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Xcel Energy		Information Request No.	6
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:
Refer to Xcel's IDP, p. 25. Would Xcel agree to collaborate with stakeholders in 2024 to develop an approach for "strategically applying CBAs to program level investments"? If not, please explain why.

Response:
On IDP, page 25, we stated, "we believe strategically applying CBAs to program level investments would be valuable and will work towards evaluating and developing an approach to do so."

First, we note that we do apply CBAs to some program-level investments today. For example, the Commission Order requires CBAs for grid modernization investments, and we also use CBAs in evaluation of customer programs, including the programs, pilots, and demonstrations proposed in the Transportation Electrification Plan portion of the IDP.

We would support collaborating with stakeholders in 2024 as we develop an approach for strategically applying CBAs to program-level investments.

Preparer:	Karin Haas
Title:	Regulatory Policy Specialist
Department:	NSPM Regulatory
Telephone:	612-216-5690
Date:	December 14, 2023

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Xcel Energy		Information Request No.	7
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:
Refer to Xcel's IDP, p. 34. Please explain how Xcel's Demand Side Management action plan informs and influences its current and future IDPs.

Response:
As provided in Appendix A1, page 33, the sales model implicitly accounts for some portion of changes in customer use due to conservation and other influences by basing projections of future consumption on past customer class energy consumption patterns. Expected impacts of Company-sponsored Demand Side Management (DSM) programs are a reduction of peak demand in the regression model.

The DSM adjustments for the IDP were based on the Company's July 1, 2021, Minnesota Resource Plan Supplement and therefore do not reflect our 2024-2026 Energy Conservation and Optimization Triennial Plan, which was not approved until December 1, 2023, in Docket No. E,G002/CIP-23-92.

Preparer:	Jessica Peterson
Title:	Manager, Program Policy
Department:	Customer Energy and Transportation
Telephone:	612-216-7972
Date:	December 14, 2023

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Xcel Energy		Information Request No.	9
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:
Refer to Appendix A1, p. 22. Please explain the extent to which Xcel's Demand Side Management planning and activities are or will be integrated with Xcel's Integrated System Planning business unit.

Response:
Appendix A1, p. 22 discussed the creation of our Integrated System Planning (ISP) business unit within the Company. From an organizational standpoint, the Company's demand-side management (DSM) planning and activities are managed within the Customer Energy & Transportation Solutions business unit. ISP and the Customer Energy & Transportation Solutions groups work closely together, along with many other departments within the Company, to ensure alignment in planning and operations. For example, the DSM teams work closely with the Load Forecasting and Analysis teams (within the Corporate Finance business unit) to ensure corporate forecasts incorporate the effects of energy efficiency and demand response, as discussed in Appendix A1 (see pp. 32-34). In turn, the corporate forecasts are an important input into annual distribution planning and DSM continues to be a factor in the reduction of annual peak load.

See also our response to FE-7.

Preparer:	Brian Monson
Title:	Manager, Distribution System Planning and Strategy
Department:	Integrated System Planning
Telephone:	763-493-1811
Date:	December 14, 2023

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Xcel Energy		Information Request No.	10
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:
Refer to Appendix A1, p. 41. Please explain how Xcel's residential DR programs are "grouped for distribution needs as determined by the Company".

Response:
The Company has two Residential DR offerings: Saver's Switch and AC Rewards. Both are aimed at reducing peak load from air conditioner use during hot summer days. Because the Saver's Switch product is significantly larger based on participants and load, the focus for grouping participants for distribution needs has been on Saver's Switch. However, as the AC Rewards program (which uses smart communicating thermostats) grows, benefits from grouping those will materialize as well. When activating the Saver's Switch product during a peak event, the load reduction on the grid is substantial, as the participant population in the NSP territory is about 400,000 customers. If the Company has a need to reduce load at a specific geographic location (a feeder, substation, etc.), switches can be programmed to be included in a localized control group. This allows the Company to reduce grid congestion at a particular location without activating the full population.

Preparer:	Patrik Ronnings
Title:	Sr. Program Manager
Department:	Demand Management
Telephone:	612-330-5787
Date:	December 14, 2023

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Xcel Energy		Information Request No.	13
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:
Refer to Appendix A1, p. 59, Figure A1-20. Please explain why Xcel forecasts negative Corporate demand growth each year 2029-2033.

Response:
The forecasts included in the referenced figure include corporate growth and demand side management programs, inclusive of energy efficiency programs. During the years 2029-2033, the Company anticipates growth in demand side management programs, causing the corporate demand growth to be negative. Demand side management reduces load during peak hours, meaning that if demand side management is growing faster than local demand, then this will result in overall negative growth.

Preparer:	Brian Monson
Title:	Manager, Distribution System Planning and Strategy
Department:	Integrated System Planning
Telephone:	763-493-1811
Date:	December 14, 2023

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Xcel Energy		Information Request No.	16
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:
Refer to Appendix A2, p.1. Is Xcel intending to replace assets (such as overhead poles and substation transformers) at the end of their anticipated useful life, regardless of the asset condition? If not, please explain Xcel's criteria for asset replacements.

Response:
No. For substation assets, when an asset reaches the end of its useful life, it undergoes evaluation for potential replacement. Based on its condition, a decision is made regarding whether to plan for its replacement or to continue maintaining it for an extended operating period. This evaluation considers historic failure rates, reliability, the asset's criticality, etc., to determine condition and degradation rates that may indicate the need for a replacement or the potential to remain in service without any significant reliability concerns.

Similarly, the Line Asset Health and Reliability programs make replacements based on condition and performance factors. Age is highly correlated with equipment condition and performance (Figure A2-1), and this allows for estimation of broad system conditions. The Pole Assessment and Replacement program makes criteria based replacements based on visual and physical assessment. Wood poles are assessed on a rotating cycle, with all wood poles receiving a visual inspection and poles older than 15 years old receiving an invasive ground line inspection, assessment, and remedial treatment to arrest any existing deterioration and prevent future damage from insects and fungi. Poles receiving an invasive inspection are assessed for remaining strength in the ground line region of the pole using a software program to calculate the remaining pole strength from measurements of the pole and any defects. Each pole is classified as compliant with or not compliant with National Electric Safety Code (NESC) guidelines. Poles found to be compliant with the NESC guidelines receive remedial treatments and will remain in service as is. Poles found to be not compliant with the NESC guidelines are prioritized for either replacement with or for ground line reinforcement to bring the pole into compliance with the NESC guidelines.

Preparer:	Michael Renman
Title:	Manager
Department:	Electric System Performance
Telephone:	616-566-4918
Date:	December 14, 2023

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Xcel Energy		Information Request No.	24
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:
Refer to Appendix B1, p. 4. Please explain why Xcel believes that, as the operation of the distribution system becomes more complex through more integrated field devices and the increased adoption of DER, it will be "increasingly important for the Company to invest in asset health and reliability projects".

Response:
The Company descriptions on pp. 2-5 of Appendix B1 describe the drivers of our Grid Modernization strategy. As referenced on p. 4, our strategy recognizes the importance of focusing on our customers' reliability experience, which is at the core of quality electric service. Continued investment in the "business as usual" portion of our operations or asset health and reliability projects are *equally* as important as new technology.

The traditional paradigm of the grid is evolving. This includes changes such as the need to accommodate two-way power flows, instead of the one-way flows of electricity from centralized generators to customers, which is what the grid was designed to support for the last 100 years. Customers' electricity requirements are also increasing, in terms of more devices in their homes, beneficial electrification, and the need for greater power quality to support sensitive electronics. These changes and evolution mean that grid operators need to update core aspects of the grid infrastructure that were installed before any of these changes that are underway were contemplated. Installing smart meters or integrated field devices does not prevent assets from failing which ultimately can, for instance, cause outages and impact DERs from operating. In addition, maintaining assets is a critical component of maintaining safety for our employees and the public.

These investments are core to the integrity, reliability, safety of our operations and service to our customers. We believe it is important to invest in both modernizing the grid and the "business as usual" portion of our operations.

Preparer:	Chad Nickell
Title:	Senior Director, Grid Transformation
Department:	System Planning and Strategy
Telephone:	303-571-3502
Date:	December 14, 2023

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Xcel Energy		Information Request No.	29
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:
Refer to Appendix B1, pp. 28-32. Given Xcel's deployment of ADMS, AMI, and field devices over the last four years, please explain how the current cost for IVVO deployment may have changed since 2019.

Response:
The Company did not move forward with IVVO after the Commission's decision to not certify it, as discussed in Appendix B1. As such, we have not updated costs for IVVO.

With that said, the scope of IVVO would not be reduced based on progress of the ADMS and AMI deployments.

Preparer:	Chad Nickell
Title:	Senior Director, Grid Transformation
Department:	System Planning and Strategy
Telephone:	303-571-3502
Date:	December 14, 2023

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Xcel Energy		Information Request No.	30
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:
Refer to Appendix B1, p. 31. Please provide the updated benefits from IVVO that Xcel has concluded are "lower now than they were in 2019".

Response:
Pages 28-31 of Appendix B1 describe why the Company believes that the benefits of IVVO are lower now than they were in 2019.

Preparer:	Chad Nickell
Title:	Senior Director, Grid
Department:	System Planning and Strategy
Telephone:	303-571-3502
Date:	December 14, 2023

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Xcel Energy		Information Request No.	31
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:
Refer to Appendix B1, p. 32. Has Xcel evaluated IVVO using the Minnesota Test for cost-effectiveness (See Decision, Docket No. E, G999/CIP-23-46, March 31, 2023)? If yes, please provide the results of the evaluation. If no, please explain why.

Response:
No. The Company decided not to move forward with IVVO after the Commission's certification decision, as discussed in Appendix B1. As such, we did not conduct any updated evaluations of IVVO.

Preparer:	Chad Nickell
Title:	Senior Director, Grid
Department:	System Planning and Strategy
Telephone:	303-571-3502
Date:	December 14, 2023

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Xcel Energy		Information Request No.	34
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 4, 2023		

Question:

Refer to Appendix D, pp. 12-15. Please provide a live spreadsheet containing Xcel's NSPM actual capital expenditures each year 2018-2022, forecasted capital expenditures in 2023, and budgeted capital expenditures each year 2024-2028 for:

a. Pole Replacement Program
b. Restoration/Failure Reserves
c. Routine Rebuilds/Conversions
d. Reactive Line Programs
e. SE Region Reliability Initiative Reactive Discrete Projects
f. Substation Renewal Programs
g. Line Renewal Programs – Network Renewal
h. Line Renewal Programs – Line Equipment Renewal
i. Line Renewal Programs – Pole Related Renewal
j. Line Renewal Programs – High Customer Count Taps
k. Proactive Asset Health – Discrete Projects
l. Capacity – Discrete Projects – Load Growth
m. Capacity – Discrete Projects – Customer Driven
n. Capacity – Routines
o. Capacity Programs – Feeder Load Monitoring
p. Capacity Programs – Grid Reinforcements
q. Capacity Programs – Proactive System Upgrades to Increase Hosting Capacity
r. Reliability – Cable Replacement
s. Reliability Programs – Feeder Performance Improvement Program
t. Reliability Programs – Reliability Monitoring System
u. Reliability Programs – Viper Reclosers CSG
v. New Service – Routine Extensions/Services
w. New Service – Discrete Projects
x. Routine Streetlights
y. Grid Modernization Projects
z. Mandates – Discrete and Routine Projects
aa. Meter Purchases

bb. Fleet Purchases
cc. Communications Equipment
dd. Corporate Initiatives – Fiber Buildout
ee. Corporate Initiatives – Cyber Security
ff. Tools and Equipment
gg. Transformer Purchases
hh. Electric Vehicle Programs

<u>Response:</u>
Please see Attachment A to this response. We note that Categories l and m (Capacity – Discrete Projects – Load Growth and Customer Driven) are combined in Attachment A; ultimately, all of those projects are customer-driven and separating investments within those two categories is subjective.

We also note that this type of request – providing various views of our budget across various categories – is cumbersome and may lead to confusion. Our proposal to remove the IDP-specific budget categories from the IDP Requirements – as discussed on IDP p. 5 – would facilitate more streamlined provision of budget information.

Preparer:	Scott Hafner
Title:	Manager, Investment Delivery
Department:	System Planning and Strategy
Telephone:	651-229-5537
Date:	December 14, 2023

	Actual	Actual	Actual	Actual	Actual	Forecast	Budget	Budget	Budget	Budget	Budget
DRAFT FE IR #34 categories	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
a. Pole Replacement Program	9,843,610	8,792,468	28,517,748	30,208,261	25,619,726	25,940,651	39,344,998	40,516,998	41,679,000	42,876,000	44,162,003
aa. Meter Purchases	5,890,167	7,648,483	6,894,923	6,286,413	6,677,040	5,305,100	4,136,000	4,418,000	4,700,000	4,606,000	4,512,000
b. Restoration/Failure Reserves	14,483,999	18,318,293	19,310,027	17,207,579	42,693,541	5,373,982	21,716,999	27,476,004	33,429,007	21,187,999	21,525,002
bb. Fleet Purchases	8,709,294	6,889,575	10,915,404	14,089,719	15,562,603	21,520,840	35,385,125	17,067,534	15,768,869	18,767,607	20,351,126
c. Routine Rebuilds/Conversions	25,382,713	29,530,229	34,053,523	35,133,442	34,318,368	44,608,580	36,411,001	37,503,006	38,626,995	39,784,995	41,776,004
cc. Communications Equipment	1,299,429	904,096	1,873,512	1,364,514	3,378,326	6,131,929	7,731,519	6,379,891	5,707,549	3,295,786	3,389,481
dd. Corporate Initiatives – Fiber Buildout	8,221	2,135	84,963	1,123,533	2,764,850	2,341,625	2,602,622	2,602,622	2,602,622	2,602,622	2,602,622
e. SE Region Reliability Initiative Reactive Discrete Projects				2,390,419	5,484,079	998,501	3,183,003	3,279,002	3,377,999	3,480,000	3,583,999
ee. Corporate Initiatives – Cyber Security							78,079	78,079	78,079	78,079	78,079
f. Substation Renewal Programs	6,527,934	3,486,138	2,095,290	3,964,343	13,611,739	22,850,214	19,880,519	24,305,653	35,250,658	39,720,526	41,577,544
ff. Tools and Equipment	1,670,775	1,313,446	1,292,597	2,513,693	2,466,719	2,630,213	2,854,219	2,950,513	3,055,489	3,158,730	3,313,147
g. Line Renewal Programs – Network Renewal	1,995,624	2,205,890	1,064,560	1,404,312	2,434,520	5,995,717	7,043,006	7,296,002	7,475,007	7,776,995	3,948,002
gg. Transformer Purchases	27,142,933	17,171,432	20,244,158	21,026,865	23,801,578	33,389,578	24,398,880	24,945,361	26,539,921	27,324,879	32,442,960
h. Line Renewal Programs – Line Equipment Renewal	8,290,254	3,308,697	1,445,871	3,290,545	3,145,650	5,845,721	8,758,999	23,788,000	39,895,002	159,880,000	284,383,998
hh. Electric Vehicle Programs		634,714	90,644	2,515,995	7,227,287	9,330,409	8,943,600	1,372,300	18,361,600	36,873,000	71,843,800
i. Line Renewal Programs – Pole Related Renewal							491,000	22,644,999	37,814,001	69,250,002	72,713,001
j. Line Renewal Programs – High Customer Count Taps								1,999,999	4,000,000	6,000,001	6,300,000
k. Proactive Asset Health – Discrete Projects	9,614,754	10,652,906	10,646,576	9,081,218	14,302,469	25,522,116	42,611,593	24,986,755	21,892,005	16,625,005	30,824,999
l. Capacity – Discrete Projects – Load Growth & m. Capacity – Discrete Projects – Customer Driven	7,922,361	14,632,206	42,483,418	28,678,365	24,857,789	21,101,162	52,343,891	57,571,592	69,212,880	80,388,893	112,467,523
n. Capacity – Routines	4,474,961	5,535,036	3,790,275	2,003,037	4,268,034	6,816,418	4,185,003	4,310,000	4,439,999	4,574,001	4,803,004
o. Capacity Programs – Feeder Load Monitoring	1,265,851	1,450,346	1,078,006	1,379,020	7,661,137	7,808,817	5,299,999	5,299,999	5,299,999	2,000,000	
p. Capacity Programs – Grid Reinforcements					40,259	87,063		16,000,000	20,000,000	46,360,001	49,795,000
q. Capacity Programs – Proactive System Upgrades to Increase Hosting Capacity								10,000,001	59,999,999	59,999,999	59,999,999
r. Reliability – Cable Replacement	21,688,909	17,575,937	28,430,115	23,643,674	37,268,291	31,782,517	36,003,002	38,430,004	41,385,001	44,333,997	46,551,003
s. Reliability Programs – Feeder Performance Improvement Program	1,454,793	1,137,686	1,011,179	695,167	3,271,347	6,708,543	2,122,001	2,186,002	2,252,000	2,320,000	2,390,001
t. Reliability Programs – Reliability Monitoring System	490,462	292,268	141,533	250,325	668,682	1,517,276	531,000	546,999	564,001	581,001	598,000
u. Reliability Programs – Viper Reclosers CSG				3,068,737	10,818,820	687,602					
v. New Service – Routine Extensions/Services	31,218,356	30,045,634	32,041,224	32,778,534	35,461,061	39,822,261	43,989,000	46,613,999	48,172,000	50,066,000	52,414,001
w. New Service – Discrete Projects	270,393	(6,460)	1,694,834	2,885,901	6,931,705	9,472,844					
x. Routine Streetlights	1,814,413	355,020	813,932	415,268	885,388	824,786	938,998	968,000	997,000	1,025,999	1,077,999
y. Grid Modernization Projects	436,845	6,557,897	2,695,224	7,354,188	36,882,074	115,427,733	111,288,920	56,325,514	40,948,234	33,542,250	10,811,002
z. Mandates – Discrete and Routine Projects	28,920,891	39,332,101	33,646,163	30,416,853	36,641,695	29,170,816	37,185,005	39,574,010	40,551,004	41,558,003	43,285,001
Misc other	(446,910)	2,679,571	1,509,171	2,834,118	1,466,649	4,758,853	1,030,000	1,061,000	1,093,000	1,126,000	1,182,000
Misc non-investment	(15,483,079)	(180,212)	(2,403,371)	(4,874,226)	(5,578,140)	(2,065,128)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)
Total	**204,887,950**	**230,265,531**	**285,461,501**	**283,129,814**	**405,033,285**	**491,706,740**	**556,487,981**	**548,497,838**	**671,168,920**	**867,164,370**	**1,070,702,299**

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Xcel Energy		Information Request No.	45
Docket No.:	E002/M-23-452		
Response To:	Fresh Energy		
Requestor:	Rachel Wiedewitsch		
Date Received:	December 21, 2023		

Question:
Reference: Xcel's November 1, 2023, Integrated Distribution Plan (IDP).

Please provide a live excel spreadsheet version of Attachment A to Fresh Energy Information Request 34 with formulas intact.

Response:
Please see Attachment A to this response for a live excel spreadsheet version of Attachment A of our response to FE Information Request No. 34.

Preparer:	Taige Tople
Title:	Case Specialist
Department:	NSPM Regulatory
Telephone:	612-216-7953
Date:	January 3, 2024

	Actual	Actual	Actual	Actual	Actual	Forecast	Budget	Budget	Budget	Budget	Budget
DRAFT FE IR #34 categories	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
a. Pole Replacement Program	9,843,610	8,792,468	28,517,748	30,208,261	25,619,726	25,940,651	39,344,998	40,516,998	41,679,000	42,876,000	44,162,003
aa. Meter Purchases	5,890,167	7,648,483	6,894,923	6,286,413	6,677,040	5,305,100	4,136,000	4,418,000	4,700,000	4,606,000	4,512,000
b. Restoration/Failure Reserves	14,483,999	18,318,293	19,310,027	17,207,579	42,693,541	5,373,982	21,716,999	27,476,004	33,429,007	21,187,999	21,525,002
bb. Fleet Purchases	8,709,294	6,889,575	10,915,404	14,089,719	15,562,603	21,520,840	35,385,125	17,067,534	15,768,869	18,767,607	20,351,126
c. Routine Rebuilds/Conversions	25,382,713	29,530,229	34,053,523	35,133,442	34,318,368	44,608,580	36,411,001	37,503,006	38,626,995	39,784,995	41,776,004
cc. Communications Equipment	1,299,429	904,096	1,873,512	1,364,514	3,378,326	6,131,929	7,731,519	6,379,891	5,707,549	3,295,786	3,389,481
dd. Corporate Initiatives – Fiber Buildout	8,221	2,135	84,963	1,123,533	2,764,850	2,341,625	2,602,622	2,602,622	2,602,622	2,602,622	2,602,622
e. SE Region Reliability Initiative Reactive Discrete Projects				2,390,419	5,484,079	998,501	3,183,003	3,279,002	3,377,999	3,480,000	3,583,999
ee. Corporate Initiatives – Cyber Security							78,079	78,079	78,079	78,079	78,079
f. Substation Renewal Programs	6,527,934	3,486,138	2,095,290	3,964,343	13,611,739	22,850,214	19,880,519	24,305,653	35,250,658	39,720,526	41,577,544
ff. Tools and Equipment	1,670,775	1,313,446	1,292,597	2,513,693	2,466,719	2,630,213	2,854,219	2,950,513	3,055,489	3,158,730	3,313,147
g. Line Renewal Programs – Network Renewal	1,995,624	2,205,890	1,064,560	1,404,312	2,434,520	5,995,717	7,043,006	7,296,002	7,475,007	7,776,995	3,948,002
gg. Transformer Purchases	27,142,933	17,171,432	20,244,158	21,026,865	23,801,578	33,389,578	24,398,880	24,945,361	26,539,921	27,324,879	32,442,960
h. Line Renewal Programs – Line Equipment Renewal	8,290,254	3,308,697	1,445,871	3,290,545	3,145,650	5,845,721	8,758,999	23,788,000	39,895,002	159,880,000	284,383,998
hh. Electric Vehicle Programs		634,714	90,644	2,515,995	7,227,287	9,330,409	8,943,600	1,372,300	18,361,600	36,873,000	71,843,800
i. Line Renewal Programs – Pole Related Renewal							491,000	22,644,999	37,814,001	69,250,002	72,713,001
j. Line Renewal Programs – High Customer Count Taps								1,999,999	4,000,000	6,000,001	6,300,000
k. Proactive Asset Health – Discrete Projects	9,614,754	10,652,906	10,646,576	9,081,218	14,302,469	25,522,116	42,611,593	24,986,755	21,892,005	16,625,005	30,824,999
l. Capacity – Discrete Projects – Load Growth & m. Capacity – Discrete Projects – Customer Driven	7,922,361	14,632,206	42,483,418	28,678,365	24,857,789	21,101,162	52,343,891	57,571,592	69,212,880	80,388,893	112,467,523
n. Capacity – Routines	4,474,961	5,535,036	3,790,275	2,003,037	4,268,034	6,816,418	4,185,003	4,310,000	4,439,999	4,574,001	4,803,004
o. Capacity Programs – Feeder Load Monitoring	1,265,851	1,450,346	1,078,006	1,379,020	7,661,137	7,808,817	5,299,999	5,299,999	5,299,999	2,000,000	
p. Capacity Programs – Grid Reinforcements					40,259	87,063		16,000,000	20,000,000	46,360,001	49,795,000
q. Capacity Programs – Proactive System Upgrades to Increase Hosting Capacity								10,000,001	59,999,999	59,999,999	59,999,999
r. Reliability – Cable Replacement	21,688,909	17,575,937	28,430,115	23,643,674	37,268,291	31,782,517	36,003,002	38,430,004	41,385,001	44,333,997	46,551,003
s. Reliability Programs – Feeder Performance Improvement Program	1,454,793	1,137,686	1,011,179	695,167	3,271,347	6,708,543	2,122,001	2,186,002	2,252,000	2,320,000	2,390,001
t. Reliability Programs – Reliability Monitoring System	490,462	292,268	141,533	250,325	668,682	1,517,276	531,000	546,999	564,001	581,001	598,000
u. Reliability Programs – Viper Reclosers CSG				3,068,737	10,818,820	687,602					
v. New Service – Routine Extensions/Services	31,218,356	30,045,634	32,041,224	32,778,534	35,461,061	39,822,261	43,989,000	46,613,999	48,172,000	50,066,000	52,414,001
w. New Service – Discrete Projects	270,393	(6,460)	1,694,834	2,885,901	6,931,705	9,472,844					
x. Routine Streetlights	1,814,413	355,020	813,932	415,268	885,388	824,786	938,998	968,000	997,000	1,025,999	1,077,999
y. Grid Modernization Projects	436,845	6,557,897	2,695,224	7,354,188	36,882,074	115,427,733	111,288,920	56,325,514	40,948,234	33,542,250	10,811,002
z. Mandates – Discrete and Routine Projects	28,920,891	39,332,101	33,646,163	30,416,853	36,641,695	29,170,816	37,185,005	39,574,010	40,551,004	41,558,003	43,285,001
Misc other	(446,910)	2,679,571	1,509,171	2,834,118	1,466,649	4,758,853	1,030,000	1,061,000	1,093,000	1,126,000	1,182,000
Misc non-investment	(15,483,079)	(180,212)	(2,403,371)	(4,874,226)	(5,578,140)	(2,065,128)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)
Total	**204,887,950**	**230,265,531**	**285,461,501**	**283,129,814**	**405,033,285**	**491,706,740**	**556,487,981**	**548,497,838**	**671,168,920**	**867,164,370**	**1,070,702,299**

	Actual	Actual	Actual	Actual	Actual	Forecast	Budget	Budget	Budget	Budget	Budget
DRAFT FE IR #34 categories	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
a. Pole Replacement Program	9,843,610	8,792,468	28,517,748	30,208,261	25,619,726	25,940,651	39,344,998	40,516,998	41,679,000	42,876,000	44,162,003
aa. Meter Purchases	5,890,167	7,648,483	6,894,923	6,286,413	6,677,040	5,305,100	4,136,000	4,418,000	4,700,000	4,606,000	4,512,000
b. Restoration/Failure Reserves	14,483,999	18,318,293	19,310,027	17,207,579	42,693,541	5,373,982	21,716,999	27,476,004	33,429,007	21,187,999	21,525,002
bb. Fleet Purchases	8,709,294	6,889,575	10,915,404	14,089,719	15,562,603	21,520,840	35,385,125	17,067,534	15,768,869	18,767,607	20,351,126
c. Routine Rebuilds/Conversions	25,382,713	29,530,229	34,053,523	35,133,442	34,318,368	44,608,580	36,411,001	37,503,006	38,626,995	39,784,995	41,776,004
cc. Communications Equipment	1,299,429	904,096	1,873,512	1,364,514	3,378,326	6,131,929	7,731,519	6,379,891	5,707,549	3,295,786	3,389,481
dd. Corporate Initiatives – Fiber Buildout	8,221	2,135	84,963	1,123,533	2,764,850	2,341,625	2,602,622	2,602,622	2,602,622	2,602,622	2,602,622
e. SE Region Reliability Initiative Reactive Discrete Projects				2,390,419	5,484,079	998,501	3,183,003	3,279,002	3,377,999	3,480,000	3,583,999
ee. Corporate Initiatives – Cyber Security							78,079	78,079	78,079	78,079	78,079
f. Substation Renewal Programs	6,527,934	3,486,138	2,095,290	3,964,343	13,611,739	22,850,214	19,880,519	24,305,653	35,250,658	39,720,526	41,577,544
ff. Tools and Equipment	1,670,775	1,313,446	1,292,597	2,513,693	2,466,719	2,630,213	2,854,219	2,950,513	3,055,489	3,158,730	3,313,147
g. Line Renewal Programs – Network Renewal	1,995,624	2,205,890	1,064,560	1,404,312	2,434,520	5,995,717	7,043,006	7,296,002	7,475,007	7,776,995	3,948,002
gg. Transformer Purchases	27,142,933	17,171,432	20,244,158	21,026,865	23,801,578	33,389,578	24,398,880	24,945,361	26,539,921	27,324,879	32,442,960
h. Line Renewal Programs – Line Equipment Renewal	8,290,254	3,308,697	1,445,871	3,290,545	3,145,650	5,845,721	8,758,999	23,788,000	39,895,002	159,880,000	284,383,998
hh. Electric Vehicle Programs		634,714	90,644	2,515,995	7,227,287	9,330,409	8,943,600	1,372,300	18,361,600	36,873,000	71,843,800
i. Line Renewal Programs – Pole Related Renewal							491,000	22,644,999	37,814,001	69,250,002	72,713,001
j. Line Renewal Programs – High Customer Count Taps								1,999,999	4,000,000	6,000,001	6,300,000
k. Proactive Asset Health – Discrete Projects	9,614,754	10,652,906	10,646,576	9,081,218	14,302,469	25,522,116	42,611,593	24,986,755	21,892,005	16,625,005	30,824,999
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p. Capacity Programs – Grid Reinforcements					40,259	87,063		16,000,000	20,000,000	46,360,001	49,795,000
q. Capacity Programs – Proactive System Upgrades to Increase Hosting Capacity								10,000,001	59,999,999	59,999,999	59,999,999
r. Reliability – Cable Replacement	21,688,909	17,575,937	28,430,115	23,643,674	37,268,291	31,782,517	36,003,002	38,430,004	41,385,001	44,333,997	46,551,003
s. Reliability Programs – Feeder Performance Improvement Program	1,454,793	1,137,686	1,011,179	695,167	3,271,347	6,708,543	2,122,001	2,186,002	2,252,000	2,320,000	2,390,001
t. Reliability Programs – Reliability Monitoring System	490,462	292,268	141,533	250,325	668,682	1,517,276	531,000	546,999	564,001	581,001	598,000
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v. New Service – Routine Extensions/Services	31,218,356	30,045,634	32,041,224	32,778,534	35,461,061	39,822,261	43,989,000	46,613,999	48,172,000	50,066,000	52,414,001
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Misc non-investment	(15,483,079)	(180,212)	(2,403,371)	(4,874,226)	(5,578,140)	(2,065,128)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)
Total	**204,887,950**	**230,265,531**	**285,461,501**	**283,129,814**	**405,033,285**	**491,706,740**	**556,487,981**	**548,497,838**	**671,168,920**	**867,164,370**	**1,070,702,299**

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☒ **Public Document**

Xcel Energy		Information Request No.	24
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Load Forecasting
Reference(s): IDP, Figure 1, p. 3

a. Do each of the IDP scenarios presented in Figure 1 assume achievement of state policy mandates? If not, please explain in detail why not.
b. Does the capital budget provided in this IDP (and the specific investments contemplated in this budget) correspond to any of these IDP scenarios in particular? Please explain in detail.

Response:
a. We are assuming for purposes of this response that state policy mandates refers to the new three percent Distributed Solar Energy Standard (DSES) and the new Community Solar Garden legislation established in the 2023 Minnesota legislative session. All three IDP scenarios account for the three percent DSES. Additionally, the Distributed Energy Resource (DER) Front of the Meter (FTM) Solar PV Forecast in the IDP High scenario assumes that the interconnection of community solar gardens will reach its annual cap (as outlined in the legislation) every year of the forecast. See pages 64 and 65 of Appendix A1 System Planning for more information. Please also see the Company's response to IR 28.
b. The capital budget provided in this IDP corresponds to the scenario called "Budget Plan." See pages 49 and 50 of Appendix A1 System Planning for more information. This "Budget Plan" scenario is a forecast of traditional load growth on the distribution system and does not include the impact of the scenario forecasted DER adoption. With the exception of the "Proactive Upgrades for Hosting Capacity" item, the capital budget provided in this IDP similarly only corresponds to meeting the needs of traditional load growth on the distribution system, not DER adoption. The "Proactive Upgrades for Hosting Capacity" item in the capital budget is intended to provide a high-level start to indicate costs that may be required to accommodate DER adoption but does not correspond to any of the DER forecast scenarios presented in this IDP.

Preparer:	Meghan Tisdell
Title:	Sr Engineer
Department:	NSP Distribution Planning
Telephone:	763-493-1850
Date:	February 15, 2024

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☒ **Public Document**

Xcel Energy		Information Request No.	30
Docket No.:	E002/M-23-452		
Response To:	Minnesota Department of Commerce		
Requestor:	Peter Teigland, Daniel Tikk		
Date Received:	February 5, 2024		

Question:
Topic: Distribution Strategy and Plan
Reference(s): IDP, p. 14

In the referenced section, Xcel indicates that it is "striving to load feeders to approximately 75 percent of maximum capacity."

a. Does the objective of loading feeders to approximately 75 percent of maximum capacity differ from current or historical practices? Please explain in detail.
b. On what basis has Xcel determined the goal of 75 percent of maximum capacity for feeder loading? Please explain in detail.
c. Has Xcel evaluated the cost implications of striving to load feeders to approximately 75 percent of maximum capacity rather than adopting a different standard for feeder loading? Please explain in detail.

Response:
a. No, it has been our historical guideline to load feeders to less than 75 percent of the maximum capacity. However, in the past, capacity mitigations were not required to be initiated for feeders until the N-0 loading exceeded 106 percent of the maximum capacity. Now, we are initiating capacity projects for feeders when the loading exceeds the desired utilization of 75 percent of the maximum capacity.
b. Please refer to Appendix A1, Section C - Planning Criteria and Design guideline (pages 13-18) for more information on the basis of the 75 percent loading guideline.
c. While we have begun evaluations of the cost implications, we are still refining our methodology for an accurate estimate.

Preparer:	Harith Meemaduma
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Department:	Integrated System Planning
Email:	harith.p.meemaduma@xcelenergy.com
Date:	February 15, 2024

Memo to:

David Mino, Xcel Energy

From: Kristina Kelly, DNV
Date: September 27, 2023

Copied to:

Zachary Pollock, Xcel Energy

Prep. By: David Barclay, Kristina Kelly, Kytson McNeil, Nick Posawatz, DNV

Xcel Energy NWA Independent Evaluator Recommendations for NWA Process Improvements

Public Service Company of Colorado (Xcel Energy) retained DNV to serve as the non-wires alternative independent evaluator (NWA IE) for Phase II of their inaugural distribution system plan (DSP) process. As the two NWA RFPs for the Havana and Weld feeder projects put forth by Xcel Colorado did not result in any bids, and therefore did not result in the selection of an NWA solution, DNV instead provides an independent assessment of the NWA process and future process improvements for consideration.

1 BACKGROUND OF NWA INDEPENDENT EVALUATOR

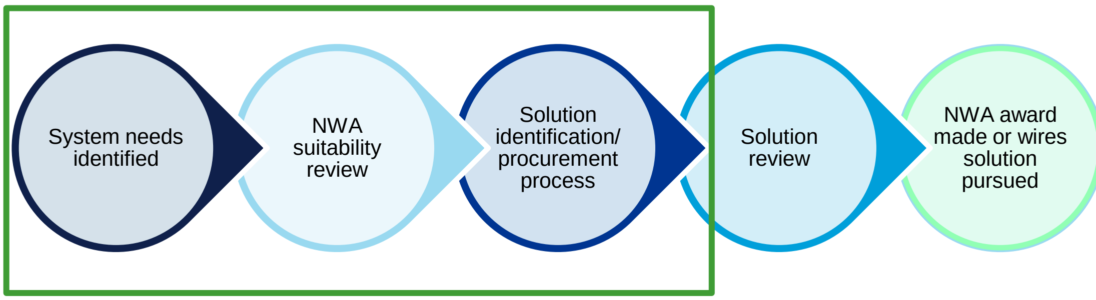
The Colorado Public Utilities Commission issued Decision No. C21-0665 in October of 2021 requiring all utilities with greater than 500,000 customers to file distribution system plans by January 31, 2022. Phase I of those plans must include the results of the utility's NWA suitability screening, an NWA cost benefit methodology, sample NWA contracts and RFPs, and a timeline for its NWA solicitation process in Phase II. Commission rule 3536 of this decision required the utility to retain an independent evaluator (IE) for major grid projects over 2 million dollars, with commission approval, to oversee the NWA solicitation and bid evaluation process and publish a report addressing whether the competitive acquisition procedures and bidding policy were conducted in a fair and reasonable manner.

Xcel Energy selected DNV as the NWA IE and obtained commission approval in December 2022. DNV has extensive experience assessing the NWA suitability of utility transmission and distribution projects and supporting utilities in improving their NWA procurement process. The team has served as the NWA Coordinator for the State of Maine since 2020, conducting NWA assessments on all transmission and distribution projects put forth by the state's utilities and supporting regulatory matters related to NWAs. They have also worked with National Grid to identify go-to-market strategies that would motivate solution vendors to submit an expanded number of cost-effective NWA proposals and have additional hands-on experience working directly with utilities to assess NWA potential and develop and implement procurement and evaluation frameworks for NWAs in California, Florida, Maryland, New York, and Canada.

Xcel Energy and DNV began discussions on the NWA RFP process in April 2023. Xcel Energy shared draft RFP documents and benefit-cost spreadsheets with DNV at this time. DNV reviewed these documents and provided recommended improvements to Xcel Energy on April 24. Xcel Energy and DNV met again on June 12 to discuss next steps in the NWA IE process and DNV submitted a draft report outline for Xcel Energy's review on June 20 and a data request on June 28. As Xcel Energy did not receive any bids on the two NWA RFPs, they requested DNV instead develop a review of the NWA process and potential process changes that could improve the next NWA solicitation process. This document serves to address that request.

2 RECOMMENDATIONS FOR NWA PROCESS IMPROVEMENTS

A typical NWA identification process has five general steps, as shown in the figure below. The process begins with identification of needs on a utility's transmission or distribution systems, followed by a review of those projects to identify those that should be further evaluated for potential NWAs. Once a project has been deemed a suitable NWA candidate the next stage is to identify potential solutions, either internally or through a procurement process. Potential solutions are reviewed to ensure they meet the technical need without introducing new violations and meet established benefit-cost criteria. After this review an NWA contract will be awarded or the wires solution will be pursued should a technically sufficient and cost-effective solution not exist.



While the steps above constitute the general NWA review and procurement process, different jurisdictions take difference approaches to pursuing each step.

- **Colorado:** The Distribution System Planning process requires utilities to identify system needs, conduct a mitigation evaluation, and identify potential NWA candidates in Phase I of the planning process using the NWA suitability review criteria. During Phase II the utility identifies potential NWA solutions through a competitive solicitation process then reviews these solutions against the system need and cost-effectiveness criteria. An NWA solution is procured based on the solicitations received.
- **Maine:** The State of Maine, through its 2019 NWA Statute[1] has retained a third-party NWA coordinator (NWAC) who works with the Office of the Public Advocate, Efficiency Maine Trust, and the investor-owned utilities to conduct the NWA assessment. Under this approach, the utilities conduct a system needs assessment and traditional solution identification process and shares these findings with the NWAC. The NWAC identifies projects suitable for further NWA review based on NWA exclusion criteria and an NWA process planning flow chart and works with Efficiency Maine Trust to identify cost-effective NWA or hybrid NWA solutions with front-of-the-meter or behind-the-meter solutions. The NWAC recommends non-wire alternatives for these projects and the commission determines the appropriate solution for large transmission projects and will resolve disputes between the NWAC and utility if they cannot agree on a solution for distribution and small transmission projects. NWA solutions identified during this process are then procured by the utility or Efficiency Maine Trust. The NWA Statute does not include a timeline in which this process must occur.
- **New York:** The New York Public Service Commission (PSC) requires utilities to evaluate DERs as an alternative to T&D capital projects. The Joint Utilities in New York follow a similar distribution system and NWA assessment process as Colorado. Utilities conduct short and long-term grid needs assessments and identify traditional solutions for each need and use NWA suitability criteria to identify candidates for NWA consideration. Suitability criteria are applied on an annual basis to evaluate projects within the utilities' five-year Capital Investment Plans (CIP), and utilities are required to file update reports 60-days after the close of each quarter. Timeline suitability metrics are applied to screen potential projects and establish evaluation timelines based on project size (small

[1] https://legislature.maine.gov/statutes/35-A/title35-Asec3132-C.html

projects with costs between $300K and $1 million have 18-24 months, and large projects >$1 million have 36-60 months). The utilities typically deploy multiple procurement approaches for individual NWA projects, first leveraging existing energy efficiency programs and contacts from previously awarded bids. If additional needs exist, they then conduct an NWA solicitation via RFP and evaluate the responses against economic and technical criteria. RFPs for market resources are open to all technology and DER approaches as long as they display the potential to provide load relief in the identified areas.

  - National Grid has begun to consider how their energy efficiency (EE) and demand response (DR) programs can support an NWA and increase its cost-effectiveness[2]. ConEd has included a new feasibility assessment step in the NWA process which considers customer demographics, consumption, and the potential for load management before moving to the NWA solicitation process[3].
  - An important factor in ConEd's successful implementation of the Brooklyn Queens Demand Management (BQDM) program has been the ability of customer-sided solutions (CSS) to provide peak reduction benefits. ConEd has used a combination of existing EE and DR programs, direct customer agreements, DER market solicitations, and non-traditional utility-side solutions since the BQDM extension in 2017 to achieve over 61 MW of peak demand reduction[4].

- **Oregon:** Portland General Electric (PGE) has developed a distribution planning process that includes consideration of NWAs throughout the process [5]. PGE conducts a system needs assessment and screens potential grid needs to determine if an NWA could feasibly address the system need. They then develop and test traditional and NWA solutions to determine how the grid needs could technically be addressed. PGE has identified a development process timeline of 6 to 12 months for analysis and development of potential NWAs, and implementation process of 20 to 40 months. They also identify a timeline suitability minimum of 30 months lead time for potential projects. Each NWA evaluation is required to develop two options (reliability and customer resiliency) compared to the traditional wires solution. These options can include a variety of NWA products and services that are selected based on their ability to provide for the required grid need. Solutions are compared using a benefit cost analysis and decision-making rubric before a final solution recommendation is made.

The recommended process improvements discussed below focus on finalizing the size of the need to be addressed by a traditional system upgrade or NWA, the NWA suitability review, and the solution identification/procurement process stages of Xcel Energy's NWA identification process. As Xcel Energy did not receive any bids on their two NWA RFPs, we did not include potential improvements associated with the solution review stage.

2.1 NWA Suitability Review

This section presents considerations for improving the NWA suitability review during Phase I of Xcel Energy's Distribution System Planning process. These include a review of the suitability criteria used to identify projects where an NWA could potentially address the system need during Phase I, surveying the market to identify capabilities of NWA resources as part of the suitability review and reviewing needs identified in the distribution system assessment for comprehensive solutions that could fully or partially address multiple needs.

[2] https://jointutilitiesofny.org/sites/juny/files/National%20Grid%20DSIP.pdf
[3] https://jointutilitiesofny.org/sites/juny/files/Con%20Edison%20DSIP.pdf
[4] https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D09E478A-0000-C53E-9B76-0DCB7E10BF1D}
[5] https://assets.ctfassets.net/416ywc1laqmd/2qj9dgDZHIlnFEPOwhgpjB/d8e47f4e477f0697f5639ee89d33355b/DSP_Part_2_-_Chapter06.pdf

Review NWA Suitability Criteria

Before beginning the second DSP, Xcel Energy should review the suitability criteria used in their inaugural to ensure the process worked as planned and met the original intention of the selected criteria. In reviewing the criteria, Xcel Energy should consider the following:

- Did the suitability criteria result in the selection of projects for further NWA review that were not good NWA candidates?
- Did the suitability criteria exclude projects from further NWA review that may have been good NWA candidates?
- Is the suitability criteria sufficiently detailed such that the decision to exclude projects from further NWA review was clear?
- Does the suitability criteria allow for projects that could be addressed by combinations of resources such as hybrid NWAs, customer resources, and market-based solutions? For example, Xcel eliminated five projects where risks would be present for more than two-thirds of the hours in the year. Projects with needs over the course of the year could be reviewed to determine if increased energy efficiency could address the risks.

We also note that five projects were eliminated from NWA review due to a concern that supply chain challenges would prevent Xcel Energy from timely procurement of the necessary equipment should an NWA be pursued but ultimately not selected. This concern would fall under the suitability criteria of "Are there operational risks presented by either waiting for NWA solicitation or by unique designs of certain distribution assets?" If supply chain challenges are expected to remain a concern in future DSPs, Xcel Energy could review their equipment ordering process to ensure they retain an inventory of spare equipment that could mitigate this concern.

Survey the market for capabilities, installation timelines, and expected costs of technologies to better inform NWA suitability review.

DER performance and costs are constantly evolving. Before finalizing the NWA suitability criteria for the next DSP or conducting the NWA suitability review, Xcel Energy should consider surveying the market to understand current and expected resource capabilities, installation timelines, and costs. Xcel Energy should ask resource providers to indicate if they have solutions that could meet different sets of needs (based on different combinations of duration, capacity, and seasonality) and provide a range of costs associated with those solutions. This information can be used to identify updates to the suitability review or be used to inform the RFP process, as discussed further below.

Identify local area studies, or studies of the needs being addressed by a combination of projects in a localized portion of the system.

After conducting the distribution system assessment and identifying needs, Xcel should consider reviewing projects in a local area to understand if a comprehensive solution exists that can address or reduce multiple needs at a lower cost than the individual projects. This analysis should also include determining how the implementation of one project may change the needs associated with another project. For example, a substation upgrade on one part of the system may allow for additional load switching opportunities during contingency events on another part of the local system, potentially reducing the size of that need. This analysis could be conducted before the NWA suitability review is completed in Phase I or to determine the final market need before Xcel Energy prepares an RFP to solicit market-based solutions.

2.2 Solution Identification

2.2.1 Determine market need.

The needs identified in Phase I of the DSP should be reviewed and translated into requirements that potential bidders can respond to. This section discusses approaches Xcel Energy could employ to finalize the current and future system needs that can be addressed through procurement of market-based solutions before preparing an RFP to solicit these resources. The magnitude, timing, and duration of the need a utility is looking to address can be larger or more complex than a single solution can cost-effectively address. Reducing the size of the need before soliciting solutions from third-parties or providing opportunities for a combination of resources to serve as the NWA, can result in successful implementation of NWA solutions. This includes understanding how system changes will impact the total need and how Xcel's internal resources could reduce the need included in the NWA RFP.

Xcel should facilitate a transparent selection process that results in a cost-effective solution for ratepayers by ensuring that internal solutions or resources installed outside of the NWA process are treated fairly. This may require these resources (internal or external to Xcel Energy) to participate in the RFP process or modifications to NWA RFPs that provide potential bidders with the option to respond to the full need or a reduced need after other resources are applied. If the RFP includes an option to respond to a reduced need, Xcel should clarify how the benefit-cost assessment will be conducted to ensure bidders understand how their solution will be evaluated.

Include approved DERs in needs assessment.

DER projects in the area can reduce or eliminate the identified system need. Xcel Energy's current mitigation evaluation process considers how DERs can meet system needs by serving as an NWA[6]. Xcel Energy should ensure that the magnitude, timing, and duration of any system need includes the impact of existing distributed energy resource (DER) projects and projects in the interconnection queue. The following should be done to ensure DERs are appropriately considered:

- Develop dispatch assumptions for DERs that are agreed upon by all internal parties conducting or utilizing the system needs assessment.
- Coordinate with the system planning department to determine if existing front-of-the-meter and behind-the-meter DERs were considered during the distribution system needs assessment and what dispatch and availability assumptions were used when including them in the assessment.
- Consider including DERs in the interconnection queue that have signed interconnection agreements as they have a high likelihood of implementation.
- Review the list of existing DERs and DERs in the interconnection queue to understand the types of resources that are available and compare against the identified system need to determine if these resources could reduce or eliminate the need if utilized as an NWA.

This process may include targeting developers of projects in the interconnection queue or owners of existing DERs to understand how their technology could support the NWA and what kind of contractual agreement and payment would be needed to ensure their participation.

[6] Xcel Energy. "Public Service Company of Colorado Distribution System Plan." May 2, 2022.

Conduct an internal NWA assessment to identify hybrid NWA opportunities.

Hybrid NWAs are combinations of modifications or improvements to infrastructure and NWA resources that more cost-effectively meet the same need as the original wires solution. These solutions often include infrastructure improvements such as new SCADA switches and distribution tie-lines that support additional load shifting during contingency events and may improve system reliability outside contingency events[7]. Xcel Energy's current system needs assessment and mitigation evaluation process seek to identify the most cost-effective solution and considers options that support load transfers and/or add additional capacity to the system[8]. When reviewing the system need for a potential NWA project, Xcel Energy should continue to evaluate opportunities to make changes to existing infrastructure or minor modifications that could cost-effectively reduce or eliminate the identified system need.

Where a minor system modification can reduce, but not eliminate, the identified system need, Xcel Energy could procure a smaller (based on duration or size of remaining need) resource through its solicitation process and potentially increasing the number of cost-effective solutions they receive from the market. However, it is not entirely clear whether the Commission's current DSP rules would allow Xcel Energy to implement internal modifications without participating in the NWA procurement process. A procedural review of the procurement process may be needed to facilitate the use of solutions internal to Xcel Energy.

Conduct an internal NWA assessment to identify customer program NWA opportunities.

A flexible NWA procurement framework that allows Xcel Energy to review internal solutions able to address all or a portion of the need could lead to more cost-effective NWA solutions. Existing customer programs or targeted customer programs can alleviate identified system need, thus reducing the services required from third-party NWA resources. Xcel Energy should consider whether the identified need could be met with a combination of resources from existing or modified customer programs (such as energy efficiency, demand response, and electric vehicle managed charging programs). Xcel Energy should increase familiarity of NWAs amongst departments engaged in developing and implementing customer solutions to improve their ability to recommend resources that could be included in an NWA.

Xcel Energy should also review customers in the area and identify large users that may be able to reduce or shift load through load curtailment or the use of energy storage. If Xcel Energy pursues this solution, they should consider how to pursue these resources in a way that ensures the NWA procurement process remains fair to the market and results in a cost-effective solution for ratepayers. This could include requiring these resources to participate in the formal RFP process and utilizing a firewall that ensures the department within Xcel Energy submitting bids in response to the NWA solicitation would not have access to data or information that external bidders would also not be able to access.

Develop a process to combine resources into a full NWA solution.

To facilitate the deployment of NWAs that are a combination of multiple resources, Xcel Energy should develop a process that allows them to manage a portfolio of resources to address the system need. This could include a DERMs system that can manage multiple DERs, resource dispatch planning and contractual agreements that determine how and when resources will be utilized, or an internal staff member that monitors the performance of all resources and works across departments to modify the portfolio as needed. Virtual power plants and energy performance contracting are examples of partnerships and resource portfolios used to facilitate market activities; Xcel could review how these programs operate to identify best practices in developing a similar approach.

[7] An example of a cost-effective hybrid non-wires alternative project that avoids the rebuild of a 34.5 kv transmission line can be found here: https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={D7C4CE6D-B70F-4995-88DB-B0D37884064E}&DocExt=pdf&DocName={D7C4CE6D-B70F-4995-88DB-B0D37884064E}.pdf

[8] Xcel Energy. "Distribution System Planning." June 06, 2020.

2.2.2 Solution Procurement Process

This section presents recommendations that would increase Xcel Energy's understanding of the market's ability to address the system need before the formal RFP process and provide more clarity to potential bidders during the NWA procurement process.

Understand potential resources through a request for information (RFI) process.

To ensure there are resources in the market that can meet the full (or modified) system need, Xcel Energy could conduct a request for information (RFI) process with potential bidders to identify potential solutions and costs before the full RFP process. An RFI can provide Xcel Energy with insights on whether bidders are interested in the potential project and what resources are available, and at what cost, to address the system need. The RFI process can reduce burden on potential bidders and Xcel Energy staff compared to the full RFP process as bidders can respond to them quicker than a full RFP and Xcel Energy staff will have information that can help them decide whether to move forward with an RFP or how to modify the RFP to align with what the market can provide.

While Xcel Energy is required to have a technology-neutral solicitation process, an RFI can provide information that will help Xcel Energy determine what solutions can meet the system needs and target potential bidders who can provide these solutions. This could however result in an increase in qualified bids as bidders with the applicable resources will have more confidence that their solution is a good fit.

Provide direction to bidders on expectations after the NWA deferral period and opportunities for additional or continued revenue.

When an NWA resource is needed to defer a wires solution, it is often utilized as an NWA resource for less time than its effective useful life. In these instances, bidders will either compare the full cost of their solution to the deferral value of the NWA or include the impact of other revenue sources in the benefit-cost assessment or the solution cost they include in their proposal. To support bidders in finding and quantifying other revenue sources and thus reducing the cost of procuring the resource for an NWA, Xcel Energy should consider the following:

- Work with other groups within Xcel Energy to determine if an NWA resource could also be used to meet additional system needs. If the NWA could support other system needs without impacting its ability to address the original system need, Xcel should include that information in the RFP so potential bidders can adjust their proposals and costs in alignment with their ability to fulfil additional use cases.
- Provide guidance to bidders on expected use of the resource after the deferral period has ended. This could include using the resource to continue mitigating thermal overloads or providing bidders the ability to relocate the resource to other parts of the system.

AGIS CPCN
Annual Forecast Report for 2024

Distribution Grid Enhancements, Including Advanced Metering and Integrated Volt-VAr Optimization Infrastructure

Proceeding No. 16A-0588E

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A PORTION OF THIS DOCUMENT HAS BEEN FILED UNDER SEAL

Confidential: Page 20

October 31, 2023

TABLE OF CONTENTS

I. INTRODUCTION

On August 2, 2016, Public Service Company of Colorado ("Public Service" or the "Company") filed an Application and Direct Testimony in Proceeding No. 16A-0588E (the "CPCN Proceeding"), requesting that the Commission grant a Certificate of Public Convenience and Necessity ("CPCN") to implement distribution grid enhancements. These included Advanced Metering Infrastructure ("AMI"); Integrated Volt-VAr Optimization Infrastructure ("IVVO"); and the associated components of an advanced communications network, known as the Field Area Network ("FAN"), to support the AMI and IVVO (collectively, the "CPCN Projects"). These CPCN Projects are part of the Company's broader Advanced Grid Intelligence and Security ("AGIS") initiative.[1]

AMI consists of meters that measure and transmit voltage, current, and power quality data through the FAN. These meters act as sensors providing near real-time monitoring to the Company and customers, which cannot be done by the Company's existing automated meter reading ("AMR") meters. IVVO uses the voltage information transmitted by advanced meters to automate and optimize the operation of distribution voltage, ultimately allowing the Company to lower voltage across the system.

The Colorado Public Utilities Commission (the "Commission") approved the Company's request for a CPCN pursuant to its Application as part of a Settlement Agreement between the parties in Proceeding No. 16A-0588E. The Settlement

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[1] In its Application, the Company also explained that the broader AGIS initiative includes components that the Company intends to implement in the ordinary course of business, which include: the Advanced Distribution Management System ("ADMS"), Fault Location Isolation and Service Restoration ("FLISR"), Fault Location Prediction ("FLP"), Geospatial Information System ("GIS"), and the portions of the FAN not associated with the CPCN Projects. (Application, p. 8, ¶3.) The Company did not seek a CPCN for these projects because they are foundational components of the grid and/or logical extensions of work that utilities have traditionally performed and signify the continued use of advancing technologies in a normal evolution of the business.

Agreement in Proceeding No. 16A-0588E was approved in Decision No. C17-0556, mailed on July 25, 2017. As part of the Settlement Agreement, the Company agreed to keep the Commission regularly updated of project milestones, scope, costs, and status of the CPCN Projects. Specifically, the Company agreed to provide two separate annual reports: an annual Actuals Report filed in May each year, and an annual Forecast Report filed in October.

On December 23, 2020, Mission:data Coalition, Inc., ("Mission;data") filed a Motion with the Commission to reopen and combine the AGIS CPCN Proceeding with the Home Area Network application in Proceeding No. 18A-0194E ("HAN Proceeding"). The Commission subsequently denied Mission:data's Motion; however, the Commission ordered Public Service to file a new Application to amend its existing CPCN in a new proceeding by June 15, 2021. Also within the Commission's decision was an order that Public Service not enable the Distributed Intelligence ("DI") functionality. This Application is located within Proceeding No. 21A-0279E, where the Commission approved the Unanimous and Comprehensive Settlement Agreement by Decision No. R22-0131 in that proceeding.

This report is the seventh annual Forecast Report filed by the Company, and provides information on each of these topics, as well as information regarding the implementation of the Home Area Network ("HAN"). Consistent with the Direct Testimony of Company witness Ms. Alice K. Jackson in Proceeding No. 16A-0588E, the annual Forecast Report provides: (1) a forecast summary for the upcoming year; (2) a full-term business plan, including the scope of work for the CPCN Projects; (3) forecasted operations and maintenance ("O&M") and capital expenditures for the upcoming year; (4)

parent project numbers including details of additions and closings of parent project numbers; and (5) planning and implementation of customer education surrounding the CPCN projects.[2] The remainder of the report is organized in the following sections:

- Section II. Full-Term Project Business Plan – This Section of the Report identifies the project milestones and overall project status, as detailed in the second category of information required in this Report as identified in Ms. Jackson's Direct Testimony.

- Section III. 2024 Individual Project Business Plans – This Section of the Report details the business plan overview for the upcoming year as detailed in the first category of information required in this Report as addressed in Ms. Jackson's Direct Testimony.

- Section IV. Forecasted O&M and Capital Spend for 2024 – This Section of the Report provides a cost summary, as required by the reporting requirements consistent with Ms. Jackson's Direct Testimony and includes the forecasted O&M and capital spend for the next calendar year. It also includes the individual internal orders ("I/O's") associated with O&M costs which address the issue of potential double recovery. [3] are provided in this section of the report. This addresses the third and fourth categories of reporting requirements consistent with Ms. Jackson's Direct Testimony and the Settlement Agreement.

- Section V. Customer Education – Per the Settlement Agreement and as identified above as the fifth category of information required by this Report, the Company is required to provide an update on the planning and implementation of customer education related to AGIS.

- Section VI. Advanced Meter and TOU Implementation – This Section addresses the Company's requirement for bi-monthly reporting on the deployment of advance meters, specifically deferred net-metered customers, and time-of-use rates.

- Section VII. Conclusion

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[2] Proceeding No. 16A-0588E, Direct Testimony Ms. Alice K. Jackson, at p. 59, line 18 – p. 60, line 6; Settlement Agreement Settlement Agreement, at 6.

[3] *See, e.g.* Settlement Agreement, at 11-13; 17.

A. AMI

The deployment of AMI has two components: Software Deployment and Meter Deployment. Regarding Software Deployment, AMI head-end software has been deployed into the production environment and interfaces have been built to transfer the data to other applications. Regarding Meter Deployment, in 2019, the Company completed a plan for the purchase and delivery of advanced meters to initially support IVVO. Full scale deployment of the AMI meters began in June of 2021 and will continue into 2025.

Advanced meters deployed by the Company have embedded Distributed Intelligence ("DI") capabilities. DI involves a localized computer processing capability at the meter itself, which is designed to minimize calculating and feedback time to both the meter and a centralized computing/control system. The Company is in the process of deploying initial foundational grid-facing and customer-facing capabilities in accordance with the settlement agreement. For instance, The Company is in the process of releasing a mobile application called My Energy Connection that provides customers with one-second, detailed information on their energy usage.[4] The first release of this mobile application provides users with real-time meter data, energy usage, and rate information starting with the ability to access this information from home via the DI enabled HAN. The Company completed installation of 310,000 AMI meters in 2021 and 413,030 in 2022. Further details associated with mass meter deployment in 2023 and beyond is described in Section III.

[4] One-second data is available in home; away from home, the data is 15-minute usage intervals.

B. IVVO

In 2019, the Company completed a plan for the purchase and delivery of advanced meters to initially support IVVO and conducted testing of those meters and associated data in preparation for deployment; in December 2019, the Company completed installation of the required 13,000 advanced meters per the Settlement Agreement in Proceeding No. 16A-0588E. A subset of the 13,000 meters is used as bellwether meters for IVVO. Bellwether meters are meters that are strategically located on distribution feeders to help measure quantities such as voltage and power that can be used in conjunction with ADMS to manage voltage and power flow along distribution feeders. The IVVO advanced application was initially enabled at one transformer area in April 2019, and to-date, there are 73 additional areas fully enabled. To support this functionality, the installed intelligent field devices have been integrated into ADMS and are controlled by the IVVO application.

In 2024, the Company will continue the deployment of IVVO-enabling devices, including capacitors, secondary static VAr compensators ("SVCs"), and Load Tap Changer ("LTC") controllers. Section III quantifies the device installation and accomplishments for 2023, the forecasted deployment for 2024, and addresses increased installations based on delays from previous years.

C. FAN

In 2024, the Company will continue to work toward FAN implementation targets as detailed in Sections II and III. The portion of the FAN that is associated with the implementation of AMI and IVVO is known as the Wireless Smart Utility Network ("WiSUN"). The backbone of the WiSUN network is comprised of strategically located

Access Points ("APs") and Repeaters installed across the system primarily on existing Company assets such as wood poles and streetlights; cellular modems are utilized in conjunction with the APs to provide communication with the Company's network, utilizing public or private Long Term Evolution ("LTE") or other forms of wireless and wireline communications technologies to communicate with the Xcel Energy Wide Area Network ("WAN"). Cellular modems and WiSUN bridge technology will be installed in IVVO devices to provide communication with the Company's network. Once fully implemented, the Company will have a mesh-network enabling multiple pathways for communication with AMI, IVVO, and other intelligent field devices such as Fault Location Isolation and Service Restoration ("FLISR").

II. FULL TERM PROJECT BUSINESS PLAN

A. AMI

The Company plans to deploy a total of approximately 1.6 million advanced meters in Colorado. The future deployment for the initiative is set forth in Releases as shown in Tables 1 and 2 in order to establish the functionality and desired outcomes. This Section provides the current plan for the initiative encompassing AMI, IVVO, and FAN through 2025. Individual plans follow in Section III, Individual Project Business Plans. Table 1 below outlines significant AMI deployment milestones organized by year and quarter:

Table 1 – AMI Meter Deployment Milestones

YEAR	Quarter 1	Quarter 2	Quarter 3	Quarter 4
2021	AMI Release 3: Functions deployed to support mass AMI deployment		Deployment of 310,000 advanced meters	Completed deployment of 310,000 advanced meters AMI Release 3: interfaces code in production
2022	Deployment of 413,030 advanced meters		Deployment Plan revised as a result of global supply chain constraints	Completed deployment of 413,030 advanced meters[5] AMI Release 4: interfaces in production.
2023	Began deployment of 345,000 advanced meters. Itron drove meter deployment adjustments that pushed end of deployment into 2025		Additional adjustments by Itron on expected meter install volumes for 2024 and 2025 established in Q1-Q2, 2023	Complete deployment of 345,000 advanced meters
2024	Begin deployment of 372,000 advanced meters			Complete deployment of 372,000 advanced meters
2025	Begin deployment of remaining advanced meters			Complete deployment of remaining advanced meters

Software development is a significant component of the overall AMI initiative, and as new system Releases are brought on-line, the overall level of functionality of the system increases. Table 2 below outlines major functionalities that have been released and that are planned as part of the project:

[5] See Table 5 below for discussion about the revision to the deployment plan.

Table 2 – AMI Software Milestones by Year

2021 (Release 3)	2022 (Release 4)	2023	2024
My Account/Mobile – customer access to usage information	Analytics – theft use case	EV rate programs	Complex Rates capability
Analytics – Non-Theft Use Cases	Non-critical reporting – data warehouse	Benefit / Value Realization reports	Grid Visibility Tool
Remote connect/disconnect	Provide usage data to customers up to last regular read	Disaster Recovery capabilities	New Meter Configuration
Expanded events processing capability	TOU rate programs		Benefit / Value realization reports
Green Button Connect My Data	Customer on-demand reads		
Real-time Customer Care data access	Meter Exchange enablement, Billing programs and Usage Presentment for Large Commercial Customers		
Expanded over the air programming and configuration use cases	Net metering rate programs		
HAN			

As mentioned in Section I, all meters have DI capabilities, which are further outlined in Proceeding No. 21A-0279E. DI or "grid edge computing" refers to the distribution of computing power, analytics, decisions, and actions away from a central control point and closer to localized devices or platforms where it is actually needed. For some of these capabilities, data will no longer have to traverse over the network and thus these technologies will improve the computational speed, efficiency, and capabilities derived from these platforms. The Unanimous and Comprehensive Settlement Agreement in Proceeding No. 21A-0279E details the parameters of the Company's DI capabilities moving forward.

B. IVVO

The full scope of the deployment provides for energy savings through IVVO operations on 450 feeders, enabled through work performed from the end of 2017 through

2024. During this period, the Company will deploy approximately 884 overhead and 97 pad-mounted capacitor banks, 4,060SVCs, and replace LTC controllers on 128 substation transformers. As this equipment is deployed, the Company is able to begin lowering the LTC voltage setpoint to achieve initial energy savings. Through IVVO, the benefit of energy savings through voltage reduction is planned to ramp up to approximately 330,000 MWh annually. Concurrently, the Company estimates an additional approximately 9,167 MWh in annual loss reduction through power factor improvement and approximately 44 MW in demand reduction.

The Company has also been working to enable substations with IVVO functionality. IVVO is enabled one transformer area at a time, with each transformer generally consisting of three or four feeders. The Company began fully enabled IVVO operation on five transformer areas in 2019 and expanded to 46 more areas by third quarter 2022. In addition, the Company lowers the LTC setpoint or voltage at each substation transformer areas when the LTC upgrades are complete and areas that we have capacitors fully deployed, and where there is confidence in the local voltage support. This also results in a lower voltage and energy savings for customers prior to fully enabling IVVO functionality for each substation transformer area.

Reducing voltage at the customer's point of service results in energy savings because many appliances and loads operate more efficiently at reduced voltages. As equipment (capacitors, SVCs, and LTC controls) is deployed, the Company is able to begin lowering the LTC setpoint to achieve initial energy savings, even prior to ADMS control of IVVO. This is possible because the capacitance installed for the project can safely allow for a partial reduction without risking low voltage to customers.

IVVO 2023 Milestones:

- Enable 110 feeders in ADMS – Quarters 1-4, 2023
- 15 LTC upgrades complete – Quarters 1-4, 2023

Table 3 – IVVO Deployment by Year

	Previous Years	2022	2023	2024
Capacitors	620	200	42	119
SVCs	3,160	400	261	239
LTCs	74	30	15	9
Original Energy Savings (MWh)	295,000	255,000	336,000	332,000
Energy Savings (MWh)	210,064	193,932	336,000[6]	332,000
Net[7]	**-84,936**	**-61,068**	**0**	**0**
	Previous Years	**2022**	**2023**	**2024**
Original Loss Reduction Forecast (MWh)	7,792	6,875	9,167	9,167
New Loss Reduction (MWh) Forecast	7,121	8516	9,167	9,167
Net[8]	**-679**	**-1641**	**0**	**0**
Original Demand Reduction Forecast (MW)	22.5	33.4	43.9	43.4
New Demand Reduction Forecast (MW)	20.5	32.0	33.4	43.4
Net[9]	**-2.0**	**-1.4**	**0**	**0**

[6] 2023 Energy Savings (MWh) are expected to be in the range 240,000 MWh to 255,000 MWh. The lower energy savings is based on the increased complexity and time to deploy the technology to each transformer area. Despite the reduced rate of deployment, the areas that are running IVVO have seen average energy reduction greater than 2 percent, considerably higher than the expected reduction of 1.83.

[7] "Net" is the decrease in actual energy savings currently projected from the original forecast in this Proceeding.

[8] "Net" is the decrease in loss reduction currently projected from the original forecast in this Proceeding.

[9] "Net" is the decrease in demand reduction currently projected from the original forecast in this Proceeding.

C. <u>FAN</u>

Public Service's FAN is a resilient wireless communications network that will provide connectivity and enable two-way communications between the existing infrastructure at the Company's data centers and new and planned field devices up to and including the customer meters.

The FAN is comprised of two components that rely on a third – Xcel Energy's wide area network ("WAN"), as follows:

(1) a *mesh* Wireless Smart Utility Network (WiSUN) network between and among field access points and field devices that uses radio frequency (RF) technologies,

(2) a *backhaul* network that delivers data collected by the mesh network to the existing WAN, using varying wireless and wireline communications technologies – delivering data to the Xcel Energy WAN or backbone, which uses Layer-3 networks (routers, switches, and circuits) to deliver data to and from the Company's information systems.

(3) the corporate *wide area network*, which contains the AMI head-end application, other advanced grid and business applications, and the company's server and storage infrastructure.

WiSUN will be deployed throughout the entire network where we are connecting to field devices such as AMI meters. We are currently primarily utilizing public LTE (cellular) for the backhaul connectivity between the WiSUN network and the Company's WAN.

Utilization of LTE, whether it is public or private, consists of wireless cellular modems installed adjacent to WiSUN access points, and connecting to the Xcel Energy wide area network ("WAN") via a public carrier such as AT&T or Verizon, or a private solution. This is proven technology that is used by other utilities with similar needs and will ensure the Company meets its commitments to our customers. In some cases, it is necessary and appropriate to utilize other technologies, where LTE coverage may not be sufficient for the Company's data needs. In much more limited circumstances, the Company is identifying remote locations where there may not currently be a cost-effective technology to transmit data from the AMI meters wirelessly – and so, we are evaluating short-term alternatives to AMI meters to perform the necessary meter reads until such time as LTE or some other wireless or wired solution becomes economically viable to support AMI meters.

The FAN is being implemented in three phases: (1) Design, (2) Surveys, and (3) Installation. WiSUN devices are located on the Company's distribution poles or pad-mounted equipment to have effective communication coverage with end-devices. Site surveys are performed. Also, the Company inspects each location identified in the design phase and evaluates the potential to install a FAN device. These inspections confirm that the Company can receive the appropriate signal anticipated in the design phase at the height and location on the pole where the FAN device is planned to be located. In instances where the Company cannot add a FAN device to the existing pole, a new location is evaluated.

Installation of FAN devices will continue through 2024. Network optimization occurs throughout the project as AMI deployment is completed in geographic areas.

Table 4 – WiSUN Deployment Timeline

YEAR	Quarter 1	Quarter 2	Quarter 3	Quarter 4
2021		Complete WiSUN Installation for Release 3		Complete WiSUN Installation for 200 Capacitors Network Optimization for 13,000 Meters
2022	Network Optimization for Release 3	Complete WiSUN Installation for Release 4		Complete WiSUN Installation for 250 Capacitors
2023	Network Optimization for Release 4. Complete WiSUN Installation for 60 Capacitors	Complete WiSUN Installation for 70 Capacitors	Complete WiSUN Installation for 70 Capacitors	Complete WiSUN Installation for remainder of meters. Complete WiSUN Installation for 50 Capacitors
2024	Complete WiSUN Installation for 50 Capacitors	Complete WiSUN Installation for 65 Capacitors	Network Optimization for remainder of meters complete WiSUN Installation for 64 Capacitors	

III. 2024 INDIVIDUAL PROJECT BUSINESS PLANS

A. AMI

In this subpart, the Company first describes what is needed to integrate to complete the overall AGIS initiative related to AMI.

i. **Software Development** – Technology Services (formerly Business Systems) is responsible for integrating AMI, as well as other AGIS systems and related data, with the Company's existing applications. Specifically, Technology Services has implemented new AMI head-end software that has been installed and configured to run on new server hardware. From the AMI head-end, interfaces have been built to transfer the data to other applications, such as the billing and customer service system. This integration work allows the Company's existing infrastructure to "speak with" the new infrastructure being implemented pursuant to the AGIS initiative. For any software capability that is deployed into Production the following phases of software development are followed which include but are not limited to:

- Blueprinting, Analysis and Requirements,
- Design with extensive reviews,
- Build,
- Testing, and
- Deployment into Production
- In certain cases, such as Billing, Business partners go through thorough Billing validation testing to ensure that Bills produced are accurate.

From an AMI Core functionality perspective, work began in 2020 to provide several critical business applications, including mass meter deployment and exchanges, interval billing of simple residential rates, and AMI meter opt-out tracking. The following functions were deployed in 2023:

1) Net Metering: A billing mechanism that credits solar energy system owners for the electricity they add to the grid is a software capability being built and tested in Q4 2022. Business partners from various groups will conduct Billing validation tests once the software capability is deployed into Production. This capability was available for customers starting Q1 2023.

Also, the Company completed design and planning of additional interfaces of the AMI software solutions continued through 2023 for the following projects:

1) The Company continues to enhance Meter Data Lake capabilities with the intent to support analytics capabilities for additional customer types (Complex Rate Customers – Large C&I). Company will continue to enhance Meter Data Lake as a platform to consolidate meter data and support use cases around data sharing and analytics on top of the platform. The goals for the Meter Data Lake are:

    - Ingest data from meters that come from head ends and from Meter Data Management system into a cloud storage layer,
    - Solve for connectivity between on-premises systems and cloud layer to support data ingestion,
    - Solve for storage layers for retention of meter data,
    - Solve for data access for consumption by other systems and users, and
    - Solve for reporting/analytics on top of meter data for various use cases by users' information to AMI such as aggregate data leveraging connectivity model to calculate load by distribution asset and support power quality investigations. Software that can leverage AMI data to identify momentary outages is also being built.

2) Complex Rates: In 2023, the Company is in the process of deploying the final software release, which includes a scope of work needed for bridge meters and non-residential "complex" rates with polyphase meters. These meters are currently billed using the Company's legacy meter data system. In order to transfer the information for these meters to the new meter data management system, all of the meter billing data and information for metering reading and exchanges needs to be automated to support the number of meter exchanges as it is not possible to transfer it manually. The Company will automate this process to support the meter exchange for customers with bridge meters and "complex" rates with polyphase meters. The software is anticipated to be

deployed in 2024 and the transfer of information would happen in 2024-2025, at which time the Company will begin meter exchanges for these meter types.

3) New Meter Configuration: In 2023, the Company has also been in the process of enhancing meter to bill functionality to support new Riva 3.1 capabilities. Also, data processes will be updated to deploy new meter programs across all meters, improving meter operations.

4) Grid Visibility Tool: The Company is in the process of building software that can leverage AMI data in conjunction with the GIS asset information to calculate load by distribution asset and support power quality investigations. Software that can leverage AMI data to identify momentary outages is also being built.
5) Benefit / Value Realization reports: The Company is in the process of building reports to summarize AMI deployment-related stats and to capture and approximate value/benefits the Company is realizing from the deployment of AMI. Examples are: (1) to demonstrate a reduction in the numbers of estimated bills the Company issues to customers, one report captures the number of estimated bills for customers with AMI meters and compares that to pre-AMI, (2) volumes of remote connect/disconnect ("RCD") commands, which can be used to approximate the efficiency of avoided field trips to perform the connect/disconnect, and (3) an approximation of the reduction in avoided energy losses, which reduces fuel costs for our customers, stemming from RCD by preventing usage on accounts where there is no registered customer. An example of a deployment-related report is the numbers of customers opting-out of an AMI meter.
6) Disaster Recovery: In 2023-2024, the Company will conduct Disaster Recovery tests/exercises on the application within AMI software solution to ensure that the Company can restore data and applications and continue business operations in case there is an interruption of its services, critical IT failure, or a broader disruption.

ii. **Meter Deployment –** Meter Deployment includes AMI hardware evaluation, testing, acquisition, configuration, and deployment of electric meter assets. An AMI meter contract was signed in September 2019. Because of the timeline required to have the advanced meters with DI capability available, the Company shifted out the start of mass deployment from the original start of 2020 that was originally detailed in the Settlement Agreement in Proceeding No. 16A-0588E. The Company started mass deployment in 2021 and expects to be complete in 2025. The Company included early opt-in information for customers with onsite solar systems when they began receiving their meters.

iii. As of September 30, 2023, a total of 986,713 meters have been deployed. Table 5 below identifies the difference in number of meters anticipated to be deployed from the original settlement:

Table 5 – Amended Meter Roll-Out Target Schedule

Year	Original Settlement	2021 Adjustment	2022 Adjustment	2023 Adjustment
2020	162,000	-	-	-
2021	395,000	310,000	310,000	310,000
2022	480,000	534,000	400,000	413,030
2023	450,000	504,000	448,920	345,000
2024	Remainder	Remainder	Remainder	372,000
2025				Remainder

Additionally, the original 13,000 meters deployed in 2019 are being replaced during the mass rollout with the new DI-capable Advanced meters. The Company negotiated for the AMI vendor to replace the meters at no cost to the Company, including both the cost of the advanced meter and labor associated with replacement.

The reduction in deployment of meters from 395,000 to 310,000 in 2021 was the result of the global supply shortage of components required in the manufacturing of the meters. In July 2021, Itron informed the Company of increased lead times for components from their suppliers and impacts on meter availability. The supply chain impacts continued into 2022, necessitating the Company and Itron to develop another revised meter deployment plan for 2022-2025 as reflected in Table 5.

<u>Testing</u> – In 2020, the Company began testing next generation, or DI-capable, advanced meters from Itron, focusing on electric distribution and customer operational requirements. The Company then conducted Integration Testing, which examines business requirements and functionality across all products, applications, and platforms involved in the implementation of AMI, from meter to bill.

The Company continued AMI meter testing in 2022 and 2023. Meter testing included polyphase first article testing, integration testing, and final validation testing, where data is gathered for billable reads to produce customer bills.

Table 6 – Continued Meter Testing Schedule

Scheduled Milestone	Timeframe
Start Mass Deployment Single Phase	End of 2nd Quarter to 4th Quarter 2021
First Article Testing Polyphase	4th Quarter 2021 to 2nd Quarter 2023
Integration Testing Polyphase	1st Quarter 2022 to 2nd Quarter 2023
Production Sample Test Polyphase	3rd Quarter 2023
Start Mass Deployment Polyphase	3rd Quarter 2023

The Company must also provide the cost of the selected meters per the Settlement Agreement in Proceeding No. 16A-0588E. Costs associated with the Itron meters by type are listed below.

Table 7 – AMI Forecasted Meter Costs

Meter Type	Average Cost ($/unit)[10]
Residential	[redacted]
Commercial	[redacted]
Blended (all meters)	[redacted]
Installation Cost	[redacted]

iv. AMI Meter Installation - Customer vs. Company Funded Repairs

On April 20, 2021, the Company filed Advice No. 1853 – Electric in Proceeding No. 21AL-0158E, to allow the Company to facilitate minor repairs to customer-owned meter sockets and housings, but limited that to facilities located before the customer-owned

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[10] Several assumptions went into the calculation of this meter price, including:

- Blended costs combine various meter forms into two categories.
- [redacted]

conductor found during the installation of their AMI meter. As part of the approval of this filing, the Company is to report on Company funded work, the number of customers and dollars spent on that work in the semi-annual AGIS CPCN Reports. As of September 30, 2023, the Company performed 1,809 meter-related repairs in which the equipment on the customer's side required repairs that fall within the specific guidelines under which the Company would perform such repairs. The cumulative costs attributed to this work is $1,644,011.

B. IVVO

During 2024, the Company will continue to install voltage control devices and enable IVVO on additional feeders in accordance with our plans. The updated deployment plan can be seen in Table 3 above.

The Company will continue enabling substations with IVVO functionality within ADMS in 2024. Specifically, 25 substations, comprising 40 transformer areas are planned to be enabled with IVVO functionality throughout 2024. Work to enable substations will consist of testing and commissioning new field devices, running supervised IVVO operations within the ADMS (where operators must approve device state changes), and running a short duration of closely monitored, unsupervised IVVO operation[11] within the ADMS. IVVO is enabled one transformer area at a time, with each transformer generally consists of 3 or 4 feeders. Immediately following successful testing, the substation's transformer area will be considered fully IVVO ready and placed into operation.

During 2024, the Company will continue to operate IVVO and expand the operations to incorporate additional feeders with plans to complete the deployment in

[11] "Unsupervised" does not mean "unmonitored," but that the system will be operating automatically and should not require manual intervention.

2024. The energy savings benefits are projected to increase from 193,932 MWh in 2022 to an expected range of 240,000 MWh to 255,000 MWh in 2023. Line loss reduction is expected to increase from 8, 516 MWh in 2022 with a baseline of 9,167 MWh in 2023. Calculated demand reduction, at the end of 2023, will increase from 32.0 MW in 2022 with a baseline of 43.9 MW in 2023.

Capacitors

The Company plans to install 179 capacitors on the primary voltage distribution system during 2024.

SVCs

The Company has 239 SVCs included in 2024 in Table 3 – IVVO Deployment by Year, to remain consistent with the estimated 4,350 SVCs that were estimated as part of the CPCN; however, there is a high likelihood there will be a fewer number of SVCs required. The SVCs are installed on the secondary voltage of the distribution system, and as the Company has progressed in the deployment, there have been fewer required than originally estimated as part of the CPCN. This is predominately due to finding suitable locations for installation of SVCs on overhead portions of the distribution system – and as we have progressed to underground portions of the distribution system, the SVC the Company utilizes is only designed for overhead distribution systems. The Company plans to finalize the total number of SVCs that are planned to be deployed after it has finalized the Engineering review of the remaining transformer areas.

LTC Controllers

The Company plans to update 9 LTC controllers on substation transformers during 2024.

For each of the above, note that engineering and design efforts support the deployment needs, and that the pace of installation will support the rate of IVVO enablement.

IVVO Enablement

The forecast for enabling ADMS IVVO on 40 additional transformer areas (120 feeders) in 2024 as shown in Table 8. As of October 2023, the Company has fully enabled IVVO on 73 transformer areas. The time required to enable the first transformer areas in ADMS has had a higher level of complexity and took longer than originally anticipated, however as the Company has gained experience it has been able to improve the time to complete these activities and will continue to look at ways enhance this process as we complete these activities for additional areas. Despite the reduced rate of IVVO enablement, the areas that are running IVVO have seen average energy reduction greater than 2 percent, considerably higher than the expected reduction of 1.83 percent in 2022. The Company plans to partially offset these delays with deployment by lowering the LTC setpoint at transformer areas that have primary capacitor banks fully deployed, and where there is confidence in lowering the voltage.

Table 8 – IVVO Enablement Timeline for 2024

2023 Enablement Goals	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Total
Transformers Enabled in ADMS	12	11	11	6	40
Feeders Enabled in ADMS	35	39	31	15	120
Lowered LTC Setpoints	4	3	2	0	9

Integration with AMI

The deployment of AMI meters has enabled the bellwether meter functionality in ADMS. The meter deployment creates the network necessary to enable the use residential meters as bellwether meters, allowing the near real-time voltage insights from these meters to flow into ADMS. Additional bellwether meters will be enabled in ADMS as the AMI meters are deployed and the IVVO footprint expands. With the expanded AMI fleet, bellwether enablement will become a step in the IVVO process to ensure that IVVO is always enabled with the supporting bellwether meters.

C. FAN

As described above, the portion of the FAN that is associated with the implementation of AMI and IVVO was approved as part of the Settlement Agreement in Proceeding No. 16A-0588E. This portion of the FAN is known as the WiSUN, which is a wireless communications mesh network. In 2024, the Company will continue to deploy the WiSUN, including site surveys and installation of WiSUN equipment. The Company expects to install 910 WiSUN devices in 2024. This is based on completed site surveys, which determine network needs to support AMI 2024 deployments. The head-end is in place to support this work. Below is the forecasted WiSUN Device installation by quarter for 2024. This schedule will support AMI, IVVO, and FLISR requirements.

Table 9 – 2024 WiSUN Device Installation

	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Total
WiSUN Device Installation	225	270	265	150	910

Concurrent with the deployment of WiSUN, the Company will continue to deploy the backhaul solution described above, providing the necessary connectivity between the WiSUN mesh network and the back-office systems in Xcel Energy data centers.

IV. FORECASTED O&M AND CAPITAL SPEND FOR 2024

As agreed in the Settlement Agreement in Proceeding No. 16A-0588E, forecasted costs for 2024 are broken down into capital costs and O&M. The Settling Parties agreed to continued deferred accounting for O&M as well as capital associated with AMI, IVVO, and the associated components of the FAN. Two deferred accounting mechanisms were established for each project: one for deferred capital and one for O&M costs. Table 10 below provides forecasted 2024 capital and O&M costs necessary to accomplish the key tasks outlined previously for the CPCN Projects.[12] These costs include increased costs for the expanded capacity of the AMI head-end in order to utilize this asset for other jurisdictions served by Xcel Energy. In exchange, a portion of the carrying costs will be credited back to Public Service through a "shared asset credit" mechanism, allocated by the number of active advanced meters in each jurisdiction. Table 11 below provides forecasted capital additions for 2024. Attachment 2 provides the current I/O's utilized by the Company.

[12] This table excludes any benefits as outlined in our CPCN filing as the information portrays the cost of implementation for the upcoming year and not a specific rate request. Benefits will be included within specific rate requests as they are applicable to the period of the request.

Table 10 – Forecasted Capital and O&M Expenditures in 2024

Capital Expenditures		2024
AMI	Technology Services	$ 16,545,705
	Distribution	57,200,112
	FAN	3,260,073
	Total	**$ 77,005,890**
IVVO	Technology Services	$ -
	Distribution	7,000,000
	FAN	2,561,486
	Total	**$ 9,561,486**
Total Capital Expenditures		**$ 86,567,376**
O&M Costs		
AMI	Technology Services	$ 6,250,223
	Distribution	160,808
	FAN	8,038
	Enterprise Security	-
	Shared Asset Credit	(11,175,419)
	Total	**$ (4,756,350)**
IVVO	Technology Services	$ 191,084
	Distribution	2,304,849
	FAN	6,316
	Enterprise Security	-
	Total	**$ 2,502,249**
Grid Common O&M		69,963
Total O&M Costs		**$ (2,184,138)**
Total Capital O&M Costs		**$ 84,383,238**

Table 11 - Capital Additions for 2024

Project	Order	Order Description	Amount
AMI	900000074501	BCWP-BUD-AMI-BS-Interface-SW-PSCO	$149,556,840
AMI	900000080119	BCWP-AMI-DIST-PSCo-CO Full AMI-R	55,655,709
AMI	900000075320	BCWP-AMI-Meter-Data-Lake-BS-SW-PSCo	11,679,930
AMI	900000060544	BUD-AMI Software Release 4 SW PSCO	5,187,321
AMI	900000082150	BCWP-AMI-ODS-BS-SW-PSCo	2,985,155
AMI	900000075526	BCWP-AMI-SW-License-BS-PSCo-NEW	750,001
AMI	900000078972	BCWP-AMI-HAN-BS-SW-PSCo	717,230
AMI	900000078973	BCWP-AMI-HAN Mobile App-BS-SW-PSCo	161,466
FAN	900000063489	BUDCWIP-PSC - FAN - Dist WISUN Blanket	5,821,559
IVVO	900000062583	BUDCWIP-IVVO New OH AGIS - PSCo	4,432,500
IVVO	900000070444	BUDCWIP-IVVO Advanced Function CPCN	2,514,752
		Total PSCo CPCN 2024 Capital Additions	**$239,462,462**

V. CUSTOMER EDUCATION

The current AGIS Customer Education Plan (“Plan”), exclusive of the Residential Energy Time-of-Use (“RE-TOU”) rate[13] or the Small Commercial Time-of-Use (“C-TOU”) rate[14], is attached to this report as Attachment 1. A communications plan and budget for the RE-TOU rate was submitted separately and was part of the RE-TOU settlement.

In 2024, the Company will continue to carry out its Plan, continuing the cadence of communications on smart meter installations that began in April 2021. Communications include a series of touchpoints with customers before and during their meter installations, including a bill onsert about 90 days before their installation, a postcard 60 days before, and a letter or email about 30 days out, in addition to a phone call about a week ahead of their installation. The effort also includes paid digital and social media advertising targeted to communities ahead of their smart meter installations.

A total of $832,000 is forecast to be spent on customer education and communications in 2024, including $150,000 for paid advertising and social media to raise awareness of the transition to smart meters; $502,300 for the onsert and direct mail customer communications 90, 60, and 30 days before meter installation; and $170,000 for door hangers for use at customer properties.

[13] Proceeding No. 19AL-0687E
[14] Proceeding No. 20AL-0432E

VI. ADVANCED METER ROLL OUT PROGRESS

Pursuant to Decision No. C23-0184 (mailed on March 15, 2023) in Proceeding No. 22D-0461E, the Company is required to report to the Commission, on a bi-monthly basis, the Company's progress of the roll out of the advanced meters to customers and the Company's communications to net metered customers regarding their transition to Time-of-Use ("TOU") rates. Pursuant to that decision, these reports are to be filed in Proceeding No. 21A-0279E, with the exception of the bi-monthly reports that will be incorporated into the Semi-Annual reports in the Company's Advanced Grid Intelligence and Security Proceeding, Proceeding No. 16A-0588E.

A. Meter Installs

The Company has installed a total of 986,713 meters to date through September 30, 2023. Table 12 shows the Amended Meter Roll-out Schedule, for which an estimate is shown for the year 2023. Information for the timing and type of meter installations can be found in Table 13 below.

TABLE 12 – Amended Meter Roll-Out Schedule

Year	Original Settlement	2021 Adjustment	2022 Adjustment	2023 Adjustment
2020	162,000	-	-	
2021	395,000	300,000	310,000	310,000*
2022	480,000	534,000	400,000	413,030*
2023	450,000	504,000	448,920	345,000**
2024	Remainder	Remainder	Remainder	372,000**
2025				Remainder**

* Actual meter installations
** Estimates dependent upon meter supply

TABLE 13 – Meter Deployment Progress

Meter Type/Rate	Deployment Timeline
Residential “Simple” Rates with Single Phase Meters (Schedule R)	Currently deploying
Residential “Complex” Rates with Single Phase Meters (e.g., net metered, EV)	Currently deploying
Residential Customers with “Bridge” Meters (*e.g.*, RE-TOU pilot customers)	Meter deployment starting in 2024 after the completion of Complex Rates..
Small Commercial with Single Phase Meters	Currently deploying
Non-Residential “Simple” Rates with Polyphase meters	Currently deploying
Non-Residential “Complex” Rates with Polyphase meters	Meter deployment starting in 2024 after the completion of Complex Rates.
Advanced Meter Opt-Out (residential and small commercial)	Deployment tentatively planned to start First half 2024

B. <u>Deferred Net Meter Customer Meter Installations</u>

Net metered customers in geographic areas where advanced meters were installed prior to December 2022, had their advanced meter installations “deferred” pending the deployment of software across multiple categories of requirements including:

- Rendering bills;
- Automating existing processes that were manual (enrollment, meter exchange) for net-metered customers that were necessary to support the volume of meter exchanges and could not be supported by manual processes;
- Energy usage presentment on the customer portal; and
- Meter opt-out for net-metered customers.

Installations began in March 2023 after completing the software release on December 10, 2022, after which the Company performed a final production billing validation prior to the start of the mass deployment of advanced meters to net-metered customers. As reported in the Company's September 15th report, meter installation attempts for all of the approximately 89,000 customers were completed by August 31st.

C. "Deferred" Net Metered Customer Participation In Schedule RE-TOU

As part of the Company's communication plan for "deferred" net meter customers, the Company committed to provide information to customers regarding their TOU participation options. For those eligible customers[15] who elected to receive email communication, the Company has sent over 38,160 emails informing customers of their option to opt-in to the TOU rate, while customers who opted-out of email communication received direct mail pieces. For customers receiving email communications, these emails were sent prior to and after meter installation. Of the deferred net metered customers who received advanced meters in 2023, 355 have already enrolled in the TOU rate, 13 have opted out of the TOU rate, and 44,767 are pending enrollment onto the TOU rate and will be transitioned according to the approved schedule.[16]

D. SG-TOU Pilot

In the Company's 2020 Phase II Electric Rate Case (Proceeding No. 20AL-0432E), the Company was ordered to work with interested stakeholders to develop a time-of-use pilot ("the SG-TOU Pilot") for commercial & industrial customers who take service at secondary distribution voltage ("C&I Secondary Customers"). After working with stakeholders on the design of the SG-TOU Pilot, the Company filed Advice Letter No. 1883-Electric (in Proceeding No. 22AL-0143E) on March 31, 2022, requesting approval

[15] Not all "deferred" net meter customers are eligible for Schedule RE-TOU, as some of these customers take service under other rate schedules such as Schedule C.

[16] As discussed above, the Company has installed over 73,000 meters and has contacted approximately 31,000 customers. This discrepancy is because the typical net metered customer requires 2 meters and so the meter count will be approximately two times the customer count.

of the SG-TOU Pilot tariff, which was allowed to go into effect on July 1, 2022, by operation of law. The SG-TOU Pilot tariff requires that pilot participants must have received an advanced meter in order to participate in the pilot. Per Decision No. R21-0400 (mailed on July 12, 2021) in Proceeding No. 20AL-0432E,[17] the Company was required to file an advice letter in the fourth quarter of 2024 reporting the results of the SG-TOU Pilot along with a proposal of whether to continue, amend, or terminate the pilot.

Because the majority of C&I Secondary Customers utilize polyphase meters, and the polyphase meter deployment began in the third quarter of 2023, very few customers are eligible at this time to participate in the SG-TOU Pilot. The Company has conducted outreach to all C&I Secondary Customers who are eligible to participate in the SG-TOU Pilot (approximately 350 customers), which at this time is limited to those who have received single-phase advanced meters, and none of these eligible customers have yet opted to participate in the SG-TOU Pilot. As the polyphase advanced meter deployment continues, the Company is prepared to conduct SG-TOU Pilot outreach to the newly eligible C&I Secondary Customers and is prepared to enroll interested and eligible customers in the SG-TOU Pilot.

E. Advanced Meter Opt-Out Customers

Customers that opt-out of an advanced meter will receive a new non-communicating meter that is capable of interval-based billing and time of rates. The "opt-out" meters have to be manually read on a monthly basis at the location of the meter by Company representatives. The Company has not started meter exchanges for customers that have

[17] The requirements of Decision No. R21-0400 regarding the Schedule SG TOU pilot were affirmed by the Commission, with minor modifications, in Decision No. C21-0536 (mailed on September 2, 2021) in Proceeding No. 20AL-0432E.

opted out of an advanced meter as the Company just started deploying polyphase AMI meters in September,2023. Customers will not be charged the monthly “opt-out” charge until the meter exchange is completed. Once polyphase advanced meters are installed and meter reading staff has availability to read opt-out meters, the Company will begin installing opt-out meters. This work is tentatively planned for first half of 2024.

F. <u>Polyphase Meters</u>

Polyphase meters are typically installed for medium and large commercial and industrial customers. Polyphase meter installations began in Q3 2023.

G. <u>Supply Chain Disruptions/Concerns</u>

Since the Company’s last report provided on September 15, 2023, the Company and Itron, Inc. have continued to work collaboratively to address supply chain disruptions and maintain meter installation targets. At this time, the Company does not have any additional updates to report and will continue updating stakeholders and the Commission on the topic in future reports.

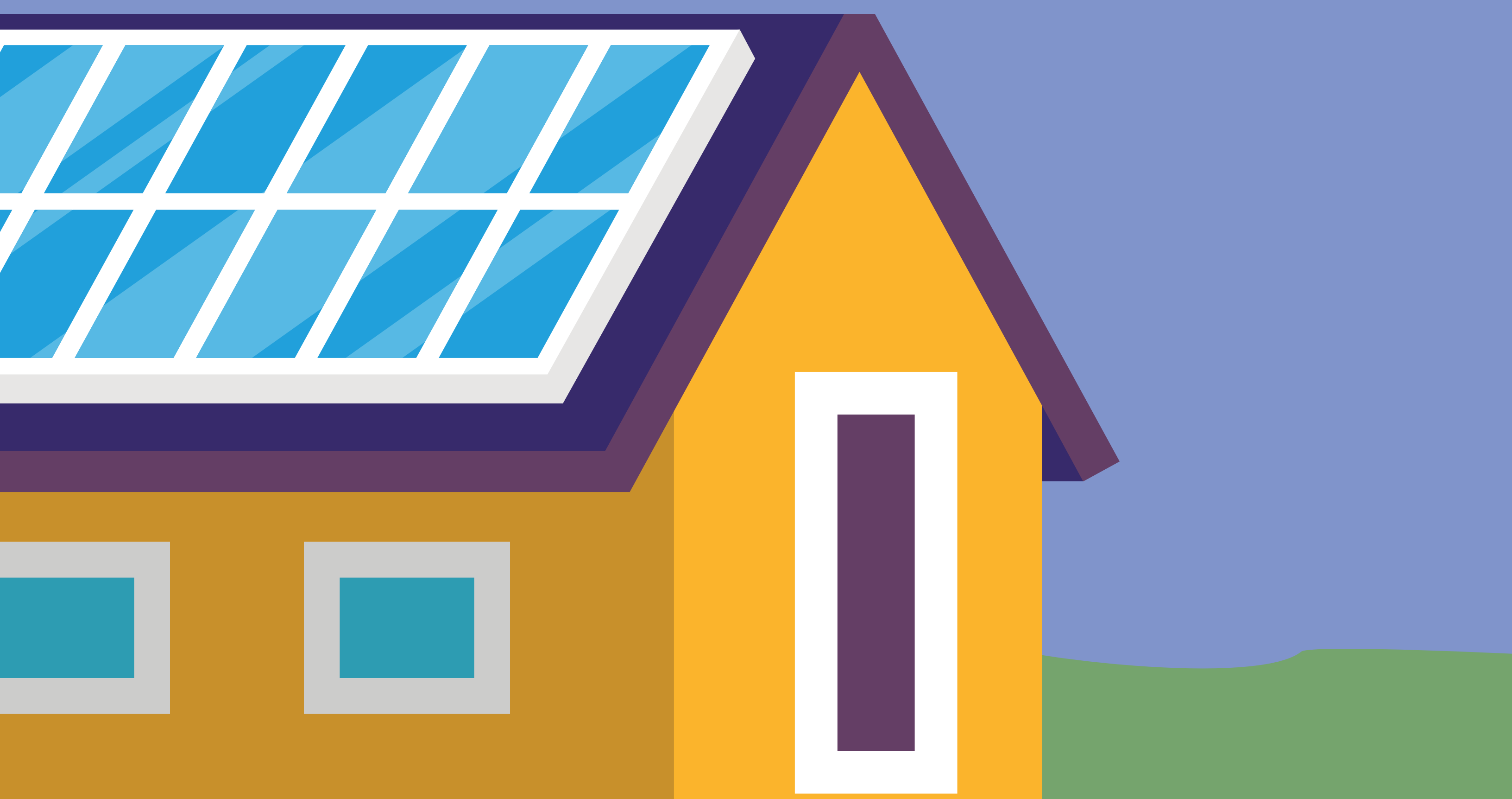
H. <u>Future Software Wave Plans (Bridge Meters And Non-Residential “Complex” Rates With Polyphase Meters)</u>

The Company is in the process of deploying the final software release, which includes a scope of work needed for bridge meters and non-residential “complex” rates with polyphase meters. These meters are billed using the Company’s legacy meter data system. In order to transfer the information for these meters to the new meter data management system, all of the meter billing data and information for metering reading and exchanges needs to be automated to support the number of meter exchanges as it is not possible to transfer it manually. The Company will automate this process to support the meter exchange for customers with bridge meters and “complex” rates with polyphase meters. The software is anticipated to be deployed in 2024 and the transfer of information would happen in 2024-2025, at which time the Company will begin meter exchanges for these meter types.

VII. CONCLUSION

Public Service appreciates the opportunity to update the Commission regarding the Company's ongoing progress to implement the Grid CPCN Projects through this Annual Forecast Report for 2023. Public Service plans to file its next semi-annual update with the Commission in May 2024, which will include its actual work and budgets for 2023. Its next bi-monthly report will be filed by December 31, 2023.

Distribution Planning Methodology



JUNE 2020

Hawaiian Electric

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Table of Contents

01 INTRODUCTION

1.1 Background

As it strives to provide 100 percent renewable energy by 2045, Hawaiian Electric (Company) faces an unprecedented situation: a comprehensive transformation of its five electric power grids. Attaining the state's renewable energy goals represents uncharted territory for both short-term and long-term resource planning. Performing the analyses necessary to attain this goal is a complicated resource planning process, requiring new tools and new processes: modeling across generation, transmission, distribution, infrastructure, and behind-the-meter resource options. This report describes the distribution planning methodology used to analyze the current state of the grid and its capability to meet future needs. Through this process, grid needs essential to support the transformation to a clean energy future are identified and solution options are explored.

The Company's distribution system is the part of its electric power system that distributes or disperses power to individual customers. The electrical distribution system (commonly referred to as the distribution grid) was originally planned and designed for the sole purpose of delivering electricity to customers from a small number of large power plants. In general, power flowed in only one direction, and it did not have to be flexible or adaptable—just strong and reliable.

Because centralized power plants have provided all of the power for its customers, the Company's traditional distribution planning methodology did not have to consider power generation. Instead, its methodology concentrated only on developing a distribution system that had the capacity to serve customers while maintaining power quality and a high level of reliability. Any deficiencies in the distribution system were solved by upgrades to the existing electrical system, including the installation of more substation transformers, more circuits, larger circuits, or larger distribution transformers.

Today, power plants can be found everywhere, connected to the distribution system in the form of privately owned rooftop solar systems, for example, that send power back onto the grid to serve other customers. The Company recognizes the potential and value of these distributed energy resources (DER) and agrees with the Commission's direction to "include the locational benefits of customer-sited distributed energy resources"[1] in the distribution planning process.

[1] HPUC Docket No. 2018-0055, Decision and Order No. 36288 Ka'aahi Substation, filed May 3, 2019, at 22.

As the power supply and electrical distribution systems transition to an integrated system, the planning processes must also transition. Hence today's distribution planning methodology must ensure the orderly expansion of the distribution system and fulfill the following core functions:

- Plan the distribution system's capability to serve new and future electrical load growth, including electric vehicle (EV) growth
- Safely interconnect DER, such as photovoltaic (PV) systems and energy storage systems that transmit power across the system in a two-way flow, while maintaining power quality and reliability for all customers
- Incorporate the locational benefits of DER in the evaluation of grid needs and system upgrades

The Company has engaged with customers and stakeholders to seek input and feedback on the distribution planning methodology as part of the Distribution Planning Working Group. This has afforded opportunities for stakeholders to collaborate and co-develop the Company's distribution planning methodology for identifying grid needs.

1.2 Scope

The objective of this report is to describe the first three stages of the distribution planning process, particularly the planning methodology that will be used to identify distribution grid needs. The grid needs will be the foundation that drives solution options, including non-wires alternative (NWA) opportunities.

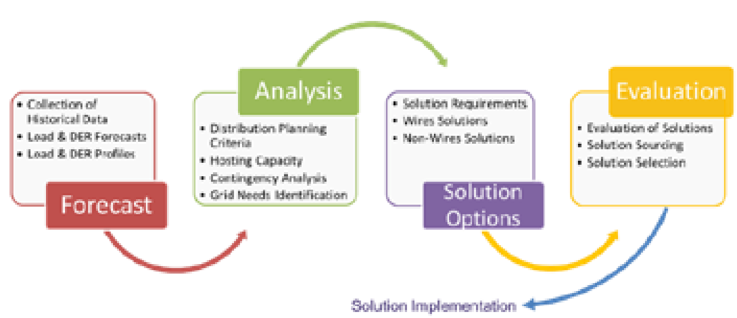
This report is a Distribution Planning Working Group deliverable as described in the Integrated Grid Planning (IGP) Workplan accepted by the Commission. [2]

02 DISTRIBUTION PLANNING PROCESS

2.1 Overview

The distribution planning process occurs annually and includes four stages: forecast, analysis, solution options, and evaluation (see Figure 1). This report focuses on the first three stages, and the fourth stage is described in the *Non-Wires Opportunity Evaluation Methodology* report.[3]

Figure 1: Stages of the Distribution Planning Process

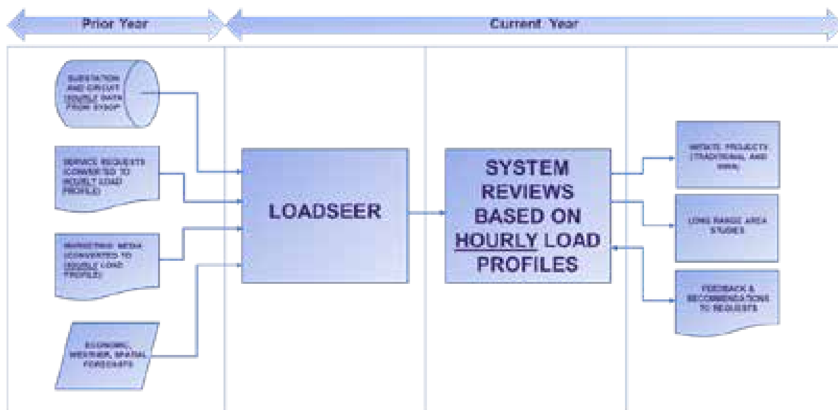


[2] HPUC Order No. 36218, Accepting the IGP Workplan and Providing Guidance, Docket No. 2018-0165.
[3] Hawaiian Electric, *Non-Wires Opportunity Evaluation Methodology*, June 2020.

2.2 Stages

The forecast stage begins at the start of the calendar year when the prior year's data and corporate demand forecast are available for analysis (see Figure 2). LoadSEER, an integrated spatial load forecasting product developed by Integral Analytics, Inc., is used to create circuit- and transformer-level forecasts.

Figure 2: Data from Prior Years used for Current Year Analysis



The analysis stage involves the analysis of the electrical system to ensure that there is adequate capacity and reliability (back-tie capabilities). Planning criteria have been established that provide the basis for determining the adequacy of the electric distribution system. In situations where the criteria are not met, grid needs are identified.

In the solution options stage, requirements to meet the grid needs are determined, and wires and non-wires options are developed. These options are evaluated in the fourth stage of the distribution planning process, which is discussed in the *Non-Wires Opportunity Evaluation Methodology* report.

It is worth noting that during the calendar year, it is expected that new service requests or projects will arise that will require modifications to the circuit- and or transformer-level forecasts. The Company will, therefore, continually evaluate grid needs throughout the year and make decisions on when to address any grid deficiencies identified outside of the forecast and analysis stages.

03 FORECAST STAGE

During the forecast stage of the distribution planning process, the Company develops a corporate demand forecast and uses LoadSEER to create circuit- and transformer-level forecasts.

3.1 Corporate Demand Forecast

The Company develops a corporate demand forecast that will be used throughout the distribution planning process. This forecast is built with layers that include sales, DER, energy efficiency (EE), and EV. The corporate forecast is developed as an 8760 for the Company by layers. The 8760 is named for the number of data points it contains: one for every hour of every day of the year (24 x 365 = 8760). This will include DER (PV), battery energy storage system, EV, electric bus, and EE (8760 EE provided by AEG). For further information on the methodology of developing the corporate forecast, see the Integrated Grid Planning presentation by the Forecast Assumptions Working Group.[4]

3.2 LoadSeer

LoadSEER is recognized as an industry-leading tool for use in forecasting and integrating DER with distribution planning.[5] LoadSEER has been adopted by the Company as a key component to advancing the distribution planning methodology. This electric load forecasting software uses the Company's corporate load forecasts and a multitude of other inputs to create forecasts at the circuit and transformer level.

The objective of LoadSEER is to statistically represent the geographic, economic, and weather diversity across a utility's service territory, and to use that information to forecast how circuit- and transformer-level hourly load profiles will change over the next 30 years. Because of the complexity of the forecasting challenge, LoadSEER employs multiple statistical methods, including hourly load modeling, macro-economic modeling, customer-level economic modeling, and geospatial agent-based modeling, which taken together increase the validity and reduce uncertainty associated with the forecasts.

3.2.1 CIRCUIT-LEVEL FORECASTS

The allocation of the forecasts to the circuit level is accomplished by integrating geospatial factors, historian data, historical and forecast weather, and customer billing information. This provides the granular data sets that are required to properly analyze the integration of increasingly dynamic DER.

LoadSEER employs familiar econometric forecasting methods at the circuit level and adds GIS-based spatial forecasting capabilities to aid in the identification of granular pockets of load growth, changes in loads, and load shape alterations that occur over time. Using these forecasting and modeling methodologies, LoadSEER is able to produce circuit-level new load, DER, EE, and EV forecasts.

3.2.2 GRANULAR DATA SETS

Traditionally, non-coincident peak loading was used in the distribution planning process. For instance, the peak load for a new service that was proposed to be energized in year X was added to the peak load forecast for year X to determine the new forecast. If the peak load for the new service did not occur at the same time as the peak load for the circuit or transformer, the resultant peak forecast may be overestimated.

The Company has recognized that this methodology does not properly evaluate the temporal nature of load and, in a similar manner, does not properly evaluate the effect of DER. By using LoadSEER, the annual circuit-level peak load has been replaced by an 8760 hourly load profile as the mechanism for forecasting future load. While traditional planning used one value to plan for a year, this methodology uses a large set of hourly profiles. LoadSEER can convert the large 8760 load profile to a more manageable 576 load profile. The latter profile is composed of a weekday and weekend profile per month [(weekday 24 hours + weekend 24 hours) x 12 months].

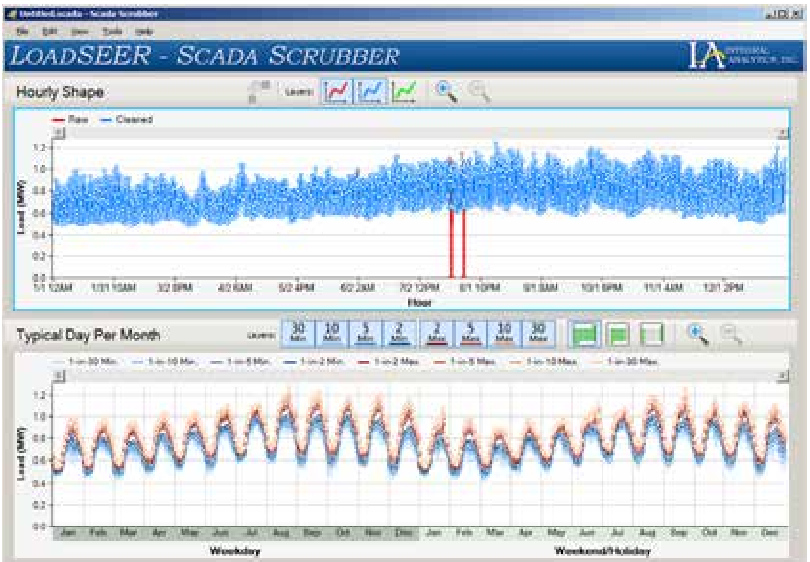
3.2.3 FORECASTING TOOLS

A component of LoadSEER is SCADA Scrubber (see Figure 3). This tool takes the hourly data and analyzes it for trends, which the tool then uses to normalize periods where planned maintenance or system interruptions occurred.

[4] Hawaiian Electric, Forecast Assumptions Working Group Meeting, July 17, 2019 (available at https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/forecast_assumptions/20190717_wg_fa_meeting_presentation_materials.pdf).

[5] See https://www.utilitydive.com/news/how-leading-utilities-are-planning-for-distributed-energy-resources/516260/.

Figure 3: LoadSEER SCADA Scrubber Screenshot



After the data has been "cleaned," 8760 and 576 profiles based on actual data are available to determine the historical peak load and to provide profiles for future year forecasts.

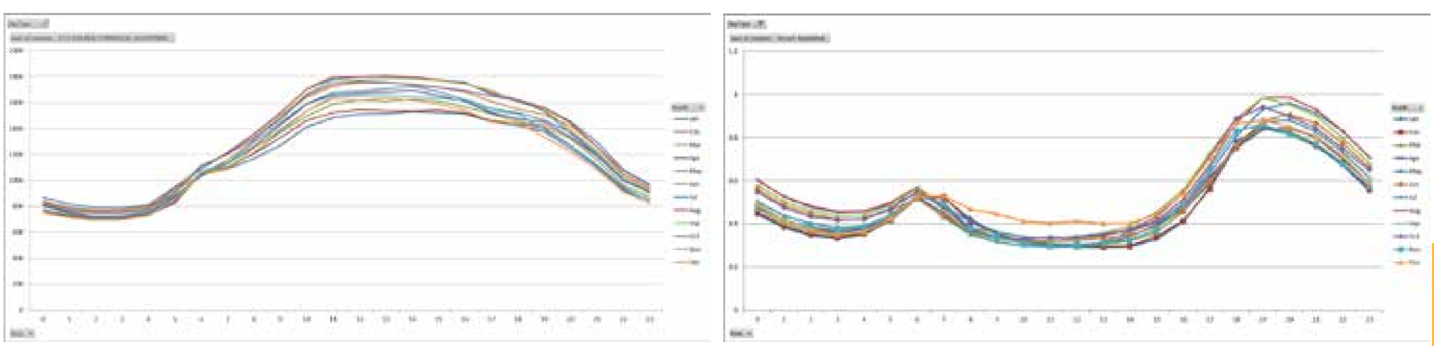
New load requests, DER requests, and marketing and media information of new developments that have been received in the past calendar year are used to refine the forecasts at the circuit and transformer level. Normally, customers who submit new service requests to the Company provide only a peak load estimate and a rough in-service date. As such, LoadSEER has default commercial and residential load profile shapes that are based on the Company's actual commercial and residential load profiles, respectively (see Figure 4). The Company is continuing to explore ways to work with large real estate developers to gain better insight and local knowledge to inform load forecasts, such as, to the extent possible, requiring developers to provide expected load profiles of their developments rather than just a peak megawatt load increase. The Company intends to use additional sensing data as it becomes available to develop customer class profiles by type or sector, which will improve the accuracy of the load forecasts.

These default profiles are used to scale the peak load estimates for the new developments to create a proxy load profile. Similarly, a load profile of an existing, comparable customer could be used in this manner. This local knowledge is a key component because it generally has the greatest impact on circuit-level forecasts.

LoadSEER also has tools to apply various scenarios to the forecasts. For instance, a range of forecasts can be applied to DER, EV, and EE layers to plan for their inherent uncertain nature.

In addition, tools are available to further modify the circuit- and transformer-level forecasts by

Figure 4: Scalable Commercial and Residential Profiles



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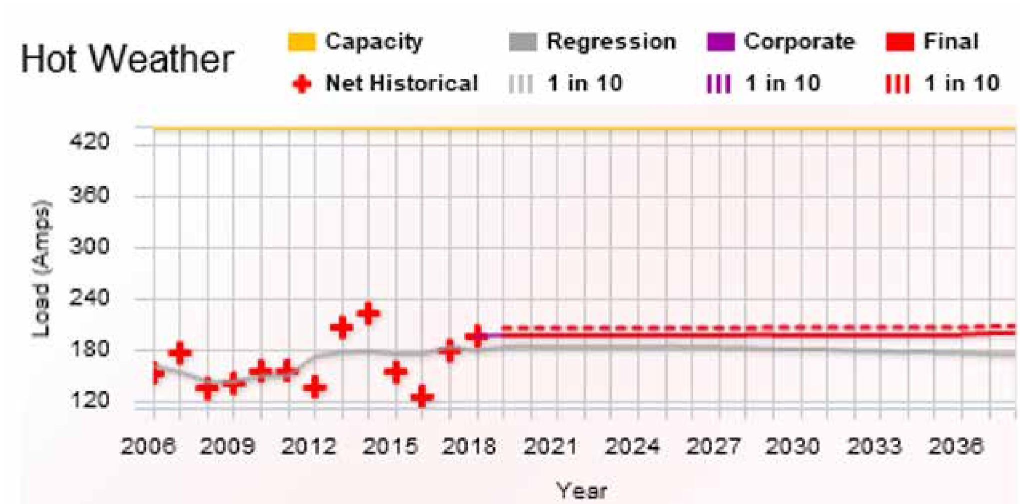
using regression analysis or econometric variables, or a blending of these two methodologies. An example of a feeder forecast is shown in Figure 5.

Figure 5: Example LoadSEER Circuit Forecast



04 ANALYSIS STAGE

During the analysis stage of the distribution planning process, the Company uses distribution planning criteria to determine the adequacy of the electric distribution system. In addition, the Company assesses DER hosting capacity, conducts a contingency analysis, and identifies grid needs.

4.1 Distribution Planning Criteria

Distribution planning criteria have been established as technical guidelines to ensure that the distribution system has adequate capacity and reliability for the Company's customers. Hence the distribution system is planned and designed to operate under both normal and contingency conditions. In addition, it is important to consider normal and contingency overloads, and thermal and voltage issues.

4.1.1 NORMAL CONDITIONS

The distribution system, or a subset of the distribution system, is operating under normal conditions when all circuits and transformers in the subject area are configured as designed. Under this normal condition, the circuits and transformers are planned to have adequate capacity to serve electrical peak load, and with DER, the circuits and transformers are also planned to be adequate for the backflow of generation caused by the DER.

4.1.2 CONTINGENCY CONDITIONS

The distribution system, or a subset of the distribution system, is operating under contingency conditions when a single circuit or transformer is out of service. This is also referred to as an N-1 scenario. A circuit or transformer may be out of service or de-energized because of equipment failure or planned maintenance. As such, a level of capacity must be available on the circuits and transformers to be available to serve the Company's customers during these N-1 scenarios. For instance, because an adjacent circuit or transformer is often used as a backup source for another circuit or transformer, N-1 scenarios also need to be analyzed to ensure that back-tie capacity is available.

4.1.3 NORMAL AND CONTINGENCY OVERLOADS

Normal overload occurs when the load exceeds the normal equipment rating of distribution circuits or distribution substation transformers under normal operating conditions. Normal overload is identified by comparing the forecasted load with the equipment rating.

Contingency overload occurs when the load exceeds the emergency equipment ratings of a piece of equipment due to other equipment failure or other equipment being out for maintenance. Contingency overload is identified by studying the forecasted load for possible contingency situations.

4.1.4 THERMAL AND VOLTAGE ISSUES

The overload of a circuit or transformer may lead to overheating issues that will damage equipment; hence, overloads are considered thermal issues. In addition to thermal overloads, the Company also ensures that there are no voltage issues. In general, the voltage level must be maintained within 5 percent of the nominal voltage at any point on the distribution system (primary and secondary).

When circuit or transformer loading exceeds the equipment thermal ratings, damage may occur to the equipment. This damage may lead to extended service interruptions and high maintenance expenses. Low or high voltage may lead to power quality issues that could damage customer-owned equipment or cause nuisance electrical issues, such as flickering light or tripping of equipment.

4.2 Equipment Thermal Ratings

Distribution circuit thermal ratings are primarily based on the following factors:

- Conductor size
- Conductor material
- Number of conductors in a duct bank (underground construction)
- Temperature
- Type of insulation
- Conductor configuration

Distribution substation transformer thermal ratings for normal and contingency conditions are primarily based on the following factors:

- Expected hourly loading
- Oil and ambient temperature
- Allowable insulation degradation (loss-of-life limits)
    - A 0 percent loss-of-life factor is the basis for the normal transformer rating.
    - A 1 percent loss-of-life factor is the basis for the emergency rating.

4.3 Grid Analysis and Modeling

Analysis is necessary to identify any violations of the distribution planning criteria. The load forecasts are analyzed under normal and contingency operating conditions to determine the location, cause, and severity of any unacceptable thermal or voltage situations.

Simulations of the various normal and contingency operating conditions are analyzed using LoadSEER as well as Synergi, which is a load flow software developed by DNV-GL. By using LoadSEER and Synergi in concert, the Company determines any existing or forecasted grid needs. Both software products also facilitate the development of solution options for the identified issues.

4.4 DER Hosting Capacity

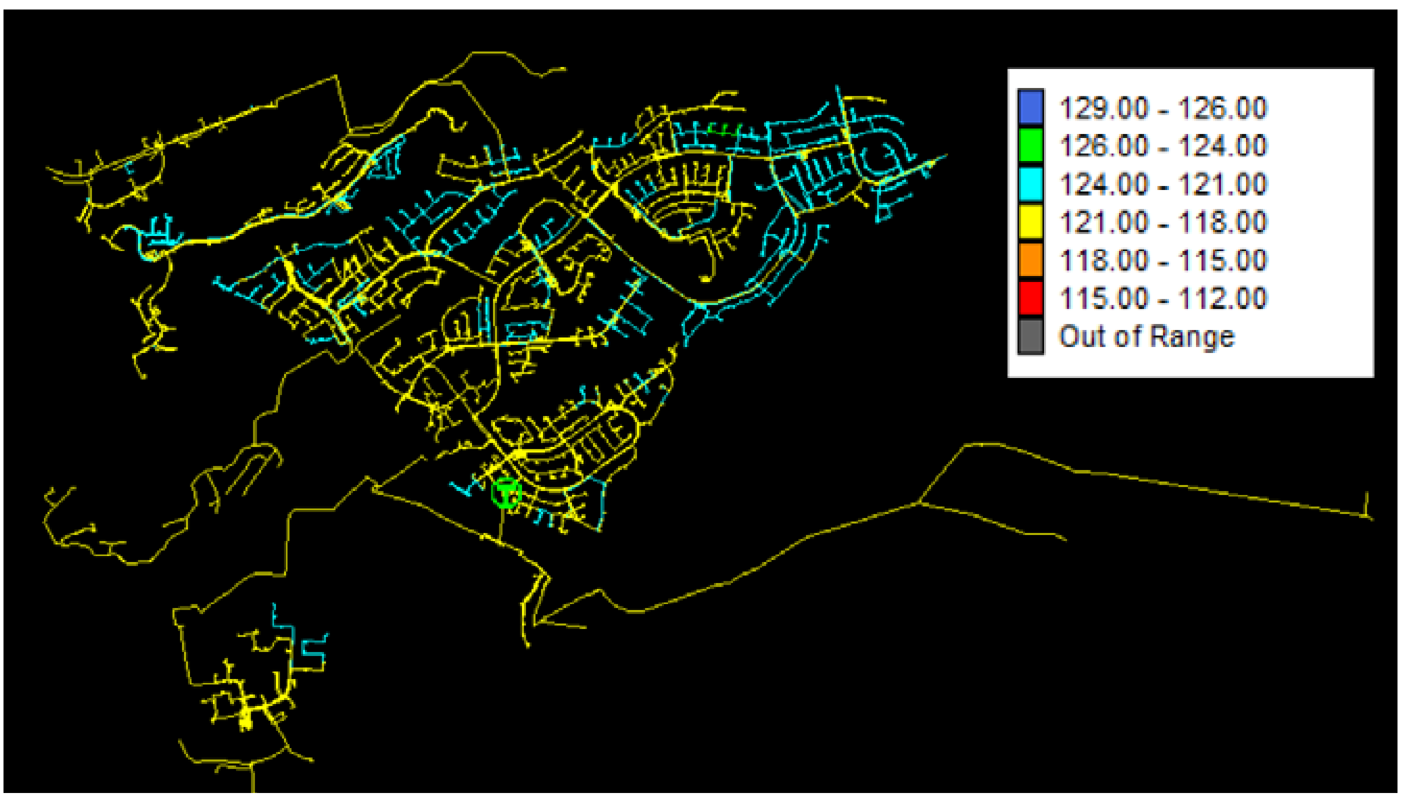
During the analysis stage, DER hosting capacity is assessed to determine any future grid needs required to create capacity for future DER. In general, the hosting capacity analysis involves the use of Synergi circuit models where DER growth is simulated to determine the maximum amount a circuit can host before any thermal or voltage violations occur. The loadflow capabilities of Synergi provide information on the location and magnitude of these issues (see Figure 6).

4.4.1 EXISTING HOSTING CAPACITY METHODOLOGY

Figure 7 illustrates the existing hosting capacity methodology. With today's methodology, DER is added to a circuit according to the location of current DER applicants, and those amounts are grown until a violation occurs. Any violation is a potential grid need.

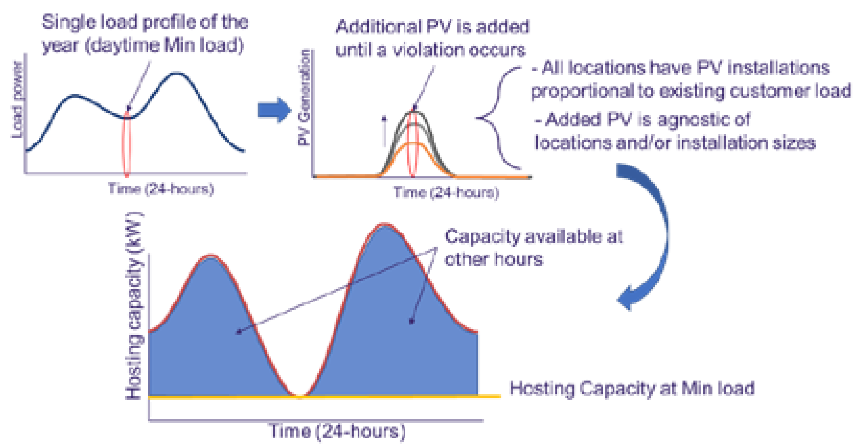
As illustrated, this methodology uses only a single, minimum load profile and does not consider the capacity available during all other hours. Although this does not account for the temporal nature of solar output, this single hosting capacity figure still provides valuable screening thresholds to help determine the circuit's ability to accommodate additional DER without the need for in-depth analysis. If the circuit has reached or exceeded its hosting capacity threshold, then any new DER will require

Figure 6: Synergi Screenshot



more advanced studying until system changes warrant the development of a new hosting capacity threshold.

Figure 7: Existing Hosting Capacity Methodology



4.4.2 FUTURE HOSTING CAPACITY METHODOLOGY

The Company is updating the existing methodology to account for the hosting capacity available during all hours. This can be accomplished only by using time-sensitive profiles of the unique DER programs as well as the modeling of advanced inverters in a time-series analysis. Furthermore, because there are many ways that DER can develop on a feeder, multiple DER growth scenarios need to be studied, applying probabilistic modeling techniques and analysis. A comparison of the existing hosting capacity with the future hosting capacity analysis is shown in Figure 8.

The Company is working with Electric Power Research Institute (EPRI) to refine the hosting capacity analysis.[6] The methodology is scheduled to be developed by the second quarter of 2020. The new DER hosting capacity methodology will be implemented in the distribution needs assessment as part of the transmission and distribution needs assessment step of IGP.

Figure 8: Future Hosting Capacity Enhancements

	Current HECO HC analysis	Future HECO HC analysis
Model Unique DER Programs (Non-Export & Smart Export)	×	✓
Advanced Inverter (VV/VW)	×	✓
Time Series (576/8760)	×	✓
Probabilistic model	×	✓
Add PV in realistic installation sizes	×	✓
Add PV in locations that make sense	×	✓

[6] Hawaiian Electric, Distribution Planning Working Group Meeting, November 18, 2019 (available at https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20191204_dpwg_meeting_presentation_materials.pdf).

The updated hosting capacity methodology being developed with EPRI incorporates several new aspects to determine an hourly circuit hosting capacity profile. The assessment considers the effects of smart inverter functions and the temporal load characteristics of the different Company programs, such as smart-export systems, non-export systems, and storage profiles via time-based analysis. The Company is seeking data from solar installers to help inform the generation output model for these systems.

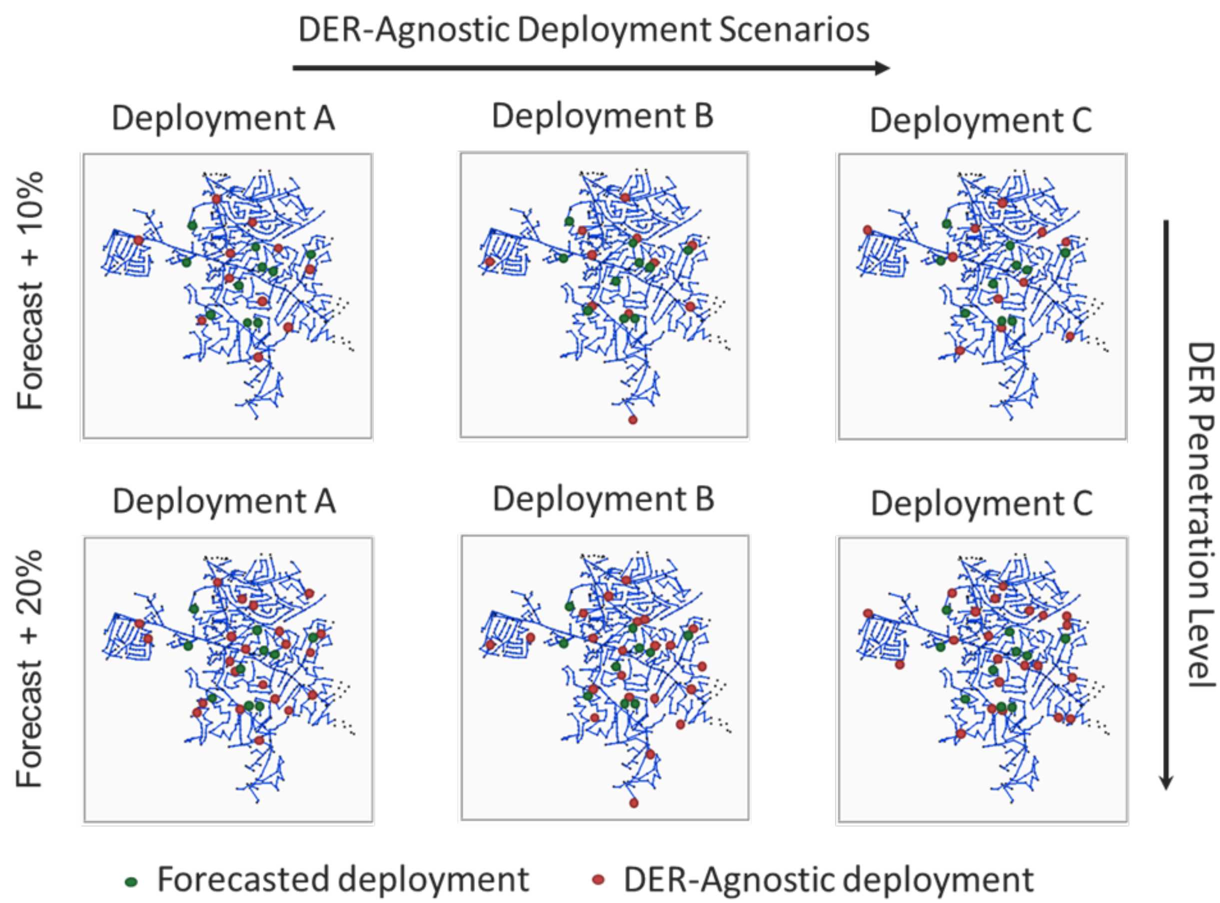
The updated methodology plans to use circuit-level forecasts (for example, circuit load shapes and future DER growth) that are generated from LoadSEER. The Company will use a 576-hour time-series model format that corresponds to 24-hour observations for 24 days. Typically, this represents 2 days for each month. These 2 days are either the peak/minimum load days or the weekday/weekend days of the months. Alternatively, the profile can be expanded to include as many hours as desired, such as a full 8760-hour profile representing all 365 days of the year at a 1-hour resolution.

An additional enhancement is the modeling of future DER deployments. Incorporating user input, the addition of future DER will be modeled in a more realistic manner. The size of each new residential DER is randomly chosen between the bounds defined by the user, allowing flexibility to preserve the prevalent DER size belonging to circuits in unique areas. The user also defines the threshold to identify either a commercial or residential load type.

The DER is then sized according to the load type it is connected to. The size and location of future DER installations are normally unknown variables in hosting capacity analysis. Unlike the existing hosting capacity methodology, which simply scaled up existing DER installations to represent DER growth, the new methodology explores multiple scenarios where DER deployments of different sizes and locations are added to the model to develop a probabilistic hosting capacity. Traditionally, hosting capacity is set by the first DER scenario, causing the first bus/element to have a violation at any instance in time. Probabilistic hosting capacity, on the other hand, allows one to consider additional hours, buses, and/or DER deployments beyond the first violation before the hosting capacity is determined.

The hosting capacity assessment is performed in three primary steps: base case, forecasted DER, and agnostic DER. The base case assessment analyzes the existing circuit conditions for the year. The forecasted DER assessment explores multiple scenarios of adding new DER deployments onto the circuit, totaling the forecasted DER amount for the year of study. The generation profile for the forecasted DER deployments is a function of the DER size, program type, and solar irradiance for the area. Finally, the agnostic DER assessment adds agnostic DER deployments on top of the forecasted DER assessment. Full generation output is considered from each agnostic DER at each hour because it is not known how or when that resource would be online (such as solar plus storage projects), thus providing circuit impact results agnostic to future DER type. The order by which the agnostic DER is allocated is cumulatively split into a number of penetration levels that are independently analyzed so that the impacts from the additional agnostic DER can inform hosting capacity. More penetration levels can be analyzed and will effectively produce finer resolution hosting capacity results because the maximum agnostic DER penetration level scenario

Figure 9: Forecasted and Agnostic DER Deployment Scenarios



is always based on full feeder saturation where all customers have DER. Figure 9 illustrates two penetration levels out of ten, which would take the feeder to 100 percent customer penetration.

After each simulation, power flow data is captured to quantify impacts. This data is used to process the probabilistic hosting capacity depending on time, breadth of the violation, and number of agnostic DER deployments indicating violation. Therefore, the probabilistic hosting capacity is dependent on the number of violated hours, the number of violated locations, and the number of agnostic DER deployments experiencing a violation. In planning studies with so many variables, these probabilistic metrics are more beneficial than planning for the worst-case scenario. The worst-case scenario would identify when the first sampled condition experiences a violation, but it also has the lowest chance of occurrence/risk. The probabilistic hosting capacity allows one to identify a more likely chance of occurrence with slightly increased risk. For example, if the probabilistic hosting capacity is based on 10 percent of the sampled conditions experiencing a violation, the amount of DER that can be accommodated is greater than the conservative worst-case scenario. In this example, this probabilistic hosting capacity defines that 10 percent of the sampled conditions could not accommodate more DER due to more adverse violation, whereas 90 percent of the sampled conditions could still accommodate more

DER. The analysis illustrated in Figure 10 shows the frequency of hosting capacity of a circuit throughout the hours in a day. Figure 11 is its the associated color index.

Figure 10: Daily Hosting Capacity Profile

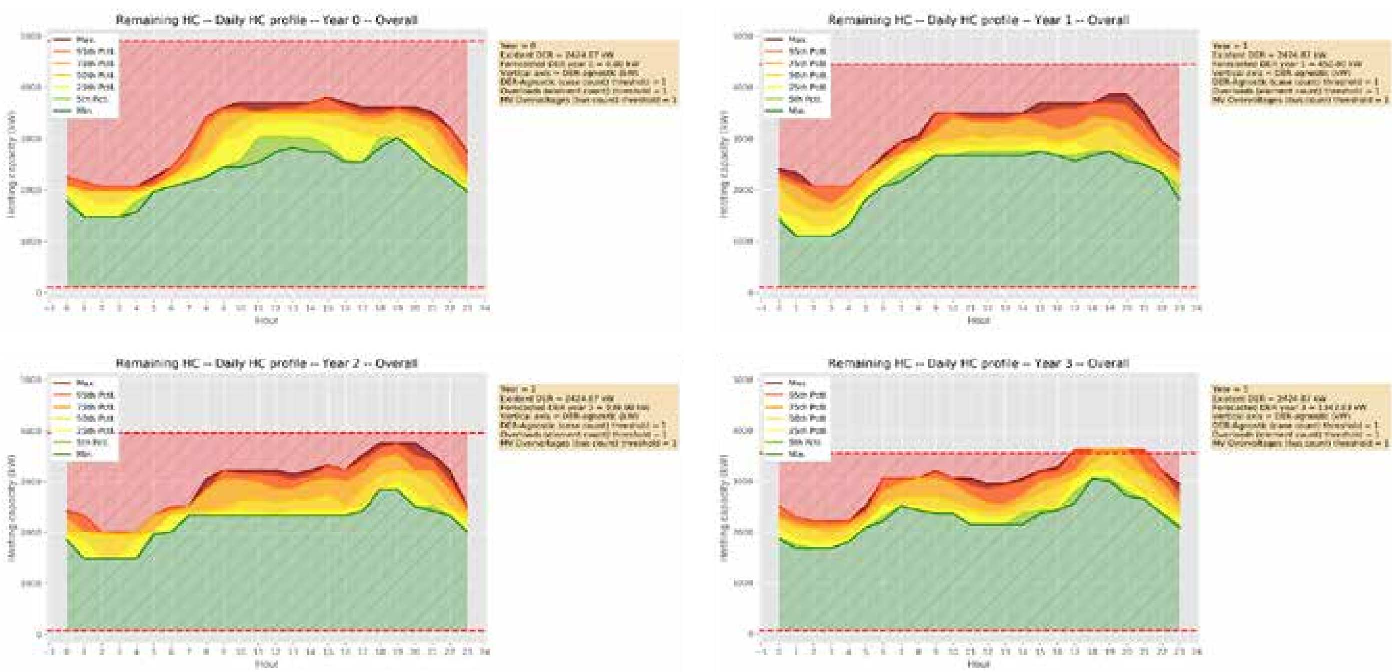


Figure 11: Daily Hosting Capacity Color Code

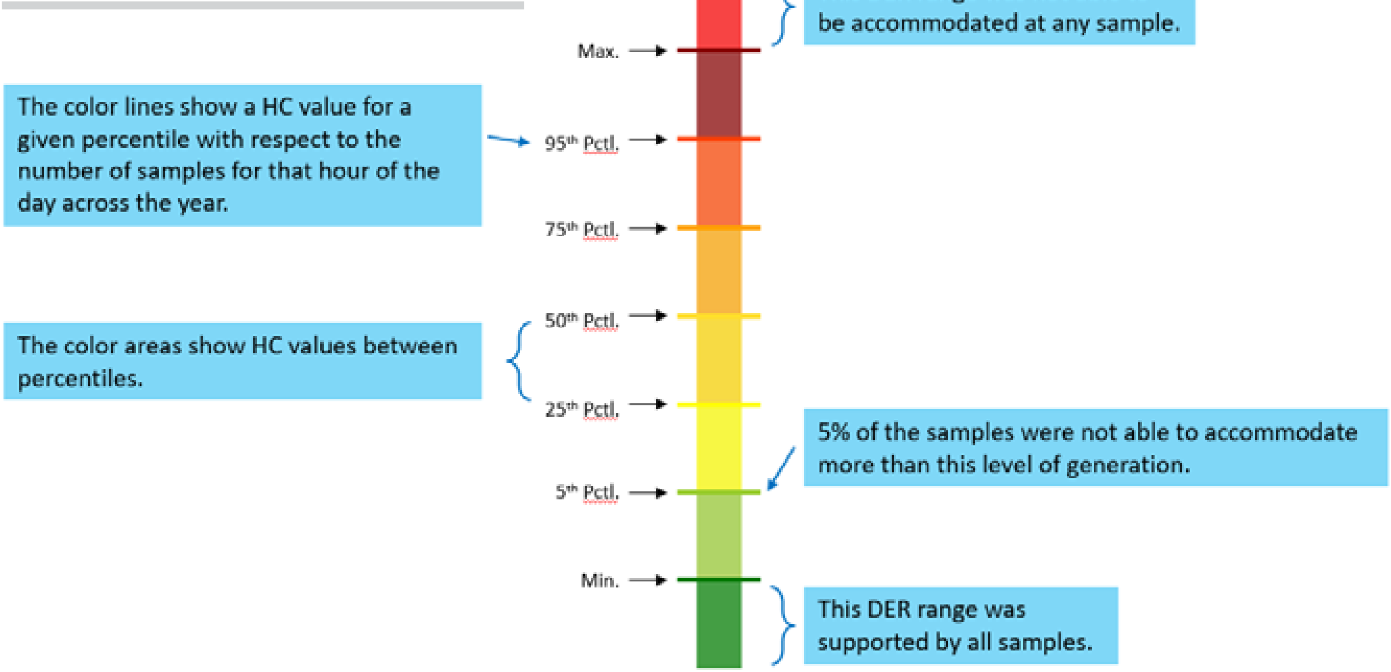
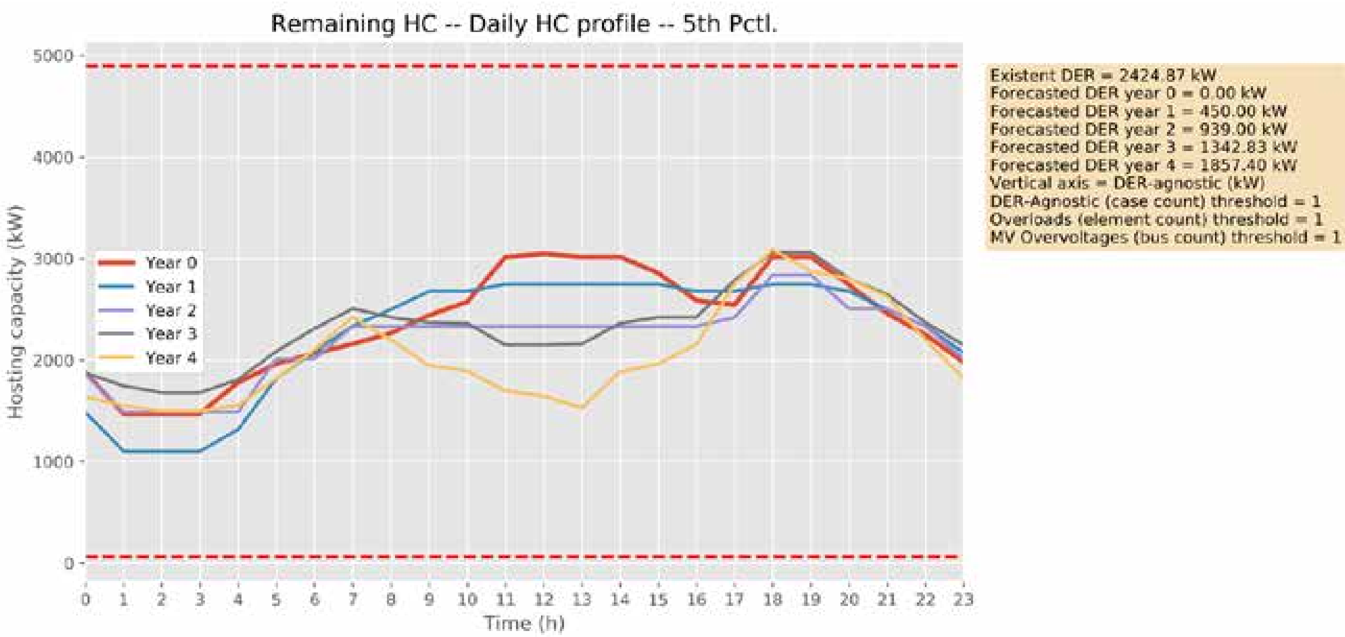


Figure 12: Example Daily Percentile-Specific Hosting Capacity Result



In the example shown in Figure 12, the results of a probabilistic analysis of the fifth percentile shows the daily hosting capacity available forecasted over multiple years on a circuit.

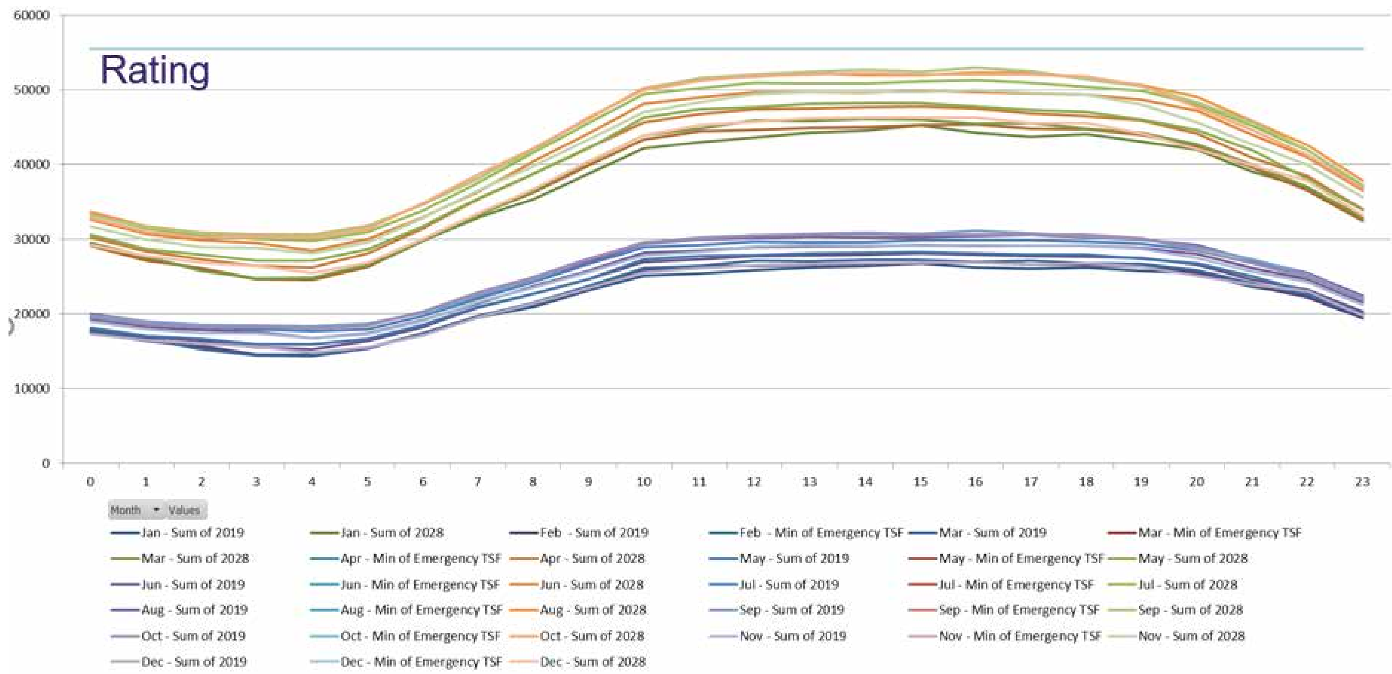
Overall, the Company's updated hosting capacity methodology will be a time-based analysis that takes into consideration the Company's unique programs, the impact of advanced inverter functions, and the two key variables of DER deployment—size and location—that form the core structure for a probabilistic analysis. By considering these new variables, it is expected that the methodology will produce less conservative and more realistic hosting capacity results. The updated methodology is performed in three steps that each provide different objectives: (1) the base case assessment to identify any underlying conditions on the feeder; (2) the forecasted DER assessment to identify underlying conditions due to the DER forecast; and (3) the agnostic DER assessment to identify the remaining hosting capacity. Separating these steps helps the analysis incorporate the information from the Company's forecasting tool and inform its future grid needs assessments.

4.5 Contingency Analysis

For the Company circuits and transformers, LoadSEER produces 576-hour profiles for both normal and contingency (N-1) cases. Furthermore, new developments that have a direct impact on the circuits or transformers that are being analyzed can be added to the profiles created for the various cases.

Figure 13 shows an example of a contingency analysis using the hourly profile from LoadSEER. The darker group of lines represent the forecast loading on a distribution substation transformer for a peak day per month when an adjacent distribution substation transformer fails. The lighter group of lines represents the forecast loading if new large services are energized in the area. The example shows that the forecast for this N-1 scenario does not cause a thermal rating violation.

Figure 13: N-1 Example



4.6 Planning Criteria Violation

The analysis stage of the distribution planning process should identify existing or forecasted thermal or voltage issues on the Company's circuits and substation transformers. Issues may also be identified through data provided directly by devices installed throughout the Company's system that record voltage and current. These devices include advanced meters and OptaNode Grid2020 units.

Regardless of the manner in which an issue is identified, any situation where planning criteria are violated will need further review to determine the grid needs and the associated solution options.

4.7 Grid Needs Identification

To identify grid needs, the Company develops a demand forecast, a demand forecast by load type, a grid needs assessment, and an hourly grid needs summary, as discussed in the following sections.

4.7.1 DEMAND FORECAST

As part of the distribution grid needs documentation,[7] the Company will submit a demand forecast that will list the grid assets and show the net peak forecast (including DER layers) for these assets over the next 5 years. The data to be provided for this demand forecast is described in Table 1.

Table 1: Demand Forecast

SPECIFICATION	DEFINITION
Facility type	Circuit or transformer
Facility name	Circuit or transformer identifier
Equipment rating (MW)	Equipment's rated capacity
Year XXXX peak load (MW)	Peak load forecast for year XXXX
Year XXXX+1 peak load (MW)	Peak load forecast for year XXXX+1
Year XXXX+2 peak load (MW)	Peak load forecast for year XXXX+2
Year XXXX+3 peak load (MW)	Peak load forecast for year XXXX+3
Year XXXX+4 peak load (MW)	Peak load forecast for year XXXX+4

4.7.2 DEMAND FORECAST BY LOAD TYPE

The Company will submit a demand forecast by circuit by load type per year (5 years of forecasts). The data that will be included is described in Table 2.

Table 2: Demand Forecast by Load Type

SPECIFICATION	DEFINITION
Circuit name	Circuit identifier
Year XXXX residential load (MW)	Residential load forecast for year XXXX
Year XXXX commercial load (MW)	Commercial load forecast for year XXXX
Year XXXX EV	EV load forecast for year XXXX
Year XXXX DER	DER load forecast for year XXXX
Year XXXX EE	EE load forecast for year XXXX

[7] IGP Workplan at 26 (avaliable at https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/dkt_20180165_20181214_igp_workplan.pdf).

4.7.3 GRID NEEDS ASSESSMENT

A grid needs assessment will be performed to identify situations where planning criteria are violated based on the per circuit or transformer forecasted net demand described in Section 4.7.1. In addition, a traditional solution will be defined for each grid need identified, as discussed in Section 6, Solution Options. The data that will be included in the grid needs assessment is described in Table 3.

Table 3: Grid Needs Assessment

SPECIFICATION	DEFINITION
Substation	Transformer asset identification
Circuit	Feeder asset identification
Distribution service required	Distribution capacity or distribution reliability (back-tie) service
Primary driver of grid need	Whether the identified grid need is primarily driven by DER growth, demand growth, other factor(s), or a combination of factors
Operating date	The date at which traditional infrastructure must be constructed and energized in advance of the forecasted grid need to maintain safety and reliability
Equipment rating (MW)	Equipment's rated capacity
Peak load (MW)	Peak loading on asset for given year
Deficiency (%)	Deficiency divided by the rating for each of the forecasted years
Traditional solution	Traditional solution identified, as discussed in Section 6, Soution Options
NWA qualified opportunity	Whether the grid need is a qualified opportunity for further evaluation based on technical requirements and timing of need

Note: A qualified opportunity has passed "Step 1" as outlined in the *Non-Wires Opportunity Evaluation Methodology* report and will proceed to "Step 2," where it will be further analyzed and prioritized.[8]

[8] Hawaiian Electric, *Non-Wires Opportunity Evaluation Methodology*, June 2020, Section 4.

4.7.4 HOURLY GRID NEEDS SUMMARY

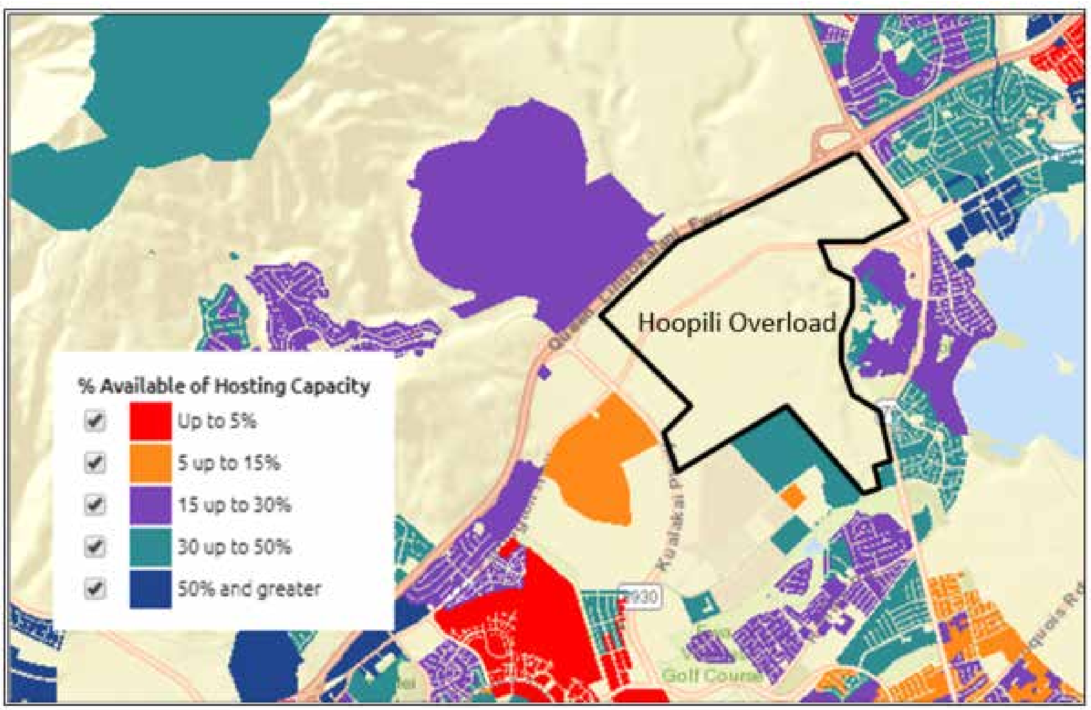
For the grid needs determined to be qualified opportunities, solution requirements will be defined in technology-neutral terms, such as the amounts of energy, time(s) of day, and days of the year. This hourly grid needs summary will be provided as described in Table 4.

Table 4: Hourly Grid Needs Summary

SPECIFICATION	DEFINITION
Substation	Transformer asset identification
Circuit	Feeder asset identification
Capacity (MW)	Amount of power required to mitigate the grid need
Energy (MWH)	Amount of energy required to mitigate the grid need
Delivery time frame	Months/hours when the planning criteria violations occur
Duration (hours)	Length of time of the grid need
Maximum Number of calls per year	Maximum number of days in the year requiring mitigation

During the NWA opportunity evaluation, as outlined in the *Non-Wires Opportunity Evaluation Methodology* report, each NWA opportunity assigned to Transmission and Distribution Action Plan Track 1 or Track 2 will have an associated map of the general area of need overlayed with available hosting capacity. An example of this integrated map for the Ho'opili area is provided in Figure 14.

Figure 14: Integrated Grid Needs Map Example



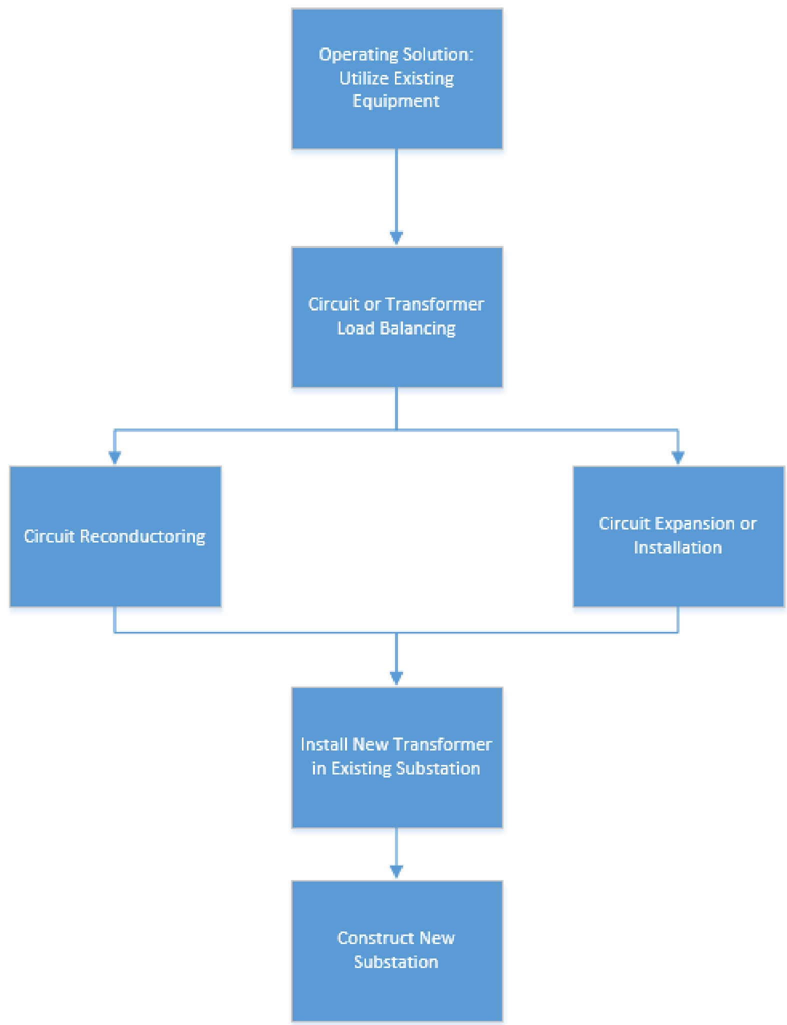
05 SOLUTION OPTIONS STAGE

During the solution options stage of the distribution planning process, the Company determines solution requirements and develops wires and non-wires solution options.

5.1 Solution Requirements

An identified grid need is the foundation of a solution's requirements. There may be other requirements, including some unique to the specific opportunity, that will provide additional constraints that solution options must meet. Examples of additional requirements may include a minimum level of reliability or physical/economic constraints. While factoring the solution requirements, a project scope for solution options will be developed that may involve the creation of work plans, such as planning single-line diagrams for wires solutions or time-based capacity requirements for non-wires solutions.

Figure 15: Wires Solution Development Steps



5.2 Wires Solution Development Process

To develop the scope of a wires solution, the simplest solution will be analyzed first, followed by solutions of increasing complexity. Once a solution is identified that fulfills the grid need, any additional, more complex solutions will not be analyzed. In general, the more complex the solution, the more expensive the solution. LoadSEER or Synergi, or both, will be used to analyze the solutions. The general process flow is shown in Figure 15.

Once the least complex solution is identified, a project scope is typically developed in the form of a planning single-line diagram. This diagram is a sketch that provides sufficient information for design engineers to develop a project scope and cost estimates, and if necessary, to provide the guidance to develop drawings and specifications used by construction personnel to execute the work. The project scope and cost estimates will inform the avoided cost that will be used in the NWA screen and will be evaluated as described in the *Non-Wires Opportunity Evaluation Methodology* report.

5.2.1 OPERATING SOLUTION: USE EXISTING EQUIPMENT

It is possible that a particular grid need can be satisfied by a simple reconfiguration of the existing distribution system. For instance, existing switches could be operated to resolve overload conditions, and the recalibration of the settings for existing voltage regulation devices could be employed to increase hosting capacity.

In this solution scenario, no cost estimates would be developed, and the Company would proceed without any further wires or non-wires analysis.

5.2.2 CIRCUIT OR TRANSFORMER LOAD BALANCING

If the existing electrical system cannot be simply reconfigured using existing equipment, the next type of solutions to be analyzed involves circuit or transformer load balancing. Load balancing can often resolve capacity issues. For instance, new switches may be installed on existing overhead circuits to provide circuit sectionalization to balance circuit loading (that is, reduce capacity on one circuit but increase capacity on another). Also, taps on overhead circuits could be cut and tapped elsewhere to change the configuration and loading on circuits. Similarly, cuts and taps (new splices) can be made in manholes of existing underground distribution systems to balance underground cable loading.

The taps of individual distribution transformers could also be modified to balance the loading among the three electrical phases. This type of balancing is referred to as phase balancing and is a method that can increase hosting capacity.

5.2.3 CIRCUIT RECONDUCTORING OR CIRCUIT EXPANSION/INSTALLATION

The next type of solutions, in terms of complexity and cost, to be analyzed involve upgrades to the distribution circuits. One type of upgrade is the reconductoring of existing overhead conductors or underground cables. In general, this involves the removal and replacement of the existing lines with larger-sized lines. This will directly increase the available capacity on the circuit.

For overhead systems, it may not only involve changing the conductors but also may require installation of new poles because the existing poles may not be strong enough to carry the weight of the larger-sized conductors. Similarly, for underground systems, the existing underground infrastructure (handholes, manholes, conduits) may not be large enough to accommodate physically larger-sized cables. Therefore, reconductoring of underground cables may also involve installation of new underground infrastructure.

Another type of upgrade on a distribution circuit involves the expansion of the circuit. In this situation, new overhead conductors or underground cables are installed where existing equipment does not exist. For instance, a new pole-line consisting of new wires and new poles may be constructed between two existing circuits to create back-tie capacity. For underground systems, new cables can be installed in existing spare conduits to create new underground ties or to balance underground circuits.

Circuit reconductoring and circuit expansion are considered in parallel because the complexity and, therefore, the cost is highly dependent on physical conditions. For example, for the same physical distance, reconductoring is typically cheaper than new construction. However, if reconductoring involves changes in the existing infrastructure, as noted previously, new construction could potentially be less complex to execute and more cost effective.

5.2.4 NEW TRANSFORMER IN EXISTING SUBSTATION

The Company's substations are typically designed to accommodate more than one substation transformer. If grid needs cannot be fulfilled with distribution circuit line work, the next solution option is to analyze installation of new transformers at existing substations. This solution involves the installation of a new substation transformer and associated circuits.

5.2.5 NEW SUBSTATION

The last wires solution to analyze is the construction of a new substation.

5.3 Contingency Plans and Schedule

The lead times to engineer and execute wires solutions is highly dependent on the required permitting and approvals. In general, the least complex solutions, as shown in Figure 15 and discussed in Section 5.2, have the shortest lead times. The following lead times will need to be incorporated into any contingency plans, as described in the *Non-Wires Opportunity Evaluation Methodology* report:

- Operating solution: 1 month
- Circuit or transformer load balancing: 18 months
- Circuit reconductoring or expansion (infrastructure upgrades not required): 24 months
- Circuit reconductoring or expansion (infrastructure upgrades required): 36 months
- New transformer (existing substation): 36–48 months
- New substation: 48 months

Except for operating solutions, deferral of capital expenditures opportunities may exist for the type of solutions listed above. However, as described in the *Non-Wires Opportunity Evaluation Methodology* report, the economic assessment and lead times will be taken into account when determining the path forward on non-wires solutions, if any.

5.4 Wires and Non-Wires Solution Options

Examples of wires and non-wires solution options are provided in Table 5.

Table 5: Example Wires and Non-Wires Solution Options

ISSUE	TRADITIONAL (WIRES SOLUTION)	TECHNOLOGY (NON-WIRES SOLUTION)
Distribution capacity	• Overhead and underground conductor upgrades to relieve capacity overloads from excess load or generation • Distribution transformer and secondary conductor upgrades to relieve equipment overloads during peak load or generation periods • New substation transformer or circuit installation	• Energy storage or export during peak generation or peak loading periods, respectively • Power electronic devices that regulate volt-amperes reactive (increase hosting capacity)
Distribution reliability (back-tie)	• All of the above • Circuit reconfiguration to help rebalance loads and generation between circuits to maintain the N-1 planning criteria and operational flexibility	• All of the above • Advanced inverter DER controllability to allow system operators to manage the resources during abnormal conditions, similar to grid-scale projects that allow system operators to control active power output when safety and reliability are at risk

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Charging Ahead

GRID PLANNING FOR VEHICLE ELECTRIFICATION

A Report of the Energy Systems Integration Group's Grid Planning for Vehicle Electrification Task Force

January 2024

ESIG
ENERGY SYSTEMS
INTEGRATION GROUP

About ESIG

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation, particularly with respect to clean energy. More information is available at https://www.esig.energy.

ESIG's Publications

This report and its accompanying fact sheet are available at https://www.esig.energy/grid-planning-for-vehicle-electrification/. All ESIG publications can be found at https://www.esig.energy/reports-briefs.

Get in Touch

To learn more about the topics discussed in this report or for more information about the Energy Systems Integration Group, please send an email to info@esig.energy.

Charging Ahead: Grid Planning for Vehicle Electrification

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Disclaimer

Contents

Abbreviations Used

ADMD	After diversity maximum demand
ALM	Automated load management
DER	Distributed energy resource
EV	Electric vehicle
NERC	North American Electric Reliability Corporation
PV	Photovoltaic
TOU	Time of use
V2H	Vehicle-to-home
V2G	Vehicle-to-grid
V2X	Vehicle-to-everything

Executive Summary

Transportation electrification is accelerating and will affect all facets of the power system, but the effects will be most pronounced for distribution systems where vehicle charging could quickly overwhelm grid edge equipment. Public charging sites and vehicle fleet depots can be planned, permitted, and constructed much more quickly than other loads such as commercial sites or industrial facilities. Utilities therefore have much less time to upgrade distribution system infrastructure for electric vehicle (EV) integration compared with new loads historically.

Faced with this rapid change, planning practices need to evolve to keep pace. Decisions today will strongly affect the preparedness of the grid for vehicle electrification. This has implications for customers' EV adoption, vehicle manufactures' ability to sell new cars, and public policies intended to reduce emissions and encourage EV growth. The distribution planner's job is not an easy one. Planners must grapple with the possibility of either over-building the system for load that may not materialize or under-building and potentially leaving the system with insufficient infrastructure to meet EV charging demand.

Depending on the approach chosen, the distribution system can be a bottleneck for vehicle electrification, hamstringing EV adoption, or it can support more sustainable transportation thanks to thoughtful planning. Despite incomplete information about the timing, magnitude, and location of EV charging behavior, there are opportunities to lay a grid planning foundation today that will support the evolution of the grid and enable widespread vehicle electrification.

Priority Actions to Take Today

Priorities for effectively integrating vehicle electrification into grid planning include improving forecasting, embracing smart charging, incorporating future-ready equipment, and promoting proactive upgrades.

Improve Forecasting

Forecasting vehicle impact can be improved by enhancing adoption and behavior models to consider multiple vehicle end uses, new vehicle technologies, and additional data sources. First, forecasting adoption at a granular level can be achieved through likelihood models informed by costs, policies, and customer preferences, as well as through new sources of data, such as fleet electrification surveys. These adoption models can include locational components and characterize the types of vehicles that will connect to the grid, including the technology that underpins the vehicle (the battery technology, size, and charger). Second, forecasting charging behavior and how the vehicle is used (e.g., school bus vs. city bus) will inform impacts of EVs both temporally and locationally.

These two key elements—the location and timing of charging—are intertwined, elastic, and changing as EV adoption increases and vehicle technologies progress. Even with the best models and data, forecasts will not capture everything. In time, we will learn how technological, regulatory, and social-human factors will impact EV charging. Embracing the uncertainty around EV adoption and charging patterns through scenario planning helps planners think in broad strokes rather than narrow solutions. Scenario planning can help identify the suitability of the power system—generation resources through distribution equipment—to support a range of futures, not just the adoption timeline and charging behavior that grid planners hope will manifest.

Targeted smart charging, operating limits, and strategically located storage can help with immediate load growth, and these remain useful as more solutions are implemented over time.

Embrace Smart Charging

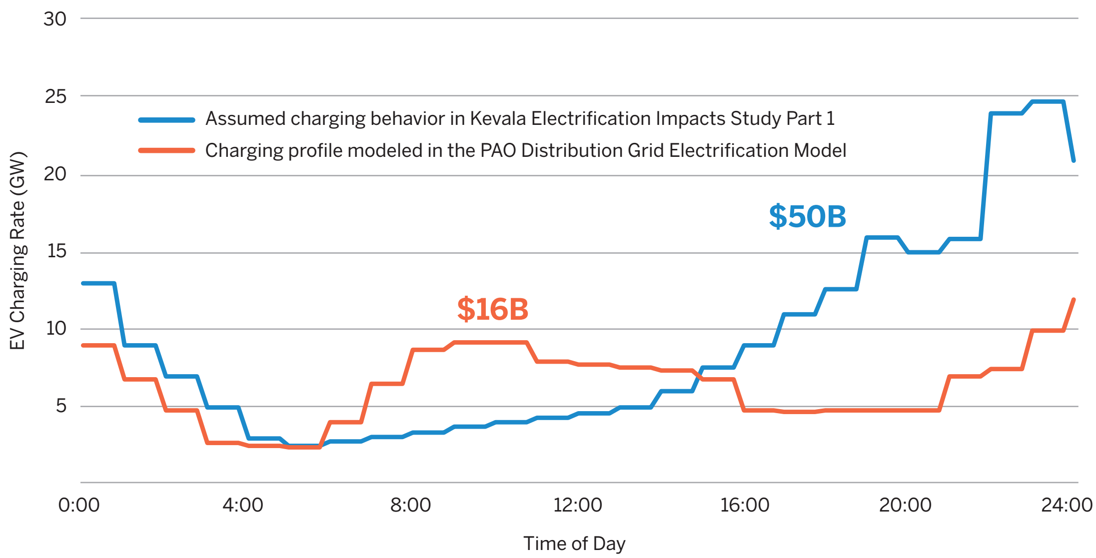
Smart charging programs hold great promise for utilizing grid infrastructure efficiently, aligning charging with infrastructure capabilities and the lowest-cost electricity. Smart charging options using rate designs, automation, or demand response programs can align charging with more affordable energy and reduce total infrastructure needs at every level of the grid from the premise to the bulk system. Targeted smart charging, operating limits, and strategically located storage can help with immediate load growth and remain useful as more solutions are implemented over time.

Studies recently completed in California highlight the impact of smart charging on estimates of distribution upgrades that will be needed as vehicles electrify (Figure ES-1, p. xi). One study found that unmanaged EV charging, coupled with some electrification of other loads, could lead to $50 billion in distribution upgrades in California alone (Kevala, 2023). Another study, which used different assumptions on charging behavior, found that distribution upgrade costs could be $16 billion (roughly $800 per metered user) (PAO, 2023). While these studies assessed different levels of electrification, they underscore the wide range of potential costs being contemplated. With smart charging increasing the utilization factor of grid infrastructure, new EV loads may be able to justify grid upgrades by spreading the costs across a larger volume of electricity sales, thereby potentially decreasing rates for everyone, not just EV owners.

Smart charging strategies vary from simple tools (such as predefined time-of-use rates and demand charges) to sophisticated control measures (like dynamic operating envelopes) that can address varying grid needs. The overarching goal of each strategy is to align charging within grid infrastructure limits, help integrate clean energy, and reduce the costs of charging. As such, the costs of sophisticated smart charging solutions, including participation incentive costs, can be evaluated against the cost of traditional upgrades, such as the installation of larger equipment. Multiple smart charging strategies could be used to simultaneously address multiple grid constraints, as is shown in Figure ES-2 (p. xi).

FIGURE ES-1

Differences in EV Charging Assumptions and Costs of Distribution Upgrades in Two Recent Studies

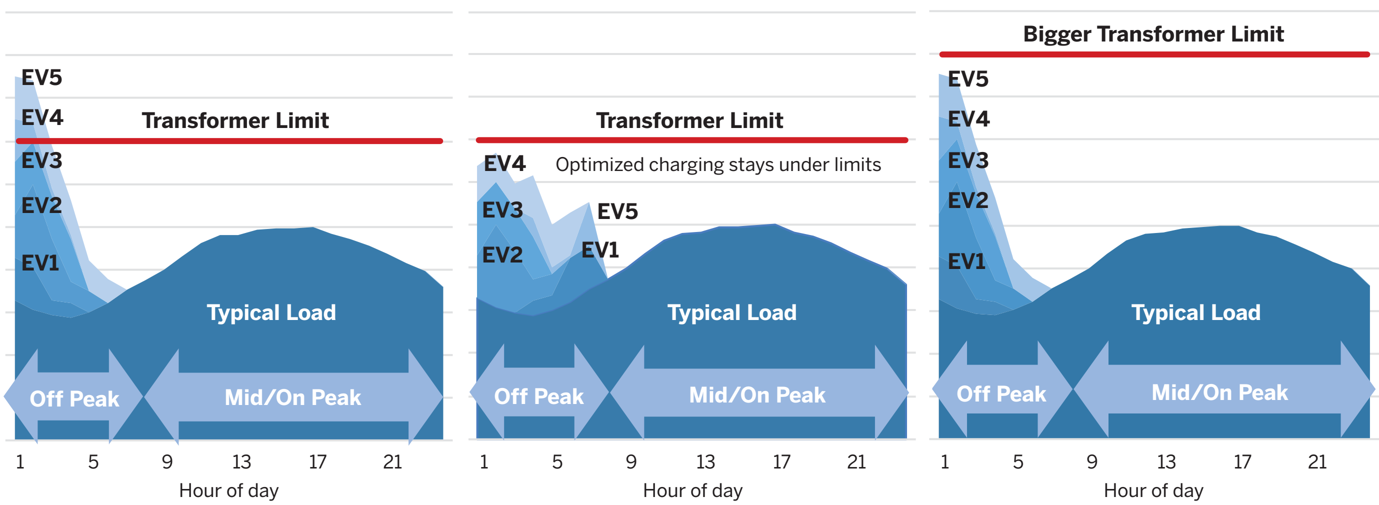


Differences in charging assumptions can have a large impact on the cost of distribution upgrades. Smart charging can adjust the charging profile.

Source. Energy Systems Integration Group. Data from Kevala (2023) and the California Public Utilities Commission's Public Advocates Office (2023).

FIGURE ES-2

Optimized Charging Aligned with Time-of-Use Rates



Time-of-use (TOU) rates with load optimization can simultaneously address bulk system and distribution constraints. If we only focus on bulk system needs with rate designs, EV charging may all start at the beginning of the off-peak period and overwhelm the distribution equipment (left). We can instead stagger charging and get the bulk system benefits of TOU without overwhelming the distribution system (middle). However, simply upgrading the distribution transformer may be more cost-effective and requires less of customers (right). The industry is learning more about the best mix of solutions to enable charging.

Source: Energy Systems Integration Group.

Incorporate Future-Ready Equipment

The optimal grid plan will likely be some combination of smart charging paired with infrastructure upgrades. More subtle strategies can enable electrification over time, including using future-ready equipment designed to support future load growth from EVs and other sources. Distribution utilities can strategically plan for the future by upgrading equipment when it is slated to be replaced or first commissioned, thus making better use of the labor and maintenance costs associated with grid equipment with the goal of limiting the long-term cost associated with grid upgrades for higher levels of electrification.

Planning for EVs requires a holistic analysis of the assumptions that drive grid planning decisions. Many of those assumptions are embedded in equipment design standards, which are assessed infrequently, and leading utilities are re-evaluating these design standards because of vehicle electrification. Unfortunately, there is no consensus on optimal designs today as engineers balance uncertain equipment loading levels (driven in part by the diversity of charging behavior) and equipment rating methodologies that are also undergoing innovation thanks to new equipment-ageing methodologies.

The risks of over-building and under-building the distribution system have asymmetric impacts. The impact of over-building includes increased costs, while under-building leads to stunted interest in electric vehicles and falling short of public policy.

Promote Proactive Upgrades

Future-ready grid upgrades that take place over decades may not be sufficient to meet all projected EV charging needs, and specific locations within a region may need upgrades before the existing equipment has reached the end of its expected lifespan. Widespread just-in-time upgrades of distribution equipment to support the level of electrification projected would likely be both costly and infeasible for utility construction crews. Distribution utilities can be proactive but should do so intelligently by working with multiple stakeholders and using improved, granular forecasts that may help to avoid overbuilding the system and creating stranded assets. The risks of over-building and under-building the distribution system have asymmetric impacts. The impact of over-building includes increased costs, while under-building leads to stunted interest in electric vehicles and falling short of public policy. By analyzing forecasts, working with a multi-stakeholder group, and considering these asymmetric impacts, distribution planners can prioritize areas for targeted upgrades.

TABLE ES-1

Multiple Processes Provide a Holistic Approach to Grid Planning for EVs

Existing Processes
While today's grid planning processes vary across the country, they generally include: • Annual system reviews • Regularly updated grid plans with a medium- to long-term planning horizon • Isolated evaluation of interconnection requests
Customer-Collaborative Processes
A customer-collaborative process between planners and customers allows for open communication about: • Multiple options for interconnection • Multiple locational alternatives
Proactive, Multi-Stakeholder Processes
Given the volume and multiple use cases of EVs, proactive processes can be well suited to: • Ensure access to EV charging for underserved communities and determine where local, traffic-related pollution may be mitigated through vehicle electrification • Facilitate regional networks • Provide clear roadmaps for electrification planning progression

Multiple planning processes can be used together to effectively plan the grid for vehicle electrification. This approach supplements existing processes with customer-collaborative processes and proactive, multi-stakeholder processes.

Source: Energy Systems Integration Group.

Proactive upgrades could include larger equipment, new equipment, or non-wires alternatives, such as batteries or behind-the-meter generation. These upgrades can be strategically implemented based on improved forecasting techniques and identified by a multi-stakeholder group, to help ensure a targeted and efficient response to changing needs. Regulatory and policy efforts may be needed to support proactive upgrades because these upgrades may not be "used and useful" when they are first implemented.

Diversifying Planning Processes

Different processes can be used to identify different types of grid solutions. While much of distribution system planning has traditionally been handled by utilities, the role of state legislators, regulators, and other state officials will continue to grow as multiple power grid objectives compete for priority. Similarly, retail rate designers, vehicle manufacturers, and charge station operators will need to work with grid planners to design solutions that balance the cost of new infrastructure with customer charging flexibility. And the need to ensure equity in designing the grid that supports an electrified future is best accomplished through a broad range of stakeholder input.

Design of a grid that supports an electrified future can draw from multiple planning processes working together by supplementing existing processes with new approaches.

Given the scale and layers of considerations that go into grid planning for vehicle electrification, three types of planning processes can be helpful to facilitate EV grid integration. Table ES-1 describes the role for existing processes, customer-collaborative processes, and proactive multi-stakeholder processes in enabling vehicle electrification.

This report walks through four high-level steps in grid planning and suggests good, better, and best practices associated with the planning attributes that lead to effective grid planning for vehicle electrification. It also discusses the areas where improvements are needed, gaps in our collective knowledge, and the role of various stakeholders. The four steps are to: (1) improve forecasting, (2) embrace smart charging, (3) incorporate future-ready equipment, and (4) promote proactive upgrades and processes to support an electrified future. Because of the multi-billion-dollar scale of these grid planning decisions, coordinated and holistic planning is needed to design grid architecture that effectively balances uncertainty around EV adoption and when and where vehicles will charge, which can lead to an overly cautious investment approach, with ensuring the grid is adequately prepared for EVs. Grid planning for vehicle electrification is an opportunity to further integrate the energy systems that power our lives while establishing a platform for a wholly sustainable future.

Introduction

While electricity loads across the United States have been relatively flat or declining over the past 20 years, with sectoral changes in the economy and improved energy efficiency reducing load even as the economy grew (EIA, 2023), loads are now projected to grow dramatically. The rapid rise in electric vehicles (EVs), the electrification of buildings and industry, and a proliferation of data centers will increase loads significantly and require substantial changes to grid planning (Figure 1, p. 2). However, no consistent or thorough method exists for grid planners to integrate EVs into the power grid as both a load and potentially a resource.

No consistent or thorough method is available across the industry for grid planners to integrate EVs into the power grid.

The electrification of transportation affects all facets of the power system—from generation to transmission—but the effects will be most pronounced for distribution systems. Distribution system equipment is smaller and has lower power transfer capabilities, and will be impacted by even a few EVs charging at the same time in a local area. In addition, the first deployments of EV charging stations tend to be concentrated in specific locations—at depots for fleet vehicles, alongside highways and transportation corridors, and in communities with relatively high early adoption. As EVs become more common, they can quickly overwhelm local distribution systems.

Distribution networks will be able to support more EV charging at some grid locations than others. For example, some substations are more amenable to electrification, or more capacity is available at one service transformer than another. In the past, a utility may have provided more headroom at a given distribution level than another, making it more suitable to integrate EVs at the substation level than the service transformer, or vice versa. EV adoption will require new infrastructure upgrades across the country, but often at a highly local level—simultaneously challenging system planners to evaluate impacts across a broad region while targeting upgrades with precision.

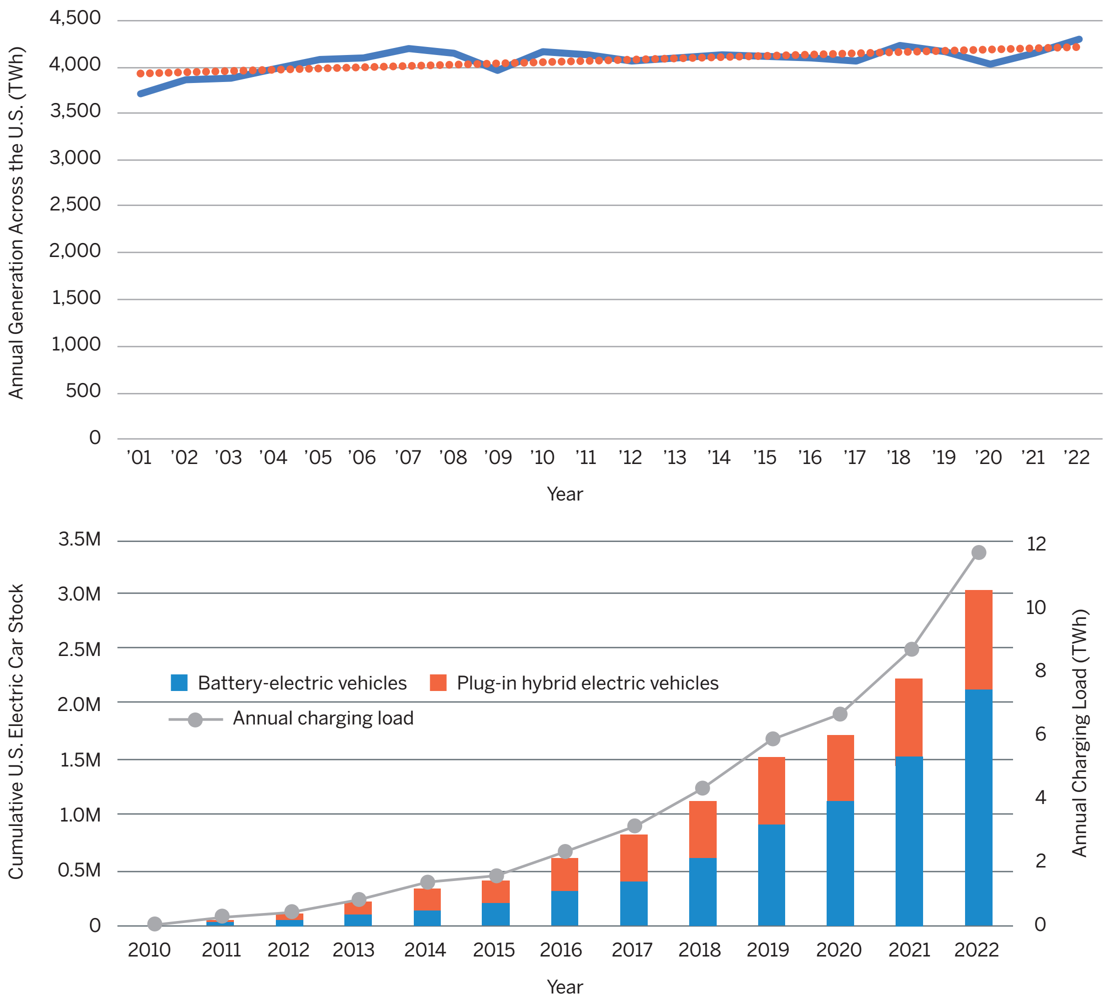
EV adoption will require new infrastructure upgrades across the country, but often at a highly local level—simultaneously challenging system planners to evaluate impacts across a broad region while targeting upgrades with precision.

New technologies and solutions are available that can help manage EV charging and discharging. This report explores ways that planners can prepare the distribution system for EV growth now by both determining where to make upgrades and evaluating the efficacy of smart charging solutions.

Increased Adoption of EVs

Transportation electrification is accelerating due to consumer demand, commitments from vehicle manufacturers, and public policy targets and incentives. U.S. sales of electric cars increased by 55% from 2021 to 2022, led by all-electric vehicles, which saw increased sales of 70% in 2022 (IEA, 2023). Thirty-eight percent of U.S. adults say they are somewhat likely or very likely to seriously consider an EV for their next vehicle purchase. That

FIGURE 1
Fairly Flat Annual Generation Compared to Rapidly Rising EV Charging Demand



Total generation across the country has remained relatively steady in recent years (top). Meanwhile, the cumulative EV stock has grown rapidly in the last decade (bottom), and the charging load will soon influence the generation trends.

Source: Energy Systems Integration Group. Data from the U.S. Energy Information Administration and the International Energy Agency.

number rises to 45% for people under the age of 50 (Pew, 2023).

Vehicle manufacturer commitments, such as the adoption of electrification targets and announcements of corporate net-zero pathways to reduce carbon emissions by 2030, are leading to major car manufacturers investing billions of dollars annually in research and development. Ford, General Motors, Toyota, and Volkswagen each invested at least $6 billion annually from 2019 through 2022 in EVs and digital technologies (IEA, 2023).[1]

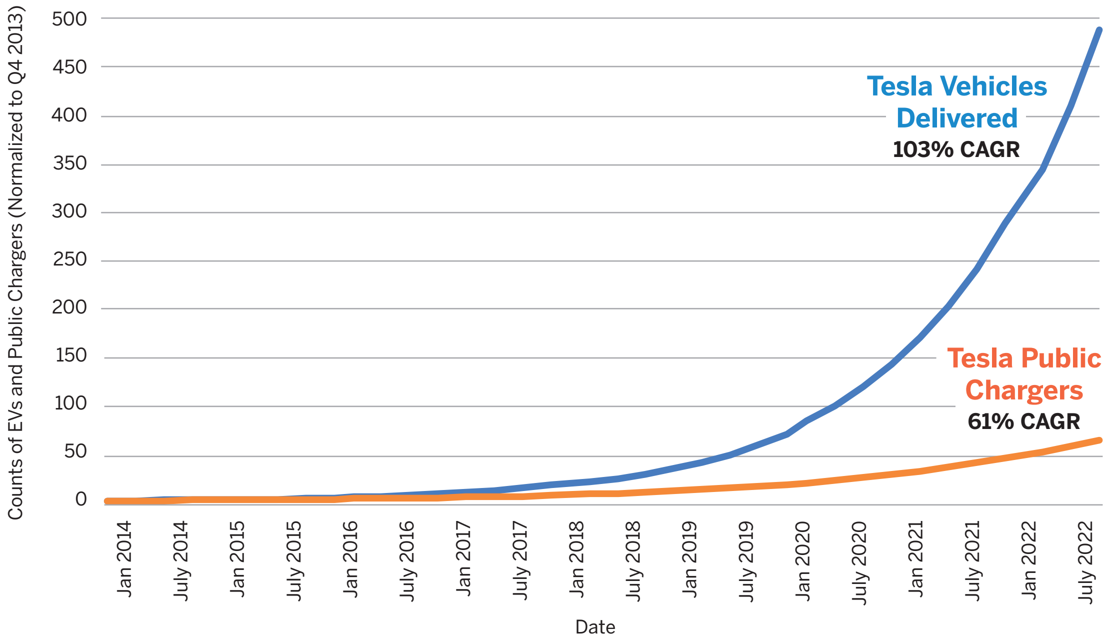
While EV adoption accelerates, public charging infrastructure has lagged (see Figure 2, p. 3).[2] However, this

1 Recently, some car manufacturers have backed off of some of their near-term execution plans for electrification, but their long-term goals remain intact.

2 This report adopts language proposed in Wood et al. (2023) that groups various types of charging together into at-home and public charging. In this context, public charging includes any charging that takes place away from a person's primary residence, including workplace charging, destination charging, and corridor charging en route, and may be provided free for the driver or require payment.

FIGURE 2

Comparison of Number of EV Vehicles on the Road and Number of Public Chargers



The increases in the number of Tesla vehicles on the road has far exceeded Tesla public charging network roll-out for a variety of reasons, including a lack of sufficient grid infrastructure. This illustrates the challenge in building out an EV charging network fast enough to keep up with demand from EV drivers. This trend is also seen in non-Tesla charger deployments and highlights the accelerating demands of grid planning to support vehicle electrification.

Note: CAGR = compound annual growth rate.

Source: Tesla comments to the California Energy Commission, 9/1/2023 (https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-03).

is changing quickly with recent public policy focusing on both getting more EVs on the road and getting the chargers installed. The Inflation Reduction Act (IRA) provides tax credits of up to $7,500 per vehicle, and the Infrastructure Investment and Jobs Act (IIJA) makes $7.5 billion available for EV charging infrastructure. Many states and municipalities have additional incentives for both vehicle purchases and charging infrastructure. As of March 2023, an estimated $23.7 billion had been committed by federal, state, and local governments, as well as from private firms, for publicly accessible EV light-duty charging infrastructure, which represents between 43% and 76% of the funding that will be needed for public chargers to support a mid-adoption EV scenario by 2030 (Wood et al., 2023).

Resulting Grid Planning Challenges for Charging Infrastructure

However, despite interest in and commitments to EVs from consumers, manufacturers, and policymakers, distribution system planning for vehicle electrification remains a challenge. Since public charging sites require relatively little supporting infrastructure beyond the electrical equipment and the charger itself, they can be planned, permitted, and constructed much more quickly than other types of sites with similar power requirements (such as housing, commercial sites, and industrial facilities). This means that utilities have much less time to upgrade distribution system infrastructure for public charging sites compared with new loads historically. Faced with

Utilities have much less time to upgrade distribution system infrastructure for public charging sites compared with the new loads that have historically required energization. Faced with this rapid change, grid planning practices need to evolve to keep pace with EV charger deployment.

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The rapid increase in EVs and associated grid upgrades is under discussion in individual jurisdictions and state regulatory proceedings, and specific issues have been explored at a national scale. For example, studies have been done on national charger requirements to support EVs (Wood et al., 2023), the role of smart charging in grid integration (SEPA, 2022), and generation requirements for new EVs (MISO, 2021). The Modern Distribution Grid (DSPx) reference documents discuss EVs and distribution engineering amongst myriad other considerations (PNNL, 2019). EPRI has recently launched a three-year initiative, EVs2Scale2030™, to support the rapid deployment of EVs while minimizing grid impacts and enabling benefits to the nation's grid. The EPRI initiative recently published eRoadMAP™, an interactive energy map that presents the amount of energy needed to electrify transportation with granularity down to 0.28 square miles.[3]

However, there is a need for coordinated and holistic evaluation of how distribution planning practices and processes can adjust to support continued increases in EV adoption. Aligning grid planning and charger siting will be crucial in transitioning to an electric transportation future.

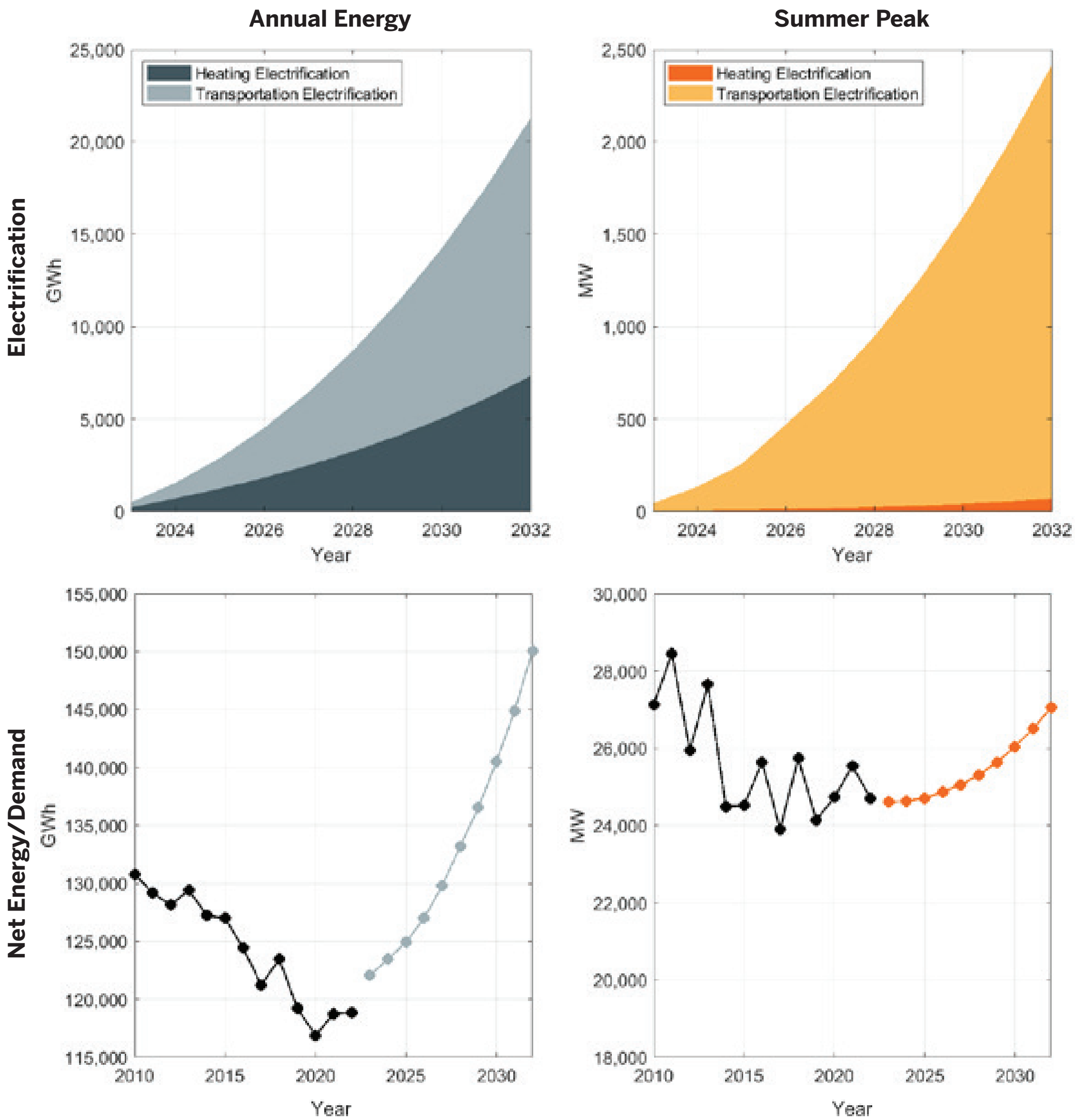
A Need for Smart Approaches to Grid Planning for EV Growth

EVs will change power system needs more than at any time since the uptake of air conditioning in the 1960s. Rapid and sustained increases in electricity demand from EV charging will put increasing stress on distribution systems. One EV could double the maximum demand from an individual household (Engel et al., 2018), and a concentration of EVs in a neighborhood could overwhelm local distribution system capacity. When high levels of EV charging occur across a region, it becomes a significant impact across all voltage levels. For example, the Independent System Operator of New England

3 See https://eroadmap.epri.com/.

FIGURE 3

ISO-NE System Load Forecast



The load forecast for the ISO-New England system shows growth across both energy and demand due to vehicle electrification (in light gray and light orange) and heating electrification (in dark gray and dark orange). On certain distribution circuits, growth will be more rapid than shown here.

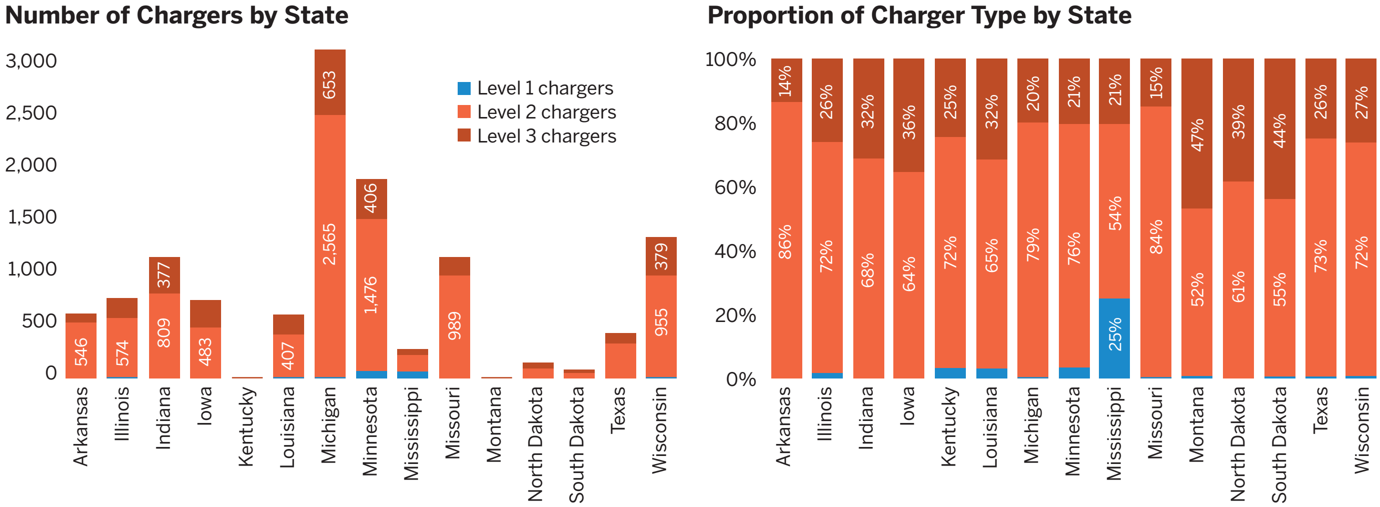
Source: Independent System Operator of New England.

(ISO-NE) has forecast that transportation electrification will increase annual energy requirements for the region by 10% and contribute between 8% and 12% to system peaks by 2032 (Figure 3).

EV adoption rates will vary significantly from community to community, amplifying challenges in specific regions at a pace rarely seen in power system planning. For example, the Midcontinent Independent System Operator (MISO) is seeing chargers deployed at very different paces across the states that it serves. Variation in EV charging will be even more pronounced on the distribution level (Figure 4, p. 6). This variation in geographical location increases the need for accurate forecasting.

FIGURE 4

Variability in EV Charger Deployment in MISO States



States in the MISO territory deploy chargers at very different paces and with different mixes of Level 1, Level 2, and Level 3 chargers. This variation in EV charging will be even more pronounced on the distribution level.

Source: Midcontinent Independent System Operator, based on U.S. Energy Information Administration data with participation rates applied.

Maintaining Reliability at a Reasonable Cost

Studies have found a wide range of potential costs for grid upgrades. While it would be costly to build the infrastructure necessary to accommodate unconstrained EV charging, new technologies and incentives can change consumer charging behavior and reduce the need for new distribution system infrastructure. One study's high- and low-cost cases differed by a factor of 10, with the high case estimating cumulative investment across the country by 2050 at around $200 billion (Cutter et al., 2021). Analysis of California, meanwhile, found that unmanaged EV charging and electrified space heating could cost Californians $50 billion in distribution grid upgrades by 2035—roughly $2,500 per utility customer (Kevala, 2023). The second phase of that study will estimate the reduced costs with managed charging. Similarly, MISO analysis found that generation requirements could increase substantially depending on base assumptions for demand profile and utilization rates of grid equipment (MISO, 2021).

Grid planners must estimate how many EVs to expect, predict where and when they will charge, account for technology innovation, and prioritize grid upgrades to supply them. Regulators must review plans and ensure that ratepayer funds are spent prudently. This is a delicate balancing act.

As distribution system planning increasingly includes higher levels of EV adoption, both utility engineers and utility regulators are grappling with new and complex challenges. Grid planners must estimate how many EVs to expect, predict where and when they will charge, account for technology innovation, and prioritize grid upgrades to supply them. Regulators must review plans and ensure that ratepayer funds are spent prudently. This is a delicate balancing act. Inadequate distribution infrastructure will stall EV adoption, frustrating consumers and policymakers alike. Underestimating load growth could jeopardize reliability at both the local distribution and bulk system levels, while overestimating demand could lead to over-investment in infrastructure and stranded utility assets, raising electricity costs without commensurate benefit. And the lack of planning and support for bi-directional charging or further technology innovation could strand assets that could otherwise provide significant value. At the same time, EV charging can

increase the utilization factor of new and existing infrastructure, potentially decreasing electricity rates (PAO, 2023; Cutter et al., 2021).

Making Use of Smart Charging, Data Analytics, and Advanced Grid Technologies

There are ample opportunities to mitigate the undesirable outcomes. Consumer-side resources—most notably, smart charging—can be part of the solution. And the power industry can look to recent advances in analytics and data science, while embracing advanced grid technologies that would make the most of existing infrastructure, to integrate new EV demands. The industry can also apply lessons learned from other activities—for example, demand response programs to manage air conditioning loads.

Planning for transportation electrification requires coordination among a wide range of stakeholders—from utility planners and policymakers to vehicle manufacturers, charge station aggregators, commercial fleets, public transportation departments, and EV users. An integrated distribution planning approach would incorporate modern grid technologies and distributed energy resources (DERs) into distribution planning, with linkages to bulk power system planning and alignment with community and state goals, objectives, and priorities. Such an approach can help to determine where and when EV adoption will likely happen and help to prioritize the grid upgrades necessary to effectively integrate EV charging with input from multiple perspectives.

Focus of this Report

The Energy Systems Integration Group (ESIG) convened the Grid Planning for Vehicle Electrification Task Force to discuss the challenges throughout the grid planning process from multiple perspectives, identify gaps in distribution system planning for vehicle electrification, discuss ways to address these gaps, and articulate promising practices and next steps. The task force included grid planners from across the globe, vehicle and charge station manufacturers, charging network operators and aggregators, regulators and state offices, researchers, and consultants active in the intersection of EVs and grid planning.

This report provides a holistic, national-level examination of transportation electrification challenges that directly impact integrated distribution planning, and outlines how coordinated planning that addresses the largest grid challenges can help instill confidence in long-term plans. The primary audiences are utilities, utility regulators and other state decision-makers, EV manufacturers, charge station operators, aggregators, and other technical experts. With such rapid changes, approaches to meeting distribution system needs in light of vehicle electrification need to remain nimble. The themes, concepts, and areas of emphasis conveyed in this report will continue to evolve as we learn more.

This report provides a holistic, national-level examination of transportation electrification challenges that directly impact integrated distribution planning, and outlines how coordinated planning that addresses the largest grid challenges can help instill confidence in long-term plans.

Grid Planning in the Context of Vehicle Electrification

EVs are the latest addition to the list of emerging distribution planning considerations, which have included rooftop solar photovoltaics (PV), aging infrastructure, enhancements in grid modernization technology, and improvements in analytic capabilities. Historically, distribution system planning was a "black box" exercise wholly contained within the utility and primarily oriented around ensuring that energy could be delivered from the transmission grid to meet load growth throughout local networks. As expectations of electricity systems have changed in recent years, many states require utilities to file some type of plan that describes how the utility intends to upgrade its distribution system. Plans vary significantly in how they consider EVs, depending on the jurisdiction and utility. There is a lack of consensus on how to address EVs alongside other distribution planning considerations.

Many states require holistic integrated distribution system plans that provide detailed analyses and roadmaps for the next 5 to 10 years for distribution system expenditures to meet projected load, enhance utility capabilities through improvements to data and tools, make the best use of DERs, improve reliability and resilience, and meet other public policy objectives.[4] Other states, either as part of integrated distribution system planning filings or separately, require utilities to file electrification plans that articulate how they are aligned with state policy objectives related to vehicle and building electrification.

A distribution system built to maximize every objective simultaneously would be unaffordable; however, these objectives can be prioritized and optimized for an affordable outcome. Figure 5 (p. 9) shows how the integrated

Distribution system plans vary significantly in how they consider EVs, and there is a lack of consensus on how to address EVs alongside other planning considerations.

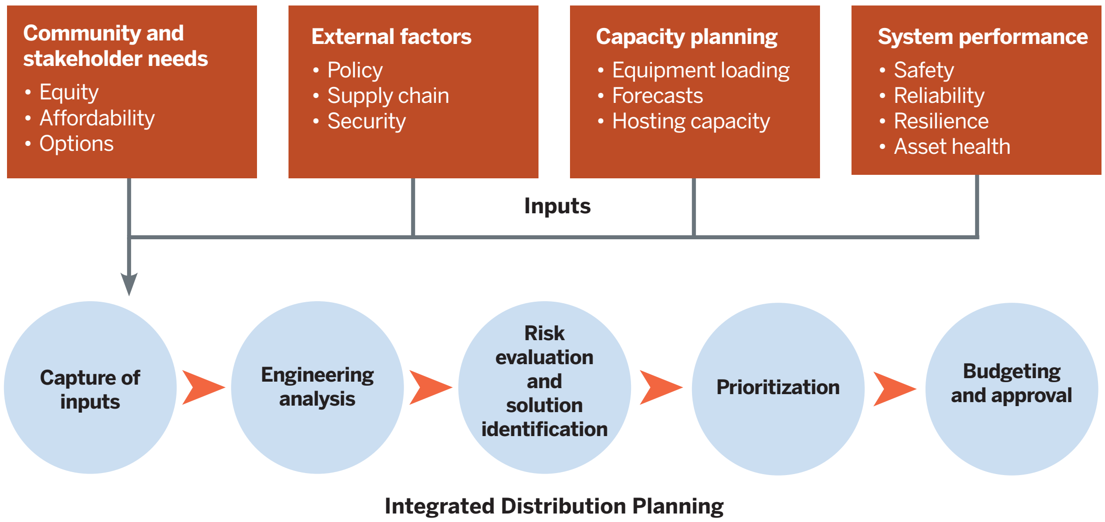
distribution system planning process includes inputs beyond load growth in determining the grid plan. Increasingly, ensuring equity and access for grid upgrade benefits is a key outcome for these processes.

Integrated distribution system planning processes are driven by a need to optimize across multiple objectives, including grid resilience, reliability, affordability, and safety, as well as to empower customer choice through

4 Twenty-six states, the District of Columbia, and Puerto Rico are somewhere in the process of enhancing their distribution planning processes (Cutler and Chew, 2020).

FIGURE 5

An Integrated Distribution Planning Framework



A simplified integrated distribution planning framework inspired by ComEd's 2023 Multi-Year Integrated Grid Plan. This report considers the entirety of integrated distribution system planning, but is primarily focused on capturing inputs and assessing risks and mitigation measures.

Source: Energy Systems Integration Group. Adapted from Commonwealth Edison (2023).

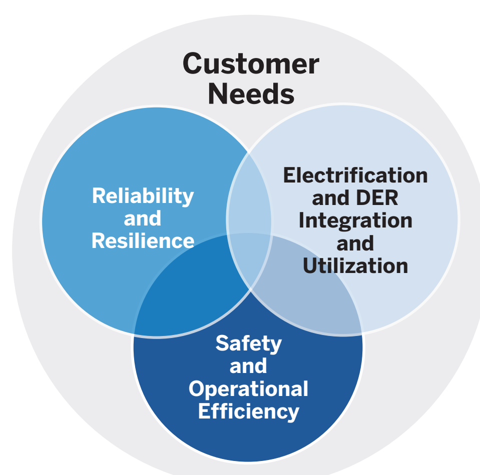
DER and EV integration and utilization (Figure 6). Still, simply switching to a process that considers these objectives is insufficient for solving grid planning for vehicle electrification; innovation and change is also needed in engineering and regulating. EV sales have outpaced the deployment of public charging infrastructure in recent years, which will lead to insufficient charging access if this trend continues.

Figure 7 (p. 10) summarizes the steps needed to plan the grid for vehicle electrification. This report discusses these steps in sequential order, but in practice, numerous feedback loops are needed, as smart charging strategies can alter plans.

EV sales have outpaced the deployment of public charging infrastructure in recent years, which will lead to insufficient charging access if this trend continues.

FIGURE 6

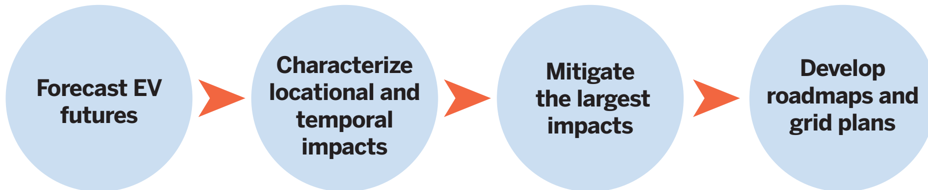
Electrification as One of Many Considerations in Integrated Distribution Planning



EVs are among multiple considerations of a consumer-centric grid planning process.

Source: Pacific Northwest National Laboratory (2019).

FIGURE 7
High-Level Steps in Grid Planning for Vehicle Electrification



These are simplified steps needed to plan the grid for vehicle electrification. There will be feedback loops and iterations between and within these steps, to be discussed throughout this report.

Source: Energy Systems Integration Group.

Impact of EVs on the Distribution Planning Process

This new source of load will affect all layers of the power grid. In addition to requiring changes to wiring in individual homes and businesses, EV adoption may require utilities to install equipment capable of carrying more electricity, which would mean larger primary and secondary wiring and larger (or more) service transformers, lines, or substation equipment.

Figure 8 (p. 11) shows a typical grid hierarchy with bulk system, distribution, and premise levels. Depending on the size, EV chargers can be installed at any of these levels. In some places, the equipment can handle the added EV load. In other areas, EVs can cause equipment to be overloaded. At the bulk system level, new capacity may be required to meet demand, particularly during peak charging periods. EVs can affect different grid topological levels differently and affect individual pieces of equipment within a level differently.[5]

Historical Approach to Planning

Traditionally, distribution planning has used a standards-based approach that provides engineers with a select set of equipment to design sufficient capability on the system to serve load. Equipment standards serve two primary functions: (1) to help streamline utility supply chains and inventory and simplify installation and construction processes, and (2) to provide sufficient headroom for distribution equipment serving ordinary premises.[6] For example, an equipment standard could specify that a certain size of service transformer can serve 10 single-family homes with sufficient headroom to preserve the equipment capabilities over its useful life. As distribution system planners design the power system for a new 100-home neighborhood, they would use 10 of these service transformers. Utilities also commonly extend this approach to procuring land for substations and other equipment. By leaving room for additional equipment in a substation, future flexibility is preserved.

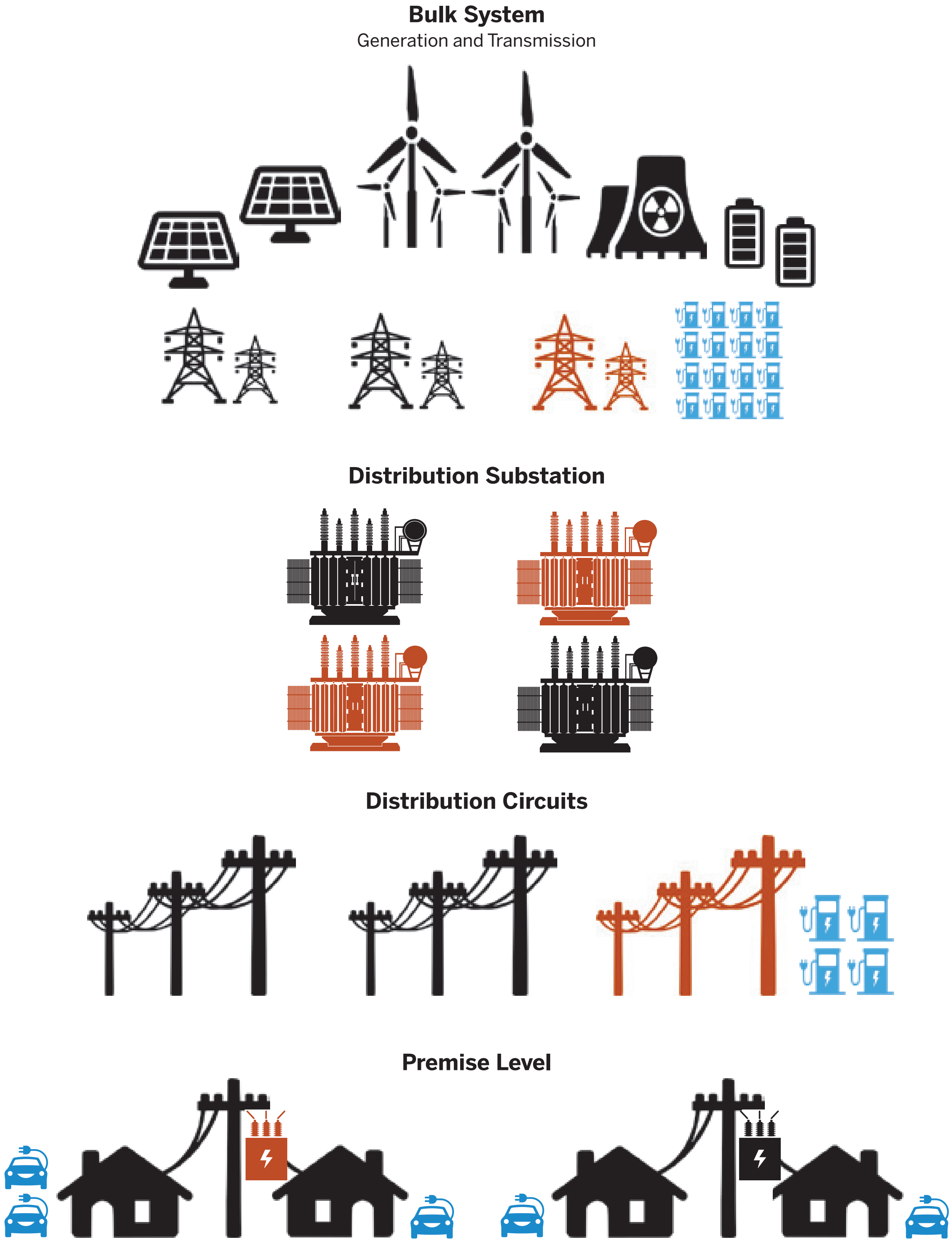
However, this approach was developed when load grew much more slowly, entirely new types of loads were not emerging, and distributed generation and storage were rare. But increasingly, these standards are being revisited as engineers evaluate new data and question the assumptions underpinning design criteria. Given the potentially large impact of EVs and the impact of various EV load shapes on distribution equipment, standards and approaches will need to be reevaluated for long-term suitability. For example, including more headroom on today's distribution equipment may help avoid the cost of mid-life upgrades driven by EVs. Ensuring more space in new substations would allow for future growth in electrification.

5 Throughout this report, "topological level" indicates when granular analysis beyond "distribution system" is helpful. For instance, premises, circuits, and substations are all part of the "distribution" system, but EVs may impact these components differently depending on the circumstance.

6 The amount of headroom afforded on the distribution system is highly variable across utilities, with some evaluating their loading under normal operations and others using N-1 contingency situations to drive sizing. Still, many utilities have historically allowed 10% to 30% headroom for future load growth.

FIGURE 8

High-Level Layers of the Power Grid



Bulk System
Transmission-connected charging stations can overload the transmission system in specific areas.

Distribution Substation
Substation equipment, such as substation transformers, can be overloaded by the aggregate impact of charging on the distribution system.

Distribution Circuits
Distribution-connected charging stations can overload specific distribution circuits.

Premise Level
EV charging at homes can overload premise-level infrastructure, such as service transformers.

EVs affect all layers of the power system and can cause system overloads (represented by orange objects) at each level. EV charging is represented by the blue icons.

Source: Energy Systems Integration Group.

Grappling with Uncertainty Introduced by EVs

Distribution system planners need to consider a wide range of potential outcomes for EVs. Each of the plausible outcomes identified in Table 1 has ramifications for how the distribution system is planned and ultimately operated in the future. Moreover, these uncertainties stack on top of each other and are often correlated.

These questions highlight the need to better understand (1) types of EVs and associated consumer behavior, and (2) adoption trends and medium- and heavy-duty fleet decisions. Some regions are already experiencing grid bottlenecks for public and private charging. It is important to understand grid bottlenecks and approaches to alleviate them, especially for medium- and heavy-duty fleets, which can introduce large new loads effectively overnight and outpace utilities' grid planning and construction capabilities.

Thinking Holistically: Forward-Looking Planning with Incomplete Information

At the core of the planning challenge is right-sizing the power grid for an uncertain future, while maintaining affordability and equity. Because of the rapid widespread adoption of EVs and since public EV charging plazas can be built much faster than traditional types of new electricity demand, distribution system planners may need to build out distribution system capacity in advance

TABLE 1

Questions about EV Futures and Plausible Outcomes

Question about EV Futures	Plausible Outcomes
At what pace will EV adoption take place?	• Current policy trends hold, and the majority of new light-duty vehicle sales are EVs by 2035. • Waning consumer interest stalls EV adoption following early adopter sales. • Battery technology improves and EV costs continue to decline, leading to rapid adoption. • Medium- and heavy-duty EVs become cost-competitive for some use cases and are rapidly deployed.
When will consumers want to charge EVs? Can we rely on early adopter or commuting trends to forecast the future?	• Existing charging profiles continue into the future—with most public charging in the daytime and at-home charging at night. • Charging coincides with commuting trends as people charge immediately upon arrival at most destinations. • Rapid charging times similar to refueling a gas vehicle become common. • Midday public charging becomes common.
How will EV technology change?	• EVs only get bigger, trending toward sport utility vehicles (SUVs) and trucks with bigger batteries. Consumers want a longer range. • Consumer interest in vehicle-to-home (V2H) discharging for resilience purposes leads to an increase in EVs with bi-directional charge/discharge capabilities. • Ride-sharing and work-from-home trends fundamentally change how society uses vehicles.
What will charging and discharging demands look like?	• EV charging demands (peak and energy) remain at their present level. • Charging demands decrease as work-from-home trends continue with level 1 (120 V) charging supporting transportation needs.
Where will consumers want to charge EVs?	• EV charging reflects traffic patterns. • Consumers prefer charging at home. • Destination charging is common. • Commercial truck fleets initially rely on depot charging.
To what extent will EV owners be willing to adjust their charging?	• EV owners prioritize economics over convenience. • EV owners attempt to maintain maximum battery capacity, regardless of economics. EV owners are not effectively incentivized by economic indicators. • EV owners allow third-party managed charging. • Commercial truck fleets are as flexible as their business model will allow.

Source: Energy Systems Integration Group.

Because of the rapid widespread adoption of EVs and since public EV charging plazas can be built much faster than traditional types of new electricity demand, distribution system planners may need to build out distribution system capacity in advance of new service connection requests.

of new service connection requests. Carrying out such a forward-looking build-out would include more uncertainties than the just-in-time planning that utilities have typically performed, thus bringing with it a greater risk of wrong-sizing the grid.

Avoiding Over- and Under-building

If significant new infrastructure is built to support EVs and the load fails to materialize, the industry risks stranding investments. In most state regulatory environments, assets that are not "used and useful" are denied rate recovery by public utility commissions, and utilities are generally reluctant to take on this risk. Depending on the nature of the asset and state regulatory decisions, the customer that spurred the need for new assets could have to pay for most of the new equipment, or the utility could be denied rate recovery and costs would be paid by utility shareholders. In some cases, the cost of unused equipment could be spread across all utility ratepayers (Wilson, 2023). Each of these has downsides, with the risks stemming from policy choices being borne by different groups.

If, in contrast, the industry underbuilds and provides insufficient infrastructure to meet EV charging demand, the result could be an unreliable power grid that can at times not handle demand, increasing reliability risks. A grid with insufficient capabilities could lead to constraints on charging that stunt public interest in EVs or prematurely degrade utility infrastructure. Just 17% of Americans are extremely or very confident that the U.S. will build sufficient infrastructure to support large numbers of EVs (Pew, 2023). High-profile restrictions on EV charging could further erode confidence in electrification.

Simply put, this new load source seems to be driving grid planning toward two paths: (1) increasing the utilization of existing distribution infrastructure, and (2) expanding the grid to meet new local peaks. Faced with similar problems in the 1960s and 1970s as air conditioning loads transformed consumer demand, grid planners used both paths in building large new infrastructure projects combined with some demand response (Eto, 1996). A similar plan today would supplement traditional infrastructure investments with modern grid technology, load flexibility, rigorous planning, and improved asset utilization. Because of the multi-billion-dollar scale of these planning decisions, coordinated and holistic grid planning is needed to design distribution system architecture that effectively balances the risks of over- or under-building the system to serve EV demand.

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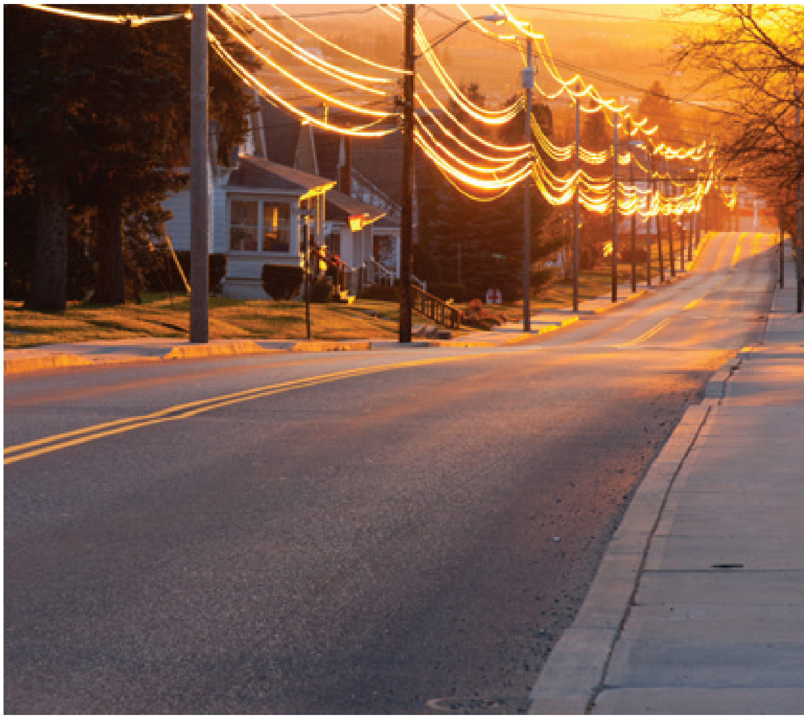


Equity and Affordability

To maintain affordability as the system transitions, careful planning is needed to ensure that distribution system capacity is built in areas that will have high utilization, while also providing opportunities for charging to all consumers, whether they use it yet or not. Building infrastructure to support EV adoption could put either upward or downward pressure on electricity rates, depending on the revenue received from EV charging compared to the investments made to serve that load. For example, a public charging site with low utilization could bring less revenue than its cost to serve, increasing rates for other customers, whereas a site with high utilization could provide significant revenue to the utility relative to the cost of the equipment needed to serve that site, and the increased revenue could reduce rates for other customers in that rate class.

Accounting for energy equity is also important when evaluating grid plans. Improper planning and cost allocation could inequitably burden low-income ratepayers with the costs from affluent early adopters. Because of risks associated with uncertain grid equipment utilization when enabling EV charging plazas, the regulatory landscape may need to re-evaluate how costs are attributed and recovered. The traditional cost recovery mechanisms —through rates—may be insufficient as smart charging incentivizes different types of behavior and the anticipated amount of charging may not materialize.

Energy equity has many dimensions. Ensuring distributional equity will help protect vulnerable consumers from unmanageable energy prices, while transitional equity will ensure that the shift to vehicle electrification happens at a pace that communities can handle. Finally, procedural equity promotes an inclusive engagement of affected parties in the decision-making process.[7]

Decisions Needed at Multiple Levels

These grid planning activities are not solely the responsibility of utilities. The role of state legislators, regulators, and other state officials will continue to grow as multiple energy system objectives compete for priority. Similarly, retail rate designers, vehicle manufacturers, and charge station providers will need to work with distribution system planners to design solutions that balance the cost of new infrastructure with consumers' charging flexibility. Analytical rigor and adaptability will be needed to incorporate new lessons learned and technological advances quickly into grid plans.

Retail rate designers, vehicle manufacturers, and charge station providers will need to work with distribution system planners to design solutions that balance the cost of new infrastructure with consumers' charging flexibility.

Decision-makers will need to think holistically as costs are shifted from one industry (petroleum) to another (electricity). The impact on rates of this shift will depend on the utilization of grid infrastructure, among other things. With high utilization, electrification could make electricity more affordable on a dollar-per-kilowatt-hour basis due to the increased consumption of electricity. With low utilization, the cost of new infrastructure to support electrification could exert upward pressure on rates. However, the California Public Advocates Office has found that all ratepayers, even those who cannot electrify, could financially benefit from electrification (PAO, 2023). Ultimately, the impact of electrification is still being determined, with many options available on how to enable electrification.

The costs for enabling vehicle electrification will need to be balanced against competing priorities and uncertainties in other industries as policymakers aim for an equitable energy transition. Priorities for the electric power system include enabling electrification, supply-side changes, reliability, and resilience, as well as safety and security. Uncertainties in other industries, such as fossil fuel and supply chain industries, could have large impacts on the future and our ability to execute the energy transition. Grid planning for vehicle electrification needs to be considered in this wider context.

7 The various dimensions of energy equity and how to plan for each in the context of vehicle electrification are important but not the focus of this paper. For more complete discussions of equity, and particularly energy equity in the context of DERs, see Woolf et al. (forthcoming) and Morell-Dameto et al. (2023).

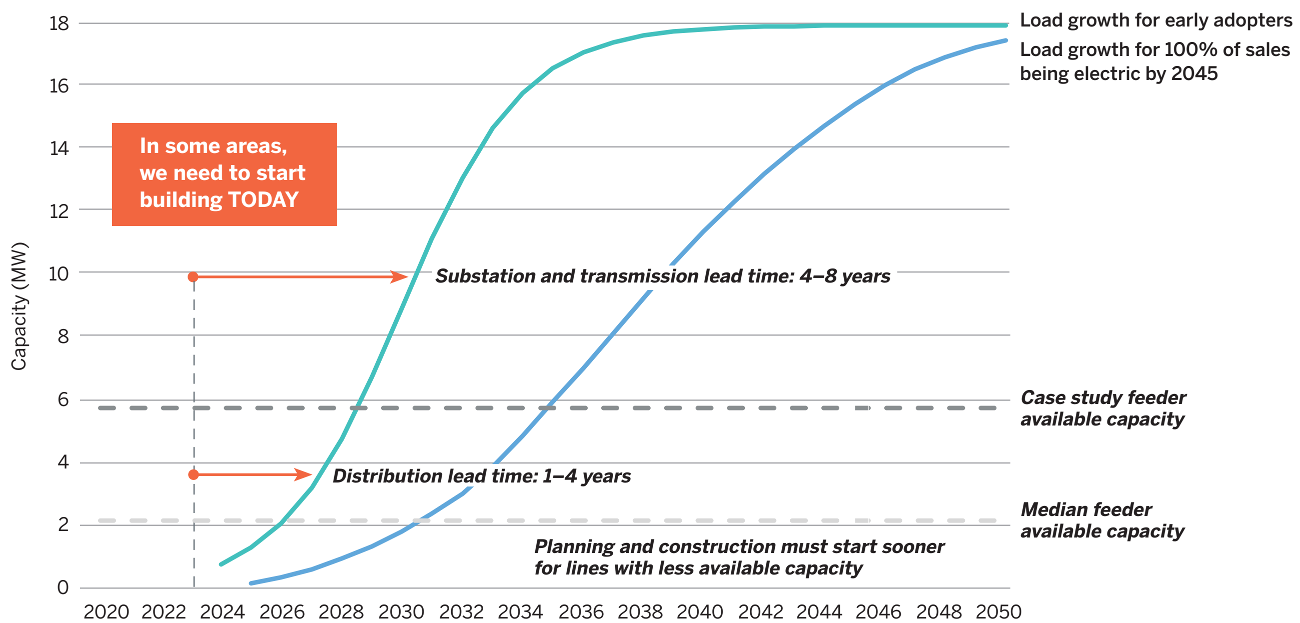
Forecasting EV Futures

The first step in planning for EVs is to forecast potential EV futures so that upgrades can be prioritized based on forecasts of the timing and locations of EV impacts. Historically, distribution projects did not require long-term forecasts, because they could be constructed at roughly the same pace as specific areas saw load growth. But going forward, longer-term forecasting of EV adoption and behavior will be critical for prioritizing regions and grid topological levels for various grid solutions since EV charging stations can be built much more quickly than new grid infrastructure.

As shown in Figure 9, the rapid increase in load growth from fleets together with the lead time needed to plan and build new infrastructure means that decisions on building new infrastructure should start today if electrification goals are to be met. Decisions about grid equipment, such as transformers, are expected to support grid needs for many years, as grid equipment has historically had a useful life of (and been depreciated over) 45 years or more (Eversource, 2023). However, grid planners have to make these decisions without perfect foresight on how local grid needs will evolve.

FIGURE 9

Time Frames for Grid Infrastructure to Meet Fleet Electrification Needs



The lead time needed for deploying grid equipment means that in some areas, to support electrification targets, decisions are needed today. Given that grid equipment is expected to be used for 45 to 50 years, the grid designed today will be expected to support our electricity needs in 2070.

Source: National Grid and Hitachi Energy (2023).

The rapid increase in load growth from fleets, paired with the lead time needed to plan and build new infrastructure, means that decisions on building new infrastructure should start today if electrification goals are to be met.

Unfortunately, general trends in EV adoption are insufficient to make distribution infrastructure decisions, as they do not inform a particular circuit's electrification trajectory or outline when consumers will want to charge throughout the day and week. While forecasting is not perfect for any type of load, modern forecasting practices can make grid planning decisions more informed by providing ranges of likely futures. The magnitude of likely EV adoption means that forecasting for EVs requires the best data, probabilistic methods, and scenarios to inform grid planning.

Forecasting EVs' impact on the distribution system boils down to two key questions:

- How fast will EVs be adopted?
- For each use case, when and where will customers charge?

Forecasters need to consider how quickly vehicles of different types will electrify, estimate how they will be used and charged, and assess how technological change may lead to different grid impacts. The nuances of translating regional forecasts of the timing of EV adoption to local distribution levels also need to be captured.

Anticipating EV Trends: Light-, Medium-, and Heavy-Duty EVs and Their Charging Technologies

First, it is important to understand how a particular vehicle will be used across the year. EV classification needs to be more granular than high-level categories such as buses, trucking, and light-duty vehicles; for example, school buses and city buses have very different charging patterns. Similarly, medium- and heavy-duty truck categories can be broken down into nearly countless end uses including long-haul, drayage around ports, and delivery vans (NACFE, 2018). Light-duty categories can be broken into commuter and secondary vehicles with charging patterns that vary significantly depending how the vehicle is used.

Modeling these end uses quickly becomes an exercise in managing model granularity and scenarios. The industry has developed tools to manage these large datasets, but care should be taken to limit the quantity of variables, and an early effort to align assumptions can be helpful. Still, agent-based simulations can be used to model how operators of these different types of vehicles make individual charging decisions.[8] Ultimately, it is individual decisions (represented by "agents" in a model) that stack together to create load profiles.[9] Forecasting the medium- and heavy-duty fleet is an area where improvement is needed. Fleet operations are not common knowledge among power systems engineers and load forecasters,[10] and these loads can be large on an individual vehicle level, with driving patterns that can vary significantly.[11]

8 Idaho National Laboratory's Caldera tool is built to simulate multi-agent decisions algorithms to better understand the light-duty charging requirements across multiple charging levels (Level 1 and Level 2 charging, DC fast charging, etc.) and is available as an open source tool for more broad industry utilization (INL, 2023).

9 These individual agents can be used to simulate how charging profiles may be different by changing certain assumptions, such as how an autonomous ride-hailing fleet is dispatched for different optimization functions (Yi and Smart, 2021).

10 The North American Council for Freight Efficiency has a large library of white papers on commercial electric trucks and has conducted demonstrations in recent years to provide insights into the behaviors of fleets with electric trucks. See https://www.nacfe.org and https://www.runonless.com.

11 Lawrence Berkeley National Laboratory is developing a tool, HEVI-Pro, that is built to inform decision-makers on medium- and heavy-duty charging requirements based on a trip activity model from real-world datasets (Wang, 2021). HEVI-Pro is being used to underpin the medium- and heavy-duty load forecasts in California with consideration for 11 vehicle end uses for the medium- and heavy-duty segment alone.

As of today, the largest charger for a single truck is a 750 kW charger, but larger charging systems and connectors are in development, including plugs that provide individual vehicles with over 1 MW of charging. Recognizing these different use cases of charging, Box 1 outlines how Southern California Edison has developed forecasts to capture those impacts.

Changing battery technology is another major consideration for vehicle trends, which goes beyond the plug used to connect the EV. As EV batteries get larger and have faster charging capabilities, grid impacts will change. With larger batteries, EVs may not need to charge every day. With faster charging capabilities, we will see more diversity of charging behavior as fewer cars charge simultaneously. However, with both larger batteries *and* faster charging, the diversity benefits may erode—for example, cars will charge faster for longer—and the importance of larger infrastructure or more sophisticated load management solutions grows.

With larger batteries, EVs may not need to charge every day. With faster charging capabilities, fewer cars charge simultaneously. However, with both larger batteries and faster charging, the diversity benefits may erode, and the importance of larger infrastructure or more sophisticated load management grows.

Different vehicles also pull power at different rates across their state of charge, which forecasters and planners can try to capture in their models. By understanding the intricacies of a variety of EV technologies and their future, grid planners can begin to navigate the uncertainties of EV charging.

Forecasting Adoption Timelines

Added to the question of vehicle technology and use patterns is the question of when vehicles will electrify. For light-duty vehicles, stock turnover models that incorporate historical trends, along with policy and economic factors, can be informative. Meanwhile, electrification decisions for medium- and heavy-duty fleet vehicles can be difficult to model and can happen very quickly, potentially outpacing both existing grid capabilities and grid construction timelines. While historical and current data still establish the starting point for forecasts, estimates of future trends are needed and can be gleaned from a variety of sources. Effective adoption forecasting is based on three principles: (1) understanding the impact of policy, (2) effective use of available data and models, and (3) recognizing that individual fleet decisions can disrupt forecasts.

BOX 1

Southern California Edison's Multi-Pronged Approach to Fleet Electrification

Southern California Edison demonstrates an example of the customer-collaborative model, in which the customer and utility collaborate to identify the best solution to the charging needs. In anticipation of significant EV growth in California, Southern California Edison first developed a transportation electrification load forecast informed by the state of California's policies to achieve its greenhouse gas goals. This approach focused on the increase in demand around major freight transportation corridors, medium/heavy-duty vehicle truck stops, and warehouse distribution centers, and identified long-lead-time grid expansion investments needed over the next five to seven years to ensure the grid is ready to serve this increase in demand.

For discrete EV charging requests, Southern California Edison works with some customers to select sites that best meet their needs. The utility's geographic information system (GIS) Power Site Search Tool maps 7,000 industrial buildings and land sites over 50,000 square miles to enable consideration of land, building, power, and broadband fiber availability for locating charging sites in its service territory. Customer-collaborative processes are covered in more detail in the "Coordinated and Holistic Planning" section below.

Incorporating Policy

"Backcasting" from stated policy objectives can be a helpful tool for forecasting. For instance, seven states have adopted advanced clean trucks rules that require vehicle manufacturers to sell zero-emission vehicles as an increasing percentage of their sales from 2024 through 2035 (McNamara, 2023).[12] This accelerated adoption of medium- and heavy-duty EV trucks is not in the historical record, but can be projected using estimates of policy effects. By "backcasting" from policy objectives rather than forecasting from scant historical observations, forecasters can better understand the trajectory needed to achieve the policy.

Effectively Using Available Data and Models

Trends can also be observed in department of motor vehicle registrations to establish a solid starting point from which to forecast the local vehicle stock, although assigning load to a given location based solely on vehicle registration data is problematic.[13] More information is required to effectively characterize where and how a given vehicle will charge.

By "backcasting" from policy objectives rather than forecasting from scant historical observations, forecasters can better understand the trajectory needed to achieve a policy goal.

Electrification likelihood models can also be highly informative in prioritizing areas where the distribution system may be insufficient in the near term. These models can be created in a variety of ways, including through surveys, heuristics, analysis of public data,[14] or agent-based tools.[15] The models capture local trends and key indicators for electrification likelihood at levels granular enough to help prioritize distribution system upgrades.

For example, Eversource introduced an adoption propensity model that combined variables that drive electrification likelihood with circuit-level information to prioritize circuits where EV adoption may quickly outpace grid capabilities. Even more simply, customer demographics, such as the mix of residential and commercial customers on a circuit, can be included when downscaling estimates of regional load impacts to the distribution level.

However, while electrification likelihood models can be helpful, any model must be enhanced with real-world data and an understanding of the decision-making considerations. Many of today's data collection efforts focus on combining indicators of potential EV impact. A wide range of data types can be informative, such as the number of buses by transportation authority (from state agencies), school bus ridership (from state agencies), employment level in the transportation and warehousing industry (from the census), traffic patterns (from state and federal agencies), population density (from the census), and car registrations. However, these datasets are not sufficient to characterize future grid impacts. For example, they do not provide expected charging locations and primary transportation use case.

The good news about data collection is that many regions are still in the early stages of vehicle electrification, and systematic data collection on behalf of grid planning at the time of vehicle purchase can still be implemented. Data on an EV driver's likely charging location or primary use of the vehicle will help grid planners characterize both where and when the vehicle is likely to charge. There are multiple ways that EV adoption data may make their way to the utility, but distribution system planners could be involved in designing data collection efforts, including those by state agencies. Data collection efforts by state departments of motor vehicles or departments of transportation may be the most suitable avenue for utilities to collect what they need; there is no need

12 The seven states are California, Maryland, Massachusetts, New Jersey, New York, Oregon, and Washington.

13 Department of motor vehicle registration data are often insufficient for medium- and heavy-duty vehicles, as these may be registered at a headquarters building but operate exclusively at a warehouse in another state from headquarters.

14 The Brattle Group performed an EV allocation study for the Electric Reliability Council of Texas (ERCOT) that projected the impact of vehicle electrification at each substation in ERCOT's territory. The medium- and heavy-duty vehicles were allocated using a variety of metrics and methods that considered things like the employment level in the transportation and warehousing industry in a given zip code (Sergici et al., 2022).

15 Similar to forecasting the impact of the type of EV from bottom-up agent-based simulations, Exelon is using a tool developed by Argonne National Laboratory that simulates individual decisions about whether or not to switch from gasoline-powered vehicles to EVs (Sagodd, 2019).

The good news about data collection is that many regions are still in the early stages of vehicle electrification, and systematic data collection on behalf of grid planning at the time of vehicle purchase can still be implemented.

to request the same information of consumers across multiple large entities.

Recognizing Fleet Impact on Forecasts

The electrification of medium- and heavy-duty vehicles can happen at a pace faster than typical utility planning. These vehicles are usually replaced at end of life (typically 12 years) or as vehicles are up for trade-in (typically every five years). Thus, all new vehicles in a fleet can potentially be electrified in a span of just a few years. Electrifying fleets would bring a significant new demand at a particular location very quickly, and utilities typically have little data on the fleets that operate in their territories and the fleets' electrification plans.

For commercial fleets, the best data available publicly and through private providers are still insufficient to meet grid planning needs. In response to this need, the distribution utility Oncor developed a suite of tools to characterize the likely fleet locations and their impacts on substations (Treichler, 2020). Oncor's Clean Fleet Partnership Program also provides prospective EV fleets with educational materials on how the process of electrification works and collects information from the fleets on their operations and electrification potential (Oncor, 2023).

Table 2 outlines good, better, and best practices associated with forecasting EVs, with some examples. Similar tables appear below with respect to different planning attributes.

TABLE 2
Potential Practices for Forecasting EVs

PLANNING ATTRIBUTE	
Forecasting includes consideration of: • **EV trends, including granular end use characterization** • **Local EV adoption trends**	
Good practices	• Multiple EV end uses are modeled (light-duty vehicles, fleet vehicles, trucking, etc.), including different charging profiles for each. • Backcasting from today's policy goals is reflected in the forecast of EV stock turnover used to estimate rate of EV adoption. **Example:** The Independent System Operator of New England's Transportation Electrification Forecast includes multiple end uses and policy impacts at both the federal and state levels.
Better practices	• Forecasting considers trends in vehicle battery sizing and efficiency. • Customer demographics, such as the mix of residential and commercial customers, are included when downscaling estimates of regional load impacts to individual circuits. **Example:** Portland General Electric uses the AdopDER model to conduct bottom-up forecasting of EV locational adoption trends.
Best practices	• All model results are supplemented with data collected from local surveys and observations. • Planners partner with EV manufacturers to use telematics data for grid planning. **Example:** Oncor's Clean Fleets Partnership Program surveys fleets in its service territory to find more information about their electrification plans.

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

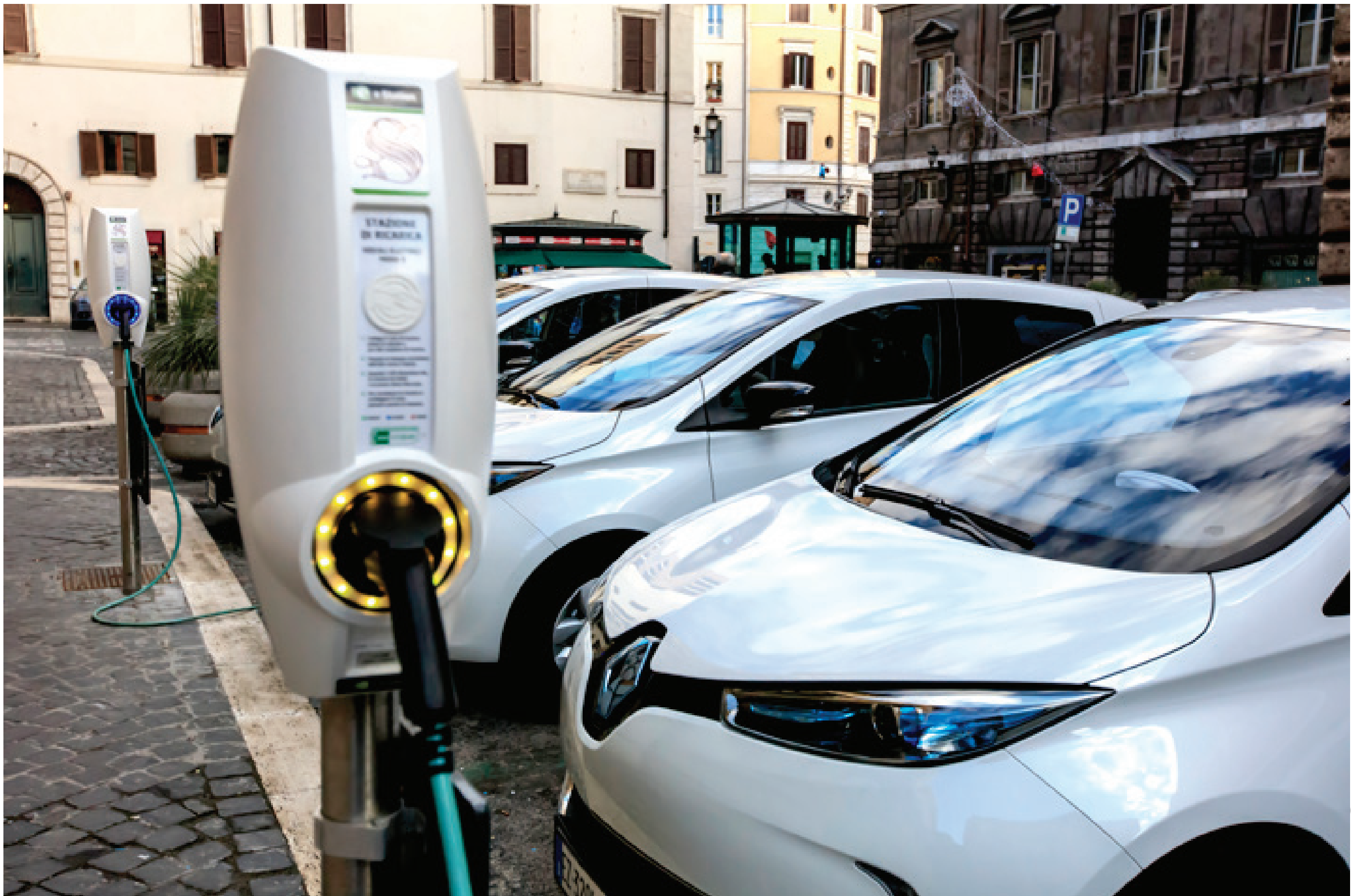
Source: Energy Systems Integration Group.

Characterizing Locational and Temporal EV Impacts

Once the base inputs of EV forecasting are gathered, the second step is to characterize EV load across time (by hour of day, season, etc.) and space, using scenarios to understand potential futures. This section translates the modeling inputs and assumptions into tangible grid impacts. Once the grid impacts have been estimated, plans can be developed to most cost-effectively integrate EVs, as discussed in the following section, "Mitigations: Avoiding the Largest Impacts."

Best practices around EV forecasting to guide analysis include to:

- **Take into account the vehicle use case.** For example, a personal pickup truck and a company pickup truck may have very different charging patterns. They likely have different access to charging infrastructure and different purposes for travel, which shape their charging behavior in time and space.
- **Consider calendar effects.** A "typical day" analysis will be insufficient, as charging will vary between weekdays, weekends, and holidays, and potentially seasonally (e.g., related to tourism, temperatures, school calendars).
- **Evaluate charging flexibility.** Many EV use cases leave room for flexibility in charging within a charging session, but some EV owners can also choose between charging sessions—a driver could choose to charge at their workplace or at home. Planning studies can consider some form of smart (managed) charging either



embedded in the load profile or, preferably, as a tool available to distribution system planners to evaluate the efficacy of smart charging to address grid needs.

- **Prepare for technological evolution.** Technological advances—such as faster charging capabilities and larger vehicle batteries—may affect forecasted EV impacts in terms of both their charging (energy (kWh) and peak demand (kW)) and their discharging (vehicle-to-home (V2H) or vehicle-to-grid (V2G) operation).
- **Use blended forecasts.** For developing scenarios, blended forecasts provide the most well-rounded insights for distribution planning because they consider both the top-down and granular bottom-up inputs. Blended forecasts allow policy shifts to be considered, while also incorporating local trends in the analysis. Admittedly, bottom-up analyses are data intensive, but they provide the most granular insights for distribution planning purposes.[16]

Timing: Developing Charging Profiles

Assembling the inputs and assumptions about types of EVs and their adoption allows us to stack data together to develop location-specific charging profiles. These charging profiles can start with understanding day-to-day charging behavior, showing likely variability throughout the day and across weekdays and weekends, and then move on to understanding charging around holidays and extreme weather.

Helpful sources of typical EV daily load shapes include EV Watts (managed by Energetics), EPRI's Load Shape Library, the National Renewable Energy Laboratory's EVI-X suite of modeling tools, Stanford University's SPEECh model, and other sources of publicly available data (such as independent system operators' load forecasts).[17] Vehicle manufacturers, charge station operators, and national aggregators will also have data on charging across jurisdictions. Utilities can make use of any directly metered EV loads within their jurisdictions to understand how their local circumstances may differ from national datasets. These data sources are growing in sample size; as more charging sessions inform the underlying datasets, forecasters can be more confident that they are capturing typical behavior. However, all of these datasets are biased in that they only reflect early adopters and are not necessarily representative of how vehicles will charge as more and different types of consumers go electric. The timing of charging will continue to be evaluated as different users electrify and as smart charging programs are implemented.

Setting the Baseline: Typical-Day Behavior

EV charging experience to date shows that charging profiles will vary based on location but generally follow a diurnal pattern, with more charging in the daytime for public chargers and in the evening and overnight for at-home charging. Figure 10 (p. 22) shows how public charging usage changes from weekdays to weekends. Early research also indicates that traffic patterns can be indicative for EV charging needs en route, but that light-duty vehicles still spend roughly 70% of the time parked at home (Pearre, 2013).

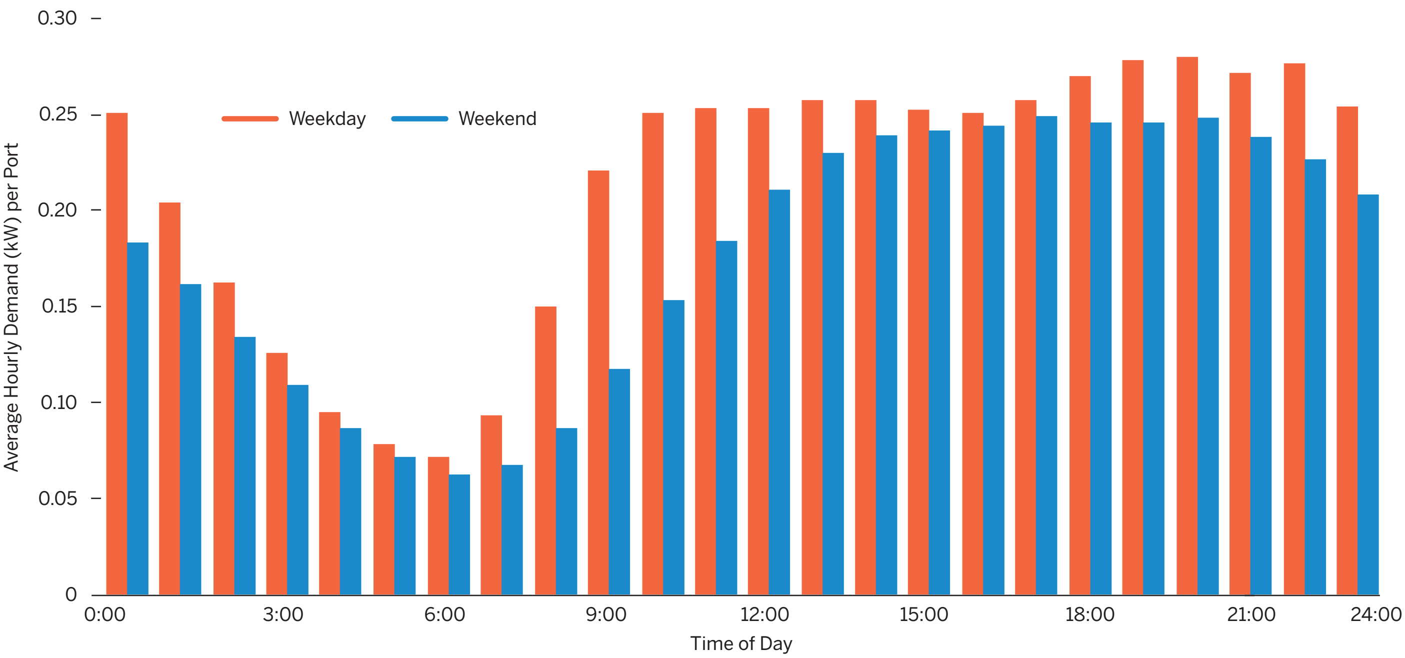
However, it remains to be seen how flexibility afforded by larger batteries will manifest in charging profiles and charge session duration (Avista, 2019). Recent advances in EV range that are made possible by larger batteries could allow for flexibility both within and between

16 As covered elsewhere, bottom-up analyses often gather data from sources that are not traditionally used in utility planning, such as telematics information, department of motor vehicle records, or fleet data providers.

17 See https://www.energetics.com/evwatts-station-dashboard, https://loadshape.epri.com/, and https://www.nrel.gov/transportation/evi-x.html.

FIGURE 10

Typical Aggregate Charging Profile for Public Charging



The typical charging profile for public charging differs on weekend and weekdays with the highest usage coinciding with traditional system peaks in evenings on weekdays, and the minimum charging occurring at 6:00 am.

Source: Energy Systems Integration Group. Data from Energetics, "EV Watts Charging Station Dashboard Q3-23," 2023, https://www.energetics.com/evwatts (accessed July 1, 2023).

charging sessions. Flexibility within a session could take the form of delayed start charging, where the vehicle waits to charge for some time after it is plugged in. Flexibility between sessions could take the form of a driver choosing to charge in public during the day instead of at home overnight.

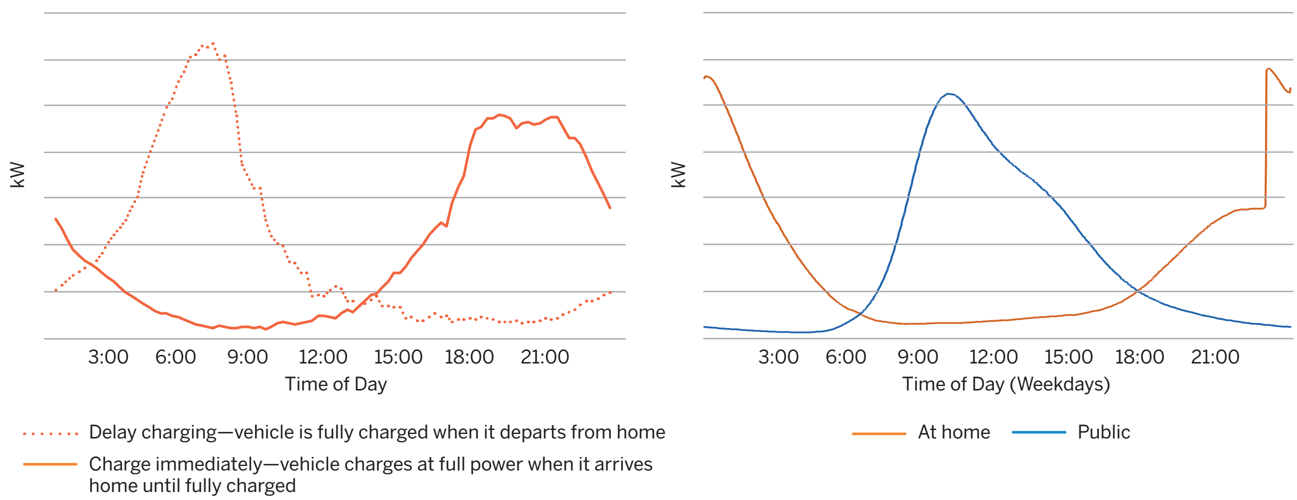
Related to between-session flexibility, we do not yet know the preferred mix of public vs. at-home charging for the majority of EV drivers.[18] Will light-duty EV drivers charge primarily in public or at home? How will this vary based on residence type, income level, and adoption likelihood? We also do not know whether drivers will want to charge immediately upon arrival or whether delayed charging will be acceptable with appropriate incentives. These dynamics will become clear as EVs are more heavily adopted, through open conversation about early experiences, and through analytical studies. Customer charging behavior can also be influenced through policy, pricing, and programs. For example, free public charging may incentivize drivers to forgo home charging. These behaviors and decisions will also change over time as the type of EV adopter changes and public charging networks become more robust.

Specific assumptions made in analytical studies can significantly alter the charging profile for grid planners. Figure 11 (p. 23) shows the impact to the aggregate load shape of different assumptions around immediate vs. delayed at-home charging (left) and public vs. private charging profiles (right). The graph on the left isolates at-home charging behavior, while the one on the right shows how charging behavior can vary by location, illustrating how an EV charging profile needs to consider the impact of public vs. at-home charging along with the timing of vehicle charging.

18 This report adopts a public vs. at-home charging paradigm that has been used in other recent publications (see, for example, Wood et al. (2023)), in which workplace charging is grouped into public charging. This framework allows for consideration of EV drivers who may not have a distinct workplace.

FIGURE 11

Charging Profiles Can Vary Based on Location and Charge Time Strategy



Large differences can be observed in charging profiles based on charging assumptions that can have a large impact on the aggregate profile observed from EV charging. The left-hand graph shows that the shape of at-home charging can vary significantly based on the charging strategy. Similarly, the right-hand graph shows how at-home and public charging profiles can vary significantly. These graphs are conceptual and meant only to show general charging shapes.

Source: Energy Systems Integration Group. Data from the U.S. Department of Energy's Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite (left) and Powell, Cezar, and Rajagopal (2022) (right).

Planning for Peaks

For the power system, marginal investments in capacity—for generation, transmission, and distribution—are not made based on average conditions, but rather the highest loading. Abnormal circumstances determine when the grid is most stressed and drive the largest investments. Planning for EVs is no different, and studies must consider how consumer charging expectations may change around holidays and weather events.

Abnormal circumstances drive the largest investments, and studies must consider how consumer charging expectations may change around holidays and weather events.

Another key input affecting EV forecasting is the impact of temperature, as batteries are less efficient when they are cold; their capacity declines and they take longer to charge (Motoaki, Yi, and Salisbury, 2018).[19] Additionally, the vehicle occupant uses battery-provided heat to keep the cabin comfortable, so miles travelled per kWh decrease as ambient temperature falls. This will contribute to increased weather-dependence of the power system, which is also driven by availability of wind and solar resources, heating and cooling demand, and increased electrification. There is a growing trend in resource adequacy analysis to consider the impact of multiple weather years on the load profile, and distribution planning could use such an approach as well.

Extreme weather will also need to be considered. Because EVs still represent a relatively small portion of the primary driving mix today, there is limited public data on how charging needs change around extreme weather events that may require evacuation, such as hurricanes, wildfires, and floods. With the multiple days' notice that is typical for hurricanes, there may be an opportunity to stagger charging as people prepare to

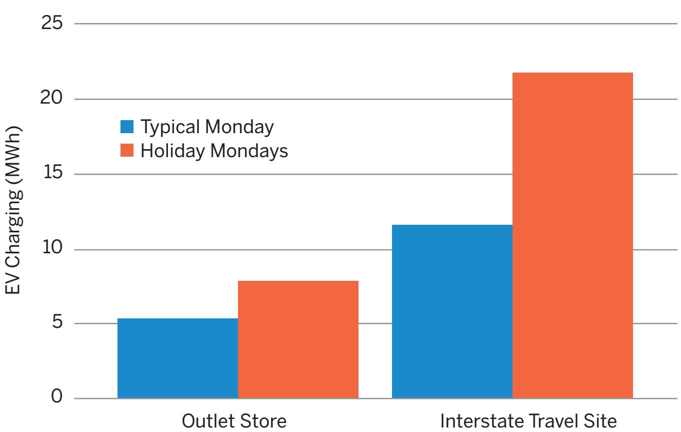
19 Motoaki, Yi, and Salisbury (2018) found that "the average deterioration of a 30-min [direct current fast charger] charge from warm temperature (25 °C) to cold temperature (0 °C) can be as large as a 36% decrease in the end [state of charge]."

evacuate. However, without sufficient notice or sufficient grid infrastructure, the grid could be unable to support charging requirements in this type of emergency. Lessons for how to prioritize EV charging within grid capabilities prior to extreme weather events can come from experiences pre-cooling homes and ensuring fully charged EVs in response to California's Public Safety Power Shutoff events. There is an opportunity for the industry to learn from early experiences, but only if information is exchanged openly with ramifications readily discussed.

Lastly, charging profiles around holidays need to be considered. Just as highway rest areas are busier during holidays, public charging adjacent to transportation corridors sees a rise in traffic and charging demand around holidays. At-home charging may also see increases prior to holidays as EV owners prepare for longer trips. These spikes in demand may warrant grid infrastructure upgrades, but they could also be offset by reductions in demand from commercial sectors during these holidays. At the system level the net effect may be limited, but the distribution system could be stressed in specific locations. The industry has little experience with the holiday effect on charging. What we do know is that charging profiles will vary across the year aligned with trends that may not appear in typical load forecasting efforts.

FIGURE 12

Utilization of Public Charging Infrastructure Can Vary by Site and on Holidays



Public charging stations can have distinct utilization rates that are also affected differently by holidays.

Source: Energy Systems Integration Group.

Figure 12 shows how two sites experienced notable increases in charging demand associated with holidays in 2022. Increases of this magnitude can strongly affect infrastructure sizing considerations, consumer experience, and grid operations.

There is still much to learn about when the early majority of EV drivers will want to charge their vehicles. Early adopters' choices are informative, but mass adoption will adjust the early trends in subtle but important ways.

Charging Location: Where the Grid Needs Arise

When prioritizing distribution system locations for added grid planning attention, location-specific needs can be assessed via scenarios that illustrate different possible future pathways. This analysis must bridge the gap between two overlapping definitions of location: the geographical origin, corridor, and destination locations for EV traffic, and the grid's topological (or electrical) locations. Distribution planners usually have good information about the locations of grid assets, so the discussion here focuses on pairing that information with charging demand location, which arises from transportation and parking behavior.

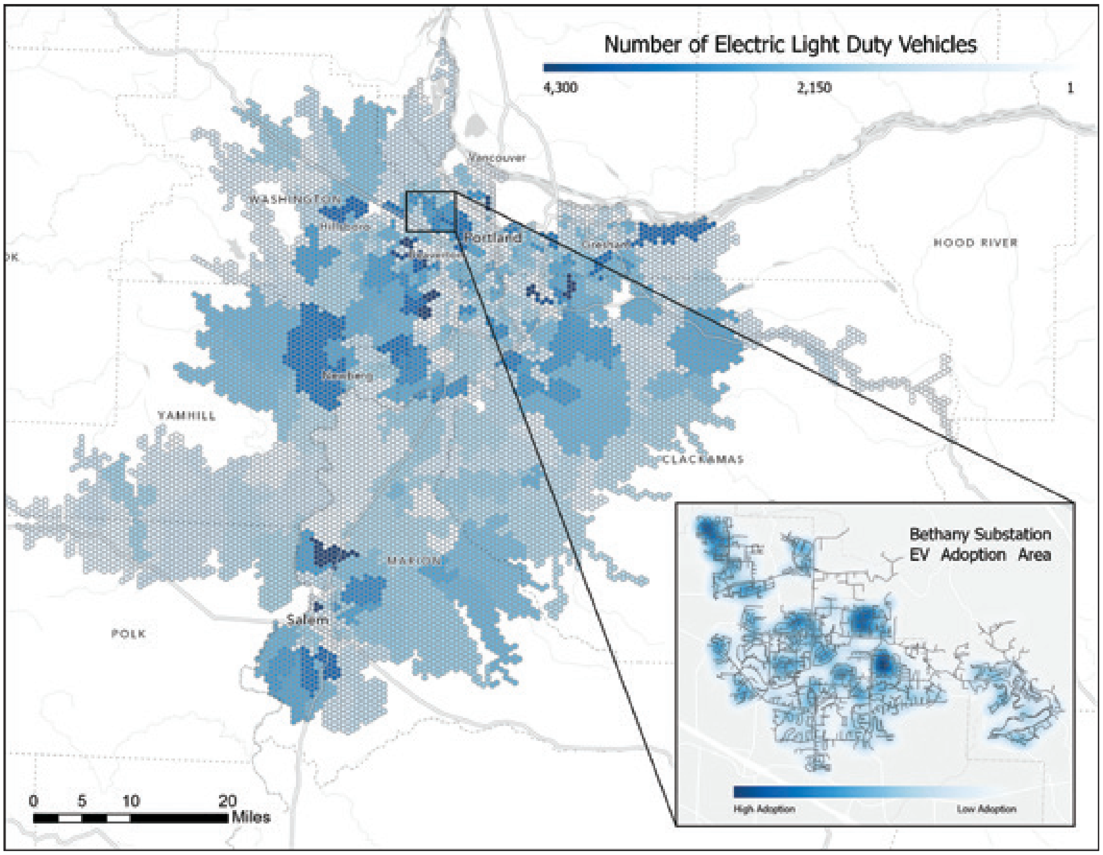
Scenario analysis must bridge the gap between two overlapping definitions of location: the geographical origin, corridor, and destination locations for EV traffic, and the grid's topological (or electrical) locations.

Location-Sensitive Adoption and Access

Geographic locational analysis considers how EV adoption may be localized to certain sections of a planning region, creating EV hotspots. For instance, local municipalities may have decarbonization plans or tax incentives that drive the electrification of light-duty vehicles or medium- and heavy-duty fleets. Locations around ports or colleges and universities may also be hot spots in the near term. The implications of EV hotspot scenarios can help with prioritizing initiatives in distribution system plans.

FIGURE 13

Light-Duty EV Adoption Forecasts by Location in Portland, Oregon



Various neighborhoods around Portland, Oregon, are forecasted to see different rates of adoption. Portland General Electric has developed forecasts that show the effects of EVs at different points served by each of its substations.

Source: Portland General Electric.

Topological location hot spots can be a function of the existing infrastructure loading and times when EVs charge—namely, whether they charge at home, typically at night, or in public, typically during the day (Powell, Cezar, and Rajagopal, 2022). Local housing situations also influence EVs' impacts. In multi-family housing and areas with higher percentages of renters, EV drivers may rely more heavily on public charging than those who live in single-family homes.

Figure 13 shows how various neighborhoods around Portland, Oregon, are forecasted to experience different adoption. It zooms into a specific substation and shows the differing effects on the various electrical locations served by a given substation.

By varying the grid charging location assumptions, grid planners can better understand how the distribution system can support the charging needs. Early understanding of grid and EV capabilities can be helpful in designing effective solutions to future challenges.

Vehicle Mobility

EVs' ability to move around represents a new type of load for grid planners. There is still much to learn about the incentives required to convince folks to charge in different locations, but the first step in understanding EV movement is to understand today's transportation behaviors. The troves of data available via global positioning system (GPS) tracking of vehicles can shine light on how and when people drive their vehicles. GPS

> **By varying the grid charging location assumptions, grid planners can better understand how the distribution system can support the charging needs.**

tracking data are generally available for a price from vehicle telematics for light-duty vehicles and other tracking systems for medium- and heavy-duty fleets.

For example, Eversource Energy uses anonymized GPS vehicle tracking data to understand vehicle electrification impacts on the power system. In Eversource's evaluation of the transportation trends in Cambridge, Massachusetts, winter traffic was found to be roughly 10% higher than summer traffic due to local universities' schedules (Walker, 2023). There were also upticks in vehicle miles traveled around holidays and at weather-driven vacation destinations (such as Cape Cod in the summer). Translating these traffic patterns into forecasts of power requirements still requires some assumptions on state of charge across vehicle trips and consumer behavior; however, understanding trip origin and destination can inform likely charging locations and charge start times.

Scenarios to Manage Inherent Uncertainty in Forecasts

Given the uncertainty in EV adoption and the timing and location of charging, distribution system planners can use scenarios to understand how the grid may be affected by a variety of key variables. Distribution planners are just beginning to use scenario analysis to understand potential futures, and scenarios run explicitly for EVs have not yet been implemented broadly across the industry; thus they represent an aspirational best practice.

Embracing the uncertainty around EV adoption and charging patterns through scenario planning helps planners think in broad strokes, rather than narrow solutions. Scenario planning helps identify the suitability of the power system (generation resources through distribution equipment) to support a range of charging behavior. Solutions can then be designed to improve the power system as appropriate or encourage alternative charging behavior. Table 3 (p. 32) lists good, better, and best planning practices.

Early identification of the key scenarios to use for grid planning purposes is important. First, wide bookends can be evaluated to understand the implications of very different futures. For instance, an unmanaged charging scenario would show the many huge investments in the generation fleet that would be required to serve such a load. Although wholly unmanaged charging is usually untenable, unmanaged charging scenarios can nonetheless be informative for considering the magnitude of potential grid needs as we learn more about how to best manage charging. Another bookend to consider is that a community's vehicle transportation needs may diminish with urbanization and remote work trends. These bookends can address the medium-term horizon, leaving longer-horizon, speculative technology advancements to be addressed in future iterations of grid planning.

> **Embracing the uncertainty around EV adoption and charging patterns through scenario planning helps planners think in broad strokes, rather than narrow solutions.**

In addition to bookend analysis, forecasts for distribution planning include top-down policy implications blended with data on local trends. Scenarios built from the blended forecast can provide broad ranges of outcomes as they vary underlying assumptions to capture multiple potential futures.

Since significant action is likely required to meet the vehicle electrification needs on even a 10-year horizon, three scenarios targeting the short- to medium-term are recommended, each of which highlights different plausible ways that the grid might be stressed. These would include the following:

- Some sort of stress on the charge-time expectations from consumers, such as their prioritizing rapid **15-minute charging** to get to some extended level of charge. Some auto manufacturers have recognized the need for rapid charging capabilities to relieve range anxiety; the long trend toward faster and faster charging continues.
- A **medium- and heavy-duty vehicle growth** scenario. This will help to understand how and whether the typical stock turnover in this segment may shift expectations rapidly if electric trucks become cost-effective for medium-duty fleets.
- A scenario that emphasizes **at-home charging**, which would stress the premise-level distribution equipment.

Scenario analysis becomes increasingly challenging as different planning sensitivities are considered simultaneously. Utilities and regulators will want to coordinate with stakeholders early—local community members, consumer and environmental advocates, and others—to understand how vehicle electrification scenarios should be considered alongside other planning variables, such as the growth of distributed solar, building electrification, dealing with aging assets, and other challenges for reliability and resilience.

TABLE 3

Planning Practices Associated with Characterizing EV Impacts

PLANNING ATTRIBUTE	
EV impact characterization varies across time of year and by location.	
Good practices	• **Use case:** Differences in charging access between geographical regions are considered, and charging profile matches charger type. For example, distribution circuits serving predominantly multi-family housing would have a higher percentage of public charging, which is likely to occur more during the day than at night. • **Calendar effects:** Analysis goes beyond "typical day" characterization to capture differences in weekday, weekend, and holiday charging patterns. • **Scenario analysis:** Multiple scenarios are considered to understand the implications of key modeling assumptions. For example, distribution planners characterize how varying charging profiles on representative circuits can change the grid solution needed. **Example:** The New York State Energy Research and Development Authority (NYSERDA) used a scenario-based analysis to understand distribution upgrade costs associated with various clean transportation futures.
Better practices	• **Use case:** Different load profiles are developed for different vehicle use cases (e.g., personal pickup truck vs. company pickup truck). • **Calendar effects:** Changes are captured in charging profiles across the year due to weather and seasonal travel trends in the study region. • **Scenario analysis:** A variety of stress-test scenarios are built, each highlighting a different way in which the distribution system might be stressed. **Example:** The California Energy Commission is using a tool developed by Lawrence Berkeley National Laboratory, HEVI-PRO, to capture 19 use cases for medium- and heavy-duty trucking.
Best practices	• **Blended forecasts:** Top-down trend data are supplemented with bottom-up behavioral data to understand temporal and spatial transportation patterns in the study region. These bottom-up data could include GPS data or observed charging session data, if available. • **Use case:** Statistical variability of observed charging behavior is captured within each defined use case. The effect of vehicle-to-everything (V2X) is also captured to the extent that charging needs are affected by the EV battery used for non-mobility use cases. • **Scenario analysis:** Separate scenarios are carried all the way through distribution planning to identify impact on specific distribution equipment decisions. **Example:** Eversource, Portland General Electric, and Pacific Gas and Electric use Stanford's SPEECH model to capture statistical variability of charging behaviors.

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

Mitigations: Avoiding the Largest Impacts

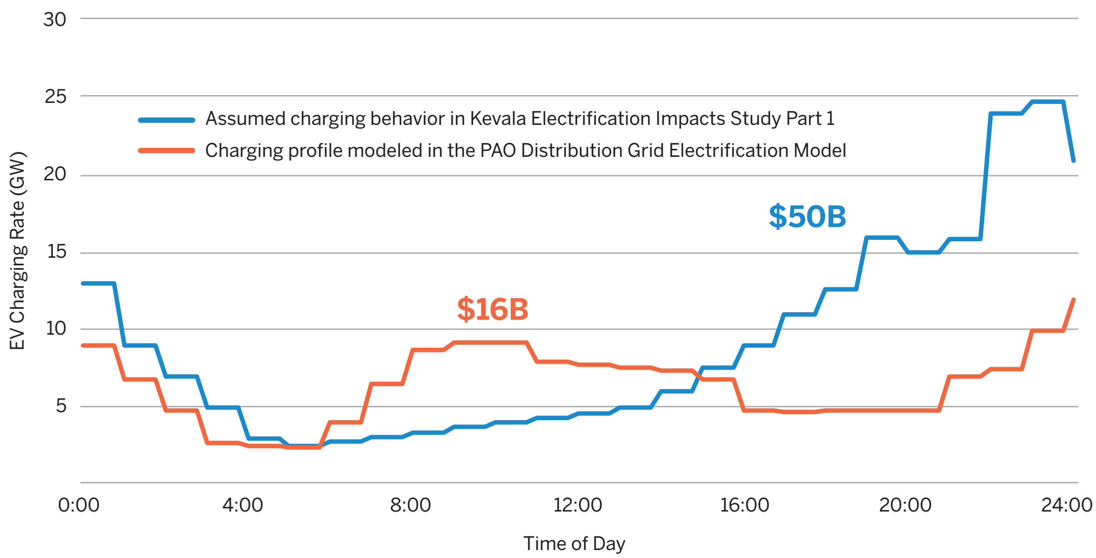
The third step in grid planning for vehicle electrification is to consider mitigations that can diminish, defer, or eliminate the need for grid upgrades. New technologies, programs, rate design, and other mitigations can be included in grid plans to help address EV integration challenges, increase EV hosting capacity, and potentially reduce costs, while providing EV opportunities for all consumers. These mitigations may be suitable for near-term implementation while EV adoption is in its early stages, to gain experience and bridge the gap between today and the future grid design, yet to be identified. They may then be part of that future to help keep down costs in the long term. Early assessments of the effectiveness of various mitigation strategies will be of tremendous value as EV growth progresses.

New technologies, programs, rate design, and other mitigations can be included in grid plans to help address EV integration challenges, increase EV hosting capacity, and potentially reduce costs, while providing EV opportunities for all consumers.

Historically, utilities assumed load profiles for grid planning to be static inputs that did not vary in modeling efforts according to grid conditions or the availability of supply-side resources. When the impact of time-of-use

FIGURE 14

Differences in EV Charging Assumptions and Costs of Distribution Upgrades in Two Recent Studies



Differences in charging assumptions can have a large impact on the cost of distribution upgrades. Smart charging can adjust the charging profile.

Source. Energy Systems Integration Group. Data from Kevala (2023) and the California Public Utilities Commission's Public Advocates Office (2023).

(TOU) rates or other demand management programs is included in the load forecast, these are also typically considered to be static inputs. However, EV demand can fluctuate based on local (or bulk) system needs, prompting an evolution in demand management planning practices. Programs and tariffs can address grid needs, with planners incentivizing EV-related behavior change as an alternative to building new infrastructure.

Recent work in California highlights the importance of managed charging to adjust the EV load shape, which in turn can reduce the need for distribution upgrades. Two recent studies—the Electrification Impacts Study Phase 1 (Kevala, 2023) and the Distribution Grid Electrification Model (PAO, 2023)—analyzed distribution upgrade costs in California due to vehicle electrification. A comparison of the two studies, and accounting for differences in capital costs between them, shows that different charging profile assumptions can reduce forecasted distribution upgrade costs. The Phase 1 Kevala study estimated $50 billion in distribution upgrades costs, while the Public Advocates Office study estimated those costs at $16 billion.[20] The charging profiles, captured in Figure 14, highlight the importance of robust data and analytics in planning studies, while also highlighting the importance of TOU rates and other incentives to adjust charging behavior based on system needs at both the bulk and distribution levels.

Smart Charging—Getting to the Right EV Load Shape

Smart charging ranges from predetermined price signals (such as demand charges and TOU rates) that inform EVs when it is cheaper to charge based on typical grid characteristics during different time periods, to dynamically managed charging that addresses grid needs as they arise. Each can be an important tool in planning the grid and managing variability on a daily basis by helping to avoid the degradation of grid equipment and operational challenges before they arise.

20 Additional cost savings could be accrued from bulk system capacity deferral and curtailment reductions.

Demand management, including smart charging, will not be able to mitigate the need for all EV-related infrastructure investments. However, many planning studies show that smart charging can alleviate grid stress induced from unmanaged charging profiles (Greenblatt, Zhang, and Saxena, 2021). Indeed, forecasting for EV adoption usually begins with understanding the raw charging demand and then layering in smart charging impacts (Kevala, 2023). Smart charging has been shown to have a significant effect on power system reliability and infrastructure costs (PAO, 2023).

Smart charging will be needed on a regular basis to address potentially conflicting grid needs. Given the scale of EVs to be integrated, demand management approaches that embrace each type of mitigation in Table 4 may be most effective. Embedding smart charging capabilities in distribution planning can lead to greater utilization of existing infrastructure, helping to meet the charging requirements of multi-family housing and constrained corridors without requiring upgrades. For that same reason, smart charging is a tool to integrate more EVs quickly. However, consideration of smart charging in planning should be grounded in studies of actual consumer behavior and technology adoption.

Table 4 broadly categorizes common mitigation measures, indicating the relative suitability for a given grid level and the relative ease and cost to implement. The degree of shading in the table cells indicates the suitability of the measure to address challenges for the grid level and the complexity associated with implementing the measure. Lighter shading indicates greater suitability and less complexity.

Each of these measures aims to encourage charging at times that are optimal from the grid perspective. While some stakeholders assert that managed charging of EVs is needed, others believe that price signals provided by time-varying rates can sufficiently incentivize EV charging behavior. Each approach has advantages and

> **Smart charging will be needed to address potentially conflicting grid needs. While some stakeholders assert a need for managed charging of EVs, others believe that pricing signals provided by time-varying rates can sufficiently incentivize EV charging behavior.**

TABLE 4

Suitability of Different Types of Smart Charging to Address Grid Challenges

Mitigation Measure	Classification		Suitability to Address Challenges at Multiple Levels				Ease of Implementation	Cost
	Signal	Timing	Site	Distribution	Transmission	Generation		
Demand charge	Pricing	Preset						
Time-of-use rate	Pricing	Preset						
Dynamic price signal	Pricing	Dynamic						
Consumer response to event-based demand response	Control	Dynamic						
Dynamic managed charging	Control	Dynamic						
Automated load management	Control	Preset						

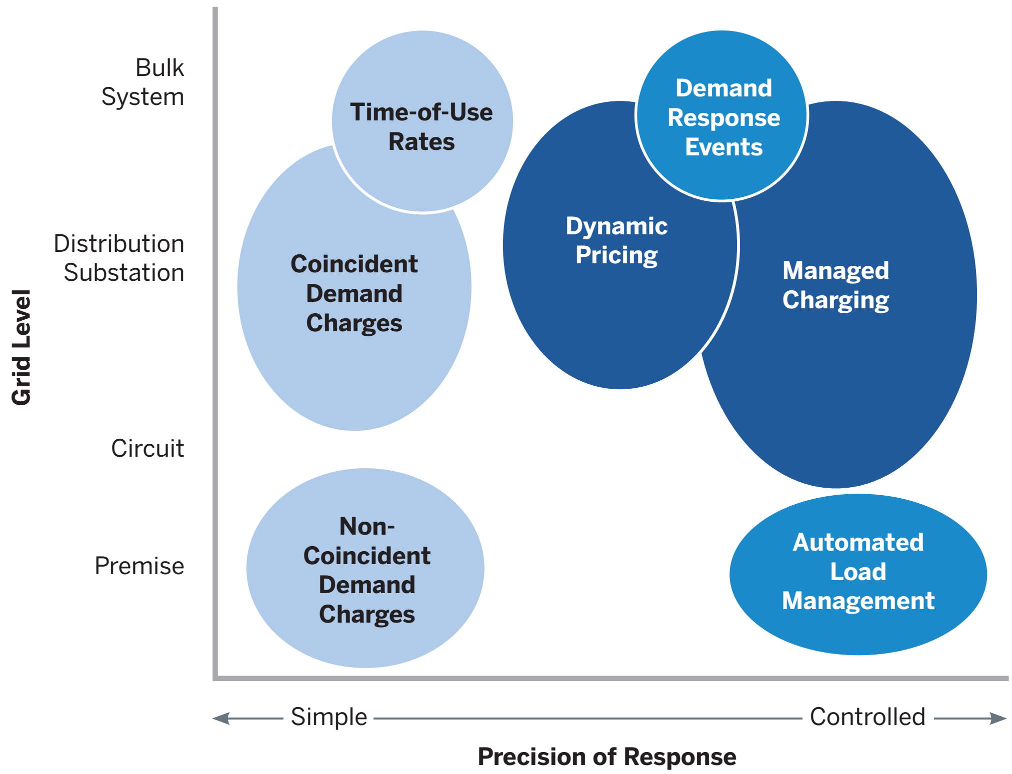
More to less suitable ▶ ▶ ▶ Less to more complex ▶ ▶ ▶

Various types of smart charging can be accomplished through pricing or control programs, with preset or dynamic definitions, and can address grid challenges at different levels. The ease of implementation and relatively lower cost tend to go hand in hand, and this type of mitigation measure should be evaluated against all alternatives including infrastructure improvements. The degree of shading indicates suitability of the measure to address challenges for the grid level and the complexity associated with implementing the measure. Lighter shading indicates more suitability and less complexity.

Source: Energy Systems Integration Group.

FIGURE 15

Smart Charging Measures' Precision of Response and Alignment with Grid Needs



Demand-side management measures range from blunt tools to readily adaptable measures to address varying grid needs. The measures can address challenges at all grid levels, but the chart indicates the best alignment. The shading reflects ease of implementation, with lighter shading denoting measures that are easier to implement.

Source: Energy Systems Integration Group.

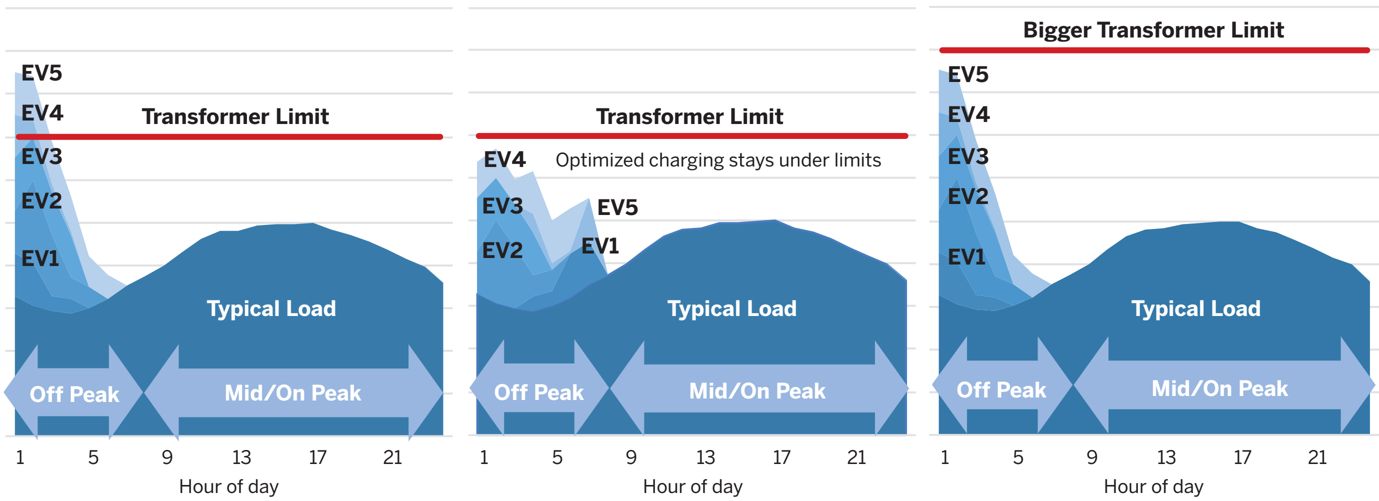
disadvantages, and because consumers are not monolithic, it is important that they have choices that suit their needs. Prices and programs can be used in concert, with prices providing general shaping of demand and programs providing a precise tool to manage real-time events.

Figure 15 shows how demand-side management measures vary from simple tools to more precise, adaptable measures to address different grid needs. Some demand-side management measures—specifically, TOU rate structures and demand response events—have typically been oriented toward addressing bulk system challenges. The shading in the figure reflects ease of implementation, with lighter shading denoting easier implementation.

As noted above, TOU rates represent a somewhat blunt instrument, most often aligned with bulk power system needs, that can potentially lead to spikes in demand in the hour when the off-peak rate takes effect. In EV-dense neighborhoods, this can lead to the sudden overloading of distribution system infrastructure. Recent work by Portland General Electric and Weavegrid outlines how TOU with load optimization can simultaneously unlock value in the bulk system without creating unintended impacts on the distribution system (Mills et al., 2023). This stacking of smart charging is shown in the middle image of Figure 16 (p. 32). The costs of such management solutions should be evaluated against the cost of traditional upgrades, such as the installation of larger equipment.

FIGURE 16

Optimized Charging Aligned with TOU Rates



Time-of-use (TOU) rates with load optimization can simultaneously address bulk system and distribution constraints. If we only focus on bulk system needs with rate designs, EV charging may all start at the beginning of the off-peak period and overwhelm the distribution equipment (left). We can instead stagger charging and get the bulk system benefits of TOU without overwhelming the distribution system (middle). However, simply upgrading the distribution transformer may be more cost-effective and requires less of customers (right). The industry is learning more about the best mix of solutions to enable charging.

Source: Energy Systems Integration Group.

There is still much to learn. Designing smart charging programs and rates requires an understanding of the customer and the grid needs. In particular, the industry needs to better understand customers' willingness to adopt smart charging and adjust charging profiles dynamically (temporally and locationally), both in every-day circumstances and during extreme weather events. There are opportunities to learn more about customers' responsiveness to rates and the price elasticity of charging demand. Demand-side management strategies almost universally include a customer override or opt-out provision, and grid planners will want to understand smart charging override statistics before relying on it. Finally, data are available on enrollment success, but there is a need to extend the data to track consumers from recruiting through smart charging participation to understand effective enrollment practices that accomplish smart charging.

Pricing

Some utilities have established EV-specific rates. EV rate design focuses on three principal paths: demand charges, TOU tariffs, and dynamic pricing.[21]

Demand Charges

Demand charges have been applied to large commercial and industrial customers for many years. These charges are based on the customer's peak demand in a billing cycle, with some programs using the customer's highest monthly demand to set the demand charge for each bill in a year. Demand charges can comprise minor additions

There are opportunities to better align demand charges with distribution system costs, including setting coincident peak demand charges specific to a given distribution circuit or zone.

21 See the series of white papers written by members of ESIG's Aligning Retail Pricing and Grid Needs Task Force, including the framing paper by Ela, Lew, and Linvill (2023), at https://www.esig.energy/aligning-retail-pricing-with-grid-needs.

or a majority of the bill. They are intended to reflect the costs of infrastructure needed to support high demand.

However, there are opportunities to better align demand charges with distribution system costs, including setting *coincident peak* demand charges specific to a given distribution circuit or zone. These types of demand charges are common in regional transmission organization and independent system operator markets to reflect a load-serving entity's (e.g., a utility's) contribution to peak demand. Demand charges coincident with local peak conditions would need to be applied retroactively—charge station operators would be charged after the fact based on how their demand interacted with their neighbors' to create a coincident peak impact on equipment.

There are also opportunities to better align demand charges with affected infrastructure. For instance, San Diego Gas & Electric's Vehicle Grid Integration rate is a dynamic, hourly charge that includes a distribution capacity adder for the top 200 hours of distribution circuit load, with those hours varying by circuit. Equity should be taken into account in the design of such rates, because, among the considerations, coincident peaks may differ by circuit and could unfairly penalize some consumers based solely on how and when their neighbors use electricity.

Traditional assumptions for what can be accomplished through TOU rates should be re-evaluated in the context of EVs. For example, San Diego Gas & Electric observed that 77% to 87% of charging happened off-peak across various versions of TOU rates.

Time-of-Use Tariffs

TOU tariffs can incentivize EV charging during targeted hours. Prices and times are predetermined with set schedules throughout a day or week, which is preferable for some charge station operators that can optimize charging in line with TOU price signals. In addition, as shown in Figure 16 (p. 32), a diversification of TOU rates can avoid unintended consequences. However, TOU rates cannot be adjusted in real time to allow flexible loads to respond to real-time grid stress. Absent sufficient planning, autonomous response to TOU rates may trigger thousands of vehicles to simultaneously charge, creating a new peak issue for the utility companies.

TOU rates are most often used to align loads with bulk system generation capabilities, but they can also be used to shift loads for other purposes, such as limiting the impact of EV charging on distribution system equipment. About 9% of U.S. retail electricity customers are on some form of time-varying rate (EIA, 2022a). TOU rate designs with large price differences between peak and off-peak pricing have been shown to be more effective in encouraging customer behavior change (Satchwell, 2022). For example, the Hawaii Public Utilities Commission recently approved tariffs that charge customers three times as much during the evening peak period (5 pm to 9 pm) as the daytime period (9 am to 5 pm).[22] AusNet in Australia has proposed a tariff that *pays* customers to charge their cars from 10 am to 3 pm (AusNet, 2023).

Because EVs have the potential to be flexible loads, the impact of TOU rates on their load profile can be significant. San Diego Gas & Electric observed that 77% to

22 Hawaii Public Utilities Commission Order 40118, 2019-0323, July 11, 2023. https://hpuc.my.site.com/cdms/s/search?term=Order%2040118&excludeObjects.

87% of charging happened off-peak across various versions of TOU rates (Cutter et al., 2021). That stands in contrast to TOU pilots from 2008 through 2012 targeting the whole home, which resulted in a 2% to 21% reduction in daily peak load (Badtke-Berkow et al., 2015). An Octopus Energy program in the UK showed that program participants who had an EV reduced peak consumption by 47% compared to 28% for non-EV drivers (Octopus Energy, 2018). Traditional assumptions for what can be accomplished through TOU rates should be re-evaluated in the context of EVs.

Dynamic Pricing

Dynamic pricing programs incentivize EV load-shifting behavior based on fluctuating pricing that reflects the needs of either the bulk or distribution system on a closer-to-real-time and granular level. These prices can be determined in a day-ahead time frame or reflect real-time needs.

> **Utilities are working with aggregators and vehicle manufacturers on technology that optimizes charging at times when it is most beneficial for the grid based on price signals.**

Dynamic pricing depends on individual customers' response. Automation technology enables customer charging decisions based on pricing changes. Utilities are working with aggregators and vehicle manufacturers on technology that optimizes charging at times when it is most beneficial for the grid based on price signals. Xcel Energy's Charge Perks program is one such program that works with aggregators and vehicle manufacturers to automate charging schedules aligned with grid prices and customer charging requirements. The utility is recruiting customers with a $100 upfront incentive and sharing savings at the end of each year (Xcel Energy, 2023).

Dynamic pricing increasingly considers distribution infrastructure. The California Public Utilities Commission developed a policy roadmap and retail rate strategy known as CalFUSE (California Flexible Unified Signal for Energy) that prioritizes dynamic prices and demand flexibility. The rate design concept includes distribution capacity among the calculation inputs.[23]

Vehicle-to-everything (V2X) applications can also be enabled through dynamic rates with export compensation. For example, the New York Value of Distributed Energy (VDER) tariff has a location-specific component in addition to other components of the value stack referred to as the Locational System Relief Value (LSRV), which compensates resources located within zones that are constrained.

Control

Three primary types of potential control over EV charging are event-based demand response, dynamic managed charging, and automated load management (AML). The control paradigm considered here allows customers to opt out of utility or aggregator management if needed.

Event-Based Demand Response

Event-based demand response provides signals to customers to curtail EV charging when it would help manage grid stress. Events could be called based on the day's forecasts or as system conditions change in real time. Events can include calling on EVs to begin charging or increase charging level for a period of time.

Event-based demand response allows consumers to respond to grid events that may occur just a few times per year. These programs typically allow the consumer to opt out of events. Some programs penalize customers for non-conformance with the demand response event or allow only a certain number of times per year the customer can opt out, while others provide incentive mechanisms alone. Portland General Electric, Holy

23 Decision 23-04-040, Rulemaking 22-07-005, California Public Utilities Commission, April 27, 2023, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M507/K837/507837776.PDF.

24 Portland General Electric's Smart Grid Test Bed tariff explicitly tested price-based demand response as a non-wires alternative to distribution substations. Peak time rebates in the test bed area reduced peak demand by about 4% in summer and 3% in winter. In a recently announced study, the utility took this concept further by introducing location-based price signals to achieve load-shifting or load-reduction goals for a specific distribution circuit or geographical area. See https://portlandgeneral.com/smart-grid-test-bed-ev-charging-study.

Cross Energy, and Baltimore Gas and Electric are among those utilities that offer a peak time rebate that rewards consumers who reduce their consumption during peak events.[24]

Event-based demand response targeting EV charging holds promise because, unlike other types of load, energy inefficiencies from delaying EV charging are minimal. For example, programs that adjust buildings' air conditioning thermostat settings can suffer from energy losses when precooling leads to increased losses through the building envelope or after events as the building is re-conditioned following the event. Depending on the home's efficiency, this can be less efficient than keeping the building conditioned continuously.[25] But with respect to EVs, the charging loads simply shift in time and remain of the same magnitude.

EV participation in demand response programs can sometimes be constrained by consumers' state-of-charge requirements. Similar to event opt-outs for thermostat programs at times when consumers do not want to adjust temperature settings, some EV customers will need to have their vehicle fully charged for a specific reason—a road trip, for example—regardless of the grid conditions.

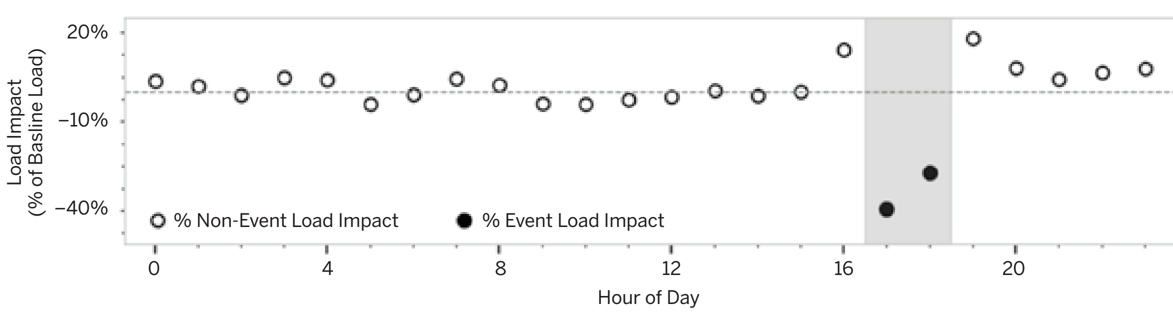
With any of these options, care must be taken to avoiding "snapback" or rebound effects. Rebound effects can influence the power system in multiple ways (Morash, 2018). Figure 17 shows these effects in action, with the demand response event highly effective at limiting demand during the event, but increasing demand immediately before and immediately after the event. Care should be taken such that these before- and after-event spikes do not cause more stress than the original event avoided. Some utilities have adopted a simple approach of limiting charging in the first hour post-event to 50% charging capability. While this strategy subdues the rebound, other solutions have been proposed to stagger the start and end times of control signals to improve the overall event performance, particularly for EVs (Pennington, 2023).

Dynamic Managed Charging

Dynamic managed charging involves the utility or a third party adjusting the vehicle's charging in real time to align with consumer requirements and grid constraints. The architecture of dynamic managed charging can be a hierarchical mechanism with a managing entity coordinating charging. This can be implemented through centralized control with all signals originating from a central entity, or a decentralized architecture in which control signals could originate from multiple managers. The decentralized approach could involve signals originating from the regional transmission organization

FIGURE 17

Snapback Effect in Demand Response Events



EVs can be highly effective at limiting charging during events, but care should be given to avoid snapback effects before and after the event. This chart shows a classic whole-home demand response event with good performance during the event (shaded area), but with rises in usage immediately before and after the event.

Source: Glass et al. (2022).

25 These energy losses are highly dependent on the length of the event and efficiency of the home, and have historically been of secondary importance to the capacity constraints on the grid.

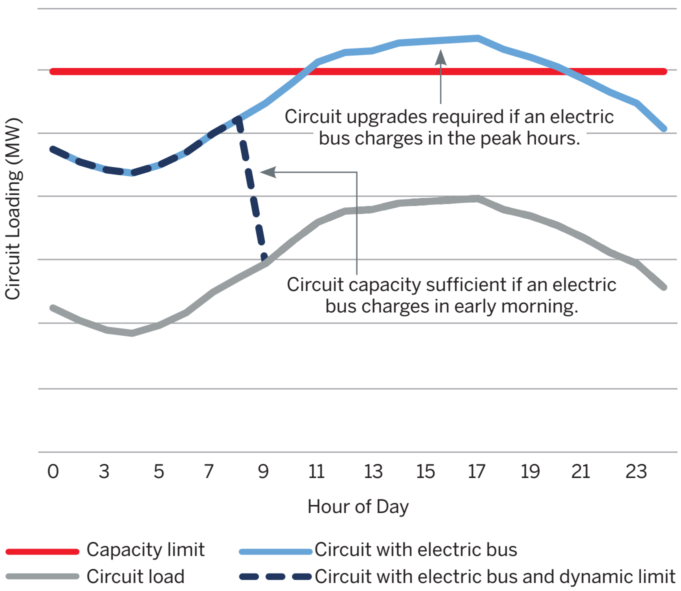
or independent system operator to be implemented by distribution utilities, or it could involve distribution utilities issuing commands to field equipment that uses local information and communication with nearby devices to coordinate actions. Similarly, a utility could issue a command to multiple aggregators for execution. The benefit of this hierarchical approach, which is aligned with IEEE 2030.11, is that the control mechanisms can adapt and change based on different factors, including how grid needs arise at the distribution or bulk system level and the priority of those grid needs.[26]

Dynamic operating envelopes and dynamic interconnection limits can shape load based on grid conditions. Dynamic operating envelopes can be used in an operational setting to communicate allowable ranges of charging by time of day. Meanwhile, dynamic interconnection limits can be used to limit EV charging to certain times of day as a condition of connection with

the grid. Both are valuable tools for distribution planners considering how the system can support EV charging.

FIGURE 18

Dynamic Operating Limits Specify when Electric Buses Charge



To avoid exceeding the capability of the circuit, the electric bus is provided with a dynamic operating limit that restricts charging to early morning hours.

Source: Energy Systems Integration Group.

Figure 18 shows how circuit loading varies throughout the day and how the addition of a 2 MW electric bus would exceed the circuit's capacity limit at certain times of day. To avoid exceeding the capability of the circuit, the electric bus confines charging to overnight hours. Vector, a distribution system operator in New Zealand, is using this approach, and other utilities have indicated interest (Head and Heinen, 2022).

It is possible that entities focused on different levels of the grid could request that the same vehicle perform different charging or discharging actions to meet different objectives, and these various layers of demand-side management will need to be coordinated. Some jurisdictions are pursuing tariff options that simply pay customers based on when the vehicle is plugged in and leave the complex optimization and accounting between the utility and a third-party manager.

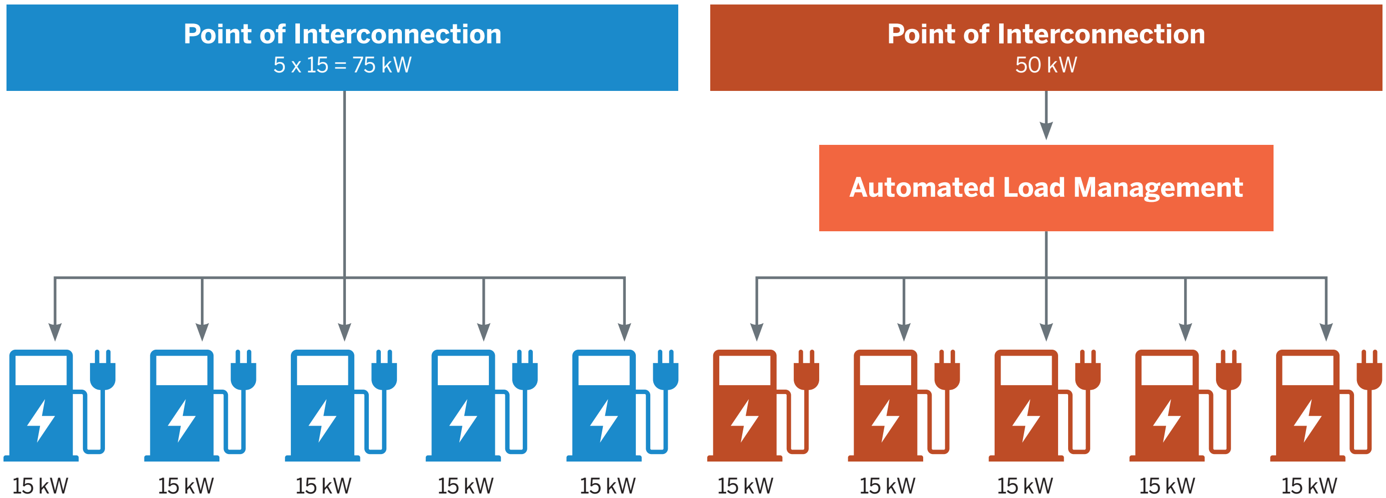
Automated Load Management

ALM schedules EV demand to keep it within a specified range over time. As grid planners develop the grid to support greater volumes of EVs, there may be a tendency to build distribution equipment to serve the sum of the nameplates of all chargers. However, ALM is executed at

26 IEEE 2030.11 is the IEEE Guide for Distributed Energy Resources Management Systems (DERMS) Functional Specification. It outlines the aggregation function and describes the grid services that aggregated DERs can provide.

FIGURE 19

Example of Using ALM to Integrate the Same Charger Rating at Points of Interconnection with Lower Limits



Automated load management (ALM) schedules and prioritizes EV demand to remain within a specified range over time. On the right side in this example, five chargers are integrated with ALM to remain below a 50 kW interconnection limit. This allows for more efficient use of distribution infrastructure.

Source: Energy Systems Integration Group.

When developing the charging network in its territory in northern California, Pacific Gas and Electric used ALM to reduce requested distribution capacity by more than 50%, with cost savings of $30,000 to $200,000 per project.

the premise level and can allow the nameplate of downstream chargers to exceed the maximum power available at the point of interconnection (see Figure 19). ALM then manages the downstream chargers within that point of interconnection limit, helping to minimize the EVs' impact on the distribution system.

ALM is beginning to be implemented in some U.S. jurisdictions. For example, Pacific Gas and Electric included ALM in its plan for developing the charging network in its territory in northern California. The utility used ALM "in order to reduce costs and physical design constraints at customer sites.… When using ALM, PG&E deployed charging infrastructure 'at sites in a manner that reduced the originally requested capacity by more than 50 percent to stay within the electrical capacity of the existing or lower cost infrastructure.' This resulted in cost savings ranging from $30,000 to $200,000 per project."[27] The California Public Utilities Commission found that "utilization of ALM will help lower program costs and promote efficient use of electric grid infrastructure."[28]

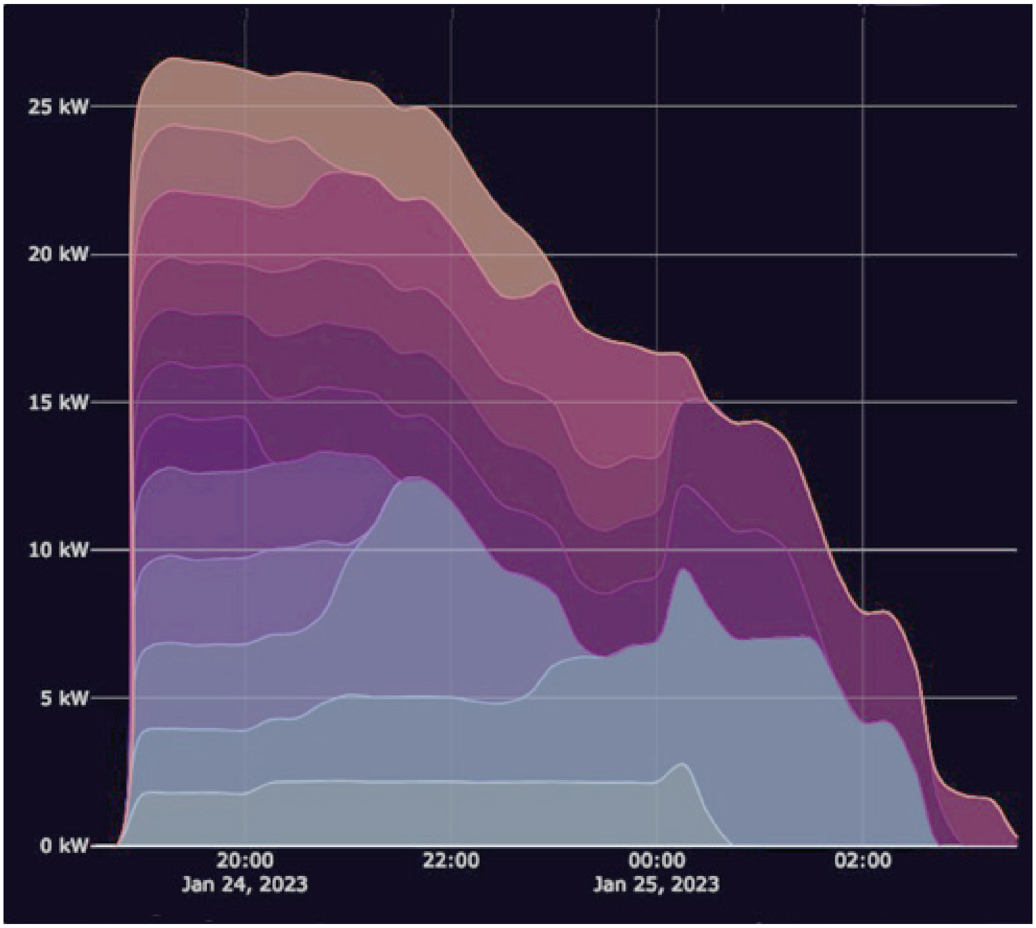
ALM is more common in the European Union and UK for both fleet and residential loads. The mail delivery service in Ireland, Irish Post, is an example of ALM in action. Irish Post is using ALM technology to manage its EV loads at more than 100 sites across the country.

27 Opening Brief of Pacific Gas and Electric Company, California Public Utilities Commission Application No. 21-10-010 (August 24, 2022). https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=496592994.

28 Decision Authorizing Pacific Gas and Electric Company's Electric Vehicle Charge 2 Program, 22-12-054, California Public Utilities Commission, December 19, 2022. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043974.PDF.

FIGURE 20

Example of EV Load Scheduling Using Automated Load Management



The mail delivery service in Ireland uses automated load management to allow the total nameplate rating of their chargers to exceed site infrastructure limits. In this example, the site's nameplate rating is 88 kW, but automated load management coordinates EV charging to keep the simultaneous demand below the site's service limit of 28.9 kW. As the fleet operator prioritizes some chargers to receive more power, others decrease their usage to limit aggregate load. This type of automated load management system allows more flexibility than standard power sharing, which splits connection capacity evenly across all chargers.

Source: The Mobility House.

At one site, the total nameplate rating of the chargers is 88 kW, while the site service limit is 28.9 kW (Figure 20).

ALM shifts some of the risk of service from the utility to the charge station operator. The utility must provide reliable power only at the level agreed to at the point of interconnection. The charge station operator takes on the risk of managing charging demands that may exceed the service limit, including managing customer expectations. It is the responsibility of the charge station operator to accurately model customer EV usage and help customers understand if avoiding an upgrade would compromise the customer's mobility experience.

In implementing ALM, some utilities may use separate distribution protection hardware to enforce infrastructure limits and ensure the efficacy of ALM. Utility hardware solutions would stack on top of vendor-provided software control mechanisms. Rigorous testing of third party–managed ALM software capabilities can avoid potentially redundant equipment, such as utility-managed protection

devices placed upstream of the ALM solution. Underwriters Laboratory (UL) is investigating standards and certifications so that individual utilities would not need to perform their own testing of ALM reliability. UL 916 and UL 60730-1 are both potential standards that can be applied to ALM, but there is little consensus among the engineering community on the applicability of these standards to ALM, making it hard for vendors to justify pursuing certification. Such certifications would guarantee implementation of software safeguards, including a safe failure mode if communication with the command module is lost.[29] Regardless of hardware/software implementation, consistently defined rules are needed upfront for using ALM in distribution planning and operations.

Smart Charging Challenges

Smart charging is a central tool in limiting the impact of EVs on distribution infrastructure and can help to minimize the grid upgrades needed to support a transition away from gasoline-powered cars. However, even using the smartest of charging strategies, it may be necessary to upsize distribution equipment, particularly if customers do not participate in demand response programs or will not provide flexibility based on price differentials. While smart charging is an imperfect solution with things still to learn, and distribution system investments would carry a price tag, these should be evaluated against the broad benefits of EVs, including sustainability.

29 OSCP (Open Smart Charging Protocol), the standard that enables smart charging between the EV and charger, embraces such a "fail-safe" approach.

Customer Participation

The principal challenge with smart charging is convincing customers to participate, incentivized by the value stream that the utility or aggregator can monetize. But while this value stream may include reduced costs of electricity generation or reduced need for new generation capacity, transmission capacity, or distribution upgrades, these values may be difficult for the utility, and especially for an aggregator, to monetize. Even though large infrastructure investments may be deferred by managing demand across many EVs, the savings passed on from a utility or aggregator to an individual EV owner may not be large enough to incentivize the EV owner's participation. Research from Pacific Gas and Electric's service territory suggests that a $50 enrollment incentive would entice about half of the owners of smart level 2 chargers (240 V chargers) to participate in an EV demand response program, but work remains to translate this finding to practical grid impacts (Opinion Dynamics, 2022).

In some cases, it may simply not be possible to recruit enough customers into a load management program to avoid distribution system upgrades at localized points. For example, the California investor-owned utilities have regularly held solicitations inviting third-party DER aggregators to submit bids for load management projects to avoid planned distribution system upgrades, and those solicitations have largely not attracted significant interest from the developer community.[30]

Preserving Benefits of Load Diversity

Load diversity, a core principle of distribution planning used to size infrastructure, allows planners to use smaller equipment than would be required if every load's maximum demand were simply added together.[31] However, large numbers of EV owners participating in demand response programs could remove the diversity of their charging behavior and overload distribution equipment. For example, smart charging that is driven by bulk power system needs could undermine load diversity on the distribution system by concentrating charging during specific time periods that address bulk system needs but exacerbate stress on the distribution system. A combination of ALM and other mitigation measures that avoid uniform load responses may help to preserve diversity benefits while aligning with other grid needs.

Given the multiple standards required to enable effective communication of smart charging signals, early definitions are essential.

Communication and Control: Standards and Implementation

Smart charging requires appropriate development of communication and control architecture so that EVs can help address—and not exacerbate—grid issues. The architecture to enable smart charging requires data exchanges across multiple software systems designed by different vendors with different risk tolerances. Some utilities have developed interoperability guides to help shape the communication and control market in their service territory (Vector Electricity, 2023). These guides are helpful for charge station operators and aggregators to understand how the utility plans to manage activity across vendors. Early definition of open standards helps to avoid technology obsolescence from the deployment of proprietary data architectures. Given the multiple standards required to enable effective communication of smart charging signals, early definitions are essential (ElaadNL, 2017). Moreover, defining standards and certifications can help to de-risk the implementation of software safeguards, such as a safe failure mode if communication with the command module is lost.

Specifying a standard may not be enough to effectively ensure interoperability for EVs, however,[32] and an interoperability profile, specifying how a standard will

30 For example, the Independent Evaluator Report for Southern California Edison's Distribution Investment Deferral Framework (DIDF) Partnership Pilot (prepared by Merrimack Energy Group) found non-competitive developer interest in the identified distribution deferral opportunities. See https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M509/K081/509081080.PDF.

31 The interplay of load diversity and EVs is discussed at length in the "Future-Ready Infrastructure" section of this report.

32 For example, standards often allow for custom fields or special error codes. Unfortunately, vendor implementation of the early versions of the Open Charge Alliance's standards, Open Charge Point Protocol (OCPP) and Open Smart Charging Protocol (OSCP), used custom fields liberally. As a result, error codes meant different things depending on the vendor. Efforts are underway to remedy these interoperability issues at the data level (LF Energy, 2022).

be implemented, may be needed (SEPA, 2022; EEA, 2023). A similar effort was undertaken with the common smart inverter protocol (CSIP) that provided additional clarity for implementation of smart inverter functionality in PV installations (SunSpec Alliance, n.d.).

Pricing Sensitivity and Reliability

Pilots have demonstrated the potential of pricing to influence smart charging, but work remains to be done. As discussed above, some pilots and small programs have demonstrated the potential of dynamic pricing and control of EVs. However, recent research was unable to identify even one currently offered or proposed EV-specific rate that incorporated locational differentiation in the design (Cappers et al., 2023). Some pilots have paired EVs with distributed batteries to tailor the aggregate (EV+battery) charging profile to predefined TOU periods, but those EV+battery solutions may be cost-prohibitive for the customer.

Similarly, the degree to which we can rely upon pricing in all situations is still under investigation. Outlier events and peak conditions drive significant investment in grid infrastructure, and understanding how EVs will impact these outlier events will be critical in distribution system planning. There are few publicly available datasets on charging behavior around holidays and weather events—high travel periods. The Public Safety Power Shutoff events in California could offer some indication for how customers would charge around potential disaster events, such as winter storms or hurricanes, but information is scarce on EV behavior before and during these events. And overall, early lessons learned on the efficacy of targeted pricing will be informative in developing a strategy that effectively balances reliability, consumer choice, and cost effectiveness.

Modeling

Lastly, improvements are needed for modeling smart charging. Even after data on smart charging are widely available, distribution system planning tools and processes will need to be updated to consider smart charging as an option. Lawrence Berkeley National Laboratory has identified key barriers to integrating price-based demand response in grid planning for bulk power systems and distribution systems (Carvallo and Schwartz, 2023). Price-based demand response resources are often ignored or treated as an input in grid modeling, rather than as part of the optimization function. Considering the scale and flexibility of EV charging, planning tools and processes will need to evolve to include a variety of smart charging options.

The blending of behind-the-meter asset classes offers the opportunity to create grid-friendly load through intelligent optimization strategies. In particular, the effects of distributed solar and EVs are helpful to analyze.

Considering EVs Together with Other Behind-the-Meter Solutions

EVs should not be planned in isolation, as they are part of a broader set of distributed resources that includes distributed solar, storage, energy efficiency, and grid-responsive loads. If each DER addition is studied independently, we may miss potential opportunities for grid solutions that consider generation, storage, and loads holistically. The blending of behind-the-meter asset classes offers the opportunity to create grid-friendly load through intelligent optimization strategies.

Analyzing Distributed Solar and EVs Together

The effects of distributed solar and EVs in particular are helpful to analyze together. With appropriate planning and well-designed retail rates, solar and EVs can be synergistic in helping to decarbonize the U.S. energy economy with little impact to the grid in many locations. At high levels, distributed PV produces surplus generation during midday hours that may not be usable locally given distribution system constraints. EV charging—potentially supplemented by distributed storage—can soak up excess generation. EVs also can address bulk system challenges by charging from utility-scale PV that may otherwise be curtailed, provided that the grid can facilitate the delivery.

33 The 1200 GWh figure assumes current battery sizes, a split of battery-electric vehicles and plug-in hybrid vehicles, and that each vehicle is half charged.

The integration of DERs into EV charging stations offers a prospective solution to alleviate stress on the distribution system. In addition to considering solar and short-duration battery solutions, charge station operators and utilities should consider their resilience plans. As EV adoption grows, there is a growing need for resilient charging infrastructure capable of withstanding severe weather and offering backup power potentially for weeks to facilitate emergency transportation needs. A project in Korea uses hydrogen as a back-up fuel to generate electricity to charge EVs at gas stations, which provides just this resilience benefit.

Accounting for Vehicle-to-Everything (V2X) Bi-directional Charging

Creating a future-ready system means evaluating each EV charging station for potential bi-directional charging capabilities. Many U.S. and global EV manufacturers have announced plans to make their EVs bi-directional, with most, including the leading EV automaker, Tesla, looking at the 2025 model year. Numerous charger manufacturers have publicly announced plans to design, build, and sell bi-directional chargers, adding to the limited number of DC bi-directional chargers on the market today. This is not to say that vehicle export considerations should supersede the urgency of single-directional charger interconnection, but that vehicle exports should be considered as the grid is planned given the industry trends referenced (Greenblatt, Zhang, and Saxena, 2021).

Bi-directional charging is important because of the potential scale of storage accessible in EVs. The mid-adoption scenario of 33 million EVs in a recent report by the National Renewable Energy Laboratory could represent approximately 1,200 GWh of energy storage available across the U.S. in the EV fleet (Wood et al., 2023).[33] For reference, the amount of utility-scale batteries currently planned through 2025 is approximately 120 GWh (EIA, 2022b). The vehicle fleet could dwarf all utility-scale stationary batteries by an order of magnitude.

Bi-directional vehicles will be able to support energy needs for individual homes through vehicle-to-home (V2H) energy transfer for up to a few days in the event

TABLE 5

Planning Practices Associated with Mitigating Grid Impacts of EVs

PLANNING ATTRIBUTE	
Smart (managed) charging is used to mitigate the largest impacts of EVs aligned with grid needs.	
Good practices	• Smart charging is present as a load modifier for the load forecast. • Time-of-use rates are used throughout the planning process to adjust EV charging profiles. • Demand charges are aligned with coincident peaks that drive investment in bulk system and distribution infrastructure. **Example:** San Diego Gas and Electric has a rate with a demand charge that varies based on the customer's coincident demand with the top 200 hours of its distribution circuit's load.
Better practices	• Automated load management is used to integrate EVs in planning and schedule charging at the premise-level in operations. • Distributed solar, storage, and EVs are analyzed together to capture benefits of on-site consumption and storage of solar generation. • Bi-directional EVs are considered in the interconnection process to allow for future innovation and benefits for the utility system and consumers. **Example:** Austria's postal service uses automated load management to manage the charging across its fleet, limiting impact on the distribution system and aligning with grid capabilities.
Best practices	• Interoperability guides are available to charge station developers and manufacturers to help shape the implementation of standards in utility service territories. • Dynamic pricing reflecting bulk and distribution system needs is available for interested consumers, including through aggregator-managed models that simplify the customer experience. • There are plans to leverage the expected growth of bi-directional charging in the coming years. **Example:** The distribution utility in the Netherlands, ElaadNL, publishes an interoperability guide to facilitate open communication within the charging ecosystem.

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

of a grid outage. In the short term, public charging networks can consider the incremental cost of bi-directional charger installations, even if the bi-directional capability is not used immediately. Grid planning practices will need to consider how to model bi-directional capabilities of chargers and associated EVs to consider dynamic and grid-responsive capabilities, including assessing the likelihood that EVs are not plugged in to provide response at a given time.

Many consumers will find value in vehicle-to-home applications that help ensure that their home has power through short outages as well as major events. In addition, this could in theory reduce resource adequacy and resilience requirements for the bulk system. And vehicle-to-home capability can help shape aggregate load profiles as vehicle export is integrated into power system operations in the long term. Good, better, and best planning practices associated with mitigating EVs' grid impacts are given in Table 5.

Developing Roadmaps and Grid Plans

After establishing the likely amount, timing, and location of charging needs, distribution planners use that information to develop roadmaps and grid plans to guide distribution system upgrades to support the expected integration of EVs. These grid plans prioritize initiatives based on a variety of objectives, including meeting EV needs, addressing imperfect existing infrastructure, and designing a grid that is equitable, affordable, and reliable. Here we discuss grid planning actions that can be taken today to prepare the grid for vehicle electrification impacts in the long, medium, and near term. These actions manifest change in the grid in different ways, building toward supporting forecasted EV loads.

- Plans focused on **future-ready infrastructure** aim to ensure that the long-term infrastructure can support EV loads. These plans are more passive in nature and help to spread across years any costs of infrastructure upgrades required to meet long-term policy goals.
- **Targeted system upgrades** can be undertaken where forecasting scenarios or historical data show grid needs at localized points. These upgrades may take three to five years from conceptualization to commissioning.
- **Energization and interconnection plans** deal with discrete near-term requests to integrate new EV chargers.[34]

Some of these planning practices are not currently part of annual cycles of distribution planning. For example, the suitability of standard equipment used on the distribution system is assessed infrequently. Similarly, energization and interconnection requests typically arrive out of sync with regular distribution planning cycles.

Grid planning actions can be taken today to prepare the grid for vehicle electrification impacts in the long, medium, and near term.

Currently, near-term developer requests inform the distribution planning processes that are completed regularly, and those regular processes inform long-term studies. However, there is a need for long-term study findings to be integrated with medium- and short-term plans to avoid widespread constraints. Too often, long-term study results are left in isolation.

This section, rather than prescribe specific solutions or recommendations, describes the types of analysis that are needed. Each distribution system, policy landscape, and EV forecast represents a unique situation that will need to be addressed by local distribution planners.

Future-Ready Infrastructure

Planning for EVs requires a holistic analysis of the assumptions that drive grid planning decisions—assumptions that are embedded in design standards and load forecasts. Typically, equipment design standards are re-evaluated every decade or two; however, these standards are being reassessed by leading utilities facing

34 "Energization" generally refers to situations where the EV is in load-only or islanded power configurations, whereas "interconnection" refers to situations in which the V2X can export to either the site or the grid. We find that "interconnection" is helpful to frame V2X and solar in similar terms for new audiences, while also allowing for future V2X strategies; however, both terms are used as appropriate throughout this report. For more on this, see VGIC (2022).

growing EV loads. Design standards typically use the diversity of demand to plan infrastructure with smaller equipment than would be required if maximum demand for every end use was simply added together.

Although future-ready equipment will not be sufficient to meet all projected EV charging needs, it is an important part of preparing for EV loads. In practice, future-ready design standards will manifest change on the distribution system both when replacing existing equipment (upgrading the size of the equipment when it is due for replacement) and when planning new distribution circuits (by building in additional margin from the beginning).

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Reconsidering Equipment Design Standards

Standards for grid equipment affect distribution planning in multiple ways, in particular, through voltage classes and equipment sizes. Generally speaking, costs increase with higher voltage and larger equipment, so distribution planners try to right-size the equipment to meet today's needs and expected future demand.

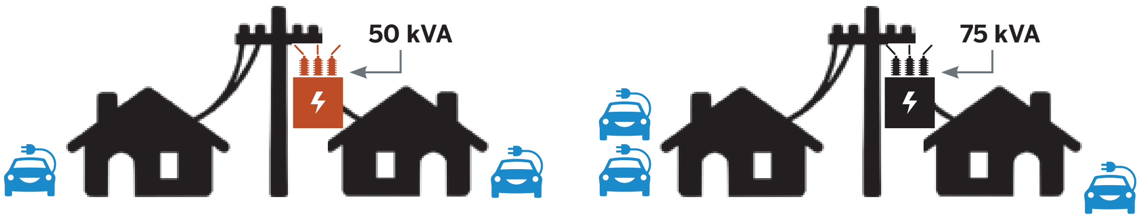
- **Voltage classes:** Utilities typically design power systems at discrete voltage steps to help maximize supply chain efficiency and simplify both construction efforts and some electrical engineering. The voltage classes most common in grid planning in the U.S. are 4 kV, 12 kV, 35 kV, 69 kV, 115 kV, 230 kV, 345 kV, and 500 kV. Utilities will increasingly be considering converting from one voltage class to a higher class at the same location to facilitate electrification.
- **Equipment sizing:** Distribution equipment is usually sized in a standard fashion: a given voltage class uses a certain size wire appropriate for thermal loading. Service transformers are sized at discrete blocks, such as 50 kVA or 100 kVA, to service a given need. These small transformers typically serve 3 to 15 residential customers or a few small commercial customers. They are typically sized assuming a certain amount of load diversity, which allows homes to exceed their expected load at any given time on the assumption that not all homes will hit their peak demand at the same time. With the introduction of EVs, these design decisions are being reassessed, and larger wires and larger-capacity service are being considered.

Reconsidering standard voltage classes requires a strategic shift that goes beyond typical distribution planning activities. Because of EVs' potential effect, they warrant just such a strategic shift in grid planning: distribution system wiring may need to get larger and voltage levels may need to increase. Planners are tasked with determining where to make those upgrades in the absence of definitive data on the where, when, and magnitude of EV charging. Historically, another substation or distribution circuit would be built if customers required more power capabilities. But as utilities look toward the long-term needs of customers and their EVs, they may consider upgrading system equipment rather than continuing to build more of an undersized network, particularly in areas where land acquisition for a new substation is challenging. Moreover, the industry faces a timeline challenge, as building grid infrastructure could be much slower than building the necessary EV charging infrastructure.

Since the shift up in voltage class (from 4 kV to 12 kV, for example) is an expensive investment, many utilities have staged this investment and architectural shift by upgrading equipment as it is due for replacement or by

FIGURE 21

Example Utility Approaches to Sizing Service Transformers



Exegol Utility District

When equipment is a candidate for replacement, the utility replaces legacy designs with similar design standards that may become overloaded with incremental EVs.

Tatooine Cooperative

When equipment is a candidate for replacement, either at end of life or when the utility is doing things like pole replacement, the utility replaces legacy designs with future-ready solutions.

Utility strategies for equipment sizing are being reconsidered as electrification adds load to the system. To be future-ready, some utilities are upsizing equipment when it reaches the end of its useful life or by providing all new construction with the upgraded voltage class. On the right, the service transformer has been upgraded and can accommodate increased EV adoption, while on the left, the legacy equipment (in orange) is at risk of overloading.

Source: Energy Systems Integration Group.

providing all new construction with the upgraded voltage class. Over time, the entire service territory will be upgraded to accommodate higher loading levels. A similar strategy has been used for most pieces of grid equipment, including service transformers. These upgrades allow for more electrification of vehicles and buildings at a pace that attempts to balance customer demand and costs.

The impact of design standards is shown in Figure 21, which compares two hypothetical utility strategies.

This upsizing approach holds promise because the cost of the grid equipment itself is only one part of the cost to replace aging infrastructure. Labor required for planning and installation makes up a large share of the cost of a service transformer upgrade; therefore, the marginal cost of a higher-capacity transformer is often small compared to the costs of replacing or supplementing the transformer in a few years. A national reference quantifying the soft costs of utility equipment and the cost-effectiveness of upsizing could help utilities and regulators think through this strategy within their territory.

Revisiting Load Diversity Assumptions

Determining loading levels and designing appropriate grid architectures centers on the interaction of the diversity of loads with equipment rating methodologies. The diversity concept is central to grid planning. If all consumers hit their individual peak load at the same time, the grid would be overwhelmed. An example of this planning practice can already be observed on distribution circuits where the aggregated rating of service transformers far exceeds the capability of the distribution circuit to meet that demand. Similarly, the aggregate nameplate rating of the deployed charging infrastructure will soon outpace local distribution transformers, circuits, and even transmission and generation capabilities in some regions. This should not be too problematic on its own, as the aggregate rating of distribution equipment already outpaces generation capabilities, but distribution planning headroom may need to change or evolve to support integrating EVs. Planning appropriate headroom begins with understanding load diversity.

By their nature, load diversity calculations are inexact approximations of the grid impact of an aggregation of customers. Similarly, the ratings that protect grid equipment can be inexact thresholds in operations. IEEE C57.91—the guide for loading transformers and voltage regulators—follows a "loss-of-life" concept where excessive loading (among other factors such as ambient temperature) contributes to a reduction in equipment lifespan. In practice, this means that transformers and other grid equipment can be operated above their rated capacity, but the equipment will degrade more quickly, potentially failing before it is fully depreciated from an accounting perspective. Taken together, diversity of load and loss-of-life calculations create multiple variables that drive infrastructure sizing considerations. When preparing future-ready plans for EVs, the interaction of these variables needs to be carefully considered.

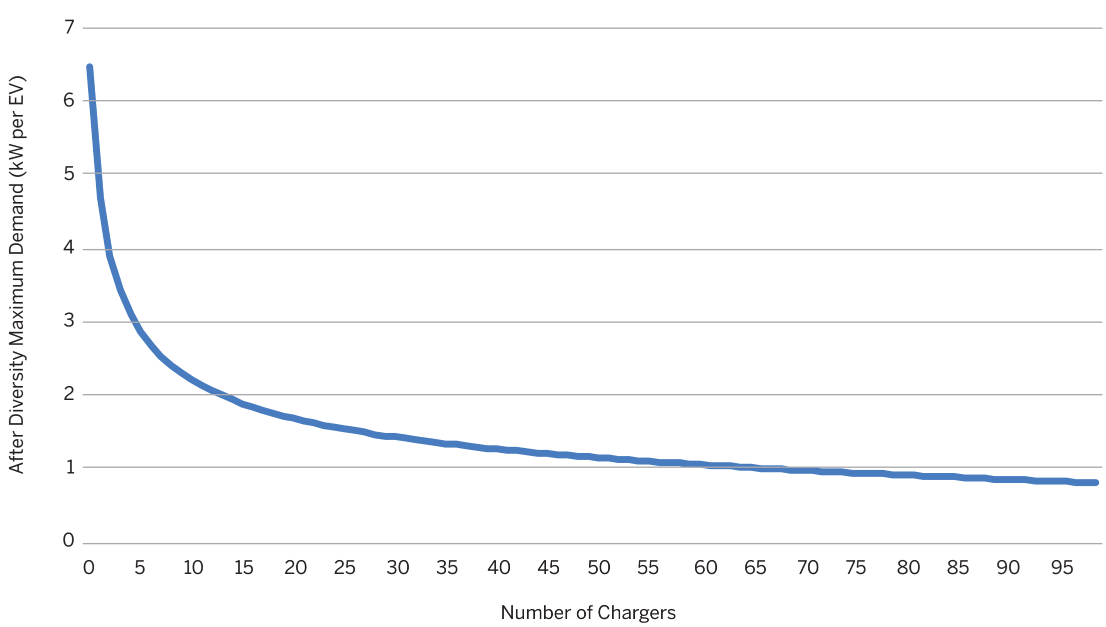
Managing Changing Diversity Factors as EV Adoption Proceeds

The diversity of load can be measured through diversity factors and calculations of "after diversity maximum demand" (ADMD). To meet the anticipated demand on the distribution system, ADMD is used to calculate the coincident peak that the distribution system is likely to experience based on the customers connected to the particular system. Infrastructure planners have historically discounted the demand contributed by individual customers, assuming a diversity benefit, and are able to get by with smaller equipment than would be required if every home's maximum demand were simply added together. Whereas a given house could add up to 20 kVA of new demand, it's unlikely to do so at the exact time that all other houses maximize their demand.

The current diversity assumptions used by utilities are based on historical data in the coincidence of typical loads. However, there are relatively little data on EVs' diversity factors. EVs will change ADMD calculations for typical customers, and some utilities are rethinking their ADMD curves to better evaluate how diversity of load is measured (NIE Networks, 2023). As evidenced by Figure 22, EVs appear to have large diversity in residential charging across a large number of EVs, as consumers vary their charging both by time of day and day of week. However, the maximum demand remains fairly high when there are few chargers.

Because of the change in ADMD as the charger count increases, diversity only goes so far in distribution planning. In the United States, most service transformers

FIGURE 22
After Diversity Maximum Demand (kW per EV)



The diversity of times when people choose to charge their cars means that the contribution to the coincident peak demand from charging declines as more chargers are considered. The diversity of all loads allows the distribution system to support individual demands with equipment that could not serve everyone's peak demand simultaneously.

Source: Energy Systems Integration Group. Data courtesy of Vector.

serve relatively few households, often fewer than 10 (Taylor and Christian, 2023). With such few customers, there is little diversity available in charging behavior and a relatively greater likelihood that small numbers of residential EV chargers on the same street could cause a problem. Diversity assumptions and implications for distribution planning should be carefully evaluated.

Because of the potential conflict between the needs of the bulk system and distribution system, diversity assumptions should be coordinated across stakeholders as the power system is optimized for different objectives.

Considering Potential Conflicts Between Bulk System and Distribution System Needs

As utility rates and other signals influence behavior, and as EV charging is shifted toward times with high levels of clean electricity, the degree of natural diversity in EV loads will likely diminish. With large peak vs. off-peak ratios for TOU rates, many drivers will charge when it is cheaper. But while this may be helpful for the bulk power system and align with low-emissions generation, the distribution infrastructure may not be able to accommodate this coincident charging demand.[35]

Because of this potential conflict between the needs of the bulk system and distribution system, diversity assumptions should be coordinated across stakeholders as the power system is optimized for different objectives. Solutions—such as some rate designs—that are appropriate for bulk system planning may be particularly problematic for the distribution system. For example, a higher "cloudy day" rate could make it more expensive to charge EVs when solar generation is low. Currently, part of the diversity seen in EV charging comes from customers only charging their cars every three to four days, but such a rate could reduce some of this weekly diversity if the price signal from the bulk system were large enough. Moreover, this type of rate could place strain on the distribution system as drivers charge their cars on non-cloudy days exclusively.

35 As discussed in the section "Smart Charging," there are opportunities for managed charging programs to effectively stagger charging to avoid violations of localized infrastructure capacity.

TABLE 6

Planning Practices Associated with Future-Ready Design Standards

PLANNING ATTRIBUTE	
The suitability of upgrading standard distribution system equipment is assessed to facilitate vehicle electrification.	
Good practices	• The suitability of distribution system voltage classes is assessed to determine whether they support long-term load growth and equipment standards are upgraded as necessary. **Example:** A variety of utilities have upgraded 4 kV systems to 12.47 kV or even 34 kV to facilitate EV growth, including Los Angeles Department of Water and Power (LADWP) and Commonwealth Edison (ComEd).
Better practices	• Advanced metering infrastructure (AMI) data are integrated into demand diversity calculations to inform distribution equipment standards. • A program is established to regularly assess the suitability of distribution equipment standards amid a dynamic planning reality. Suitability considerations include a broad range of stakeholder inputs. • New smart charging programs include provisions that allow for staggered charging, preserving some diversity of loads. **Example:** A distribution utility in New Zealand, Vector, used AMI data in its EV smart charging trial to better understand charging behavior and diversity.
Best practices	• Diversified EV loading shapes are developed using telematics or submetering and are regularly refreshed as the vehicle mix changes or smart charging influences patterns. • Diversified EV loading shapes inform equipment standards. **Example:** EPRI is developing maps for the U.S. that leverage vehicle telematics to better understand vehicle travel patterns.

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

Coordination is needed among rate design, charger availability, and grid architecture. A Stanford study found that more public charging is necessary to facilitate utility-scale solar powering EVs, because public charging tends to take place during daytime hours (Powell, Cezar, and Rajagopal, 2022). Such a strategy would also be coupled with distribution grid plans to prioritize such charging.

ADMD calculations will likely need to shift over time as vehicle patterns shift and smart charging becomes more of a complex optimization problem. In the short term, it seems likely that grid planners will plan for full capacity of the EV chargers even though the charging will seldom get anywhere close to that peak load. Diversity will remain an active area of research as data on charger site diversity continue to inform design criteria as more vehicles electrify.

These future-ready approaches serve to upgrade the power system over time, although the totality of up-grades required to reach the grid of the future cannot happen through a single initiative over the course of just a few years. Promising practices for future-ready systems are given in Table 6.

Targeted System Upgrades

Future-ready infrastructure upgrades that take place over decades will not be sufficient to meet all projected EV charging needs, and specific locations within a region may need upgrades before the existing equipment has reached the end of its expected lifespan. By analyzing forecasts and electrification likelihood indices, distribution planners can prioritize areas for additional, targeted upgrades. These could include larger equipment, new equipment, or non-wires alternatives such as batteries or behind-the-meter generation. Grid solutions discussed in this section are independent of the EV itself; how EVs may be part of the solution is discussed in "Mitigations: Avoiding the Largest Impacts," above.

Targeted system upgrades can be difficult to identify when the prioritized areas may not see load growth immediately or even in the typical distribution planning horizon. However, longer planning horizons can identify the areas where grid needs will likely arise, and such horizons will help to achieve the goals of long-term electrification policy. Rather than wait for the grid needs to arise, proactive planning can consider solutions today to spread out the impact of construction more evenly on rates. If grid planners implement grid solutions only once they are needed, they risk infeasible construction timelines and drastic rate impacts hitting customers suddenly. Targeted system upgrades will, however, require distribution system planners to identify the exact locations where the grid will be stressed long before the dynamics of EV adoption and behavior are known.[36]

An important component of grid planning is adaptability. Short-term solutions may look different from the long-term answers as we learn more about consumer behavior, adoption rates, and the types of EVs that drive the greatest grid impacts.

Because of the uncertainty in how exactly EVs will impact the grid, an important component of grid planning—for both transmission and distribution systems—is adaptability. Short-term solutions may look different than the long-term answers as we learn more about consumer behavior, adoption rates, and the types of EVs that drive the greatest grid impacts. For example, storage can be used as a short-term solution to address targeted issues in the near term while infrastructure is being built. Some utilities are temporarily siting storage to address short-term capacity needs and then moving it to a new location as needs shift. For example, Southern California Edison is planning to use movable storage as a short-term solution to facilitate a timely customer interconnection while a permanent solution (DER or wire solution) is being constructed. Attempting to serve customers that are asking for large service upgrades with short lead times, the utility plans to procure 37 1 MW/4 MWh batteries over the next five years and anticipates a large need for these to facilitate the electrification of medium- and heavy-duty vehicles. Because of storage's flexibility and multiple value streams, storage that is placed for transmission and distribution capacity deferral today may find value as a bulk system resource after grid upgrades are made to the underlying infrastructure.

Storage can also be integrated into the design of a charging station. Charging stations can use storage to minimize the maximum demand on grid equipment or perform energy arbitrage with a goal of providing energy to vehicles at a lower price. Charging vehicle batteries from charge stations' batteries introduces energy losses but may help to avoid curtailment of utility-scale solar or wind and align cheap energy with consumer demand. Storage charging from grid or on-site resources in a microgrid configuration could be particularly beneficial for the electrification of medium- and heavy-duty fleets when the business function may not allow for smart charging aligned with grid capabilities—when the vehicles are in use during periods of high renewable generation.

Targeted upgrades are an opportunity for grid planners to provide leadership in early EV integration decisions. Rather than react to where consumers want to charge, grid planners can work with others to identify areas where consumers are likely to charge and that are aligned with existing grid capabilities. For example, collaborating with transportation agencies can help to identify opportunity zones to support future high-demand areas. Similarly, proactive interviews and/or surveys of commercial fleet customers can improve the accuracy of forecasts and better align grid upgrades with future fleet expansion plans, timing, demand, and location.

Targeted upgrades are an opportunity for grid planners to provide leadership in early EV integration decisions. Rather than react to where consumers want to charge, grid planners can work with others to identify areas where consumers are likely to charge and that are aligned with existing grid capabilities.

36 This paper does not advocate for widespread proactive grid investments; rather, it emphasizes how a proactive grid planning process would identify targeted system upgrades that address customer needs both in specific locations and at the appropriate grid topology level. The decision to make those upgrades will depend on each utility's or system's needs.

TABLE 7

Planning Practices Associated with Targeting System Upgrades

PLANNING ATTRIBUTE	
Targeted system upgrades consider electrification impacts on the grid.	
Good practices	• A longer planning horizon (seven or more years) is used in distribution planning to understand how forecasted electrification will impact grid needs. **Example:** Hawaiian Electric's Grid Modernization Strategy considers ways to achieve the 2045 renewable portfolio standard.
Better practices	• Short-term solutions (like storage or smart charging) are used to quickly integrate EVs while permanent solutions that address the long-term need are identified. • Proactive interviews and/or surveys of commercial fleet customers are conducted to understand fleet expansion plans, timing, demand, and location to improve accuracy of electrification likelihood indices. **Example:** Avangrid is using a flexible interconnect capacity system to avoid costly upgrades caused by new DERs during some hours of the year.
Best practices	• Regular medium- to long-term locational forecasting is conducted, in collaboration with transportation agencies, to identify opportunity zones to support future high demand areas. **Example:** GRE provided developers with a two-page summary of a vacant lot along a highway where 5 MW of distribution capacity was available.

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

The targeted system upgrade approach may be to initially enable public charging plazas in areas where the grid can handle it. Such decisions can help reduce some of the uncertainty that currently plagues grid planning decision-making, while these early deployments remain useful as levels of EV grow.

The targeted system upgrade approach may be to initially enable public charging plazas in areas where the grid can handle it. Such decisions can help reduce some of the uncertainty that currently plagues grid planning decision-making, while these early deployments remain useful as levels of EV grow. Targeted system upgrades can look like traditional solutions or non-wires alternatives, such as batteries. Similarly, these may be prospective or reactive, as the grid prepares for or catches up to charging needs. There are a variety of planning practices associated with identifying where to upgrade the grid, but Table 7 captures some of the characteristics of planning specifically for vehicle electrification.

Transparent Energization and Interconnection Processes

Roadmaps and distribution system plans will also need to include plans for responding to requests for public EV charging stations as they arise. Assessing EV charging requests will happen multiple times per year or potentially much more often. Given policy expectations for levels of EV adoption, energization and interconnection requests for EVs may exceed the volumes seen to date for solar PV installations and may further strain grid planning and line design departments unless new tools and increasingly streamlined processes can be deployed. Without proactively addressing this anticipated volume,

Distribution planning for EVs is an opportunity for the power industry to apply lessons learned from behind-the-meter solar deployment, such as developing retail rate designs that address EV impacts, new software tools to streamline processes, and public indicators of grid locational capabilities.

timelines for approval are likely to be longer than consumers expect to wait.

A cohesive plan is needed to deal with EV requests. Here, the power industry has an opportunity to apply lessons learned from behind-the-meter solar deployment to assist in distribution planning for EVs, such as developing retail rate designs that address EV impacts, new software tools to streamline processes, and public indicators of grid locational capabilities.

While public charging plazas and fleet depots will sometimes be constructed on the bulk system, and other public plazas will present large amounts of new load to small distribution systems, the effects of single-car charging stations at homes will be more subtle. These single-car charging stations will have a large aggregate impact on the power system even if their individual impact is minimal. Utilities have different degrees of visibility into at-home charging: most charging done with a 120 V charger (3 to 4 miles of charge per hour) can be done without utility approval, while in most cases, a 240 V charger (20+ miles of charge per hour) will need an electrical permit to install a new EV charging circuit. These applications for service will likely be voluminous, and a cohesive evaluation plan will be needed to assess the impact of EV chargers at the premise level and public chargers on the distribution system, in addition to transmission-connected highway charging plazas that support trucking electrification.

Distribution system planners can make processes for integrating EVs smoother and establish a trajectory for successful long-term integration of EVs by providing:

- Early indication of **likely capacity availability**
- Clear articulation of the **steps and data needed to connect new load**, including when the vehicle owners should engage their utility
- Defined expectations of the **grid-response characteristics of EVs**, along with any **control schemes used to manage load**

Indicating Capacity Through Queues and Maps

Queues and capacity-availability maps are needed at both the transmission and distribution level to give developers a better sense of where grid infrastructure is most capable of supporting public charging.

The concept of a public queueing process for new loads is relatively novel. Historically, projects that added new load to the system were concealed, as community developers protected their long-term plans from competitors. However, that is starting to change. For example, the Hawaiian Electric Company has requested regulatory approval for a customer reservation pilot program that would allow developers to reserve distribution capacity to serve their projects for up to five years (HECO, 2022). Reservation charges can be repaid through bill credits. This program gives developers certainty that the grid infrastructure will support their projects and provides the utility with more insights earlier in the development processes as it considers multi-year grid plans and multiple potential futures.

EV capacity maps can borrow from the concept of public hosting capacity maps that indicate the likely ability of the distribution system to accommodate new generation at different points on the grid. These EV capacity maps have been implemented in some regions, such as by

EV capacity maps can borrow from the concept of public hosting capacity maps that indicate the likely ability of the distribution system to accommodate new generation at different points on the grid.

California investor-owned utilities in their integration capacity analysis maps. However, additional information about capacity would also be useful for developers, such as whether or how others are queued in a given location. Such queues could be maintained as projects are energized or abandoned.

Hosting capacity analysis at the distribution level has become more sophisticated in recent years as simplified heuristics have been replaced with topology-specific simulations and the evaluation of multiple technology scenarios. Similarly, capacity maps can embrace topology-specific details and provide a range of feasibility across scenarios, even if they are just indicative of the results of more rigorous analysis. Appropriate data sharing will ultimately result in a more effective grid that integrates EVs at scale.

Articulating Process Steps and Data Requirements

Each utility has its own method for evaluating requests for public EV charging. Those processes are informed by the utility's capabilities and systems and should remain tailored to its circumstances. However, the basic data required to perform energization and interconnection studies can be standardized across utilities to assist data exchanges among stakeholders—between applicant and utility and between utilities. The industry could formulate a standard application for large charging station requests that builds upon similar efforts, such as Orange Button, the effort to standardize distributed PV data to enable data exchanges.[37] An effort like this for EVs would include information about the supply equipment, ranging from proposed nameplate ratings on the chargers to information about the electrical and information architectures that would support the site.

In addition, the timelines and process steps can be made readily available to homeowners, businesses, and developers, in terms understandable to people unfamiliar with electrical engineering grid considerations. For example, Oncor's Clean Fleets Partnership Program includes educational materials for fleets on the energization process. Developers need to be aware of the difference between screening maps and detailed interconnection analysis, particularly as surprising grid upgrade costs can disrupt project economics after significant effort has been performed by the developer.

Establishing Grid Response Characteristics for EV Chargers

The power industry is currently working out inverter specifications for wind and solar resources at the bulk and distribution levels to ensure stable operations during grid disruptions, with significant attention from the North American Electric Reliability Corporation (NERC), standards organizations, and manufacturers. Many utilities have updated or are in the process of updating their requirements for new generator interconnections to align with the new NERC Reliability Guidelines[38] and/or specifications from IEEE Standard 1547-2018 and IEEE Standard 2800-2022, which establish the criteria and requirements for interconnection of inverter-based resources and DERs interconnecting with transmission and sub-transmission systems, respectively. However, similar attention has not yet been afforded to new loads, particularly EVs.

Because EVs' charging demand is large in aggregate, it behooves the power sector to work with the transportation sector to develop requirements and standards for the EV chargers—particularly with respect to their behavior on the grid, including responses to changes in grid voltage and frequency. In addition, V2G applications will see inverters either embedded in the vehicle itself or within the charger that will need to behave in a predictable and beneficial manner.

Because EVs' charging demand is large in aggregate, it behooves the power sector to work with the transportation sector to develop requirements and standards for the EV chargers—particularly with respect to their responses to changes in grid voltage and frequency.

37 See https://myorangebutton.com/.

38 See https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf.

Defining a Grid-Friendly Operational Profile for Chargers

Aggregated charging loads, with EVs reacting in unison to conditions on the grid, pose both challenges and opportunities for utilities attempting to maintain reliability and serve load. Recent work examining the behavior of different types of chargers during a fault showed that some chargers have grid-friendly behavior in supporting fault-induced delayed voltage recovery (FIDVR) events while others do not (Tuffner et al., 2021). If chargers were required to provide sub-second responses—either increasing or decreasing their consumption—the aggregated benefits could be significant and the impact on charging times minimal.

Although EVs as a load can potentially have large impacts on sub-second grid operations, today's EV chargers do not share a standard grid-friendly sub-second operational profile (Tuffner et al., 2021). Grid operators and system stability would benefit from EV chargers that react to grid conditions, such as voltage fluctuations, in a standard and predictable manner.[39] Even beyond standardizing the grid response characteristics of EVs for system stability, there can be benefits to using a power electronics controls functionality to allow additional EV charging at the grid edge by mitigating the extent of service transformer overloading (Aswani and Mycko, 2022). Grid voltage measured by the EV charger could be used as a signal to throttle charging in real time (a volt-watt response function), but work remains to demonstrate the effectiveness of this concept around risks associated with more dynamic distribution system operations, such as potential overuse of on-load tap changers.

The need to define these types of grid response characteristics is immediately apparent when considering vehicle export applications in which the vehicle sends power back to the home, grid, or other end uses using V2G technology. This is another area where distribution planning for EVs can learn from integrating higher levels of PV and the "smart inverter" requirements that have been phased in for PV interconnections.

Grid-friendly EV loads are at the intersection of several standards across the vehicle and power industries, but no standards clearly define the expected grid response characteristics of EVs as a load. IEEE 1547 was intended for generators and does not directly apply to loads. Similarly, IEEE 1547.9-2022 covers energy storage and thus includes EVs only when they export energy from their batteries to the grid. IEEE 1668 provides a recommended practice for "voltage sag and short interruption ride-through performance and compliance testing" of equipment, but does not outline the performance requirements of loads on distribution systems. The Society of Automotive Engineers' SAE J2894 provides a recommended practice for EV chargers to consider the impact of the power quality of the electrical service on the charger, but not the impact of the charger on the grid.[40] Distribution planners will need to communicate with automotive engineers about the grid interactive expectations and build these expectations into contractual agreements and chargers.

Characterizing Frequency Response and Voltage Support

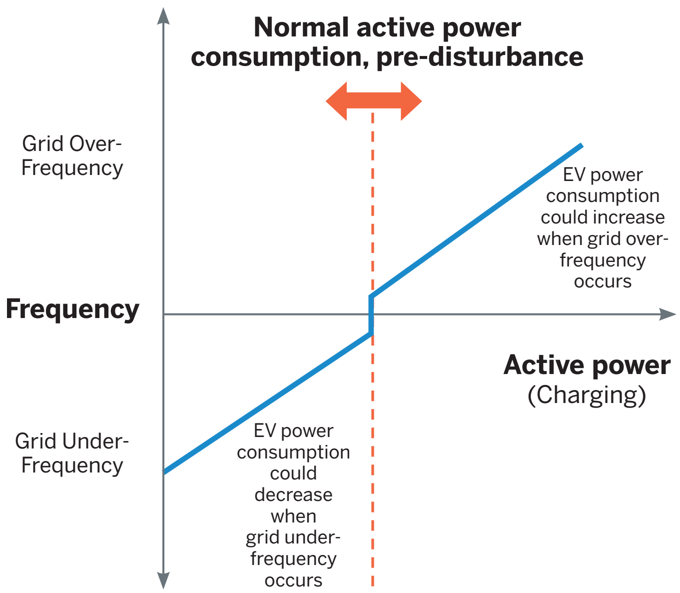
A natural starting point for specifying grid-friendly response characteristics for grid stability time frames—sub-seconds to seconds—is to look to traditional characteristics of some loads and generators that are known to

39 Zhu et al. (2021) compared a standardized volt-VAR curve (the default IEEE 1547-2018 curve) with a customized curve applied to the individual circuit's topology and found that the standard is "good enough" for large station voltage controls, but more fragile locations may require more care.

40 See https://standards.ieee.org/ieee/1547/5915/, https://standards.ieee.org/ieee/1547.9/10875/, https://standards.ieee.org/ieee/1668/6798/, and https://www.sae.org/standards/content/j2894/1_201901/.

FIGURE 23

Potential Frequency-Response Characteristic of an EV

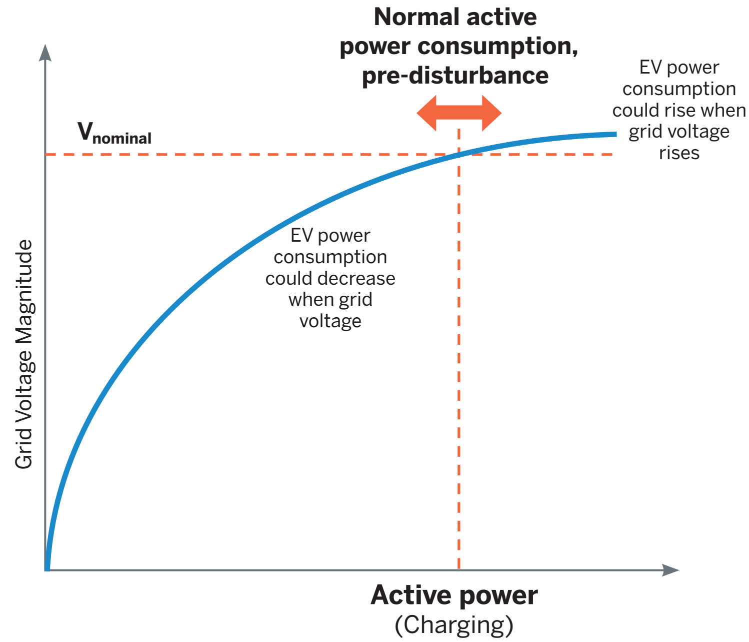


The droop curve (solid blue line) shows how an EV could respond to changes in system frequency according to grid needs. The vehicle's normal active power consumption with normal grid frequency is shown at the intersection of the X axis and the vertical dotted line. When the grid frequency is within a normal range, the vehicle charges and discharges normally. If the grid frequency rises above that range, the EV's active power consumption rises. Similarly, if the grid frequency drops, the EV's active power consumption drops.

Source: Energy Systems Integration Group.

FIGURE 24

Potential Voltage Response Characteristic of EVs



A constant-impedance characteristic would make EVs grid-friendly by responding to changes in distribution voltage. The vehicle's normal active power consumption with normal grid voltage is shown at the intersection of the nominal voltage on the Y axis and the vertical dotted line. If the grid voltage rises, the EV's active power consumption rises along the blue line to the right. Similarly, if the grid voltage drops, the EV's active power consumption drops along the blue line to the left. Similar behavior could be implemented for EVs in discharging mode.

Source: Energy Systems Integration Group.

provide a stabilizing effect for all power systems. Two stabilizing characteristics describe the response of grid-connected EVs to changes in grid frequency and grid voltage—frequency droop response and constant-impedance characteristics—and are applicable for charging operation and discharging (V2G) operation.

The frequency response characteristic is described with a droop characteristic, as shown in Figure 23, that has been used since the beginning of interconnected resources for passive coordination. The droop curve shows that increases in grid frequency, indicative of excess generation on the grid, cause an increase in power consumption (or a decrease in power generation for V2G operations). Conversely, for under-frequency events where the grid is temporarily "starved" for power, the EV would temporarily reduce consumption (or increase power delivery to the grid). This operation is identical to that described in IEEE 2800 for stationary battery resources. Such frequency events on the grid typically last for tens of seconds and occur relatively infrequently, such that there is very little impact to the EVs' state of charge. However, the maximum and minimum power limits of the equipment must be respected, even for brief excursions, which may limit the amount of response delivered by any single EV.

The voltage response characteristic, known as a constant-impedance characteristic, is shown in Figure 24, where the EV appears to the grid as a constant resistance, much the way a conventional toaster oven would appear to the grid. This characteristic gives the EV stabilizing properties during voltage excursions. When grid voltage is low, indicating that the grid is stressed and has a reduced

ability to transfer active power, the EV would reduce its active power charging from the grid, thereby mitigating grid stress.[41] Dynamically, the constant-impedance characteristic exhibits a damping effect that helps to quell oscillations in the grid.

These frequency and voltage responses would have essentially no negative impact on the use and functionality of EVs, while allowing EVs collectively to offer a significant benefit to the stability of the grid at very little cost.

Both of these response functions would operate quickly in the EV inverter controls—with very low latency between detected deviations in the grid and the response of the EV. If implemented properly, these responses would have essentially no negative impact on the use and functionality of EVs, while allowing EVs collectively to offer a significant benefit to the stability of the grid at very little cost. Discrete requests for EVs to connect to the grid can come at all times of the year with different types of information flowing across stakeholders depending on the nature of the request. In addition to the distribution engineering required to evaluate these requests, planning practices related to the energization and interconnection of EVs are captured in Table 8.

TABLE 8

Planning Practices Associated with Energization and Interconnection Processes

PLANNING ATTRIBUTE	
The EV integration process provides information to developers and owners on the locations of available capacity, clearly articulates the needed steps and data, and defines the grid response characteristics expected of EVs.	
Good practices	• The utility provides an overview of the steps and timelines for EV energization and interconnection review. • Data requirements for the utility's EV impact analysis are defined upfront. **Example:** Pacific Gas and Electric has a guidebook for fleet electrification that provides a 15-step process and expected timeline for the utility's process.
Better practices	• The interconnection/energization queue is available, maintained, and transparent to EV site developers. • Load integration maps are publicly available to indicate the distribution system's available capacity at different locations. **Example:** Potomac Electric Power Company (PEPCO) provides an EV load capacity map to guide large-scale electrification toward areas where there is capacity on the system.
Best practices	• The grid-response characteristics of EVs as a load are defined, and consideration for their voltage responsive characteristics is included in the engineering analysis. **Example:** No examples are available in practice, but the Pacific Northwest National Laboratory has simulated of EV load response to transmission faults.

Practices identified by members of the Grid Planning for Vehicle Electrification Task Force.

Source: Energy Systems Integration Group.

41 This characteristic is focused on active power exchange with the grid because it is assumed that the EV is designed to operate at unity power factor with little to no exchange of reactive power.

Coordinated and Holistic Planning

For grid planning for EVs to be successful, utility grid planners and state regulators must coordinate across a wide range of stakeholders, including communities, consumers, vehicle manufacturers, charge station operators, aggregators, and others. Grid planners and regulators will need to navigate the macro trends of policies and consumer interests to implement distribution system plans that appropriately consider the opportunities and challenges that higher numbers of EVs will bring.

Utility planning processes are increasingly adopting an integrated grid planning approach that solicits input on grid plans from key stakeholders and the public at large. EVs will increase the need for these integrated approaches because of their impact at all layers of the power grid.

Coordinating the Approach

Utility planning processes are increasingly adopting an integrated grid planning approach that solicits input on grid plans from key stakeholders and the public at large. EVs will increase the need for these integrated approaches because of their impact at all layers of the power grid. Consumers' behavior will heavily affect how EVs impact the grid, and grid planning will need to consider consumer input and feedback. In addition, utilities will need to coordinate EV assumptions, inputs, and scenarios across planning processes and departments. This includes assessments of equipment standards that influence premise-level plans as well as annual distribution, transmission, and generation planning.

While a distribution upgrade may alleviate an overload in one part of the system, the new distribution capacity could move grid constraints elsewhere. A holistic grid plan ensures that the customers receive the benefits of upgrades wherever they are implemented. For example, upgrading every customer's electrical panel and every service transformer could still leave electric power deliverability insufficient without appropriate upstream capacity.

Smart EV charging, a key enabler of efficient utilization of grid infrastructure, requires coordination among distribution and transmission operators to align charging behavior with grid needs and capabilities. Certain charging behavior suited for the bulk system may not be feasible because of distribution system constraints.[42]

Federal Energy Regulatory Commission (FERC) Order 2222 requires improved coordination to allow for distributed resource aggregations to participate in wholesale markets (FERC, 2020). Regulations will need to evolve along with planning practices to support policy and customer needs. Regulators can consider how to support proactive planning processes, determining how and when to approve projects that aim to address forecasted load growth that has large uncertainties. Beyond distribution projects explicitly aimed at EVs, such as building a new substation for a highway charging plaza, regulators will need to understand the costs and impacts of higher-capacity equipment for distribution components—for instance, increasing standard distribution voltages from 12 kV to 35 kV. While defining the suitability of distribution equipment for a heavily electrified future, regulators will need to understand how and when smart charging

42 See the discussion on smart charging above. Of particular interest is Table 4.

can provide a non-wires alternative for certain types of distribution system investments.

Importantly, utility equipment standards may need to be modified to specify larger (and more expensive) equipment to support EV charging needs. Equipment standards have a large and often understated impact on the grid's ability to support electrification because of the volume of standards-based equipment deployed annually as part of regular utility maintenance. Standards should be continually evaluated as the impact of EVs and the electrification of buildings changes underlying assumptions about customer load that has not seen significant increases in decades.

An iterative and adaptable grid planning approach is called for. Grid plans are preferred that are cyclic, are innovative, and embrace new technologies, as grid planners keep pace with EV growth and learn from early deployments.

Aligning the Grid Planning Process with the EV Use Case

Both reactive and proactive grid planning present challenges. But it's important to navigate these options because of the large climate change policy goals of vehicle electrification. There is a chicken-and-egg problem in which consumers are hesitant to buy EVs without sufficient charging infrastructure in place even as charging providers are hesitant to install charging stations without sufficient EV demand. One approach to balancing proactive and reactive actions is for grid planners and regulators to consider potential future scenarios for the power system by aligning planning processes with the EV use case, including vehicle type, supporting battery technology, and the function of the vehicle. For example, the same passenger van with a 200 kWh battery could be used as a flower delivery service or by a weekend hiking club, with very different charging (and potentially discharging) profiles for the same vehicle type. By focusing on which electrification use cases to enable, the appropriate planning process can be used, ultimately resulting in the appropriate grid design.

Collaborative and Proactive Planning Paradigms

Existing grid planning processes, which are regularly updated and include a medium- to long-term planning horizon (e.g., five years), can integrate EVs under some circumstances (Table 9). However, while existing processes vary significantly across the country in how they consider transportation electrification among other objectives, such as replacing aging assets,[43] they generally

Collaborative and proactive planning approaches could identify the need to build transmission and distribution infrastructure in advance of EV load arising in specific locations.

TABLE 9
Multiple Processes Provide a Holistic Approach to Grid Planning for EVs

Existing Processes
While today's grid planning processes vary across the country, they generally include: • Annual system reviews • Regularly updated grid plans with a medium- to long-term planning horizon • Isolated evaluation of interconnection requests
Customer-Collaborative Processes
A customer-collaborative process between planners and customers allows for open communication about: • Multiple options for interconnection • Multiple locational alternatives
Proactive, Multi-Stakeholder Processes
Given the volume and multiple use cases of EVs, proactive processes can be well suited to: • Ensure access to EV charging for underserved communities and determine where local, traffic-related pollution may be mitigated through vehicle electrification • Facilitate regional networks • Provide clear roadmaps for electrification planning progression

Multiple planning processes can be used together to effectively plan the grid for vehicle electrification. This approach supplements existing processes with customer-collaborative processes and proactive, multi-stakeholder processes.

Source: Energy Systems Integration Group.

43 Some utilities are adopting multi-objective planning that attempts to co-optimize across reliability, electrification, affordability, and other goals. On the other end of the spectrum, some utilities' maintenance processes include like-for-like replacements that effectively refresh undersized equipment that is ill-suited to meet future electrification needs.

will not sufficiently integrate EVs as these vehicles become more numerous and travel between utility service territories. Collaborative and proactive planning approaches could identify the need to build transmission and distribution infrastructure in advance of EV load arising in specific locations. Benefits of these planning approaches include avoiding long wait times for enabling grid upgrades, identifying opportunities for cost savings by making larger upgrades at fewer circuits along travel corridors, and allowing for better community input and consolidation of services around locations where EVs charge. Table 9 outlines how these types of planning processes differ from existing processes.

Existing processes will need to continue to evolve to embrace new planning techniques, including new analytics capabilities and smart charging as tools to effectively design the grid. Even the most advanced utilities in North America can continue to build in new capabilities in grid planning practices. The customer-collaborative and proactive processes move beyond existing processes as follows:

- **Customer-collaborative processes** can help identify the best solutions to fulfill EV charging needs and V2G program participation. There are opportunities to integrate new EV loads without new grid infrastructure, but those can best be identified through conversations and trade-offs between grid planners and EV customers. Fleet owners can expedite planning processes by reaching out to the utility early about potential plans to electrify. Utilities can collaborate by providing options rather than a yes/no response to an EV charging request, such as "yes, with these restrictions." To facilitate the collaboration, utilities can provide dynamic interconnection limits or make use of operating envelope restrictions that vary by time of day.
- **Proactive multi-stakeholder processes** are particularly helpful for regional and long-term planning for EV charging. Some types of EVs (such as long-haul trucks) require coordination across jurisdictions. These processes also help to align grid plans with the needs of communities and articulate a clear multi-year plan. Some jurisdictions already require integrated distribution plans and include electrification considerations in those plans. Multi-stakeholder planning is similar to these proceedings but also includes inter-regional and longer time horizon considerations and is inclusive of different perspectives in the formulation of grid needs and solutions. The ESIG Grid Planning for Vehicle Electrification Task Force identified a wide variety of stakeholders who should be involved, including vehicle manufacturers, charge station operators, distribution utilities, transmission owners, regional grid operators, community-based organizations (leadership as well as constituents), state and local governments, fleet managers, rural communities, urban planners, community developers (single- and multi-family housing, commercial), environmental justice organizations, and large commercial centers or businesses (e.g., malls/town centers).

Large shifts in planning practice will initially be driven by groups of larger EVs—medium- and heavy-duty fleets—and the coordination of regional and national transportation needs, which includes highways and other charging corridors.

Large shifts in planning practice will initially be driven by groups of larger EVs—medium- and heavy-duty fleets—and the coordination of regional and national transportation needs, which includes highways and charging corridors. Another key outcome of proactive planning processes at each of the utility, regional, and national levels is ensuring access to EV charging for underserved communities and determining where local, traffic-related pollution may be mitigated through electrification of medium- and heavy-duty fleets in the area.

Suitability of Different Processes to Address Different EV Charging Needs

Figure 25 (p. 60) articulates the suitability of each type of process—existing, customer-collaborative, or proactive multi-stakeholder—to support a given need for EV charging. The amount of shading in each cell indicates the suitability of that process to support the stated EV charging need.

FIGURE 25

Suitability of Grid Planning Processes to Address EV Charging Needs

Managed Charging of Light-Duty Vehicles		
Existing processes	**Customer-collaborative processes**	**Proactive processes**
• Daily-routine charging • Demand for L1 charging • Elastic demand	• Perceived charging deserts • Service provider requests	• High vehicle deployment • Heavily loaded distribution • Inflexible demand

Charging Along Highways and Corridors		
Existing processes	**Customer-collaborative processes**	**Proactive processes**
• Minimal highway usage	• Along private highways	• Grid limitations along highways • Regional EV growth • Interregional trucking

Charging of Vehicle Fleets		
Existing processes	**Customer-collaborative processes**	**Proactive processes**
• Small fleets • Sufficient highway charging	• Inflexibility in timing and location • Large fleets	• Multiple fleets competing for capacity • Limited land availability

Charging in Underserved Communities		
Existing processes	**Customer-collaborative processes**	**Proactive processes**
• Equity considerations included • Incentives for EV purchase and smart charging	• New multi-family housing	• Insufficient opportunity for charging • MHD vehicles near communities

Each grid planning process can be used to address certain types of EV scenarios, but some processes are more suitable than others depending on the objective. All types are needed to enable widespread vehicle electrification.

Source: Energy Systems Integration Group.

The figure connects each EV charging need to the most suitable grid planning process.

- **Light-duty vehicles** can largely be integrated with existing planning processes as long as demand flexibility can be captured through managed charging and existing distribution infrastructure is not heavily loaded. If infrastructure is already heavily loaded, a long-term proactive plan for distribution upgrades will be needed to enable vehicle electrification.
- **Medium- and heavy-duty fleets** represent a unique combination of opportunity and challenge. Existing planning processes may be sufficient to integrate fleets under some circumstances, but a collaborative back-and-forth is likely needed to arrive at the most affordable and appropriate grid solution for fleet charging needs. The North American Council for Freight Efficiency has recommended early engagement between fleets and utilities to increase understanding of fleets' charging needs (NACFE, n.d.; 2022).
- **Highways** often cross grid planning boundaries and thus require multi-stakeholder input. Planning for the Interstate-5 corridor by the West Coast Clean Transit Corridor Initiative illustrates a best practice for coordinating the charging corridor plan across utilities (WCCTCI, 2020).[44]
- Ensuring EV and charging access to **underserved communities** requires proactive planning, given that affluent early adopters may use up available capacity. The electrification of medium- and heavy-duty vehicles in proximity to underserved communities can also be proactively planned to reduce street-level air pollution where there is heavy truck traffic.

Coordinating Equitable Plans

The fundamental challenges with proactive planning and creating a future-ready power system involve cost allocation and risk management:

44 The West Coast Clean Transit Corridor Initiative is a consortium of utilities working together to assess the feasibility of electrification of long-distance truck travel and goods movement along the Interstate-5 transportation corridor. See https://westcoastcleantransit.com/.

- Who pays for grid upgrades?
- What happens if the load doesn't show up?

Cost recovery for grid upgrades has historically been governed by a complex set of rules that differentiates grid upgrade costs borne by different types of projects. Generally, single-family residences are exempt from any costs associated with service lines and distribution system investments resulting from increased load. However, commercial customers can be responsible for these types of costs, which can sometimes total multiple millions of dollars.[45]

California recently adjusted the rules to "socialize across all ratepayers the costs of service line extensions and electrical distribution infrastructure for EV charging."[46] This decision is aligned with recent California legislation (AB 841) intended to accelerate the deployment of distribution infrastructure to support charging stations. These changes were made in part because it was found that "there is a significant need for more EV charging infrastructure in the near term to meet California's [transportation electrification] and emissions goals."[47] Other jurisdictions may also find it necessary to reconsider their rules governing cost allocation in support of electrification policy goals.

Proactively upgraded grid infrastructure targeting EV charging can be encouraged through regulatory mechanisms as well, although determining the prudence of proactive upgrades can be challenging for regulators. Stakeholders can work together to identify metrics appropriate for evaluating these utility upgrades. A combination of metrics that assess reliability, asset utilization, and levels of vehicle electrification could appropriately incentivize utilities to design distribution systems that support vehicle electrification while balancing other priorities.

Regulatory mechanisms, accounting measures, and policies can align grid planning with the needs of all consumers, providing opportunity and access to electrified transportation. This means that renters can charge their cars because there is sufficient public charging and the latest consumer to buy an EV is not stuck with the entire bill to upgrade the transformer they share with neighbors. These issues are complex and have no regulatory precedent in many areas, but broad stakeholder involvement can ensure that various interests are reflected in equitably planning the grid.

45 Some jurisdictions require customers to pay upfront distribution costs for new loads, while other jurisdictions have customers pay for grid upgrades over time through rates. With uncertainty around EV infrastructure utilization and future rate designs, thorough consideration of who pays for these distribution costs will promote equity.

46 California Public Utilities Commission Decision D.22-11-040, November 2022.

47 Ibid.

Next Steps

Despite interest in and commitments to EVs from customers, manufacturers, and policymakers, grid planning for vehicle electrification remains a challenge, particularly on distribution systems where vehicle charging could quickly overwhelm grid edge equipment. Public charging sites and vehicle fleet depots can be planned, permitted, and constructed much more quickly than other loads such as commercial sites or industrial facilities. Utilities therefore have much less time to upgrade distribution system infrastructure for electric vehicle integration compared with new loads historically.

Depending on the approach, the distribution system can be a bottleneck for vehicle electrification, hamstringing EV adoption, or it can support more sustainable transportation thanks to thoughtful planning. Despite incomplete information about the timing, magnitude, and location of this new EV demand, there are opportunities to lay a grid planning foundation today that will support the evolution of the grid and enable widespread vehicle electrification.

Improve Forecasting

Industry forecasting of vehicle impact can be improved by enhancing adoption and behavior models to consider multiple vehicle end uses, new vehicle technologies, and additional data sources. First, forecasting adoption at a granular level can be achieved through likelihood models informed by costs, policies, and customer preferences, as

well as through new sources of data, such as fleet elec-trification surveys. These adoption models can include locational components and characterize the types of vehicles that will connect to the grid, including the technology that underpins the vehicle (the battery technology, size, and charger). Second, forecasting charging behavior and how the vehicle is used (e.g., school bus vs. city bus) will inform impacts of EVs both temporally and locationally.

Forecasting models that consider these impacts have been developed by leading researchers and industry and will continue to be improved as the underlying data becomes more robust. The two key elements of forecasting —the location and timing of charging—are intertwined, elastic, and changing as EV adoption increases and vehicle technologies progress. Even with the best models and data, forecasts will not capture everything. In time, we will learn how technological, regulatory, and social-human factors will impact EV charging. Embracing the uncertainty around EV adoption and charging patterns through scenario planning helps planners think in broad strokes rather than narrow solutions.

Embrace Smart Charging

Smart charging programs hold great promise for using grid infrastructure efficiently, aligning charging with infrastructure capabilities, and utilizing lowest-cost electricity. Smart charging options using rate designs, automation, or demand response programs can align charging with more affordable energy and reduce total infrastructure needs at every level of the grid from the premise to the bulk system. Targeted smart charging, operating limits, and strategically located storage can help with immediate load growth and remain useful as more solutions are implemented over time.

Smart charging is a central tool in limiting the impact of EVs on distribution infrastructure and can help to minimize the grid upgrades needed to support a transition away from gasoline-powered cars. However, even using the smartest of charging strategies, it may be necessary to upsize distribution equipment, particularly if customers do not participate in demand response programs or will not provide flexibility based on price differentials. There is much still to learn on the practicalities of implementing smart charging, including customer participation, its impact on load diversity, effective and reliable operations, and incorporating it into modeling tools.

Recognizing that smart charging is an imperfect solution with things still to learn, the potential flexibility of EV charging merits fundamental consideration in planning. This goes beyond cursory evaluation and leads to utilities embracing smart charging as a tool to meet the challenges presented by vehicle electrification. In addition to smart charging, grid upgrades will be needed in some areas and the industry will need to continue to use the appropriate solutions to meet the multiple distribution planning objectives.

Incorporate Future-Ready Equipment

The optimal grid plan will likely be some combination of smart charging paired with infrastructure upgrades. More subtle strategies can enable electrification over time, including using future-ready equipment designed to support future load growth from EVs and other sources.

Planning for EVs requires a holistic analysis of the assumptions that drive grid planning decisions. Many of those assumptions are embedded in equipment design standards, which are assessed infrequently, and leading utilities are re-evaluating these design standards because of vehicle electrification. Unfortunately, there is no consensus on optimal designs today as engineers balance uncertain equipment loading levels, driven in part by the diversity of charging behavior, and equipment rating methodologies that are also undergoing innovation thanks to new equipment-ageing methodologies.

This future-ready approach holds promise because the cost of the grid equipment itself is only one part of the cost to replace aging infrastructure. Labor required for planning and installation makes up a large share of the cost of a service transformer upgrade; therefore, the marginal cost of a higher-capacity transformer is often small compared to the costs of replacing or supplementing the transformer in a few years. A national reference quantifying the soft costs of utility equipment and the cost-effectiveness of upsizing could help utilities and regulators think through this strategy within their territory.

Promote Proactive Upgrades Based on Multi-Stakeholder Input

Future-ready grid upgrades that take place over decades may not be sufficient to meet all projected EV charging needs, and specific locations within a region may need upgrades before the existing equipment has reached the end of its expected lifespan. Widespread just-in-time upgrades of distribution equipment to support the level of electrification projected would likely be both costly and infeasible for utility construction crews. Distribution utilities can be proactive, and by using improved, granular forecasts while working with a multi-stakeholder group, can prioritize areas for targeted upgrades that balance the asymmetric impacts of over- and under-building the distribution system.

Proactive upgrades could include larger equipment, new equipment, or non-wires alternatives, such as batteries or behind-the-meter generation. These upgrades will balance the short-term with the long-term as we learn more about charging needs. Regulatory and policy efforts may be needed to support proactive upgrades because these upgrades may not be "used and useful" when they are first implemented.

While much of distribution system planning has traditionally been handled by utilities, the role of state legislators, regulators, and other state officials will continue to grow as multiple power grid objectives compete for priority. Similarly, retail rate designers, vehicle manufacturers, and charge station operators will need to work with grid planners to design solutions that balance the cost of new infrastructure with customer charging flexibility. And the need to ensure equity in designing the grid that supports an electrified future is best accomplished through a broad range of stakeholder input.

As air conditioning loads transformed customer demand in the 1960s/1970s, grid planners innovated by pairing large grid build-outs with demand response. Thanks to their lead, we do not need major technological innovation to meet EV demand. We know how to meet large demand growth; we have done it before. We do, however, need to quickly understand the magnitude of change that will be required and take action. Because of the multi-billion-dollar scale of these grid planning decisions, coordinated and holistic planning is needed to design grid architecture that effectively balances uncertainty around EV adoption (and when and where vehicles will charge), which can lead to an overly cautious investment approach, with ensuring the grid is adequately prepared for EVs. Grid planning for vehicle electrification is an opportunity to further integrate the energy systems that power our lives while establishing a platform for a wholly sustainable future.

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Charging Ahead: Grid Planning for Vehicle Electrification

A Report of the Energy Systems Integration Group's Grid Planning for Vehicle Electrification Task Force

The report is available at https://www.esig.energy/reports-briefs.

To learn more about ESIG's work on this topic, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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NOVEMBER 2022

REGULATORY ASSISTANCE PROJECT

Using Benefit-Cost Analysis to Improve Distribution System Investment Decisions

Issue Brief

John Shenot

Contributing authors: Elaine Prause and Jessica Shipley

I. Introduction[1]

This issue brief explores the many opportunities for electric utilities and public utility regulators to use benefit-cost analysis techniques to evaluate potential investments. The foundational premise of the issue brief is that these techniques can contribute to decisions that better serve the public interest than decisions made solely based on traditional least cost methods. Benefit-cost analysis is, to put it simply, a superior tool to other analytical methods in many (but not all) cases. Increasing its use in utility regulation can result in better outcomes for ratepayers and society.

Benefit-cost analysis techniques can contribute to decisions that better serve the public interest than decisions made solely based on traditional least cost methods.

For those interested in a more thorough treatment of this topic, we are simultaneously publishing a reference report as a companion to this issue brief that offers more detail on the subjects covered herein as well as examples from state regulatory proceedings.[2]

[1] The authors wish to thank the following people for providing helpful insights into early drafts of this issue brief: Tim Woolf, Synapse Energy Economics, and Patrick Hudson, Michigan Public Service Commission staff (retired). Ruth Hare and Steena Williams of RAP provided editorial support.

[2] Shenot, J., Prause, E., & Shipley, J. (2022). *Using benefit-cost analysis to improve distribution system investment decisions: Reference report.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/using-benefit-cost-analysis-improve-distribution-system-investment-decisions-reference-report

Background

Historically, utility regulators have exercised relatively limited oversight with respect to the maintenance and operation of the electric distribution system. For the most part, regulators have relied on utility experts to make prudent decisions about investments in the distribution system that are necessary to accommodate growth, replace failing assets and ensure power quality. During rate cases, past utility investments may be reviewed for prudence and future distribution system spending budgets may be determined as part of establishing the revenue requirement, but individual distribution system investment options are rarely scrutinized.

For a variety of reasons, regulators in recent years have increasingly turned their attention toward the distribution system:

- Some utilities, particularly those in restructured states, do not own generation assets and might not own transmission assets, yet their operation of the distribution system is still regulated by a state public utility commission (PUC) or public service commission (PSC).
- The vast majority of service outages occur due to problems on the distribution system, not because of problems on the high-voltage transmission system or inadequate generation resources.
- Among investor-owned electric utilities throughout the United States, distribution system spending is increasing as a share of total utility capital investment and operational expenses.
- Investment in distributed energy resources (DERs)[3] has grown rapidly.
- In addition to building out the system to accommodate load growth, and replacing aging or failing assets, new utility investments are needed to modernize the grid — especially at the distribution system level.

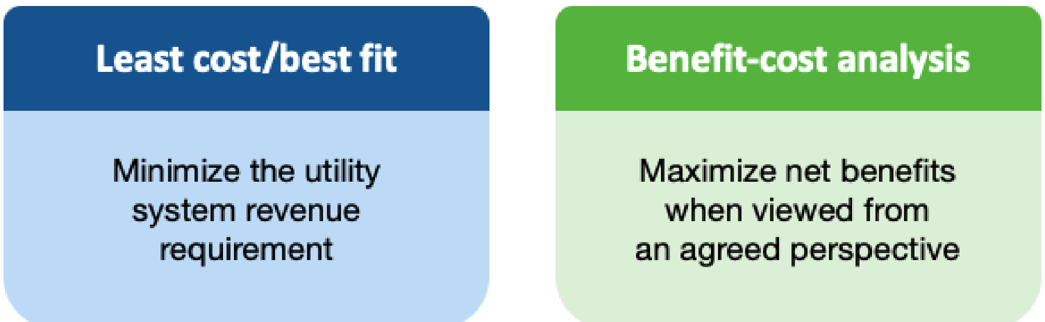
Regulators today are paying closer attention than ever to individual distribution system investment decisions, more frequently requiring utilities to transparently evaluate alternatives to meet customer needs, and increasingly requiring utilities to file long-term distribution system plans (DSPs). This increased scrutiny is sometimes applied to traditional distribution system assets like substations and transformers but is even more likely to be used to evaluate “grid modernization” investments.

[3] States vary in how they define DERs. Most states limit this term to resources interconnected to the distribution system or operating behind the customer’s meter. In terms of resource types, most DER definitions encompass a subset of energy efficiency, demand response or “flexible loads,” distributed generation, distributed energy storage, microgrids and electric vehicles.

Two Common Approaches to Evaluating Utility Investments

This issue brief compares two analytical approaches that can be used to evaluate utility investments in DERs and the distribution system and ensure that investments in grid modernization are smart: least cost/best fit (LCBF) techniques and benefit-cost analysis (BCA) techniques. Figure 1 summarizes the approaches.

Figure 1. Two analytical approaches to evaluating investments



Least cost/best fit: We categorize analytical methods as LCBF if decisions are made by comparing the total costs of investment alternatives over a defined period of time, including capital costs as well as operations and maintenance costs, and identifying the options that minimize the net present value of the revenue requirement associated with the entire power system, or in some cases just a portion of the power system (e.g., just the transmission system).

Occasionally, an option may be chosen that isn't technically the least cost solution (doesn't minimize the revenue requirement) but is considered the best fit — for example, because it reduces uncertainty about future operations and maintenance costs. The benefits associated with each investment alternative do not need to be identified or quantified. LCBF methods are typically used when action is needed, or presumed to be needed, and the goal is simply to minimize the cost.

Historically, utilities have relied on LCBF techniques to make decisions about investments in utility-owned infrastructure like power plants, transmission lines, substations or systems monitoring equipment or to evaluate power purchase agreements and other utility contracts with vendors. After the utility identifies something that is needed to maintain safe and reliable electric service or extend service to a new area, it then seeks the least costly way to meet the identified need in a manner that complies with all applicable legal requirements.[4]

[4] Options that do not satisfy all applicable legal requirements are not considered "solutions" to an identified need. This distinction is important but easily overlooked. For example, if a utility is subject to a renewable portfolio standard, it will seek to minimize the costs of meeting customer demand *while complying with that standard*. This is consistent with minimizing the revenue requirement because utilities include the costs of complying with legal obligations in the revenue requirement.

Benefit-cost analysis: In contrast, we apply the term BCA to methods that compare the costs and benefits of investment alternatives to assess and *maximize the net benefits* (i.e., benefits minus costs) when viewed from an agreed perspective.[5] This can include situations where the options being considered include the status quo or a "take no action" alternative.

For decades, utilities, PUCs and independent evaluators have used BCA methods to assess whether certain types of utility expenditures will be (or in retrospective evaluations, were) cost-effective. The most common and widespread use of BCA has been for evaluating utility programs offered to customers, such as incentive programs that support energy efficiency or other DERs. BCA has also been used in many cases to evaluate utility investments in new technologies, such as advanced metering infrastructure, or other assets.

Before going any further, we must acknowledge that the lines separating LCBF methods from BCA methods can be blurry. There are at least two reasons for this:

1. Some of the benefits of almost any utility program or investment come in the form of reducing the revenue requirement — for example, by reducing total systemwide demand or peak demand through an energy efficiency program. When benefits come in the form of reducing the revenue requirement, they are considered in both LCBF and BCA methods. But benefits that don't reduce the revenue requirement, such as increases in homeowner comfort or employee productivity that might result from some energy efficiency measures, are usually not considered in an LCBF approach.

2. In some cases the "best fit" part of an LCBF-based decision may take into consideration costs and benefits that have nothing to do with the revenue requirement, such as reductions in greenhouse gas emissions beyond any existing legal requirements.

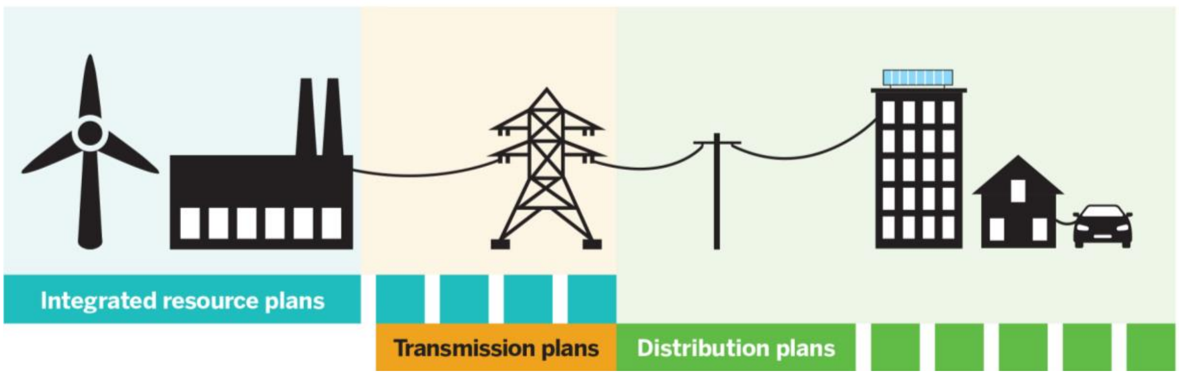
Regardless of any differences over terminology or the way we've characterized LCBF and BCA, we hope readers will agree there are differences between these two methods and opportunities to use BCA in new and better ways to improve decisions.

[5] The perspectives that might be considered are explained in more detail in Section III of this issue brief.

II. Use of LCBF Techniques in Utility Planning

Many utilities are required by state laws, state rules or PUC orders to prepare and file detailed long-term investment plans for satisfying their customers' demand for electricity. Other utilities not subject to these requirements may develop similar plans for internal use. Long-term planning processes have historically focused on only one part of the electric power system at a time (see Figure 2).

Figure 2. Scope of typical long-term planning processes by electric utilities



- Integrated resource plans (IRPs) typically focus on generation resource adequacy, though they sometimes also address transmission capacity needs associated with acquiring new generation resources.
- Transmission plans focus on ensuring adequate transmission capacity to serve peak demands and, in some cases, relieving congestion between low-cost generation resources and load centers.
- Distribution system plans focus on minimizing distribution system costs, but generation and transmission costs may be considered as well. DSPs are a relatively new development for utility commissions, with a small number of states instituting a regulated DSP process in the past few years and additional states now developing rules or investigating distribution system planning. Prior to these recent developments, DSP activities in virtually all jurisdictions were conducted by utilities in-house with little or no regulatory oversight or transparency. DSP processes vary from state to state in terms of which types of investments fall under the scope of the planning process.

In each case, LCBF techniques are normally used to make most planning decisions, though there are many examples (as we will see later in this issue brief) of using BCA methods in concert with LCBF.[6] DSP processes are more likely than integrated resource planning or transmission planning to incorporate benefit-cost analysis — for example, as a way of testing whether DERs can cost-effectively substitute for some infrastructure investments.

[6] And, as previously noted, non-utility-system costs and benefits may sometimes be evaluated in these plans to arrive at the "best fit" solution.

III. Use of BCA Techniques

Benefit-cost analyses are used to assess whether an expenditure a utility is considering (or has already made) is cost-effective. An expenditure is cost-effective if its lifetime benefits exceed its lifetime costs, as examined through an agreed perspective and cost test. BCA techniques are routinely used to evaluate utility demand-side management programs in most states and are sometimes used to evaluate other types of programs or expenditures.

The essence of BCA is a comparison of two or more potential courses of action. The analyst first looks at the marginal impacts (ideally, long-run marginal impacts) of a proposed expenditure on grid capacity needs and how the power system is operated, when compared to an assumed reference case. The analyst then looks at the costs or avoided costs associated with those marginal impacts. Depending on the cost test used, additional non-utility-system costs and benefits (or avoided costs) may also be assessed.

The essence of BCA is a comparison of two or more potential courses of action.

Perhaps the most crucial decision that must be made before conducting any BCA is the selection of a perspective from which to evaluate costs and benefits. This is because some of the costs and benefits of an expenditure can look different when viewed from different perspectives.

For decades, state PUCs have borrowed ideas from a BCA manual published by the California Public Utilities Commission and adapted them to meet their own needs. The *California Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects*[7] defines five cost-effectiveness tests and offers a standard methodology for conducting each test. Each test considers the question of cost-effectiveness from a different perspective.

The *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM) is the most up-to-date reference available on BCA principles.[8] A key contribution of the NSPM is that it offers a structured framework and set of guiding principles for states to develop their own jurisdiction-specific test (JST). Table 1 on the next page compares the JST with traditional cost tests described in the *California Standard Practice Manual*.[9]

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[7] California Public Utilities Commission. (2001). *California standard practice manual: Economic analysis of demand-side programs and projects*. https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf

[8] National Energy Screening Project. (2020). *National standard practice manual for benefit-cost analysis of distributed energy resources*. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

[9] Adapted from Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013). *A framework for evaluating the cost-effectiveness of demand response*. U.S. Department of Energy and Federal Energy Regulatory Commission. https://www.ferc.gov/sites/default/files/2020-04/napdr-cost-effectiveness.pdf; and National Energy Screening Project, 2020.

Table 1. Cost-effectiveness tests

Test	Perspective	Key question answered	Impacts accounted for
Participant cost test[10]	Customers participating in a program	Will program participants' costs be reduced?	Includes the benefits and costs experienced by the customers in the program
Ratepayer impact measure[11]	Impacts on rates paid by all customers	Will utility rates be reduced?	Includes the benefits and costs that will affect utility rates, including utility system benefits and costs plus lost revenues
Program administrator cost test/ utility cost test	The utility system	Will utility system costs be reduced?	Includes the benefits and costs experienced by the utility system
Total resource cost test	The utility system plus participating customers	Will utility system costs plus program participants' costs be reduced?	Includes the benefits and costs experienced by the utility system, plus benefits and costs to program participants
Societal cost test	Society as a whole	Will total costs to society be reduced?	Includes the benefits and costs experienced by society as a whole
Jurisdiction-specific test	Regulators or decision-makers	Will the cost of meeting utility system needs while achieving policy goals decrease?	Includes utility system costs and benefits and any additional costs and benefits associated with achieving applicable policy goals

Sources: Adapted from Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013). *A Framework for Evaluating the Cost-Effectiveness of Demand Response*; and National Energy Screening Project. (2020). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*

Every state that mandates energy efficiency programs currently uses one or more of the tests identified in Table 1 to evaluate programs and projects, albeit in some cases with state-specific modifications. Most states designate one of the tests as their primary test for making decisions. Current state practices for evaluating energy efficiency programs can be compared by reviewing the *Database of State Practices* maintained by the sponsors of the NSPM.[12] It details which cost tests are used and how they are applied in each state.

[10] The participant cost test provides useful information about whether participating customers will save money and thus the likelihood that customers will participate in the program, but it is not helpful for deciding whether the utility should offer the program and is never used as a primary test.

[11] The ratepayer impact measure is identical to the program administrator cost test, except that the ratepayer impact test also treats utility lost revenues as a cost. As explained in the NSPM, evaluating the potential impacts of a DER program on retail rates is subtly different from a true benefit-cost analysis and should be conducted only as an adjunct to other cost tests, never as a primary test.

[12] National Energy Screening Project. (2021, April 1). *Database of screening practices*. https://www.nationalenergyscreeningproject.org/state-database-dsp/

IV. Comparing LCBF and BCA as Investment Decision-Making Tools

LCBF methods begin with an attempt to find the least cost solution to identified resource or grid needs from the utility perspective. The least cost solution is then modified in some cases to select a best fit solution that is not strictly least cost under assumed baseline conditions. But for now, consider a case where the least cost solution is in fact also the best fit solution. What would we expect to happen if alternative or additional expenditures are proposed and subject to BCA?

If the LCBF exercise considered every potential solution to grid needs, if the BCA used the program administrator cost test/utility cost test (UCT),[13] and if the two types of analysis used the same data assumptions, then in theory none of the proposed alternative or additional expenditures would pass the test. In other words, if LCBF yields a least cost solution for the utility system, then the proposed expenditures subject to BCA won't reduce utility system costs (i.e., the revenue requirement). One might then argue that BCA is unnecessary at best and a waste of time and resources at worst. But this is where theory runs into the reality of LCBF and BCA techniques. The two techniques can lead to divergent conclusions for the following reasons, which we explain in more detail in this section:

- Use of costs tests other than the UCT.
- Practical limitations of power sector modeling.
- Timing of different evaluations.
- Level of detail in analysis/modeling.
- Differences in whether the evaluation looks holistically across the generation, transmission and distribution portions of the power system.

First, one must start by acknowledging that as of August 2022, only six jurisdictions used the UCT as their primary test, according to the *Database of State Practices*. The moment one considers using a test other than the UCT, the biggest differences between BCA and LCBF become readily apparent. BCA quantifies all costs and benefits relevant under the chosen cost test, while LCBF (as we use the term in this issue brief) quantifies avoided utility system costs but no other categories of relevant benefits.[14] BCA allows for decisions that maximize net benefits, while LCBF allows only for decisions that minimize costs.[15] If an action will have significant non-utility-system benefits that are included in the cost test

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[13] The term "utility cost test" is frequently used as a substitute or synonym for the program administrator cost test in recognition of the fact that most customer-facing programs are in fact administered by utilities. There is no methodological difference.

[14] Again, we acknowledge that others may define LCBF differently. For example, some jurisdictions may impute a cost per ton of greenhouse gas emissions, which is not actually part of the utility system revenue requirement, and include the imputed costs in what they call a least cost or LCBF decision-making framework. However, this is not an LCBF as we define the term in this issue brief, but rather an example of using BCA concepts to supplement LCBF results, which we encourage. In any event, it is an example of how the lines between LCBF and BCA can be blurry.

[15] While it is possible that the best fit adjustment to a least cost evaluation might replicate some aspects of a total resource cost test, societal cost test or JST framework, the non-utility-system impacts included in those tests can be more accurately and more transparently accounted for using BCA techniques, because one only needs to quantify the marginal impacts from specific proposed expenditures rather than trying to quantify the non-utility-system impacts of all potential expenditures.

chosen by a jurisdiction, the action could easily maximize net benefits while not minimizing costs.

Even in states that use the UCT as their primary test, there are still several reasons why BCA and LCBF may lead to different conclusions. In practice, it is virtually impossible to construct workable models for planning processes that consider every potential solution to every potential need. This problem is addressed through two common shortcuts:

Assuming that existing grid assets will remain on the system. Resource planning processes almost always seek LCBF solutions to identified *incremental* system needs. They focus almost exclusively on finding ways to satisfy load growth, though they do also seek to replace any capacity that is scheduled for retirement. But until recent years, planners have generally assumed as a shortcut that existing grid assets are part of the LCBF solution and will remain part of the system unless and until they are scheduled for retirement as a result of some separate evaluation. Because of this simplified approach, the possibility that existing assets could be replaced *before* their scheduled end of life by lower-cost solutions is not always examined as part of the utility's planning process. Wherever this kind of shortcut persists, BCA methods can readily be used to evaluate whether early retirement of specific power plants would reduce the revenue requirement (or, under a different cost test, increase net benefits).

Treating DERs differently from utility-scale assets. This is done in large part because it is easier to model utility-scale assets. For example, modeling the impact of adding a 1,000 MW utility-owned power plant at a specific location on the grid requires far less computational power than modeling hundreds of thousands of individual customer-owned solar photovoltaic systems rated at less than 10 kW each that are scattered all over the system. To make matters worse, some DERs pose their own modeling challenges because their impact on the system depends on day-to-day operational decisions made by customers, not by the utility. This is especially true for distributed energy storage solutions and electric vehicle charging but also true for demand response. Out of necessity, power system modelers make simplified assumptions about how those DERs will operate. They can model different scenarios with different assumptions, but the models cannot possibly compute every theoretical combination of assets and how they are operated to arrive at a true least cost solution. Instead, the most common approach is to assess likely scenarios for DER growth outside of the resource planning models, and then use the results of the exogenous DER assessments to modify the load forecast that goes into the planning process. This approach has a serious limitation, however, because there is no guarantee that utility-scale resources selected via the planning process will actually cost less than adding even more DERs than was determined exogenously. A detailed BCA of a specific DER proposal may find that the proposal reduces the revenue requirement below what the simplified modeling identified as the LCBF solution.

Timing differences can also cause these two techniques to lead to different answers even if BCAs are conducted using the UCT. Utility IRPs are huge undertakings; for that reason, most states require utilities to update them only every two or three years. Transmission plans and DSPs may be updated more or less frequently (usually more frequently) but are rarely completed on the same schedule as IRPs. In the intervals between different types of plans (for example, between the issuance of an IRP and the start of a DSP process) or the periods in between updates of a single type of plan, utilities or others may have reason to propose expenditures that were not included in the most recently issued plan. In those cases, it makes little sense to evaluate the proposed expenditures using the exact same data assumptions as the recent plan, if different and more accurate data are available today. For example, because energy storage costs have plummeted faster than expected, it would be unwise to assess a utility energy storage proposal today using data assumptions about storage costs from an IRP completed three years ago. A BCA might reveal that a storage project that was not included in the LCBF portfolio three years ago is cost-effective today even under a UCT.

Because BCA is used to evaluate specific proposed expenditures, rather than every possible solution to meeting a grid need, it is possible to look at costs and benefits associated with those proposed expenditures in much greater detail than is normally done with LCBF. This, by itself, can generate different answers from an LCBF evaluation even if the UCT is used. For example, the models used for IRP purposes might make little or no attempt to minimize costs for ancillary services, but with BCA the costs and benefits of a demand response program or energy storage system that is designed specifically to provide needed ancillary services can be assessed in exacting detail, perhaps revealing that those DERs can reduce the revenue requirement.

And that brings us to the final reason why BCA can lead to different (and better) decisions than total reliance on LCBF methods, even in jurisdictions that rely on the UCT. As we've already noted, most planning processes focus on only one portion of the electric power system: generation, transmission or distribution. To keep the analysis manageable, the LCBF approach described above identifies the least costly way of meeting identified needs *for that portion of the system*. But because BCA is only used to evaluate specific options, rather than all options, a more detailed examination of costs and benefits across all parts of the electric power system is possible. So, for example, one can imagine a hypothetical case where an IRP process finds that a new power plant is the least costly way to meet future needs for power generation. But a BCA might reveal that a distributed energy storage solution which costs more than the power plant (while providing equivalent contributions to resource adequacy) will reduce distribution system costs and, considering all parts of the power system, be cost-effective under a UCT.

For all these reasons, it is entirely possible that BCA techniques will reveal utility expenditures (for utility assets or for DER programs) that reduce the revenue requirement (i.e., pass the UCT) compared to the portfolio of assets identified in an IRP, transmission plan or DSP. If a different cost-effectiveness test is used, there is an even greater likelihood that some expenditures will be cost-effective because additional potential benefits will be quantified. This conclusion does not diminish the value of LCBF techniques; rather it underscores the usefulness of both methods in certain circumstances.

V. When Might BCA Be Used?

Utility regulators have historically used BCA techniques primarily to assess energy efficiency and demand response programs.[16] Almost every state is familiar with this practice. In the past decade, however, utilities and regulators have increasingly used BCA methods in other contexts, such as those shown in Table 2, to inform a broader set of regulatory decisions. The detailed reference report published as a companion to this issue brief provides insights into the circumstances or conditions under which BCA might be used in some of these proceedings to improve regulatory outcomes. The reference report includes links and further details regarding the specific state examples noted in Table 2. Armed with this information, regulators can decide whether they wish to expand the use of BCA methods in their own jurisdictions.

Table 2. Regulatory proceedings where BCA techniques are increasingly being used

Type of regulatory proceeding	Goal of BCA	State PUC examples cited in reference report
Customer-facing DER programs	Determine whether to implement a program and/or how to design the program	Energy efficiency: CO, MI, UT Demand response: CA, CO, IL, MI, PA, UT Building electrification: CO Distributed generation: PA, WI Distributed storage: CT, MA, MI
Distribution system infrastructure investments	Determine whether to make the investment	Advanced metering infrastructure: AR, CT, MA, MD, ME, NY, VT Electric vehicle charging infrastructure: CO, MI, NY Energy storage: MD Grid modernization: CA, HI, MI
Long-term plans (IRP, transmission and DSP) and procurement of nonwires alternatives	Determine optimal DER investment levels and contributions to preferred resource portfolio	Determining investment levels for energy efficiency and demand response: CA, ID, OR, UT, WA, WY Identifying locational net benefit opportunities: CA Evaluating nonwires alternatives to utility infrastructure: MI, MN, NV, NY, OR, RI
Rate cases/rate design	Determine the value of DER as basis or justification for compensation rates	AR, CA, DC, GA, HI, LA, ME, MN, MS, NV, NY, OR, SC, UT, VT
Performance-based regulation	Determine value of utility incentives	Energy efficiency programs: AR, AZ, MN, MO

[16] To be more precise, in nearly all cases a utility or another party conducts the BCA and then enters the results into the record of a utility commission proceeding.

VI. How Might BCA Be Used to Optimize Investment?

While recognizing that there is a long and rich tradition of papers, reference reports and regulatory decisions addressing the question of *how* to evaluate utility investments, we view the NSPM as the essential document for anyone interested in understanding how to apply BCA methods to DERs or almost any kind of utility investment. In addition, the same team that created the NSPM published a companion document in 2022 that provides more details on methods, tools and resources for conducting BCA studies.[17]

Rather than summarizing the content of the NSPM, in this issue brief we will instead focus on five crucial questions regulators must answer as they shape BCA policies for their jurisdictions. The answers to these questions can strongly influence the extent to which a BCA furthers the public interest and leads to better investment decisions. This issue brief cannot tell regulators the "right" answers to these questions, but we will suggest some factors for regulators to consider as they develop their own answers and, where possible, note some examples of commissions that are trying to tackle these issues.

1. In what proceedings will we use BCA methods?

BCA methods can point the way to smarter utility investment decisions, but a BCA can also be complex, costly and time consuming. State regulators can protect the public interest and the interests of ratepayers by encouraging or requiring parties to use state-of-the-art BCA methods when and where doing so is appropriate. The fundamental question for regulators will always be, perhaps ironically, whether the benefits of doing a BCA will exceed the costs. This will always be a judgment call, since the two variables in that equation can never be known until the BCA itself is completed. We suggest that regulators consider opening a proceeding or hosting a workshop to consider this specific question in the broadest sense — that is, to consider what types of proceedings are suitable for using BCAs. Or regulators can pose the question in specific dockets where BCA methods might be used and solicit responses from the parties.

Regulators in some states have hosted workshops with presentations from invited subject matter experts to explore the question of when and how to use BCAs in specific regulatory proceedings — for example, a DSP investigation in Illinois, a transportation electrification docket in Oregon, a distribution planning workgroup in Michigan and a grid modernization initiative in New Mexico.

2. Who will conduct BCAs?

Utilities will sometimes present regulators with a BCA they completed or a contractor completed on their behalf. But in other cases, the regulators themselves may come to appreciate that a BCA would be helpful in making decisions, and a key question then becomes, whom should they direct to do the work and who will oversee it? The answers

[17] National Energy Screening Project. (2022). *Methods, tools and resources: A handbook for quantifying distributed energy resource impacts for benefit-cost analysis*. https://www.nationalenergyscreeningproject.org/resources/quantifying-impacts/

could involve a utility, a contractor, commission staff or another state agency. Furthermore, the PSC might consider ordering a utility to provide data and otherwise cooperate with a party to a proceeding that wishes to complete its own BCA and submit it into the record.

3. How will we engage stakeholders?

There is considerable variability among the states in how stakeholders have been allowed to participate in developing, contributing to or reviewing BCAs. In some states, the answer to this question has even varied across different types of proceedings.

Our research finds that it is standard practice to allow stakeholders to review and comment on filed BCA results before regulators make a final decision, but regulators need to also think about whether BCA results will be presented in a sufficiently detailed and transparent manner for stakeholders to meaningfully review them.

Some of the other key aspects of this decision revolve around whether stakeholders will be participants or spectators in or completely excluded from the following key steps that occur before a BCA is completed and results are filed at the PSC:

- Designing or deciding on the cost-effectiveness test(s) that will be used.
- Choosing scenarios, portfolios or test cases that will be evaluated.
- Selecting BCA input data sources or assumptions.

In several jurisdictions, task forces or working groups have been established that allow many parties to play an active role, as full participants, in energy efficiency potential studies, program plans and evaluations. To name just two examples, the Northwest Power and Conservation Council established the multiparty Regional Technical Forum (https://rtf.nwcouncil.org/) to help quantify the costs and benefits of energy efficiency measures. The results are used by utilities and regulators across a four-state region. And in 2013, the Arkansas PSC ordered the creation of an ongoing multistakeholder group that came to be called the Parties Working Collaboratively. Although these two examples apply only to energy efficiency programs, there is no reason why stakeholders could not or should not be proactively involved in decisions about how to conduct BCAs for other investment decisions.

4. Which cost-effectiveness test(s) will we use?

As we explained in Section III, the question of whether an investment is cost-effective depends on the perspective from which costs and benefits are tallied. Different tests evaluate cost-effectiveness from different perspectives. For the purposes of reviewing energy efficiency programs, most states have chosen to use one test as their primary test for making decisions, even though they often review BCA results from more than one perspective. However, many states have not decided on a primary cost test that applies to other DERs, let alone all DERs or all types of distribution system investments.

One of the most consequential decisions regulators must make for any proceeding in which they will request BCA results is to decide on a primary cost test. We believe that regulators will find no better source of guidance in making decisions about BCA policies than the NSPM. The manual offers regulators a set of principles that can guide their selection of a cost test and their decisions on many detailed questions about how to apply BCA methods. It also describes a clear five-step process that regulators can use to design their own tailor-made JST.

Reviewing the cost tests currently in use in any jurisdiction can be a significant undertaking, even more so if that is but the first step in changing the tests to be used or developing a JST. It is not something regulators should undertake casually. However, jurisdictions that are inconsistent in the tests they use for different DERs run the risk of allocating resources in suboptimal ways, spending too much on one type of DER and too little on another. The larger the scale and the faster the pace of investment, the greater the risk. Jurisdictions may also be evaluating resources in ways that are inconsistent with established environmental or social policies, which can interfere with or increase the cost of meeting those policy goals. Getting the cost tests "right" can help to address this problem. We suggest that each jurisdiction weigh the risks of making bad investment decisions against the cost of reviewing and updating the BCA tests they use.

Several states, in fact, have already embarked on designing their own JST for energy efficiency programs, following the recommended steps in the NSPM. The sponsors of the NSPM have published case studies describing efforts in Arkansas, Minnesota, New Hampshire and Rhode Island.[18] These case studies provide a good preview of what regulators in other states pursuing a JST might expect to happen. In addition, the reference report published as a companion to this issue brief cites examples from two states (California and New York) that have established a uniform BCA framework for all DERs and two examples of states (Maryland and Washington) that have open proceedings investigating a uniform BCA framework for all DERs.

We note that there are many challenging aspects of applying BCA methods beyond merely choosing (or designing) a cost test. These include questions about how to quantify and monetize DER impacts, especially difficult-to-quantify impacts like safety, resilience, energy security, equity and risk impacts. Selecting a discount rate to apply to future year benefits and costs is another difficult, controversial topic. Fortunately, the newly published companion document to the NSPM (*Methods, Tools and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis)* offers fairly detailed guidance on how to address some of these questions.

Although it is helpful to use consistent BCA tests and methods for all types of resources, some states may find it impossible or impractical to revamp all their evaluation practices all at once. In those cases, incremental steps toward a consistent approach can be taken each time a relevant proceeding is adjudicated.

[18] National Efficiency Screening Project. (n.d.). *Application of NSPM — case studies*. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/nspm-application-by-state/

5. How will we use BCA results to make decisions?

Although this issue brief encourages regulators to make greater use of BCA methods, we do not intend to suggest that the quantitative results of a BCA should bind the hands of decision-makers. Regulators have discretion in how they exercise their authority, including discretion over whether and how they will use BCA results to inform their decisions.

A variety of practices can be observed as one pores over the many examples of BCAs used by state regulators. We see cases where regulators have chosen to use BCA results in the following ways:

- As the determinative factor in preapproving investment decisions or allowing cost recovery for past decisions — for example, in approving a proposed utility investment in energy storage or advanced metering infrastructure.
- To establish investment budgets or ceiling prices for procurement — for example, energy efficiency program budgets.
- To design programs or retail rates — for example, in choosing an incentive level for demand response program participation or a compensation rate for energy exported by customers with solar photovoltaics.
- To set investment priorities — for example, in deciding which utility grid modernization investments to do first.
- To determine monetary incentives for a utility or program administrator operating under a performance-based regulatory regime.
- As supplemental information — for example, as one of many quantitative and qualitative factors considered when comparing potential utility investments or deciding if a particular utility investment is in the public interest.

VII. Conclusion

Least cost/best fit methods still have a significant role to play in making decisions about electric utility investments and probably always will. However, benefit-cost analysis methods can play a much bigger role in the power sector transformation we see happening today and can contribute to better decisions about distribution system investment.

Opportunities abound for using BCA in a wide variety of proceedings to improve investment outcomes, thereby maximizing net benefits (from an agreed perspective) rather than simply minimizing costs. In addition to their traditional use in planning and evaluating energy efficiency programs, BCA methods are increasingly used to evaluate other customer-facing DER programs, such as incentive programs for demand response, behind-the-meter energy storage and electric vehicles. BCA methods can also be applied to decisions about utility investments in infrastructure, either as a stand-alone proceeding, in a rate case or as part of a long-term planning process. And finally, for those DERs that can inject energy into the distribution system, state utility commissions have reviewed BCA results to inform decisions about net metering tariffs and other retail rate designs. Examples of all these uses of BCA are documented in detail in the reference report published as a companion to this issue brief.

Public utility commissions will play a large role in determining whether and when BCA methods will be used to evaluate investment options. They can also dictate whether utilities, commission staff or other parties will conduct the BCAs, whether stakeholders will be active or passive participants in the analysis, what costs tests and methods will be used and how the BCA results will be used when it is time to make investment decisions. None of this is easy, but in many cases the level of effort that is required to do a BCA can easily be justified because it supports and validates decisions that optimize benefits, avoid expensive mistakes and protect ratepayers and utility shareholders.

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