CURSO EN INGENIERÍA DE SUBESTACIONES ELÉCTRICAS DE POTENCIA

Septiembre 2004

SISTEMAS DE TIERRA EN SUBESTACIONES ELÉCTRICAS

CONFERENCISTA:
ING. RODOLFO LORENZO BAUTISTA

MEMORIA DE CÁLCULO

RED DE TIERRAS SUBESTACIÓN 13.2 kV

POZO CNA 966

RANCHO TEPETATILLO

NORMA IEEE Std 80 – 2000

Objetivo

Verificar que los potenciales de contacto y de paso en la red de tierras de la subestación del pozo CNA 966 (Rancho El Tepetatillo), no excedan los valores límite de los potenciales tolerables por el cuerpo humano.

Verificar también que la resistencia a tierra de la red se encuentre dentro del rango de valores recomendados por las normas.

Procedimiento

Basado en la Norma IEEE Std 80-2000 Guide for Safety in AC Substation Grounding.

Referencias

Plano: Sistema de tierras. Pozo CNA 966 Rancho El Tepetatillo.

La red de tierras se construirá en un área de 14 m de ancho y 16.30 m de longitud, fuera del perímetro del área de la subestación como se muestra en el plano.

Contribución de corriente de falla monofásica de la Comisión Federal de Electricidad en el punto de acometida

Se ha considerado la contribución de potencia de corto circuito monofásico en el punto de acometida igual a 100 MVA (4373.86 Amperes) con una relación X/R de 10.0.

Se considerará para los cálculos una corriente de 4375 Amperes simétricos.

Datos para el cálculo

Corriente de falla	4375 A
Resistividad del terreno	30 Ω m
Resistividad superficial (Grava triturada)	3000 Ω m
Profundidad de la red	0.5 m
Espesor de la capa de grava.	0.10 m
Longitud de red	16.3 m
Ancho de red	14.0 m
Área de la red	228.2 m^2
Tiempo de duración de la falla	0.5 seg.
Relación X/R en acometida	10.0
Longitud de varillas	3.0 m
Diámetro de varillas	0.0159 m

Diseño de la red

Cálculo de la sección del conductor de la red:

Factor de decremento (Asimetría):

Constante de tiempo subtransitoria equivalente:

$$T_a = \frac{10.0}{120\pi} = 0.0265 seg$$

Tiempo de duración de la falla:

$t_f = 0.5 seg$ (30 ciclos)

Factor de decremento:

$$D_f = \sqrt{1 + \frac{0.0265}{0.5}\left(1 - e^{-\frac{2(0.5)}{0.0265}}\right)}$$

$D_f = 1.0262$

Factor de proyección C_P:

No existe incremento futuro de la corriente de falla: $C_P = 1$

Corriente máxima de malla:

$I_G = 4375 \times 1.0262 \times 1.00 = 4489.62$ A

Sección de conductor:

Conectores mecánicos $T_m = 250$ grados C

Fórmula simplificada

$A_{KCM} = I \cdot K_f \cdot \sqrt{t_c}$

De tabla 2 de la Norma, el factor de multiplicación K_f es 11.78

A = 4489.62 x 11.78 x 0.7071 = 37397.26 cmil = 37.39 kCM

El conductor de cobre calibre 4 AWG tiene 41.74 kCM de sección.

Se empleará por resistencia mecánica el calibre 4/0 AWG (211.6 kCM) con diámetro de 0.0134 m.

Cálculo de potenciales tolerables

Factor de reducción C_S

$$\text{Factor de reflexión} = \frac{30 - 3000}{30 + 3000} = -0.98$$

De la figura 11 de la Norma:

Factor de reducción C_S = 0.68

Calculando el valor de C_S:

$$C_S = 1 - \frac{0.09\left(1 - \frac{30}{3000}\right)}{(2x0.1) + 0.09} = 0.6928$$

Potenciales tolerables

Paso:

$$E_S = [1000 + 6(0.68)3000]\frac{0.157}{\sqrt{0.5}}$$

$$E_S = 2939.69V$$

Contacto:

$$E_T = [1000 + 1.5(0.68)3000]\frac{0.157}{\sqrt{0.5}}$$

$$E_T = 901.44V$$

Diseño inicial

Disposición de conductores y varillas

Conductores paralelos	4
Conductores transversales	5
Varillas de tierra	4

Resistencia a tierra de la malla

Longitud de conductores: (4 x 16.3) + (5 x 14) = 135.20 m

Longitud de varillas: 4 x 3.00 = 12m

L_T = 135.20 + 12.0 = 147.20 m

Área = 16.3 x 14 = 228.2 m^2

$$R_g = 30\left[\frac{1}{147.2} + \frac{1}{\sqrt{20x228.2}}\left(1 + \frac{1}{1 + 0.5\sqrt{\frac{20}{228.2}}}\right)\right]$$

$$R_g = 1.0347\Omega$$

Corriente máxima de malla

I_G = 4375 x 1.0262 x 1.00 = 4489.62 A

Cálculo de GPR

I_G = 4489.62 A y R_G = 1.0347 Ω

GPR = 4489.62 x 1.0347 = 4645.40 V

4645.40 > 901.44 V

Cálculo de potenciales en la malla

Cálculo del valor de "n":

$$n_a = \frac{2x135.20}{60.6} = 4.462$$

$$n_b = \sqrt{\frac{60.6}{4x\sqrt{228.2}}} = 1.0014$$

$$n_c = 1.0$$

$$n_d = 1.0$$

$$n = 4.462x1.0014x1.0x1.0 = 4.468$$

Cálculo de K_{ii}:

K_{ii} = 1.0

Cálculo de K_h:

$$K_h = \sqrt{1+0.5} = 1.2247$$

Cálculo de L_M (Para calcular E_M):

$$L_M = 135.20 + \left[1.55 + 1.22\left(\frac{3.0}{\sqrt{16.3^2 + 14^2}}\right)\right]x12 = 155.84m$$

Cálculo de L_S (Para calcular E_S):

L_s = (0.75 x 135.20)+ (0.85x12)= 111.6m

Cálculo de K_m:

$$K_m = \frac{1}{2\pi}\left[Ln\left(\frac{4.66^2}{16x0.5x0.0134} + \frac{(4.66+2x0.5)^2}{8x4.66x0.0134} - \frac{0.5}{4x0.0134}\right) + \frac{1}{1.2247} Ln \frac{8}{2x4.468-1}\right]$$

$$K_m = \frac{1}{2\pi}[Ln(202.57+64.28-9.328)-0.928]$$

$$K_m = 0.7357$$

Cálculo de K_i:

K_i = 0.644 + (0.148x4.468) = 1.3053

Cálculo del potencial de malla

$$E_m = 30x0.7357x1.3053x\frac{4489.62}{155.84}$$

$$E_m = 829.97V$$

Cálculo de potencial de paso:

$$K_S = \frac{1}{\pi}\left[\frac{1}{2x0.5} + \frac{1}{4.66+0.5} + \frac{1}{4.66}\left(1-0.5^{2\ 468}\right)\right]$$

$$K_S = 0.436$$

$$K_i = 0.644 + (0.148x4.468) = 1.3053$$

$$E_S = 30x0.436x1.3053x\frac{4489.62}{111.6}$$

$$E_S = 686.85V$$

Comparación entre el potencial de malla y el potencial de contacto tolerable

829.97 < 901.44 V

Comparación entre el potencial de paso en la malla y el potencial de paso tolerable

686.85 < 2939.69 V

Resumen de resultados

La malla tiene una R_g menor a 5 Ohms (subestaciones de distribución), por lo que el diseño cumple con los requerimientos del Artículo 14 de la Norma IEEE Std 80-2000. Asimismo, los potenciales de malla y de paso son menores que los potenciales tolerables, por lo que el diseño cumple con el Artículo 16 de la Norma anterior.

SUBESTACIONES Y COORDINACIÓN DE AISLAMIENTO

CONFERENCISTA:
ING. RAFAEL GUERRERO CEPEDA

AISLAMIENTO: GUIA DE PENSAMIENTO

1: MATERIALES

SOLIDOS: ALGODÓN, SEDA, PAPEL, MICA, VIDRIO, PORCELANA, CUARZO, PLÁSTICOS, CAUCHO MADERA Y OTROS.
LIQUIDOS: ACEITE, ASKARELES ....
GAS: AIRE, SF_6
OTROS: SILICON, VACIO.

2: MECANISMO DE LA FALLA:

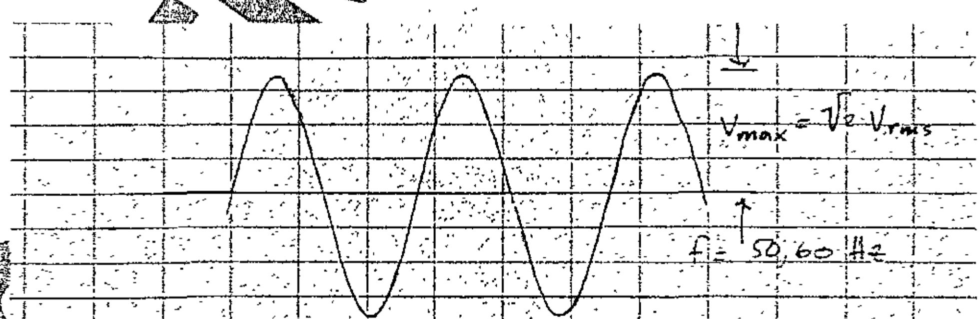
AISLAMIENTO AUTORECUPERABLE: puede recuperar totalmente sus propiedades aislantes después de una descarga violenta (que vence la resistencia del aislamiento).
ASILAMIENTO NO RECUPERABLE: queda dañado permanentemente por la descarga violenta.

3: TIPO:

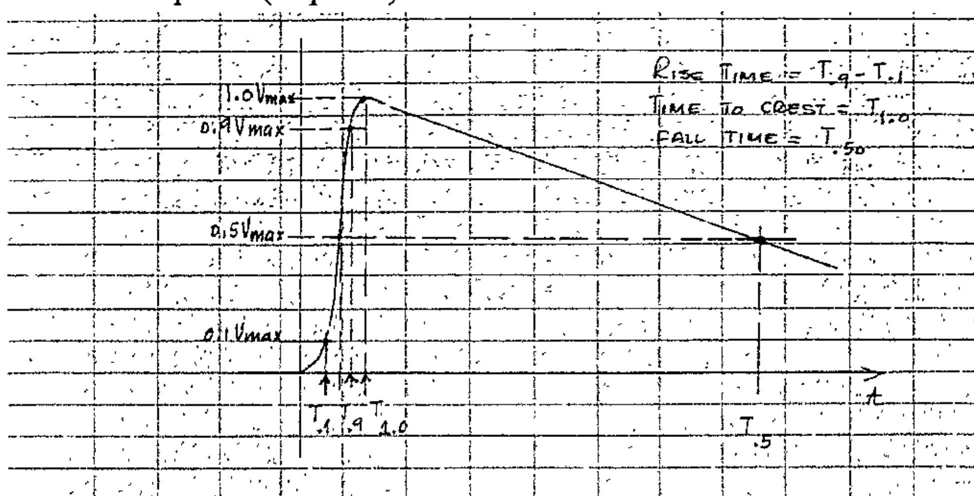
INTERNO: cualquier tipo de aislamiento protegido contra condiciones atmosféricas directas.
EXTERNO: cualquier tipo de aislamiento expuesto a las condiciones atmosféricas: precipitación variable, humedad, etc.

4: PRUEBAS

A: ONDAS DE PRUEBA:
1: En estado estable



2: De pulso (impulso):



a) Descarga atmosférica 1.2/50 μ seg. (la onda de corriente: 8/20 μ seg.

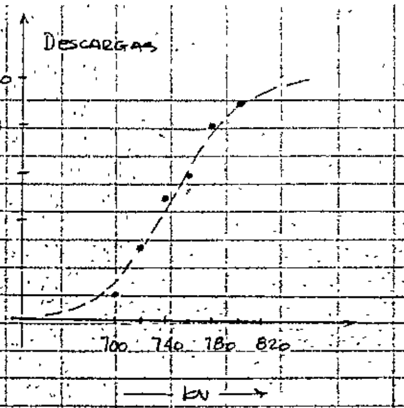
b) Switcheo. 250/2500 μ seg
100/2500 μ seg
500/2500 μ seg

B.

Imaginemos la siguiente prueba: una cadena de aisladores se somete a una serie de impulsos consecutivos (10) de 250/2500 μ seg, cada uno separado por un tiempo considerable (10 seg) para permitir la dispiación el aire ionizado. Cada pulso puede ocasionar dos posibles eventos (acontecimiento de realización incierta); o se produce la descarga súbita porque se vence la resistencia del aislamiento, o no pasa nada. Después de que los 10 impulsos o pulsos se han aplicado, el voltaje se aumenta (la cresta) y se repite el ciclo.

Supongamos los siguientes resultados:

VOLTAJE (Cresta)	DESCARGAS #
700	1
720	3
740	5
760	6
780	8
800	9



Podemos proceder (usar la información) de dos maneras:

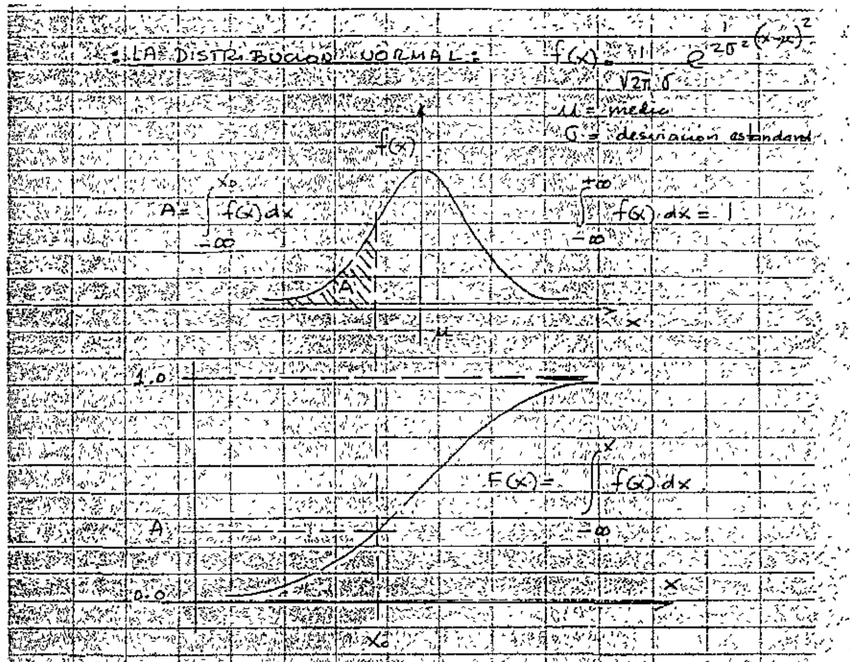
1. Podemos pensar que los datos han revelado la distribución <u>exacta</u> de ***fallas vs voltaje*** y por lo tanto, de ahí en adelante, deben usarse para todos los análisis posteriores.

2. Podemos pensar que los datos se apartan de una distribución normal (Gaussiana) de fallas vs voltaje y, por lo tanto, pudieran o debieran usarse para determinar la media (μ) y la desviación estandar (σ) para una distribución normal.

El problema con (1) es que resulta perfectamente demostrable que está mal. Si repetimos la prueba no obtendremos, en general, la misma distribución.

El problema con (2) es que es perfectamente demostrable que está bien. La experiencia vivida con las pruebas de aislamiento, no lleva a creer que aunque (2) no sea rigurosamente cierta, no es irazonable proceder con esta suposición. Podríamos escoger el procedimiento (2), por lo que se dijo y porque es matemáticamente cierta..

La Distribución Normal



CFO = 745 kV

CFO – σ = (745 – 40) = 705 kV

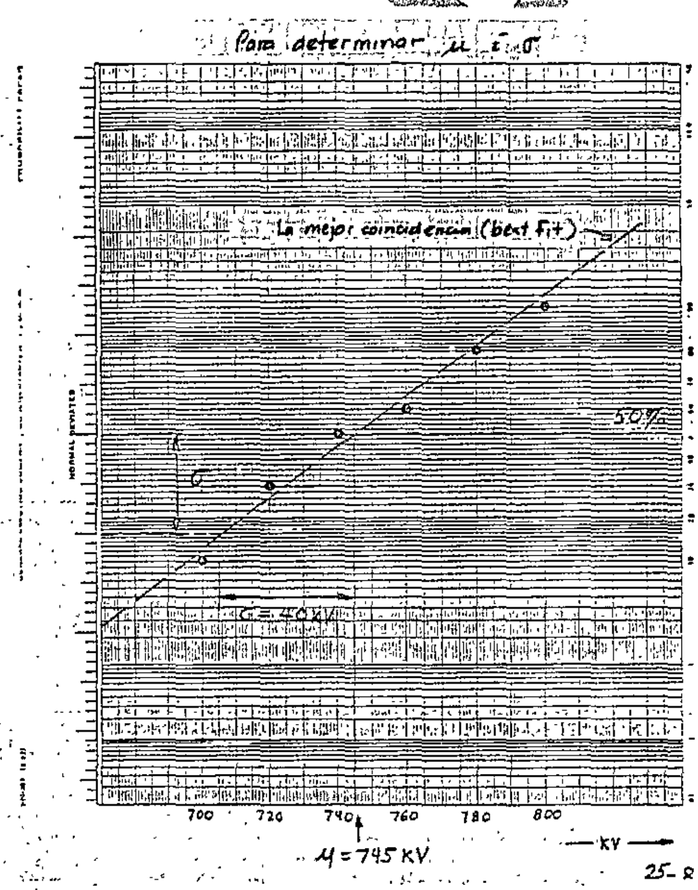
$$\sigma = \frac{745 - 705}{1} = 40 \text{ kV}$$

$$\sigma = \frac{40}{745} = 0.054 \quad \text{O sea:} \quad 5.4\ \%$$

Algunos valores interesantes:

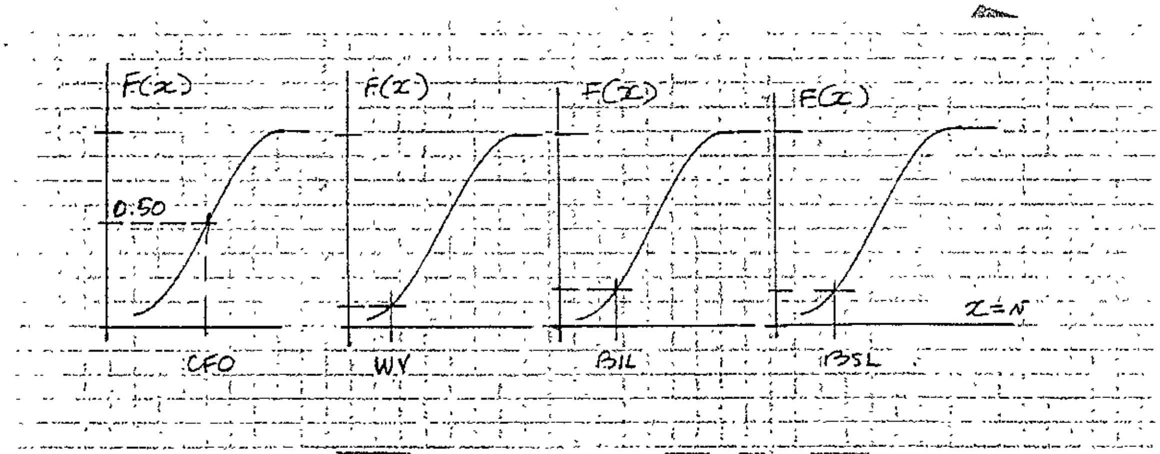
x	$\frac{x-\mu}{\sigma}$	F(x)	
μ	0.	0.500	
$\mu - \sigma$	–1.	0.1587	
$\mu - 2\sigma$	–2.	0.0228	
$\mu - 3\sigma$	–3.	0.0013	(0.13 %)
$\mu - 2.237\sigma$	–2.237	0.01	
$\mu - 1.645\sigma$	–1.645	0.05	
$\mu - 1.282\sigma$	–1.282	0.10	(10 %)

Nuestro problema:
Se tiene o conoce F(x). Deseamos que nuestros datos encajen en una distribución normal (escoger μ y σ). Un método simple es usar papel papel probabilistico:



Definiciones:

CFO – La tensión de cresta para la cual la probabilidad de descarga es de 50%
WV – (Withstand Voltage). La tension de cresta 3σ abajo del CFO
BIL – Basic Lightning Impulse Insulation Level. La tension de cresta para la cual la probabilidad de descarga es 10% usando un pulso de prueba de 1.2/50 μ seg.
BSL – Basic Switching Impulse Insulation Level. La tension de cresta para la cual la probabilidad de descarga es 10% si se usa un pulso de prueba de 250/2000 μ seg.



Para nuestro ejemplo:

$$CFO = \mu = 745 \text{ kV}$$
$$WV = 745 - 3(40) = 625 \text{ kV}$$
$$BSL = 745 - 1.282(40) = 649 \text{ kV}$$

Para calcular el BIL necesitaremos resultados de prueba con pulso de 1.2/50 µ seg.

Nota muy importante: para el aislamiento no renovable el BIL ó BSL es el voltaje máximo para el cual el aislamiento no tendrá descargas súbitas, por vencimiento de la resistencia de aislamiento, cuando se somete a un número específico de pulsos estandar.

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IDEARIO

COMENTARIOS: Coordinar el aislamiento es una actividad muy subjetiva.
Por una parte, sobre_aislar resulta muy caro.
Por la otra, bajo_aislar resultara, siempre, extraordianariamente caro y además catastrófico
El equilibrio justo es a lo que debe aspirar un buen criterio de ingeniería.

CIERTAS IDEAS:

Temas interesantes ligados con la coordinación del aislamiento.

- Protección contra impulsos
- TRV's
- Estudios especiales: Acoplamientos
  Transposiciones
  Blindajes
- Maniobras de switcheo
- Desenergización de líneas
- Inicio y libramiento de fallas
- Determinación del riesgo
- Evaluación del riesgo
- Etcétera.

ESPECIFICACIÓN DEL EQUIPO

ONDAS: comentarios (restantes)

La curva (3) se usa para someter a esfuerzos al aislamiento como si hubiera existido una descarga atmosférica; se especifica porque es imposible reproducirla.
Esfuerza el aislamiento entre vueltas en función de la capacitancia entre espiras.

La curva (1): el aumento rápido del voltaje y su colapso posterior esfuerza al bushing, a las guías y a las primeras vueltas del devanado

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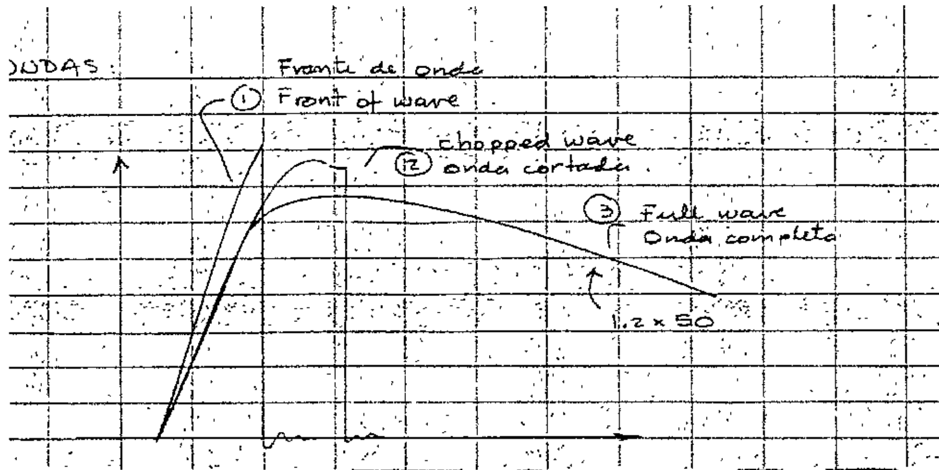


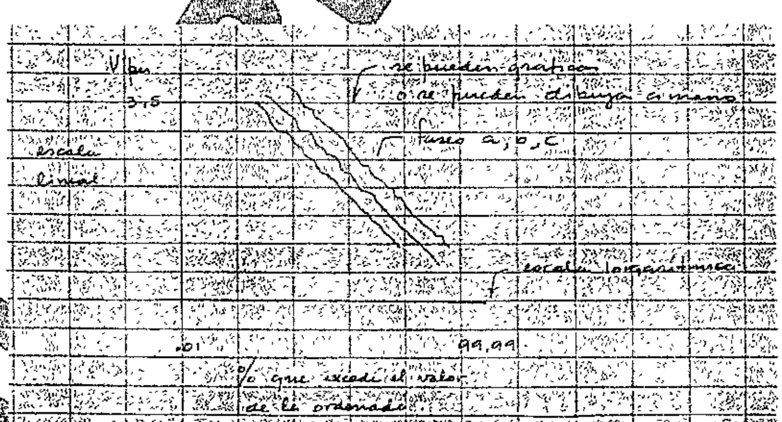
(1) y (2) se traen a cero mediante la descarga de un gap

La curva (2) impone un esfuerzo diferente dado que tiene tiempo para penetrar en el aislamiento, antes de que se produzca el colapso del voltaje. Consecuente mente, la mayor parte del aislamiento se ve afectada por esta prueba.

La onda (4) es de switcheo. Tiende a acoplarse inductivamente a través del transformador. Aplicada a un devanado, se aparece en el otro o los otros devanados, esencialmente, en forma proporcional al número de vueltas.

MAS SOBRE LA ESTADÍSTICA

Algo que se puede obtener con el #WAVE:



Pregunta: PFO = 0.50 % es aceptable ?

0.5 PFO quiere decir que de 200 cierres (por ejemplo) se espera una descarga

- si la línea cierra 2 veces al día
- cierra 700 veces al año
- 3 ó 4 descargas/año son tolerables ?

- si la línea cierra 10 veces al año
- se presentará 1 falla en 20 años

Ahora: PFO = 0.50 %

$SS_{max} = 3.89 \text{ pu} = 3.89 \times 326.6 = 1269.60$ kV

PFO = 0.50 % (a 2.58 sigmas).

Si aplicamos un onda de 1270 kV:

$$CFO - CFO \times 0.06 \times 2.58 = 1269.6 \cong 1270 \text{ kV}$$
$$CFO = 1502 \text{ kV}$$

Esto considerando que $\sigma_{CB} = 6\ \%$

Bien, si CFO = 1502 kV, ¿ cuanto vale 10% PFO ?

(10% PFO) está a 1.29σ de la media; por lo tanto:

$$(10\%\ PFO) = CFO(1 - 0.06 \times 0.06 \times 1.29) = 1386 \text{ kV}$$

Comentarios sobre la selección: tenemos en la bodega un interruptor con PFO =1175 kV (se requieren 1386); ¿ que pasa si se usa ?

$$\left[\frac{\mathbf{ss - CFO}}{\mathbf{CFO \times sigma}}\right] = \#\sigma \quad \text{lejos de la media}$$

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$$= \frac{1269.6 - 1273.6}{1273.6 \times 0.06} = -0.500 \quad \text{que equivale a 48 \% del PFO}$$

48% de PFO es inaceptable. Sin emabrgo la máxima sobretensión (3.89 pu) casi nunca ocurrirá (1 en 50) por lo que hay que extender el análisis estadístico.

Criterio monofásico

Se dispone de la siguiente tabulación:

Cierre	A	B	C	Máxima	
1	2.115	3.107	2.029	3.107	
2	1.862	2.574	1.953	2.574	
3	2.381	1.997	2.319	2.381	
⋮					
50	2.352	1.874	2.087	2.352	← máximos separados

Considerando que:

- La probabilidad asociada con cada cierre es 1/N (N=50)
- Si calculamos el PFO asociado con cada maximo (como lo hicimos para 3.11 pu)
- Si multiplicamos el PFO por la probabilidad de que ocurra la onda (1/N)
- Y si sumamos los resultados
- Obtendremos una estimación más realista

Sin embargo, para obtener mejores resultados, deberán correlacionarse las <u>tres</u> fases. Es decir, considerando la probabilidad de que cualquiera de las tres fases descargue:

$$\text{PFO}_{3\text{ Fases correlacionadas}} = \frac{1}{\mathbf{N}}\sum(1-(1-\mathbf{pfo_a})(1-\mathbf{pfo_b})(1-\mathbf{pfo_c}))$$

donde: pfo_x = PFO para una fase dada considerando la sobretensión aplicada a esa fase específica

Así, para CFO de 2.5 pu, σ = 6 % tendríamos:

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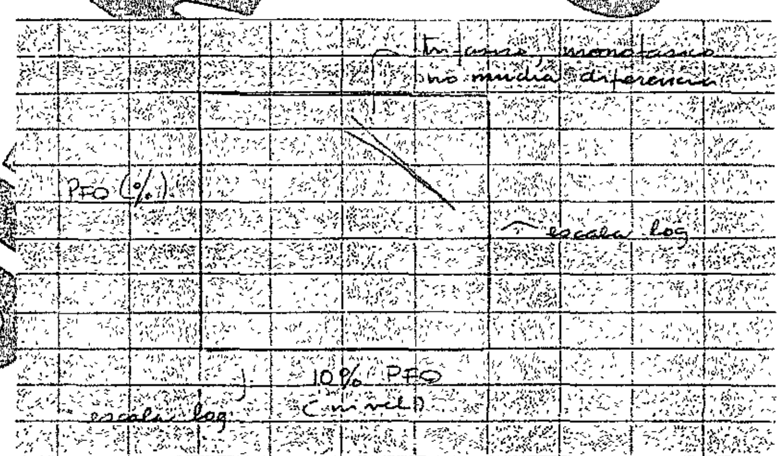
	pfo_a	pfo_b	pfo_c	pfo_{cierre}	Σ
1	0.00013	0.99396	0	0.99396	0.99396
2	0.	0.21770	0	0.21770	1.2166
3	0.02442	0.	0.00939	0.03358	1.24524
⋮					

La suma total (3 cierres en este caso) daría:

$$1.24524/3 = 0.41508$$

41.5 % indica claramente que hay que subir el aislamiento.

USO DE LAS GRAFICAS:
Figura (1):



Observación: entre el análisis trifásico y monofásico no se percibe gran --- diferencia.

Figura (2):
Si en lugar del 3.89 pu, que da un 10% PFO = 1386 kV, pensamos lo siguiente: el 10% PFO para un PFO de 0.50 % se ubica cerca de 1250 kV. Este no Está tan lejos del 1175 que es mucho menor que 1386 kV.

Figura (3):
PFO para 1175 kV se lee como de 2 pu (quiere decir una descarga para 50 cierres).

Otro modo: $\dfrac{\mu - \mathbf{CFO}}{\sqrt{\sigma_{ss}^2 + \sigma_{\mathbf{Aisl}}^2}} = \#\sigma$ lejos de la media para una distribución Gaussiana

Si $\mu = 3.08$ pu $= 1004.7$ kV con $\sigma = 0.24$ pu (97.98 kV)

se obtine: $\dfrac{1004.7 - 1273.6}{(98^2 + 76.4^2)^{1/2}} = -2.16\,\sigma$ que da 1.5 % PFO. Esto vale si se tienen distribuciones Gaussianas.

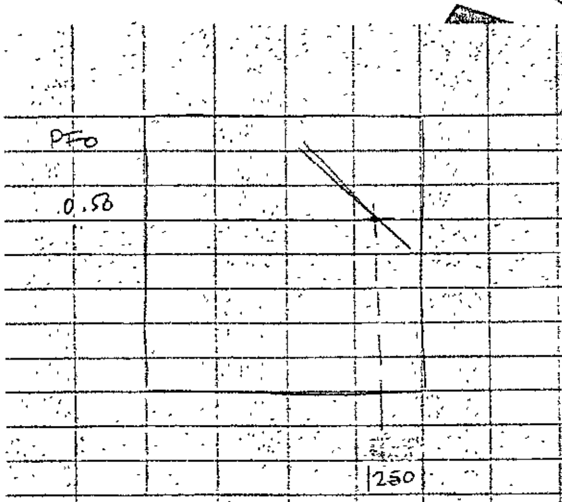


Figura 2

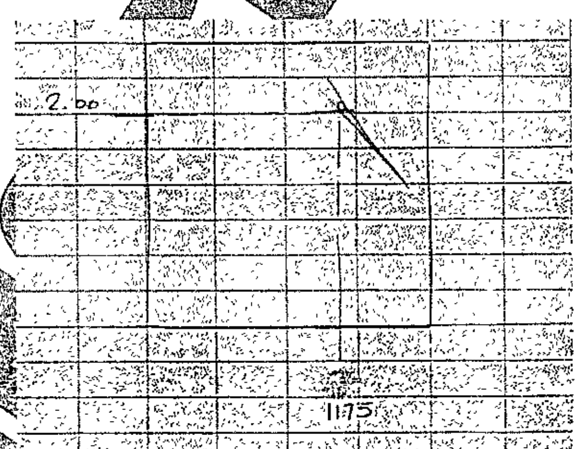


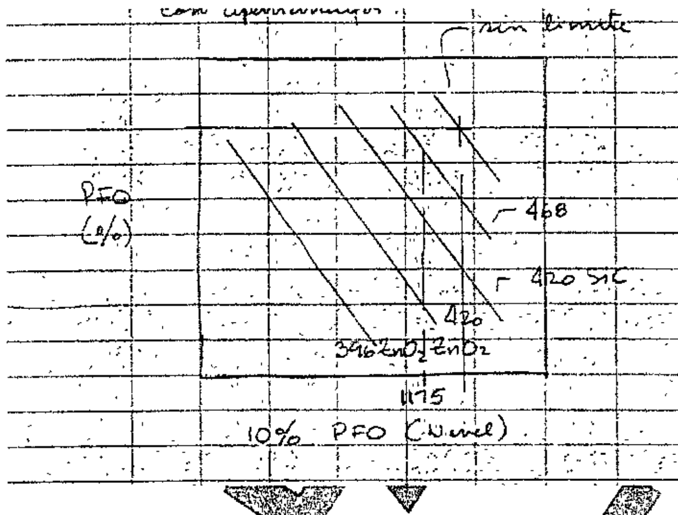
Figura 3

APLICACIÓN DE RESISTENCIAS Y APARTARRAYOS

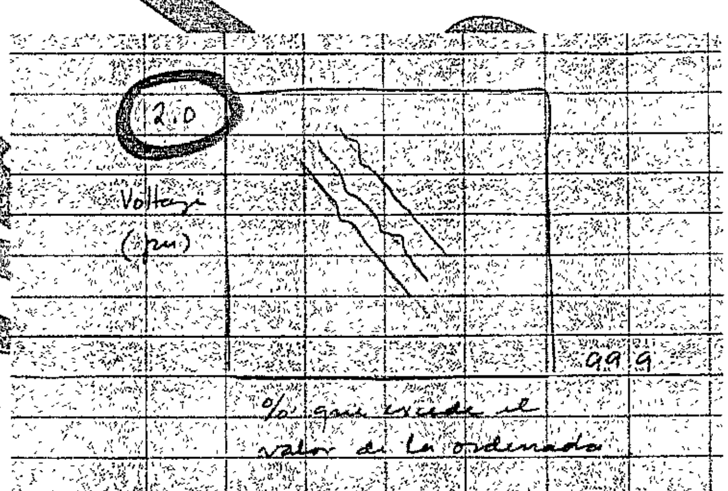
En la Figura siguiente se puede observar la clase de curvas que se obtiene con apartarrayos.

El cálculo correlaciona las tres fases. 1175 kV daría, por ejemplo, 0.009 PFO

espacio en blanco intencional

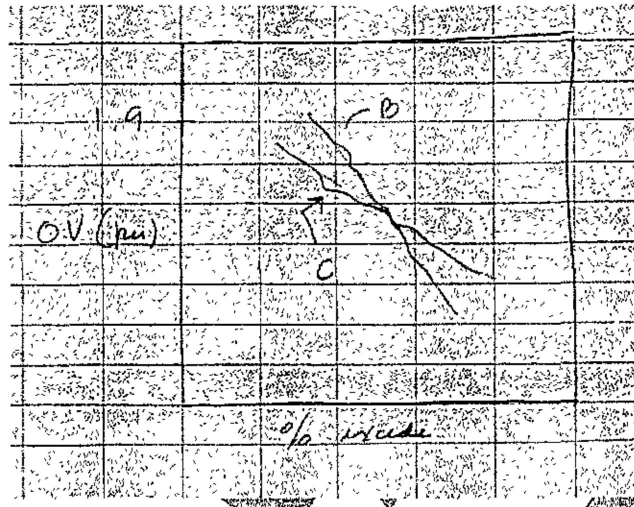


La siguiente Figura muestra lo que ocurre si se usan resistencias. Por lo que se nota, se reducen μ ε σ. Esto equivale a decir que se hace evidente una gran efectividad de las resistencias.

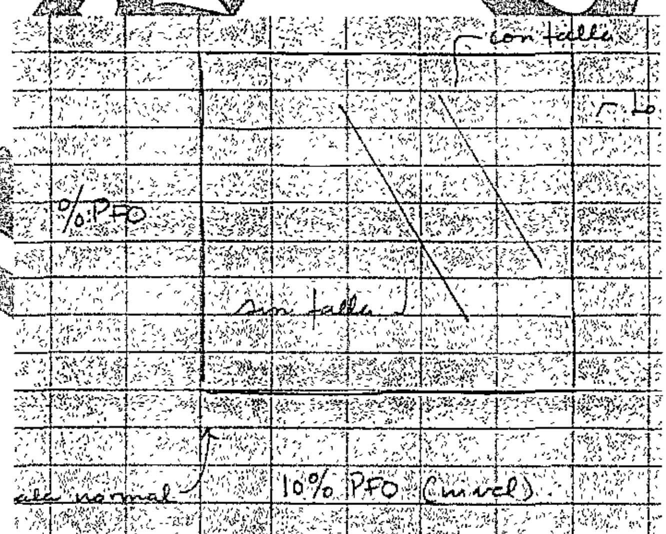


Si se analizara la diferencia entre "máximo voltaje" y "correlación de las tres fases", se notaría que la última da PFO's mayores.

Por otra parte, todo esto se basa en una energización. ¿que pasa si se energiza sobre falla?
La línea no tiene obligación de aguantar, pero el equipo terminal si debe; sobre todo interruptores, cuchillas desconectadoras, estcétera. Para una falla en la fase *a* se tendría:



Al visualizar los PFO's veríamos:



Si se acepta 0.5 PFO, entonces 1% ó 2% es aceptable para el cierre sobre falla, esto por la frecuencia de ocurrencia.

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ISA Embraces Open Architecture

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Integration and automation are key factors when upgrading or building new substations.

Fig. 1. Control centers in the Purnio and La Sierra substation control rooms.

Interconexion Electrica S.A. E.S.P. (ISA), Medellin, Colombia, has embarked on a program of installing standardized digital control systems (DCSs) for its high-voltage transmission substations. Although ISA has been installing DCSs in its substations since 1992, these systems have all been of a nonstandardized design. This practice resulted in many problems including the difficulty of providing additions or changes to a system, the lack of interchangeable parts, and the need for specialized knowledge and training ˆr each substation and system.

A acquired these varied designs from public open bids. The company now has 10 different DCS solutions from 6 different suppli-

Incentives for Standardization

- By developing a standard functional specification, the functionality of an applied substation automation system (SAS) is consistent and independent of the supplier and supplier product line.
- Lower design and engineering costs with the reduction in the number of different SAS solutions.
- A reduction in operation and maintenance costs associated with training of personnel, purchase and tracking of spare parts, and customized upgrades to the SAS.
- Standardization creates a simplified and cost-effective system because the specification restricts the functionality to that only required to satisfy ISA's specific expansion and upgrade objectives at the time of bid.
- The specification of equipment with an open-system architecture that must comply with international standards ensures a low-cost migration path with the possibilities to extend or replace existing parts of a SAS with the most suitable products available.
- A standardized specification will drive competing bidders to provide only the required functionality at the lowest cost. The supplier also will consider the economies of scale in the bid price and the reduction or integration of functions and devices in the system design.

Table 1: Non-Standardized Substation Automation Systems in ISA

Substation	Year	Vendor		System Type			
				Substation Level	Operating System	LAN	Bay Level
San Marcos 230 kV	1995	Schneider	France	ISIS 7000 (v0)	VMS	APRILNet	Telemecanique (APRIL 5000)
Primavera 230 kV	1996	AEG	Colombia	Factory Link	Windows NT	Modbus Plus	Modicon 984
La Sierra 230 kV	1997	AEG	Colombia	Factory Link	Windows NT	Modbus Plus	Modicon 984
Purnio 230 kV	1997	Schneider	Colombia	Factory Link	Windows NT	Ethway	Telemecanique TSX 107
San Marcos 230 kV (extension)	1998	Automatización Avanzada	Colombia	Factory Link	Windows NT	Ethway	Telemecanique TSX 107
Páez 230 kV	1998	Alstom	Colombia	Factory Link	Windows NT	ILSA	IMOS-HV
Sabanalarga 230 kV (extension)	1999	Schneider	France	ISIS 7000 (v8)	Windows 3.11	LAN 7000	BC 7000 (APRIL 5000)
Fundación 230 kV (extension)	1999	Schneider	France	N.A. [1]	N.A. [1]	JBUS	BC 7000 (APRIL 5000)
Cerromatoso 230 kV	1999	Schneider	Colombia	Factory Link	Windows NT	Modbus Plus	SEPAM 2000
Sochagota 230 kV	1999	ABB	Sweden	MicroSCADA	Windows NT	LON	REC 561
Guatiguará 230 kV	1999	ABB	Sweden	MicroSCADA	Windows NT	LON	REC 561
Chinú 500 kV (SVC)	1999	Siemens	Germany	WinCC	Windows NT	SINEC-H1	Simadyn + SU200
La Virginia 230 kV	1999	Cegelec	France	ALSPA P320	UNIX	CONTRONET	CE2000/C370
San Marcos 500 kV	2000	Automatización Avanzada	Colombia	Factory Link	Windows NT	Ethway	Telemecanique TSX 107

[1] Controlled from Sabanalarga.

ers—many of them foreign—in 14 substations. Clearly there was a need for a change to a standardized design.

The SAS provides the framework to enable existing and future intelligent electronic devices (IEDs) from various suppliers to work together to facilitate more efficient and cost-effective monitoring and control.

ISA is the largest electrical energy transmission company in Colombia. It owns and operates more than 75% of the country's power-transmission system. The ISA transmission system consists of: thirty-three 230-kV substations and four 500-kV substations; more than 6058 km (3765 miles) of 230-kV overhead transmission lines (66% of total country) and 1068 km (664 miles) of 500-kV overhead transmission lines (100% of total country); and a total installed transformation capacity of 5294 MVA. ISA supervises and controls the operation of the National Interconnected System (SIN) from its National Dispatch Center. The SIN includes all of Colombia's 230-kV and 500-kV network, as well as 30 hydroelectric and 60 thermal power plants.

ISA began studying the possible introduction of DCSs for its substations in the late 1980s. In 1992, ISA purchased the first DCS for the San Marcos 230-kV substation—located about 300 km (186 miles) southwest of Bogotá—which went into commercial operation in September 1995. After that, ISA continued specifying and acquiring more DCSs for its substations and now has 12 substations equipped with DCSs. Two more DCSs will go into operation in the next 12 months.

To reduce design, specification and operation and maintenance (O&M) costs, ISA initiated a standardization project to coordinate and unify the technical specifications and procurement of future DCSs. In 1997, ISA contracted with a local consulting company (Mejia Villegas S.A.), with external advice from KEMA Consulting, for the preparation of standard technical specifications for DCSs, which was referred to as the substation automation system (SAS). The standards address the application of the SAS in the construction of new substations, as well as in retrofit and extension work in existing substations.

Incentives for Standardization

Table 1 summarizes the various generations of non-standardized SASs (DCSs) currently installed and planned for ISA's substations.

ISA has found that the non-standardized systems, such as the one shown in Fig. 1, provide the required functionality, but extensions or changes impose complications because specific and detailed knowledge of each particular system is required. ISA also has found that it becomes dependent on the manufacturer because it is almost impossible to add and integrate products and functions from other vendors, most of which are foreign suppliers. This dependency has driven up the price of each installed SAS. Some of the other major difficulties with current SAS implementations include:

- The need for specific and intensive training of personnel for each proprietary system and substation
- The need for a large stock of different, specific spare parts for each system.

The advantages of implementing a standardized SAS include significant savings in investment and life-

Table 2: SAS Logical Architecture

Level			
Level 3	Remote Control & Supervision, and Corporate Users		
	Level 3 – Level 2 Communications and Interfaces		
Level 2	Level 2 Processing System	Online & Historic Data Repository	Application & Substation User Interface
	Level 2 – Level 1 Communications and Interfaces		
Level 1	Bay Controller	Basic User Interface	
	Level 1 – Level 0 Communications and Interfaces		
Level 0	Intelligent Electronic Devices and Individual I/O Points		
	Power System Equipment		

cycle costs, and the functionality becomes independent of a supplier's product line and O&M costs are reduced.

System Architecture

The SAS is a computer-based system used to bring together independently operating subsystems—such as supervisory control and data acquisition (SCADA), communications, protective relaying, power apparatus control, metering, and alarm annunciation—into a unified data acquisition, monitoring and control system in the substation. The SAS provides the framework to enable existing and future intelligent electronic devices (IEDs) from various suppliers to work together to facilitate more efficient and cost-effective monitoring and control.

The SAS architecture consists of two structured hierarchical levels, the bay level and the substation level (Table 2). Equipment is interconnected through a distributed data network to provide full-operation autonomy at the bay level.

The standardized specification of the SAS architecture required that the SAS satisfy ISA's existing functional requirements with a low-cost migration path to satisfy ISA's future envisioned requirements and expected changes in integration and automation technology.

Functional Criteria

The control modes correspond to the control hierarchical levels as shown in Table 2. Control actions are only possible from one location. Selection of local control overrides any control mode higher in the hierarchy.

Selection of local control overrides any control mode higher in the hierarchy.

Level 1 (Bay Level) Criteria:

■ *Data Acquisition* allows for the acquisition of data from IEDs and the means to acquire inputs that are not available from IEDs.

■ *Processing of Digital Status and Alarms* provides verification and storage of digital input data.

■ *Processing of Measurement Signals* enables the acquisition of measurements from energy-revenue meters and other IEDs, such as multifunction measurement units and protection devices

■ *Interlocking* provides continuous evaluation of the status of power equipment and operating and protection trip conditions before executing control commands.

■ *Protection Trip Commands and Transfer Trips* are implemented in hardwired schemes separate from the bay controller.

■ *Communications with Local Area Network* handles and monitors communication among all Level 1 devices.

■ *Automatic Monitoring and Control Functions* are based on analog and status inputs acquired at the bay level to consolidate functions currently performed by separate control systems and programmable logic controllers. Time-critical functions, such as fault isolation, are accomplished directly by the protective relays.

Level 2 (Substation Level) Criteria.

■ *System Security.* Each user is assigned one name and code (password) associated with a security level to determine the accessible displays, the data to be consulted or modified, and the functions available in user interface, both for its own operational works and for engineering works.

■ *Historical Data Management* monitors specified substation events, performs calculations on data, and stores the information—including data from digital fault recorders (DFRs) and sequence-of-events recorders (SERs)—in bulk read/write memory

■ *Device Tagging* blocks the operation of substation devices at all control levels.

■ *Sequence-of-Events, Alarms, Reports and Trending* records, displays and allows analysis of historical and real-time data with a 1 ms time resolution..

■ *Operations Log* allows operators to establish a log of substation operations, equipment failures, equipment maintenance and any other information required for later reference.

■ *Mass Storage Backup* of all information in the processor and controller hard drives.

■ *Automatic Monitoring and Control Functions* is similar to Level 1 functionality, but offers higher levels of monitoring and control for the substation level

Hardware and Software Criteria

■ *Substation Host Processor* The substation host processor must be based on industry standards and strong networking ability, such as Ethernet, X/Windows, Motif, TCP/IP, UNIX and Windows NT, as well as an industry accepted relational database with SQL capability and enterprise-wide computing. A full graphics user interface (bit or pixel addressable) must be provided with Windows-type capability. There also must be interfaces to Windows-type applications (Excel, DDE interface and OLE interface). The substation host processor must be flexible and expandable, and transportable to multiple hardware platforms (PCs, Power PC, DEC Alpha, Sun and HP). For a smaller substation, the host processor may be a single processor. For a large substation, redundant processors with failover options may be present. Smaller "slave" or "server" substations will have IEDs, but may not have a SAS The IED data from these "server" substations will be sent upstream to a larger "master" or "client" substation that contains a SAS.

■ *Substation Local Area Network (LAN).* The substation LAN must meet industry standards to allow interoperability and plug-and-play capabilities.

Open-architecture principles must be followed, such as use of industry standard protocols (TCP/IP, IEEE 802.x [Ethernet], UCA 2.0, IEC 61850). The LAN must interface to bay-level equipment and be hardened for the substation environment. The LAN must have enough bandwidth to support integrated peer-to-peer data acquisition and control requirements.

■ *User Interface.* The user interface in the substation must be an intuitive design to ensure effective use of the system with minimal confusion. An efficient display hierarchy will result in all essential activities being performed from a few displays. The amount of typing must be minimized or eliminated. There must be a common "look and feel" for all displays. A library of standard symbols must be used to represent substation power apparatus on graphical displays. Multiple databases must be avoided. The substation one-line displays may be similar in appearance to the displays on a SCADA/EMS.

■ *Communication Interfaces.* Interfaces to IEDs are required to acquire data, determine the operating status of each IED, support communication protocols used by the IEDs, interface to the SCADA/EMS and to provide data to corporate users over the wide area network. Remote dial-in capabilities may be considered in the future for authorized access to data and alarms, the execution of diagnostic programs and to configure IEDs. An interface to a time reference source, such as a global positioning system, should be available as well.

■ *Corporate Data Repository.* The corporate data repository enables users to access operational and non-operational (load forecasting, engineering studies) substation data while maintaining a firewall to substation control and operation functions. Both operational and non-operational data is needed. The utility must determine the SAS data users, the nature of their application, the type of data needed and the frequency of update required for each user. ISA identified the user groups (operations, planning, engineering, SCADA, protection, metering, maintenance and information technology) of the data from the SAS, and also determined the user requirements for the type, periodicity, accuracy and format of the data.

System support should be provided for comprehensive diagnostic software routines, online software module integration, as well as online modification of database parameters.

Performance Criteria

System performance criteria determine the operation of the SAS, and allow quantitative and qualitative comparison of different vendor proposals. Performance criteria include response times, system utilization, storage capacity, availability and redundancy, failure recovery, maintainability and expandability. Clear criteria must be established to deal with availability, minimal transfer times, fault tolerance and redundancy, which permits the vendor to define the type of redundancy of this equipment to comply with the requirements. No single component failure or detectable communication error should disable or degrade the performance of primary substation monitoring and control functions. For maintainability, self-diagnostics must be performed by all SAS components, and all problems or failures detected must be alarmed. System support should be provided for comprehensive diagnostic software routines, online software module integration, as well as online modification of database parameters.

Supplier Pre-Selection

ISA has established a separate, standardized process for the acquisition of SAS equipment. To ensure that a standardized technical specification results in the procurement of a standardized SAS, ISA has adopted a rigorous procurement strategy.

In the standardized acquisition process, the main suppliers that ISA recognizes will be invited to submit pre-selection proposals for the SAS. The invitation includes a document of pre-selection criteria and questions issued with the standardized specification. The pre-selection proposals will be evaluated by ISA and assigned weighted scores based on the level of compliance to obligatory requirements and desirable requirements.

The resulting scores of compliance to obligatory and desirable requirements will be related to the prices of the proposals to obtain a total technical-economic score. The evaluation of the proposals will result in the selection of two suppliers with the best technical-economical solutions for the SAS. Selection two suppliers minimizes the number of variations of SAS systems installed in ISA and ensures a competitive bid process. Demonstrations of the proposed systems may be evaluated before the final selection.

Contract Negotiation

After the pre-selection process, the objective is to make an alliance with one or both strategic partners, which guarantees their participation in the provision of the required SAS during a five-year period. With this option, ISA guarantees that the most recent and standard hardware and software technology is used in the SAS. This will produce significant time and costs savings in the acquisition, negotiation, contracting, development, implementation, maintenance and training for the SAS. The agreement with the pre-selected suppliers will stipulate that contract terms and prices are valid for the five-year period, and that purchase of the SAS from any one supplier depends on ISA's evaluation of the performance of the suppliers, the standardization of the installed systems and any new technology available.

Organizational Changes

ISA requires organizational changes to ensure a standardized specification and procurement process, and coordinated management of the resources related to the SAS. ISA will create a group of design, construction, operation and maintenance personnel to specialize in the standardized SAS technology. The main functions of the group will be to participate in the planning, design and specification of the SAS; to keep updated on the evolution of the technology of the SAS; and to be involved in all aspects of acquisition and commissioning of the SAS, as well as the maintenance and expansion of SAS installations.

Summary

ISA, as a transmission utility in a recently deregulated and privatized market, is facing several challenges with the use of SASs. In a competitive utility environment, standardization and open-system architectures for integration and automation of substations are key factors in considering substation additions or upgrades to ISA's transmission system. The standardized SAS specification and procurement process ensures that any substation additions or upgrades are at minimal cost by facilitating competitive bids with comparable functionality. ISA's substations interconnect the various parts of the Colombian transmission system, as well as the interconnection to several distribution networks. In a deregulated market, information regarding the status of the network and all of its components is critical. Standardized open systems facilitate the requirement that data must be supplied on an as-needed basis to various users in the enterprise, because the functionality of the SAS can be revised accordingly. Furthermore, the functional requirements of the SAS can follow the migration of the business strategies of ISA, thus providing more cost-effective solutions. For example, ISA is considering a decision regarding the manning of substations versus distributed control. The implementation of this decision will be facilitated by the flexibility of the SAS standardized specification and implementation process.

Vertical disintegration of the industry, unbundling of services, open-transmission access and retail wheeling are requiring the sharing of much more data at the transmission level in real-time. At the same time, a tremendous amount of standardization activity is occurring in substation communications and protocols. Fortunately, the primary groups sponsoring these activities—EPRI, IEEE and IEC—are working together with a high level of input from vendors, utilities and consultants. The great collective purchasing power of major electric utilities in North America has forced the vendors to redesign their products. This amount of industry support and harmonization is proving to be the vehicle for rapid deployment and acceptance of an industry-wide communication standard for field device integration that will support the needs of automation and integration projects being considered at many utilities. ■

Stuart H. Borlase, senior consultant with KEMA Consulting, has more than seven years of experience in the analysis, design and specification of substations, protection schemes, system integration, substation and feeder automation and associated communications. Borlase received the D Eng degree in electrical engineering from Texas A&M University.

David G. Cáceres, principal consultant with KEMA Consulting, has 24 years of experience in Control Center SCADA/EMS and power plant/substation automation technologies. He has worked with several electric utilities in Latin America, Canada, India and Vietnam. Cáceres has been assistant professor at UNI in Perú and presented several technical articles to international conferences.

Marco C. Janssen, a consultant with KEMA T&D Power in The Netherlands, has nine years of experience on conventional control and substation automation systems, protective relaying, the use of quality assurance systems and quality surveillance. Janssen is involved in standardization processes related to substation automation and substation design and testing.

John D. McDonald, senior principal consultant and manager of substation automation with KEMA Consulting, has more than 25 years of experience in the electric utility industry. Currently, he is assisting electric utilities in substation automation, distribution SCADA, communications protocols and distribution management systems (DMS). McDonald has the BSEE and MSEE degrees from Purdue University and the MBA in finance from the University of California at Berkeley. He is a member of the Governing Board of the IEEE Power Engineering Society and is vice-chair of the Substations Committee. He has published 15 papers in the areas of SCADA, energy management systems, DMS and communications.

Juan Carlos Olaya, an electronics engineer with data communications specialization in Japan, works with Interconexion Eléctrica S.A. (ISA) in Colombia. He has 16 years of experience in the planning, design and specification of conventional control and substation automation systems (SAS)for HV and EHV substations at ISA. He was the manager of the SAS standardization project at ISA. He has published five papers on substation control systems in Colombian and regional technical publications and seminars.

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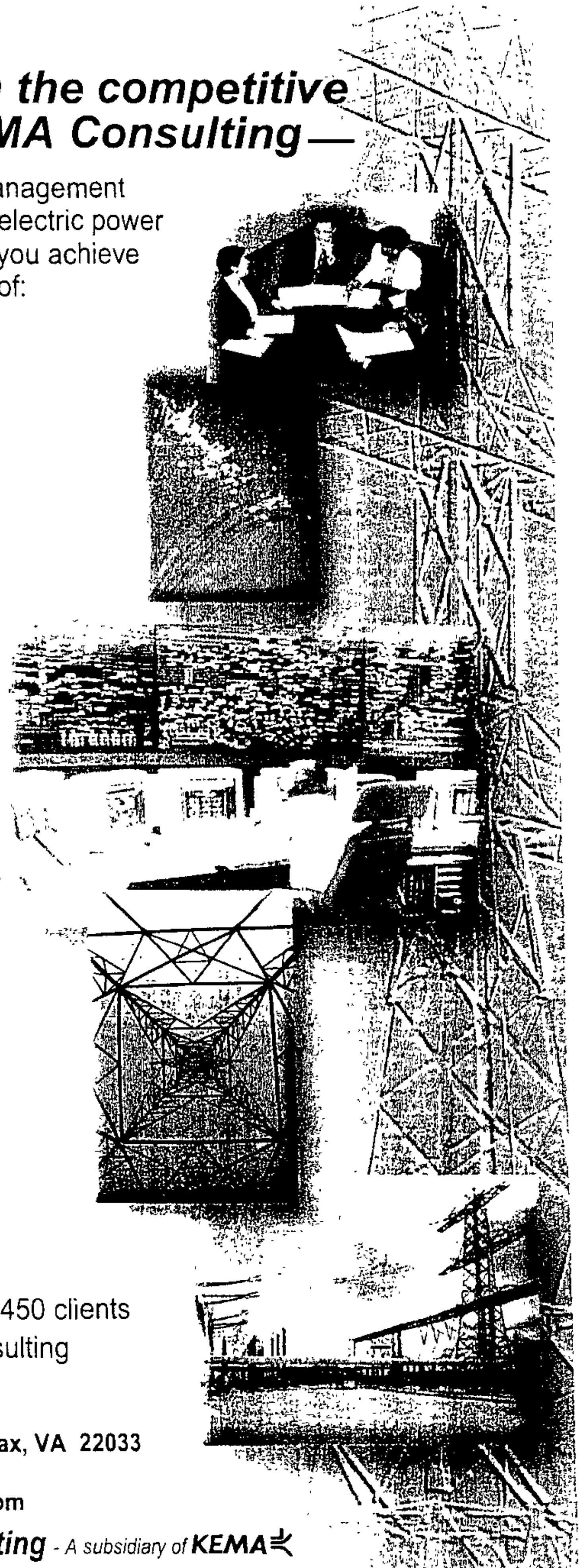

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INDUSTRY ACTIVITIES IN SUBSTATION PROTOCOL STANDARDIZATION

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ABSTRACT

The need for information in the deregulated, competitive utility environment places even greater emphasis on the communication protocol. Historically, suppliers have developed their own protocols that best suited their products The systems suppliers and integrators who tried to integrate these products had a difficult time making these products talk to each other Worse yet, even the same protocol had different versions that caused incompatibility between two systems or devices With the greater emphasis on the communication protocol today, there is greater emphasis on standardization of communication protocols. The most focused industry activity today in protocol standardization is in the substation integration and automation area. Specifically, these efforts address a standard intelligent electronic device (IED) protocol, as well as a standard substation local area network (LAN) technology. The efforts also include a standard protocol to bring the substation information out of the substation and into the utility enterprise.

INTRODUCTION

Electric utility deregulation, economic pressures forcing downsizing, and the marketplace pressures of potential takeovers have forced utilities to examine their operational and organizational practices. Utilities are realizing that they must shift their focus to customer service Customer service requirements all point to one key element, information – the right amount of information to the right person or computer within the right amount of time The flow of information requires data communication over extended networks of systems and users. In fact, utilities are becoming among the largest users of data and, are the largest users of real-time information

The communication protocol is needed for data communications and the subsequent flow of information. Communications and protocols enable automation to be implemented. The success of the automation applications is very dependent on the selected devices, the communications media and the communication protocol Standard industry protocols for different application areas (e.g., control center, substation, wide area network, customer site) allow the electric utility the flexibility to choose the best products from suppliers for their system, without the constraint of unique protocols and unique devices.

PROTOCOL FUNDAMENTALS

The communication protocol allows two devices to communicate with each other. Each device must have the same protocol implemented, and the same version of the protocol. Any differences in the implementation of the protocol in either device will result in communication errors.

If both devices are from the same supplier, as well as the communication protocol, there is little risk that the devices would not be able to communicate with each other This is typical of the situation where the supplier has developed a unique protocol to allow all the capabilities of the two devices to be utilized. In other words, by using the supplier's unique protocol, the utility guarantees the maximum return on their investment in the devices. They are able to use all the device's functionality. However, because of the unique protocol, the utility is constrained to one supplier for support and purchase of future devices

If both devices are from the same supplier, but the protocol is an industry standard protocol supported by the device supplier, there is little risk that the devices would not be able to communicate with each other The device supplier has designed their devices to operate with this industry standard protocol, and with the same version in each device The utility is not constrained to one supplier for future device purchases, and will be able to realize lower device prices due to competition Industry standard protocols typically have much more overhead than a supplier unique protocol, and therefore require a higher speed channel for the same efficiency or information throughput. There is some risk that device functionality may be not be totally realized by using an industry standard protocol. Were the devices designed before the industry standard protocol was available? If so, there may be device functionality not supported by the protocol. If the devices were designed after the industry standard protocol was available, the supplier should have designed the devices in conjunction with the protocol functional capabilities.

With the advent of open system concepts, which ideally allow devices from different suppliers to communicate with each other (interoperate with each other), it should be possible for a device from one supplier to talk to a device from another supplier, using an industry standard protocol. In this scenario, it is critical for factory testing to verify that the functions of one device are supported by the protocol and by the other device, and vice versa Since the devices are from different suppliers, there is risk that each device may have capabilities not supported by the other device There is also risk that the protocol implementations of the industry standard protocol by the two suppliers in each device may have differences. These differences would need to be found and corrected during factory testing.

Having an industry standard protocol, where the device suppliers have designed their devices so all device functionality and capabilities is possible with this protocol, provides the utility the flexibility to choose the best devices for each application With multiple sources for the devices the competitive purchase process results in lower prices for the utility. Higher speed communication channels are more prevalent today to make up for the increased overhead of industry standard protocols

EPRI UCA PROTOCOL PROFILE

During the late 1980s, the Electric Power Research Institute (EPRI) commissioned a study into the communications requirements of the electric utility industry. That study, released in 1991, performed a needs assessment, looked at the then available open systems networking protocols, and made recommendations regarding the best fit between available protocols and the industry's communications needs. The results of the study were the Utility Communication Architecture (UCA1) The study recommended that the framework underlying the UCA be the OSI basic reference model and that the protocols chosen be ISO standards, wherever possible. The UCA is a subset of the ISO/OSI standards chosen to be an internally consistent set of protocols that conceptually provide all communications services that would be required in the electric utility business and operations environment. Such a suite of protocols, which is chosen to provide a vertical set of communications services, is called a profile. UCA1 included two profiles, one using the full seven layer OSI model, and one Enhanced Performance Architecture (EPA) three layer profile for simpler, less complex devices or IEDs.

UCA2 was developed by EPRI as an update of version 1 incorporating definition work done by an industry group and several utility demonstration projects. Like version 1, UCA does not define one communication profile, but rather provides for a selection of standards to create a profile for specific applications. In all cases, the profile includes the Manufacturing Message Specification (MMS) protocol standard at the application level as a messaging service. UCA2 provides increased functionality going beyond most proprietary and some de facto standard protocols

Although UCA2 has been announced and documentation has been released, work still continues in a number of committees to define the object models (software modules associated with components such as breakers or switches) needed to support interoperability of devices This work has been completed for basic power system devices, and is known as GOMSFE (Generic Object Models for Substation and Feeder Equipment).

UCA devices are self-describing. The self-describing supplier-independent device object models, when combined with the supporting profiles, provide a seamless view of real-time data throughout the utility enterprise. Using standard commercial off-the-shelf PC and/or workstation packages (e.g , MMS browsers), individual users anywhere in the UCA enterprise can, subject to security and access controls, directly access real-time data from substation devices, or customer interface – and beyond.

An IEEE Standards Coordinating Committee (SCC) of the IEEE, called SCC 36, oversees and coordinates the further evolution of UCA specifications into IEEE Technical Reports. The committee's scope includes data communication standards for electric, gas and water utilities Relevant IEEE standards committees manage progress of the various parts of UCA, and SCC 36 assures consistent and productive overall direction SCC 36 organized an IEEE review of the existing UCA documents and determined how they can be adopted and/or revised as IEEE Technical Reports (TRs), resulting in the publication of IEEE TR1550 in December 1999 SCC 36 issued a solicitation for members to numerous bodies that are developing standards related to utility data communications, including for example, the American Gas Association, the American Water Works Association, and within the IEEE (the Power Engineering Society, the Industry Applications Society, and the Communications Society). EPRI continues its active role in UCA development. It will support standardization committee activities, including IEEE, and will continue to identify new utility requirements and solutions in data communications.

The UCA2 MMS and GOMSFE work is being integrated into IEC 61850 This substation automation communications standard is bringing European and North American standards developers together to produce one worldwide standard.

UTILITY SUBSTATION COMMUNICATION INITIATIVE

The EPRI UCA/Substation Automation Project began over five years ago to produce industry consensus regarding substation integrated control, protection and data acquisition, and to allow interoperability of substation devices from different manufacturers. In mid-1996 the Utility Substation Communication Initiative had its first meeting as a continuation of the EPRI UCA/Substation Automation Project. Approximately 25 utilities and 15 suppliers are participating, having formed supplier/utility teams to define the supplier IED functionality, and to implement a standard IED protocol (UCA2 profile) and LAN protocol (Ethernet). Initiative meetings are held three times each year, including UCA interoperability demonstrations of supplier IEDs at every other meeting. New IED products with this functionality are now commercially available, and compiled in a UCA products list maintained by the Initiative (available from ftp sisconet.com/epri/subdemo/products.zip). The utilities provide demonstration sites for the implementation of the new IED products to demonstrate interoperability between IED equipment from different suppliers. The widespread consensus and collective buying power of many utilities caused the suppliers to redefine their products toward industry standards. The supplier/utility teams are working together in two ways redefinition of the supplier products, and utilities providing actual substation demonstration sites for the implementation and testing of the new products

DNP USER GROUP

Since 1993 vendor and utility membership in the DNP User Group has steadily grown to its current worldwide membership of more than 300. The ongoing management of the protocol is directly in the hands of the utilities and vendors who use it. The DNP User Group acts the focal point for this ongoing evolution, bringing the DNP3 community together to collectively manage and evolve the protocol.

A primary reason for DNP3's success has been its stability, coupled with interoperability and enhancements to ensure compatibility with existing implementations. Acceptance of the conformance testing process now means users have a high expectation that devices from different suppliers will work correctly out-of-the-box The DNP Technical Committee responds to market needs while ensuring that extensions to DNP3 do not make existing implementations obsolete Both suppliers and utilities benefit from this commitment to compatibility and continuity.

There is an updated DNP web site (www dnp.org) and a new DNP membership structure. The goal of the new web site is to provide new features to enhance the site's usefulness for both visitors and members In addition to the Basic Membership level, a new Premium Membership level providing additional membership services will be offered

CHOOSING THE BEST PROTOCOL

How do you choose the best protocol for your application? There are a number of questions to be answered. First, what area of your system are you concerned with? Is it the protocol from a SCADA master station to the SCADA RTUs? Is it a protocol from substation IEDs to an RTU or a Programmable Logic Controller (PLC)? Is it a local area network in the substation? This is the first question to be answered

Second, what is the timing of your installation? Is it in the next six months, or is it in the next eighteen to twenty-four months? Or, is it even longer term, in the next three to five years? In some of the application areas technology is changing quickly, and the timing of your installation has a great impact on your choice of protocol. For example, if you are implementing new IEDs in the substation, and need them to be in service in six months, your protocol choices will be DNP3, Modbus and Modbus Plus. These protocols are used extensively in IEDs today. In some cases, if you choose an IED that is commercially available with UCA2 MMS capability today, then you may chose UCA2 MMS as your protocol. However, if your time frame is one to two years, you should consider UCA2 MMS as the protocol. You should monitor the results of the Utility Substation Communication Initiative utility demonstration sites, implementing new supplier IED products which have implemented UCA2 MMS as the IED communication protocol, and using Ethernet as the substation local area network.

If your time frame is near term, such as six months, it is important that the protocol choices you make are from suppliers who are participating in the industry initiatives and are incorporating into their products' migration paths to this future technology In this way, you are assured of protection in your current investment, so that it does not become obsolete, and must be thrown away and replaced by new technology, but can be incrementally upgraded to the new technology as much as possible.

SUBSTATION PROTOCOL APPLICATION AREAS

There are various protocol choices depending on the protocol application area of your system. In the previous section the first question to ask is the area of the system being considered. The protocol choices vary with the different application areas. In the following sections different application areas are reviewed with respect to the present state of protocol development and industry efforts The time frame of development efforts is discussed to help determine what is real for your specific project and its schedule for implementation.

IED to RTU/PLC (Within the Substation)

The need for a standard IED protocol dates back to the late 1980s. IED suppliers will be the first ones to say that their expertise is in the IED itself, and not in the addition of two-way communications capability to the IED, not in the communications protocol, and not in the added functionality from a remote user. At the same time there were industry efforts to add communications capability to the IEDs, each IED supplier was extremely concerned that any increased functionality did not drive the cost of their IED so high that no utility would buy it, and that the performance would not be compromised by the added functionality Therefore, the cost must remain competitive, and the performance must remain the same, as standardization is incorporated into the IED

With the IED suppliers' lack of experience in two-way communications and communication protocols, the result was IEDs with crude, primitive protocols and, in some cases, no individual addressability and improper error checking (no select-before-operate). Therefore, each IED required its own communication channel, and RTUs at the time were limited in the number of these channels that were available, if they were available at all. There was pressure on the Supervisory Control and Data Acquisition (SCADA) system and RTU suppliers to be able to communicate to these IEDs purchased by the utilities Each RTU and IED interface required the implementation of a new protocol, and a proprietary protocol not used by any other IED.

It was at this point that the Data Acquisition, Processing and Control Systems Subcommittee of the Institute of Electrical and Electronics Engineers (IEEE) Power Engineering Society's (PES') Substations Committee recognized the need for a standard IED protocol. The Subcommittee formed a task force to examine existing protocols and determine, based on two sets of screening criteria, the two best candidates IEEE Standard 1379, *Trial Use Recommended Practice for Data Communications Between Intelligent Electronic Devices and Remote Terminal Units in a Substation*, was published in March 1998. This document does not establish a communication standard. To quickly achieve industry acceptance and use, it instead provides a specific implementation of two existing communication protocols in the public domain.

The first protocol is DNP3, the Level 2-subset implementation as published by the DNP User Group The DNP protocol was developed by GE Harris Canada (at the time, Westronic, Inc) in order to stabilize the expansion of unique protocols used to communicate between SCADA RTUs and a variety of IEDs The DNP protocol used as its basis several IEC 870-5 documents, which were then in development, but extended and/or modified these to accommodate North American preferences and practices. There has been work done to harmonize the IEC 870-5 documents, which were later made International Standards, with the DNP variations. DNP is essentially a four layer protocol using layers 1, 2 and 7 of the ISO/OSI communications profile set, and adding a pseudo-transport layer 4 to facilitate transmission of large data messages. It is specifically designed for data acquisition and control applications, and focuses its application information in the area of electric utility data transmission.

The second protocol is IEC 870-5-101, developed by IEC Technical Committee 57 Working Group 03, including the 101 companion standard (profile). The IEC TC57 WG03 was chartered to develop protocol standards for telecontrol, teleprotection, and associated telecommunications for electric utility systems, and it created IEC 870-5, a group of five utility-specific protocol standards IEC 870-5 specifies a number of links, frame formats and services that may be provided at each of three layers, similar to the EPRI UCA specification. IEC 870-5 uses the concept of a three-layer Enhanced Performance Architecture (EPA) reference model for efficiency of implementation in devices such as RTUs, meters, relays, etc. Additionally, IEC 870-5 includes a "User Layer", which is situated between the OSI Application Layer and the user's application program to add interoperability for such functions as clock synchronization and file transfers. Another document developed by IEC TC57 WG03 is IEC 870-5-101, a companion standard (profile) that contains definitions specific to RTUs and IEDs Three other companion standards that support the communications requirements for other utility devices have been defined These are commonly known as 102 for metered values, 103 for substation protection and automation, and 104 for network communications.

The task force decided to use the IEEE "trial use recommended practice" designation for this work, with a limited lifetime, that these recommendations would fill a void on an interim basis until a longer term, more permanent solution was ready to be implemented.

The EPRI/UCA Substation Automation Project began over five years ago, to produce industry consensus regarding substation integrated control, protection and data acquisition, and to allow interoperability of substation devices from different manufacturers. An open process has been followed on this project, to review each major project document and milestone in the open forum of standards-related organizations. There have been over 600 participants in this review process worldwide. The Substation Protocol Reference Specification recommended three of the ten UCA2 profiles for use in substation automation. Future efforts in this project are integrated with the efforts in the Utility Substation Communication Initiative

Generic Object Models for Substation and Feeder Equipment (GOMSFE) are being developed to facilitate suppliers in implementing the UCA/Substation Automation Project substation and feeder elements of the Power System Object Model. The GOMSFE work merges the UCA Forum Substation and Feeder Automation work with that of UCA2 in order to produce common generic object models for implementation of UCA2 compliant field devices in electric utilities

New IED products with this functionality are commercially available. The utilities are providing demonstration sites for the implementation of the new IED products to demonstrate interoperability between IED equipment from different suppliers and to evaluate and recommend a suitable UCA-compliant substation LAN

In summary, for IED communications, if the time frame for implementation is within six months or so, the choice should be for products existing today, with DNP3, Modbus or Modbus Plus communication protocols. However, if the implementation time frame is longer, say one year or more, you should seriously consider EPRI UCA2 with MMS as the communications protocol. With all suppliers, it is imperative that you evaluate their product migration plans. For example, can you migrate from today's IED with DNP3 to tomorrow's IED with EPRI UCA2 MMS without replacing the entire IED? In this way, even with a short time frame for implementation, you have the future option of migrating the IEDs in the substation to EPRI UCA2 in an incremental manner, without wholesale replacement. As stated previously, if you choose an IED that is commercially available with UCA2 MMS capability today, then you may choose UCA2 MMS as your protocol.

RTU/PLC to Master (Substation to Utility Enterprise)

This is the area of traditional SCADA communication protocols. The Data Acquisition, Processing and Control Systems Subcommittee of the IEEE Power Engineering Society (PES) began work on a recommended practice in the early 1980s as an attempt to standardize master/remote communications practices. At that time, each supplier of Supervisory Control and Data Acquisition (SCADA) systems had developed a proprietary protocol based on technology of the time. These proprietary protocols exhibited varied message structures, terminal-to-Data Circuit Terminating Equipment (DCE) and DCE-to-channel interfaces, and error detection and recovery schemes. IEEE Std 999-1992, *IEEE Recommended Practice for Master/Remote Supervisory Control and Data Acquisition (SCADA) Communications*, addressed this non-uniformity among the protocols, provided definitions and terminology for protocols, and simplified the interfacing of more than one supplier's remote terminal units to a master station

Unfortunately, this work was completed well after the industry need for the work. In the absence of a standard, suppliers continued to develop their own proprietary protocols. Many of these protocols became de facto standards due to their widespread use However, these protocols did not incorporate all of the advanced features offered by some other protocols already in use

The major standardization effort that has been undertaken in this application area over the last few years is an international effort in Europe as part of the IEC standards making process The effort resulted in the development of the IEC 870-5 protocol, which was slightly modified by GE Harris (Canada) to create DNP. A number of years ago Working Group 03 of IEC Technical Committee (TC) 57 commenced work on a "telecontrol" protocol. The primary idea was to develop a single international standard that all suppliers would implement It addressed the telecontrol domain where the primary constraints were low bandwidth communication channels (in Europe, these typically ranged from 75 bps to a maximum of 600 bps), and a configuration of a single master station interacting with simple devices (RTUs)

The design of the resulting telecontrol protocol, IEC 870-5, reflects these constraints It is a very efficient protocol, and assumes a single master station scanning status and analog values from simple RTUs over point-to-point communication channels. In the United States, GE Harris (Canada) modified the protocol, primarily at the Data Link Layer, and named it DNP (Distributed Network Protocol) This protocol incorporated a "pseudo" transport layer, allowing it to support multiple master stations. The goal of DNP was to define a generic standards-based (IEC 870-5) protocol for use between IEDs and data concentrators within the substation as well as between the substation and the SCADA/EMS control center. Success led to the creation of a supplier-sponsored user group that currently maintains full control over the protocol and its future direction. DNP3 has become a de facto standard in the electric power industry, and is widely supported by suppliers of test tools, protocol libraries, and services.

CONCLUSIONS

As we look to the future, it seems the time between the present and the future is shrinking! When a PC bought today is made obsolete by a newer model with twice the performance at less cost in six months, how do you protect your investment made today? Obviously, there is no way you can keep up on a continuous basis with all the technology developments in all these areas You must rely on others to keep you informed, and the choice of these "others" is critical. Every purchase you make must evaluate the supplier not only on their present product(s), but also on their future product development plans Is the supplier continuously enhancing and upgrading their products? Is the supplier developing new products to meet future needs? Do the existing products have a migration path to the enhanced products, and the new products? These are all important questions. The choice of the right supplier today will help ensure you stay current with future industry developments and trends, and allow you to take advantage of these new technologies with the least impact on your current operation

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PRESENT AND FUTURE INTEGRATION OF DIAGNOSTIC EQUIPMENT MONITORING

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ABSTRACT

Like most electric utilities, the Omaha Public Power District (OPPD) has installed various equipment condition monitoring (ECM) devices. These devices are monitored locally, or monitored remotely via a dial-up connection The data downloaded through the remote connection is stored in individual databases, and not in the corporate data warehouse. OPPD discovered a potential catastrophic failure with a generator step up transformer, and was able to "manage" the problem and avoid the ramifications of an unexpected failure with diagnostic equipment monitoring. Last year OPPD began a substation integration and automation project under EPRI Tailored Collaboration, resulting in a standard integration architecture for the intelligent electronic devices (IEDs) in the substation This architecture is capable of integrating ECM IEDs, resulting in the benefits of additional device data extraction and the sharing of this data throughout OPPD utilizing the corporate data warehouse. Integration architectures will be installed in two pilot substations that include ECM IEDs. In addition, a Substation Automation Training Simulator (SATS) with ECM IEDs will be used by OPPD for training, testing and development

INTRODUCTION

The advent of industry deregulation has placed greater emphasis on the availability of information, the analysis of this information, and the subsequent decision making to optimize system operation in a competitive environment. The IEDs being implemented in substations today contain valuable information, both operational and non-operational, needed by many groups within the utility The challenge facing utilities is determining a standard integration architecture that meets the utility's specific needs, and can extract the desired operational and non-operational information, and deliver this information to the users who have applications to analyze the information. The ECM IEDs are a major source of this information, and can be integrated into the substation architecture identical to the other substation IEDs, such as the relay IEDs.

EXISTING EQUIPMENT CONDITION MONITORING DEVICES

The following equipment condition monitoring devices are currently installed at OPPD.

- Six GE Harley LTC-MAP 2126 devices on three transformers in one substation
- Six GE Harley LTC-MAP 2130 devices on two transformers in one substation and four devices on two transformers in another substation
- Four GE Harley LTC-MAP 3030 devices: one on the generator step up (GSU) transformer at Nebraska City Plant, two on 345/161kV 300/400/500 MVA auto transformers, and one on a GSU peaker unit transformer

The on-line Maintenance Action Planner (MAP) for load tap changers (LTCs) continuously monitors performance data from various types of sensors, such as temperature and current. It stores this data in non-volatile memory for downloading to a personal computer. These monitors have analog input channels, which are used for sensor, current, and voltage inputs, and digital input channels. OPPD monitors the main tank, LTC, tap position, phase current, motor current, voltage, coil, contacts, and other items. Samples or readings are taken every five minutes, and are stored locally until the data is downloaded. The downloaded data is reviewed every morning The four conditions that are reported are:

1 OK (indicated by green)
2. Alert (indicated by yellow)
3 Alarm (indicated by red)
4 Communication failure (indicated by blue)

The majority of the non-OK reports are for communication failures. OPPD is sampling twelve devices every five minutes and each device has one or two cards with thirteen to seventeen ports on each card. In other words, there are a lot of data points being sampled. It is common to clear several hundred-communication failures every week. The majority of the other reports are for the partial discharge (PD) channels, since OPPD has not standardized the settings in the partial discharge monitors.

- Four GE Harley T-MAP 3100 devices

The on-line transformer Maintenance Action Planner remotely gathers and processes data in order to access and communicate the on-line condition of transformers. The analog input channels are used to monitor partial discharge (six different sensors and one additional for ambient PD), currents, motor, top oil, and bottom oil The digital input channels are used to monitor loss of AC, fans, contacts, GenBus, TCG (total combustible gas), and winding temperature.

- One GE Syprotec TNU (transformer nursing unit) on a 345/161kV 300/400/500 MVA auto transformer

This unit is part of an EPRI TC project. It is called up separately. It samples the oil for dissolved gases and saves the data in the CPU in the TNU. This unit was to sample the gases in the head space (gas space above the oil in the main tank). This portion of the TNU has not worked on the unit at OPPD, resulting in dropping this part of the EPRI project. The TNU does a good job of displaying the results of the on-line DGA (dissolved gas analyzer) results There have been some fluctuations in the DGA readings due to the wide ambient temperature swings experienced in Nebraska.

- One Mitsubishi DGA also mounted on the Nebraska City Plant GSU

The Mitsubishi DGA does the same thing as the GE Syprotec TNU unit Unfortunately, the only way to get the data from the unit is to take a laptop to the unit and download on site This is currently being corrected

In summary, OPPD accesses these monitors by connecting a computer locally on site or by dial up connection and downloading the data. Each type of monitor has its own software for accessing the data. All data is stored in an individual database (not the corporate data warehouse) Most of the monitors are set up to download the data on a regular interval, such as every night.

Engineering Technical Support, Substation and System Protection, and Substation Engineering are all involved in the monitoring program. Technical Support has the overall responsibility.

OPPD is going to add monitoring on all new critical substation class transformers. The possibility of adding monitoring to circuit breakers and other substation equipment exists for future applications

EQUIPMENT CONDITION MONITORING RESULTS

One specific incident will be discussed where equipment condition monitoring detected problems with a GSU. OPPD made modifications to the FOA cooling system in an effort to mitigate the occurrences, and reduce the duration of the internal electrical disturbances

History

Nebraska City GSU #1 is a 17 1 kV - 345 kV, 600/672 MVA Westinghouse shell-form transformer, built in 1978 This transformer is part of a family of Westinghouse generator step-up transformers, which have exhibited two known problems:

- Uninsulated T-beams - Core laminations can come into contact with the vertical members of the T-beam that are not insulated The subsequent hot spot involving the magnetic circuit in the transformer will produce a variety of hot metal gases, including acetylene. The severity of the heating and the associated insulation breakdown is directly related to the rate and composition of the gases detected in the insulating oil

  (Note: The uninsulated T-beam situation has been recognized for several years as the principal cause of problems associated with these transformers. However, OPPD tests indicate that the failure mode described below may be a more serious concern.)

- Open Winding Failures - Turn-turn failures in the high-voltage coils of these transformers have been occurring at an alarming rate. The root cause of the problem is usually difficult to determine since the failure is typically violent, and causes substantial coil and core damage.

  The uninsulated T-beam problem will cause low level gassing, but did not show itself to be progressive. The open winding problem, however, is a serious situation that should be immediately addressed and continuously monitored

  With these problems known, an extensive monitoring package was added to the OPPD transformer in October 1997. The monitoring package installed consisted of a GE Harley T-MAP 3100 system (Figures 1 and 2). This system was designed and installed to monitor the following quantities:

  - A, B, and C phase 345kV Amps
  - A, B, and C phase Generator Bus Volts
  - Cooling Group 1 Amps (Fans + Pumps)
  - Cooling Group 1 Contactor Status
  - Cooling Group 2 Amps (Fans + Pumps)
  - Cooling Group 2 Contactor Status
  - Top & Bottom Oil Temperature
  - Ambient Oil Temperature
  - Partial Discharge Detection System
  - Various Transformer Alarms also monitored by Power Plant

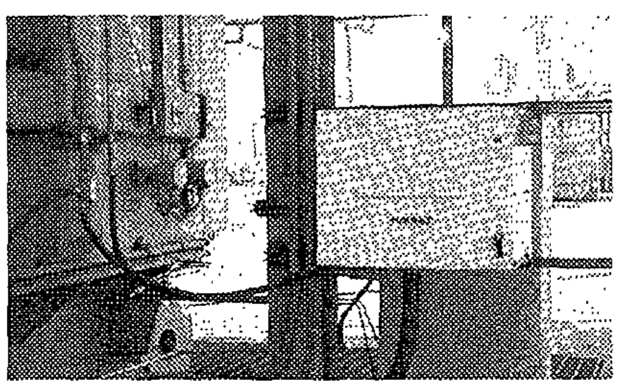


Figure 1 – GE Harley T-MAP 3100

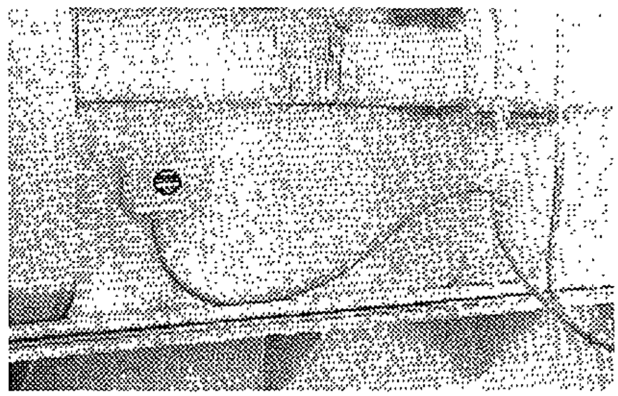


Figure 2 – GE Harley T-MAP 3100 PD Sensor

Early Detection

At the time the transformer monitoring system was being installed, an upgrade was being implemented at the Nebraska City generating plant to increase capacity by ~30 MW. Increasing the maximum net GSU transformer output from 660 MVA to 692 MVA required OPPD to operate the transformer above its original nameplate rating of 672 MVA. Given the transformer's history of thermal problems, the decision was made to replace the original coolers with newer, larger, more efficient units. This work was completed in late fall of 1997. With the new coolers installed, the GSU transformer operated at full power throughout the summer of 1998 without generating the thermal alarms that had previously plagued the unit

Routine checking of data brought random acoustic partial discharge (PD) events to the attention of OPPD and customer service personnel at GE Harley. With experience gained through participation in the tests of a TXU Electric transformer and tests at the Ramapo Substation of the Consolidated Edison Company of New York, the combination of low oil temperature and PD events signaled the possibility that the static electrification cycle of charge build-up and discharge was occurring.

The on-line partial discharge system detects the highest level of acoustic emission activity each second and records the highest level in each minute. Six piezo-electric sensors (Figure 2) with a frequency range centered at about 150 kHz were installed externally on the transformer tank wall. An additional "ambient" sensor was installed separately to determine whether acoustic activity is due to a source external to the transformer.

The most frequent and the highest levels of activity occurred on the south side of the transformer tank close to the top. There was no activity in the ambient sensor, indicating the acoustic source was within the transformer.

The pattern of acoustic activity increased in intensity of count level in several cases at about 50°C and noticeably at temperatures below about 40°C. This occurred even with only one bank of cooling in operation.

Cooling Modifications

OPPD decided to uniformly reduce the cooling on the four manually controlled coolers These coolers are considered the base-cooling group, and operate anytime the transformer is energized. Consequently, these coolers would be the only cooling operating during the light load, low ambient conditions. Each cooler assembly consists of one oil pump forcing oil through an oil cooler that has four fans forcing air across the radiator fins. In order that the reduction of cooling was uniform, one fan from each of the four manually controlled cooler group assemblies was disconnected (Figure 3).

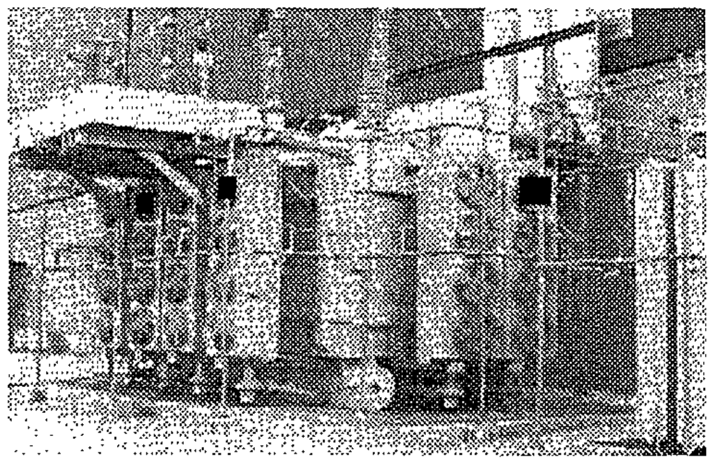


Figure 3 – Blocks indicates fans removed from service

The results of the modifications revealed that the oil temperature increased during "light" load conditions above 35°C. The PD readings decreased to previously observed values, and the power plant's status returned to normal. The GSU cooling returned to normal (all fans back in service) in early April to prepare for upcoming "high" load conditions.

During June 1999 a close trip sequence occurred and the subsequent signature of the transformer changed completely. The pattern of discharges increased sharply. Additional cooling modifications were needed to maintain the oil temperature above 30°C and reduce the oil speed to reduce the risk of static electrification.

In July 1999 the cooling pump control scheme was changed from 4-4 operation to 2-3-3 operation. The first two pumps were always on The first group of three pumps turned on around 55°C to 60°C, and the second group of three pumps turned on around 70°C. These cooling modifications were done with the transformer on-line. The GE Harley system was used to control the second and third group of pumps, and a Qualitrol system was used as a backup system for pump control.

Conclusions

The life of the transformer was extended for the six months needed for OPPD to procure and receive a replacement transformer. During this period there was extensive monitoring of the transformer with multiple monitoring systems.

The events in this example were real. Decisions reached were based partly on empirical data received from the GE Harley monitor, and partly on previous knowledge learned through various research projects and technical reports.

The Nebraska City GSU #1 operating conditions were temporarily modified in an effort to reduce the likelihood of a prolonged incidence of internal static electrification Empirically, OPPD was successful.

Mitigating the risk of critical equipment failure, and the subsequent costs associated, remain the predominant justification for the continuing utilization of on-line monitoring equipment

An unexpected failure of this transformer would have caused OPPD to purchase 660 MW of replacement power, as well as the cost for the transmission transfer capacity.

SUBSTATION AUTOMATION PROJECT

OPPD has been automating its power system operations and corporate business operations for a long time Traditionally, departments have automated their own operations, creating islands of automation. Some on-line or off-line sharing of data among automation systems was possible, but this was not the result of preconceived designs. More recently, automation systems have been developed or expanded which are intended to serve several departments, and OPPD determined that an automation plan for all the operations departments needed to be developed.

OPPD has recently initiated the "OPPD Automation Plan" to coordinate and integrate systems District-wide Implementation of the Plan is in progress and further focus on each system (Energy Management System, Distribution System, Substation Automation, Automated Mapping, etc.) is deemed necessary.

In June 2000, OPPD contracted with KEMA Consulting to assist in developing the automation plan pertaining to electrical substations and to assist in implementing the Substation Automation (SA) Plan at two pilot substations, 912 and 1345. In addition, a Substation Automation Training Simulator (SATS) is being procured that includes one of every type of IED that will be in the SA Systems for 912 and 1345.

Project Charter

OPPD's primary goal is to develop an integrated approach for implementing SA Systems in a manner that is consistent with OPPD's SA Project Charter. Key issues in the SA Project Charter include:

- Use of Intelligent Electronic Devices (IEDs) to reduce the number of components required to support protection, control, and data acquisition functions in the substation environment
- SA System design must be suitable for new substations, but must have sufficient flexibility to allow integration into existing facilities.
- SA protocols and equipment must be scaleable to accommodate Distribution Automation functions
- Substation safety must be a top priority

One of the objectives of the Substation Automation (SA) Plan is to integrate maintenance and diagnostic data collected by SA Systems into the Substation Maintenance Management System (SMMS).

Integration Architecture

The implementation of substation integration and automation has three different levels. IED Implementation, IED Integration, and Substation Automation. The first level is simply installing IEDs in the substation. The second level is the integration of the installed IEDs, using the two-way communications capability of the IEDs, via a local area network in the substation. The third level is running applications at the substation level to automate various substation functions The different levels are shown in Figure 4 below·

Utility Enterprise Connection
Substation Automation Applications
IED Integration Via Data Concentrator/Substation Host Processor
IED Implementation
Power System Equipment (Transformers, Breakers)

Figure 4 – Levels of Substation Integration and Automation

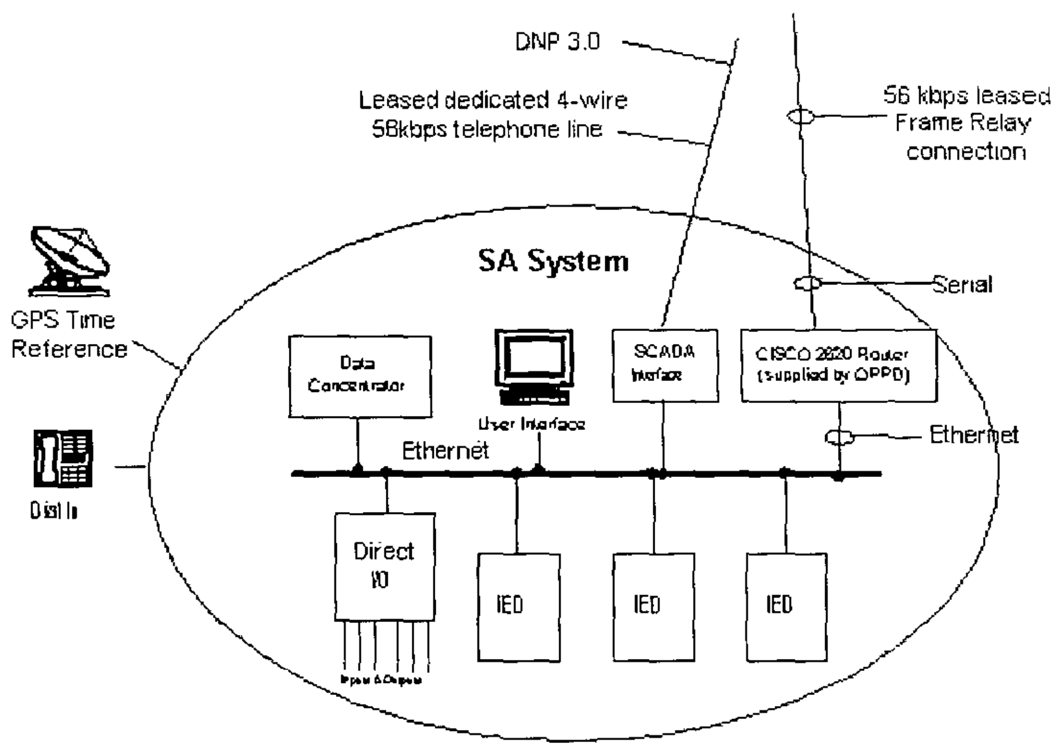
The SA System is a computer-based substation control and monitoring system that will be used to integrate independently operating subsystems, such as SCADA, communications, protective relaying, power apparatus monitoring, control and diagnostics, metering, alarm annunciation, and distribution automation, into a unified data acquisition and control (DAC) system The SA System will provide the framework to enable existing and future IEDs and conventional electromechanical devices from various suppliers to interoperate, the result being a more efficient and cost-effective monitoring and control system for OPPD's substations.

The implementation of SA Systems at OPPD's pilot substations is being conducted as part of an EPRI TC project. Therefore, the SA Systems should employ to the fullest extent equipment and principles that are consistent with EPRI's Utility Communications Architecture version 2 (UCA2), including.

- Ethernet local area network

- Manufacturing Messaging Specification (MMS) application layer
- GOOSE event objects
- GOMSFE device object models

Approximately 50 IEDs will be installed in Substation 912, which is scheduled for energization in July 2001. A local LAN will be provided by the integrator for handling communications among the IEDs in the substation. All IEDs required by OPPD that support UCA2 MMS will be directly connected (no interface module that is external to the IED is required) to the SA System using UCA2 MMS and Ethernet. For OPPD's IEDs that do not support UCA2 MMS, the integrator will provide appropriate interfaces to translate the different IED protocols to the common LAN protocol for common access services A data concentrator will be provided for the IED data. A local user interface will be included The interface to the Energy Management System (EMS) will use OPPD-supplied leased telephone lines. The integration architecture for Substation 912 is shown in Figure 5 below.



Substation 912

Figure 5 – Substation 912 Integration Architecture

The SA System for Substation 1345, which will be energized in June 2002, will use the same general configuration as the SA System for Substation 912, with the following exceptions. The SA System for Substation 1345 will interface with approximately 25 IEDs. All IEDs required by OPPD that support UCA2 MMS will be directly connected (no interface module that is external to the IED is required) to the Substation 1345 SA System using UCA2 MMS and Ethernet For OPPD's IEDs that do not support UCA2 MMS, the integrator will provide appropriate interfaces to translate the different IED protocols to the common LAN protocol for common access services The SA System for Substation 1345 will interface to the EMS via OPPD's optical fiber communication network.

A separate SA System will be provided to enable OPPD to conduct training in a simulated but realistic manner without impacting substation operations The SATS will also enable OPPD to develop and test new SA System software, including displays, databases, and reports, and modify existing software. The SATS will be a fully operational system that will include all SA System software and all major components of the SA System, including the local user interface, local area network, IED interfaces (as required), EMS and data warehouse interfaces, and other SA System components. The SATS equipment is identical to the system provided for Substation 912, except that the SATS database sizing will be smaller to reflect the smaller number of hardwired I/O and I/O from IEDs The interface to the EMS and the data warehouse will use the OPPD-supplied fiber communication network. The SATS will accept simulated analog and digital inputs from an OPPD test panel. The test panel will be equipped with test switch isolation as well as current and voltage injection capabilities.

The integration architecture for Substation 1345 and the SATS is shown in Figure 6 below

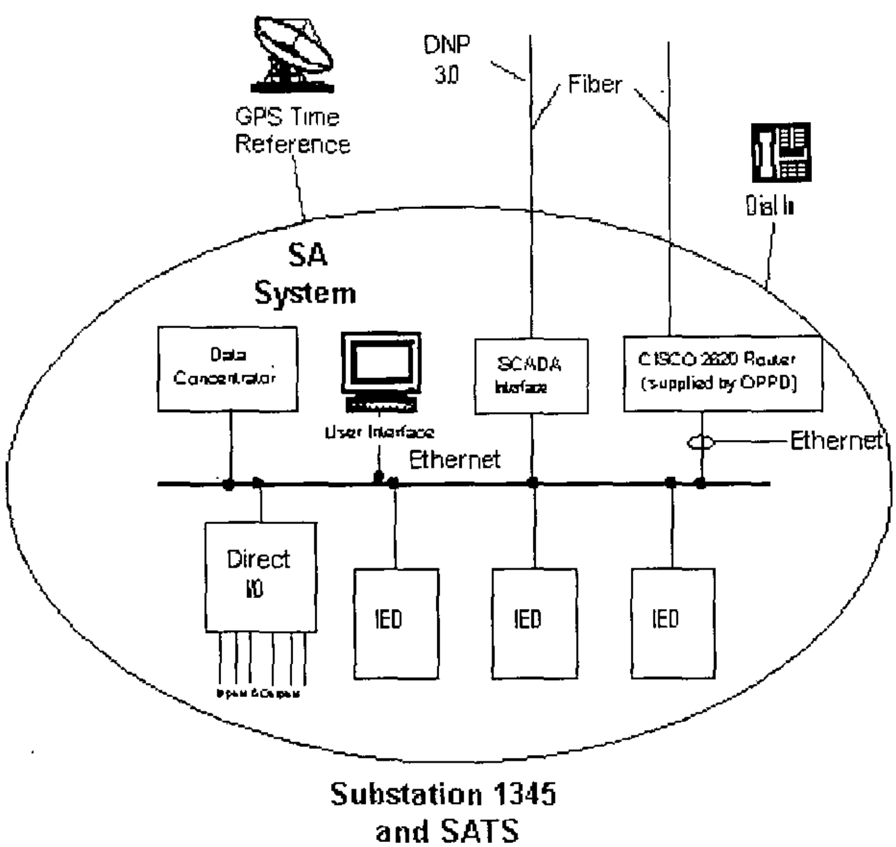


Figure 6 – Substation 1345 and SATS Integration Architecture

Equipment Condition Monitoring at Pilot Installations

ECM devices will be integrated into the SA System architecture. In this way, the data from these devices can be sent to both the EMS SCADA system and the corporate data warehouse OPPD users will be able to access this data on the corporate network This sharing of device diagnostic data is not possible now with the dial up connections used to interrogate the devices, and the subsequent storing of retrieved data in various office PCs

In general, depending on the specific substation, the following ECM devices will be included in the SA System:

- Beckwith LTC Controller, Type M-2001B
- Rochester (RIS) Transformer Alarm Annunciator AN-3196B
- Hathaway Breaker Condition Monitor BCM 200
- Qualitrol Transformer Temperature Monitor TTM 509-100
- Barrington Temperature Differential TDM System 3
- Barrington STAR10000 (timing and velocity)
- Doble On-Line Diagnostics Expert System INSITE
- GE Harley T-MAP 3100
- GE Harley LTC-MAP 2130
- GE Syprotec FARADAY TMMS (transformer monitoring and management system)

The following ECM devices will be integrated in the SA System for Substation 912.

- Four Beckwith LTC Controllers, Type M-2001B (in transformer cabinet)
- Four Rochester (RIS) Transformer Alarm Annunciators AN-3196B (in transformer cabinet)
- Four Qualitrol Transformer Temperature Monitors TTM 509-100 (in transformer cabinet)
- Four GE Harley LTC-MAP 2130 (in transformer cabinet)

The following ECM devices will be integrated in the SA Systems for Substation 1345 and the SATS

- One Beckwith LTC Controller, Type M-2001B (in transformer cabinet)
- One Rochester (RIS) Transformer Alarm Annunciator AN-3196B (in transformer cabinet)
- One Qualitrol Transformer Temperature Monitor TTM 509-100 (in transformer cabinet)
- One GE Harley LTC-MAP 2130 (in transformer cabinet)

The goal of the project was to interface these devices using UCA2 MMS However, none of the devices support this interface The secondary goal was to interface the devices using DNP3. Only the Beckwith and Qualitrol devices support DNP3 The Rochester unit supports Modbus. A separate interface module will be developed, at additional cost, to integrate the GE Harley devices into the SA System architecture

CONCLUSIONS

ECM IEDs are being implemented by many utilities. In most implementations, the communication link to the IED is via a dial up telephone line. To facilitate integrating these IEDs into the substation architecture, the ECM IEDs must support at least one of today's widely used IED protocols: Modbus, Modbus Plus or DNP3. In addition, a migration path to UCA2 MMS is desired by the utility.

If the ECM IEDs can be integrated into the substation architecture, the operational data will have a path to the EMS or SCADA system, and the non-operational data will have a path to the utility's data warehouse (or equivalent). In this way, the users and systems throughout the utility that need this information will have access to it.

Once the information is brought out of the substation and into the SCADA system and data warehouse, users share the information in the utility. The "private" databases that result in islands of automation will go away

Therefore, the goal of every utility is to implement ECM IEDs, integrate these IEDs into a standard substation integration architecture, so that both operational and non-operational information from the IEDs can be shared by utility users.

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1. D. Dahlgren and J. Harley, "Implementing a Static Electrification Diagnostic Model", presented at the EPRI Transformer Reliability: Management of Static Electrification in Power Transformers Symposium, Monterey, California, May 1999

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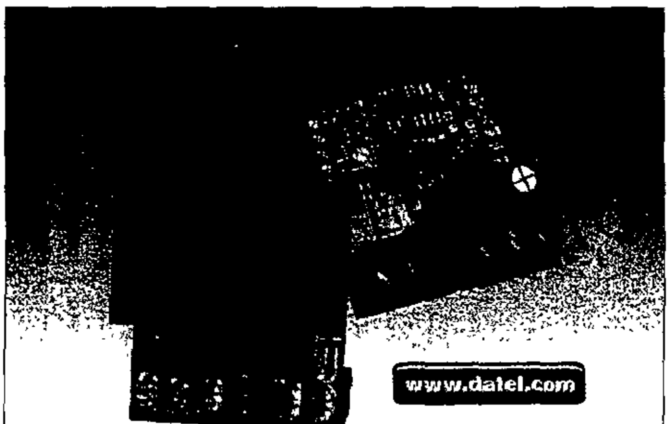
Successful Integration and Automation Relies on Strategic Plan

Automation Requires Integration

Electric distribution utilities frequently ask the question, "Can we afford to automate?" Given the potential cost, the question is certainly reasonable. But in the era of deregulation and ever-increasing regulatory pressure, the question really ought to be, "Can we afford not to?" The truth is that if you don't spend the money to automate in the near future, your competitor probably will. And from that point on, instead of competing head-on, you will be playing catch-up in a marketplace geared toward competition. In that light, it's best to consider distribution automation as an investment rather than an expense.

The cost-saving advantages of automation are well documented – systems operate more efficiently with fewer outages, assets are better utilized and maintained, and personnel safety improves. These add up to reduced costs and greater reliability, which ultimately wins customers and pleases regulators.



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But there is another equally important, yet less tangible, pay-off from automation — information. It's the commodity of the 21st century and it's what will provide the competitive edge in the utility industry from now on Implemented correctly, automation puts information about the distribution system — and your customers — onto the desktops of every department in the enterprise for analysis.

Suddenly, the guys in marketing are brainstorming with the engineers about how to create and sell customized services. When accurate information is available quickly to personnel at all levels, everyone starts making better decisions, and that benefits the entire organization.

Better yet, automation positions a utility to serve real-time information directly to the customer. Several savvy distribution companies already are publishing detailed system reliability information and up-to-date customer usage data on their web sites. Voltages, currents, megawatts and outage history are all right there on the Internet for existing and potential customers to see.

For consumers who have grown accustomed to immediate online access to bank balances and credit card statements, such web-based information is more than a nice feature. It's a benefit that can attract and retain them

As is true with many high-tech innovations, utility automation requires proper implementation to deliver the advertised benefits. In the distribution network, a correctly implemented automation project does not stand alone. Automation devices must be integrated into the architecture of the distribution system itself, most effectively at the substation level, drawing data from every piece of equipment and subsystem.

Secondly, integration and automation require communication links between the computerized devices and the rest of the utility enterprise. There are at least three distinct paths that can be exploited for data from the substation to travel within a distribution utility This is how automation data is shared for simultaneous access and analysis throughout the company.

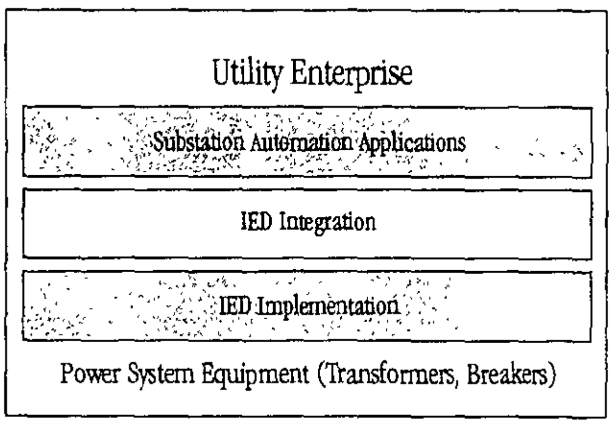


Fig. 1 Substation Integration and Automation Levels

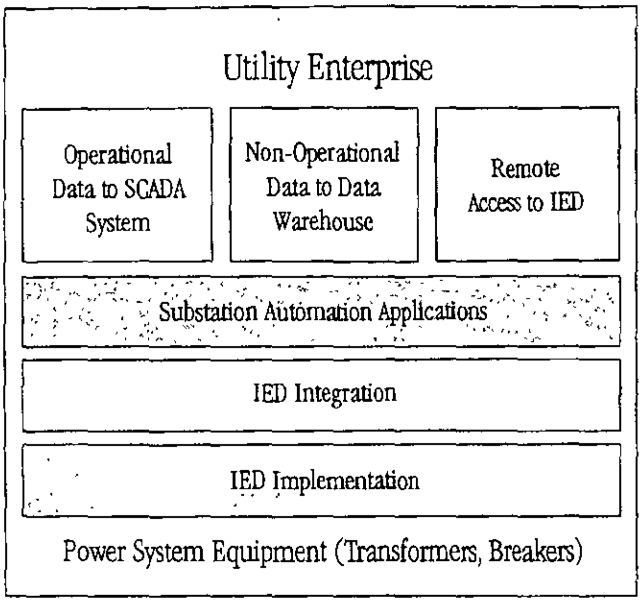


Fig. 2 Three Functional Data Paths from Substation to Utility Enterprise

Ensuring that automation and integration proceed hand-in-hand guarantees a quick return on investment. Making it happen requires a strategic plan and a commitment to carry out that plan as it was designed. And in all cases, communications infrastructure must be sufficient to successfully support the automation.

What is Distribution Automation?

In a distribution utility there are three areas where automation can be implemented – at the customer location, on the feeders and in the substation. Each has pros and cons, but substations are the typical focal points because they are the greatest source of information.

Every utility has varying needs for automation depending on the age of its infrastructure, service area demographics and degree of existing automation. For this reason, all three sources of distribution automation should be considered in developing a strategic implementation plan. Here is a quick overview of the benefits, and possible pitfalls, of each:

Customer Automation – Automatic Meter Reading (AMR) technology and services associated with it, such as automatic connect/reconnect, are gaining in popularity. AMR periodically records meter readings and relays this information back to a utility office. Installed at the customer location, AMR replaces a human meter reader. It is especially effective in high-crime neighborhoods where utility personnel may find themselves in danger.

The primary expense involved in AMR is not the meter itself Rather it is the communications link, usually a wireline (telephone) or wireless connection, that transmits to the utility office from each individual user location. For large commercial and industrial customers who use a lot of power, this expense is quickly repaid. But for tens of thousands of residential customers, the cost is difficult to justify for simple meter reading.

A related service that can pay for itself is automatic connect/reconnect. In cities with rapid population turnover, several utilities have found it is cost-effective to remotely disconnect service every time a customer moves rather than send a crew to do it manually. But this may be the exception in regards to AMR pay-out.

However, just because AMR might not be cost-effective or improve utility personnel safety, it should not be discounted from an automation plan. The reason is that AMR requires the utility to make a live communications link with each customer, and that link may serve as the conduit through which other valuable services can be offered.

Once two-way communication has been established to a residential user, the utility has opened the door to offering such lucrative services as remotely monitored home security, high-speed Internet access and cable television. But the key to providing these services is including them in the strategic distribution automation plan at the outset so the appropriate telecommunications infrastructure can be installed.

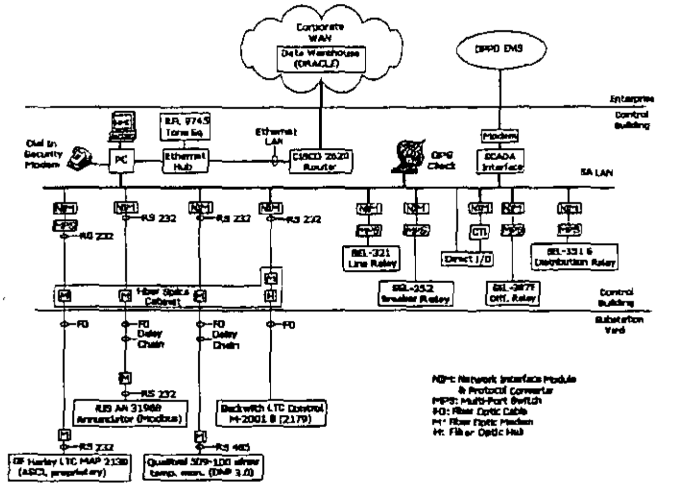
Feeders – Automating feeders typically entails installation of sectionalizing devices, or switches, along the feeder. When there is a problem with the feeder, data will be fed back to the substation or control center for analysis. Once the problem has been identified, a technician can remotely activate the switch to isolate the segment causing the trouble and reroute service to sections on either side of the problem, or this process may be done automatically.

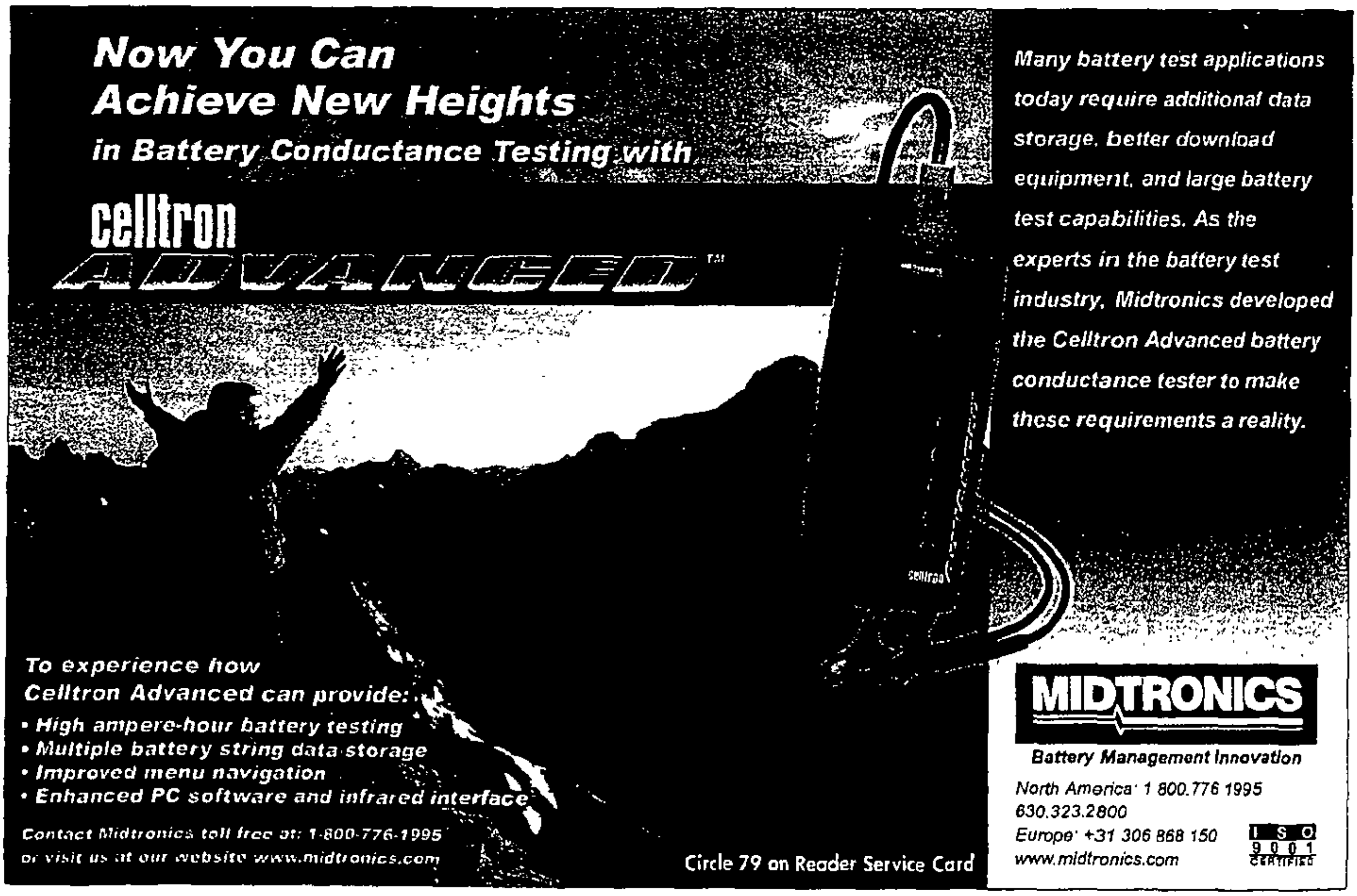
The financial challenge of feeder automation is similar to that of AMR – feeders are numerous and are spread over large geographic areas, making installation and maintenance of two-way communication an expensive proposition. As a result, feeder automation is often limited to the 10 or 15 worst performing feeders.

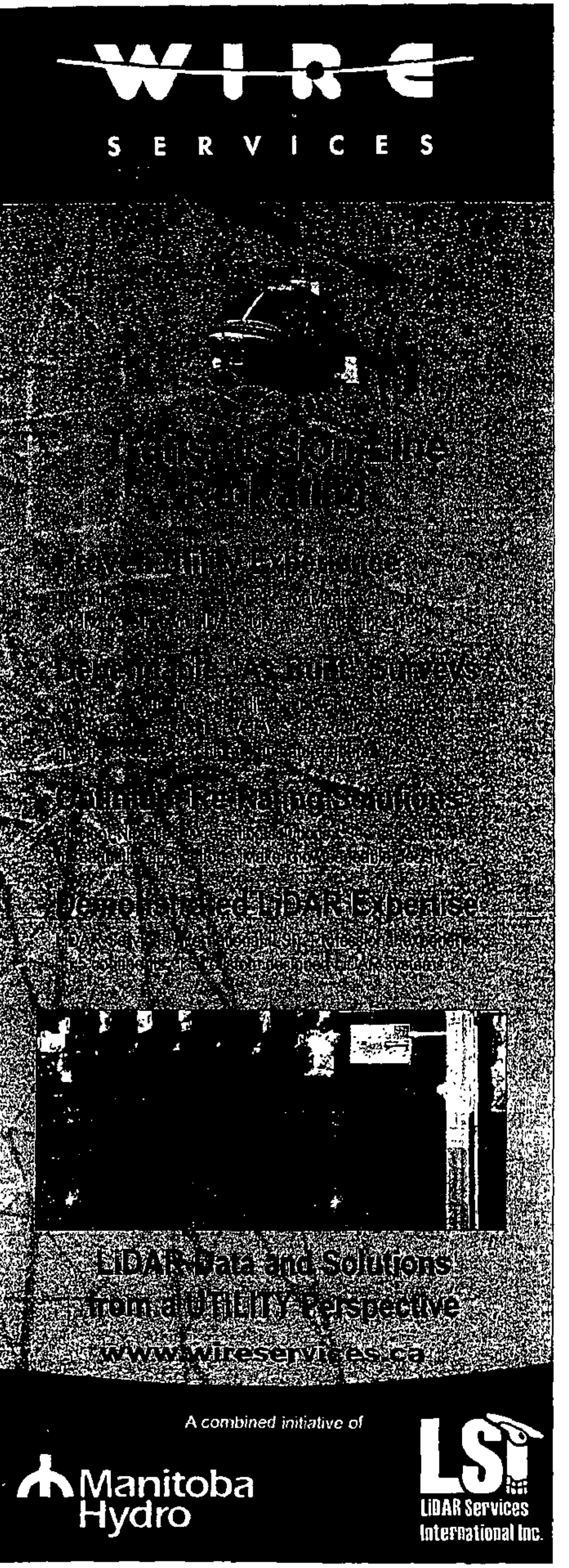
By concentrating on problematic feeders, utilities spend less money and can guarantee their automation investment will pay off in reduced duration and frequency of outages. This sort of targeted feeder automation is likely to remain standard procedure in distribution automation projects.

A typical initial step in implementing feeder automation is to install a tie switch on a feeder between two substations. Often referred to as using half switches, the method provides the capability to shift feeder load segments from one substation to another.

Substation – Integration and automation typically focus here because the substation is where all of that valuable operations and customer information resides. Whether they know it or not, most utilities already engage in the first level of substation automation – intelligent electronic device (IED) implementation. <see graphic>







Since the late 1980s, advancements in microprocessor technology have eliminated single function electromechanical equipment in favor of multi-function IEDs. These single-function electromechanical devices have given way to multi-function electronic devices with built-in two-way communications capabilities.

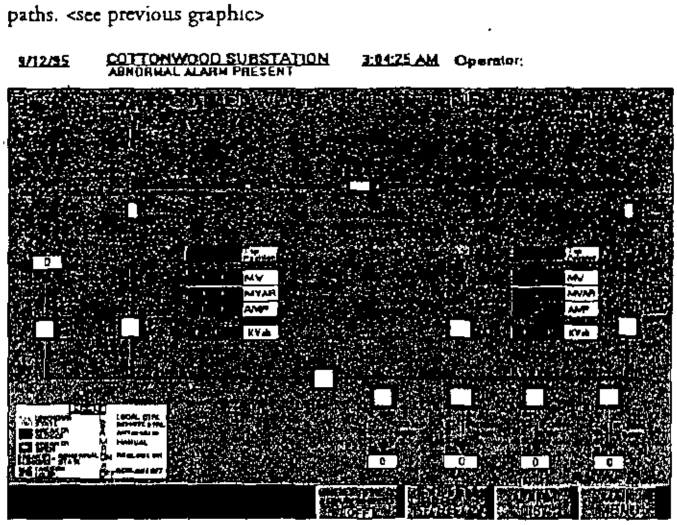
Years ago, separate electromechanical relays were required for overcurrent and undervoltage protection Today, one microprocessor-based device does that and more. They not only protect the power system, but they can also perform calculations of energy in a circuit breaker and store historical data in their memory. Microprocessor-based relays can identify when a fault occurred and the series of events that resulted from it.

That's incredibly valuable information. Too bad so few utilities use it. This is because most have not tapped the two-way communication capabilities in these devices to access and integrate the data they hold into the information flow of the enterprise. The average utility is realizing about 10 percent of their investment in a $5,000 microprocessor-based relay.

A substation integration mistake made most commonly is not creating and following a strategic substation integration and automation plan Too often an engineer gets excited about a vendor's substation integration and automation architecture and has it installed. Next, a different vendor offers a substation integration and automation architecture with different features, and that one is installed too. The next thing a utility knows, it has 12 substations operating with substation architectures from five different vendors. No utility has the resources to use and support such a variety of equipment and architectures.

Integrating the Substation

The key to capitalizing on the capabilities of automated devices is integrating the devices and linking them to the utility enterprise along three data paths. <see previous graphic>



Substation integration systems are a combination of software and hardware to meet the needs of an individual utility. These integration systems are offered as products by companies well known to the industry – Tasnet in Clearwater, Florida; Hathaway in Hunt Valley, Maryland; GE in Calgary, Alberta, Canada; ABB in Allentown, Pennsylvania; and Siemens in Raleigh, North Carolina. Each integration architecture is different, but all exploit the three data paths into and out of the substations to take advantage of IED installations.

Often referred to as the operational data path, the first is between the substation integration and automation system and the SCADA system. The SCADA can be programmed to scan automated devices in the substation every few seconds to retrieve instantaneous values on voltage, current and other data. The operational data path is established for a continuous feed of data.

Several factors must be considered in leveraging this path. First, substation integration and automation systems must have the capability to interface with older SCADA systems and their proprietary protocols. Secondly, the bandwidth of the communications infrastructure chosen for this path must support requirements of the SCADA and the substation integration and automation system.

The second data path is more of a challenge. It involves gaining access to the non-operational information in the IEDs. Non-operational data includes fault event logs, harmonic information, and power quality information such as voltage sags and swells, information that needs to be transferred to a corporate data warehouse where many users can retrieve it into their desktop applications for analysis.

Each different device in the substation typically operates with a different protocol for this non-operational data path. The data on this path is on-demand, non-periodic, which means protocol issues are more complicated. Usually the demand is for a large file or a burst of data, necessitating a bandwidth of at least 56 kbps on a frame relay or fiber optic network.

Non-operational data is transmitted back to the corporate data warehouse. This warehouse is typically a series of centralized servers for redundancy that incorporate all business and operations information from around the utility for enterprise-wide access. Because not all utilities currently have such a data warehouse, installation of one is often included in an automation project.

The third path is remote access, which allows a user at a location outside the substation to access the IEDs. With proper security and access privileges, the user might review device settings or actually change parameters, as well as download non-operational IED data for analysis.

Often called pass-through or loop-through, this communication path is typically a dial-up phone line or dedicated fiber optic connection. The user dials into a secure modem, which then calls the user back if his or her phone number is approved. The user then dials a code to specify which device the communications link should be established with. Data flow between the caller and the device is two-way.

By integrating IEDs into the architecture of the substation and linking the flow of data from the substation to the enterprise, the utility truly realizes the potential in the investment it has made in the IEDs.

Creating a Strategic Plan

Successful integration and automation projects require a strategic plan, or a blue print for how and when various IEDs and integration architectures will be installed. The first step is to examine the integration and automation functions available and perform a cost-benefit analysis to determine if a specific utility will benefit from the implementation of that function. Not all will.

Matching the needs of the utility with available technology is critical. As odd as it may sound, sometimes automation technology is not yet available to accomplish what the utility needs. Off-the-shelf products are always preferred over customized ones simply because of the cost involved. Customization may completely destroy a return-on-investment estimate.

The next step is developing a phased-in approach for implementation of integration and automation. Few utilities can afford to pay for a large-scale implementation in one year, so the project may be spread over five or more. But it is critical to stick with the original plan and determine how implementation of integration and automation should proceed to ensure the utility begins experiencing benefits immediately.

Keep in mind that communications is the enabling technology of integration and automation. This means that existing communications capabilities must be compared with what will be needed for the planned project and for future automation.

As mentioned at the outset, most utilities can't afford not to integrate and automate. With a simple substation pilot costing around $50,000 to $100,000 per substation, the benefits typically are far greater than the costs, especially since the IEDs are already installed in the substation.

Measuring Success

In terms of substation integration, look for positive operational changes to see if benefits of specific functions are being realized. For example, in the successfully integrated substation there will be smaller control panels, reduced wiring and elimination of many conventional displays as computers replace mechanical devices. The result is that utilities begin building much smaller substations at significantly less cost. With respect to cost/-benefits, the advantages of these changes quickly impact the bottom line.

Even enterprise-wide integration and automation projects pay off in one to three years, but utilities and their stockholders want to see quantitative results immediately. The best measurements to use in assessing the success of any size distribution automation project are the industry standard indices of reliability – System Average Interruption Frequency Index (SAIFI), Momentary Average Interruption Frequency Index (MAIFI) and System Average Interruption Duration Index (SAIDI).

These are the same indices regulatory agencies use to measure utility performance, and as deregulation progresses the typical residential customer is likely to become savvy in their meaning too. In the near future, we are likely to see these numbers like report cards on publicly available web site. And you can be sure the utilities with the scores that show steady improvement are the ones that have invested in automation and integration. ■

M-3410

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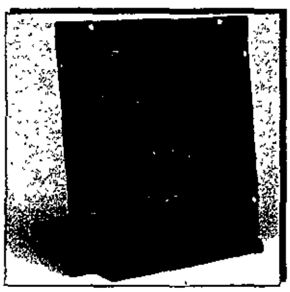

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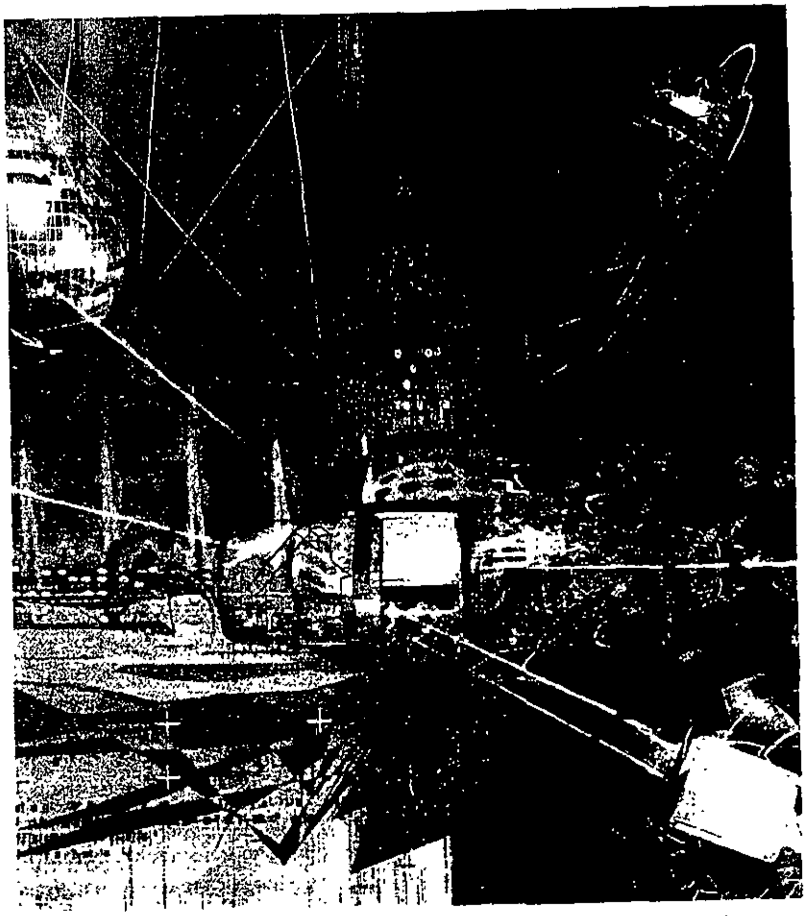
John D. McDonald

substation automation

IED integration and availability of information



DIGITAL VISION

Utilities must determine a standard integration architecture that meets their secific needs in extracting desired opertaional and nonoperational data and delivering it to the users.

ELECTRIC UTILITY DEREGULATION, economic pressures forcing downsizing, and the marketplace pressures of potential takeovers have forced utilities to examine their operational and organizational practices. Utilities are realizing that they must shift their focus to customer service. Customer service requirements all point to one key element: information, i.e., the right amount of information to the right person or computer within the right amount of time The flow of information requires data communication over extended networks of systems and users. In fact, utilities are becoming among the largest users of data and are the largest users of real-time information.

The advent of industry deregulation has placed greater emphasis on the availability of information, the analysis of this information, and the subsequent decision-making to optimize system operation in a competitive environment. Intelligent electronic devices (IEDs) being implemented in substations today contain valuable information, both operational and nonoperational, needed by many user groups within the utility. The challenge facing utilities is determining a standard integration architecture that meets the utility's specific needs, can extract the desired operational and nonoperational information, and deliver this information to the users who have applications to analyze the information.

This issue of *IEEE Power & Energy Magazine* focuses on substation integration and automation My Guest Editorial provides an overview of substation integration and automation fundamentals and focuses on best practices. It also includes a list of:

- ✔ further reading material for those who require more information on the same subject
- ✔ acronyms and abbreviations for those readers who are not familiar with the terminology.

Three feature articles follow with more specific information on:

- ✔ a business case methodology for expanding the implementa-

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tion of substation automation technologies at MidAmerican Energy Company
- ✔ a pilot project at Omaha Public Power District to integrate data from various devices within two substations and a simulator
- ✔ a generic architecture that applies the multiagent systems methodology to the field of substation automation.

Open Systems

An open system is a computer system that embodies supplier-independent standards so that software may be applied on many different platforms and can interoperate with other applications on local and remote systems. An open system is an evolutionary means for a substation control system that is based on the use of nonproprietary, standard software and hardware interfaces. Open systems enable future upgrades available from multiple suppliers at lower cost to be integrated with relative ease and low risk.

The concept of open systems applies to substation automation. It is important to learn about the different de jure (legal) and de facto (actual) standards and then apply them so as to eliminate proprietary approaches. An open systems approach allows the incremental upgrade of the automation system without the need for complete replacement, as happened in the past with proprietary systems. There is no longer the need to rely on one supplier for complete implementation. Systems and IEDs from competing suppliers are able to interchange and share information. The benefits of open systems include longer expected system life, investment protection, upgradeability and expandability, and readily available third-party components.

Levels of Integration and Automation

Substation integration and automation can be broken down into five levels, as shown in Figure 1. The lowest level is the power system equipment, such as transformers and circuit breakers. The middle three levels are IED implementation, IED integration, and substation automation applications. All electric utilities are implementing IEDs in their substations. The focus today is on the integration of the IEDs. Once this is done, the focus will shift to what automation applications should run at the substation level. The highest level is the utility enterprise, and there are multiple functional data paths from the substation to the utility enterprise.

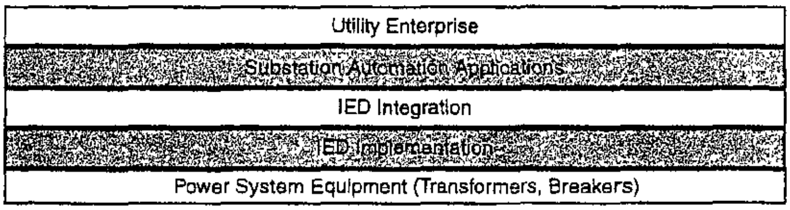

figure 1. Five levels of substation integration and automation.

Since substation integration and automation technology is fairly new, there are no industry standard definitions, except for the definition of an IED. The industry standard definition of an IED is given below, as well as definitions for substation integration and substation automation.

- ✔ *IED*. Any device incorporating one or more processors with the capability to receive or send data/control from or to an external source (e.g., electronic multifunction meters, digital relays, controllers). An example of a relay IED is shown in Figure 2.
- ✔ *Substation integration*: Integration of protection, control, and data acquisition functions into a minimal number of platforms to reduce capital and operating costs, reduce panel and control room space, and eliminate redundant equipment and databases.
- ✔ *Substation automation*: Deployment of substation and feeder operating functions and applications ranging from supervisory control and data acquisition (SCADA) and alarm processing to integrated volt/var control in order to optimize the management of capital assets and enhance operation and maintenance (O&M) efficiencies with minimal human intervention

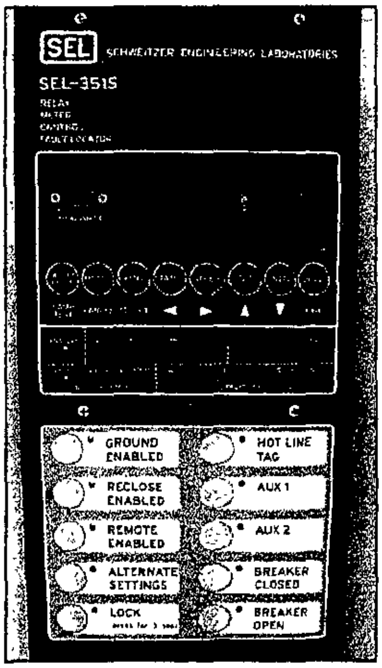

figure 2. Example of a relay IED.

Architecture Functional Data Paths

There are three primary functional data paths from the substation to the utility enterprise, as shown in Figure 3. The most common data path is conveying the operational data (e.g., volts, amps) to the utility's SCADA system every 2 to 4 s. This information is critical for the utility's dispatchers to monitor and control the power system. The most challenging data path is conveying the nonoperational data to the utility's data warehouse. The challenges associated with this data path include the characteristics of the data (waveforms rather than points), the periodicity of data transfer (not continuous, on demand), and the protocols used to obtain the data from the IEDs (not standard, IED supplier's proprietary protocols). Another challenge is whether the data

A corporate data warehouse enables users to access substation data while maintaining a firewall to substation control and operation functions.

is pushed from the substation into the data warehouse, pulled from the data warehouse, or both. The third data path is remote access to an IED by passing through or looping through the substation integration architecture and isolating a particular IED in the substation.

Data Warehouse

The corporate data warehouse enables users to access substation data while maintaining a firewall to substation control and operation functions. Both operational and nonoperational data is needed in the data warehouse. To size the data warehouse, the utility must determine who the users of the substation automation system data are, the nature of their application, the type of data needed, how often the data is needed, and the frequency of update required for each user. Examples of user groups within a utility are substation design engineering, protective relay engineering, protective relay technicians, substation metering, substation operations, control center operations, engineering planning, transmission and distribution engineering, power quality, substation test, substation maintenance, predictive maintenance, communications engineering, SCADA, feeder automation, and information technology.

SA System Functional Architecture Diagram

The functional architecture diagram in Figure 4 shows the three functional data paths from the substation to the utility enterprise, as well as the SCADA system and the data warehouse. The operational data path to the SCADA system utilizes the communication protocol presently supported by the SCADA system. The nonoperational data path to the data warehouse conveys the IED nonoperational data from the SA system to the data warehouse, either being pulled by a data warehouse application from the SA system or being pushed from the SA system to the data warehouse based on an event trigger or time. The remote access path to the substation utilizes a dial-in telephone connection. The global positioning system (GPS) satellite clock time reference is shown, providing a time reference for the SA system and IEDs in the substation. The PC provides the graphical user interface (GUI) and the historical information system for archiving operational and nonoperational data. The SCADA interface knows which SA system points are sent to the SCADA system, as well as the SCADA system protocol. The local area network (LAN) enabled IEDs can be directly connected to the SA LAN. The non-LAN enabled IEDs require a network interface module (NIM) for protocol and physical interface conversion. The IEDs can have various applications, such as equipment condition monitoring (ECM) and relaying, as well as direct (or hardwired) input/output (I/O).

New Versus Existing Substations

The design of new substations has the advantage of starting with a blank sheet of paper. The new substation will typically have many IEDs for different functions, and the majority of operational data for the SCADA system will come from these IEDs. The IEDs will be integrated with digital two-way communications. The small amount of direct input/output (hardwired) can be acquired using programmable logic controllers (PLCs). Typically, there are no conventional remote terminal units (RTUs) in new substations. The RTU functionality is addressed using IEDs, PLCs, and an integration network using digital communications.

In existing substations, there are several alternative approaches, depending on whether or not the substation has a conventional RTU installed. The utility has three choices for their existing conventional substation RTUs:

- ✔ Integrate RTU with IEDs: Many utilities have integrated IEDs with existing conventional RTUs, provided the RTUs support communications with downstream devices and support IED communication protocols. This integration approach works well for the operational data path but does not support the nonoperational and remote-access data paths. The latter two data paths must be done outside of the conventional RTU.
- ✔ Integrate RTU as another substation IED: If the utility desires to keep its conventional RTU, the preferred approach is to integrate the RTU in the substation integration architecture as another IED. In this way, the RTU can be retired easily as the RTU hardwired direct input/output transitions to come primarily from the IEDs.

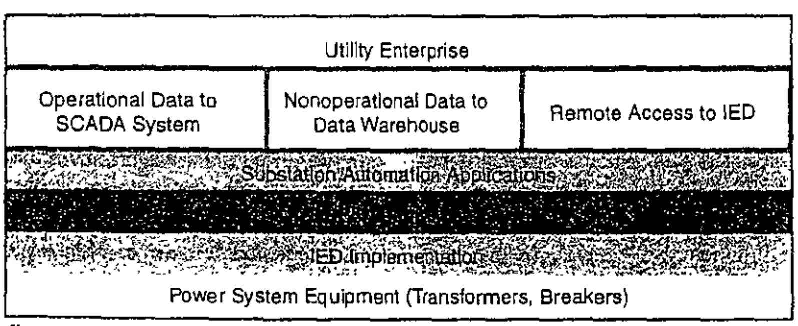

figure 3. Three functional data paths from substation to utility enterprise.

- ✔ Retire RTU and use IEDs and PLCs as with a new substation: The RTUs may be old and difficult to support, and the substation automation project may be a good time to retire these older RTUs. The hardwired direct input/output from these RTUs would then come from the IEDs and PLCs as with a new substation.

Equipment Condition Monitoring

Many electric utilities have employed ECM to maintain electric equipment in top operating condition while minimizing the number of interruptions. With ECM, equipment-operating parameters are automatically tracked to detect the emergence of various abnormal operating conditions. This allows substation operations personnel to take timely action when needed to improve reliability and extend equipment life. This approach is applied most frequently to substation transformers and high voltage electric supply circuit breakers to minimize the maintenance costs of these devices, as well as improve their availability and extend their useful life. Figure 5 shows an ECM IED installed on a substation transformer.

Equipment availability and reliability may be improved by reducing the amount of offline maintenance and testing required, as well as reducing the number of equipment failures. To be truly effective, equipment condition monitoring should be part of an overall condition-based maintenance strategy that is properly designed and integrated into the regular maintenance program.

ECM IEDs are being implemented by many utilities. In most implementations, the communication link to the IED is via a dial-up telephone line. To facilitate integrating these IEDs into the substation architecture, the ECM IEDs must support at least one of today's widely used IED protocols: Modbus, Modbus Plus, or Distributed Network Protocol version 3 (DNP3). In addition, a migration path to utility communications architecture version 2 (UCA2) manufacturing message specification (MMS) protocol is desired. If the ECM IEDs can be integrated into the substation architecture, the operational data will have a path to the SCADA system, and the nonoperational data will have a path to the utility's data warehouse. In this way, the users and systems throughout the utility that need this information will have access to it. Once the information is brought out of the substation and into the SCADA system and data warehouse, users can share the information in the utility. The "private" databases that result in islands of automation will go away. Therefore, the goal of every utility is to integrate these ECM IEDs into a standard substation integration architecture so that both operational and nonoperational information from the IEDs can be shared by utility users.

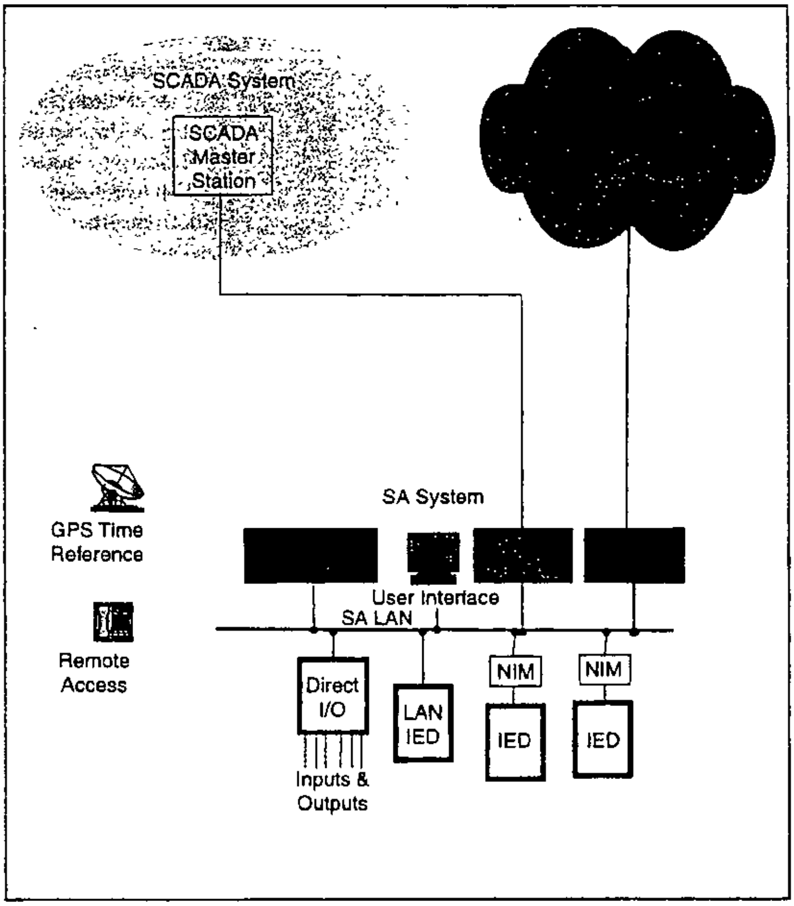

figure 4. SA system functional architecture diagram.

Substation Automation Training Simulator

One of the challenges for electric utilities when implementing substation automation for the first time is to create

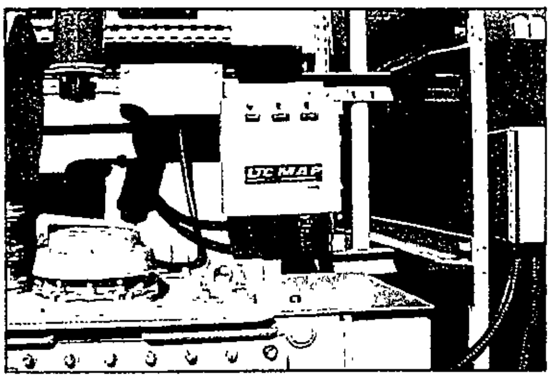

figure 5. ECM IED installed on substation transformer

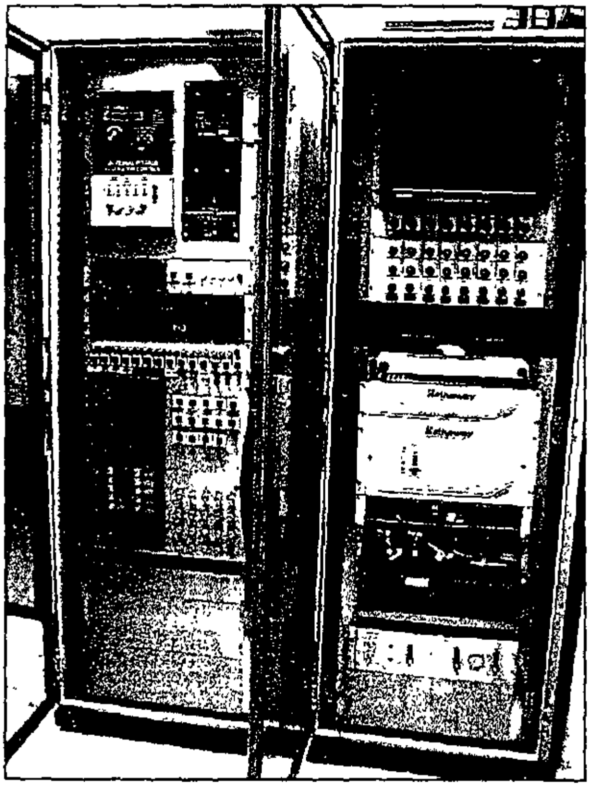

figure 6. Substation automation training simulator.

"buy-in" for the new technology within the utility. The more people know about a subject the more comfortable they feel and the better the chance they will use the technology. It is much easier and less stressful to learn about substation automation technology in a training environment, away from the substation, than on a system installed in an energized substation. For these reasons, many utilities purchase a substation automation training simulator (SATS), which is an identical configuration to that installed in substations. The main difference is that the SATS includes at least one of every kind of IED installed in all substations. In addition to training, SATS is used for application development and testing of new IEDs. An example of a SATS presently installed at an electric utility is shown in Figure 6.

Protocol Fundamentals

A communication protocol allows communication between two devices. The devices must have the same protocol (and version) implemented. Any protocol differences will result in communication errors.

If the communication devices and protocols are from the same supplier, i.e., where a supplier has developed a unique protocol to utilize all the capabilities of the two devices, it is unlikely the devices will have trouble communicating. By using a unique protocol of one supplier, a utility can maximize the device's functionality and see a greater return on its investment; however, the unique protocol will constrain the utility to one supplier for support and purchase of future devices.

If the communication devices are from the same supplier but the protocol is an industry-standard protocol supported by the device supplier, the devices should not have trouble communicating. The device supplier has designed its devices to operate with the standard protocol and communicate with other devices using the same protocol and version. By using a standard protocol, the utility may purchase equipment from any supplier that supports the protocol and, therefore, can comparison-shop for the best prices.

Industry-standard protocols typically require more overhead than a supplier's unique protocol. Standard protocols often require a higher speed channel than a supplier's unique protocol for the same efficiency or information throughput. However, high-speed communication channels are more prevalent today and may provide adequate efficiency when using industry-standard protocols. UCA2 MMS is designed to operate efficiently over 10 Mb/s switched or 100 Mb/s shared or switched Ethernet. If a utility is considering UCA2 MMS as its protocol of choice, a prerequisite should be installation of high-speed communications If the utility's plan is to continue with a communication infrastructure operating at 1,200 to 9,600 b/s, the better choice for an industry-standard protocol would be DNP3.

A utility may not be able to utilize all of a device's functionality using an industry standard protocol. If a device was designed before the industry standard protocol, the protocol may not thoroughly support the device's functionality. If the device was designed after the industry standard protocol was developed, the device should have been designed to work with the standard protocol such that all of the device's functionality is available.

The substation integration and automation architecture must allow devices from different suppliers to communicate (interoperate) using an industry-standard protocol. The utility has the flexibility to choose the best devices for each application, provided the suppliers have designed their devices to achieve full functionality with the protocol. Though devices from different suppliers can operate and communicate under the standard protocol, each device may have capabilities not supported by the other device. There is also a risk that the protocol implementations of the industry-standard protocol by the two suppliers in each device may have differences. Factory testing will verify that the functions of one device are supported by the protocol of the other device and vice versa. If differences and/or incompatibilities are found, they can be corrected during factory testing.

Protocol Considerations

There are two capabilities a utility considers for an IED. The primary capability of an IED is its standalone capabilities, such as protecting the power system for a relay IED. The secondary capability of an IED is its integration capabilities, such as its physical interface (e.g., RS-232, RS-485, Ethernet) and its communication protocol (e.g., DNP3, Modbus, UCA2 MMS).

Today utilities typically specify the IEDs they want to use in the substation rather than giving a supplier a turnkey contract to provide the supplier's IEDs only in the substation. However, utilities typically choose the IEDs based on the IED's standalone capabilities only, without considering the IED's integration capabilities. Once the IEDs are installed, the utility may find in the future, when they want to integrate the IEDs, that the IEDs were purchased with the IED supplier's proprietary protocol and with a physical interface not desired (RS-485 purchased when Ethernet is desired). When purchasing IEDs, the utility must consider both the standalone capabilities in the choice of the IED and the integration capabilities when ordering the IED, even if the IEDs will not be integrated in the near future.

Today, the most common IED communication protocols are Modbus, Modbus Plus, and DNP3. The UCA2 MMS protocol is becoming commercially available from more IED suppliers and being implemented in more utility substations. However, the implementations may not be optimal (adding a separate box for the UCA2 MMS protocol and Ethernet networking) and may result in poor performance (data latency due to the additional box) rather than the supplier incorporating the new functionality into the existing IED. The utility must be cautious when ordering an IED with other than the IED supplier's target protocol, often supplier proprietary, used in the design of the IED. Some IED functionality may be lost when choosing other than the IED supplier's target protocol.

The most common IED networking technology today in substations is serial communications, either RS-232 or RS-485. As more and more IEDs become available with Ethernet ports, the IED networking technology in the substation will be primarily Ethernet.

Utility Communication Architecture

The use of international protocol standards is now recognized throughout the electric utility industry as a key to successful integration of the various parts of the electric utility enterprise. One area addresses substation integration and automation protocol standardization efforts. These efforts have taken place within the framework provided by the Electric Power Research Institute's (EPRI's) UCA.

UCA is a standards-based approach to utility data communications that provides for wide-scale integration from the utility enterprise level (as well as between utilities) down to the customer interface, including distribution, transmission, power plant, control center, and corporate information systems. UCA version 1.0 specification was issued in December 1991 as part of EPRI Project RP2949, Integration of Utility Communication Systems. While this specification supplied a great deal of functionality, industry adoption was limited, due in part to a lack of detailed specifications about how the specified protocols would actually be used by applications. For example, the MMS (ISO/IEC 9506) protocol was specified for real-time data exchange at many levels within a utility, but specific mappings to MMS for exchanging power

Acronyms and Abbreviations

DNP	distributed network protocol
ECM	equipment condition monitoring
EPRI	Electric Power Research Institute
GOMSFE	generic object models for substation and feeder equipment
GPS	global positioning system
ICCP	inter-control center communications protocol
IEC	International Electrotechnical Commission
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers, Inc.
I/O	input/output
ISO	International Standards Organization
IT	information technology
LAN	local area network
Mb/s	megabits per second
MMS	manufacturing messaging specification
NIM	network interface module
O&M	operations and maintenance
PES	IEEE Power Engineering Society
PLC	programmable logic controller
PSRC	IEEE PES Power Systems Relaying Committee
RF	radio frequency
RFP	request for proposal
RTU	remote terminal unit
SA	substation automation
SATS	substation automation training simulator
SCADA	supervisory control and data acquisition
TC	technical committee
TCP/IP	transmission control protocol and Internet protocol
UCA	utility communication architecture
var	volt ampere reactive
WAN	wide area network
WG	working group

Benefits of open systems include longer expected system life, investment protection, upgradeability and expandability, and readily available third-party components.

system data and schedules or for communicating directly with substation or distribution feeder devices was lacking, resulting in continuing interoperability problems.

The UCA (MMS) Forum was started in May 1992 to address these UCA application issues. Six working groups were established to consider issues of MMS application in power plants, control centers, customer interface, substation automation, distribution feeder automation, and profile issues. The MMS Forum served as a mechanism for utilities and suppliers to build the technical agreements necessary to achieve a wide range of interoperability using UCA MMS. Out of these efforts came the notion of defining standard power system objects and mapping them onto the services and data types supported by MMS and the other underlying standard protocols. This heavily influenced the definition of the UCA2 specification issued in late 1996, which endorses ten different protocol profiles, including transmission control protocol and Internet protocol (TCP/IP) and inter-control center communications protocol (ICCP), as well as a new set of common application service models for real-time device access.

The EPRI UCA Substation Automation Project began in the early 1990s to produce industry consensus regarding substation integrated control, protection, and data acquisition and to allow interoperability of substation devices from different manufacturers. The Substation Protocol Reference Specification recommended three of the ten UCA2 profiles for use in substation automation. Future efforts in this project were integrated with the efforts in the Utility Substations Initiative.

In mid-1996, American Electric Power hosted the first Utility Substations Initiative meeting, as a continuation of the EPRI UCA Substation Automation Project. Approximately 40 utilities and 25 suppliers are presently participating, having formed supplier/utility teams to define the supplier IED functionality and to implement a standard IED protocol (UCA2 profile) and LAN protocol (Ethernet).

Generic object models for substation and feeder equipment (GOMSFE) are being developed to facilitate suppliers in implementing the UCA Substation Automation Project substation and feeder elements of the power system object model. New IED products with this functionality are now commercially available. The Utility Substations Initiative meets three times each year, in January, May, and September, immediately following the IEEE PES Power System Relaying Committee (PSRC) meetings and in conjunction with the UCA Users Group meetings. Every other meeting includes a supplier interoperability demonstration. The demonstration in September 2002 involved approximately 20 suppliers with products interconnected by a fiber Ethernet LAN interoperating with the UCA2 MMS protocol, the GOMSFE device object models, and Ethernet networks.

The UCA Users Group is a nonprofit organization whose members are utilities, suppliers, and users of communications for utility automation. The mission of the UCA Users Group is to enable utility integration through the deployment of open standards by providing a forum in which the various stakeholders in the utility industry can work cooperatively together as members of a common organization to:

- ✔ influence, select, and/or endorse open and public standards appropriate to the utility market based on the needs of the membership
- ✔ specify, develop, and/or accredit product/system-testing programs that facilitate the field interoperability of products and systems based upon these standards
- ✔ implement educational and promotional activities that increase awareness and deployment of these standards in the utility industry.

The UCA Users Group was first formed in 2001 and presently has 34 corporate members, including 17 suppliers, 14 electric utilities, and three consultants and other organizations. The UCA Users Group organization consists of a Board of Directors, with the Executive Committee and Technical Committee reporting to the board. The Executive Committee has three committees reporting to it: Marketing, Liaison, and Membership. The Technical Committee has a number of committees reporting to it, including Substation, Communications, Products, Object Models (IEC 61850/GOMSFE), and Test Procedures. The Web site for the UCA Users Group is www.ucausersgroup.org. The group meets three times each year, in January, May and September, immediately following the IEEE PES PSRC meetings and in conjunction with the Utility Substations Initiative meetings. In addition, the UCA Users Group will meet at the IEEE PES Substations Committee Annual Meeting 27-30 April 2003 in Sun Valley, Idaho. This meeting will include a supplier interoperability demonstration with 20 to 25 suppliers demonstrating the implementation of the UCA2 MMS protocol and Ethernet networking technology into their IEDs and products and interoperating with the other suppliers' equipment.

IEC 61850

The UCA2 substation automation work has been brought to IEC Technical Committee (TC) 57 Working Groups

(WGs) 10, 11, and 12, who are developing IEC 61850, the single worldwide standard for substation automation communications. IEC 61850 is based on UCA2 and European experience and provides additional functions such as substation configuration language and a digital interface to nonconventional current and potential transformers.

Distributed Network Protocol

The development of DNP was a comprehensive effort to achieve open, standards-based interoperability between substation computers, RTUs, IEDs, and master stations (except inter-master-station communications) for the electric utility industry. DNP is based on the standards of the IEC TC 57, WG 03. DNP has been designed to be as close to compliant as possible to the standards as they existed at the time of development with the addition of functionality not identified in Europe but needed for current and future North American applications (e.g., limited transport layer functions to support 2K block transfers for IEDs, radio frequency (RF), and fiber support). The present version of DNP is DNP3, which is defined in three distinct levels. Level 1 has the least functionality, for simple IEDs, and Level 3 has the most functionality, for SCADA master-station communication front-end processors.

The short-term benefits of using DNP are:

- ✔ interoperability between multi-supplier devices
- ✔ fewer protocols to support in the field
- ✔ reduced software costs
- ✔ no protocol translators needed
- ✔ shorter delivery schedules
- ✔ less testing, maintenance, and training
- ✔ improved documentation
- ✔ independent conformance testing
- ✔ support by independent user group and third-party sources (e.g., test sets, source code).

In the long term, further benefits can be derived from using DNP, including:

- ✔ easy system expansion
- ✔ long product life
- ✔ more value-added products from suppliers
- ✔ faster adoption of new technology
- ✔ major operations savings.

DNP was developed by Harris, Distributed Automation Products, in Calgary, Alberta, Canada. In November 1993, responsibility for defining further DNP specifications and ownership of the DNP specifications was turned over to the DNP User Group, a group composed of utilities and suppliers who are utilizing the protocol. The DNP User Group is a forum of over 300 users and implementers of the DNP3 protocol worldwide. The major objectives of the group are to:

- ✔ maintain control of the protocol and determine the direction in which the protocol will migrate
- ✔ review and add new features, functions, and enhancements to the protocol
- ✔ encourage suppliers and utilities to adopt the DNP3 protocol as a standard
- ✔ define recommended protocol subsets
- ✔ develop test procedures and verification programs
- ✔ support implementer interaction and information exchange.

The DNP User Group has an annual general meeting in North America, usually in conjunction with the DistribuTECH Conference in February/March. The Web site for DNP and the DNP User Group is www.dnp.org. The DNP User Group Technical Committee is an open volunteer organization of industry and technical experts from around the world. This committee evaluates suggested modifications or additions to the protocol and then amends the protocol description as directed by the User Group members.

Choosing the Right Protocol

There are several factors to consider when choosing the right protocol for your application. First, determine the system area with which you are most concerned, e.g., the protocol from a SCADA master station to the SCADA RTUs, a protocol from substation IEDs to an RTU or a PLC, or a LAN in the substation. Second, determine the timing of your installation, e.g., six months, 18 to 24 months, or three to five years. In some application areas, technology is changing so quickly that the timing of your installation can have a great impact on your protocol choice. If you are implementing new IEDs in the substation and need them to be in service in six months, you could narrow your protocol choices to DNP3, Modbus, and Modbus Plus. These protocols are used extensively in IEDs today. If you choose an IED that is commercially available with UCA2 MMS capability today, then you may choose UCA2 MMS as your protocol.

If your timeframe is one to two years, you should consider IC 61850 and UCA2 MMS as the protocol. Monitor the results of the Utility Substation Communication Initiative utility demonstration sites. These sites have implemented new supplier IED products that are using UCA2 MMS as the IED communication protocol and Ethernet as the substation local area network.

If your timeframe is near term (six to nine months), make protocol choices from suppliers who are participating in the industry initiatives and are incorporating this technology into their product's migration paths. This will help protect your investment from becoming obsolete by allowing incremental upgrades to new technologies.

Communication Protocol Application Areas

There are various protocol choices depending on the protocol application area of your system. Protocol choices vary with the different application areas. Different application areas are in different stages of protocol development and industry efforts The status of development efforts for different applications will help determine realistic plans and schedules for your specific projects.

Selecting the right supplier ensures that you stay informed about industry developments and trends and allows you to access new technologies with the least impact on your current operation.

Within the Substation

The need for a standard IED protocol dates back to the late 1980s IED suppliers acknowledge that their expertise is in the IED itself, not in two-way communications capability, the communications protocol, or added IED functionality from a remote user. Though the industry made some effort to add communications capability to the IEDs, each IED supplier was concerned that any increased functionality would compromise performance and drive the IED cost so high that no utility would buy it. Therefore, the industry vowed to keep costs competitive and performance high as standardization was incorporated into the IED.

The IED supplier's lack of experience in two-way communications and communication protocols resulted in crude, primitive protocols and, in some cases, no individual addressability and improper error checking (no select-before-operate). Each IED required its own communication channel, but only limited channels, if any, were available from RTUs. SCADA system and RTU suppliers were pressured to develop the capability to communicate to IEDs purchased by the utilities. Each RTU and IED interface required not only a new protocol but a proprietary protocol not used by any other IED.

It was at this point that the Data Acquisition, Processing and Control Systems Subcommittee of the IEEE Power Engineering Society (PES) Substations Committee recognized the need for a standard IED protocol. The subcommittee formed a task force to examine existing protocols and determine, based on two sets of screening criteria, the two best candidates. *Trial Use Recommended Practice for Data Communications Between Intelligent Electronic Devices and Remote Terminal Units in a Substation* (IEEE Standard 1379) was published in March 1998. This document did not establish a new communication protocol. To quickly achieve industry acceptance and use, it instead provided a specific implementation of two existing communication protocols in the public domain, DNP3 and IEC 870-5-101.

For IED communications, if your implementation timeframe is six to nine months, select from protocols that already exist: DNP3, Modbus, and Modbus Plus. However, if the implementation timeframe is one year or more, consider UCA2 MMS as the communications protocol. Regardless of your timeframe, evaluate each supplier's product migration plans. Try to determine if the system will allow migration from today's IED with DNP3 to tomorrow's IED with UCA2 MMS without replacing the entire IED. This will leave open the option of migrating the IEDs in the substation to UCA2 in an incremental manner, without wholesale replacement. If you choose an IED that is commercially available with UCA2 MMS capability today, then you may want to choose UCA2 MMS as your IED protocol.

Substation to Utility Enterprise

This is the area of traditional SCADA communication protocols. The Data Acquisition, Processing, and Control Systems Subcommittee of the IEEE PES Substations Committee began developing a recommended practice in the early 1980s in an attempt to standardize master/remote communications practices. At that time, each SCADA system supplier had developed a proprietary protocol based on technology of the time. These proprietary protocols exhibited varied message structures, terminal-to-data circuit terminating equipment (DCE) and DCE-to-channel interfaces, and error detection and recovery schemes. The *IEEE Recommended Practice for Master/Remote Supervisory Control and Data Acquisition (SCADA) Communications* (IEEE Standard 999-1992) addressed this nonuniformity among the protocols, provided definitions and terminology for protocols, and simplified the interfacing of more than one supplier's RTUs to a master station.

The major standardization effort undertaken in this application area has taken place in Europe as part of the IEC standards-making process. The effort resulted in the development of the IEC 870-5 protocol, which was slightly modified by GE (Canada) to create DNP. This protocol incorporated a pseudo transport layer, allowing it to support multiple master stations. The goal of DNP was to define a generic standards-based (IEC 870-5) protocol for use between IEDs and data concentrators within the substation, as well as between the substation and the SCADA system control center. Success led to the creation of the supplier-sponsored DNP User Group that currently maintains full control over the protocol and its future direction. DNP3 has become a de facto standard in the electric power industry and is widely supported by suppliers of test tools, protocol libraries, and services.

Cyber Security

When today's control systems were designed, information and system security was not a priority. SCADA and other control systems were designed as proprietary, stand-alone systems, and their security resulted from their physical and logical isolation and controlled access to them. As information technology becomes increasingly advanced, substation automation continues to move to open, standards-based networking technologies and/or the Internet to bring the benefits of information sharing to operations. All suppliers have the capability to implement Web-based applications to perform monitoring, control, and remote diagnostics. This, however, leads to control system cyber vulnerabilities. Existing information technology (IT) can protect substation control systems from traditional IT vulnerabilities, but they are not designed to protect control systems against vulnerabilities unique to control systems.

A security policy and a mechanism for its enforcement should be developed for the substation. A minimum list of questions to be addressed before attaching the SA system (or SCADA system) to the network include the following.

- ✔ Which network users and applications require control system access?
- ✔ What do they need access to?
- ✔ What type of remote access does the user require (e.g., dial-up, telnet, ftp, X-sessions, PCAnywhere, etc.)?
- ✔ What are the security risks associated with each type of access?
- ✔ Is the information required worth the security risk?
- ✔ Is the password capable of being changed?
- ✔ How often should it be changed?
- ✔ Who is the system administrator?

Make Decisions with the Future in Mind

As we look to the future, it seems the time between the present and the future is shrinking. When a PC bought today is made obsolete in six months by a new model with twice the performance at less cost, how can you protect the investments in technology you make today? Obviously, there is no way you can keep up on a continuous basis with all the technology developments in all areas. You must rely on others to keep you informed, and who you select to keep you informed is critical. With every purchase, you must evaluate not only the supplier's present products but also its future product development plans.

- ✔ Does the supplier continuously enhance and upgrade products?
- ✔ Is the supplier developing new products to meet future needs?
- ✔ Do existing products have a migration path to enhanced and new products?

Selecting the right supplier will ensure you stay informed about new and future industry developments and trends and will allow you to access new technologies with the least impact on your current operation.

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Biography

John D. McDonald received his B.S. and M.S. degrees in electrical engineering from Purdue University and an MBA from the University of California at Berkeley. As senior principal consultant and manager of Automation, Reliability, and Asset Management for KEMA Consulting, he assists electric utilities in substation integration and automation, distribution management systems, distribution SCADA systems, and communication protocols. He is a Fellow of the IEEE, secretary of the IEEE PES, past-chair of the IEEE PES Substations Committee, and recipient of the IEEE Millennium Medal in 2000 and the IEEE PES Award for Excellence in Power Distribution Engineering in 2002. He gives tutorials and seminars in substation automation, distribution SCADA, and communications for various IEEE PES local chapters as an IEEE PES Distinguished Lecturer. He was editor of the "Substations" chapter and a coauthor for the book *The Electric Power Engineering Handbook*, cosponsored by the IEEE PES and published by the CRC Press in 2000. He is editor-in-chief and author of the "Substation Integration and Automation" chapter for the book *The Electric Power Substation Engineering Handbook*, to be published by the CRC Press in 2003.

KEMA experience you can trust

EXPERT PUBLISHED ARTICLE

North Carolina Municipal Power Agency Boosts Revenue By Replacing SCADA

John McDonald, Manager of Automation, Reliability and Asset Management and Senior Principal Consultant, KEMA

The impacts on distribution operations and overall revenue caused by an underperforming SCADA system can easily outweigh the benefits it is supposed to provide. Fortunately – as the North Carolina Municipal Power Agency No 1 (NCMPA1) discovered over the past year – advancements in SCADA technology have enabled utilities to replace their existing systems with new ones capable of boosting profits and quickly paying off the expense of implementation

One of two power agencies operated by ElectriCities of North Carolina, NCMPA1 has been distributing electricity on behalf of municipal utilities across the state since 1983. For nine months a year, the peak load is approximately 600-650 MW, nearly 250 MW below generation capacity. To sell the additional power on the wholesale market, NCMPA1 contracts with a power marketing and trading company

In 1996, NCMPA1 implemented a SCADA system to monitor the operations of its distribution network. This system included installation of 49 meters to measure instantaneous power and energy usage at 47 substations located throughout the piedmont area of the state. At each metering site, remote terminal units (RTUs) collected, processed and formatted the meter data values using the industry de facto standard DNP3 protocol for transmission back to the SCADA system master station at the Raleigh, N C., headquarters

In each substation, the RTUs served as interfaces between the meters and a frame relay system This telecommunications system provided a very reliable 56 kbps link between the substations and the Raleigh control center. The SCADA system also relayed peak load and generation data via FTP to the power marketing company so that it would have quick access to information regarding the availability of excess capacity.

Losing Revenues with a Buffer

Power marketing was enabled through the use of "block scheduling" which required a short term (hourly) forecast of excess or surplus energy. In the months and years after the SCADA system was installed, NCMPA1 personnel encountered a growing number of difficulties with it One of the most serious stemmed from the way the system was designed to operate The system vendor had set up the SCADA master station to poll the RTUs for load data once every five minutes Over time, increasing reliability problems with the SCADA system plus the five-minute scan rate caused additional forecasting error.

NCMPA1 recognized the problem and found the only solution was an expensive change of hardware In the meantime, utility personnel worked around the inaccuracy by constantly holding some power in reserve

"We were unable to sell a portion of our surplus energy at market prices," said Jim Deaton, Power Operations Manager for NCMPA1, "because we had to maintain a significant buffer of unsold energy to be sure we did not sell more surplus than was actually available in a given hour "

The buffer typically totaled about 25 MW of power the organization could not sell, which translated directly into lost revenue

"Reliability problems were a result of the inability of the SCADA system to withstand normal North Carolina thunderstorms," said Deaton. "The failure rate was increasingly unacceptable and was a contributor to the overall low reliability problem "

"We realized that additional functionality and reliability were needed," said Ron Brady, NCMPA1 Project Manager

Additionally, a move to dynamic scheduling was being contemplated that would eliminate the forecasting errors associated with block scheduling. And dynamic scheduling required control area quality SCADA system with 4-second scan rate telemetry

"We decided to replace the system rather than upgrade," said Brady

Proposing a New SCADA

After making the decision to replace the SCADA, NCMPA1 moved swiftly completing the RFP, vendor selection and implementation in less than nine months. In early 2002, NCMPA1 contracted with KEMA Inc , an international management consulting and technical services firm based in Fairfax, Va , to provide services preparing for and during implementation of a new SCADA. Together, personnel from the utility and the consulting company drafted requirements for the new system and solicited bids from vendors

"KEMA was selected by an evaluation process based on qualifications such as industry knowledge and SCADA expertise," said Brady

With input from NCMPA1 personnel recounting the historical problems, KEMA analyzed the existing SCADA system. The goal of this phase was to identify operating parameters and hardware components that could be replaced with more advanced technology that would provide improved performance This implementation had to be accomplished within a budget of approximately $700,000.

KEMA quickly focused on the issue that was directly costing the utility in lost revenue – the five-minute scan rate The consulting firm recommended replacing the SCADA system master station with one capable of a reporting rate of four seconds or less, which is more in line with industry average performance.

The master station is the nerve center of the system It is a network of computers in the control center that processes the incoming power and energy usage data and feeds it to a terminal for display. By viewing this information onscreen, the dispatcher or other personnel can immediately see the condition of the distribution system and make changes as necessary to keep power flowing to customers

As an important part of this recommendation, the consultant also analyzed the North Carolina frame relay system and concluded it could support transmission of meter data every four seconds A scan rate more frequent than four seconds probably would have necessitated use of an alternative communications method, which was not an option given the tight budget Four seconds were considered adequate for NCMPA1 requirements.

Another recommended change involved the metering system NCMPA1 requested Duke Power Co , who operates a nuclear plant partially owned by NCMPA1 and owns the substation meters, to replace their older meters with microprocessor-based units called intelligent electronic devices (IED) These IEDs are now favored in SCADA design because they digitally convert measured load data directly and are capable of two-way digital communications using an industry standard protocol, such as DNP3, which has become the de facto SCADA standard.

Installation of IEDs eliminated any need for the troublesome RTUs KEMA recommended pulling the RTUs and interfacing the frame relay access devices (FRADs) directly to the meter IEDs The FRAD is a simple, low-cost unit that couples the IED to the frame relay communications system Data in the DNP3 protocol flows seamlessly through the FRAD to the telecommunications network and back to the master station

In a modification of procedure, the consulting firm also advised the utility to build redundancy into its SCADA operations by splitting the master station, installing one-half at the control center in Raleigh and the other half in another facility in Huntersville, N.C. Typical of SCADA operations today, the two facilities are linked by high-speed T1 lines, which means that both sites are receiving the same data inputs instantaneously The objective of this is to create a back-up system, whereby either facility can assume dispatch functions in the event the other is disabled by a flood, fire or other disaster

For further reliability of the overall SCADA system, KEMA recommended installing dial-up communications capability as a back-up at all 47 meter sites

Based on these recommendations, KEMA and NCMPA1 drew up a request for proposal in summer 2002 Included in this RFP was a requirement that the selected system must be based on Open Systems Interconnection and industry standards to ensure hardware independence, interoperability with current applications and easy access by NCMPA1 MIS personnel.

Implementing the New SCADA

NCMPA1 invited four vendors to Raleigh for demonstrations of their products This not only allowed personnel to directly compare systems, it gave them a valuable opportunity to see the full spectrum of SCADA technology. The utility ultimately selected Open Systems International (OSI) of Minneapolis to implement the new system in fall 2002

Before the integrated system was shipped to North Carolina, NCMPA1 operations personnel visited the OSI facility in Minnesota for a factory test of the hardware and software, a crucial, yet often overlooked, aspect of implementation The first of two goals was for OSI to run the integrated system with all of its modules to ensure that it performed according to RFP specifications

Secondly, and just as importantly, the factory test gave NCMPA1 personnel an opportunity to learn the intricacies of the new SCADA system's operation and maintenance Essentially a tutorial, this served as a practical training session in which OSI programmers and engineers could answer questions and help NCMPA1 digest the volumes of information contained in the training courses and accompanying system documentation

After the successful factory test in November, OSI delivered the system equipment in December and had the SCADA system operational by January The positive results were immediate and impressive The new SCADA system master station achieved the scan rate of four seconds, providing NCMPA1 and its power trading company with extremely accurate details of power and energy usage On April 1, 2003, NCMPA1 began dynamic scheduling for its surplus energy and for the first time in years, NCMPA1 was able to operate without the 25 MW buffer

"The new SCADA system allows us to sell virtually all of our surplus energy at market prices, which has resulted in a significant increase in revenues," said Deaton. "It also provides us with highly reliable, four-second load data which has allowed us to move from block scheduling to dynamic scheduling of surplus sales and supplemental purchases "

NCMPA1 estimates that elimination of the buffer and the switch to dynamic scheduling went a long way toward paying off the new SCADA system within its first six months of operation In addition, the availability of faster and more reliable SCADA system data played a role in helping NCMPA1 to negotiate a more favorable contract with a new trading representative, Southern Company of Atlanta SCADA system data is relayed to Southern Company via a virtual RTU using leased lines, by FTP over a leased line, and through web access.

Adding to the fast return on investment is the overall greater operational efficiency of power distribution thanks to enhanced functionality of the new system which scores a much higher online performance than the old SCADA system And the accessibility of the open operating system has helped NCMPA1 MIS personnel with system maintenance

"The system has proved reliable, easy to operate and easy to modify," said Brady "The SCADA system is contributing to lower operating costs through improved continuity of service and its redundancy is invaluable "

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OVERWHELMED BY ALARMS: BLACKOUT PUTS FILTERING AND SUPPRESSION TECHNOLOGIES IN THE SPOTLIGHT

By John McDonald, P.Eng.

The Blackout of 2003 has focused attention on a serious flaw in the design and operation of SCADA/Energy Management Systems (EMS). Developed to warn dispatchers of impending problems in generation and transmission networks, SCADA/EMS have little or no ability to suppress the barrage of alarms that bombard control room personnel during a rapidly escalating event.

This can pose an almost debilitating challenge for dispatchers facing a major outage situation. In just a few minutes, thousands of warnings can pour into the control room in the form of text messages clogging computer printers, filling the alarm zones on console displays and scrolling down screens faster than anyone can read them. With limited ability to prioritize the power system failures and decipher the sequence of events, overwhelmed dispatchers often ignore the very system that is designed to help them.

While the exact role of SCADA/EMS alarms in the Blackout of 2003 has yet to be determined, this incident has forced the utility industry to examine all of the factors that potentially contribute to major outages. Power alarm overload has been well documented as a control room distraction at the very least, but utilities are now scrutinizing this phenomenon as a dangerous contributor to situations that cascade out of control.

Upon closer scrutiny of the SCADA/EMS alarm issue, utilities will be surprised and possibly frustrated to learn that power alarm overload should not have been tolerated for this long. Viable alarm processing technology already exists. In fact, utilities need look no further than their own distribution SCADA systems to find alarm suppression and filtering techniques that have been implemented for the past 15 years.

Alarm processing technology ensures that dispatchers receive only those alerts relating to events that must be addressed immediately, while the details of less critical secondary warnings are sent to databases and possibly printed for later review. With only the most important distribution system alarms presented in a prioritized fashion, dispatchers can assess problems more easily and make better decisions to prevent a bad situation from getting worse.

The reason that alarm-processing technology has been implemented in distribution SCADA and not in SCADA/EMS is a combination of application necessity and customer demand. And the fact that companies providing distribution SCADA products are typically different from those offering SCADA/EMS has not helped the situation. Fortunately, these two types of SCADA systems operate similarly, which means distribution alarm suppression technology can readily be implemented in SCADA/EMS.

On the distribution side, SCADA alarms are typically triggered by faults and the events surrounding them, which occur continuously during routine operations. When a breaker on a substation feeder trips due to a transient fault, for instance, up to seven alarms may be triggered - one for the breaker trip and three each when voltages and currents on all three phases hit zero. The dispatcher only needs the breaker trip alarm, and he may not even need that if the breaker is automatically reclosed after a transient fault where the situation resolves itself.

With audible and visual alarms inundating the control room throughout the day, dispatchers asked distribution SCADA vendors to suppress some alarms while letting critical ones through. In response to this demand, the vendors developed several filtering techniques, some of which can be configured during SCADA implementation or activated on the fly during a storm.

Such demand never occurred on the generation and transmission side since SCADA/EMS alarms are triggered less frequently and only during actual outage events. Because these alarms have not

Developed to warn dispatchers of impending problems in generation and transmission networks, SCADA/EMS have little or no ability to suppress the barrage of alarms that bombard control room personnel during a rapidly escalating event

posed the same daily nuisances, utilities simply never pressured vendors to implement alarm filters in SCADA/EMS — until now.

FOUR SUPPRESSION TECHNIQUES

The 2003 Blackout has compelled the power industry to revisit the alarm issue. With prompting from utility customers, SCADA/EMS vendors are now considering their options. In general, there are four proven alarm processing methods currently used in distribution SCADA systems, which vendors can choose from for implementation in their future products.

AREA-OF-RESPONSIBILITY (AOR) ALARM FILTERING

Inherent in the SCADA architecture is the ability to partition the system by function or geography. This allows a utility to separate the monitoring and operation of various SCADA displays, alarms and control points and assign responsibility for them to different control rooms, dispatchers, or even other utilities. Distribution SCADA systems can usually be partitioned into 64 functions or geographic areas

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SCADA systems are designed this way due to the broad variety of their applications. A water, gas and electric utility, for instance, may want to invest in only one SCADA system but establish separate control rooms for each of its three services. Creating AORs for gas, water and electric service accomplishes this. A more common example is a generation-transmission co-op that turns distribution network monitoring functions over to its electric member cooperatives from 9 am to 5 pm every day and resumes those duties at all other times. Some large utilities divide their service territory by geographic region and assign one dispatcher to each.

AOR Partitioning also gives utilities tremendous flexibility in routing alarms. For example, all operational alarms can be sent to the control room while equipment monitoring alarms go to maintenance. Or one dispatcher may receive alarms pertaining to one geographic region while another dispatcher gets the alarms for another geographic region. The variations of alarm partitioning are almost endless, but the bottom line is that this enables the utility to filter the alarms so that only the most important reach the people who can handle them.

The good news for utilities that have purchased SCADA/EMS in the past three to five years is that partitioning is probably already built into the system, although the number of partitions may not be as numerous as those in distribution SCADA. Regardless, power system alarms can be divided and filtered in the exact same way as those on the other side and with the same result - less distraction for the dispatcher.

ALARM POINT PRIORITY FILTERING

During the configuration of a distribution SCADA database, each monitoring and control point in the network is assigned an alarm priority level by the utility. These points usually rank in importance from one to eight, with eight being the most critical. On the distribution side, for example, breakers on critical feeders could be assigned high numbers.

At consoles in the control room, dispatchers can select which alarms they want coming through to their display window based on priority level. In daily operations, the dispatcher may want to see alarms from all priority levels on the screen, but when a storm starts moving into the territory, for example, the dispatcher can dynamically change the preference to show only priority alarms six and higher. This gives dispatchers control over the filtering and suppression of warnings based on the gravity of the situation at hand.

As with AOR filtering, utilities operating new SCADA/EMS may find they already have some ability to establish point alarm priorities and set control room display parameters accordingly.

TIMED-ALARM SUPPRESSION

When a SCADA system is configured during installation, the utility can determine the length of time that an out-of-threshold situation must last before it actually triggers an alarm. If the situation is transient or resolved before this time period elapses, the trigger never occurs, and the dispatcher is not bothered with a non-critical event, although details are still written to the alarm and event disk file and possibly printed.

An example is a distribution feeder with an automatic recloser. When a tree branch blows against the feeder in the midst of a wind storm, the recloser opens and then recloses as programmed. If the branch is no longer striking the line, the recloser remains closed. But the dispatcher would needlessly receive two alarms, one for the opening and one for the reclosing, despite the fact that normal operations had been restored.

Under the Timed-Alarm Suppression process, a timer begins when the recloser first opens, and no alarm is activated. Once the pre-determined time period ends, perhaps two to four seconds, the SCADA system again looks at that point to see if the recloser is still open. If it is, the alarm is triggered and the dispatcher knows a situation more serious than a transient condition has occurred. Otherwise, if the SCADA system finds the feeder operation has returned to normal, there is no alarm.

For use in generation and transmission SCADA operations, the Timed-Suppression technique would be applied to the status of transmission lines and power generation units. Since SCADA/EMS typically monitors whether these components are inside or outside certain limits, acceptable durations of threshold exceptions can easily be assigned to each control point for alarm suppression.

KNOWLEDGE-BASED ALARM SUPPRESSION

Within the SCADA database, direct linkages can be created between network elements that trigger primary and secondary alarms. By linking them, the secondary alarms can be eliminated if the primary one has already been activated. This can be illustrated using the above example of the feeder opening that causes voltages and currents to drop, sending six needless warnings to the dispatcher.

Database records can be created for the voltage and current measurement points on the feeder and linked to the status of the feeder breaker. If the value drops to zero at any of those points, an address pointer in the SCADA database will automatically check the measurement point of the feeder breaker status before activating the low voltage alarm. If the breaker status is open, the SCADA system knows a primary alarm has already been triggered, and it suppresses the redundant low voltage alarm. Occurring in a split second, this process then records the secondary alarm in the alarm and event disk file and sends the alarm to the alarm/event printer.

Feeders and breakers are elements of the electric distribution system, but knowledge-based alarm suppression can be applied just as easily on the generation and transmission side. The key in implementing this technique in SCADA/EMS is identifying and linking critical system functions that secondarily impact other operations which can trigger alarms. For example, when a generator breaker trips, the terminal voltage will go to zero. The breaker trip would be the primary alarm and the terminal voltage would be a secondary alarm.

VENDORS, UTILITIES CONSIDERING OPTIONS

With pressure from the utility industry, SCADA/EMS vendors will undoubtedly consider implementing one or more of these filtering and suppression techniques. Since the basic technology that makes AOR and Alarm Point filtering possible already exists in some SCADA/EMS, it is likely these two will emerge as the dominant alarm processing methods.

Vendors, however, will need to enhance both techniques significantly to make these solutions more practical. Currently, for example, the typical

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SCADA/EMS offers a limited number of priority levels. These will have to be expanded to at least eight, and the dynamic activation capability will have to be added. Vendors will also need to give SCADA/EMS the ability to partition into a greater number of Areas of Responsibility. Most now offer less than 64 partitions.

In addition to enhancing or introducing these processing techniques, SCADA/EMS vendors must improve the memory capacities of their systems for filtering and suppression to work properly. The key is to add a function alternately called "status with memory" (SWM) or "momentary change detection" (MCD), which is common in distribution SCADA systems.

SWM or MCD points essentially provide multiple levels of memory with every SCADA status point. These memory units record very fast or brief events such as recloser operations, that occur between the scan rate of the SCADA system. By including up to seven levels of memory with these points, the SCADA system does not miss any vital operating functions that might trigger an alarm.

With these new alarm processing capabilities almost certain to be introduced by SCADA/EMS vendors in the next few years, utilities will face a tough decision regarding upgrading or replacing existing systems.

For utilities operating newer systems implemented in the last five years or so, it is likely their SCADA systems can be upgraded to accommodate the new technology. But SCADA/EMS older than five to eight years may have to be replaced. Attempting to refit these systems with alarm suppression technologies will degrade SCADA performance.

Utilities will soon have to decide if alarm filtering and suppression and other new technologies now offered in SCADA systems are worth the cost of implementing an entirely new system. When the final North American Electric Reliability Council report on the Blackout of 2003 is released and the contributing role, if any, of SCADA/EMS alarms is revealed, this decision could become much easier to make.

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