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Comparing a Transmission Planning Study of Cascading with Historical Line Outage Data

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***Abstract*— The paper presents an initial comparison of a transmission planning study of cascading outages with a statistical analysis of historical outages. The planning study identifies the most vulnerable places in the Idaho system and outages that lead to cascading and interruption of load. This analysis is based on a number of case scenarios (short-term and long-term) that cover different seasonal and operating conditions. The historical analysis processes Idaho outage data and estimates statistics, using the number of transmission line outages as a measure of the extent of cascading. An initial number of lines outaged can lead to a cascading propagation of further outages. How much line outages propagate is estimated from Idaho Power outage data. Also, the paper discusses some similarities in the results and highlights the different assumptions of the two approaches to cascading failure analysis.**

***Index Terms*—cascading, GATORS, outage data, planning, transmission equipment**

I. Introduction

The impact of cascading outages and blackouts on the economy and society is extremely high. The power grid around the globe today experiences an increased number of cascading outages due to factors such as stress due to increased transfers and unpredictable fluctuations due to increased integration of variable energy sources.

Typical planning and seasonal operating studies, performed by Western Electricity Coordinating Council (WECC) member utilities, use base cases that model the entire Western Interconnection. Idaho Power, since the major blackout event on July 2nd, 1996 that originated in its service territory, continuously evaluates and study its system to ensure that its performance meets not only North Electric Reliability Corporation (NERC) standards and WECC Reliability Criteria [1]-[2] but also going beyond those requirements [3]-[5]. Idaho Power system is a portion of the Bulk Electric System (BES) in the Western Interconnection.

Understanding cascading outages and being able to predict the associated risks is becoming an integral part of planning and operation studies by Idaho Power [5]. In order to achieve the secure operation of the system under not just traditional n-1 and credible n-2 contingencies but also under other type of n-k contingencies with high risks, Idaho Power has developed a comprehensive risk-based methodology [3].

Historical assessment of outage data was used for realistic identification of outages that likely lead to cascading in the past [6]-[11].

Both predictive and historical evaluations of cascading outages are essential complementary approaches for assessing the impacts and risks of cascading outages on system reliability. However, there has been relatively little attention given to linking these two approaches.

Historically, there have been a number of blackouts worldwide that show the vulnerability of the power grid to a cascading sequence of events. Considerable efforts have been put into research and development to identify the causes of these outages and methods to mitigate them [12]-[15].

This paper investigates the outages that lead to cascading in Idaho system by comparing predictive results and results obtained from historical outage data. The approach takes into consideration outages that lead to cascading and those that result in load curtailment. Evaluation of historical outages is based on the Generation and Transmission Outage Reliability System (GATORS) outage database that was started at IPC in 1991 [16]. We also discuss some similarities in the results and highlight the different assumptions of the two approaches to cascading failure analysis.

II. TRANSMISSION PLANNING STUDY OF CASCADING

A. Idaho Power System

Idaho Power Company service territory covers an area of 24,000 square miles serving over 520,000 customers. The structure of the load is a combination of residential, commercial, and industrial customers coupled with a large component of irrigation and air-conditioning loads during the summer. The system is summer peaking, with the all time peak of 3407 MW attained on July 2nd, 2013. The source of most of IPC's generation is hydroelectric (17 plants), but the company also shares ownership of three coal fired plants. The total installed generating capacity is over 3500 MW with an electric power delivery system containing more than 5,800 miles of transmission and 18,000 miles of distribution lines. The bulk power system of Idaho is shown in Fig. 1

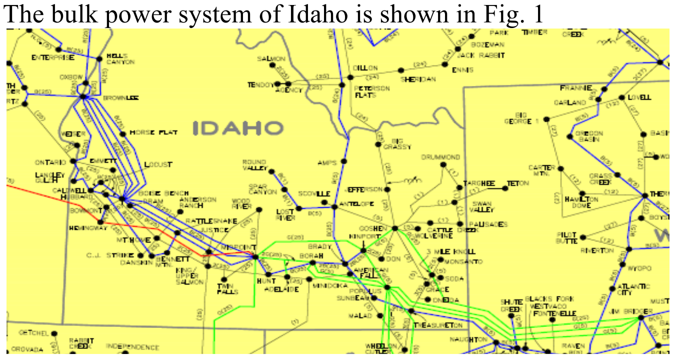

Figure 1. Idaho Power System

B. Generation and Transmission Outage Reporting System (GATORS)

Idaho Power's GATORS collects outage data and monitors the performance of all generation sources and transmission facilities with an operating voltage of 46 kV and above [16].

In this paper, all transmission lines are categorized and studied by voltage class. The emphasis is placed on the analysis of sustained automatic outages of transmission lines.

The cause codes for sustained outages that are incorporated into GATORS are listed in [16]. Each cause-code category has been expanded with associated sub-categories. For instance, the weather category has the following subcategories: adverse, clear/calm, extreme cold, fog, hail, heavy rain, heavy snow, high winds, ice, light winds, lightning in area, major storm disaster, microburst, normal, overcast, rain, snow, and storm.

C. Approach to cascading

1) Aims of Study

Historically, the Idaho system is designed to perform reliable service without interruption for all n-1 and credible n-2 contingencies. However, widespread interruption and cascading remain possible, especially if these contingencies are accompanied by other system vulnerabilities that can result in complex contingencies. Identification and analysis of complex contingencies in Idaho Power system became important issues that have been investigated in recent work in both planning and operation environments [3]-[5]. Reference [4] presents a risk-based approach for contingency analysis implemented at Idaho Power Company. The practical approach to identify and analyze the effects of complex/extreme contingencies is presented in [5]. The identification and mitigation of system risks and vulnerabilities as results of extreme contingencies, that are critical to ensuring the reliable operation of the bulk electric system (BES), is presented in [5]. It is very important to identify contingencies that lead to voltage instability, widespread power disruptions and the vulnerability of the power grid to cascading. The aim of this planning study is to perform a comprehensive evaluation of five base cases by applying a great number of n-2 initiating events and to identify those events that potentially can lead to cascading

2) Assumptions

In this paper a "Cluster" based approach is utilized to perform analysis of cascading outages [12]. It can be used to quickly identify not just possible initiating events that may lead to cascading outages but also to automatically determine possible cascading chains. A power system network is represented as a number of groups (clusters) that are connected to the network with "critical" lines (cutsets) [12]. In a cluster approach, the system is represented via three types of clusters: load clusters, generation clusters, and connecting clusters.

If one of the "critical" lines (e.g., initiating events) within the cluster or connecting two clusters is outaged, it may cause large overloads on other line(s). If an overloaded line(s) is switched off as a system protection measure, this may lead to cascading. Those clusters that experience large flows on the cutset are of a particular interest in this analysis.

3) Tool used

The cluster-based methodology presented in [12] has been extended and implemented in the Potential Cascading Modes (PCM) tool [17]. The PCM tool was used extensively at Idaho Power Company in the past and also to perform study for this paper. Basic input data to PCM tool are: base case, list of initiating events, monitored constraints (thermal, voltage), tripping thresholds (line, transformer, load, and generator). The most frequent scenarios of cascading outages are that branches are overloaded above a certain limit, and protection schemes initiate tripping of overloaded branches. Also, outage can cause a deficit in reactive margin, so a considerable reduction of voltages might be present that could further cause motors to stop. Output results from the planning study can be grouped as: list of initiating events that lead to cascading, list of initiating events that propagate over several generations, the impact of cascading outages measured by load interrupted, and geographical locations of cascading events.

The list of initiating events that may lead to cascading is identified by applying "smart" logic. The same logic is used to predict development of cascading chains. Analysis of the cascading outages is an important aspect of the planning compliance studies where utilities are required to meet requirements of the new NERC standard TPL-001-4 [1]. In this approach all overloaded branches are identified and those that are overloaded above the tripping threshold are automatically tripped to simulate operation of protection schemes. Thus, tiers or generations in the cascading chain are identified.

Following an initiating event, branches are consecutively tripped until one of the following events occurs: system fails to solve due to voltage instability, loss of load exceeds a user-specified threshold value, islanding with imbalance of load and/or generation within an island, and a thermal and voltage violation is alleviated or drops below the threshold limits.

Our study focuses on the evaluation of initiating events that potentially could lead to stability violation, large loss of load, and to cascading.

4) *Results*

The planning study to identify initiating events that lead to cascading was performed on five base cases that represent BES of the WI (12hs, 13lw, 13hw, 14hw, and 14lw). A list of N-1 breaker-to-breaker contingencies (around 200) for each base case was combined into N-2 contingencies.

TABLE I

A summary of planning study cascading results

Case	# of initiating events	#of stability violations	#of events leading to cascading chains	#of events leading to cascading
12hs	26565	0	150	6
13lw	22155	1	22	10
13hw	23005	6	16	5
14lw	20503	4	16	6
14hw	20910	2	7	5

Over 100,000 initiating events were created in five studied cases. Each case was processed for a corresponding list of initiating events. A total of summary of results for each case, that includes voltage stability in an initial case, outages that lead to cascading generations, to cascading is presented in Table I. All five cases except one experience voltage stability under one or more contingencies. In all five cases 32 initiating events (< 0.03% of all initiating events) progress to cascading over four or less generations. In order to compare planning study results with the statistical approach, the list of events that lead to cascading is further reduced to 26 by eliminating those that include the combination of two transformer outages. In addition planning study includes eight initiating events that combine new facilities that have been in operation for about four years and therefore there were limited historical outage data statistics observed. Based on the above observations to compare the results obtained by planning and statistical approaches we use the total of 18 initiating events even though 9 of those combine a line and transformer. These 18 initiating events progress to cascading over 4 generations (1), 3 generations (3), 2 generations (3) and 1 generation (11).

III. Analysis of Historical Outage Data

A. *Historical outage data*

The historical data analysis begins with 8084 transmission line outages recorded by Idaho Power Company in GATORS over the 24 years from January 1991 to December 2014. Each transmission line outage includes the outage start time (to the nearest minute), the names of the buses at the ends of the line, and the initial cause. The substation outages in the data are not considered.

The first step is to clean and filter the data. Bus names and line descriptions are standardized, and 7 rare outages of 6 lines isolated from the main network are removed. Outages involving lines joining more than 2 buses are simplified and approximated by an outage of a line joining two buses, usually by ignoring tapped line segments.

The line outages can be classified as planned or automatic according to their initial causes. (Planned outage causes are general maintenance, ground switch, maintenance, new construction, removal, replace transformer, safety precaution, sectionalizing-switching, and automatic outage causes are all other causes, including unknown.) There are 3875 automatic outages in the dataset, and these are the outages used for the cascading analysis.

While historical data processing has many advantages, including no modeling assumptions and a very favorable grounding in reality, it should be kept in mind that the power grid changes over 24 years, and that statistical analysis of historical cascades necessarily describes cascading risk averaged over the time period of observation.

B. *Grouping outages into cascades and generations*

Cascading starts with initial outages (generation 0) and then continues with further outages propagating in successive generations until the cascade stops. We process the line outages by grouping the line outages into individual cascades, and then within each cascade grouping the outages that occur in close succession into generations. The grouping is done based on the outage start times according to the method of [8]. In particular, we look at the gaps in start time between successive outages. If successive outages have a gap of one hour or more, then the outage after the gap starts a new cascade (note that operator actions are usually completed within one hour). Within each cascade, if successive outages have a gap of more than one minute, then the outage after the gap starts a new generation of the cascade (note that fast transients and protection actions such as auto-reclosing are completed within one minute). For example, one of the longer cascades in the data set is shown in Table II (bus names and times are altered to preserve confidentiality).

TABLE II

Example: Generations of Outages in One Cascade

Transmission Line	Outage Start Time Hour: Minute	Generation
BYRD-ISAAC	8:01	1
LASSUS-BYRD	8:01	1
ANON-LASSUS	8:13	2
DUFAY-JOSQUIN	8:14	2
LASSUS-DUFAY	8:14	2
ANON-DUFAY	8:14	2
DUFAY-JOSQUIN	8:22	3
LASSUS-DUFAY	9:04	4

This procedure applied to the 3875 automatic outages yields 2983 cascades. Most of the cascades are short: 91% of the cascades have only the first generation of outages and do not spread beyond these initial outages. It is important for a fair statistical analysis to include the short cascades (even if they are for other purposes not thought of as cascades); the short cascades usually represent a successful case of resilience in which no load is shed. That is, excluding the short cascades would misleadingly bias the results towards the undesirable and damaging cascades that do not stop quickly.

C. *Initial outages and total outages after cascading*

The grouping of outages in each cascade into generations allows the initial outages (generation 0) to be distinguished from the subsequently cascading outages in generations 1,2,3,… This is of interest because the mechanisms and mitigations of the initial line outages differ to a significant extent from the interactions between line outages that are involved in the subsequent cascade. Most of the initial outages are single outages, but there are also multiple initial outages. In other words, there are single, double, triple, etc contingencies. The probability distribution of the number of initial outages is shown by the black dots in Fig. 2. The distribution of the initial outages is one way of looking at the severity of initial events: 9% of the initial events have 2 outages and 2.7% of the initial events have 3 outages. Under 3% have 3 or more outages.

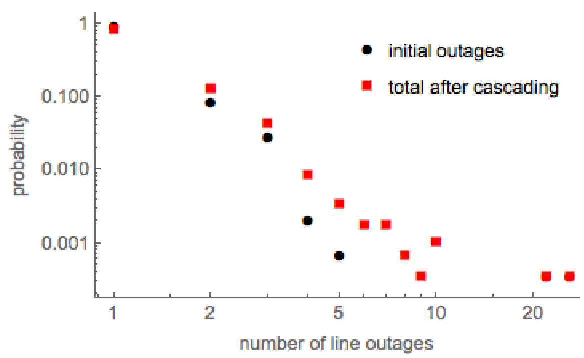

Figure 2. Probability distribution of the number of initial outages and the total number of outages after cascading. Note the log-log scales.

We can also look at the total number of outages after both the initial outages and the subsequent cascading. The probability distribution of the total number of outages after the cascading is shown by the red squares in Fig. 2.

The difference between the initial outages and the total number of outages shows the additional effect of the cascading after the initial outages. There are more outages after cascading, although the largest cascades are infrequent and so their probability estimates shown in Fig. 2 are highly variable. The difference due to cascading can also be seen in a different presentation of the same data in Fig. 3. The cascading has a modest effect in increasing the probability of more than 1 or 2 outages, but an order of magnitude increase in the probability of more than 4 outages. That is, the data supports the unsurprising but important result that cascading is most important for large blackouts. For smaller number of outages (less than or equal to 3), the effect of the cascading is modest. This seems to support the use in the planning analysis of an initial outage followed (typically) by one further generation of contingencies. That is the planning analysis captures much of the cascading for short cascades.

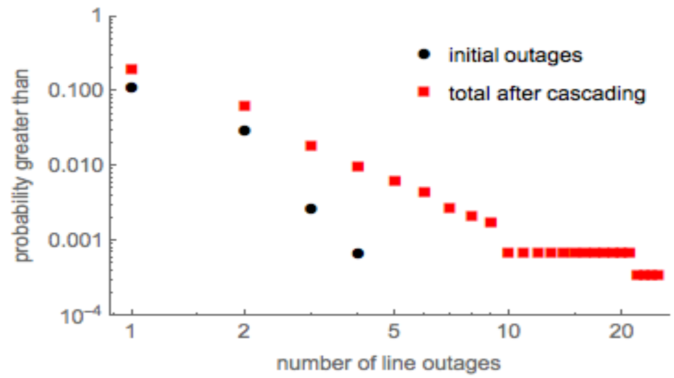

Figure 3. Probability of more than k outages against k for the initial outages and for the total outages after cascading

The effect of the further cascading becomes much more important for 4 or more outages, in which the probabilities of occurrence are small, but the cascading can make an order of magnitude increase in the probability of that number of outages. This leaves it open to other methods for estimating and controlling the risk of large blackouts, such as monitoring and limiting both initial outages (which is already done) and propagation (which is new).

The distinction we can now make in the outage data between initiating outages and subsequently cascading outages allows us to find out and compare which lines are most involved in these two different processes. The top 10 lines involved in initiating outages overlap with but do not coincide with the top 10 lines involved in subsequent cascading; there are 6 lines in common but there are 4 lines in each list that differ.

D. *Quantifying cascade propagation*

The total number of outages in each generation of all the cascades is shown in Table III.

TABLE III

Outages in Cascade Generations

Generation	1	2	3	4	5	6	7	8	9
Outage Count	6715	896	189	47	16	5	4	1	1

The generations of outages in the cascades are analogous to human generations; parents in one generation give rise to children in the next generation. The average propagation per parent λ is the total number of children outages in all the generations divided by the total number of parent outages in all the generations. λ calculated from data is 0.12. That is, each outage in a generation will, on average, be followed by 0.12 outages in the next generation. λ has the effect of controlling how much the cascading will increase the number of outages starting from the initial outages. The average propagation can depend on the types of outages considered. Weather related outages have increased propagation from 0.10 (normal weather conditions) to 0.23 (adverse weather conditions). Outages in the peak hours between 3 pm and 8 pm have increased propagation from 0.10 (not peak hours) to

0.19 (peak hours). However, outages in the summer months of June, July, August, September have nearly the same propagation of 0.11 as all outages. Since the cascades depend also on the initial outages, it is still possible to have more cascading in the summer with the same propagation. Indeed the data in the summer months shows 27% more cascades per month and 32% more initial outages per month. Idaho Power system is heavily stressed in the summer particularly in months of July and August and therefore probability of cascading under these conditions is higher than during other seasons (both major blackouts in 1996 involved Idaho system happened in July and August).

The average propagation λ_k at each generation k can be defined as the number of outages in generation k+1 divided by the number of outages in generation k. The data has $\lambda_0 = 0.10$, $\lambda_1 = 0.21$, $\lambda_2 = 0.34$, $\lambda_3 = 0.48$, and average propagation for generation 4 or more $\lambda_{4+} = 0.50$. The average propagation increases with k as the cascade propagates through its generations; that is, the grid resilience is progressively weakened by the preceding generations of outages.

Given the distribution of initial outages shown in Fig. 2, the propagations λ_0, λ_1, λ_2, λ_3, λ_{4+} can be used in a branching process model to predict the distribution of the total number of outages using the method of [8]. The match with the observed data is shown in Fig. 4.

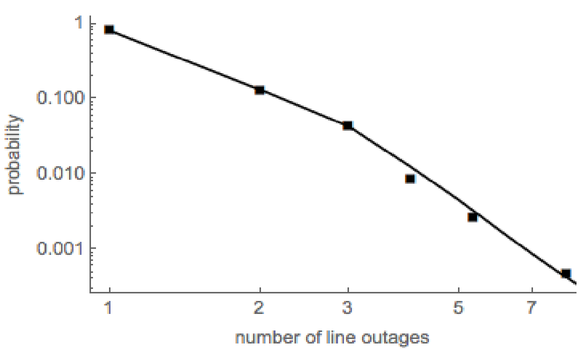

Figure 4. Probability distributions of the total number of outages after cascading; dots are the binned data and the lines join the branching process predictions.

The usefulness of this result is that the distribution of the total number of outages propagation can be estimated via the propagations with much less data (about one year) [8].

E. Cascade spreading

The method of [10] is used to construct a network directly from the outage data as shown in Fig. 5 (the network is constructed simply by joining two buses with a transmission line if the data includes an automatic or planned outage of the line joining those buses.) The advantage of forming the network in this way is that the outages can easily be located on the network. Then statistics of how the cascades spread in the network can be obtained. One limitation to be addressed in future work is that the formed network currently corresponds to the union of the actual grid lines as they change over the time period of observation.

One way to measure the network distance between two line outages counts the minimum number of buses in a path in the network joining the two lines. For example, two lines with a common bus are a distance one apart.

Figure 5. Network formed from line outage data. Layout is not geographic

We extend this definition [10] to the average distance between generations of line outages to obtain the spreading statistics of Figs. 6 and 7. One useful application for the propagation and spreading results in this section is the validation of models of cascading by comparing the match between the simulated and observed results [7], [18].

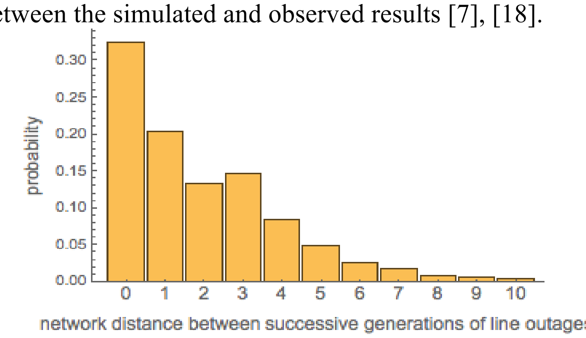

Figure 6. Probability distribution of the network distance between successive generations of line outages

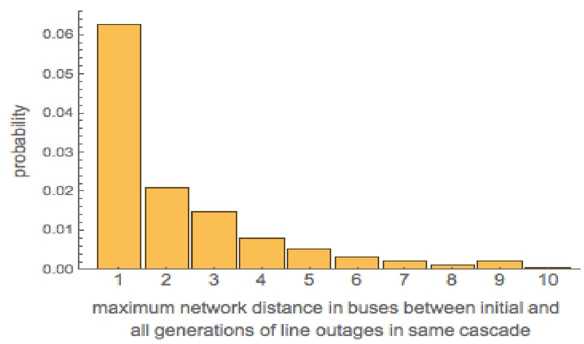

Figure 7. Probability distribution of the maximum network distance in buses between initial and all generations of line outages in same cascade

IV. COMPARISON

This section compares the two quite different approaches to assessing system cascading performance described in the previous sections. The planning predictive approach evaluates with simulation carefully chosen stressed cases and identifies initiating events that progress through several tiers (generations) and lead to cascading. The historical approach extracts statistics describing the observed cascades of transmission line outages over a period of time. The two methods are compared by applying them to the Idaho system looking for consistent and understandable results, initial events, propagation, cascading and impacts.

The planning study is based on a limited number of base cases and a defined set of likely initial events and thresholds for tripping load and/or generation during the cascading process. This approach is useful for analyzing potential risks for cascading under a defined set of initiating events and conditions. The initiating events causing the more serious cascades and more consequential overloads and outages can be identified. Moreover, since it is simulation based, mitigation measures can be identified to prevent and minimize the impact of cascading outages. In this approach, analyzing and mitigating a judicious selection of stressed cases is expected to limit the general cascading risk. Moreover, the projected future system can be analyzed.

On the other hand, the historical approach statistically quantifies observed initiating line outages and their propagation. There are no modeling assumptions, but the analysis is limited to the quantities recorded and processed. In effect all the system states, initiating events, and cascade progressions are sampled over the time period of observation. The blackout risk expressed as the distribution of the total number of line outages can be estimated using a probabilistic branching process model of the cascading. The lines of Idaho power network historically vulnerable to cascading failures can be identified. However, while the cascading risk is directly assessed, in a historical approach it is impossible to test potential mitigations, and difficult to assess the effect of individual implemented mitigations.

Both approaches are capable to identify the top risk outages that potentially could lead to cascading. Evaluating results for eighteen common initiating events show that 3 initial events (16%) in both approaches have been identified by both approaches to be top risk cascading events.

Joint application of these two different approaches ensures that advantages of each method can be used to help in better understanding of the entire cascading process. By performing a quick comparison of the results obtained by historical and predictive approaches, one can immediately conclude that there exists a correlation but also differences in modeling assumptions and how initiating events, system configuration changes, operational conditions, and maintenance requirements are taken into account.

The selection of initiating events plays an important role in the planning study since more complex initiating events are likely to lead to cascading or local and widespread blackouts. The planning study was based on a list of initiating events that include two simultaneously outaged elements defined by breaker-to-breaker operation. All five study cases show no problems under any of the N-1 outages (this basically shows that system was correctly designed to operate in safe operating region for any of the N-1 outages.) Initiating events in the planning study include lines or transformers or their combination. The historical approach only considers automatic line outages as initiating events. Often there was no cascading beyond the initiating events, but 263 cascades had more than one generation. Of these 263 cascades with more than one generation, 222 began with a single outage, 29 began with a double outage, 9 began with a triple outage, and 3 began with a quadruple outage. Presumably some of the 222 cascades starting with a single automatic line outage cascaded further also because of simultaneously occurring unusual patterns of load, planned line outages, or outage of other equipment.

There is much less average propagation of line outages in the simulated cascades used in the planning approach than in the historical cascades. The simulated events overload many lines, but fewer of these overloaded lines subsequently outage. In this sense the planning approach focuses more on the initiating events and the impacts of these initiating events rather than the longer cascades occasionally observed in practice in the historical data. There are interesting distinctions involved in considering this difference. In particular, in a given situation, no further cascading can be both a more likely and a plausible outcome, but further cascading remains possible and does occasionally happen. That is, a simulation that produces plausible and likely cascading sequences may not sample some of the unlikely long cascades that occasionally occur in practice, and are of concern due to their high impact.

The statistical approach based on historical outage data has a capability to estimate the overall blackout risk since it includes all outage data with its actual frequency of occurrence. If the branching process model parameters are found from about one year of historical data, then the effect of the cascading in producing the unlikely long cascades can be predicted [8]. (The alternative of gathering historical data for decades to directly estimate the rare events can be used, but requires averaging the results over too long a period.)

The historical approach is much newer and less systematically developed than the planning approach. Needed elaborations to the historical approach include using inventory additions to the system to correctly track the changes to the system over time, considering the outages of transformers and generators, and relating the outages to the recorded load curtailments. The changes in topology should be monitored using the sources of inventory data such as the list of new additions with timing (planning) and SCADA data (operation).

In order to map future challenges, advantages and disadvantages of both approaches are discussed. These two methodologies are applied to an actual system, considering data from the Idaho power system (cases in a period 2012-2014 and historical outage data statistics collected in a period 1991-2015).

The statistical approach based on historical outage data can be in some way used to validate and ensure the credibility of planning studies. It is important to note that the statistical approach does not replace the cascading planning studies performed under the set of contingencies defined in NERC TPL-001-4 standard [1].

As was pointed out in Section III, the main advantage of historical data processing is that it doesn't require any modeling assumptions and it has a very favorable grounding in reality. Also, the statistical analysis of historical cascades describes cascading risk averaged over a time period of observation, during which the system changes. While the statistical requirements for a long enough observation time can be mitigated using branching process models, about a year of data still seems to be needed for much of the analysis. Bulk measures of propagation are also averaged over the entire system.

While the main objectives of the comparison are to benchmark the two methodologies and estimate the top risk initiating events, additional results are obtained by both methods.

The statistical approach provides a more general solution to estimating an overall blackout risk than the standard planning study approach, but historical approaches cannot evaluate proposed mitigations. However, the planning study approach may provide a practical way to prevent and mitigate the cascading risk from specific sets of contingencies. The planning approach may not be suitable to simulate the uncertain variables such as random outages of generators and transmission lines in power systems.

V. CONCLUSIONS

The study reported in this paper compares the historical approach with a predictive approach for outages that lead to cascading in the Idaho Power bulk electrical system. The assessment of cascading outages is a task in planning and operating a transmission system that goes beyond standard requirements. The comprehensive historical and predictive analysis of cascading outages provides a utility with a quantitative method to identify the outages with the highest risks. The knowledge gained from this study helps company to understand potential risks and to identify the potential mitigation measures to prevent or minimize the impacts of those outages. The approach presented here can be, in general, helpful to utility industry in the process of monitoring risks of cascading outages.

The results show advantages of performing both predictive and historical evaluation of cascading outages. By performing a quick comparison of past and predictive results, one can immediately conclude that there are some conclusions in common but also some basic differences in the framing of the problem, modeling assumptions and how system configuration changes, initiating events, cascade propagation, operational conditions, and maintenance requirements are taken into account. The two approaches broadly agree in determining the parts of Idaho power network vulnerable to cascading failures. The joint application of the two proposed approaches appears useful for analyzing potential risks for cascading and for identifying potential mitigation measures to prevent and minimize the impact of cascading outages. Although we have emphasized some of the differences in the approaches, future work might combine parts of the approaches. For example, one could try to apply the methods used to quantify the historical cascading to simulated cascades that are suitably sampled.

In this paper, basic issues and practical applications of the two presented approaches have been presented. The aim of the paper is not to develop new contributions to the cascading theory but to highlight and contrast advantages and disadvantages and practical constraints when the two methods are applied to an actual system.

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