UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

KEVIN E. SPRAGUE

EXHIBIT KES-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

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I. INTRODUCTION

Q. Mr. Sprague, would you please state your name and business address?

A. My name is Kevin E. Sprague. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities?

A. I am Vice President of Engineering for Unitil Service Corp., which is a subsidiary of Unitil Corporation ("Unitil") that provides managerial, financial, regulatory and engineering services to Unitil's principal utility subsidiaries, including Unitil Energy Systems, Inc. (hereinafter "UES" or the "Company"). In this capacity, I manage all of the Company's engineering functions, including electric engineering, gas engineering, computer-aided design and drafting, Geographic Information Systems ("GIS"), and management of utility-owned land and property.

Q. Please describe your business and educational background.

A. I have been employed by Unitil Service Corp. for approximately 25 years. I was originally hired as an Associate Engineer in the Electric Distribution Engineering group. I have held the positions of Engineer, Distribution Engineer, Manager of Distribution Engineering, Director of Engineering and now Vice President of Engineering. I accepted the Vice President of Engineering position in January of 2019. I hold a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute and a Master of Business Administration from the University of New Hampshire.

Q. Do you have any licenses that qualify you to speak to issues related to engineering?

A. Yes. I am a registered Professional Engineer in the State of New Hampshire and the Commonwealth of Massachusetts.

Q. Have you previously testified before the Commission, or other regulatory agencies?

A. Yes, I have testified on previous occasions before the New Hampshire Public Utilities Commission, the Maine Public Utilities Commission and the Massachusetts Department of Public Utilities. Most recently, I have testified in UES' Least Cost Integrated Resource Planning docket DE 20-002. I have also testified in several of UES' annual Reliability Enhancement Program ("REP") and Vegetation Management Program ("VMP") filings, and Grid Modernization related dockets. I also testified in the last base rate case filing by UES in docket DE 16-384.

Q. What is UES's overriding objective for the operation of its electric system?

A. The Company's primary objective is the provision of safe and reliable service for our customers in the most economical manner. We accomplish this objective, in part, with a rigorous annual planning and budgeting process with a focus on the reliability of our system. The costs of projects to improve or maintain reliability, including investment needed to replace aging electric infrastructure, affect other important objectives, such as the Company's efforts to minimize or mitigate electric rate increases to customers.

Q. What is the purpose of your testimony and how is it organized?

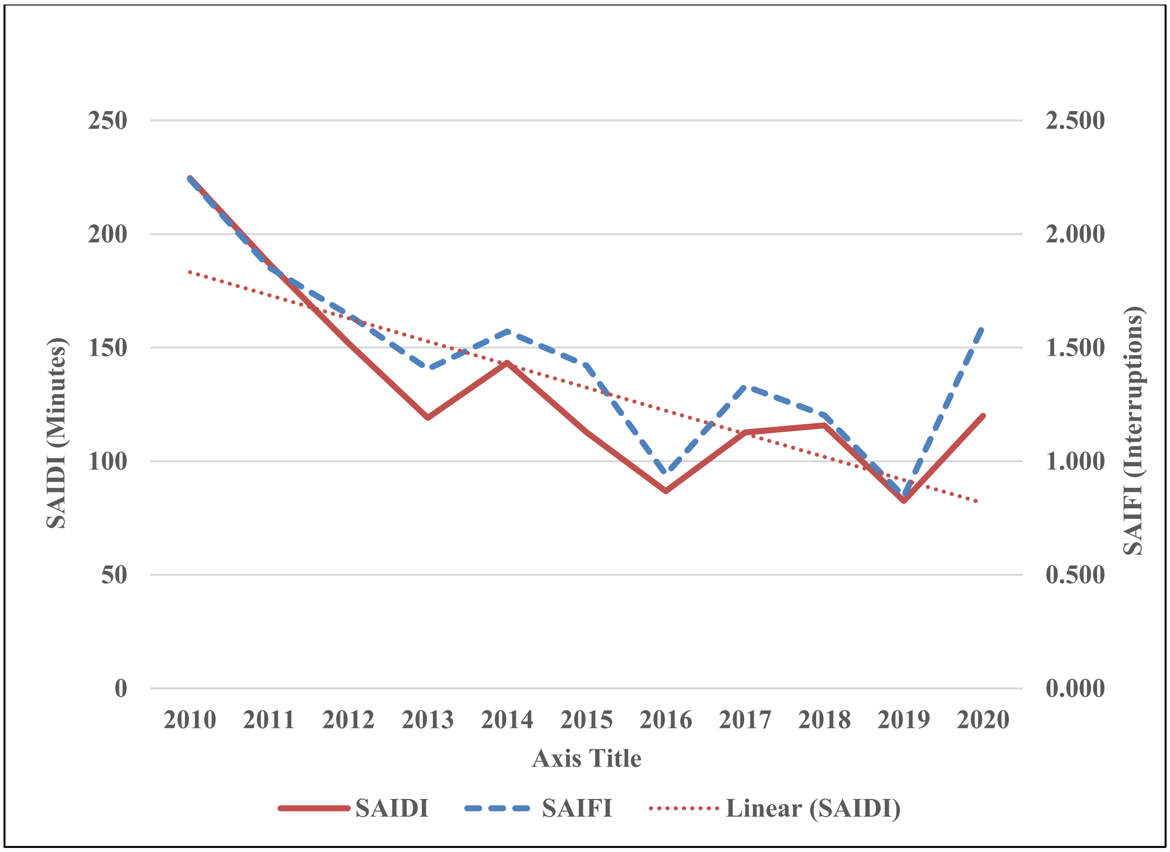
A. The purpose of my testimony is to describe the Company's annual planning and capital budgeting process and the positive effect this approach has had on the reliability of the electric system for our customers. My testimony begins with a description of the Company's reliability performance since the most recent base rate case. Section III describes the Company's approach to capital spending and investment planning including the planning and budgeting process, authorization and control of capital spending and the five year capital budget. This section also identifies several projects that require some additional explanation due to the associated amount of capital spending. Section IV describes the Company's proposed Grid Modernization Plan.

II. RELIABILITY PERFORMANCE

Q. Please describe the reliability performance of the Company?

A. The Company continues to implement an aggressive approach to reliability planning which includes daily, weekly, monthly and annual reliability analyses designed to address overall reliability performance. The Company's reliability performance has shown considerable performance since 2010. Since 2010 the Company's reliability has experienced significant improvement. This is in contrast to the worsening trend in reliability that was identified before the start of the REP program.

Chart 1. UES Reliability Performance



Q. Can you explain the apparent increase in System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") from 2019 to 2020?

A. The Company responded to an unusual number of storm events in 2020, including ten requiring activation of our Emergency Response Plan. The Company restored service quickly and effectively each time. The quick restoration resulted in fewer storm events reaching the exclusionary criteria. Following Tropical Storm Isaias in early August, the Company restored electric service to all customers in under 24 hours. The Company has provided mutual assistance to neighboring utilities eight times in 2020, the most ever in a single year. The Company recently won EEI's Emergency Response (Assistance) Award for the third time in four years.

Q. How does this performance compare to the industry?

A. The Company benchmarks its performance against other utilities. The current industry trend is a worsening reliability over the past several years. The Company's performance in 2020 is in line with the median of the industry. The Company continues to improve performance towards top quartile performance for the industry which tends to be historically be around the mid-80 minute range.

Q. There has been a lot of discussion about electrification in recent years. How will that change customer's view of reliability performance?

A. There has been a great deal of attention provided to decarbonization. The leading solution favors electrification of the heating and transportation sectors. An increase in electrification will make customers more reliant on their electric service for charging their cars and heating their homes. An increase in the number of people working from home also places a greater reliance on electric service. Customer satisfaction will be driven by reliability and the convenience of knowing that customers can rely on their electric company to provide reliable service.

Extended outages due to storm events and rolling blackouts like customers recently experienced in Texas cannot be tolerated in a world that has been electrified. Reliability and resilience will be key to customer satisfaction.

Q. Is the Company proposing to continue its approach to reliability?

A. The Company is proposing to continue to implement the same reliability based analysis and capital improvements as it has done for many years. In addition, some of the projects in the Company's Grid Modernization plan (discussed below) are designed to improve reliability performance.

Q. Is the Company proposing to continue the VMP program?

A. Yes. The testimony of Sara Sankowich describes the success of our vegetation management and storm resiliency programs and the proposal to continue these programs.

III. CAPITAL SPENDING AND INVESTMENT PLANNING

A. PLANNING AND BUDGETING PROCESS

Q. How does the Company plan for needed investments?

A. The annual planning process starts with engineering studies performed by the Company's engineering group. This includes: system studies (34.5kV off road distribution which is used to serve distribution substations and circuits) performed using load flow analysis; joint system planning with Eversource; circuit studies performed using circuit analysis software and protection studies; and area reliability studies. These studies are updated annually with the latest load forecasts at the circuit level and at the transmission level and are employed to identify both short term and long term needs. Engineering planning studies are the first and most important input into the capital planning process.

Q. Please describe the Joint Planning process between UES and Eversource.

A. The goal of the Joint System Planning between UES and Eversource is to develop the most cost effective alternatives for the combined UES and Eversource system. Absent this process, UES and Eversource customers may be subject to more expensive system enhancements due to duplication of facilities between UES and Eversource. This process is intended to promote coordinated planning efforts between UES and Eversource to develop a single "best for all" plan that potentially affects both companies. The objective is to provide a consistent approach for the planning of safe, reliable, cost effective, and efficient expansion and enhancements to each other's local area systems while meeting regulatory and contractual requirements.

By agreement, this process establishes a Joint Planning Committee of Eversource and UES representatives. This committee meets several times on an annual schedule to bring all parties together to coordinate each company's individual plans. The committee considers the application of consistent planning criteria using agreed upon system data; the total cost of planned additions, including internal costs of each utility; the reliability impact of planned additions and modifications; operational considerations, system losses, and maintenance costs; technical considerations for standardized designs and equipment; and the intent of the wholesale supply contract.

Q. Please describe the annual budget process and explain how needs are identified and prioritized as part of this process.

A. As described above, the engineering group identifies the need for system improvement and reliability projects. Operations personnel identify the need for condition replacements based on inspection and maintenance programs. Budgets are constructed using a “bottom up” process each year with input from dozens of employees from engineering, operations, information technology and facilities. Technical and managerial personnel with responsibility for planning, designing, operating and maintaining the electric delivery system are responsible for identifying needs and developing cost-effective solutions. A multistep process is used to budget hundreds of individual projects, and to then prioritize needs and determine which projects are essential to meet our objective of safe and reliable service for our customers. Projects are also proposed that may not be essential, but which represent an improvement or enhancement to existing systems or capabilities, including projects to improve reliability, replace old or obsolete equipment, and projects with a defined economic payback.

Q. How does the Company ensure projects are appropriately specified, estimated and prioritized?

A. In advance of the budget cycle each year, instructions are provided to all budget managers and other contributors that define expectations for the proper development and justification of projects. These instructions ensure that individual budget items are well defined, estimated and justified, and ensure accurate and consistent entry into the budget system. Comparative analysis of competing project costs is completed to identify the most economical solution. The goal of this process is to streamline the review and approval process. Specifically, each submitted project is expected to meet the following requirements:

- Each project must have a well-defined project scope, which fully describes the project and the extent of work to be undertaken.
- Each project must also have a detailed justification that describes the need for the project, including quantitative analysis where possible.

In general, only projects that are well-defined and appropriately justified are included in the budget. Project entries intended to be "place holders" for undefined plans or needs are not accepted. This allows management to efficiently and effectively review priorities and spending, and ensure an appropriate level of funding for important projects.

Q. Please describe how individual projects are categorized within the budget.

A. First of all, the UES capital budget is separated by operating location: UES Capital and UES Seacoast. This provides an additional level of detail used during the management review of the budget. In addition, each project is classified into one of seven categories, which include substation, distribution, annual requirements, transportation, structures and general equipment. Each category is further broken down into subcategories such as overhead extensions, underground extensions, street light projects, telephone company requests, line relocations (highway projects), and reliability projects. Blanket authorizations for annual requirements are broken down into subcategories for T&D improvements, new customer additions, outdoor lighting, emergency & storm restoration, billable work, transformers, meters, and water heater replacements.

Q. How are projects prioritized within the budget?

A. In addition to being appropriately categorized, and having a well-defined scope, justification and cost estimate, all projects in the capital budget are also assigned one of three priorities, defined as follows:

Priority 1: Essential for the Company to meet its service obligation to customers, including the provision of safe and reliable service. Included are projects to address critical constraints such as load and voltage where they jeopardize the Company's ability to distribute electricity, activities to restore service during following emergencies, and construction required to serve new customer load. All projects in this category are considered non-discretionary.

Priority 2: Includes projects that are essential for the Company to perform business activities in the required manner including regulatory or legal requirements, intercompany operating agreements, and supporting facilities, equipment, and vehicles. These projects and activities are also considered to be non-discretionary, though there may be discretion as to timing.

Priority 3: Includes projects and activities that are considered an improvement or enhancement to existing systems or capabilities. These projects are considered to varying degrees to be discretionary.

Q. How is all this information reviewed and validated in developing a final budget

compilation?

A. As budgets are compiled and submitted for review and approval, the budgets are reviewed project-by-project, line-by-line, and category-by-category in a series of meetings held with all applicable budget managers and contributors. Each project is reviewed to ensure that it has been appropriately categorized and prioritized within the budget, and to ensure complete documentation of scope, justification and cost estimates have been provided. Categories of spending, including annual requirements, are scrutinized to ensure the budgeted spending levels are appropriate based on historic spending levels and current assumptions, and adjustments (if needed) are made to ensure budgeted spending levels are appropriate. Priorities are reviewed to ensure all projects have complete justification. Projects without adequate justification are removed or deferred as appropriate. Once a well-prepared budget has been validated and fully vetted, it is advanced through the formal review process for final approval.

Q. How does the Company optimize cost-to-benefit decisions with regard to replacement of aging facilities?

A. The capital planning and budgeting process provides the structure and discipline to carefully evaluate, prioritize and approve those projects that offer the most cost-effective solutions to improve reliability or address significant risks, while also identifying and addressing aging or obsolete facilities. As noted above, budgets are established through a "bottom-up" process each year, with input from dozens of engineering and operations employees. Hundreds of individual projects are scoped, estimated, justified and then prioritized to determine which projects are required to ensure a safe and reliable system for our customers.

B. AUTHORIZATION AND CONTROL OF CAPITAL SPENDING

Q. How does the Company approve, authorize and control spending to ensure the reasonableness and prudence of capital additions?

A. There are several layers of controls on spending. First, and perhaps most important, is the budget process. The capital budget represents the culmination of a lengthy planning process to identify and prioritize important needs, while ensuring that projects submitted for approval are the most cost effective solutions to address identified needs and are estimated appropriately. The budget proceeds through several rounds of review at multiple levels of the organization before concluding with review and approval by executive management, and by the Company's Board of Directors.

Q. Are there other controls over budgeted spending on capital additions?

A. Yes. After the budget is approved, each project within the budget must be further authorized before spending can occur. This is a second step in the approval process, and occurs on a project-by-project basis. A construction authorization must be prepared and submitted for approval for each planned expenditure and each project in the budget, even though the budget has already been approved. Each authorization must be fully approved prior to the commencement of any work, except where an unforeseen emergency occurs that requires the work to be completed to ensure public safety or restore service to customers, in which case the authorization can be completed immediately following the work.

C. FIVE YEAR CAPITAL BUDGET

Q. Has the Company completed the capital planning and budgeting process for 2021 through 2025?

A. Yes. The Table 1 below is the Company's most recent five-year budget for electric projects over the period 2021 to 2025.

Table 1 – 2021-2025 Capital Budget Forecast

Budget Category	**5-Year Budget Forecast**				
Annual Requirements Blankets	**2021**	**2022**	**2023**	**2024**	**2025**
T&D Improvements	$ 2,878,068	$ 2,895,380	$ 3,415,493	$ 3,444,473	$ 3,622,165
New Customer Additions	957,175	983,925	1,187,145	1,206,173	1,286,522
Outdoor Lighting	267,712	281,423	342,710	342,701	359,628
Emergency & Storm Restoration	1,339,224	1,354,155	1,590,379	1,597,322	1,683,570
Billable work	676,909	683,558	809,010	812,547	857,620
Transformers	2,434,392	2,582,342	2,824,038	2,902,620	3,054,949
Meters	1,466,771	1,547,410	1,763,253	1,787,365	1,852,832
Sub-Totals:	**$ 10,020,251**	**$ 10,328,193**	**$ 11,932,028**	**$ 12,093,201**	**$ 12,717,286**
Distribution					
Overhead Line Extensions	115,015	116,398	148,732	150,558	162,610
Underground Line Extensions	966,920	994,010	1,248,444	1,266,319	1,366,936
Street Light Projects	4,657	4,737	5,637	5,625	5,929
Telephone Company Requests	13,365	18,985	22,665	22,580	23,788
Highway Projects	318,584	297,812	352,591	1,012,579	1,043,251
Distribution Pole Replacements	1,551,171	1,809,384	2,153,189	2,214,972	2,334,567
Specific Projects: Distribution	12,191,099	13,911,248	11,050,740	14,035,294	15,819,016
Sub-Totals:	**$ 15,160,811**	**$ 17,152,574**	**$ 14,981,998**	**$ 18,707,927**	**$ 20,756,097**
Substation					
Specific Projects: Substation	1,699,762	5,415,393	6,420,793	3,693,529	4,797,465
Sub-Totals:	**$ 1,699,762**	**$ 5,415,393**	**$ 6,420,793**	**$ 3,693,529**	**$ 4,797,465**
Communications	**$ 3,872,953**	**$ 4,178,905**	**$ 3,197,467**	**$ 3,051,599**	**$ 2,712,445**
Tools, Shop, Garage	**$ 214,500**	**$ 194,500**	**$ 126,700**	**$ 127,900**	**$ 127,900**

Laboratory	**$ 14,000**	**$ 14,000**	**$ 14,000**	**$ 14,000**	**$ 14,000**
Office	**$ 4,000**	**$ 7,000**	**$ 7,000**	**$ 7,000**	**$ 7,000**
Structures	**$ 600,000**	**$ 236,000**	**$ 298,000**	**$ 458,000**	**$ 333,000**
Distribution Totals:	**$ 31,586,277**	**$ 37,526,565**	**$ 36,977,986**	**$ 38,153,156**	**$ 41,465,193**

Q. What is included in the category for "Annual Requirements Blankets"?

A. This category includes blanket authorizations for categories of projects where each individual project is small in value (under $30,000) except for small equipment and general purchases (which are under $4,000) and cannot be individually anticipated at budget time. As I previously explained, these projects are budgeted and authorized under a single blanket authorization representing the anticipated aggregate level of spending. The categories are generally self-explanatory. For example, distribution improvements include: minor upgrades and replacements and repairs to the distribution system; new customer additions consisting of new customer requests for service, including new services and small line extensions; outdoor lighting, which includes repairs and replacements of existing street lights and customer lighting fixtures; emergency and storm restoration, which includes capital repairs and replacements required to restore service to customers following storms or outages; billable work, which includes customer projects, pole accidents, cable TV projects and other projects where all or a portion of the work is billable; and, lastly, the purchase of transformers and meters.

Q. What is in the category for "Distribution"?

A. These projects are individually authorized projects involving capital additions where the value of the project exceeds the maximum threshold allowed under blanket authorizations. The projects are generally self-explanatory. For example, overhead and underground line extensions are new extensions of primary facilities required to provide service to customers; street light projects are new projects to add street lighting; telephone company requests include pole replacements and relocations required under our intercompany agreements with Verizon; highway projects are typically line relocations driven by state or municipal roadway projects; distribution and sub-transmission poles replacements include costs associated with replacing poles that failed inspection during the Company's 10-year pole inspection program; and, specific projects are all other projects in excess of $20,000 that are identified by engineering or others that are needed to meet service obligations.

Q. What is included under the category "Substations"?

A. These are individually-authorized projects involving projects and capital additions to distribution substations. Each project is individually budgeted and authorized. The projects are typically identified by engineering, though the projects may also be identified as the result of inspection and maintenance activities.

Q. What are included under the remaining categories?

A. Communications includes additions and replacements of communication-related equipment such as Supervisory Control and Data Acquisition ("SCADA"), radio systems for field communications, and communication equipment for the Company's Advanced Metering Infrastructure ("AMI") system; tools, shop, and garage includes most tools and test equipment used by electrical workers in the performance of their job; laboratory includes test equipment used to test meters and other devices; office includes furniture and office equipment, including normal additions and replacements; and structures includes upgrades and improvements to the Company's buildings, including the Company's operations center building.

Q. Can you explain where the Company expects to invest most of its capital spending in the subsequent five years?

A. Yes. Table 2 below categorizes the five-year capital budget (in dollars) into two primary categories: Customer Expansion (addition of new customers and new load) and Non-Customer Expansion (no new load added to support the investment).

Table 2 – Forecast Customer Expansion and
Non-Customer Expansion Capital Spending 2021 - 2025

	Capital Budget Spending				
	Forecast				
Electric Category	**2021**	**2022**	**2023**	**2024**	**2025**
Growth					
Customer Additions (C)	5,060,266	5,226,172	6,175,383	6,307,286	6,680,272
Subtotal Growth	**5,060,266**	**5,226,172**	**6,175,383**	**6,307,286**	**6,680,272**
Non-Growth					
Reliability (R)	1,177,285	750,000	750,000	821,457	750,000
Maintenance Replacement (M)	16,548,634	15,375,776	11,222,996	11,209,592	10,551,594

Mandated (H)	318,584	297,812	352,591	1,012,579	1,043,251
System Improvement (I)	2,831,181	5,827,249	7,263,344	6,863,031	8,522,006
Grid Modernization (G)	0	4,979,977	7,304,037	8,013,500	10,450,675
Other (O)	5,650,327	5,069,579	3,909,635	3,925,711	3,467,395
Subtotal Non-Growth	**26,526,011**	**32,300,393**	**30,802,603**	**31,845,870**	**34,784,921**
Total	**31,586,277**	**37,526,565**	**36,977,986**	**38,153,156**	**41,465,193**

% Growth	16%	14%	17%	17%	16%
% Non-Growth	84%	86%	83%	83%	84%

Q. Please describe the way in which you have categorized this capital budget?

A. The table above has been categorized into customer expansion (addition of new customers resulting in revenue producing projects) and non-customer expansion (non-revenue producing) projects.

Customer expansion projects include: new customer services, new customer transformer purchases, new customer meter purchases, overhead line extensions and underground line extensions. These projects are directly related to adding new customers and new load to the system.

The non-customer expansion related category is broken down into reliability, maintenance replacement, mandated, system improvements and other projects. I can explain the types of projects that make up these categories:

Reliability – Projects where the primary justification is to improve reliability (i.e. reduce customer minutes of outage time and/or reduce customer interruptions) such as: distribution automation, recloser additions, spacer cable, adding fusing locations, circuit reconfiguration to reduce outage size, circuit ties.

Maintenance Replacement – Normal replacement of aged equipment such as: distribution pole replacement, distribution improvements, outdoor lighting, emergency and storm restoration, billable work, meter replacements, underground cable replacement, and equipment replacement.

Mandated – Projects necessary to perform assigned business functions in required manner including regulator or legal requirements, intercompany operating agreements and related facilities such as: highway relocation projects, telephone company requests, and third party attachments.

System Improvement – Projects required to address engineering planning constraints such as overloads and voltage problems which violate planning criteria such as: new system supply substations, transformer replacements, voltage regulation projects, reconductoring, and stepdown transformer replacements.

Grid Modernization – These are projects that the Company is proposing within its Grid Modernization Plan. Typical projects in this category consist of (but are not limited to) data sharing, field area network, advanced distribution management system, distributed energy resource management system, SCADA, volt-var optimization, and electric vehicle ("EV") make ready program, in addition to other projects. These projects are discussed in further detail later in this testimony and within the Company's Grid Modernization Plan provided as Exhibit KES-3.

Other – All other projects that do not fit into the categories above such as: equipment and tools, communication projects, office furniture, structure projects, software, and substation modifications.

Q. Can you provide the same table as provided in Table 2 but for actual spending from 2016-2020?

A. Yes. Table 3 below categorizes actual spending from 2016-2020.

Table 3 – Actual Customer Expansion and
Non-Customer Expansion Capital Spending 2016 – 2020

	Actual				
Electric Category	**2016**	**2017**	**2018**	**2019**	**2020**
Growth					
Customer Additions (C)	4,030,800	4,496,900	5,924,000	5,450,400	5,682,300
Subtotal Growth	**4,030,800**	**4,496,900**	**5,924,000**	**5,450,400**	**5,682,300**
Non-Growth					
Reliability (R)	346,100	667,000	740,000	920,500	867,600
Maintenance Replacement (M)	6,359,800	8,823,800	8,617,600	11,149,200	9,048,800
Mandated (H)	1,361,200	154,900	582,400	23,500	333,600
System Improvement (I)	10,692,900	6,106,700	967,900	4,509,900	5,629,400
Grid Modernization (G)		0	0	0	0
Other (O)	396,900	3,500,100	1,455,200	7,015,300	15,684,100
Subtotal Non-Growth	**19,156,900**	**19,252,500**	**12,363,100**	**23,618,400**	**31,563,500**
Total	**23,187,700**	**23,749,400**	**18,287,100**	**29,068,800**	**37,245,800**

% Growth	17%	19%	32%	19%	15%
% Non-Growth	83%	81%	68%	81%	85%

Q. Can you describe the breakdown between customer expansion related and non-customer expansion related capital spending?

A. Yes. As shown in tables 2 and 3 above, the average annual percentage of spending on customer expansion is virtually identical over both the historic five-year period and the future five-year period with 2018 being the one outlier of a year. In 2018 the Company spent less on non-growth related projects resulting in a higher percentage of capital spending on growth related projects.

Q. Can you describe the increase in non-growth related spending in 2019 and 2020 as compared to previous years?

A. Yes. In 2019 and 2020, the table shows a considerable increase in the "Other" spending category. This increase is directly attributed to the construction of a new operating center. This project is discussed in the testimony presented by John Closson.

Q. What is the relevance of categorizing Tables 2 and 3 into Customer Expansion and non- Customer Expansion categories?

A. In times of higher customer expansion, the electric system benefits from renewal of aged equipment during the projects which are designed to increase the capacity of the system. When the number of new customer projects slows, the Company's facilities are not benefitting from this customer expansion related renewal and, as a result, it becomes much more challenging to address all of the periodic replacement that would be optimal for the distribution system. Over the next five years, the Company is forecasting that, on average, over 84% of its capital investment will be on projects that will not result in any increase in system load or revenue.

Q. Have you provided any historical capital spending information?

A. Yes. Exhibit KES-2 provides project by project capital spending by year from

2010-2020. The same exhibit also provides the project-by-project capital spending for 2021-2025.

D. SIGNIFICANT PROJECTS

Q. Do you have any projects in particular that you would like to describe that have already been completed?

A. Yes. I would like to describe the Concord Downtown Conversion project.

Q. Please describe the Concord Downtown Conversion?

A. In 2019 UES began construction on the conversion of portions of the Concord downtown area from 4.16kV to 13.8kV operation including associated substation and sub-transmission upgrades. These upgrades were required to accommodate customer load additions in the downtown area. These load additions consisted of approximately 5.6MW of additional customer load and another 1MW of load within the next 5 to 8 years. This project was placed in service and used and useful in 2020.

Q. Can you identify the projects that were included as part of the Concord Downtown Conversion?

A. The table below identifies the projects that were completed to convert a portion of the Concord downtown from 4kV to 13.8kV.

Auth No.	Project	Cost
190149	Conversion in Downtown Concord Part 1	$194,714
200124	Conversion in Downtown Concord - Part 2	$447,840
190181	Reconductor/Convert Circuit 1H6 - Thompson	$137,385

	Street, Concord	
190174	Reconductor 1H6 - Pleasant and Green Street, Concord	$161,963
190192	Reconductor/Convert Circuit 1H6 - S Spring St., Concord	$371,975
190118	Gulf Street Substation – Outside Services	$3,164,045
190198	374 Line Rebuild with 15kV Underbuild	$787,358

The project consisted of a rebuild of Gulf Street substation and conversion to 13.8kV and a conversion of the Gulf Street circuits and the reconductoring and conversion of Bridge Street circuit 1H6. The downtown conversion is expected to accommodate up to 10MVA of additional load without further substation upgrades. Depending on where load enters the area, additional work could be required to connect the load to this capacity. In addition to the 10MVA of additional capacity, Gulf Street substation was designed to accommodate the future conversion of the remaining 4.16 kV circuit, the future installation of a second 14MVA transformer and the future installation of a fourth circuit position.

Q. Did the Company evaluate alternatives to the Concord Downtown projects listed above?

A. Yes. The Company also evaluated 1) replacing Gulf Street transformer 3T2 with a 34.5kV/13.8kV transformer and transferring some load away from Gulf Street substation (a.k.a. downtown conversion), 2) creating a 13.8kV transformer grid by installing several taps off of the 34.5kV system and installing several 34.5/13.8kV pad-mounted transformers, 3) Upgrade and convert Bridge Street substation to 13.8kV, 4) add transformation to Iron Works Substation, or 5) upgrade of circuits

21W1P and 21W1A.

Q. Which alternative was chosen for this project?

A. Option 1 was selected to convert a portion of downtown Concord to 13.8kV because it was the most feasible and cost effective option to increase the capacity of the downtown Concord area within the timeframe requested.

Q. Can you describe why the other options were not selected?

A. Option 2 was not feasible due to limited space in the downtown Concord, limited timeline for completion and the unknown with the future I-93 expansion. Option 3 was not chosen due to space limitations at Bridge Street substation. The time required to locate and procure adequate land space for a new substation was outside the timeline for the in-service date. Option 4 was not selected because of loading constraints on Iron Works Road Substation. The total load on both transformers (old and new) would be greater than the combined rating for the two transformers. Option 5 was not selected because underground construction made the project too costly. There are no additional conduits in the underground for new circuits, which means excavation of several streets to install new conduit and loading issues on existing underground circuits.

Q. Are there challenges associated with the evaluation of projects?

A. Yes. The Concord downtown area is in close proximity to I-93. The State of NH is currently in the process of evaluating options for the widening of I-93. The widening project has the potential to impact UES infrastructure, including Bridge

Street and Gulf Street substations. In addition, the downtown underground was built to have a primary (21W1P) and alternate (21W1A) feed to allow one of the circuits to back the other one up completely. Due to load growth in the area this is no longer the case. Depending on the fault location, portions of the downtown underground need to be restored from overhead distribution circuits. The Capital Master Plan details the future goal of returning the downtown underground to its original purpose. Finally, available land in the downtown Concord is very limited. Combined with the unknowns of the I-93 widening and the timeframe in which upgrades are required, finding locations for new substation infrastructure will be extremely difficult.

Q. Did the Company complete an evaluation of non-wires alternatives ("NWA") for this project?

A. No. This project was evaluated per the Company's Project Evaluation Process and did not require the review of NWA because the required construction start date was one year in the future.

Q. Do you have any projects in particular that you would like to describe that will be included in upcoming step adjustments?

A. Yes. I would like to describe the 3348/3350 Line Rebuild Project, 37 Line Reconductoring Project, and the Company's proposed Grid Modernization Plan.

Q. Please begin by describing the 3348/3350 Line Rebuild Project.

A. The 3348, 3350 and a small portion of the 3359 lines are constructed across the salt marsh in Hampton, Hampton Falls and Seabrook. This line was originally constructed in the 1950's. The majority of the line is approaching 70 years old. There are condition-related concerns associated with the aging infrastructure and significant accessibility and permitting challenges exist due to the location of the lines. This can cause the line(s) to be out of service for several months at a time when structure damage occurs.

This project consists of rebuilding almost 5 miles of line in its present location with single pole, armless construction. The design for this line is currently underway. Construction will take place over two years. The current budget has the project beginning in 2021 and finishing in 2022 at a total price of $10.4 million.

Q. Can you describe the reliability performance of these lines?

A. In the past ten years, the line has been out of service more than a month at a time on five different occasions. Repairs to the line are costly and time consuming. Permitting is required to complete any work on the line due to the location in the marsh. The line is only accessible by boat. Equipment and materials must be delivered by barge and only at high tide. This limits the amount of work that can be completed at any one time. Every time the line experiences damage it affects more than 3,000 customers in the towns of Hampton, Hampton Beach, Hampton Falls and Seabrook.

Q. Did the Company evaluate different alternatives to a complete line rebuild for this project?

A. Yes. The Company evaluated options of rebuilding the lines in place, constructing new lines along a different right-of-way route, constructing a new line along the railroad right-of-way, constructing a new line in the Interstate 95 right-of-way, the option of constructing this line along Route 1 with distribution circuits attached to the same poles, and constructing a new system supply substation in Seabrook. Rebuilding the lines in place was the most cost effective option.

Q. Is this the same project that was presented in docket DE 20-002 UES Least Cost Integrated Resource Planning ("LCIRP")?

A. Yes. The Company answered many discovery requests about this project including the different options that were evaluated. During the docket, Staff requested the Company to have an outside firm evaluate if an incremental repair option would be more beneficial than a line rebuild option.

Q. Was this evaluation completed?

A. Yes. The Company hired TRC to evaluate and compare a line rebuild option versus an incremental line repair option. The Company shared the scope of work and the final report with Commission Staff in the UES LCIRP docket. Based upon the analysis, TRC recommends the complete rebuild of the lines. Considering previous data provided and the load forecast for these lines, the Company anticipates that completely rebuilding the line will cost less money over the lifetime of the lines than incrementally repairing the lines, as well as provide reliability benefits (including but not limited to splice and conductor life, increased reliability in wind events, and lightning protection) and other benefits such as avian impacts and future development options.

Q. Has the Company experienced any other outage events since the evaluation?

A. Yes. On February 17, 2021, the 3350 line experienced an outage affecting over 3,000 customers. The outage was caused by a split pole top which resulted in the bolt that holds the static wire being pulled out and the static wire falling into the phase conductors. The lines are now out of service again as the Company obtains the necessary permits to work on the marsh to make the repair. This latest outage further confirms the need for the Company to completely rebuild the 3348, 3350, and 3359 (partial) lines.

Q. Please describe the 37 Line Reconductoring Project?

A. The UES-Capital 37 line loading constraint is a planned contingency loading concern. This loading constraint exists when the 37 line is utilized to restore all load for the loss of 4X1 at Penacook with all hydroelectric generators and the trash burning generator considered out of service. Per UES's planning criteria, this is how the area would be studied during summer peak loads. The 37 line loading constraint is due to general load growth and approximately 750kVA additional load from a new commercial development that will be supplied via the 37 line. The line is forecast to be approximately 117% of the normal rating.

The 3.5MW deficiency is based on 2022 forecasted peak loads. In 2021, the 37 line, while supplying 4X1 with the largest generator and all hydroelectric generators out of service (these are typically not operating during summer peak times), is expected to be loaded to 18.1MW or 3MW above normal. It is UES's intent that any project that is implemented reduces line loading below its normal rating to provide sufficient capacity for future load growth and extend through the end of the ten-year study timeframe. Since the completion of the latest planning study and the decision to reconductor the 37 line, additional information was received regarding the proposed commercial development mentioned above. Phase 1 of this development is currently under construction and is now anticipated to be between 1.5MW and 2MW of load. This project consists of reconductoring the 37 Line from Penacook substation to the MacCoy Street tap.

Q. Is this the same project that was presented in docket DE 20-002 UES LCIRP?

A. Yes. The Company answered many discovery requests about this project including the different options that were evaluated.

Q. Did the Company consider NWAs for this project?

A. Yes. When the 37 line loading constraint was identified, the needed in-service date of the project(s) to address the constraint was one year in the future. Based on UES's Project Evaluation Guideline, this project did not require a review of NWAs. The primary reason projects need to be three to five years in the future to require NWA review is to provide the Company adequate time to explore and implement NWA projects, including energy efficiency and load curtailment. However, in an attempt to test the possibility of an NWA, the Company elected to accept limited risk and defer the implementation of a traditional alternative and issue an NWA Request for Information ("RFI"). This was done to allow the Company to learn from the process of issuing an RFI for NWAs to external vendors, including types of technologies that would be proposed and costs of said technologies. The NWA RFI was open to all solutions, including energy efficiency and demand response. In the event the RFI resulted in an economically feasible project, UES would have issued a more detailed Request for Proposal.

Q. What was the result of the RFI for the 37 Line?

A. The Company issued an RFI to 19 different companies. Four of those companies presented proposals for consideration. Each of the proposals consisted of a Photovoltaic ("PV") or PV plus storage solution. Based on the analysis of all project alternatives, including the NWA proposals, the conclusion was that the best project option to address the identified 37 line constraint is to reconductor the 37 line from Penacook to the MacCoy Street tap.

Q. How has this process informed the Company's approach to future NWA analysis?

A. The Company determined that the traditional project cost to trigger an NWA review remain at $250,000 without overheads. However, it is also determined that the review of NWA projects be triggered when equipment is expected to exceed 80% of its normal rating during the first five years of the study period and exceed 90% of its normal rating in year five of the study period under base case/normal configuration conditions. Under planned contingency configurations it is recommended that NWA project reviews be triggered when equipment is expected to exceed 90% of its normal rating during the first five years of the study period and exceed 100% or its normal rating in year five of the study period. The intent of these loading thresholds is to review and possibly implement NWA projects to defer planning violations opposed to using NWA projects to resolve planning violations.

Q. Are there any other significant projects being presented in the testimony of other witnesses in this rate case?

A. Yes. The Company is proposing an EV Make Ready Program and associated time-of-use ("TOU") rate offering that is discussed in the testimony of Cindy Carroll and Carleton Simpson. Mark Lambert has submitted testimony on the Company's Customer Information System ("CIS") project. John Closson has submitted testimony on the Company's new operations building located in Exeter, NH.

IV. GRID MODERNIZATION PLAN

Q. Is the Company proposing a Grid Modernization Plan as part of this rate case?

A. Yes. The Company is proposing a group of foundational grid modernization projects to be included within its capital spending plan. The proposed Grid Modernization Plan (the "Plan") covers a span of ten years and has been provided as Exhibit KES-3.

Q. Can you summarize the proposal?

A. Yes. The table below identifies the proposed projects and spending estimates.

	Project Costs (000's)										
Projects	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Field Area Network	$ 90	$ 56	$ 127	$ 626	$ 325	$ 463	$ 780	$ 811	$ 640	$ 704	$ 4,622
ADMS and DERMS	$ 668	$ 468	$ 378	$ 298	$ 170	$ -	$ -	$ -	$ -	$ -	$ 1,981
Volt/VAR Optimization	$ -	$ 383	$ 2,000	$ 2,929	$ 2,731	$ 2,862	$ 2,880	$ 3,416	$ 3,488	$ 4,292	$ 24,981
SCADA	$ -	$ 1,530	$ 1,740	$ 760	$ 790	$ 250	$ 340	$ 420	$ 550	$ 760	$ 7,140
Mobile Damage Assessment	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
AMI/OMS Integration	$ 107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 107
Data Sharing Platform	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
Total	$1,763	$2,437	$4,245	$4,612	$4,016	$3,575	$4,000	$4,647	$4,678	$5,756	$ 39,729

Q. Why is the Company filing a Grid Modernization Plan separate from its LCIRP?

A. The least cost planning approach to grid modernization will effectively identify "geographic" grid investments. "Geographic" grid investments target specific constraints on the distribution system to alleviate capacity concerns in a certain area by introducing more DERs in a specific geographic area. The LCIRP approach is not focused on the "foundational" grid modernization projects designed to implement base functionality required to advance the grid. This is an effort by the Company to begin making progress on "foundational" grid modernization projects while the LCIRP docket continues. The Company will propose "geographical" grid modernization projects when they make sense in subsequent LCIRP filings.

In addition, the Company's next LCIRP filing is projected to be filed in 2023. The Company is proposing to begin implementation of "foundational" grid modernization investments prior to the filing of the next LCIRP. With that said, the Company will include this Plan and any updates to the Plan based upon stakeholder input and changing requirements within its next LCIRP filing.

Q. Can you describe what you mean by "foundational" grid modernization projects?

A. Yes. "Foundational" Grid Modernization projects are those projects that are required to achieve the desired outcomes and core functionality. Foundational projects are typically focused on communication or technology required to implement programs or services. AMI is a foundational investment used to facilitate time-varying rates (including TOU) and data sharing, as well as planning and operational needs. Foundational investments include grid monitoring and control center software and communications systems designed to assist grid operators make better decisions in response to reconfiguring the grid in response to service outages, variation in DER output and optimization of system performance.

I will provide an example of a "foundational" Grid Modernization investment. One key foundational area of Grid Modernization is the ability to have real-time monitoring and control of the distribution system, allowing the distribution system to be operated in optimized manner. An Advanced Distribution Management System ("ADMS") and SCADA are the means to enable real-time monitoring and control. Neither of these projects are successful without a Field Area Network ("FAN") to enable communications between the central office and the field edge devices. These types of projects are not identified through least cost planning. They are foundational projects used to implement the capabilities and functionalities of a modern grid. These systems need to be put in place before the functionality can be extended to the outer edges of the system. For this reason, there is justification to consider these foundational types of investments outside of the least cost planning approach.

Q. How does this differ from the proposal in the Grid Modernization docket?

A. This does not change the efforts or the approach to planning that have been proposed in the Grid Modernization docket. The Company has been engaged with the Commission Staff, Office of the Consumer Advocate, other utilities, and stakeholders in a Grid Modernization process which is heavily focused around Grid Modernization through a least cost planning lens. The Company supports this approach for "geographic" based grid modernization investments. However, this approach does not address how "foundational" projects are implemented. Least cost planning will identify that a demand response program in a certain area of the system may be the most appropriate plan for shifting load enough to defer a capital investment, but without a foundational Distributed Energy Resource Management System ("DERMS") in place, a demand response program can be extremely difficult to implement with the level of control necessary to rely on it from a distribution planning and operations perspective.

Q. How does the Company propose to evaluate "foundational" grid modernization investments?

A. One of the most effective ways to evaluate "foundational" grid modernization investments is on a benefit-cost basis. However, most foundational grid modernization projects do not result directly in benefits to the customer. In this case, the cost of the "foundational" investment is included in the benefit-cost analysis of the project which delivers the benefits. For instance, a FAN in and of itself does not lead to quantifiable benefits. However, when a FAN is combined with a Volt/Var Optimization ("VVO") project, the benefits can be quantified and compared to the cost.

Q. Are you saying that a portfolio approach to a benefit-cost analysis is the best approach?

A. Yes. In the FAN and VVO example, if the FAN is evaluated as a stand-alone project, it would not pass a benefit-cost analysis. However, the VVO project would generally provide enough saving to pass a benefit-cost analysis, but the project will not be effective without the FAN. A portfolio approach to the group of the projects proposed in the Company's plan will provide the best indication if the Plan as presented provides benefits that exceed the estimated costs.

Q. Can all benefits be quantified in the benefit-cost analysis?

A. No. There are quantitative and qualitative benefits to all of the projects. The VVO project can provide measurable and quantifiable benefits related to reduced energy consumption and reduction in demand. It can also reduce greenhouse gas emissions, but the monetary benefit to reduced greenhouse gas emissions is not as straightforward to calculate.

Q. Now that you have explained the difference between "foundational" versus "geographical" investments, can you provide an overview of your proposed Grid Modernization Plan?

A. Yes. A reliable, affordable and fully modernized electric grid is an essential pillar of modern society. It will power the basic necessities of life while supporting new technologies, services and interactivity. It will operate more efficiently, optimize grid-connected resources and enable dramatic expansion of clean energy to protect and preserve the environment. It will foster innovation and enable new markets by optimizing benefits to customers, service providers and other stakeholders. At its fullest potential, it will harness technology innovation to connect customers, markets, solution providers and new technologies to achieve the full potential of an advanced 21st Century energy system.

Over the years this vision has been variously referred to as Grid Modernization, the Modern Grid, and the Smart Grid. But what is a Modernized Grid exactly? What does a Smart Grid look like? Is it the poles, wires and electrical infrastructure of the utility? Is it an intelligent, highly digitized electricity network that forms the basis for a "smart" power delivery system? Does it refer to the utility system, or the broader integration of customers, markets, solution providers, and others? If you ask ten different people, you will get ten different answers.

To achieve the promise of a fully modernized grid, UES views the electric grid and the devices connected to it as a communicating, intelligent grid-connected ecosystem of people, devices, information and services. The grid is only a part of this larger energy ecosystem, but it is the foundation upon which everything is built. The role of utility in this context is to enable seamless grid access, link participants, optimize resources and foster technology innovation. The modern grid isn't just an electrical network, it's a community of grid-connected and grid-enabled customers and third parties.

Q. In the past the Company has focused on the grid as an enabling platform. Has this changed in the Advancing the Grid vision?

A. Not at all. The Company's Advancing the Grid vision is focused on developing an enabling platform for customers and users of all types. The vision encompasses much more than a "poles and wires" delivery system for electricity. It will enable electrical, informational and financial transactions among customers, grid operators, service providers, markets, and other stakeholders. In doing so, it will improve load factor, lower system losses, optimize asset utilization and avoid unnecessary investments driven by "peaky" load and poor utilization. Planners and engineers will have the information to build what is needed, when it is needed, while more effectively managing capacity and resources on a day-to-day basis. Reliability will be improved through advanced outage management, distribution management and automation systems, geographical information systems and other technologies.

Achieving this vision requires a paradigm shift in what has traditionally been viewed as grid infrastructure, as well as the types of investments needed to achieve advanced functionality. Traditional utility investments focused primarily on upgrading and maintaining “electrical” infrastructure to ensure safety and reliability, increase capacity, and expand service to new customers. Customers were viewed as consumers of electricity, and the grid was designed to distribute power from large centralized generating plants to end-use consumers. Assets and investments have traditionally consisted of poles, wires, substations, and electrical equipment.

To achieve the promise of the advanced grid, investments in Information Technology (“IT”) and Operational Technology (“OT”) are needed to create an open, flexible platform integrating customers, competitive markets and service providers. Collectively known as “intelligence” infrastructure, these investments will include communication networks, sensors and control devices, and advanced information and management systems. Under this vision the Eco-Grid is not simply a newer, upgraded version of the legacy electric system, nor is it a specific technology or suite of technologies layered onto the existing utility systems. The Eco-Grid is instead the foundation of a larger ecosystem of customers, competitive markets and service providers who are interacting with the utility electric grid and the utility's information systems. Information and the exchange of information will be the lifeblood of this grid-connected ecosystem.

Q. Can you explain the foundational objectives developed to support the vision?

A. Yes. UES has identified a series of eight objectives that together ensure support of a modern energy ecosystem. Our objectives were crafted with guidance from the United States Department of Energy, Massachusetts Department of Public Utilities and New Hampshire Public Utilities Commission and are used to identify the investments and technologies that best serve this new era.

Objective 1: Environmentally Friendly – We must firmly support the region's goals in reducing emissions in the battle against climate change.

Objective 2: Safety and Reliability – We must continuously improve safety, reliability and resilience while reducing the effects of outages.

Objective 3: Customer Service – We must improve and embrace customer empowerment, engagement, and education. We must give the customer the tools they need to understand and control both their own energy usage and energy matters in the region.

Objective 4: Security – We must ensure the cyber and physical security of the grid remains strong.

Objective 5: Flexibility – We must ensure the grid remains flexible enough to accommodate and integrate all types of new energy sources.

Objective 6: Affordability – Energy for life must remain affordable for all.

Objective 7: Demand and Asset Optimization – The grid must be designed to get the most out of the tools and resources interconnected in order to best serve the region.

Objective 8: Technology Innovation – The grid must enable the easy adoption of new technologies as they are developed to further support customer choice and system operations.

Q. How has the Company used these objectives to develop a roadmap to the future?

A. The roadmap to the future is a journey that must be planned carefully and executed in a precise manner. It is not a sprint to implement technology just to have that technology become obsolete in two years. Some technology will serve as a foundation to other technologies. Implementing the building blocks of the advanced grid in a well thought out manner creates the enabling platform that is the basis for the Company's vision.

The Company has identified six categories of technologies required to develop the grid as an enabling platform.

1. Grid Intelligence
2. Advanced Metering
3. Distributed Energy Resources
4. Advanced System Planning and Forecasting
5. Enhanced Customer Services
6. Innovative Rate Design

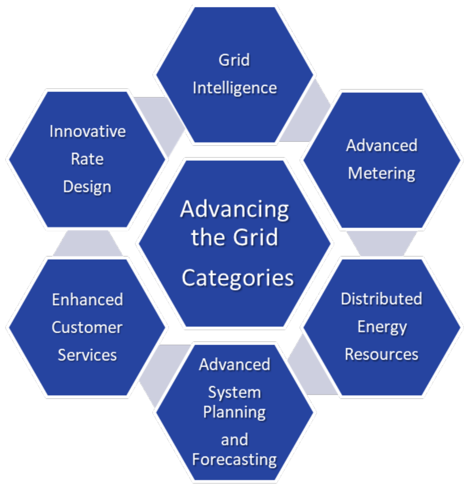


Figure 1: Advancing the Grid Categories

Category 1 - Grid Intelligence: The modern electric system is changing at a rapid pace with the integration of distributed, variable and renewable resources combined and the focus on electrification of the transportation and heating sectors. New and different users are connecting to the system every day. The ever increasing levels of these resources will have a significant impact on the safe, reliable and cost effective operation of the distribution system. Increased visibility and control deep into the distribution system is quickly becoming a necessity. System optimization and efficient use of the grid resources is increasingly more important in providing a safe, reliable, sustainable and cost effective electric system. Grid Intelligence technologies rely upon a safe and reliable advanced communications system to provide communications for the monitoring and control of field devices. The Company’s Grid Intelligence vision consists of centralized software systems and the installation of field devices for ADMS, DERMS, Outage

Management System ("OMS"), SCADA, VVO, and further integration of the AMI and OMS systems.

Category 2 – Advanced Metering - The modern electric system is also driven by data and information. Customers need data to inform their usage decisions. They need flexible pricing options that allow them to take advantage of their investments. Customers need to know how much electricity they are using and when that electricity is being used. Customers are willing to reduce their peak hour usage as long as they have the knowledge and tools to achieve the benefits. Timely and user-friendly data starts with a metering system that can accurately and automatically gather granular usage data, store the data in a meter data management system where it can be pushed to customers in a timely manner. Advanced Metering Functionality ("AMF") refers to the capabilities provided by the metering system. AMF provides the platform for the company to measure and provide detailed and granular interval metering data of each individual customer. In some cases AMF provides data in real-time or near real-time and in some case the AMF provides data on a daily or monthly basis. AMF data provides the information necessary for demand management programs, time of use or time varying rates, and other customized programs focused on controlling or reducing energy consumption.

Category 3 – Distributed Energy Resources: The Advanced Grid has the ability to plan for, monitor and control a diverse set of distributed assets on the system all designed to support the safe and reliable operation of the electric system.

Advanced monitoring and control technology evaluates the system in real time and issues control commands to optimize the system. An environmentally friendly grid is one that is optimized for interconnection and use of renewable resources while optimizing the system demand at all times of the year. The Advanced Grid needs to be flexible enough to integrate increased amounts of renewable energy and use these resources to optimize the system and minimize GHG emissions. The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. The Company's vision of the advanced grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other Distributed Energy Resources ("DERs").

Category 4 – Advanced Planning and Forecasting: The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. The Company's vision of the advanced grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other DERs. Advanced system planning forms the foundation for an enabling platform willing and ready to accept DERs and other electrification technologies. Advanced system planning begins with an accurate system model. Geographic Information Systems that are maintained on a timely basis form the network model used in Advanced System Planning. A complete and detailed network connectivity model is essential and is used across multiple platforms allows for consistent results for real time operation of the electric system. Advanced system planning reduces the risk associated with DER interconnections and enables the benefits to be realized by the system and customers. Hosting capacity and locational value analysis are tools that can be used to identify the optimal locations for DER interconnections maximizing the benefits to the customers and the system. Understanding the value and benefits of DERs will allow utilities to plan for and rely-on cost effective DER solutions to defer distribution system upgrades

Category 5 – Enhanced Customer Services: Superior customer service is fundamental to Unitil's Vision, Mission and Values. In 2020, Unitil Corporation's 93% overall customer satisfaction results were the highest in our history and significantly higher than most of our peers. From a benchmarking comparison perspective, Unitil ranked 10th out of 114 measured utilities nationally, 2nd out of 23 utilities in the Eastern Region and the 1st rated utility out of our peers in the Northeast. We earned these high levels of satisfaction by recognizing our customers' increasingly diverse and complex needs. Looking forward, we will continue to invest in technologies designed to support our commitment to the customers experience and to their satisfaction in all facets of that experience. We will strengthen current service offerings, make enhancements to our customer web portal, and add self-service options that enable customers to better manage their energy usage and accounts. These planned enhancements include a mobile app, artificial intelligence and chat features, and a robust notification engine to proactively alert customers regarding payment activity, changes in usage patterns, outages, and scheduled appointments.

Category 6 – Innovative Rate Design: The Company strongly believes the overarching objective of rate redesign should be the development of pricing for grid services that adhere to the principles of fairness, transparency and economic efficiency.

Only through transparent and economically efficient pricing structures will a viable and sustainable long term model be developed that provides sufficient revenue to support the significant investments needed to modernize the grid, while encouraging appropriate behaviors and assuring fairness and equity among customers. We continue to review how rate design must evolve to enable customers to more effectively manage their energy needs. The testimony of Cindy Carroll, Carleton Simpson, and Carol Valianti and will describe the Company's proposed EV and TOU proposal.

Q. How does the Company's Plan ensure that the included functionalities support the Plan objectives?

A. The Company's Plan maps projects and functionalities within each identified category back to the foundational objectives developed to support the Advancing the Grid vision.

Q. Does the Company detail all of the projects in its Plan?

A. Yes. Section 6 of the Plan details each proposed project, provides a project description, describes the quantitative and qualitative benefits to our customers and the grid, provides a project timeline and cost and additional description of the project and technology to be deployed.

Q. Does the plan provide net benefits to customers?

A. Yes. The benefit cost analysis uses a net-present value approach to benefits, capital cost and incremental O&M costs. The 15 and 20 year analysis results in a benefit cost ratio greater than one which is an indication of net benefits to customers.

Q. What is the Company's proposal for measuring progress towards its Plan?

A. The Company has proposed a set of metrics that will be used to quantify the Company's progress. These proposed metrics will be broken down into 1) infrastructure metrics which tracks the implementation of grid modernization technologies and 2) performance metrics that measure progress towards the objectives of grid modernization. These metrics are designed to measure quantitative benefits associated with grid modernization benefits. These metrics will be filed on an annual basis with the Plan update.

Q. How does the Company propose to report on its progress towards grid modernization?

A. The Company proposes to continue to follow the filing requirements for the LCIRP plan which is proposed to be filed every three years. The Company will continue to work with the Commission and the stakeholders to finalize the requirements of the LCIRP filing. The Company is also proposing to file additional information on an annual basis.

Q. Please identify the additional information the Company proposes to file and is the information consistent with the information that would be filed as part of the LCIRP.

A. The Company proposes to file annual planning studies, load forecasts, circuit and substation level forecasts, identification of constraints and alternative evaluated, NWA analysis for projects over estimated to be over $250,000, a summary of stakeholder input, DG interconnections by circuit and type of prime mover, discussion of progress on grid modernization projects including reasons for deviation from the prior year's plan and metrics. This information is consistent with the information required as part of the LCIRP filing. This additional information would be filed annually on the years in between the LCIRP filings.

Q. Does the Company propose a stakeholder process as part of its Plan?

A. Yes. The Company vision of Advancing the Grid is to develop an enabling platform that serves all customers and users of the system. Stakeholder engagement is designed to improve the overall transparency of the distribution planning process. Stakeholder engagement is an important aspect to determining the functionality desired in the advanced grid. The Plan is a living document and will be flexible enough to adjust to the changing requirements of the system.

Q. What does your proposed stakeholder process look like?

A. The Company will follow the stakeholder process that is required in conjunction with the LCIRP filing. However, if a stakeholder process is not detailed, the Company proposes to use the following process:

Meeting 1: Pre-Planning Meeting – The goal of this meeting is for the stakeholder to provide some initial feedback to the Company prior to plan development, review of previous plan and any changes to assumptions.

Meeting 2: Project Identification and Consideration – The Company presents preliminary findings as a result of the planning process. Stakeholders have the opportunity to provide input to the proposed alternatives and project priorities.

Meeting 3: Project Plan – The Company presents the proposed Plan and seeks any final input.

Ultimately, the Company is responsible for the safe and reliable operation of the electric distribution system at a reasonable cost. Any alternatives considered should have an equivalent capacity, reliability, availability and life span of the competing options. The Company is confident that this approach will increase the transparency of the planning process to the stakeholder group.

Q. Is the Company proposing special rate treatment for specifically for these Grid Modernization investments?

A. The Company proposes to include these Grid Modernization investments through step adjustments as part of a multi-year rate plan as described in the testimony of Messrs. Christopher Goulding and Daniel Nawazelski.

Q. Does this conclude your testimony?

A. Yes, it does.