Valuating Infrastructure for a Self-Healing Grid

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Abstract — **This paper presents fundamentals of a general methodology and scalable framework for valuating a high performance IT infrastructure to support a self-healing grid. The infrastructure calls for a distributed architecture as well as geographically and temporally coordinated autonomous intelligent controls and is designed to realize major improvements in grid reliability by addressing various operating concerns.**

The methodology exploits published industry statistics regarding physical and financial attributes and can be adapted for assessment of self-healing capabilities for any power system. The cost models include research and development as well as productization and shake-down costs associated with autonomous intelligent agents' algorithms and software as well as system integration and basic computing and communication hardware. The benefit models conservatively consider only two financially significant benefits including improvements in production costs/market efficiency and reduction of unserved energy. The models are justified analytically and validated against industry experiences. An empirical model is derived to facilitate the feasibility analysis. The analysis establishes the financial feasibility of the far reaching IT infrastructure.

Index Terms — **Self-healing grid, wide area control, IT infrastructure, business case analysis, power system operations, power system control, large-scale systems, distributed autonomous systems, power system security/reliability.**

I. Introduction

THIS paper presents a general methodology and scalable framework to valuate the costs and benefits associated with the research, development and field implementation of an IT infrastructure to realize a self-healing power grid. The conceptual design including functional capabilities and architectural requirements for such infrastructure was developed and reported in [1,2,3,4,5]. The high reliability expected of such a self-healing grid can be accomplished through better prediction, analysis and control by preventing and/or containing unplanned transmission outages [1].

A. Motivation for a Self-Healing Grid

Large disturbances are few and far between but their consequences can be disastrous. Most large disturbances in power grids are a consequence of very low probability events. In most cases, the system gradually becomes more vulnerable as events unfold and there is usually enough time to react if only the appropriate IT infrastructure were in place. Figure 1, adapted from [6], depicts one of several indicators of brewing trouble preceding the blackout of August 14, 2003.

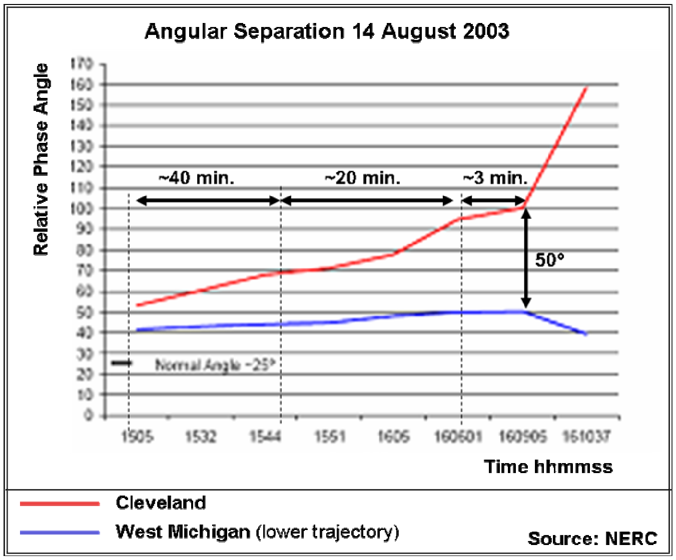

Figure 1: Scope for Intelligent Control Action

The figure suggests that despite the numerous monitoring problems encountered at the local control centers, appropriate grid-wide monitoring of phase angles and reactive reserves could have forewarned the impending disaster. Such advance notice could allow regional and grid-wide analyses to identify and implement control actions.

B. Overview of IT Infrastructure for a Self-Healing Grid

A distributed intelligent infrastructure is prescribed in [1,2] to enable timely recognition and diagnosis of problem conditions to contain the spread of disturbances. Addressing the multiple time-scales associated with the physical behavior of the system requires coordination of monitoring, analysis and control at various geographical scales (substations, zone/vicinity, control area, etc.) and in several sub-second and slower execution cycles based on robust algorithms for:

- Improving the deployment of on-line and off-line resources (e.g., spinning reserves, reactive reserves)
- Calculating various security margins and recognizing problem conditions (e.g., intermittent tree contacts, permanent line faults, stuck breakers)
- Identifying, executing and confirming appropriate control actions (e.g., block unwarranted zone-3 trips, load-shedding, generation tripping, system separation, activation of special control devices such as braking resistors, series capacitors, fast valving)

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The infrastructure, depicted in Figure 2, responds to actual steady-state as well as transient operating conditions in real-time and near real-time. This would make it more effective than and qualitatively distinct from conventional solutions that are generally based on off-line analyses. The infrastructure is applicable to power systems of any size coordinated by any number of organizational entities (regulated or deregulated utilities, transmission operators, ISOs, etc.).

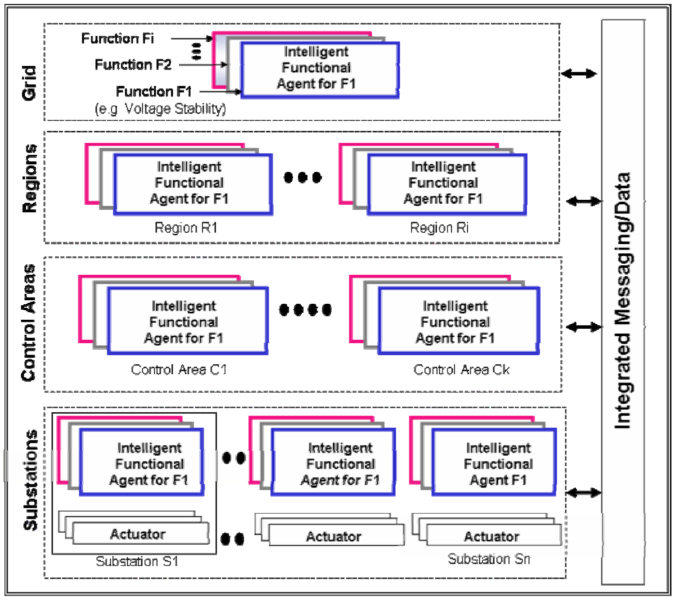

Figure 2: Geographical Coordination

The infrastructure encompasses the entire power grid at all control levels and includes functions implemented through autonomous intelligent agents deployed on an evolving computing network, potentially of a continental scale. It includes all known analytical functions in the following areas:

- Data Acquisition and Maintenance
- System Monitoring (e.g., state estimation, power flow, various security analyses, look-ahead)
- Performance Enhancement (e.g., corrective/preventive actions, security constrained dispatch)
- Control (e.g., AGC, automatic emergency controls)

In each functional area, there are agents operating at different time-scales ranging from milliseconds to an hour (Figure 3) corresponding to the physical phenomena of the grid. The virtual distribution of the agents in various locations enables rapid local control actions coordinated by global analysis. It facilitates near-real-time tuning of control parameters, automatic arming and disarming of control actions and coordination of all functional areas in multiple dimensions such as: organizational hierarchy, geographical locations, multiple time-scales, and multiple generations of systems.

This high performance infrastructure includes effective visualization for monitoring and control. In its full implementation it encompasses the functions of substation automation as well as area and higher level control centers. The IT infrastructure design enables local, global or cooperative solution processes regardless of the organizations or service providers using those processes. This requires that the locations of specific processes and data should be virtualized and transparent to the users. Access should be limited by business needs and authorizations. Technical feasibility of such a system has already been established [1, 2]. Background information relevant to self-healing capabilities in power systems is available in [7 through 12].

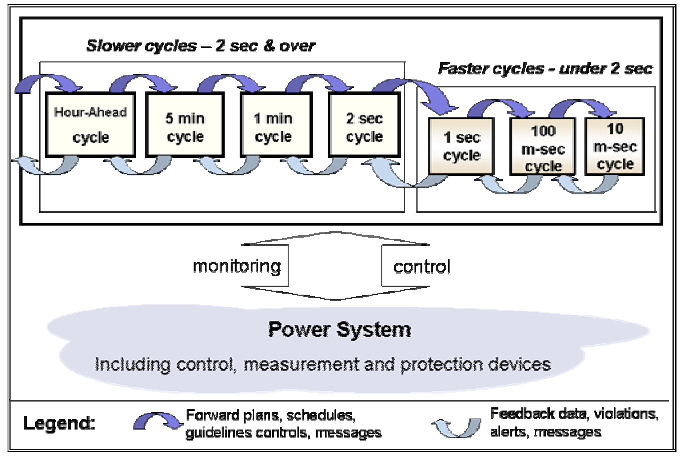

Figure 3: Temporal Coordination

II. Methodology

A methodology is purposefully designed to be applicable to valuation of the costs and benefits of any general IT infrastructures for power grid reliability enhancement. As such the methodology is more important than the specific numerical data used in this paper. The methodology is based on consideration of operating concerns and their potential impacts. It uses established methods based on clearly identifiable generic cost and benefit models validated against industry statistics and experiences. The methodology includes a costing approach to model significant cost components as well as a benefit evaluation based on analytically justifiable models to quantify the most significant benefits.

A. Costing Approach

Operating concerns/problems can be mitigated by using a variety of traditional and modern operating practices, generation resources, transmission resources and control equipment. However, in many cases, exploiting the existing physical resources to the maximum through intelligent strategies is the most cost effective alternative. In this context, a preferred solution includes only software, computing hardware, and communication systems. To the degree possible, such solutions exclude the addition of new power equipment and even new control devices (e.g., capacitor banks, FACTS devices, synchronous condensers, generator controls, etc.). Such solutions are characterized as "no new wires" and emphasize advanced control strategies enabled by the global coordination of the distributed intelligence.

However, such intelligence alone cannot be a substitute for "absolutely" needed additional control equipment. The intelligence can only provide the most reliable and efficient operation that can be achieved with available resources. Taking full advantage of the intelligence may often require the addition of new control equipment such as automatically switchable capacitors or adding new remote feedback capabilities to automatic voltage regulators (AVR).

Cost of implementing the required IT infrastructure depends heavily on several factors such as: required software and hardware capabilities, degree of penetration of the enhanced capabilities, economy of scale, standardization of design and implementation, as well as compatibility of existing products and standards. Therefore, in this work the focus is on the cost of software (applications/business logic) development and productization, system integration, as well as basic computing and communication hardware. The costing excludes operating systems, middleware and database management systems where they can be acquired through open sources.

Hence, the approach focuses on IT solutions considering:

- Deployment of software/intelligence at all hierarchical levels and execution cycles to operate any and all available remotely controllable equipment
- Cost models that facilitate identification of reasonable upper bounds on the deployment of cost items with decisive impact on the financial feasibility
- Ability to validate the models and methods based on various "what if" analyses

In order to quantify the costs of various solutions, published work from various surveys, analyses etc. and public domain information from vendors are used. In some cases, such as software components and field implementation, appropriate experts in the relevant subjects, as well as interested stakeholders are consulted as needed.

B. *Benefit Evaluation Approach*

The approach focuses on:

- Selection of financially significant benefits resulting from the higher reliability of the self-healing grid
- Appropriate methods for quantifying reasonable lower bounds on the selected benefits
- Analytical justification of the parameters used to estimate the potential for reliability improvements

C. *Feasibility Analysis Approach*

Financial feasibility is assessed "conservatively" by using reasonable "lower bounds" on the benefits along with reasonable "upper bounds" on the costs. The analysis provides an empirical model to establish costs and benefits for systems of various sizes and provide break-even points and entry barriers to support strategic decisions.

III. Cost Models

Cost models are presented for the following categories:

A. Software components/intelligent agents
B. IT hardware
C. Control equipment
D. System deployment and integration

A. *Software Components/Intelligent Agents*

The software components/agents should be representative of distributed intelligence based on autonomous functional modules conforming to the functional and architectural requirements of the IT infrastructure [1,2]. The hardware and software components would be "plug-and-play". It is assumed that all agents for the same function at the same geographical level (e.g., substation, zone/vicinity, control area) are identical and configurable to meet local requirements. As such, the following costs are considered for each agent:

- *R&D Costs:* All costs including the risks of implementing the various innovative features are lumped together as R&D costs. These represent a one-time cost perhaps incurred on behalf of all the industry.
- *Productization Costs:* A considerable effort would be needed to move the results of the R&D to a standardized implementation.
- *Shakedown Costs:* A successful productization would require multiple diverse implementations in order to achieve "plug-and-play" status. This cost is distributed over the first few implementations for each agent. The following numbers of field implementations would be required for the necessary maturity:
  - Substation: 10 implementations
  - Zone/vicinity: 5 implementations
  - Control Area: 2 implementations

The biggest R&D costs and risks are related to development of innovative and reliable software intelligence. The research work [1,2] so far has considered the design for 1) Distributed Voltage and VAr Management and all supporting functions including: 2) Distributed State Estimation, 3) Look-Ahead and Forecasting, and 4) Static Security Assessment. Together these four functions would exercise most of the novel functionalities and address many operational concerns. Once the necessary new techniques are prototyped, demonstrated and implemented they can easily be adopted for other functions e.g. Distributed Dynamic Security Assessment. Other important functions such as visualization tools and intelligent alarming, etc. are not considered as cost components since they are expected to evolve independently.

The software functional agents corresponding to the four selected functions at different hierarchical levels (substation, zone/vicinity, control area, etc.) are costed. The effort required for the development and deployment of the agents are independently estimated in detail and summarized as totals for each geographical level in Table 1. The total efforts for the prototype and production-grade development are 21 and 67 person-years, respectively. At approximately $400k per person-year, these estimates translate to $8M and $27M, respectively. The table also presents the factors used to estimate the shake-down cost associated with the first few field implementations and lower costs for later mature components.

#	Level	Prototype / Productizatn. (Person-Yrs)	Field Deployment (Shake-down/ Later implementations)
1	Substation	3 / 11	10% for the first 10 substations (13 person-months each) and 0.5% later (3 person-weeks each)
2	Zone/Vicinity	4 / 13	15% for the first 5 zones/vicinities (23 person-months each) and 3% later(5 person-months each)
3	Control Area	10 / 30	25% for the first 2 control areas (90 person-months each) and 15% later (54 person-months each)
4	Region	2 / 8	25% for the first 2 regions (24 person-months each) and 15% later (14 person-months each)
5	Grid	2 / 5	25% for the first 2 grids (15 person-months each) and 15% later (9 person-months each)
	Total	**21 / 67**	Use above formulae to estimate field implementation costs for various system sizes

Table 1: Efforts for Productization of Functional Agents

Considering the "shake-down" costs, according to the formulae given in column 3 of Table 1, it is estimated that the first field implementation for a control area of 200 substations, including 20 zones/vicinities, may take 45 person-years and subsequent implementations may take about 24 person-years.

B. IT Hardware

The cost of the required IT hardware for a full-scale implementation is roughly proportional to the number of substations involved (due to the relatively large number of substations vs. areas and other grid levels, and use of plug-and-play design) and is a recurring cost. The IT hardware considered includes standard high-end low cost modules for 1) measurements, 2) communications, and 3) computing.

1) Measurements: PMUs are considered as a primary enabling technology to support sub-second execution cycles. A momentum has been building within the industry for incorporating PMUs to provide accurate synchronized data over wide areas [13]. It is assumed that PMUs installed as replacements for traditional RTUs would eventually replace all conventional measurements. At present, PMUs cost about $15k to monitor four 3-phase equipment. For budgetary purposes, one can assume that all the transmission lines are monitored using about 2 PMUs per substation at a cost of about $30K per average substation [2]. In addition, it is assumed that each zone/vicinity hosts two Phasor Data Concentrators (PDCs) at a cost of $22.5K each.

2) Communications: The cost of connectivity is highly utility specific and is not considered here since communication links for grid-wide data exchange already exist to support existing requirements [14] or being added to meet future requirements (e.g., dark fiber). The necessary data standards and infrastructure are mostly in place in the context of NERC's SDX, ICCP etc. [14] to support collection and dissemination of real-time status and planned outage data for critical equipment every 5-minutes. Enabling the faster execution cycles may require an upgrade of the relevant routers to realize further improvements in data volumes, speed, synchronization, latency and reliability of communication. To accommodate the data throughput requirements identified in [2] and reproduced in Table 2 below, each substation needs capabilities equivalent to at least three CISCO3745 routers and other accessory equipment that may cost about $30k.

Requirement	Substn.	Zone/ Vicinity	Control Area	Region	Grid
Snapshot size (kB)	2.5	25	1250	25,000	250,000
Transfer rate (MB/sec)	3.31	8.1	5.089	0.548	2.65
Latency (msec)	2.2	4.8	240	9,600	96,300
Skew (msec)	~ 1	~ 1	~ 1	~ 1	~ 1
Routers	3	6	4	1	2

Table 2: Data Communication Requirements

A case study of upgrading the instrumentation and control at a typical substation by adopting a communication processor star relay network concluded that the costs would be approximately $25K [15]. This lends additional credibility to our estimated cost of about $30K for routers at a substation.

3) Computing: The category of computing includes computers necessary for data management and analytical tasks. The CPU requirements for the analytical tasks are estimated from the requirements stipulated in [1] based on typical power network model sizes at various hierarchical levels. The CPU requirements associated with data management were stipulated in [2]. Table 3 presents the CPU requirements as a percent of Standard Computing Modules

(SCM) defined in [2]. An SCM consists of 2 CPUs, each with 3.6 GHz clocks, 4 GB memory, and two 145 GB disks. For costing, a SCM is priced at $7.5K.

#	Execution Cycle	Substn	Zone/ Vicinity	Contrl Area	Region	Grid
1	10 msec	88.0	55.0	Very Small	Very Small	Very Small
2	100 msec	18.0	74.0	Very Small	Very Small	Very Small
3	1 sec	33.1	62.0	101.0	Very Small	Very Small
4	2 sec	Very Small	7.4	71.0	Very Small	Very Small
5	1 min	Very Small	Very Small	88.9	Very Small	Very Small
6	5 min	Very Small	Very Small	72.6	79.67	102.33
7	Hour-ahead	Very Small	Very Small	49.3	50.33	52.33
Total CPU Requirement (in %SCM)		139.1	198.4	382.8	130.0	154.66
SCMs (for 100% redundancy)		3	4	8	3	4

Table 3: Computing Requirements by Cycle & Hierarchy

Summary of IT Hardware Cost Models: Table 4 summarizes the hardware requirements at each hierarchical level to support the above measurement, data management and the associated computing requirements and the corresponding costs using the prices: $15k/PMU, $22.5k/Concentrator, $10k/Router and $7.5k/Computer. These estimates do not include the additional hardware necessary to provide the appropriate user interfaces which could be available independent of these requirements.

#	Level	PMU/PDC	Routers	SCM	Cost/Site
1	Substation	2 PMUs	3	3	$83 k
2	Zone/ Vicinity	2 PDCs	6	4	$135 k
3	Control Area	0	4	8	$100 k
4	Region	0	1	3	$33 k
5	Grid	0	2	4	$50 k

Table 4: Summary of HW Requirements and Costs

C. Control Equipment

The need for advanced control equipment is highly system specific. In case of the need for such equipment (FACTS devices including SVCs, STATCOMs, and providing new feedback signals to existing devices such as AVRs and PSSs, etc.), their cost is subtracted from the value of the expected benefits before comparison with the cost of the IT infrastructure. For budgetary purposes, shunt devices are preferred over series devices because of differences in the impact on cost, reliability, and losses. For typical load centers, it appears that approximately 10% of the reactive power requirements should be provided by FACTS devices to enable the required fast voltage and VAr management control capabilities. For a substation with 100 MW peak load this typically corresponds to about 4 MVAr of FACTS controlled reactive sources (at $50K per MVAr). For a summary of modern reactive power compensation techniques, see [16].

D. System Deployment and Integration

These costs are roughly proportional to the number of substations and recur for each implementation. They include field verification and acceptance testing. Integration costs depend on the power system and the preferred technology, standards, etc. Typically, integration costs in large advanced IT projects with significant development content are about 30% of the total cost of software deployment and hardware.

IV. Benefit Models

Properly addressing a comprehensive set of operating concerns is essential to support a highly reliable power grid. Though ultimately system operators are responsible for operational reliability, automated solutions are required to address operating concerns effectively. These solutions include analysis to identify and implement control actions in several time-scales to address various categories of concerns such as:

- Performance enhancement (e.g. adequacy & efficiency)
- Equipment limits (e.g., maximum voltage and current)
- System operating reliability (e.g., voltage minimum limits, voltage stability limits)
- Sustaining stability (e.g., system frequency, generator transients, wide-area/inter-area swings)
- Primary/backup protection against fault conditions

A comprehensive list of potential benefits including the following is considered for quantification:

- Improvements in production costs/market efficiency
- Reduction of unserved energy
- Faster restoration of service
- Improved utilization of ancillary service resources
- Improved situational awareness for better coordination.
- Enhanced quality of life through better reliability
- Others (environmental impact, safety, etc.)

A "lower bound" on the total benefit can be established by ranking the benefits and quantifying them in order until the cumulative benefits exceed the cost. Specifically, the following two benefits are adequate to justify the cost of the infrastructure - the first one is of primary interest to all stakeholders while the second one is to all end users:

A. Improvement in production cost/market efficiency
B. Reduction of unserved energy

Models and methods for quantifying the above benefits are developed using industry statistics and reports as primary inputs. The results of the models are validated against historical statistics instead of specific major events (e.g., the blackout of 14 August 2003 [17], a large number of hurricanes in 2004 [18]). These benefit models are described below.

A. Improvement in Production Cost/Market Efficiency

From transmission perspective, the best way to achieve this benefit is to improve transmission capability to substitute expensive generation with the cheaper resources. Any such improvement is of value only if there is congestion. Its financial value is proportional to 1) the amount of congestion relief, 2) its duration, and 3) the price differential across the congested interface. These parameters are discussed below:

1) Magnitude of congestion relief (MW): Ideally, all resources in a power system should be used at their individual maximum thermal limits. However, under stressed conditions, the operation is constrained below the thermal limits, usually by various stability limits (voltage, transient, dynamic/small signal, etc.). These limits can be relieved using the analysis and control capabilities of a self-healing grid. The six boxes in Figure 4 correspond to the six possible permutations among the three limits considered. The arrows conceptually represent an upper bound on the magnitude of possible improvement. The analysis in the Appendix establishes a conservative lower bound on this improvement as 1% of total base load.

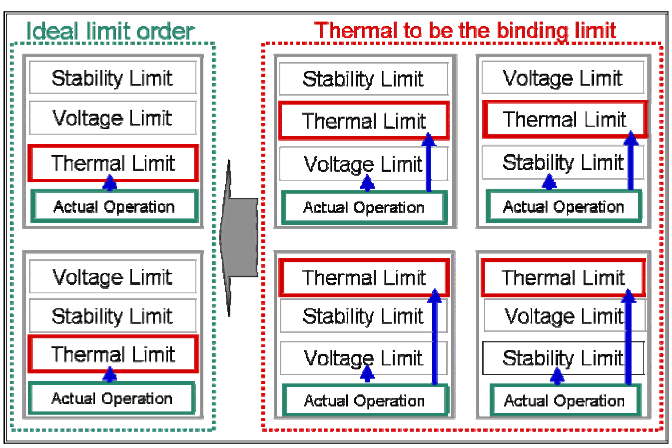

Figure 4: Scope for Limit Improvement

2) The duration of congestion (hours/year): This parameter is basically the peak load hours in which the limits are actually constraining system operation and there is a significant price differential between the two sides of a constrained interface. This parameter is determined using statistics presented in [19] and depicted in Figure 5.

The figure shows the weighted average of the Locational Marginal Prices (LMPs) by hour of day in PJM's day-ahead and real-time markets in 2004. Consistent with the average load factors of gas burning combined cycle units [20] considered as peak load units, we select peak load duration as 45% (3942 hours/year). The final result is not very sensitive to this selection as the effect of a shorter duration is countered by a correspondingly higher price differential.

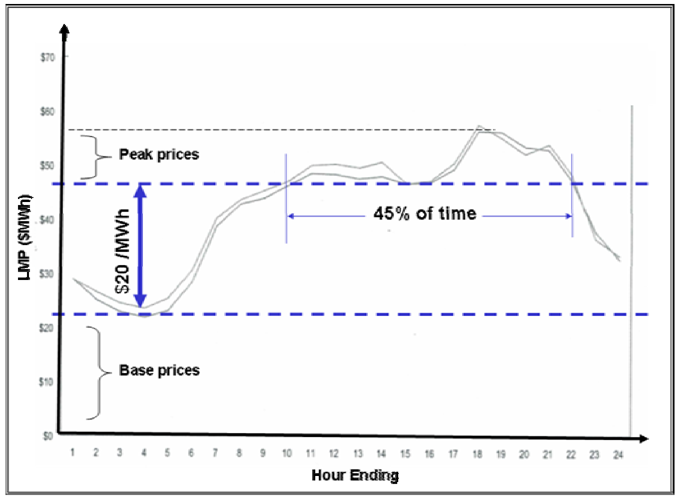

Figure 5: Weighted Average LMPs for PJM Market

3) Price differential ($/MWh): Corresponding to the selected 45% peak load duration, the price differential is set to $20/MW. The price differential is very variable and depends on the amount of available capacity, native load, and marginal prices on both sides of a congested interface. All these items can depend on time of day, day of week, season, weather, geography, etc. This price differential can also be justified by comparing historical and forecast prices ($/MBTU) of gas and coal along with unit efficiencies [21].

Validation of the Model

As estimated in Table 5 using the above model, the impact of limit improvement for the entire U.S. is about 14,034 GWh/Yr with corresponding savings of $280M/Yr.

Description	Value
Energy served in the U.S. (from [22])	3.9 * 10^6 GWh/Yr
Average load (Energy / 8760hrs/Yr)	445 GW
Base Load (80% of Average load)	356 GW
1% of base load for entire U.S.	3,560 MW
Effective congested hours (45%)	3942 hr/Yr
Potential Impact	14,034 GWh/Yr
Expected benefit ($20/MWh * 14,034GWh/Yr)	$280 M/Yr
Present worth (5 * Annual value, assuming 20% carrying charge)	$1.4 B/Yr

Table 5: Estimated Impact of Limit Improvement in the US

This is credible when compared to the statistics below:

(i) Energy transfer over congested paths: Energy transferred over the top 20 congested paths of the U.S. Eastern Interconnection during the congested hours was about 107,470 GWh as derived from the results of a DOE simulation [23]. The corresponding number for the Western Interconnection was 38,548 GWh [23]. Note that the benefits are by no means restricted only to the top 20 congested paths.

(ii) Energy schedules actually cut by TLRs: In the Eastern Interconnection 3,468 GWh of energy transfers were curtailed during the 12 months ending 7/31/2004 [24]. Note that the TLRs account for only reductions in previously permitted transactions between control areas and do not capture the impact of transmission constraints on the permission process and on transfers within the control areas.

(iii) Reported Congestion Costs: In 2003, congestion costs were estimated to be $499M in PJM [25] and $688M in New York [26].

B. Reduction of Unserved Energy

This benefit ($/Yr) can be estimated from:

- Value of unserved energy ($/MWh)
- Amount of unserved energy (MWh)
- Expected reduction of unserved energy (%)

The value of unserved energy to the customers is large and extremely variable. The corresponding loss of revenue to the supplier is relatively very small. The value varies with several factors including customer type (e.g., residential customers with inconvenience, commercial customers with disrupted business and industrial customers with loss of productivity and/or damage to unfinished products and production equipment). Reference [27] calculates the value of unserved energy as $24K/MWh for a mixed load of industrial, commercial and residential customers.

Frequency and duration of various types of service interruptions [28,29] are used to derive the parameters (Table 6) used to model reduction of unserved energy.

#	Description	Range	Value Used
1	Service interruptions due to transmission problems (Excluding major disturbances)	6-22 System-minutes [28,29]	10 sys.min.
2	Interruptions during major disturbances	0-133 system-minutes [29]	20 sys.min
3	Reduction in unserved energy	-------	10% of the above
4	Value of unserved energy	$1K-$361K /MWhr[27,30]	$24,000/MWh [27]

Table 6: Parameters for Reduction of Unserved Energy

In the Appendix, we establish a conservative lower bound of 10% reduction in unserved energy due to deployment of the IT infrastructure. Based on Table 6, this translates to a reduction of 1 sys-min./Yr of unserved energy due to non-major disturbances, and 2 sys-min./Yr due to major outages.

Validation of the Model

As estimated in Table 7 using the above model, the reduction of expected unserved energy for the entire U.S. is about 22,563 MWh/Yr. Valuated at $24,000/MWh, this translates to a benefit of about $540M/Yr. This appears to be within a credible range when compared to the cost of the August 14, 2003 blackout estimated to be over $6B [30].

#	Description	Value
1	Energy Served in the US (adapted from [22])	3,953 TWh/Yr
2	Reduction of unserved energy –Non-major events (1 System-Min/Yr), Major events (2 System-Min/Yr), total= 3*energy/(8760*60 min/Yr))	22.56 GWh/Yr
5	Value ($24,000 /MWh x 22,563 MWh/Yr)	$540 M/Yr
6	Present worth (5 x annual value)	$2.7 B

Table 7: Reduction of Unserved Energy for the US

V. Business Cases

As part of the feasibility analysis and to illustrate the application of the methodology and the models in performing a quantitative assessment of costs and benefits the following two distinct situations are considered. The values of model parameters are taken from Sections III and IV. They can be adjusted as needed to reflect the needs of specific analyses.

A. Full-scale Implementation

In order to capture the full cost, a “big bang approach” for a full-scale implementation from ground up is considered as the worst case scenario. The analysis is done for a reasonable size power system consisting of 200 substations and 20 zones/vicinities with 20,000 MW of peak load, 10,000 MW of base-load and 12,500 MW of average load.

Software redeployment costs for all 200 substations, 20 zones/vicinities and a control area with interfaces to regional and grid levels are considered. All necessary productization and shake-down costs are assumed to have been already incurred in previous implementations. Based on this, full implementation costs are estimated as $40M [31] including software redeployment costs ($11.4M), hardware costs ($19.4M) and 30% for system integration costs ($9.2M).

In this case, the costs incurred at region and grid levels would be rather small. Even for a full implementation at those levels, their costs would still be relatively small when distributed over all substations. Therefore the total cost is almost linear with the number of substations.

The benefits for this system are calculated using the models described in Section IV. Table 8 and Table 9 outline the calculation of the expected benefits due to reduction in production costs and unserved energy respectively. Considering a 20% carrying charge, the present worth of the two benefits are evaluated as $39.42M and $75M respectively. These conservatively calculated benefits far exceed the total cost of implementing the IT infrastructure. These results can be scaled up or down for other size systems.

#	Description	Value
1	Congestion relief= 1% of base load	100 MW
2	Congested hours (45%)	3942 hrs/Yr
3	Impact of improvement	394,200 MWh
4	Value of improvement (@$20/MWh)	$7,884,000/Yr
5	Present worth (5 x annual value)	$39.42 M

Table 8: Reduction in Production Costs for Full-Scale Case

#	Description	Value
1	Avoided unserved energy – Non-major events (1 Sys.Min/Yr = 12,500/60)	208 MWh/Yr
2	Avoided unserved energy – Major events (2 Sys.Min/Yr = 2 x 12,500/60)	416 MWh/Yr
3	Total avoided unserved energy	624 MWh/Yr
4	Total expected savings (@$24k/MWh)	$15M/Yr
5	Present worth (5 x annual value)	$75 M

Table 9: Reduction in Unserved Energy for Full-Scale Case

B. Partial Implementation

This case estimates the costs for partial implementations in specific locations for addressing specific known problems using an advanced IT infrastructure incorporating some of the “traditional” solution concepts. Such implementation starting with a handful of substations in a few “high-benefit” problem locations can serve as a catalyst to full scale evolutionary implementation of the IT infrastructure for the entire system. In this approach, each solution should conform to the design requirements of a comprehensive infrastructure.

Two specific problems are considered. The first problem involves reduction of transfer limit in an EHV corridor by 1000 MW to cover EHV outages. The second problem involves the need for expensive combustion turbines (80 MW each) to avoid voltage collapse due to transmission outages. In each case, most of the benefit can be realized by upgrading IT infrastructure at 3 substations and their zone/vicinity. The total cost for the three substations and one zone/vicinity is under $400K based on the cost models of Section III.

However, the benefits associated with the two problems are significantly different. In the first problem it is estimated that limit reduction could be avoided for 613 hours/year using an advanced intelligent control scheme where the present worth of the resulting benefits would be $61.3M [32]. Faster control devices (e.g. add 100MVA capacitors with FACTS controls for 10MVA and/or intelligent rapid generation reduction on the sending end) to avoid such reduction of the interface limit may cost about $2.2M leaving about $59M net benefits.

In the second problem, it is estimated that CT operation can be avoided in 402 hours/year leading to benefits with present worth in the order of $3.2M [32]. New and faster control devices (e.g., FACTS based control for about 4% of the 80MW capacity i.e. 3.2 MVA) can be implemented at about $0.6M leaving $2.6M as the present worth of net benefit.

In general, costs are roughly proportional to the number of substations monitored where as the benefits are proportional to the magnitude of the loads. Therefore the benefit-to-cost ratio becomes more favorable (as high as 20 in some cases) as the magnitude of the affected load increases.

VI. FINANCIAL FEASIBILITY ANALYSIS

The cost and benefit models of earlier sections are used to develop an empirical model presented graphically in Figure 6. This model shows the various estimated costs and benefits for full-scale implementation as a function of the number of substations. In the model, an average substation is assumed to have a peak load of about 100 MW. The present worth of benefits is calculated as 5 times the annual value, assuming a 20% carrying charge. The model can be used as a reference for assessing costs and benefits for other systems. Various lines in the figure depict the following:

- Line A shows the full cost of implementation including the four costs components: 1) One-time R&D cost for the industry as a whole, 2) The one-time shake-down cost, 3) The cost of software implementation and integration and 4) The cost of hardware.
- Line B shows the total cost for the first implementation after the prototype is already demonstrated, thus eliminating the risk associated with R&D. To be exact, lines A and B should be augmented by segments showing higher costs for the shake-down at the first 5 zones/vicinities, and the first 10 substations. However, the resolution available in the figure is not sufficient to show the segments. The shake-down cost at the area level is just a constant because only one control area is included in these costs.
- Line C shows the costs for later implementations, thus excluding the costs of R&D and shakedown, but including hardware, software implementation and integration costs.

- Line D shows the costs of later implementations excluding the costs of R&D, shakedown and hardware, but including only the software implementation and integration costs.
- Line E shows the benefits associated with production cost improvements.
- Line F shows the total benefits including avoided unserved energy and production cost improvements.
- Line G shows the total benefits (as given by Line F) discounted by the cost of expected new control equipment that may be required to reap the benefits.

Figure 6 suggests that the benefits are proportional to the number of substations. The proposed IT infrastructure can be justified for a system of 12,000 MW peak load at a cost of $65M (see intersection of benefit line F and cost line A). When additional new control equipment is required, the entry barrier is higher but breaks even for a larger system of 25,000 MW peak load at a cost of $90M (see the intersection of benefit line G and cost line A). Other utilities following on the heels of the first implementation face a lower entry barrier that can be justified for systems of peak load in the range of 8,000 to 16,000 MW, at a cost of $44M (intersection of benefit line F and cost line B) to $60M (intersection of benefit line G and cost line B). Later implementations can avoid the R&D and shakedown costs. The resulting reduction in the entry barrier would make it financially feasible for a system of 2,000 MW peak load at a cost of $3M to $4M (see benefit line E and cost line C). At this point, potentially hundreds of utilities around the world will be interested in implementing the infrastructure. As hardware costs go down, and all components become "plug and play", eventually smaller municipal utilities or even individual large customers can afford the infrastructure at a cost of $3M or less (see cost line D). In systems of all sizes, the production cost savings alone can compensate for most if not all of the costs of hardware and system integration (see benefit line E and cost line C).

The cost of software R&D is the biggest "entry barrier" for implementations. The estimated cost of initial development of the required software modules or intelligent agents would be in the order of $8M for prototype development, and $27M for production grade development. These costs are negligible compared to the expected benefits. Once the first implementation is accomplished the "entry barrier" at the control area level would be in the order of about $3M which is similar to the conventional control center budgets.

After the first few implementations, the "entry barrier" at the substation level would be about $183k per substation including both hardware and software. This cost may go down to as low as $58k as the cost of hardware reduces.

A similar analysis is made to compare the costs and benefits associated with implementing self-healing capabilities at a single substation [32]. Results indicate that problem-specific implementations can be feasible for substations with capacity in the range of 30 MW and up. With steadily decreasing computing costs and truly "plug and play" components, this barrier may go down even further, thus virtually guaranteeing grid-wide penetration.

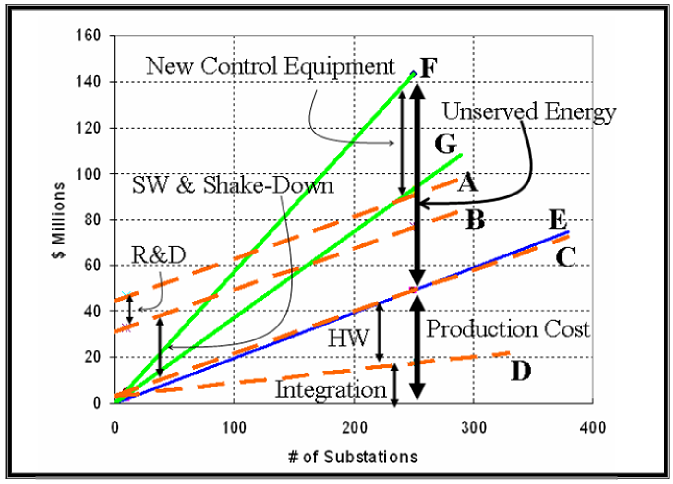

Figure 6: Costs & Benefits for Full Scale Implementation

VII. Conclusions and Recommendations

In essence, the realization of self-healing capabilities requires a high performance IT infrastructure [1,2]. To process information and provide timely responses to fast unfolding events, intelligence should be made available locally, but also coordinated at higher levels, thus a distributed hierarchical control system is needed for an intelligent grid. Such infrastructure responds to actual steady-state as well as transient operating conditions in real-time and near real-time. This would make it distinctly more effective than conventional solutions that are generally based on off-line analyses. The modular and distributed design of the infrastructure allows for lower overall cost of adapting the solution throughout the grid as opposed to conventional special protection schemes targeted to specific problem locations.

This paper presents a general methodology and scalable framework to analyze costs and benefits for investigating the financial feasibility of the research, development and field implementation of an IT infrastructure to realize a self-healing power grid. The focus is on IT based intelligent solutions with emphasis on the advanced control strategies enabled by the global coordination of distributed intelligence.

The greatest benefit of self-healing capabilities is in "taming" the "unruly" power grid. To be certain that the estimated benefits are conservative, the focus is kept on intelligent solutions for prevention and containment of more predictable disturbances (based on industry statistics). However the same intelligent solutions would result in dramatic impact on system behavior during the extremely large-scale blackouts such as the August 14, 2003 event.

The key contributions of this paper are:

- Development of a systematic and general methodology to capture salient aspects of the very broad scope of self-healing capabilities and concepts and translate them into quantifiable cost and benefit models.
- Development of a scalable framework of models that can be used to assess reasonable "upper bounds" on costs associated with specific localized solutions or system-wide implementations. The models can be tailored to include or exclude specific cost components for identifying the breakeven points and the "entry barriers" for various implementation approaches.
- Identification of significant cost components in the categories of functional agents, IT hardware (measurement, communication and computing), control equipment and system integration.
- Identification of financially significant benefits and development of corresponding quantifiable models for analysis. The key benefits are improvement of production costs/market efficiency, and reduction of unserved energy.
- Validation of the models against industry statistics.
- Analytical justification of model parameters.
- Development of an empirical model to facilitate feasibility analysis based on lower bound on benefits and upper bound on costs. The empirical models can be used to assess representative costs for full-scale (e.g., system-wide) and/or limited (e.g., substation or problem specific) implementations.

The feasibility analysis indicates that the first implementation would substantially bring down the "entry barrier" for the remaining utilities to a level comparable to traditional control centers. This combined with the steady decline of the cost of computing power virtually guarantees the grid-wide penetration of self-healing capabilities. In addition, the value of the benefits continue to increase as the economy and quality of life become more dependent on a reliable power grid, thus decreasing the entry barrier. When extrapolated to the entire U.S. the benefits would be in billions of dollars making the initial costs of $65M for R&D and the first implementation almost negligible.

The major conclusion of this paper is that once past the initial R&D, productization and shake-down investments, the grid-wide penetration of self-healing capabilities would be inevitable. It is our belief that this conclusion remains valid and unaffected by any reasonable changes in the specific values of the parameters used in the calculations.

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X. Biographies

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APPENDIX:

Justification of Benefit Model Parameters

The following two benefit model parameters used in are justified analytically:

1. An improvement of 1% in operating limits (~31.5 sys-hrs/year if only 45% of the hours are considered)
2. A reduction of 10% in expected unserved energy (equivalent to 1 system-minute/year)

A. Problem Definition

Several load center configurations with prescribed number of alternate paths to deliver power were considered [32]. In each configuration, the normal thermal ratings of the paths are selected to meet the following common design criteria:

- Keep the unserved energy at 10 system-minutes/Yr.
- Even with one of the paths unavailable, the remaining thermal capacity should be adequate to carry peak load.

However if additional line outages result in violation of a stability limit, the transfer limit is reduced before the outages actually happen. To estimate the potential for avoiding such pre-contingency reduction in each configuration, one has to consider the probability of having various number of lines being in service. For each possibility, one can then estimate the operating limit improvement as the difference between the corresponding normal thermal limit (based on N paths in service) and stability limit (based on N-1 paths). A weighted average of the improvements can be calculated and normalized to be expressed in terms of expected system-hours.

In addition, one can calculate the mean and standard deviation of the available transmission capability subject to all the considered possibilities. Given the mean and standard deviation of the load at the load center, one could use the cummulant method [33] to calculate the expected unserved energy for the configuration. The unserved energy calculation can be done twice, first considering only normal thermal limits and then with only stability limits. The difference between the two values represents the reduction in unserved energy.

B. Results

The above procedure is applied to each configuration using primary inputs adapted from industry statistics [19,22,34,35]. The impact in each configuration is then calculated and the results are presented in Table A-1 below.

Number of alternate paths	Total Thermal Capacity (MW)	Impact of Limit Improvement (Sys. Hrs)	Unserved Energy (in Sys. min./Yr)		Reduction in Unserved Energy (%)
			Without self-healing	With self-healing	
<=3			Need SPS/RAS		
4	3206	676.36	10.02	0.03288	99.7
5	2724	252.75	10	0.4137	95.9
6	2487	34.77	10.03	2.404	76.0
7	2338	2.98	9.98	8.216	17.6
8	2298	0.31	10	9.74	2.6
>=9	< 2278	< 0.04	10.0	> 9.966	< 0.4

Table A-1: Analytical Justification of Parameters

As expected, with less than 4 alternate paths, the required design criterion cannot be met without special protection schemes (as is usual practice at large substations). However, in a self-healing grid such capability is provided wherever and whenever needed. The impact of limit improvement and reduction of unserved energy are significantly better than the values of 31.5 system-hours and 10% used in our benefit models whenever the number of alternate paths available is 6 or less. Load centers with 7 or more alternate paths are rare. The configurations considered are benign enough to be regarded as "systems with no problems". Therefore the benefits in practical systems are bound to be better.