2018 General Rate Case
Rebuttal Testimony

Policy

Before the
Public Utilities Commission of the State of California

Rosemead, California
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I.

INTRODUCTION

At the outset of our rebuttal showing, I would like to thank the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), Coalition of California Utility Employees (CUE), and each of the other intervenors for their efforts in reviewing and assessing our showing. This has been a substantial undertaking. SCE’s direct showing consists of 50 volumes of prepared testimony and 4 volumes of supplemental testimony, and approximately 22,500 pages of supporting workpapers. SCE also responded to nearly 8,000 data requests. Finally, SCE presented at several “deep dive” workshops attended by parties, where we reviewed key parts of our showing and answered questions. We appreciate the role that the other parties play in our GRC.

That said, SCE respectfully disagrees with many of the recommendations put forth by ORA, TURN, and other parties. In some cases, parties appear to have not really grasped our request, and recommended blanket disallowances without providing convincing analysis or evidence. And in some instances, no analysis or evidence was provided at all. In certain other cases, parties appear to have passed over information that SCE provided, whether in the form of our prepared testimony or our detailed responses to data requests. Our rebuttal testimony seeks to clarify our positions and requests in areas where SCE and other parties appear to be at odds.

My rebuttal testimony will not cover each instance where SCE rebuts the positions taken by the other parties. Instead, I will highlight some important general themes and larger points. Our detailed reply to the recommendations of ORA, TURN, and others are contained in the various volumes of our rebuttal testimony, and I thank Administrative Law Judges Roscow and Wildgrube in advance for their careful reading and thoughtful consideration of our rebuttal showing.
II.

OUR MODERN GRID WILL BE SAFER, MORE RELIABLE AND RESILIENT, AND HELP US FULFILL COMMISSION POLICIES

The Commission and California legislators have envisioned a greener energy future where customers enjoy greater access and can elect to play a more prominent role in managing their energy use. SCE shares this vision. To get there, we must change the way the grid is designed, managed, and used. We must also recognize that “greening” the system and enabling distributed energy resources (DERs), although very important, cannot be the only objective. The distribution system, apart from wear and tear over the course of a century, was originally designed and built for a very different customer base, and stakeholders with very different lifestyles and expectations regarding options for energy supply and control of energy use.

In the work we undertake in this rate case cycle, we will hold fast to key values that have defined our service to our customers:

• Safety as more and more people live and work near our equipment, and interact directly with our grid.
• Reliability as the communities we serve depend to a greater degree on 24/7 electric service in every aspect of their work and personal lives, and as we manage an aging system.
• Resilience in light of natural disasters, and malicious and ever-expanding cyber-hacks and cyber-attacks.

SCE has been updating some of our equipment during routine maintenance and infrastructure replacement, and we have undertaken certain limited-scope programs to modify system design. But this is not sufficient to provide our customers with a 21st century grid. For example, SCE started the distribution automation programs in the 1990’s, and has gradually installed some form of automation equipment on the substantial majority of its distribution circuits over more than 20 years. However, higher levels of more sophisticated automation are needed on our distribution and substation systems to operate an increasingly dynamic grid. Trying to update equipment and modernize capabilities in a limited and piecemeal fashion will take many more decades to cover our territory, lead to patchwork solutions, and undoubtedly cost more in the long run.

As the Commission examines our request, it may be helpful to draw an analogy to maintaining a home versus remodeling it. Every year, various items have to be fixed in a home -- broken doorknobs, leaky faucets, etc. (This is maintenance). As the house gets older, the roof or cabinet doors needs to be
replaced (This is infrastructure replacement). But over an extended period of time, two things happen. First, the house reaches a point where it no longer meets current design or living standards. Second, the owner’s expectations and needs change -- perhaps a larger family, or a desire to be much more eco-friendly, or a need to start a business from home. At this point, a home remodel (modernization) becomes unavoidable. Due to the significant capital investment that occurs when one undertakes a remodel, it makes good sense to not only consider the current needs, but also take into account future needs so that another major remodel will not be required in the near future, and so that additional improvements can readily be added on when necessary. It is not prudent to perform the remodel work in a fragmented fashion, such as doing the structural work one year, replacing the plumbing system the next year, and updating the electrical system in the third year. Instead, it’s more efficient and cost-effective in the long run to implement and integrate the major elements contemporaneously.

I respectfully submit that it would be shortsighted to narrowly focus on DER enablement. At the same time, we cannot afford to simply ignore the reality and promise of DERs; we should not only prepare the grid for organic DER growth, but also build the functionality to utilize and encourage DERs for grid services in the not-so-distant future. We have to start the transformation of our electric grid with an integrated and measured “no regrets” approach that will:

• Begin providing customer benefits now;
• Start preparing the workforce and the grid for all realistic future scenarios;
• Build in flexibility for uncertainties; and
• Leverage the available and upcoming resources from customer sites and DER providers to a greater degree.

Failing to take meaningful efforts now in grid modernization will set back California’s efforts to achieve a cleaner energy future, and will reduce reliability performance when just the opposite is needed.

The capabilities we need to operate a modern grid and interact with our customers in a more collaborative fashion are the same as those we need to prepare the grid for increased distributed generation hosting capacity and utilize DERs for grid services. Moreover, SCE’s proposed solutions for automation, communication networks, and analytics platforms work hand-in-hand to provide benefits that these programs cannot yield if implemented individually. Our proposal in this GRC is a thoughtful and integrated approach designed to provide dual value to customers immediately and in the future.
A. **What Truly Defines a Modern Grid Is Not the Technologies It Uses or Supports, But the Capabilities It Provides**

Today, the entire world relies on generating information in real-time, accessing the information in near-real-time, and then using the information to make decisions quickly. We see this every day in our lives. We see it when we book airline tickets over the internet, check traffic conditions and driving directions, and look at available inventory and manage delivery when we shop online. Yet these capabilities do not exist to the extent needed for something as critical in our lives as electricity delivery.

In our opening showing and in numerous data request responses, we have detailed the value our customers and the communities we serve will obtain from the grid efforts we are proposing. For SCE, such functionality will include improved visibility and awareness of conditions on the grid; fast, accurate, and efficient decision-making; quicker and more precise control and operation to avoid problems or promptly resolve them; enhanced security and resistance to outside threats; and a system that democratizes energy choice and energy management. Each of SCE’s customers will benefit from these capabilities. They are necessary to, among other things, provide grid operators timely information and heightened ability to prevent or respond to outages, and give customers timely information as they make decisions about installing DERs. SCE witness Brandon Tolentino discusses these items in more detail.\(^1\)

Approximately half of our distribution circuits have some form of automation today. Currently, when outages occur on one of these circuits, the automation allows our system operators to perform remote switching to restore service to approximately 50% of the affected customers within about 30 minutes on average. The distribution automation program we propose in our Grid Modernization request will allow us to restore service to 75% of affected customers within this timeframe.\(^2\) This represents a 50% improvement. For the remaining customers on these circuits whose service we cannot remotely restore, our proposed enhancements will enable SCE to restore their power roughly 30 minutes faster than today. Thus, all affected customers will benefit from our Grid Modernization automation when an outage occurs.\(^3\)

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\(^1\) *See* SCE-18, Vol. 10, pp. 9-11.

\(^2\) *Id.* at pp. 1-2. Later in my testimony, I discuss why improvements in reliability are warranted.

\(^3\) *Id.* at p. 10.
Pairing the distribution automation technologies with our proposed Grid Management System (GMS) and telecommunications technologies will help us achieve even more significant reliability improvements. By assisting system operators with troubleshooting procedures and developing service restoration plans, the GMS will reduce the restoration time for 75% of the customers on the circuits in scope to about 10 minutes. The telecommunications technologies will then further cut the restoration time down to approximately one minute by shortening the signal transmission times between the field and the back office. This allows the GMS to directly execute automated restoration plans.

In addition, the proposed GMS and telecommunications replacement and upgrades will strengthen our cybersecurity infrastructure. Today, cybersecurity threats present as great a challenge, or an even greater one, to our grid than physical security threats. Recent events, such as the worldwide Ransomware attacks, have shown the critical need for steadfast cybersecurity capabilities that can withstand potentially crippling attacks. Mr. Haddox’s rebuttal testimony details the context and the prudence of our efforts.

B. **We Are Helping California Reach Its GHG Goals by 2030 By Proposing Grid Transformation That Does Not Just Accommodate DERs, But Encourages DERs**

California legislators and regulators have taken an aggressive stance toward reducing GHG emissions. But from where we stand today, increasing renewable procurement to 50% and achieving a 40% reduction in overall GHG emissions by 2030 cannot be achieved by organic growth of distributed energy resources. Deployment of DERs will need to significantly accelerate to meet this goal. Doing “just enough” and “just in time” to accommodate DERs as they happen to show up on our system, as some parties suggest, is not going to be sufficient. Essentially “skipping” a GRC cycle to make refinements as intervenors recommend, is simply not going to help California achieve its goals. With little time to lose, the grid must not become a barrier to hosting more DERs. SCE and others have to partner to modernize our infrastructure so that it enables and fosters accelerated adoption of DERs. Besides improving safety and reliability, which are foundational for a modern electric system, the grid needs to serve as a catalyst for DER proliferation, so that DERs can provide greater energy management choices to customers, and can support grid services.

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4 See SCE-20, Vol. 1C, pp. 9-10.
5 Id. at pp. 33-52.
An important lesson can be illustrated by the Tehachapi Renewable Transmission Project (TRTP). This was the first major transmission project built to accelerate renewable generation in support of California’s Renewable Portfolio Standard (RPS). At the time it was conceived, transmission upgrades were handled through a slow and cumbersome interconnection process that focused on the incremental impact of each generator in the queue. With the aggressive RPS deadlines looming, and thousands of megawatts of new generation needed, California realized that proactive steps were needed. So, without knowing exactly which generators would ultimately come on-line and when, and with the recognition that any large new transmission project would take many years to complete, California opted to proactively move forward with TRTP. The completion of TRTP has spurred significant development of new renewable electricity generation, has added the capacity to deliver 4,500 MW of renewable energy to customers in SCE’s service territory, and has been instrumental in allowing the California utilities to meet their RPS goals. In addition, TRTP provides significant reliability benefits to the bulk electric system.

SCE’s Grid Modernization proposal is similar in that we know California’s 2030 GHG goals will require proactive steps to integrate renewable energy and DERs, we know it will take many years to modernize the grid to meet these requirements, and we have identified the early “no regrets” investments that will improve reliability for customers and keep us on the path to achieving these goals. If renewable transmission had only been authorized to solve problems that already existed, and not undertaken to facilitate future needs, then California would not be on a path to achieve its 33% RPS goal today. Similarly, if proactive grid modernization action is not started now on the distribution system, there will be insufficient time build the 21st century grid necessary to support California’s 2030 RPS and GHG reduction goals.

Regardless of the market and regulatory uncertainties over the next few years, we can still agree on where the grid needs to be by 2030. There may be differing viewpoints in terms of the pace that grid modernization efforts need to occur. However, most people can reasonably agree that the vast majority of SCE’s electric distribution systems will need to be modernized by the end of the next decade. We have a 100-year old distribution grid, spread over 50,000 square miles and servicing five million customers and a population of nearly fifteen million people. Updating this grid is an extraordinary

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To date, the TRTP project has enabled a total of 4,617 MW of Solar PV, Wind and Battery Storage and approximately 5,802 MW by 2020 (subject to change as developers might request modifications following the Material Modification Assessment process).
responsibility, and we cannot keep pushing off the work by waiting another GRC cycle or two and then hoping that the work can be completed in a few years. It simply cannot be done. Waiting to perform the necessary work until we have better DER growth forecasts, or more specific Commission guidance on a Distributed Resource Plan (DRP) framework, or higher confidence in market mechanisms, is not practical. It’s our responsibility to propose the projects according to a timeline that provides our Commission and our customers with the grid they need in ten years to support California’s goals. (I will discuss this more in the next section.) The necessary volume of work cannot be completed if we start any later. The only viable option is to:

- **Focus now** on grid capacity and functionality that provide the dual benefits of fostering reliability and integrating DERs (automation, telecommunications, grid analytics, and 4kV elimination);
- **Prioritize** the location-specific work based on current needs (worst performing circuits and circuits with high DER penetration); and
- **Undertake cost-effective** solutions (as demonstrated by our benefit/cost analyses and revised forecasts based on the results of those analyses, as discussed in SCE-18, Volume 10).

C. **SCE Is Proposing A “No Regrets” Approach**

SCE has been thoughtful in developing its Grid Modernization programs in terms of technologies selected, scope, and pace of deployment. Distribution automation is a proven means of improving our ability to detect faults, isolate them, and restore service. SCE is asking to deploy distribution automation on 200 of its worst performing circuits, in conjunction with other programs targeting these circuits, which fosters efficiency. SCE’s choice of DER-driven circuits represents less than 2% of its circuits per year from 2018-2020. The field area network that SCE is planning to install replaces the nearly-obsolete NetComm system\(^2\) while providing significant improvements in speed, capacity, and cybersecurity.

We are also prudently selecting technology platforms that are based on internet protocols and use open-standards software that will not rely on continued support from a particular vendor. By doing this, we will obtain the ability to efficiently accommodate new requirements and policies as our distribution automation and customer needs evolve over time. The flexibility designed into our Grid Modernization

\(^2\) The NetComm system is a radio-based, wireless communications channel for the devices located along SCE’s distribution circuits and substations.
technology platforms enable interoperability among multiple vendors. This facilitates the vendor
diversity that is critical for obtaining best-fit functionality and prices. It also mitigates the risks of rapid
technology obsolescence that could require replacing entire technology platforms due to the use of
proprietary technologies and/or lack of flexibility when new requirements or policies are established. To
further improve management of this risk, SCE has carefully chosen technologies that have been
evaluated in demonstration projects and pilots, and we are proceeding with integration testing before we
finalize our vendor selections.

The More Than Smart Final Report, cited by ORA, addresses the lifecycle for utility
infrastructure and technology deployment projects. That Report argues that utilities can mitigate the
timing risk associated with long utility development lead times by “identifying those investments that
are required under any future scenario.” The Report explains that “[t]hese ‘no regrets’ investments
include advanced field telecommunications networks and increasing grid operational visibility – to allow
more operational data, moving freely, in real time.”

These are precisely the type of investments that SCE has included in its Grid Modernization
program, and we have included them for precisely the reason that the Report identifies. Our projects are
foundational ones, that must be undertaken now, and that are designed to offer benefits and increased
capabilities under all realistic future scenarios. For example, deploying SCE’s proposed automation on
worst performing circuits and putting in the upgraded communication and analytics backbone are
needed regardless of additional DER growth. Our efforts here will provide the near-term benefit of
improving reliability, while readying the circuits for DER integration when needed at no or very low
additional cost. These projects and programs are designed to benefit all of our customers, regardless of
the customer’s income level, ability to install DERs, or interest in pursuing DERs.

Intervenors have suggested that we need to exploit AMI, smart inverters and the DER provider
network in lieu of the projects and programs in our request. They are correct that we should use these
sources of information as much as possible. What they may not understand is that AMI cannot provide
real-time data. Moreover, smart inverters and DER networks can only provide data from customer sites
that have DERs, which would leave out the vast majority of customers, particularly our customers in

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8 ORA-09, p. 38.
10 Id. at p. 14.
disadvantaged communities. In addition, these systems cannot provide visibility and control of the grid itself. DER data and control are necessary, but not sufficient to operate a complex distribution grid.

D. **SCE’s Request In This GRC is a Prudent Mix Of Conventional Grid Management And Grid Modernization That Largely Focuses On Safety And Reliability**

ORA and SEIA/Vote Solar have suggested that our Grid Modernization program serves the sole purpose of integrating DERs and fulfilling DRP goals.\(^{\text{11}}\) This is incorrect. Separate and apart from DER integration, SCE’s Grid Modernization efforts in this GRC are still justified based on the reliability and safety benefits we discuss in our opening and rebuttal testimonies. Figure II-1 helps illustrate how our Grid Modernization program is needed even if we see no significant additional DERs interconnecting with our system. Our figure is similar to the one that the CPUC Energy Division Staff presented in its recent Grid Modernization whitepaper,\(^{\text{12}}\) but as I discuss below there are a few key differences.

\(^{\text{11}}\) See, e.g., ORA-09, pp. 13, 57; SEIA/Vote Solar testimony, pp. 10-11.

\(^{\text{12}}\) See R.14-08-013, April 2017 Staff Whitepaper on Grid Modernization, p. 10.
The red shaded area on the left under Grid Management represents programs we currently undertake to maintain safety and reliability. This includes inspection-based maintenance and infrastructure replacement programs and load-growth driven programs that SCE has undertaken for decades. The red shaded area also includes preemptive programs (based on engineering analysis) that we have undertaken and expanded since approximately 2006 to address the safety and reliability challenges triggered by our aging grid infrastructure. All of these can be viewed as “conventional” programs and part and parcel of owning and managing the electric grid.

But owning and managing the grid also entails prudently updating the grid so that it can continue providing safe and reliable service to our customers year after year after year. As I discussed previously, at this juncture the grid needs more than limited and piecemeal improvement. It needs the capabilities I mentioned above, improved in meaningful phases of modernization starting in this GRC cycle. This brings us to the purple shaded region in the middle, which represents new programs that are driven by conventional needs, and hence can be viewed as both Grid Management and Grid Modernization. These are upgrades we would have to undertake regardless of any additional DER growth. They are triggered by safety and reliability needs, but in the future will provide ancillary benefits associated with DER enablement.
Next, the blue area on the right under Grid Modernization, represents new programs driven by new needs to support DER growth, enable DER penetration, foster DER integration, and maximize DER value. This is the subject of matters being evaluated in DRP. Mr. Tolentino summarizes the programs and projects we propose and their drivers in SCE-18, Volume 10.

Please note that some of the solutions needed for the purple and blue sections (the areas in the middle and on the right in the Figure) are largely the same, except the locations selected for deployment would differ based on the driver. For example, distribution automation to improve reliability will be directed towards worst performing circuits, whereas distribution automation for DERs will be driven by where we expect high DER penetration will occur or where the DERs may someday be able to provide value in terms of deferrals of conventional projects or other grid services. But there are other system-wide programs that will work in conjunction with automation to reduce the number and duration of outages experienced by customers. Examples of this are found in our telecommunication efforts that connect grid devices to the Grid Control Centers, and our Grid Management Systems that analyze the incoming information and manage the power flow. Developing and deploying these programs needs to start now to support the reliability projects, and the items we propose can be used for DER integration whenever they are needed.

1. **ORA Has Taken An Extreme Position By Embracing a “Cut Everything” Philosophy for Grid Modernization Capital Spending**

   For Grid Modernization, SCE provided 138 pages of prepared testimony and 308 pages of workpapers, conducted two (2) three-and-a-half hour workshops, answered more than 2,000 data requests, and provided a detailed benefit/cost analysis. ORA’s reaction is to propose no capital funding for Grid Modernization, a reduction of $637 million to SCE’s request. ORA’s blanket denial of SCE’s Grid Modernization capital request is simply unreasonable in light of the need to improve safety and reliability. ORA’s position is also inconsistent with State policymakers’ priorities for meeting State-mandated 2030 GHG reduction levels and Commission-driven DER penetration objectives.\(^\text{13}\)

\(^\text{13}\) ORA asks this Commission to summarily disallow any capital spending that falls under the name “grid modernization.” See ORA-09, pp. 2-3. In some cases, such as with the Distribution Resource Plan External Portal (DRPEP) and System Modeling Tool (SMT), ORA provides no actual analysis. ORA also asks this Commission to disallow O&M funding associated with the Grid Modernization capital projects.
ORA suggests that Grid Modernization efforts can only occur in the context of the Distributed Resource Proceeding (DRP) and DER integration. ORA is mistaken. SCE is undertaking Grid Modernization efforts not simply to address the need to integrate distributed energy resources (as cited in the Distributed Resources Proceeding and Assembly Bill 327), but to serve safety and reliability as well, even in the absence of increased DER adoption. The benefits that a modernized grid will provide in integrating distributed energy resources is just one part of a larger “package” of benefits that our customers will realize from a more modern grid.

2. **ORA Mistakenly Suggests that Utilities Should Not Try to Improve Reliability**

As I discussed in my opening testimony, in a rapidly transforming electric power industry the responsibility for providing reliable electric service still rests with the utility. It’s our core responsibility, and is the focus of our GRC showing. ORA appears to take the view that utilities are not allowed to improve reliability, but must only seek to maintain it.

a) **The Commission Has Encouraged Reliability Improvement**

ORA’s position is contrary to Commission guidance. For example, in PG&E’s Cornerstone Improvement Project (Cornerstone) request, the Commission confirmed that it is certainly appropriate for a utility to improve reliability, and provided criteria for such efforts. In its Cornerstone request, PG&E sought to “improve the resiliency and reliability of its electric distribution system to a level better than the ‘adequate’ service standard adopted for PG&E in past General Rate Cases (GRCs).”

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14 See ORA-09, pp. 32-44, 56-58.
15 SCE-01, p. 2.
16 Id. at p. 1.
17 Id.
18 See ORA-09, pp. 47-49.
19 See D.10-06-048, Decision on Pacific Gas and Electric Company Request to Implement a Program to Improve Electric Distribution System Reliability.
20 D.10-06-048, p. 3.
The Commission stated that “electric distribution reliability is still important, and we support necessary and optimal programs or projects that will increase such reliability.”\footnote{Id. at p. 19.} The Commission also stated that “[i]n general, we support specific reliability improvement programs or projects that are cost-effective.”\footnote{Id. at p. 28.} In SCE’s Test Year 2015 GRC Decision, the Commission “agree[d] with SCE and CUE that improving reliability through WCR [Worst Circuit Rehabilitation] and CIC [Cable in Conduit] replacement is an important goal.”\footnote{D.15-11-021, pp. 72-73 (emphasis added). The Commission noted that the goal must be balanced against customer costs. Id.} In SCE-18, Volume 10, Mr. Tolentino explains how SCE’s Grid Modernization proposal meets the reliability improvement criteria outlined by the Commission in the Cornerstone decision in a cost-effective manner.\footnote{See SCE-18, Vol. 10, p. 28.}

The Commission has also spelled out the importance of avoiding outages, and the consequences of reliability gaps. For example, when the Commission commenced an investigation after the SCE outage in Long Beach, the Commission put SCE on notice that the Commission could consider a penalty for each violation and for each day that the outage was ongoing.\footnote{See I.16-07-007 Order Instituting Investigation Order to Show Cause and Notice of Hearing (Long Beach OII Order), (July 14, 2016), p. 7.} The Commission indicated it could potentially impose penalties of $500 to $50,000 per day per offense.\footnote{Id. at pp. 7, 11 (Ordering Paragraph Number 4).} The Commission also noted that it may “require payment of remedies to repair any damage to property” caused by the outage.\footnote{Id. at p. 11.} As I discussed in my opening testimony,\footnote{SCE-01, pp. 1-2.} it is SCE’s responsibility to keep the lights on, and it is SCE that shoulders the consequences of reliability failures, not ORA, TURN, or other parties that oppose our request.

\begin{footnotes}
\item[21] Id. at p. 19.
\item[22] Id. at p. 28.
\item[23] D.15-11-021, pp. 72-73 (emphasis added). The Commission noted that the goal must be balanced against customer costs. Id.
\item[25] See I.16-07-007 Order Instituting Investigation Order to Show Cause and Notice of Hearing (Long Beach OII Order), (July 14, 2016), p. 7.
\item[26] Id. at pp. 7, 11 (Ordering Paragraph Number 4).
\item[27] Id. at p. 11.
\item[28] SCE-01, pp. 1-2.
\end{footnotes}
b) SCE’s Reliability Performance Needs To Be Improved

Next, ORA asserts that SCE does not need to improve reliability since SCE’s reliability performance is slightly better than PG&E’s.\textsuperscript{29} There are four basic responses to this. First, when comparing SCE to the other IOUs, SCE’s 10-year reliability track record (excluding major events) has unfortunately actually declined, and is lower than PG&E’s.\textsuperscript{30} Further details on this are found in Mr. Tolentino’s testimony in SCE-18, Volume 10.

Second, a comparison of 2016 SAIDI\textsuperscript{31} in relation to the rest of the country demonstrated that, while the utility industry is seeing reliability improvement year-over-year in controlling both the duration and the frequency of outages, SCE’s reliability is actually declining.\textsuperscript{32} This reliability comparison is particularly illuminating when one considers that outages should be lower in Southern California, where the weather is relatively temperate and winters are mild.

Third, according to the Commission’s own definition of adequate service, SCE needs to keep up with changing times and the “maturity of the public industry,” and “continuously meet and exceed public demand for its output.”\textsuperscript{33} The term “adequate” in this context does not connote minimal efforts or staying with the status quo no matter what. Also, as computers, personal and work devices, and technologies increase their role in our customers’ daily lives, customers are demanding more from their grid. Assembly Bill 66 (AB66),\textsuperscript{34} passed in 2013, provides an example. That bill’s provision concerning Commission enforcement authority over utilities sprang from strong customer dissatisfaction with electric service reliability. In the report supporting the passage of Assembly Bill 66, the author stated that “Inconsistent electricity service in Rancho Palos Verdes and throughout the South Bay has resulted in growing frustration amongst ratepayers in the region.”\textsuperscript{35}

\textsuperscript{29} See SCE-18, Vol. 10, pp. 19-20.
\textsuperscript{30} See http://www.cpuc.ca.gov/2015_aers/. Major events are justifiably excluded from this metric, as discussed in SCE-18, Volume 10, pp. 19-20.
\textsuperscript{31} SAIDI (System Average Interruption Duration Index) excluding transmission and planned outages.
\textsuperscript{32} SCE-18, Vol. 10, pp. 19-21.
\textsuperscript{33} D.00-02-046, at p. 18.
\textsuperscript{34} Muratsuchi, 2013.
\textsuperscript{35} SCE-18, Vol. 10, pp. 24-25.
Fourth, independent customer surveys by J.D. Power show that customers value reliability and want SCE to do better here.\(^{36}\) In the surveys of both residential customers and business customers, SCE was ranked in the third quartile of Power Quality and Reliability when compared with other large utilities, and SCE showed a decline.\(^{37}\) Residential customers felt that SCE very much needed to improve its reliability during periods of extreme temperature, and relegated SCE to the fourth (or worst) quartile in this area.\(^{38}\) However, both business and residential customers ranked SCE in the top half of the second quartile in price of electric service.\(^{39}\)

This objective feedback from our customers shows that gains in reliability are warranted, and that price is not all that customers care about. ORA attempts to minimize this polling data, suggesting that while customers will always say they care about reliability when polled, they aren’t actually willing to pay for it.\(^{40}\) But recent results from SCE’s summer discount program show the opposite: customers leave the program when temperatures rise and after the first event call of the season.\(^{41}\) This demonstrates that customers are not as willing to trade reliability for discounted power as ORA suggests.

Other objective surveys show that customers are concerned about the reliability of their electric service. For example, several years ago a nationwide reliability survey found that:

- Over 25% of customers across the U.S. believe they should never experience an electric power outage, unless there is an extreme weather event.
- 42% of customers in the West would not accept a two-day power outage, even if they were paid as much as $1,000 for it.
- 64% of customers responded that power outages cause “really significant problems” for their households.

\(^{36}\) SCE-18, Vol. 10, pp. 21-25.
\(^{37}\) Id. at pp. 21-23.
\(^{38}\) Id. at pp. 21-24.
\(^{39}\) Id. at pp. 21-22.
\(^{40}\) See ORA-09, pp. 48-49.
\(^{41}\) SCE-18, Vol. 10, p. 23.
• 71% of customers with income less than $40,000, said outages cause “really significant problems.”42

Accordingly, ORA is incorrect in attacking SCE’s attempt to make its grid more reliable.

3. Our Stand-Alone Infrastructure Replacement Programs Are Needed, But Are Not Sufficient

SCE is committed to maintaining and replacing the aging and deteriorated infrastructure on our grid. Besides compliance-driven programs, SCE developed various preemptive replacement programs that the Commission has supported in the 2009, 2012 and 2015 GRCs. We have increased the scope of these programs substantially. For example, the chart below illustrates how SCE has increased its efforts in underground cable infrastructure replacement in the 2009, 2012, and 2015 GRC cycles.

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We need to continue these programs until we reach steady state replacement levels.\textsuperscript{43} But these programs, standing alone, have not been sufficient.\textsuperscript{44} They can help stem the decline in reliability and safety, but more fundamental changes are necessary in grid configuration and operations to improve safety and reliability.

4. **TURN Takes An Inconsistent Approach To Safety and Reliability**

TURN assesses SCE’s safety and reliability efforts in an internally inconsistent way. TURN acknowledges the importance of safety and reliability,\textsuperscript{45} and generally agrees that funding is warranted for safety and reliability. However, TURN then opposes SCE’s requested funding for specific

\textsuperscript{43} See SCE-01, pp. 10-12.
\textsuperscript{44} See SCE-18, Vol 10, Figure I-3.
\textsuperscript{45} See TURN-10, p. 23.
and important projects such as SCE’s Overhead Conductor Program, which is part of SCE’s Infrastructure Replacement program.\textsuperscript{46} TURN suggests that SCE only be permitted funding to perform this Overhead Conductor work on a “breakdown basis” -- in other words, that SCE should be restricted to only reacting to wire-down events, not proactively trying to prevent them.\textsuperscript{47}

The Commission has focused on safety in several proceedings, such as the Safety \textit{en banc}, and the Safety Model Assessment Proceeding (SMAP). TURN’s position is out of step with this intensified focus by all stakeholders on grid safety.

TURN’s proposal for Grid Modernization is to only perform the most cost-effective portions of our request. When TURN suggests we are attempting to “gold plate” our power system,\textsuperscript{48} they are mistaken. For the long-term interests of our customers, our goal cannot be to just blindly take the most cost-effective incremental step. Instead, we must find a cost-effective way to get to the right destination. As an example, the first hospital built in a county may have a higher benefit-to-cost ratio than the third hospital built in the same county. This comparison is irrelevant, however, in determining whether the third hospital is needed and adds value. If the demand is high enough so that the first and second hospital cannot accommodate the needs of the county, then the third hospital should be built, even if it has a lower benefit-to-cost ratio than the first or second hospital.

Moreover, TURN proposes a scaled-down effort for reliability-driven distribution automation that lowers the number of switches and ties being installed, and includes less effective switching technology.\textsuperscript{49} TURN’s scaled-down automation scheme does not really “move the needle” sufficiently in terms of reliability improvement, achieving a SAIDI reduction of 7.2 minutes.\textsuperscript{50} This would still leave SCE below average in reliability among U.S. utilities. By contrast, SCE proposes a configuration that achieves SAIDI reductions three times greater than TURN’s recommended approach. TURN’s proposal is also problematic because TURN does not want SCE to replace its NetComm

\textsuperscript{46} See TURN-04, pp. 15-16.
\textsuperscript{47} \textit{Id.} at p. 15.
\textsuperscript{48} See TURN-06, p. 58.
\textsuperscript{49} See SCE-18, Vol. 10, pp. 39-40.
\textsuperscript{50} \textit{Id.} at pp. 26, 40.
system (as discussed below), but TURN’s automation proposal cannot be supported by NetComm. The additional automation devices will in fact accelerate NetComm’s saturation.

Similarly, TURN proposes implementing only a portion of the GMS functionality that SCE is requesting funding for.\(^{51}\) TURN estimates that its proposal would reduce costs by 50%. Unfortunately, TURN is incorrect. The functionality that TURN endorses covers approximately 90% of the costs.\(^{52}\) So the 50% cost reduction estimated by TURN simply would not happen. Moreover, the additional scope that TURN seeks to erase will also provide DER integration benefits, in addition to safety and reliability improvement benefits. Given DER integration needs, these capabilities would have to be installed within the next few years, and are expected to cost more to implement separately.

TURN’s recommendations against replacing SCE’s telecommunications system (NetComm)\(^{53}\) are illogical, and inconsistent with TURN’s purported support for reliability. NetComm is over 20 years old, is very slow, and is nearing full capacity.\(^{54}\) It may be worth remembering the types of first-generation technologies that we had to rely on back in the 1990’s when NetComm was installed. Since that time, cell phone communications have evolved to the fourth generation (4G) technology used today. SCE proposes to replace NetComm with the current industry standard, the field area network (FAN). The FAN is considerably faster than NetComm and provides additional benefits, such as modern cyber-protection. Because it is inevitable that we will need to replace NetComm, any proposed solution that involves “patching up” NetComm with the goal of avoiding the FAN will only create more costs in the long run, while also delaying the benefits that the FAN can provide.\(^{55}\) Mr. Tolentino discusses this in greater detail in SCE-18, Volume 10.

In sum, SCE’s efforts to improve reliability are prudent and should be approved.

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\(^{51}\) See TURN-06, p. 84.

\(^{52}\) See SCE-18, Vol. 10, p. 68.

\(^{53}\) See TURN-06, pp. 80-81.

\(^{54}\) See SCE-18, Vol. 10, pp. 51, 53-55.

\(^{55}\) We cannot immediately transition from NetComm to the FAN. As discussed in our Grid Modernization testimony, the changeover will take approximately five years. See SCE-18, Vol. 10, p. 52.
E. **Safety and Reliability Are Intertwined: Our Efforts Will Foster Safety As Well As Reliability**

Although SCE’s Grid Modernization proposals are justified based on reliability concerns, I must also note that there is a safety impact here as well. Safety and reliability cannot be thought of as two separate concerns, with our Grid Modernization projects serving the cause of reliability but not doing anything for safety. As the Commission’s Safety Enforcement Division (SED) stated in the Report it issued in this GRC:

> Although safety and reliability are distinct aspects of the Commission’s core mission, there is an undeniable overlap and intertwining of the two concepts. Factors that are frequently the cause of disruptions to reliability, including downed lines, equipment failure, lightning strikes and other major weather events, may have direct safety consequences.

> Extended power outages or supply disruptions during extreme summer heat or winter cold could impair the ability of utilities to ensure safe and reliable service to critical facilities, including hospitals, medical facilities, police and fire operations, and to customers who rely on life-supporting medical devices.\(^{56}\)

> In other proceedings, the Commission has tied safety and reliability together. For example, the Commission has stated:

> *SCE has an obligation to maintain its facilities in a safe and reliable manner pursuant to State law including P.U. Code § 451, General Orders, and Commission Decisions. The California Legislature has recognized in P.U. Code § 330(g) and other parts of the P.U. Code that an electric utility such as SCE has “a duty to provide electricity to the public” because “electric service is of utmost importance to the safety, health, and welfare of the state’s citizenry and economy.” There is a strong presumption that power should stay on. The Commission has repeatedly stated that public safety is a top priority and that “operating a safe system also includes the reliable provision of electricity. Without power, numerous unsafe conditions can occur. Traffic signals do not work, life support systems do not work, water pumps do not work, and communication systems do not work … In short, there is a strong presumption that power should remain on for public safety reasons.”*\(^{57}\)

I will point out three examples where our Grid Modernization efforts will provide safety as well as reliability benefits by detecting problems more quickly, reducing the impact of outages, and reducing the number of outages.

\(^{56}\) SED, *Risk and Safety Aspects of Southern California Edison’s 2018-2020 General Rate Case Application 16-09-001*, pp. 43-44.

\(^{57}\) I.16-07-007, Order Instituting Investigation, Order to Show Cause and Notice of Hearing (July 14, 2016), pp. 5-6 (internal citations omitted).
First, as SED touches on in the cited language above, equipment failures can expose high-voltage equipment to the general public, and create direct risks to public safety. Downed power lines and fallen power poles are examples of equipment failures that trigger these public safety risks. The severity of any given equipment failure is a function of the time required to identify and resolve the incident. By improving our visibility of the real-time conditions of the distribution system, Grid Modernization will achieve a 30-minute reduction on average in the time needed to locate and resolve many of these safety incidents.\textsuperscript{58} So Grid Modernization will have a direct and positive impact on public safety by reducing the amount of time the public is actually exposed to potential safety hazards.

Second, Grid Modernization will also enhance public safety by helping us reduce the magnitude and duration of outages. This means that customers and facilities in our service territory -- including (as SED notes) hospitals, police, fire services, and others directly responsible for maintaining the safety, security and health of customers -- will experience fewer and shorter periods without the electric service they need to perform their duties. This will be achieved through Grid Modernization’s faster and more precise fault detection and restoration capabilities.\textsuperscript{59}

Third, Grid Modernization will improve public safety by helping us avoid some outages altogether. Because Grid Modernization will enhance our visibility of real-time grid conditions, system operators will be able to readily identify overload conditions and resolve them through preemptive switching operations. This will reduce the likelihood of in-service failures of distribution equipment, thereby preventing our customers and communities from being exposed to the attendant safety hazards of such equipment failures.

F. Our Approach Takes Into Account the Long-Term Outlook for Distributed Energy Resources Connecting To Our Grid

As I mentioned before, reasonable minds can differ on the pace that DERs are appearing on our grid. But I think we can acknowledge that ten years from now, there will be a very significant penetration of DERs onto our grid, and a need to have capabilities in place to accommodate those DERs without compromising reliability or safety. For example, SEIA/Vote Solar disagree with SCE’s view on

\textsuperscript{58} See SCE-18, Vol. 10, p. 29.
\textsuperscript{59} Id. at pp. 10, 36.
short-term DER growth and penetration, but these parties actually predict double the DER growth that
SCE forecasts in year 2020.\textsuperscript{60} Moreover, SEIA/Vote Solar projects double-digit DER growth in year
2022.\textsuperscript{61} Most of our distribution circuits have been able to accommodate DERs so far, but that should
not be taken as an indication that we can continue to interconnect DERs over the next few years without
adding hosting capacity, given the type of increased DER penetration contemplated by SEIA/Vote Solar.

Even assuming that our Commission believes that we should temper the pace of our efforts to
accommodate DERs, the foundational projects we propose in this case are designed to not just address
shorter-term needs, but to make sure we are not critically behind at the ten-year mark.\textsuperscript{62}

1. \textbf{ORA Mistakenly Claims that SCE Must wait Until Phase 3 of the DRP Rulemaking
Concludes Before Working to Integrate and Enable Distributed Energy Resources}

   a) The Commission Has Already Considered This Position, and Rejected It

ORA suggests that SCE should not undertake its Grid Modernization efforts until
the Commission has ruled in Track 3 of the DRP Rulemaking. But TURN made this same argument
against grid modernization in PG&E’s Test Year 2017 GRC, and the Commission rejected it. There,
PG&E argued that “the question of whether or not to include costs in a GRC should not depend on
whether or not there are concurrent CPUC proceedings relating to those costs. Rather, the test should be
whether the costs are reasonably forecast to be incurred during the GRC period at issue.”\textsuperscript{63} The
Commission found that:

   PG&E’s reasoning makes sense. \textit{The scope of this proceeding should include evaluation of
all of PG&E’s forecast distribution-related investments, even if they may be conceptually
related to the DRP proceeding.} Like all of its forecast investments, PG&E must meet its
burden to demonstrate that these investments are reasonable in order to be authorized to
move forward with those that are established to be necessary beginning in 2017.\textsuperscript{64}

   Accordingly, the timing of SCE proposing its GRC Grid Modernization projects
is appropriate. The projects and efforts should be judged on their reasonableness, rather than simply

\textsuperscript{60} See SEIA/Vote Solar Testimony, p. 12, table (estimating 9% growth of DERs in 2020, while SCE estimates
4%).

\textsuperscript{61} Id. at p. 13, lines 10-13 (anticipating double-digit growth in 2022).

\textsuperscript{62} I discuss the longer-term needs in my opening testimony. \textit{See SCE-01}, pp. 7, 13-14.

\textsuperscript{63} A.15-09-001, PG&E’s Reply to Protests and Responses in PG&E’s 2017 GRC, p. 7 (October 15, 2015).

\textsuperscript{64} A.15-09-001, Assigned Commissioner’s Ruling and Scoping Memo in PG&E’s 2017 GRC, p. 14 (December
1, 2015) (emphasis added).
disallowed based on the status and progress of the DRP. ORA’s “timing” argument cannot be used to reject, on a blanket basis, the projects that SCE is proposing in this GRC.

2. **SEIA/Vote Solar Inaccurately Suggests That SCE is Overemphasizing Problems with DERs and Underestimating DER Benefits**

SCE strongly believes in DER benefits, but our grid operations must be upgraded to accommodate DERs so that these benefits can be realized. Our system, like that of other utilities, was designed many decades ago, before DERs existed or were even contemplated. We have proposed solutions in our Grid Modernization proposal to address those challenges. SCE believes that, ultimately, DERs will play an important role in achieving California’s 2030 goals. However, SCE has to proactively implement solutions so that DERs can proliferate without the grid becoming a barrier.

DERs can only defer or eliminate some capacity-related projects. Perhaps they can even slightly delay certain infrastructure replacements or upgrades. But the reality is that SCE’s distribution circuits were designed for one-way power flow from central generation. This design provides (a) high capacity near the substations that feed in the power and (b) lower capacity at the end of the line, which needs to meet peak capacity during high usage. To support higher penetration of DERs, the system must have more uniform capacity throughout the circuit, allowing for two-way power flows that can peak in the traditional direction during high usage periods, and in the opposite direction during periods of high solar generation and low residential loads. The system must also be able to support reliable operations when circuits are reconfigured during normal and emergency conditions. These changes cannot be supplanted by interconnecting DERs. Similarly DERs cannot provide distribution circuit telemetry and help with load transfer between circuits, as some of our proposed Grid Modernization programs do.

The costs associated with accommodating DERs is real. As Energy Division Staff stated in the white paper they published on May 16, 2017.\(^{65}\)

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\(^{65}\) *Staff White Paper on Grid Modernization* (May 16, 2017), appended to Assigned Commissioner’s Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff White Paper on Grid Modernization, R. 14-08-013 et al.
Customers today adopt DERs with expectations that the distribution system will be able to integrate these technologies. The growth of DERs adds a new level of complexity to the planning and function of the distribution grid. The current grid can’t respond to the operational conditions that are emerging, requiring new technological upgrades to manage the challenges of grid operations. In response to these new demands, California adopted Assembly Bill (AB) 327 in order to modernize the distribution system to support the state’s policy objectives of increasing interconnection of DERs to the distribution system and decreasing greenhouse gas emissions.

Acknowledging the necessity of this work, and the associated costs in a collaborative and timely manner is the only practical way to make sure that DERs can be effectively used to reduce GHG and provide grid services.

G. **SCE has Proposed a Cost-Effective Plan For Initiating Grid Modernization**

In our opening showing and data request responses, SCE has demonstrated the cost-effectiveness of these programs. ORA suggests that SCE has not shown that its Grid Modernization projects will be cost-effective. ORA, however, never even attempts to address the detailed benefit/cost analysis that SCE provided.

When we presented that benefit/cost analysis, I must note that SCE’s analysis focused on one quantifiable reliability benefit (customer costs saved from reduced outage times), and we used conservative assumptions. These assumptions tended to actually lower the benefits that SCE could show. For example, SCE used an overly-conservative assumption of the costs to its customers for each minute of power outage, which was lower than that of PG&E’s customers. In fact, energy intensity of economic output in Southern California compared to Northern California demonstrates that SCE’s customers experience costs from an outage on par with those experienced by PG&E’s customers. After updating our analysis based on this information, our benefit/cost ratio is even stronger. We also updated our analysis with the most recent reliability data, which takes into account worsening SAIDI for 2016; this updated analysis yields 10% more avoided Customer Minutes of Interruption.

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66 See, e.g., ORA-9, p. 32.
67 See SCE-18, Vol. 10, pp. 30-34.
68 Id. at pp. 31-33.
69 Id. at pp. 30-33.
SEIA/Vote Solar challenges our analysis based on a calculation error on our part, and removes certain benefits. Specifically, they take out benefits associated with time saved from not having to analyze circuits that are characterized by two-way power flows before restoring an outage. (Benefits associated with addressing DER impacts, in other words.) Even after correcting for the calculation error, the benefits of SCE’s proposal outweigh the costs. SCE disagrees with SEIA/Vote Solar’s view that DERs require no additional analysis on the part of system engineers when making outage restoration decisions. Nevertheless, if for the sake of argument we exclude these DER impacts from our current analysis, the benefits still exceed the costs by more than 26%.

In sum, our updated analysis clearly demonstrates that the benefit/cost ratio is considerably higher than one, even if the DER impacts are removed. Mr. Tolentino addresses this in detail in SCE-18, Volume 10.

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70 Id. at p. 32.
III.

TURN’S PROPOSAL FOR COMPLETE DISALLOWANCE OF HISTORICAL POLE REPLACEMENT COSTS WOULD PENALIZE SCE FOR ERRING ON THE SIDE OF SAFETY

Pole-loading has drawn substantial attention from TURN, with recommendations for a very large disallowance. So that the Commission has a fuller record on this issue, SCE witnesses Christy Fanous and Bill Chiu address the management and engineering issues in detail. Moreover, Andy Stewart, a pre-eminent pole engineer based in Fort Collins, Colorado, provides independent expert opinions on SCE’s process and decisions in developing, deploying, and improving its pole-loading software in the period from 2012 to 2016. Mr. Stewart has advised public utilities commissions and utilities regarding pole design and safety issues.

In light of the detailed showings by Ms. Fanous, Mr. Chiu, and Mr. Stewart, I am going to only provide a few observations on how the pole-loading narrative reflects SCE’s priorities and illustrates the effort to balance competing management considerations. When SCE launched its Pole-Loading Program (PLP) in 2014, we did so with a sense of public safety urgency, given past pole failures during high winds. Those pole failures resulted in some cases in wildfires, and led to a recognition that a significant number of the 1.5 million poles in the SCE system probably had become overloaded, particularly with the addition of telecommunication wires and equipment by non-SCE parties. PLP was endorsed by the Commission, but it was an SCE safety initiative.

SCE had selected the SPIDA software in 2012 for all pole-loading assessments. SPIDA yielded results for certain, more complex pole configurations that seemed more conservative than necessary to experienced SCE pole designers. To address those concerns, PLP managers asked for a comprehensive engineering review. This review led to a conclusion at the end of 2014 that there were some pole configurations where SPIDA was calling for pole replacements that might not actually be necessary at that time. SCE and SPIDA undertook work starting in 2015 to modify the software to reduce such situations. When that work was completed at the end of 2015, SCE not only deployed the new SPIDA

See TURN-12, pp. 1, 20-21.
See SCE-18, Vol. 9; SCE-25, Vol. 3.
See SCE-25, Vol. 3.
software version for new pole-loading, but we also decided to re-assess poles that had been evaluated using the earlier software version. We did so in an effort to reduce the number of early pole replacements while still meeting safety factor requirements.

At every point, SCE managers faced trade-offs. Do we delay or suspend PLP until the SPIDA software is yielding design results that are meeting but never exceeding the safety factor, or do we continue to improve the program even though that means we are installing some poles that are providing a greater safety margin than required? What will be the safety, schedule and cost impacts on this urgent, safety-based program if we halted all of the work to re-assess every pole using the newer software? These are not easy questions, and in fact SCE carefully balanced these competing interests over time. But I believe the record shows those making the decisions did so in careful recognition of our priorities of safety, continuous improvement, and lowest reasonable cost for our customers.
IV.

**TURN’S AFFORDABILITY TESTIMONY DOES NOT PROVIDE GROUNDS FOR DISALLOWING THE WORK WE SEEK TO DO ON BEHALF OF OUR CUSTOMERS**

SCE appreciates that TURN has tried to show the affordability impacts of our requests, as we care a great deal about the affordability of the services we provide. I want to briefly point out that there are key points that TURN fails to address, or that TURN addresses without providing the proper context. Mr. Garwacki responds to TURN’s claims regarding bill impacts to our customers, and shows that TURN is mistaken. Mr. Garwacki also addresses TURN’s assertions regarding utility disconnections of service for non-payment.

Next, SCE’s capital expenditures have indeed increased, as TURN points out. But the focus should not just be on the fact that it has increased, but also on why it has increased. I discussed in my opening testimony how many of our asset populations were installed back in the 1950’s and 1960s, are now past their mean-time-to-failure ages or getting very close to it, and are continuing to age. Our need to keep our aging system reliable and resilient for our customers drives infrastructure replacement, which in turn drives prudent but increased capital spending. TURN acknowledges “that there are some legitimate reasons for increased capital spending, such as SCE having embarked on a course of ‘replacing aging infrastructure’” as well as “transmission spending to interconnect renewable resources.” SCE is expected to balance the needs of the customers, the grid, and the regulators with just and reasonable costs. To meet these needs, increased expenditures were necessary in the last few years. The Commission has recognized these needs and approved funding accordingly.

Finally, we are very mindful that utility spending impacts our customers. Since 2012, we have implemented a number of ambitious initiatives so that we work more effectively and efficiently. This has helped us hold the line on cost increases despite the increasing workload and demands of our system. For example, our 2018 operating expense request is nearly $130 million lower than what the

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74 See SCE-25, Vol. 1, Chap. VII.

75 Id.

76 See SCE-01, pp. 10-11.

77 TURN-10, p. 10.
Commission previously authorized for 2015, even though costs have risen in areas like pensions and benefits and IT license renewals.\footnote{See SCE-01, pp. 7-8, 19-21.}
V.

MANAGEMENT DISCRETION

TURN suggests that SCE should be denied recovery for spending on programs in excess of what the Commission has authorized.\(^79\) SCE-25, Volume 3, Chapter III contains a detailed rebuttal to TURN’s proposal. I simply note that the Commission has acknowledged the prudency of these programs in previous GRCs. SCE has put forth detailed testimony on the prudency of new programs. The Commission has also repeatedly ruled that utilities have the flexibility to use their best judgement to manage the business.\(^80\) The future cannot be foretold years ahead, and utilities cannot be subject to treating every activity as a one-way balancing account. Especially in the case of safety and reliability programs, the Commission has encouraged flexibility and increased spending. For example, in PG&E’s Test Year 2017 GRC decision, the Commission stated that “the utility has the obligation to maintain its operations and its plant in the condition to provide efficient, safe and reliable service, even if that condition requires more expenditures than the Commission has authorized.”\(^81\)

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\(^79\) See TURN-12, p. 13.


\(^81\) D.17-05-013, p. 185 (citing D.11-02-018).