Integrated System Planning

Holistic Planning for the Energy Transition

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This whitepaper was prepared by:

Aaron Burdick

Joe Hooker

Lakshmi Alagappan

Michaela Levine

Arne Olson

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Motivation for Integrated System Planning

The electric grid is a modern marvel, constructed over many decades and many billions of dollars for the benefit of society. Planning has always been a critical component of electric power systems, serving as a key foundation for utilities to make large investments in their systems, regulators to evaluate the need for these investments, and stakeholders to meaningfully engage in those decisions.

Power system planners face a novel set of technological changes and planning challenges

Today, power system planners face a growing array of new challenges. The threat of climate change is driving action to ***decarbonize electricity generation*** by states, utilities, and major corporations. After decades of relative stability, ***electric load growth is accelerating***, driven by vehicle and building electrification in support of economywide decarbonization, rapid growth in data centers, and new industrial loads. ***Novel technologies and communications devices are rapidly unlocking new opportunities and markets*** for battery storage, distributed energy resources, and flexible loads. Amidst these changes, utility infrastructure and historical planning methods face ***the reality of a changing climate***, requiring new planning methods amidst higher peak temperatures, more extreme weather events, and increased wildfire risks. Climate extremes are putting even more focus on electric system safety, reliability, and resilience.

The challenge to decarbonize electricity under rapidly growing loads while ensuring safety, reliability, and resilience will require a new scale of investment in electric generation and delivery infrastructure. The Edison Electric Institute estimates utilities are currently investing nearly ~$150 billion per year on electric energy infrastructure and predicts rapid growth in electricity demand of nearly 5% per year over the next five years.[1] Some utilities, such as APS, Dominion, and Georgia Power, are facing much more rapid demand growth of 40-60% before the end of this decade.[2] Decarbonization may require more than tripling the size of the current transmission grid.[3] Including customer and manufacturing investments in electrification, BNEF estimates over $300 billion was invested in the US energy transition in 2023 and that a tripling of global investment is needed to meet net-zero

[1] EEI, "America's Electric Companies: Delivering the Future of Energy." Electric Power Industry Outlook, February 20, 2024. https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/WSB-Presentation.pdf

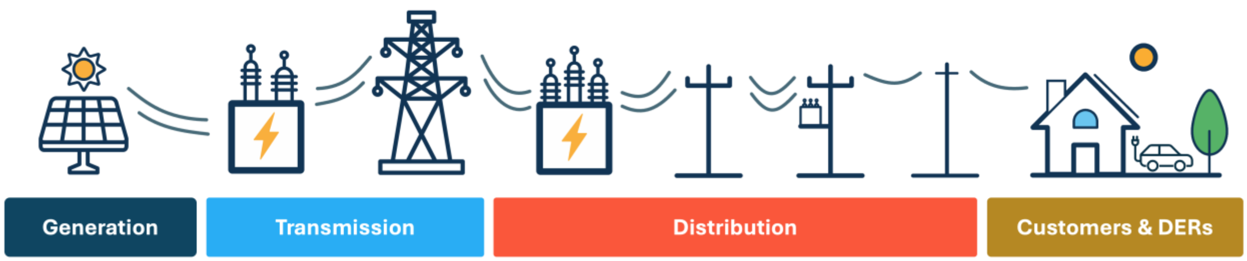
[2] Tory Clark, E3, "Long-term challenges for near-term large loads." EFI Foundation Workshop. February 12, 2024. https://www.ethree.com/wp-content/uploads/2024/02/EFI-Foundation_Long-term-implications-of-near-term-large-loads_2024-02-12_Clark.pdf

[3] US DOE, Grid Deployment Office. "The National Transmission Planning Study." October 2024. https://www.energy.gov/gdo/national-transmission-planning-study

carbon targets by 2050.[4] This transformation is forecasted to occur continuously over the next two decades.

If the supporting grid infrastructure buildout is done efficiently, ***growing loads can provide downward pressure on electric rates*** to support additional load growth in a virtuous cycle. In other scenarios, the **cost of *new grid infrastructure may be a substantial challenge to customer affordability*,** limiting electrification and inhibiting the transition to a decarbonized economy. Managing this balancing act is the unenviable imperative of the current generation of system planners.

Traditionally siloed planning processes are no longer sufficient to plan the grid of the future



Electricity planning needs are generally categorized into four key areas: generation, transmission, distribution, and distributed energy (customer) resources. Each of these four planning domains has traditionally had its own planning horizon, planning cycle timeline, scenarios evaluated, model(s) used, key constraints, and set of investment solutions considered.[5] For many utilities, these processes have been siloed historically. Misalignment from siloed processes may take on many forms, including different data inputs (load forecasts, scenarios and sensitivities, resource and fuel costs, etc.), analytical processes without clear connections, and different planning teams with insufficient coordination.

Planning in silos may have been sufficient for building the grid of the past, with flexibly sited dispatchable generation and a one-way flow of power from bulk grid generators down to customers. However, the power grid of the future – comprised of many remote variable renewable energy resources, a diverse set of energy storage technologies/locations, and two-way power flow from controllable DERS and flexible loads – can no longer effectively be planned through siloed processes. New technologies and communications and control platforms are increasingly enabling deployment of new resources to support multiple system needs. If siloed planning continues, it is likely to result in key misalignments and missed opportunities. Examples are shown in Table 1 below.

[4] BNEF, "Energy Transition Investment Trends 2024: Tracking Global Investment in the Low-Carbon Transition." January 30, 2024. https://assets.bbhub.io/professional/sites/24/Energy-Transition-Investment-Trends-2024.pdf

[5] A comparison of the traditional approaches for each planning process is captured in an appendix.

Table 1. Missed opportunities from siloed planning the grid of the future

Processes Impacted	Potential Misalignment	Impact
T → G	If transmission upgrade costs are not properly incorporated into generation planning…	…a higher cost, sub-optimal generation (and transmission) portfolio will be selected
Storage ←→ G/T/D/C	If the grid benefits of storage siting are not considered…	…storage may end up in sub-optimal locations creating missing opportunities to avoid or defer T&D investments
G → T	If changing risk periods from evolving resource mixes are not considered…	…the wrong periods for transmission deliverability and stability studies may be modeled, missing necessary reliability upgrades
C ←→ G/T/D	If DERs + flexible loads are not considered as generation or grid resources (e.g., virtual power plants or non-wires alternatives)…	…it may lead to over-building of bulk grid generation and distribution infrastructure

Integrated planning can identify optimal system investments

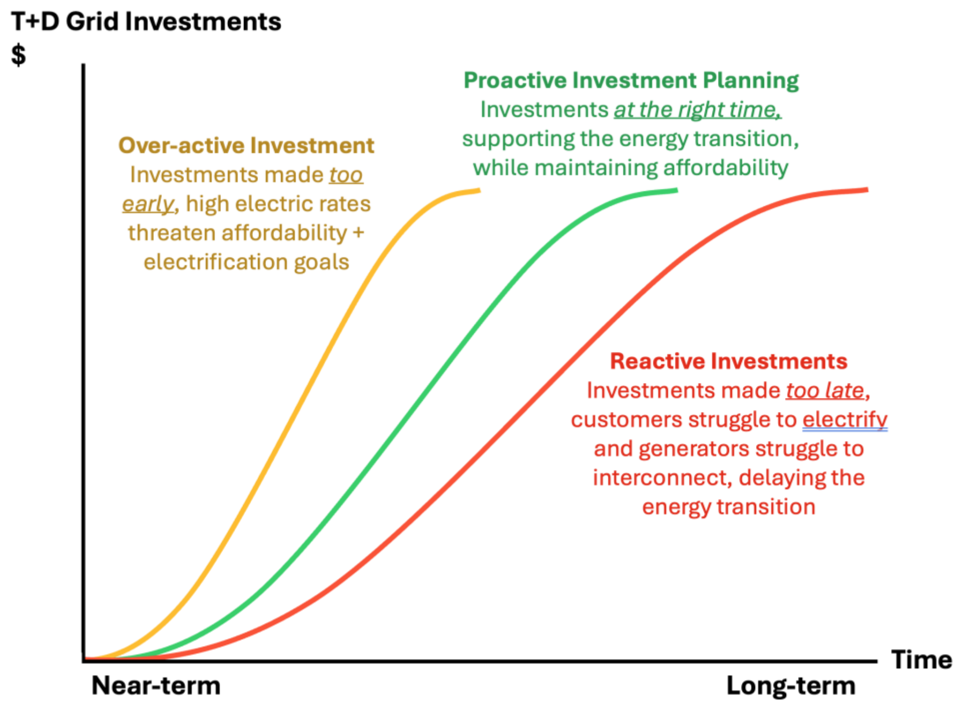
Integrated system planning (ISP) utilizes a ***cohesive set of data, processes, and models to integrate generation and customer resource planning with transmission and distribution grid planning***. This integration is critical to making decisions that balance ***making the right investments, in the right places, at the right times***. As technology and participatory models advance, customers will increasingly be involved in this transition, ***requiring utilities and regulators to know when to support customer investments or behavioral changes over their own historical "wires" investments***, while ensuring sufficient reliability and operational control over the broad and powerful set of emerging customer resources.

Making the right investments requires a robust decision framework that allows for co-optimization across a broad range of all potential solutions. There are increasing interdependencies between investments in generation, energy storage, customer resources, flexible loads, or expansion of the grid. An integrated planning framework ensures a globally optimal planning solution by considering the interactions of investments across planning domains.

Making investments in the right places requires increasingly granular geospatial forecasting of loads and generation resource options. Investments to expand the grid are critical to support both remote renewable resource development as well as local economic development and electrification. Ensuring the right locations for new grid investments requires increasingly granular geospatial planning for both bulk grid resources as well as loads and DERs, so that grid limitations do not limit renewable energy, local business development, or customer electrification growth.

Making investments at the right time requires expanded planning horizons and investment-grade forecasts of grid needs. Reactive grid investments that wait for new load or generation interconnection requests need to be sped up to the extent possible, but *proactive* grid investments that prepare for expected new load growth or remote generation delivery will be required to keep pace with the scale and speed of investment needed for mid-century decarbonization. Over-investment will drive up electric rates, while insufficient investment may threaten the energy transition, frustrating customers and leading to delays in retirement of emitting, legacy generation. Proactive planning and integrated scenarios across G/T/D/customer planning can support the right timing of grid investments, as shown in Figure 1.

Figure 1. Optimal timing of grid investments



The same principles that apply to utility investments in generation, transmission, and distribution, also apply to customer loads and DERs. Flexible loads should be incentivized to increase or decrease their demand in the right places and the right times. DER investment should be right-sized to support least-cost planning and customer equity, directed to optimal locations to maximize grid value and grid utilization, and operated in alignment with the timing of system value.

Robust and transparent integrated planning can facilitate the regulatory processes needed to build the grid of the future

Regulators today face challenging decisions as they weigh the utility capital spending needed to maintain and expand today's grid while ensuring affordability and equity amongst customers. Integrated system planning processes can help facilitate this process of evaluating the need for new investment:

+ Integrated planning identifies the least-cost global optimal solution across planning domains, supporting customer affordability objectives.

- Robust long-term scenario planning across G/T/D ensures near-term investments remain prudent and valuable in the long run.
- Proactive integrated planning can help identify the investments needed to avoid delays in customer load growth and the energy transition.
- A centralized, integrated planning process increases transparency and streamlines participation for regulators and stakeholders.

Leading utilities have already begun building innovative integrated system planning practices. In 2022, Xcel Energy created a new integrated system planning department responsible for planning its generation, transmission, distribution, and natural gas systems.[6] In 2023, Hawaiian Electric released its inaugural Integrated Grid Plan, outlining a pathway to reach 100% renewable energy on its five island grids by expanding investments in generation, transmission, distribution, customer resources, and advanced rate design.[7] In 2024, the Salt River Project (SRP) released its first Integrated System Plan, which identifies generation, transmission, distribution, and customer program investments, strategies, and actions to guide planning and achieve sustainability goals through 2035.[8]

This paper presents E3's vision for Integrated System Planning and highlights a path for electric utilities of all sizes to begin to unlock the opportunities of integrated planning.

[6] https://www.utilitydive.com/news/xcel-srp-planning-teams-integrated-planning/639674/
[7] https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning
[8] https://www.srpnet.com/grid-water-management/future-planning/integrated-system-plan

Vision for Integrated System Planning

There is no single, standard blueprint for integrated system planning. In this section, we put forward one vision for integrated system planning based on decades of E3's experience supporting system planners in planning all aspects of the electric system. We describe which cross-system interactions are important to capture, which analytical processes should be integrated, and how to organize these analyses through an implementable end-to-end process.

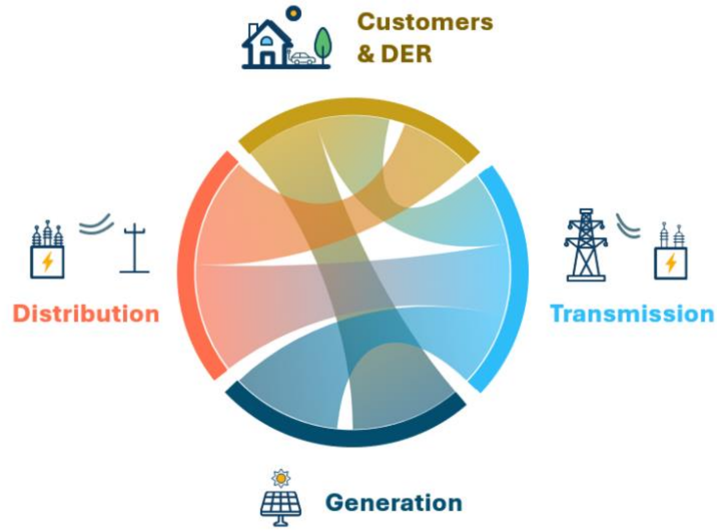
Integrated System Planning Captures Interactions Across the Power System

Planning one part of the system impacts planning for all other parts of the system. Bulk-grid resources need transmission to deliver energy to load centers but can also be sited to reduce transmission infrastructure needs. DER can reduce, increase, or shift local and total system energy demand, so their value depends on impacts to distribution, transmission, and bulk-grid resource needs. Distribution infrastructure must be built to serve increasing energy demand, including from electrification, but the management of DER can also help to mitigate or defer a portion of those infrastructure needs (e.g. by managing the timing of electric vehicle charging). Transmission infrastructure must be built both to connect bulk-grid resources and to deliver energy to constrained load areas.

The goal of integrated system planning is to capture these interactions to help identify investments are optimal from a system-wide planning perspective. By considering the full value of investments across all parts of the system, system planners can identify the best solutions.

Figure 2 conceptually illustrates some of the key interactions enabled by an integrated system planning process. Integrated system planning recognizes planning interdependencies and creates an interconnected planning process to address them, rather than planning each individual area an independently or with a single, one-way flow of information.

Figure 2: Integrated system planning interactions



This graphic and the remainder of this section focuses on the best practices for robust, holistic system planning for all parts of the electric power system: bulk-grid generation, transmission, distribution, and customers and DER. Vertically integrated utilities may be able to perform all these integrated planning functions themselves. However, depending on the system planning entity (or entities) and which planning functions are under their purview, integrated system planning may look different in different locations.

Figure 3: Planning Responsibilities by Organization Type

Organization type	C/DER	D	T	G
Vertically-integrated utility	●	●	●	●
Transmission & distribution utility	●	●	●	
Generation & transmission co-op			●	●
Federal power marketing administration (PMA)			●	●
Regional transmission organization (RTO)			●	
Non-RTO transmission planning regions			●	
Competitive supplier	●			●
Community choice aggregator	●			●
Distribution co-op / municipal utility	●	●		

Planned by organization   Need to consider in planning

In a restructured electricity market, bulk transmission planning is the responsibility of the market operator and generation planning – to the extent that it occurs at all – is carried out by competitive power suppliers. As another example, a generation and transmission (G&T) co-op does not perform distribution planning in the way that a vertically integrated utility would. Nevertheless, utilities in both systems would still need to consider how other parts of the system are evolving when performing planning analysis. The restructured utility would need to consider bulk-grid resource dynamics and customer DER adoption—including expected resource needs and locations, locational energy prices, ancillary service prices, and capacity prices—when planning grid investments. The G&T co-op would need to consider changes in system dynamics and load shapes as adoption of DER grows. Regardless of the system being planned, system planners need to consider value provided across the entire system when identifying optimal investments.

In non-vertically integrated utility processes, this requires collaboration not just within an organization, but also across organizations. While this introduces additional challenges, it has been done successfully by the California Public Utilities Commission (CPUC) and California Independent System Operator (CAISO), which have been coordinating their generation and transmission planning processes since 2010, a case study highlighted later in this paper.

Key Steps in an Integrated System Planning Process

E3 has identified which analyses are needed to perform integrated system planning and one potential way to stitch these analyses together through an integrated process (see Figure 4). The process consists of three sequential steps:

1. Forecast system needs across scenarios: The first step in the process is to develop scenarios for how the world could unfold and impact system needs. For each scenario, system planners would need to forecast the timing and magnitude of energy demand, DER adoption, and other impacts across all parts of the system to characterize reliability needs and sustainability needs.
2. Perform system analysis across scenarios: In this step, system planners identify solutions to meet system needs safely, reliably, affordably, and sustainably across all scenarios. This is the most modeling-intensive step in the process, including generation, transmission, distribution, and customer/DER planning analyses. While scenario planning is already standard practice for generation planning, integrated system planning extends it to customer/DER, distribution, and transmission planning to understand how the entire system could evolve under different scenarios.
3. Develop a preferred plan and action plan for investment: The final step in the process is to identify a preferred system plan, which appropriately balances reliability, cost, sustainability, and other factors, and an associated action plan that details next steps for implementing specific investments.

Figure 4 illustrates these three steps and the types of analyses that, when properly coordinated, can allow a system planner to perform integrated system planning.

Figure 5 provides a description of each of the analyses and highlights which parts of the system are considered by each analysis. The following sections describe each of these steps and the underlying analyses in more detail.

Figure 4: Integrated system planning process

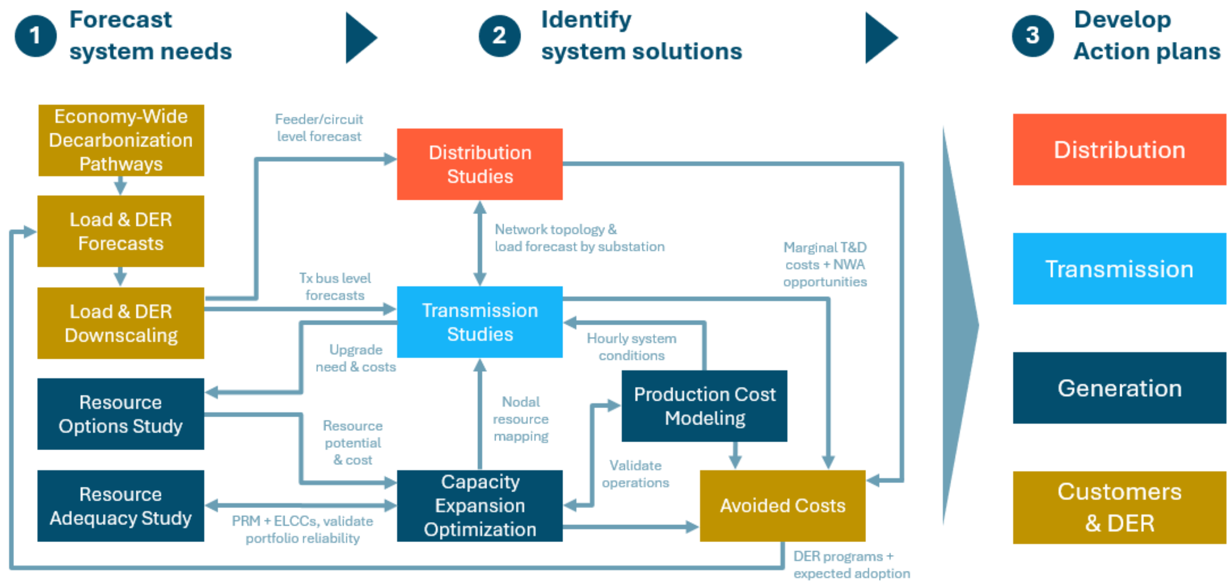


Figure 5: Components of Integrated System Planning

ISP Analysis Component	Description	C/DER	D	T	G
Decarbonization Pathways	Forecasts alternative economy-wide decarbonization pathways and informs electrification impacts to the load forecast	●			
Load & DER Forecasts	Forecasts customer energy demand, incorporating electrification, and customer program + DER adoption forecasts	●			
Load & DER Downscaling	Downscales system-wide load forecast to distribution, transmission, and zonal levels	●	●	●	●
Resource Options Study	Evaluates resource options, potentials, costs, transmission costs for remote resources, etc.	●		●	●
Resource Adequacy Study	Determines system total resource need for ensuring resource adequacy and contributions of resources at various penetration levels	●		●	●
Distribution Studies	Identifies distribution infrastructure needed to accommodate load growth and distributed resources	●	●		
Capacity Expansion Optimization	Identifies generating resource portfolio, including bulk grid generators, enabling transmission investments, storage, distributed energy resources, etc.	●		●	●
Production Cost Modeling	Assesses zonal and/or nodal resource operations and quantifies production costs at granular hourly or sub-hourly timescales	●		●	●
Nodal Resource Mapping	Maps generation and storage resources across the network to help minimize transmission investment needs and inform detailed transmission studies			●	●
Transmission Studies	Identifies transmission infrastructure needed to accommodate load growth and resource additions, ensure reliability and system stability		●	●	●
Avoided Costs	Translates infrastructure planning needs into granular marginal avoided costs to value customer programs and inform rate design	●	●	●	●

Step 1: Forecast system needs across scenarios

The first step in the ISP process is to develop several robust scenarios for system needs, including standardized load forecast scenarios. It is no longer sufficient to evaluate a single preferred scenario for resource planning. The wide range of plausible yet highly uncertain path s for public policy, technology costs, and customer preferences requires evaluating multiple scenarios to enable informed decision making by planners, regulators and stakeholders.

Economy-Wide Decarbonization Pathways

For best-in-class load forecasting, new methods will be needed to address climate change impacts and to forecast electrification load growth. Analysis of economywide decarbonization pathways can inform electrification load growth scenarios, while other analyses can help determine EV charging patterns and flexibility as well as building electrification shapes. Accounting for the electrification of space heating is especially important for system planning in cold climates, where cold snaps can result in significant surges in electricity demand. These spikes in energy demand not only change energy usage patterns but also have the potential to significantly increase the system peak demand.

Load & DER Forecasts and Downscaling:

After accounting for future trends in energy usage and DER adoption, system planners must then downscale system-level forecast to specific locations on the transmission and distribution network to understand both where and when new loads and DERs will appear in the system. Often, utilities develop bulk system and distributions system load forecasts through independent and siloed processes leading to inconsistent views on load growth and peak loads. Downscaling bulk system load and DER forecasts to the granular elements of the distribution system allows planners to conduct distribution studies and develop resource plans based on a unified load forecast. Also, the downscaled forecasts can help utilities better incorporate DER and flexible loads into distribution planning. Aggregating up a distribution system level forecast to a zonal level can then be used in transmission planning activities further unifying the vision of load growth across generation, transmission, and distribution planning.

Step 2: Perform system analysis across scenarios

In this step, system planners identify solutions to meet system needs safely, reliably, affordably, and sustainably. This is the most modeling intensive step in the process, including bulk-grid resource, transmission, distribution, and DER analyses.[9]

While the ideal would be to create a single planning model that solves all system needs simultaneously, optimization models that are in common use today in the industry do not allow this. First, given the immense complexity of the electricity system, computing power is not sufficient for such a planning model to find an optimal solution. Second, system planners do not only rely on least-cost optimization to identify investments. For example, for customer program offerings, system planners may also consider other factors such as access, equity, understandability, etc. For these reasons, system planning must include a series of analyses to identify system investments.

Our vision for integrated system analysis is not a single integrated model or end-to-end linear process but rather includes feedback loops to capture interactions between distinct planning

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[9] The specific level of integration between the modeling in each process will be unique to each integrated system planning process. Multi-organization processes may require additional time for iteration between processes (such as an extended iterative loop between planning cycles). Vertically integrated utilities have the most ability to co-optimize all their planning models, though the more co-optimization performed (either within a larger model or between models), the longer and more effort an ISP process will be.

processes and to ensure that the solutions identified consider reliability and costs across the entire system. Based on our experience, the key feedback loops to incorporate are as follows.

Electrification Adoption ←→ Distribution Studies

The adoption of electric vehicles and electric heat pumps are increasing energy demand, and, if not managed properly, can lead to significant infrastructure requirements. The timing of this energy demand is critical for determining the needs for new infrastructure and where to make proactive investments. Rate and program design can encourage customers to take actions that benefit the grid, such as charging electric vehicles during low-cost periods, pre-cooling buildings in summer, and reducing electric heating demand during extended cold periods. A scenario planning approach allows scenario planners to understand load impacts of electrification and the implications for infrastructure needs. Integrated system planning and the quantification of avoided costs, as discussed further below, can help system planners design rates and programs to enable electrification more cost effectively.

Load Flexibility and DER Adoption ←→ Distribution Studies

Utilities perform distribution studies to identify new equipment and upgrades needed to accommodate new customers, energy demand growth, and/or DER—such as very high levels of rooftop solar. Under certain conditions, load flexibility and DER solutions may be able to speed up interconnection timelines, increase utilization of existing infrastructure, and help replace or defer the need for some investments through load reductions or dispatchable virtual power plant (VPP) services. Solutions to replace or defer investments, known as non-wires alternatives, would require a sufficient customer/DER response to meet the reliability need on the distribution system, and with enough certainty to be relied upon for planning purposes. If planning identifies non-wires alternative solutions, then procurement mechanisms will be required with sufficient lead time to ensure that these resources can be in place and obviate the need for traditional infrastructure investments. Regardless of whether customer/DER response can obviate the need for a particular distribution system investment, these resources should still be incentivized in a way that encourages their cost-effective integration and operation to reduce overall system costs.

Distribution Studies ←→ Transmission Studies

The buildout of the delivery system must be coordinated. While distribution planning and transmission planning are differentiated by different voltage levels and the type of infrastructure required, they are part of one integrated delivery system that must be planned together. In a siloed process, transmission and distribution planners make independent assumptions regarding load shapes and the timing of peak loads. This could result in distribution planners modeling load growth and new substation additions that exceed the local transmission capacity. Under an integrated planning process, load and DER can be downscaled to the feeder level and then aggregated back up to the substation level to ensure that distribution and transmission analyses utilize the same load assumptions. If loads and DER are responding flexibly to rates, pricing signals, or programs that allow for more efficient system investment and operations, including addressing local distribution constraints, then these operations are important to capture in transmission studies. As new transmission and distribution substations are added, they will need to be coordinated to ensure that the delivery infrastructure is in place in time to respond to new system needs.

Resource Adequacy Study ←→ Capacity Expansion

Resource adequacy analysis quantifies the total reliability need via a planning reserve margin (PRM) and the contribution of all resources toward that need via effective load carrying capability (ELCC) values. While ELCCs have traditionally been quantified for renewable and storage resources, they can be quantified for all resources to ensure that all resources are evaluated on a level playing field. Using ELCC for thermal resources can account for potential correlated outages and the outsized impact that large unit outages can have on system reliability. Using ELCC for DER, such as demand response, energy efficiency, and sources of load flexibility, such as managed charging, can account for the potential for these resources to contribute to overall system reliability. Resource adequacy analysis consolidates information from hundreds of years of simulations into a series of simplified inputs for capacity expansion modeling. Because of this information consolidation, it is important to perform resource adequacy analysis on one or more portfolios resulting from capacity expansion to ensure that the resulting portfolio is in fact reliable and that the simplified inputs for capacity expansion are well-calibrated to the extreme events captured in the resource adequacy study.[10] As climate change continues to alter the timing and nature of extreme events, those impacts should be incorporated consistently into both capacity expansion and resource adequacy studies.

Transmission Studies → Capacity Expansion → Production Cost Modeling → Transmission Studies

The need for transmission upgrades depends on the location of resource additions and retirements, the location of loads and DER, and the operations of the system. To better align transmission upgrades with resource additions, iterations are needed between transmission and resource planning tools. Transmission studies, which can include power flow analysis and stability analysis, can identify which transmission upgrades are needed and under what conditions. The existing transfer capacities, costs of new transmission upgrades, and operational constraints can, in turn, be input into a zonal capacity expansion model to inform the selection of resources across different areas of the system. The resulting zonal builds can then be mapped to specific buses on the system for detailed transmission analysis. Because capacity expansion simplifies system operations and samples a subset of operating conditions, production cost modeling may be needed to characterize the detailed commitment and dispatch across all hours of the year and to capture detailed sub-hourly constraints including flexibility and operating reserve requirements. Production cost modeling outputs can then be used as inputs into transmission studies to characterize the

[10] For utilities operating in organized markets, the PRM and ELCC values are determined by the market operator. In this context, the utility may not perform an independent resource adequacy analysis but would still need a forecast of ELCC values over time.

operations of resources across the system. These transmission studies can then be used to identify the transmission investments needed to maintain system reliability for the portfolio of interest, focusing on snapshot scenarios of transmission reliability risk.

Avoided Costs

Avoided costs are one of the key tools for properly assessing DER, customer programs, and sources of load flexibility. Avoided costs quantify the full system value from reducing load by 1 kWh (or generating 1 kWh) during different times of day and different periods of the year. Because integrated system planning identifies the investment and operational costs needed to meet system needs in the future, the outputs from this planning can be used to forecast the avoided costs over time. Also, because integrated system planning looks at all system needs, the outputs can be used to quantify the avoided costs for generation energy, generation capacity, transmission capacity, distribution capacity, environmental attributes, etc. Some of these values, such as distribution capacity value, vary greatly based on the location of DER or customer response, meaning avoided costs can also be differentiated by location. Most of these values, such as generation energy, will depend heavily on the time of day and season and will differ with each scenario. System planners can use avoided costs as part of more expansive studies to assess changes to time-varying rates, customer programs, and DER incentives to align the price signals for these initiatives with the costs to serve future system needs. This allows system planners to incentivize actions that would benefit the overall system and can incorporate the results of those actions in subsequent planning exercises. For example, if a utility modifies time-of-use rates to better align with avoided costs, then this could induce a customer response that shifts energy demand from higher-cost periods to lower-cost periods. In this way, the avoided costs can be used to iterate between integrated system planning and detailed rate, customer program, and DER program design.

Through these analyses and the feedback loops between them, system planners can identify solutions while considering value provided to all parts of the power system and the interrelated nature of planning different parts of the system. By doing this across different scenarios, system planners can identify a range of system plans based on future conditions. System planners can quantify and compare the performance of these plans along system-wide metrics, including reliability, cost, and carbon emissions.

Step 3: Develop a preferred plan and action plan for investment

The third and final step is to develop a preferred plan and action plans. The system analysis is performed across different scenarios, but ultimately system planners need to identify a preferred plan to guide near-term actions. Choosing a preferred plan does not mean that system planners are locking in all decisions through the end of the planning horizon. Many investments in later years do not need to be (and should not be) locked in today and can be re-evaluated in future planning cycles. Rather, the preferred plan is helpful for defining a long-term planning vision and identifying which near-term investments and actions are needed.

Identifying a preferred plan needs to balance competing objectives for system planning, including reliability, cost, and emissions. The preferred plan should be based on the analysis performed but may not correspond to a single system plan that is identified from modeling. Because the future is uncertain, system planners need to weigh the potential for different future outcomes and make judgements for how best to balance planning objectives and hedge against future risks.

Engagement with regulators and stakeholders is essential for developing a preferred plan and taking action following the planning process. Only through transparency and engagement will system planners gain the support and approvals to make investments, incentivize customer/DER actions through rate design and programs, and make other changes that are beneficial to customers. This will require producing key metrics to support investment decisions, such as system cost forecasts, customer rate impacts, reliability risk metrics, and emissions reduction benefits.

After developing a preferred plan, the next step is to develop an action plan. The action plan should detail the near-term activities that allow the planning organization to realize system additions and customer actions consistent with the preferred plan. Below are some examples of potential actions:

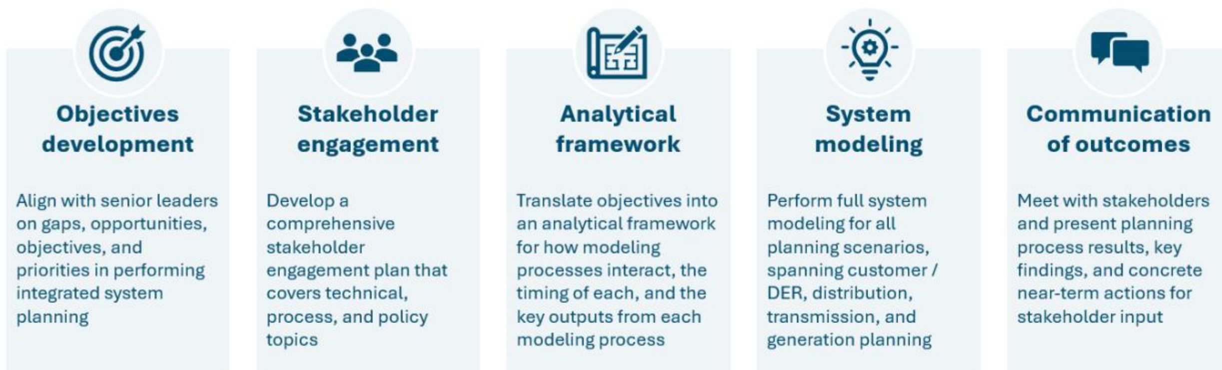
- A **resource procurement plan** details procurement targets and timelines, which may include issuance of an all-source request for proposals for new resources to provide capacity, energy, and/or clean energy. Any assessment of bid options would leverage the models developed for the ISP.
- A **transmission investment plan** outlines specific transmission system investments and non-wires alternatives to be made in support of reliability, cost reduction, and generation resource growth.
- A **distribution investment plan** that details modifications to near-term plans for grid investments and customer programs based on DER adoption, electrification, and other factors explored in the ISP. This may be approved separately or within a utility general rate case.
- **Assessment of rate design and customer programs**, including time-of-use rates and demand side management programs, to incentivize customers to shift energy usage and mitigate a portion of future investment needs. Modifications to rates and programs should be informed by near-term avoided costs as well as policy and equity considerations.

There are many other potential actions that organizations could incorporate into an action plan, including more detailed follow-on studies, pilot projects, roadmaps, and communication strategies. The action plan is one of the most important outputs from integrated system planning, as it translates planning analysis into real-world actions to improve the system. By performing integrated system planning, system planners can ensure that their actions are well-coordinated and consider costs and benefits across all parts of the system.

Roadmap to Integrated System Planning

In addition to the technical framework presented above, additional key components of integrated planning are highlighted in Figure 6. Objectives development is a critical starting point for organization(s) initiating integrated planning, whereby staff and leadership develop alignment on the core planning objectives to guide the scenario development and analytical design. Stakeholder engagement is a critical part of planning, where planners need to gain input from internal and external stakeholders on both technical and policy topics. The analytical framework and system modeling proceeds as described in detail above. Finally, communications of planning outputs ensures stakeholders understand analytical results and regulators can approve proposed near-term actions with confidence in the robustness of the planning completed.

Figure 6. Key steps in ISP implementation



When considering the creation of an integrated system planning process, planners may commence the journey from different starting points with their own unique set of challenges and constraints. Some planning is done by a single vertically integrated utility, while in other cases planning is done across multiple organizations. Some utilities are still completing important updates to bring their existing planning processes up to industry best practice. Some are budget or personnel constrained. Some may have already pursued planning integration and are now focused on making continuous – but more incremental – improvements.

Barriers to integrated planning may be technical, procedural, organizational, or cultural. For most systems, adopting an approach of gradual improvement will facilitate a sustainable pace of change management. Figure 7 below outlines key steps for planners to take at three archetypical stages of integrated planning.

The “walk” stage focuses on the key activities to begin planning process integration, focused on alignment of key assumptions, scenarios, and timelines for separate planning processes. At this stage, existing processes may be significantly siloed and each process may need individual improvement. To begin, each planning process should be updated to use industry best practices, in preparation for later stages of integration. Team structures would generally remain, but coordination amongst existing teams would increase. Sourcing methods would begin integration, such as developing avoided costs from generation planning to use for customer program evaluation. There is value in completing a limited initial round of integrated system planning, allowing a launching pad for continued refinement in the second and future planning cycles.

The “jog” stage picks up from the walk stage activities, focusing on the development of models, datasets, planning scenarios, and organizational structures to explore more integrated solutions. At this stage, utilities should consider whether organizational changes are needed to increase efficiency, such as the creation of an integrated planning team to oversee ISP activities. Key connections between models and processes should be developed, such as development of detailed transmission inputs for capacity expansion analysis or a clear process to integrate DER planning into generation resource planning. Sourcing methods evolve to explore and pilot procurement methods to source alternative solutions, such as a solicitation process for DER providers to bid non-wires alternatives to compare against traditional investment costs or consideration of flexible load programs as alternatives to bulk grid energy storage procurement.

By the “run” stage, planners have developed fully integrated planning and procurement processes. ISP cycles, methods, data, and models are solidified. Integrated sourcing solutions are considered within planning and there are clear feedback loops and processes between planning and procurement.

Figure 7. Stages of Integrated Planning

	Walk Stage Get started	**Jog Stage** Increasing connections	**Run Stage** Full integration
Organizational Alignment	Key **thought leader(s) drive integration** and increase cross-team coordination	Creation of an **integrated planning team**	**Full integration with other business units** (strategy, finance, rate design, etc.)
Scenario Planning	**Standardize scenarios and key inputs**	**Planning process timelines and scenarios/inputs are standardized** into an ISP cycle	Integrated scenario development across all planning processes
Technical Analysis	Improve each individual process to industry best practice, limited connections between individual models	**Increased model + data connections** (co-optimization and/or established data connection between processes, etc.)	**Fully integrated modeling processes**
Procurement Integration	Increased connection to planning (e.g., developing DER avoided costs using ISP preferred plan)	Initiate **new procurement pilots using ISP results** (e.g., flexible EV charging, non-wires alternatives, etc.)	**Fully integrated procurement processes** with feedback to and from the ISP process

Many system planners may be starting at the “walk” stage, while a few leading organizations may already be at the “jog” stage. For smaller organizations, getting from the “walk” to the “jog” stage may be sufficient, while larger organizations and regional planning entities should aim to initiate integrated planning and eventually arrive at the “run” stage. E3 believes that all entities should explore gradual integration activities while maintaining the pace of infrastructure development needed to support their systems and their customers. It is better to complete multiple integrated planning cycles with incremental improvements than to get bogged down for years trying to leapfrog to a fully integrated process.

Conclusion

Transformational changes are occurring in the rate of electricity demand growth, technology expansion, and the scale of investments in the electric grid. These drivers require planners to integrate previously siloed planning processes to facilitate coordinated planning that ensures the right investments in the right locations at the right time. Integrated system planning will continue to evolve as planners experiment with new methods and new tools for linking generation, transmission, distribution, and customer/DER planning. The foundational principles outlined in this whitepaper – aligning inputs and scenarios, establishing key data linkages between planning processes, and coordinating near-term investment actions – are the foundations that will enable electricity planners to holistically plan a clean, affordable, and reliable 21st century power system.

The following section presents case studies from recent E3 projects for organizations in various stages of integrated planning.

Case Studies

Below are three case studies from recent E3 projects supporting system planners in performing integrated system planning.

1. The Salt River Project (SRP) case study highlights a vertically integrated utility developing its first integrated system plan.
2. The California case study highlights the public utilities commission and independent system operator collaboration to coordinate generation and transmission planning, including the optimal siting of battery storage resources.
3. The New York City PowerUp case study focuses on geospatial load forecast data development and application for studying electrification distribution grid impacts.

Salt River Project's Integrated System Plan

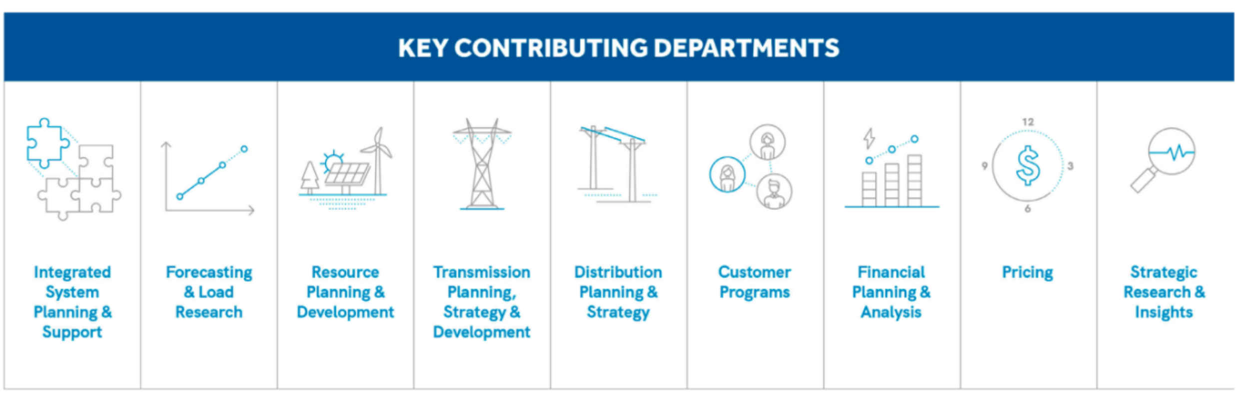
In April 2024, SRP published its first-ever Integrated System Plan (ISP).[11] To develop the ISP, SRP engaged community stakeholders and brought together planning groups across SRP to perform comprehensive system-wide planning and to identify strategies to guide planning through 2035. E3 supported SRP throughout this effort, starting in 2021, by advising on the objectives, analytical framework, and overall process; performing analysis; supporting stakeholder engagement; and presenting to SRP's stakeholders and leadership teams.

Creating a foundation

In 2020, SRP created a new team, Integrated Planning, to identify how SRP can integrate planning processes better and to lead the development of the first ISP, as well as future ISPs. The first ISP, while groundbreaking in and of itself, sets a strong foundation for future ISPs by setting up a collaborative process, standardizing planning inputs and assumptions, and identifying opportunities for improvements.

Collaborative process: To carry out the first ISP, SRP convened team members from across the organization (see Figure 8). Because the analysis covered load forecasting, generating resources, transmission, distribution, and customer programs, SRP brought together members from each of these teams, as well as members from the finance, pricing, and strategic research teams to understand rate impacts and customer preferences across system plans. Throughout the ISP, members from these teams and many others met regularly to align on planning inputs and assumptions, understand interactions between planning analyses, and discuss modeling results. This collaboration had many benefits, within and outside the ISP, including establishing an end-to-end system modeling framework, deepening understanding of other groups' planning processes, and understanding the impact of actions across different parts of the system.

Figure 8: SRP ISP Project Team



Standardized inputs and assumptions: One of the first steps in the ISP was to develop planning scenarios and modeling inputs. SRP standardized these scenarios and inputs across all planning

[11] https://www.srpnet.com/grid-water-management/future-planning/integrated-system-plan

analyses to ensure consistency. While some planning teams regularly perform scenario planning, this was a new planning framework for other teams. SRP also standardized the planning horizon, which was 2025 through 2035, a key milestone for SRP's Sustainability Goals. The ISP was the first time that all planning groups at SRP performed planning through 2035.

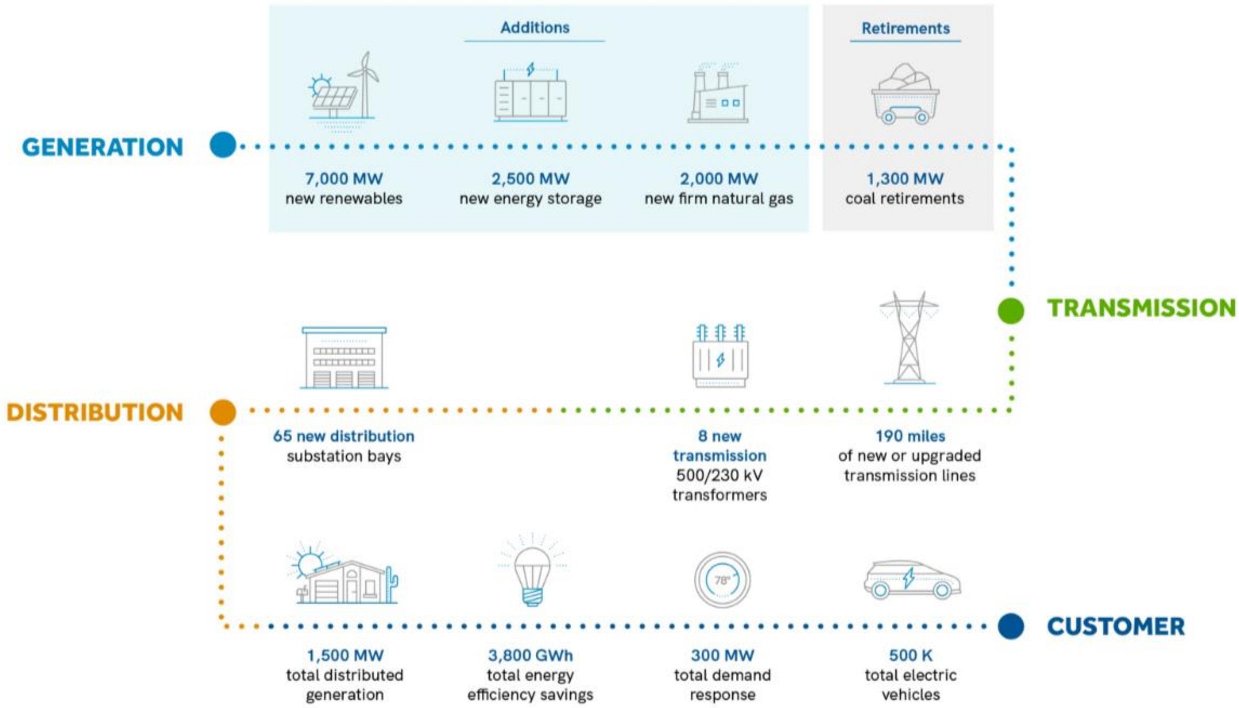
Opportunities for improvements: SRP plans to conduct ISPs on a regular cycle and make improvements with each one. The first ISP allowed SRP to learn a lot about how to perform integrated system planning. SRP can take lessons learned on what went well and what didn't to make the next ISP better and more efficient to carry out. Moreover, SRP can evolve methodologies in the next ISP to better capture the interactions between different parts of the system. Now that SRP has a solid foundation from the first ISP, SRP can continue to improve and build out the ISP process.

Outcomes from the first ISP

This was the first time that SRP performed system-wide modeling through 2035 to understand the affordability, reliability, and sustainability implications of different planning pathways. SRP performed analysis across more than 40 planning cases to understand investment needs, customer contributions to planning needs, and system operations across a diverse range of futures. Based on the key findings from this analysis, SRP developed seven System Strategies to guide planning decisions between 2025 and 2035, as well as ten near-term ISP Actions that further the System Strategies. The SRP District Board of Directors approved the System Strategies on 10/2/2023.

SRP also developed a Balanced System Plan (BSP), which illustrates how SRP’s system could evolve through 2035 through implementation of the System Strategies (see Figure 9). The BSP underscores the magnitude of change across all parts of the system between now and 2035, adding more than 11,000 MW of new resources, retiring 1,300 MW of coal capacity, adding 190 miles of transmission, adding 65 new distribution substation bays, reaching 3,800 GWh of energy efficiency and 300 MW of demand response, and helping facilitate customer adoption of 1,500 MW of rooftop solar and more than half a million electric vehicles. As SRP works to carry out the System Strategies and realize these monumental shifts in the energy system, the ISP will play a key role in guiding SRP’s planning efforts.

Figure 9: SRP's 2035 Balanced System Plan



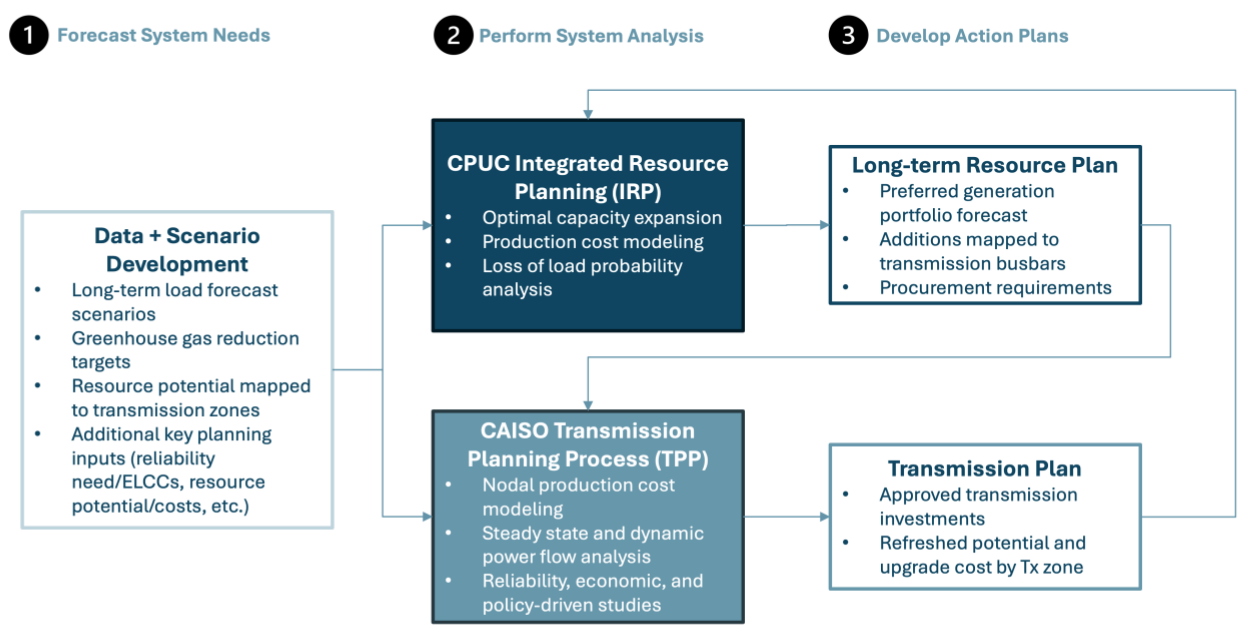
California's Integrated Generation and Transmission Planning Process

Having been a pioneering leader in the growth of renewable energy capacity and associated transmission since the early 2010s, California has developed and refined an innovative, iterative approach to integrated planning. As a semi-deregulated electricity market, bulk grid generation and transmission planning is not just performed by California utilities. Instead, it involves collaboration across three California regulatory agencies—the California Public Utilities Commission (CPUC), California Air Resources Board (CARB), and California Energy Commission (CEC)—and the California Independent System Operator (CAISO) throughout the entire process. E3, as the CPUC's technical consultant for resource planning for over 10 years, has helped the CPUC to develop and improve this process.

Integrating Planning Processes

Figure 10 summarizes how California agencies and the CAISO coordinate resource and transmission planning through a three-step process.

Figure 10. California Integrated Generation and Transmission Planning Processes



Forecasting system needs occurs across multiple processes that set key inputs for statewide planning. The CARB determines the electric sector greenhouse gas reduction planning targets. The CEC annually sets the load forecast over the next decade or more. The CPUC develops resource portfolios and additional key inputs and assumptions for their Integrated Resource Planning (IRP) analysis. The CAISO provides detailed transmission system potential and upgrade costs, which the CPUC and the CEC map to specific renewable energy resources zones that are considered for future resource investments.

Integrated system planning analysis is performed through two iterative and complementary processes. The CPUC's IRP process identifies an optimal long-term plan for resources to meet

California's clean energy goals and maintain reliability at least-cost. This process uses zonal capacity expansion modeling, but with transmission deliverability constraints and upgrade costs developed from the prior CAISO Transmission Planning Process (TPP). The Commission-approved Preferred System Portfolio from the IRP is then transmitted to CAISO for study in the next TPP, where detailed study by CAISO can result in identification of associated transmission needs. The CPUC collaborates with the CEC and CAISO to spatially disaggregate the zonal resource builds from the capacity expansion model and allocate these resources to substations via a busbar mapping analysis.[12] The amount and location of resources may trigger additional transmission investment approvals in the CAISO's TPP, which then form the basis for the transmission constraints in the next round of the IRP.

Each planning process results in ***long-term (10-15 year) action plans***: the CPUC's Preferred Portfolio informs procurement requirements for CPUC jurisdictional load serving entities, and drives the CAISO's TPP results in a long-term transmission investment plan. These plans are finalized sequentially, approximately one year apart from one another. This sequential process results in a well-refined loop that allows both processes to take the time required to conduct detailed planning and substantial stakeholder engagement.[13]

Co-optimizing Generation, Transmission, and Battery Storage in the CPUC's 2023 Preferred System Plan

The iterative IRP and TPP process has led to a robust and innovative set of data inputs that facilitates integrated planning of generation, transmission, and battery storage. The CAISO's TPP deliverability studies result in three distinct constraints based on three key periods that serve as inputs into the E3's RESOLVE generation capacity expansion model. These constraints allow RESOLVE to consider optimal siting for battery storage to ensure state goals are met with minimized need for additional transmission investment and cost. A mid-day off-peak constraint may become constrained by mid-day solar energy delivery, while an afternoon gross peak constraint and an evening net peak constraint are more likely to be constrained by on-peak storage discharge.

As shown in Figure 11, storage in RESOLVE can either be sited in load centers, whereby transmission investment is generally sized to deliver solar off-peak, or sited co-located with remote renewables, whereby transmission investment is generally sized to deliver storage discharge on-peak.

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[12] The busbar mapping analysis allocates both generation resources and storage resources to transmission (and sometimes sub-transmission)-level busbars. It also takes into consideration qualitative data—such as landscape intactness, disadvantaged communities, and commercial interest—not considered directly in the least-cost optimal capacity expansion analysis.

[13] This iterative process may also work within a utility, though vertically integrated utilities may have more opportunities for co-optimization within the same generation and transmission planning cycle.

Figure 11. Storage Siting Options in CPUC IRP Capacity Expansion Modeling

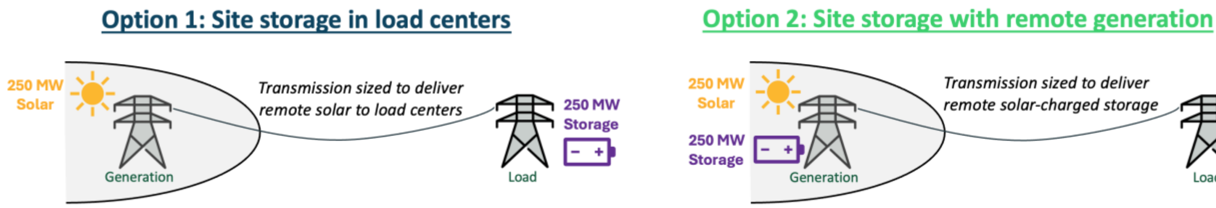
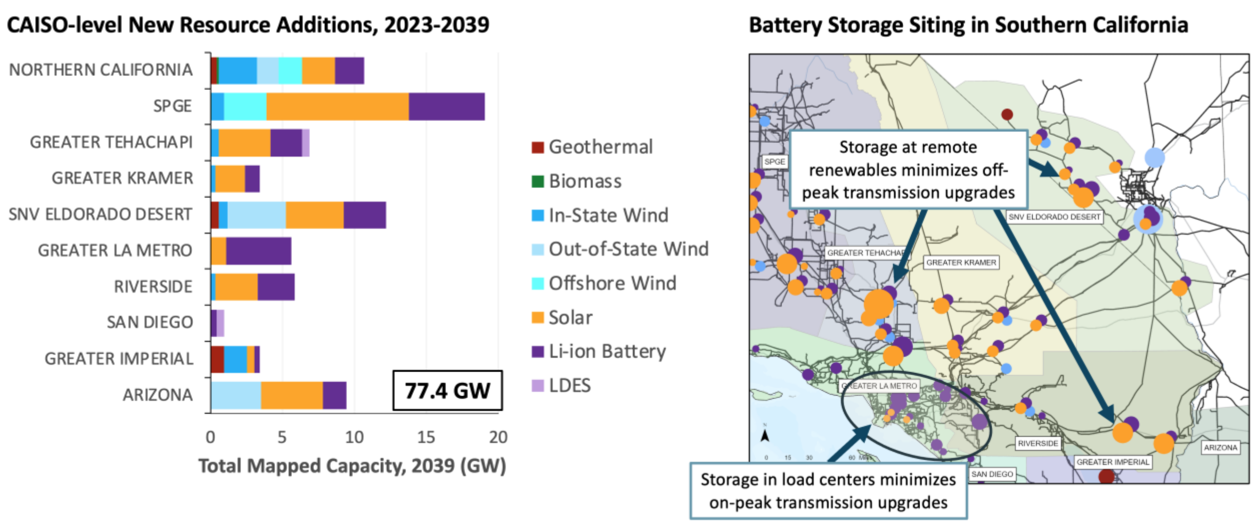


Figure 12 shows the result of the 2023 CPUC Preferred System Plan optimization, showing RESOLVE's optimization chose to site storage both at remote locations (to reduce long-distance transmission upgrades for solar) and at load centers (to reduce transmission upgrades for on-peak energy delivery). This highlights the ability of storage to address both generation needs for reliability and renewable integration, but also for the optimal siting of energy storage to maximize the utilization of the transmission grid to minimize total system costs.

Figure 12. Mapped Resource Portfolios and Storage Siting Results for the 2023 Preferred System Plan



New York City PowerUp Electrification Distribution Impacts

PowerUp NYC is New York City’s first long-term energy plan, outlining 29 clean energy initiatives across three main topic areas: energy grid, transportation, and buildings. As the city pushes towards ambitious climate and sustainability goals, driven by state and local policies like Local Law 154 of 2021, there is a need to assess how the electric grid can handle rising energy demands from the electrification of buildings and transportation. The PowerUp NYC plan addresses these challenges with its grid readiness study, which analyzed the current capacity of the city’s grid and determined where upgrades or new infrastructure will be necessary to accommodate future energy demands.

The grid readiness study in PowerUp NYC focused on ensuring that the city’s distribution networks are prepared for the expected increases in electricity usage from widespread building electrification (e.g., electric heating and appliances) and transportation electrification (e.g., electric vehicle charging infrastructure). The objective of this study was to develop a comprehensive understanding of how electrification will impact the grid at a detailed network level, particularly identifying which distribution networks will need upgrades to accommodate the increased load.

E3 used its Forecasting Anywhere (FA) tool as part of the PowerUp NYC project to create a detailed geospatial load growth forecast, specifically targeting the impacts of electrification across New York City's distribution networks. E3 used publicly available data from Con Edison, such as hourly peak load data and information on planned upgrade projects. E3 employed Forecasting Anywhere to downscale citywide electrification forecasts to the individual distribution network level, providing a granular understanding of how building and transportation electrification would affect localized grid infrastructure. This advanced modeling helped identify where potential upgrades or the integration of DER would be necessary to manage increased energy demand.

Long-term scenario planning has long been a core component of bulk grid generation planning processes, allowing utilities to evaluate various resource mix futures, policy changes, and load growth patterns. However, it remains relatively rare in the context of distribution planning. This work illustrated the benefits of performing and presenting scenario analysis for distribution plans to gain informed community and stakeholder input. For the project, E3 modeled three scenarios to explore different levels of load management and their impact on the grid. The levels of building and transportation electrification remained consistent across all three scenarios to allow for a direct comparison of grid impacts based solely on the variations in load management. The three scenarios were:

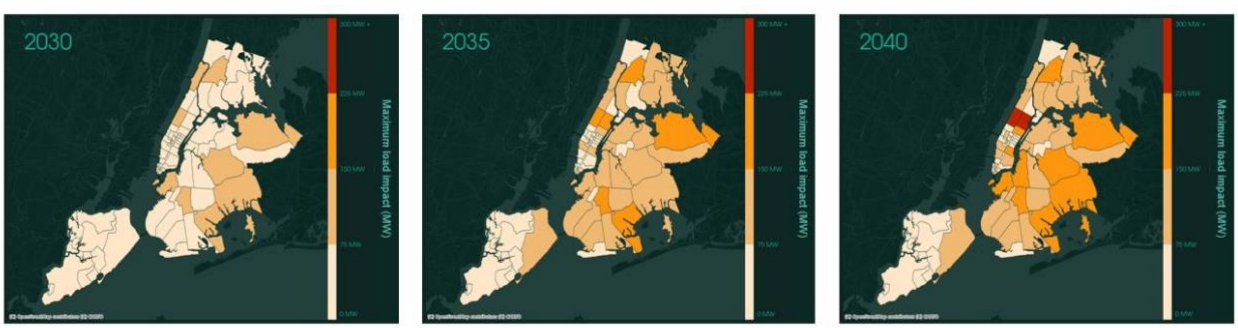
+ **Unmanaged Load:** This scenario assumed no efforts to manage electricity demand, representing a business-as-usual approach.
+ **Managed Load:** This scenario incorporated load management strategies, such as shifting EV charging to off-peak hours and encouraging energy efficiency measures.
+ **Managed Load + Exporting Technologies:** This scenario built upon the Managed Load scenario by adding exporting technologies, such as battery storage and vehicle-to-grid (V2G) systems, which allow electric vehicles to discharge electricity back to the grid.

Utilities typically present a single "black box" distribution plan for stakeholder consideration and commission approval, limiting the opportunities for informed input. This approach often lacks transparency, as utilities bundle their assumptions, methodologies, and projections into a single plan without sufficient detail or alternative scenarios. As a result, stakeholders, including regulators and community groups, are left with limited visibility into the underlying decisions and trade-offs, which hampers their ability to provide meaningful feedback, recommend changes or strongly advocate for specific strategies or utility investments. Using advanced forecasting tools like Forecasting Anywhere, the project assesses the grid's capacity under various electrification scenarios. These forecasts consider spatial and temporal variations in energy demand, helping to pinpoint areas where additional grid or DER investment in the grid will be necessary to avoid bottlenecks and ensure reliable service as electrification progresses.

The study revealed several critical insights about the grid's capacity to handle anticipated electrification:

- **Unmanaged loads will stress distribution system capacity by 2030 :** This scenario showed significant pressure on the grid, with load peaks in many Con Edison distribution networks exceeding capacity limits, particularly in outer boroughs like Brooklyn and Queens. The study indicated that without interventions, the distribution grid could become a bottleneck to electrification by 2030.
- **Managed loads are effective at delaying but not avoiding all grid upgrades:** By managing loads, the stress on the grid was significantly reduced. This approach helped delay the point at which networks would exceed capacity limits and provided a feasible pathway to manage the increasing demand from building and transportation electrification. However, even with managed load, 25 networks were projected to face capacity constraints by 2040 – only some of which had publicly planned upgrade projects at the time of the project.
- **The grid remains summer peaking through 2040:** The results indicated that even with significant building electrification, New York City's grid would likely remain a summer-peaking system through 2040.

Figure 13. Maximum incremental load impacts (MW) of building and transportation electrification for each Con Edison distribution network in the Managed Load Scenario



E3's modeling results were presented at multiple community town halls across the five boroughs, as well as a series of more technical, virtual sessions. Residents could see visualizations of potential electrification impacts in their neighborhoods, raise questions and concerns, and provide input for discussions about necessary grid upgrades. Community-based organizations (CBOs) partnered with the city to facilitate outreach and engagement, ensuring representation from diverse communities and incorporating the needs of historically underserved neighborhoods. The PowerUp NYC initiative demonstrated how scenario analysis for distribution planning facilitates community engagement and can enable the city and its residents to advocate for their specific needs in the Con Edison distribution planning process.

Appendix: Overview of Electricity Planning Processes

Planning Process	Timelines	Analytical Methods/Tools	Planning Constraints	Traditional Investments	New Investments	Emerging Topics/Challenges
Generation Resource Planning	Occurs every 2-5 years Planning horizon of 10-25 years	Optimal capacity expansion Loss of load probability analysis Zonal and/or nodal production cost modeling	Clean energy policy Resource adequacy Operational reliability/flexibility Least-cost economics	Dispatchable thermal resources (gas, coal, biomass, etc.) Nuclear Hydroelectric power Geothermal Demand response	Solar Wind (onshore and offshore) Battery energy storage Long-duration energy storage Gas/coal w/ carbon capture + storage Load flexibility / virtual power plants	Evolving resource adequacy needs Increasing operating reserve requirements Climate change impacts Common mode failures
Transmission Planning	Occurs every 1-3 years Planning horizon of 5-20 years	Nodal production cost modeling Power flow analysis Dynamic stability studies	Thermal limits Voltage limits Stability	Power lines Substations + transformers Protection/control equipment Series compensation	Storage as a transmission asset Advanced transmission technologies (advanced conductors, dynamic line ratings, etc.)	Proactive investment for remote generators Siting and permitting Interconnection queue backlog + delays Interregional transmission development
Distribution Planning	Occurs every 1-3 years Planning horizon of 3-10 years	Peak load forecasting Power flow analysis	Asset health Thermal limits Voltage limits Protection	Distribution lines Substations + transformers Protection/Control equipment	Storage as a distribution asset Smart inverters Distributed Energy Resource Management Systems	Uncertainty in location + timing of load growth, incl. electrification Need to extend planning horizon versus traditional near-term focus
Customers and Distributed Energy Resource Planning	Occurs every 1-3 years Planning horizon of 2-5 years	Avoided costs and cost-benefit analysis Tariff/rate design	Cost-effectiveness Equity Market transformation	Energy efficiency Demand response	BTM solar, storage Flexible loads (incl. EV charging) Virtual power plants	Advanced rate design DER operational control