CARNEGIE MELLON UNIVERSITY

CARNEGIE INSTITUTE OF TECHNOLOGY

THESIS

SUBMITTED IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE

DEGREE OF DOCTOR OF PHILOSOPHY

ELECTRIC POWER SYSTEMS UNDER STRESS:

AN EVALUATION OF CENTRALIZED VERSUS DISTRIBUTED

SYSTEM ARCHITECTURES

by

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Carnegie Mellon University

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A DISSERTATION

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Pittsburgh, Pennsylvania

September, 2004

In memory of my grandfather, Dr. Henri M. Yaker, whose great intellect, diverse academic and professional pursuits, and love of life and family have been an inspiration. I only hope to live up to his example.

Abstract

It is well recognized that electric power systems do not always perform perfectly and that maintaining reliability of supply is one of the important tasks for power system planners. However, there are circumstances under which power systems can face persistent stresses or have the possibility of being under high stress conditions. These stresses arise from and affect both the technical systems designed to generate and deliver electricity, as well as the commercial and political organizations designed to undertake those tasks and to govern these activities. The issue of electric power systems under persistent and high stress conditions and possible changes to electric power systems to deal with this issue is the subject of this dissertation. The stresses considered here are not the single event type of disruptions that occur as a result of a hurricane or other extreme weather event or the large blackouts that result from a particular set of circumstances. Instead the focus is on conditions that cause systematic and long-term performance degradation of the system.

Electric power systems have been and will continue to be challenged by a number of stress conditions that can come from a variety of sources. Extreme weather has long been recognized as a contingency that must be planned for as best as possible and then mitigated against when it occurs. However, there are a number of other stressors that could have effects that rival that of extreme weather events (or could be even worse). Such stressors can have very different characteristics than extreme weather events (e.g. in the scope and nature of the stress or the persistence of the stress) rendering some of the solutions developed for extreme weather events less suitable for such contingencies. Example of such a stress include underinvestment in infrastructure (e.g. transmission),

lack of access to spare parts or trained personnel and the set of problems created for electric power systems during conflict situations. The particular stress conditions faced by an electric power system will depend heavily on context and will likely be different for industrialized versus industrializing countries.

It has long been recognized that stresses such as conflict and war can have a large impact on electric power systems. There have even been arguments made regarding how changes in the system architecture from a centralized to a distributed system can aid in mitigating the impacts of such stresses. However, there have been few systematic analyses of the problem. The contribution of this research has been primarily in three areas:

- The systematic characterization of stresses on electricity infrastructure
- The development of a method to analyze stress on electric power systems (particularly the application of a stress adjustment factor and the creation of non-coincident demand)
- The quantification of the impacts of making a large-scale change to a distributed system architecture and the reliability impacts of changing to such a system under stress conditions, including the impacts of fuel supply.

Some of the issues related to having a system based upon a significant level of distributed generation that have been explored include the reliability of different mixes of centralized and distributed generation technologies, the impact of load coincidence on reliability and needed DG investment, and changes in the usage of the high voltage transmission network.

As expected, a model that compares a hypothetical centralized system with a completely distributed system demonstrates that the distributed system has two reliability advantages. First, under normal operating conditions it is possible to reduce drastically, or almost eliminate, the reserve margin in the system while at the same time improving the adequacy of the system to provide real power (as measured in MWh/year not supplied). Second, under stress conditions the reliability advantages of most distributed systems are demonstrably higher than a centralized system of standard design. Most notably, as stress levels are increased, the loss of energy expectation does not rise as rapidly for the distributed systems as for the centralized system. These are reliability advantages for the whole system.

Furthermore, under normal conditions, the decrease in required capacity and the use of waste heat for co-generation make the distributed system competitive with a centralized system in terms of levelized cost of electricity supply. Under stress conditions, the economic losses suffered by various sectors of the economy become increasingly significant. The improved performance of the distributed system under stress translates directly into economic benefits. The model was also extended to include the likely supporting natural gas infrastructure for currently competitive DG technologies in order to determine the impact of dependence upon that infrastructure on the reliability of the system. It was found that under normal operating circumstances, due to the high reliability of natural gas systems, there is a negligible impact on the reliability of the power system. In order for stress on the natural gas system to have a significant impact on electricity provision, the stress level has to result in unavailabilities that are hundreds of times higher than the baseline reliability of the natural gas system. This might occur, for example, if the system is above ground and easily targeted.

While it is useful to think of the two ends of the centralized/distributed spectrum, as was done in the initial engineering economic modeling (see Chapters 3-5) and in the natural gas network model, the reality is that any power system will be a mix of distributed and centralized generating technologies. In Chapter 6 a number of mixed system topologies were evaluated using the engineering-economic model. The model was re-run with various strategies for replacing centralized with distributed generation. In each case, the amount of centralized generation removed from the system was replaced with differing amounts of distributed generation. The results of these model runs were compared with model runs for the purely centralized and purely distributed systems. The results indicate that three inter-related factors are critically important in determining the relative performance of the different mixed systems. First is the relative size of the centralized units being replaced. This is due to the fact that the impact of any particular generator failing is dependent upon its size. Replacing larger units results in a system composed entirely of distributed and relatively small or medium sized centralized units and a decreased dependency on a few large units. Second are the relative reliability characteristics of the centralized units being replaced. Replacing highly reliable centralized units with less reliable (though more numerous) distributed units leads to no change. The third is the degree of distributed generation penetration and resulting reserve capacity. At high penetration rates (e.g. on the order of 40%) it is possible to maintain or even significantly improve system performance while at the same time reducing overall generation capacity and essentially eliminating the reserve capacity. The result is that the needed reserve margin is not a fixed number but highly dependent on the mix of technologies and the degree of DG penetration.

The reliability of the system is not simply a function of the generation and transmission of electricity. The other side of the equation is the demand for electricity itself. Specifically, reliability is determined by comparing the energy that can be delivered in any given time period with the demand for that time period. In order to assess some of the impacts of load non-coincidence on reliability and on power sharing between micro-grids, a method was established to systematically vary the loads at different customer load buses. The result is demand profiles that are not artificially set to be coincident and therefore, there are greater opportunities for sharing power than might be indicated in a model that does not include differentiated non-coincident loads.

The results show the inter-relationship between installed capacity at the micro-grids, the degree of load non-coincidence, power sharing between the micro-grids and the reliability and cost of the system. Load non-coincidence was introduced in a systematic fashion and under two different assumptions (constant system peak vs. constant micro-grid peak). In both cases, changing the load non-coincidence had an impact on system reliability and the degree of power sharing. However, in the constant system case, increased load non-coincidence eventually resulted in reduced reliability for the completely distributed (and no reserve margin) case as compared to the centralized case.

In the constant micro-grid approach, after a certain amount of load shifting the micro-grid loads are sufficiently different that they can take maximum advantage of power sharing options. This model also shows that allowing for power sharing can decrease the amount of DG capacity that is necessary in order to meet demand.

The final set of model runs were conducted to determine whether the power sharing that occurs could result in significant usage of the higher voltage transmission network. One of the stated advantages in the use of distributed generation is reduced reliance on the transmission network. With a system that is dominated by distributed generation, it might be expected that the power sharing would remain within clusters of neighboring micro-grids in the network. The model used to test this hypothesis is no longer a reliability model but a network flow analysis for every hour in the year for differing levels of load non-coincidence and for the centralized versus distributed cases – assuming all components work perfectly. The load flow is an optimal DC power flow that minimizes a combination of generation and load shedding costs.

This pattern of flows over the transmission network is indeed confirmed by the model. In a completely distributed system the flows over the high-voltage network drop and are comparatively inconsequential. There is still flow between microgrids, but this is within clusters of microgrids that are all attached to the same high-voltage bus. Flows along the high-voltage lines increase if load types are clustered and DG installations are not randomly placed. However, even under these assumptions, which should maximize load flow, the line loadings remain significantly lower than in the centralized case and for seventy percent of the line-hours there is no flow over the high voltage network. Overall energy flow (including over the linkages between microgrids) is orders of magnitude lower than in the centralized case.

The results summarized above indicate that there are potentially significant macro-level reliability advantages to increasing the amount of distributed generation in a system. Electric power systems are installed and operated under a wide variety of conditions, some of which can be characterized as "high stress" conditions in which the adequacy of the system to provide energy is challenged. The contribution of this research has been to quantify and to explore the implications of wide-scale grid connected distributed generation. In particular, the emphasis has been on systems under stress conditions, but the results under low stress conditions are more widely applicable.

The first goal of this research was to model and quantify the reliability and economic differences between centralized and distributed energy systems for providing electricity and heat, particularly under stress conditions. The second goal was to determine the impact of heterogeneity of local loads on the desired level of decentralization of the system and the impact of decentralization on the network requirements. The first goal was met through the development of Monte Carlo reliability simulations, applied to different system network topologies. The results of those models show significant potential improvements in energy delivery with distributed systems. The second goal was met through a combination of Monte Carlo simulations applied to systems with differentiated and non-coincident loads and an optimal power flow applied to a more realistic network topology. The results of those models show the potential for improvements when loads are non-coincident and micro-grids can share power as well as the fact that the power sharing may be largely limited to local clusters of micro-grids. This research also showed the need for incorporation of stress in power systems modeling and a method for characterizing stress.

Acknowledgements

While it seems at times that the Ph.D. is a lonely and solitary task, the truth is that it is only possible through the support and help of a number of people. First and foremost, I would like to thank my advisors, Hadi Dowlatabadi and Alex Farrell. The two of you, each in your own way, have pushed me to think in new ways and be rigorous in my work and your guidance and advice has been invaluable. I would like to thank Granger Morgan, not only for being on my committee and for his input on my work over the years, but also for his part, as head of the department, in making EPP what it is today. My thanks also go to my final committee member, Marija Ilic, for her input. I only regret that we did not have more time to work together.

My fellow grad students in EPP played a large role in having made the last four years enjoyable. I have appreciated both the intellectual challenges and the friendship. I would also like to thank the faculty of EPP for providing a rich learning environment. The staff of EPP is wonderful and made life much easier and for that I am grateful. My life in Pittsburgh, thankfully, has not all been spent in EPP and I would like to thank all of my non-EPP friends for making life fun and keeping me sane. I also owe much to Arjun Makhijani, who taught me to always ask the questions nobody else was asking and look for the answers that made a difference. I would also like to thank my family, particularly my parents, and all of my friends everywhere for their support and encouragement. Finally, I would like to thank Elaine. Thank you for being by my side through this. You have made the impossible seem possible.

Of course, the Ph.D. cannot be done with intellectual and emotional support alone, money helps as well. This work was supported in part by the Alfred P. Sloan Foundation, the Electric Power Research Institute, and the U.S. National Science Foundation (ECS-0224837) through the Carnegie Mellon Electricity Industry Center (www.cmu.edu/electricity). This research was also made possible through support from the Center for Integrated Study of the Human Dimensions of Global Change. This Center has been created through a cooperative agreement between the National Science Foundation (SBR-9521914) and Carnegie Mellon University. I am grateful to both of these Centers for their generous financial support over the last four years.

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Chapter 1 Introduction: Energy Systems Under Stress and Distributed Generation

It is well recognized that electric power systems do not always perform perfectly and that maintaining reliability of supply is one of the important tasks for power system planners. Supply reliability has to take into account the routine failure of system components and the tools to do so under normal operating conditions are fairly well-developed and understood. However, there are circumstances under which power systems can face persistent stresses or have the possibility of being under high stress conditions. These stresses arise from and affect both the technical systems designed to generate and deliver electricity, as well as the commercial and political organizations designed to undertake those tasks and to govern these activities. The issue of electric power systems under persistent and high stress conditions and possible changes to electric power systems to deal with this issue is the subject of this dissertation. The stresses considered here are not the single event type of disruptions that occur as a result of a hurricane or other extreme weather event or the large blackouts that result from a particular set of circumstances. Instead the focus is on conditions that cause systematic and long-term performance degradation of the system. While it may be possible to modify the methods described in this dissertation in order to address severe weather conditions and the impacts of major blackouts, the focus is instead on these persistent stress conditions rather than single large events.

The stress conditions (as will be described below) can have various root causes and effects on the system. One very concrete example of how stress can impact a power system is the case of power systems in areas of military conflict. In times of war, attacking infrastructure is a common military tactic – and electric power systems are obvious targets. Since electricity cannot be easily stored or rerouted, supply must match demand. In an integrated electric system, a disruption can bring down large parts of the network.[1] This can have severe economic consequences (Eto, Koomey et al. 2001)[2], and pose a threat to human life, as has been seen in a variety of conflicts (e.g. Bosnia). Moreover, the rise of organized and systematic global terrorism has demonstrated that an attack on an electricity system is an issue for all countries, not just for those currently undergoing conflict or at war. Thus, while it is not the rich industrialized nations that have experienced such damages to their system in the post-World War II era, it is possible that deliberate and repeated attacks against such systems could occur in the future. While this is one example, it is emphasized here (and in subsequent sections below), only because it is such a concrete example where the stress and the impact of the stress can be easily seen and understood. The challenge of reliable electricity supply is made even more difficult by the fact that, even in the absence of stress conditions, integrated electric system are susceptible to unavoidable cascading failures that can bring down large parts of the network (Talukdar, Apt et al. Forthcoming 2003).

[1] For example, the ice storm of 1998, which hit Quebec, Ontario, New York, and parts of New England, left millions of people without power. In some areas, power was not restored for weeks.

[2] The economic impact of any outage will depend on a range of factors, including the area affected, the duration and a host of other factors. For example, Hydro Quebec's direct losses to its electricity system were estimated at approximately a half billion US dollars. Overall economic losses could have been around three times that amount (Committee of Experts Appointed by Hydro-Quebec's Board of Directors 1998). Similarly, Niagara Mohawk Power Company in New York lost around $100 million due to damage to its equipment. (Federal Emergency Management Agency 1998)

There are a number of different options for dealing with the various stresses that a power system can face. These can range from increased investment in capacity to improved physical protection of key sites. One approach is to account for the need for reliability under stress in the design of the system architecture and implement technologies that are inherently more robust and which allow the system to perform better under stress conditions. It is this option that is the focus of this research, and in particular, it is the change from a centralized system architecture (a relatively small number of large power plants far from demand) to a more distributed architecture (a relatively large number of small power plants co-located with demand) that is analyzed for its impact on reliability and cost. As will be described below, there are a number of options for a more distributed system architecture. This research focuses specifically on small generators (~500 kW) located at the site of demand and serving as baseload generators in a local power network (or micro-grid), with all of these local micro-grids joined by a higher level transmission network. It should be noted that, unlike analyses that attempt to address the question of differentiating customers by their need for reliable power, the goal of this analysis is to assess *system* reliability. Thus, the generators are at the customer level but the analysis is at the systems level.

This introductory chapter will first describe how stress, as defined and analyzed in this dissertation, is different from the types of reliability problems that are typically analyzed in power systems. Next, the context dependency of stress will be described. There are a number of different types of stresses and the type of stress, its severity and impact, and the ability to cope with the stress is dependent upon the context being considered. In order to make these arguments more concrete, one particular context is outlined more fully, that of power systems in areas of military conflict. Two specific examples, the Palestinian Territories during the current intifada and Bosnia-Herzegovina during the civil war of the nineties are summarized. Finally, the role that distributed generation can play in high stress contexts is reviewed and the different technology options discussed. This includes a qualitative discussion of the potential benefits of a system based largely on distributed generators fueled by natural gas. It also outlines the specific DG technology and options analyzed.

1.1 Stress is not Just a Hurricane

The difference between the stresses considered here and weather related events is worth discussing in some further detail, as it forms the basis for the contribution of this work to the larger literature on reliability and electric power systems. Planning for reliable electricity supply has traditionally involved a careful analysis of equipment failure and redundancy needed to continue or restore service, including at times of weather extremes (e.g. lightening and hurricanes). Stress differs from the modes of disturbance analyzed in typical reliability planning in several important ways, as seen in Table 1.[3] Some of the major differences include the possibility that the stress will be non-stochastic (i.e. coordinated), the scope of impacts, the persistence of the stress and the existence of socio-political imperatives that either contribute to the stress or make it difficult to manage:

[3] One aspect of this issue that has not been examined is the relationship between the size of the system and its vulnerability to either extreme weather or conflict. A larger system may be less vulnerable to extreme weather simply because of the redundancy in the system and the localized nature of impacts. On the other hand, a large system may be *more* vulnerable to deliberate attack because of the larger number of potential targets and reliance on key nodes, which can be identified and attacked (e.g. key transmission lines).

1. **Coordination of Attack:** Unlike equipment failures or even extreme weather events, deliberate attacks are not short-term random events. Both militaries and terrorists alike have the capabilities to devise attacks that intentionally maximize damage to the system. For example, the Farabundo Marti National Liberation Front (FMLN) were able to interrupt service to up to 90% of El Salvador at times and even produced manuals on disrupting electricity systems (Office of Technology Assessment 1990).

2. **Scope of Impacts:** The failure of distribution equipment within 1/2 mile of the customer is the cause of 60% of interruptions in the US (Willis and Scott 2000). However, in conflict situations, remote transmission lines, generating stations and transformer sub-stations can also become targets or be impacted by indirect damage stresses. The non-conflict stresses discussed below (e.g. access to spare parts due to poor capital) would also have a wider scope of impacts. It is not at all clear that existing reliability assessments account for these types of failures across a broader set of components, and the subsequent impact on the integrated electricity network.[4]

3. **Persistence of Outage:** Long outages are not considered normal by electricity planners in industrialized countries (a 'sustained interruption' is generally classified as one that lasts more than one hour, there is no classification level for longer outages). (Willis and Scott 2000, pp. 67-70). Stress conditions can result in more frequent outages that are considered to be long by making necessary routine maintenance, restoration of service and repair more difficult. When outages do occur there are a number of factors that can lead to outages that persist for days or even longer. Such factors would include: risks to personnel in conflict situations, impeded transportation of personnel and parts,

[4] For example, inclusion of weather effects in reliability analysis (the closest analogue to conflict situations that exists in the literature) only considers its impacts on the transmission and distribution level and not at the generation level.

lack of funds for replacement parts, absence of technical expertise, and the possibility of subsequent sabotage. Furthermore, in addition to being coordinated, deliberate attacks may not be single events and repaired system components could be damaged after their initial repair.

4. **Socio-Institutional Imperatives:** There may be socio-institutional imperatives that become serious enough to threaten the functioning of the energy system. Such imperatives can result in power systems that cannot recover costs and result in difficulties in maintaining and upgrading the system, resulting in continued degradation over time. An example would be the un-metered and heavily subsidized agricultural electricity consumers in India. The importance of agriculture makes it extremely difficult to change the tariff structure and the losses due to the agriculture sector are an important part of the reason the Indian electricity boards are heavily in debt and the power quality in the rural distribution system is very low.

These stresses have the potential to impact electric power systems and to change the role infrastructure development plays within the larger socio-economic framework. Unfortunately, these social contexts are often not explicitly considered in power system planning (where more traditional considerations of scale, technical failure, weather and efficiency are commonplace). This creates a policy challenge and a set of needed activities, some of which are addressed here:

1) Stress must be defined and characterized

2) Methods to analyze stress must be developed

3) Management options (investment choices) and institutional frameworks that are best suited to handle stress must be developed.

TABLE 1: MODES OF DISTURBANCE IN ELECTRIC POWER SYSTEMS

Mode of Disturbance	Possible Causes	Likely Characteristics	Likely Impacts
Weather Related Damage*	Hurricanes, tornadoes, floods, ice storms	Random, not repeated, not targeted, regional	Impacts T&D primarily. No long term impacts on failure probabilities, magnitudes or durations. Recovery only hampered by environmental conditions.
Equipment Failure*	Trees, animals, or vehicles contacting power lines, unanticipated wear	Single events occur randomly, but at a known, acceptable rate.	Reduces the equipment available to the system by one component. Managed to obtain desired balance of cost and reliability.
System-wide Direct Conflict Damage (e.g. attacks on centralized generating facilities)	Civil War (e.g. Bosnia), guerilla movement	Persistent, system-wide, impacts all levels of system	Both failure probabilities and magnitude of damage high, recovery difficult and expensive due to continuing conflict.
Regional Direct Conflict Damage (e.g. attacks on transmission)	Regional Insurgency	Persistent but localized, impacts all levels of system	Failure probabilities and magnitudes increase in affected region, recovery difficult.
Localized Direct Conflict Damage (e.g. attacks on major transformer substations)	Terrorism or Sabotage	Targeted, repeated (lower frequency), less damage per attack on average, less damage to large generators	Failure probabilities increase, magnitudes do not increase greatly except for the most extreme acts, recovery relatively unhampered.
System-wide Indirect Conflict Damage (e.g. deferred repairs due to dangerous work conditions)	Civil War (e.g. Bosnia), guerilla movement	Mobility hampered, increased non-technical losses creating financial problems	Failure probabilities increase, magnitudes of failures do not increase, recovery more difficult.
Regional Indirect Conflict Damage (e.g. same as above but on smaller scale)	Regional Insurgency	Regional mobility hampered, increased non-technical losses, financial problems	Failure probabilities increase, magnitudes of failures do not increase, recovery more difficult.
Lack of Investment in New Capacity	Capital access, investment uncertainty	Units need to be run more often and for longer as reserve margins decline, transmission system strained	Possible increase in failure rates over time.
Poor Maintenance	Capital and spare parts access		Failure rates increase over time, repair times increase.

*Note: These disturbances are part of reliability planning. All others are stress conditions.

Since electrification occurred first in industrialized countries and has been studied most extensively there, analysis of the electricity sector reflects conditions in these settings. In order to better understand the impact of stress on electric power systems, it is necessary to delineate the modes of stress, their possible causes, the likely characteristics of the stress and the likely impacts of the stress. Table 1describes these factors for weather related damage, different types of conflict-related damage, and other non-conflict stresses that could be experienced by an electric power system. This systematic definition of stress conditions in terms of characteristics and impacts is one of the contributions of this research. It is necessary to properly understand the nature of the stress affecting any given system in order to understand both the impact of that stress and the possible options to mitigate and adapt to the stress.

Table 2 summarizes the nature of the literature that currently exists for those different disturbance modes and some possible modeling options that could be applied to analyze the disturbance mode. As can be seen from Table 2 there has been little research on the specific concerns considered here. Typical conditions in low-income countries have not been very well studied or have been only studied within a specific geographic context. In addition, large-scale deliberate attacks on infrastructure have not been a significant concern in industrialized countries until relatively recently, so these conditions have not been well-studied either (with a few exceptions). Those studies that have been done, while sometimes motivated by examples from the industrializing world, have tended to focus on areas that may only be applicable in a limited fashion outside the industrialized countries. Often system architecture and other structural features of the system have been taken as a given and the focus has been on physical and cyber-security, as well as organizational and technical approaches, that may not be suitable in developing or stressed countries (Office of Technology Assessment 1990; Bowers 1999; Ocana and Hariton 2002; Seger 2003).

TABLE 2: PREVIOUS LITERATURE AND POSSIBLE MODELS FOR DIFFERENT DISTURBANCE MODES

Mode of Disturbance	Previous Literature	Possible Modeling Options
Normal Operating Conditions	Extensive. OECD focused.	Established simulation and analytic methods.
Weather	Extensive.	Already included in models.
System-wide Direct Conflict Damage	Focus on OECD. Older literature on nuclear security.	Unit availability adjustment. Application to multiple system architectures.
Regional Direct Conflict Damage	Focus on OECD (limit to damage due to size of system). Focus on Physical and Cyber Protection. DG benefits qualitatively described.	Unit availability adjustment in affected area.
Localized Direct Conflict Damage	Focus on OECD. Focus on Physical and Cyber Protection. DG benefits qualitatively described.	Unit availability adjustment, spatial distribution of attacks according to Poisson distribution.
System-wide Indirect Conflict Damage	Limited. Focus on "terror" aspects (e.g. nuclear).	Unit availability adjustment.
Regional Indirect Conflict Damage	Limited. Focus on "terror" aspects (e.g. nuclear).	Unit availability adjustment in affected area.
Lack of Investment in New Capacity	Restructuring literature.	Increase demand; slowly increase failure rates over time.
Poor Maintenance	Literature on rehabilitation of rural networks in developing world.	Unit availability adjustment (perhaps a dynamic model with decreasing availabilities over time). Forced outages could be made a function of planned outages (for regular maintenance).

As a result, current reliability planning models have three major limitations in dealing with these contexts. The first is that they are generally applied in the context of well-functioning electric power systems (generally in higher income countries, like those in the OECD). The second is that they do not consider stress on the system other than damage related to major weather events. The third is that they are applied to systems that are overwhelmingly dominated by centralized power production and do not consider structural changes to the system that fundamentally change the system architecture. Such structural changes would include significant levels of power generation co-located with demand (distributed generation).

Given the discussion above, the purpose of this dissertation is to develop some quantitative tools to understand the impact of stress and to determine the impact that changes in system architecture have on the ability of the system to meet demand under stress conditions. The change in system architecture envisioned is one of greater reliance on small distributed generators close to demand centers. It has been proposed that distributed generation may be more robust and resilient for primarily two reasons. First, the co-location of generation and demand reduces the need for a hard-to-protect and hard-to-operate high voltage transmission system. Second, the small size and large number of generators reduces the impact of failure of any individual generator. These and other advantages and disadvantages of distributed generation are discussed below and in Chapter 2.

Therefore, the overall goals of the dissertation are summarized below.

Goal 1: To model and quantify the reliability and economic differences between centralized and distributed energy systems for providing electricity and heat.

- What are the reliability impacts of switching from a system that relies on a small number of large generating units far from the demand to one that relies on a large number of small generating units close to the demand? How do the systems compare when they are under stress, e.g. due to direct or indirect damage during a conflict?
- How is the likely dependence of distributed generation units on the natural gas infrastructure going to impact any reliability advantages that may be gained by a distributed system?

- What will the economic implications be of a more distributed system once all productions costs and benefits, as well as benefits of supply security under various levels of stress are accounted for?

Goal 2: To determine the impact of heterogeneity of local loads on the desired level of decentralization of the system and the impact of decentralization on the network requirements.

- For the proposed size of microgrids (~10 MW), how different will the load profiles be for different load centers?
- How will this non-coincidence in load profile impact the need for power sharing between the microgrids and what impact will this have on the need for higher voltage transmission capacity and their potential role in security of supply in a DG architecture?

The rest of this introduction will further detail the importance of considering stress conditions and some issues involved and then outline the role that distributed generation can play. Chapter 2 provides a literature review on distributed generation, critical infrastructure protection and security and the modeling of power systems. Chapters 3 and 4 present an engineering economic model that determines the reliability of power systems under stress conditions. Chapter 5 addresses the issue of increased reliance on natural gas as a result of having a distributed system. Chapter 6 moves from a comparison of purely centralized and purely distributed systems to assess mixed system topologies. Chapter 7 examines how load non-coincidence impacts reliability and the need for DG investment. Chapter 8 uses a power flow model to determine the need for maintaining a high voltage transmission system even when the generation is distributed. Chapter 9 provides overall conclusions and final thoughts.

1.2 The Context Dependency of Stress

The discussion above has referred to the differences between industrialized and industrializing contexts and between different types of stresses. Indeed, this is an important issue and one that has to be kept in mind when extrapolating from the computer models and hypothetical systems described in later chapters to real-world contexts. The potential effects of different forms of stress have been discussed above, but it is necessary to spend some time discussing the importance of the context in which the stress occurs.

The industrialized countries of the world have well-developed and long-lasting electricity infrastructures already in place. These systems are based primarily upon large power plants at significant distances from the end-users, necessitating long-distance transmission of electricity and radial distribution of electricity at the local level. For the majority of the people in the industrialized nations the electricity system functions exactly as it is supposed to for the vast majority of the time. There are, of course, outages but these generally arise from rather mundane and easily fixed problems at the local level (cars crashing into poles, trees, etc.). For those living in areas where severe weather can be a problem (e.g. ice storms in the North or hurricanes in the Southeast of the United States), these random weather events can disrupt service over hundreds of square kilometers and for several days, and occasionally much longer. These severe weather events, too, are problems that are well understood with known solutions, and they are relatively rare events. Even major blackouts, such as the Aug. 14th blackout in the United States and the blackouts in England and Italy that occurred shortly thereafter are rare (though expensive) events.

However, these systems could potentially face a number of stress conditions of the type considered in this dissertation. The California electricity crisis could arguably be seen as a case of persistent and high stress due to factors such as market design and transmission capability, conditions that were not likely to change quickly. Terrorism and the risk of deliberate and coordinated attack is another example. As discussed further in Chapter 2, there has been considerable emphasis placed in the United States and elsewhere on Critical Infrastructure Protection, including protection of power systems against deliberate physical or cyber-attack.

In terms of changing the system architecture in order to cope with these stresses, the challenge is that systems in industrialized contexts are already well developed. These systems are capital intensive and the assets are long-lived. This creates path dependency issues regarding evolution of the electric power system. Not only is there significant investment in basic network topology, the supporting infrastructures (such as fuel supply) and technologies (such as the control systems) have been designed to serve that network topology. There is also the issue of stranded assets and capital retirement that may make it difficult for new technologies to supplant old ones. On the other hand, their growing economies and advances in changing the regulatory structure of the industry could leave room for distributed generation to play a role in the growth of the electric power system. New office parks, for example, offer a greenfield opportunity to develop and deploy new technologies under new institutional arrangements.

These contexts also have other attributes that would seemingly allow them to take advantage of the opportunities that DG offers, including functioning capital markets and institutional structures, and well-trained human capital. There are, of course, various barriers to the deployment of distributed generation in many industrialized nations that would have to be overcome. In these industrialized settings, there are a number of possible advantages of distributed generation, including cost and improved reliability at the facility level. The possibility of blackouts and other issues related to stress (e.g. lack of transmission or centralized generation investment) may play a role in DG deployment. However, it would appear more likely that cost considerations (e.g. savings due to CHP), as well as ordinary reliability considerations (e.g. need for backup for sensitive equipment and processes or improved power quality) are more likely to be driving forces.

Industrializing contexts provide a different set of circumstances, both technically and institutionally, under which distributed resources might be deployed. There are large portions of the world's population that live either without electricity service or have electricity service that can be considered to be of poor quality or availability (e.g. electricity is only one for a certain number of hours a day). Under the most extreme examples (e.g. parts of sub-Saharan Africa or Afghanistan), there is very little pre-existing infrastructure and the situation is close to being completely a greenfield opportunity. In other cases, there is a large amount of unmet demand or poorly met demand (e.g. India), technical and institutional barriers to improvements in the existing grid system and higher occurrences of civil and international conflicts. Therefore, it would appear that if stress is going to play a role in the development and deployment of distributed generation, it is more likely to occur in industrializing, rather than industrialized, contexts. That is not to say that distributed generation is more likely to be developed and deployed in these contexts, only that stress is more likely to play a role in these contexts. At the same time, there are serious issues including the lack of access to capital for investing in distributed resources (especially at the local level), potential problems with maintenance and spare parts, the need for continued institutional development to promote investment and innovation that could impede adoption of distributed options

In order to further understand the role of context in this problem one particular form of stress is discussed below, that of military conflict. First a brief overview of how the conflict context can impact industrialized and industrializing nations differently is presented. Then two specific examples are reviewed. The first is the Palestinian case, which exemplifies a system that has a lot of room to grow but that has been hampered by the most recent conflict, particularly in indirect ways. The second is the Bosnian case, a system that was relatively well developed, but which was devastated by damage during the civil war of the mid-nineties.

1.2.1 The Conflict Context

In order to provide a more concrete example of the types of stresses that can impact an electric power system, and how these conditions differ from those usually analyzed, this section will outline the problem of electric power systems in areas of conflict and provide two short examples.

Policy consideration of conflict on electricity systems can be different for countries at varying stages of economic development or at different risk to deliberate attack. Table 3 presents a simplified classification. In general, less industrialized and at risk countries have not considered conflict in electricity planning due to limited resources to address it. However, their energy systems are less developed and, as part of expansion planning, can be designed to withstand attacks more effectively.[5] On the other hand, more industrialized countries are now forced by the prospect of terrorist attacks on energy infrastructures to reassess the vulnerability of their relatively mature energy systems. They have large sunk costs in infrastructure, but have greater capabilities to meet this challenge. The economic and general health impact of major disruptions to the electricity system is also likely to be different between industrialized and less industrialized countries.

[5] The concept of industrializing countries being able to "leapfrog" over some stages in the development process is well recognized. By not having a large infrastructure to replace over time, energy planning in these countries could be considered close to being greenfield developments and it may be easier to develop electricity system plans that rely on new technologies. Furthermore, in post-conflict cases, there may be additional financial resources available through specific post-conflict infrastructure aid as has been seen in a number of cases.

The issue of deliberate attacks on electric power systems and the various problems raised by trying to run a system under high stress conditions is not simply a theoretical problem. There have been numerous examples of both direct and indirect effects of conflicts on electric power systems. As noted above, the FMLN in El Salvador were effective in attacking transmission infrastructure. The conflict in Colombia has also resulted in damage to both the electric power and natural gas systems. This section provides a brief description of two examples of how conflict can impact an electric power system. First we will discuss the Palestinian case, in which the power system has been disrupted largely from indirect conflict damage at the same time as massive organizational and physical changes were being attempted. Second, the case of Bosnia-Herzegovina case will be described. This is a case of relatively well developed system that suffered extensive physical damage as a result of the conflict.

Table 3: Simplified Classification of Conflict Contexts and Electricity Systems

	More Industrialized / Least Risk	**Less Industrialized / Most Risk**
Electricity planning	Conflict rarely considered	Conflict rarely considered
Type of conflict	Systematic terrorism	War or terrorism
Electricity infrastructure	Existing	Growing
Natural gas infrastructure	Existing	Growing
Finance	Available	Sparse
Engineering skills	Available	Sparse
Replacement parts	Available	Sparse
Economic loss[6]	Likely High in Absolute Terms	Likely High in Relative Terms
Threat to human health[7]	Possible	Likely

[6] The economic impacts on industrialized countries are likely to be higher in absolute terms due to the highly integrated and high value-added nature of these economies. The economies of industrialized countries are, in part, based upon high value-added sectors (in part, through the use of highly productive capital equipment) such as manufacturing, finance, service, and telecommunications rather than being more resource based as in less industrialized countries. This also means that there are fewer time substitution possibilities. Furthermore, the economies of industrialized countries are also more highly integrated than less industrialized countries in that the effects on one high value-added sector can ripple through the economy to other high value-added sectors creating further economic losses. However, the relative economic losses in industrializing countries could be quite high and have a significant impact on already fragile economies. Many of these economies depend on a small number of key sectors that could be impacted by loss of electricity. In addition, even a small loss of productivity in absolute terms could have a large impact given the overall size of these economies. In other words, the more robust economies of the industrialized nations may be better equipped to absorb the losses that occur even though those losses are higher in absolute magnitude.

1.2.1.1 The Palestinian Case

The electric power system serving the Gaza Strip and West Bank Palestinian Territories is an excellent example of how stress on a system can be the result of both physical and institutional factors and how those stresses can manifest themselves directly and indirectly in a conflict context.

Prior to the Oslo peace accords, the electric power system in the Palestinian Territories was characterized by a nearly complete dependence upon Israeli Electric Company, poor infrastructure, and non-existent or fragmented institutions. Oslo allowed the Palestinian Authority to plan for an autonomous, independent electricity system with new institutional structures and to plan construction of a new generation and transmission system to serve the Palestinian population. However, this was not an easy task and as with everything else, it was bound up with the overall peace process. This can be seen in the negotiating language (a sample of which is shown below) in which final arrangements on the electricity sector is dependent upon the outcome of further peace negotiations[8]:

> The Israeli side shall transfer to the Palestinian side, and the Palestinian side shall assume, all powers and responsibilities in this sphere [I: in Areas A and B] [P: in the West Bank] that are presently held by the military government and its Civil Administration, including the power to set tariffs and issue licenses [P:, as well as all existing property related to this sphere and the grid, as defined in paragraph 4]. [I: In Area C, powers and responsibilities relating to this sphere will be transferred gradually to Palestinian jurisdiction that will cover West Bank and Gaza Strip territory, except for the issues that will be negotiated in the permanent status negotiations, during the further redeployment phases, to be completed within 18 months from the date of the inauguration of the Council.]

[7] We also suggest that the adaptive capabilities of industrialized countries are generally greater and that industrialized countries therefore have a greater capability to mitigate the impacts of damage to the electric power system. The lack of resources and lower adaptive capacity would mean health and mortality consequences would be more severe in developing countries. An industrial country is likely to have backup generators for their hospitals and can easily install the same for water supply. These backup systems will not keep the economy humming, but will save lives. In a less industrialized country, the absence of these localized adaptations will cost lives (e.g. through spoiled medicines and untreated water, a major cause of disease).

[8] Brackets with an I are the Israeli preferred text while brackets with a P are the Palestinian preferred text.

Since then, the Palestinian Authority, in the form of the Palestinian Energy Authority (PEA), has been working to develop a quasi-independent electric power system based on three large natural gas plants and transmission lines linking the Gaza Strip and West Bank as well as running north-south through the two territories. This would replace the radial lines that feed electricity in from Israel under the old system. However, in devising these plans, little or no analysis of robustness/economics was performed to compare the plans with either continued reliance on Israeli system or a more distributed system. It would appear that continued reliance on the Israeli system was considered undesirable, not only from a technical perspective, but also from a political perspective as it would have continued to make the Palestinian territories dependent upon Israeli actions.

Table 4: Comparative Statistics for Israel, the Palestinian Territories, Jordan and Egypt

Indicator	Israel	Palestinian Territories	Jordan	Egypt
Land Area∗	20,330 km^2	6,000 km^2 WB: 5,640 km^2 Gaza: 360 km^2	91,971 km^2	995,450 km^2
Population (2001)	6,400,000	3,400,000 WB: 2,200,000 Gaza: 1,200,000	5,000,000	65,200,000
Annual Electricity Consumption (2001)	35,000 GWh	1,400 GWh	7,100 GWh	65,000 GWh
Per Capita Consumption	5,500 kWh	410 kWh	1,400 kWh	1,000 kWh
GDP (2001, US$, PPP)∗	$119 billion	WB: $2.1 billion Gaza: $750 mil.	$21.6 billion	$258 billion
GDP/capita	$18,600	West Bank: $950 Gaza: $625	$4,300	$4,000
Electricity Consumption per GDP	0.29 kWh/$	0.49 kWh/$	0.33 kWh/$	0.25 kWh/$

Since Oslo, the current intifada has resulted in both direct damage to system and in significant operational challenges. The previous lack of development of an autonomous system and the current conflict have together resulted in a number of challenges and stresses on the system, which are described below. In order to better understand the relative situation in the Palestinian Territories, Table 4 compares the Palestinian Territories with its neighbors, Israel, Jordan and Egypt. As can be seen, per capita electricity consumption is significantly lower than the others and much lower than the global average of roughly 2000 kWh/person. The GDP per capita is also lower than it neighbors, while electricity consumption per dollar of GDP is higher than all of its neighbors. This would indicate either inefficient use of electricity or that more of the electricity is going towards non-productive uses.

1.2.1.1.1 Challenges: Evolving Institutions

The Palestinian electricity system is moving from an institutional structure that was very fragmented or even non-existent in some aspects to an institutional structure that combines competition and regulation of the system. In the past there was no overall coordination and responsibility. There was one private electricity distribution company that served a portion of Jerusalem and the West Bank plus over a hundred local municipal utilities. In all cases, nearly 100% of the electricity was purchased from the Israeli Electric Company and sold to consumers. In addition, there were two regulatory authorities (Israeli military and civilian) prior to Oslo and then a third added on (Palestinian civilian) after Oslo.

The institutional changes that have resulted from Oslo include the creation of a Palestinian Energy Authority (PEA) that has a combination of functions including system planning, rehabilitation and development of a competitive (but highly regulated) independent electricity system. In addition, investment laws and a regulatory system to encourage investment have been put in place. The plan is for privatized power generation and consolidation of distribution companies. However, this has created at least one problem, the change in revenue flow for municipal utilities. Municipal utilities had been using electricity revenues to cross-subsidize other services. Possible solutions include transfers from the central government over the short term and privatization of the other services over the long term.

1.2.1.1.2 Challenges: Evolving Infrastructure

The system is not only changing on an institutional level, it is also changing physically. Prior to Oslo, there were "Islands of Electricity." As noted above, there were only radial distribution lines that fed in from Israel. There was no transmission system and no linkage of Palestinian population centers. The distribution system itself was poorly maintained and service was poor, with even some electrified areas not receiving 24/7 service.

The planned system would have three large natural gas fired power plants (roughly a couple of hundred MW each) and they would be owned by private power producers. A 220 kV transmission system was planned that would join the Palestinian system together in its own grid and would link with other neighbors in addition to Israel. Finally, major rehabilitation of the distribution system has been ongoing through donor funded projects.

It should be noted, however, that there is an acknowledged conflict between reliability and the budget. The goal of the PEA was to plan for a future "perfect" system, and implement what was possible as the budget allows. Thus, many of the improvements outlined here are still on the drawing boards (with the exception of the one power plant for Gaza, portions of the transmission system and the distribution rehabilitation)

1.2.1.1.3 Challenge: Planning Uncertainty

A major challenge facing the PEA is the great deal of uncertainty in planning for the future system. There are a number of reasons for this uncertainty. First demand is hard to predict for three reasons. The future population of the Palestinian state is unknown due to unresolved issues regarding refugee return. There is a great deal of suppressed demand that may create much larger load growth than expected once the economy improves. However, the improvement of the economy is itself uncertain and the nature of the future Palestinian economic system (e.g. the degree of international trade) is uncertain.

Second, the geographic boundaries of the future Palestinian state are currently unknown. The future status of the Israeli settlements in the occupied territories is currently unknown. The degree to which any parts of Jerusalem will be part of the future state is unknown. The extent and nature of future Israeli security areas (e.g. along the border with Jordan) are also unknown.

1.2.1.1.4 Stress: Restricted Mobility

Periodically during the period between Oslo and the current intifada and increasingly since the beginning of the intifada, the mobility of Palestinians has been restricted. This has created a number of issues for the electric power system:

- Operations: It is difficult for West Bank Palestinians to report to work in Jerusalem (a problem for JDECO, the private utility that serves east Jerusalem and parts of the West Bank). It is also difficult for crews to reach sites requiring repair or maintenance (and sometimes unsafe even if the road is open). As a result, some rural areas can go weeks or months without a needed repair crew visiting.
- Economic Problems: The economic difficulties that are the result of the collapse of the Palestinian economy and lack of employment have reduced collections. However, payment must still be made to the IEC for the electricity (and for the connection even when electricity not consumed). This was apparently a problem during the first intifada as well. The distribution companies and the PA have been caught in the middle. JDECO had already lost 70 million NIS ($17 million), or a quarter of their revenue, by summer of 2001.
- Project Delays: Most significantly, the Gaza power plant was delayed because crucial equipment was being held in the Israeli port of Ashkelon.

1.2.1.1.5 Stress: Direct Damage

In addition to the stress on the system that is the direct result of restricted mobility in the Palestinian Territories and between the territories and Israel, there has been direct damage to portions of the electric power system. Parts of the electricity distribution system have been targeted (e.g. in Hebron). Damage has been estimated at around $15 million (US) up to May 2002 (mostly due to spring 2002 incursions). The result is now a fear that if the new electricity system is built, it will simply become a target.

1.2.1.1.6 Possible "Solutions"

There are no easy solutions to the stress and challenges faced by electric power system planners in the Palestinian Territories. There is a reliance on scenarios in order to explore and prepare for different outcomes. Demand projections of the PEA include assumptions regarding GDP growth, etc. but also include a number of scenarios to account for the different possible outcomes of the peace process.

There is also a "wait out the storm" approach at the moment in the PEA. This appears to be the view of donors as well. They view their role as fostering the development of a Palestinian state. Explicit planning for a resurgence of violence was not included because they were transitioning from relief to development and because they view the endpoint as still being the same, a functioning and viable Palestinian state. There has been some re-programming of aid money to alleviate immediate needs and future projects uncertain until the current crisis is over.

1.2.1.1.7 Lessons Learned

There are a number of lessons that can be learned even from this quick overview of the Palestinian case:

- Capital costs are paramount but money is also needed for continuing maintenance and training
- Conflict does not have to result in damage in order to have an impact on the electricity system
- Independence is politically important
- The most difficult problems hinge on the most difficult problem: a political solution
- Institutional development is important

1.2.1.2 Bosnia-Herzegovina

Bosnia-Herzegovina is a recent example[9] of deliberate targeting of electric power infrastructure. Information on conflicts in this country clearly indicates that a relatively small amount of damage can result in severe and long-lasting disruptions to an electricity system.

Prior to the war in Bosnia-Herzegovina[10], electricity consumption was approximately 12,000GWh (1990). Demand was met by a domestic combination of coal-fired thermal plants (~72% of supply), and hydropower plants (~28% of supply).[11] By 1996 the electricity production situation in Bosnia had dramatically changed. Over 56% of total generating capacity was unavailable due to direct damage. Of the remaining capacity, a

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[9] See also ((Gordon 1999)) on the NATO bombing of Yugoslavia. See (Energy and Defense Project 1980) and (Griffith 1994) on the hampering of Germany's industrial production in World War II and other historical examples of attempts to disrupt electric power systems as part of strategic warfare.

[10] Unless otherwise noted, information from (World Bank 1996) and (World Bank 1999).

[11] Figures provided are for 1990 production. In general, the hydropower plants (which have a capacity equal to the thermal plants) had an average yearly output of 6,900 GWh, which could provide ~54% of the electricity supply.

lack of fuel (the mining sector was also targeted), and 50% loss of both transmission and distribution system capacity (often from lack of maintenance) severely impacted supply.

Post-conflict, electricity infrastructure reconstruction costs were relatively modest when compared to the cost of building new power plants. The first rehabilitation project spent approximately $50/kW to restore and rehabilitate plants with a total capacity of 960MW. This cost is a factor of 10 less than new plant construction. Thus, a small amount of damage to a centralized power generating facility is sufficient to render it inactive. The second rehabilitation project (budget $170 million), allocated approximately equal amounts to generation ($46M), transmission ($44M), and distribution ($47M) with the remainder for coal mine rehabilitation and other technical assistance. However, it remains true that total rehabilitation and reconstruction costs are significant in the context of post-war economies and require significant international aid.

The impact of the Bosnian conflict was much less severe on the natural gas infrastructure. There was limited damage to the largely underground natural gas transmission and distribution network, and many of the post-war problems were due to lack of maintenance and a sharp increase of illegal and makeshift connections. Prior to the war, the natural gas system served major industrial customers and the city of Sarajevo. During the conflict, imported natural gas was shut off to all parts of the network except Sarajevo, where the flow was reduced and restricted to residential and small commercial consumers.[12] As a result, gas consumption dropped from 610 million cubic meters in

[12] In this case, the natural gas supply came from Russia. It should be noted that when the conflict involves a primary fuel supplier, it might be difficult to ensure supply regardless of whether the system is centralized or distributed. There is a difference depending

1990 to 125MCM by 1992. Natural gas became the major source of energy in Sarajevo (with the unavailability of electricity) and supplied 70% of the city's energy use by the end of the war. While a thorough analysis remains to be completed on the robustness of the natural gas system under conflict conditions, the experience in Bosnia-Herzegovina indicates that as long as supply arrangements can be assured, natural gas can more often continue to be provided when electricity cannot.

1.3 DG Systems and Reliability under Stress

As seen from the discussion above, there is a need to address high stress conditions when planning an electric power system in a number of different contexts. In some cases, changes to the institutional structure may be necessary (e.g. to encourage investment and reduce generation shortfalls). In other cases, increased physical security might be the appropriate response. The analysis presented in this dissertation examines another alternative response to the problem of electric power systems under stress. It is possible that by changing the actual system architecture, reliability and robustness of the system could be improved cost effectively. The change in system architecture considered here is the widespread deployment of grid-connected distributed generation resources. This dissertation seeks to answer the question of whether a system based primarily upon natural gas distributed (co)generation or DG, will be more robust under the adverse conditions of conflict and whether an integrated energy generation and delivery network based on current DG technologies can offer economic savings.

upon the fuel. Coal (which is more likely to be domestic) can be feasibly stored for a season. On the other hand, with natural gas, it may be possible to initiate a degree of fuel switching if another fuel (e.g. diesel) is available.

Distributed generation systems are hypothesized to be generally more robust due to two main factors:

1) There is less reliance on an electricity transmission system due to co-location of generation and demand. There will still be some level of transmission necessary in order to capitalize on the advantages that power sharing between distributed generation units (or groups of units) can offer.

2) It has long been recognized that the impact of a loss of a single generator is not as significant if that generator is small (U.S. Department of Energy 1981). This is effectively a law of large numbers argument. Furthermore, in a system with significant distributed generation there are potentially too many targets to affect a system-wide shutdown.

A system with significant distributed generation would almost certainly result in an increased use of natural gas for electricity generation and a potential reduction in fuel diversity, given the state of current technology options for distributed generation. This raises questions regarding the interdependence of the electricity and natural gas infrastructures. Such infrastructure interdependencies are a recognized concern (Rinaldi, Perenboom et al. 2001). However, there are a number of relatively obvious reasons why a system based on natural gas DG units would be expected to be more robust under stress, even when accounting for the fact that the electricity transmission system would have to be replaced by a natural gas transmission system. For example, grid operations for electricity and gas have different requirements for balancing supply and demand and some distributed generators can take advantage of dual fueling options. The ability to use other fuels will depend on the technology chosen. Gas turbines, for example, while not the specific technology analyzed here, have the ability to use a variety of fuels (albeit with a possible reduction in efficiency) (Willis and Scott 2000; Brent 2001).

There are a number of relatively obvious reasons why a system based on natural gas DG units would be expected to be more robust under conflict, even when accounting for the fact that the electricity transmission system would have to be replaced by a natural gas transmission system. Some of these are summarized in Table 5.

TABLE 5: POTENTIAL ADVANTAGES OF DG SYSTEMS IN CONFLICT

Features of DG	**Conflict Context Advantages**
Increased Number and Smaller Size of Generators	When one generator is damaged, a much smaller proportion of the generating capacity is unavailable.
Decreased Reliance on Electricity Transmission and Distribution	The electricity transmission and distribution system is harder to protect than generators. Having generation close to the load reduces the reliance on the vulnerable transmission system.
Underground Natural Gas T&D	Natural gas transmission and distribution systems are generally underground and therefore better protected than electrical transmission and distribution lines.
T&D Real-Time Operational Advantages	Gas pipelines do not have the strict real-time operational problems that electric power grids do such as stability, and there is no gas system analog for cascading failures.
Fuel Substitutability	Some DG technologies have dual fuel capabilities, which mitigates against the impact of replacing a multi-fuel centralized system with a system predominantly reliant on a single fuel.
Fuel Storage	Electricity storage is not economically feasible. Hence, while primary fuel storage (in both centralized and distributed systems) is a security of supply measure, it does not isolate consumers from electricity T&D failures. In the DG system, local fuel storage offers this extra level of security.

However, it is recognized that the distributed system could become significantly more reliant on a single fuel; therefore a conservative analysis will be conducted to determine the impact of NG fuel dependency. This analysis is conservative in that it only considers disruptions of natural gas and does not consider disruptions to other fuel sources for central generation, such as coal or oil.

While there has been little quantitative analysis of distributed generation as a reliable energy source under stress, there is a general literature on the reliability advantages of distributed generation (some of which is reviewed in the next chapter). For the most part, such analyses have considered only small-scale or individual applications of distributed generation in specific applications (e.g. peak shaving and providing reliable power to remote locations or critical facilities). (Arthur D. Little 2000; Bluestein 2000; Cowart 2001) Other analyses have been limited in the contexts they considered and/or did not include quantitative assessments of the reliability benefits of distributed generation (Energy and Defense Project 1980; Lovins and Lovins 1981).

One work that did look at the reliability implications of a system wide implementation of distributed generation was a Ph.D. dissertation by Gilbert Miller. (Miller 1981) Using similar methods to those employed in this study, Miller studied the reliability of centralized and distributed systems and their costs. However, Miller's dissertation focused on understanding the costs of *improving* the reliability of a system like those in OECD countries from its current levels and the economic and technical limits to these improvements and did not examine the impact of stress on the system. There are also differences between Miller's work and this analysis in the DG technologies considered, the system topologies considered, and the inclusion of the fuel supply infrastructure.

In order to consider distributed generation (DG) as a viable alternative to centralized generation in conflict conditions, the relative economics of the two systems must also be compared. The range of commercially available natural gas fired DG technologies includes gas turbines, internal combustion (IC) engines, micro-turbines and fuel cells. Distributed (co)generation (DG) technologies can deliver economic and environmental benefits in specific applications with consistent and well-matched electricity and heat demands. (Gas Research Institute 1999) Until now centralized generation's economies of scale, the low price of coal as a fuel for electricity generation, and regulatory barriers or disincentives to on-site generation has precluded the widespread adoption of DG. However, changes in the relative economics of centralized versus distributed generation, the increasing use of natural gas, restrictions on new electricity transmission lines, recognition of the environmental benefits of DG (Bluestein 2000; Lents and Allison 2000), and improved DG control technologies[13], has resulted in the reconsideration of widespread use of DG[14].

1.3.1 Technology Options

There are a number of technology options to provide electricity (and possibly heat) on a smaller scale and physically closer to load centers. Each technology differs along key parameters, such as cost and efficiency, even under ordinary conditions. Consideration of the particular conditions of high stress contexts adds other performance dimensions that must be considered. The following criteria were used to qualitatively rate common distributed generation technologies (as seen in Table 6).

Physical Vulnerability: If the stress circumstance is a conflict situation then physical vulnerability of the distributed resource technology may be an important consideration. Technologies such as wind turbines and photovoltaic cells are exposed outside while fuel cells, turbines, engines and storage units can be housed in physical structures and be

[13] Remote digital control of now commercialized DG technologies allows a higher level of reliability and eases the grid control issues that arise from locating DG units within the electric distribution network (since they must still be run in parallel and coordinated with other generation plants).

[14] For example, in 1998 the Netherlands had 6% national electricity capacity as DG units of <1MWe, and 35% of national electricity capacity as DG units of <50Mwe. (Strachan and Dowlatabadi 2002)

better protected from damage. In fact, such units are currently often housed in basements, which would make them difficult to attack en masse.

Intermittency: Intermittency is a problem for using distributed resources to contribute to the reliability and security of a power system under both stress and normal conditions. Unless the technology is dispatchable, there is no guarantee that the distributed resource can continue to provide power when there are problems with the rest of the grid. The vulnerability of the grid due to stress conditions makes the dispatchability requirement even higher than under normal conditions.

Cost: While the contribution of distributed resources to reliability under stress must be valued, the cost of the technology can be a barrier to implementation of a technology. Fuel cells fall under the category of technologies that would have a number of beneficial features but have costs that are significantly higher than other generation options.

Cogeneration Capability: The capability of a technology to cogenerate both usable heat and power can contribute to its financial viability.

TABLE 6: DISTRIBUTED GENERATION TECHNOLOGY OPTIONS AND PERFORMANCE CHARACTERISTICS

Technology	Physical Vulnerability	Intermittency	Cost	Cogeneration
Wind	High	Intermittent	Near Competitive	No
Photovoltaic Cells	High	Intermittent	High	No
Fuel Cells	Low	Dispatchable	High	Yes
Turbines	Low	Dispatchable	Near Competitive	Yes
IC Engines	Low	Dispatchable	Competitive	Yes
Storage	Low	Dispatchable	High	No

1.3.1.1 DG Options Analyzed

Not only are there a number of distributed generation technologies available or potentially available in the foreseeable future, there are also a number of options for the deployment of distributed resources. The placement, sizing, and degree of interconnection with the rest of the grid system are important considerations, as will be discussed further in the literature review on distributed generation and reliability in the next chapter.

This analysis considered one very specific set of options for deploying distributed generation. First, the specific technology used in all of the models presented in this dissertation was 500 kW internal combustion engines with the possibility of co-generation. This technology was chosen because it is a commercially available and widely deployed technology that can be cost-competitive with centralized generation options. It would be possible to duplicate the analysis with differing distributed resources by changing the economic parameters and the reliability parameters to match those characteristic of alternative technology choices (e.g. fuel cells or microturbines). There is nothing inherent in the model that requires IC engines to be the technology of choice.

Second, the assumption was made that the distributed generators would be installed at customer sites and be able to provide power to its native load even in the case of problem on the distribution system. For example, generators could be placed in hospitals, commercial districts, industrial sites or schools. The heat generated could be used by the site and electricity shared between the site and local neighbors (e.g. houses or other commercial entities). Furthermore, generators and loads are assumed to be grouped together in a micro-grid structure (Lasseter, Akhil et al. 2002) rather than having every generator hooked up the grid system individually. It should be noted that this is very different than one of the common paths considered for DG deployment, in which smaller generators are placed closer to loads by installing them at the distribution sub-station. In that case disturbances on the distribution network would not be mitigated against as in the deployment scheme envisioned here.

It should be noted that even though the assumption is made that DG installation is at the customer site, this analysis looks at the reliability of the overall bulk power system with both centralized and distributed power generation. Thus, it does not have fine enough resolution to examine the issue of reliability directly at the customer site. The question that is being answered here is not one of priority for reliability or looking in depth at customer profiles to determine "reliability for whom" and the impact and role of individual investment decisions of facilities to improve their own reliability. Instead it is a systems level model that looks at the overall reliability of the system in order to answer a different set of questions.

Furthermore, the analysis presented in this dissertation does not directly address the evolution of the electric power system towards increasing distributed generation. While there are interesting questions that could be answered with such an analysis, there are not the ones addressed here. Instead, this analysis takes what are essentially a series of snapshots of power systems with different configurations and under different stress conditions to compare their performance. The question being asked here is not how, or why, a system evolved into a particular configuration, but rather, given a system architecture, how does it behave and how does it compare to other possible system architectures?

Chapter 2 Literature Review

The work presented in this dissertation builds upon the existing research and literature in a number of different areas. This literature review will begin with a discussion of the role that distributed generation can play in improving system reliability. Increasing the level of distributed resources in the system will impact reliability in a number of ways, many beneficial, but some also possibly detrimental to system operations. Subsequently, the issue of electric power system infrastructure security will be reviewed and the role that distributed systems play in changing the security of the system will be highlighted. While there is significant overlap in the issues of system reliability and infrastructure security, there are also differences that require the literature in these two areas to be reviewed separately. Finally, as the analysis presented in subsequent chapters relies on modifications of reliability models that are commonly used in power systems engineering, a review of those models and the issue raised when trying to apply them to systems under stress will be reviewed. This section also includes a review of the issue of the value of maintaining reliability as there are often tradeoffs between cost and reliability that depend critically on the value of reliability.

2.1 Distributed Generation

2.1.1 Economics and Policy

In order to consider distributed generation (DG) as a viable alternative to centralized generation in conflict conditions, the relative economics of the two systems must also be compared. The range of commercially available natural gas fired DG technologies includes gas turbines, internal combustion (IC) engines, micro-turbines and fuel cells. Distributed (co)generation (DG) technologies can deliver economic and environmental benefits in specific applications with consistent and well-matched electricity and heat demands (1999). Until now centralized generation's economies of scale, the low price of coal as a fuel for electricity generation, utility opposition, and regulatory barriers or disincentives to on-site generation has precluded the widespread adoption of DG (Alderfer, Eldridge et al. 2000; Morgan and Zerriffi 2002). However, changes in the relative economics of centralized versus distributed generation, the increasing use of natural gas, restrictions on new electricity transmission lines, recognition of the environmental benefits of DG, and improved DG control technologies, has resulted in the reconsideration of widespread use of DG (Borbely and Kreider 2001). For example, in 1998 the Netherlands had 6% national electricity capacity as DG units of <1MWe, and 35% of national electricity capacity as DG units of <50MWe. (Strachan, Zerriffi et al. 2003) New system topologies are also being developed that take DG out of niche applications to create independent "micro-grids" of DG units that are also linked to the larger electricity system (Lasseter, Akhil et al. 2002).

Previous work by Strachan has shown that, even in the absence of any reliability advantages of DG, not only can DG be economically competitive for specific applications, electricity *systems* based on DG can provide cost savings over centralized systems (Strachan 2000). A green-field economic optimization model shows that if both the heat and electricity can be utilized, then the increased overall efficiencies of the distributed system outweigh the economic penalty of increased capital costs for DG units

(Strachan 2000; Strachan and Dowlatabadi 2002). The result of Strachan's analysis indicates that DG can be used for meeting all segments of electricity and heat loads -- the ratio and concurrence of the two demands permitting. This includes meeting baseload electricity demand rather than just at peak times, as back-up power, or in a small number of niche applications. If DG is used as a baseload generating technology it will likely be for the provision of both electricity and heat through the use of cogeneration (or Combined Heat and Power or CHP for short). Thus, this analysis will consider systems in which distributed units are operated to provide both power and heat. In such cases, there is a credit for the useful heat generated that has to be factored into the comparative economic analysis.

One important question is whether it is better to invest in distributed generation or to invest in extending the wires of the grid for the last customer (commonly referred to as the "last-mile" question). While this is an important topic, it is beyond the purview of this dissertation. This dissertation is primarily concerned with the reliability behavior of the bulk power system under different system architecture assumptions and different levels of stress. Questions about how to deal with changes in the system at the margin (both technical and economic) require a different type of analysis.

The analysis presented in the body of this dissertation does not make any claims about the likelihood that distributed generation will play a large role in the energy systems of the future. It only analyzes the impacts of having a system consisting of grid-connected distributed generation rather than centralized generation on reliability and economics of the system, including under stress conditions. However, it must be noted that the analysis is based upon a currently available and commercialized technology and there is no doubt that there are other distributed generation technologies that can now or could in the future be cost competitive with centralized generation across a range of conditions. There are, of course, technical issues that are important to solve (e.g. in the area of control and power system protection) before wide-scale deployment of grid connected distributed generation can be possible (assuming it is considered desirable). However, just as importantly, there are a number of policy issues that require resolution in order for distributed generation technologies to meet their full technical potential and it is worth reviewing a few here briefly.

Interconnection Barriers: Common barriers to the deployment of distributed resources are the interconnection barriers that are often placed in the way. Interconnection refers to the physical connection between the DG unit and the rest of the electrical grid. As has been documented by a National Renewable Energy Laboratory study, utilities have placed a number of barriers in the way of interconnecting distributed resources to their system. (Alderfer, Eldridge et al. 2000) While there are legitimate safety and operational issues in properly interconnecting distributed resources with the rest of the grid, these interconnection issues can also be utilized in order to prevent interconnection by requiring expensive equipment that nullifies the economic benefits of the distributed resource. Recently an IEEE standard was issued that may help in dealing with these interconnection issues, but there is concern that even this standard could be interpreted in ways that reduce the incentives to invest in DG.

Regulatory Barriers: The historical evolution of electric power systems has been towards centralization of both the technology and the institutional entities involved. In places such as France this resulted in a large national electricity company. In the United States the result was investor owned utilities that had a monopoly service territory. The result is that institutional and technical structures that could result in economic DG installations may not be allowed under the regulatory regimes that currently exist in numerous places. For example, while it is possible and legal for a single end-user to install distributed generation for their own consumption and perhaps to sell back to the grid, it is not possible for that end-user to sell to another end-user across the street directly, even though it may be in both of their best interests, as it would violate the exclusive service territory of the utility. Work is on-going to understand how different business structures might fare under the current regulatory regime (Morgan and Zerriffi 2002) and to develop regulatory rules that level the playing field for distributed generation in the United States (King and Morgan 2003) and elsewhere.[15]

Under-Valuing of Services: There are two ways in which distributed generation may be under-valued. The first and most direct under-valuation is in the tariff structure for sites with distributed generation. In some case, the tariff received by the DG operator for providing power to the grid is significantly less than what is paid if power is taken from the grid. There may also be connection fees that are quite high; these are the fees that the utility charges simply to have a connection in case it is needed, essentially a fee for acting

[15] See, for example, the website of Sustelnet (www.sustelnet.net) which seeks to develop "Policy and Regulatory Roadmaps for the Integration of Distributed Generation and the Development of Sustainable Electricity Networks."

as the back-up to the DG unit. In addition, distributed generation can provide (under certain circumstances) other useful benefits to the overall system. The one that is shown in this dissertation is a robustness benefit in that the distributed systems are generally better able to meet demand under stress conditions. But there are also other services, often called ancillary services, that distributed generation can provide (e.g. voltage support). However, these services continue to be under-valued and markets for them under-developed (this is true in general, not just for the case when these services are provided by distributed generation). Markets for real power cannot guarantee that the other requirements for proper functioning of the power system are met. This is a particular problem if there is a tradeoff between providing real power (for which one is paid) and ancillary services (for which one may not be paid). The under-production of reactive power is a perfect example of this dilemma and some contend it may have contributed to the August 2003 blackout.

Another service that may be under-valued is reliability. It is virtually impossible at the moment to provide differentiated reliability service to different customers on the grid. Under the current system (at least in the industrialized countries) reliability (including power quality) is essentially uniform and is not priced as a commodity. Distributed generation, because of its ability to meet local load, can improve reliability for customers that value it highly. As will be shown in this dissertation, a system based on distributed generation can also have higher overall system reliability.

2.2 Distributed Generation and System Reliability

As a result of a combination of forces and events (for example, the California energy crisis, difficulties in siting and constructing large energy and transmission facilities, increased security concerns), distributed generation systems have been promoted for their potential reliability benefits. In fact, distributed generation has long played an important role in maintaining electricity supply, mainly in the form of emergency generators (e.g. in hospitals) or as a stand-alone alternative to grid connection (e.g. for companies in India that do not want to rely on an unreliable grid). More recently, the concept of grid-connected distributed generation units used as the primary electricity provider (rather than as a backup) has gained renewed interest, though it has long been considered a possibility. (Miller 1981) There are a number of potential reliability benefits that distributed generation can provide, including increasing generation capacity, reducing transmission and distribution losses, reducing loading and use of lines, and increasing the number of generators and reducing the size of generators to minimize the impact of losing any single generator. (Arthur D. Little 2000; Lovins, Datta et al. 2002)

However, hidden behind such statements are a large number of assumptions regarding the nature of the DG system, the nature of the electrical system in which it is embedded, as well as a host of other factors (such as the institutional setting and choices about how the DG system is operated). In this section, we outline some of the important issues involved in determining whether and how the addition of distributed generation may aid in the reliability of an electric power system. We will first begin discussing the concept of reliability itself and briefly review two key concepts in power system reliability:

adequacy and security. Then, we will review some of the literature that has specifically discussed the impact of distributed systems on the adequacy and security of power systems. Though by no means a comprehensive list, the literature cited provide examples of the types of studies that have been conducted and the issues to be evaluated in any real-world installation of distributed resources. Finally, as an outcome of the literature review, we will outline some of the characteristics (both physical and operational) of distributed systems that could impact the system reliability (either negatively or positively) and which must be considered when assessing the potential reliability impacts of installing distributed resources.

2.2.1 What is Reliability?

In the field of power systems, there is no precise definition of "reliability," nor are there universal standards for defining a reliable system. In fact, reliability is often divided into two separate concepts: adequacy and security. Unfortunately, the term reliability is often used to mean either concept (or sometimes an agglomeration of both). We will attempt in this section to differentiate where possible and necessary between these two concepts.

Adequacy is primarily a function of long term planning and refers to a system's ability to meet its power needs (e.g. is access to generation sufficient to meet demand, is there sufficient transmission capability to handle required power flows, etc.). It is measured by a variety of indices that specify the length or extent or magnitude of outages. On the other hand, security is primarily a function of shorter term operational and management choices and decisions. A key issue here is the stability of the system in the face of disturbances and maintaining voltages and frequencies within pre-specified limits. A somewhat related concept is that of power quality. In this case, the concern with voltage or frequency is not for maintaining stability, but rather for protection and proper operation of end-use devices. For a more complete discussion of electric power system reliability, the reader is referred to any number of standard texts on the subject. Any of these texts will also cover the various indices used to measure reliability in electric power systems.

In addition to the fact that reliability can be defined and measured in a variety of ways, it is important to bear in mind that reliability is not a concept that can be considered in isolation. Most importantly, reliability cannot be separated from cost. Lack of energy supply or other reliability problems cause real economic losses and damage to utilities and customers. Conversely, investments must be made to improve the reliability of the system. This creates a reliability/cost tradeoff that has to account for both customer outage costs and infrastructure costs. It will become increasingly important to be able to provide differentiated reliability to end-use customers that are willing to pay for improved reliability. Distributed resources, due to their modular nature, location and other characteristics, could play an important role in such reliability differentiated markets. (Willis and Scott 2000)

2.2.1.1 Adequacy

One potential reliability impact of installing distributed resources is to change the adequacy of the system (the ability of the system to meet end-use demand, accounting for equipment failures). Distributed resources can improve the supply of power to the end-user in two ways. First, it changes the mix of generating technologies, potentially displacing large generators far from the load with a larger number of small generators close to the load. Second, by providing power close to or at the location of demand, distributed resources can potentially reduce the loadings on distribution lines or even possibly transmission lines as well as mitigate against failures at the transmission and distribution level. Another potential impact of installing distributed resources is to reduce the required reserve margin to meet a certain level of reliability (or alternatively, to have improved reliability for a given level of installed capacity).

At the simplest level, installing distributed resources can change the adequacy of supply for an individual facility. Whether it is run in back-up mode or as a stand-alone primary generator or in parallel to the grid, the duration and magnitude of failures will be affected. A facility that installs a single distributed unit with no back-up from another unit or the grid will experience significantly lower reliability than the norm in the United States for grid power. (Willis and Scott 2000).

An example of how distributed generation can contribute to system reliability in a cost effective manner is provided in (Chowdhury, Kumar et al. 2003). The authors argue that the current challenge in providing electricity is that customers in restructured markets will increasingly demand lower rates and improved reliability, while at the same time the system is being divided among multiple actors rather than the traditional vertically integrated utility. A probabilistic model that can be used to compare different options for improving the reliability of the system at the distribution level, including the installation of distributed units, is developed and presented in the paper. The example problem is the need to improve energy delivery in a distribution system fed by two feeders from the grid (reliability here being measured by the Expected Energy Not Served in kWh/year). Installation of distributed generation (ranging from 1-6 MW each and up to 2 units being installed) is compared to addition of a third distribution feeder from the grid. It is found that adding either one 6 MW unit or two 3 MW units would result in the same reliability improvement as installing the third feeder for the particular system studied. The authors recommend the next step of evaluating the relative cost effectiveness of the DG versus additional feeder options. While they do not perform the calculation, they do note that if the DG is constructed and operated by an independent power producer, they should receive a credit for the deferred investment in the additional feeder, which could compensate for the higher DG base costs. Other examples of the potential for DG to improve adequacy at the distribution system level are given by (Brown and Freeman 2001; Hegazy, Salama et al. 2003).

In addition to changing the adequacy of the system at the individual facility or distribution system level, it is possible that widespread use of grid-connected DG could materially impact the adequacy of the overall power system. However, prior literature in this area is minimal and the arguments have been primarily qualitative rather than quantitative (as discussed elsewhere with regards to the work done in the late seventies by Lovins and Lovins and with the exception of the work of Miller). It is precisely in this area that this dissertation makes a contribution to the literature. The work presented in the subsequent chapters attempts to quantify the potential reliability benefits of wide-spread distributed generation, particularly under stress conditions.

2.2.1.2 Security and Power Quality

The impact of distributed resources on the security of the system and, more generally, on system operations is more complicated than is the case with adequacy. Conventional utility practices has been predicated on power flowing from the grid, through substations, and then on predominantly radial distribution lines to end-users. Control and operation of the distribution level is for one-way power flows and distributed resources could result in power flows that are different than originally designed for. This could result in the need for new equipment, new operating procedures, or both. (Wan and Adelman 1995) As a result, dependent upon a wide variety of factors, distributed resources could either improve or degrade system reliability and evaluations have to be made beforehand considering specific technologies deployed under specific circumstances. This section outlines some of the issues to be considered.

Distributed resources can provide improved power quality to end-users under a variety of circumstances, particularly when installed at a particular customer site (McDermott and Dugan 2003). Beyond the improved power delivery discussed above, these benefits would include avoiding temporary interruptions and avoiding voltage sags. In addition to aiding individual customers, distributed resources have the potential to provide voltage support for the entire distribution subs-system to which they are connected. With the proper equipment, the distributed resources can also provide other ancillary services, such as harmonic cancellation and reactive power compensation. (Joos, Ooi et al. 2000; Kashem and Ledwich Accepted for Future Publication)

While it is true that distributed units can provide voltage support on feeders, this can also create a problem with service restoration after a fault. If the load becomes dependent upon the distributed unit for voltage and the DG unit must disconnect due to a fault, the utility may not be able to maintain voltage at acceptable levels when the fault is cleared, necessitating changes in procedures and possible delays in restoring power. (Dugan and McDermott 2002)

One major issue with installing generation at the distribution level is the effect it can have on the stability of the system. (Cardell and Tabors 1998) This is the result of changes in designed power flow direction as well as the electrical characteristics of the lines themselves (low resistance lines at the high transmission level versus higher resistance lines at the distribution level), which can affect the degree to which connected generators and loads can impact one another. In other to better understand the impact of installing distributed resources on system stability at the distribution level, (Cardell and Tabors 1998) develop a dynamic model to analyze frequency stability and apply it to a sample distributed system with generation. The authors find that under certain combinations of distributed generation technologies, the system can become unstable when a disturbance is introduced. The results are dependent upon factors such as the particular technology chosen (e.g. combustion turbines versus hydro-plants) and the number of DG units installed (e.g. four turbines were unstable while two was not). The first reason given for the instabilities is that changes in local state variables are not transmitted throughout the system due to the high resistance at the distribution level. The second reason is that the relatively small mechanical inertias of the distributed units cannot compensate for the oscillations resulting from the disturbance (in contrast to centralized generators that have large inertias). The authors argue that these results show the need for new methods to control and stabilize systems that have numerous distributed generators.

Distributed resources can also create issues when there is a fault on the system due to the fact that power is no longer flowing radially. It is no longer possible to simply open one breaker on the radial line and it may be necessary to disconnect the distributed unit. The DG infeed also reduces the "reach" of the breakers and reclosers, the distance down the line that the devices can detect a fault, used to protect the system. This can potentially result in larger faults and damage. Another potential issue has to do with the time it takes for the protection device to reclose on a temporary fault. Short reclose times are beneficial from a power quality point of view as they can avoid some issues (e.g. blinking clocks). However, the reclose time must be long enough that the DG system is able to disconnect before the reclose occurs or it may become damaged and/or the failure may not clear. (Dugan and McDermott 2002) A number of other potential issues with interconnecting DG are presented in (Dugan and McDermott 2002), however, the authors conclude that these issues can be resolved with careful engineering (though there may be some tradeoffs regarding either cost or operations of the system).

The literature reviewed above share one common view of distributed generation, that the distributed units are placed within the pre-existing distribution system as an add-on. While some changes may be made to protection and control equipment, the result is that problems on the system require the distributed units to disconnect. There is another alternative, in which the system at the distribution level can act as its own grid, continuing to function even if disconnected from the main grid and in which multiple distributed units can meet the needs of several loads. This "Micro-Grid" is seen by the larger utility grid as a single load, not as a collection of loads and generators. Designed properly, such micro-grids could provide all of the benefits that distributed resources have the potential to supply while alleviating many of the voltage, frequency and control problems that may be associated with installing large number of distributed units. The Consortium for Electric Reliability Solutions, run out of Lawrence Berkeley Laboratories, has a number of reports detailing various aspects of the MicroGrid concept, including (Lasseter, Akhil et al. 2002) which describes the control of the micro-grid, protective relaying and relation between the micro-grid and the utility grid.

2.2.2 Characteristics of DG Systems

While it is convenient to group a set of technologies under the "distributed generation" rubric, there are in fact significant differences between technologies and in the operation and management of distributed resources. These differences can have an impact on the role that the distributed resource plays in the reliability of the system as seen in the review of literature presented above. This section briefly describes the relationship between different characteristics of DG systems and reliability.

Size: There is no standard definition of distributed generation, though some use the size of the units (in addition to their location) to define DG. Size of distributed resources can play a role in reliability in a variety of ways. If a distribution system becomes too dependent on a single large distributed unit to maintain reliability on the feeder, this can create a vulnerability. On the other hand the contribution of small generators may not be sufficient to materially affect the reliability indices of the system.

Location: The location of the DG units can have an impact on their reliability benefits. For example, a cluster of generating units at the sub-station level cannot mitigate against a line fault further down the distribution line (the site of the majority of incidences, though not the cause of major outages). On the other hand, placement of a distributed resource on a distribution feeder can cause problems for operation of the line.

Dispatchability and Intermittency: Intermittent resources, such as photovoltaics or wind, can aid in reducing power needs, but can either create reliability issues or have a negligible impact on reliability needs due to their lack of dispatchability. Such technologies cannot be counted on for example to provide grid support as needed.

Controllability: The controllability of a technology (e.g. the time necessary to connect or disconnect from the system, the time required to ramp up or down, etc.) plays a role in the operation of the system and therefore in the reliability of a system. Technologies with fast switching times can potentially provide a wider variety of reliability support. On the other hand, if a technology is installed that has a slower response time, it may be necessary to modify the operation of other components in the system, potentially degrading one measure of reliability even as another is increased.

Fuel: For those distributed systems that rely upon a fuel, the reliability of the fuel supply must also be considered when evaluating the reliability of the distributed technology.

Cost: Even if a distributed technology can improve the reliability of a system, the benefits of deploying the technology may not outweigh the costs. Benefits can be both in the form of other deferred investments (e.g. in distribution system upgrades) or in the form of reduced outage costs to customers. As with all other reliability investments, overall system costs (including customer outage costs) decrease until a certain point, after which additional investment to improve reliability results in increasing overall costs.

Operating Mode: Distributed resources can be run in a variety of operational modes. The most common probably continues to be as a back-up to the grid. In these cases, the distributed resource only operates when there is a problem on the utility system and it is operated essentially in isolation until grid power is restored. A second application and operation mode is as a peak shaving unit. In this case, it runs in parallel with the utility system at times of peak load in order to reduce requirements on the grid system. Distributed units can also be run at a high capacity factor, in some cases even as the primary source of power for a load. In these cases, the unit can be a stand-alone unit (as might be common for remote loads) or run in parallel to the grid (with the grid providing either supplemental power or acting as the back-up for the distributed unit).

Unit Reliability: The reliability characteristics of the distributed resource itself will play a role in determining its contribution to system reliability. A distribution system that is dependent upon a single DG unit with a high forced outage rate would likely provide unacceptable performance when compared to either relying upon the grid alone or deploying an alternative technology.

2.2.3 Conclusion

Distributed resources can improve the reliability of electric power systems by providing increased availability of power, reduced loadings on distribution feeders, voltage support and a host of other benefits. The particular benefits and the value of those benefits (either to the utility or to specific customers) will depend upon a large number of factors, including the nature of the distributed resource evaluated, its operation and the incentive and regulatory structure in place. On the other hand, installing distributed resources on pre-existing distribution lines can create problems due to new directions of power flow and the traditional design and operation of the control system. Engineering and operational solutions can be found to these problems, but in some cases, trade-offs may have to be made. These tradeoffs will continue to be made between reliability and cost, but tradeoffs may also have to be made between different aspects of reliability (e.g. adequacy and voltage support).

2.3 Distributed Generation and Infrastructure Security[16]

Shaped primarily by the security and energy concerns of the seventies and eighties, previous work on the security of energy systems has tended to focus on vulnerability to fuel supply disruptions, large scale conflict with the Soviet Union (with a particular

[16] Note that the term “security” is used in this section to refer to traditional concepts of physical and cyber security of infrastructure systems, which is the security of the system against shocks and attacks. This is different than the way the term “security” is used by power systems engineers, as discussed in the section above on reliability. This section is drawn from (Farrell, Zerriffi et al. 2004)

emphasis on nuclear weapons) and isolated acts of terrorism.[17] The few works that address possible changes to the overall physical topology of the system, including some that have directly addressed the reliability advantages of distributed generation, have been qualitative in nature.[18] These works have generally been concerned solely with energy systems in advanced industrialized countries and have not attempted to systematically quantify both the reliability advantages and the economic consequences of using distributed generation in conflict contexts.

However, since this earlier work, there have been a number of changes in both the political and security context in which these technologies are assessed. In addition, there have also been significant changes in the technical and economic characteristics of electricity production technologies in the intervening years. Recent work on critical infrastructure protection has added the issue of information technology vulnerabilities, highlighted the issue of critical infrastructure interdependencies, and sought to assess the threats to specific infrastructures. (President's Commission on Critical Infrastructure Protection 1997; Rinaldi, Perenboom et al. 2001; Farrell, Lave et al. 2002) There have also been efforts to develop new methods and frameworks to understand how complex systems work and the survivability of such systems, including critical infrastructures.[19]

2.3.1 Background

The modern idea of 'energy security' emerged in the 19th century as warfare became mechanized and began to require substantial fuel inputs, first as coal for warships and

[17] See, for example, (Energy and Defense Project 1980) (also available in book form as (Clark and Page 1981)), (Office of Technology Assessment 1990) and (Plummer 1982)

[18] Most notably, see (Energy and Defense Project 1980) and (Lovins and Lovins 1981) and (Cowart 2001)

[19] One important concept is "survivability" (as distinct from reliability), developed at the CERT Coordination Center. See (Lipson and Fisher 1999)

trains (Bucholz 1994). The decision of the British Admiralty prior to the First World War to switch from coal-fired to oil-fired vessels marked the start of the now traditional link between petroleum and security (Lovins and Lovins 1982, pp. 2, 391; Yergin 1991, pp. 155-6; Bohi and Toman 1996, pp. 2-3; Klare 2001, pp 29-31). Today, the term energy security and oil supplies are implicitly linked. The links between energy security and resource depletion (Rogner 1997; Campbell and Laherrere 1998; Bentley 2002), and geographic concentration of resources (e.g. oil in the Persian Gulf region) are also important themes (Gause 2000; Jaffe and Manning 2000; Gately 2001; Klare 2001; Morse and Richard 2002), but they are beyond the scope of this review. This review is focused on the issue of intentional acts aimed at disruption of an energy infrastructure and measures to reduce their occurrence and impact, so while the concepts of scarcity and geopolitics may accentuate infrastructure security concerns, they are not central.

2.3.2 Early Analyses

The theme of energy infrastructure and security appears in more general studies of national security and warfare. During the Second World War, the Allies missed a significant opportunity to shorten hostilities by failing to target Germany's energy infrastructure (Clark and Page 1981, pp. 49-55). A similar failure to attack Japan's energy infrastructure was less important because it was highly decentralized and thus would have been very difficult to damage. An analysis of strategic attack of electric power systems during the Korean, Vietnam, and First Gulf War showed that such efforts were not highly effective in affecting public morale, economic activity, or war-fighting capability (Thomas E. Griffith 1994). Moreover, this study argues that the requirements for international support during the prosecution of a contemporary limited war would likely make strategic attack on energy infrastructure an unattractive option. However, there may be underlying issues for the lack of success of such attacks, such as little dependence on electricity on the parts of the Koreans and North Vietnamese, and significant preparations on the part of the Iraqis. Further, the successful attacks by U.S. forces operating under NATO auspices on the Serbian electric power system during May, 1999 suggest military campaigns may continue to feature attacks on electric power systems (Mijuskovic 2000).

Cold War analyses focused on limited or full nuclear exchange between the United States (and its NATO allies) and the Soviet Union (and its client states), and often discussed the potential impacts of such a nuclear exchange on energy infrastructure. We can only guess that much relevant analysis remains classified, but the 1958 U.S. Department of Defense report "Emergency Plans Book" has been published in the open literature (Keeney 2002). Reporting the expected outcome of a large-scale nuclear war, the report predicts that much of the energy infrastructure will be destroyed, but so, too, would much of the demand. Many electricity generators were expected to survive an urban-focused strike, but transmission systems were expected to be largely destroyed, as were petroleum refining and shipping facilities. Local fuel stocks were expected to be consumed relatively rapidly, while massive loss of life, widespread contamination, and destruction of transportation systems were expected to greatly delay recovery. However, the report notes that "With strict rationing, of petroleum products and allocation of coal, the surviving [civilian] fuel production …is sufficient to meet properly time-phased military requirements and minimum essential civilian needs…" (Keeney 2002)

In 1979, the Office of Technology Assessment (OTA) published a study, *The Effects of Nuclear War*, which emphasized the devastation and difficulty in recovering from such an attack (Office of Technology Assessment 1979). One of the cases studied in the report is a strike against oil refineries using 10 missiles with multiple warheads (pp. 64-80). This case was chosen because energy systems were considered to be the most vulnerable sector of the U.S. economy and refineries best met the study criteria of criticality, vulnerability and long recovery times. The conclusion is that most refining capacity in each country (the U.S. and the Soviet Union, or USSR) would be destroyed and both would suffer extensive reductions in industrial productivity and significant changes in socio-economic organization, although differently. For example, the already precarious Soviet agricultural sector was thought to be heavily affected, while in the U.S. the concern was the devastating impact on industrial sectors dependent on refined petroleum products and the socio-economic changes that would result from living with scarcity (e.g. greatly restricted mobility). The OTA report generally recognizes that decentralization and redundancy could reduce the impact of any of the attack scenarios considered.

Two reports commissioned by the US government greatly sharpened the focus on decentralized energy technologies to mitigate security concerns.[20] The first, later republished as a book, *Energy, Vulnerability, and War,* provides a fairly detailed examination of the existing energy infrastructure at the time and the effects of a nuclear attack on it (Energy and Defense Project 1980; Clark and Page 1981). After detailing current vulnerabilities, the report reviews potential options including energy efficiency,

[20] The reports were initially commissioned by the Defense Civil Preparedness Office of the Department of Defense. During the time that the reports were being prepared that office became part of a new organization called the Federal Emergency Management Agency (FEMA), a civilian agency established in 1979 that brought together many disparate federal entities that were involved in some aspect of emergency management.

storage (e.g. superconducting magnets and hydrogen), and renewable energy sources. *Energy, Vulnerability, and War* discusses Libyan and Soviet-sponsored terrorism and notes that from 1970 to 1980, over 250 terrorist attacks against energy infrastructure were carried out (Energy and Defense Project 1980; Clark and Page 1981).

The report's final chapter ranks technology options in terms of vulnerability, based on their degree of centralization, local fuel supply, local maintenance, cost, lead-time and other criteria. Ethanol, low and medium BTU gas, new domestic petroleum and methanol received the highest ratings (8-10). Diesel, biogas, synthetic natural gas, biomass oils, and coal-derived oil receive medium ratings (5-7). Gasoline (3) and hydrogen (1) receive the lowest ratings. A second ranking for decentralized energy sources was also created. Cogeneration, small fossil plants (<250 MW), small hydro, geothermal and fossil fuel gasification all receive the highest ratings. Next are biomass steam (8), wind and biomass low BTU gas (7). Solar technologies (both thermal and PV) have vulnerability ratings between 4 and 5. The lowest ratings are received by fuel cells (3), waves (1) and ocean thermal energy conversion (1).

This report also suggests a fundamental institutional response, the creation of Defense Energy Districts, "which would be administratively responsible for categorizing, inventorying, and coordinating the implementation of dispersed, decentralized and renewable energy resources technologies" (p. 319). While the report describes the potential for decentralized energy technologies to address security concerns, it does not provide a method for quantifying this effect. The report emphasizes civil defense preparedness, not efficiency and renewable energy, per se. Political choices regarding possible trade-offs between conflicting goals (e.g. more security vs. lower prices) are not addressed in *Energy, Vulnerability, and War*, which assumes a unitary decision-maker with a single goal, civil defense.

The second report was reproduced as the ground-breaking book *Brittle Power* by Amory and Hunter Lovins (Lovins and Lovins 1981; Lovins and Lovins 1982). It documents an amazing array of accidents, malicious attacks, and near-misses on U. S. energy systems, identifying the infrastructures for electricity, natural gas, oil and nuclear power as "Disasters Waiting To Happen" (Lovins and Lovins 1982, Part Two, pp. 87-174). The key factors that make these centralized energy infrastructures "the root of the problem" (Lovins and Lovins 1982, p. 218) include the use of dangerous materials (fuels); limited public acceptance of centralized energy infrastructure; centralization of fuel sources; little fuel substitutability; the length, operational requirements and inflexibility of energy shipment systems; interactions between energy systems; high capital intensity, long lead times; and reliance on specialized skills.

Brittle Power highlights the benefits of efficiency and small-scale renewable energy technologies under routine conditions. In their work, one paper that attempts to model the effect of decentralized energy technologies in abnormally stressful situations is identified (Kahn 1980). Lovins and Lovins argue that the mismatch between the scale of centralized energy system components (large) and the scale of most power consumption (small) is at the core of energy system vulnerabilities, and can be rectified by increasing end-use energy efficiency and using more decentralized renewable energy. This approach, they argue, is cheaper than the centralized approach, in addition to any security implications.

Another key concept in *Brittle Power* is resilience, which is borrowed from ecology (Holling 1978; Clark, Jones et al. 1979), and which the authors argue should be designed into energy systems. Elements of a resilient system would include a modular structure, redundancy and substitutability, diversity, possibility of decoupling, and dispersion (pp. 179-182). This discussion is remarkably similar to the concept of 'survivability' that was developed in the computer security field in the late 1990s (Ellison, Fisher et al. 1999; Lipson and Fisher 1999). Lovins and Lovins even use a discussion of mainframe versus distributed computation as an analogy for decentralized energy systems (pp. 208-213). However, *Brittle Power* goes further, emphasizing social factors such as minimizing the need for social control to operate and protect the energy system and understandability of the technology to enhance social acceptance.

Both *Energy, Vulnerability, and War* and *Brittle Power* summarize relevant literature, provide numerous relevant facts and examples, make many logical arguments, and offer compelling visions, but they do not attempt any quantitative assessment of the value of resilience or the comparative values of centralization versus decentralization. Moreover, the details of energy system design, investment and operation are ignored, despite the many examples provided. Crucially, both books (but especially *Brittle Power*) inextricably link the concepts of efficiency, renew ability, decentralization and security together, offering little conceptual space for decentralized energy infrastructures based on fossil fuels: "Ultimately, high national levels of end-use efficiency could … allow the entire grid to depend on inherently resilient, largely local energy sources." (*Brittle Power*, p. 281). It is hard to imagine how large concentrations of people or industry could be served this way, even with significant energy efficiency improvements, yet Lovins and Lovins insist their vision does not require "social decentralization" (*Brittle Power*, pp. 219-220).

Thus both books offer an idealized vision with heavy reliance on decentralized renewable energy sources. Unfortunately, when larger renewable energy systems are mentioned, the problems of grids are barely mentioned (e.g. *Energy, Vulnerability, and War* pp. 171-185, 204-215; *Brittle Power* pp. 264-268, 277-282). Both books generally ignore key issues about large-scale, renewables-based energy systems that might be needed for cities and industry, or assume they can be solved relatively easily. For instance, the problems of 'long haul distances' and resulting vulnerability of energy infrastructures are associated with centralized energy systems. This may simply be technological optimism. In addition, some key challenges such as: network coordination, backup power, and line-worker safety continue to pose challenges to distributed generation for which no universal solutions have emerged. Nonetheless, some elements of the vision outlined in *Brittle Power* are being put into practice, which will provide the lessons and experiences necessary to make progress in resolving issues. If this vision proves accurate in the long term, it changes the nature of the debate on how much energy security a society wants, how best to obtain it, and who should pay for it.

2.3.3 Critical Infrastructure Protection

As noted above, concerns about the security of energy and other infrastructures faded with the Cold War in the late 1980s. However, the rise of catastrophic terrorism within industrialized countries (e.g. the truck bombing of the World Trade Center in 1993), the Western States power outage in 1996, and the realization in the mid-1990s that the transition from 1999 to 2000 might cause significant disruptions led to a renewed concern about the potential vulnerability of key infrastructures. The response to these developments has come to be termed Critical Infrastructure Protection (CIP), which links energy and other infrastructures with national security (General Accounting Office 2001; Luiijf, Burger et al. 2003). Many nations have undertaken CIP activities in the last several years, especially the United States(Moteff 2002).

Definitions of CIP vary somewhat. For instance, Section 1016(e) of the USA PATRIOT Act defines critical infrastructure as

"systems and assets, whether physical or virtual, so vital to the United States that the incapacity or destruction of such systems and assets would have a debilitating impact on security, national economic security, national public health or safety, or any combination of these matters." (2002)

The White House subsequently highlighted the symbolic value of critical infrastructures, which

"provide the foundation for our national security, governance, economic vitality, and way of life. Furthermore, their continued reliability, robustness, and resiliency create a sense of confidence and form an important part of our national identity and purpose." (President of the United States 2003, p. viii)

However, international agreement on a definition of CIP does not exist, for instance, some would add maintaining ecological health (Luiijf, Burger et al. 2003). However, despite the specific definition of critical infrastructure, all nations that use this term include energy systems (or networks) in this categorization. Other sectors usually include Banking and Finance, Communications, Transportation, Water Supply, Emergency Services (Police, Fire, etc.), Law Enforcement, and Public Health.

Another key issue in defining CIP, and one that distinguishes it from previous analysis, is the role that cyber-security plays in the operation of critical infrastructures (President's Critical Infrastructure Protection Board 2002). All infrastructure systems in industrialized economies are highly computerized and cyber-security is as serious a challenge as physical security. For example, the White House has released one national strategy documents on physically protecting infrastructures and another on securing cyberspace (President's Critical Infrastructure Protection Board 2002; President of the United States 2003). This has occasionally resulted in the terms Critical Infrastructure Protection and cyber-security of infrastructures being used synonymously. However, it is difficult to determine the likelihood of success or the impact of a cyber-attack on an energy infrastructure, as there is scant historical precedent to analyze.

In an interesting review of definitions, Moteff et al. note that since Executive Order 13010 was signed in 1996, the definition of CIP used in by the federal government in the

United States has grown broader (Moteff, Copeland et al. 2002). They note that an overly broad and overly flexible definition of CIP is problematic since this could lead to vague, ineffective policies and a growing commitment by the federal government. If the list of critical infrastructures continues to change, or multiple lists of critical infrastructures are created, public and private decision-makers may find it more difficult to actually protecting these infrastructures. This problem raises the need for prioritization, and Moteff et al. propose different approaches focused on different aspects of the problem: the degree of criticality of any infrastructure element, vulnerabilities that cut across infrastructures, interdependencies among infrastructures, key geographic locations where multiple critical infrastructures co-exist, or assets owned by or relied on by the federal government.

2.3.3.1 Practice

Australia and the United States were the first nations to address CIP, and we will focus on CIP efforts in the U.S. because they are by far the most comprehensive. The first formal CIP measure in the U.S. was the establishment of the President's Commission on Critical Infrastructure Protection (PCCIP) under Executive Order 13010 (President of the United States 1996). This commission's documents, as well as subsequent analyses, highlighted the potentially serious consequences of attacks on critical infrastructure. The commission issued its final report in 1997 which had several key recommendations, including the creation of a national warning center, an idea that was acted on by the creation of a National Infrastructure Protection Center (NIPC, see www.nipc.gov) within the Federal Bureau of Investigation (FBI) in 1998 (Booz-Allen & Hamilton 1997). The PCCIP also identified a large number of gaps in existing capabilities needed for successful CIP and called for a significant research, development, and education initiative (President's Commission on Critical Infrastructure Protection 1997)

These recommendations were taken up in Presidential Decision Directive 63, which called for a range of activities (President of the United States 1998). Among these steps was an enhancement of the NIPC as “a national focal point for gathering information on threats and facilitating government’s response to computer-based incidents” and to provide “the principal means of facilitating and coordinating the Federal Government’s response to incidents, mitigating attacks, investigating threats, and monitoring reconstitution efforts.” (General Accounting Office 2001, p. 8). Since that time, especially after the attacks on the World Trade Center on September 11, 2001, a significant CIP bureaucracy has been developed in the U.S. government, some of which has (or may have) significant impacts on the energy sector. The new Office of Energy Assurance in the U.S. Department of Energy identifies over 60 CIP organizations, ranging from the President to the National Security Council, to the U.S. Coast Guard, to the North American Electricity Reliability Council (NERC) (Townsend 2002).

One of the most significant organizational developments since PDD-63 has been the creation of the new Department of Homeland Security (DHS). Initially a White House Office created by Executive Order, it has now become a government department and has taken over several roles (and organizations) once located in various parts of the federal government (President of the United States 2001; 2002)

Other new federal organizations include the National Coordinator for Security, Critical Infrastructure, and Counter-Terrorism in the NSC; the Critical Infrastructure Assurance Office (CIAO); the National Infrastructure Simulation and Analysis Center (NISAC); a set of lead agencies for individual critical infrastructures (the Department of Energy, DoE, is the lead agency for the energy sector, although the Nuclear Regulatory Commission (NRC) has a role as well); the Critical Infrastructure Coordination Group; the Department of Energy's Office of Energy Assurance; and several other intergovernmental groups focused on cyber security (President of the United States 2001; 2002). The key roles of these organizations are to coordinate public sector activities, from the Federal to the local level; conduct research and development; and 'coordinate' and encourage private sector owners of critical infrastructure to help assure its protection. (A large majority of the energy infrastructure in the U.S. is privately owned.) Another important issue is determining the level of control and funding for government activity at the federal, state, and local levels. O'Hanlon, et al. argue that activities with primarily local benefits should be decided upon and paid for locally, while those with national implications should be under the jurisdiction of the federal government (O'Hanlon, Orszag et al. 2002, pp 77-97).

Coordination between the federal government (through the NIPC) and the private sector is conducted through Information Sharing and Analysis Centers (ISACs), which for the energy sector are coordinated by NERC (www.esisac.com), and the American Petroleum Institute (www.energyisac.com). There is considerable disagreement about the appropriate role of legally binding CIP standards or requirements versus voluntary targets and self-regulation. Naturally, industry prefers less regulation yet the public good nature of CIP makes it unclear that wholly voluntary approaches can yield a socially optimal level of CIP. At the moment, the government has only officially called for "standardized guidelines" for risk assessment and security that would be developed in partnership with industry and other levels of government (President of the United States 2003).

The issue of financing overall Homeland Security measures, including critical infrastructure protection, is complex and will remain a mix of both public and private expenditures (O'Hanlon, Orszag et al. 2002). In the United States, proposed public expenditures for infrastructure protection in 2005 are over $850 million dollars out of a total non-defense homeland security budget of almost $34 billion. There is some concern over the economic impact that expenditures in these areas may have. O'Hanlon, et al. recommend a Homeland Security program that would result in $45 billion of public and $10 billion of private costs per year. Their estimate is that this would result in a 0.3 to 0.5 percent reduction in real output from the economy and reduces growth rates by 0.1 percentage points or less. The National Strategy for Homeland Security states that the federal government will set priorities based on a consistent methodology and an approach that will allow it to balance costs and expected benefits, but does not state what an appropriate methodology or approach might be (Moteff, Copeland et al. 2002; Office of Homeland Security 2002).

The key issues associated with recovering security-related costs in regulated utilities are summarized in a recent NRRI white paper (Burns, Wilhelm et al. 2003). Some of the most important issues include differentiating security-related from competition-related costs, applying tests of 'reasonableness' appropriately to CIP expenditures, and devising cost recovery mechanisms (e.g. rates). A survey conducted by NRRI showed that in 2003, only 17% of state public service commissions either had or were developing guidelines for the prudence of CIP-related expenditures, even though 45% reported that utilities had filed requests for recovery of such costs (Burns, Wilhelm et al. 2003). Of those states reporting such filings, only a small fraction (23%) reported that utility CIP-related expenditures were driven by state or federal regulations.

Some business leaders have raised concerns that the high level of security expenditures in the United States could result in a reduction in international competitiveness and requires a balance between security and competitiveness (Council on Competitiveness 2002). They argue that "[T]op-down, prescriptive security standards could drain productivity and dampen growth prospects, putting U.S. companies, universities and workers at a disadvantage vis-à-vis their foreign competitors. Only the private sector is able to design integrated security solutions to protect productivity and competitiveness." In contrast, O'Hanlon et al. argue that "in most cases, providers and owners of the property or activity should generally pay for the costs of additional security. Furthermore, in most cases, the action should take the form of performance-oriented mandates on the private sector, perhaps coupled with insurance requirements or incentives, rather than direct subsidies or tax incentives." This approach is thought to discourage risky activities, prevent rent-seeking behavior and promote innovation in anti-terror strategies.

Another particularly important area of disagreement is disclosure of information about critical infrastructures by private owners to the federal government (Stevens 2003).This debate focuses on the reconciliation of two conflicting public goals: the need to share information confidentially for CIP purposes and the need for public access to information to ensure open government. Private owners of critical infrastructure are reluctant to provide information that may have security or commercial value to the government for the fear of it falling into the wrong hands under provisions like those of the federal Freedom Of Information Act (FOIA). Advocates for civil liberties and for changes in regulation (e.g. environmental groups) are concerned that special protection of 'critical infrastructure information' would preclude the ability to obtain information about abusive government practices, cast a veil of secrecy over central DHS activities, possibly allow industry to improperly shield information with policy implications unrelated to CIP, and are unnecessary due to existing FOIA exemptions. Some public interest groups are concerned that such protection would improperly shield infrastructure owners and operators from liability under antitrust, tort, tax, labor, and consumer protection laws (Moteff and Stevens 2003).

Action in this area has already been taken by many regulatory agencies. In 2003, FERC issued a rule providing definitions for 'Critical Energy Infrastructure Information' (CEII) and procedures besides the FOIA for obtaining CEII information that has been submitted to FERC (Federal Energy Regulatory Commission 2003). In addition, the National Regulatory Research Institute (NRRI) found in surveys that the percentage of state public utility commissions offering FOIA protection for sensitive information increased from 42% in 2002 to 82% in 2003 (McGarvey and Wilhelm 2003).

Nonetheless, concerns about secrecy have lead to bills such as the Leahy-Levin-Jeffords-Lieberman-Byrd “Restore FOIA” proposal. Specific concerns include third-party liability, the lack of anti-trust exemptions for industry-wide information sharing, and the release of competitively sensitive information. These issues will most likely take several years to be resolved by Congress and the courts. However, there have already been some examples identified of public-private information sharing that have been considered successful (one in telecommunications and one in health care) and these could act as models for future activities (Robinson, Woodard et al. 1998).

Similar, if smaller, CIP activities are underway in many other countries. The idea of a warning center and information-sharing mechanism embodied in the NIPC has been replicated in at least ten countries (Australia, Canada, Germany, Israel, Italy, Japan, the Netherlands, New Zealand, South Korea, Sweden, and the United Kingdom) and over a dozen more have investigated the concept (2002; Luiijf, Burger et al. 2003; Stein, Hammerli et al. 2003). Many, such as New Zealand’s Center for Critical Infrastructure Protection, formed in August 2001, and the United Kingdom’s National Infrastructure Security Co-Ordination Centre, focus on cyber attack.

2.3.3.2 Research

Research into CIP has begun to appear in the literature, although it is likely that a considerable amount of such activities will remain classified or proprietary. The U.S.

National Academy of Sciences produced a comprehensive survey of, and strategy for, research and development in support of counter-terrorism (National Research Council 2002). This effort stressed the vulnerabilities of the electric power infrastructure, and recommended research into tools for identifying and assessing infrastructure vulnerabilities, improving monitoring, hardening energy infrastructure from attack, enabling faster recovery, preventing cyber-attack, and deploying an 'intelligent, adaptive power grid'. Related research is also going on outside the U.S., some of it oriented towards survivability concepts (Schmitz 2003).

Several themes have emerged from this research so far. A fundamental goal of these research efforts has been to better understand the specific vulnerabilities of infrastructure systems. There have been significant research efforts underway in academia, government and private industry in this area. A corollary to this effort has been research on robustness and survivability of current and alternative infrastructure systems. The goals of such efforts have included gaining a better understanding of the vulnerability of individual infrastructure systems, specific interdependencies between infrastructure systems, survivable systems and the larger economic impacts of infrastructure failures.

Another major focus of research has been to develop modeling, simulation and analysis tools to analyze infrastructures. Several of the U.S. National Laboratories have taken on this role. Sandia National Laboratory has recently created NISAC in order to apply the largest scale computational capabilities to model and analyze infrastructure vulnerabilities and provide support to government and industry (Robinson, Ranade et al.

2001, and see also www.sandia.gov/CIS/NISAC). Modeling and the development of energy infrastructure test beds are under development at the Idaho National Engineering and Environmental Laboratory (see www.inel.gov/nationalsecurity/infrastructure_protection). One of the key strengths of modeling and simulation is that it can shed light on infrastructure interdependencies that are otherwise very hard to quantify (Robinson, Ranade et al. 2001; Rinaldi 2004).

In many cases, the questions that have been asked over the last five to ten years could not be analyzed with the tools available (in some cases, simply because the problem has been posed in a slightly different manner). Combined with improvements in computational capabilities (including the development of new super-computers for the national energy laboratories), this has led to significant advances in modeling capabilities. This includes the improvement of traditional risk, vulnerability and engineering methods, as well as the application of more recent modeling methods (such as agent-based models) to the infrastructure protection problem.

Another tool being used to understand the vulnerability of energy infrastructure systems are simulation exercises, similar to those used in military war-gaming or in disaster response preparation. In the United States these have included the Blue Cascades (focused on the Pacific Northwest) and the Silent Vector (focused on how to deal with a potential terrorist strike) exercises(Anonymous 2003). These exercises have highlighted a number of issues related to the coordination of protection efforts, risk communication, differences between the public and private sector, and vulnerability of different infrastructure and economic sectors to disruption.

2.3.4 The Role of Diversity

One of the key methods for achieving reliable energy supply and secure energy infrastructures has been through diversity, even if accidentally achieved. This concept was imported to some degree from ecology (Holling 1978; Clark, Jones et al. 1979; Lovins and Lovins 1982, pp 195-8). Vulnerability due to a lack of diversity was well demonstrated in the first oil crisis. The price hikes in 1973 led to active and successful search for oil reserves away from the Middle East and by non-OPEC countries. The resulting diversity of supply reduced the power of OPEC as an oligopoly. However, non-OPEC production seems to be peaking and demand in China is booming, thus the concentration of reserves and production capacity in the Middle East renews concerns about vulnerability in supply (Leiby, Jones et al. 1997; Greene, Jones et al. 1998; Salameh 2003; Salameh 2003).

Another form of diversity is not across suppliers of one fuel, but across types of fuels and technologies for their utilization. Diversity of fuel mix often occurs in the production of electricity, and advocates of every fuel can use this term to support policies that could mandate minimum and maximum market shares. For instance, Porter (Porter and Steen 1996) illustrates how diversity in fuel supplies is being sought through renewable energy in the United Kingdom and Lemar shows how it can be achieved in the U.S. through Combined Heat and Power (Lemar 2001). Diversity in technology is also important as a means of reducing vulnerability to a design error leading to wide-spread failures or preemptive shut-downs in order to affect repairs. Evans and Hope argue that while standardized designs in nuclear plants improve economies of production, they also increase exposure to the possibility of systematic unknown failures due to that design (Evans and Hope 1984). They stress the need for a range of nuclear plant designs. Taking a longer-term perspective, several researchers have documented the need for diversity in energy research and development in order to assure a broad choice of technologies into the future (Margolis and Kammen 1999; Gritsevskyi and Nakicenovic 2000).

In recent times there is evidence that neither political control nor market forces can be counted on to yield diversity in energy systems. For instance, before market liberalization in the United Kingdom (UK) political pressure from coal miners' unions prevented coal-fired plants from being installed near ports because this would open them up to steam-coal imports at a quarter of the prevailing price from UK mines. At the same time, however, the public electricity monopoly in England and Wales (CEGB) included diversity of supply as an operational issue. After privatization, market forces have yielded a singular 'dash to gas'. A strong preference for local fuels is common in electricity generation, as is a preference for whatever the least cost or most fashionable technology happens to be. For instance, in Spain, dirty, expensive local brown coal was used for power generation long after it was economic to do so, largely to preserve local jobs (Farrell 2004). In the U.S., a fairly diverse set of fuels for the electricity sector has come from a century of investment decisions in generation technologies that have been relatively uniform nationwide within each cohort, but have shifted from primary reliance on one technology to another with each pulse of system renewal and expansion starting with hydroelectric, then coal, nuclear, and, now, gas-fired plants. If global oil markets were strictly competitive, much more production in the ultra-low cost Mid-East region might result, although risk aversion by producing firms might cause them to broaden their production portfolio to include other regions, even if a cost premium was required. However, the balance that would be struck in this way would reflect the interests of the infrastructure owners more than the public's interest.

Such portfolio management approaches are based on a probabilistic framework for quantifying the risks of various technologies and the use of utility maximization or other probabilistic techniques. It has been suggested that such techniques can fail if the uncertainty and risk cannot be adequately characterized and in such cases diversity may yield benefits that would not be captured by such techniques (Awerbuch 2000). There have been several efforts at formalizing the benefits of diversity, which could include mitigating technological path dependencies for the future, allowing for multiple and contradictory social choices to be met, fostering innovation and hedging against "ignorance" (Stirling 1994; Stirling 1998).

2.3.5 The Role of Centralization

A key theme in the literature on energy infrastructure and security is centralization, particularly as it applies to the electricity sector. Several observers have documented how the combination of technological innovation and social (political and financial) forces has led to ever larger centralized electricity generation plants connected by ever larger synchronized grids throughout the 20th century (Hughes 1983; Hirsh 1999, Ch. 3; Hyman 2002, Ch. 19). Even a quadruple crisis in the late 1970s that led to fundamental change in the electric utility industry (the introduction of competition) failed to completely arrest this process.[21] Centralization also affects oil and gas infrastructures due to the number and location of key parts of the supply chain, including facilities for production, gathering, shipping, processing, and delivering raw materials and products (Lovins and Lovins 1982; Adams 2003). Given the geographic concentration of petroleum and gas deposits in a relatively small number of locations worldwide, and the need to ship petroleum through constrained corridors, the potential for decentralization in this sector seems slight. In addition, it is not clear that resilient technologies for these sectors exist other than those that result in more efficient use of fuels.

Critics of centralized energy systems argue that they are 'brittle' and prone to failure, while decentralized systems can be resilient (Lovins 1976; Lovins and Lovins 1982; Cowart 2002). Resilient technologies are argued to include efficiency improvements, electricity generation near point-of-use, responsive demand, and renewables (which require no fuel supply). Supporters of these approaches also claim other benefits, such as lower costs, lower environmental impact, and, sometimes, more decision-making power in local (not federal or corporate) hands (Martin 1978). One of the main promoters of such concepts, Amory Lovins, claimed that "[t]he distinction between the hard and soft energy paths rests not on how much energy is used but rather on the technical and political *structure* of the energy system." (Lovins 1978, p. 38)

[21] The four horsemen of this "apocalypse" were technological failures, fuel price shocks, environmental control costs, and unexpected interest rate increases.

In contrast, supporters of centralized electricity systems focus on the need for a sufficiently large grid in which to embed higher-efficiency centralized plants and the ability of a grid to capture the time-diversity of demand allowing the integrated system to have a higher load factor. The reliability benefits of large, coordinated systems are only visible by looking at unexpected flows on transmission lines during partial network failures, which is uncommon outside of the electricity industry. Thus, supporters of large, centralized systems tend to support technologies that will make electric power grids connecting large, centralized plants 'smarter' (increased automation and computation), more 'aware' (more and better sensors and communications), and faster to react (power electronics instead of electromechanical controls) (Amin 2001; Electricity Advisory Board 2002; United States Energy Association 2002).

For instance, the recent National Transmission Grid Study includes "targeted energy efficiency and distributed generation" as one of ten approaches to 'relieving transmission bottlenecks', not as a central organizing paradigm to be applied widely. Similarly, the United States Energy Association's National Energy Security Post 9/11 is asymmetrical in the treatment of centralized energy supply and of efficiency, renewables and decentralized supply (United States Energy Association 2002). Strong policies to support centralized supply are recommended without reservation (e.g. "Allow refiners and other energy producers to recapture the full cost of meeting new environmental regulations."), while policy recommendations on efficiency are limited to research and development, and policy recommendations for renewables are weak and contingent (e.g. "Encourage deployment of renewable energy supplies when doing so will strengthen the energy infrastructure and/or increase U.S. energy security”) (United States Energy Association 2002).

Government efforts to support improved security of energy infrastructure generally ignore these issues as well, generally leaving decisions regarding technology choice to the private sector. The cost of government efforts tend to be socialized by being supported by general revenue, not by the infrastructures that create concerns. This approach may yield more infrastructure and more infrastructure security activities than would an efficient market outcome and would tend to subsidize technologies with greater concerns over those with fewer (Kunreuther, Heal et al. 2002). This would likely be both inefficient and unfair, as those that impose security burdens are not required to pay for them (O'Hanlon, Orszag et al. 2002, pp. 77-97).

More recently, von Meier used the term ‘supple’ electric power technologies to identify technologies that promote decentralization without regard to renewability, which characterized prior analyses from the 1980s (von Meier 1994). Supple technologies are modular, suited to dispersed siting, and fuel-flexible, and include reciprocating engines, microturbines, and fuel cells. She notes other important differences, including the fact that the current energy system can no longer be characterized as purely hard, energy efficiency improvements and smaller scale generation are now more common and accepted.

However, von Meier notes that the fundamental political changes Lovins and others sought in order to achieve widespread adoption of soft technologies have not been accomplished. Instead, technological improvements in decentralized technologies have had an effect, and, more importantly, market forces have come to the fore. von Meier argues that “the ensemble of supple technologies does not support a natural monopoly in … electricity” (p. 213). This may not be strictly true; Strachan and Dowlatabadi document the very successful deployment of decentralized energy technologies in the Netherlands by incumbent utility companies once proper incentives were provided (Strachan and Dowlatabadi 2002). However, the potential antagonism between the interests of large, incumbent energy firms operating a centralized infrastructure and the deployment of decentralized energy technologies may be a significant limit to their potential contributions to the security of energy infrastructures. Ample evidence in the U.S. supports the claim that large, incumbent energy firms tend to be antagonistic to decentralized energy (Alderfer, Eldridge et al. 2000).

2.3.6 The Concept of Survivability

The traditional reliability planning approach does not lend itself well to responding to unexpected, deliberate, and potentially very high impact attacks. For one thing, it is very difficult to imagine all possible attack modes or strategies. Even if this problem could be overcome, current practices in reliability analysis allow for essentially only one strategy – provide more reserve capacity – a very costly solution that competitive firms are not likely to implement, and one that may divert resources from other important uses and possibly slow economic growth (Council on Competitiveness 2002). Thus, supply-side solutions are not likely to be sufficient any longer; more attention will need to be paid to the economic and social implications of end-use disruptions. One concept that may serve to link reliability and security, and also be compatible with competitive energy industries is *survivability*, also known as 'the self-healing grid' or 'the resilient network.' Survivability is similar to the ecological concept of resilience that was applied to energy systems over twenty years ago (Holling 1978; Lovins and Lovins 1982, Ch. 13; Lipson and Fisher 1999; Byon 2000; Farrell, Lave et al. 2002; Longstaff and Haimes 2002; Strachan and Dowlatabadi 2002; Zerriffi, Dowlatabadi et al. 2002; Farrell and Zerriffi 2004).

Survivability is the ability of a system to fulfill its mission in a timely manner, despite attacks, failures, or accidents.[22] It can be contrasted with the current 'fortress' model of security that tries to prevent or counter all attacks but has disastrous outcomes (e.g. cascading failures) when it does inevitably fail. A fundamental assumption of survivability analysis and design is that no individual component of a system is immune from attacks, accidents, or design errors. Thus, a survivable system must be created out of inherently vulnerable sub-units, making survivability an emergent property of the system rather than a design feature for individual components.

Due to the size and complexity of energy system operations, and the speed at which faults can propagate in some of them, it may be difficult to recognize attacks until there is extensive damage. Thus, ways must be found to recognize attack early and isolate the affected area in order to protect the rest of the system. Survivable systems must be able to function autonomously and maintain or restore essential services during an attack, and

[22] Some find the phrase 'in a timely manner' redundant in this definition.

recover full service after the attack. Thus, the system must 'fail gracefully,' shedding low priority tasks and later resume tasks in a priority ordering during recovery. Our current energy systems are optimized for operation in routine conditions and cannot do this. The prolonged outage (in many locations as long as 5 days) of power delivery in Ontario in the aftermath of the August 2003 blackout was primarily due to system stability concerns when energizing a grid that would immediately have to meet peak demand conditions from air conditioners that could not be remotely shut down.

For example, in most cities, traffic signals are powered by the same circuits that provide service to much less critical loads like billboards. During blackouts, injury and property loss may occur due to blank traffic signals. Worsening the problem, blackouts cause gridlock that hinder police and emergency response crews from reaching their destinations. This demonstrates the fortress aspect of traditional reliability planning – it creates a system in which frequent or large-scale blackouts are not supposed to occur, but when they do, the consequences are severe. In contrast, a system designed around survivability concepts might use low power Light Emitting Diode traffic lights with battery backup to ensure that a blackout does not interrupt traffic flow.

2.4 Reliability Modeling

In order to assess the relative robustness of centralized and distributed electric power systems, an engineering analysis using industry standard methods was developed that models the reliability of hypothetical test-bed systems under deliberate attack. The basis of the analysis is modeling how reliably different systems meet a given load. Each system architecture will have characteristic failure modes and probabilities that will provide differing responses to adverse conditions.[23] The reliability models described here are used to determine the adequacy of the electric power system (recall above, the definition of adequacy as the ability of the system to meet a given load). These models are not operational models and so do not address the issues related to security of the system and any given point in time of operation.

2.4.1 Standard Model

The first step in the reliability analysis is to set up a model of generating capacity adequacy. A Monte Carlo simulation was developed that compares available capacity to demand over a number of runs and follows the standard framework established in reliability texts. (Billinton and Li 1994) The key variable in the simulation is the availability of the individual generating units (the probability that a particular unit is operational when it is called upon to function). The state of each generator (j) is sampled in each run (k) by drawing a random number. If the random number is less than the unavailability of the unit, the generator is considered to be unavailable for that run. Otherwise, it is assumed to be available and its capacity is added to the total available capacity for that run. The total available capacity for the run is then compared to a load duration curve, which has been divided into 20 steps. The assumption at this stage is that the transmission and distribution system is perfect and available. For each step, the generating capacity available is compared to the demand (D) and the Demand Not Served (if any) is determined for each step:

[23] This includes possible dependencies on major supporting infrastructure networks (such as natural gas delivery for DG). These infrastructure interdependency issues have not been addressed in this analysis, other than the qualitative arguments presented above with regard to the nature and operation of natural gas networks.

$$DNS_k = \max\left\{0, D - \sum_{j=1}^{m} G_{jk}\right\},$$

where G is the available capacity of the generator for that run.

Hence the model compares capacity and demand in each run for each load step. The model records the runs in which capacity did not meet demand (Loss of Load) and the energy shortfall in those runs (Energy Not Supplied [ENS]). After N runs the model calculates two reliability indices (and their variances):

- Loss of Load Expectation (LOLE, hours per year)
- Loss of Energy Expectation (LOEE, MWh per year)

The LOEE is the primary reliability criterion used in this analysis for two reasons. First, it was the reliability index that was more sensitive to stress in preliminary modeling. Second, it is used in the Cost of Electricity calculations presented below. This calculation requires knowing the amount of energy produced, which is simply an integration of the load demand curve (the total number of kWh demanded in a year) minus the LOEE (kWh per year that is not supplied).

2.4.2 Monte Carlo Simulation

There are two main methods used in Monte Carlo simulation of generating capacity adequacy. The first is the State Duration Sampling Method. This is a chronological method in that each generator is tracked through a large number of simulated years. The generator has an exponentially distributed time to failure and time to repair and these distributions are sampled every time a transition occurs for the generator. For every hour of the year, the capacity of the operational generators is compared to the load for that hour. While conceptually easy, this method requires significant computational power for larger systems because the system state of every generator needs to be stored (as well as the hourly load levels). This method was used to obtain early results.[24] The second method is called the System State Sampling Method and it is used in the analysis presented in the body of the paper.

2.4.2.1 System State Sampling Method[25]

The system state sampling method does not track each generator chronologically. Instead all generators are sampled in each run and their availability determined. The total capacity available for the run is the sum of capacities of the available generators. This available capacity is then compared to the load. However, rather than comparing it against the load for every hour in a year, the capacity is compared to the load duration curve. The load duration curve is derived by sorting the hourly loads. The point at which the available capacity equals the load on the LDC determines whether there is demand that is not being met and how much demand is not served. In order to increase the computational speed, the load duration curve is actually divided into twenty steps. The load level for that step is assumed to apply to all of the hourly load points included in the step.

The load demand curve is divided into 20 steps (NL), containing NI load points. The probability of any step (i) is then:

[24] Zerriffi, Dowlatabadi and Strachan, 2001.
[25] This description of the basic system state sampling method is taken from Billinton and Li 1994, pp. 91-96.

$$P_i = \frac{NI_i}{8760}$$

The details of the individual load steps are given in Table 7. The load duration curve is shown in

Figure 1 (with the first 500 hours shown in Figure 2 as the first few load steps are close together).

The advantage of this method is that it is computationally more efficient than the State Duration Sampling Method and thus allows systems with a larger number of units to be considered. This is necessary in this analysis due to the large number of units in the distributed systems.

Each simulation run begins by sampling each generator (j) to determine its availability for the run. If the random number is less than the unavailability, then the available capacity of that generator (G) is zero. If the number if above the unavailability then G is equal to the capacity of that generator. The sum of the capacities of the available generators is the total available capacity for the run. This is then compared to the load level steps in the LDC. It is important to note that the model actually considers each load step separately. The reliability indices are calculated for each load step as if the load-level for that step were the actual load for the entire year. The reliability indices for the twenty different load steps can then be multiplied by the probability of that step and summed to get a composite reliability index for the system. The following equations show calculation of reliability indices.

Table 7: 20 Step Load Level Model of IEEE RTS

Step	Load Level (p.u.)	Probability	Load Level (MW)	# of Load Points
1	0.99	0.0006	2822	5
2	0.9505	0.0034	2709	30
3	0.921	0.0061	2625	53
4	0.8896	0.0171	2535	149
5	0.8612	0.0236	2454	206
6	0.8348	0.0371	2379	324
7	0.8068	0.0482	2299	421
8	0.7782	0.0499	2218	436
9	0.7467	0.0517	2128	452
10	0.7126	0.059	2031	515
11	0.6792	0.0711	1936	621
12	0.6481	0.0738	1847	645
13	0.6179	0.0754	1761	659
14	0.5866	0.063	1672	550
15	0.5519	0.0695	1573	607
16	0.5184	0.0805	1477	703
17	0.4864	0.0949	1386	829
18	0.4512	0.0769	1286	672
19	0.4149	0.069	1182	603
20	0.3733	0.0292	1064	255

Figure 1: IEEE-RTS Load Duration Curve

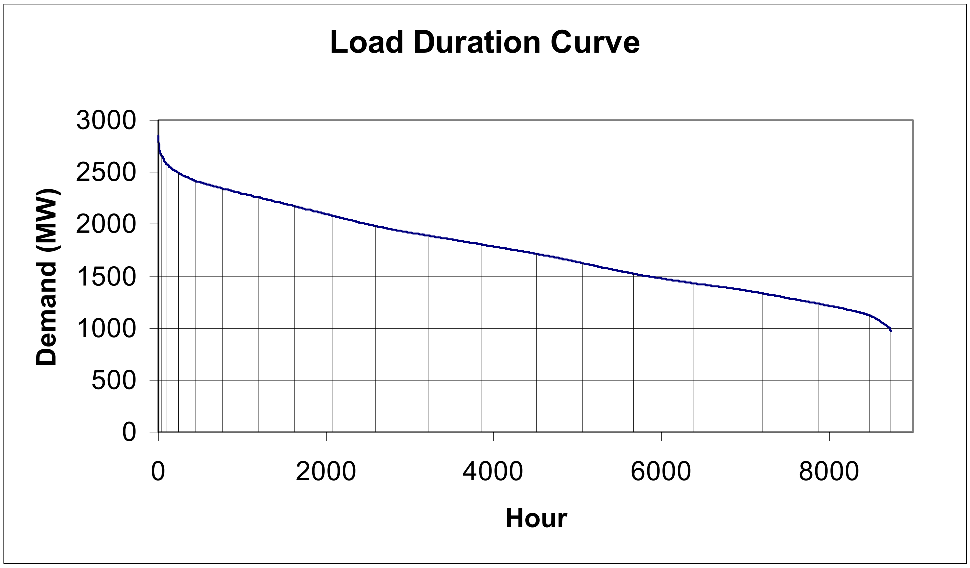
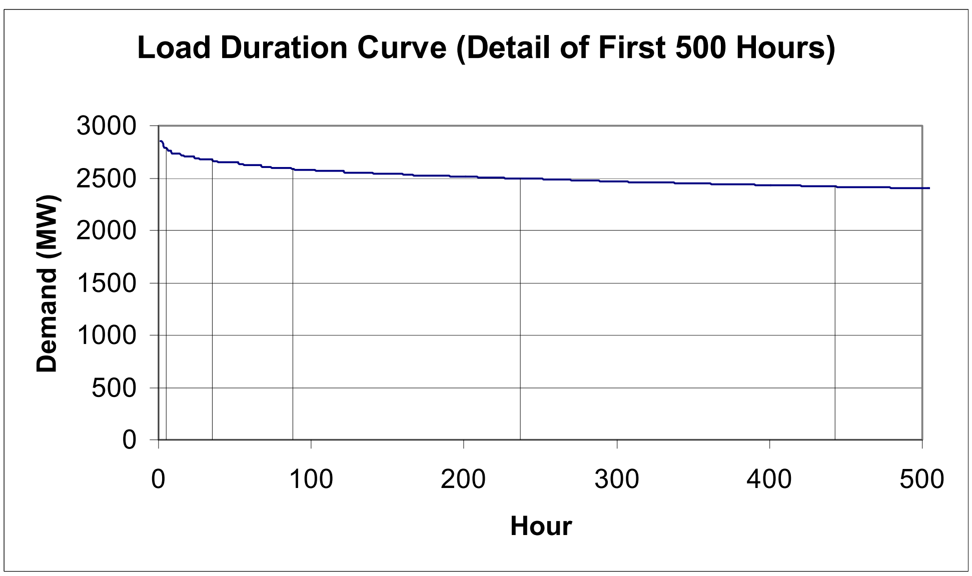


Figure 2: First 500 Hours of Load Duration Curve



If the total generating capacity available is less than the demand, then there will be demand that is not served (DNS). For a given run (k), the DNS is given by:

$$DNS_k = \max\left\{0, D - \sum_{j=1}^{m} G_{jk}\right\}$$

The expected demand not served for a load step (i) is the mean of the DNS from all of the runs:

$$EDNS_i = \frac{\sum_{k=1}^{N} DNS_k}{N}$$

In a given run, the Demand Not Served, in kW, is multiplied by 8760 hours to calculate the Loss of Energy for that run. The Loss of Energy Expectation for a given load step is given by the mean Loss of Energy:

$$LOEE_i = \frac{\sum_{k=1}^{N} DNS_k * 8760}{N}$$

$$LOLE_i = \frac{\sum_{k=1}^{N} I_k(DNS_k)}{N} * 8760, \text{ where } I_k = \begin{cases} 0 \text{ if } DNS_k = 0 \\ 1 \text{ if } DNS_k \neq 0 \end{cases}$$

The EDNS, LOEE and LOLE calculated above for each load step must then be multiplied by the probability of that load step and summed in order to obtain the composite reliability index for the system:

$$EDNS_T = \sum_{i=1}^{NL} ENDS_i P_i$$

$$LOEE_T = \sum_{i=1}^{NL} LOEE_i P_i$$

$$LOLE_T = \sum_{i=1}^{NL} LOLE_i P_i$$

In each run, the variance of each of these reliability indices can also be calculated using the following recursive equation:

$s_N^2 = \frac{1}{N-1}\left[(N-2)s_{N-1}^2 + (N-1)\overline{X}_{N-1}^2 - N\overline{X}_N^2 + X_N^2\right]$, where X is the index of interest (in this analysis, the LOEE is used) and N is the number of runs.

As with any Monte Carlo simulation, a stopping rule must be used in order to terminate the simulation. This can either take the form of a maximum number of runs or a calculated precision, or both. In this case, following the example of (Billinton and Li 1994), three stopping rules were used for each load step:

a) If the LOEE of a given step contributed less than 3% to the final LOEE after 10,000 runs, the simulation stopped evaluating the reliability indices for that step. This saves computational effort as steps that do not contribute to the final value of the LOEE are not evaluated unnecessarily.

b) If the coefficient of variation of the LOEE for a given step was less than 5% after 1,000 runs, the simulation was stopped for that step.

c) If the total number of runs reached 80,000 the simulation was stopped. It was necessary to set an upper limit to the number of runs in order to handle the systems with high reliability as they can have difficulty converging due to their low frequency of outages.

This standard methodology was modified by adding in the system topology described in the body of the paper. This required adding in another index over which to sum, the Local Power System. In the centralized case, the generators are sampled and their power transmitted to an area bus and then to the local load (dependent upon the availability of the transmission link and the link to the local load). In the distributed case the generators in each local power system had to be sampled and compared to the local load to determine whether a surplus or deficit existed. If a surplus exists and the link to the area grid is functional for the run, then the surplus can be used by other load blocks that have a deficit of power (assuming their link to the grid is functional). For each load step, the available surplus is re-apportioned to the load blocks that require it and have a functional link to the grid. The reliability indices are then calculated for that load step.

The purpose of having these simplified transmission and distribution topologies is to explore the impact that transmission could have on the electricity supply. Therefore, we have not conducted a load flow analysis to ensure that the transmission and distribution lines are not overloaded. We have assumed that the lines have been built to the capacity necessary to meet the demand for power flows.

The key parameter in the reliability analysis is the base-case availability of the individual generating units (i.e. their availability under normal conditions). For the distributed systems using 500 kW IC engines, the base availability used was 95.3%. The unavailability of generators larger than 100 MW is taken from a report by UNIPEDE and the WEC.[26] The unavailability of smaller plants (including the DG units) is taken from the Gas Research Institute.[27] In the models presented in subsequent chapters, the centralized generators were assigned to different power groups. Further details on how this modeling framework was used are provided in those chapters.

2.4.3 Stress and Conflict: Methodological Implications

In order to examine the impact that conflict would have on an electric power system's generating capacity adequacy a method had to be developed to model the stress on the system. The challenge in doing so lies in the fact that there are a number of different types of conflicts, different ways in which conflict can impact the electric power system, and different ways to translate that conflict impact into a mathematical modification of the reliability model.

Conflicts can be categorized in a number of different ways. For example, conflicts can be between states (inter-state) or within states (intra-state). Furthermore, there can symmetric conflicts between equal opposing forces and asymmetric conflicts between unequal forces (including terrorism on major powers). Even within one of these types there can be great variation in the typology of the conflict.[28]

For all of the different types of conflict, the impact on the electric power system could be quite different. One possibility is sustained and extensive physical damage to the system

[26] *Thermal Generating Plant (100 MW+) Availability and unavailability factors 1998 (Data 1994-1996).* Joint UNIPEDE/WEC Committee on Availability of Thermal Generating Plants, UNIPEDE Network of Experts for Statistics. Ref: 1998-514-0004 (September 1998), Appendix C6. Data is for North American plants greater than 100 MW and operating on gaseous or liquid fuels.

[27] William E. Liss, "Natural Gas Power Systems for the Distributed Generation Market." Gas Research Institute Technical Paper (GRI-99/0198). Prepared for Power-gen International '99 Conference, New Orleans, LA. November 30, 1999. See Table 2.

[28] For example, Ivan Arreguín-Toft, "How the Weak Win Wars: A Theory of Asymmetric Conflict." *International Security,* Vol. 26, No. 1 (Summer 2001), pp. 93-128. This work looks at the outcomes when weak actors and strong actors take different strategic approaches to conflicts.

as occurred to the Bosnian electric power system. Another possibility is highly localized damage to one region of the conflict. Damages also can be non-physical in their primary impact. For example, the Jerusalem District Electricity Company (JDECO) is responsible for delivering electricity to East Jerusalem and parts of the West Bank. While there has been some damage to their physical assets, by far the greater impact has been due to their inability to collect payments and their increased difficulties in maintaining the system.[29] The economic hardship due to the current unrest has made collecting payments difficult. The closures and the unsafe conditions in parts of their service area have prevented them from making necessary repairs. JDECO estimated that as of July 2001 (less than a year from the beginning of the intifada), they had lost a quarter of their revenues. Another possible impact on the overall electricity sector is to change the demand, particularly if the conflict is long-term and has a widespread economic impact. For example, industries may reduce production, or even stop production, and household demand is likely to change.

There are a number of different means to translate this conflict impact into a form that can be used in the reliability model. One possibility would be to use a Poisson distribution to determine on a spatial grid where damage occurs. This grid would overlay the electric power system to then determine which generators and transmission or distribution lines were impacted. Another possibility would be to adjust the availability of the individual generating units (and transmission lines) that constitute the system. These adjustments could be non-uniform (i.e. different units are impacted to a different

[29] Interview with Hisham Omary, General Manager of the Jerusalem District Electricity Company. July 17, 2001.

degree), correlated (e.g. spatially) or they could all be adjusted in a uniform manner.

For this analysis, all of the unit availabilities are adjusted in a uniform manner. To be more specific, five levels of conflict are modeled. For each level of conflict, the unavailability of each unit in the system is adjusted by the same factor, called the Stress Adjustment Factor (SAF). Thus, for SAF 1, all of the unit unavailabilities are at their nominal level. At SAF 2, all of the unavailabilities are multiplied by two. For each SAF, the reliability model is re-run and the reliability indices determined for each of the five DG scenarios. The result is a system-wide degradation in reliability as the SAF is increased. Since the model is re-run for each SAF and the SAF is not changed while the model is running, this implies an impact that is also persistent. In other words, the hypothetical scenario is that the system is built from scratch and then a conflict (of a certain intensity, determined by the SAF) commences and continues for the duration of the simulation. This method of modeling the conflict was chosen as an initial proxy for conflict both because it is the easiest both conceptually and in terms of modeling and because it represents a realistic impact of conflict.[30] Looking at the historical record of conflicts such as Bosnia (with an extensive pre-existing infrastructure sustaining physical damage), it appears that the impact is often persistent and system-wide.

Future work will develop a more formalized typology of conflicts, impact, and modeling options in order to explore different conflict contexts. There are also a number of other stresses that could impact an electric power system. A typology of non-conflict stresses,

[30] It should be noted that this method of modeling the stress on the system does not include modifications to the demand. The load duration curve specified in the base case also applies to all of the stress cases. The potential impact of conflict upon the load duration curve will be addressed in future work.

impact, and modeling methods will also be developed in order to make the model more widely applicable. It should be noted, however, that at the moment, there is nothing in the model that specifies that the impact on the system is due to conflict or even to physical damage. Any stress on the system that would be persistent and system-wide in reducing the availability of generating units (or transmission systems) would be characterized by this model. For example, if the system was dependent on a single fuel and the availability of that fuel became limited, this model would be able to determine the impact on the system reliability.

2.4.4 The Value of Reliability

The loss of electricity has both direct and indirect consequences on society, including economic consequences due to loss of productivity. As the reliability of an electric power system decreases due to increased stress on the system, these economic costs will rise. The extent of economic damage will depend on the length of outage, area affected, and a number of other context specific factors. The standard methodology to determine the value of reliability is to survey customers on their estimated economic losses and damage if electricity is not provided for a given period of time (e.g. ten minutes, half hour, one hour).[31] The one disadvantage of such a method is that it relies upon surveys. While such surveys provide valuable information on the value of electricity to specific customers, it is difficult to generalize such results.

There are a number of other methods to calculate the economic impact of unserved energy. One method compares the economic output of a region to the commercial and

[31] See, for example, R. Billinton and W. Zhang, "Cost related reliability evaluation of bulk power system." *Electrical Power and Energy Systems* 23 (2001) 99-112.

industrial consumption of that region.[32] A variant on this method compares the total wages paid in a region to the commercial and industrial consumption. The rationale is that for long-term changes in the reliability of the electric power system, labor productivity will change as workers are paid when they cannot be productive due to lack of power. Both of these methods are considered to be upper bounds by Telson. One issue in all of these methods (and one of the reasons Telson considers his methods to be upper bounds) is how to account for the residential sector. This issue is discussed further at the end of the Appendix.

A new method to determine the economic damage caused by interruptions in the supply of electricity was devised that does not rely on survey information. For a given electricity system at a given stress adjustment level, the reliability model will calculate a Loss of Energy Expectation (LOEE) in MWh/yr. This LOEE can be used to calculate the economic impact of this level of reliability on the commercial and industrial sectors of the economy. The basic method is to apply this LOEE to all sectors of the economy with each sector's share of the loss of energy determined by its proportion of total electricity consumption. This weighted loss of energy can then be multiplied by the electricity intensity of each sector of the economy (the economic output of the sector divided by the electricity consumption of the sector) and summed to determine the total economic impact of the LOEE. By dividing by the total electricity consumption determined by the reliability model, the economic cost of unreliability in c/kWh can be determined. The following equation shows the calculation. In this case, the sectoral electricity

[32] Michael L. Telson, "The economics of alternative levels of reliability for electric power generation systems." *The Bell Journal of Economics* vol. 6, no. 2 (Autumn 1975), pp. 679-694.

consumption and economic output are based upon United States data. The total electricity consumption of the United States is significantly greater than the consumption in the reliability model. However, the U.S. sectoral data can be used directly because they are normalized by the U.S. electricity consumption. These data could be replaced by data from any other nation without concern about scaling effects. In this way, the cost of unserved energy can be determined based solely on national economic data and without relying on surveys. It would also be possible to determine the impact of unserved energy on different sectors of the economy. It should also be pointed out that this equation can obviously be simplified as some terms will cancel. However, it is presented in this manner, because it presents a more complete picture of the steps in the calculation to go from LOEE to a cost of unserved energy (CUE):

$$CUE = \frac{\sum_{\substack{\text{All}\\\text{Economic}\\\text{Sectors}}} \frac{E_{US-Sector}[kWh]}{E_{US-Tot}[kWh]} * LOEE_{Model}[kWh] * \frac{Output_{US-Sector}[\$]}{E_{US-Sector}[kWh]}}{\text{Total Energy Produced}_{\text{Model}}[\text{kWh}]}$$

The LOEE and the total electricity produced are provided by the reliability model. The other two required inputs are the electricity consumption of each sector in the economy and the economic output of each sector. The data on electricity consumption per sector were obtained from the data used in the Economic Input-Output Life Cycle Assessment of the Green Design Initiative. The data provided were total annual electricity consumption (in kWh/yr) for each sector, with the sectors identified by the six-digit Input-Output number from the Department of Commerce. However, a matched set of data of economic output were not available.

The economic output data were instead obtained from the Department of Commerce Bureau of Economic Affairs website.[33] In order to simplify the task of matching electricity consumption data and economic output data an aggregation of economic sectors were used. The six-digit I-O coded electricity consumption data were aggregated into 38 economic sectors according to an aggregation system used by the Department of Commerce.[34] This aggregation was comparable to an economic output table available from the Commerce website that aggregated the output of various sectors of the economy into a similar number of economic sectors.[35] In this manner, a table of 38 economic sectors with electricity consumption (kWh) and economic output ($) could be developed. The electricity consumption for all sectors was summed in order to determine the total electricity consumption in the U.S.

It should be noted that this method for determining the cost of unserved energy is by nature an approximation (as is the traditional survey method). In this case, there are a number of factors that are important in considering the cost of unserved energy that are not captured by the calculation.

Time Substitution: If a particular economic activity is interrupted due to a loss of electricity, it may be possible for that activity to occur at a different time (e.g. a factory could shift its production so that a double shift occurs to make up for a lost shift the day

[33] Bureau of Economic Analysis, U.S. Department of Commerce, "Industry Accounts Data: gross domestic product by industry." http://www.bea.doc.gov/bea/dn2/gpoc.htm

[34] U.S. Department of Commerce, *Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System (RIMS II)*. Third Edition. (Washington, DC: U.S. Government Printing Office). March 1997, Appendix B and C.

[35] In a couple of sectors, there was not a direct correspondence between the sectors described by the 38 sector I-O aggregation and the sectors described by the economic output table. The economic output was apportioned to the possible sectors according to their electricity consumption in these cases.

before). However, in some cases time substitution either may not be possible (for example, a factory may already be working triple shifts at capacity and a lost shift could not be made-up at a different time) or may be expensive (e.g. overtime may be incurred for the double shift). To the degree that time substitution is possible, the calculation presented for cost of unserved energy would be an overestimate.

Interruption and Resumption of Processes: In some processes (e.g. some batch processes in the chemical industry), a momentary loss of electricity is sufficient to ruin the batch and the process must be restarted from the beginning. In this case, the economic loss is greater than simply the value of the product being produced. To the extent that interruption and resumption of batch processes results in increased costs, the calculation presented for the cost of unserved energy is an underestimate.

Loss of Load Duration: The calculation of economic damage is based upon the loss of energy in MWh/year. However, the same amount of MWh/year can be lost through a small number of long duration events or through a large number of short duration events. The duration of an outage is an important factor in determining the economic consequences of outages and that information is not captured by this method.

Finally, as noted above, one category of losses is not considered in this analysis and that is the economic impact of losses to the residential sector. This is a particularly interesting issue that will need to be addressed in future work. Assessing the economic or welfare losses that result from curtailments of electricity to the residential sector is not simple, in part because it is highly context dependent. Losses in this sector are also fundamentally different than losses in the commercial and industrial sector. The losses are not tied directly to the production of a good or provision of a specific service. Instead, they result from a number of different potential consequences on the household. These consequences could range from loss of food due to spoilage to changes in consumption patterns to changes in the availability of human capital. There may also be greater possibilities for time substitution in the residential sector, which would reduce the economic impact of lost electricity.

As with determining the overall costs of lost electricity, there are a number of methods to determine residential losses specifically. The survey methods mentioned above do include surveying residential consumers. Other methods include the lost leisure approach (which views lost leisure as the most important outage cost of the household), a consumer-surplus approach (which uses the electricity demand function to determine willingness to pay), and a "productive unit" approach (which attempts to transform household tasks into equivalent wages), as well as others.[36] However, as discussed further below, it is not clear how applicable some of these methods may be in conflict contexts.

Not including the residential sector results likely results in an overestimate of the consequences of unserved energy. Telson argues that his methods, which do include the residential sector, provide an upper bound based on the argument that the residential

[36] See for example, Billinton and Zhang 2001, Alice Morgan, "The Cost of Electricity Supply Reliability: A Review of the Existing Literature." Cambridge Energy Research Group, Cavendish Laboratory (ERG 84/42), August 1984 and U.S. Department of Energy, 1981, Chapter 5.

sector does contribute to the economic output of a region. Thus, dividing the *total* economic output of the region by the commercial and industrial electricity consumption (rather than the total consumption) results in a lower denominator and thus a higher estimate of the cost. Similarly, his second method of dividing wages in the region by commercial and industrial consumption results in an upper bound.

In the method utilized in this study we did not simply divide total output or total wages by the commercial and industrial consumption. Sector specific data were used to divide only the economic output of those sectors by their electricity consumption. However, this should also be considered to be higher than what would result if the residential sector were included. If residential economic losses were added to the numerator and residential consumption were added to the denominator, the loss of energy cost would likely decrease. While residential consumption may be 33% of the total consumption, it is unlikely that residential economic losses would be 33% of the total losses. If residential losses were added to the CUE the equation would then become:

$$CUE = \frac{\sum_{\substack{\text{All}\\\text{Economic}\\\text{Sectors}}} \frac{E_{US-Sector}[kWh]}{E_{US-Tot}[kWh]} * 0.67 * LOEE_{Model}[kWh] * \frac{Output_{US-Sector}[\$]}{E_{US-Sector}[kWh]} + 0.33 * LOEE * \text{Residential Losses}\left[\frac{\$}{\text{kWh}}\right]}{\text{Total Energy Produced}_{\text{Model}}[\text{kWh}]}$$

Thus, the commercial and industrial costs would go down by 33%. This would likely not be made up by the residential losses and the overall CUE would decrease. More simply:

$$\frac{L_C + L_I + L_R}{E_C + E_I + E_R} < \frac{L_C + L_I}{E_C + E_I}$$

Where L is the economic loss and E is the electricity consumption for the commercial (C), industrial (I) and residential (R) sectors.

The problem of assessing residential losses is even harder in the context of conflicts because the methods developed to assess the cost of lost electricity were primarily developed in the context of industrialized countries and primarily short-term electricity losses. The socio-political and economic contexts of conflict situations and their impact on individual households will likely be different from this and vary widely. Residential and household level consequences of loss of electricity are going to be very different in the case of an industrialized country facing a terror attack as opposed to the case of a civil war in a less industrialized country. In the industrialized country case, action might be taken to mitigate the impact of the attack (e.g. if it is known that an outage will be lengthy, hotel stays may be increased, small generators may be purchased, etc.). Furthermore, there may be government or insurance compensation.

In the case of conflict in an industrializing country, the impact may range from loss of human capital (e.g. students can't study or go to school), increased household non-wage earning activity (more time doing daily shopping because lack of refrigeration) as well as a host of other potential consequences. Future work will seek to tie this issue to the further development of a typology of conflict, a better understanding of the sociological and economic responses to conflict, and conflict durations (since actions taken may be very different depending on the expected length of the conflict and persistence of outages).

Chapter 3 Stress on Electricity System Components

Initial models developed to incorporate the possibility of stress on the system assessed stress only on the electricity system components (generation, transmission, distribution). This chapter details two models that were developed. The first model was the initial proof of principle model that indicated that a switch to smaller generators could result in increased reliability.(Strachan, Zerriffi et al. 2003) The second model included a simplified network topology to accommodate inclusion of transmission and sub-transmission effects, as well as a change in the technologies considered. It also includes an overall economic comparison of centralized versus distributed system that accounts for the difference in cost of the system and the value of the reliability that they can provide.

3.1 CEIC Working Paper Model[37]

3.1.1 Standard Model Modifications

The basic generating adequacy model presented in Chapter 2 was modified in two ways. First, a system topology was developed that allowed for the examination of simple transmission and distribution systems in order to determine what impact they may have on the reliability of the systems. The topologies developed for the centralized and distributed systems are very similar and each are described below.[38] The second change made to the basic model was to include the effects of conflict or stress on the system. As discussed above, there are a number of different possible stresses on an electric power

[37] This section taken from (Zerriffi, Dowlatabadi et al. 2002).

[38] An interesting issue for examination in future work is the modification of existing centralized system topologies for distributed generation and the design of optimal greenfield topologies.

system and a number of ways these stresses can be modeled. The method chosen for this analysis was to change the availability of each unit in the generation system. For example, if a unit has a nominal unavailability of 0.05 (i.e. it is unavailable 5% of the time and available 95% of the time), and the Stress Adjustment Factor (SAF) is 2, the unit's unavailability would be 0.10. For a given SAF this would hold true for all of the generating units in a system. Stress adjustment factors from 1 to 5 were used to examine the impact of stress on the system. Stress adjustment factor 1 corresponds to a system in its normal state without stress and would be the system considered in typical capacity planning. Thus, for each system described below, the model is run five times, once for each SAF. The real-world analogue of this method of modeling stress would be a conflict that is widespread and persistent, impacting all parts of the system equally.

Adequacy analysis of electric power systems is a subset of reliability analysis that is concerned with electric power system planning in order to ensure that the generation, transmission, and distribution assets of the system are adequate to meet a given load at an acceptable level of reliability.[39]

Electric power system adequacy analyses generally divide the system into three hierarchical levels. The first level is the generation capacity of the system. Once the adequacy of the generating capacity is evaluated, the second hierarchical level includes the transmission system (this is also called bulk power system reliability analysis). .

[39] It is necessary to note that there is another category of reliability analysis for electric power systems, generally called security analysis. "Security relates to the ability of the system to respond to dynamic or transient disturbances arising within the system. Security is therefore associated with the response of the system to whatever perturbations it is subject to." (Billinton and Li 1994, p. 9) Security is a more difficult reliability analysis to address and is highly dependent on the specific topology of the system. Most probabilistic reliability analyses are therefore limited to determining adequacy (Billinton and Li 1994, p. 10). This study also limits itself to conducting adequacy analyses.

Finally, the third hierarchical level analyzes the system from the distribution level, treating the generation and transmission as an input into the distribution system analysis. This analysis is a generating capacity adequacy assessment in order to determine how changes in the generating system impact the reliability of the system. Simplified transmission and distribution topologies have also been included because of the important T&D differences between centralized and distributed systems.

There are both analytical and simulation methods for conducting generating capacity adequacy assessments. The analytical methods require specifying all of the possible system states (in a system with N generators and no transmission, there are 2^N system states). The transition probabilities between these system states must also be specified.[40] Thus analytical solutions require either a truncation of the system state space considered and/or are limited to smaller systems in which specifying all of the system states (and their transition probabilities) is not an insurmountable obstacle.

The alternative is to conduct a simulation in which the system state of the generating units is sampled in each run. Over a large enough number of runs, the simulated answer will converge to the analytical solution. There are a number of advantages of the simulation method that lead to its use in this analysis[41]:

a) it does not require explicit specification of the system states and their transition probabilities

[40] J. Endrenyi, *Reliability Modeling in Electric Power Systems*. (Chichester: John Wiley & Sons, 1978), Chapter 4.
[41] Endrenyi 1978, pp. 103-108 and Billinton and Li 1994, p. 4 and p. 75.

b) non-exponential distributions can easily be considered

c) the distribution of reliability indices can be determined

d) multi-area studies can be conducted.

For the purposes of this analysis, (a) and (d) are the most crucial advantages of the Monte Carlo simulation approach. The distributed systems have a large number of system states (since the number of generators is approximately 6000). Furthermore, the distributed system topology investigated allows for power to be shared among the distributed micro-grids. Load sharing is relatively easy to add into the simulation (especially as load-flow analysis has been ignored).

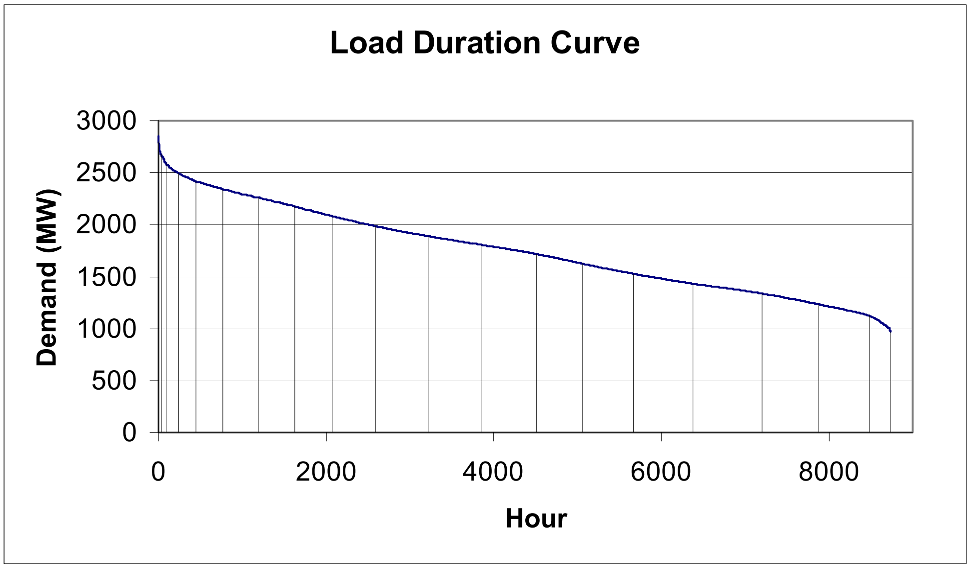
3.2 Systems Modeled

The reliability model was used to evaluate one centralized system and five different distributed systems. All six systems are required serve the same load, which is provided in a standard test system called the IEEE Reliability Test System (IEEE-RTS).[42] The load profile of the IEEE-RTS has a peak demand of 2850 MW.[43] The twenty-step load duration curve is shown in Figure 3.

[42] The Institute for Electrical and Electronic Engineers Reliability Test System is described more fully in Billinton and Li 1994, Appendix A.

[43] To put this system in context, it is approximately equal in energy consumption to Duquesne Light (DQE), which has approximately 580,000 customers (of which 90% are residential) in Allegheny and Butler counties. According to DQE's 2000 filing of Form 1 with the Federal Energy Regulatory Commission (FERC), their total billed MWh sold in 2000 was 13.2 million MWh. The total energy demanded by the IEEE-RTS is 15.2 million MWh. Assuming 2.3 persons per household, this system would serve a city of approximately 1.4 million people.

Figure 3: IEEE-RTS Load Duration Curve



3.2.1 Centralized System

The centralized electricity system modeled is based on the IEEE-RTS. The original RTS consists of a variety of electricity generating technologies ranging from oil burning plants to hydro plants. The RTS includes 32 generating units ranging in size from 12 MW to 400 MW. The total generating capacity of the centralized system is 3405 MW (for a capacity reserve of approximately 20%). The IEEE-RTS generating units are a mix of technologies including coal-fired steam units, hydropower units and oil-fired units. In order to compare both the centralized and distributed system across a similar class of technologies, the RTS generating technologies were changed so that all units are natural-gas fired turbines. The original sizes (in MW) of the RTS units were maintained. However, both their reliability characteristics (in terms of the availability of individual units)[44] and their economic characteristics (capital and O&M costs) were changed to reflect numbers characteristic of combined cycle natural gas turbines.

Centralized System Topology: The IEEE-RTS also specifies a system topology. In order to simplify the analysis and to provide a comparable topology for the centralized and distributed systems, the IEEE-RTS grid topology was not utilized. Instead, a simple hierarchical topology was developed that is similar to the one developed by Gilbert Miller to assess the relative performance of centralized and distributed systems.[45]

In the centralized system, all of the power must be transmitted to an area grid and then delivered to the load via a radial distribution system. Figure 4 shows the centralized system topology. The generating units are apportioned among four power groups (PG). Each power group is then connected to the load center via a transmission line (T1–T4). The transmission lines each have a probability of failure and are sampled each run.[46] If the transmission line has failed (the line is out at point A for that group), then none of the electricity generated by that power group is available to meet demand. Generators were assigned to power groups in such a way as to ensure that each group was providing approximately the same amount of power (PG1 has 845 MW, PG2 and PG3 have 855 MW each, and PG4 has 850 MW) and that no group had a disproportionate number of large generators. This information is shown in Table 8.

[44] The availability rates of the centralized units range from 0.935 to 0.979 (see Chapter 2).
[45] Miller 1981, pp. 4, 48-58.
[46] The availability of the lines is 0.9993, based upon data from Billinton and Li 1994, Table A.11

The load center itself is subdivided into 285 independent local load blocks, each with a peak demand of 10 MW.[47] Each of the 285 local load blocks is connected to the larger area grid through a radial distribution line (D1–D285). The distribution line also has a probability of failure and is sampled in each run. If the distribution line has failed (the line is out at point C), then the local load block is unable to receive power. On the other hand, the area power grid is assumed to be a redundant network, with the ability to sectionalize and reroute power. Therefore, the area grid does not have a failure probability and is assumed to work perfectly (the area grid cannot be cut at point B). Therefore, each local power load of 10 MW is considered to be independent of the others, and failure of one distribution line (e.g. in the 95th load block) does not impact delivery of power to any of the other load blocks.

As with the availability of the generating units, which change as the SAF increases, the availability of the link to the area grid is similarly impacted by changes in the SAF. Therefore, as the stress on the system becomes more severe, not only are generating units increasingly unavailable, the transmission and distribution lines to deliver power are increasingly unavailable.[48]

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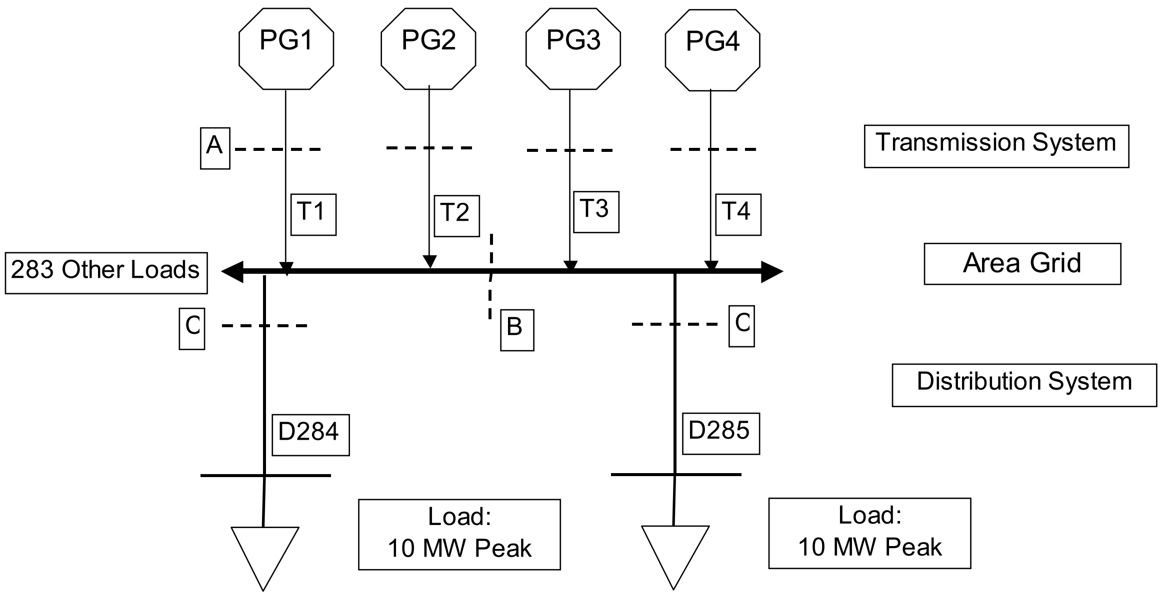
[47] Assuming a customer and consumption profile that is similar to DQE's, this would correspond to approximately 2300 customers. Of these, approximately 2070 would be residential. At 2.3 persons per household, this would be 4760 people.

[48] It should be noted that in both the centralized case and the DG cases, the physical line losses that occur along the transmission and distribution lines have been ignored. However, this should not impact the analysis, as these losses occur at both the transmission level and at the distribution level. Both the centralized system and the DG systems are assumed to have identical distribution level topologies. Therefore, it would only be the high-transmission lines of the centralized system that would reduce the delivered power. Data from Norway indicate that losses in the distribution system are two times the losses in the transmission system (E Jordanger, K Sand, and R Kristensen, "Method for Calculation of Cost of Electrical Power System Losses," *CIRED2001*, 18-21 June 2001). Models developed for the Argentinean system on transmission through a 132 kV transmission line and then distribution through 33 kV, 13.2 kV, and 0.4 kV lines indicates that transmission through the lower voltage systems result in losses up to 2.5 times that of the 132 kV system and that transformer losses at the distribution level are also higher than at the transmission level (R. O. Ferreyra and P.J. Paoletich, "Model For Losses Calculation and Breakdown in Distribution Systems," *CIRED2001*, 18-21 June 2001).

Table 8: Unavailability of Centralized System Generating Plants and Their Associated Power Group

Unit #	Capacity	Unavailability	Power Group
1	12	0.065	1
2	12	0.065	1
3	12	0.065	2
4	12	0.065	2
5	12	0.065	3
6	20	0.065	1
7	20	0.065	1
8	20	0.065	3
9	20	0.065	4
10	50	0.021	1
11	50	0.021	2
12	50	0.021	2
13	50	0.021	3
14	50	0.021	3
15	50	0.021	4
16	76	0.021	1
17	76	0.021	2
18	76	0.021	3
19	76	0.021	4
20	100	0.058	1
21	100	0.058	2
22	100	0.058	3
23	155	0.058	1
24	155	0.058	2
25	155	0.058	4
26	155	0.058	4
27	197	0.058	3
28	197	0.058	4
29	197	0.058	4
30	350	0.063	3
31	400	0.05	1
32	400	0.05	2

Figure 4: Centralized System Topology



3.2.2 Distributed System

A DG system consisting of interconnected distributed micro-grids was developed to compare to the centralized system. The technology chosen as representative of DG was 500 kW internal combustion engines,[49] with an availability of 0.953. The number of generating units in the DG system was varied until the LOEE of the DG system matched that of the centralized system under normal operating conditions. This results in a DG system consisting of 5749 IC engines (a total of 2874 MW of capacity). This implies that the DG system can meet the same demand, at the same level of reliability, as the centralized system (under normal conditions) with only a 0.9% capacity reserve (as opposed to the nearly 20% capacity reserve of the centralized system). By comparison,

[49] 500 kW IC engines were chosen as the representative technology because there is data available on such technologies, they are commercially available, and it is the DG technology primarily analyzed in the work of Neil Strachan, allowing comparisons between this work and his work to be made more easily as they are based on a consistent set of technologies.

in order to have the same generating capacity as the 3405 MW centralized system, a total of 6810 IC engines would be required.

Five distributed generation scenarios were chosen for analysis. The first is a system that has the minimum number of DG units necessary to match the reliability of the centralized system under normal conditions. For modeling purposes, this system was rounded down to 5700 units.[50] In addition, four other scenarios were analyzed in which the generating capacity reserve was set to 5%, 10%, 15%, and 20%. The table below summarizes the different generating scenarios modeled.

Table 9: Parameters of the Distributed Systems

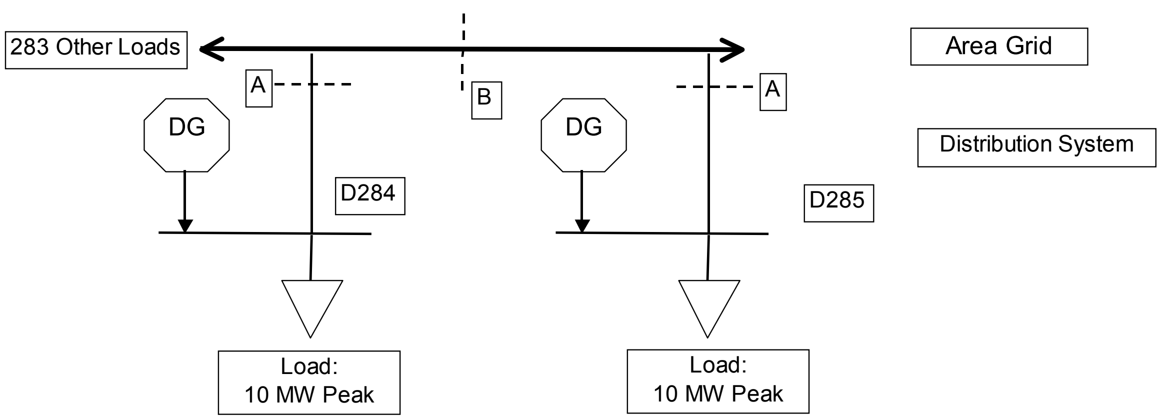
Scenario	Number of Units	Unit Sizes (MW)	Total Capacity (MW)	Capacity Reserve (percent)
C (Centralized System)	32	12-400	3405	19.5
DG1 (Minimum System)	5700	0.5	2850	0
DG2	5985	0.5	2992.5	5
DG3	6270	0.5	3135	10
DG4	6555	0.5	3277.5	15
DG5 (Close Match to Centralized System)	6840	0.5	3420	20

Distributed System Topology: As with the centralized system, the distributed system load is also divided into 285 load blocks of 10 MW, connected to an area grid by radial distribution lines. However, unlike the centralized system, in the DG system these blocks are individual local power systems with local power generation. The total generating capacity is divided evenly into each of the 285 local power systems (see Figure 5). Thus,

[50] This is exactly zero capacity reserve. This was done in order to facilitate modeling of the transmission and distribution system, which requires the same integer number of generators to be in each local power system.

if the connection to the area grid (point A) is out, the local generators can still be used to meet local load. Power exchanges can also occur between the distributed micro-grids as long as the connection to the area grid is operational for the run. Local systems with a functional link to the area grid can either send their surplus to the area grid or use available surplus as necessary. Generating units and the links to the area power grid are both impacted by stress on the system and become increasingly unavailable as the SAF increases. The area grid is assumed to have redundancy and is not impacted (i.e. no faults can occur at point B).

Figure 5: Distributed Generation System Topology



3.3 Results

Before presenting the impact of stress on the reliability of the different systems considered, it is useful to examine the reliability implications of replacing the centralized system with a distributed system. Under normal operating conditions the centralized system has an LOLE of approximately one and a half days in ten years. The general standard that North American utilities try to meet is an LOLE of one day in ten years. Replacing the small number of large generators in the centralized system with a large number of small units in the DG systems results in significant capacity savings. DG1 can meet the same demand with higher reliability with a capacity equal to the peak demand (instead of 20% capacity reserve). Increasing the capacity reserve to only 5% (DG2) results in a system that is significantly more reliable than the centralized system.[51]

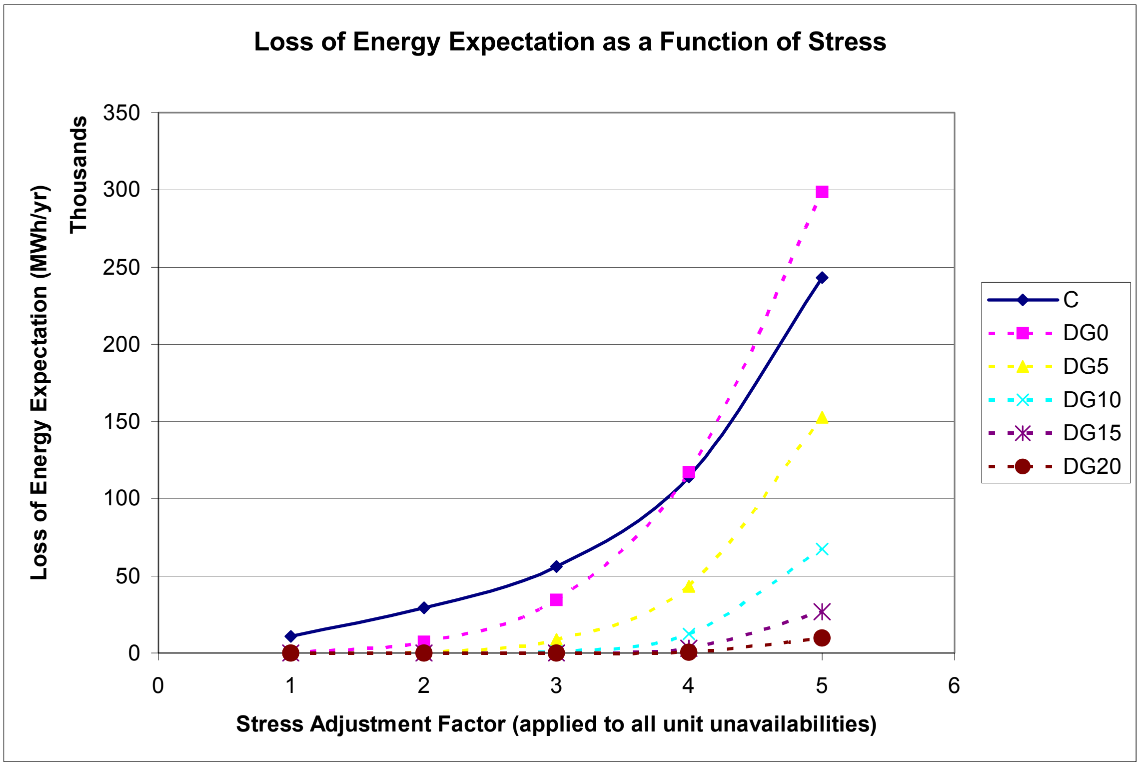
As the systems are stressed, the loss of load and loss of energy expectations increase to many times their original values. Figure 6 shows the impact of stress on the six systems. As can be seen, systems DG2 through DG5 are able to meet more of the demand than the centralized system (i.e. their LOEE is lower). The centralized system LOEE at the highest stress level considered (SAF=5) is 24 times that of DG5.

DG1 is an interesting case, as it runs counter to the hypothesis that distributed systems would perform better under stress. As can be seen from Figure 6, DG1 has a lower LOEE than the centralized system for normal operating conditions and Stress Adjustment Factors 2 and 3. At SAF 4, the DG1 system and the Centralized system have comparable LOEE and for higher stress, the Centralized system has a lower LOEE than DG1. DG1's performance is due to the fact that it takes advantage of all of the potential capacity savings under normal and near-normal operating conditions. However, as a result, the system is operating at its margin, with no reserve capacity to handle problems. The small impact of losing individual generators allows it to continue to perform well under some stress, but at a certain level of stress the lack of a reserve margin begin to hamper its performance severely and make it less reliable than the Centralized system. This indicates that there is a limit to the capacity savings that distributed generation can offer. Taking advantage of all potential capacity savings results in a system that is more

[51] DG2 has an LOEE of 1MWh/yr as opposed to an LOEE of 604 MWh/yr for the centralized system.

sensitive to stress. This sensitivity will also be seen in the economic calculation (below) in terms of higher costs for unserved energy.

Figure 6: Impact of Stress on Loss of Energy Expectation



Chapter 4 Economics of Centralized and Distributed Systems

As noted above, previous work on the relative economics of centralized and distributed systems has found that DG units can be economically competitive both in well-matched applications, and as a system. The goal of the economic calculations presented here is to compare the specific systems considered above in the reliability analysis in order to determine their relative economic performance. The Cost of Electricity is calculated in cents per kilowatt-hour of energy delivered (c/kWh) and it is the cost to the generator of producing and transmitting the electricity. This is not the price paid by the consumer.

4.1 Cost Components

In order to understand the relative economics of the centralized versus distributed systems considered in this analysis a number of cost elements must be included. The standard terms in cost of electricity calculation include capital, fixed operations and maintenance, variable operations and maintenance and fuel. To these terms, a heat credit must be added for the DG systems if the waste heat is utilized in cogeneration. Finally, a cost of unserved energy term has to be added due to the economic losses that occur when electricity demand is not met and provide a measure of the social welfare costs of reliability degradation. The equation to calculate the Cost of Electricity (COE, c/kWh) for either a centralized system (C) or a distributed system (DG) is:

$$COE_{C,DG}(c/kWh) = \frac{1}{P}CR * u_{C,DG} * 100 * \sum_{\substack{All \\ Units}} Cap + \frac{1}{P}FOM_{C,DG} * 100 * \sum_{\substack{All \\ Units}} Cap + VOM_{C,DG} + \frac{1}{\eta_{C,DG}} * FC + TC + CUE_{C,DG} - HC_{DG}$$

Where:

COE – Cost of Electricity (c/kWh)

P – Electricity Produced (kWh) from reliability model

CR – Capital Recovery (based on lifetime and discount rate)[52]

$CUE_{C,DG}$ – Cost of Unserved Energy

HC – Heat Credit (DG systems only) – see calculation below

Table 10 compares the centralized and DG systems according to these various cost components. The technology parameters used to make the cost calculations are shown in Table 11.

[52] A discount rate of 10% has been used for this analysis.

Table 10: A Comparison of the Cost Components of Centralized and DG Systems

Cost Component	Centralized	Distributed
Capital Cost	-Lower unit costs	-Higher unit costs -System-wide savings due to reduced capacity -System-wide savings due to use of waste heat in cogeneration, avoids purchase of boilers
Fixed Operations and Maintenance (O&M)	-Same as DG	-Same as Centralized -System-wide savings due to avoided boiler fixed O&M
Variable O&M	-Lower than DG	-Higher than Centralized -System-wide savings due to avoided boiler variable O&M
Fuel	-Same unit cost as DG	-Same unit cost as Centralized -System-wide savings due to avoided boiler fuel purchases
Transmission	-High voltage transmission required -Higher unit cost than DG	-Only distribution required -Lower unit cost than Centralized
Heat Credit	-No heat credit	-Sum of the savings in Capital, Fixed O&M, Variable O&M, and Fuel -Varies according to the assumptions made about the extent to which the useful heat of the DG systems can be utilized. -Calculation follows the standard method for calculating the cost of electricity for a single cogeneration plant, but it is applied to the entire system.[53]
Cost of Unserved Energy[54]	-Higher than all DG systems except DG1	-Lower for all DG systems except DG1

Table 11: Technology Parameters for Economic Calculations[55]

Parameter	Description	Centralized	DG
Cap	Size (MW)	12-400	0.5
μ	Capital Cost ($/kWe)	500	700
FOM	Fixed OM Cost ($/kWe)	15	15
VOM	Variable OM Cost (c/kWh)	0.55	0.7
FC	Gas Price (c/kWh)	0.891	0.891
t	Lifetime (years)	30	15
TC	Electricity trans cost (c/kWh)	1.606	0.203
η	Electricity Prod. Efficiency (%)	55	29
HPR_{max}	Maximum Heat to Power Ratio		2.1

[53] J.H. Horlock, *Cogeneration – Combined Heat and Power (CHP)*. (Oxford: Pergamon Press, 1987), pp. 114-115. The heat credit can be subtracted from the overall cost or the heat credit for a specific cost component can be subtracted from that cost component.

[54] The method for determining the cost of unserved energy is explained in Chapter 2. The loss of electricity results in economic losses due to lost productivity and inventory as well as other factors. The results of the reliability model can be used to determine the cost of unserved energy for a given system and given stress level. While this cost would not be borne directly by the electricity generating entity, adding this cost provides some measure of the social welfare impacts of reliability degradation.

[55] Taken from Strachan and Dowlatabadi 2001.

4.2 *Heat Credit*[56]

The heat credit is dependent upon the amount of cogenerated heat from the DG units that can be utilized. This will have a significant impact on the relative economics of the centralized and distributed systems. This will depend on both the amount of heat demanded by users and the amount of useful heat produced by the DG units. DG systems will have the highest savings when there is a match between the heat demand and the heat produced. In this case, there is no need for supplemental boilers (as would be the case if the heat demand is higher than that produced by the DG unit). There is also no need to dump excess heat that cannot be utilized (as would be the case if the DG units can produce more heat than is demanded).[57] The key parameter is the Heat to Power Ratio (HPR) of the demand and of the DG units.

The following equation shows the amount of money saved in DG systems by producing heat. The boilers that would have to be purchased and operated to produce this heat are avoided costs and are a credit to the DG system. This heat credit is composed of the capital cost, fixed O&M, variable O&M and fuel savings of the avoided boilers (b). The relevant unit costs are shown in Table 12.

$$HC_{DG}(c/kWh) = HPR_{eff}\left[\frac{CR_B * \mu_B * 100}{8760} + \frac{FOM_B * 100}{8760} + VOM_B + \frac{FC}{\eta_B}\right]$$

[56] See Chapter 2 for more details on the heat credit calculation.
[57] Dumping excess heat is not a significant problem, however, as it can simply be radiated into the atmosphere.

Table 12: Boiler Technology Parameters[58]

Parameter	Description	Boiler
Cap	Size (MW)	0.5
μ	Capital Cost ($/kWth)	200
FOM	Fixed OM Cost ($/kWth)	10
VOM	Variable OM Cost (c/kWh)	0.2
FC	Gas Price (c/kWh	0.891
t	Lifetime (years)	20
η	Efficiency (%)	92

The HPR_{eff} represents the maximum heat produced by the DG units that can be utilized. The heat credit was calculated at three different HPR_{eff} (0, 1, 2). This spans the range of possible values for the IC engine.

4.3 Results

The cost of electricity is dependent, in part, upon the HPR_{eff}, which determines the amount of heat credit. The results shown below assume that the HPR_{eff} is 1, implying that approximately half of the useful heat output of the DG units is being used.[59]

The cost of providing electricity for the different systems at the five stress levels is shown in Figure 7. Consistent with previous findings by Neil Strachan, even under normal operating conditions (i.e. no stress), the distributed systems have a lower cost than the centralized system if at least some of the useful heat can be captured and used. The cost savings for the DG systems per unit of energy delivered range from 13% (DG5) to 20% (DG1). As the stress level increases, the cost of providing electricity increases. As shown below, this is almost entirely due to the cost of unserved energy. With the

[58] Taken from Strachan and Dowlatabadi 2001.
[59] Supplemental results with the HPR_{eff} equal to 0 and to 2 are presented below.

exception of DG1 (due to its increased sensitivity, as discussed above), the cost savings of the DG systems increase as the stress level increases. For example, DG5 provided electricity at a cost 13% lower than the centralized system under the base case. At Stress Adjustment Factor 5, this distributed system now has a cost savings of approximately 55%. These results are shown in Table 13.

Figure 7: Cost of Providing Electricity

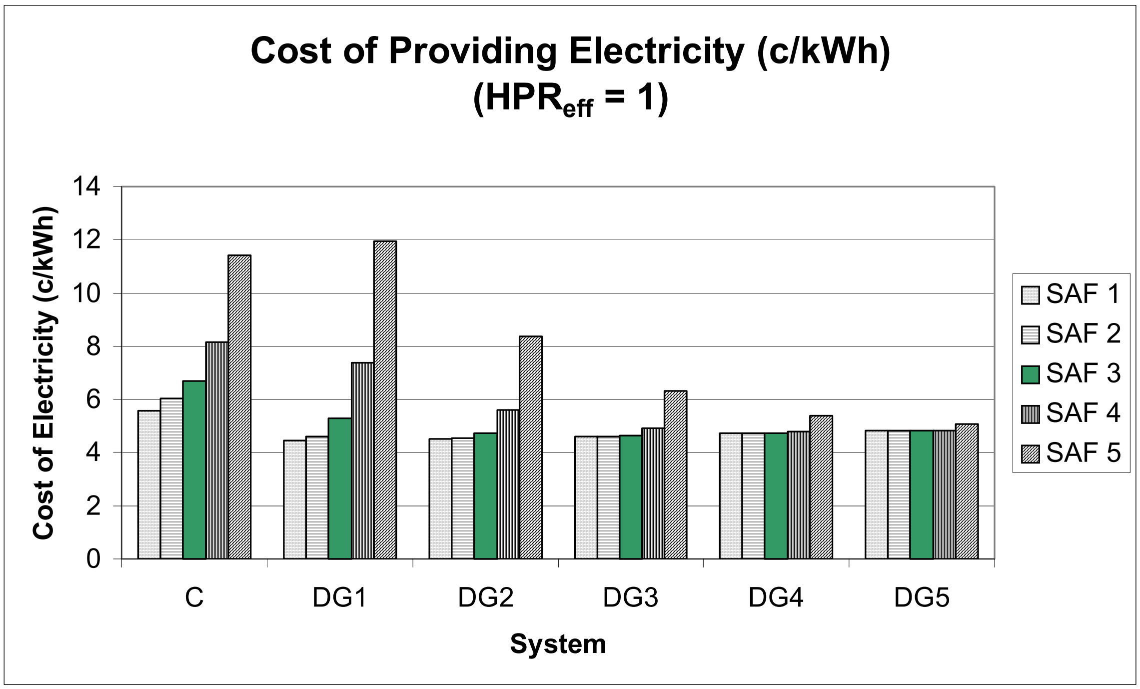


Table 13: DG System Cost of Electricity Savings (Over Centralized System)

	DG1	DG2	DG3	DG4	DG5
SAF 1	20%	19%	17%	15%	13%
SAF 2	24%	25%	23%	22%	20%
SAF 3	21%	29%	31%	29%	28%
SAF 4	10%	31%	40%	41%	41%
SAF 5	-5%	27%	45%	53%	56%

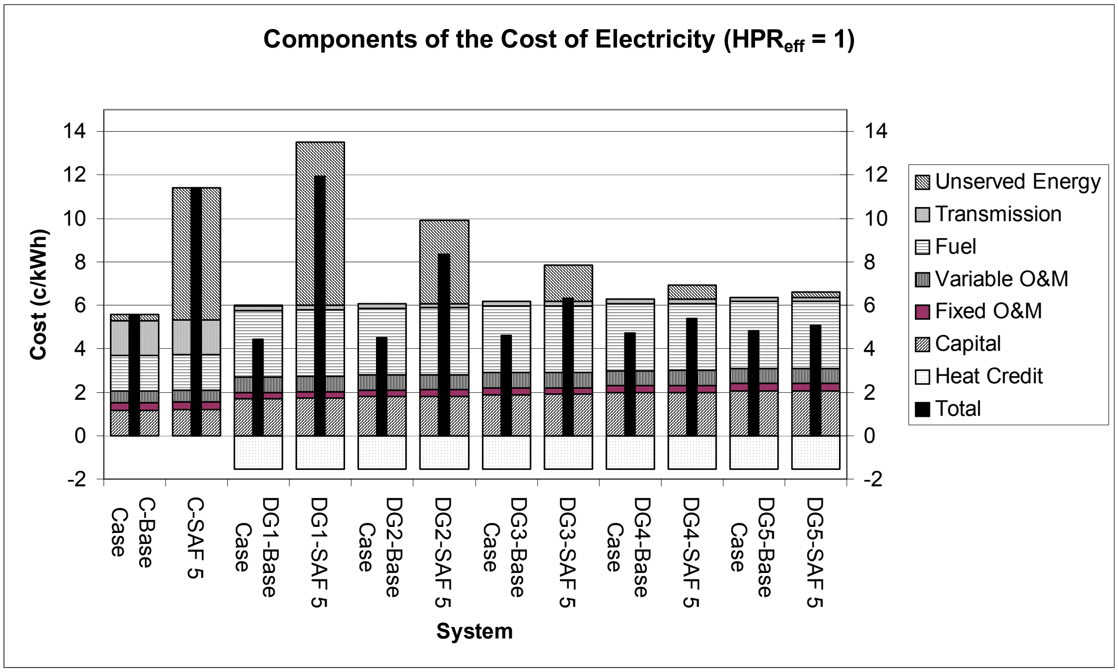
It is also instructive to examine the cost of electricity according to the different cost components that make up the total cost. This is shown in Figure 8 (for $HPR_{eff}=1$). In order to show the impact of stress, the relative cost components are shown for each system under normal operating conditions and under the highest stress level considered (SAF=5). The capital cost, fixed O&M, variable O&M and fuel components are added to a negative heat credit. The total is shown as a thin black bar. As can be seen, without the heat credit, all of the DG systems are more expensive than the centralized system (in the base case). With the heat credit, the DG systems under normal operating conditions are all less expensive than the centralized system.

Figure 8 also shows that the primary cost impact of decreased reliability is to increase the cost of unserved energy. In the case of the centralized system and DG1, the cost of unserved energy at least doubles the base case cost of electricity provided. On the other hand, DG5 has low cost of unserved energy and the cost of electricity changes very little as the stress level increases. This raises an important question as to the public versus private benefits of increased robustness. If the cost of unserved energy is not considered, then DG1 is the least cost option and would be attractive to a profit-maximizing (or cost-minimizing) private utility. However, DG1 has the highest cost of unserved energy under high stress, indicating that the social costs in terms of lost productivity would be much higher. This indicates a potential divergence in the public and private interests of moving to a distributed system in areas of conflict.[60] There may, therefore, be an overall societal

[60] It should be noted that planning margins and other indirect criteria have traditionally been used to achieve the necessary level of reliability. The alternative is to use reliability criteria based upon calculation similar to the work done here. The problem in this case would arise if the system were developed under no-stress conditions, but in an area with a possibility for future conflict. In this case, the reliability would be acceptable at the time of system development. How to include consideration of such issues is a matter for future work.

benefit to an incentive that would lead to the construction of a system like DG2–DG5 or to a method to makes reliability a more explicit dimension of the private power market.[61]

Figure 8: Electricity Cost Components



4.4 Results at Different Heat to Power Ratios

Internal combustion engines run as cogenerators of power and heat can produce up to 2.1 kWh of useful heat for every kWh of power produced. The ratio of heat utilized to power produced is called the Heat to Power Ratio (HPR). Three levels of cogeneration were considered in this analysis and they are represented by three different levels of DG Heat to Power Ratios from 0 to 2. If the DG-HPR is 0, then the DG units are run as electricity only units and none of the heat produced during electricity production is utilized. A DG-HPR of 1 implies that some of the useful heat produced by the DG units is utilized, but that there are limits to the amount of cogeneration potential that can be utilized. This

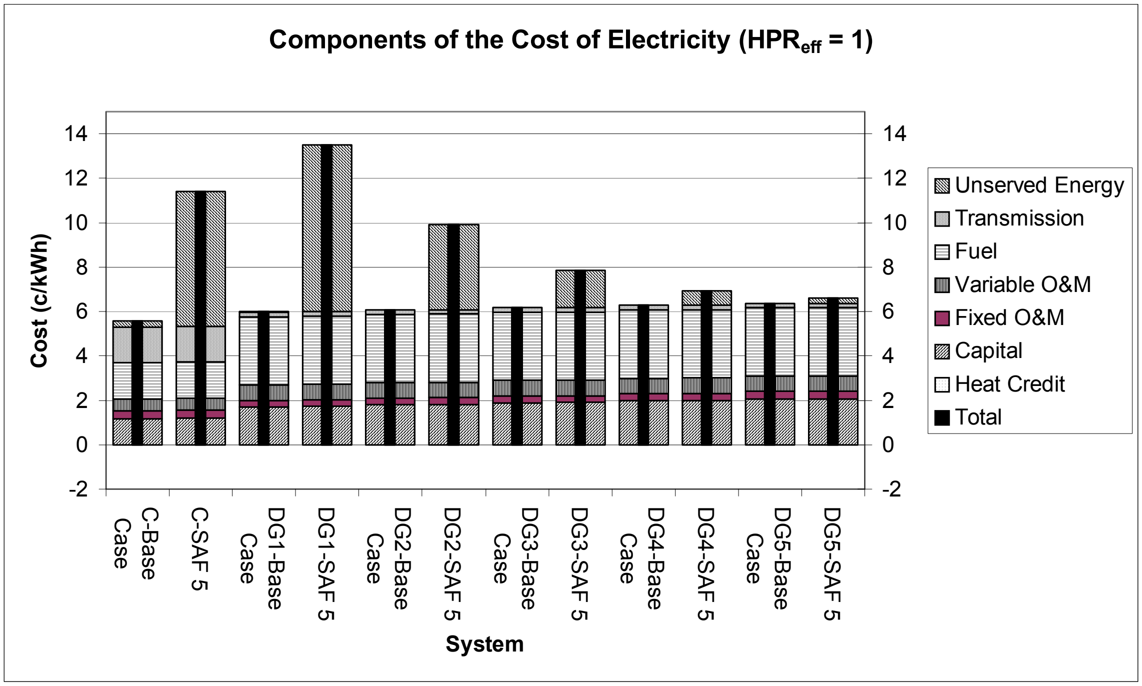
[61] For example, the cost of generating electricity using DG2 in the base case is 0.09 c/kWh higher than for DG1. However, the cost of unserved energy at SAF=5 is 3.58 c/kWh lower for DG2 as compared to DG1.

might occur for example if there is an imperfect match between the heat output of the IC engines and the heat demand. Finally, a DG-HPR of 2 implies that nearly all of the cogeneration potential of the DG system is utilized.

The cogeneration of both heat and power by the DG units results in cost savings due to the fact that boilers would otherwise be required to supply the heat produced by the DG units. This results in a heat credit for DG systems that depends upon the amount of heat generated by the DG units, the heat demand, and the match between the two. If the heat created by the DG units is greater than the heat demanded then excess heat must be dumped. If the heat demanded is greater than the heat production of the units and there is an aggregation of the load such that all of the usable heat from the DG units can actually be utilized, then the full Heat to Power ratio of 2.1 can be used. This study considers three effective heat to power ratios (HPR_{eff}). An HPR_{eff} of 0 means that there is no cogeneration and consequently no heat credit. An HPR_{eff} of 1 means either the heat demand is equal to the power demand or that there is an imperfect match between the heat and power loads and only half of the potentially usable heat is used. An HPR_{eff} of 2 means essentially all of the usable heat of the DG units is utilized (resulting in a maximum heat credit).

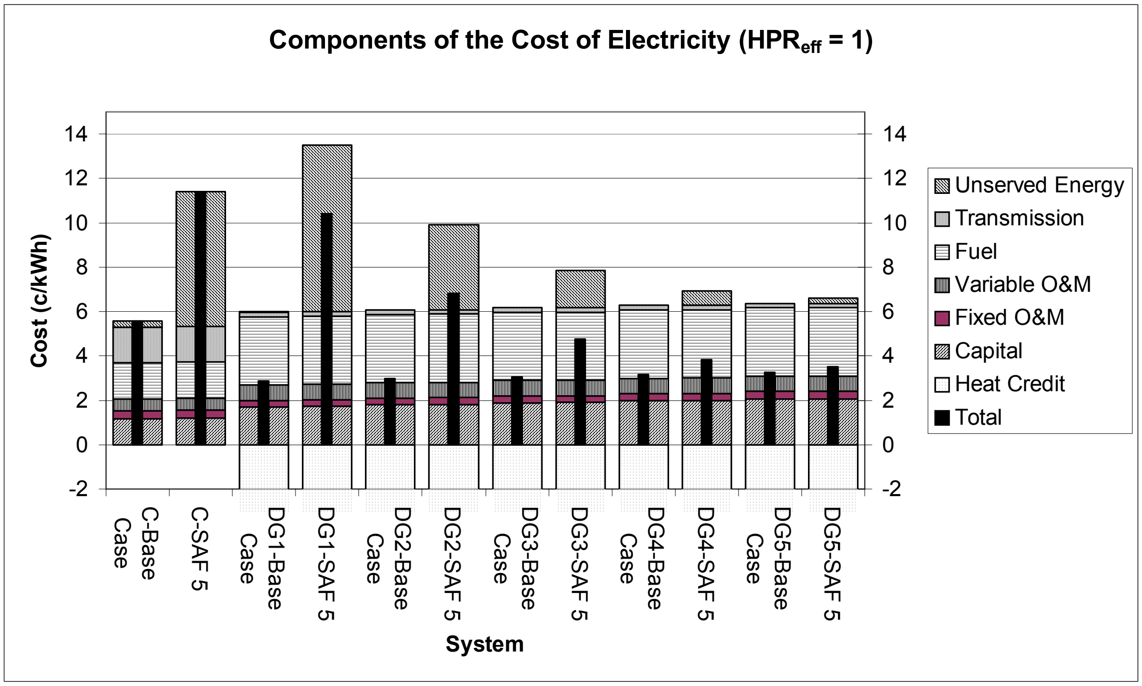
The results shown in the paper were for an HPR_{eff} of 1. Thus, the assumption was that not all of the heat from the DG units could be utilized. If none of the cogeneration potential of the DG systems is utilized ($HPR_{eff} = 0$) then the DG systems do not receive a heat credit. Figure 9 shows that in this case, the DG systems are more expensive in the base case, but that at higher stress levels some DG systems can still be less expensive because of the high cost of unserved energy in the centralized system.

Figure 9: Cost of Providing Electricity (No Cogeneration Case)



If all of the cogeneration potential of the DG units is utilized ($HPR_{eff} = 2$) then the heat credit will be near its maximum. As can be seen from Figure 10, the cost savings in this case are significant, both in the base case without stress and as the stress level increases.

Figure 10: Cost of Providing Electricity (Maximum Cogeneration Case)



4.5 Components of the Heat Credit

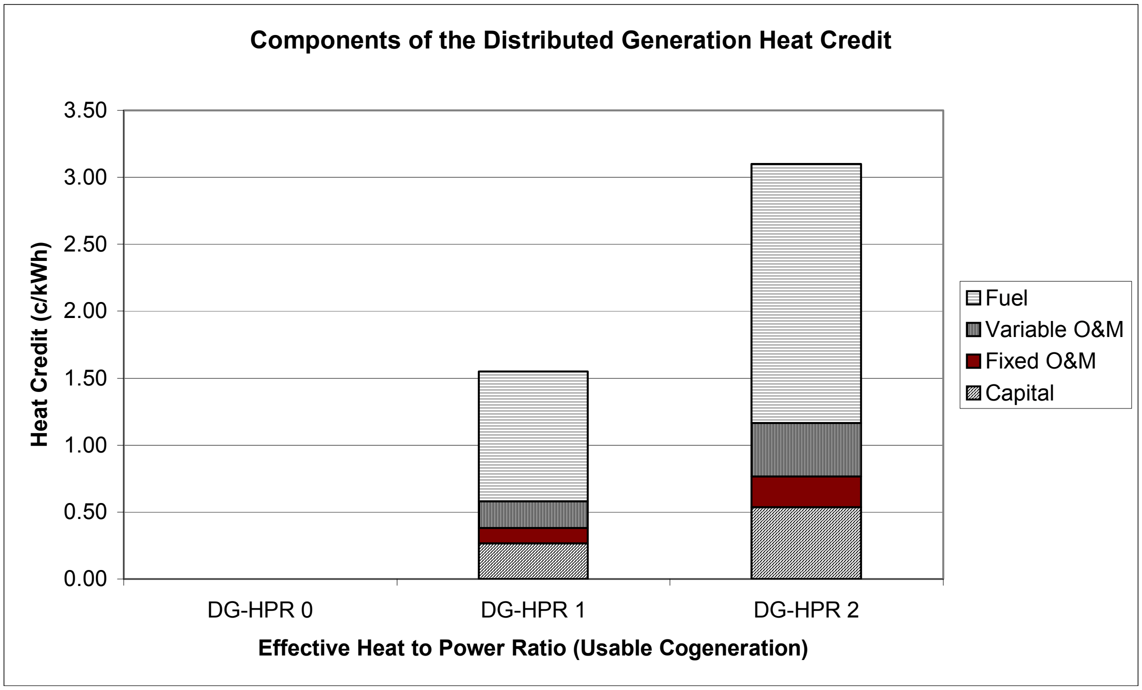
The heat credit itself, as it is the result of avoiding the purchase and operation of supplemental boilers, is composed of a capital cost, fixed operations and maintenance cost, variable O&M cost, and fuel cost. This can be seen in the equation for the heat credit.

$$HC_{DG}(c/kWh) = HPR_{eff}\left[\frac{CR_B * \mu_B * 100}{8760} + \frac{FOM_B * 100}{8760} + VOM_B + \frac{FC}{\eta_B}\right]$$

Figure 11 shows the contribution that each of these cost components make to the overall heat credit for the three different levels of cogeneration (HPR_{eff}). As the heat credit is proportional to the HPR_{eff}, the heat credit at HPR_{eff} of 2 is twice the heat credit at HPR_{eff}

of 1. Furthermore, this true for each component of the cost. As can be seen, the fuel credit is the largest component of the heat credit.

Figure 11: Breakdown of Components of the Heat Credit for Distributed Generation



4.6 Conclusions

The historical record of regional conflicts, and the rise of global terrorism lead us to seek to limit vulnerability to deliberate and systematic attacks when planning electric power systems. Length of outages, co-ordination of attack and scope of damage make conflict conditions very different than random equipment failure, extreme demand and severe weather events for electricity system planning. Natural gas fired distributed (co)generation holds the promise of improved reliability and maintenance of service under these conditions.

In order to determine the reliability advantages offered by DG, a Monte Carlo simulation model was developed to conduct generating capacity adequacy assessments. The model was used to determine the Loss of Energy Expectation (MWh/yr.) for both a modified standard test system (the IEEE-RTS) and for five distributed systems consisting of 500 kW natural gas fired internal combustion engines. In order to simulate the effects of conflict on the systems, the unavailability of each unit was increased and the reliability indices re-calculated. The model finds that with the exception of one distributed system (operating close to the margin), the distributed systems are less sensitive to this measure of systematic conflict. This supports our hypothesis that DG systems will have improved reliability over centralized systems when operated under adverse conditions.

Even without considering the benefits of robustness under conflict conditions, a DG system offers substantial costs savings. Based on current IC engine cogeneration, and with utilization of only half of the cogeneration capabilities of the IC engines, savings of up to 20% can be realized in the cost of electricity with a DG system. At the highest stress level considered, the advantages of DG system are even greater. The cost of electricity can be up to 56% lower with a DG system as compared to a centralized system. These savings increase if more cogeneration is used.

These findings suggest that distributed systems can provide electricity more reliably and at a cost savings both under normal operating conditions and under conditions of stress, such as in a conflict area. Future work will seek to extend the model to examine “mixed systems” that consist of both centralized and decentralized generation as well as the transition of systems over time. An improved typology of conflicts, conflict impacts, and conflict modeling options will also be developed. This will be used, in conjunction with work in the field of development economics, to improve the understanding of the financial and socio-economic impact of electricity system in conflict areas. Finally, political and institutional factors that could influence the viability of distributed generation's implementation in conflict areas will be addressed.

Chapter 5 Inclusion of Natural Gas Dependency[62]

As discussed above, systems with significant levels of distributed generation may have the potential to mitigate against stress, particularly in contexts with either minimal pre-existing infrastructure or heavily damaged infrastructure. In order to assess the relative robustness of centralized and distributed electric power systems, an engineering analysis using industry standard methods was developed that models survivability of hypothetical test-bed systems under stress. The basis of the analysis is modeling how reliably different systems meet a given load. Each system architecture will have characteristic failure modes and probabilities that will provide differing responses to adverse conditions.

5.1 Standard Model for Generating Capacity Adequacy

The model used is based on a Monte Carlo simulation of generating capacity adequacy and follows the standard framework established in reliability texts (Endrenyi 1978; Billinton and Li 1994). The model uses some concepts and features of the IEEE Reliability Test System (IEEE-RTS) but with simplifications and modifications made to suit the particular modeling requirements (Reliability Test System Task Force of the Application of Probability Methods Subcommittee of the IEEE 1996).

The key variable in the simulation is the availability of the individual generating units (the probability that a particular unit is operational when it is called upon to function). The state of each generator (j) is sampled in each run (k) by drawing a random number. If

[62] The author would like to thank Stephen Folga, Michael Mclamore, and William Buehring of Argonne National Laboratory and Daniel Fowler of Dominion for their assistance regarding the network topology and reliability of the natural gas system. Any errors are solely the responsibility of the author.

the random number is less than the unavailability of the unit, the generator is considered to be unavailable for that run. Otherwise, it is assumed to be available and its capacity is added to the total available capacity for that run. The total available capacity for the run is then compared to a load duration curve, which has been divided into 20 steps. The assumption in the base model is that the transmission and distribution system is perfect and available (this is modified below). For each step, the generating capacity available is compared to the demand (D) and the Demand Not Served (DNS) is determined for each step:

$$DNS_k = \max\left\{0, D - \sum_{j=1}^{m} G_{jk}\right\}, \qquad (1)$$

where G is the available capacity of the generator for that run.

Hence the model compares capacity and demand in each run for each load step and calculates the Loss of Energy Expectation (LOEE, MWh per year) after N runs. The LOEE is the primary reliability criterion used in this analysis for two reasons. First, it was the reliability index that was more sensitive to stress in preliminary modeling. Second, it is used in the Cost of Electricity calculations presented below. This calculation requires knowing the amount of energy produced and the amount of energy unserved (leading to economic losses).

5.1.1 Standard Model Modifications

This basic generating adequacy model was then modified in three ways. First, in addition to modeling central generation units, systems comprised of distributed generation units were also modeled (descriptions of the centralized and distributed systems are below).

Second, an electric power system topology was developed that allowed for the examination of simple transmission and distribution systems in order to determine what impact they may have on the reliability of the systems. The topologies developed for the centralized and distributed systems are very similar and each are described below. A natural gas supply network topology was also developed and is linked to the electricity system in order to determine the impact of fuel disruptions. The third change made to the basic model was to include the effects of conflict or stress on the system. There are a number of different possible stresses on an electric power system and a number of ways these stresses can be modeled. The methodology used here to incorporate stress is described below.

TABLE 14: GENERATING TECHNOLOGIES, CAPACITIES, UNAVAILABILITIES AND ASSIGNED POWER GROUP

Unit #[a]	Capacity	Unavailability[b]	Power Group	Technology	Old Technology
1-3	12	0.02	5	Oil/Steam	Oil/Steam
4-5	100	0.04	3	Oil/Steam	Oil/Steam
6-8	197	0.05	4	Oil/Steam	Oil/Steam
9	20	0.1	1	Oil/CT	Oil/CT
10	20	0.1	2	Oil/CT	Oil/CT
11-13	50	0.1	9	Oil/CT	Hydro
14-15	12	0.065	5	CCGT	Oil/Steam
16	20	0.065	1	CCGT	Oil/CT
17	20	0.065	2	CCGT	Oil/CT
18-20	50	0.021	9	CCGT	Hydro
21	76	0.021	1	CCGT	Coal/Steam
22	100	0.058	3	CCGT	Oil/Steam
23	155	0.058	5	CCGT	Coal/Steam
24	76	0.02	1	Coal/Steam	Coal/Steam
25-26	76	0.02	2	Coal/Steam	Coal/Steam
27	155	0.04	6	Coal/Steam	Coal/Steam
28-29	155	0.04	10	Coal/Steam	Coal/Steam
30	350	0.08	10	Coal/Steam	Coal/Steam
31	400	0.12	7	Nuclear	Nuclear
32	400	0.12	8	Nuclear	Nuclear

[a] Units are shown in reverse merit order for dispatch. Nuclear units are dispatched first and oil/steam units last.
[b] Availabilities from (Reliability Test System Task Force of the Application of Probability Methods Subcommittee of the IEEE 1996) for non-CCGT, for CCGT > 100MW and (1998) for <100MW.

5.1.1.1 Systems Modeled

The reliability model was used to evaluate one centralized system and five different distributed systems. All six systems are required to serve the same load, which is provided in a standard test system called the IEEE Reliability Test System (IEEE-RTS) (Gas Research Institute 1999). The load profile of the IEEE-RTS has a peak demand of 2850 MW and the load duration curve was divided into twenty steps for computational efficiency. The center point of the first step of the curve is 2822 MW and this is the peak load used in calculations for the model.

5.1.1.1.1 Centralized System

The centralized electricity system modeled is based on the IEEE-RTS. The RTS includes 32 generating units ranging in size from 12 MW to 400 MW. The total generating capacity of the centralized system is 3405 MW (for a capacity reserve of approximately 20%). The IEEE-RTS generating units are a mix of technologies including coal-fired steam units, hydropower units and oil-fired units.

In order to compare both the centralized and distributed system across a similar class of technologies, the RTS generating technologies were changed so that 16% of the capacity was combined cycle gas turbines (approximately reflecting current U.S. conditions). The original sizes (in MW) of the RTS units were maintained (that is, if the changed unit was a 50 MW hydro plant, the new unit is a 50 MW gas turbine). However, both the reliability characteristics (in terms of the availability of individual units) and their economic characteristics (capital and O&M costs) of the modified units were changed to reflect numbers characteristic of combined cycle natural gas turbines. The reliability and cost characteristics of the different technologies can be seen in Table 14 and Table 15 as well as their placement within the system topology described below. The hydro units were completely eliminated and replaced by a combination of gas turbines and oil turbines. This was done due to the lack of supporting data on capital and other costs of hydro plants, making the economic analysis difficult.

Centralized System Topology: In the centralized system, all of the power must be transmitted to an area grid and then delivered to the load via a radial distribution system. A simple hierarchical topology was developed to assess the relative performance of centralized and distributed systems (Figure 12). This topology shares the following feature with the IEEE-RTS: the generating units are apportioned among ten power groups (PG), matching the ten generation buses in the IEEE-RTS.

Each power group is then connected to the load center via a transmission line (T1–T10). The transmission lines each have a probability of failure and are sampled each run. If the transmission line has failed (the line is out at point A in for that group), then none of the electricity generated by that power group is available to meet demand. It should be noted that in both the centralized case and the DG cases, the physical line losses that occur along the transmission and distribution lines have been ignored.

The load center itself is subdivided into 273 independent local load blocks, each with a peak demand of 10.3 MW. Each of the 273 local load blocks is connected to the larger area grid through a radial distribution line (D1–D273). The distribution line also has a probability of failure and is sampled in each run. If the distribution line has failed (the line is out at point C), then the local load block is unable to receive power. On the other hand, the area power grid is assumed to be a redundant network, with the ability to sectionalize and reroute power. Therefore, the area grid does not have a failure probability and is assumed to work perfectly (the area grid cannot be cut at point B). Therefore, each local power load of 10.3MW is considered to be independent of the others, and failure of one distribution line does not impact delivery of power to any of the other load blocks.

5.1.1.1.2 Distributed System

A DG system consisting of interconnected distributed micro-grids was developed to compare to the centralized system. The technology chosen as representative of DG was 500 kW internal combustion engines, with an availability of 0.953. The engines are fueled with natural gas and have cogeneration capabilities. It is assumed that half of the waste heat produced by the engines is used for useful purposes. The cogeneration of heat and power by the distributed units has two effects due to the avoidance of installation and operation of boilers that would otherwise be required to provide that heat. First, this reduces the additional natural gas network requirements necessary to provide gas to the distributed generation units. Second, the distributed generation system receives a credit in the cost of electricity due to avoided boiler costs. This heat credit is factored into the levelized cost of electricity calculated for the different systems.

Five distributed generation scenarios were chosen for analysis. The number of generating units in the DG systems is set such that the capacity reserves are 1.6, 6.4, 11.2, 16, and 20.9%. The number of units in the system ranges from 5733 (2866.5 MW of generation to 6825 (3412.5 MW). The number of units and reserve margins are set by the need to have an integer number of generation units and micro-grids.

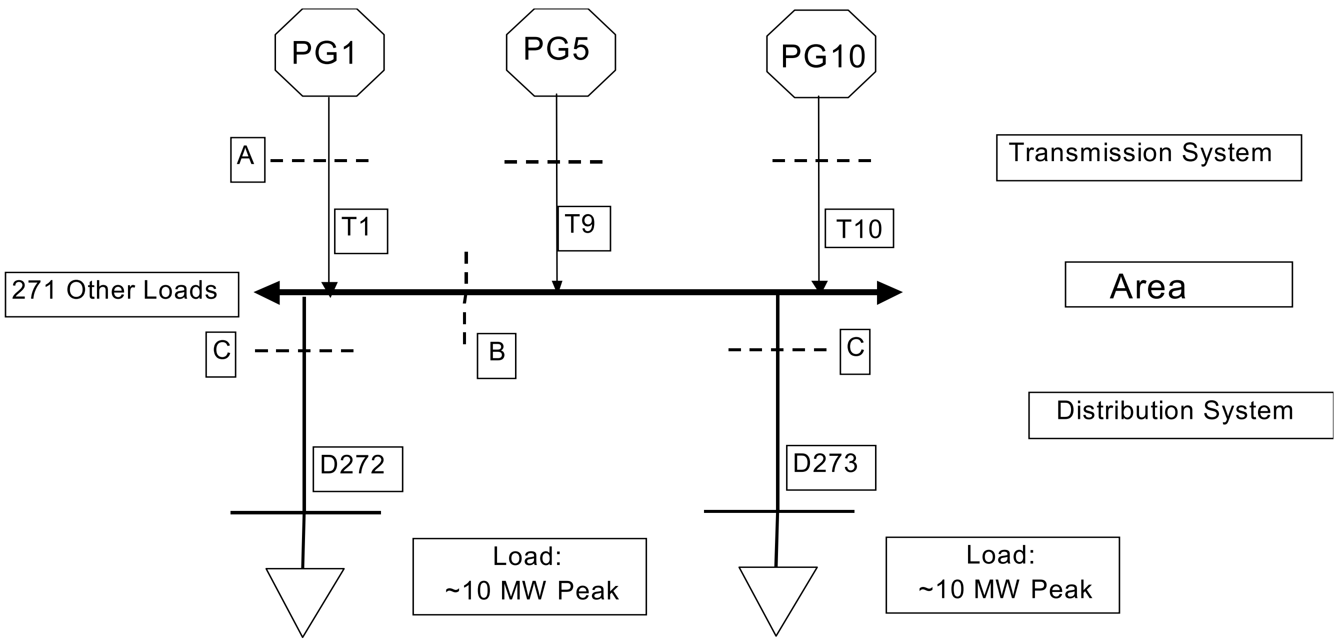


Figure 12: Centralized System Topology

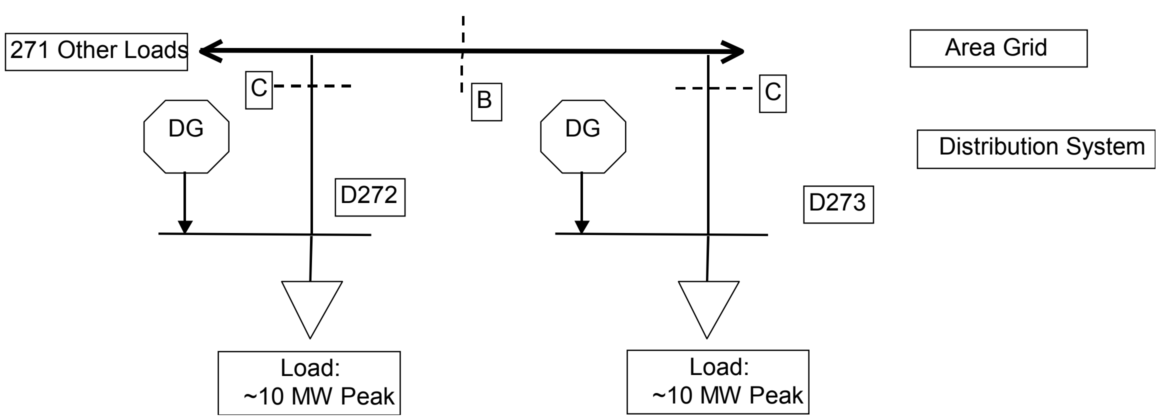


Figure 13: Distributed Generation System Topology

TABLE 15: TECHNOLOGY COST CHARACTERISTICS

Description	Size (MW)	Capital ($/kWe)	Fixed OM ($/kWe)	Var. OM (c/kWh)	Fuel Price (c/kWh)	Lifetime (years)	Electricity trans (c/kWh)	Fuel Trans (c/kWh)	Efficiency (%)
CCGT	12-155	536	12.26	0.204	0.891	30	1.606	0.04	55
Oil Turbine	20-50	409	10.22	0.409	1.48	30	1.606	0.13	23
Oil Steam	12-197	409	10.22	0.409	1.48	30	1.606	0.13	20
Coal	76-350	1154	24.52	0.307	0.4	30	1.606	0.08	38
Nuclear	400	2117	58.48	0.043	0.04	30	1.606	-	30
DG	0.5	700	15	0.7	0.891	15	0.203	0.44	29
Boiler	0.5	200	10	0.2	0.891	20		0.44	92

Sources: (Reliability Test System Task Force of the Application of Probability Methods Subcommittee of the IEEE 1996), (Energy Information Administration 2003) for distributed generation, boiler and transmission costs, (Strachan, Zerriffi et al. 2003).

Distributed System Topology: As with the centralized system, the distributed system load is also divided into 273 load blocks of 10.3MW, connected to an area grid by radial distribution lines. However, unlike the centralized system, in the DG system these blocks are individual local power systems with local power generation. The total generating capacity is divided evenly into each of the 273 local power systems (see Figure 13). Thus, if the connection to the area grid (point C) is out, the local generators can still be used to meet local load. Power exchanges can also occur between the distributed micro-grids as long as the connection to the area grid is operational for the run. Local systems with a functional link to the area grid can either send their surplus to the area grid or use available surplus as necessary. The area grid is assumed to have redundancy and is not impacted (i.e. no faults can occur at point B).

TABLE 16: ELECTRICITY AND NATURAL GAS FAILURE MODES

Failure Mode	Description
Generator	A generator (either centralized or distributed) fails due to attack or other cause
Electricity Transmission Line	A transmission line joining a centralized power group to the load area fails
Electricity Micro-grid Connection	The connection between a micro-grid or load center and the area grid fails
Natural Gas Transmission	A natural gas transmission line or large scale supply shortage that impacts both centralized and distributed systems
Natural Gas Distribution	A failure in the NG distribution system that affects only the local micro-grid

5.1.1.1.3 Natural Gas Network

Natural gas systems consist of production facilities, transmission pipelines, storage areas, city-gates and sub-transmission mains, distribution vaults and distribution pipes. For this model, the natural gas network has been decomposed into two parts: (a) transmission pipelines (here assumed to be 200 miles long) from storage areas to either natural gas fired central generation units or to the city gate and (b) sub-transmission mains from the city gate to distribution vaults that are radial and non-redundant.

The gas network for both the centralized and distributed systems consists of seven storage areas. In the case of the centralized system these storage areas feed through transmission pipelines to the five power groups that contain natural gas generation units. In the case of the distributed system the seven storage areas feed to 13 city-gates. Each pipeline from the storage areas connects to four city-gates and two pipelines supply each city-gate. Each city-gate has three sub-transmission mains that are 10 miles long and are radial and non-redundant. There are seven micro-grids that are fed by each sub-transmission main. The size of the network was established by using data from the Energy Information Administration on natural gas and electricity consumption for the United States and for the Northeast and the topology was based on discussions with industry experts. Each natural gas system is unique and this topology was developed to approximate an "average" topology.

Long-distance pipelines and the distribution level have not been modeled. The storage areas are assumed to be sufficient to handle a disruption along the long-distance transmission pipelines from the source for anywhere from days to weeks. At the distribution level, the network topology of distribution systems is nearly a perfect mesh with the ability to use alternate paths to reach the load. Therefore, the distribution network is assumed to not contribute to reliability issues regarding delivery of natural gas to distributed generators.

Natural gas supply disruptions are assumed to occur at two possible locations. First, the disruption can occur in the transmission systems (with an unavailability of $9.5*10^{-5}$). The second failure mode is at the sub-transmission main level (with an unavailability of $9.5*10^{-6}$) and impacts the group of micro-grids on that main (Johnson and Keith (Submitted October 2002)). It should be noted that, by only considering natural gas disturbances, and by comparing failure modes on the basis of their impact on the electricity reliability, the possibility of natural gas storage is subsumed under the failure mode probability. That is, given a low impact disturbance on the natural gas system, it is possible that the impact was low either because the attack was small or ineffectual or because the attack was larger and successful, but that there was sufficient storage to mitigate.

5.1.1.2 Stress

Five failure modes exist in the model (failure of generators, failure of electricity transmission, failure of the link between the micro-grid/load and the area grid, failure of natural gas transmission, failure of natural gas sub-transmission). (See Table 16) The fundamental parameter that determines the reliability of the system is the availability of the individual components. In this model stress is added to the system by changing the availability of network components. In order to determine the sensitivity of the electricity supply reliability index (the Loss of Energy Expectation) to the five failure modes, each of the failure modes is subject to stress while keeping the other four constant at their nominal level.

The model is initially run with all system components (generators, electricity and natural gas transmission and distribution lines) set to their nominal level. A stress adjustment factor (SAF) is then applied such that the unavailability of components in a given failure mode is multiplied by the SAF to determine the new unavailability and the model is re-run. For example, if the unavailability of the DG units is 0.047, then applying an SAF of 2 would mean that the unavailability of all DG units for that model run would 0.094 whereas the unavailability of the electricity distribution system and the natural gas system would remain at their nominal levels.

The stress adjustment factors were set such that the unavailability of each failure mode was varied between its minimum nominal value and the maximum value of 1 in 20 steps. However, evenly spaced steps would not provide the necessary resolution, particularly for failure modes with very low nominal unavailabilities. Therefore, in order to adequately explore the unavailability space between the nominal level and 1, the adjustment factors for each failure mode are determined using a logistic curve. The parameters of the curve are set according to the nominal values for that failure mode and result in a set of adjustment factors that are closely spaced together at low stress levels and at high stress levels. The logistic function used had the following form and parameters:

$$
\begin{aligned}
&U(AF) = \frac{C}{1 + A\exp(-B(AF))} \\
&AF = \text{Adjustment Factor (1 - 20)} \\
&U = \mathit{Unavailability} \\
&C = 1 \\
&A = \frac{1}{U_O} + 1 \\
&U_O - \text{nominal unavailability at } AF = 1 \\
&B = \frac{\ln(A)}{\mathit{halfstep}} \\
&\text{halfstep - the number of steps required for } U = 0.5{*}C
\end{aligned} \qquad (2)
$$

It should be noted that the generation failure mode for the centralized system required creating a composite unavailability. Unlike the DG systems and unlike the other failure modes, there is not a single unavailability for the centralized generators. Therefore, the capacity weighted average unavailability of the different generators was used to calculate adjustment factors, which were then applied to the actual unavailabilities of the generation units when the model was run. This same composite unavailability is used to graphically display the results of stressing the generators in the centralized system.

The impact of stress on reliability of the electric power system can subsequently be translated into economic terms. There are a number of different methods used for determining the value of reliability or the potential economic losses due to loss of service (Folga 2003). The calculation of the cost of unserved energy used in this study is based on a consumption weighted sum of the impact of electricity losses to different sectors of the economy. Based on electricity consumption per dollar of output in the United States (Bureau of Economic Analysis; Eto, Koomey et al.), the loss of a kWh of electricity (based on the results of the reliability model) to a given sector can be translated into a dollar amount (in this case \$3.83/kWh unserved). This economic loss due unserved energy can be combined with the levelized cost of energy generation and transmission in such a way that the different systems can be compared using one metric. While this loss would not be borne directly by the electricity generating entity, adding these economic losses provides some measure of the social welfare impacts of reliability degradation. The advantage of this method is that it can quickly be applied to other contexts as long as data on economic output and electricity consumption are available.

Given the sensitivity of the system reliability index to individual failure modes it is then possible to combine failure modes according to impact of stress. First, values of LOEE can be set that correspond to low, medium, and high impacts of stress. The corresponding failure probability for any of the failure modes can then be found based on the sensitivity of that particular system to that failure mode. The failure modes can then be combined according to expected impacts based upon the stress regimes defined above. For example, if it is possible to state that a conflict will likely result in a high impact on the electricity distribution system but a low impact on the natural gas delivery system, the model could be run with the $D_{electric}$ failure probability set to high according to the previous sensitivity curve and the D_{NG} set to low according to the same curve. Obviously, higher order effects would now come into play, as two failure modes, each with impacts different than their nominal value, are both factored into the reliability analysis.

5.2 Results

Overall reliability model results are shown in Figure 14 for the centralized system, Figure 15 for the distributed systems with 1.6% reserve and Figure 16 for the distributed system with 11.2% capacity reserves. These two distributed systems were chosen to highlight the reliability of DG systems with a minimal capacity margin of 1.6% (DG-1.6) and with about one half the reserve capacity of centralized systems in DG-11.2. The figures show the change in Loss of Energy Expectation (LOEE) as a function of the Stress Adjustment Factor (SAF) applied to a given failure mode.

As can be seen from the figures, at a stress adjustment factor of 1 (normal operating conditions) the DG-1.6 system is significantly more reliable that central generation and DG-11.2 is orders of magnitude more effective in provision of reliable service. Furthermore, when different elements of the electricity supply system are stressed, the DG architectures continue to hold greater promise of relative robustness. Here we present the impact of escalating stress on different elements of the system architecture. Considering the centralized case on its own, the system is significantly more sensitive to stresses on the generation system than to stresses on the natural gas or electricity transmission and distribution systems. Disruptions to the electricity distribution system result in a linear increase in LOEE due to the network topology. Stresses on the electricity transmission system begin to have an effect around SAFs between 10 and 100 whereas stresses on the natural gas transmission system do not impact the system until the SAFs reach into the thousands.

The distributed systems also exhibit greater sensitivity to stresses on the generation system, though the reliability of both systems is higher than the centralized case (this is discussed further below). The impacts of stresses on electricity distribution and on gas transmission and distribution show significant differences between the two distributed cases and between the distributed and centralized architectures. The distributed systems are both less sensitive to disruptions in the electricity distribution system. In the DG-1.6 case, electricity system disruptions do not have an impact until SAFs reach 100 or more. This is due to the low reserve capacity of the generation system, which makes that failure mode the incapacitating failure mode at lower stress adjustment factors (this system also is not able to share much power since there can only be a small surplus). The DG-11.2 case does exhibit the same linear relationship as the centralized case between SAF and LOEE for electricity distribution. However, the distributed nature of the generation reduces the magnitude of the LOEE for distribution failures.

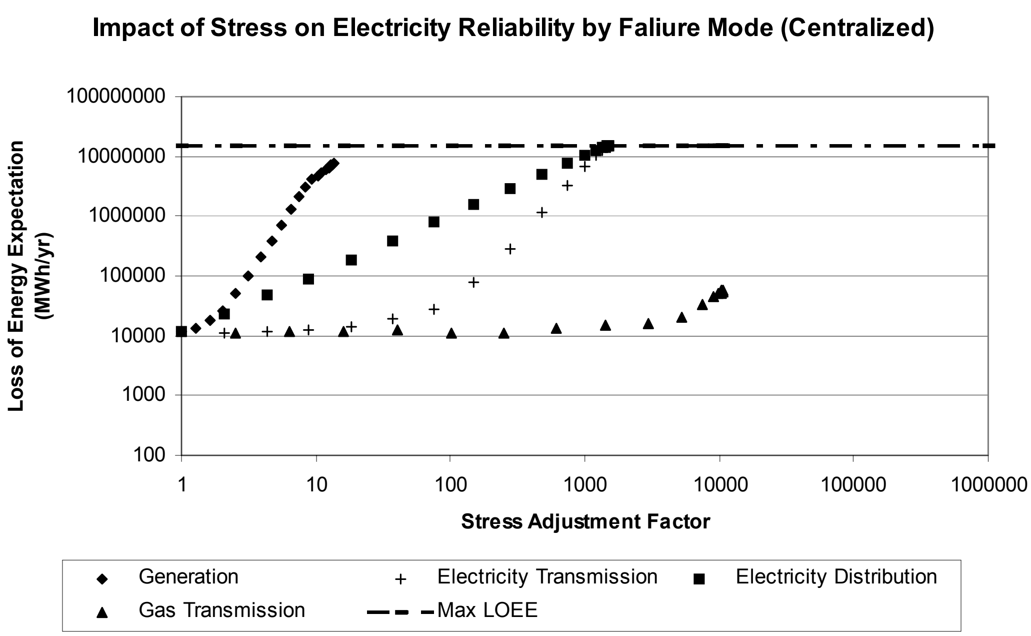


Figure 14: Impact of Stress on Electricity Reliability by Failure Modes for the Centralized System

Note: The curve for Generation does not reach the maximum LOEE only because the stress adjustment factors applied stopped short of reaching the level at which the generation system would no longer supply any electricity (as with the other systems).

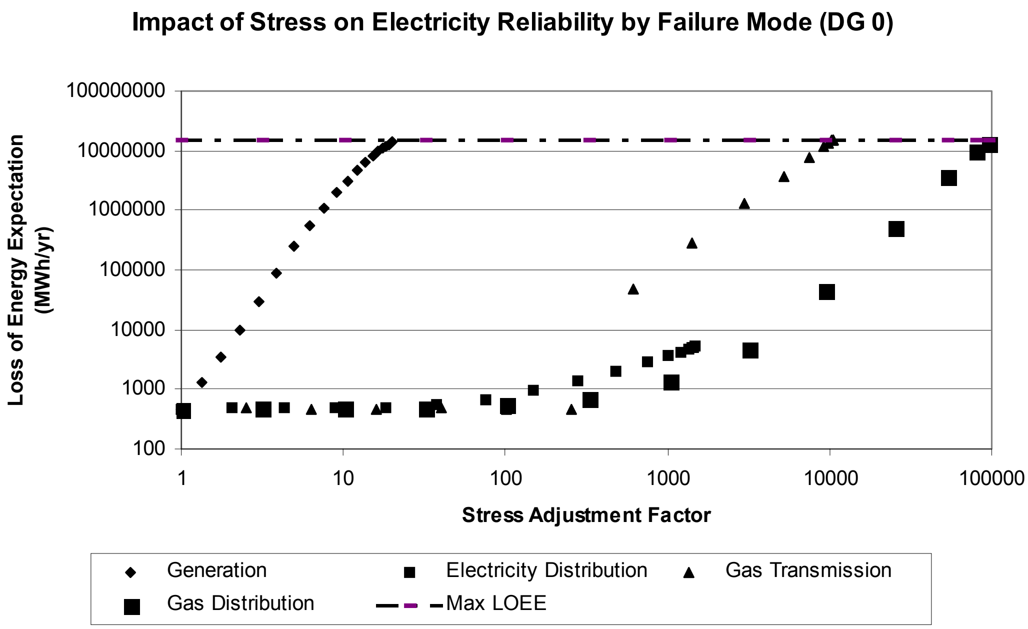


Figure 15: Impact of Stress on Reliability for a Distributed System with no Capacity Reserve

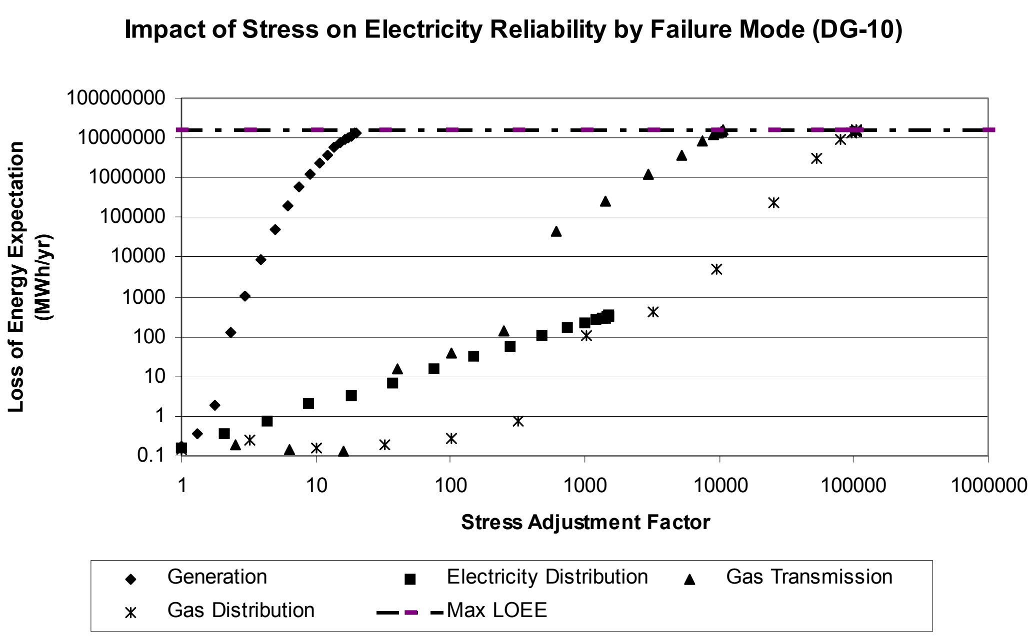


Figure 16: Impact of Stress on Reliability for a Distributed System with Capacity Reserve

Note: The reader will notice a slight increase and then decrease in the LOEE for low stress adjustment factors applied to the gas transmission and distribution systems. This non-monotonicity is due to the fact that the results of the modeling method are sensitive to random fluctuations at extremely low levels of LOEE, as exhibited here.

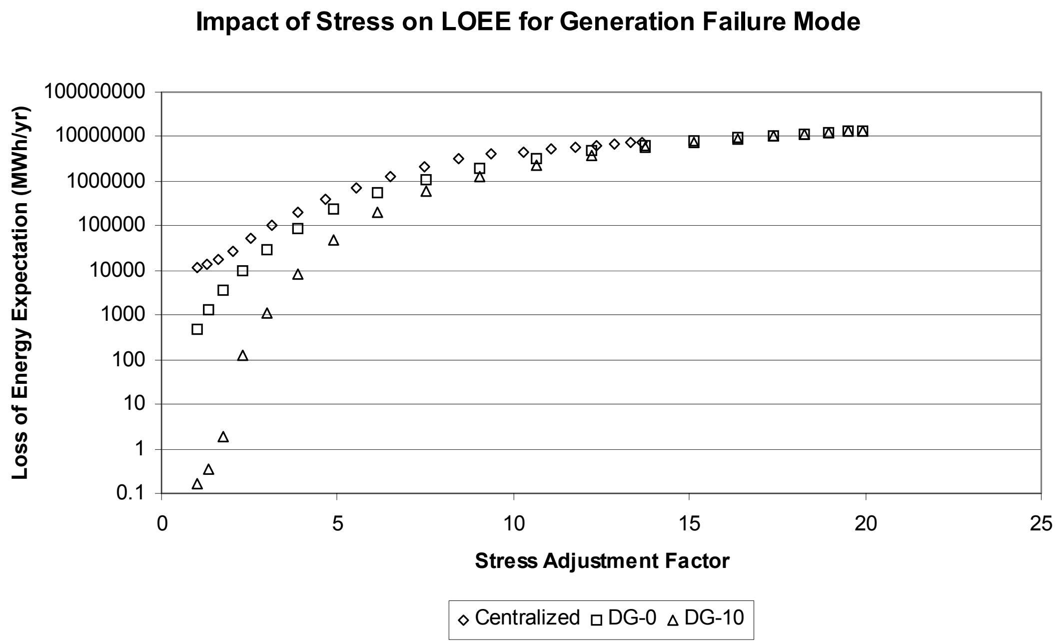


Figure 17: Impact of Stress on Reliability for the Generation Failure Mode

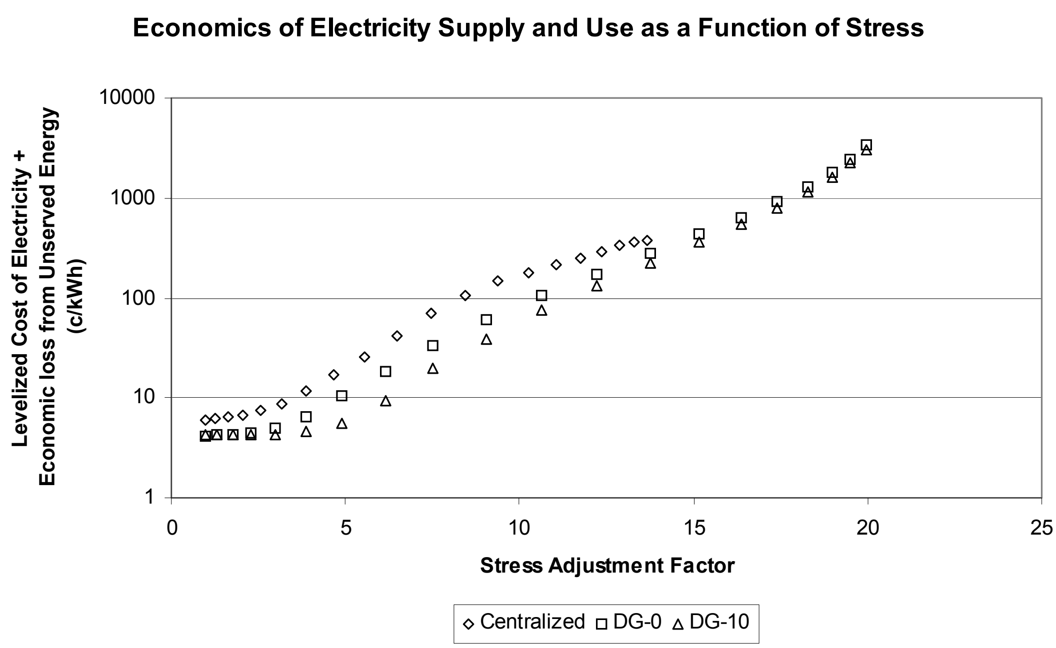


Figure 18: Cost of Electricity as a Function of Stress

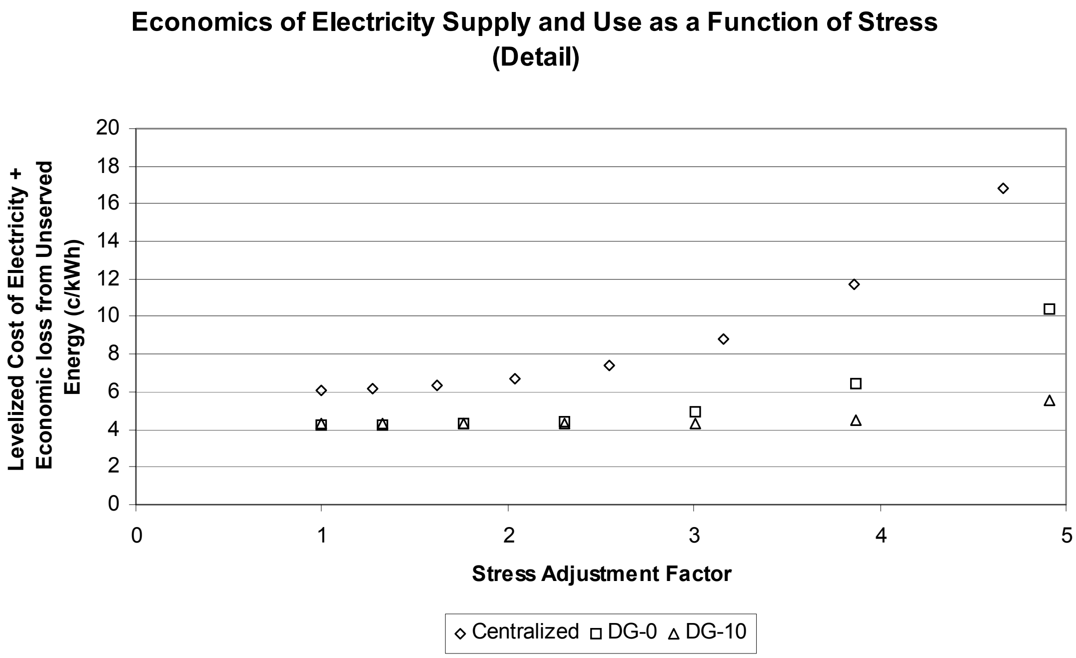


Figure 19: Cost of Electricity as a Function of Stress (Detail)

As with electricity distribution, the DG-1.6 system exhibits relatively low sensitivity to stress on the gas distribution system. Again, this is due to the fact that the generation system is the incapacitating failure mode due to low reserve margins. The DG-11.2 case begins to be affected by failures in gas distribution at SAFs of around 100. However, it should be noted that the SAF must reach approximately 10 000 before the LOEE of the DG-11.2 system equals the LOEE of the *unstressed* centralized system.

The results for the gas transmission do show a dependence of the distributed system on natural gas as compared to the centralized system. For both the distributed systems, the LOEE becomes higher than in the centralized case at a SAF of around 500. This is around the point that the unavailability of the gas transmission lines is comparable to that of power generation facilities.

As noted in Chapter 1 , there are fundamental differences between gas and electricity transmission and distribution systems. One of these differences is the relative effort required to disrupt each system. The electricity transmission and distribution system is a prominent and visible feature of our landscape while gas networks are more often buried underground. While we have presented the results on a common scale of increasing stress, inflicting equal stress on these systems requires different levels of effort. Hence from a security standpoint, there should perhaps be a further modulation of the SAF reflecting the differential effort required to bring about that level of stress on each component of the system architectures presented here. For example, the war in Bosnia-Herzegovina of the mid-nineties had a much greater impact on the electricity transmission system than it did on the natural gas system. There was limited damage to the largely underground natural gas transmission and distribution network, and many of the post-war problems were due instead to lack of maintenance and a sharp increase of illegal and makeshift connections. However, this is also based upon the fact that the Bosnian natural gas supply was underground. A system that has more aboveground transmission of natural gas (e.g. Colombia) could be expected to have more severe supply problems.

Figure 17 shows the impact of stress on the generation system for the centralized and two distributed systems. As can be seen, the centralized system has the highest LOEE of the three at low stress adjustment factors. However, as the stress adjustment factor increases, the centralized system and the DG-1.6 system begin to have equivalent levels of LOEE. This is due to the fact that there is almost no reserve margin (1.6%) in this system. At low stress the occasional loss of small generators has a low impact. However, as the stress increases and more generators are simultaneously affected, there is insufficient reserve margin to maintain supply. By contrast, the DG-11.2, with roughly one half the capacity margin of the centralized system, has significantly lower LOEE across all stress adjustment factors.

As discussed above, it is possible to convert loss of energy into an economic loss and compare the systems using a single financial metric by combining the levelized cost of electricity with the economic impacts of unserved energy. Figure 18 shows an overall economic comparison (including generation costs and economic impacts of unserved energy) between the three systems for stresses on the generation system whereas Figure 12 shows the same data, but limited to lower levels of stress. As can be seen, even under normal operating conditions the distributed systems have superior economic characteristics. This confirms the results in (U.S. Department of Commerce 1997). At low stress levels, the supply side costs of generation, fuel and transmission dominate the economics. It is the heat credit and the capacity savings (the low reserve margins) of the distributed generation systems that result in cost savings.

However, as soon as the LOEE is over one percent of the overall energy demand, the economic losses due to unserved energy begin to equal and then to dominate the supply side economics. Therefore, as stress levels increase, the comparative economic benefits of the distributed systems increases due to their superior reliability performance.

5.3 Conclusions

The need for improved electric power systems planning under stress conditions and the results presented herein indicate that system architectures with significant distributed generation could result in improvements in system reliability and possibly cost (dependent upon heat utilization). However, there are a number of issues that merit further inquiry. Future work seeks to determine the impact of heterogeneity of local loads on the desired level of decentralization of the system and the impact of decentralization on the network requirements. In particular, we are interested in how the non-coincidence of load between different types of load profiles impacts the need for power sharing between the microgrids and what impact will this have on the need for higher voltage transmission capacity and their potential role in security of supply in a DG architecture? This work will be based on utilizing the full IEEE-RTS network topology. Research is also underway to better understand the energy and electricity planning process in high stress cases such as conflict and post-conflict situations.

Chapter 6 Mixed System Topologies

6.1 Introduction

Previous model runs compared power systems that were either completely composed of centralized generating units or distributed generating units. It is most likely, however, that if distributed generation begins to play a significant role in electricity generation, it will be as part of a mix of centralized and distributed generation technologies. Even if it is determined that a system composed entirely of distributed generation is feasible and desirable, it is certain that there will be a period of transition during which both scales of technology will co-exist. It is therefore of interest to compare various configurations of a mixed centralized-distributed system to determine how they compare to the centralized case and the pure distributed cases on both reliability and cost.

This chapter will first outline the method used for setting up the scenarios of mixed centralized and distributed generation. This will be followed by a comparison of the investment costs necessary to deploy the various mixed system topologies to be analyzed. The next section will describe the results of running the reliability and economic model under normal operating conditions (including the impact of the heat credit on system economics). Finally, the chapter will conclude with results from running the model under stress conditions.

6.2 Methodology

The baseline centralized scenario analyzed here continues to be based upon the IEEE RTS with a simplified hierarchical network topology. The distributed cases replace all of the generation in the centralized case with 500 kW internal combustion engines fueled with natural gas. Two scenarios were analyzed, one with nearly zero percent capacity reserve and one with approximately 10% capacity reserve.

For the mixed systems, four fundamental scenarios were considered in which natural gas units, small centralized generating units, coal fired units and large generating units were replaced. The scenarios described below are not meant to be projections. They were designed to help explore how different system characteristics such as unit sizes, fuel choices, DG penetration, and reserve margins impact system reliability. However, they might be similar to future systems that result from policies and priorities currently in place.

- Replacement of all centralized natural gas fired units. This represents a scenario in which natural gas is the fuel of choice for current and future installations but that installations are of DG units rather than centralized natural gas units. This eliminates the plants that are in the middle of the dispatch order, leaving expensive oil and inexpensive coal/nuclear plants.
- Replacement of all of the centralized units less than (or equal to) 50 MW in capacity. This represents a scenario in which smaller (peaking) units are retired or not constructed in favor of distributed generation. This also eliminates many of the generators that are at the bottom of the dispatch order due to their higher variable costs.

- Replacement of all centralized coal fired generators. This represents a scenario in which environmental pressures might result in the replacement of coal with more natural gas generation in the form of DG. This eliminates the generators that are at the top of the dispatch merit order (with the exception of the nuclear facilities).
- Replacement of all of the centralized units greater than (or equal to) 197 MW. This represents a scenario in which large units are considered unfavorably (e.g. for siting reasons or to minimize long-distance transmission) and DG is installed instead. This eliminates many of the generators that are the top of the dispatch order (e.g. nuclear, large coal and large combined-cycle gas turbines).

It is impossible to determine a priori which of these scenarios might arise as the result of evolution of large existing centralized systems or the development of systems in areas of minimal infrastructure. Whether priorities are placed on economic factors or environmental factors will play a role. The ability to take advantage of cogeneration opportunities will also be important. Priorities on environmental emissions could lead to a system with fewer coal fired power plants. However, if cogeneration options are low, then installation of DG rather than expensive small centralized facilities may be more likely. If siting of either large generation or transmission is an issue then DG may be used in a way to defer or avoid new investments in those areas.

Differences may also occur depending on the structure of the industry. In state-controlled systems (as exists in many parts of the world), the policies of the national government and its electricity utility will determine the nature of the system. On the other hand in systems with competitive generation or private parties, then cost becomes an even more important factor as does modularity and ease of siting (in order to reduce regulatory and public affairs burdens). The installation of DG and the evolution of the power system in a privatized and competitive setting will have less central coordination and will be the aggregate of individual decisions that are made. The resolution of institutional and regulatory issues that prevent DG options from being used to their full potential will also play a role in shaping the future mix of any energy system.

The prior modeling efforts described in Chapter 3 and Chapter 5 demonstrated that replacing centralized generation with distributed generation can result in significant capacity savings for the same (or even better) reliability performance. Therefore, for each of the four fundamental replacement scenarios analyzed, it did not seem likely that the entire replaced capacity (e.g. of natural gas units) would be replaced with distributed generation. Instead, three replacement strategies were analyzed for each of the fundamental scenarios. The first two replacement strategies are based on the assumption that each of the generating units in the centralized case contributes equally to the overall reserve capacity of the system. For example, if Generator X has a maximum output of Y MW, then it is assumed that Y/(1+R) is the portion of the capacity used for generation and the rest is for reserve capacity, where R is the percentage reserve capacity. In the first replacement strategy the generating units to be replaced are removed and Y/(1+R) MW of DG generation is installed. In other words, the portion of the generating capacity to be replaced that contributes to the reserve margin is not replaced. In the second replacement strategy, the reserve margin for the replaced units is set to be 10% so that the DG capacity is 1.1*Y/(1+R).

Since only a portion of the generating capacity is being replaced, the first two replacement strategies can still result in relatively large reserve margins. The third replacement strategy is an aggressive strategy. In the case of replacing gas units and replacing small units, the aggressive strategy was to replace those units with half of the original capacity (Y/0.5). In the case of coal and large unit replacement scenarios, the aggressive strategy was to install only as much DG as necessary to make the overall system reserve equal zero. Finally, another aggressive strategy was run in which the large units were replaced with enough DG so that overall system reserve was 3% of peak load.

The scenarios described result in a mix of distributed generation and centralized generation. Table 18 provides a summary of the statistics for the different scenarios. As can be seen, the centralized capacity ranges from 0 in the distributed case to 3405 MW in the centralized case with the mixed systems ranging from 1664 MW to 2965 MW. The amount of distributed generation in the mixed systems ranges from 220 MW to 1602.5 MW. As a result the amount of DG penetration in the mixed systems ranges from only 7% up to 49% and the reserve margins range from 0 to 19%. The mix of centralized and distributed capacity can also be seen graphically in Figure 20.

Table 17: Scenario Descriptions for Mixed System Topologies

	0	10	A	A2
Distributed	5699 generating units, each 500 kW internal combustion engines with cogeneration. (Zero percent reserve margin).	6269 generating units, each 500 kW internal combustion engines with cogeneration. (Ten percent reserve margin).		
Gas	All natural gas units replaced with DG with replacement ratio of 1/1.1947	All natural gas units replaced with DG with replacement ratio of 1.1/1.1947	All centralized gas units removed, 50% of capacity replaced with DG	
Small	All natural gas units replaced with DG with replacement ratio of 1/1.1947	All natural gas units replaced with DG with replacement ratio of 1.1/1.1947	All centralized small units removed, 50% of capacity replaced with DG	
Coal	All coal-fired units replaced with DG with replacement ratio of 1/1.1947	All coal-fired units replaced with DG with replacement ratio of 1.1/1.1947	All coal fired units removed, DG capacity added up to 0% reserve	
Large	All units >= 197 MW replaced with DG with replacement ratio of 1/1.1947	All units >= 197 MW replaced with DG with replacement ratio of 1.1/1.1947	All units >= 197 MW removed, DG capacity added up to 0% reserve	All units >= 197 MW removed, DG capacity added up to 3% reserve

Table 18: Summary of Scenario Statistics

Scenario	Centralized Capacity	Distributed Capacity	Total Capacity	Percent DG	Reserve Margin
Centralized	3405	0	3405	0%	21%
Distributed (0)	0	2849.5	2849.5	100%	1%
Distributed (10)	0	3134.5	3134.5	100%	11%
Replace Gas (0)	2860	456	3316	14%	18%
Replace Gas (10)	2860	501.5	3361.5	15%	19%
Replace Gas (A)	2860	272.5	3132.5	9%	11%
Replace Small (0)	2965	368	3333	11%	18%
Replace Small (10)	2965	405	3370	12%	19%
Replace Small (A)	2965	220	3185	7%	13%
Replace Coal (0)	2362	873	3235	27%	15%
Replace Coal (10)	2363	960	3323	29%	18%
Replace Coal (A)	2362	460	2822	16%	0%
Replace Large (0)	1664	1457	3121	47%	11%
Replace Large (10)	1664	1602.5	3266.5	49%	16%
Replace Large (A)	1664	1158	2822	41%	0%
Replace Large (A2)	1664	1229	2893	42%	3%

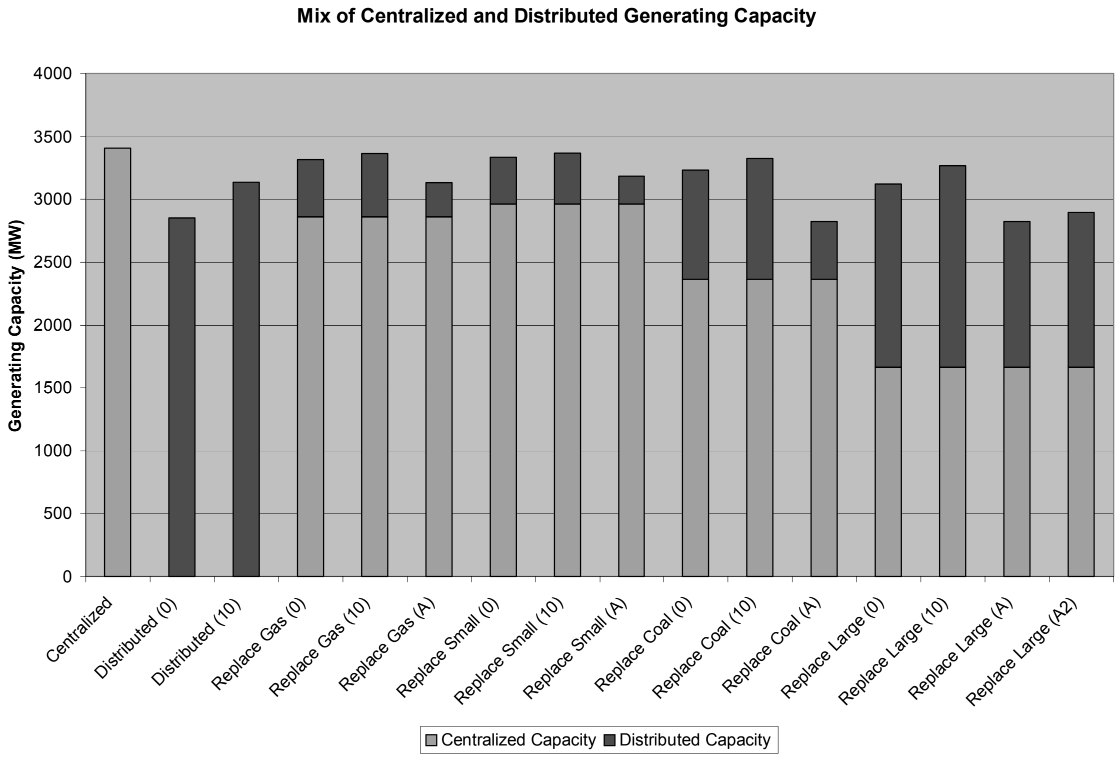


Figure 20: Mix of Centralized and Distributed Generation Capacity

6.3 Results

6.3.1 Investment Costs

The differences in generation mix and capacity for each of the scenarios described result in differences in overall investment costs. The differences in capital expenditures are shown in Figure 21 in terms of annualized costs (accounting for differing lifetimes and the discount rate) and in Figure 22 in terms of a levelized cost (annualized costs divided by the number of kWh produced by the system). As these figures show, the capacity savings of the DG systems (as well as the elimination of high capital cost coal and nuclear facilities) results in significant capital cost savings. Scenarios in which the large units are replaced by distributed generation also result in significant capital cost savings (again, due to the elimination of expensive nuclear and large coal plants).

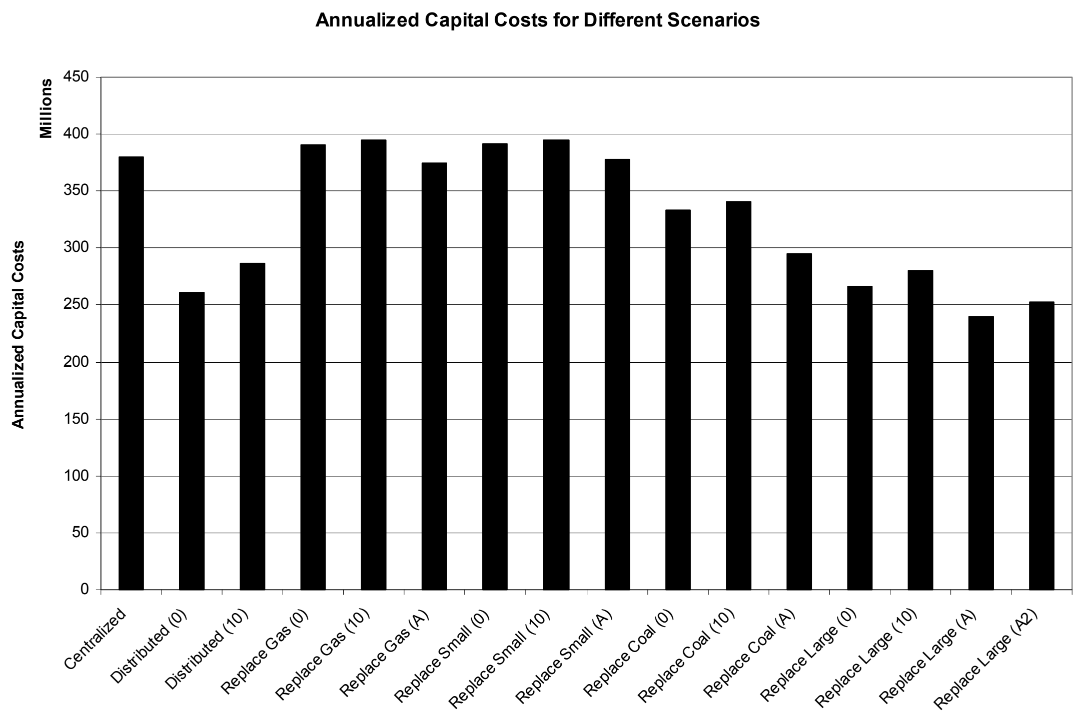


Figure 21: Annualized Capital Costs for the Different Scenarios (Not including Capital Cost Savings for Distributed Systems Due to Avoided Boiler Capital Costs)

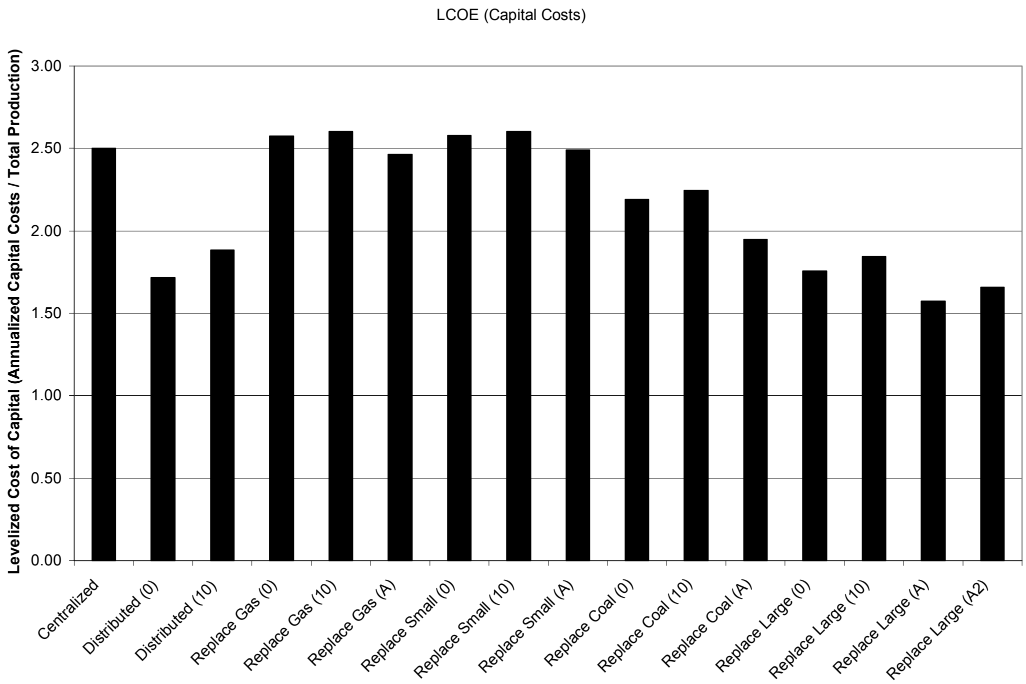


Figure 22: Levelized Cost of Capital Expenditures for the Different Scenarios

6.3.2 Results: Normal Operating Conditions

As with prior modeling efforts on centralized and distributed systems, reliability models were run to determine the reliability and cost of the systems as a function of stress on the system. In this section, results are presented for normal operating conditions, absent extraordinary stress on the system. The following section will show results for stress on the generating units.

Figure 23 and Figure 24 show the Loss of Energy Expectation (in MWh/year) and cost (in c/kWh due to both the levelized cost of electricity and the economic impact of unreliability) in absolute terms for the different scenarios considered. Figure 25 and Figure 26 show the same data, but normalized so that the centralized case is 100%, in order to show the change from the baseline centralized case for each scenario. The first thing to note is that for normal operating conditions the relative differences in LOEE are much larger than the relative differences in economic cost. This is because at the levels of LOEE that exist under normal operating conditions, the economic losses are not large enough to dominate the cost function.

The two distributed cases clearly have the lowest LOEE and cost. The worst performers in terms of LOEE were the aggressive strategies for gas, small units and coal units. However, it is interesting to note that while the aggressive strategy for replacing small units results in a slightly higher LOEE than the centralized system, it actually results in an overall economic cost that is slightly lower. The strategies that replace gas, small units and coal with 0 or 10 percent reserve result in modest savings over the centralized system (up to 11%). The scenarios that replace the large generating units, on the other hand, result in savings of almost 25%.

Coal(A) fares poorly because there is only a very limited introduction of distributed generation and zero percent reserve capacity. By comparison, while Coal (A) and Large (A) both have the same generating capacity overall, the Large (A) scenario has over twice as much distributed generation. This illustrates the dangers of scenario construction that does not account for the overall reserve margins, as well as the relative mix of centralized and distributed technologies. These results indicate that the capacity savings possible with distributed generation is function of the amount of centralized generation that is being replaced.

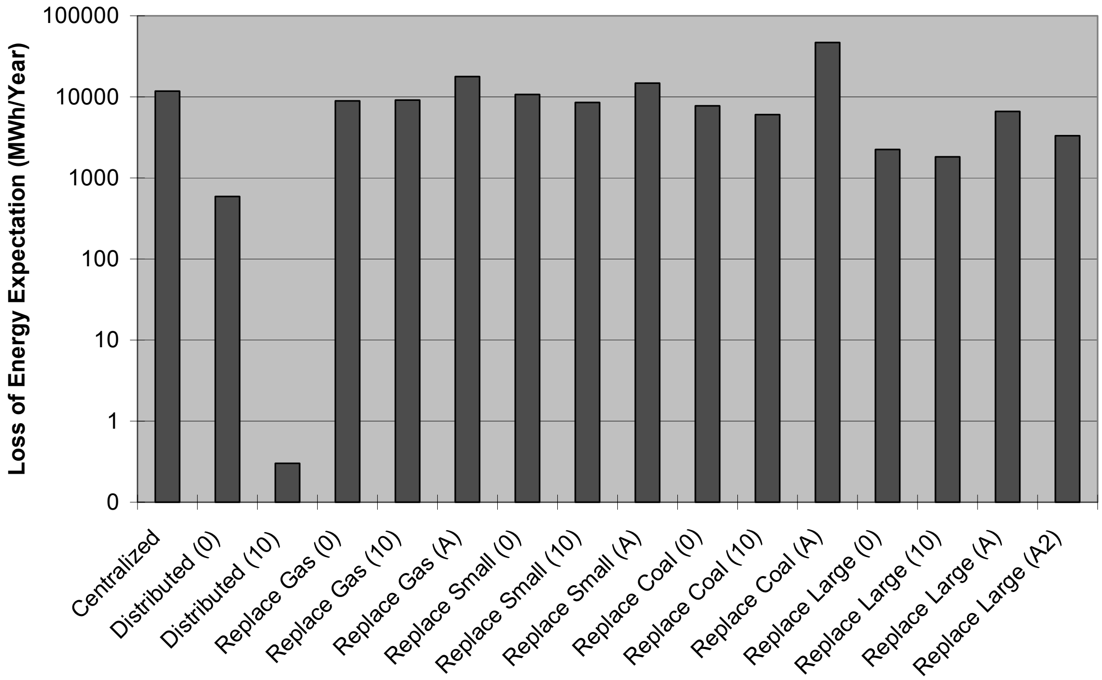


Figure 23: Loss of Energy Expectation Under Normal Operating Conditions

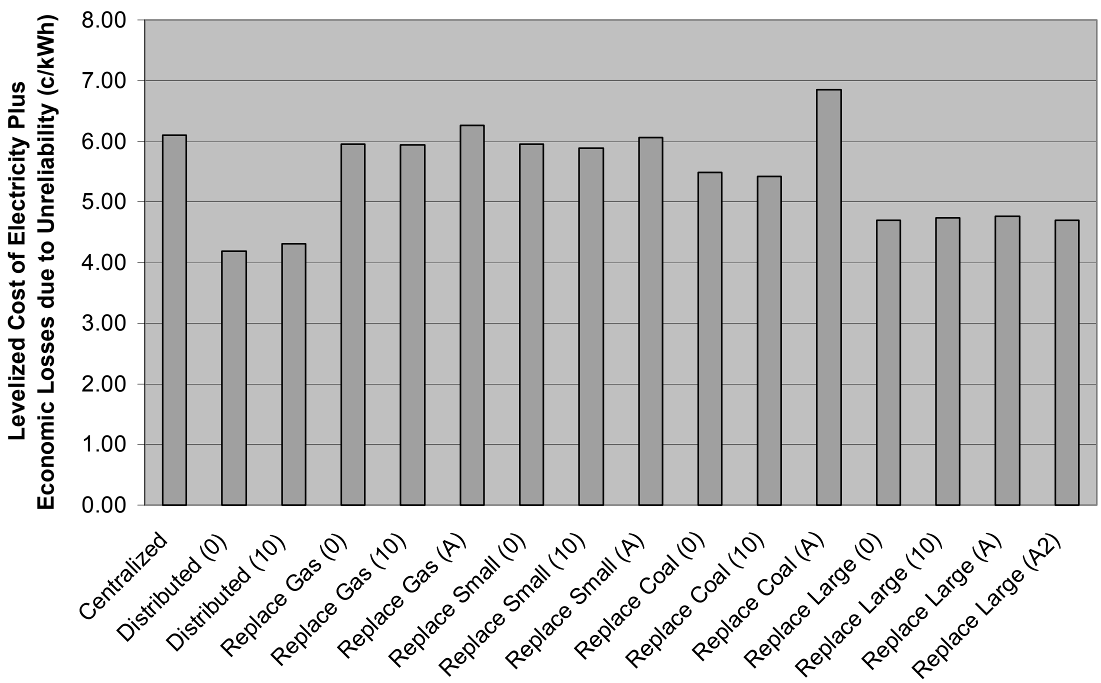


Figure 24: Economics of Electricity Supply and Use Under Normal Operating Conditions

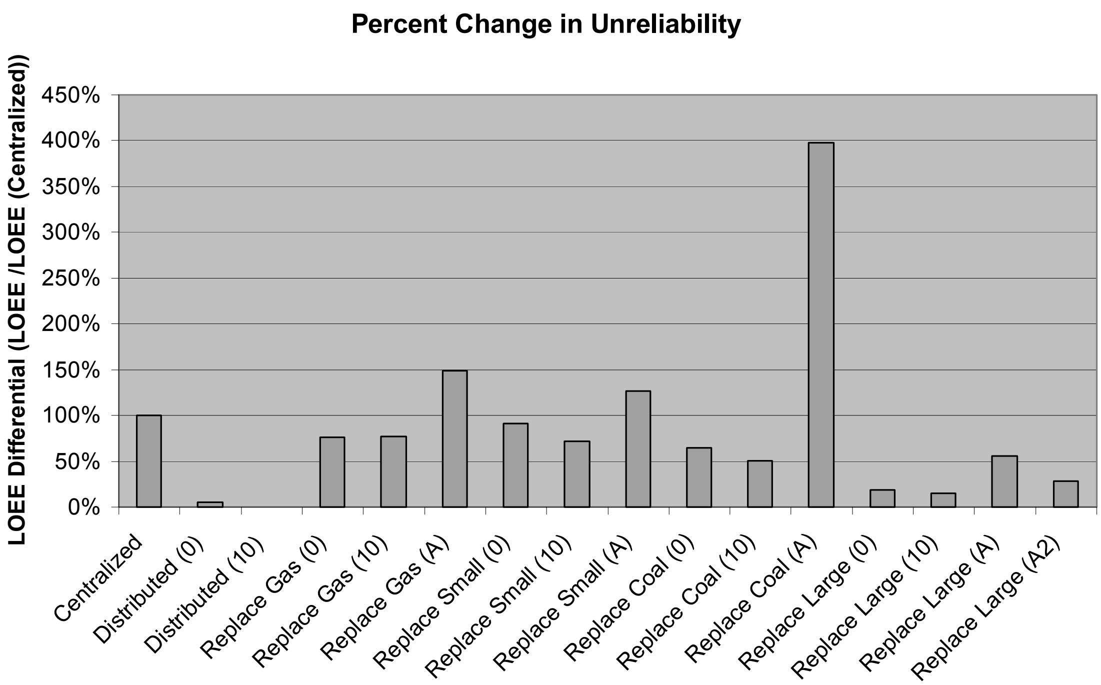


Figure 25: Loss of Energy Expectation Relative to Centralized Case

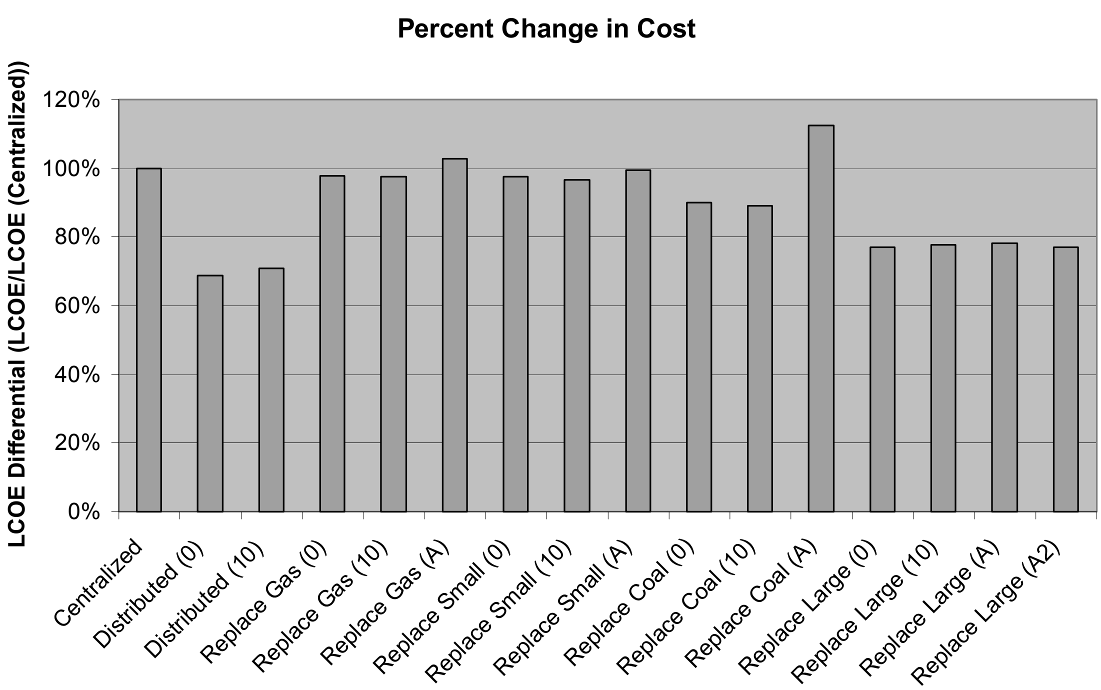


Figure 26: Economics of Electricity Supply and Use Relative to Centralized Case

6.3.3 Impact of Heat Credit

All of the economic results include a heat credit for the distributed generation (assuming that half of the waste heat is used). Without that heat credit, almost all of the alternative scenarios result in cost increases. Most of the scenarios have costs that are 3-8% higher than the centralized case. The aggressive coal replacement strategy, however, has costs that are 21% higher. The two aggressive strategies to replace the large units result in a 1% savings (Replace Large (A)) and costs equal to the centralized case (Replace Large (A2)). These results can be seen in Figure 27 for absolute numbers and Figure 28 for relative numbers.

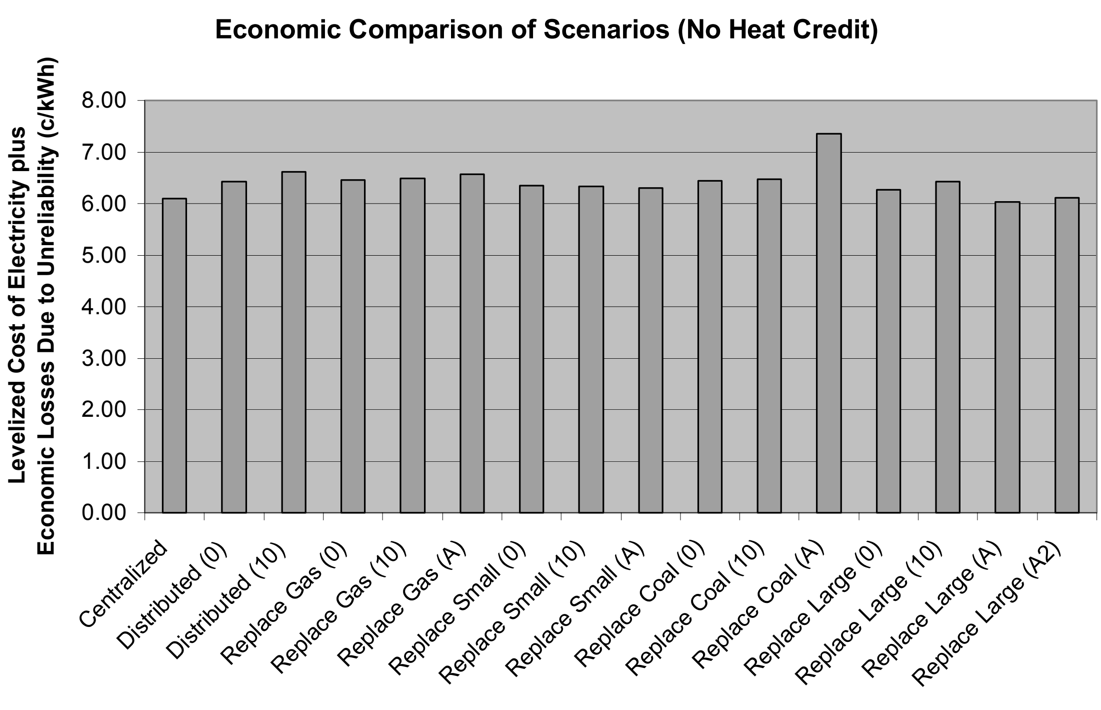


Figure 27: Comparison of Economics of Electricity Supply and Use with no Heat Credit

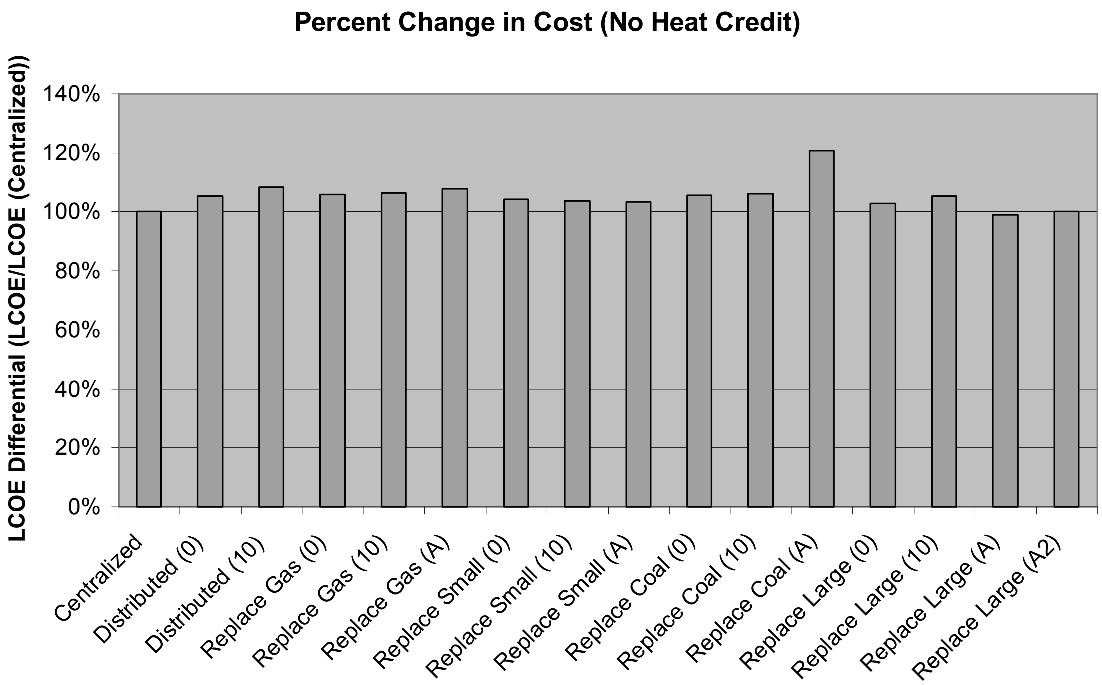


Figure 28: Comparison of Economics of Electricity Supply and Use with no Heat Credit (Relative to Central Case)

6.3.4 Results: Stress Conditions

In this section, results are presented to show how the different scenarios perform under stress conditions. The particular stress condition examined is stress on the generating units. Model runs could also be used to examine stress at the transmission or distribution level. The method used to apply stress on the system is described in Chapter 5.

6.3.4.1 Reliability

The impact of stress on the Loss of Energy Expectation can be seen in Figure 29. The alternative scenarios can be compared to the baseline centralized system scenario to see whether there are improvements or not over the baseline. The aggressive strategies for gas, small units and coal units are all above the centralized system. This is due to the low reserve margins coupled with relatively low DG penetration. The other replacement strategies for gas, small units and coal are all roughly equivalent to the centralized case. The reserve margins are higher for these cases (15-19%) but DG penetration is also not as high as some of the other scenarios. Another factor is that most of the coal units have baseline unavailabilities that are comparable or better than the DG units. Therefore, more reliable (though larger) units are being replaced with a larger number of slightly less reliable units.

By contrast, the two distributed cases and all of the scenarios for replacing the large generating units perform better than the centralized case. These are shown in Figure 30 (with the axes also cut-off to show the area of most interest). As can be seen from the figure, some of the large unit replacement scenarios begin to have LOEEs that are lower than the Distributed (0) scenario at stress adjustment factors between 1 and 2. By stress adjustment factors of around 6, the scenario of replace the large units with 10% reserve capacity begins to have a lower LOEE than even the Distributed (10) scenario. There are two factors that could contribute to these results:

- The large unit replacement scenarios result in both moderate reserve margins (> 10%) and high levels of DG penetration (nearly 50%).
- The large units generally have low baseline unavailabilities. Their elimination reduces the composite unavailability of the system and improves reliability

This further reinforces the point that the performance of the system is a complex function of the overall reserve margin, the level of distributed generation penetration and performance characteristics of the remaining centralized units in the system.

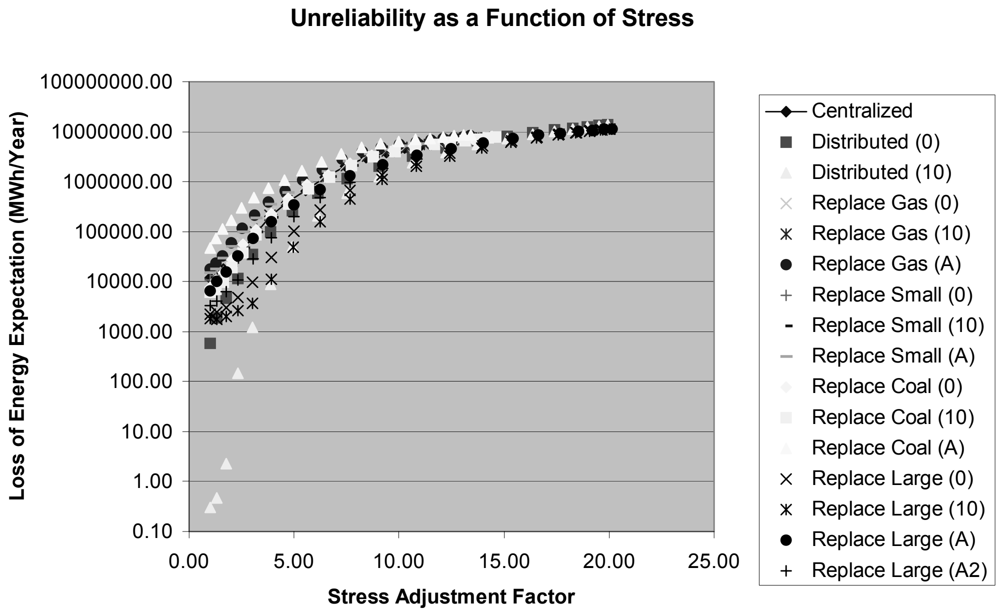


Figure 29: Impact of Stress on Reliability for Different Scenarios

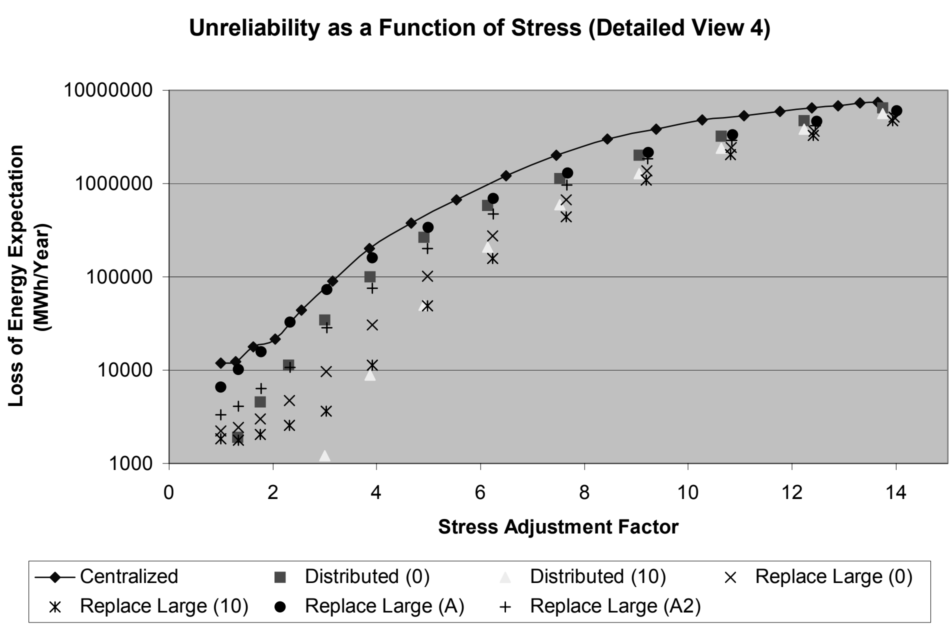


Figure 30: Impact of Stress on LOEE for Centralized, Distributed and Large Unit Replacement Scenarios (Detailed View)

6.3.4.2 Cost

Similar results are seen when comparing the economics of electricity supply and use. Figure 31 shows the levelized cost of electricity, not accounting for the heat credit for distributed generation and not accounting for the economic losses due to unserved energy. The centralized system shows a sharp rise in the LCOE as a function of stress. This is due to the fact that costs such as capital and fixed operations and maintenance are being divided by progressively smaller number of kWh of electricity served to end-users. The increased reliability of the distributed and Large Unit replacement scenarios mean that the kWh served only decreases gradually and the levelized costs therefore rise much more slowly.

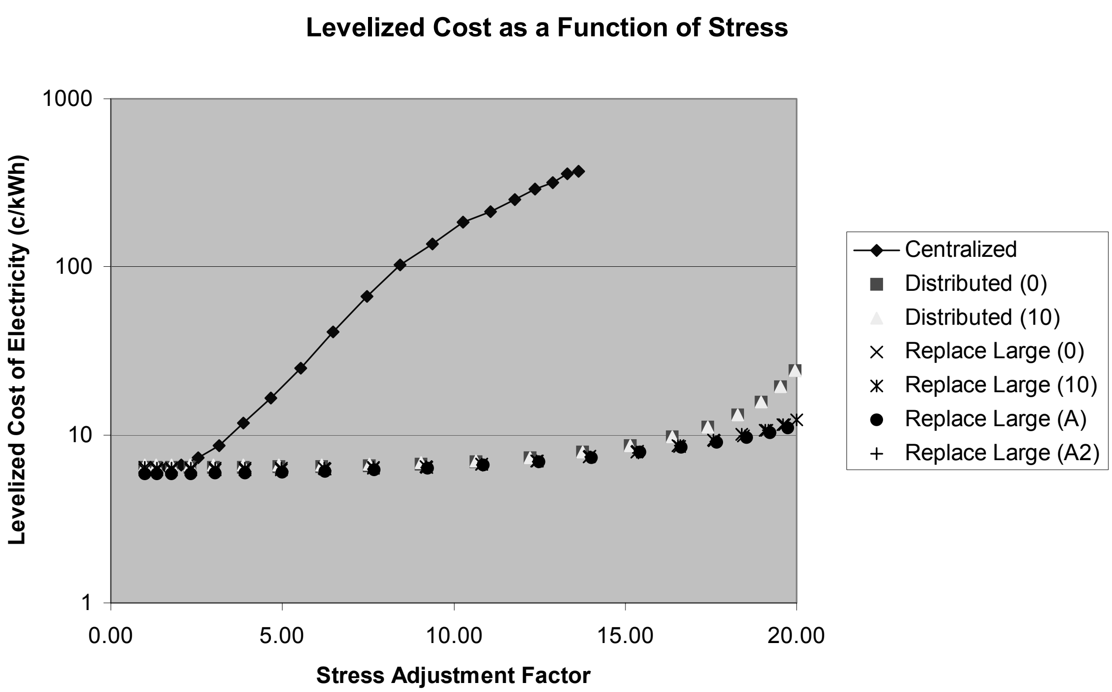


Figure 31: Levelized Cost of Electricity for Capital, Fuel and Operations and Maintenance

Note: The figure above does not account for the credit given to distributed generation units for providing heat and does not account for the economic losses due to the failure to provide energy.

The complete results are shown in Figure 32, now including the full set of costs (i.e. the heat credit is given to the distributed generation capacity and the economic losses due to unserved energy are added in. Results for the same sub-set of scenarios discussed above (centralized, distributed and large unit replacement) are shown in Figure 33 (a detailed view is shown to highlight the area of most interest). In this case, the differences are much smaller, but no large replacement scenario has a lower cost than a distributed scenario until stress adjustment factor 3.

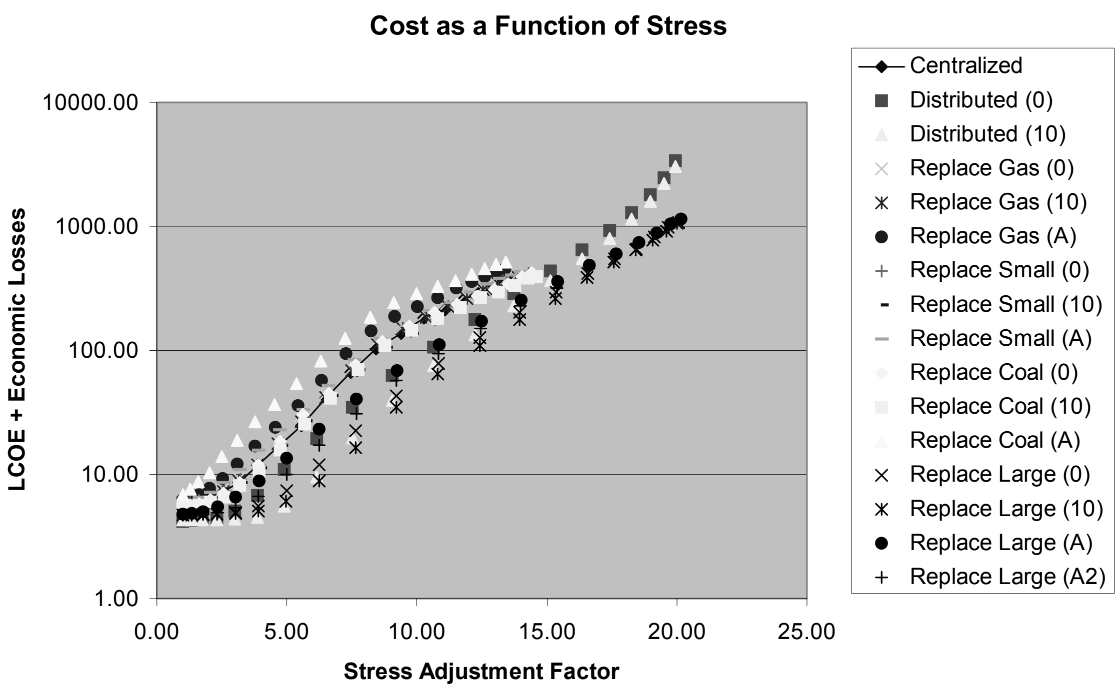


Figure 32: Impact of Stress on the Economics of Electricity Supply and Use for Different Scenarios

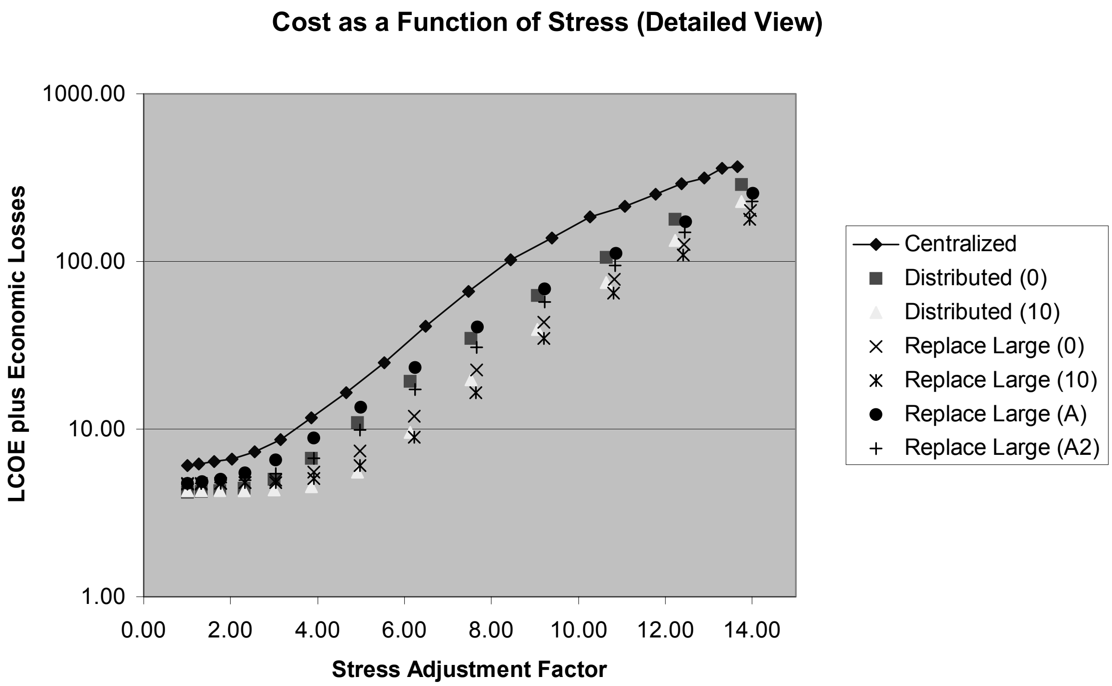


Figure 33: Impact of Stress on Economics of Electricity Supply and Use for Centralized, Distributed, and Large Replacement Scenarios (Detailed View)

6.3.4.3 Impact of Heat Credit

As with the comparison under normal operating conditions, the heat credit given to the distributed units can make a significant difference in the economic comparison. As seen in Figure 28, under normal operating conditions the centralized case has the lowest cost except for one of the large unit replacement scenario. Figure 34 shows a detailed view of the levelized cost of electricity plus economic losses due to loss of energy for the centralized, distributed and large unit replacement scenarios under increasing stress. It can be seen that as stress increases the Centralized scenario is again more expensive than the distributed or large unit replacement scenarios. Figure 35 shows an even more detailed view to see what happens at low levels of stress. The large unit replacement scenarios all become less expensive than the centralized case at a stress adjustment factor that is less than 2 and the distributed scenarios cross the centralized case at approximately stress adjustment factor 2.

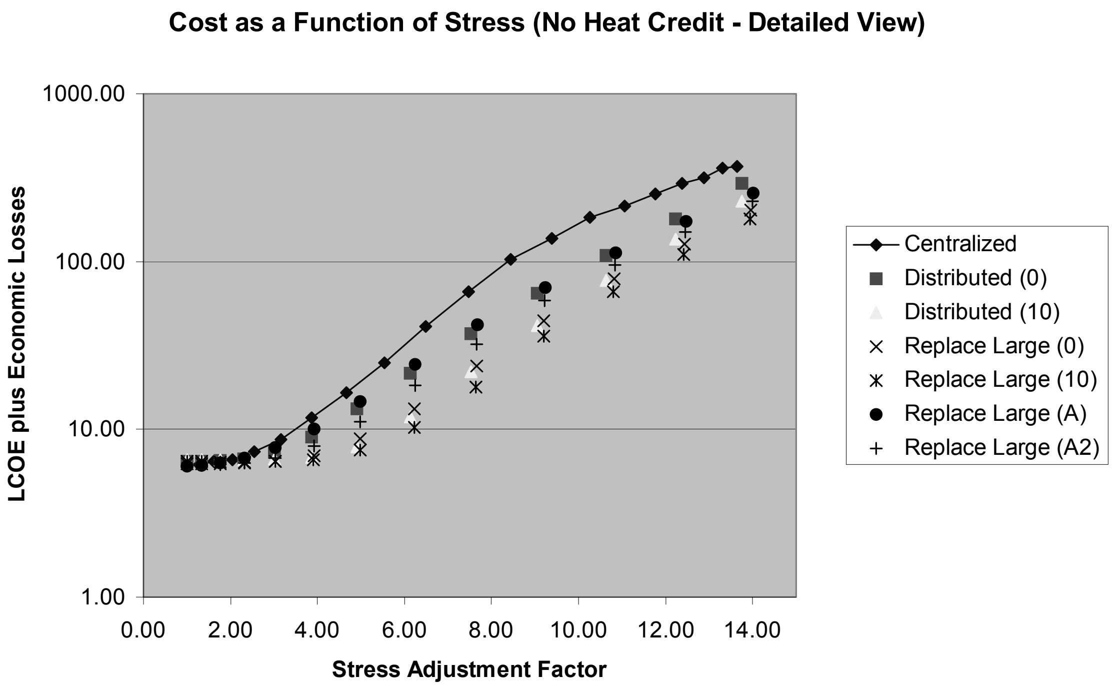


Figure 34: Economics of Electricity Supply and Use with no Heat Credit as a Function of Stress (Detailed View)

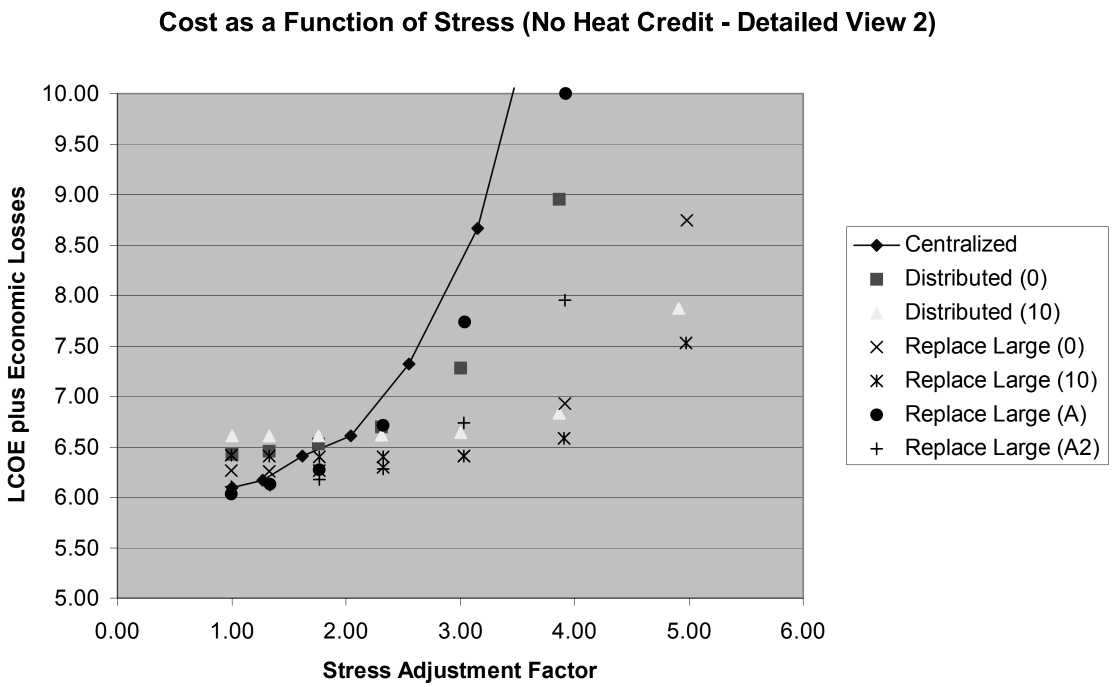


Figure 35: Economics of Electricity Supply and Use With no Heat Credit as a Function of Stress (Detailed View 2)

6.4 Conclusion

The results of this chapter illustrate the need to move beyond simple indicators of system characteristics (such as system reserve). Not only is overall system reserve of importance, the particular mix of technologies impacts the performance of the system. The degree of DG penetration, the characteristics of the replaced centralized units and the characteristics of the remaining centralized unit all play a role in the performance of the mixed centralized-distributed system. For example, replacing the coal units in this particular baseline system may not have the expected consequences because it can result in relatively low DG penetration rates and result in the removal of some generators with low unavailabilities. On the other hand, the strategies that involve replacing "large" generators in this system result in high DG penetration and the replacement of large, unreliable generators with smaller and more reliable distributed units.

Chapter 7 The Effect of Load Non-Coincidence on Reliability and Cost of Distributed Energy Systems

7.1 Introduction

The models developed in the previous chapters of this dissertation were based upon a sampling technique, akin to stratified sampling, that sorted the loads into a Load Demand Curve (LDC). The hours in the load demand curve were clustered using a k-means algorithm to create a twenty step load demand curve. For those models, when the system load was divided among the different micro-grids, it was actually the load demand curve that was divided among those micro-grids. While this allows for more efficient computation, the drawback is that all of the micro-grid peaks are effectively made to be coincident. For example, if micro-grid 24 has a peak in hour 4587 and micro-grid 56 has a peak in hour 345, these peak hours are both the first hour in the LDC and the information that they actually occurred at different times of the year is lost.

Losing the temporal information about loads is significant when considering how systems behave when a) the loads at the different micro-grids are not of the same class (e.g. residential versus commercial) and b) significant distributed generation is used to meet demand. The goal of this set of models is to determine how load non-coincidence impacts the reliability of the system, particularly the ability of micro-grids with distributed generation to share load.

The next section will describe the method used to create loads that have varying degrees of load non-coincidence. There are two possible approaches to creating load non-coincidence and the differences between the two are highlighted because each can provide different, but complementary information about the system. This section also describes the method used to calculate the loss of energy expectation and costs, as this differs from the methods used for the prior models described in this dissertation. Section 3 describes the results obtained from the model. First, we will discuss the impact that load non-coincidence has on the reserve margin of the system. Next, the results will be presented for the two different approaches to creating load non-coincidence.

7.2 Method

7.2.1 Creating Load-Non-Coincidence

The first step in the analysis was to actually create systems with varying levels of load non-coincidence in order to compare them. One method would be to take data from real systems with differing mixes of customer classes and compare those. Another method would be to take a characteristic load profile applied to all of the loads in an area, but then assume that some loads have the same profile, just shifted in time. This creates a systematic way of measuring the impact of load non-coincidence without changes to the actual load profiles themselves. This was done with the load profile used by the IEEE Reliability Test System.

The IEEE Reliability Test System load data has 8736 hours and a peak load of 2850 MW. The load profile can be evenly divided among any number of micro-grids. For example, in this section, it was assumed that there were 256 micro-grids in the system, each with a peak load of approximately 11.1 MW. The hourly load for a sample micro-grid is shown in Figure 36. If all of the micro-grids are perfectly coincident (that is, their hourly loads are exactly as shown in Figure 36), then there is no difference between the sum of the load profiles of the micro-grids and the original over-all system load profile.

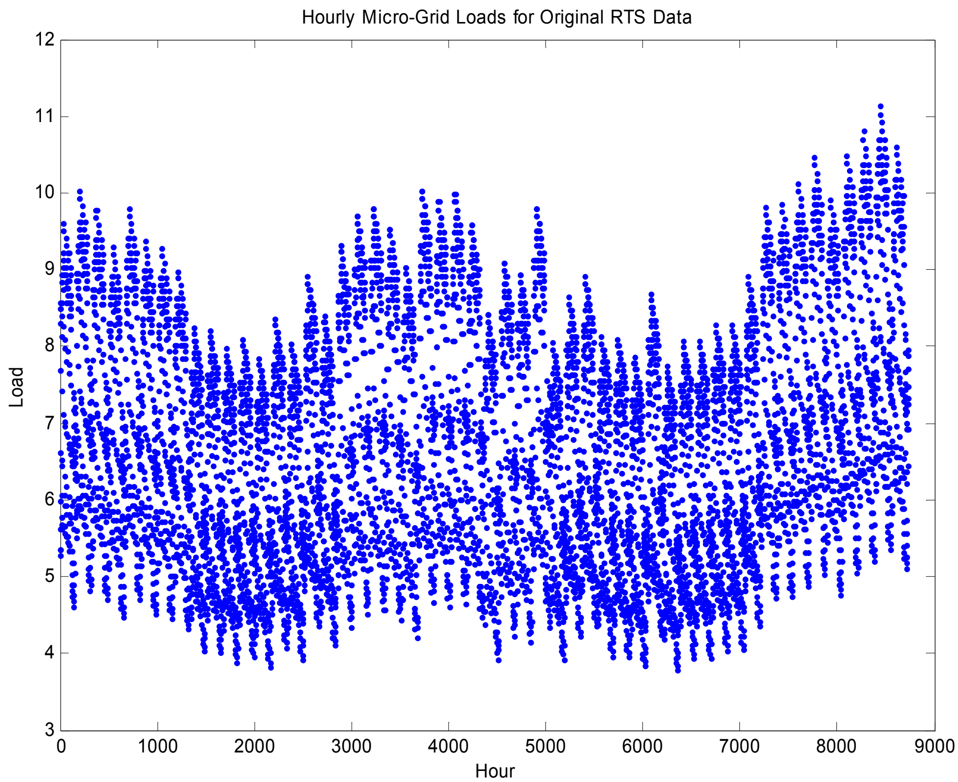


Figure 36: Hourly Micro-Grid Load for RTS Data

Load non-coincidence is introduced by shifting the loads in a subset of the micro-grids. The first load shift is achieved by taking half the islands and shifting them by a half year. The loads can be re-normalized so that the peak load of the system remains 2850 MW (more on this below). The renormalized original hourly load can be seen in Figure 37 and the shifted micro-grid load can be seen in Figure 38. As can be seen, the peak load is now occurring around hour 4000 rather than hour 8000. In this way, there a two self-similar islands with half the micro-grids having a load profile as in Figure 37 and the other half having load profiles like that of Figure 38. As can be seen, when half the micro-grids are at peak, the other half are not and this introduces possibilities for power sharing. Summing all of the micro-grid loads together to get the system load results in a new system load that has a dual peak, one at 4000 hours and one at 8000 hours.

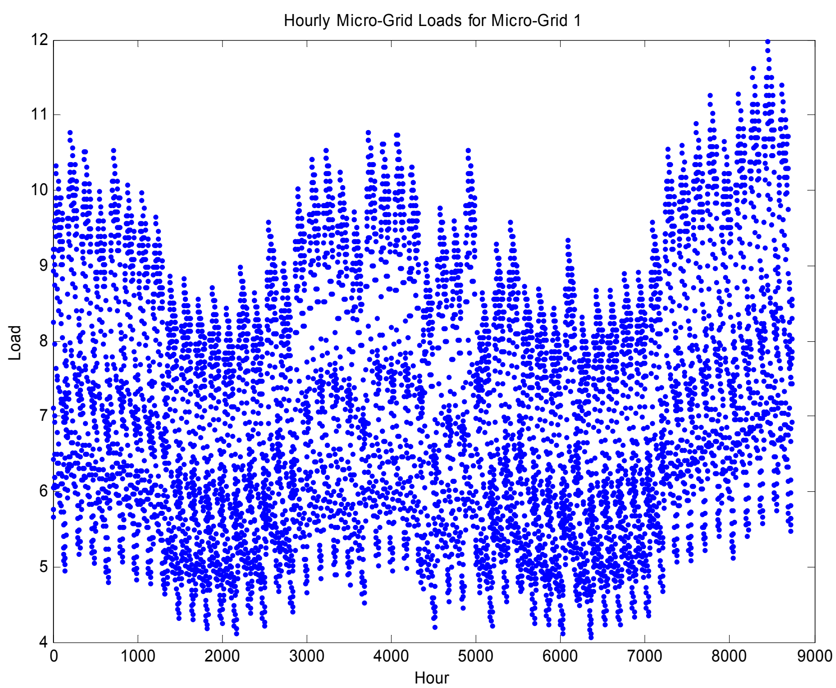


Figure 37: Hourly Loads for Micro-Grid 1

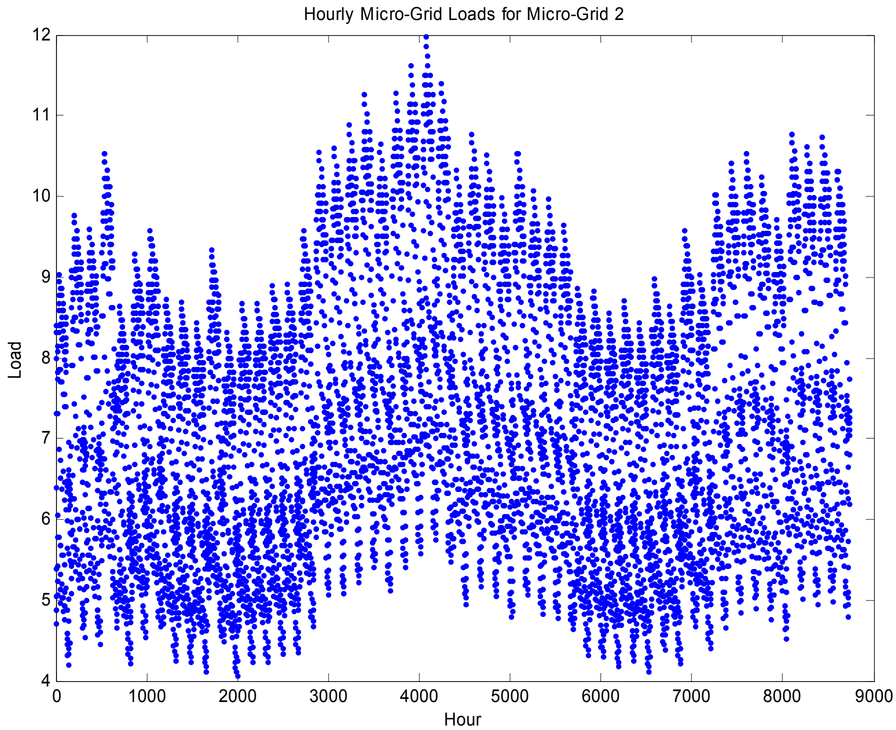


Figure 38: Hourly Loads for Micro-Grid 2

This process can be repeated using progressively smaller time shifts. For example, the second shift is achieved by taking half the load (a quarter from each of the two areas created in the first shift) and shifting them by a quarter year each. These shifts are repeated (1/8 year, then an 1/16 year, etc.). After 8 steps, each of the 256 islands has its peak in a different hour. The algorithm for creating the load shifts is shown in the appendix to this chapter.

Clearly, this method can generate load profiles that are significantly more different than would occur in a real power system. However, this method has the advantage of providing a systematic basis for comparing system behavior for known levels and changes in load non-coincidence. For comparison purposes, results are also presented using real world data (the data is for the San Diego Gas and Electric system for 1995). Furthermore, this dissertation provides a method for understanding the importance of load non-coincidence and evaluating its impact, and as such, the method can be applied to any desired load set.

It should be noted that there are two ways to handle the shift of areas. The first is to renormalize the load after each shift. In that case the system peak load is constant, but the area peaks increase. This difference is what causes the rise in necessary generation. In the second case, as areas are shifted out of coincidence, the overall system peak begins to decline. However, the area peaks remain the same which creates the difference between the required generation based on an area calculation and one based on the system load. This is the method that has been used here. The calculation can be done either way and the numeric comparison of reserve margins will remain the same. However, the two methods do have different conceptual interpretations. In the first case it is a comparison of different systems with the same amount of peak system load but different levels of load coincidence. In the second case, it is the effect of load shifting (without changing the load levels themselves).

The difference between the two approaches can be seen as one of choosing between two different units of analysis. In approach 1 (renormalize to keep system peak load constant), the unit of analysis can be seen as the overall system. In this case, the micro-grids have to be multiplied by a normalization factor so that the overall system peak remains constant and as a result the peak load of the micro-grid itself will increase, as will the overall energy consumption of the system. Conceptually, this corresponds to comparing different systems that are comparable in size (as measured by peak load) but differ in the coincidence of their loads and in the size of the micro-grids that make up the system. Alternatively, this can be seen from the perspective of an energy system planner trying to determine the impact of load aggregation. Different combinations of loads can all result in the same peak load, but with radically different load profiles and possibilities of load sharing. This will have an impact, for example, on the degree to which distributed generation can actually result in reductions in system reserve, as indicated in previous models in this dissertation.

In approach 2 (shift micro-grid loads without renormalizing to keep overall system peak constant), the unit of analysis is essentially the micro-grid. Micro-grids remain fixed in both their shape and in the value of the loads. However, the system peak load decreases. Conceptually, this corresponds to comparing systems that are the same on the micro-level, but as a result of load aggregation differ on the macro-level. This could also be the result of having a system in which a decision is made by some micro-grids to shift their loads (of course, this assumes some control over load). Assume for a moment that each micro-grid corresponds to an individual decision-maker that is trying to determine their investment in DG for their micro-grid. One of the factors, of course, will be load non-coincidence and the ability to share load. A micro-grid operator may be tempted to simply install enough capacity to meet all of native load, but depending on power sharing capabilities that might be an overinvestment. More importantly, however, from the perspective of the micro-grid decision maker, their load does not change as the loads of other micro-grids shift in time. Having micro-grids that are larger or smaller depending on the load non-coincidence means we cannot assess how the level of load non-coincidence impacts investment decisions on the micro-grid level.

To see the impact of the load shift, the following figures show the hourly load and the sorted load demand curve for the original RTS data and for two successive shifts of the load, such that there are four self-similar groups of loads, each with a peak in a different quarter of the year. The results are shown for both approaches. As can be seen, under the constant peak load approach, the system peak remains at 2850 MW, but the range in loads decreases. The differences in peak locations can also be seen. Under the constant micro-grid approach, the overall system peak load decreases as well as the spread of the loads.

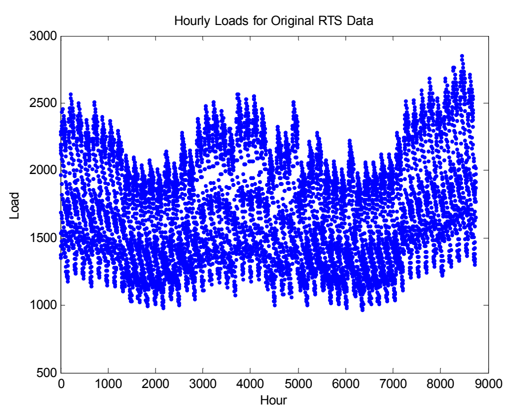


Figure 39: Hourly Loads for 1 Area (Original RTS Load Data)

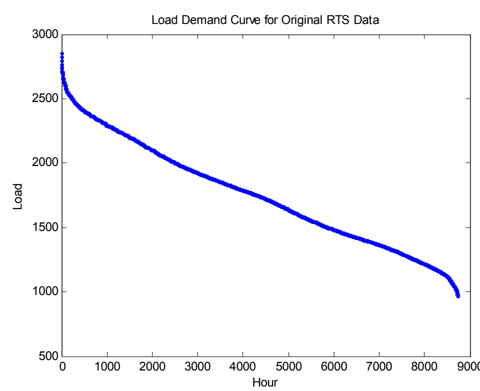


Figure 40: Load Demand Curve for 1 Area (Original RTS Load Data)

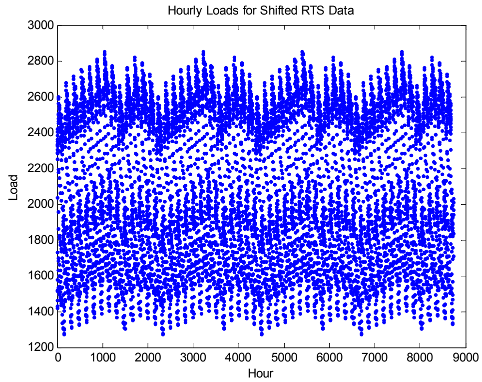


Figure 41: Hourly Loads for 4 Areas

(Constant System Peak Load Shifting)

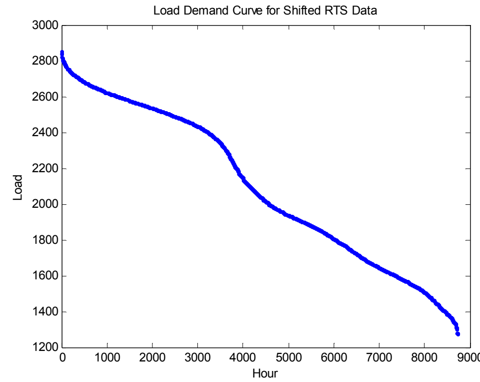


Figure 42: Load Demand Curve for 4 Areas

(Constant System Load Shifting)

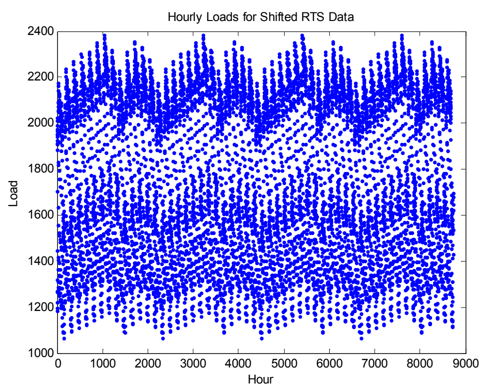


Figure 43: Hourly Loads for 4 Areas

(Constant Micro-Grid Peak Load Shifting)

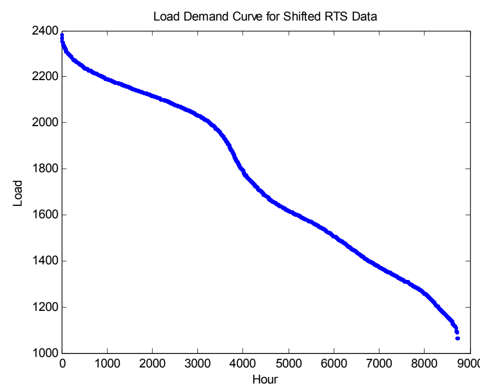


Figure 44: Load Demand Curve for 4 Areas

(Constant Micro-Grid Peak Load Shifting)

Further details about the effect of load shifts, including all of the load and load demand curves for each load shift is provided in the appendix to this chapter.

7.2.2 Calculating Reliability and Cost as a Function of Load Non-Coincidence

The models described in prior chapters of this dissertation used the Load Demand Curve to calculate reliability and then translated those reliability figures into economic losses which could be added to the levelized cost of electricity for an overall economic comparison. The Load Demand Curve is used because it offers computational advantages. The generation in the system can be totaled and then compared with the LDC. If the LDC is divided into steps then the data storage requirements are reduced.

The disadvantage of the LDC method is that it does not preserve the time domain information in the load data. Since load non-coincidence is a function of load peaks occurring at different times of the year in different areas, it is impossible to use this method. Instead we have preserved all of the load data in original form (i.e. they are not sorted as in an LDC and not clustered either). The data are in an M x N matrix, where M is the number of hours (8736 or 8760 depending on the dataset) and N is the number of micro-grids in the system and each element in the matrix is the load for that hour and that micro-grid. In each model run, a random number is drawn for each component in the system (generating unit and distribution line). The amount of generation in each micro-grid is applied for all of the hours for that micro-grid. A new M x N matrix is created, where each element is now the surplus or deficit of generation for that hour and that micro-grid. Taking into account the operational condition of the distribution level linkages for that run, the surpluses and deficits for each hour can be summed across the micro-grids. Micro-grids with a deficit and a downed link have their deficit contributed to the LOEE. Micro-grids with a surplus and a downed link contribute neither to the LOEE nor to the flow of power between micro-grids. For the rest, the surpluses are used to offset the deficits. The total flow for that run and the loss of energy expectation can then be computed depending on whether surpluses exceed deficits. Economic calculations are done as in the other models (with the same parameters), including a heat credit.

7.3 Results

7.3.1 Load Non-Coincidence and Reserve Margins

As load non-coincidence increases, the reserve margin can significantly increase if the same level of generation is maintained at each micro-grid. The following example is an illustration of this. If each micro-grid constructs enough generating capacity to provide for its own native load plus ten percent reserve then the overall system reserve margin will also be ten percent if all of the micro-grids have perfectly coincident loads. If some of the load is shifted so that the loads are no longer perfectly coincident, then the overall system peak load decreases. However, if each micro-grid still has 10% more generation than the peak load of the micro-grid, the overall system reserve margin will be greater than 10%.

Figure 45 shows the results of a calculation on the reserve capacity required for increasing load non-coincidence. The IEEE-RTS demand curve was divided among 256 micro-grids. Each micro-grid had 10% reserve margin and the overall system reserve margin is also 10% when all loads are coincident with fixed capacity. The loads were then shifted as described above. For each shift in load, the total generation (which remained fixed at 3135 MW) was compared to the new system peak load and the new reserve margin calculated. As can be seen, as load non-coincidence increases the system reserve increases dramatically from 10% up to 80%, indicating that the system would be vastly overbuilt.

This illustrates nicely one of the network externalities that led to the development of large networks. The ability to use a network to provide power to multiple loads, and therefore, take advantage of the load non-coincidence and the effect of aggregation, provided a strong incentive to centralization of the electric power system.

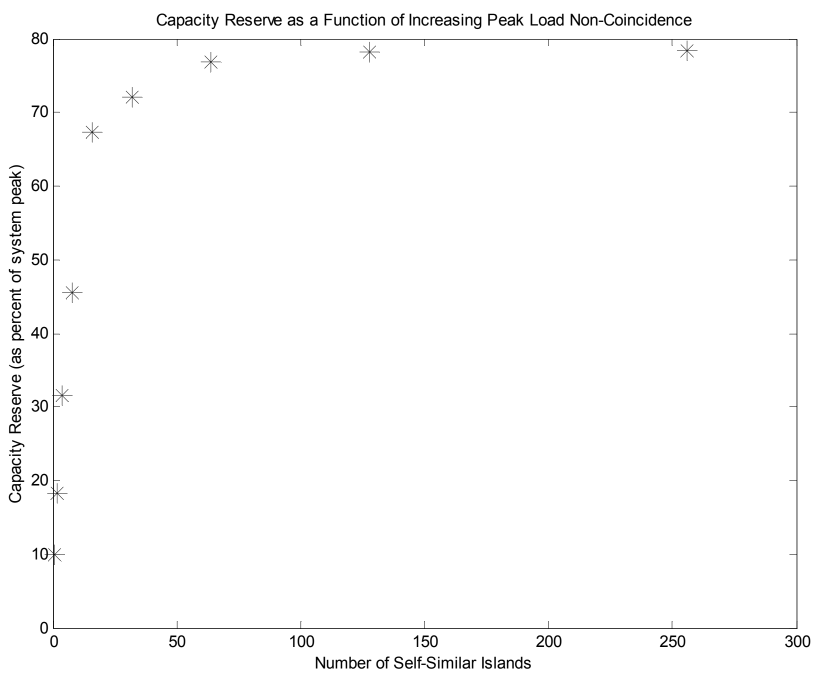


Figure 45: Capacity Reserve as a Function of Increasing Peak Load Non-Coincidence

7.3.2 Constant System Peak Approach

Using the method described above, load non-coincidence data were generated for a system with 256 micro-grids. The model was run for 9 different levels of load non-coincidence (perfectly coincident loads and 2^0-2^8 self-similar islands). Each time the load was shifted, the loads were renormalized such that the system peak was maintained at 2850 MW. In addition to the systematically shifted IEEE RTS demand profile, data were also downloaded for the San Diego Gas and Electric system in 1995. The SDGE data provide load profiles for residential, commercial, and industrial loads. These were renormalized such that each customer class provides approximately 30% of the demand and the system peak is 2850 MW to match the IEEE RTS.

Using the method described above, the LOEE and cost were calculated for a system with 256 micro-grids using the IEEE-RTS load data. Using the system peak modeling approach, the model was run with the centralized system and with a distributed system that had zero percent reserve margin for each shift in load.

Figure 46 compares the centralized system and the distributed system reliability for two distributed systems (one with zero percent capacity reserve and the other with five percent capacity reserve). Along the x-axis is the number of load shifts (e.g. 4 load shifts corresponds to 2^4 or 16 unique load profiles). Along the y-axis is the unreliability of the system in terms of the energy that is not supplied (MWh per year). The figure shows that the distributed systems do have a lower LOEE (i.e. it is more reliable) under baseline conditions. However, after a couple of shifts, the centralized system begins to perform better than the DG-0 system (zero percent capacity reserve). To understand why, recall that shifting the loads results in a flattened load curve and fewer hours in which loads are low. As a result, the loss of generators becomes significant for more hours out of the year. Hours during which the loss of a couple of generators would not have made a difference before, can now result in loss of energy to the end-user. As a point of comparison, the system using the SDGE data has an LOEE of 1950 MWh/year for the distributed system and 1015 MWh/year for the centralized system.

It is important to note that as the number of load shifts increases, the overall consumption of energy increases. Therefore, a given LOEE corresponds to a lower percentage of energy unserved at low load shifts versus a higher number of load shifts. Thus, in Figure 46, one cannot directly compare the LOEE at one load shift with the LOEE at another. However, within a given load shift, the comparison of LOEE between the distributed and centralized system is a fair one, since both have to meet the same level of demand and total consumption. However, as can be seen in Figure 47, even when the LOEE is expressed as a percentage of total possible consumption, the pattern remains that the distributed system with zero percent capacity reserve, is less able to continue to meet demand as the level of load non-coincidence increases in comparison with the centralized system.

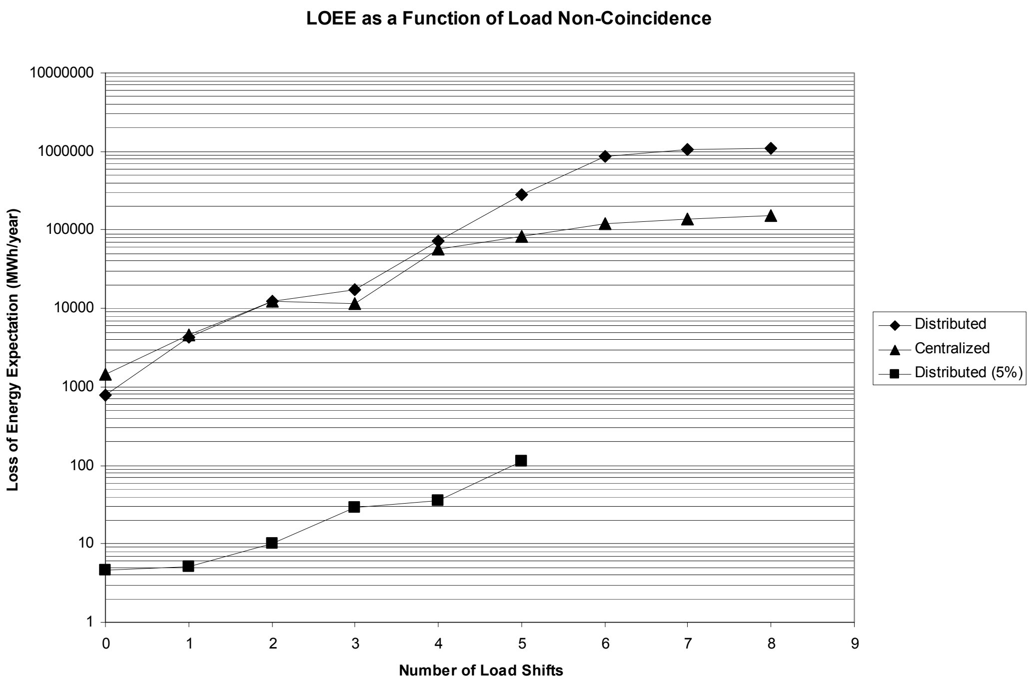


Figure 46: Reliability of Centralized Versus Distributed System as a Function of Increasing Load Non-Coincidence

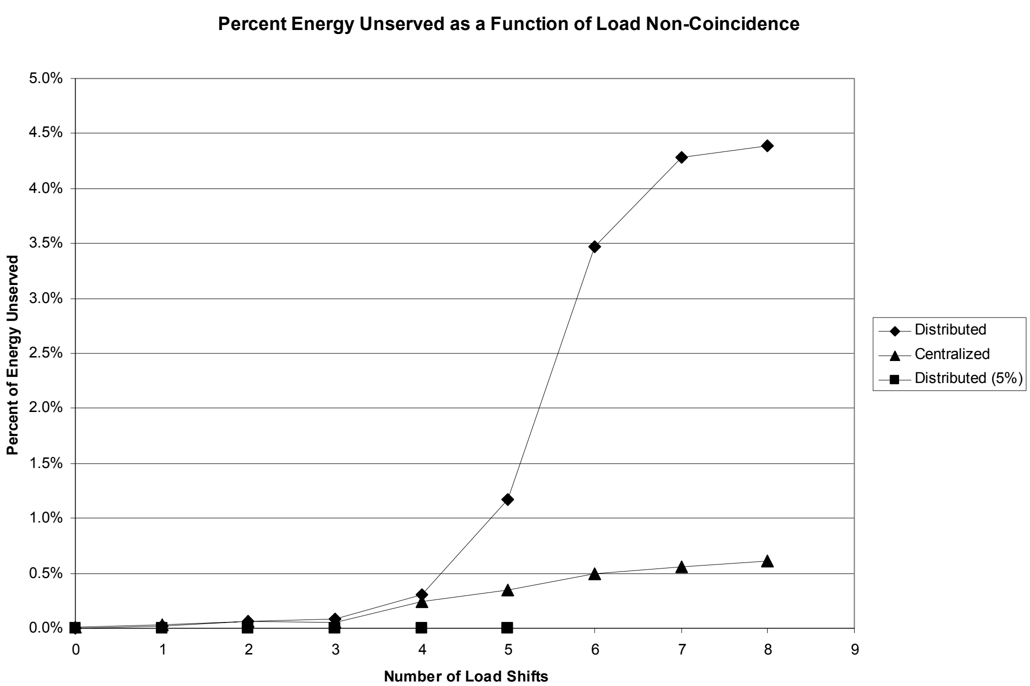


Figure 47: Percent Energy Unserved (LOEE/Total Possible Consumption) as a Function of the Level of Load Non-Coincidence

The cost calculations show a slightly different picture, however (Figure 48). For low levels of load non-coincidence, the LOEE is not high enough to contribute significantly to the overall costs of the system. Therefore, if the heat credit is included, the DG-0 system continues to exhibit lower overall costs than the centralized system even for levels of load non-coincidence in which the centralized system has lower LOEE. However, at high enough levels of load non-coincidence, the economic losses due to unserved energy begin to dominate the costs and the DG-0 system is more expensive. The distributed system with 5% capacity reserve (DG-5), on the other hand, experiences declining costs with increased load non-coincidence. This can be explained by the high reliability of the distributed system when just 5% of reserve capacity is added. As the load non-coincidence increases, the LOEE does not increase significantly with this system (as seen above). However, total consumption does increase. Therefore, fixed costs (capital and fixed operations and maintenance) are spread out over a larger number of delivered units of energy and the cost per kWh decreases. This costs decrease outweighs the very modest cost increases due to unserved energy.

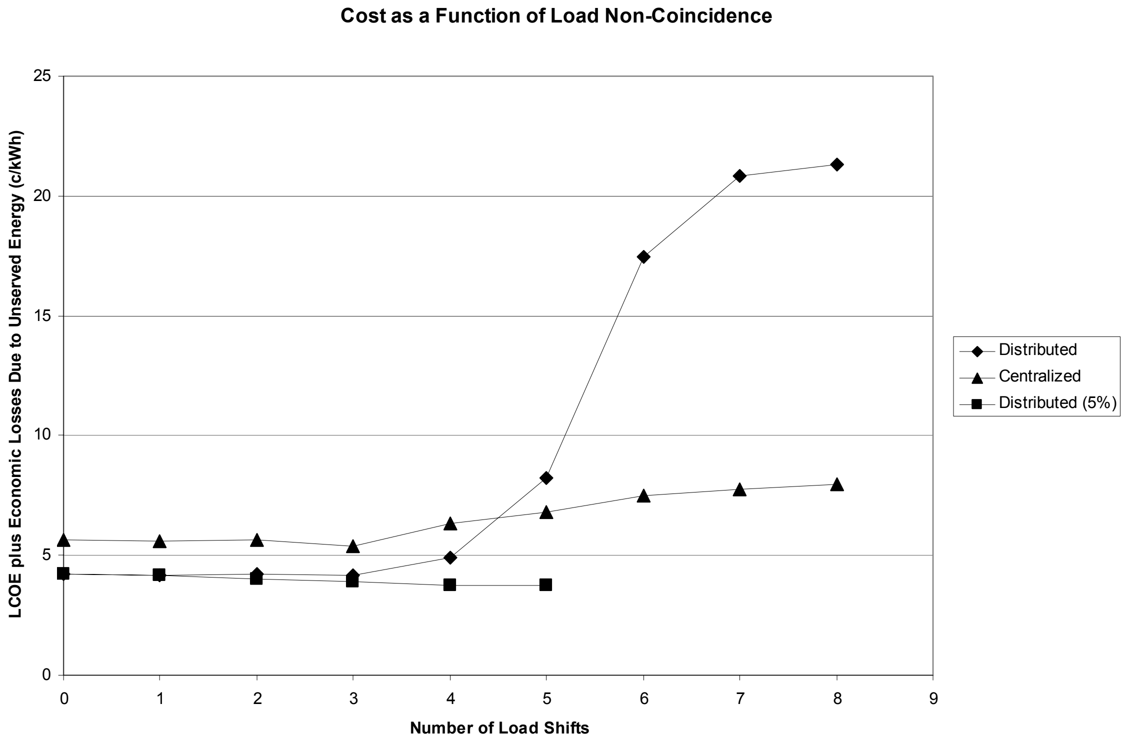


Figure 48: Cost of Centralized Versus Distributed Systems as a Function of Increasing Load Non-Coincidence

However, one big difference between the centralized and distributed system is their reliance on the network. The centralized system relies on the network to deliver 100% of the energy produced. On the other hand, the distributed system can always supply at least some power locally before relying on the network. This can be seen in Figure 49 which compares the centralized system to the distributed system with 0% reserve margin. At the moment, the results are based on a network in which there is an "area grid" that is assumed to be perfect while the linkages to and from that grid can fail. For the distributed systems with 0% the area grid is essentially not required in order to meet the load when the loads are perfectly coincident. Completely eliminating access to the area grid would increase the LOEE from ~800 MWh/year to ~6500 MWh/year, which might appear to be a large increase. However, it should be remembered that this represents only 0.043% of annual consumption. When load non-coincidence is increased, there is greater demand and the dependence on the area grid increases. At very high levels of load non-coincidence the area grid is required to meet approximately 8-9% of the demand. Again, this is compared to a complete dependence of the centralized system on the area grid to meet 100% of demand.

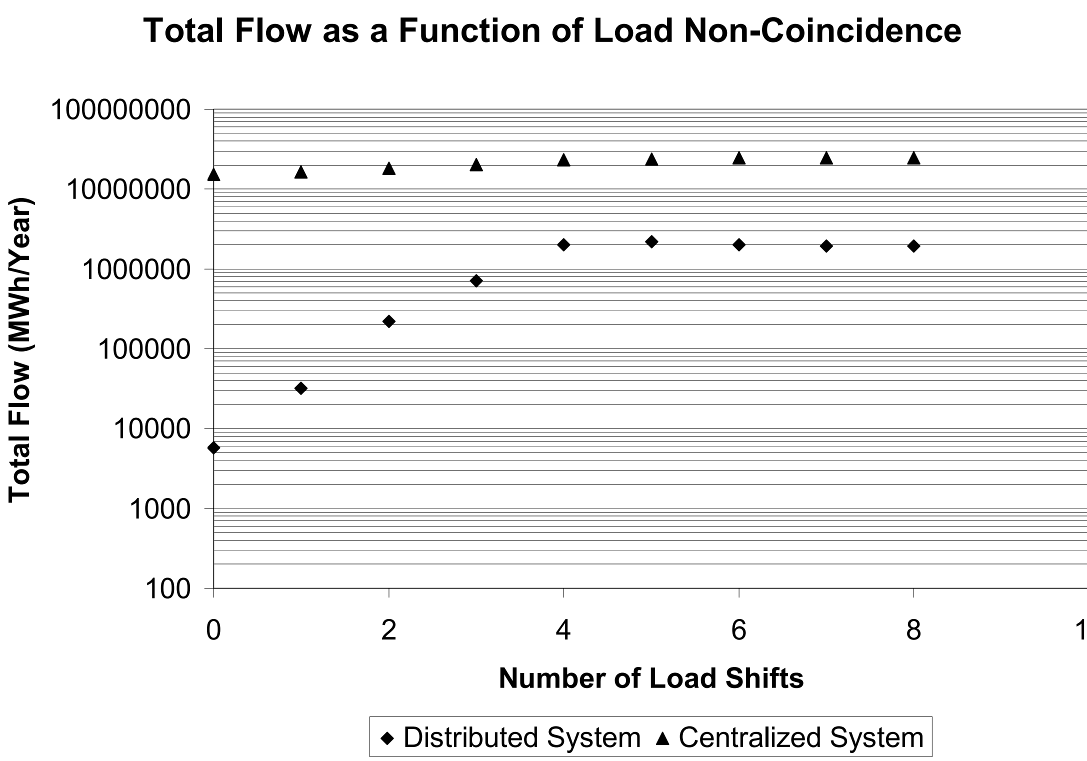


Figure 49: Total Flow on the Distribution Links as a Function of Increasing Load Non-Coincidence

The results presented in this section show the difference that load non-coincidence can make in the reliability of the system and the need for a network to carry the power to end-users. These results are based on a constant system peak approach, so that in all cases the peak load of the system is 2850 MW. This a comparison at the systems level rather than at the micro-grid level. The result of shifting the load is to flatten the load curve and to increase the peak load in each of the micro-grids. As this is done, there is an increased reliance on power sharing to maintain reliability. In the limiting case where the reserve margin is zero and the system is completely distributed, the loss of energy expectation of the distributed system is higher than the centralized system after a couple of load shifts. This is because there is no slack in the generation system and the only slack in the system comes from the fact that the loads are non-coincident. There are in fact, however, two countervailing effects. The first is that increased load non-coincidence allows for more power sharing. The other is that in this approach the loads of the micro-grids are increasing while the generation is not due to the fact that the system peak is remaining constant and the amount of DG generation is based on system peak rather than on micro-grid peak. For the DG-0 case, the second effect is stronger and there is too little surplus capacity available as the micro-grid loads increase to take advantage of the power sharing opportunities. Increasing the reserve margin to 5% for the distributed case puts slack back into the generation system and allows the distributed system to take advantage of the increased power sharing opportunities. Thus, the DG-5 system remains at nearly 0% energy loss as the load shifts, unlike the centralized system and the DG-0 system.

This shows the need for system planners to know the nature of the load at a more disaggregated scale. Systems with relatively flat and large loads at the local level could require more distributed generating capacity than a system with the same overall peak but with micro-grids that have a lower load factor (ratio of average to peak load).

7.3.3 Constant Micro-Grid Approach

In this section, results are presented for another set of model runs in which the second approach to load shifting was taken and the load data were not re-normalized to 2850 MW after each load shift. In this case, there were 273 micro-grids in the system and the model was run for only 7 different levels of load non-coincidence (perfectly coincident loads and 2^1-2^6 self-similar islands). In addition to the systematically shifted IEEE RTS demand profile, data were also downloaded for the San Diego Gas and Electric system in 1995. The SDGE data provide load profiles for residential, commercial, and industrial loads. These were renormalized such that each customer class provides approximately 30% of the demand and the system peak is 2850 MW to match the IEEE RTS.

Using the method described above, the LOEE and cost were calculated for a system with 273 micro-grids using the IEEE-RTS load data. In order to explore the full range of possible outcomes, the model was run with each microgrid having a range of installed capacities. At the low end, each micro-grid had 12 distributed units (amounting to a reserve capacity for each individual micro-grid of negative 43%). At the high end, each micro-grid had up to 24 generating units (amounting to a reserve capacity for each micro-grid of 15%). Unlike the constant system peak approach, in this approach the peak load of each micro-grid was kept constant (with the resulting system peak declining with each load shift but overall consumption remaining constant). The unit of analysis in this case is the micro-grid itself and less the overall system. By varying the number of DG units installed in each micro-grid it is possible to determine the impact that load non-coincidence and load sharing can have on installed capacity requirements and the potential trade-offs between load flow, installed capacity and reliability (as will be seen in the modeling results).

In each case, the LOEE, cost, total flow and system reserve was calculated according to the method described above. Figure 50 shows the Loss of Energy Expectation for differing levels of load non-coincidence and for differing numbers of units in each micro-grid. Figure 51 shows a more detailed view of the same data. There are a number of interesting features to the data. First, it can be seen that as the load non-coincidence increases, the LOEE decreases for the same number of distributed units in each micro-grid.

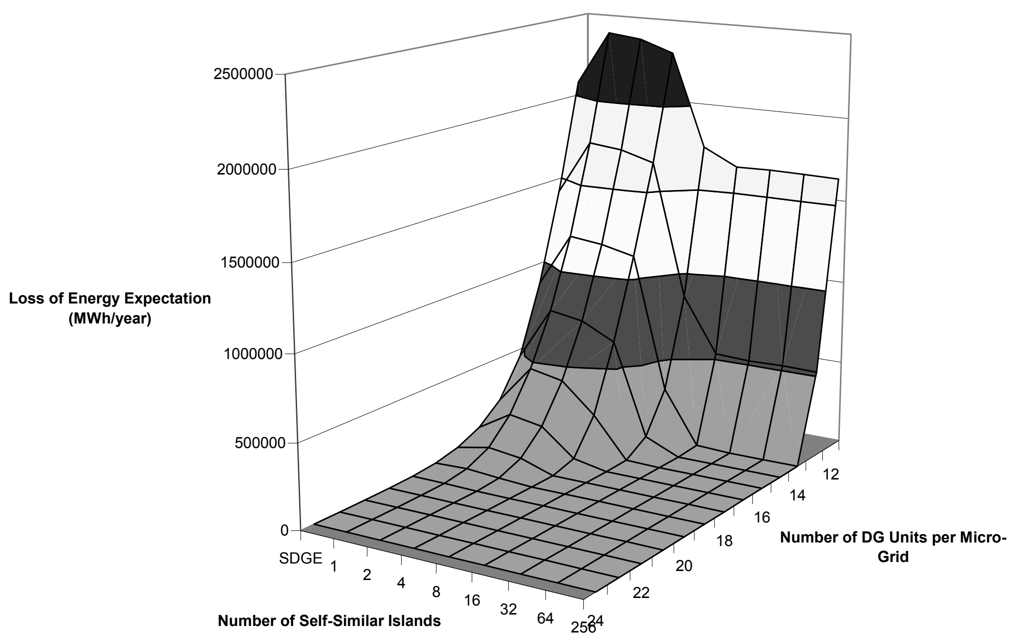


Figure 50: Loss of Energy Expectation as a Function of Load Non-Coincidence and DG Units per Micro-Grid

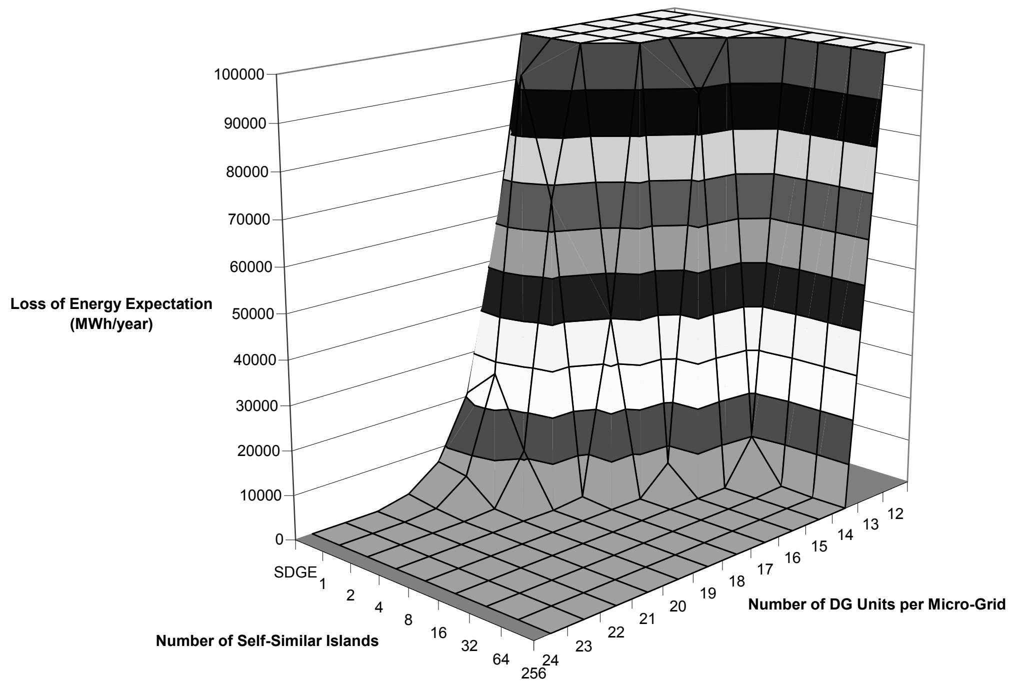


Figure 51: Loss of Energy Expectation as a Function of Load Non-Coincidence and DG Units per Micro-Grid (Detailed View)

The increased reliability of the system at higher levels of load non-coincidence is the result of the increased power sharing capabilities between the micro-grids. Figure 52 shows the flow between the micro-grids. As can be seen, the total flow between the micro-grids begins at a higher level for the systems with a greater degree of non-coincidence. As the number of DG units in the micro-grid is increased, the total flow on the network increases as there is a greater amount of power available for sharing. At a certain point, however, each micro-grid begins to have enough generation to meet native load without relying as heavily on transfers from other micro-grids and the total flow on the network begins to decrease. However, even at its peak, the flows between areas are only around 8% of total consumption for the year, comparable to the flows in the constant system peak approach above. The peak flows occur when load non-coincidence is high and dg installations are a little higher than the minimum level but cannot meet their own native peak loading requirements. The model results show at that point that LOEE is close to zero as a result of the power flows. Higher levels of DG installation still have zero LOEE, but power flows decrease due to increased ability to meet native load. Lower levels of load non-coincidence result in increased LOEE as power sharing becomes less of an option.

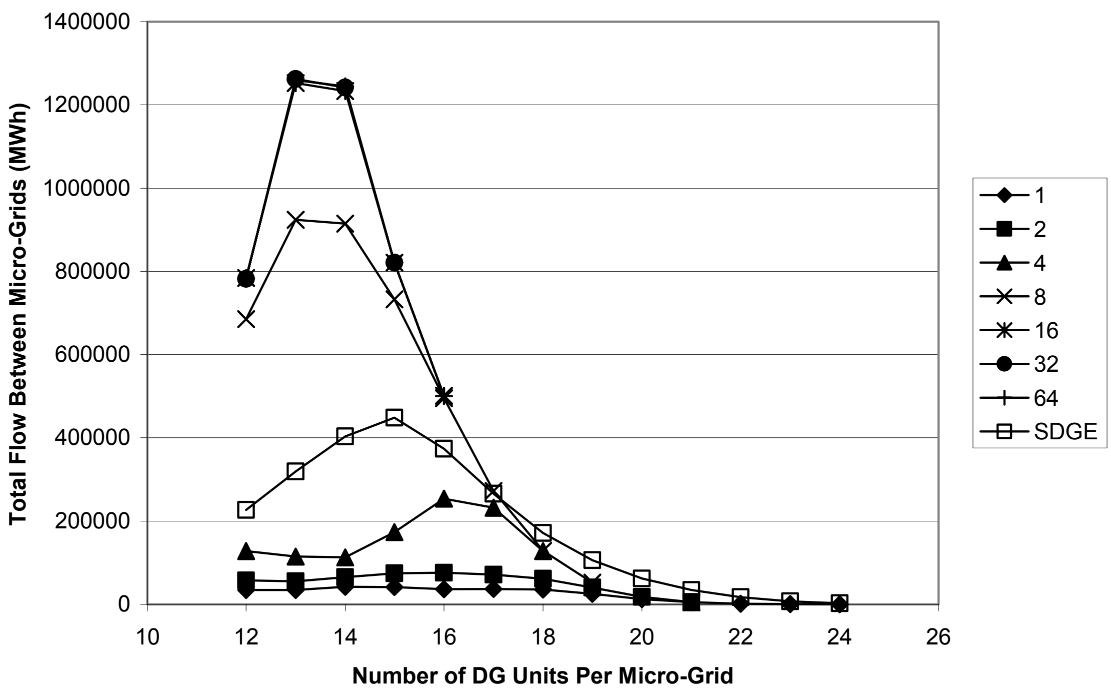


Figure 52: Total Flow Between Micro-Grids as a Function of the Number of DG Units per Micro-Grid and Load Non-Coincidence

As noted above, as the load non-coincidence increases (i.e. there are a larger number of self-similar islands), the peak load of each micro-grid remains the same while the overall system reserve margin decreases. Figure 50 and Figure 51, which plot the LOEE as a function of installed DG units, do not give information about how that number of DG units is related to overall generation and demand levels (which fall as load non-coincidence increases). Figure 53 plots LOEE as a function of the system reserve. Figure 9 shows that, while it requires almost 20 DG units per micro-grid to have equivalence with the centralized system when all of the loads are perfectly coincident (Figure 51), the system reserve in this case is actually less than 0. On the other hand, for loads with 64 self-similar islands the equivalence is at 14 DG units per micro-grid, but the overall system reserve is around 2%.

Figure 54 shows the same LOEE data, but now plotted as a function of the reserve margin for each individual micro-grid. In this case, the order of Figure 51 is preserved, the 64 self-similar islands curve crosses the centralized threshold at a much lower reserve margin than when loads are perfectly coincident. It is also worth noting that the reserve margins at the point when equivalence is reached with the centralized system range from almost -10% to over -30%, showing the reliance on power sharing to achieve reliability.

The reliability of the system as a function of system reserve rather than micro-grid area reserve illustrates how focusing on one or the other measure of adequate generation capacity can lead to a misunderstanding of the reliability of the system.

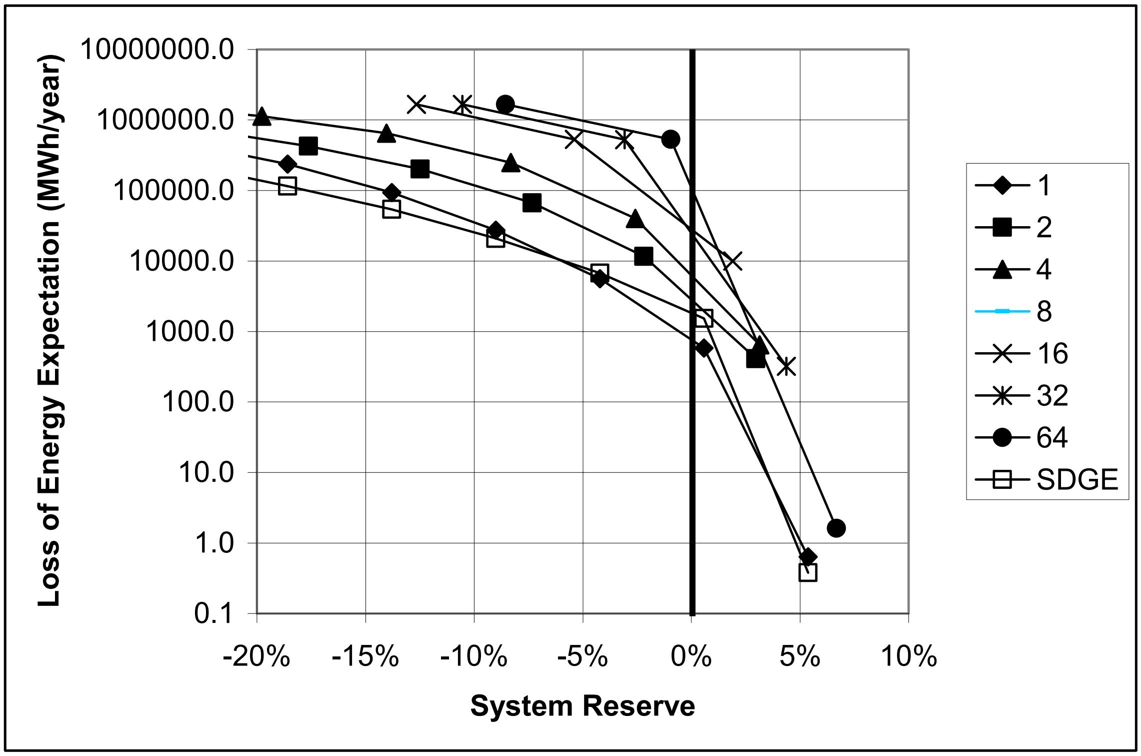


Figure 53: Loss of Energy Expectation as a Function of System Reserve for Different Levels of Load Non-Coincidence

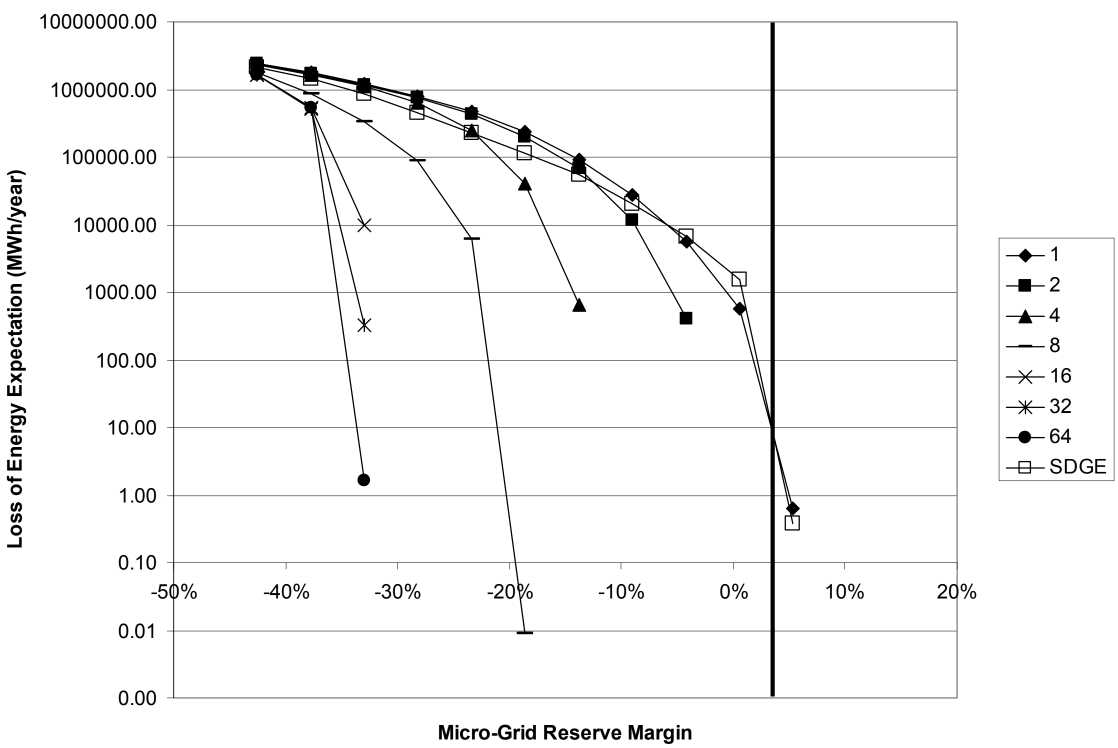


Figure 54: Loss of Energy Expectation as a Function of Individual Micro-Grid Reserve Margin for Different Levels of Load Non-Coincidence

Similar results are found when comparing the system costs as a function of installed capacity and load non-coincidence. Figure 55 shows the cost as the number of DG units installed per micro-grid is changed from 12 to 24 for different levels of load non-coincidence. As load non-coincidence increases, the levelized cost decreases for the same amount of installed generating capacity. For example, if each micro-grid has 16 DG units installed, then the levelized cost of electricity and economic losses amount to around 5 c/kWh when there are 8 or more self-similar load configurations. For lower levels of load non-coincidence, there is less possibility of sharing energy between micro-grids and the cost is 10 c/kWh or more. Another way of looking at this figure is that for a given target cost of electricity, the number of DG units that have to be installed per micro-grid is less when load non-coincidence increases (up to a certain point, at which time increased load shifting does not result in significant changes to the cost). Figure 56 and Figure 57 show the costs as a function of system reserve and micro-grid reserve respectively.

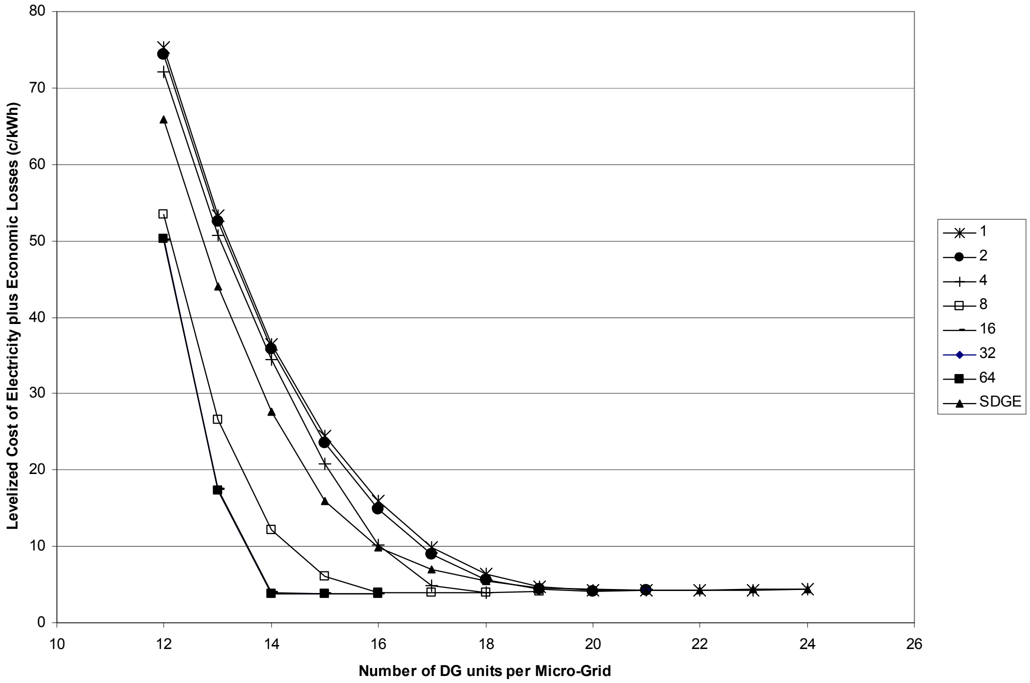


Figure 55: Levelized Cost of Electricity plus Economic Losses as a Function of Installed DG Capacity per Micro-Grid and Load Non-Coincidence

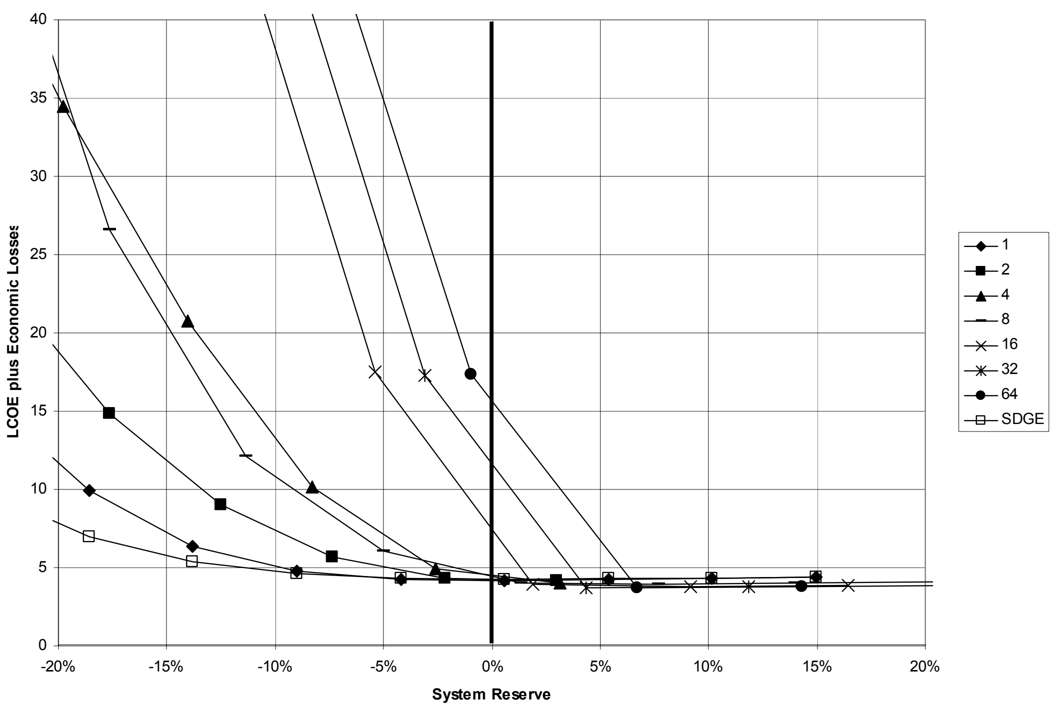


Figure 56: LCOE plus Economic Losses as a Function of System Reserve for Different Levels of Load Non-Coincidence

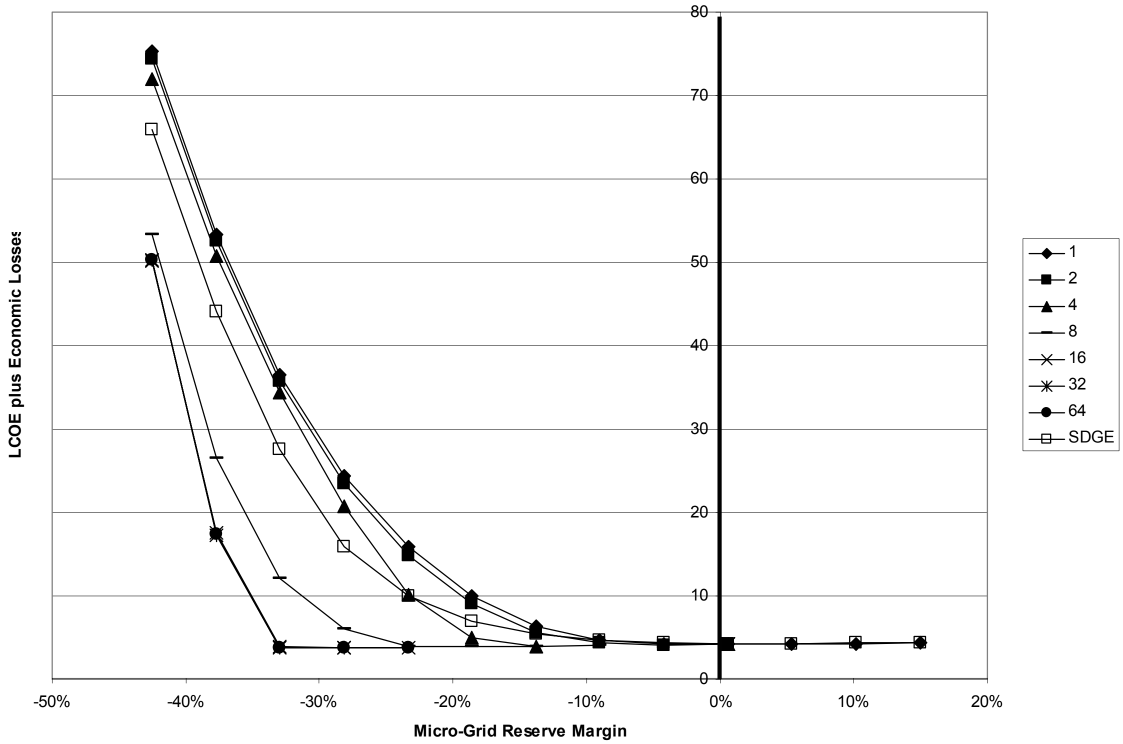


Figure 57: LCOE plus Economic Losses as a Function of Individual Micro-Grid Reserve for Different Levels of Load Non-Coincidence

If individual decision makers exist at each micro-grid and overall system effects are ignored in favor of building enough generation to meet local load, the result is a system that could be over-built, with corresponding economic costs. For example, for a system in which there are 16 self-similar islands, the lowest cost occurs when there are 15 DG units in each micro-grid (3.79 c/kWh). If enough units were constructed to meet all of native load (21 units) then the cost would be 4.18 c/kWh (approximately 10% higher). If each micro-grid built in a 10% reserve margin, then the cost increases to 4.32 c/kWh (14% higher).

At the same time, the ability to install less distributed generation capacity at each micro-grid and rely upon network flows to maintain high levels of reliability results in a dependence on power flows. If those power flows are interrupted, the potential economic losses could be quite high. For the same example as above, if only 15 DG units are installed and all the power flow is interrupted then the economic losses increases and overall cost is 25.75 c/kWh. On the other hand, the loss of shared power has a minor impact if 21 units are installed and costs only rise to 4.32 c/kWh.

A decision maker will be indifferent between installing 15 units and 21 units at a certain value for the availability of the link to the area grid. If D is the probability of failure for the distribution link then:

$$(1 - D) * 4.18 + D * 4.32 = (1 - D)*3.79 + D * 25.75$$

$$4.18 + 0.14 * D = 3.79 + 21.96 * D$$

$$21.82 * D = 0.39$$

$$D = 0.018$$

The baseline failure probability is 0.00067, therefore the stress adjustment factor on the distribution link (see previous chapters for discussion of stress on differing components in the system) must reach 26.7 ($D/D_o = 0.018/0.00067 = 26.7$) for the decision maker to be indifferent between the two options.

7.4 Conclusion

The degree to which loads in different micro-grids are coincident has a large impact on the level of distributed generation necessary for a given level of reliability. In this section, model results were presented that are based upon the micro-grid being the unit level of analysis. That is, as loads were shifted the micro-grid peak and load shape were kept constant (resulting in a decreasing system peak load). The model was run for various levels of load non-coincidence and for various levels of DG installation. The results show that LOEE and power flow between micro-grids depends upon load non-coincidence, the ability to meet native load and having a minimum level of generation in order to be able to share power. As load non-coincidence increases, the possibility of power sharing between micro-grids increases. However, if the number of DG units installed is too low, then there is minimal power sharing and micro-grids have a hard time meeting their own load even in off-peak times. Increasing generation allows for increased power sharing, up to the point where the amount of DG installed at the micro-grids is sufficient to meet most or all of native load all the time. The greatest amount of power sharing occurs at high levels of load non-coincidence and low (but not minimal) levels of DG installation.

These results indicate that decision-makers need to be cognizant of the possibilities of load sharing and the investment in distributed generation across micro-grids. As the owner or planner of a micro-grid, installing enough generation to meet all of native load (and perhaps a little extra for reliability reserve) may not make economic sense if there is the possibility of load sharing with other micro-grids. If each micro-grid decision-maker were to invest in such a way, there would be overinvestment in generation (as can be seen in the reserve margins, which could rise dramatically higher than the current 20% in centralized generation).

As the calculation presented above shows, the decision to rely on the rest of the micro-grids should also depend upon the reliability of the link to the grid. However, that calculation indicates that distribution level failures would have to be significantly higher than the baseline norm in order to make the investment in extra generation worthwhile.

The decision will also depend on the value of lost energy. At the moment all of the micro-grids are assumed uniform in their cost to produce energy and their value of lost energy. Changes in either of these parameters for a subset of the micro-grids would change the calculation in terms of the value of investment. There may, therefore, be a subset of customers for whom the value of lost energy is exceedingly high (e.g. semiconductor manufacturers) and installing enough DG to meet all of native load would not be an overinvestment. On the other hand, given that the value of lost energy used above is a composite of different sectors of the economy, there is also a subset of people for whom the value of lost load would be lower and the overinvestment could be considered to be even larger.

Future work could include adding stress on the system, as with previous models. The impact would obviously depend on whether the stress is placed on the generation system or the distribution system. For a given level of reliability and a given level of load non-coincidence, increasing stress would require increased generation. If the stress were on the distribution system, the increased generation would be used to meet native load. If the stress were on the generation system, the increased generation would be used to increase power sharing. Another extension of the model could vary the economic loss coefficient for different micro-grids based upon the nature of the load in the micro-grid (residential, commercial, industrial).

A third possible extension of the model would allow for uneven distribution of DG units in each micro-grid. Given the need for heat credit to make the distributed generation economically competitive with centralized power, and the actual history of installed DG capacity, it would be more realistic that distributed generation would be installed at commercial and industrial micro-grids rather than residential ones. This would increase the reliance on power flows between micro-grids.

7.5 Appendix: Creating Load Non-Coincidence

This appendix provides supplemental information on the load shifting methodologies and the results of shifting the loads.

7.5.1 Load Shifting Algorithm

The steps in the load-shifting algorithm are shown below (as Matlab code). RTSDEMAND is a vector containing the original load profile of the IEEE RTS. Line 1 divides this vector by the number of micro-grids. Lines 2 and 3 then create a matrix that is that vector of micro-grid loads repeated once for each micro-grid. This is the base matrix that is then modified to create the load shift. The loop in lines 5 to 13 creates the load shift for up to 2^N microgrids. Lines 15-18 handle cases in which the number of micrograms is not a power of 2. In that case, the remaining micro-grids are randomly assigned a load-shifted micro-grid. For example, if there are 273 micro-grids, the first 256 micro-grids will be shifted N times. If N is 2, for example, then there would be 2^2 basic load profiles with peaks occurring a quarter year apart, created by shifting the first 256 micro-grids. The remaining 273-256 micro-grids would be randomly assigned to have one of those four characteristic load profiles.

```
1.      areademands = rtsdemand/LEPSTot;
2.      demand_full = zeros(8736,LEPSTot);
3.      demand_full = repmat(areademands,1,LEPSTot);
```

```
for n = 1:N
    areademands = repmat(areademands,1,2);
    areademands_temp = areademands;
    [rows cols] = size(areademands);
    k = round(rows/(2^n))';
    areademands_temp(1:k,(cols/2+1):end) = areademands((end-k+1):end,(cols/2+1):end);
    areademands_temp((k+1):end,(cols/2+1):end) = areademands(1:(end-k),(cols/2+1):end);
    areademands = areademands_temp;
end

demand_full(:,1:floor(LEPSTot/2^n)*cols) = repmat(areademands,1,floor(LEPSTot/2^n));
a = 1;
b = (LEPSTot/2^n - floor(LEPSTot/2^n))*cols;
demand_full(:,(floor(LEPSTot/2^n)*cols+1):end) = areademands(:,floor(a+(b-a)*rand(1,b)));
```

7.5.2 Characteristics of Shifted Loads

As noted above, there are two approaches to shifting the loads to create load non-coincidence. In one the loads are renormalized after the shift process described above in order to keep the system peak constant. In the second, the loads are not renormalized, resulting in decreasing system peaks but constant micro-grid peaks. Summary data for the two methods are shown in Table 19. Note that in both cases, the load shift has the effect of flattening the load curve (i.e. reducing the variance in the load).

Table 19: Summary Data for the Two Load Shifting Approaches

Summary Data for Constant System Peak Load Shifting					
Number of Shifts	Number of Areas	Mean	Median	Variance	Peak
0	1	1751	1738	160470	2850
1	2	1883	1869	176430	2850
2	4	2095	2041	184550	2850
3	8	2317	2305	47341	2850
4	16	2664	2662	4163	2850
5	32	2740	2727	2192	2850
6	64	2814	2814	291	2850
7	128	2838	2838	26	2850
8	256	2841	2841	12	2850
Summary Data for Constant Micro-Grid Peak Load Shifting					
Number of Shifts	Number of Areas	Mean	Median	Variance	Peak
0	1	1751	1738	160470	2850
1	2	1751	1738	152620	2651
2	4	1751	1706	128870	2382
3	8	1751	1743	27051	2154
4	16	1751	1750	1799	1873
5	32	1751	1743	895	1821
6	64	1751	1751	113	1773
7	128	1751	1751	10	1759
8	256	1751	1751	4	1757

7.5.3 Distribution of Peak Hours

The distribution of hours in which the peak occurs is shown in the following four figures. Along the x-axis is the micro-grid number. Along the y-axis are the hours in the year. In the case of perfectly coincident loads each micro-grid would have its peak load in the same hour of the year and the result would be a horizontal set of points at that hour. When the load is shifted once half the micro-grids have their peak at the same hour as in the original and the other half have their peaks in another hour. The result would be two horizontal sets of points (micro-grid one would have a peak at Hour A, micro-grid 2 at Hour B, micro-grid 3 at Hour A, micro-grid 4 at Hour B, and so on). The graphs below show what happens when the load shifting results in 4, 8, 16 and 256 groups of micro-grids, each micro-grid in a group having the same peak hour as the micro-grids in that group. As you can see, in the final one there is no peak load coincidence at all. The graphs below are based on comparison of different systems with the same area loads and declining system peaks).

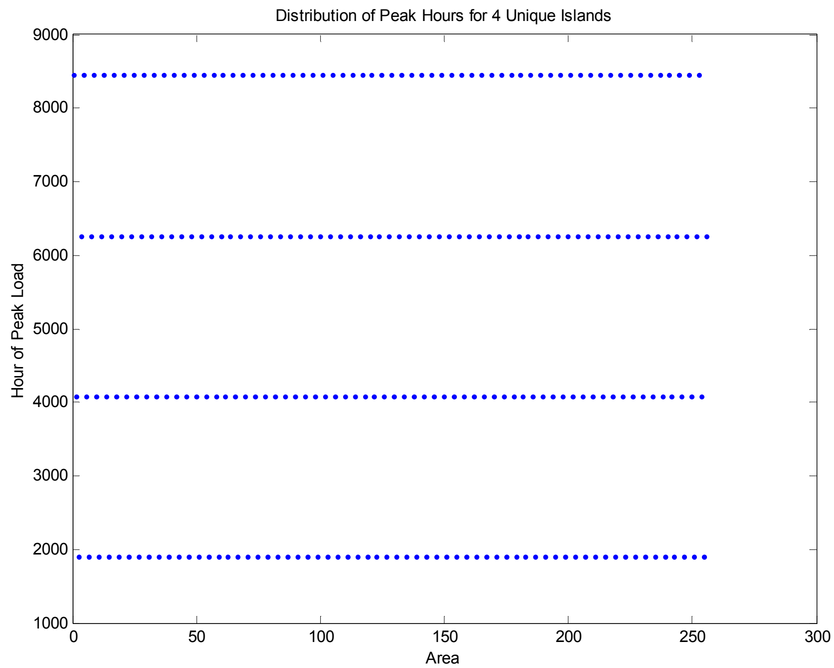


Figure 58: Distribution of Peak Hours for 4 Unique Islands

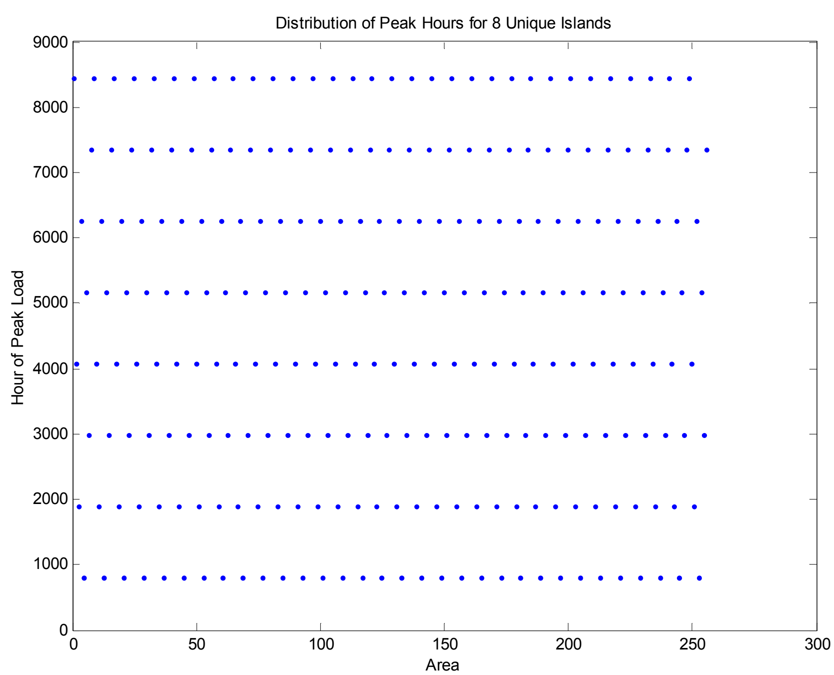


Figure 59: Distribution of Peak Hours for 8 Unique Islands

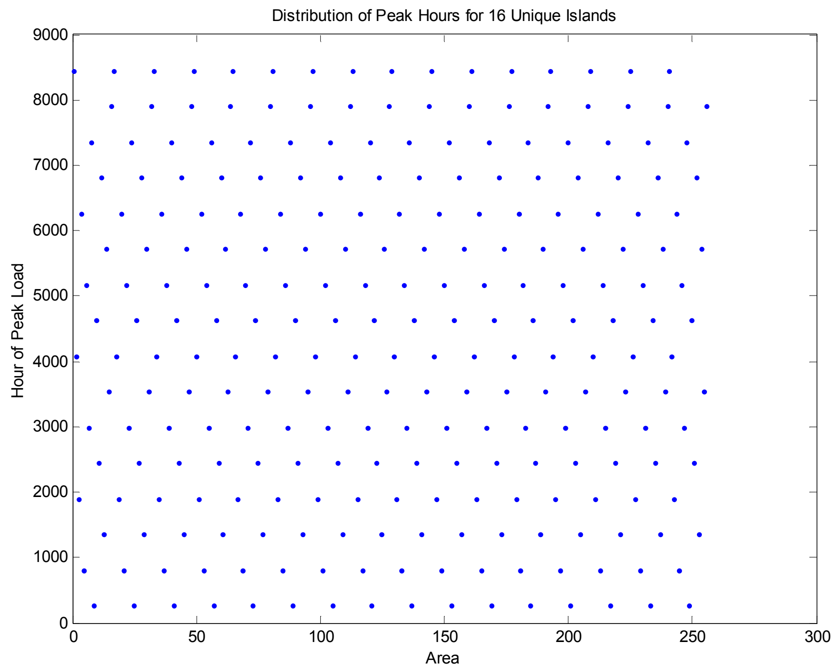


Figure 60: Distribution of Peak Hours for 16 Unique Islands

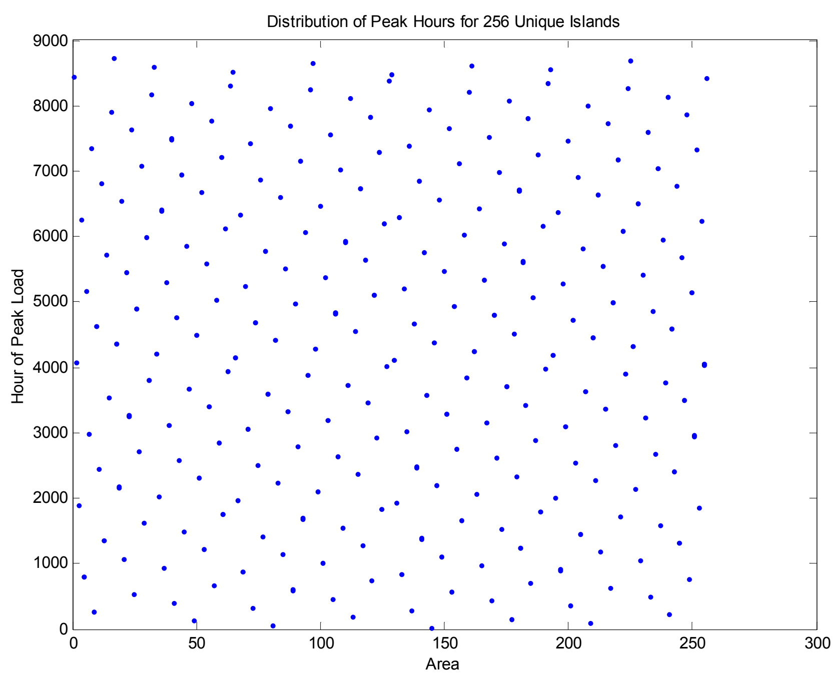


Figure 61: Distribution of Peak Hours for 256 Unique Islands

7.5.4 Effect of “Extra” Micro-Grids

One minor issue that should be noted in this method is the issue of “extra” micro-grids. The load shifting is based on powers of 2 since in each load shift, the characteristic loads are split into two groups and one group is shifted. If there are 256 islands (as the examples above show), there are always the same number of micro-grids in each group. However, it is also possible to use a different number of islands. In those cases, the number of islands is not divisible by 2^n. In order to assign all micro-grids to one of the load profile clusters, the “leftover” micro-grids can be assigned to one of the groupings randomly.

Chapter 8 Transmission Line Usage

8.1 Introduction

One of the oft-stated advantages of distributed systems is a reduced reliance on the transmission system due the generation of power at the demand center. However, unless each load or micro-grid installs sufficient generation to meet all of its demand, there will be a need for power sharing in order to meet load. Furthermore, it may even be desirable to reduce the generation installed and allow for power to be shared in order to meet demand at a lower cost. The previous chapter has shown the amount of power sharing between micro-grids is a function of a number of parameters, including the shape of the individual load profile and the amount of DG installed at each micro-grid.

If power sharing between micro-grids is desirable, there remains the question of whether such power sharing would be limited locally or would involve the use of the higher-voltage network. In the model described below the network consists of 138 kV and 230 kV transmission lines connecting 24 buses. This is considered to be the high voltage network and is necessary for transporting power from generation to load in the centralized case. If power sharing is more "local" then it occurs between micro-grids that are linked to the same high-voltage bus. This will be referred to as a micro-grid cluster. As noted elsewhere, the distribution system within each micro-grid is not explicitly modeled. The voltage level at which the power sharing occurs and the level at which it is modeled has implications for the necessary system protection, however, this is not a focus of this thesis. In the previous models, all of the micro-grids were radially attached to an area grid that was assumed to be perfect (essentially, it acted as a single bus). In this chapter, a model is detailed in which the micro-grids are attached to a more realistic network topology than in the previous models that used a hierarchical network topology. The following section will describe the network and the methods used to analyze power flows on the network. The section after will describe model results.

8.2 Methods

This section will briefly describe the network topology used for this model and then the modeling methods used to determine network flows.

8.2.1 Network

There were two basic network configurations compared in this model. In both cases, the network topology itself is the IEEE-RTS 24 bus network. This is shown in Figure 62. The first network configuration is the original IEEE-RTS with centralized generation. The centralized generators are depicted in Figure 62 as circles with a sine wave. The loads are depicted as triangles. The second network configuration removed all of the centralized generators. The loads (which are in the range of tens or hundreds of megawatts) were replaced with micro-grids at the original load point. Thus, if a bus (e.g. bus 1) originally had a load of 90 MW, it would now have 9 microgrids, each with a peak load of approximately 10 MW. The microgrid would contain both generation and load. A different number of distributed generators can be placed at the microgrid, however, the generated power produced by the set of DG units at any micro-grid is assumed to range from 0 to the maximum possible total generation for the units at that micro-grid (that is, they behave essentially as one unit).

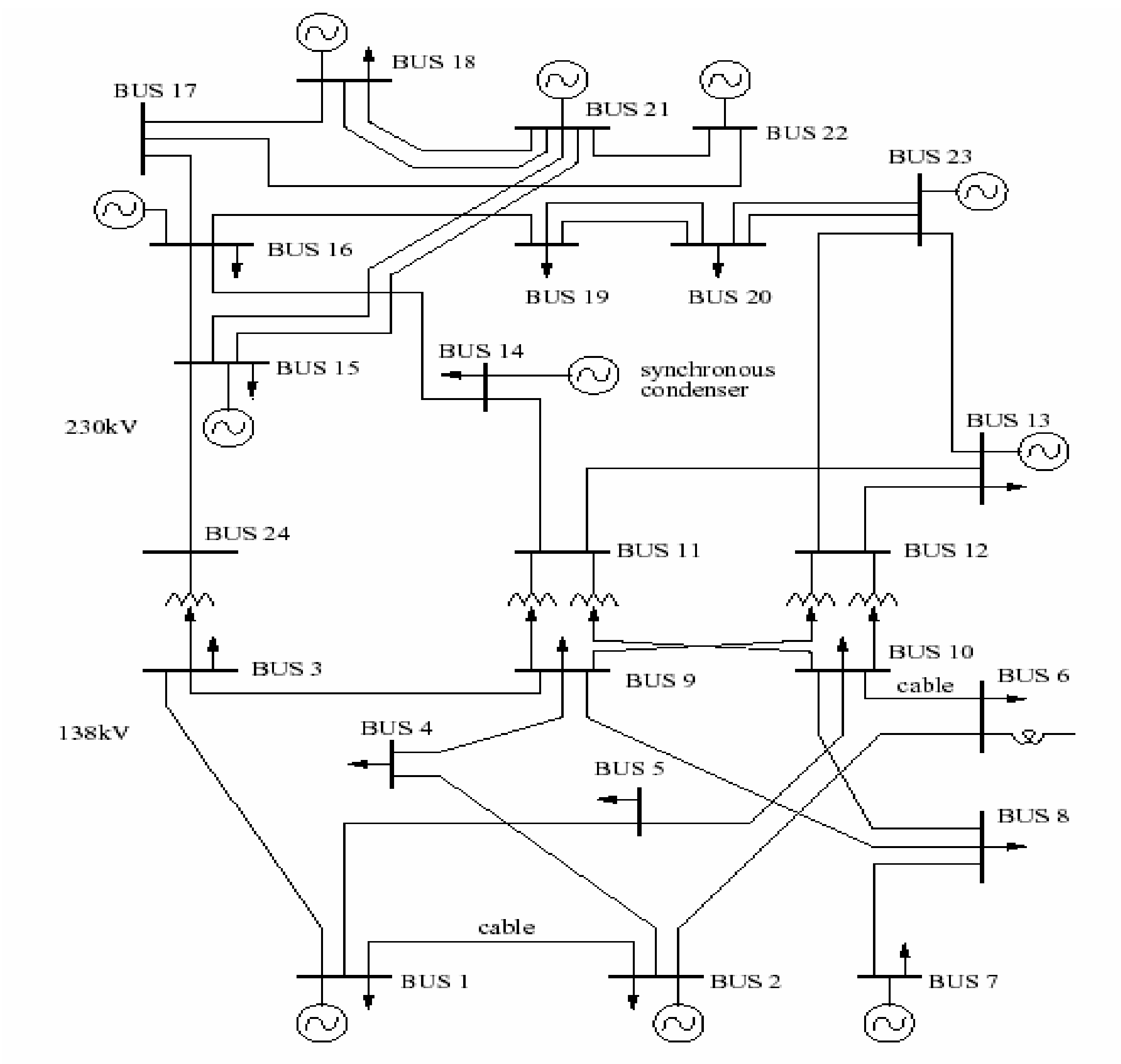


Figure 62: IEEE-RTS Network Topology

8.2.2 Optimal Power Flow

In order to determine network usage, an optimal power flow algorithm was used. The optimal power flow attempts to meet demand at the lowest cost for the two different network configurations. The optimal power flow consists of two basic parts. The first is a DC Power Flow that determines an initial starting point for the OPF by determining line flows and generation without consideration of cost or limits on power generation or transfer. The second is an optimal power flow that minimizes cost subject to certain constraints. The formulation for both of these is presented below.

8.2.2.1 DC Power Flow

The DC Power Flow is a simplification of the full AC power flow. Its advantages are that it is computationally much faster than the AC power flow and less subject to non-convergence or other issues when considering large networks or islanded networks.

The power flow (P) is a function of the voltage (E) and the current (I). The current, I, is in turn a function of the network parameters and is given by Y*E. Y is the admittance matrix and is determined by the physical line parameters of the system. Diagonal elements Y_{ii} of bus (i) are the sum of the impedances connected to a node and off-diagonal elements are the negative of the impedance connecting to buses in the network. For real and reactive power then, the following equations are used:

$$P_j = E_j I_{ij}$$

$$\begin{bmatrix} I_1 \\ I_2 \\ I_3 \\ \\ I_n \end{bmatrix} = \begin{bmatrix} Y_{11} & Y_{12} & Y_{13} & Y_{1n} \\ Y_{21} & & & \\ Y_{31} & & & \\ Y_{n1} & & & Y_{nn} \end{bmatrix} \begin{bmatrix} E_1 \\ E_2 \\ E_3 \\ \\ E_n \end{bmatrix}$$

where,

$Y_{ij} = -y_{ij}$ (if i connected to k, zero otherwise) and

$$Y_{ii} = \sum_j y_{ij} + y_{ig}$$

$$P_i + jQ_i = E_i I_i^*$$

$$I_i = \sum_{k=1}^{N} Y_{ik} E_k$$

These equations can be expanded to show both the real and complex parts of the equation (below). Thus, the power becomes a function of the voltage magnitudes (E), the resistive and reactive components of the impedance (G and B) and the voltage angle (δ) as shown in the following equations. At this point, iterative methods such as the Newton-Raphson method would be used to solve the AC power flow. However, making certain assumptions (a subset of which are shown below), it is possible to simplify these equations into a DC power flow that can be solved analytically, rather than iteratively.

$$P_i + jQ_i = \sum_{k=1}^{N} |E_i||E_k|(G_{ik} - jB_{ik})\varepsilon^{j(\delta_i - \delta_k)}$$

$$= \sum_{k=1}^{N} \begin{Bmatrix} |E_i||E_k|[G_{ik}\cos(\delta_i - \delta_k) + B_{ik}\sin(\delta_i - \delta_k)) + \\ j|E_i||E_k|[G_{ik}\sin(\delta_i - \delta_k) - B_{ik}\cos(\delta_i - \delta_k)) \end{Bmatrix}$$

Assumptions:

$\cos(\delta_i - \delta_k) \cong 1$

$r_{ik} << x_{ik}$

$E = 1$

Drop Q - V Equations

The result of these assumptions is to only account for real power flow and to eliminate the resistive component of that real power flow in order to make the flow DC. The real power flow component of the summation above is a function of the voltage magnitude (E), the resistive impedance (G) times the cosine of the voltage angles and the reactive impedance (B) times the sine of the voltage angles. The G term is dropped because the resistance is much smaller than the impedance (Assumption 2) and the cosine of the angles is assumed to be equal to 1 (Assumption 1). Along with Assumption 3, that the magnitudes of the voltages are 1, the real power flow is now a function only of the reactive impedance (thus there are no line losses, since those are a function of resistance) and the voltage angles.

With the assumptions above, the equations for power take on the following form:

$$\begin{bmatrix} \Delta P_1 \\ \Delta P_2 \\ . \\ . \\ . \end{bmatrix} = [B'] \begin{bmatrix} \Delta \delta_1 \\ \Delta \delta_2 \\ . \\ . \\ . \end{bmatrix}$$

where,

$$B'_{ik} = -\frac{1}{x_{ik}} \text{ (if i connected to k, zero otherwise) and}$$

$$B'_{ii} = \sum_{k=1}^{N} \frac{1}{x_{ik}}$$

$$P_{ik} = \frac{1}{x_{ik}}(\delta_i - \delta_k) \text{ and } P_i = \sum_{\substack{k=\text{buses} \\ \text{connected to i}}}^{N} P_k$$

Again, this is now a DC power flow since there are no line losses (the resistive component has been dropped out of the equations) and no reactive component (the Q-V equations have been dropped). These equations can be used to computer power flows on lines (P_{ik}) and power injections (P_i) based on the reactance of the connecting lines and the voltage angles at the buses.

However, it is necessary to note that there are an infinite number of combinations of voltage angles that would result in a balanced power flow. In order to set a unique solution, one bus is set to be the reference bus and its voltage angle is fixed at zero. All of the voltage angles of the other buses are set accordingly. The power generation at the reference bus is set in order for the power flow to balance.

8.2.2.2 Optimization[63]

The preceding equations are insufficient because they do not account for limits on either generation or transmission. In fact, because it is necessary to set a reference bus, generation at that bus will be set to whatever value is necessary in order for generation to meet demand. It is therefore necessary to optimize the power flow in order to a) ensure that the lowest cost units are being used to their full capabilities (this is called merit order dispatch in centralized systems), b) ensure all limits are adhered to, and c) ensure that load shedding minimizes economic losses.

The following linear minimization was developed in order to accomplish that task. The three sets of decision variables are the power generated by each generator, the voltage angle at each bus (which determines power flow) and the load shed at each load bus. The cost is a sum of the power generation costs (Power generated times variable O&M costs per kWh generated), the cost of setting the voltage angle (which is zero, but has to be included in the minimization because it is a decision variable) and the load shed cost (the amount of load shed times the load shed cost for that bus).

The costs are subject to the constraint that the line flows (from and to each bus) are below the capacity of the line, that for each bus the power transferred to or from the bus plus the

[63] The Optimal Power Flow was run in Matlab using the linprog solver. The formulation described here is a modification of an OPF developed by Paul Hines of the Carnegie Mellon Electricity Industry Center (phines@cmu.edu for more information) and also uses some of the supporting files of the MatPower package developed by PSERC ((Strachan 2000)) Modifications to Paul Hines' OPF include turning it into a DC power flow, allowing the OPF to run on the individual islands in an islanded system and using a linear cost function that accounts for load shed costs.

power generated at the bus plus the load served at the bus be equal to zero (this ensure generation meets demand) and the final constraint is that the reference angle remain zero.

$$\min_{P,\delta,L} \sum_{i=1}^{N} b_i P_i + \sum_{j=1}^{M} c_j \delta_j + \sum_{k=1}^{T} d_k D_k L_k$$

$$s.t.$$

$$B_f \delta_j \le C_{\max}$$

$$B_t \delta_j \le C_{\max}$$

$$B_p \delta - P + D(1-L) = 0$$

$$\delta_{ref} = 0$$

where

P = Power Generated by Generator i

N = Number of Generators

b = Variable O & M of Generator i

δ = Voltage Angle at bus j

M = Number of Buses

c = cost coeffecient of angle = 0

L = Load shed at bus k

D = Original Demand at bus k

d = Load shed cost at bus k

B_f = B Matrix "From Bus"

B_t = B Matrix "To Bus"

B_p = B Matrix

8.2.2.2.1 Setting Initial Conditions

Setting the initial conditions correctly for the distributed cases is important in order to avoid artificially high power flows that result directly from the absence of line losses and penalties for line usage and indirectly from uniformity in generation costs and load-shed costs. In the case that all of the distributed generators have equal dispatch costs and all the loads the same load-shed costs, the optimal power flow cannot distinguish between sending power from one micro-grid to another within its own cluster and sending power across the higher voltage network. Penalizing line flows directly is not an option if the OPF is to be kept linear. The flow on a given line is the function of the difference in voltage angles between the buses. More importantly, the line flow can be positive or negative. Without moving to a non-linear cost function (i.e. by squaring the line flow to ensure it is positive and adds to the cost) it is not possible to assign a cost to line flows. It is also not possible to add it directly into the constraint functions.

This problem was solved by setting the initial conditions and boundary conditions for generation at the microgrids. The minimum generation at each microgrid was set to be either the minimum of the load at the microgrid or the generation at the microgrid. In other words, microgrids try to meet as much of their own native load as possible. Any generation available above their native load can be used to meet the load of other micro-grids that are not able to meet their native load. The initial starting conditions of the power flow were set the same way so that microgrids start off trying to meet their native load. It was found that this helped with convergence of the power flow. With these initial conditions and boundary conditions the flow on the IEEE-RTS high voltage network is kept to a minimum. There is still a small residual amount of power flow that occurs over those lines that is not strictly necessary and is an artifact of the structure of the optimal power flow. However, we estimate that it introduces an error of only around 10%.

8.3 Results

In order to determine network usage it was necessary, as with the previous chapter, to use the hourly loads at each micro-grid. For this model, what was of interest was not the reliability of the system, but rather the network usage. Therefore, rather than run a reliability analysis, all of the components in the system were assumed to be perfectly reliable and the network flow was determined for every hour of the year and recorded.[64] Furthermore, while it would be interesting to run a full reliability analysis including the power flow, it would be computationally intensive as the OPF has to be run for every hour and for every run in the simulation. Assuming just 500 runs per hour for the simulation and 8760 hours per year, this would entail over 4 million calls to the OPF (possible solutions to this problem are briefly summarized in the concluding section of this chapter).

Results are shown first for the centralized case as it is the baseline against which the line flows in a distributed case must be compared against. The load data used were the static load profiles for residential, commercial and industrial users in the San Diego Gas and Electric utility area (see previous chapter). The loads were clustered together as described below for the distributed scenarios and then aggregated up to the IEEE-RTS load bus level.

[64] If there was shed load, this was recorded as well. However, since this is not a Monte Carlo simulation based on the failure probabilities of the system components, this cannot be equated to the reliability of the system and compared to the previous model results. However, it can be used to compare system performance for systems evaluated using this model, under the generous assumption of lack of failures.

The data are shown first as a histogram of line flows. Figure 63 shows a histogram of the power flowing over the transmission lines. The x-axis is MW of line flow, the y-axis is the number of hours and each colored bar represents one of the 38 branches connecting the 24 buses in the system. Thus, if one added up all of the brown bars, the total would be 8760 hours. Not surprisingly, the line loadings range from nearly zero to over 300 MW. Given that different lines have different maximum capacity ratings, it is perhaps more useful to present the data as a percent of maximum line ratings. This is shown in these line loadings reach up to approximately 90% of rating for the most heavily loaded line.

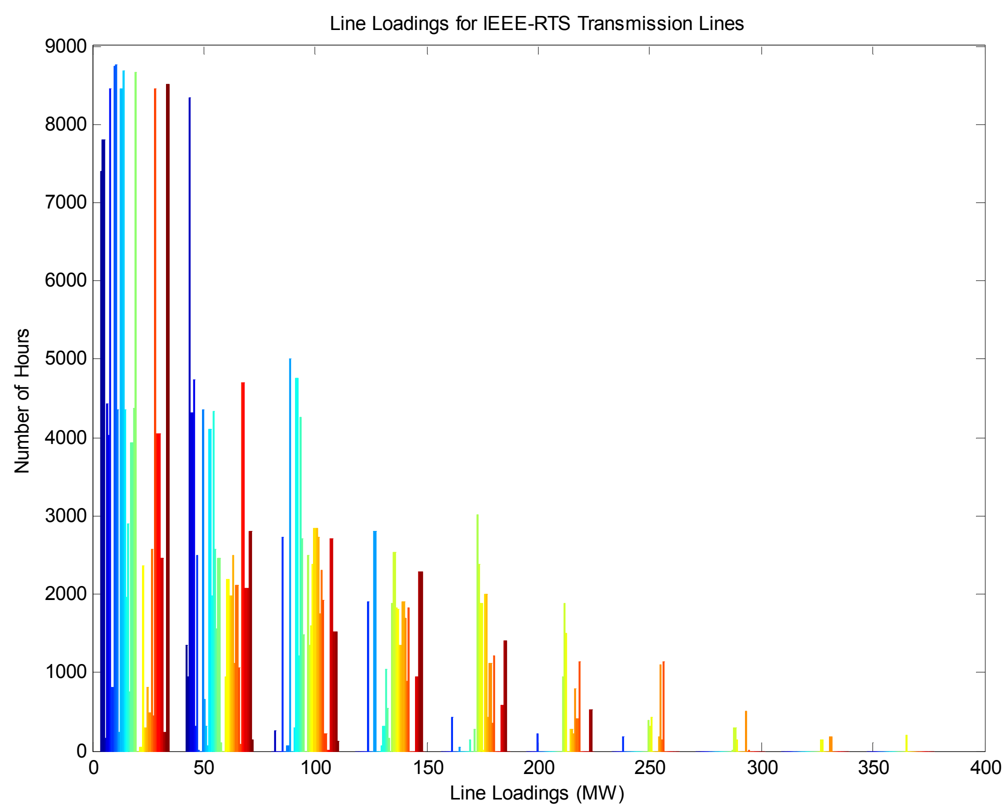


Figure 63: Line Loadings on IEEE-RTS Network Transmission Lines for the Centralized Generation Case

The data can also be viewed as a cumulative distribution function of line loadings and hours. This is shown in Figure 64. Along the x-axis are line flows in MW and along the y-axis is the cumulative probability that a combination of transmission line and hour has a line flow of that magnitude. This figure shows that 90% of the line-hours have power flows less than 150 MW. The same type of CDF can be constructed for the percent maximum line rating data. This is seen in Figure 65. From this figure it can be seen that for well over 90% of the lines and hours, the line flows are below 50% of the maximum rated capacity.

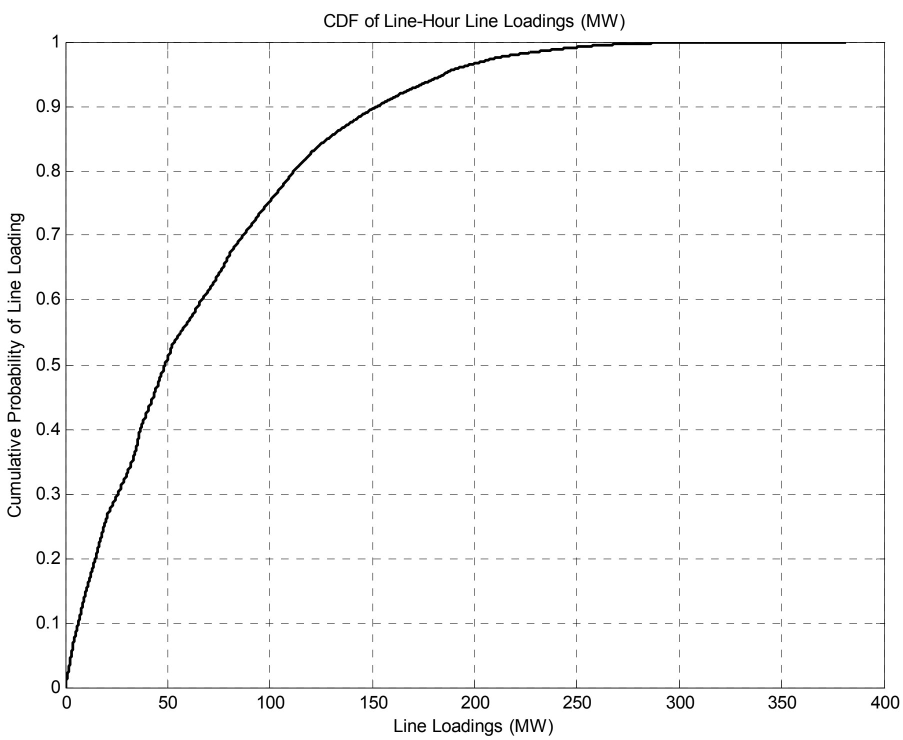


Figure 64: Cumulative Probability of Line Loadings for the Centralized Case

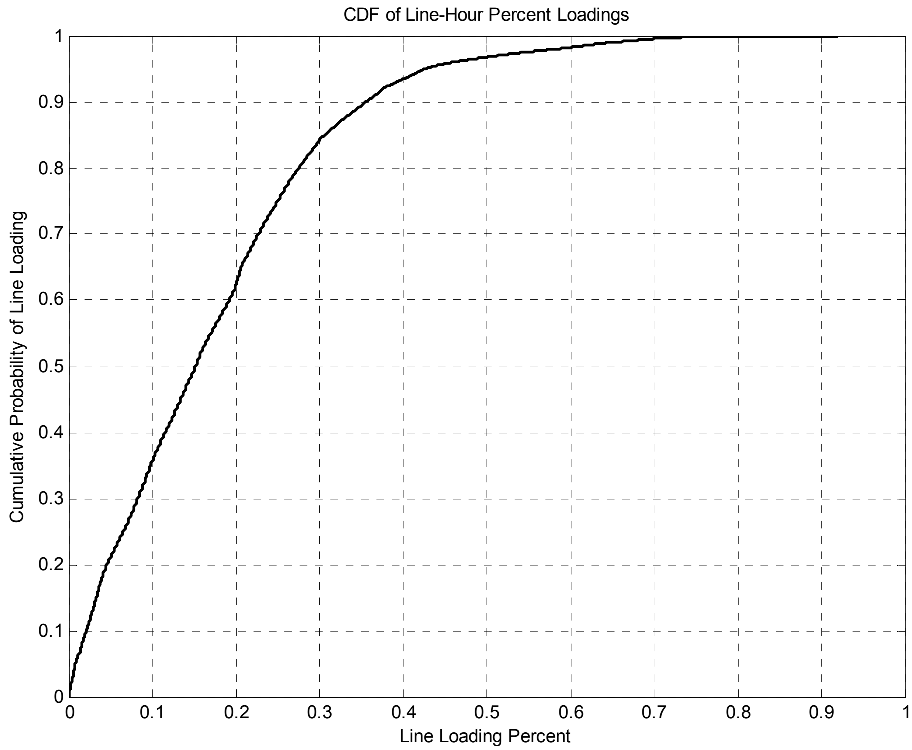


Figure 65: Cumulative Distribution Function for Percent Maximum Line Rating

The optimal power flow was then run with distributed scenarios in order to compare line flows, particularly over the 38 lines that join the 24 IEEE-RTS buses. Again, the San Diego Gas and Electric data were used. This allows testing of different scenarios for load placement and generation placement. In the first case the loads were placed randomly. That is, there was no attempt to cluster industrial, commercial or residential loads together. Instead, a cluster of microgrids would have a mix of the three types of loads. The distributed generation units were also placed uniformly at the microgrids. The cumulative distribution of percent maximum line rating used is shown in Figure 66. As can be seen, for nearly 100% of lines and hours there is no flow over the IEEE-RTS high-voltage lines. We have not shown the histogram of line flows or the CDF of line flows as they simply show the same information in a different form. For all of the following results, we will present only the CDF of the percent of maximum line rating used.

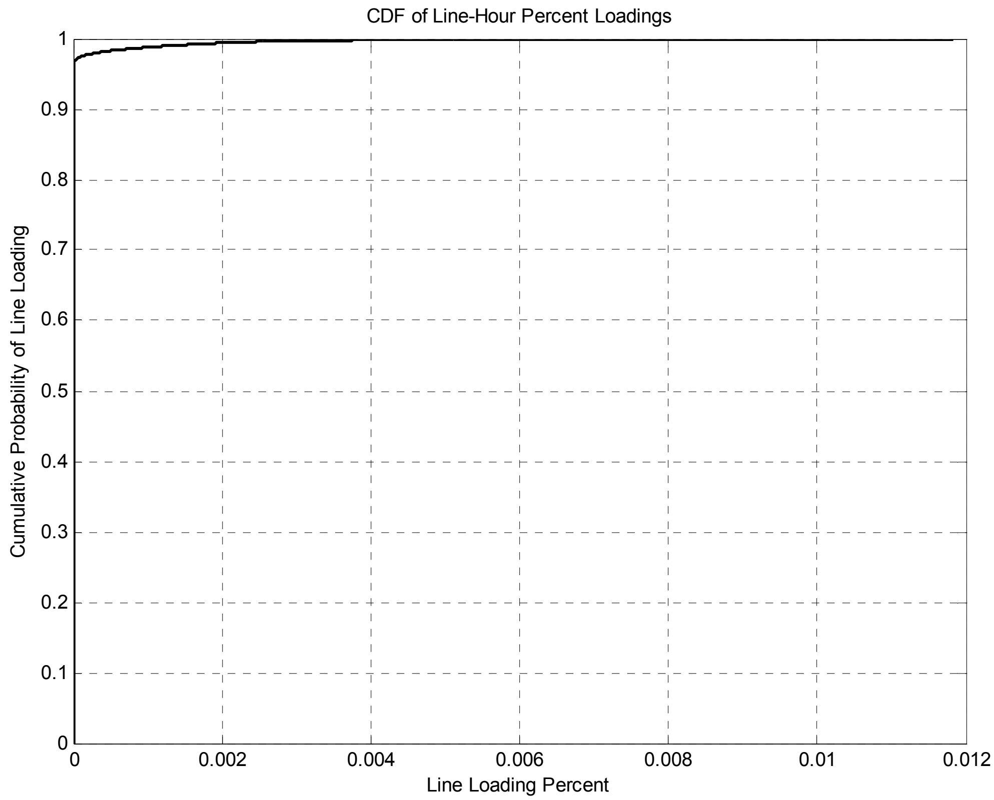


Figure 66: Cumulative Distribution Function for Line Loading Percents (Random Load and Uniform Generation Placement)

It is not surprising that a completely distributed system with randomized load placement, load non-coincidence and uniform placement of DG units would have minimal use of the high-voltage transmission system. However, it was hypothesized that there may be some circumstances under which greater use of the high-voltage transmission system would be observed. An obvious one (and not one modeled here) would be mixed systems in which some of the load is still being met by centralized generation. The question is whether there would be use of the high-voltage system in a completely distributed system.

One scenario under which such flows might be observed is if the load placement was not random, but rather that similar loads would tend to cluster near one another. This is, in fact, more realistic as residential loads, commercial loads and industrial loads are not likely to be completely mixed. These loads were placed into the IEEE-RTS in such a way that industrial loads were clustered together, residential loads were clustered together, commercial loads were clustered together and there were some clusters that had a combination of residential and commercial. The line loading percentage CDF for the IEEE-RTS transmission lines are shown in Figure 67. As can be seen, the line loadings only reach up to about 12% of the maximum line rating and for over ninety percent of the lines and hours, there is no line loading on the transmission. The total flow over the microgrid links in this case is 9.5×10^4 MWh. Given that this includes line flows up from micro-grids with excess power as well as the flows down to micro-grids with power shortages, this indicates that reliance on power sharing remains relatively small.

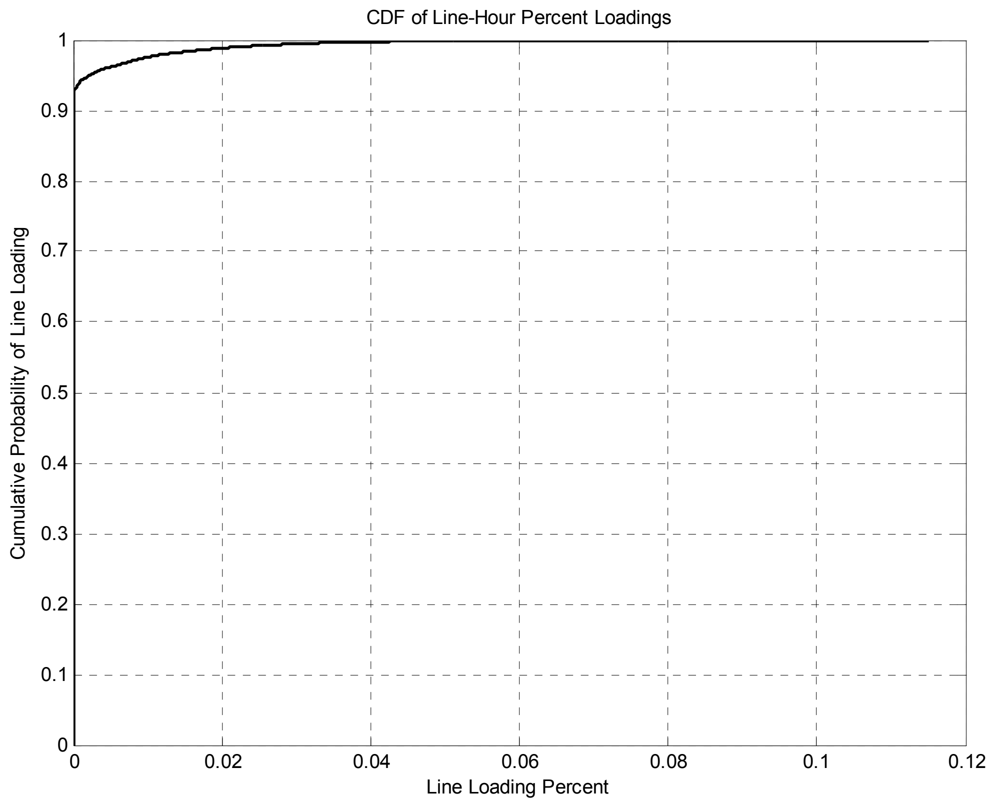


Figure 67: Cumulative Distribution Function of Percent Line Loadings for Non-Uniform Load Placement

Another version of the scenario just presented adjusts the placement of generation in addition to the placement of loads. In this case, it is assumed that industrial loads are more inclined to install excess generating capacity and the minimal capacity will exist in residential areas. Therefore, in this scenario the same amount of generation was installed as in the previous scenario. However, rather than it being evenly distributed, industrial loads have 1.25*(peak industrial micro-grid load) installed. Commercial loads have just enough to meet their peak and the remaining distributed units are spread out among the residential microgrids (roughly equivalent to meeting half their peak load). The results are shown in Figure 68. As can be seen from the figure, percent line loadings are now reaching 25% of maximum. However, there are still 70% of line-hours that have no line loading and over 95% have line loadings that are less than 5% of maximum. Total flow over the microgrid linkages is 8.7x10^5 MWh. This is about 6% of what it is in the centralized case.

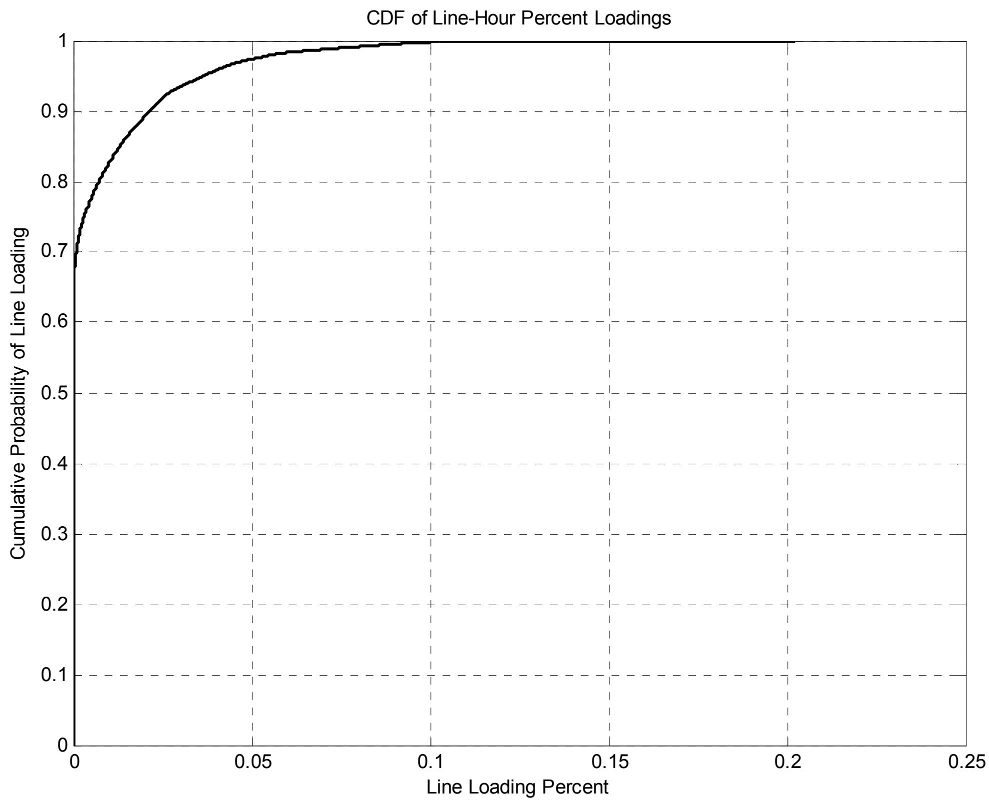


Figure 68: Cumulative Distribution Function of Percent Line Loadings for Non-Uniform Load Placement and Non-Uniform Generation Placement

As discussed in Chapter 6 , it is also useful to look at systems with a mixture of centralized and distributed generation. The optimal power flow model was re-run with the large unit replacement scenario of Chapter 6. The cumulative distribution of line-hour percent loadings is shown in Figure 69. In this case, roughly 90% of the line-hours have flows that are 20% of the maximum line rating or below, a significant improvement over the centralized case.

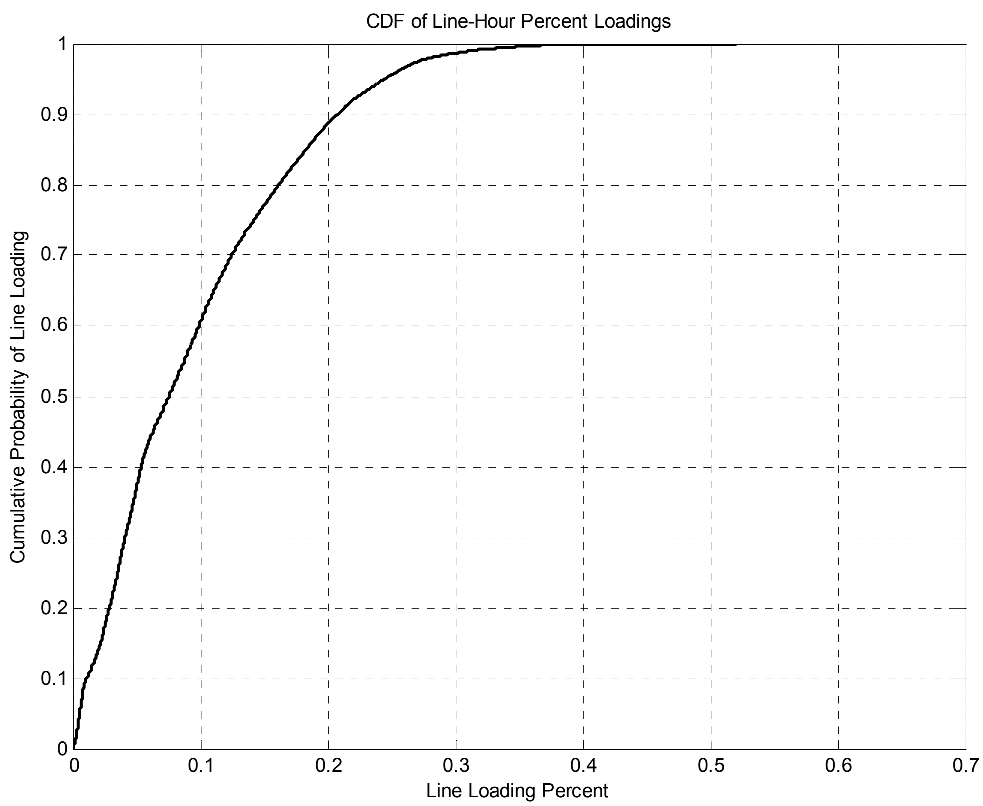


Figure 69: Cumulative Distribution of Line-Hour Percent Loadings for the Large-Unit Replacement Scenario Mixed System Topology

8.4 Conclusions

In the model considered in this chapter, the network topology consisted of a high voltage network (operating at 230 and 138 kV) and clusters of micro-grids attached to some of the high voltage buses. Power sharing between micro-grids could occur at the cluster level or it could occur over the high voltage network joining the clusters of micro-grids. The results of this model indicate that power flow is generally limited to local clusters of micro-grids. However, the power flows are not entirely limited to the local clusters and different scenarios result in different usage of the high voltage network (though in all the scenarios considered here, that usage is significantly less than in the centralized case). Therefore, not all distributed scenarios result in an avoided use of the higher voltage level network.[65] However, the usage is low enough that if DG were to be used in an existing system there would be a surfeit of higher voltage line capacity. In other words, the same network could serve load densities that were significantly higher than they are now (up to 500% higher for the particular cases modeled above). However, this also brings into question whether alternative network architectures to join microgrid clusters are worth exploring as opposed to designing systems to have optimally matched micro-grid clustering and minimal or no higher voltage transmission joining the clusters. As with previous model, results depend upon level of distributed generation investment and shape of load profiles. The results also depend on the network topology. Thus these results should be considered illustrative of the potential impact of a more distributed system on line flows.

[65] While the model presented in this chapter is not a reliability model, the results of the previous models indicate that it is also likely that failures at the generation level will increase need for transmission (up to a point).

Future work could include rewriting the optimal power flow in order to use a different optimization package that could perhaps solve the power flow more quickly. An alternative would be a multi-stage formulation of the problem, in which the first set of simulations would identify a second, smaller set of detailed simulations to perform. A probabilistic optimal power flow that uses a two-stage approach and probabilistic load patterns based on the system load duration curve has been developed by others and it might be possible to modify the general method for use with differentiated loads as used here. (Zimmerman and Gan 1997) This could allow integration of the power flow and reliability models. Alternatively, it may be possible that commercial-grade software exists that could be modified to include more distributed generation. Applying such a model to a real world case (e.g. a conflict area such as Colombia) could lead to an even more nuanced understanding of the impact of stress in a real-world case.

Chapter 9 Conclusion

Electric power systems have been and will continue to be challenged by a number of stress conditions that can come from a variety of sources. Extreme weather has long been recognized as a contingency that must be planned for as best as possible and then mitigated against when it occurs. However, there are a number of other stressors that could have effects that rival that of extreme weather events (or could be even worse). Such stressors can have very different characteristics than extreme weather events (e.g. in the scope and nature of the stress, the persistence of the stress, etc.) rendering some of the solutions developed for extreme weather events less suitable for such contingencies. Example of such a stress include underinvestment in infrastructure (e.g. transmission), lack of access to spare parts or trained personnel and the set of problems created for electric power systems during conflict situations. The particular stress conditions faced by an electric power system will depend heavily on context and will likely be different for industrialized versus industrializing countries.

It has long been recognized that stresses such as conflict and war can have a large impact on electric power systems. There have even been arguments made regarding how changes in the system architecture from a centralized to a distributed system can aid in mitigating the impacts of such stresses. However, there have been few systematic analyses of the problem. The contribution of this research has been primarily in three areas:

- The systematic characterization of stresses on electricity infrastructure

- The development of a method to analyze stress on electric power systems (particularly the application of a stress adjustment factor and the creation of non-coincident demand)
- The quantification of the impacts of making a large-scale change to a distributed system architecture and the reliability impacts of changing to such a system under stress conditions, including the impacts of fuel supply.

Some of the issues related to having a system based upon a significant level of distributed generation that have been explored include the reliability of different mixes of centralized and distributed generation technologies, the impact of load coincidence on reliability and needed DG investment, and changes in the usage of the high voltage transmission network.

As expected, a model that compares a hypothetical centralized system with a completely distributed system demonstrates that the distributed system has two reliability advantages. First, under normal operating conditions it is possible to reduce drastically, or almost eliminate, the reserve margin in the system while at the same time improving the adequacy of the system to provide real power (as measured in MWh/year not supplied). Second, under stress conditions the reliability advantages of most distributed systems (with the exception of one that has essentially eliminated the reserve margin) are demonstrably higher than a centralized system of standard design. Most notably, as stress levels are increased, the loss of energy expectation does not rise as rapidly for the distributed systems as for the centralized system. These are reliability advantages for the whole system. Clearly a real system would have differentiated reliability according to customer needs, however, the goal of this research was to determine the impact of DG on system reliability. Further work addressing the question of differentiated reliability would be useful as this would have an impact on location and type of DG investment and therefore on both reliability and power flow.

Furthermore, under normal conditions, the decrease in required capacity and the use of waste heat for co-generation make the distributed system competitive with a centralized system in terms of levelized cost of electricity supply. Under stress conditions, the economic losses suffered by various sectors of the economy become increasingly significant and begin to match and then dwarf the direct cost of electricity generation and supply. The improved performance of the distributed system under stress translates directly into economic benefits due to decreased economic losses as a result of lack of energy supply. As a result, the distributed systems with some reserve capacity become significantly less costly than the centralized system if economic losses are accounted for in the cost.

Due to the current state of development of the various options for distributed generation, the technology that has made the most significant in-roads in terms of power provision has been natural-gas combustion engines (e.g. in the Netherlands). Diesel engines are very common as a backup, but natural gas based engines (and turbines) appear to be the short term favored technology for future DG development. The distributed generation scenarios described above are all based upon widespread deployment of natural gas fired engines. This has raised the question of dependence upon the natural gas infrastructure.

In other words, the result would be replacing one vulnerable transmission and distribution system (electrical) with another vulnerable transmission and distribution system (natural gas). There are a number of qualitative arguments that can be made regarding the greater robustness of distributed generation based upon natural gas (see Chapter 1 for a summary). However, it is also possible to quantify the potential differences and this quantification is one of the core contributions of this thesis. Therefore, the model was extended to include the supporting natural gas infrastructure in order to determine the impact of dependence upon that infrastructure on the reliability of the system. It was found that under normal operating circumstances, due to the high reliability of natural gas systems, there is a negligible impact on the reliability of the power system. In order for stress on the natural gas system to have a significant impact on electricity provision, the stress level has to result in unavailabilities that are hundreds of times higher than the baseline reliability of the natural gas system. This might occur, for example, if the system is above ground and easily targeted. However, for an underground system, it would appear that significant effort would have to be made to disrupt the system and other targets might be more readily available. This is anecdotally borne out by the evidence from the conflict in Bosnia-Herzegovina. While the above-ground electrical system suffered heavy damage, the below-ground natural gas pipelines emerged relatively less damaged. In fact, the bigger problem was that natural gas became the only reliable fuel delivery into Sarajevo and a large number of illegal connections were made to use the gas.

While it is useful to think of the two ends of the centralized/distributed spectrum, as was done in the initial engineering economic modeling (see Chapters 3-5) and in the natural gas network model, the reality is that any power system will be a mix of distributed and centralized generating technologies. Even if it was desirable in the long-run to have a completely distributed system, any current system would go through a transition period in which distributed and centralized technologies would both be in use. It is therefore, instructive to evaluate the reliability of mixed system topologies containing both centralized and distributed generation.

In Chapter 6 a number of mixed system topologies were evaluated using the engineering-economic model. The model was re-run with various strategies for replacing centralized with distributed generation. These strategies were to replace all of the natural gas fired units, all of the coal fired units, all of the small units and all of the large units in the original system. In each case, the amount of centralized generation removed from the system was replaced with differing amounts of distributed generation. The results of these model runs were compared with model runs for the purely centralized and purely distributed systems. The results indicate that three inter-related factors are critically important in determining the relative performance of the different mixed systems. First is the relative size of the centralized units being replaced. This is due to the fact that the impact of any particular generator failing is dependent upon its size. Replacing larger units results in a system composed entirely of distributed and relatively small or medium sized centralized units and a decreased dependency on a few large units. Second are the relative reliability characteristics of the centralized units being replaced. Replacing highly reliable centralized units with less reliable (though more numerous) distributed units leads to no change. The third is the degree of distributed generation penetration and resulting reserve capacity. At low levels of DG penetration, the reserve margin must remain relatively high because there are still a number of large units operating and the advantages of DG can be fully exploited. However, at high penetration rates (e.g. on the order of 40%) it is possible to maintain or even significantly improve system performance while at the same time reducing overall generation capacity and essentially eliminating the reserve capacity. At these higher penetration rates, the reduced reliance on transmission and the large-number / small-size advantages of DG play a significant role in system reliability. The result is that the needed reserve margin is not a fixed number but highly dependent on the mix of technologies and the degree of DG penetration. It should also be noted that, as stated above, these three factors are inter-related and it is really the combination of size and reliability of the technologies as well as the degree of replacement of centralized with distributed generation that determines system performance.

The reliability of the system is not simply a function of the generation and transmission of electricity. The other side of the equation is the demand for electricity itself. Specifically, reliability is determined by comparing the energy that can be delivered in any given time period with the demand for that time period. The reliability models used for the preceding engineering-economic models are based upon comparing available generation to a load demand curve that has been sorted from highest to lowest demand in the year. The load at each individual micro-grid was simply a mirror of the larger system load, but at a lower peak level (~10 MW instead of 2850 MW). The result is that the loads in all of the micro-grids were identical and in perfect coincidence.

However, in any real system the loads at the local level are not in perfect coincidence, nor do they necessarily have the same shape or peak demand. The result is that there are greater opportunities for sharing power than might be indicated in a model that does not include differentiated non-coincident loads. In order to assess some of the impacts of load non-coincidence on reliability and on power sharing between micro-grids, a method was established to systematically vary the loads at different customer load buses.

The results show the inter-relationship between installed capacity at the micro-grids, the degree of load non-coincidence, power sharing between the micro-grids and the reliability and cost of the system. Load non-coincidence was introduced in a systematic fashion and under two different assumptions. In the first case, the unit of analysis is the overall system and so as loads were shifted the system peak was kept constant. Since the system peak no longer occurred during the same hour in all of the micro-grid peaks, the normalization back to a constant system peak resulted in micro-grids that were larger than before. In the second case, the micro-grid was the unit of analysis. As micro-grids were shifted to create load non-coincidence their loads were kept constant. The result is that the overall system peak declined with greater load shifting.

In both cases, changing the load non-coincidence had an impact on system reliability and the degree of power sharing. However, in the constant system case, increased load non-coincidence eventually resulted in reduced reliability for the completely distributed (and no reserve margin) case as compared to the centralized case. The flattening of the load curve, increased micro-grid peaks and lack of spare capacity all result in decreased reliability. In the constant micro-grid approach, after a certain amount of load shifting the micro-grid loads are sufficiently different that they can take maximum advantage of power sharing options. This model also shows that allowing for power sharing can decrease the amount of DG capacity that is necessary in order to meet demand. As discussed earlier, the approach to the analysis depends on the starting conditions of the system. In a setting that has a number of independent systems and is seeking to link them up, the latter (constant micro-grid) approach highlights the capacity savings from interconnection. However, if the setting is one of an existing centralized system, the load non-coincidence has already been exploited by the system and any further capacity reductions in the DG units would be related to the chosen capacity margin and tolerance for loss of load.

The final set of model runs were conducted to determine whether the power sharing that occurs could result in significant usage of the higher voltage transmission network. As noted in the introductory chapter, one of the stated advantages in the use of distributed generation is reduced reliance on the transmission network. With a system that is dominated by distributed generation, it might be expected that the power sharing would remain within clusters of neighboring micro-grids in the network. The model used to test this hypothesis is unlike the other four models developed in this thesis. Its focus is no longer reliability but a network flow analysis for every hour in the year for differing levels of load non-coincidence and for the centralized versus distributed cases – assuming all components work perfectly. The load flow is an optimal DC power flow that minimizes a combination of generation and load shedding costs. In order to ensure that the power flows being observed are solely the function of the load non-coincidence in the distributed case, the distributed generation at each load bus is identical and the load shed cost at each bus is identical. Therefore, load flows are *not* a function of differentials in generation cost or load shed cost.

This pattern of flows over the transmission network is indeed confirmed by the model. In a completely distributed system the flows over the high-voltage network drop and are comparatively inconsequential. There is still flow between microgrids, but this is within clusters of microgrids that are all attached to the same high-voltage bus. Flows along the high-voltage lines increases if similar load types are clustered together rather than randomly distributed in the system. Flows increase even further if the assumption is made that DG is installed preferentially at industrial sites, then commercial sites and minimal installations occur at residential sites. However, even under these assumptions, which should maximize load flow, the line loadings remain significantly lower than in the centralized case and for seventy percent of the line-hours there is no flow over the high voltage network. Overall energy flow (including over the linkages between microgrids) is orders of magnitude lower than in the centralized case.

The results summarized above indicate that there are potentially significant macro-level reliability advantages to increasing the amount of distributed generation in a system.

Electric power systems are installed and operated under a wide variety of conditions, some of which can be characterized as "high stress" conditions in which the adequacy of the system to provide energy is challenged. Aside from severe weather conditions, there has been little systematic analysis of persistent stress on power systems, particularly in non-OECD contexts where many of these stresses are potentially more severe. Despite this, there have been numerous claims made regarding the advantages of distributed generation as a more secure and robust technology choice. However, quantification of distributed generation's potential reliability advantages and potential implications have been primarily at the micro-level (i.e. impacts on a particular facility or on a distribution system), rather than on the system as a whole. The contribution of this research has been to quantify and to explore the implications of wide-scale grid connected distributed generation. In particular, the emphasis has been on systems under stress conditions, but the results under low stress conditions are more widely applicable.

This research shows that options that include high levels of distributed generation planning should be considered further, particularly under stress conditions, something that is not done now. These options have to be considered in the context of the whole system, not just as piece-meal distributed generation installations or one application at a time. This is not to suggest that all of the issues regarding control of such a system have been resolved or that a completely distributed system is necessarily the ideal. The potential reliability advantages indicated by the modeling are based upon particular technologies and particular network topologies and only look at one aspect of reliability, the ability of the bulk power system to supply energy to end-users. However, the advantages are significant enough that they are worthy of further exploration and potential incorporation in planning models. In order for this to happen, further development of modeling tools and options for analysis of large-scale complex systems and specifically of wide-scale distributed generation is necessary.

There are, however, a number of barriers to the development of systems with significant levels of distributed generation that must be considered. For example, while siting of large units such as nuclear reactors or coal plants has been problematic, there are likely to be siting issues that arise with distributed generation as well due to concerns such as local air pollution. More importantly, regulatory and institutional conditions create a number of barriers to DG penetration in many markets, including in the major U.S. and European markets. In the end, it is these other issues related to DG (control, local air pollution, system stability, institutional barriers) that may limit the penetration of grid connected distributed generation. This research illustrates the potential value of overcoming those barriers in order for wide-scale distributed generation to be considered as an option in power system planning. In particular, a level playing field for distributed generation within the regulatory structure must be created. Preventing DG interconnection and prohibiting the development of multi-unit, multi-customer microgrids to protect monopoly territories may eliminate distributed generation options that should be considered.

There is also a need to understand the particular stresses on a given system and incorporate those more formally into planning models. Such improved understanding could aid in determining whether and how increased distributed generation can be a benefit. Determining whether increased distributed generation is a lower cost alternative requires knowing the value of electricity in that context, the nature and level of the stress, its impacts on the system and the options for distributed generation available in that context.

The modeling results also indicate a need for information on the nature of different loads in the system, even if decision-making is occurring on the local level. The possibilities of power sharing among microgrids are dependent upon the level of DG installation and the level of load non-coincidence. These power sharing opportunities can reduce the requirements for installed capacity, the value of which to a microgrid operator will depend upon the value of their own load, the reliability of their connection to the other microgrids and the decisions of other microgrid operators regarding their own installations. Further developing methods for gathering and analyzing information on both stresses and system load is necessary in order for stakeholders and decision-makers to make informed decisions about the different options for power systems planning.

The first goal of this research was to model and quantify the reliability and economic differences between centralized and distributed energy systems for providing electricity and heat, particularly under stress conditions. This goal was met through the development of Monte Carlo reliability simulations, applied to different system network topologies. The results of those models show significant potential improvements in energy delivery with distributed systems. The second goal was to determine the impact of heterogeneity of local loads on the desired level of decentralization of the system and the impact of decentralization on the network requirements. This goal was met through a combination of Monte Carlo simulations applied to systems with differentiated and non-coincident loads and an optimal power flow applied to a more realistic network topology. The results of those models show the potential for improvements when loads are non-coincident and micro-grids can share power as well as the fact that the power sharing may be largely limited to local clusters of micro-grids. This research also showed the need for incorporation of stress in power systems modeling and a method for characterizing stress.

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