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Electric grid vulnerabilities to rising air temperatures in Arizona

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Abstract

Ambient air temperatures are expected to increase in the US desert southwest by 1-5°C mid-century which will strain the electric power grid through increased loads, reduced power capacities, efficiencies, and material lifespans. To better understand and quantify this risk, a power infrastructure failure model is created to estimate changes in outage rates of components for increases in air temperatures in Arizona. Components analyzed include generation, transmission lines, and substations, because their outages can lead to cascading failures and interruptions of other critical infrastructure systems such as water, transportation, and information/communication technology. Preliminary results indicate that components could require maintenance or replacement up to 3 times more often due to mechanical failures, outages could occur up to 30 times more often due to overcurrent tripping, and the probability of cascading failures could increase 30 times as well for a 1°C increase in ambient air temperature. Preventative measures can include infrastructure upgrades to more thermal resistant parts, installation of cooling systems, smart grid power flow controls, and expanding programs for demand side management and customer energy efficiency.

Keywords: electric power; energy; infrastructure; reliability; resiliency; failure analysis; climate change; extreme heat

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1. Introduction

The electric power grid in the USA, and desert southwest specifically, is of the most reliable in the world [1-2], but like all electrical power systems it is sensitive to heat in terms of its power capacity and component materials' life-span [3]. Arizona's power authorities typically plan 10-15 years in advance to manage risk considering increased system burdens due to social, economic, and technological, environmental, and policy factors [4-5]. These plans do not explicitly consider potential effects of rising ambient air temperatures. Significant increases in ambient air temperatures (1-5°C) are predicted by mid-century [4-5], and grid construction projects require as much as 10 years and many millions of dollars each to complete. Therefore, developing a better understanding of the risks of rising air temperatures to the power grid is both timely and necessary to maintain reliable critical infrastructure systems.

Predicting the change in probability of electric power failing is obtained using fault-tree logic in this study [8]. A failure analysis framework is developed inclusive of generation, transmission, and substation component performance using thermophysical equations for power flow and material degradation rate with stochastic inputs for air temperature. The model estimates the probability of failure when supply is insufficient or component outages occur. The effects of increases in air temperature are quantified as changes in power flow capacity (MW) and efficiency (% MWh), as well as the mechanical mean time to failure (MTTF) of component parts. The potential change in multiple simultaneous outages occurring and triggering cascading failures is also quantified. This research estimates the magnitude of the risk of rising air temperatures to critical civil infrastructure systems, and identifies corresponding vulnerabilities within the power grid.

Nomenclature

θ_μ	°C	mean of the maximum ambient air temperature during June, July, and August
θ_σ	°C	standard deviation of θ_μ
θ_+	°C	increase in θ_μ, input control variable
θ_{PRM}	°C	average temperature at which the PRM is engaged on a day
$\theta_{PRMcrit}$	°C	average temperature at which the PRM reaches its critical value on a day
β_{GC}	%	loss of generation capacity per θ_+
β_{TDE}	%	loss of T&D network efficiency per θ_+
β_{PKload}	%	increase in peak load per θ_+
β_{TC}	%	loss of transmission line current capacity per θ_+
β_{SC}	%	loss of substation transformer current capacity per θ_+
β_{PK}	%	net peak load adjustment factor per θ_+
α	%	probability that two simultaneous component outages lead to a cascading failure in the system
λ	#/day	failure rate
ΔPf_b^a	%	change in probability of failure, or λ, of a system component, where a = P or M, b = G or T or S
Pf_{bk}^a	%	probability of failure, or λ, of a system component, where a = P or M, b = G or T or S, k = i or f
A_b	years	age of component, where b = G or T or S
IP	%	current in a system component as a percentage of the component's rated ampacity
MTTF	years	mean time to failure
PRM	%	planning reserve margin
PRM_{crit}	%	PRM critical value for potential service interruption and the possibility of cascading failures
S	%	strength loss per year
S_{Teol}	%	strength loss for a transmission line to reach expected lifespan

<u>Commonly used subscripts and superscripts</u>

P, M	power- or mechanical-based component failure
G, T, S	generation, transmission, substation
i, f	initial (current air temperature scenario with θ_μ and θ_σ), final (higher ambient air temperature scenario θ_+)
μ, σ	mean, standard deviation

2. Methods

This analysis focuses on the thermal performance of the three major current carrying components in the electric power grid: generation, transmission, and substation transformers. This approach is consistent with other recent studies of the impact of rising air temperatures on power infrastructure such as [9]. To estimate how much increasing ambient air temperatures can increase component outages, cascading failures, and ultimately service interruptions, it is necessary to first understand the flow of electric power in the system, as well as the sequence of events that can lead to interruptions and potentially cascading outages. See Fig. 1. System operators maintain an n-1 redundancy standard in design at the high-voltage transmission level meaning that the single largest generator, transmission line branch, or substation (of which there are at least hundreds in every region) can fail at any time without any interruption to service [10]. These n-1 redundancies are represented in Fig. 1b using octagon boxes and logical AND gates. Service interruptions due to major component failures only occur when more than one individual component fails at the same time. Such events can lead to cascading failures including blackouts as in [11].

Service interruption occurs when power does not reach the load, such as a building or street light, and this analysis estimates specifically how much the frequency of service interruptions can increase. Fig. 1b shows the two ways that a service interruption can occur that are analyzed in this paper: either there is not enough total generation to meet total demand, or particular power pathways (transmission lines and substations) do not have sufficient capacity to deliver power to the load. The following list explains how increases in ambient air temperatures can trigger failures leading to service interruptions consistent with the lettering in Fig. 1b.

A. High air temperatures can result in reduced peak energy generation capacity and or efficiency losses in the transmission and distribution (T&D) network [8, 11]. If the system is also in high demand, (B), then load can exceed generation and put the system in a state of over demand. If there are insufficient generation reserves, then there will be a service interruption.

B. High air temperatures can result in higher demand, especially during the already hot summer months due to increased burden on building air conditioning systems [12].

C. High air temperatures result in less T&D power flow capacity in lines and transformers [8, 11]. If a circuit is in high demand, then power flow can exceed safe operating capacity and lines and transformers can exceed their rated ampacities and become in a state of overcurrent [11].

    i. If protection devices function correctly, then overcurrent will cause tripping of the line or transformer within the T&D network [11]. If there is insufficient capacity in parallel branches to provide power to the load, then there will be a service interruption [11].

    ii. If a protection device fails to trip and a circuit is overcurrent, then a component can exceed its thermal rating. Excess heat accelerates the chemical degradation rate of sensitive materials and can result in mechanical failure (E) [12-13]. Protection devices can fail because they are not accurately designed or calibrated for local climate conditions or other reasons [1]. Depending on the type and location of overcurrent failure, a generator, transmission line, substation, quality device, or other protection device can fail. If a generator fails, then the system state goes to (A) as the system now has less generation. If a transformer fails, then it goes to (A) and or (C) as the T&D network operates at lower efficiency and or has less power flow capacity. If a power quality device fails, then it goes to (C) again or directly to overcurrent depending on the circumstances. If another redundant protection device fails, then the cycle of potential failures repeats for additional components on connected circuits.

D. High air temperatures can result in a protection device failing to trip [1]. The device could be calibrated to a certain power rating that should be lower for the actual air temperature. If that occurs during high loading, then a component can go overcurrent and fail as in (ii).

E. High air temperatures can result in an accelerated physical material degradation rate, which can result in accelerated failures for any electrical devices [3]. The same failure scenarios can occur as described above, with the addition of an undesired trip of a protection device. If a protection device fails with an undesired trip, and there is no redundant power flow, then a service interruption occurs.

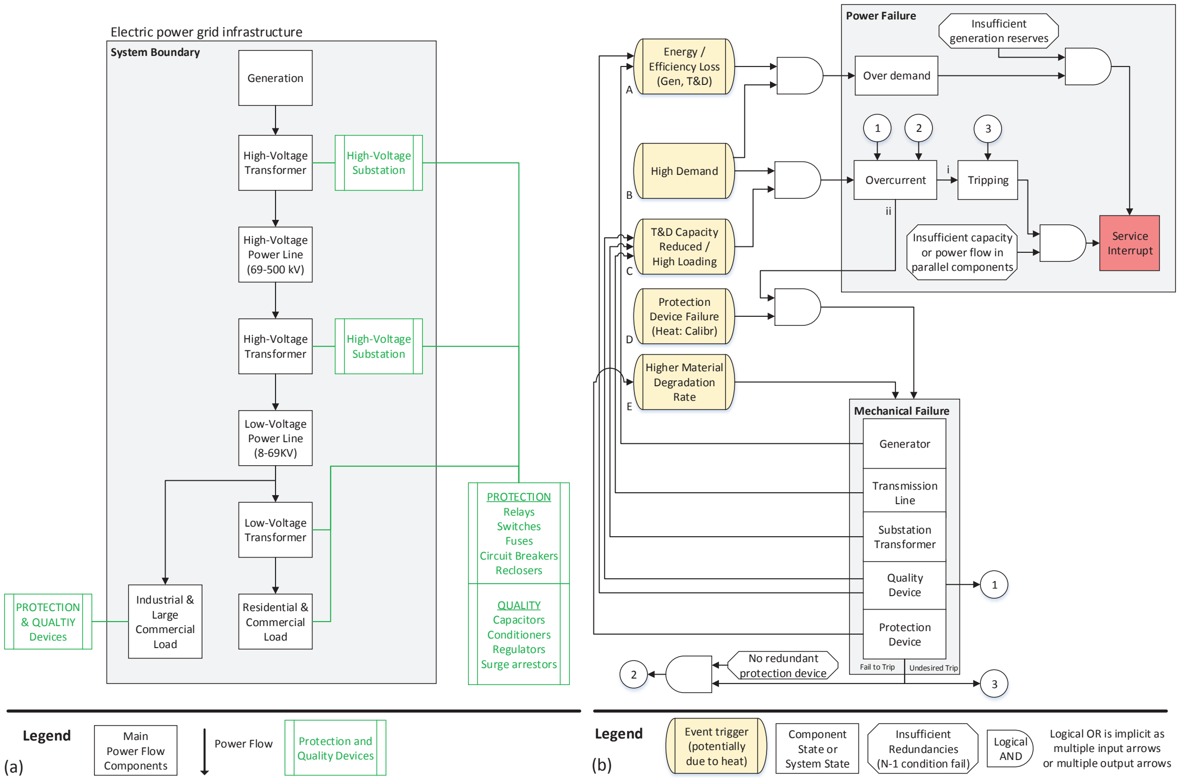

Fig. 1. (a) Power grid infrastructure analysis system boundary; (b) Fault tree to service interruption. (a) Shows the flow of power from generation to load through system components and identifies the analysis system boundary inclusive of major power-flow components including: generation, transmission, substation transformers, and load. Changes in performance of protection and power quality devices are not analysed. (b) Shows the terminal event of a service interruption on the right, and the power- and mechanical-failures that can lead to a service interruption logically preceding from the left. On the far left are the events that can be caused by higher ambient air temperatures and ultimately lead to service interruption in conjunction with other failures as indicated. Mechanical failures feedback into the event triggers as their loss of functionality results in a loss of power-flow that could cause an interruption.

A model is developed to estimate the change in probabilities of component failures (or failure rates) and service interruptions due to increases in ambient air temperatures, shown in equation (1). This is done by quantifying the fault processes in Fig. 1 for the primary current-carrying components. The structure of this model is shown in Fig. 2 where climate and infrastructure inputs are used to estimate changes in power-based and mechanical-based failures. These values are used to estimate the change in probability of a cascading event that can be triggered by two or more component failures occurring at the same time.

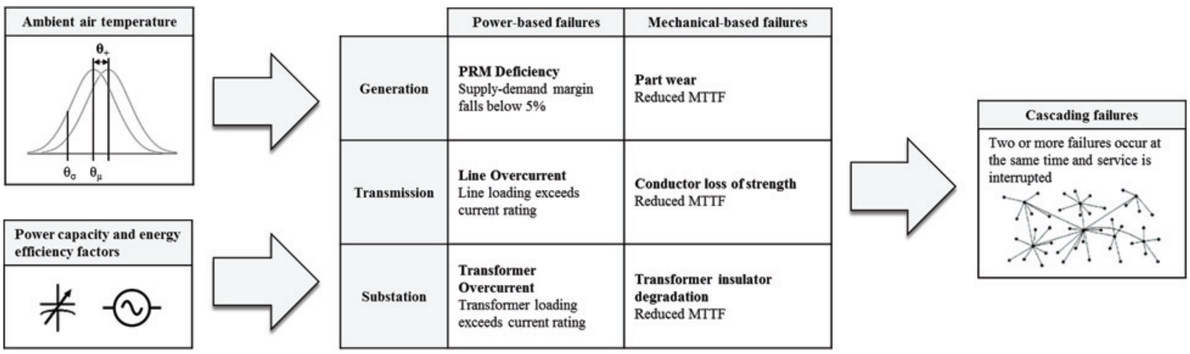

Fig. 2. Failure analysis model. The model is structured in five parts: (i) ambient air temperature, the increase of which is the primary control variable, θ_+; (ii) power capacity and energy efficiency factors, β's, which are proportional to ambient air temperature; (iii) probability of power-based failures for each component type, Pf_b^P, for which there could be insufficient capacity to support power demand; (iv) probability of mechanical-based failures for each component type, Pf_G^M, wherein the wear of thermally sensitive parts over time results in a higher failure rate or probability of failure on a given day; (v) cascading failures, that can occur if two or more component failures occur at the same time.

$$\Delta Pf_b^a = \frac{Pf_{bf}^a - Pf_{bi}^a}{Pf_{bi}^a}, \quad a = \begin{cases} M & mechanical-based\ \ failure \\ P & power-based\ \ failure \end{cases}, \quad b = \begin{cases} G & generation \\ T & transmission \\ S & substation \end{cases} \qquad \text{\% per day} \qquad (1)$$

2.1. Ambient air temperature

Ambient air temperature is the primary control variable in the model, and is defined as a normal distribution curve with base case mean maximum temperature θ_μ = 42.22°C and standard deviation θ_σ = 3.04°C from the average maximum temperature at the Phoenix airport for the months of June, July, and August 2009 to 2014 [15]. Summertime increases in air temperature, θ_+, are modeled as increases in the mean of the maximum temperature θ_μ with no change in standard deviation θ_σ.

2.2. Electric power capacity and energy efficiency factors

Electronic components are generally subject to at least two stresses: electrical and thermal [3]. Electrical resistance increases as conductor temperature increases, which further increases operating temperature and decreases efficiency [16]. The model inputs for capacity and efficiency losses are β_{GC} = 0.7%, β_{TDE} = 0.5%, β_{PKload} = 7.5%, β_{TC} = 1.5%, and β_{SC} = 0.7% per 1°C increase in ambient air temperature as are the marginal unit linearization of the results in [5, 11]. The generation factor only considers natural gas plants. These values are for high operating temperatures, which are within the range of this analysis, and are combined into the net adjustment factors $\beta_{PK} = \beta_{PKload} + \beta_{TDE} + \beta_{GC}$ = 8.7%, $\beta_T = \beta_{PKload} + \beta_{TC}$ = 9%, and $\beta_S = \beta_{PKload} + \beta_{SC}$ = 8.2% per °C.

2.3. Power-based failures

Power-based failures are failures where there is insufficient capacity in a circuit to meet demand. These can occur due to insufficient generation, when a transmission line is overcurrent, or a substation is overcurrent.

2.3.1. Generation – PRM deficiency

PRM is the amount of generation capacity available to meet expected demand, and is calculated as the difference in prospective resources and net internal demand, divided by net internal demand [17]. PRM is institutionally managed to maintain reliable grid operations in the event of unexpected increases in demand and or outages of existing capacity [17]. System operators historically issue alerts when PRM falls below 5% and ask customers to curtail their electricity usage [18]. Therefore 5% is used as the critical PRM value, PRM_{crit}, where other simultaneous component failures can cause a service interruption and trigger cascading failures.

ΔPf_G^P is estimated in equation (1) assuming PRM is marginally engaged for the top 5% of air temperature values for θ_μ and θ_σ, which is ≥ 47.22°C and represents the expected 4.6 hottest days per year from 2009 to 2014 [15]. The temperature that PRM_{crit} occurs at is estimated in equation (2), where PRM_i = 17% as is WECC's 2024 projected summer PRM [19]. Pf_{Gi}^P = 1.8% per day is the area under a normal curve of θ_μ and θ_σ above $\theta_{PRMcrit}$. Pf_{Gf}^P is estimated by shifting θ_μ by θ_+.

$$\theta_{PRMcrit} = \theta_{PRM} + \frac{\left(PRM_i - PRM_{crit}\right)}{\beta_{PK}} \qquad °C \qquad (2)$$

2.3.2. Transmission – Line Overcurrent

ΔPf_T^P is estimated in equation (1) assuming that if a line exceeds its rated amperage it will trip. Pf_{Ti}^P = 0.0032% per day is the area under a normal distribution for the line load as a percentage of the current carrying capacity where $IP_{T\mu}$ = 60%, $IP_{T\sigma}$ = 10%, and rated amperage is equal to 1. Pf_{Tf}^P is estimated by shifting $IP_{T\mu}$ by θ_+ and β_T.

2.3.3. Substation – Transformer Overcurrent

ΔPf_S^P is estimated using the same method as 2.3.2 by using equation (1), and assuming that if a transformer exceeds its rated amperage it will trip. Pf_{Si}^P =0.0032% per day is the area under a normal distribution for the transformer load as a percentage of the current carrying capacity where $IP_{S\mu}$ = 60%, $IP_{S\sigma}$ = 10%, and rated amperage is equal to 1. Pf_{Sf}^P is estimated by shifting $IP_{S\mu}$ by θ_+ and β_S.

2.4. Mechanical-based Failures

Mechanical failures occur due to physical degradation of thermally-sensitive parts within components such as a conductor, insulator, or contact. A failure rate, λ, is defined as the inverse of the MTTF with units of failures per day. Change in failure rates are estimated as the percent change in the initial and expected λ for increased air temperature conditions as in equation (1).

2.4.1. Generation – Part Wear

A value of 0.001% is assumed for Pf_{Gi}^P, and Pf_{Gf}^P is set to that multiplied by $(1+\theta_+/100)$.

2.4.2. Transmission – Conductor Loss of Strength

There are three primary factors considered in defining the thermal limit of a power line: sag, loss of strength, and the fittings of the conductor [20]. Sag is measured as the vertical distance that the line moves closer towards the ground due to thermal expansion, and increases the chance of flashover resulting in a ground fault and outage of the circuit. Such an event typically occurs when a line comes too close to trees, which may occur because trees have not been trimmed, or the line sags beyond the safety margin [13]. While sag is a mechanical process, it is not associated with conductor damage or loss of life [13]. Therefore analyzing the physical conductor sag constraints would be redundant with the previous power-based failure analysis for transmission line overcurrent. Loss of conductor strength occurs due to annealing, a gradual process whereby a metal recrystallizes over time, and ACSR conductors anneal at operating temperatures above 100°C [21]. Significant loss of strength may result in breakages during high mechanical stress events such as gusts of wind [21]. Properly designed and selected fittings are not a thermal limiting factor for the conductor [13].

ΔPf_T^M is estimated by equation (1) assuming a $MTTF_{Ti}$ = 70 years for ACSR lines based on [22] and that it is causally proportional to loss of conductor strength due to annealing. Pf_{Ti}^M = λ_{Ti} = 0.0039% per day is the inverse of the $MTTF_{Ti}$. Pf_{Tf}^M is estimated by adjusting MTTF as in equation (3). The strength loss associated with conductor end of life, S_{Teol}, is estimated as the weighted sum of the hours per day over $MTTF_{Ti}$ that a transmission line is expected to exceed nominal current by 10%, 20%, and 30%, and log-linear strength loss factors of 3%, 5%, and 7.5% respectively that are the approximate results of [23]. This assumes that percentage loss of tensile strength relates 1:1 to reduced lifespan. The initial strength reduction rate, S_{Ti}, is estimated linearly as S_{Teol} per $MTTF_{Ti}$. Transmission line current is assumed to be normally distributed with initial current loading $IP_{T\mu}$ = 60% and $IP_{T\sigma}$ = 10% as in 2.3. Nominal current is assumed to be 85% of rated capacity. The higher ambient air temperature scenario strength reduction rate S_{Tf} is estimated using the same approach, increasing $IP_{T\mu}$ by β_T and θ_+ accordingly.

$$MTTF_{Tf} = \frac{(S_{Teol} - S_{Ti}A_T)}{S_{Tf}} + A_T \quad \text{years} \qquad (3)$$

2.4.3. Substation – transformer insulation degradation

Substations consist of several power quality and protection devices to ensure safe and reliable grid operations, and this analysis focuses on transformers which are current-carrying devices used to change voltage levels for safe and efficient T&D of power throughout the network. The major parts of interest within transformers are the conductor windings and their insulation.

ΔPf_S^M is estimated by equation (1) assuming an initial MTTF of insulation life of 48.9 years as are the results of [24] for an oil-based distribution transformer, and is assumed representative of substation transformers. Pf_{Si}^M = λ_{Si} = 0.0056% per day. Pf_{Sf}^M is estimated scaling MTTF by the marginal unit linear adjustment factor from the same study where MTTF decreased from 48.9 to 46 years per 1% increase in ambient air temperature. It is important to note that this method does not explicitly consider the current loading at the substation IP, and that an oil-based distribution transformer may not be representative of transmission-level transformers.

2.5. Cascading failures

The change in probability of a cascading failure, ΔPc, is calculated in the same manner as equation (1). Pc_i = 0.0013% per day and Pc_f are estimated in equation (4) as one minus the probability that no failure occurs on a random day minus the probability of exactly one failure occurring on a day, times the cascade trigger coefficient α=10%. The probability that two simultaneous outages trigger a cascade are the results of [25] wherein a dynamic power flow simulation of a 2,383-bus system was used to assess the probability of cascading failures occurring in the event of two simultaneous outages within 2,896 component branches for n-1 contingency.

$$Pc_k = \alpha\left(1-\left[\prod_{a,b}(1-Pf_{bk}^{a})\right]-\left[\sum_{a,b}\left(Pf_{bk}^{a}\prod_{\overline{a,b}}(1-Pf_{bk}^{a})\right)\right]\right),\quad where\ k=\begin{cases} i & initial \\ f & final \end{cases},\quad \overline{a,b}=\{other\ a,b\} \qquad \%\text{ per day} \qquad (4)$$

3. Results

A 1-5°C increase in ambient air temperatures can significantly increase the rate of mechanical- and power-based failures as well as the cascading outages in the electric grid in Arizona. As listed in Table 1, mechanical failures in transmission lines could increase almost 200% for a 1°C increase. This means that the same strength loss that occurs in an overhead ACSR line over 70 years due to annealing could occur in 25 years, and lines could need to be reconductored or replaced that much more often. Mechanical failures in substations could increase by 16% with the first 1°C θ_+, and then approximately double for each 1°C thereafter if conductor insulation oil is not changed with that additional frequency. Power failures due to insufficient generation could be more than twice as likely with a 1°C increase in air temperatures. In that case reserve margins would fall below 5% on very hot days more often with additional load, reduced generation capacity, and reduced distribution efficiency proportional to the distribution of daily max temperatures. Power failure frequency in substations and transformers can increase 22x to 30x respectively for a 1°C θ_+. Increases in system peak load and decreases in current capacity in those components during peak hours could result in exceedance of rated current and tripping with much higher frequency. The probability of two or more failures triggering a cascading outage can increase by 26x with the first θ_+=1°C. The change in probability of cascading failures grows exponentially with θ_+ and increases in power-based failures. If the probability of a cascading failure event is currently once every 20-30 years, then that probability could increase to once every 1-2 years with hotter summers if preventative measures are not taken.

Table 1. Increased probability of failures per degree increase in ambient air temperature.

θ_+ (°C)	ΔPf_G^P	ΔPf_T^P	ΔPf_S^P	ΔPf_G^M	ΔPf_T^M	ΔPf_S^M	ΔPc
0	-	-	-	-	-	-	-
1	135	2,955	2,225	1	183	16	2,587
2	400	43,799	28,751	2	409	39	77,788
3	871	305,542	194,967	3	576	73	1,287,827
4	1,620	1,087,885	744,306	4	685	128	10,275,393
5	2,691	2,183,150	1,704,373	5	711	236	35,679,472

4. Conclusion

Specific vulnerabilities in the electric power grid are identified where proactive governance may be able to prevent future outages otherwise resultant from rising ambient air temperatures in Arizona. Preventative measures in operations and maintenance could include more frequent reconductoring and changing of insulators, component derating, upgrades to more thermal resistant parts, forced-air cooling systems, dynamic power-flow routing, and or demand side management programs including energy efficiency, demand response, and peak load shifting [4, 11, 19, 24]. Increased inspections and flexible maintenance schedules around weather patterns could be useful in the interim. Failure to do so may result in outages in other critical interdependent infrastructure systems including water, transportation, telecommunications, and information technology [27].

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