Transmission Line Reliability: Climate Change and Extreme Weather

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ABSTRACT

Transmission lines in service today in the US have been designed using a multitude of design approaches and structural loading criteria. The principal cause of structural failures is associated with weather events that produce loads that exceed the structural loading design criteria. In some cases, failures have been the result of inadequate design, construction and/or maintenance practices, airplane or vehicle accidents and criminal activities.

The cost of storm-caused transmission outages is significant, costing utilities and users on the order of $270 million per year and $2.5 billion per year (2003 $'s) respectively. The cost of storm damages may be under-appreciated by utilities and regulators since standard industry reliability indices (SAIDI & SAIFI) omit the costs of large storm related outages.

Currently available data suggest that the frequency and severity of hurricanes and ice storms will increase in the future. There has been a doubling of Category 4 and 5 Atlantic hurricanes from 1970 to 2004 which is the same time period during which ocean temperatures have increased. If this trend continues, it will have a significant impact on utility and user costs due to structural failures. Studies have shown that increases in CO_2 levels in the atmosphere could increase hurricane wind velocities by about 10%, resulting in an increase in wind loading of about 20%.

Under current policy, there is a lack of financial incentives for transmission line owners to upgrade/uprate, refurbish and/or build new lines. For example transmission line owners in restricted jurisdictions do not incur penalties associated with user costs caused by storm outages.

Based on the above observations and conclusions, recommendations are made concerning the collection and scope of SAIDI & SAIFI data, the adoption of a Survivability Design Concept, the adoption of transmission line investment incentives

and the revision of structural loading design criteria manuals to include survivability design concepts and the impacts of climate change.

INTRODUCTION

Current practice of designing electric transmission lines includes the application of the following loading criteria:

1. Climatic Loads
2. Security Loads
3. Construction and Maintenance Loads
4. Code Loads

Transmission lines in service today in the U.S. have been designed using a multitude of design approaches and structural loading criteria. The principal cause of structural failures is weather events that produce loads that exceed the structural loading design criteria. In some cases, failures have been the result of inadequate design, construction and/or maintenance practices, airplane or vehicle accidents and criminal activities. Examples of weather events that can produce loads in excess of design loads are tornadoes, hurricanes, and long-return period (low probability) wind and ice storms.

Interruptions in the delivery of electric power associated with structural failures are a continuing problem and can have significant economic impacts on the local economy. The North American Electric Reliability Council logged 533 significant disturbances over the period of 1984-2000 (NERC, 2003). Of these 533 events, 144 (27%) were due to structural failures.

The economic impact of transmission line failures can be significant, as shown by the recent events that occurred in the Montreal, New York and New England areas in 1998; in France in 1999; and in Florida in 2004.

Montreal, New York and New England Areas, 1998: In January 1998, an ice storm devastated Hydro Quebec's transmission and distribution systems in the area of Montreal, Canada. This failure was caused by a five-day-long ice storm that dropped up to 100 mm of radial ice on transmission lines and structures. The return period of this event was estimated at 200 to 500 years (Bigras, 1998). At one point, 1,400,000 customers were without power in 733 cities and towns in the Province of Quebec and 1,500,000 customers in the New York and New England areas for periods ranging from a few days to about four weeks. The direct cost of this extensive failure to Hydro Quebec was in excess of $580 million (US 2003 $'s), and the overall economic impact of the storm on the Canadian economy was estimated at $2.4 billion (US 2003 $'s) (Nicolet, 1998)

France, 1999: In December 1999, two wind storms swept across France over a two-day period. Gusts reached 200 kmph (124 mph) causing 3,500,000 customers to lose power. The cost of this failure to Electricitie de France (EdF) was 1.1 billion euros ($1.2 Billion US 2003 $'s), and the society costs were in excess of 11.5 billion euros ($12.8 Billion US, 2003$'s) (Le Du, 2002)

Florida, 2004: In 2004, Hurricanes Charley, Frances, Ivan and Jeanne struck Florida. Florida Power and Light's (FPL) service area was affected by all four hurricanes and reported the most widespread hurricane damage, primarily to the distribution network (FPL, 2004). Electricity was not restored to all customers until after 13, 12, 13 and 8 days, for Charley, Frances, Ivan and Jeanne, respectively. Customers without power varied from 364,500 for Ivan to 2,786,000 for Frances. While many of the outages caused by the 2004 hurricanes were related to distribution system failures, past hurricanes have severely damaged Florida's transmission system. For example, Hurricane Andrew in 1992 damaged or destroyed 1900 transmission structures and customers were without power for up to 37 days (FPL, 1992).

Before Andrew in 1992, FPL had a transmission and distribution system insurance policy to protect against catastrophic storms (Johnson, 2005). The annual premium was $3.5 million with a limit of $350 million per occurrence. After Andrew in 1992, commercial insurance carriers stopped writing such policies or made them prohibitively expensive. FPL elected to self-insure. In the years prior to the 2004 hurricanes, FPL funded a storm reserve account at a level of about $20 million per year or about 20 cents per residential consumer per month. At the time of the 2004 hurricanes, FPL had a balance of $345 million in its reserve balance account which was used to help pay for part of the $890 million 2004 hurricane damage costs.

Thus, as shown by the above examples, weather events that exceed structural loading design criteria, can result in significant economic impacts on the affected utility and its customers. In addition, it appears that, over the past several years, the number of severe weather events is on the rise. Global warming appears to be the reason for this trend. The continuation of this current trend would have a significant effect on the extreme-value statistics of weather events. Florida hurricane strike statistics since 1851 have followed a Gaussian, or normal, distribution. These statistics predict that the 2004 hurricane season (4 strikes) and the 2005 hurricane season (3 strikes) would occur in consecutive years only once every 1200 years, unless an underlying change is occurring. Will a 50-year return period wind event of 80 mph increase to 100 mph , thereby increasing wind loads by 56% on transmission line systems that were originally designed for 80 mph.? If this is the case, the number of failures in the future would increase.

A solution to reducing the economic impact of transmission line failures on utilities and their customers is to implement a "Survivability Design Concept," a concept that is being implemented by EdF in France. In simple terms, this concept involves identifying a critical backbone transmission line and substation system that would be designed for a higher level of structural reliability than the remainder of the system. The answer to the question of "how much higher" is based on optimizing the sum of the cost for building the backbone system and the remainder of the system plus the life-cycle cost of future failures where future failure costs would include both utility and user costs.

STRUCTURAL LOADING CRITERIA

Electric utilities in the U.S. are responsible for developing structural loading criteria for their service areas. Many states have legislated The National Electric Safety Code -NESC (2002) into law which requires the utilities in these states to include the minimum requirements of the NESC loading districts in their loading agenda. Over the years, utility-specific structural loading criteria have been refined based on the availability of new climatic data. In addition, improved analytical models have been developed in the recent past for the determination of wind loads (Davenport, 1967) as well as for ice and wind-on-ice loads on conductors, overhead ground wires and structures.

Over the past several years, professional societies, such as the American Society of Civil Engineers (ASCE) and the Institute of Electrical and Electronic Engineers (IEEE), and standard–writing organizations, such as the International Electrotechnical Commission (IEC), have published papers and guidelines for the development of structural loading criteria. The IEC published guidelines titled "Loading and Strength of Overhead Transmission Lines" (IEC, 1991).

The ASCE has also published guidelines for the determination of loading criteria for the design of transmission line structural components (ASCE 1991). The ASCE document discusses the following loading criteria:

Weather Related Loads (probability based)

$\Phi R_n >$ effects of [DL and γQ_{50}]

Security Requirements

$\Phi R_n >$ effects of [DL and SL]

Construction and Maintenance Loads (Safety)

$\Phi R_n >$ effect of [γ_{CM} (DL and C&M)]

Code Loads

$\Phi_{LL} R_n >$ effect of [LL]

where Φ = a strength factor. Φ takes into account variability in material, dimensions, workmanship, and the uncertainty inherent in the equation used to calculate R_n.

R_n = the nominal strength of the component

DL = dead loads, i.e., weight of bare wires, hardware, insulators, etc.

γ = the load factor applied to the load effect, Q_{50}, under consideration.

SL = Security loads such as broken conductors and overhead ground wires, dropped ice, etc.

γ_{CM} = the load factor applied to all of the dead (D), construction (C) and maintenance (M) loads

Φ_{LL} = the load factor applied to legislated loads (LL)

The reliability of lines can be increased by adopting load return periods greater than 50-year events, as shown in Table 1.

Table 1. Load Factor γ or Load Return Period RP to Adjust Line Reliability by Factor LRF

Line Reliability Factor, LRF	Load Factor, γ (applied to Q_{50})	Load Return Period, RP (years)
1	1.0	50
2	1.15	100
4	1.3	200
8	1.4	400

If the line designer wants to adjust the reliability level between line components, the strength factors presented in Table 2 would be used for a strength exclusion limit of 5 – 10 %.

Table 2. Strength Factor Φ to Adjust Component Reliability by Factor CRF

CRF[1]	Exclusion Limit, e (%)	Strength Factor, Φ, for COV_R[2]			
		10 to 20 percent	30 percent	40 percent	50 percent
1	5 to 10	1.00	1.05	1.09	1.11
2	5 to 10	0.85	0.87	0.88	0.90
4	5 to 10	0.73	0.76	0.77	0.75

(1) CRF is component reliability factor

(2) COV_R is the coefficient of variation of component resistance

UTILITY AND USER COSTS DUE TO EXCEEDENCE OF DESIGN LOADS

From 1994 to 2004, utilities incurred an average of $270 million per year (2003 $'s) to repair their systems from damage due to 81 major storms (Johnson, 2005). As shown in Table 3, the four most expensive storms occurred between 2000 and 2004 and cost utilities between $205 million (2003 $'s) and $890 million (2003 $'s).

Table 3. Economic Impact of the Four Most Expensive Storms in History to Individual Utilities (Johnson 2005)

Storm Description	Date	Storm Cost $Million ($2003)	%of Annual T & D Expenses	% of Net Operating Income
Progress Energy Florida Hurricanes	2004	$366	303.80%	104.10%
FPL Hurricanes	2004	$890	305.20%	97.00%
Progress Energy NC Ice Storms	2000	$205	259.80%	96.70%
Dominion Energy Hurricane Isabel	2003	$212	72.30%	24.80%

Two of these events were the 2004 hurricanes that affected both Florida Power and Light and Progress Energy - Florida. The fact that the 4 most costly storms occurred since 2000 is due in large part to increased population and infrastructure growth. Florida utilities have experienced a 20% increase in customers (about 1 million) for the 10 year period spanning 1994-2003. (Johnson, 2005). Table 3 also shows that the cost of these storms amounted to between 72 and 305% of each utility's annual T&D expenses and from 25% to 104% of their net operating income.

Table 4 presents information concerning the total customers affected and the cost to Duke Power due to storms that occurred from May, 1989 through September, 1996. These data show that the customers affected varied from 88,076 to 1,800,000 and that the cost to Duke Power varied from $753,805 ($0.42 per customer) to $64,671,150 ($ 113.77 per customer).

Table 4. Costs of Storms on Duke Power (1989-1996)

Storm Date	Storm Type	Total Customers Affected	Cost to Duke Power	Cost to Duke Power per Affected Consumer
May-89	Tornadoes	228,341	$ 15,189,671	$ 66.52
Sept-89	Hurricane Hugo	568,445	$ 64,671,150	$ 113.77
1990[(1)]	ALL STORMS	1,800,000	$ 753,805	$ 0.42
Mar-93	Wind, Ice and Snow	146,436	$ 9,176,203	$ 62.66
Oct-95	Hurricane Opal	116,271	$ 1,655,350	$ 14.24
Jan-96	Western NC Snow	88,086	$ 872,585	$ 9.91
Feb-96	Ice Storm	660,000	$ 22,905,627	$ 34.71
Sept-96	Hurricane Fran	409,935	$ 17,471.826	$ 42.62

[(1)] 1990 was a “typical” year

While utility repair costs are reasonability easy to determine, placing a user’s cost on unserved energy is more difficult. Investments in back-up power provide a lower bound to such loses. A cost-minimizing organization will invest in back-up power if the annual investment plus operations and maintenance costs are less than the expected annual cost of power outages. Backup power expenditures in the United States have been roughly $700 Million per year (2003 $’s) (DOE, 1998)

Estimating unserved electricity cost is also possible by using survey information. Table 5 presents survey data collected by Billington (1994) and Balducci (2002).

Table 5. Balducci and Billington Comparison of Unserved Energy Costs

	Interruption Duration in Hours							
	0.33	1.0	4.0	8.0	0.33	1.0	4.0	8.0
Source	Billion Dollars (2003 $’s)				$/kWh (2003 $’s)			
Balducci (2002)	1.9	3.6	11.5	22.0	14.2	9.1	7.2	6.9
Billington (1994)	0.5	1.5	7.2	17.2	3.7	3.9	4.5	5.4

The data in Table 5 shows that unserved electricity costs in 2003 dollars have varied from $3.9/kWh to $9.1/kWh at an interruption duration of 1 hr and between $5.4/kWh and $6.9/kWh at an interruption duration of 8 hrs.

However, utility analysts estimate that system outage costs can vary from $1.70 to $8.40/kWh. (2003 $’s). These costs vary considerably by type of customer, the condition of the outage, the length of the outage, etc. (Alessio, 1986). Higher costs were estimated for the 1977 New York City blackout, where indirect user costs where estimated at $10.48/kWh (2003 $’s) and direct user costs at $2.00 /kWh (2003 $’s)

(OTA, 1990). The unusually high indirect user cost was attributed to looting, which accounted for about 50 percent of the total cost.

Economic losses from the massive blackout that struck the Midwestern and northeastern United States and parts of Canada in August, 2003 have been estimated at between $4 and $6 billion (Hilsenrath, 2003). Based on data from the North American Electric Reliability Council (NERC), the amount of electric energy that went undelivered because of the blackout totaled some 920,000 MWh. This implies that the economic cost of the blackout came to approximately $5 per undelivered kWh.

Utilities commonly use two indices, SAIFI and SAIDI, to benchmark reliability:

SAIFI (System Average Interruption Frequency Index) is defined as

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}}$$

SAIDI (System Average Interruption Duration Index) is defined as

$$\text{SAIDI} = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customers served}}$$

SAIDI and SAIFI data reflect only outages of 5 minutes in duration and longer. In addition, SAIFI and SAIDI reports generally exclude storm related outages. In a 2002 study, the 50th percentile SAIDI outage duration time was 1.74 hours without storm data and 3.00 hours when storm data are included (Sundaram, 2003; Short, 2002). Thus, 1.26 hours or 42 percent of the total 3.00 hour outage duration can be attributed to storm outage. In 2002, U.S. electric utilities (all sectors) generated about 3.5 x 10^{12} kWh or about 4.0 x 10^{8} kWh per hour. The unserved electricity from storm outages is then approximately 5 x 10^{8} kWh each year. Using an estimate of $5 per unserved kWh, the 50% percentile annual cost of unserved electricity due to storm outages would then be $2.5 billion.

To summarize, on the average, electric utilities incur costs of roughly $270 million per year (2003 $) due to major storm damage, with recent year costs substantially higher than the average due primarily to hurricanes. Consumers may be incurring costs of roughly $2.5 billion per year based on survey cost data and outage data. While this user cost might be inaccurate due to reliance on survey data, the fact that users spend on the order of $700 million per year for backup power indicates that they value the cost of outages at least to this expenditure level. Based on this information, user costs of storm damages are three to ten times higher than utility costs.

SURVIVABILITY DESIGN CONCEPT

Based on the variability in design practices and methods that have been utilized in the past for establishing structural loading criteria, it is realistic to assume that the structural reliability of the present electric transmission line system in the U.S. is quite variable. Thus, structural failures associated with exceeding structural design criteria will continue to occur in the future. The basic issue then becomes a question of how does a specific transmission line system perform when subjected to a loading condition that exceeds design criteria. Will the system experience extensive structural cascading-type failures or will the system limit cascades? Are the resulting utility and user costs due to failures unacceptable? If so, it appears that the implementation of a "Survivability Design Concept" would be very cost-effective. The Concept involves designing a backbone system of transmission lines and key substations to have a significantly higher level of structural reliability than the remainder of the system. This Concept could be applied to existing and new transmission line systems and on a regional, utility–specific or RTO system-wide basis. To demonstrate the Concept, Figure1 shows a new regional transmission line system consisting of 54 lines and 43 substations.

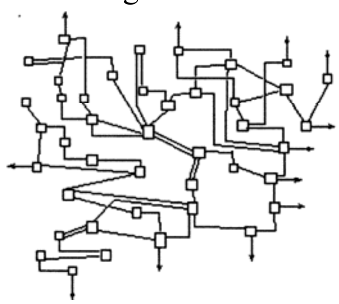

Figure 1 – A Typical Regional Transmission Line System.

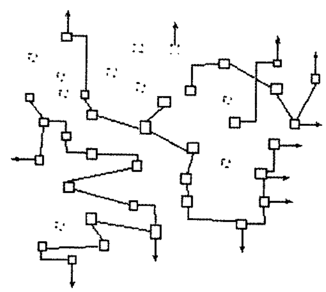

Figure 2 – Lines Needed to Maintain Power Delivery (Backbone system)

Assume that the utility's system planners decide that the 28 lines and 32 substations shown in Figure 2 make up the backbone system needed to deliver power to customers. Thus the critical lines and substations shown in Figure 2 would be designed for a higher level of structural and electrical reliability than the remainder of the system.

Since implementation of the Concept requires the determination of an optimum return period loading level for the design of the backbone system, the designer would initiate the following study;

1. Design and estimate total construction costs for the entire transmission line and substation system using 50-year return period load events
2. Evaluate life-cycle utility and user costs due to structural failures for the system designed in Step 1 for return period loads greater than 50-years, eg.100-years, 200-years, and 400-years.
3. Determine total construction and life-cycle utility and user costs for backbone systems designed for 100-, 200-, and 400-year return period events and the remainder of the system designed for 50-year events.

Figure 3 schematically shows the results of the above computations. For the example shown in Figure 3, it appears that an optimum return period for designing the backbone systems is on the order of 200-years.

The calculations described above in Steps 1-3 can be repeated for remainder systems designed for higher return period events. This will enable the designers to establish an optimum return period loading criteria for the design of the remainder system and associated return period loading level for the backbone system.

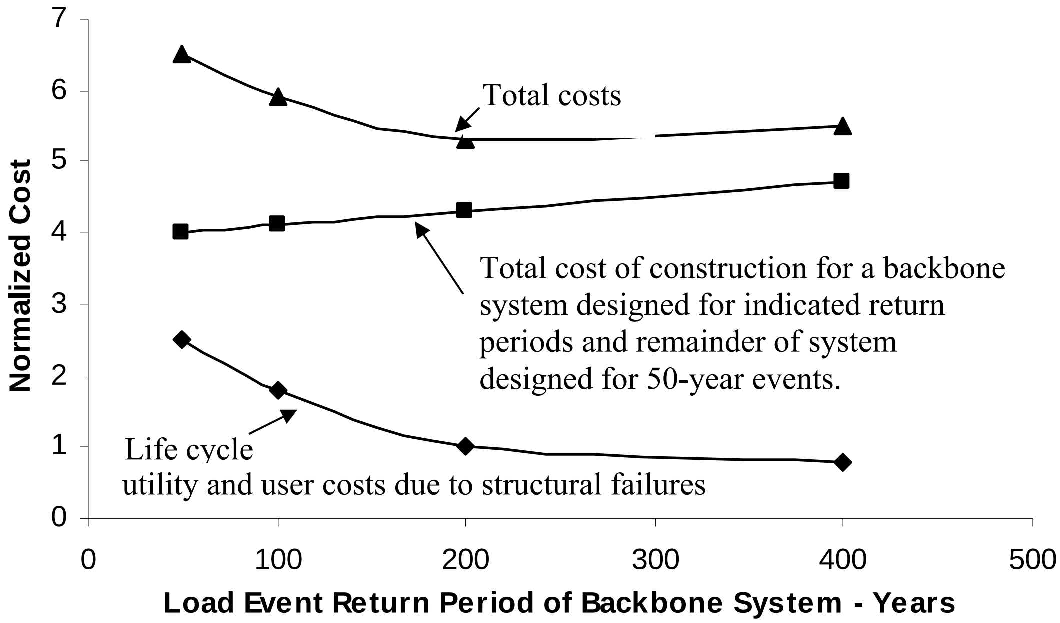

Figure 3. Normalized Costs versus Load Event Return Period For the Design of the Backbone System

Electricitié de France (EdF) is in the process of implementing a backbone system strategy to enhance the reliability of critical sub-transmission and transmission lines in an effort to decrease downtime to 5-days for storms similar to the December 1999 storm. EdF has also upgraded the wind design criteria by applying a maximum design wind velocity of 170-180 kmph (106 – 112 mph) to a larger costal area and increasing the design wind for all “inland” transmission structures from 150-160 kmph. (93 – 99mph) to 160-170kmph (99 – 105 mph) (EdF, 2000).

CLIMATE CHANGE IMPACTS

Recent studies have shown that global mean surface temperatures have increased by 0.6$\pm$0.2 degrees C in the past 50 years (IPCC 2001). There is a growing consensus that this change in temperature is part of a human-induced climate change, not normal variation (Oreskes, 2004). There is also building evidence that our changing climate will lead to more “extreme” weather events (Frances, 1998; Knutson, 1998, Yonetani, 2001 and Bell, 2004).

One of the major challenges for climatologists is determining which climate changes are due to natural variations and which are due to anthropogenic reasons. It is not yet possible to say how El Niño, and other factors affecting hurricane formation, may change as the world warms (Trenberth, 2005). However, changing environmental conditions can increase hurricane wind velocities. Knutson, et al 1998 have shown that the maximum hurricane surface wind speeds can increase due to increased atmospheric CO_2 levels. Figure 4 summarizes the number of all hurricanes and Category 3-5 hurricanes to strike the US in each decade since 1851.

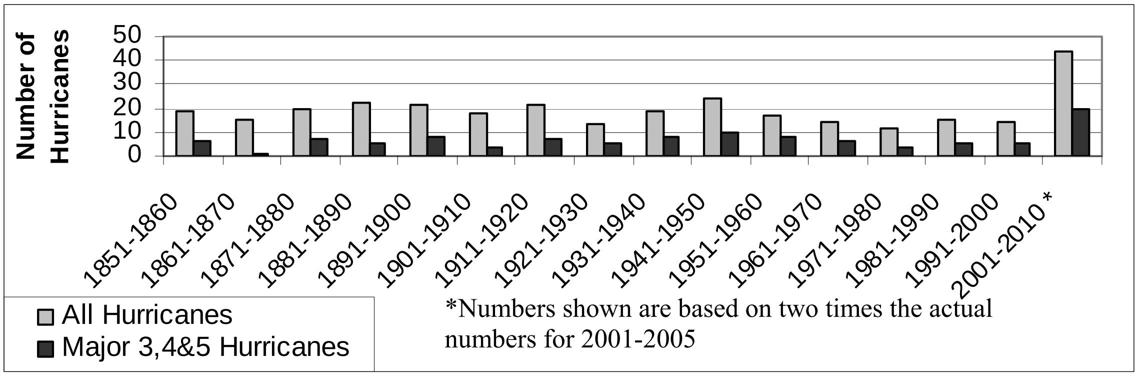

Figure 4. Number of Hurricanes by Saffir-Simpson Category to Strike the Mainland U.S. Each Decade.

Figure 5 shows the percentage of Category 1, 2 & 3 and 4 & 5 hurricanes that have occurred since 1970. Note that the Category 4 & 5 hurricanes are increasing over the same time period that ocean temperatures are increasing. (Webster, 2005).

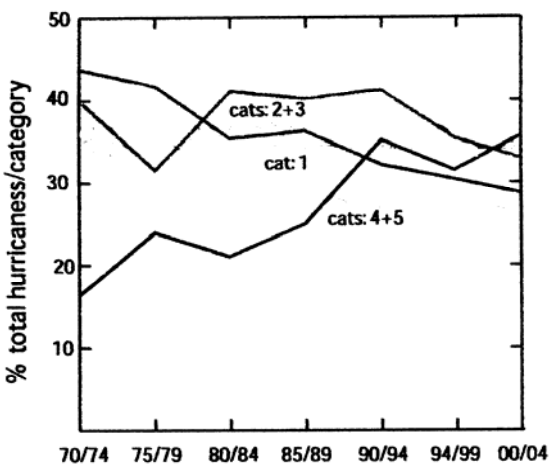

Figure 5. The Percentage of Category 1, 2 & 3 and 4 & 5 Hurricanes From 1970 to 2004

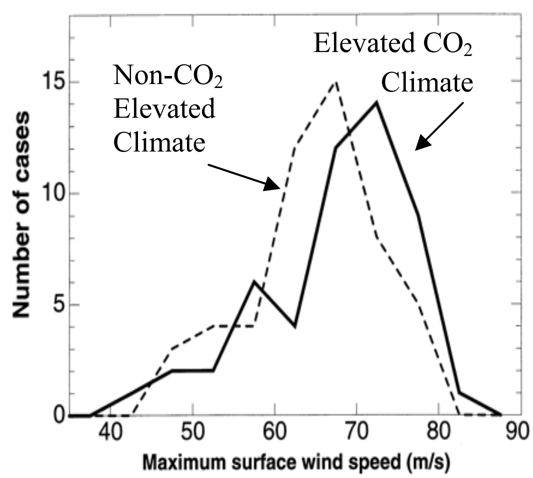

Figure 6. A Comparison of Maximum Surface Wind Speeds (Knutson, 1998)

Figure 6 shows a distribution of maximum surface wind speeds obtained from a hurricane model for 51 cases (Knutson, 1998) for a non-CO_2 elevated climate and an elevated CO_2 climate. The increase in velocities shown in Figure 6 would result in a 15-20 % increase in structural loads. Thus, hurricanes affecting Florida transmission lines in the future are likely to be more frequent, as well as more intense due to a multi-decadal variation of natural conditions (Goldburg, 2001),

In many cases, wind loads can govern the design of transmission lines. However, in many areas of the U.S., wind on ice-covered conductors and overhead ground wires can govern design. Ice storms are created when a mass of warm moist air collides with a mass of cold air forming rain. In a study of ice storms from 1982-1990, Robbins (1996) identified five regions across the country where ice storms tend to occur. As shown in Figure 7, the states with the greatest number of ice storms are Pennsylvania and New York. In these states, cold-air outbreaks interact with coastal cyclones to produce prime conditions for freezing rain and ice storms.

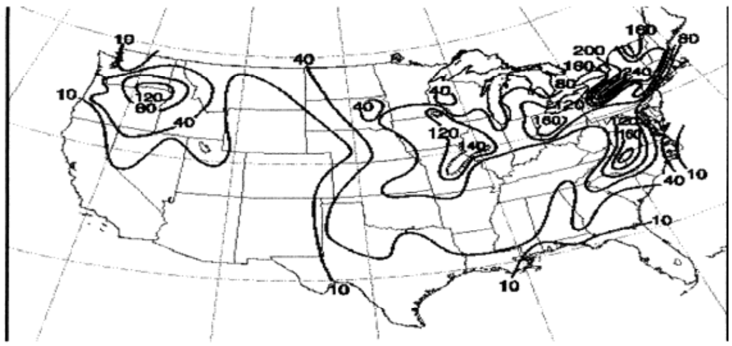

Figure 7. Number of Freezing Rain Observations – September through April, 1982-1990 (Robbins 1996)

Calculations suggest that in a warming climate, milder winter temperatures could cause an increase in freezing rain in places where average daily temperatures meander around the freezing point instead of remaining continuously below it (Francis, 1998). However, this does not necessarily translate into more frequent occurrences of ice storms, such as the 1998 ice storm described above.

While it is difficult to determine if the intensity of large and extreme ice storms, like the 1998 ice storm, will increase with climate change, general circulating models predict that winter storms in a two times CO_2 environment will become more frequent and severe north of 30 degrees North (Lambert 1995). Since ice storms account for slightly less than 10% of national winter storms (Robbins, 1996), an increase in CO_2 will most likely increase the frequency and severity of ice storms.

It is uncertain how much climate change will increase outage time, but a possible scenario is that climate change could double storm outage durations from 1.26 hours to about 2.52 hours. Doubling the interruption duration to 2.52 would cost the U.S. economy about 7.6 billion dollars (2003 $'s) annually (Baldacci, 2002); an increase of $3.3 billion.

TRANSMISSION LINE INVESTMENT INCENTIVES

Improving the structural reliability of existing and future transmission line systems in the U.S. via implementation of the Survivability Design Concept, will require a significant capital investment. However, economic incentives for investment have not been developed to date. De-regulation has changed the organizational structure of U.S. transmission lines. Long distance transmission lines are available to any user. Owners of independent transmission lines do not generally pay penalties for outages and are insulated from the user costs of storm damages. In some locations, the operation and ownership of lines are separated. A stable business model has not yet emerged which would make independent transmission lines profitable. Cost recovery uncertainties in restructured states have driven up the cost of capital for transmission project financing (Krellenstein 2004). As a result, lower investments in reliable transmission networks are likely in restructured regions.

A number of independent system operators have implemented Locational Marginal Pricing (LMP) as a mechanism for compensating transmission owners. Unfortunately, LMP provides precisely the wrong incentives to potential investors (Apt, 2003). The owner of the transmission line, paid only through LMP congestion charges, would never be encouraged to expand their capacity or invest in greater reliability. More congestion would mean more income and new transmission lines would not only be a large capital investment, but would decrease the income from LMP.

Certain regulated jurisdictions provide rate-of-return compensation for transmission investments. These jurisdictions may provide the best opportunities for investment in transmission infrastructure, and may gain a competitive advantage for those utilities that implement the rate-of-return program.

SUMMARY AND CONCLUSIONS

The cost of storm outages is significant for both electric utilities and users, with total annual costs amounting to billions of dollars. Recent storm damage has been higher than the historical record, and population growth and climate change are likely to increase these costs in the future. Some large utilities that have experienced major storm damage are in the process of upgrading their network reliability, but these investments are not universal.

The cost of storm damages may be under-appreciated because the standard industry reliability indices, SAIDI and SAIFI, omit storm related outages. A first step to making a more reliable transmission network would require that future SAIDI and SAIFI data include storm outages. Currently, 26 states require some type of reliability statistics; however, the availability of the data beyond the Public Utility Commission is often quite limited, requiring Freedom of Information Act requests in many cases (Sundaram, 2003). Transparency and a user-friendly data acquisition system should be implemented to overcome this problem..

U.S. transmission line owners in restructured jurisdictions do not incur penalties due to user costs caused by storm outages. As a result, they do not have economic incentives to invest in transmission line reliability which would minimize utility and user costs. Economic incentives via storm outage penalties could be implemented to alleviate this problem.

The development and implementation of a “Survivability Design Concept” is recommended to allow transmission line designers to minimize utility and user costs due to failures caused by exceeding structural loading design criteria. It is recommended that this “Concept” be implemented on a utility, or RTO basis.

Professional societies, such as ASCE, should be encouraged to evaluate the impact of climate changes on the wind and ice return period maps contained in their Standards and design manuals.

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