ISSN (Online) : 2319 – 8753
ISSN (Print) : 2347 - 6710

International Journal of Innovative Research in Science, Engineering and Technology

An ISO 3297: 2007 Certified Organization, Volume 3, Special Issue 1, February 2014

International Conference on Engineering Technology and Science-(ICETS'14)
On 10th & 11th February Organized by

Department of CIVIL, CSE, ECE, EEE, MECHNICAL Engg. and S&H of Muthayammal College of Engineering, Rasipuram, Tamilnadu, India

Congestion Management in Transmission lines considering Demand Response and FACTS devices

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Abstract— In a deregulated electricity market, it may always not be possible to dispatch all of the contracted power transactions due to congestion of the transmission corridors. This paper presents a transmission lines congestion management in a restructured market environment using a combination of demand response and Thyristor controlled series compensators (TCSCs). The overall objective of FACTS device placement can be either to minimize the total congestion rent or to maximize the social welfare. The main motivation of the work is to carry out the contingency selection by calculating the Generation shift factor (GSF) for generator outage and to implement the demand response and Flexible AC Transmission Systems (FACTS) in managing the transmission congestion. The effectiveness of the method has been tested and validated with TCSC and SVC in IEEE 30 bus test system.

Keywords- Demand response (DR) Thyristor controlled series compensator (TCSC), Static Var compensator (SVC), Congestion management, Genetic Algorithm, Generation shift factor(GSF)

I. INTRODUCTION

Restructuring in electric power industry has led to intensive usage of transmission grids. In a competitive market environment transmission companies usually maximize the utilization of transmission systems as construction of new transmission lines is not as straightforward as in centrally planned systems. Thus, in high demand periods, the system operates near its transmission capacity limit with security margin being reduced [1]. Existence of network constraints dictates the finite amount of power that can be transferred between two points on the electric grid. In practice, it may not always be possible to deliver all bilateral and multilateral contracts in full and to supply the entire market demand due to violation of operating constraints such as voltage and line power flow many cases by cost-free means such as network reconfiguration, operation of transformer taps and operation of flexible alternating current transmission system (FACTS) devices [3–8]..In other case, however, it may not be possible to remove or relieve congestion by cost-free means, and some non-cost-free control methods, such as re-dispatch of generation and curtailment of loads, are required [9–11]. Since there is a wide range of events which can lead to transmission system congestion, a key function in system operation is to manage and respond to operating conditions in which system voltages and/or power flow limits are violated [2].

A congestion management method proposed in this project is based on a combination of FACTS devices and demand response programs. In the present paper, Demand response is modelled considering incentives and penalty factors. The incentive and penalty factors would lead to more control on responsive demand contributions rather than just relying on changing the electricity price in the market and its effects on response rate of elastic loads. The penalty factor can also improve the response rate of responsive demands and also enhance the reliability level of these resources by decreasing the rate of response failure. In addition, deploying demand response resources at appropriate locations would allow generation to operate at a lower cost as the congestion is reduced and also transmission network investment can be postponed while maintaining the existing level of security [12–14]. In fact, the responsive demand improves the operation of electricity market and also would market electricity market more efficient and more competitive [12]

II. CONGESTION MANAGEMENT

2.1 INTRODUCTION

Congestion is a consequence of various network constraints characterizing a finite network capacity that

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may limit the simultaneous delivery of power from an associated set of power transactions (Singh et al. 1998). The network constraints include thermal limits, voltage/VAR requirements and the stability considerations. Among all the constraints, thermal limits are the most frequently considered factor in determining network capacity.

Managing congestion to minimize the restrictions of the competitive market has become the central activity of systems operators. It has been observed that the unsatisfactory management of transactions could increase the congestion cost which is an unwanted burden on customers. A number of methods dealing with congestion management in deregulated electricity market shave been discussed earlier. Hogan (1992) proposed the contract network and nodal pricing approach using the spot pricing theory for pool type market ,Chao and Peck (1996) proposed an alternative approach which is based on parallel markets for link based transmission capacity rights and energy trading under a set of rules defined and administered by the System Operator (SO).

There are two broad paradigms that may be employed for congestion management. The first method includes actions like outage of congested lines or operation of transformer taps, phase shifters or FACTS devices. These means are termed as cost-free only because the marginal costs (and not the capital costs) involved in their usage are nominal.

The *not-cost-free* means include:

(1) *RESCHEDULING GENERATION*

Here system operator re-dispatches power generation in such a way, that resulting power flows does not overload any line. Every generation unit can bid an increase or decrease of its production in a similar manner as this is done on a balancing market, while the responsibility of system operator is to select bids in efficient way. Somehow, counter trade approach based congestion management can be viewed as simplified optimal power flow problem, where optimization variables are re-dispatch of the active power production and criteria function is minimum of the costs related to this active power re-dispatch.

(2) *PRIORITIZATION AND CURTAILMENT OF LOADS/TRANSACTIONS*

A parameter termed as willingness-to-pay-to-avoid-curtailment was introduced in the objective function. This can be an effective instrument in setting the transaction curtailment strategies which may then be incorporate in the optimal power flow frame work.

2.2 TRANSMISSION CONGESTION PENALTY FACTORS

A concept of transmission congestion penalty factors is developed and implemented to control line overflows in proposed for congestion management. Transmission congestion penalty factor for each transmission line is computed which can adopt a suitable value depending upon amount of power flow (in MVA) above/below the maximum limit. Therefore, the congested line/lines and lines near to congested line/lines have higher values of transmission congestion penalty factors than other lines in the system. These transmission congestion penalty factors are helpful in deciding appropriate re-dispatchment of dispatchable resources. The procedure for determining transmission congestion penalty factors is explained below.

2.2.1Procedure to determine transmission congestion penalty factors

A base case situation is considered for congestion management. This base case refers to optimal settings of real power generation schedule, transformer tap settings and capacitor reactive support settings under normal state and with these settings now system is subjected to congestion (with one/more than one line limits is/are violated).The following steps are followed to compute these penalty factors.

Step1. Load flow solution and line flows (*Sij-base*) are obtained for base case.

Step2. Set the line limits in congestion case (*Sij-M*).

Step3. GA-Fuzzy approach as described earlier, is used to generate population of different generation schedules satisfying equality and non-equality constraints (except line flows limits).

Step4. Line flows (*Sij-tr*) are calculated for each such generation schedule and line penalty factors (*Pij*, where *i* and *j* denote bus numbers between which transmission line is connected) are calculated according to Fig. 2.1

Step5. Another parameter, *line flow sum* representing cumulative effect of penalty factors and transmission line flows in congestion is computed as follows.

$$\boldsymbol{line\ flow\ sum} = \sum_{l=1}^{n_l} \boldsymbol{P_{ij} * S_{ij-tr}}$$

Where n_l= no. of transmission lines.

These new types of transmission congestion penalty factors have two advantages. First, separate slope for penalty factor of each transmission line is determined depending upon power overflow above rated line flow value of that transmission line. It means that line with lesser power overflow will have lower value of slope, and thus will result small value of penalty factor. Similarly, it is understood that line with comparatively higher power overflow will have higher value of penalty factor. This adaptive feature is helpful in finding right solution (optimal values of control

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parameters, e.g. real power generation, transformer tapping and capacitors values) by search techniques such as GA. Secondly, only single logic mentioned in step-4 works for determining these congestion penalty factors based on magnitude of power overflow in the line/lines. Therefore, no difficulty arises in choosing suitable values of penalty factor,

2.*3PROPOSED METHODS FOR CONGESTION MANAGEMENT*

2.3.1 *Demand response allocation*

For successful implementation of demand response programs ,a set of candidate load buses should be selected, based on their influences on network response. In this regard, loads with high impact on transmission system element loadings are chosen. To achieve this goal, generation shift factor (GSF) is used [17]. In addition, this index could be either positive or negative, and for effective demand response implementation, those buses with negative indices are selected from a ranking process where higher priority is given to index with greater magnitude. However, this selection criterion is subject to the availability of the responses from the demand side at the identified locations. The load model developed in the following section will be used to quantify the expected demand response at load buses.

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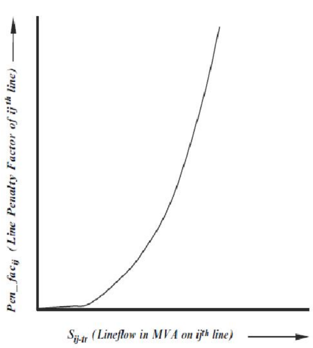

Fig. 1 Graphical representation of penalty factors as straight lines.

2.3. ECONOMIC MODEL OF ELASTIC DEMAND

2.3.1. Outline

This section derives an elastic demand model based on incentive and penalty together with the customer benefit function for the purpose of estimating the demand response capacity. This provides an economic basis on which the demand response aggregator at each location as identified in Section 2.1 formulates the bidding curve to be submitted to the market operator. The load change at the i[th] bus arising from demand response can be expressed as follows:

$$\Delta L(i) = L_0(i) - L(i) \qquad (1)$$

In Equ (2.1), $L_0(i)$ and L(i) are the load at the ith location before and after demand response, respectively.

If CR (i) is paid as incentive to the customer for each unit of load reduction, the total incentive for participating in DR program will be calculated based on Eq. (2.2). The incentive amount is a fixed value which is determined by market operator. The amount of penalty is also assumed to be a fixed amount, and the penalty is set to be 1.5*CR(i)

$$P(\Delta L(i)) = CR(i).[L_0(i) - L(i)] \qquad (2)$$

If the reduction level requested from the aggregator and penalty for the same period are denoted by LR(i) and pen(i), respectively, then the total penalty PEN(ΔL(i)) is calculated as follows:

$$PEN(\Delta L(i)) = pen(i).\{LR(i) - [L_0(i) - L(i)]\} \quad (3)$$

The requested load reduction level, LR(i), is limited to the maximum value $LR_{max}(i)$ as agreed in the contract between the aggregator and customers.If the customer revenue is considered as B(L(i)) for using L(i), the customer net benefit can be calculated as follows:

$$S = B(L(i)) - L(i).\rho(i) + P(\Delta L(i)) - PEN(\Delta L(i)) \quad (4)$$

In (2.4), ρ(i) is the price after the demand response.To maximize the customer's net benefit, $\frac{\partial S}{\partial L(i)}$ in Eq. (5) is set to zero

$$\frac{\partial S}{\partial L(i)} = \frac{\partial B(L(i))}{\partial L(i)} - \rho(i) + \frac{\partial(\Delta L(i))}{\partial L(i)} - \frac{\partial PEN(\Delta L(i))}{\partial L(i)} = 0 \quad (5)$$

From (5) $\frac{\partial B(L(i))}{\partial L(i)} = \rho(i) + CR(i) + pen(i) \qquad$ **(6)**

In general, various forms of function have been proposed for expressing the customer revenue in terms of demand [18–20]. In this project, an exponential function of demand elasticity as given in [28] is adopted for deriving the optimal demand response:

$$B(L(i)) = B_0(L_o(i)) + \frac{\rho_0(i)L(i)}{1+E(i)^{-1}}\left\{\left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}} - 1\right\} \quad (7)$$

In (2.7), E(i) is the self-elasticity of the load and ρ_0(i) is the market price prior to demand response implementation .Differentiating Eq. (2.7) yields

$$\frac{\partial B(L(i))}{\partial L(i)} = \frac{\rho_0(i)}{1+E(i)^{-1}}\left\{\left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}} - 1\right\} + \rho_0(i).\frac{L(i)}{1+E(i)^{-1}}\left\{E(i)^{-1}.\frac{1}{L_0(i)}\left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}}\right\} \qquad (8)$$

Simplifying Eq. (2.8) and substituting into Eq. (2.6) yields Eq. (2.9).

$$(1 + E(i)^{-1}).\rho(i) + CR(i) + \frac{pen(i)}{\rho_0(i)} = \left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}} - 1 + E(i)^{-1}.\left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}} \qquad (9)$$

Rearranging Eq. (2.9) leads to

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$$\frac{\rho(i)+CR(i)+pen(i)}{\rho_0} = \left(\frac{L(i)}{L_0(i)}\right)^{E(i)^{-1}} - \left(\frac{1}{1+E(i)^{-1}}\right) \quad (10)$$

The second term of Eq. (2.10) can be discarded for small amount of elasticity, and finally the demand response model can be achieved as follows:

$$L(i) = L_0(i).\left(\frac{\rho(i)+CR(i)+pen(i)}{\rho_0(i)}\right)^{E(i)} \quad (11)$$

The estimated demand response in (2.11) depends on market prices which are to be forecasted by the aggregator using historical data.

2.4 MARKET CLEARING FORMULATION

2.4.1 PROCEDURE FOR MARKET CLEARING

A two-step market clearing procedure is formulated in this project. In the first step, generation companies bid to the market for maximizing their profit, and the ISO clears the market based on social welfare maximization without considering the electricity network constraints. In the second step, the ISO will consider network losses, network constraints including those of congestion as described in below section. The electricity market-clearing procedure considered in the paper is similar to the one used by the Ontario electricity market operator [18].

First step: MARKET PRICE DETERMINATION

In this step, it is required to solve the following constrained optimization problem: $\boldsymbol{Maximize}$:

$$\sum_{i=1}^{N_D}\sum_{k=1}^{N_{Di}}(\lambda_{Dik}P_{Dik}) - \sum_{i=1}^{N_G} C_i(P_{gi}) \quad (12)$$

Subject to:

$$P_{Dik}^{\min} \le P_{Dik} \le P_{Dik}^{\max} \quad i = 1,\dots,N_D, k =,, N_{Di} \quad (13)$$

$$P_{gi}^{min} \le P_{gi} \le P_{gi}^{max} \quad i = 1,\dots,N_G \quad (14)$$

$$\sum_{i=1}^{N_D}\sum_{k=1}^{N_{Di}} P_{Dik}P_{fd} = \sum_{i=1}^{N_G}(P_{gi}) \quad (15)$$

Where P_{Dik} is the power block k that demand i is willing to buy at price k_{Dik} up to a maximum of $P_{Dik}^{\max}$ k_{Dik} the price offered by demand i to buy power block k, P_{fd} the fixed load based on demand forecasting and $C_i(P_{gi})$ is the generation cost function.

The objective function in (12) represents the social welfare, and it has two terms. The first term consists of the sum of accepted demands times their corresponding bidding prices, and the second term is the sum of the individual generator cost functions. The block of constraints in (13) specifies the sizes of the demand bids. The block of constraints in (14) limits the sizes of the production bids. The equality constraint in (15) ensures that the production should be equal to the total demand. The solution of the constrained optimization problem described in (12)–(15) specifies the power produced by every generator and the power supplied to customers together with the market price.

2.5 CONGESTION MANAGEMENT FORMULATION

The dispatch calculations are performed without taking into account the electricity network limitations such as thermal limit of transmission lines and voltage constraints. To manage the congestion due to such limits, the following constrained optimization problem is to be solved

$$\boldsymbol{Minimize}: \boldsymbol{T}.\sum_{j=1}|C_j(P_{gi}^0 + \Delta P_{gi}) - C_j(P_{gi}^0)| \ \sum_{i\in reD} r_{Di}^{down}\Delta P_{reDi}^{down}.d_i \quad (16)$$

Subject to:

$$E(|V|,\theta,u) = 0 \quad (17)$$

$$H(|V|,\theta,u) \le 0 \quad (18)$$

Where ΔP_{gj} is the change in the schedule of the jth generator,

P_{gi}^0 is the j[th] generator schedule in step 1,

r_{Di}^{down} is the price offered by demand response i to decrease its demand,

D_i is the demand response commitment variable which has a binary value,

|V| is the vector of voltage magnitudes,

h the vector of phase angles,

T is the dispatch time interval and

u is the vector of control variables**.**

E and H in (17) and (18) are the sets of equality and inequality constraints. Vector u in (17) and (18) is the control vector comprising active-power generation changes, demand response commitments, input references to generator excitation controllers and network controllers including those of FACTS devices.

The objective function in (16) has two parts. The first part is the sum of the payments received by the generators for changing their output as compared to the original generation schedule, and the second term shows the total payment received by demand response participants to reduce their load. Each demand response service provider submits to the system operator a bidding curve to specify prices and capacity. Typically, the bidding comprises a number of power blocks each of which with block size and bidding price as shown in Fig. 2. A constraint in dispatching demand responses is that only whole blocks can be committed.

The set of equality constraints in (17) includes the power-flow equations for generator nodes and load nodes. For each generator rnode, the nodal active-power is the algebraic sum of power generation as determined in the first step and the changes supplied by ancillary service providers at the node. For each load node, the total nodal active-power is the algebraic sum of load demands before the demand response and

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the decrement after demand response at the node. The nodal reactive-power at each load node used in forming the power-flow equation is determined from the active-power together with a specified power factor .The set of inequality constraints denoted by H in (18) is related to operating limits which include.

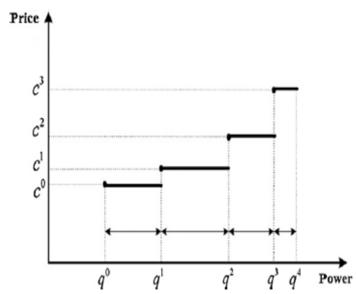

Fig 2. A typical demand response bidding

i. Power-flow constraints for transmission circuits. These constraints are required in congestion management.
ii. Nodal voltage constraints. These are related to network voltage security.
iii. Generator reactive power limits.
iv Power system controllers limits

In this paper, network controllers based on FACTS devices in the form of TCSCs and SVCs are considered. The functions of these controllers include those for mitigating congestion and/or enhancing network voltage security. The operating limit constraints on these FACTS device controllers, which are to be included in the set of inequalities in (2.18) are expressed in (19) and (20).

$$\boldsymbol{X_{TCSC}^{min} \leq X_{TCSC} \leq X_{TCSC}^{max}} \quad \textbf{(19)}$$

$$\boldsymbol{B_{SVC}^{min} \leq B_{SVC} \leq B_{SVC}^{max}} \quad \textbf{(20)}$$

For each TCSC, X_{TCSC} in (19) is the TCSC reactance variable which is a controllable quantity. In the context of steady-state analysis, a TCSC can be modelled in terms of a variable reactance within it sspecified limits. Similarly, an SVC is modelled as a variable susceptance, B_{SVC}, within its limits, as shown in (20). The SVC susceptance is determined. For each TCSC, X_{TCSC} in (19) is the TCSC reactance variable which is a controllable quantity. In the context of steady-state analysis, a TCSC can be modelled in terms of a variable reactance within its specified limits. Similarly, an SVC is modelled as a variable susceptance, B_{SVC}, within its limits, as shown in (20). The SVC susceptance is determined by the voltage controller for achieving its control objective.

III. MODELLING OF TCSC AND SVC

3.1 Thyristor Controlled Series Capacitor (TCSC)

The Thyristor Controlled Series Compensator (TCSC) allows varying the series reactance of a transmission line and, thus, regulating the active flow through the transmission line itself. The functioning of the TCSC is similar to the SVC, but for the fact that the TCSC is a series device, as shown in Figure 3.1.

(a) firing angle model and (b) equivalent susceptance Model

Fig. 3. TCSC schemes

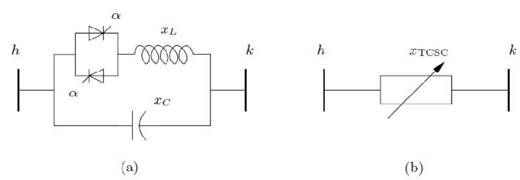

Table I TCSC parameters

Variable	**Description**	**Unit**
Kw	Regulator gain	pu/pu
p^{ref}	Reference power	Pu
T_1	Low-pass time constant	S
T_2	Lead time constant	S
T_3	Lag time constant	S
T_w	Washout time constant	S
x_C	Reactance (capacitive)	Pu
x_L	Reactance (inductive)	Pu
$x_{TCSC}^{max}\ (\alpha^{max})$	Maximum reactance (firing angle)	pu (rad)
$x_{TCSC}^{min}(\alpha^{min})$	Minimum reactance (firing angle)	pu (rad)

Static model of TCSC

In this paper ,the static model of TCSC is used and the maximum line compensation by TCSC is limited to 50%. In the steady-state operation, the equivalent TCSC reactance is presented as follows:

$$\boldsymbol{x_{tcsc} = x_{tcsc\ ref}}$$

In above equation x_{tcsc} *and* $x_{tcsc\ ref}$ are the reactance and its reference value, respectively. On this basis, a TCSC is represented as controllable reactance as shown in below Fig 4

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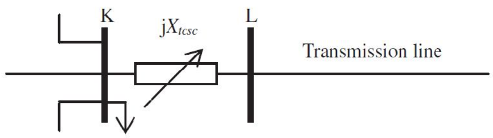

Fig 4 TCSC Model considered power flow studies

The nodal powers at nodes K and L in Fig.3.2 are described as follows

$$P_k + j.Q_k = V_k.\left[\sum_{i\neq l} Y_{ki}V_i + \frac{V_k - V_l}{j.X_{tcsc}}\right]^* \quad (21)$$

$$P_l + j.Q_l = V_l.\left[\sum_{i\neq k} Y_{li}V_i + \frac{V_l - V_k}{j.X_{tcsc}}\right]^* \quad (22)$$

In above equations Y_{ki} and Y_{li} are the elements (k, i) and (l, i) of the admittance matrix of the power system excluding the TCSC, V_k, V_l and Vi are nodal voltages at nodes k, l and i ,respectively.

IV. SIMULATION AND DISCUSSION

4.1 TEST SYSTEM

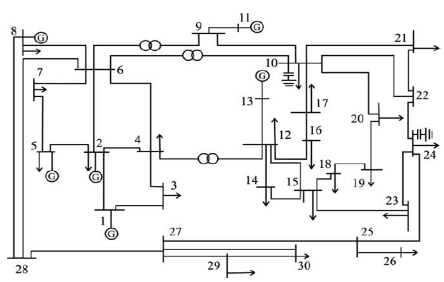

Fig 5 IEEE- 30 Bus system

bus	(mw)	(mw)	(mvar)	(mvar)	a	b	c
1	50	200	−20	250	0.0	2.0	0.00375
2	20	80	−20	100	0.0	1.75	0.0175
5	15	50	−15	80	0.0	1.0	0.0625
8	10	35	−15	60	0.0	3.25	0.00834
11	10	30	−10	50	0.0	3.0	0.025
13	12	40	−15	60	0.0	3.0	0.025

Table II Generator data

The proposed method is implemented on modified IEEE 30 bus system. Line (8,28) get congested (exceeding flow limit of 12 MVA) if outage of line (6,28) is considered.

4.2 COMAPRISION OF RESULTS UNDER NOMINAL AND PROPOSED CASE

Table III comparisons of results

Case	P(mw)	Q(mvar)	P(mw)	Q(mvar)
Nominal case	192.06	105.08	189.20	107.20
Proposed case	191.52	104.02	189.20	107.20

Table IV nominal case
Voltage constraints

Bus	Vmin (mu)	Vmin	|v|	Vmax	Vmax(mu)
29	-	0.950	1.050	1.050	29.810

Table V proposed case
Voltage constraints

Bus	Vmin (mu)	vmin	|v|	Vmax	Vmax(mu)
29	-	0.950	1.050	1.050	307.114

Table VI nominal case
Branch flow constraints

Branch	From bus	From end		limit	To end		To bus
		|sf|mu	|sf|	|smax|	|st|	|st|mu	
10	6	2.387	32.00	32	31.63	-	8
25	25	-	15.62	16.00	16.00	0.024	27

Table VII proposed case
Branch flow constraints

Branch	From bus	From end		limit	To end		To bus
		|sf|mu	|sf|	|smax|	|st|	|st|mu	
10	6	30.308	32.00	32.00	31.63	0.001	8
29	21	0.002	31.81	32.00	32.00	2.649	22

V.CONCLUSIONS

In this paper congestion management was implement using demand response and facts devices. The increment in line flow limits and and their corresponding values are shown above. A security analysis study which is run in an operations center must be executed very quickly in order to be of any use to the operators. The problem of studying thousands of possible outages becomes very difficult to solve if it is desired to present the results quickly. So it is very important to have a system which can detect the possible future outages and prioritize

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among them to determine the most critical cases for detailed analysis. This is done by Contingency Analysis which allows operators to be better prepared to react to outages by using pre-planned recovery scenarios.

With the history of more than three decades and widespread research and development, FACTS controllers are now considered a proven and mature technology. The operational flexibility and controllability that FACTS has to offer will be one of the most important tools for the system operator in the changing utility environment. In view of the various power system limits, FACTS provides the most reliable and efficient solution. The high initial cost has been the barrier to its deployment, which highlight the need to device proper tools and methods for quantifying the benefits that can be derived from use of FACTS.

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