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Electricity transmission reliability: the impact of reliability criteria

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ABSTRACT

In the presence of transmission outages, uncertain demand and variable renewable supply, network operators keep a reliability margin to avoid interruptions and black-outs. The reliability margin is presently determined by the N-1 reliability criterion. Our analytical model defines the optimal reliability margin by balancing congestion costs and interruption costs. This leads to new operational reliability margins and new transmission investment rules that are superior to the N-1 criterion. A numerical illustration shows under what conditions the new rules dominate the N-1 criterion.

Keywords: Electricity Transmission Reliability, Transmission Investment, Reliability Management, N-1 reliability criterion

1. INTRODUCTION

Reliability of electricity supply is of paramount importance to our society. Without electricity, lights go out, appliances stop working, and factories shut down. A transmission system operator (TSO) is entrusted with the task of safeguarding our supply. Reliability management affects all its decisions, from long-term system development to short-term operational planning and system operation.

Despite its importance, the economic literature has not given much attention to electricity transmission reliability (Joskow, 2006).[1] Many papers study economic transmission investment (e.g. Turvey (2006); Van der Weijde and Hobbs (2012); Doucet et al. (2013); Pozo et al. (2013)) and its regulation (e.g. Léautier (2000); Rosellón (2007); Rosellón and Weigt (2011)), but leave reliability issues aside. Considering reliability, however, is important to better understand transmission capacity investment and the use of this transmission capacity. For example, many European countries aim for more transmission investment to better cope with renewable energy integration and to lower wholesale electricity prices.[2] But, because of the costs of transmission investments and the difficulties to build new lines (Cohen et al., 2016), the question is whether a more efficient use of current transmission capacity is not an alternative. Addressing this question requires us to think about electricity transmission reliability.

This paper considers the possibility of transmission line outages, uncertainty of demand, and variable renewable supply. The model shows that TSOs use less transmission capacity than is installed, because of reliability concerns. As a result, the effect of transmission investment on reliability depends on the TSO's system operation, which is managed by its reliability criterion. Currently all TSOs use the N-1 reliability criterion or some variant. This deterministic criterion states that an unexpected outage of a single system component may not result in a loss of load. We

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[1]Joskow (2006, p.12) states that "neither reliability transmission investments nor the interrelationship between reliability criteria and economic parameters are given much attention in the literature on competitive electricity markets."

[2]The European Union wants to bring the electricity interconnection level of all member countries to 10% by 2020 and is looking into raising the target to 15% by 2030 (European Commission, 2015).

show that the N-1 reliability criterion is suboptimal since it only depends on the topology and the use of the network, not on network conditions and economic parameters. In addition, the model provides insight into the trade-off between reliability and congestion. It shows that the N-1 criterion requires the TSO to achieve an exogenous reliability level and minimize congestion costs, while optimally the reliability level and the congestion cost are determined endogenously (Hogan et al., 2010).

To our knowledge, an analytical economic model of electricity transmission reliability does not yet exist. Earlier papers discussed transmission reliability in words or focused on case studies. Blumsack et al. (2007) focus on the relationship between congestion and reliability in a Wheatstone network. In this particular network topology, adding links to increase reliability could increase congestion. By contrast, Kirschen and Strbac (2004b) argue that increasing the capacity of a transmission network does not increase reliability because of the N-1 reliability criterion. This criterion is also criticized by Joskow (2006). Joskow finds that little effort has been made to review it and evaluate its costs and benefits. Lastly, de Nooij et al. (2010) analyse the effect of the N-1 rule in a Dutch case study that compares transmission investment costs with the benefits of reduced interruption costs.

Electricity transmission reliability is related to the larger literature on generation reliability. Peak-load pricing models determine the optimal pricing of electricity and the optimal generation capacity to install (Steiner, 1957; Williamson, 1966). The optimal reliability level is determined only from a generation adequacy point of view (Chao, 1983; Kleindorfer and Fernando, 1993): the reliability level is the probability that demand is lower than *installed* (continuous) generation capacity. In contrast, this paper studies reliability from an operational point of view: the reliability level is the probability that the electricity flow is lower than *available* (discrete) transmission capacity.

The paper is structured as follows. Section 2 introduces the model that shows the trade-off between congestion cost, transmission investment cost and reliability. We determine the optimal investment and optimal use of transmission capacity. Section 3 analyses the expected interruption cost function, the optimal price difference between zones and cost recovery in the optimal solution. Next, section 4 analyses the N-1 reliability criterion and shows that its reliability margin does not depend on economic and technical parameters. Section 5 extends the basic model to multiple states of the world and a general network. In section 6, we illustrate the analysis with a numerical example. Section 7 describes the possible steps to move beyond the N-1 reliability criterion. Finally, section 8 concludes.

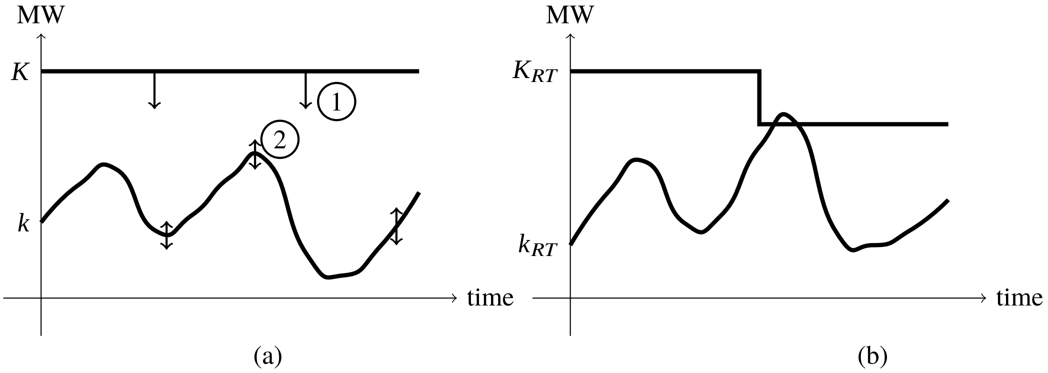
2. THE MODEL

2.1 The model setup

Consider two regions connected by multiple transmission lines. We define the maximum transfer capacity K [MW] as the maximum possible electricity flow between the two regions when all electricity lines are in operation. The scheduled electricity flow k [MW] between the regions is lower than the maximum transfer capacity K to account for (i) unplanned outages of transmission lines and transformers – which decrease the maximum transfer capacity – and to account for (ii) forecast errors, loop flows and unplanned outages of generation plants and large loads – which causes the physical flow to differ from the scheduled flow. We define the line loading α as the ratio of scheduled electricity flow and maximum transfer capacity: $\alpha = \frac{k}{K} < 1$.

The left-hand panel of Figure 1 shows the maximum transfer capacity K and the scheduled flow k as determined before real time (for example in the day-ahead market for the 24 hours of the next day). The reliability margin is defined as the difference between maximum transfer capacity and scheduled flow: $K - k$ (Neuhoff et al., 2013). The TSO keeps this margin because the physical flow could differ from the scheduled flow and the maximum transfer capacity could be lower than expected due to transmission line failures. The right-hand panel of Figure 1 shows a possible real-time realization of maximum transfer capacity and physical flow. In this case a combination of a higher physical flow and a line failure causes the physical flow to be larger than the real-time maximum transfer capacity at some point. As the transmission capacity of the remaining lines is insufficient to accommodate the physical flow between the regions, the TSO needs to do a corrective action such that the physical flow is back within the bounds of the real-time transfer capacity: $k_{RT} < K_{RT}$. Possible corrective actions are use of generation reserves or involuntary load shedding – also called non-price rationing, demand curtailment or controlled rolling blackouts (Joskow, 2008). Generation reserves allow increasing or decreasing generation in different parts of the network. Load shedding amounts to deliberately restricting electricity supply in parts of the network. If the physical overflow is not adequately dealt with within a certain period of time, this could lead to cascading uncontrolled network collapses and large-scale blackouts (e.g. in the U.S. (2003) , Italy (2003), Brazil and Paraguay (2009), India (2012) and Turkey (2015)).

Figure 1: (a) Maximum transfer capacity K and scheduled flow k before real time. (b) Real-time transfer capacity and physical flow



This paper studies the optimal investment (K^*) and optimal use (k^*) of transmission capacity between two regions. Suppose that these decisions are made by a welfare-maximizing Transmission System Operator (TSO), the entity responsible for dispatch, congestion management, maintenance and investment of the transmission network.[3] Optimally a TSO schedules less electricity flow k than the total transfer capacity K. It keeps a reliability margin $K - k$ or equivalently, it keeps a line loading $\alpha = \frac{k}{K} < 1$. Before determining the optimal investment and optimal use of transmission capacity, we study the three types of costs and benefits that constitute net interconnection surplus.

2.2 The three constituents of net interconnection surplus

First, scheduling an electricity flow k from a low-cost region to a high-cost region creates interconnection benefit, or gross interconnection surplus, by enabling a reduction of production costs. The difference of production costs[4] between a system with some constrained transmission lines and one with infinite transmission capacity, plus the consumer dead-weight loss from the associated changed prices, are called the congestion costs of the system (Joskow, 2006).[5] In addition to decreased congestion costs, interconnection decreases the cost of reserves through reserve sharing and

[3] If the operational, maintenance and investment responsibility tasks are split, the respective entities are called the Independent System Operator (ISO) and the independent transmission company (Transco). The ownership or division of tasks does not fundamentally affect the core of our analysis.

[4] Assuming perfectly competitive producers and assuming that the generation cost is the social cost of generation, i.e. including externalities like CO_2, NO_X, SO_X, particulate matter, noise, etc.

[5] To manage congestion, cheap generation in an export-constrained region is decreased, while more expensive generation in an import-constrained region is increased. In uniform-price zones redispatch is the responsibility of the TSO, who gives a congestion payment to redispatched generators. In nodal pricing or market splitting, congestion is managed implicitly by prices. Different congestion management methods lead to different physical and financial flows, and have different effects on TSOs (Holmberg and Lazarczyk, 2015) and on producers (Dijk and Willems, 2011).

demand smoothing (Baldursson et al., 2016), it creates more competition in the generation market (Borenstein et al., 2000) and facilitates the integration of renewable generation. The function $S(k)$ summarizes the interconnection benefit. It is an increasing concave function:

$$S'(k) \geq 0 \text{ and } S''(k) < 0 \tag{1}$$

Second, transmission line failures and physical flows that diverge from scheduled flows could require corrective actions by the TSO. In the remainder of this paper we will assume that load shedding is the only corrective action available. In addition, we assume that the TSO is able to estimate the expected interruption cost (EIC) of load shedding. The EIC depends on both scheduled electricity flow k and maximum transfer capacity K. Ceteris paribus, the EIC is increasing and convex in k and decreasing and convex in K.

$$\begin{aligned} EIC'_k(k,K) > 0 \text{ and } EIC''_k(k,K) > 0 \\ EIC'_K(k,K) < 0 \text{ and } EIC''_K(k,K) > 0 \end{aligned} \tag{2}$$

Third, installing and using transmission capacity has a cost.[6] Suppose that the TSO transmission costs only depend on the maximum transfer capacity K. That is, we incorporate operations, maintenance and investment costs but neglect losses and line-loading induced depreciation and maintenance, which depend on the ratio of k and K. The cost of transmission capacity, $c(K)$, is increasing in K:

$$c'(K) > 0 \tag{3}$$

2.3 The optimal solution

Following the above assumptions, net surplus of transmission interconnection is given by:[7]

$$\max_{\{k,K\}} \{S(k) - EIC(k,K) - c(K)\} \tag{4}$$

Net surplus is interconnection benefit minus expected interruption costs and transmission investment costs. Net surplus is maximized by selecting the optimal scheduled flow k and maximum transfer capacity K. These are calculated from the first order conditions of net surplus (4):

$$\begin{cases} S'(k) = EIC'_k(k,K) \\ -EIC'_K(k,K) = c'(K) \end{cases} \tag{5}$$

The first trade-off between interconnection benefit and expected interruption costs is the TSO's short-term decision. Given a constant maximum transfer capacity K, electricity flow k is optimally scheduled up to the point where the additional increase of interconnection benefit equals the additional increase of expected interruption costs. The short-term first-order condition is thus a trade-off between congestion and reliability: increasing the scheduled flow decreases congestion but increases the expected interruption cost. As a consequence, complete elimination of congestion costs at all times entails a too-large expected interruption cost, while aiming for a 100 % reliable transmission system entails a too-large congestion cost.

Both $S(k)$ and $EIC(k,K)$ could change over time. For example, $S(k)$ increases if autarkic prices are more apart, and $EIC(k,K)$ increases in case of adverse weather (Kirschen and Jayaweera, 2007).

[6]Note that in this paper, investing in new transmission lines increases the maximum transfer capacity. Blumsack et al. (2007) show that the maximum transfer capacity could decrease when adding a new transmission line in a Wheatstone network topology.

[7]The constraint $k \leq K$ is never binding. That is, it is assumed that at $k = K$, marginal interconnection benefit is lower than marginal expected interruption costs.

The second trade-off between expected interruption costs and transmission investment costs determines the TSO's long-term decision of how large the maximum transfer capacity K should be. Since the two first-order conditions are interdependent, the optimal maximum transfer capacity is a trade-off between reliability, congestion and investment. Increasing maximum transfer capacity and keeping the scheduled electricity flow constant, decreases expected interruption costs. Increasing maximum transfer capacity and keeping expected interruption costs constant, decreases congestion costs.

First-order conditions (5) lead to the following result:

Proposition 1 *Consider two regions between which a flow K can be transferred. Optimally, the TSO should:*

i. In the short term, schedule electricity flow until the marginal interconnection benefit equals the marginal expected interruption costs.

ii. In the long term, increase maximum transfer capacity K until the marginal expected interruption cost equals the marginal cost of interconnection.

3. ANALYSIS

3.1 The expected interruption cost

To make the above optimal solution more concrete, we calculate the expected interruption cost of a simple network, as a function of k and K.[8] Assume two regions connected by n identical transmission lines with a joint maximum transfer capacity of K MW. Each line has a transmission capacity of K/n MW, the same technical characteristics and the same failure probability p_f. Suppose that the scheduled flow k equals the physical flow in real time. That is, only the availability of transfer capacity is uncertain. When, due to line failures, only i of the n lines are available, the TSO needs to shed $\left(k - \frac{i}{n}K\right)^+$ MW of load, assuming that load shedding is the only available corrective action. For example, if maximum transfer capacity is 4,000 MW, scheduled flow is 3,000 MW, and only 3 of 5 identical lines are available, $3000 - \frac{3}{5}4000 = 600$ MW of load shedding is needed to keep physical flow below the available transmission capacity of 2,400 MW. The cost of shedding a MW of load is represented by the value of lost load (VOLL), which is the lost surplus when a MWh of energy is not served to consumers demanding this energy.[9] VOLL is generally expressed in €/MWh. The above assumptions lead to the following EIC:

$$EIC(k, K) = \sum_{i}^{n} p_i \left(k - \frac{i}{n}K\right)^+ V \tag{6}$$

where $p_i = \binom{n}{i}(1 - p_f)^i (p_f)^{(n-i)}$ is the probability that i of n lines are available. This specific expected interruption cost functional form fulfills the above assumptions (2): it is increasing in k, decreasing in K and convex piecewise-linear in k and K.

The short-term first-order condition showed that the optimal line loading is at the point where the marginal interconnection benefit equals the marginal EIC. Assuming the EIC of equation (6) this

[8] For a numerical illustration see Kirschen and Jayaweera (2007). They calculate the expected interruption cost of a IEEE 24-bus reliability test system.

[9] A rich literature exists on measuring the value of supply interruptions using stated-preference (Reichl et al., 2013; Pepermans, 2011), revealed preference, indirect analytical methods (de Nooij et al., 2007) or case studies.

is:

$$S'(k) = \sum_{i}^{n} p_i \mathbb{1}_+(i)V$$
$$\text{where } \mathbb{1}_+(i) = \begin{cases} 1 & \text{if } k - \frac{i}{n}K > 0 \\ 0 & \text{if } k - \frac{i}{n}K \leq 0 \end{cases} \tag{7}$$

where $\mathbb{1}_+$ is the indicator function, which is equal to one if load shedding is needed, i.e. if $(k - \frac{i}{n}K)$ is positive.

Equation (7) shows that the optimal electricity flow depends on the network topology (n), the line failure probability (p_f), the value of lost load (V), the marginal interconnection benefit (S'), and maximum transfer capacity (K). For example, in case of adverse weather (p_f high), the TSO should schedule a lower electricity flow. Likewise, when consumers have a high VOLL, the line loading should also be lower. To summarize:

Proposition 2 *When the EIC is as in equation* (6)*, the TSO should optimally increase the electricity flow when failure probabilities decrease, marginal interconnection benefit increases, VOLL decreases, and maximum transfer capacity increases.*

3.2 The optimal price difference and cost recovery of transmission investments

In the standard economic transmission investment model with 100% reliable transmission capacity, as in (Kirschen and Strbac, 2004a, p.152) and (Turvey, 2006), the optimal investment in transmission capacity is at the point where the marginal benefit of interconnection equals the marginal cost of transmission:

$$S'(K) = c'(K) \tag{8}$$

Only incorporating congestion costs into the interconnection benefit, the marginal benefit is equal to the price difference $\Delta p(k)$ between the two zones. Additionally, assuming a constant marginal cost of interconnection c, the expression becomes:

$$\Delta p(k) = c \tag{9}$$

This standard result is altered when reliability is included. Integrating the expected interruption cost of equation (6), we can combine the first-order conditions to:

$$\Delta p(k) = c + \sum_{i}^{n} p_i \mathbb{1}_+(i)(1 - \frac{i}{n})V \tag{10}$$

This shows that reliability concerns cause the optimal price difference to be larger than the marginal investment cost. The wedge between the price difference and the marginal investment cost increases with VOLL and with failure probability.

Cost recovery of transmission investments also changes by including reliability concerns. With 100 % reliable transmission lines, congestion rent ΔpK^* equals variable transmission investment cost cK^*.[10] Assuming that EIC is a homogeneous function of degree h and using Euler's Homogeneous Function Theorem[11], the first-order conditions (5) combine to:

$$\Delta p(k)k^* = cK^* + hEIC(k^*, K^*) \tag{11}$$

[10] In reality, congestion rent falls considerably short of variable investment costs, as illustrated by Pérez-Arriaga et al. (1995), due to lumpiness and decreasing marginal transmission investment costs. In addition, fixed transmission investment costs are not recovered.

[11] $EIC'_k k + EIC'_K K = hEIC$

Since the expected interruption cost of equation (6) is homogeneous of degree $h = 1$[12], its optimal price difference is just sufficient to remunerate the cost of transmission capacity and compensate consumers for their interruption costs. If the expected interruption cost is homogeneous of degree $h < 1$, congestion rent can only partly compensate consumers. To summarize:

Proposition 3 *The optimal price difference leads to more than sufficient congestion rent to remunerate the cost of transmission capacity. The remaining congestion rent can compensate consumers (partly) for their interruption costs.*

3.3 Reliability versus economic transmission investments

TSOs and regulators consider reliability transmission investments and economic transmission investment as being two separate objectives: FERC (2006), ENTSO-E (2014, p.60), PJM (Joskow, 2005, p.111). Economic transmission investments are conceptualized as being developed to reduce congestion costs, while reliability transmission investments are conceptualized as necessary to meet engineering reliability criteria. However, first order conditions (5) show that a categorization into reliability transmission investment and economic transmission investment is arbitrary. Investing in more transmission capacity can lead to more interconnection benefit and to a lower expected interruption cost, depending on the TSO's choice of scheduled flow k. In the short term, one can increase reliability by increasing congestion, and vice versa.

The European Ten-Year Network Development Plan (ENTSO-E, 2014), the biennial pan-European network development plan that is the basis for the selection of EU projects of common interest, classifies 60% of its projects as economic investments, 30% as direct interconnection of generation, and the remaining 10% as reliability investments.[13] Only projects in weakly interconnected regions, e.g. a region with only one connection to the transmission system, are considered as being reliability investments. ENTSO-E acknowledges the coexistence of economic and reliability drivers, but considers economic concerns to prevail over reliability concerns.

The fact that ENTSO-E classifies more projects as economic transmission investments than reliability transmission investments is illustrative for the way TSOs treat economic and reliability concerns differently. The next section shows that the N-1 reliability criterion requires the TSO to achieve an exogenous reliability level while minimizing congestion costs, instead of making a trade-off between reliability and congestion. As a result, transmission investments decrease congestion and keep reliability at the prescribed level.

4. THE N-1 RELIABILITY CRITERION

Currently all TSOs use the N-1 reliability criterion or some variant.[14] The N-1 criterion states that an unexpected outage of a single system component (lines, transformers, generation plants, large loads, etc.) may not result in a loss of load. That is, when a single system component fails, the transmission system should still be able to accommodate all flows without load shedding. This also implies that, following the N-1 reliability criterion, a simultaneous failure of multiple system components could require load shedding to avoid a black out. TSO decisions in all time frames should ensure that the N-1 criterion is satisfied in all real-time states.

[12] This means that with equal line loading α, an optimal transmission network that is twice as large has twice as much expected optimal interruption costs.

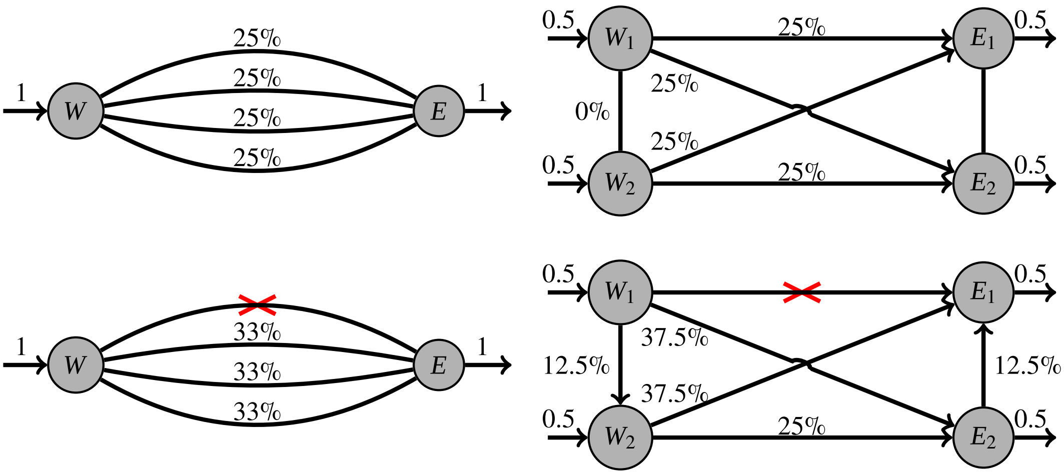
[13] ENTSO-E (2014) uses the broader term 'security of supply', which encompasses all aspects of secure electricity provision: strategic security (secure provision of primary energy resources), adequacy (capability to supply the load in all standard conditions) and security (operational reliability). This paper focuses on operational reliability.

[14] For example: N-0 during maintenance, considering double-line failures during adverse weather, N-1 of credible contingencies (like multiple dependent failures), stronger reliability criteria for cities or certain business districts, etc. For example, the Dutch regulator has changed the reliability criterion to 'N-1 during maintenance, unless the costs exceed the benefits' (de Nooij et al., 2010).

4.1 Operational planning decision

First we analyse how the N-1 reliability criterion determines the TSO's operational planning decision of how much electricity flow to schedule. By prohibiting lost load in case of a single contingency, the N-1 reliability criterion determines the electricity flow k_{N-1} allowed on the network as the maximum flow that the network can accommodate after each possible single contingency. We represent this decision by the allowed maximum line loading $\alpha_{N-1} = k_{N-1}/K$, since in the short-term maximum transfer capacity K is constant. Figure 2 shows how to determine the allowed line loading α_{N-1} for two different networks, with equal maximum transfer capacity between two regions East and West.

Figure 2: Different allowed line loadings α_{N-1}, depending on the topology of the network.



(a) $\alpha_{N-1} = \frac{0.25}{0.33} = 0.75$ (b) $\alpha_{N-1} = \frac{0.25}{0.375} = 0.67$

Network (a) shows two nodes connected by four identical transmission lines. Each line carries 25% of the total electricity flow. The line loading implied by the N-1 reliability criterion is $\alpha_{N-1} = \frac{0.25}{0.33} = 0.75$, since the network should be able to cope with a loss of one line, or a quarter of the maximum transfer capacity. For example, if each line has a thermal capacity of 1,000 MW; 3,000 MW is available in each N-1 state . Therefore, the allowed scheduled flow is 3,000 MW such that no load shedding is needed in case one line fails.

Network (b) shows the same four identical lines, but with two additional identical lines within East and West. Demand and Supply are split evenly within each zone. Nodes W_1 and W_2 each supply half of net exports, while nodes E_1 and E_2 each consume half of net imports. If a transmission line in this interconnected system fails, the power flows are redistributed automatically throughout the network according to Kirchoff's laws. A lossless DC Power flow analysis[15] calculates that in this network the maximum flow on a single line in case of a line failure is 37.5% of the total flow.[16] As a result, the N-1 reliability criterion dictates a line loading of $\alpha_{N-1} = \frac{0.25}{0.375} = 0.67$. If the flow is below 67% of maximum transfer capacity, the flow on each of the six transmission lines never exceeds its thermal limit in case one of the six lines fails. For example, if each line has a thermal capacity of 1,000 MW, the scheduled electricity flow allowed by the N-1 reliability criterion is 2667 MW. If the scheduled flow is higher, some lines will be overloaded in case an interzonal line fails, and corrective load shedding is needed.

[15] A DC power flow is a linear approximation of the Kirchoff's laws that assumes that (i) voltage angle differences between neighbouring nodes are small, (ii) the voltage is equal for all nodes, and (iii) line resistances are negligible compared to line reactances (Van den Bergh et al., 2014).

[16] The appendix shows the manual power flow calculation for this simple network.

This example shows that the allowed N-1 line loading α_{N-1} depends on network topology[17], but not on the probability of line failures or the cost of interruptions.

Proposition 4 *The N-1 reliability criterion determines a maximum line loading α_{N-1} that depends on the network topology, but does not depend on the probability of line failures, the interconnection benefit, or the cost of interruptions.*

4.2 Investment decision

A TSO following the N-1 reliability criterion ensures that in every state of the world the criterion is met. This means that the maximum line loading is α_{N-1}, irrespective of the TSO's investment decision. As a consequence, the TSO does not directly asses the effect of transmission investments on reliability. Its long-term investment decision is a trade-off between interconnection benefit and investment cost:

$$\max_{\{K\}} \{S(\alpha_{N-1}K) - cK\} \tag{12}$$

That is, an investment aims at alleviating congestion, not improving reliability. Reliability is at some level, exogenously-determined by the N-1 reliability criterion. As an example, assume two nodes are connected by four lines, each with a thermal capacity of 1,000 MW. The line loading allowed by the N-1 reliability criterion is 0.75*4,000 = 3,000 MW. Suppose that a scheduled flow of k_{max}=4,500 MW is needed to alleviate congestion. Therefore, increasing maximum transfer capacity to k_{max}/α_{N-1} = 6,000 MW and keeping the line loading at 0.75 eliminates congestion but has little effect on reliability.[18] Once maximum transfer capacity is increased beyond 6,000 MW, reliability increases since the line loading decreases. This is in line with the argument of Kirschen and Strbac (2004b) who argue that increasing the capacity of a transmission network does not increase reliability because of the N-1 reliability criterion. To summarize:

Proposition 5 *Since the N-1 reliability criterion favors reliability over congestion, transmission investment decreases congestion but has little effect on reliability.*

5. GENERAL MODEL FORMULATION

The analysis up to now was restricted to a two-region network with constant interconnection benefit, EIC, and investment cost. This section generalizes our results to a stochastic model and to general networks.

5.1 Stochastic model

If $t \in T$ is the state of the world, the objective function becomes

$$\max_{\{k_t, K\}} \{S_t(k_t) - EIC_t(k_t, K) - c(K)\} \tag{13}$$

The set T is the Cartesian product of interconnection benefit functions and EIC functions. This means that for each state of the world t – determined by demand and supply levels, failure probabilities, a VOLL, etc. – one should schedule electricity k until the marginal surplus equals the marginal expected interruption cost:

[17] In addition, α_{N-1} also depends on the technical characteristics of the transmission lines and the spatial distribution of demand.

[18] If $EIC(k, K)$ is homogeneous of degree $h = 0$, there is no effect on reliability. If $h > 0$, the expected interruption cost increases.

$$\begin{cases} S_t'(k_t) = EIC_{t,k}'(k_t, K) & \forall t \in T \\ -\int_T EIC_K'(k_t, K) f(t) dt = c'(K) \end{cases} \tag{14}$$

As a result k_t is different for different states of the world. For example, when interconnection benefit is high, increase the line loading; and when expected interruption costs are high, decrease the line loading. The long-term first order condition shows that one should increase maximum transfer capacity K until the marginal cost of interconnection equals the marginal expected (over all states of the world) interruption costs.

5.2 General network

If the network consists of N nodes and L lines, the objective function becomes

$$\max_{\{\vec{k},\vec{K}\}} \{S(\vec{k}) - EIC(\vec{k},\vec{K}) - c(\vec{K})\} \tag{15}$$

where $\vec{k} \in \mathbb{R}^L$ is the vector representing the flows over the L lines of the network and $\vec{K} \in \mathbb{R}^L$ is the vector representing the transmission capacity of the L lines of the network. However, the TSO does not directly control the flows on the transmission lines $\vec{k}$. During day-ahead generation dispatch the TSO decides on a generation schedule $\vec{g} \in \mathbb{R}^N$, which leads to a unique power flow schedule $\vec{k}$.[19] Therefore, reformulate the objective function as:

$$\max_{\{\vec{g},\vec{K}\}} \{S(\vec{g}) - EIC(\vec{g},\vec{K}) - c(\vec{K})\} \tag{16}$$

The first-order conditions are:

$$\begin{cases} S_{g_n}'(\vec{g}) = EIC_{g_n}'(\vec{g},\vec{K}) & \forall n \in N \\ -EIC_{K_l}'(\vec{g},\vec{K}) = c_{K_l}'(K_l) & \forall l \in L \end{cases} \tag{17}$$

That is, for each node n schedule generation capacity g_n until the marginal surplus equals the marginal expected interruption cost. In the optimum, congestion increasing generation ($S_{g_n}' < 0$) decreases EIC; congestion decreasing generation ($S_{g_n}' > 0$) increases EIC. The long-term first order condition shows that for each line l one should increase transmission capacity until the marginal cost of interconnection equals the marginal expected interruption costs.[20]

6. NUMERICAL ILLUSTRATION

To illustrate the analysis, we assume functional forms for the three components of net interconnection surplus: interconnection benefit, expected interruption cost and transmission investment cost.

First, suppose that interconnection benefit $S(k)$ consists only of the decrease of congestion costs. Competition effects are neglected, and the importing country is not structurally depending on imports, meaning that decreasing the scheduled electricity flow does not lead to preventive load shedding in the importing country. To express the interconnection benefit, suppose that the slope of the residual supply curve in the exporting country is b_E and the slope of the residual demand

[19] In the two-region analysis with inelastic demand D, generation g translates directly into a flow k: $g - D = k$.

[20] In reality, both the large number of states of the world and lumpy investments with large fixed costs make it impossible to satisfy the long-term first-order condition for all lines l. In addition, since lines and generation plants are discrete elements, the short-term first-order condition are not exactly met as well.

curve in the importing country is b_I. If the initial price difference before interconnection is Δp, the interconnection benefit of scheduling electricity k between East and West is $k(\Delta p - 0.5(b_E + b_I)k)$.[21] The interconnection benefit is concave in k, increasing with Δp and decreasing with $b_E + b_I$. The scheduled electricity flow that equalizes the prices in East and West is $k_{max} = \Delta p/(b_E + b_I)$.

Second, assume the following expected interruption cost function of two regions connected by n identical transmission lines:[22]

$$EIC(k, K) = \sum_{i}^{n} p_i \left[(k - \frac{i}{n}K)^+ V + \left((\frac{k - \frac{i}{n}K}{K})^+ \right)^a V_{BO} \right] \tag{18}$$

This EIC is increasing in k, decreasing in K and convex in k and K. The first part of the EIC is the expected cost of load shedding (equation (6)), the second part is the expected cost of a black out. We add this expected cost of a black out because each overflow that requires corrective load shedding has a probability of leading to a blackout, for example if corrective load shedding fails or if overloaded lines trip before load shedding is executed. We assume that an overflow $(k - \frac{i}{n}K)^+$ has a probability $\left((\frac{k - \frac{i}{n}K}{K})^+ \right)^a$ to lead to a widespread blackout.This probability is increasing with increasing overflow relative to the maximum transfer capacity ($a > 1$). That is, larger overflows have an increasingly higher probability of leading to a blackout. Suppose that V_{BO} [€/h] is the cost of a blackout.[23]

Third, suppose that increasing maximum transmission capacity K has a constant marginal cost c.[24] Following the above functional form assumptions, net interconnection surplus is:

$$\max_{\{k,K\}} \{ k(\Delta p - 0.5(b_E + b_I)k) - \sum_{i}^{n} p_i \left[(k - \frac{i}{n}K)^+ V + \left((\frac{k}{K} - \frac{i}{n})^+ \right)^a V_{BO} \right] - cK \} \tag{19}$$

Table 1 shows the parameter values for interconnection benefit, EIC and investment cost. This yields the following optimal capacities:

$$k^* = 3418 \text{ MW and } K^* = 4197 \text{ MW}$$

The optimal line loading α^* equals 0.8144, compared to the N-1 line loading $\alpha_{N-1} = 0.75$. The specific four-line topology and the chosen parameter values result in an optimal line loading that is less conservative than the N-1 line loading. Figure 3 shows the optimal short-term line loading for different values of the cost of blackout V_{BO}, line failure probability p_f, initial price difference Δp, and the sum of the slope of the residual supply and demand curves $b_E + b_W$. These graphs show that the line loading should optimally change if these economic and technical parameters change. The N-1 line loading corresponds with the dotted line. The upper right-hand graph shows that the line

Table 1: Illustrative parameter values

$\Delta p = 15$	[€/MWh]	$V = 5000$	[€/MWh]	$c = 5$	[€/MWh]
$b_E = 0.001$	[€/MW^2h]	$p_f = 0.0002$	[/]		
$b_I = 0.0015$	[€/MW^2h]	$V_{BO} = 10^8$	[€/h]		
		$n = 4$	[/]		
		$a = 2$	[/]		

[21]The interconnection benefit is the sum of additional producer surplus, congestion rent and additional consumer surplus: $S(k) = \Delta PS_E + CR + \Delta CS_I = \frac{k}{2}b_E k + k(\Delta p - (b_E + b_I)k) + \frac{k}{2}b_I k = k(\Delta p - 0.5(b_E + b_I)k)$

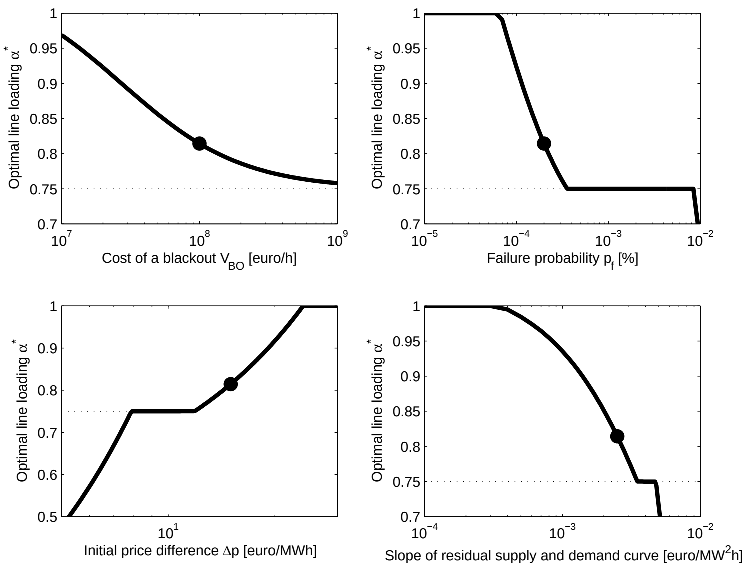
[22]Note that the first part of the EIC function is homogeneous of degree one, the second part of degree zero.

[23]As an illustration, values can be found on `http://www.blackout-simulator.com/` (Reichl et al., 2013).

[24]Obviously there are economies of scale in transmission. A cost function of $c(K) = F + cK$ has increasing returns to scale and would yield qualitatively the same results as the current analysis.

loading should optimally be higher than the N-1 line loading when the probability of line failure is low, while the line loading should optimally be lower than the N-1 line loading if the probability of line failure is high. For intermediate failure probability values, the N-1 line loading is optimal in this simple two-node example. The same is true for the initial price difference, if Δp is higher (marginal interconnection benefit is higher), the line loading should optimally be higher.[25] The dot in the four graphs indicates the optimal long-term line loading $\alpha^* = 0.8144$ for the parameter values of table 1.

Figure 3: Optimal short-term line loading α^* for different values of V_{BO}, p_f, c and $b_E + b_W$.



Net interconnection surplus also changes with economic and technical parameters. Figure 4 shows surplus as a function of the above parameters. The dashed line represents surplus when the N-1 reliability criterion is used for operational planning, while the solid line represents surplus if the scheduled flow k is chosen optimally, according to equation (5). The maximum transfer capacity is fixed at $K^* = 4197$ MW, the optimal capacity for the parameter values of table 1.

Figure 4 shows that the optimal reliability criterion weakly increases surplus in operational planning compared to the N-1 reliability criterion. This increase is 3% for the chosen parameter values, but for other values the increase is larger or even zero. In that case, the N-1 reliability criterion makes the correct trade-off. Detailed engineering studies that incorporate the network, the failure contingencies, the supply and demand conditions and the values of lost load of different consumer groups at different times are needed to get a better estimate of the inefficiencies of the N-1 reliability criterion in operational planning. Some studies have been done. As a first illustration, Heylen et al. (2016) estimate the efficiency improvement to be 2% for a 5-node system and 6.6% for the 24-bus IEEE-RTS system (Grigg et al., 1999). Second, (He et al., 2010) estimate the efficiency improvement to be between 0.3% (normal weather) and 7.1% (adverse weather) for a 6-bus system, and 4.8% for the 24-bus IEEE-RTS.

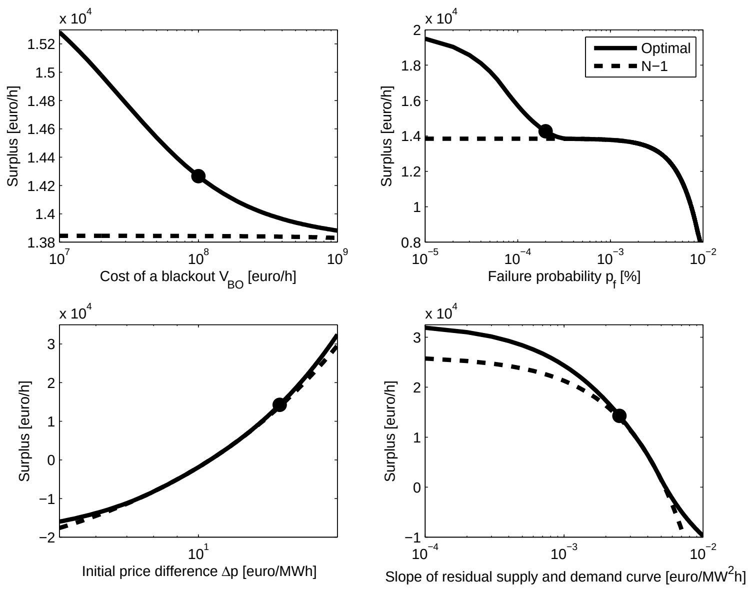
Lastly, we check the effect of the N-1 reliability criterion on transmission investment. Inserting the functional form assumptions of this illustration in equation (12) yields the following maximum transfer capacity:

$$K_{N-1} = \frac{\Delta p - c/\alpha_{N-1}}{(b_E + b_I)\alpha_{N-1}} = 4,444MW > K^*. \tag{20}$$

This equation shows that, if $\alpha^*, \alpha_{N-1} > \frac{2c}{\Delta p}$, the N-1 reliability criterion leads to an overinvest-

[25]The optimal line loading also differs with the number of lines n. With 3 lines $\alpha = 0.796$ and $\alpha_{N-1} = 0.796$; while with 5 lines $\alpha = 0.8258$ and $\alpha_{N-1} = 0.8$.

Figure 4: Optimal surplus and 'N-1 surplus' for different values of V_{BO}, p_f, c and $b_E + b_W$.



ment if it is too conservative ($\alpha^* > \alpha_{N-1}$), while it leads to an underinvestment if the N-1 reliability criterion is not conservative enough ($\alpha_{N-1} > \alpha^*$).

7. MOVING BEYOND THE N-1 RELIABILITY CRITERION

The N-1 reliability criterion has been carried over from the old regime of regulated vertically integrated monopolies (Joskow, 2006). It has achieved acceptable results over the past decades, but is considered inadequate in the future system characterized by more decentralized decision makers, more uncertainty, more interconnected networks, more variable renewable generation, more NIMBY[26] and environmental concerns, and a general trend towards more efficient management. In such a system, the probabilistic approach of this paper is more efficient than the N-1 reliability criterion because it allows TSOs to base their reliability decisions on VOLL, demand, weather conditions, (expected) intermittent generation, etc.

TSOs are starting to be aware of the inefficiencies of the N-1 criterion but many barriers still must be overcome. First, in actual large, meshed networks, calculating the expected interruption cost requires large computing power. Second, calculating the expected interruption cost is a complex issue, while the N-1 criterion is a straightforward and easily comprehensible decision rule. Third, a large amount of technical and economic data is needed. On the technical side one needs demand data; forecast errors; maintenance planning; repair times; wind and solar data; failure probabilities of all system components as a function of temperature and weather[27], etc. On the economic side one needs accurate estimates of interconnection benefit and VOLL.[28]

Despite the above-mentioned barriers, some steps are possible towards a more efficient reliability management. First, instead of only considering single outages, the contingency list could include simultaneous outages with a high probability of occurrence or high-impact outages. Similarly,

[26] Not In My Back Yard: opposition by local residents to nearby development projects.

[27] 9 out of the 10 most risky days in 2010-2014 in the North American bulk power system were caused by adverse weather (NERC, 2015)

[28] Because of difficulties to estimate VOLL (CEER, 2010), VOLL is usually assumed to be a constant value per TSO zone. In reality the VOLL depends on the type of interrupted consumer, the duration and region of interruption, the time of occurrence, etc. Including these factors yields even higher efficiency gains. Heylen and Ovaere (2016) estimate additional efficiency gains up to 43%.

single outages with a very low probability of occurrence or a very low impact could be excluded. The decision to include or exclude certain contingencies is made by calculating (an approximation of) the average impact. The contingency list could also depend on the weather and the region. Second, advances in communication and information technologies allow to record technical data at a decreasing cost. Devices to measure climatic data, real-time voltage and current data, and regional demand and generation data are in an adoption phase in Europe (GARPUR, 2015). Third, VOLL data need to be improved. VOLL studies are laborious and rather expensive, but widespread roll-out of smart meters will facilitate the determination of VOLL for different regions, different consumer types, and different interruption times. Fourth, TSO and market data could be used to determine costs of preventive and corrective actions – such as the cost of congestion and the cost of balancing and reserves. This allows to make a trade-off between the costs and benefits of reliability decisions.

8. CONCLUSION

This paper presented a model that explicitly considers the possibility of transmission line outages and uncertainty of demand and intermittent supply. The model shows that the optimal transmission reliability margin is a trade-off between congestion and reliability. These depend on economic and technical parameters, while the currently-used N-1 reliability criterion determines the reliability margin based on the network topology. Our optimal probabilistic approach is a benchmark that shows the possible efficiency improvements of moving towards a reliability criterion based on expected interruption costs. In our analysis we suggested the possible steps towards this probabilistic approach.

This paper provided a qualitative analysis of transmission reliability and reliability criteria. To support the move towards a probabilistic approach, more quantitative analysis is needed, especially on the effects of the reliability criterion on transmission investment.

In a system characterized by increased renewable generation and difficulties to build new lines, power system operation will be closer to its limits. In such a stressed system the gains of a probabilistic reliability management are expected to be even higher. Fortunately, advances in communication and information technologies are making it possible to move towards a probabilistic approach of reliability management. A reliability criterion that is adapted to the challenges and needs of our modern society affects all of us. It allows a better assessment of the risks and better integration of renewable generation, while lowering the cost of our electricity system.

An important caveat is that TSOs are assumed to pursue the correct efficiency objective and that TSOs cooperate in international transmission to maximize their joint surplus. This is obviously more difficult to monitor when TSOs use a probabilistic reliability criterion than when they use the N-1 reliability criterion.

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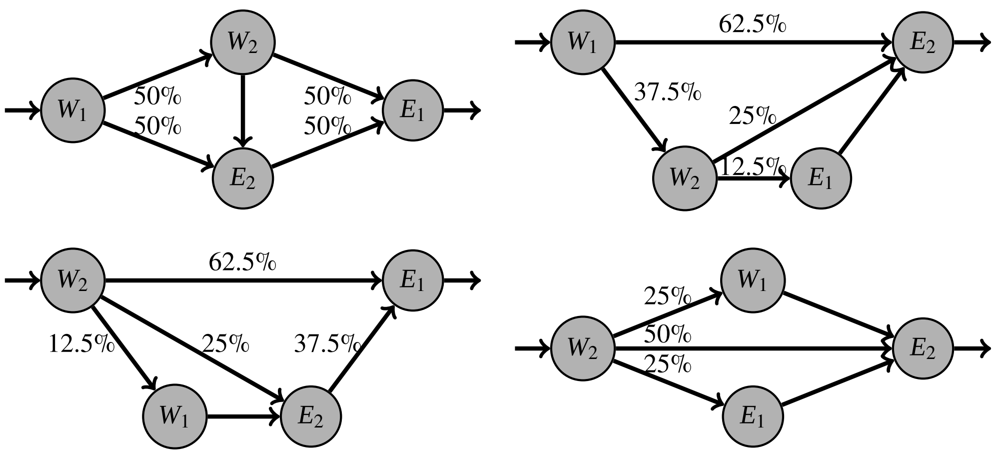
9. APPENDIX

The solution of a power flow is usually found using numerical methods, but it is possible to manually calculate power flow for simple networks using the superposition method. As an illustration, this appendix explains the power flow calculation of the four-node network where line $W_1 - E_1$ is out. Figure 5 shows the four different ways electricity flow is transferred from West to East when line $W_1 - E_1$ is out: $W_1 \to E_1$, $W_1 \to E_2$, $W_2 \to E_1$ and $W_2 \to E_2$. For each of the cases one can calculate how the flow is distributed over the different lines. The flow distribution is determined by the reactance of the difference paths. As before, suppose that all lines have an identical reactance x.

Figure 5: Different allowed line loadings α_{N-1} depending on the topology of the network: all four networks have the same K.



In case (a) the path through W_2 and the path through E_2 have equal reactance $2x$, such that the flow is distributed equally over both paths. In case (b) the reactance of path $W_1 - W_2 - E_1 - E_2$ has a reactance of $x = 1 + \frac{1}{1+0.5} = \frac{5}{3}$, while the direct path between W_1 and E_2 has a reactance of x. Therefore, the flow on line $W_1 - E_2$ is $\frac{5/3}{1+5/3} = 0.625$ %. The flow distribution of cases (c) and (d) are calculated in the same way.

The final flow on a line is calculated as the superposition of the four cases. For example, the flow on line $W_1 - W_2$ is $0.25(0.5 + 0.375 - 0.125 - 0.25) = 12.5$ %, while the flow on line $W_1 - E_2$ is $0.25(0.5 + 0.625 + 0.125 + 0.25) = 37.5$ %.