can participate in the NV GreenEnergy Program by entering into a special contract that dedicates the power owned or procured from a new or existing renewable resource to a specific customer. The customer is responsible for all of the costs associated with the contract up to a specified energy amount not to exceed the customer's total energy consumption. Customers will see the amount charged for the renewable energy on their bill. Subscription under this program is limited to the first 250,000 MWh annually. The PUCN must approve the contracts for the customers who wish to take service under the NV GreenEnergy Program.

SPPC's non-residential customers that are GS-2 or higher have the same option (Option 2 in SPPC's tariff) as described above. As with NPC, subscription under this program is limited to the first 250,000 MWh annually. Unlike NPC, SPPC's non-residential and residential customers also have the option to contract for 50 or 100 percent of their monthly consumption under Option 1 at the rate determined in Schedule NGR. The NGR Rate is recalculated and updated each quarter when the BTER is updated. The NGR Rate as of July 1, 2020 is $0.03669 per kWh in addition to the other rates and assessments paid by the customer.

The PUCN has opened an investigation in Docket No. 19-11019 to revise both NPC's and SPPC's NGR schedules. The PUCN has taken a few rounds of comments in the docket, and most recently, has asked that NV energy proposed a revised NGR program for both SPPC and NPC. A workshop in the docket is schedule for late July.

Time-of-Use Tariffs for Residential and Business Customers

Time-of-use rates provide customers with an incentive to adjust their usage to lower peak times when electricity is cheaper. Time-of-use rates, if adopted by customers, may affect grid optimization and customer engagement.

Both residential and commercial customers have the option to enroll in NV Energy's time-of-use (TOU) rates. Customers who are willing to use less electricity during periods when the total demand of energy is highest (at its peak) may save money by shifting their usage to lower peak times when rates are lower.

Except under one circumstance, TOU rates cannot be mandatorily implemented for residential ratepayers. NRS 704.085 provides that an electric utility shall not make changes in any schedule or impose any rate, and the PUCN shall not approve any changes in any schedule or authorize the imposition of any rate by an electric utility, which requires a residential customer to purchase electric service at a rate which is based on the time of day, day of the week or time of year during which the electricity is used or which otherwise varies based upon the time during which the electricity is used, except that the PUCN may approve such a change in a schedule or authorize the imposition of such a rate if the approval or authorization is conditioned upon an election by a residential customer to purchase electric service at such a rate. This does not apply to a schedule or rates imposed on a customer-generator (i.e., rooftop solar customers).

SPPC has established TOU rates for single family homes and multi-family homes. SPPC offers TOU rates to General Service and Medium General Service customers.

NPC has established TOU rates for single family homes and multi-family homes, as well as a rate for large residences. NPC offers TOU rates to General Service and Large General Service customers.

The on-peak and off-peak hours varies by rate class and specific rate design. Generally speaking, the TOU rates are higher in the summer season than in the winter season. As an example, SPPC's single family residential customers have the following on-peak and off-peak hours under the TOU rate:

- Summer on-peak: July 1 - Sept. 30, from 1:01 p.m. to 6 p.m. Monday - Friday
- Summer off-peak: July 1 - Sept. 30, all other hours Monday - Friday, and all hours Saturday and Sunday

- Winter on-peak: Oct. 1 - June 30, from 5:01 p.m. to 9 p.m. daily
- Winter off-peak: Oct. 1 - June 30, all other hours

Customers who sign up for TOU rates are provided with a "Guaranteed Lowest Rate" pledge. Specifically, if after the first 12-month period, NPC or SPPC finds that the customer has spent more on the TOU rate than he or she would have spent on the standard rate, NPC or SPPC will refund the difference and restore the customers to the standard rate if the customer chooses. In order to take advantage of the "Guaranteed Lowest Rate" pledge, customers must remain in the program for a full 12 months.

Both NPC and SPPC also offer TOU rates tailored for use in conjunction with electric vehicle charging. The information below excludes data for the EVCCR-TOU rate class discussed previously in this paper.

As of December 31, 2019, NPC had approximately 3,536 residential customers taking service under standard TOU rates in six rate classes and approximately 1,618 residential customers taking serving under TOU–EV rates in seven rate classes. There are approximately 2,894 non-residential customers/meters taking service under standard TOU rates in two rate classes and one non-residential customer/meter taking service under TOU–EV rates in one rate class.

For SPPC, as of December 31, 2019, there were approximately 876 residential customers taking service under standard TOU rates in two rate classes and approximately 335 residential customers taking service under TOU–EV rates in two rate classes. There are approximately 1,792 non-residential customers/meters taking service under standard TOU rates in five rate classes and approximately 1 non-residential customer/meter taking service under TOU–EV rates in one rate class.

NPC has approximately 13 residential standard TOU offerings and seven residential TOU–EV tariffs under which no customers were taking service. There were no TOU or TOU–EV tariffs in effect for non-residential customers where it appeared that there were no customers taking service. SPPC appears to have approximately six residential standard TOU offerings and four residential TOU–EV tariffs under which no customers were taking service, although customers may have been aggregated in total TOU and TOU–EV data. SPPC has approximately four non-residential standard TOU offerings and three non-residential TOU–EV tariffs under which no customers were taking service.

Earnings Sharing Mechanism

The earnings sharing mechanism allows customers and shareholders to share in financial benefits and financial losses. This Nevada mechanism specifically targets sharing of earnings in excess of the allowed return on equity, and thus, is primarily focused on ensuring just and reasonable rates.

An earnings sharing mechanism was first established in Nevada in NPC's general rate case, consolidated Docket Nos. 17-06003 and 17-06004. The PUCN set NPC's Return on Equity at 9.4 percent in that docket, but a mechanism was added to allow 50 percent of any excess earnings over 9.7 percent to flow back to ratepayers, with 50 percent retained for shareholders. In Docket No. 19-06002, which was SPPC's most recent general rate case, the parties stipulated to an earning sharing mechanism for SPPC that works the same, but the allowed ROE was set at 9.5 percent with excess earnings split evenly after 9.7 percent earnings occur. In both cases, the calculation of realized earnings and any excess earnings flow back is determined in the annual DEAA filings. These mechanisms are intended to provide an incentive for utilities to control costs and promote efficiency, while providing ratepayers with the opportunity of sharing in the savings that result from the improvements made by the utility.

Given the timing of adoption of an earnings sharing mechanism for SPPC, only NPC's calendar 2018 and calendar 2019 calculations for sharing have been made in the annual DEAA filings. For 2018, NPC recorded approximately $43.3 million in earnings sharing; for 2019, approximately $16.4 million. These amounts were recorded in a regulatory liability account and are being applied as a reduction to rate base (on which revenue requirement is calculated) in NPC's GRC filed with the PUCN in June 2020, Docket No. 20-06003.

Investment Support Mechanisms

Investment support mechanisms establish financial or tariff mechanisms that are explicitly intended to encourage cost-effective investment that advance improved efficiency and reliability of utility operations and support public policy goals.

Incentives for Critical Facilities

> *Incentives for critical facilities encourage outcomes associated with meeting system reliability requirements while protecting utility financial health.*

Nevada resource planning regulations were revised in 2004 and one addition to the regulations was the opportunity for utilities to seek incentives for certain facilities deemed "critical facilities." NAC 704.9484(2) specifies that a utility may seek critical facility designation if the facility fulfills one or more of a number of special criteria. The criteria include protecting reliability, promoting diversity of supply and demand side resources, developing renewable energy resources, fulfilling specific statutory mandates, promoting price stability or fulfilling any combination of these criteria. If the PUCN determines a facility to be critical, then the utility may request one or more of several incentives listed in NAC 704.9484(3), which include: an enhanced ROE over the life of the facility, inclusion of Construction Work in Progress (CWIP), and/or seeking regulatory asset designation for costs incurred during the construction of the facility.

As an example, approval of critical facility status for the Tracy Combined Cycle facility (Tracy) for SPPC was anchored on two criteria: promoting reliability and promoting price stability. The PUCN order in Docket No. 05-8004 was issued in the post-Western energy crisis period at a time when Nevada utilities were recovering from financial distress and Western energy markets were recovering from supply volatility. The order in Docket No. 05-8004 emphasized the need to support in-state generation and to support the utility in its effort to regain an investment grade credit rating for the benefit of all ratepayers given the conditions at the time.

The incentives granted for the Tracy facility included an enhanced ROE of 1.5 percent and inclusion of capital costs of Tracy as CWIP in rate base. The PUCN found that including CWIP balances in rate base would mitigate the impact of building the unit on the utility's credit metrics. The PUCN also found that the ROE adder would help offset the negative effects of regulatory lag: "Supporting a utility that has been financially troubled in improving its credit rating has both immediate and long term benefits for ratepayers. This in combination with the fact that [SPPC] has one of the highest growth rates in the country and needs to acquire new resources in order to be able to reliably and economically serve its customers makes an ROE adder appropriate."[103]

Construction Work in Progress in Rate Base

Construction work in progress allows capital expenditures to be placed into a capital account and accumulate interest prior to the asset becoming operational. The declaration supports utility financial metrics and thus may protect credit ratings for the benefit of utility shareholders and utility customers.

CWIP in rate base can be established as an incentive for critical facilities, but the consideration of Allowance for Funds Used During Construction (AFUDC) predates the critical facility designation in Nevada regulations (NAC 704.6504). Thus, the PUCN has determined that CWIP in rate base treatment can be offered even if critical facility status is denied. The previous section describes a CWIP decision for the Tracy facility where critical facility status was established.

Docket No. 08-05014 granted NPC recovery of CWIP in rate base despite the fact that critical facility status for the Harry Allen Generating Station was denied. In granting CWIP, the PUCN agreed with NPC that "if access to equity capital becomes constrained, its credit metrics may suffer and that eventually weakness in cash flows and credit metrics will have a significant impact on rates," and thus, the PUCN found that "granting CWIP in rate base will enhance NPC's cash flow and benefit ratepayers by assisting NPC to maintain its credit metrics in the current economic environment."[104] Given the foregoing, the PUCN found that NPC's request for CWIP in rate base was warranted.

Regulatory Assets and Liabilities

Declaring certain revenues/credits as regulatory assets or liabilities allows those revenues/credits to be treated as if they were associated with a capital investment. Regulatory assets and liabilities are primarily established to promote just and reasonable rates, system reliability and efficiency, or public policy goals.

[103] Docket No. 05-8004, Order, at ¶ 197 (Dec. 14, 2005).

[104] Docket No. 08-05014, Final Order, at ¶ 82 (Oct. 1, 2008).

Regulatory assets and liabilities can be created for many reasons, but no specific rules govern their use in Nevada. Utilities have sought to establish specific rules for deferred accounting that results in regulatory assets or liabilities, but the PUCN has not chosen to establish an automatic path for that determination.

In Docket No. 13-12040, the Commission conducted a regulatory investigation to assess whether a utility should be allowed to use deferred accounting that results in a regulatory asset or liability. The PUCN order affirms the recommendation of the proceeding Report that, "the Commission should not adopt a regulation regarding when a regulated utility should be permitted to use deferred accounting resulting in a regulatory asset/liability."[105] The Report also found:

> There is an overarching need for flexibility in dealing with unusual occurrences or events that may or may not reach some level of materiality. The primary concern in establishing precise parameters in a regulation is that waivers will be requested with such regularity as to render the regulation meaningless. Addressing such matters on a case-by-case basis allows the Commission to revise its policy on regulatory assets/liabilities in response to changing conditions in the utility regulatory environment based upon new and/or updated information. It is a fluid process that does not necessarily lend itself to regulation at this time.[106]

More recently in Docket No. 19-03042, the Commission denied a Southwest Gas Corporation (SWG) application to use deferred accounting to establish a Consumer Data Modernization Initiative regulatory asset account, deciding that "given the lack of quantifiable benefits available to ratepayers, combined with the ability of SWG to offset its regulatory lag and recover its costs with a timely-filed GRC, regulatory asset treatment is not appropriate in this proceeding."[107]

Regulatory asset treatment has been approved for some grid modernization expenses, however. For example, in consolidated Docket Nos. 10-02009 and 10-03023, NPC and SPPC sought permission to implement an Advanced Service Delivery (ASD) program that included installing advanced metering for most of its 1.35 million customers. A significant cost share from United States Department of Energy through American Recovery and Reinvestment Act (ARRA) provided $138 million of the $301 million cost of implementing ASD. Implementing ASD for NPC caused $67.6 million of analog meter net plant to be retired early. The PUCN authorized NPC to remove the net plant from the plant account and place it into a regulatory asset account, to be amortized over 18 years.

A second interesting use of regulatory assets and liabilities was to address the early retirement of coal plants in southern Nevada as part of the ERCR plan discussed above. Recall from that discussion that all plant constructed or acquired pursuant to an ERCR plan is required to be recorded by NPC in a regulatory asset account. More specifically, NPC was required to record an amount that reflects a return on the utility's investment in the facility, depreciation of the investment, and the cost of operating and maintaining the facility. Until the regulatory asset has been processed in a general rate case and included in the revenue requirement, however, NPC must amortize the regulatory asset balance or add to the

[105] Docket No. 13-12040, Final Order, at ¶ 1 (Mar. 27, 2014).

[106] Docket No. 13-12040, Report at 11 (Mar. 27, 2014).

[107] Docket No. 19-03042, Modified Final Order, at ¶ 89 (Nov. 15, 2019).

regulatory liability balance, using the deprecation rates included in general rates at the time each unit is retired or eliminated. The statute requires NPC to include all depreciation and remediation costs associated with each unit retired or eliminated in a separate regulatory asset or liability account.[108]

In the case of Reid Gardner Generating Station, for example, the PUCN directed NPC to put the $44 million in demolition, decommissioning and remediation expenses into a separate regulatory asset. The PUCN determined that those costs would be adjudicated in a later rate case, once the decommissioning and remediation were "substantially complete."[109]

Electric Utility Alternative Ratemaking Mechanisms Not Presently in Use

A number of alternative ratemaking mechanisms exist in Nevada that electric utilities do not currently use, including: the authority to implement decoupling; imputed debt for renewable power purchase agreements and energy efficiency contracts; additional incentives for specific energy efficiency and conservation programs; and variable interest on debt recovery. Although these mechanisms are not currently in use, they are included here to ensure a comprehensive overview of Nevada's existing alternative ratemaking mechanisms.

Authority to Implement Decoupling

Decoupling is similar to but more flexible than lost revenue adjustment mechanisms. Decoupling may also be more symmetrical in its application if implemented correctly. A decoupling mechanism addresses utility revenue impacts arising from successful efficiency, conservation and distributed energy resource programs and thus mitigates the utility's disincentive to support these programs. Decoupling directly affects just and reasonable rates, as well as advances public policy goals.

Based on prior PUCN decisions, it appears that there is sufficient authority in the statutes to permit the electric utilities in Nevada to seek authority to use a different mechanism to recover the financial disincentives resulting from implementation of energy efficiency and conservation programs. In 2012, the PUCN evaluated whether the LRAM was an effective tool for eliminating NV Energy's financial disincentives associated with implementing DSM programs. The Interim Report issued in Docket No. 12-12030 stated that there was general agreement among the participants that the LRAM was not the preferred method to eliminate NV Energy's financial disincentive. As such, the PUCN considered alternatives to it. Ultimately, the PUCN concluded that decoupling, whether full or partial, was within the authority already granted to the PUCN via statute. While NRS 704.785 has been modified by SB 150 in 2017 since the Interim Report was issued by the PUCN in Docket No. 12-12030, it appears the statute may still provide sufficient authority for decoupling to be implemented. NRS 704.785(1)(b) provides that the PUCN may:

[108] NAC 704.9453(6)(b).

[109] Consolidated Docket Nos. 17-06003 and 17-06004, Modified Final Order, at ¶ 201 (Dec. 19, 2018).

> [If it] determines that it will serve the public interest by removing financial disincentives which discourage an electric utility from implementing or promoting the participation of the customers of the electric utility in energy efficiency and conservation programs, include a rate adjustment mechanism to ensure that the revenue per customer authorized in a general rate application is recovered without regard to the difference in the quantity of electricity actually sold by the electric utility subsequent to the date on which the rates take effect. A rate adjustment mechanism adopted pursuant to this paragraph may apply to one or more rate classes.

The stakeholders may want to consider decoupling as an option when evaluating the toolbox of existing regulatory mechanisms available to electric utilities in Nevada.

Imputed Debt for Renewable PPAs and Energy Efficiency Contracts

Providing a mechanism for a utility to mitigate the impact of imputed debt on the capital structure of the utility alleviates some of the risk of these contracts for the utility. As a result, the utility may be more inclined to enter into these contracts, thus supporting the reliability and efficiency of the system, as well as state policy goals calling for efficiency and additional renewable energy.

Nevada statute requires the PUCN to adopt regulations that establish methods to classify the financial impact of each long-term renewable energy contract and energy efficiency contracts as additional imputed debt of a utility. Nevada's regulations permit a utility, for a long-term portfolio energy credits contract, long-term renewable energy contract, or efficiency contract for a term of more than 3 years, to request that the PUCN approve mitigation for the impact of imputed debt on the capital structure of the utility.[110]

If a utility wishes to submit such a request to the PUCN, it must include the request in the IRP that includes the contract that is submitted to the PUCN for approval. The utility's request must include: its estimate of the amount of the impact of imputed debt on the capital structure, measured as a percentage of the net present value of the capacity payments over the life of the contract; propose the percentage of the value of the contract payment to be assumed as a capacity payment, if the capacity of the system or measure is not specified in the contract; and may propose an amount to be added to the cost of the contract equal to a compensating component in the capital structure of the utility provider. The request shall include information to illustrate the financial impact from any imputed debt cost and any assumptions used to develop related imputed debt calculations.[111]

In evaluating a utility's request, the PUCN must consider: the effect that the proposal will have on rates; and the recovery of costs equal to a compensating component in the capital structure during the utility's next rate case. If the PUCN approves such a request, it will set forth the impact of the imputed debt on the capital structure as a percentage of the net present value of the capacity payments over the life of the contract. The costs, if any, that the PUCN determines necessary to mitigate the imputed debt, will be

[110] NRS 704.7821(7)(b) and NAC 704.88875.

[111] *Id.*

collected with other contract costs as a component of the base tariff energy rate; the utility will segregate imputed debt revenues from deferred energy revenues and record such revenues as general rate revenues in general rate cases.[112]

Additional Incentives for Specific Energy Efficiency and Conservation Programs

Energy efficiency and conservation programs are not always welcome by utilities because they reduce sales, and as a result, reduce revenues for the utilities. Providing additional incentives for these programs can align a utility's interest with a policy goal of increasing energy efficiency, which can provide numerous benefits to the system and ratepayers. This mechanism supports customer engagement and satisfaction, as well as state policy goals.

Nevada regulations provide an additional incentive for utilities related to the implementation of energy efficiency and conservation programs. Specifically, the utility, another intervening party, or the PUCN upon its own motion, may request, and the PUCN may authorize, that the amount recovered for energy efficiency and conservation programs include financial incentives to support the promotion of customer participation in energy efficiency or conservation programs. These requests must be made on a program-by-program basis. The PUCN will consider the effect of any recovery of costs for these programs on customer rates.[113] This provision applies to programs included in and approved by the PUCN in the utility's demand side plan as filed in the IRP.

Variable Interest on Debt Recovery

Utilities that recover fuel costs through an annual rate adjustment or deferred energy application may wish to recover their variable interest expense or dividends. This mechanism shields utilities from a change in the interest rate used to calculate revenue in a general rate case and thus supports just and reasonable rates by capturing the more immediate utility costs of doing business.

Utilities that recover fuel costs through either an annual rate adjustment or a deferred energy application may seek to recover deferred variable interest expense or dividends and to update the level of variable interest expense or dividends included in rates within 45 days after the end of the utility's test period or concurrent with its annual rate adjustment application.[114] The purpose of this mechanism is to shield the utilities from changes to variable interest rates between rate cases, where interest expense is calculated and included in revenue requirement. In other words, if interest rates go up, the utilities have a means to recover these increased interest rates between rate cases. It should be noted that this is a balanced

[112] *Id.*

[113] NAC 704.95225.

[114] NAC 704.210-222 and NRS 704.324.

mechanism – if interest rates go down, ratepayers will benefit.

To take advantage of this mechanism, the utility must file an application based on formulas set forth in PUCN regulations, which include: a request for approval; a calculation of the weighted average variable interest or dividend rate; a calculation of the net change in the base tariff general rate resulting from changed in the weighted average variable interest or dividend rate; and a calculation of the net change in the base tariff general rate resulting from change in the accumulation of deferred interest. A utility seeking recovery of variable interest expense or dividends must compute a carrying charge on the average monthly debit or credit balance in the appropriate accounts. Any changes in rates authorized pursuant to a utility's request are effective at the same time as a change in rates resulting from a general rate case, an annual rate adjustment, a deferred energy accounting adjustment or on an effective date authorized by the PUCN.

Section IV: A Structured Approach to Regulatory Assessment

As outlined in Concept Paper 1, the stakeholder engagement phase of this proceeding is expected to include four rounds of stakeholder discussion and comments. In the first round, stakeholders were asked to examine and refine a set of working goals and outcomes to guide the discussions of alternative ratemaking throughout this process.

Round two, the current stage, is focused on reviewing and generating a common understanding of the existing regulatory framework in Nevada and extracting insights about how well individual mechanisms within this framework incent, disincent or are neutral toward the achievement of individual outcomes. This process will help stakeholders evaluate the performance of existing Nevada regulations and help build a shared understanding between stakeholders of what opportunities may exist for alternative ratemaking to improve outcomes.

To efficiently solicit robust stakeholder feedback, RMI and RAP encourage stakeholders to use an Assessment Template in their next round of written comments (provided in Appendix B).[115] This Assessment Template provides a common format for stakeholders to conduct individual assessments of Nevada's existing regulations in relation to specific outcomes. These assessments will provide a foundation for stakeholders to share their views around how selected mechanisms impact different outcomes, and help to disentangle interactions between mechanisms and outcomes. The Assessment Template also encourages parties to include quantitative data as a reference point or highlight where more information may be needed. In addition, use of the Assessment Template in stakeholders' filed comments will also provide a common structure through which other stakeholders and the PUCN can more easily review input provided — additional accompanying discussion is welcomed and encouraged, but completed templates will serve as a valuable format for input on key regulatory mechanisms.

[115] This template is adapted from a worksheet that the Hawaii Public Utilities Commission utilized to solicit party feedback in its Proceeding to Investigate Performance-Based Regulation (Docket No. 2018-0088): *Assessing the Existing Regulatory Framework in Hawaii*; Hawaii Public Utilities Commission; September 18, 2018.

Assessment Template Overview and Instructions

The following example and step-by-step instructions are provided to demonstrate how stakeholders can use the Assessment Template to conduct their review of existing mechanisms and provide feedback in their comments.

Step 1: Choose an Outcome. The Assessment Template is designed to be applied to one outcome at a time. Accordingly, it requires stakeholders to first select an outcome to evaluate. After choosing an outcome, stakeholders should provide a short description and indicate the associated goal. For example, if "innovative services and options that customers value are introduced" is the outcome chosen, a stakeholder might begin to populate the Assessment Template as follows:

OUTCOME: Innovative services and options that customers value are introduced.
GOAL: Enrich Customer Engagement and Satisfaction

Description: This outcome seeks to ensure that customers of the utility are offered services and options that are innovative and have value. Increasingly, utility customers are interested in have options or services available to them that are different from and in addition to the standard rate offerings. Activities associated with this outcome might include special contract rates or new rate structures.

Step 2: Evaluate Each Mechanism's Effect on Chosen Outcome. The Assessment Template is structured as a table with existing regulatory mechanisms in the left-most column. Once an outcome is selected, stakeholders are asked to provide a "score" to indicate whether each regulatory mechanism, on balance incents, disincents or has no impact upon achievement of the outcome. Simple scoring is encouraged using marks of '+' for incents achievement, '-' for disincents achievement, and '0' for no (or negligible) impact. A cell for "Discussion" in each row provides a space for stakeholders to explain their scoring for the mechanism. Stakeholders are also encouraged to highlight additional "Issues for Attention," including possible interplay or tensions between mechanisms.

Continuing the example assessment for the outcome "innovative services and options that customers value are introduced", a stakeholder might populate the Assessment Template as follows:

Existing Regulatory Mechanisms	Description	Mechanisms' Effect on Outcome		Issues for Attention
		Score (+/0/-)	Discussion	
General Rate Case using Historical Test Year (with certification and/or ECIC)	Recorded results of revenues, expenses, investments and costs of capital for most recent 12 months for which data is available, with potential to update using certification and ECIC for an additional 12 months after the end of the test year.	+ and -	While new rate structures or rate classes may be offered in a general rate case, traditional cost-of-service, rate-of-return regulation may hinder participant interest in innovative rate classes or structures.	Consider that innovative services and options for customers may cause tension in terms of traditional regulatory practices. For example, innovative rate classes may not always be supported by traditional cost-of-service studies.
Special Tariff/Energy Supply Agreements	Provides the ability to structure alternative tariffs for specifically qualified customer classes that provide opportunities for rate stability and furtherance of customer “green” initiatives.	+	The flexibility provided by special tariffs or energy supply agreements for certain customers or customer classes support new options (and potentially new innovative options) for customers.	
Earnings Sharing Mechanism (ESM)	Asymmetrical earnings sharing allows the utility to keep a portion of earnings above an established ROE deadband and share the remainder to customers.	0	The ESM has no direct impact on this outcome	N/A
Integrated Resource Plan	20-year plan to increase an electric utilities' supply of electricity or decrease the demands made on its system by its customers. A 3-year action plan is	+	The utility may be able to include in its action plan, such as in the distributed resource plan, innovative means to address distributed generation	

	filed with the PUCN for acceptance, rejection or modification.		brought to the utility system by customer generators.	
[Other mechanisms can be added here as warranted]				

Stakeholders are not required to assess each mechanism listed in the Assessment Template in Appendix B. Rather, the 10 mechanisms listed in the template are provided as an initial set of representative mechanisms that RMI, RAP and the PUCN believe would be helpful for stakeholders to evaluate. However, stakeholders are free to evaluate any of the mechanisms discussed in this paper (see Table 1 in Section I for a summary list) or other relevant regulatory mechanisms that exist in Nevada that are not included in this paper.

Step 3: Assess Overall Regulatory Framework's Impact on Chosen Outcome. The Assessment Template next asks stakeholders to make a qualitative judgment of whether the existing regulatory framework sufficiently supports the overall achievement of the outcome being evaluated. Stakeholders can derive their conclusions from their assessments of individual mechanisms in Step 2; however, the overall assessment of outcome achievement is meant to be a more generalized assessment of the Nevada regulations' total support for the outcome. Additional considerations or observations not captured in Step 2 can be included in the "Discussion" field.

Overall, does the existing regulatory framework sufficiently support the achievement of this outcome?			**Discussion (Conclusions/Recommendations/Observations)**
+	**YES.** Incents achievement		NV Energy tracks participation in its existing rate classes, including rate classes related to time of use and electric vehicle charging. Some of this data might indicate whether innovative tariff options for certain customer classes will or will not be successful.
0	**NO IMPACT.**		
-	**NO.** Disincents achievement		

Step 4: Provide Supporting Data. As a final step, the Assessment Template asks stakeholders to include

any relevant quantitative data or other pertinent information to support their qualitative statements in the previous steps. This could include financial trends from utility reports or filings, recent PUCN dockets or industry benchmarks. For example, for the "innovative services and options that customers value are introduced" outcome, stakeholders could populate these fields as follows:

What supporting data or information from utility reporting, PUCN proceedings or other sources can help support the conclusions made in the prior worksheets?	
Existing Data or Measurements (e.g. recent financial or operational trends, industry benchmarks, etc.)	Adoption or participation rates in existing, optional rate classes.
Other Pertinent Information	N/A

Section V: Next Steps

Workshop 2 is scheduled to occur on July 23-24, 2020. This second workshop will provide an opportunity for structured dialogue on the mechanisms summarized in this concept paper and their influence on identified outcomes.

Stakeholders planning to participate in Workshop 2 are encouraged to contemplate the Assessment Template provided in Appendix B, as it is intended to provide a common structure for discussion. Consistent with this template, participants may want to consider the following questions in relation to each <u>mechanism</u> and <u>outcome</u> of interest discussed thus far in this process:

Please define, in specific terms, the outcome(s) of interest that you would like to evaluate against existing Nevada regulatory mechanisms.

- Please define, in specific terms, the outcome(s) of interest that you would like to evaluate against existing Nevada regulatory mechanisms.

- To what extent do individual existing regulatory mechanisms in Nevada incent, disincent or have no impact on each outcome?

- Overall, does Nevada's existing regulatory framework sufficiently support the achievement of each outcome?

- What additional information or context should be considered when evaluating the impact of individual mechanisms or the Nevada regulatory framework on each outcome?

Following Workshop 2, a comment period will provide stakeholders with the opportunity to provide written feedback on the mechanisms and issues included in this paper. In comments, stakeholders are encouraged to use the Assessment Template – which will be shared in Microsoft Word format following the workshop – to evaluate the impact of existing Nevada regulatory mechanisms on outcomes of interest. In addition, stakeholders are invited to provide further input on the topics discussed in this concept paper, including further discussion of identified mechanisms and input on their respective qualities or shortcomings in Nevada utility regulations. Stakeholders are also encouraged to provide any further input or reflections on the working set of outcomes that will be shared with parties ahead of the workshop.

Ultimately, stakeholder input in this round will be used to inform the next round of discussion in this process – which will focus on identifying and characterizing alternative ratemaking mechanisms that are consistent with SB 300 and applicable for furthering the working goals and outcomes. As with previous rounds, a concept paper – Concept Paper 3 – will provide framing and details around key alternative ratemaking mechanisms to serve as a foundation for discussion during Workshop 3. Dialogue in that round will also address how certain alternative ratemaking mechanisms can be connected to specific activities and metrics. A comment round after Workshop 3 will provide stakeholders an opportunity to state written preferences for various alternative ratemaking mechanisms and introduce or refine related activities and metrics.

Glossary

Adjustment clause: A rate adjustment mechanism implemented on a recurring and ongoing basis to recover changes in expenses or capital expenditures that occur between rate cases.

Advanced Metering Infrastructure (AMI): The combination of smart meters, communication systems, system control and data acquisition systems, and meter data management systems that together allow for metering of customer energy usage with high temporal granularity; the communication of that information to the utility and, optionally, to the customer; and the potential for direct end-use control in response to real-time cost variations and system reliability conditions. AMI is an integral part of the smart grid concept.

Allowance for Funds Used During Construction (AFUDC): Capital usually does not accumulate financing costs until the facility becomes used and useful and is added to rate base. AFUDC is a regulatory accounting treatment that allows financing cost to be recognized during construction but prior to an asset becoming used and useful. The AFUDC rate is the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Ancillary service: One of a set of services offered and demanded by system operators, utilities and, in some cases, customers, generally addressing system reliability and operational requirements. Ancillary services include such items as voltage control and support, reactive power, harmonic control, frequency control, spinning reserves and standby power. The Federal Energy Regulatory Commission defines ancillary services as those services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

Base Tariff Energy Rate (BTER): The BTER is a flat kilowatt-hour (kWh) charge that is set based on the 12-month rolling total of energy and purchased power costs.

Capacity: The ability to generate, transport, process or utilize power. Capacity is measured in watts, usually expressed as kilowatts (1,000 watts), megawatts (1,000 kilowatts) or gigawatts (1,000 megawatts). Generators have rated capacities that describe the output of the generator when operated at its maximum output at a standard ambient air temperature and altitude.

Connection charge: An amount to be paid by a customer to the utility, in a lump sum or installments, for connecting the customer's facilities to the supplier's facilities.

Construction Work in Progress (CWIP): The account that includes the total of the balances of work orders for work in progress of construction. This line item may or may not be included in the utility's rate base.

Cost allocation: Division of a utility's revenue requirement among its customer classes. Cost allocation is an integral part of a utility's cost of service study.

Cost of service: Regulators use a cost-of-service approach to determine a fair price for electric service, by which the aggregate costs for providing each class of service (residential, commercial and industrial) are determined. Prices are set to recover those costs, plus a reasonable return on the invested capital portion of those costs.

Cost of service study: An analysis performed in the context of a rate case that allocates a utility's allowed costs to provide service among its various customer classes. The total cost allocated to a given class represents the costs that class would pay to produce an equal rate of return to other classes. Regulators frequently exercise judgment to adopt rates that vary from study result.

Customer class: A collection of customers sharing common usage or interconnection characteristics. Customer classes may include residential, multi-family residential, small commercial, large commercial, small industrial, large industrial, agriculture (primarily irrigation pumping), mining and municipal lighting (streetlights and traffic signals). All customers within a class are typically charged the same rates, although some classes may be broken down into subclasses based on the nature of their loads, the capacity of their interconnection (e.g., the size of commercial or residential service panel) or the voltage at which they receive service. Specific tariffs reflect specific terms of service and pricing for customer classes. For example, large customer classes include tariffs identified as Large General Service (e.g., LGS-1 and LGS-2) and standard residential customer classes include tariffs identified as Residential Service (e.g., RS).

Decoupling: Decoupling fixes the amount of revenue to be collected and allows the price charged to float up or down between rate cases to compensate for variations in sales volume in order to maintain the set revenue level. The target revenue is sometimes allowed to increase between rate cases on the basis of an annual review of costs or a fixed inflator, or on the basis of the number of customers served. The latter approach is sometimes known as revenue-per-customer decoupling. The purpose is to allow utilities to recover allowed costs, independent of sales volumes, without under- or over-collection over time.

Deferred Energy Accounting Adjustment (DEAA): Recovers the difference between the costs collected through the BTER and the actual cost of fuel and purchased power as experienced by the electric utility.

Demand charge: A charge paid on the basis of metered demand typically for the highest hour or 15-minute interval during a billing period. Demand charges are usually expressed in dollars per watt units, such as kilowatts. Demand charges are common for large (and sometimes small) commercial and industrial customers but have not typically been used for residential customers because of the very high diversity among individual customers' usage. The widespread deployment of smart meters in NPC and SPPC service territories would enable the use of demand charges or time-of-use rates for any customer served by those meters.

Demand response: Reduction in energy use in response to either system reliability concerns or increased prices (where wholesale markets are involved) or generation costs (in the case of vertically integrated utilities). Demand response generally must be measurable and controllable to be relied upon by a utility.

Demand Side Management (DSM): Demand-side management (DSM) programs consist of the planning, implementing, and monitoring activities of electric utilities which are designed to encourage consumers to modify their level and pattern of electricity usage.

Distributed Energy Resource (DER): Any resource or activity at or near customer loads that generates energy, reduces consumption or otherwise manages energy on-site. Distributed energy resources include customer-sited generation, such as solar photovoltaic systems and energy storage.

Distributed generation: Any electricity generator located at or near customer loads. Distributed generation usually refers to customer-sited generation, such as solar photovoltaic systems.

Distributed Resource Plan (DRP): A process of planning to meet anticipated distribution system needs as customers use a growing variety of distributed energy resources. A portion of this may be adaptation to variable renewable energy, and a portion may be the use of DERs to mitigate congestion in the distribution system through demand response or dispatch of DERs.

Embedded cost of service study: A cost allocation study that apportions the actual historic test year costs among customer classes, typically using customer usage patterns in a single year-long period to divide up the costs.

Energy efficiency: The deployment of end-use appliances that achieve the same or greater end-use value while reducing the energy required to achieve that result. Higher-efficiency boilers and air conditioners, increased building insulation, more efficient lighting and higher energy-rated windows are all examples of energy efficiency. Energy efficiency implies a semi-permanent, longer-term reduction in the use of energy by the customer, contrasted with behavioral programs that may influence short-term usage habits. Because energy efficiency reduces the need for generation, transmission and distribution, these costs are properly allocated using the methods applied to all three functions.

Greenhouse Gases (GHG): Those gases, such as water vapor, carbon dioxide, nitrous oxide, methane, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride, that are transparent to solar (short-wave) radiation but opaque to long-wave (infrared) radiation, thus preventing long-wave radiant energy from leaving Earth's atmosphere. The net effect is a trapping of absorbed radiation and a tendency to warm the planet's surface.

Incremental cost: The short-run cost of augmenting an existing system. An incremental cost study rests on the theory that prices should reflect the cost of producing the next unit of energy or deployment of the next unit of capacity in the form of generation, transmission or distribution.

Integrated Resource Plan (IRP): A long-term plan prepared by a utility to guide future energy efficiency, generation, transmission, and distribution investments.

Independent power producer: A power plant that is owned by an entity other than an electric utility. May also be referred to as a non-utility generator.

Investor-Owned Utility (IOU): A privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized an opportunity to achieve an allowed rate of return.

Load: The combined demand for electricity placed on the system. The term is sometimes used in a generalized sense to simply denote the aggregate of customer energy usage on the system, or in a more specific sense to denote the customer demand at a specific point in time.

Load factor: The ratio of average load of a customer, customer class or system to peak load during a specific period of time, expressed as a percentage.

Load following: The process of matching variations in load over time by increasing or decreasing generation supply or, conversely, decreasing or increasing loads. One or more generating units or demand response resources will be designated as the load following resources at any given time. Baseload and intermediate generation are generally excluded from this category except in extraordinary circumstances.

Load shape: The distribution of usage across the hour, day and year, reflecting the amount of power used.

Marginal cost of service study: A cost allocation study that apportions costs among customer classes using estimates of how costs change over time in response to changes in customer usage.

Net Energy Metering/Net Metering (NEM): A rate design that allows a customer who has distributed generation, typically solar photovoltaic systems, to receive a bill credit at a retail rate for energy injected into the electric system.

NV GreenEnergy Rider (NGR): A supplemental rate charge applied to customers who choose to consume electricity with a renewable content of 50 percent or 100 percent.

Peak demand: The maximum demand by a single customer, a group of customers located on a particular portion of the electric system, all of the customers in a class or all of a utility's customers during a specific period of time — hour, day, month, season or year.

Performance-Based Regulation (PBR): An approach to determining the utility revenue requirement that departs from the classical formula of rate base, rate of return, and operation and maintenance expense. It is designed to encourage improved performance by utilities on cost control or other regulatory goals.

Power purchase agreement: A contract between a utility and an independent power producer or third-party energy service company to provide energy, capacity or ancillary services.

Ratepayer Impact Measure (RIM): A test of energy efficiency cost-effectiveness that measures the impact of increased energy efficiency on prices. It is used to determine whether all utility consumers, including non-participants (i.e., the customers not deploying the energy efficiency), will receive lower rates as a result of implementing an efficiency measure.

Renewable Portfolio Standard (RPS): A requirement established by a state legislature or regulator that each electric utility subject to its jurisdiction obtain a specified portion of its electricity from a specified set of resources, usually renewable energy resources but sometimes including energy efficiency or other categories. The RPS is called the Portfolio Standard in Nevada.

Resiliency: The ability to prepare and plan for, absorb, recover from, or more successfully adapt to actual or potential adverse events.

Retail competition/retail choice: A restructured market in which customers are allowed to or must choose their own competitive supplier of generation and transmission services. In most states with retail choice, the incumbent utility or some other identified entity is designated as a default service provider for customers who do not choose another supplier.

Return on equity (ROE): The amount the utility must pay an equity investor in order to use the investor's money, just as interest on debt represents the cost of borrowing from a bond investor. In rate cases, the PUCN sets a specified percentage as an ROE, which represents an allowed amount that that utility is permitted, but not guaranteed, to recover to fairly compensate investors for their capital investment in the utility.

Revenue requirement: The annual revenues that the utility is authorized to have the opportunity to collect. It is the sum of operations and maintenance expenses, depreciation, taxes and a return on rate base. In most contexts, "revenue requirement" and "cost of service" are synonymous.

Rider/tariff rider: A special tariff provision that collects a specified cost or refunds a specific consumer credit, usually over a limited period. In Nevada, an example would be the renewable energy program rate to collect costs related to clean energy incentives.

Societal Cost Test: A measure of energy efficiency cost-effectiveness that considers all costs and all benefits of a measure, regardless of who pays or who benefits. This is the broadest cost test, and includes utility, customer, and third-party payments, energy benefits, non-energy economic benefits, plus societal benefits such as public health, economic development, and energy security.

Temporary Renewable Energy Development (TRED) program: Program meant to ensure prompt payment to renewable energy providers to encourage completion of projects. A "TRED" charge is collected from electricity customers as a separate line item on their bill, and this charge is determined annually in the DEAA application.

Time-of-Use rates/time-varying rates (TOU): Rates that vary by time of day and day of the week. TOU rates are intended to reflect differences in underlying costs incurred to provide service at different times of the day or week. They may include all costs or reflect only time differentiation in a component of costs such as energy charges or demand charges.

Total Resource Cost Test: A measure of energy efficiency cost-effectiveness that considers all resource-related costs and resource-related benefits of the measure. This is a broad test that includes costs paid by utilities, consumers and third parties, and considers savings in all resource areas, including electricity, other fuels, labor and comfort.

Tracker: A rate schedule provision giving the utility company the ability to change its rates at different points in time to recognize changes in specific cost-of-service items without the usual rate case filing. Costs included in a tracker are sometimes excluded from cost-of-service studies. In Nevada, an example of a tracker would be the variable interest adjustment.

Utility Cost Test: An approach to measuring energy efficiency cost-effectiveness by measuring whether the utility revenue requirement increases or decreases as a result of the deployment of the efficiency measure. This is a narrow test, ignoring costs paid by consumers or third parties toward the measures, and also ignoring non-electricity benefits derived from the measures. **Vertically integrated utility:** A utility that owns its own generating plants (or procures power to serve all customers), transmission system and distribution lines, providing all aspects of electric service.

Appendix A: Utility Regulatory Basics

History and Purpose of Utility Regulation

Utilities are "natural monopolies," and, like other monopolies, they have the power to restrict output and set prices at levels higher than are economically justified.[116] Given these two conditions, economic regulation is needed to achieve public benefits that a monopoly market fails to achieve on its own.

A feature of the electric industry that led to the natural monopoly structure was the sheer size of the investment needed (in the billions of dollars) to build out generation, transmission, and distribution infrastructure to provide safe, reliable and affordable service across the country. There are economies of scale gained by having a single entity undertake this large investment. In addition, such an investment would have been a risky one for firms to take under the threat of competition. All of these forces contributed to the need to develop a regulatory structure that could ensure these critical investments would be made while protecting ratepayers. Regulation takes a special interest in assuring that the utility can recover its costs and earn a sufficient return on equity (ROE) to make it possible to attract the necessary capital to provide this essential service at affordable rates.

The structure of regulation of utilities has evolved over more than a century. Throughout the 19th century, legislative, judicial and regulatory actions moved to regulate the rates and terms of service for grain elevators, warehouses, canals, and eventually railroads and trucking. Over time, some historically regulated industries have been partially or fully deregulated as competitive forces replaced the need for regulation. For example, today, state and federal economic regulation of transportation has mostly ended as it is perceived that competition successfully exists in most aspects of the industry. In some states, certain aspects of the electricity sector have been deregulated as well, especially in the area of electric generation ownership. The first state regulation of electric utilities emerged in roughly 1900, and cost-of-service (COS) regulation (as discussed in this paper) evolved over the 20th century to look like what is broadly used today.

For most of its history, the electric utility industry has seen little change in the economic and physical operating characteristics of the electric system. Large central station generating plants connected to high-voltage transmission delivered power to local distribution grids for delivery to end uses, mostly by vertically integrated utilities that owned all of these components. This regulatory system successfully achieved its original policy goals which were to expand access to reliable, generally affordable and non-discriminatory electricity service across the country and make it available at all times of the day and night. As mentioned, accomplishing this goal required a significant investment over roughly a century, and regulation took a particular interest in ensuring that this investment occurred thoughtfully. The questions

[116] This appendix draws heavily from the following RAP publication. Readers interested in more information about the basics of utility regulation, including how consumer-owned utilities operate, are encouraged to see Lazar, J. (2016). Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge- center/electricityregulation-in-the-us-a-guide-2.

that many state regulators, policymakers, utilities and stakeholders are asking today are whether these policy goals are still relevant, whether other important policy goals should be considered, and whether the existing regulatory system is capable of achieving emerging goals.

Roles and Obligations of Utilities, Regulators, and Customers

Regulation imposes various obligations on utilities intended to protect the "public interest."

Investor-owned utilities (IOUs) are subject to a variety of obligations described above in the introductory section of this paper. These obligations arise through various statutes and regulatory decisions. In addition, many states require utilities to meet various environmental, economic, and social objectives imposed on them through policy and regulation. For example, because the production and distribution of electricity can have environmental and public health impacts, regulators impose environmental responsibilities on utilities to protect various public interests.

As discussed below, utility commissions determine how much revenue a utility should bring in and establish the prices or rates for each class of customers, a process that endeavors to protect customers from what might otherwise be monopoly pricing. The existing regulatory process thus ensures that customers generally have fair, affordable, and predictable electricity rates.

Utility commissions have other authority that can be used to the benefit of customers. For example, once an infrastructure project (such as a power plant) is completed, utility commissions may conduct a prudence review to determine if it has been constructed or implemented as proposed, at reasonable cost and with reasonable care. This process can ensure that customers are not unfairly charged for utility costs.

Utility commissions also adopt standards for service quality and sometimes adopt metrics to measure this, such as frequency and duration of outages. These commissions also put in place regulations governing the terms on which service is offered, such as the charges that utilities can apply when lines are extended and the circumstances when a customer can be disconnected for nonpayment.

Regulators also are usually broadly empowered to regulate in the "public interest," which may include some aspects of environmental regulation, economic goals or reliability.

In exchange for these benefits, customers are obligated to pay the regulator-approved rate for electricity service and may be subject to disconnection – according to commission-adopted rules and procedures – if they fail to do so. But utility customers' obligations also include compensating the utility for the investment that it has made in creating the electric system infrastructure that we have today. What is sometimes referred to as the "regulatory compact" states that utilities will recover from ratepayers the costs incurred for prudent investments. This has implications for customers that wish to "leave" the system, either by installing distributed generation (e.g. solar or storage) or choosing to purchase power from another supplier. Such customers have an obligation to pay for their share of the existing system and they should be compensated for services they provide that benefit all customers.

Cost of Service Basics

Vertically integrated utilities like NPC and SPPC are responsible for generation, transmission and distribution of power to retail customers. They may own some or all of their power plants or buy power through contracts from others, called power purchase agreements or PPAs. Most vertically integrated utilities use a combination of owned resources, contracted resources, and short-term purchases to meet their customer demands. These utilities manage transmission and distribution services, a customer service system, and a portfolio of generators and other resources. In addition, they execute other public interest responsibilities, such as managing customer access for those struggling to pay for service.

The reasonable costs for these services are calculated and spread over all the units sold (kilowatt-hours) and all customers in time-tested methods of cost allocation. This is commonly referred to as a *cost-of-service (COS) approach* to determining a fair price for electric service, by which the aggregate costs for providing each class of service (residential, commercial, and industrial) are determined. Prices are set to recover those costs, plus a reasonable return on the invested capital portion of those costs, and allocated based on the sales made to each class.

The utility must routinely raise significant capital to invest throughout the system. It issues debt— and in the case of investor-owned utilities, it issues stock, which is more expensive. Stockholders own the utility's equity, while debtholders have first call on the value of assets in the event the utility is liquidated. The outcome of this capital flow, continuing reinvestment in, and reliable operation of critical facilities is so important to society that regulation by utility commissions takes a special interest in assuring that the utility earns a sufficient return on equity and builds it into the cost of service.

From this allowed return set by the commission, the utility pays dividends to shareholders and reinvests in the company. This regulatory model has historically been successful at driving investment in the electric system. It has also created a number of incentives for utilities, including a strong incentive to invest in capital (also called "rate base").

Traditional utility regulation is sometimes said to operate in a "cost plus" environment, that is, in its rates and charges, the utility recovers its costs *plus* it earns a regulated return on its capital. Note that performance against specific goals is not a factor in either utility revenue or utility profits under this model.

Rather, the traditional "cost plus" regulatory model that has evolved over the past century aims to ensure that service is reliable, safe, and fairly priced.

Some note that because of the broad range of utility activities and costs, it is infeasible for regulators to oversee it all, and too easy for utilities to be inattentive to cost and quality control. Most states have experience with penalizing inferior performance. State commissions may not have an explicitly established performance system, but they have the tools they need to regulate and command improved performance when it is deficient. These tools include:

- Cost disallowance if an undepreciated asset is found to be no longer "used and useful" or for money spent with inadequate results or based on imprudent management.

- Reduction in the return on equity when the performance deficiency reflects badly on the utility as a whole.

- Fines, when there are identifiable violations, especially when there are many violations across a range of customers or events.

Basics of Regulating Utility Rates

Utility rates are meant to provide the utility an opportunity to recover prudently invested capital and a reasonable rate of return on that investment, and recovery of reasonable expenses. In other words, the utility's "revenue requirement" is the total amount of revenue the utility would need to cover its costs and earn a fair rate of return on its rate base investment. Thus, the first step to utility ratemaking is to determine the utility's costs for providing service to ratepayers. Utilities are most concerned with this element of rate cases because it affects their overall profit.

The basic formula for determining the revenue requirement is to multiply the amount of investment allowed in rate base by the allowed rate of return, and add to that the approved operating expenses (see Figure A-1). Operating expenses (such as salaries, employee benefits, taxes and depreciation) are directly passed through to customers without additional return for the utility.

Rate base (major capital expenditures, such as generation and transmission infrastructure) is traditionally the only element of the revenue requirement calculation that is allowed a return on investment, that is, the utility earns a profit on those expenditures. Thus, utilities have a profit-driven incentive to invest large amounts of capital in rate base because it is the only investment that gets a rate of return. The rate of return is recovered in rates each year until the investment is fully depreciated.

Figure A-1: Revenue Requirement Formula

The Basic Revenue Requirement Formula

Rate Base Investment (less Depreciation) + Operating Expenses
= Revenue Requirement

Utility rates that customers pay are designed to give the utility a reasonable opportunity to recover its revenue requirement through the sale of electricity services. In a utility rate case, regulators approve an authorized rate of return and revenue requirement, allocate those costs to classes of customers, and design specific tariffs per customer class. While a detailed discussion of rate design is outside the scope of this paper, it is worth mentioning that rates are generally designed to recover costs from each class of customers (residential, commercial, industrial) in proportion to how they cause costs to the system. Rates can also be designed to promote public policy objectives, such as conservation or optimal use of the power system to reduce costs. Looking forward to a world with higher levels of energy efficiency, distributed generation and customer options for managing their energy use, regulators are beginning to think about whether and how rate design needs to evolve.

Elements of Cost of Service Outside of Rate Cases

In all states, there are a number of mechanisms that allow for cost recovery outside of the general ratemaking process described above. Adjustment clauses change utility rates between rate cases to account for specific changes, such as changes to fuel prices, which to a large extent are outside utility control. This means that as prices fluctuate for the fuel utilities use to generate power (e.g. coal or natural gas), utilities pass these costs directly onto customers. Fuel adjustment clauses have evolved over time and have been criticized for removing any incentive utilities have to contain their fuel costs. For example, if utilities can pass on the costs of fuel, they have little incentive to keep power plants operating at peak efficiency.

Other adjustment clauses that are common include mechanisms that adjust revenue collected in between rate cases to compensate utilities for the disincentive they incur when providing energy efficiency and conservation programs for their customers. An example of such a clause is lost revenue or decoupling mechanism. Decoupling, for example, is designed to ensure that utilities recover their revenue requirement independent of their sales volumes. The goal is to make utilities' indifferent to sales volumes, which has the effect of removing disincentives to embrace energy efficiency or distributed generation, both of which decrease consumer usage and thus utility sales. The revenue requirement is determined in the same way as in a traditional rate case. Rates are adjusted periodically to ensure that the utility is collecting its revenue requirement (no more, no less).

Appendix B: Regulatory Assessment Template

Outcome:					
Goal:					
Description:					
Do the existing regulatory mechanisms sufficiently support the outcome?					
Key					
+	**Yes**	The mechanism incents achievement of this outcome			
0	**No Impact**	The mechanism does not seem to impact achievement of this outcome			
-	**No**	The mechanism disincentivizes achievement of this outcome			
Existing Regulatory Mechanisms	**Description**	**Mechanisms' Effect on Outcome**		**Issues for Attention**	
		Score (+/0/-)	**Discussion**		
General Rate Case using Historical Test Year (with certification and ECIC)	Recorded results of revenues, expenses, investments and costs of capital for most recent 12 months for which data is available, with potential to update using certification and ECIC for an additional 12 months after the end of the test year.				
Fuel and Purchase Power Cost Recovery	Provides for timely recovery of experienced fuel and purchase power costs adjusted on a quarterly basis.				

Lost Revenue Adjustment Mechanism	Recovery of financial disincentives which discourage an electric utility from implementing or promoting the participation of the customers of the electric utility in energy efficiency and conservation programs.			
Special Tariff/Energy Supply Agreements	Provides the ability to structure alternative tariffs for specifically qualified customer classes that provide opportunities for rate stability and furtherance of customer "green" initiatives.			
Earnings Sharing Mechanism	Asymmetrical earnings sharing allows the utility to keep a portion of earnings above an established ROE deadband and share the remainder to customers.			
Integrated Resource Plan	20-year plan to increase an electric utilities' supply of electricity or decrease the demands made on its system by its customers. A 3-year action plan is filed with the PUCN for acceptance, rejection or modification.			
Clean Energy Incentive Programs	Annual incentive programs including the low-income solar program, electric vehicle infrastructure program, residential and non-residential energy storage program, electric school bus program and solar incentives program.			
Renewable Portfolio Standard	Regulatory mandate to increase the share of electricity sales from renewable energy sources. Escalates from at least 22% in CY2020 to at least 50% in CY2030 and beyond.			

Regulatory Assets/Regulatory Liabilities	Allows for recovery of expenses from or assignment of financial benefits to ratepayers that may not otherwise be reflected in rates due to timing.			
Time-of-Use Rates	Incents customer behavior for certain activities such as EV charging or usage patterns via price signals.			
Other Mechanisms (if Relevant)				

Outcome:			Goal:
Overall, does the existing regulatory framework sufficiently support the achievement of this outcome?			
			Discussion (Conclusions/Recommendations/Observations)
+	**YES.** Incents achievement		
0	**NO IMPACT.**		
-	**NO.** Disincents achievement		

Outcome:	**Goal:**
What supporting data or information from utility reporting, PUCN proceedings or other sources can help support the conclusions made in the prior worksheets?	
Existing Data or Measurements (e.g. recent financial or operational trends, industry benchmarks, etc.)	
Other Pertinent Information	