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Resilience Service Framework Using Transactive Systems Valuation Methodology

September 2021

Sarmad Hanif
Rohit Atul Jinsiwale
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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

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Abstract

Recent outage events have spurred national and international interest in improving grid resilience. Actions to make the grid more resilient must be valued against their costs and benefits. This is the goal of this report. We explore a resilience valuation framework, where the services procured by the utility are arranged such that the values associated with them are pinpointed. This is demonstrated by utilizing various diagrams developed in Pacific Northwest National Laboratory's Transactive System Program, called the Transactive Systems Valuation Methodology (TSVM). We show that TSVM can be utilized to guide traditional valuation methodologies such as integrated resource planning so that resilience considerations can be embedded. This report demonstrates this using a three-step procedure: (1) a use case is developed to define functional requirements, (2) value identification of the utility and the actors with which it interacts (both inside and outside its internal functions), and (3) value tracking of activity performed by actors interacting with the utility while services are procured to enable a resilient grid.

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1.0 Introduction

Recent outage events, such as the 2021 Texas power outage (Smead 2021), have spurred national and international interest in improving grid resilience (Nazir 2021), (Wu et al. 2021). To improve grid resilience, actions to invest in infrastructure and operate the grid with updated approaches are being proposed. Such actions are always going to be valued against the effort to implement them, and therefore benefit from a valuation framework. Such value-based actions, although already used in the power grid industry, are nonexistent when considering resilience-oriented. This report proposes such a framework using the Transactive System Valuation Methodology (TSVM).

A large body of research exists that seeks to define and understand grid resilience. The U.S. Presidential Policy Directive (House 2013) defines resilience as “the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions.” Other works also offer their own definitions of resilience, including (Rieger et al. 2020), which presents the 5 Rs of resilience—recon, resist, respond, recover, and restore. The literature also contains works that address measuring grid resilience, i.e., resilience metrics. Indices such as the restoration efficiency index, vulnerability index, degradation index, and microgrid resilience index can be found in (Amirioun et al. 2019), while (Kazama and Noda 2012) propose quantifying the maximum number of customers out of service.

To improve grid resilience, actions and concrete steps need to be taken across all domains of the power grid. Such decision making in the current setting of power grids is done through cost-benefit analysis, which forms the basis of the Integrated Resource Planning (IRP) process. IRP is a utility process that creates an action plan to procure a set of resources to assure reliable and cost-effective delivery of electricity. The IRP process requirements and criteria for utilities are usually set by their local public utility commissions and regulators. The planning process forces utilities to objectively evaluate and generate multiple plans of action to meet expected demand over a 10–20-year horizon. Because utilities are typically investor owned, the IRP process generates a business case to justify capital being raised from investors to fund upgrades while detailing return on investments to investors from customers. Note that IRP is an advanced form of least-cost solution-based planning actions, which some utilities still deploy. Similarly, depending upon the structure of a utility (vertically integrated or restructured) and its planning requirements, jurisdiction and involvement varies. Also, even for the same type of utility, the planning process varies based on different state and federal requirements in each jurisdiction. Therefore, even though not all utilities follow the same procedure, IRP provides a standardized way for future grid investment. As an example, **Error! Reference source not found.** shows states that have IRP-related procedures in place.

As extreme events have started to cause noticeable impacts on power grids, our hypothesis is that the conventional IRP process needs to include new resilience requirements. Furthermore, to provide support to the grid, demand-side flexibility and distributed control methods must be accounted for in IRPs. To include such consideration is a nontrivial task, as any demand-side measure will inevitably impact consumers. To motivate implementation of such mechanisms, innovative valuation frameworks are required, an example of which is the TSVM (Makhmalbaf et al. 2016; Cooke et al. 2018), which consists of a set of diagramming principles to highlight the activities and associated values. These diagramming principles have already shown their applicability in explaining the IRP process (Cooke et al. 2018) and valuation of simulation studies (Widergren et al. 2017). The overall design components of the TSVM can be found in (Bender 2021). The TSVM allows valuation of both monetary and non-monetary value streams, which is done because Transactive Energy Systems (TESs) and other similar DER coordination schemes have complex decision and control systems that affect multiple layers of benefits. Because the design for a resilient grid also consists of a complex set of decisions and interacting variables, we show that TSVM provides an intuitive valuation methodology to achieve such design criterion.

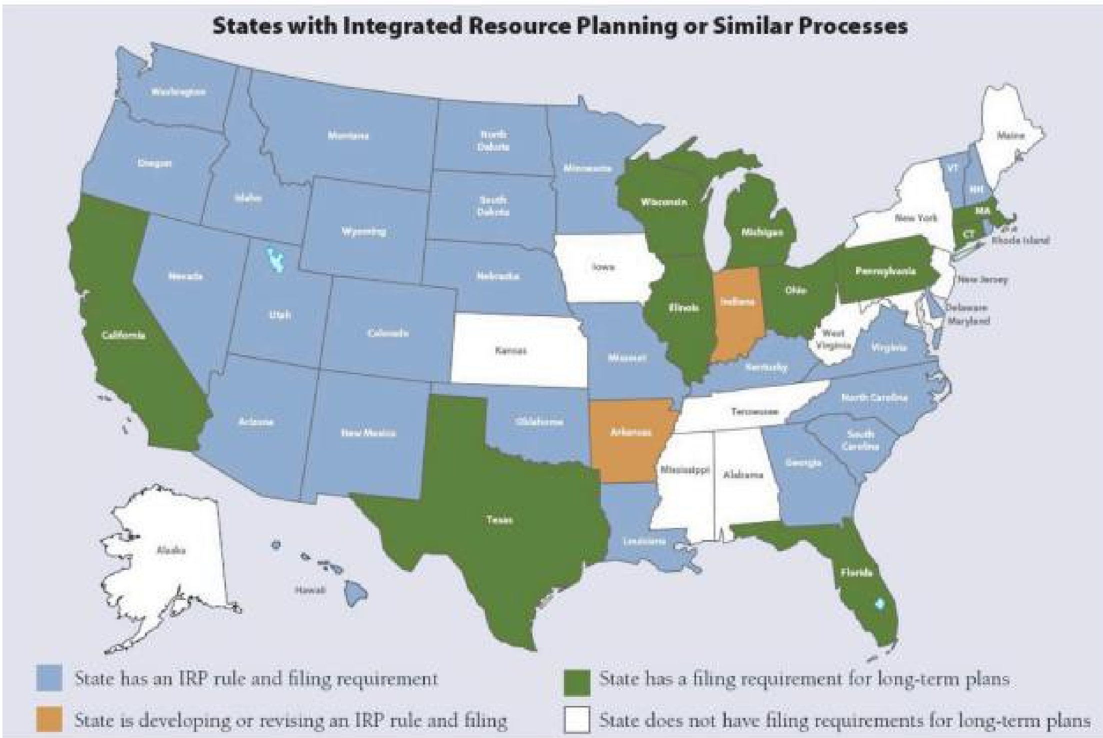


Figure 1. States with IRPs or similar procedures – Source: (Wilson and Biewald 2013).

2.0 Background

In this section, we provide a brief overview of the important concepts related to this report. Section 2.1 provides a brief overview of the definition of resilience used in this report. We provide overview of the Integrated Resource Planning (IRP) procedure in Section 2.2 to set the stage for the conventional valuation framework adopted by utilities. We then discuss in Section 2.3 a new valuation framework that promotes distributed intelligence in grid operation.

2.1 Brief Introduction to Grid Resilience

In this report, resilience is defined as the degradation in performance measures due to *any* grid disturbance. This definition comes from the grid disturbance[1] theory introduced in (Hanif, Chalishazar, and Hammerstrom 2020), which relies on the functional form model for all grid disturbances and focuses on three main features:

1. Avoiding a grid disturbance.
2. Reacting during a disturbance to lessen the extent of system degradation.
3. Recovering rapidly after a disturbance has occurred.

This methodology allows for any performance measure to be taken from either the literature on resilience metrics and/or from the system operator's/analyst's interest. Figure 2 shows these three features of grid disturbance, which are briefly explained below.

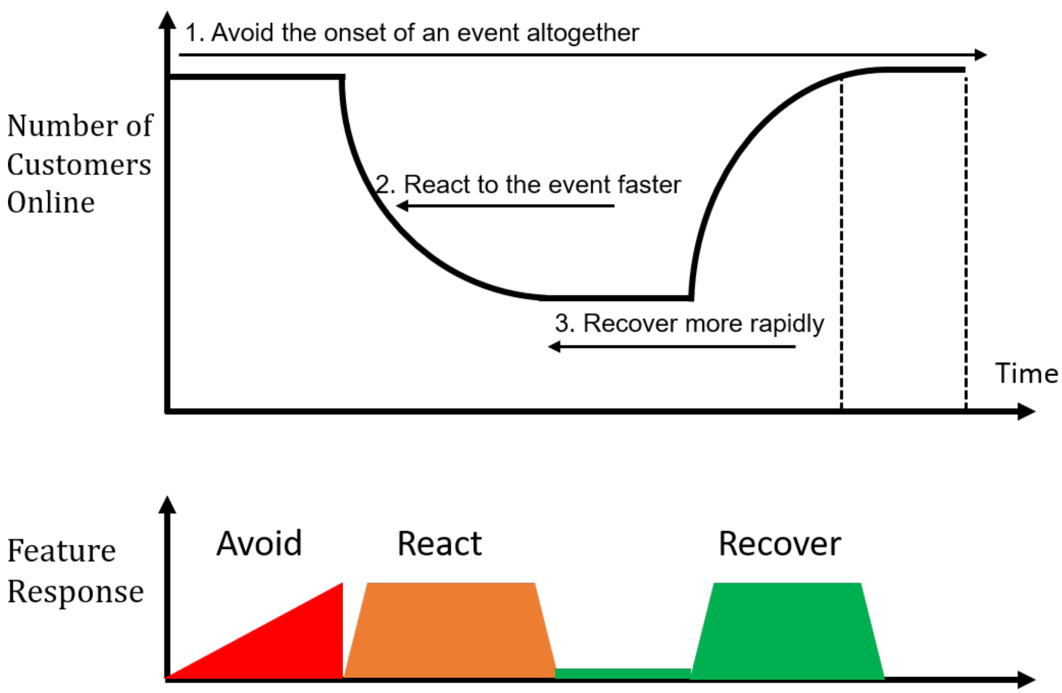


Figure 2. Typical grid disturbance system response and its features, with number of customers online as an example grid performance measure.

[1] Grid disturbance is any disturbance that may or may not cause degradation in grid performance.

Avoid: The avoid stage begins during the normal pre-contingency state and ends when the value of the performance metric degrades.

React: Upon failure of avoidance efforts, system degradation begins to occur, and the system enters the react stage. Measurable degradation of system performance defines the start of the react stage, which ends when the system settles to a steady state, i.e., when the system performance cannot or ceases to degrade.

Recover: At the end of the react stage, the system has degraded to the worst performance measure and the recover stage begins. The recover stage ends once the system performance is brought back to the nominal state.

For more information on the individual disturbance stages, interested readers are referred to (Hanif, Chalishazar, and Hammerstrom 2020).

2.2 Integrated Resource Planning

To explore decisions to plan and operate power grid with consideration of resilience, we first visit the conventional planning procedure of the utility, which is the IRP procedure. The goal of this section is not to provide an exhaustive literature search of all IRP practices, but rather offer an overview of the general guidelines and methodology.

2.2.1 Generic IRP Process

A typical IRP process consists of numerous stages. A generalized overview of the IRP process is illustrated in Figure 3. This illustration has been developed based on (Almeida, Fonseca, and Saraiva 1998) and by surveying some utility IRP documents from (California Energy Commission 2017), (Pacificorop 2017), and (Arizona Public Service Electric 2020).

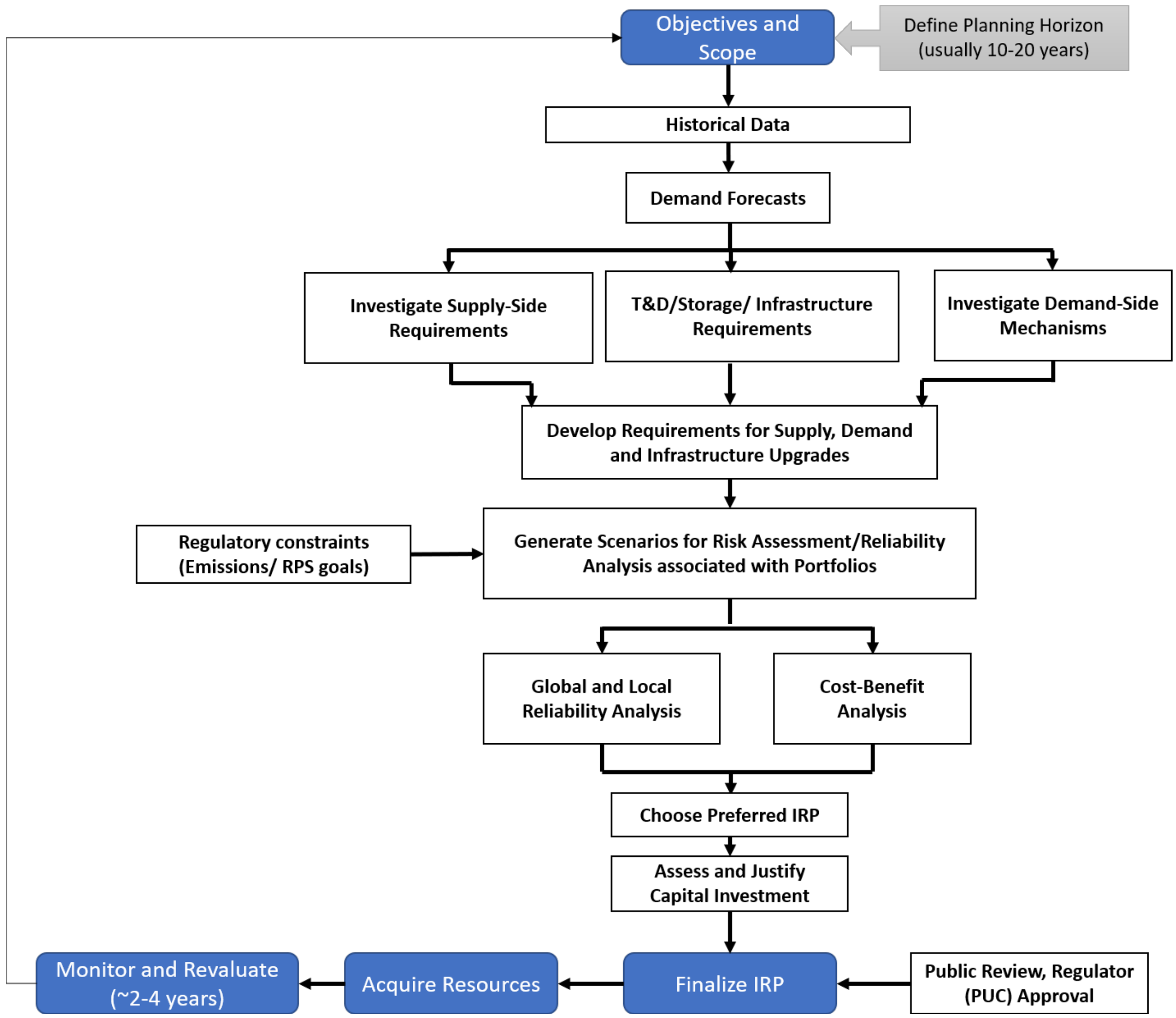


Figure 3. Generalized IRP process.

A brief explanation of the main activities in a generalized IRP procedure (Figure 3) are described below.

1. Establishing Objectives

This part of the process typically focuses on generating broader goals that a utility may want to achieve in the long term (10–20 years). While resource adequacy is a key part of these goals, reliability goals, regulatory requirements, long-term environmental goals, and maximizing returns on investment are possible goals. Utilities may choose to also implement decarbonization goals that involve aggressive renewable energy targets.

2. Analysis of Historical Data and Demand Forecasts

A thorough analysis of demand growth trends is conducted based on historical data as well as other societal and environmental factors. Peak demand requirements may also be projected in these processes.

3. Defining Supply-side and Demand-side Requirements

The generated forecasts point to resource adequacy requirements and higher reserve margins over the planning horizon. This creates the need for building new generating sources or upgrading existing ones. Because a utility is investor owned, the resource requirements must be met in a least-cost manner to minimize the financial burden to customers while providing a regulated rate of return to investors. This makes it necessary to investigate key parameters like operating costs, fuel costs, reliability, efficiency, and capacity factors associated with sources that could meet future resource adequacy requirements.

While building capacity is one way to achieve supply–demand balances, demand-side programs provide an effective way of reaching the same balance without investing in more infrastructure. Demand-side management (DSM) involves projects or programs that incentivize load shifting, load reduction, or the use of energy-efficient equipment. Utilities typically provide some incentivization through tariffs or rebates for such activities.

This stage of planning typically quantifies the requirements from the supply and demand side to assure reliability in the planning horizon.

4. Infrastructure Upgrade Requirements

Based on demand forecasts and the associated generation requirements, the infrastructure required to deliver power from source to the load needs to be identified, e.g., transmission and distribution infrastructure. A utility may also derive valuable insights associated with reliability concerns, such as N-1[1] criterion, that may necessitate additional infrastructure upgrades. In this stage of IRP planning, a utility engages in investigating and developing requirements for infrastructure upgrades to meet demand forecasts while improving system and local reliability.

5. Scenario Generation and Creation of Candidate IRPs

To meet the requirements highlighted by previous stages of the IRP process, analysts then generate resource portfolios and transmission and distribution upgrades to satisfy these requirements. Several scenarios are simulated to quantify risks and capture current regulatory constraints and future regulatory and environmental constraints to generate candidate portfolios for the planning period. Risk assessment and stochastic risk analysis is a key part of this process. For instance, variability in fuel costs, damage to infrastructure, changes in regulations, and climate change may affect the portfolio of choice. Analysts may employ commercial software packages (e.g., PROVIEW II) to conduct these studies.

Analysts usually generate three scenarios—a main or reference scenario, a high case, and a low case, along with the probability of each case materializing. The main scenario would typically include current regulatory policies and current resource mix trends. Within each of these scenarios, stochastic elements are also modeled. All these candidate scenarios are then subjected to cost-benefit analysis to identify the value and return on investment mechanisms for investors.

6. Selection of Preferred IRP

[1] N-1 criterion is that grid should be operable within specified performance, given a loss of credible (transmission line, generator, substation) asset.

Of the candidate IRPs, a portfolio is then chosen that can meet the resource adequacy requirements in a least-cost fashion while complying with regulatory and environmental constraints. The selected IRP is rigorously analyzed to assure that reliability is improved while having acceptable effects on ratepayers. The IRP is also analyzed to assure that investors have a clear strategy for return on investment.

7. Public Comment, Regulatory Approval, Monitoring, and Evaluation

The chosen portfolio is then opened for public comment to assure transparency and accountability. The IRP is also submitted to the Public Utility Commission to assure proper compliance with state and federal mandates. The IRP may be tweaked further based on public and regulator input. This creates an action plan for acquiring the required resources and instituting the proposed DSM programs. This process is reiterated every 2–4 years based on new data and trends.

2.2.2 IRP with Resilience Consideration

From the previous section, we can see that IRP is centered around resource adequacy, which is a central concept of system reliability. As new methodologies, measures, and processes emerge to improve grid resilience, the augmentation of IRP with such measures is a natural step toward planning for a resilient grid.

Traditional reliability metrics (e.g., SAIDI[1], SAIFI[2] (Billinton 1988)) are often included in IRP, and certain utilities also detail local reliability concerns in isolated grid sections, as well as the investment strategies to mitigate them. **Error! Reference source not found.** shows a possible modification to the IRP process, which is proposed in (ICF 2017) and called the Integrated Resource and Resiliency Plan (IRRP). The process attempts to incorporate resilience assessment and planning into the usual least-cost planning model.

[1] System Average Interruption Duration Index (SAIDI) is the average duration of interruptions per consumers during a specific period (usually one year).
[2] System Average Frequency Duration Index (SAIFI) is the average number of sustained interruptions per consumer during a specific period (usually one year).

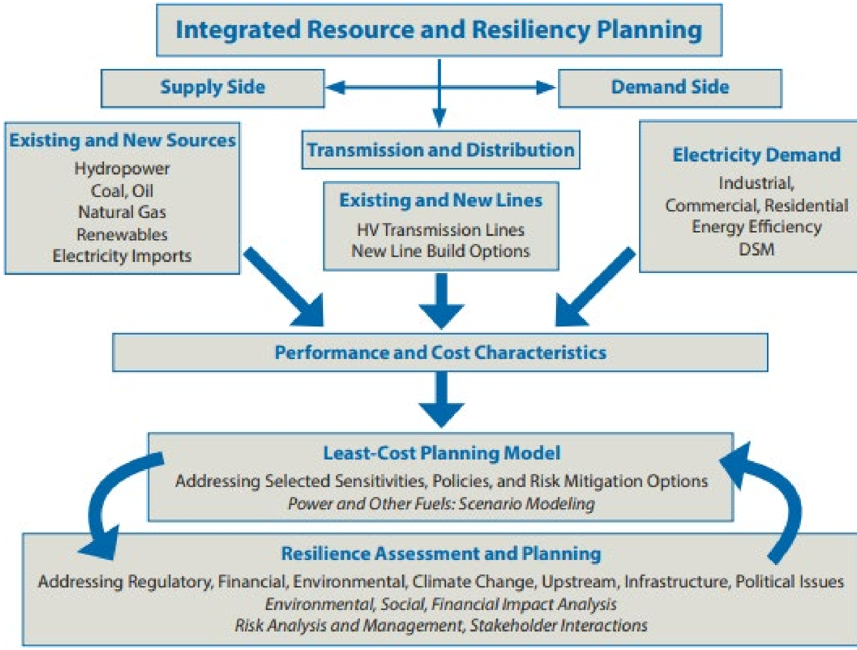


Figure 4. Proposed IRRP planning – Source: (ICF 2017).

With respect to valuing DER investments for using traditional cost-based planning measures, (NARUC 2019) summarized four case studies across the United States that were filed to justify grid reinforcement for improvements in resilience using DERs. Due to the wide variety of methodologies, technologies, and use cases available, case studies were evaluated based on four unifying factors: duration, scalability, ease-of-use, and output. Eventually, the report concluded that there is not a unifying framework to value DER investments for grid resilience improvement.

2.3 New Valuation Frameworks

This section provides a brief overview on the novel valuation framework which considers more aspects of electricity delivery than conventional IRPs.

The decision-making in power grid planning and operation is not only based on cost but also on societal expectations. Technical factors that affect these decisions include the cost of fuels and their availability, the power generation fleet, transmission and distribution system constraints, and weather conditions. Some of the societal factors that play a role in these decisions are access of electricity for all, uninterrupted supply, and a fair consumption price. Under such diverse paradigms, quantifying the value of electricity and service to the grid becomes a challenging problem. There are two common methods of assessing cost and its associated value: (1) cost-benefit analyses (CBAs) (Forsten 2015), and (2) the IRP process. CBAs conduct a comparative evaluation of a given action (e.g., investing in new technology, construction of facilities or infrastructure, regulation changes, and others), providing valuable information regarding to either perform or not perform the change. This information also assists in the selection of a given, established case. Unlike the CBAs, IRPs are more focused on system growth (e.g., growth of demand and the matching supply), projecting into the future of the system based on demand and available resources. With this information, the IRP utilizes the least-cost solution, and ISOs operate the market through multiple constructs that promote competition—the grid is maintained such that power is available to everyone at an affordable rate.

Figure 5 illustrates the valuation model considered in this report. The growth (planning) model considers the long-term changes in the system, especially the changes in energy consumption, but it is generic and includes all changes (e.g., new technology). The operational model evaluates the behavior of the system given the expected availability of resources and demand. As demonstrated by the green arrows in Figure 5, the model only proceeds to the next step once a possible feasible infrastructure has been identified. The TSVM are a set of diagraming principles to facilitate explanation of the valuation model of Figure 5.

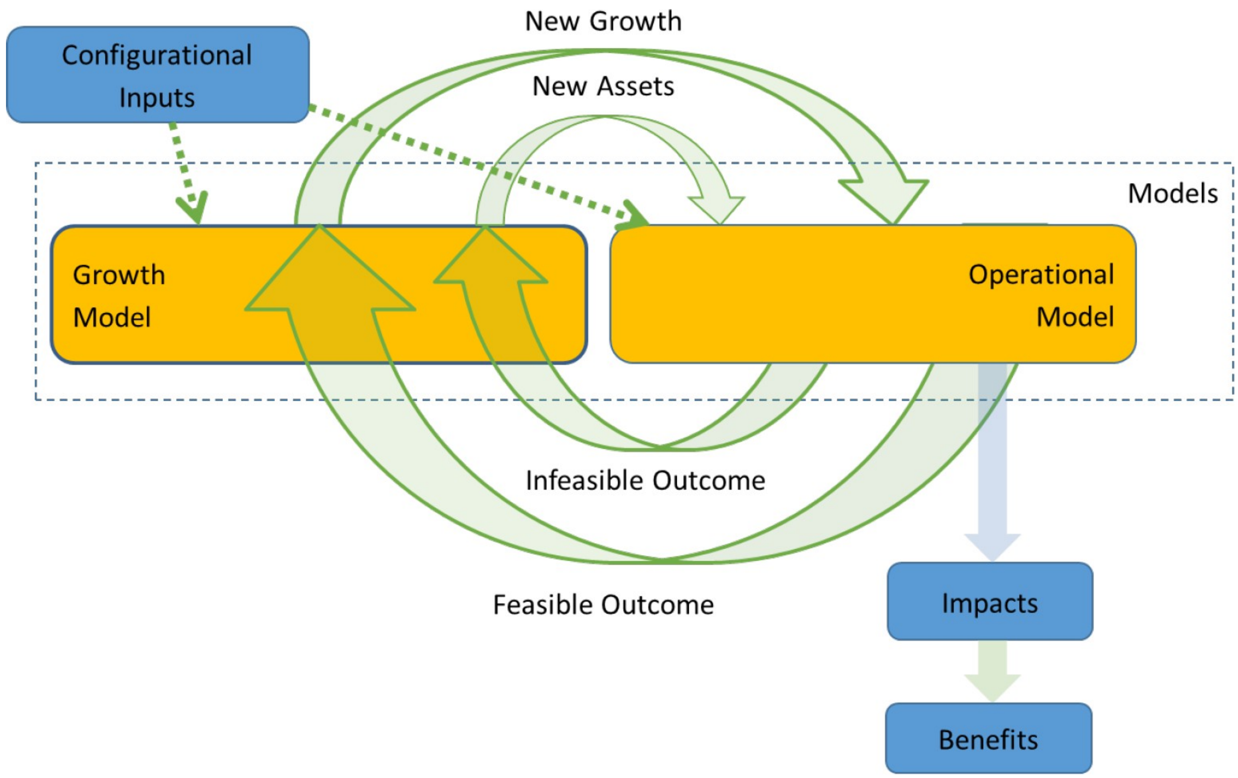
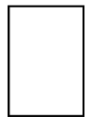
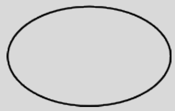
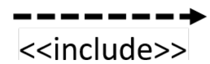
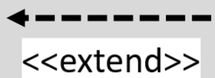
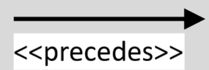
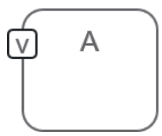


Figure 5 Conceptual valuation model – Source: (Makhmalbaf et al. 2016).

2.3.1 Introduction to Unified Modeling Language (UML)

TSVM is built using a hybrid Unified Modeling Language (UML)-based diagraming principles. Originally, UML was developed for software engineering and visualization of the system being designed. UML is part of the International Organization for Standardization and has been utilized in multiple fields. UML diagrams can be separated into two types: structural diagrams and behavioral diagrams. Structural diagrams are utilized to visually represent the structure or architecture of the system. Behavioral diagrams represent the interaction of elements that compose the system. This report employs use-case diagrams, class diagrams, and activity diagrams, which are behavioral, structural, and behavioral, respectively. Table 1 presents the symbols and their descriptions that will be utilized to explain the valuation model.

Table 1. Symbols and their description.

Description	Graphical representation	Description	Graphical representation
The system being modeled.		Actors are external to the system. They utilize the system and interact with other actors.	
A use case is an action that accomplishes a task within the system.		Notes	
Association relationships represent an interaction or communication.		Includes relationship	
Extend relationship.		Preceding relationship	
Activity “A” block showing value “v”			

3.0 Resilience Service Framework Modeling

This section shows how TSVM helps augment traditional IRPs adopted by a utility, with new approaches to grid operation that include considerations of grid disturbances (resilience). The proposed methodology is shown in Figure 6. Note that depending upon the structure of a utility (vertically integrated or decentralized) and the state and federal jurisdiction, IRP models may differ. Hence, we present the most comprehensive interaction of utilities with its internal and external actors, for which vertically integrated utility is taken as a reference. This is because they have more internal functions as compared to decentralized utilities and actors to manage. Nevertheless, with slight modification, the proposed procedure can be adapted to any utility structure.

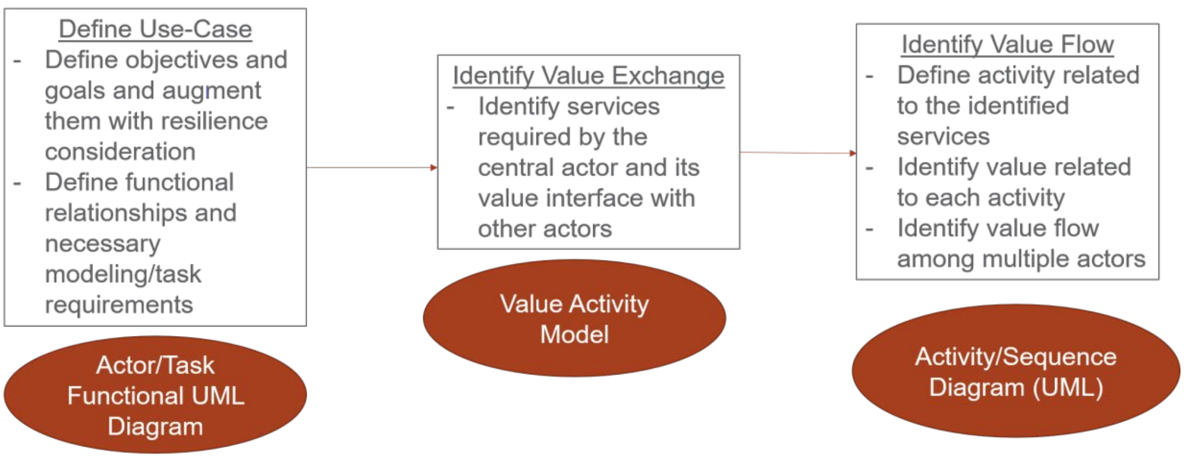


Figure 6. A three-step procedure is proposed for creating a resilience service framework.

3.1 Use-Case Definition

Figure 7 shows an example use case of functional requirements for the planning and operation stages to help the power grid avoid grid disturbances. Note that this example is not meant to be representative of all grid areas and architectures because it may very well be the case that the operator is not an independent entity but a subsidiary of a utility. Similarly, there may exist varying levels of regulatory restrictions and requirements that necessitate the utility to perform different functions. For example, ambitious renewable portfolio standards may derive additional functionalities to be distributed across the grid.

In Figure 7, green blocks represent additional required functionalities, while the black sections indicate the usual operation requirements that exist in current grid planning and operation. Note that the planning portion of the use-case setup consists of augmenting the IRP process so that it is as close as possible to the value-based decision-making process in the planning phase. In this report, representations of the functional requirements from the IRP process were inspired by (Cooke et al. 2018). Next, we explain the new proposed functional requirements in the grid disturbance avoidance use case, to be integrated into grid planning and operational decision-making.

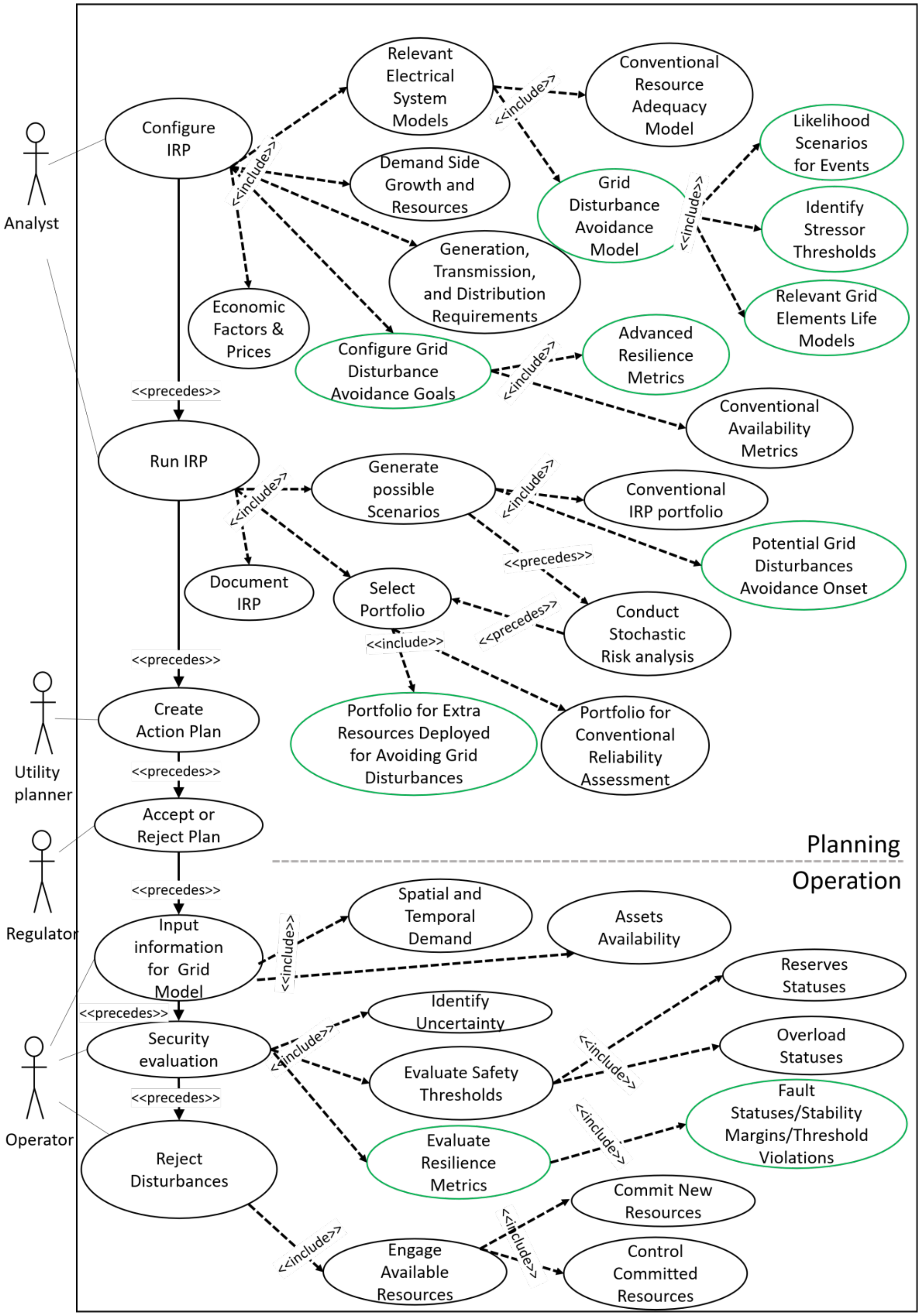


Figure 7. Use-case example of integrating grid disturbance avoidance with the IRP grid planning procedure and the operation procedure for the operator.

- Grid Disturbance Avoidance Model: During setup of relevant electrical models for subsequent analyses, the first requirement is to augment the available grid models with grid disturbances models that can model controls to avoid grid disturbances. The goal of such models is to predict the onset of an outage event based on the identified resilience scenario set. Three primary modeling techniques listed in (Hanif, Chalishazar, and Hammerstrom 2020) and described below can be used to model grid disturbance scenarios that may or may not cause an event onset.
  - Likelihood of Scenarios for Events: These modeling techniques capture probabilistic scenarios of events. An example of this could be to model a mitigative treatment which delays the outage such that by estimating the probability of a hurricane to damage the transmission/distribution assets.
  - Identify Stressor Thresholds: Apart from capturing likelihood of an outage due to external events, identifying and modeling thresholds which may get violated due to various stresses acting on the system is also needed. There exist numerous such thresholds, which are indicators of the safe operation of the grid. Since these thresholds cater for stressors acting on the system, we call them stressor thresholds. For an example, to deal with various uncertainties in the grid, reserves are placed. Based on historical data and system condition, the utility may define a reserve threshold, below which the event scenario is identified, triggering the appropriate mitigative strategy.
  - Relevant Grid Element Life Models: Finally, another outage possibility exists due to lifetime completion of vulnerable components. This may be captured by modeling vulnerable components' life degradation. An example of this modeling type is to model impact of distribution transformer life reduction, due to overheating as it experiences overloading during peak load conditions.
- Configure Grid Disturbance Avoidance Goals: Usually, the IRP considers resource adequacy in its processes, which serves as a foundation for reliability analysis. However, to avoid outages due to grid disturbances, resource adequacy goals need to be updated. That is, appropriate metrics need to be included in the IRP configuration. There is a large body of work on resilience metrics that can be adopted – e.g. see the works in (Petit et al. 2020).
- Portfolio of Additional Resources to Avoid Grid Disturbances: These are the additional resources identified in the form of next-generation capacities, transmission and distribution infrastructure, and/or updates to the control of existing infrastructure. These additional resources may or may not be easily distinguished from the current resources because some actions serve multiple purposes. For example, the total reserves procured from generators are for safeguarding the grid from any grid disturbance. Therefore, it is nontrivial to determine how much of the extra reserves are specifically placed to meet conventional resource adequacy levels and after that extra reserves are needed for improved resilience. One way to determine is to perhaps conduct sensitivity analyses in the IRP process. Two sets of reserve requirements may be obtained, one for avoiding a grid disturbance and one for conventional system adequacy. The reserve requirements may be then compared to provide quantification of extra reserves to avoid grid disturbances.
- Evaluate Resilience Metrics: In the operation stage, the operator needs to make sure that the determined resilience metrics are met. This serves as an indicator of stressors in the system, triggering control responses from the operator to avoid the outage.
  - Fault Statuses/Stability Margins/Critical Loadings: To evaluate resilience metrics, the operator needs to monitor whether vulnerabilities are appearing in the grid. These include, but are not limited to, (1) status of the faults in the system and their clearing

time, (2) the stability margins with which the system is being operated and that are calculated either through dynamic modeling and/or threshold rules, and (3) whether equipment has reached critical loading. This monitoring and modeling help the operator keep track of the resilience metrics by defining the mapping between them and position controls to improve the system state to favor them. However, note that because this functional requirement is in the operational stage, there are only small changes that can be made by the operator in (close to) real-time. Therefore, it is necessary to procure the control and methods beforehand in the planning stage.

Similar to grid disturbance avoidance, use cases for identifying the functional relationships of *reacting to* and *recovering from* grid disturbances can also be set up using the functional form guidance provided in (Hanif, Chalishazar, and Hammerstrom 2020) and their interactions with the current planning and operation function, as shown in Figure 7.

3.2 Value Exchange Identification

To identify the values from the identified functions to be performed, the first task is to determine who conducts these functions. To accomplish this, actors are identified that interact with utilities or subsidiaries of a utility that is called upon to perform tasks. Usually, a UML class diagram (for example, see Figure 3.3. of (Cooke et al. 2018) can provide a structured relationship between an actor and its components that are both internal and external to the utility. Figure 8 shows the identified value exchange between a utility and the relevant actors. The actors that interact with the utility are identified based on a vertically integrated utility[1] interaction identified in (Cooke et al. 2018). The identified value exchanges in Figure 8 are shown in two colors. The values in black show the business-as-usual values that exist between the utility and its actors, whereas the values in blue are the new values envisioned to result from improving grid resilience. It may be useful to obtain separate sets of values for staging control actions for avoiding, reacting, and recovering. However, we only present the values in their most general forms, as in outage avoidance. Note that the grid disturbance theory proposes to identify scenarios that may or may not end up as a resilience event (Hanif, Chalishazar, and Hammerstrom 2020). Therefore, an outage avoidance is in fact a subset of grid disturbance avoidance because the performance measure of degradation may be different than simply an outage. Similarly, there may be degraded operational performance (voltage deviation, etc.) that needs to be avoided but that goes undetected, because there are no noticeable wide-spread system outages and hence needs to be accounted for as per definition of grid disturbance. The values represented by the color blue in Figure 8 are further explained in Table 2.

Table 2. Explanation of value exchanged to and from the utility with different actors.

Actor	Extra Value to the Utility	Extra Value to the Actor
Investor	*Available Infrastructure Investment*: This represents the extra investment identified by the utility necessary to reduce outages.	*Deferral Benefit*: This can be attributed to all the times the installed resources cannot return the investments made by investors. There could many

[1] The rationality of adopting a Vertically Integrated Utility is that it can provide a more comprehensive picture of the entities a utility interacts with. Nevertheless, extension to another utility model can be accomplished because any utility is subjected to some sort of public accounting and therefore need to present valuation of its spending.

Actor	Extra Value to the Utility	Extra Value to the Actor
		reasons that cause the resources to stay off-line, prolonging the time it takes for investors to have their investments recovered.
Fuel Supplier	*Reserve Fuel*: The extra fuel procured by the utility that is not part of the day-to-day operations or under the normal contract with the fuel supplier.	-
Plant Upgrade or Commissioning Company	*Plant Failure:* The value of upgrading the plant or commissioning/decommissioning a new plant is that it helps increase the availability of the plant.	-
New Resource Supplier	*Resource Adequacy*: This is a generalization that represents how extra procured resources increase the availability of generation and in turn improve generation adequacy.	-
Retail Customer/DSM Program	*Customer Outages/Flexibility:* Through DSM programs, fewer customer outages increase the probability of higher demand flexibility for the utility, which may be utilized for lowering peak loading, reducing peak generation, etc.	-
Utility-Owned Generator	*Generation Outage:* Extra generation procurement by the utility reduces the probability of generation outages.	*Reserve Fuel:* To improve the existing generation capacity and the new generation procurement, the utility needs to pay for reserving extra fuel. *Reserve Maintenance:* With the increased generation fleet and to maintain its increased availability, extra maintenance is needed to maintain adequate reserves. This maintenance is termed in this report as reserve maintenance, which now represents the extra value from the utility to the utility-owned generators.
Utility-Owned Generation Staff	*Emergency Services:* In addition to the usual operations and maintenance services provided by staff, these are referred to as extra services that will be provided by the generation staff	-

Actor	Extra Value to the Utility	Extra Value to the Actor
	to help the utility reduce generation outages.	
Transmission Plant Construction Firm	*Transmission Outage:* This is the value to the utility when it invests further in improved transmission efficiency, redundant flow paths, and controllable equipment installation.	-
Distribution Plant Construction Firm	*Distribution Outage:* This value is the distribution grid equivalent of the reduction transmission grid outages.	-
Wholesale Power Marketer	*Flexibility:* This is an aggregated type value that demonstrates how extra investments in transmission, distribution, and generation improve grid availability. In addition, the utility provides more options to the wholesale marketer such that it has a more diverse portfolio.	-

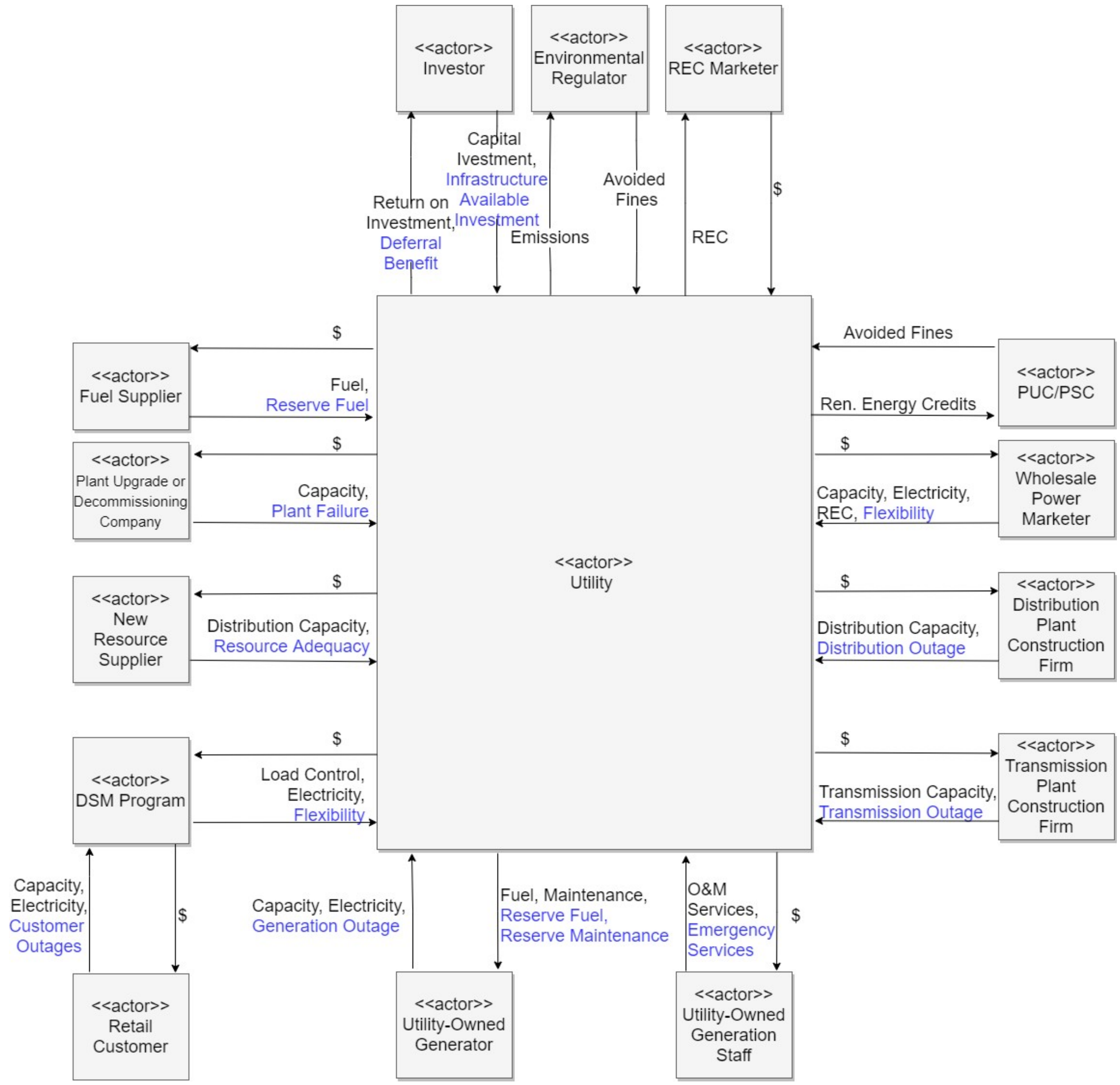


Figure 8. Value exchange between different actors interacting with a utility.

Note that in Figure 8, most of the values to the actors from the utility are identified simply as dollars ($). These values may be further decomposed into costs for various services. Similarly, the generalized values such as “generation/transmission/distribution outage reduction” may also be expanded to represent a more granular level of value exchanges. We present this in Figure 9, where the high-level value exchanges between the utility and utility-owned generators of Figure 8 are further broken down into granular components. For example, the greater cost to the utility due to increased availability of its generators can be attributed to their (1) weatherization, (2) extra (more than current) backup reserve capacity investment, (3) increased controllability of the generation by ordering installation upgrades of generator controls, and (4) dedicated black-start-capable services. Similarly, these values could also be expanded from the utility perspective because these investments will yield (1) reduced generation outages, (2) faster react capability to grid disturbances, and (3) improved recovery from a system-degraded state.

Note that with the example illustrated in Figure 9, we have also shown the mapping of values that refer to generic outages for specific avoid, react, and recover capabilities.

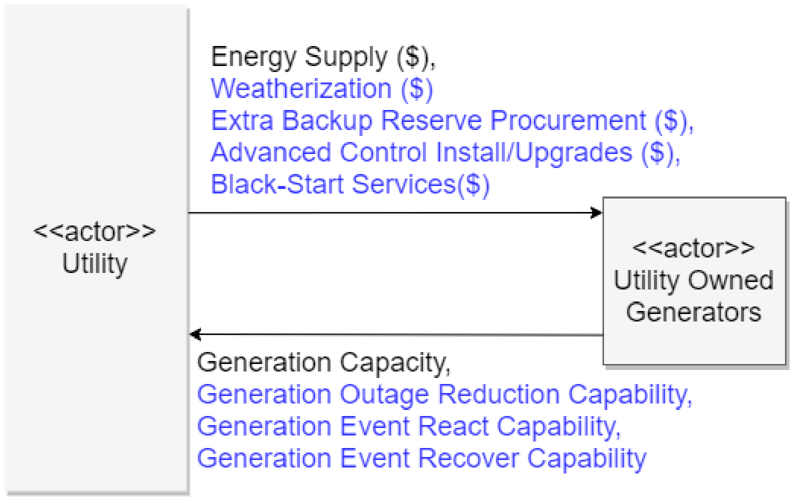


Figure 9. Fine-tuning of value exchanges between a utility and utility-owned generators for reducing grid outages.

3.3 Activity Diagram

Figure 8 demonstrated the high-level value exchange between the utility and utility-owned generators, and Figure 9 shows the extension of high-level generation to granular value exchanges. Figure 10 shows the sequence of activities that a utility takes to engage utility-owned generation for improved performance against grid disturbances. The activity sequences demonstrated in Figure 10 are in fact value-flow sequences among the interacting entities. Like the previous diagrams, we differentiate values using the colors black and blue. Values in black are associated with current utility practices for planning and operation when engaging utility-owned generators, whereas values in blue refer to newly identified values from the incorporation of measures to improve grid performance to disturbances. The usual value exchanges are explained in (Cooke et al. 2018). The key value exchanges identified for each entity to improve grid behavior for resilience are described as follows.

Planning Phase: Three key decisions, identified below, are made by a utility based on which values relate to resilience behavior due to grid disturbances.

- Decommission generation: If a utility determines that a vulnerability was introduced through one of its generators, then decommissioning that generator results in a sequence of activities in which the utility must account for how the cost of decommissioning the plant earlier than its usual time will be recovered from retail customers and eventually will be paid to a vendor for executing the decommissioning order.
- Extension and upgrades of generation: Based on the identified requirements for improving generation performance to mitigate disturbances, a utility may intend to plan alternatives for its generation fleet. In such instances, the values from these activities consist of improved control and communication regarding generation, improved emissions, and improved cost of operation and deferral benefits due to life extension. The utility deploys a vendor to implement the generation upgrade plan. Eventually, these alternative generation plans will be recovered through retail customer tariffs by justifying the avoidance of service interruption costs to the regulator.

- Maintenance of generation: The utility may intend to maintain the existing generation such that it supports grid outage avoidance by reducing the probability of generator failure and improving its response through regular maintenance to help address any performance abnormalities experienced.
- Buy fuel: The last activity and associated values for the utility in the planning stage is to procure fuel for the planned generation. The investment in “reserve” fuel is identified here as a general term for assuring that adequate fuel is present on-site such that spinning/non-spinning reserves can be supported and for non-power-related fuel that may be required for generation staff’s on-site needs (transportation/emergency power, etc.)

Operation Phase: After making purchases related to generation, the utility’s operation phase consists of selling the procured energy. Due to improvements from extra investments in the planning phase, this yields additional values for the utility, including the following:

- Outage protection price: This is an extra accounting term that a utility may quantify and separate from the final agreed-upon price with the regulator and may charge the customer, which signifies how the customers connected to the grid are better equipped to handle outages and therefore may end up paying more. These higher prices then translate into effective return on the investments for the investors.

Figure 10 demonstrates the overall activity sequence for improved generation performance to avoid disturbances—the generic terms “service interruption,” “emergency services,” and “outage protection profit” are used here. Following the grid disturbance theory, the analyst must separately define control-stage actions for each of the grid disturbance stages, i.e., avoid, react, and recover. Therefore, utility-owned generation procurement planning and operation may be distinctively divided into these three stages. An example of focusing on grid disturbance avoidance for procuring utility-owned generation is shown in Figure 11. In Figure 11, in contrast to the generalized utility-owned generation procurement activity diagram for disturbance rejection (Figure 10), activities and values in red demonstrate direct coupling to the grid disturbance avoid phase and therefore provide an opportunity to quantify the relevant costs and benefits related to avoid-stage actions.

Similarly, such generic actions may be quantified and valued for the individual control actions of avoid, react, and recover, which represent the grid disturbance phases. Examples of these extensions from the utility perspective are given in **Error! Reference source not found.**

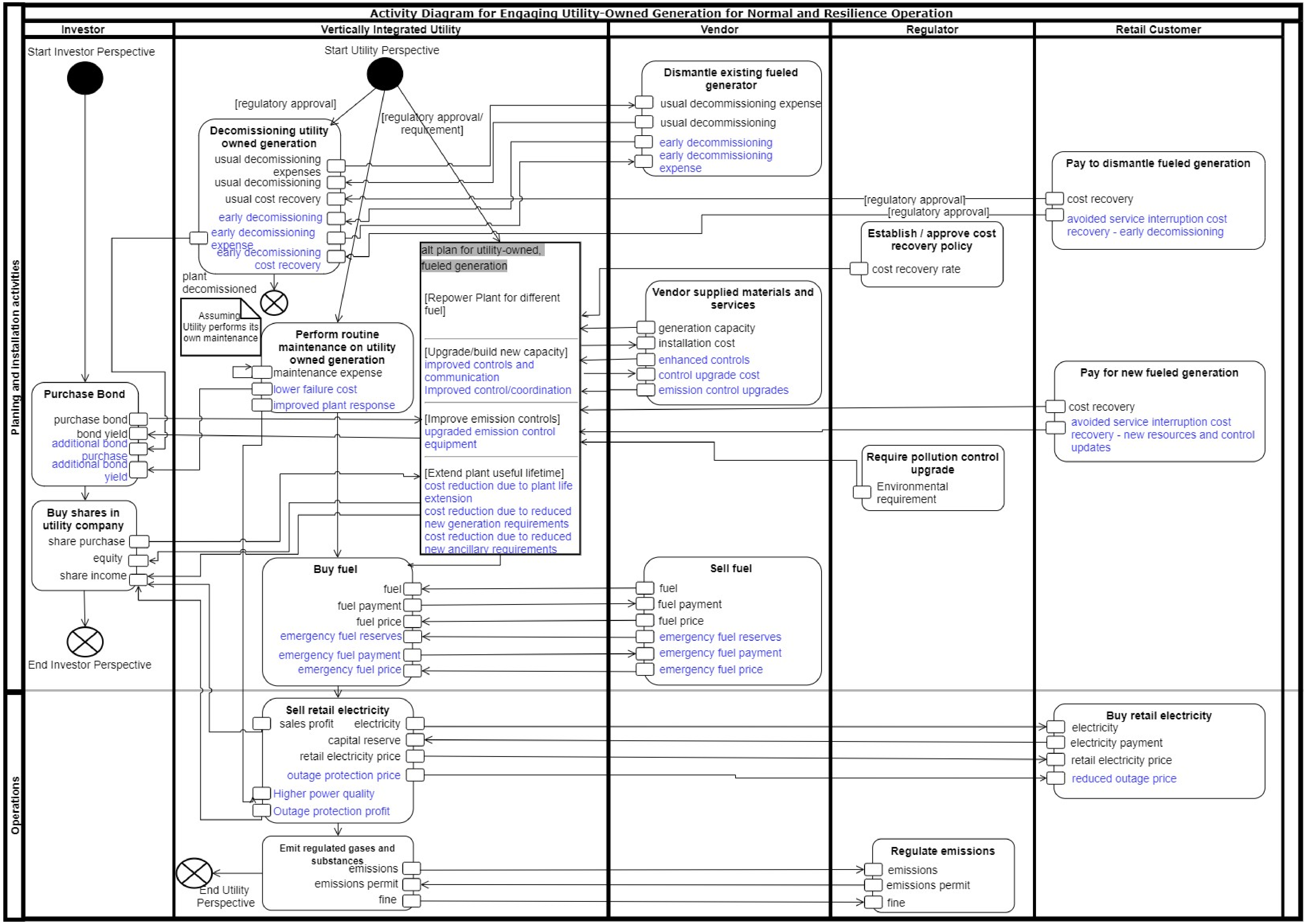


Figure 10. Activity sequence diagram for utility to engage utility-owned generation.

Table 3. Examples of generic value disaggregation from the utility perspective into individual grid disturbances phases.

Generic Value	Avoid	React	Recover
Early decommissioning cost recovery	Early decommissioning outage; avoid cost recovery	Early decommissioning outage; react cost recovery	Early decommissioning outage; recover cost recovery
Lower failure cost	Avoided plant outage costs	Lower cost of plant to react to outage triggers	Lower cost of plant to participate in recovering from outage
Improved plant response	Avoided plant outages due to reserved response	Avoided load rejection due to reserved response	Avoided less load pickup due to reserved response
Emergency fuel reserve	Outages avoid fuel reserve	Outages react fuel reserve	Outages recover fuel reserve
Emergency fuel payment	Outages avoid fuel payment	Outages react fuel payment	Outages recover fuel payment
Emergency fuel price	Outages avoid fuel price	Outages react fuel price	Outages recover fuel price
Outage protection price	Outages avoid protection price	Outages react protection price	Outages recover protection price
Outage protection profit	Outages avoid protection profit	Outages react profit	Outages recover profit
Higher power quality	Outage avoidance power quality margins	Outage triggered ramp-up capability	Load pickup capability due to advanced protection/control

Even though the examples in **Error! Reference source not found.** demonstrate the first step toward disaggregating the generic values to individual grid disturbance phases, there is no reason for further granular disaggregation. For example, avoided plant outage costs could be further divided into avoided loss of power production costs and avoided unscheduled maintenance costs due to fewer outages.

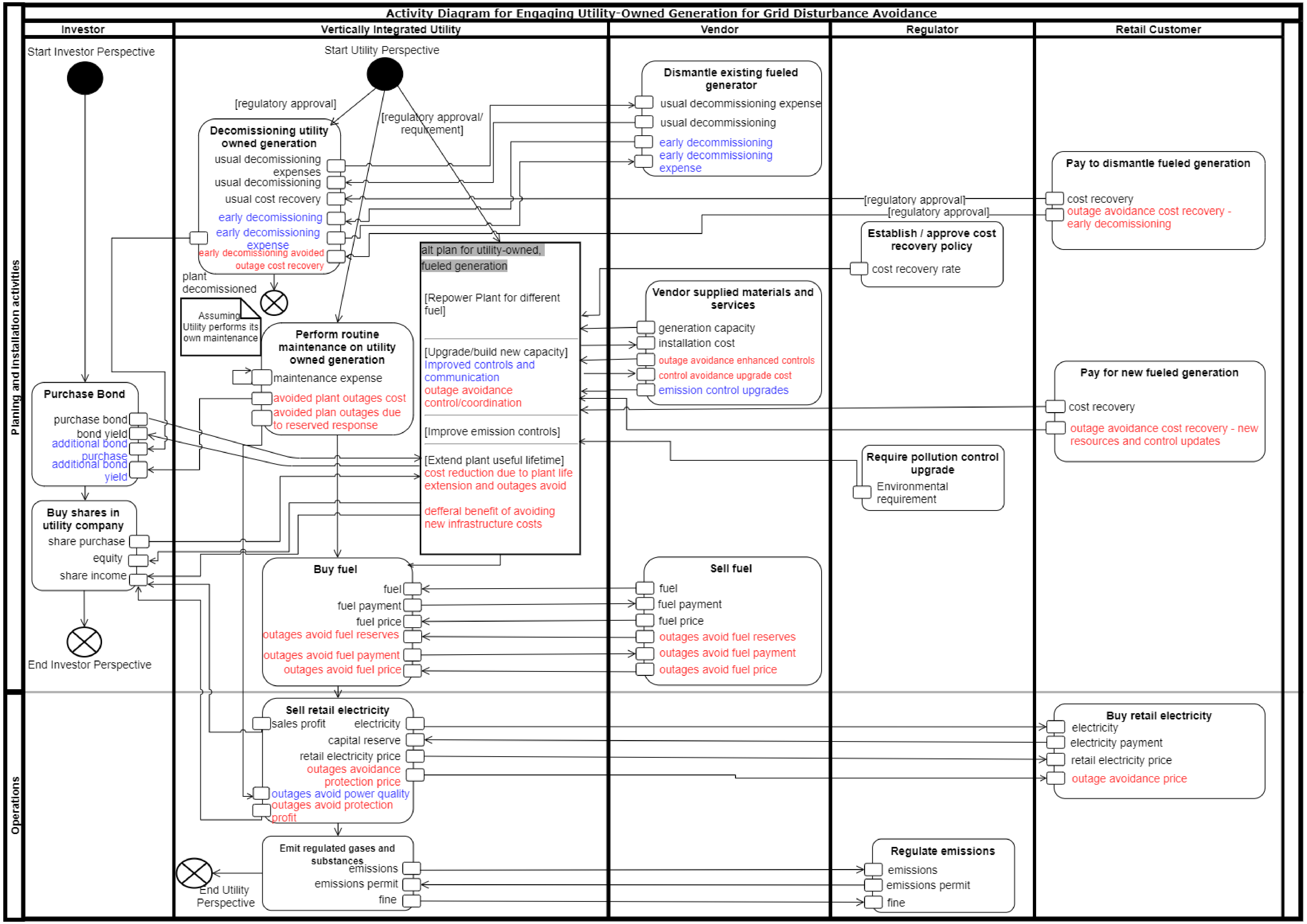


Figure 11. Activity sequence of grid disturbance outage for procuring utility-owned generation; red values correspond to the grid disturbance avoid stage.

4.0 Conclusion and Future Works

This report provides a resilience valuation framework, where the services procured by the utility are valued using TSVM. We show through TSVM the integration of traditional IRP valuation with new resilience considerations, and we provide a three-step procedure to achieve such a framework. The first step is to develop a use-case setup to define the functional requirements necessary for the utility to plan and operate a more resilient grid. Second, values are identified for all the services that will be acquired by the utility. Finally, value associated with actors' (both inside and outside of the utility's internal functions) decisions and sequences are pinpointed.

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