LLOYD'S

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SOCIETY & SECURITY

Business Blackout
Appendix 2

Scenario design and impact modelling methodologies

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This report presents a hypothetical stress test scenario developed by the University of Cambridge Centre for Risk Studies to explore management processes for dealing with extreme external shocks. It does not predict any catastrophes.

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Introduction

This paper accompanies the Lloyd's Emerging Risk Report *Business Blackout: The insurance implications of a cyber attack on the US power grid* which is available from: www.lloyds.com/businessblackout. It presents some of the key aspects of the methodology used by the University of Cambridge Centre for Risk Studies to generate the scenario and assess its impacts. The bibliography of sources is included in the main report.

The US electricity network

Safe operation of the grid

In order to physically coordinate disparate and disperse electricity resources, and ensure the safe operation of equipment, grid operators must ensure precise synchronisation of five active attributes: line voltage, frequency, phase sequence, phase angle, wave form. If any of these factors are misaligned on either side, there is a risk of physical damage, injury, outage or violation of regulation.
The widespread delivery of electrical power depends on the synchronisation and alignment of this five-factor system, and herein lies a systemic risk in the US interconnect system. Reliability coordinators in different regions are entirely devoted to maintaining these synchronisations within strict operating parameters and hundreds of thousands of protective relays are in place to protect against unsafe operating conditions in these variables, some of which are analogue and some of which are digital. Relays that rely on electronic logic and are capable of remote communication may be vulnerable to digital attacks.

Given the engineering interdependencies between reliability regions, a system issue in one part of the interconnect network can cause an outage many miles away. An example of this occurred during an outage in April 2015 when an equipment failure at a plant in Maryland caused the White House, Capitol Building and several other locations in Washington DC and Maryland to lose power for several hours.[1]

Electricity markets[2]

Electricity is traded at hubs or delivery points in the US for retail competition markets. There are two types of electricity markets in the US: vertically integrated and horizontally integrated.

Vertical electricity markets (also known as the 'regulated market' or 'regulated monopoly') conduct their own planning for meeting electricity demand and are connected directly to customers. Economic regulation controls the supply and distribution rates.

In horizontal electricity markets (also called 'restructured' or 'wholesale/retail competition' or 'separate distribution functions') generation firms do not plan loads but bid for a place in the market; thus rates are set by the market. Distribution rates are set through economic regulation by the Federal Energy Regulatory Commission (FERC). Individual state energy boards have some authority to direct generation and demand-side resources. This market structure serves 66% of US customers.

Horizontal markets are administered by independent system operators (ISO) and/or regional transmission organisations (RTO). ISO/RTOs serve as a third-party independent operator of the transmission system, and ensure that no preference is given to any one utility-owned generation firm.

The regional markets in California, the Midwest, Texas and the Northeastern US have ISO/RTOs and thus have horizontal markets; the remaining supply areas have vertical markets. Interconnects maintain common practice standards among power organisations, the engineering side of the electricity grid, while ISO/RTOs focus on the market side.

Electricity demand is forecast on a daily, monthly and yearly basis and based on historical data. Typically, generation plants are awarded bids to supply electricity to the grid and will supply from their base load (currently supplied power), spinning reserve or operating reserve. Spinning reserve refers to the additional capacity that an already active generator could feasibly supply to the grid with 10-60 minutes' notice at a time of high demand. Operating reserve refers to offline generators that can deliver supply within an hour during an outage. The July 2014 peak-hour electricity demand in the Northeast Power Coordinating Council (NPCC) and Reliability First Corporation (RFC) regions was 194,000 MW. In order to begin to cause an outage, over 18,000 MW must be taken out of these regions.

[1] *USA Today, 2015. 7 April 2015. Outages Hit DC, Including White House, Capitol. USA Today, 7 April 2015.*

[2] *North American Electric Reliability Corporation, 2013. Regional Entities: NERC Interconnections. Available from: www.nerc.com/AboutNERC/keyplayers/Pages/Regional-Entities.aspx/*

Targeting methodology

Target locations for cyber attack

The choice of target was driven by the hostile actor's motivation to cause substantial disruption to the USA, but limited in scope owing to considerations of resources, complexity and the motive to avoid 'all out war' with the USA.

With this in mind, New York City (NYC) and Washington, district of Columbia (DC) are chosen as the primary targets.

NYC and DC are located in the Eastern Interconnect. NYC is located in the NERC reliability region of Northeast Power Coordinating Council (NPCC). DC is located in the NERC reliability region of Reliability First Corporation (RFC).

NYC is located in the ISO/RTO electricity market of New York ISO (NYISO) and DC is located in the ISO/ RTO electricity market of Pennsylvania-New Jersey-Maryland Interconnection (PJM). [3]

Looking at the population breakdown of each NERC region, we see that NPCC and RFC sum to 29.5% of the total population of the US, or roughly 93 million people as of 2013.[4]

We also see that NPCC and RFC sum to 32% of the US GDP, roughly $4.97trn as of 2013. [5]

Looking at the breakdown of the types of customers for each region, NPCC and RFC account for a total of 24.7% of the industrial customers, 27.3% of the commercial customers and 24.4% of the residential customers in the US. [6]

Table 1: Customers of NPCC and RFC regions by sector

Customer base	Industrial	Commercial	Residential
RFC	21.0%	17.8%	17.5%
NPCC	3.7%	9.5%	6.9%
Total	24.7%	27.3%	24.4%

Consumption per capita data for each region as of 2014, shows that NPCC and RFC consume 24% per capita of the electricity in the US. [7]

The production breakdown of each region also indicates that the states in NPCC and RFC produce 17.9% of all energy in the US as of 2014. [8]

[3] *United States Census Bureau, 2013. Population Estimates: State Totals: Vintage 2013. [online] Available at: http://www.census.gov/popest/data/state/totals/2013/*

[4] *North American Electric Reliability Corporation, 2013. Regional Entities. [online] Available at: http://www.nerc.com/AboutNERC/keyplayers/Pages/Regional-Entities.aspx/*

[5] *US Census Bureau, Data Integration Division. "State Totals: Vintage 2013 - United States Census Bureau, ibid."*

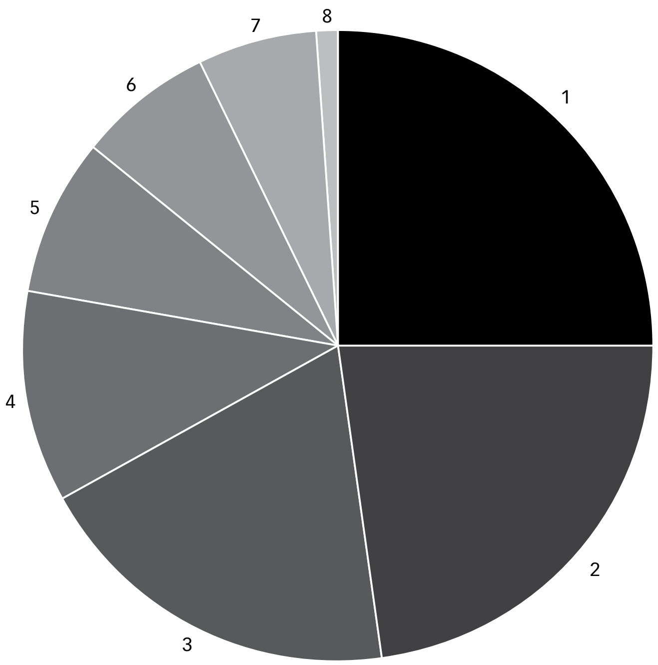
[6] *U.S. Department of Commerce, Bureau of Economic Analysis, 2015. Advance 2014 and Revised 1997 - 2013 Statistics of GDP by State. [online]. Available at: http://www.bea.gov/newsreleases/regional/gdp_state/gsp_newsrelease.htm*

[7] *Customer breakdown. EIA. Source: U.S. Energy Information Administration, Form EIA-826, Monthly Electric Sales and Revenue Report with State Distribut ions Report.*

[8] *U.S. Energy Information Administration, 2014. NERC's Summer Reliability Assessment highlights regional electricity capacity margins. [online] Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=16791*

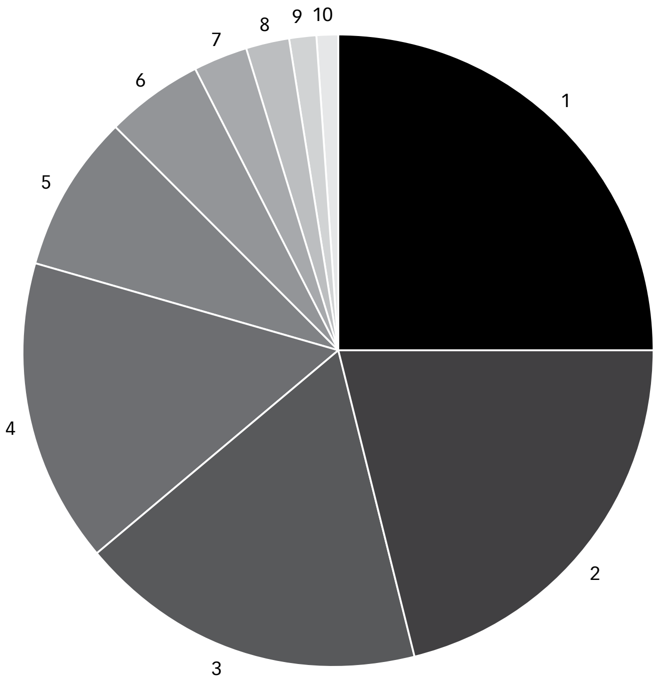
Figure 1: Population, consumption and output of NERC regions (Cambridge Centre for Risk Studies; data drawn from Wikipedia and www.EIA.gov)

Population by NERC region



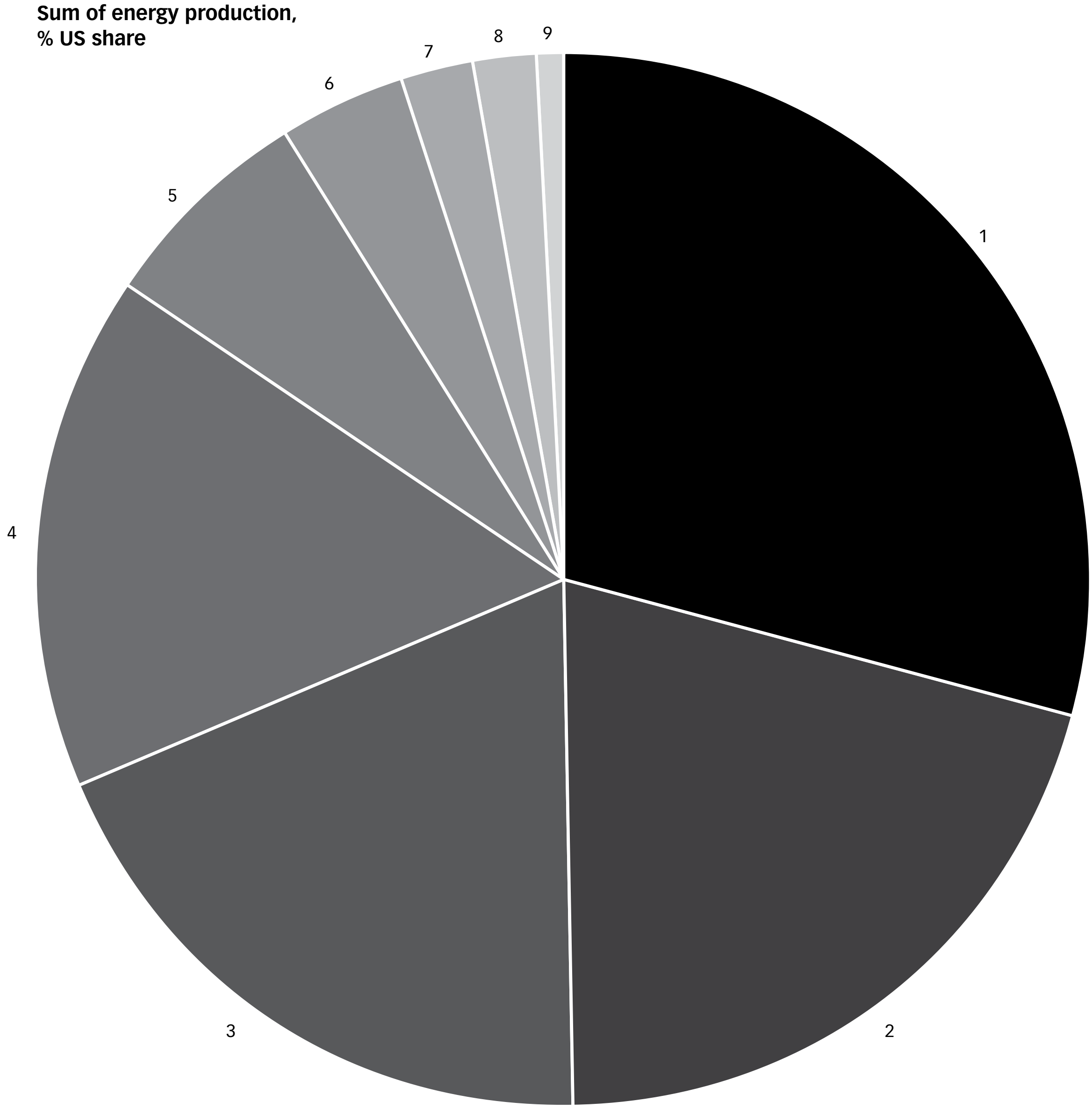
	Sector	%
1	SERC	25
2	WECC	23
3	RFC	19
4	NPCC	11
5	TRE	8
6	MRO	7
7	FRCC	6
8	SPP	1
9	Hawaii	0
10	ASCC	0

Consumption per capita, million Btu



	Sector	C.P.C
1	SERC	4,494
2	WECC	3,750
3	MRO	3,206
4	RFC	2,749
5	NPCC	1,470
6	ASCC	873
7	TRE	471
8	SPP	411
9	FRCC	210
10	Hawaii	202

Sum of energy production, % US share



	1	2	3	4	5	6	7	8	9
Sector	WECC	SERC	TRE	RFC	MRO	SPP	ASCC	NPCC	FRCC
Percentage %	29.18	20.61	19.03	15.75	6.66	3.91	2.11	2.11	0.63

Extreme event analysis – estimation of power outage duration

Extreme event analysis

An extreme event analysis was performed on historical power outages in the USA for the period 2002–2014. Data on outages was downloaded from the Energy Information Administration (EIA) website.

Data for the period 2011 to 2014 was not compatible with the data for the period 2002 to 2010, so a concordance table was built to combine these datasets. In addition, time fields were made consistent and data cleansing was performed to remove nonsensical values, or make corrections where obvious data entry mistakes had been made. Special care was given to outages occurring over the New Year period, as these often led to errors in estimates of outage duration. The cleaned historical outage database contains a total of 1,102 outage events.

In order to maximise available data some data was imputed from the data available. For example, when data on the number of customers affected was unavailable and peak capacity (MW) was available, the number of customers was estimated based on average customer demand. When total lost capacity was known, the number of customers without power was derived from total generation capacity lost.

Lost generation output in MWh is the only meaningful way to compare the severity of power outage events. Long-duration events may be caused by small capacity disruptions thus not giving a true indication of the severity of the event. On the other hand outages with large disruptions to generation capacity may only last for a short duration limiting their overall impact. As estimates on the amount of electricity not delivered were not reported in this database, a method was derived to estimate the amount of power undelivered over the period of the outage. A linear restoration function proportional to time was inferred from the data and it was assumed that the failed generators would have continued to generate electricity in the event of a widespread failure. Thus electricity undelivered or TWh@risk is derived from the following equation where E represents TWh@risk, C is the total generation capacity lost at the time of the event and t is time.

$$\int -E(t)dt = -\tfrac{1}{3} \int Ct\, dt$$

The following tables show the largest outage events occurring in the USA over the period 2002–2014.[9]

Table 2: Longest/Largest outages by duration

Rank	Year	Day	Month	Outage duration	Cause	NERC region	Peak capacity (MW)	Customers without power	Lost generation (GWh)
1	2003	26	October	23 days, 9 hrs 10 mins	Wildfire	WECC	232	108,000	130
2	2009	3	March	22 days, 23 hrs 17 mins	Transformer faulted/ unit tripped	RFC	378	175,770	208
3	2008	12	September	19 days, 5 hrs 38 mins	Hurricane Ike	TRE	8,087	2,142,678	3,733
4	2008	12	September	19 days, 5 hrs 38 mins	Hurricane Ike	TRE	5,386	2,504,366	2,486
5	2008	31	August	19 days, 1 hrs 30 mins	Fuel supply curtailed	SERC	200	93,000	92
6	2014	5	February	18 days, 0 hrs 0 mins	Fuel supply emergency - coal	NPCC	300	139,500	130
7	2006	14	December	17 days, 4 hrs 50 mins	Wind storm	WECC	258	24	107
8	2005	24	October	16 days, 17 hrs 0 mins	Hurricane wilma	FRCC	148	84,900	59
9	2009	28	January	16 days, 5 hrs 3 mins	Winter storm	RFC	495	230,300	193
10	2010	1	June	16 days, 2 hrs 27 mins	Firm load shed	RFC	500	1	193

[9] *Events are specific to regions (events that span multiple regions are entered as multiple events).*

Table 3: Outages of longest duration by generation capacity lost

Rank	Year	Day	Month	Outage duration	Cause	NERC region	Peak capacity (MW)	Customers without power	Lost generation (GWh)
1	2012	24	July	0 days, 14 hrs 30 mins	Thunderstorms	RFC	330,000	153,450,000	4,785,000
2	2012	1	July	2 days, 2 hrs 0 mins	Thunderstorms	RFC	320,000	148,800,000	16,000,000
3	2012	18	July	0 days, 7 hrs 0 mins	Thunderstorms	RFC	181,000	84,165,000	1,267,000
4	2012	5	July	1 days, 20 hrs 30 mins	Thunderstorms	RFC	111,000	51,615,000	4,939,500
5	2012	18	July	1 days, 9 hrs 42 mins	Thunderstorms	RFC	103,000	480	3,471,100
6	2012	7	July	2 days, 1 hrs 1 mins	Thunderstorms	RFC	95,400	44,361,000	4,676,190
7	2012	24	July	0 days, 9 hrs 29 mins	Thunderstorms	RFC	82,621	38,418,765	783,522
8	2012	21	July	0 days, 3 hrs 1 mins	Severe weather	SPP	70,000	220	211,167
9	2012	1	July	0 days, 4 hrs 30 mins	Severe weather	SERC	69,106	32,134,290	310,977
10	2012	18	July	0 days, 2 hrs 45 mins	Thunderstorms	RFC	67,000	31,155,000	184,250

Table 4: Longest outages by duration and capacity (electricity generated or TWh@Risk)

Rank	Year	Day	Month	Outage duration	Cause	NERC region	Peak capacity (MW)	Customers without power	Lost generation (GWh)
1	2012	1	July	2 days, 2 hrs 0 mins	Thunderstorms	RFC	320,000	148,800,000	16,000,000
2	2012	5	July	1 days, 20 hrs 30 mins	Thunderstorms	RFC	111,000	51,615,000	4,939,500
3	2012	24	July	0 days, 14 hrs 30 mins	Thunderstorms	RFC	330,000	153,450,000	4,785,000
4	2012	7	July	2 days, 1 hrs 1 mins	Thunderstorms	RFC	95,400	44,361,000	4,676,190
5	2012	7	July	2 days, 16 hrs 54 mins	Thunderstorms	RFC	64,500	29,992,500	4,186,050
6	2008	12	September	19 days, 5 hrs 38 mins	Unknown	TRE	8,087	2,142,678	3,733,229
7	2012	18	July	1 days, 9 hrs 42 mins	Thunderstorms	RFC	103,000	480	3,471,100
8	2012	26	July	2 days, 5 hrs 9 mins	Thunderstorms	RFC	65,000	30,225,000	3,454,750
9	2008	12	September	19 days, 5 hrs 38 mins	Unknown	TRE	5,386	2,504,366	2,486,234
10	2003	14	August	3 days, 7 hrs 53 mins	Unknown	NPCC	22,934	10,664,310	1,832,044

The following charts show the historical return periods by capacity, duration and lost generation output.

Figure 2: Historical exceedance probability curve for the duration of outage (hours)

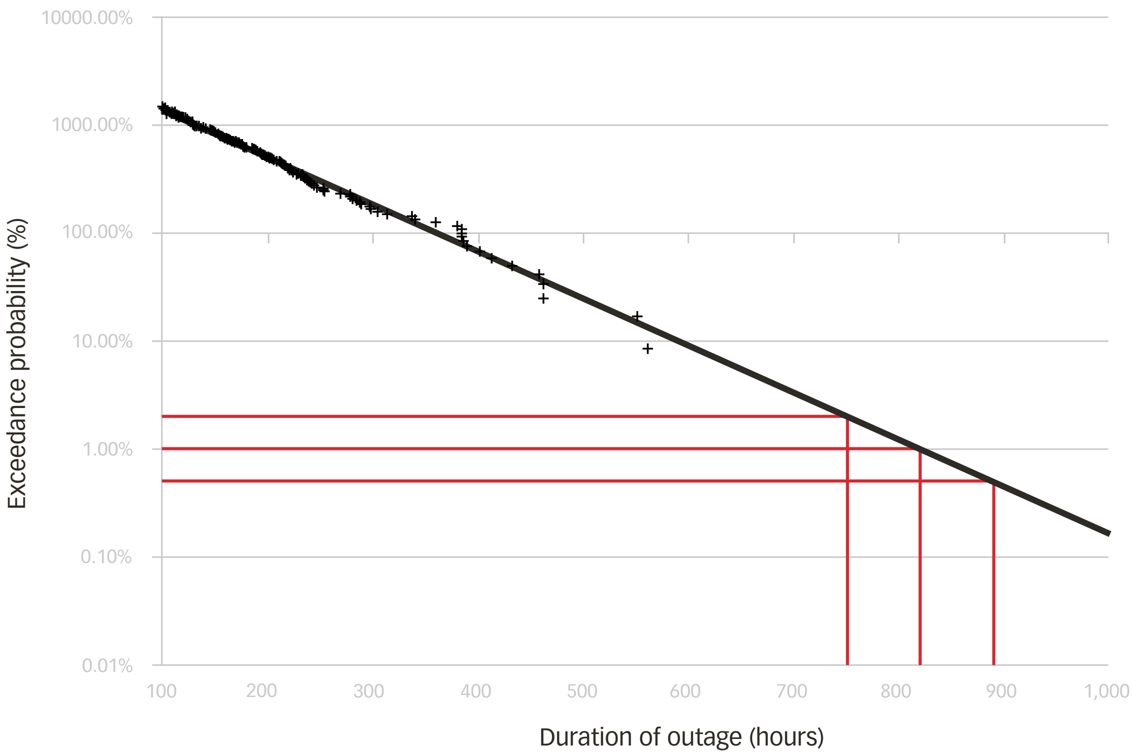


Table 5: Duration of outage (days) for different return periods

Return periods	Duration (hours)	Duration (days)
1 in 50	751	31
1 in 100	821	34
1 in 200	890	37

Figure 3: Historical exceedance probability curve for capacity loss

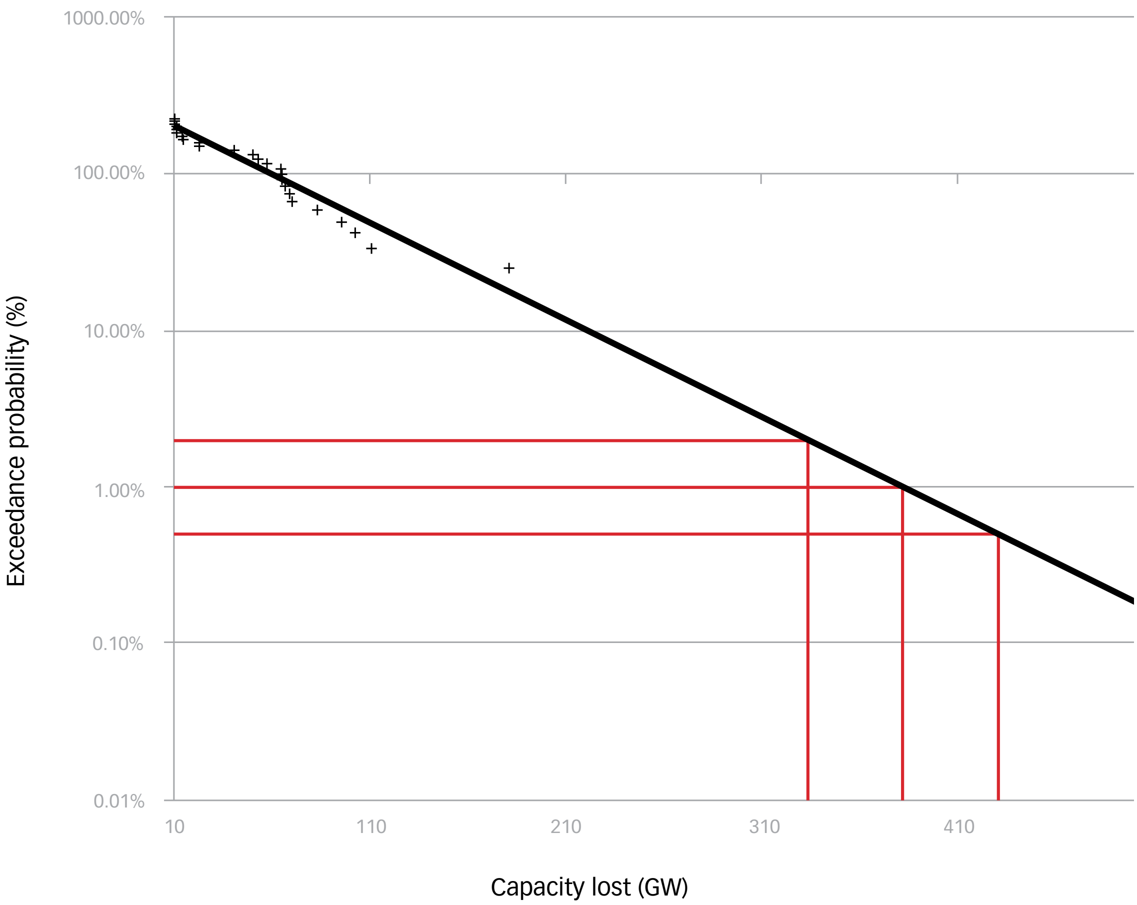
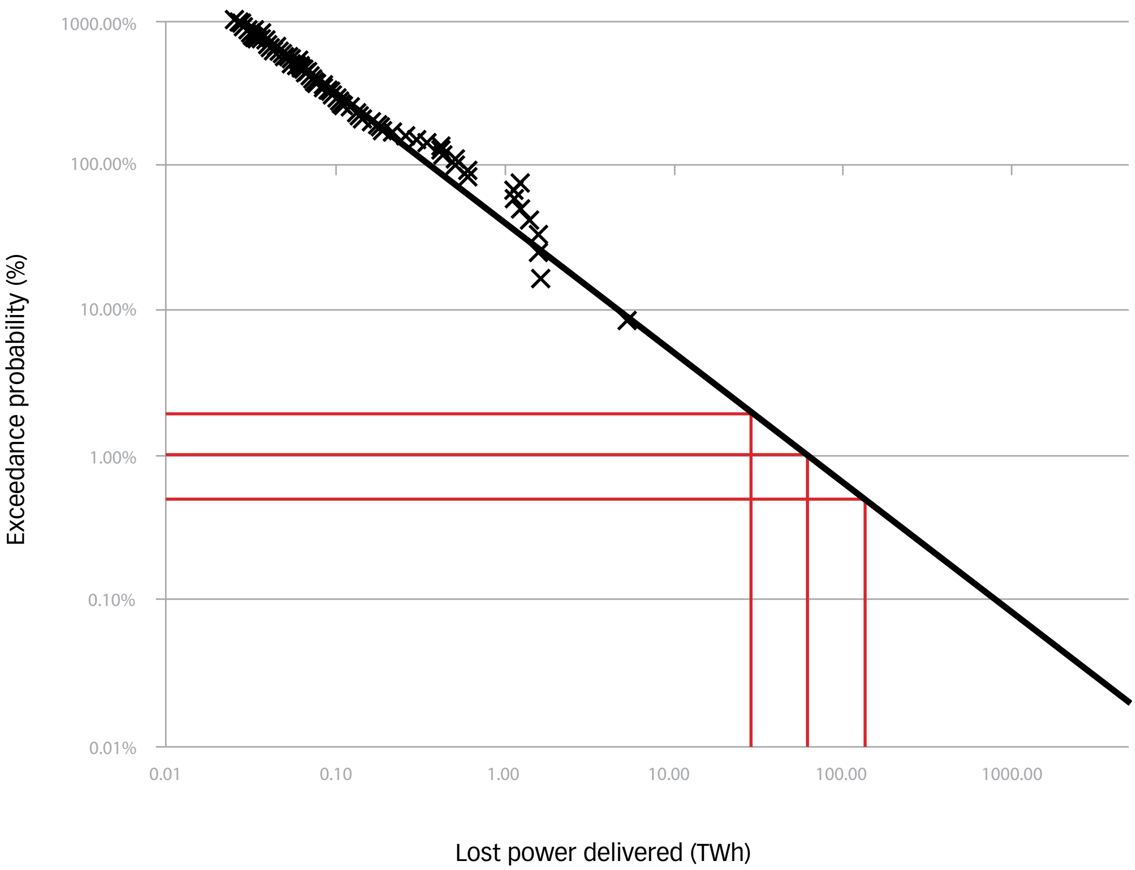


Table 6: Lost capacity for different return periods

Return periods	Lost capacity (GW)
1 in 50	334
1 in 100	382
1 in 200	431

Figure 4: Historical exceedance probability curve for power not delivered (TWh)



Scenario variants

Peak demand capacity in the RFC/NPCC region was estimated at 190 GW. This was then used to estimate the maximum amount of electricity generation over a 30-day period. When the grid is under stress it is assumed that all generators operate at their peak capacity and they would each deliver an estimated 136.8 TWh over a 30-day period. Using the outage schedule as defined in Figure 2 it was then possible to estimate the expected Electricity@Risk. As shown in this restoration diagram, the area under the curve can be estimated to give the percentage of electricity not generated over time. These percentages were then used to determine the amount of electricity not delivered over a 30-day period. Estimates for Electricity@Risk are given in Table 8 for each scenario variant.

Table 7: Lost power delivered for historical different return periods

Return periods	TWh@Risk (TWh)
1 in 50	45
1 in 100	89
1 in 200	178

Table 8: Scenario variants TWh@Risk

Scenario	Percentage	TWh@Risk (TWh)
S1	13.5%	18.5
S2	28.9%	39.5
X1	49.4%	67.7

Macroeconomic loss estimates

Historical estimates on economic loss

Literature on the cost of power system failure can be split into two distinct categories. The first category attempts to estimate the impact of average annual losses during power system failures on the economy for all interruptions over an entire year. These studies, therefore, attempt to estimate the cost of all losses over a year with a particular focus on capturing high-frequency, short-duration events. As these studies tend to focus on expected or average losses for any given year, rare long-duration events tend to be under-represented in cost estimates.

The second branch of literature attempts to estimate the economic losses that occur from large individual events that cover a large area or last for a long time. Key findings from this literature show that there are few estimates on the economic losses associated with large power system failure events. The limited literature that does exist for large events tends to use rules of thumb derived from existing studies that are then extrapolated to current situations (Eto et al, 2001).

Average annual expected losses

There are several studies that estimate the expected annual losses caused by electricity failure to the US economy. The first study, and still one of the most widely cited, was completed by Clemmensen[10] (1993) who arrived at a total loss estimate by aggregating the total annual spending on industrial equipment to avoid voltage fluctuations and power outages. There are several shortcomings in Clemmensen's approach. First, spending is used as a proxy for costs which tends to underestimate the cost of power interruption. Second, it tends to ignore the possibility of large and infrequent events. Third, the estimates were based purely on the manufacturing sector, making extrapolation to other sectors difficult. The Swaminathan and Sen study[11] (1998) used data from the 1992 Duke Power outage cost survey and applied it to the entire US based on total electricity sales. Table 9 shows the range of estimates given for the annual expected economic costs of outages. In these studies the dominant losses occur from frequent, minor fluctuations in voltage and disruptions to the power supply lasting for five minutes or less.

Table 9: Expected average annual cost of historical outages for the US[12]

Paper	Year of study	Annual loss estimate (US$ 2015 dollars)	Notes
Clemmensen	1993	$27-$52bn	Underestimate Manufacturing sector only
Swaminathan and Sen	1998	$157bn	Industrial sector only
Primen' with 'Lineweber & McNulty'[13]	2001	$138-$219bn	
LaCommare & Eto	2004	$30-$176bn	Cost of all outages over a year were calculated from Lawton et al (2003)
Campbell[14]	2012	$26-$73bn	Weather related outages

[10] *Clemmensen, J., 1993. A Systems Approach to Power Quality. IEEE Spectrum, June 1993.*

[11] *Swaminathan, S. and Sen, R., 1998. Review of Power Quality Applications of Energy Storage Systems. Sandia National Laboratories*

[12] *Values have been converted into 2015 dollars using the 2012–2015 US GDP price deflator of 1.046*

[13] *Lineweber, D., & McNulty, S., 2001. The Cost of Power Disturbances to Industrial & Digital Economy Companies. Available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002000476*

[14] *Campbell, R., 2012. Weather-Related Power Outages and Electric System Resiliency. Congressional Research Service.*

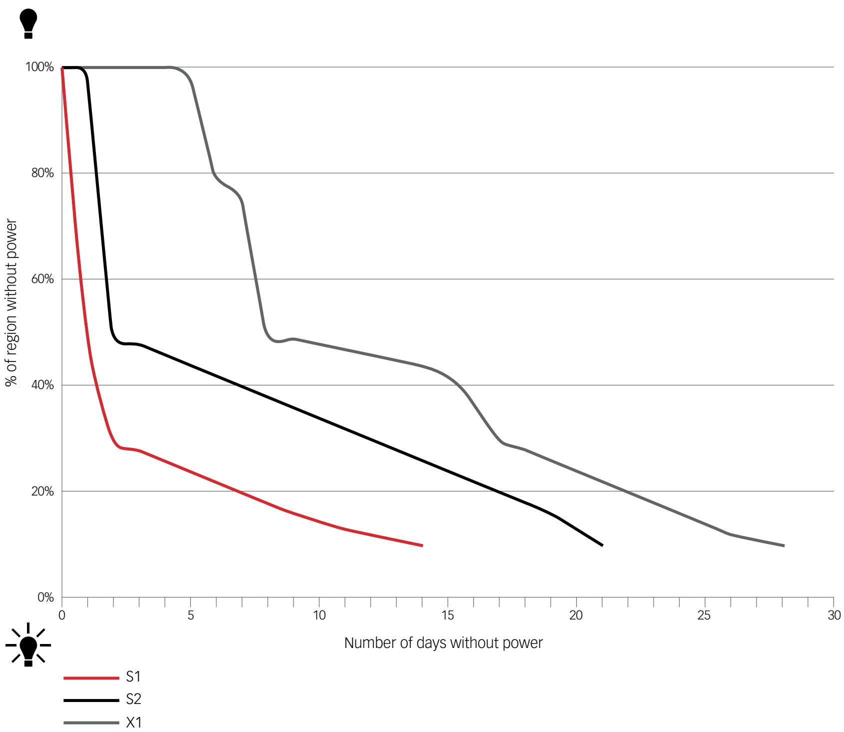
Extreme event losses

The second branch of literature looks at the economic losses associated with large single events. As most large scale outage events are generally triggered by an extreme weather event, it is often difficult to separate out the losses that are directly related to electricity failure and those losses associated with damage caused by the natural disaster. The overall cost and impact of a blackout can vary greatly depending on its duration and the area affected. A two-month blackout in downtown Auckland, New Zealand in 1998 had an overall cost of US$56m million, whereas a 1997 outage lasting two minutes in Taiwan triggered a US$11m loss, largely due to contingency losses at an affected plastics factory.

The recovery schedule

Figure 6 shows the recovery profile for each of the three variants of the Erebos Cyber Blackout Scenario. From this recovery profile, we calculate the number of 'outage-days' over which electricity is not delivered. Outage-days are defined as the integrated area under each of the variant recovery profiles. The outage-days for each scenario are shown at Table 10. The outage-day values were used to determine the amount of unsupplied electricity within each of the regions impacted by the electricity failure as a proportion of the electricity that would be expected to be delivered under normal operations.

Figure 6: Scenario power outages for affected region



Breaking down economic losses

Whether top-down or bottom-up approaches are used, the severity of the outage needs to be captured when assessing cost implications. Some studies estimate economic losses as lost capacity to the system (MW peak) but do not give any regard to the duration of the event. For outages of a small duration, this may be an acceptable approach but for events of a longer duration – like that considered in this report – the duration of the outage must also be included in the analysis. By expressing loss as the amount of unsupplied electricity over time (ie MWh) we are able to capture both the magnitude of capacity lost (MW) and how long the outage lasts for. Estimating economic loss can then be estimated using the indicator ($/MWh) which can be further separated into duration bands which specify how marginal costs may change as the duration of the outage increases in time.

Table 10: Outage-days as defined by recovery profiles

Scenario	Outage-days	As % of 30 days	As % of year
S1	3.78	12.6%	1.04%
S2	8.08	26.9%	2.21%
X1	13.83	46.1%	3.79%

Table 11 shows the annual electricity delivered to residential, industrial and commercial customers in each of the regions impacted by the failure over one year.

Table 11: Electricity sold and electricity delivered per major US power sector

	Revenue from electricity sales US ($bn)	Electricity delivered (TWh)	Customers served (thousands)
NPCC region			
Residential	$18.3	97	159,442
Commercial	$20.0	129	22,897
Industrial	$3.3	36	412
Subtotal	$41.6	261	182,751
RFC region			
Residential	$32.5	248	293,441
Commercial	$25.8	241	37,830
Industrial	$14.6	201	1,292
Subtotal	$72.9	690	332,563
Total (both regions)			
Residential	$50.8	344	452,883
Commercial	$45.8	370	60,727
Industrial	$17.9	237	1,704
Subtotal	$114.5	951	515,314

Source: US Energy Information Administration, 2015.

Table 12 below gives the total amount of unsupplied electricity assuming the outage occurs at peak-hour and, again, assuming the outage occurs at a time of average demand. We have chosen the outage to occur at a period of peak demand; however, it is unreasonable to assume the entire outage will occur at a time of peak-hour as peak-hour periods tend to be short and infrequent. As the outage in this scenario lasts for several days the actual amount of unsupplied electricity will be somewhere between the peak-hour demand and average demand. Both numbers have been provided for comparison purposes. Table 12 also includes an estimate on the number of customer-outage-days of disruption. This is simply calculated as the total number of customers without power multiplied by the number of outage-days.

Table 12: Unsupplied electricity and consumer days in the Erebos Cyber Blackout Scenario

		Unsupplied electricity assuming peak-hour (TWh)	Unsupplied electricity assuming average (TWh)	Customer-outage-days days without power (thousands)
S1	Residential	6.7	3.6	1,712
	Commercial	7.2	3.8	230
	Industrial	4.6	2.5	6
	Total	18.5	9.9	1,948
S2	Residential	14.3	7.6	3,659
	Commercial	15.4	8.2	491
	Industrial	9.8	5.3	14
	Total	39.5	21.0	4,164
X1	Residential	24.5	13.1	6,263
	Commercial	26.3	14.0	840
	Industrial	16.8	9.0	24
	Total	67.6	36.0	7,127

Adding up the losses

The revenue loss in the electricity sector ("Revenue@ Risk") was calculated'd using data on total sales revenue, price of electricity and total amount of unsupplied electricity to the regions of interest.

In this scenario, portions of the electricity network in RFC and NPCC are without power for several weeks. Revenue losses in the electricity sector due to unsold power were estimated by multiplying the amount of undelivered electricity (kWh) by the price of electricity charged to industrial, commercial and residential customers ($/kWh). This value was checked using a second method where the percentage of unsupplied electricity over the entire year was multiplied by annual revenue received from each sector. Totals from these two methods were comparable to within 5%, showing the estimates in lost revenue to the electricity sector are fairly robust. Revenue@Risk to the electricity sector is detailed in Table 13.

Table 13: Revenue@Risk in the electricity sector for NPCC and RFC regions in the Erebos Cyber Blackout Scenario

NPCC and RFC	Price of electricity	Total annual revenue	Revenue@Risk from unsupplied electricity from electricity sales (scenario variants)		
	$/kWh	$bn	S1 $bn	S2 $bn	X1 $bn
Residential	$0.195	$50.8	$0.54	$1.15	$1.96
Commercial	$0.164	$45.8	$0.48	$1.02	$1.75
Industrial	$0.074	$17.9	$0.14	$0.29	$0.50
Total		$114.5	$1.15	$2.46	$4.21

The second form of direct loss is those losses incurred by other sectors in the economy which depend on electricity for production, commerce or final consumption. The direct loss in production activity and sales revenues will incur major economic losses across all sectors of the economy. The values shown in Table 14 give estimates of 'value of lost load' (VOLL) across different sectors of the economy. These values were originally estimated by Reichl et al (2013) using survey data collected in Austria from 267 unique business locations. A similar analysis where sectors are broken down at this level of detail is not available for the United States but the relative impacts across different sectors are not expected to vary significantly for the USA.[15] As shown in Table 14, VOLL estimates decrease with length of outage, where the marginal cost of the first hour is always the most expensive and the final hour the least expensive. Thus the average cost of longer outages will have a lower per hour outage costs. The values in Table 14 represent the average value of avoiding an electricity disruption over different durations. The longest outage duration where VOLL estimates are typically available is for outages of 48 hours or less. If this curve were to be extrapolated for outages of longer durations, VOLL estimates are expected to be asymptotically decreasing. It is difficult to precisely determine where this asymptote would occur, and thus for this study the VOLL of a 48-hour outage is used as a worst-case scenario.

Table 14: VOLL estimates for different industry sectors

	Value of Lost Load (VOLL) in 2015 $US ($/kWh)		
Economic sector	4-hour outage	12-hour outage	48-Hour outage
Construction	$96.58	$52.28	$40.75
Wholesale and retail trade	$80.98	$46.13	$37.08
Information and communication	$39.18	$20.31	$15.59
Professional, scientific and technical services	$31.71	$16.77	$13.63
Administrative support services	$31.19	$17.56	$13.89
Accommodation and food services	$30.01	$15.99	$12.32
Finance and insurance	$27.26	$12.84	$9.57
Real estate	$27.13	$12.71	$9.70
Transport	$14.15	$7.73	$6.03
Public sector	$13.37	$7.08	$6.81
Manufacturing	$7.99	$4.32	$3.14
Agriculture	$7.47	$4.59	$3.41
Mining	$3.54	$1.70	$1.31
Electricity and gas supply	$2.49	$1.31	$1.05
Water supply, waste management	$1.83	$0.92	$0.66
Households	$1.70	$1.83	$2.21

[15] *Data on sectoral electricity consumption rates was taken from the energy satellite accounts of the World Input Output Database (WIOD) (www.wiod.org)*

Table 15 below gives the total annual electricity consumption by sector and by extension the amount of unsupplied electricity for each of the variants in this scenario.

The VOLL estimates were then multiplied by the total amount of unsupplied electricity to give the direct loss for each economic sector.

Table 15: Electricity consumption per industry sector

	Electricity consumed (TWh/year)	Unsupplied electricity (TWh)		
Economic sector	NPCC and RFC regions	S1	S2	X1
Households	328.91	3.406	7.281	12.463
Manufacturing	196.90	2.039	4.359	7.461
Public sector	120.93	1.252	2.677	4.582
Accommodation and food services	44.17	0.457	0.978	1.674
Electricity and gas supply	41.43	0.429	0.917	1.570
Wholesale and retail trade	37.37	0.387	0.827	1.416
Real estate	36.04	0.373	0.798	1.366
Administrative support services	32.35	0.335	0.716	1.226
Professional, scientific and technical services	29.71	0.308	0.658	1.126
Finance and insurance	17.85	0.185	0.395	0.676
Agriculture	17.51	0.181	0.388	0.663
Mining	15.07	0.156	0.334	0.571
Information and communication	11.50	0.119	0.255	0.436
Water supply, waste management	10.36	0.107	0.229	0.392
Transport	10.03	0.104	0.222	0.380
Construction	0.87	0.009	0.019	0.033
Total	951.00	9.85	21.05	36.03