行政院及所屬各機關出國報告

（出國類別：實習）

（裝訂線）

配電自動化系統控制中心設備運轉實務研討

服務機關： 台灣電力公司

出國人職　稱： 電機工程監
電機工程師

姓　　名： 蘇德來（295079）
朱文賢（577344）

出國地區： 日本、美國、加拿大

出國日期： 92.12.21～93.01.12

出國計畫： 92 年度第 239 號

報告日期： 93.02.10

行政院及所屬各機關出國報告審核表

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□6. 送上級機關參考
□7. 退回補正，原因：
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說明：

一、出國計畫主辦機關即層轉機關時，不需填寫「層轉機關審核意見」。

二、各機關可依需要自行增列審核項目內容，出國報告審核完畢本表請自行保存。

三、審核作業應於報告提出後二個月內完成。

報告人：資訊課長 93.3.4 蘇德來　業務處 93.3.8 朱文賢

單位主管：經理 93.3.5 張坤雄　副經理 93.3.5 黃三郎

主管處主管：業務處長 方俊德　業務處副處長 93.3.11 唐明紹　業務處配電自動化課長 93.3.10 林健富

總經理：

副總經理：副總經理 93.3.12

行政院及所屬各機關出國報告提要

出國報告名稱：配電自動化系統控制中心設備運轉實務研討

頁數 26 含附件：☑是□否

出國計畫主辦機關/聯絡人/電話

台灣電力公司/業務處饋線自動化課 林健富/（02）23666719

出國人員姓名/服務機關/單位/職稱/電話

蘇德來/台灣電力公司/高雄區營業處/電機工程監/（07）5519271

朱文賢/台灣電力公司/業務處/電機工程師/（02）23666719

出國類別：□1 考察□2 進修□3 研究☑4 實習□5 其他

出國期間： 92.12.21～93.01.12　　出國地區：日本、美國、加拿大

報告日期：93 年 2 月 10 日

分類號/目

關鍵詞：

DAS：Distribution Automation System 配電自動化系統

DMS：Distribution Management System 配電管理系統

EMS：Energy Management System 能源管理系統

GIS：Geographic Information System 地理圖資資訊系統

GUI：Graphical User Interface 圖形化使用者界面

SCADA：Supervisory Control And Data Acquisition 監視控制及資料蒐集

OMS：Outage Management System 本公司「停限電運轉圖資系統」

CIS：Customer Information System 本公司「用戶服務資訊系統」

DDCS：Distribution Dispatch Control System 本公司「配電調度控制系統」

FDCS：Feeder Dispatch Control System 本公司「饋線調度控制系統」

IED：Intelligent Electronic Device 智慧型電子設備

CB：Circuit Breaker 斷路器

Server：伺服器，指資訊系統作為提供使用者應用功能所採用之主機

內容摘要：(二百至三百字)

面對產業型態的迅速改變，生活品質日趨提昇，對供電品質之要求亦相對提高，為加強用戶服務及提昇用戶用電滿意度，本公司正依「加速配電饋線自動化整體實施計畫」陸續推動相關區處之「配電饋線自動化系統」，而「配電饋線自動化系統」之技術日新月異，系統之控制中心軟硬體功能及架構、現場設備、通訊模式等，均關係到供電系統之可靠度及可行性等，為確保該系統功能及設備能發揮預期中的成效，運用此研習機會，實地瞭解日本 TM T &D、美國 GE 及加拿大 SNC 公司配電自動化系統之應用情形，並探討其控制中心相關之技術及經驗，以供本公司建置「配電饋線自動化系統」之重要參考。

本文電子檔已傳至出國報告資訊網（http：//report.gsn.gov.tw）

目　　　　錄

壹、實習任務

赴日本、美國、加拿大等地參加「配電自動化系統控制中心設備運轉實務研討」。

貳、出國行程

一、92 年 12 月 22 日～92 年 12 月 29 日　日本

赴 TMT&D 公司研習配電饋線自動化系統控制中心及現場設備運轉。

二、92 年 12 月 30 日～93 年 1 月 6 日　美國

赴 GE 公司研討配電饋線自動化系統控制中心軟體。

三、93 年 1 月 6 日～93 年 1 月 9 日　加拿大

赴 SNC 公司研討配電饋線自動化系統控制中心軟體。

參、實習內容

一、 前言

面對國內產業型態的迅速改變，生活品質日趨提昇，對供電品質之要求亦相對提高，為加強用戶服務及提昇用戶用電滿意度，本公司正依「加速配電饋線自動化整體實施計畫」陸續推動相關區處之「配電饋線自動化系統」，而「配電饋線自動化系統」之技術日新月異，系統之控制中心軟硬體功能及架構、現場設備、通訊模式等，均關係到供電系統之可靠度及可行性等，為確保該系統功能及設備能發揮預期中的成效，應用

此研習機會，實地瞭解日本 TM T&D、美國 GE 及加拿大 SNC 公司配電自動化系統之應用情形，並收集其控制中心相關之技術及經驗，以供本公司建置「配電饋線自動化系統」之重要參考。

二、 TMT&D 配電饋線自動化系統控制中心及現場設備運轉研討

1. 控制中心系統軟體

TM T&D 公司為因應不同客戶 DMS 應用之需求，提供不同的應用軟體，如只需簡單遙控現場開關設備的 SCADA 應用軟體，或結合智慧型的事故區段研判、隔離及復電機制的 DAS 系統，其相關商業化的軟體功能如下：

（1）SCADA 系統軟體

a. 即時性的作業環境。

b. 高穩定性及可靠性之系統需求

c. 1 秒內圖資及現場設備狀態顯示。

d..現場異常狀態警報管理

e.遠端控制的能力

TM T&D 所開發並商轉的軟體 TOSMELS/S 即為此型式之軟體。

（2）完整 DAS 系統軟體

a. 結合所有 SCADA 系統軟體功能

b. GIS 圖資輔助功能；結合現場設備即時資料、街道、配電線路及設備圖資，做到事故點定位、快速查詢事故點鄰近供電區域相

關圖資，可幫助事故搶修人員快速到達事故現場，如圖 3.1 所示功能。

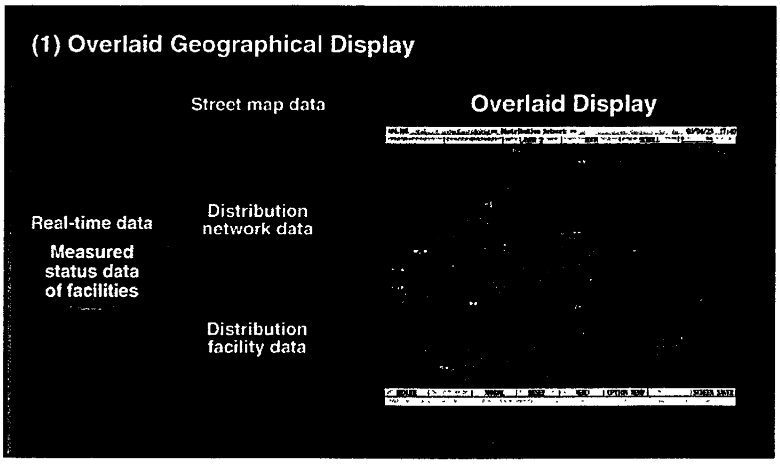

圖 3.1　GIS 輔助功能

c. 事故區段研判、隔離及復電機制(Fault Detection 、Isolation and Restoration　FDIR)；FDIR 之應用可有效縮小事故區域及減少停電時間如圖 3.2 所示。

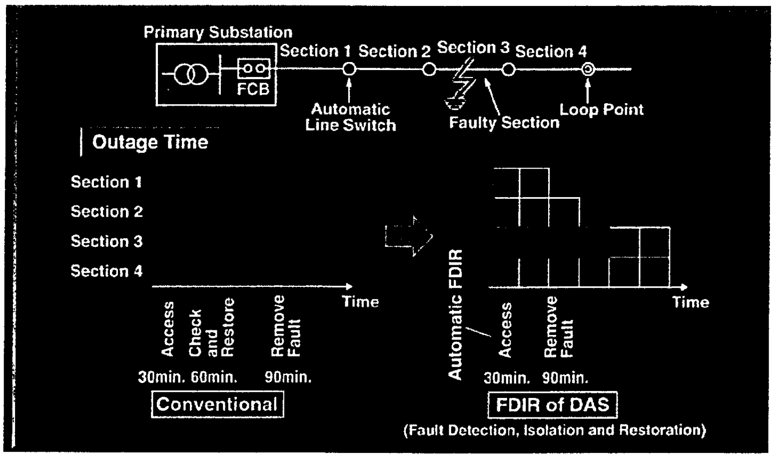

圖 3.2　DAS 之 FDIR 應用可有效縮小事故區域及減少停電時間

FDIR 功能是利用系統建置之饋線運轉圖資，如線路種類、規格、長度，變壓器容量、各供電區段匯流排電壓、電流等資料，於停電事故時，啟動內建的動態網路狀態模組及電力潮流程式，建立最佳之轉供方案，做為調度人員轉供操作之決策參考。其 FDIR 功能依事故的偵測方式及復電機制又分為：

(a) 電流偵測故障方式；其故障研判及現場設備操作方式如圖 3.3 所示，其特性如下：

a1. 以故障電流判定及藉由控制中心電腦及通訊設備遠端操作

a2. 使用閂鎖型開關

a3. 只需操作饋線 CB

目前本公司台北南區處營業處第二期、高雄區營業處配電饋線自動化系統與資訊末端設備建置案均採用此方式及開關。

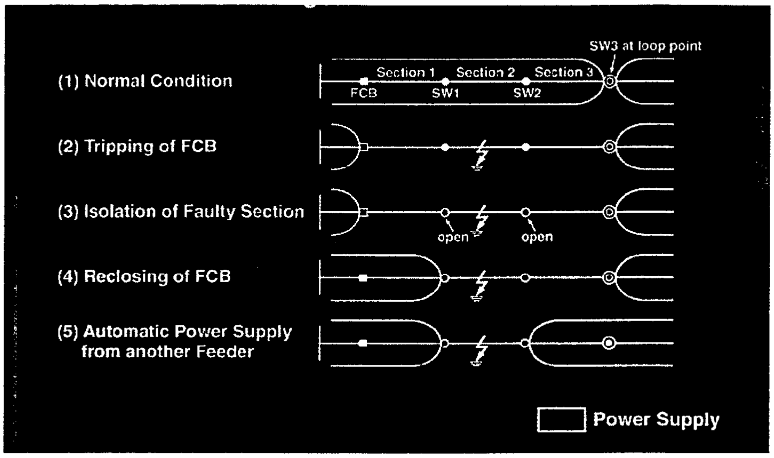

圖 3.3 電流偵測故障方式 FDIR

(b) 電壓偵測故障方式；其故障研判及現場設備操作方式如圖 3.4 所示，其特性如下：

b1. 系統以故障電壓判定及現場設備操作時間來判定

b2. 使用無電壓釋放型（非門鎖型）開關

b3. FDIR 功能較為複雜且成本較高

本公司台北南區營業區處第一期配電饋線自動化系統即採用此方式，唯本系統所使用之無電壓釋放型開關，為日本廠商之專利，較易造成壟斷或購置成本較高等顧慮。

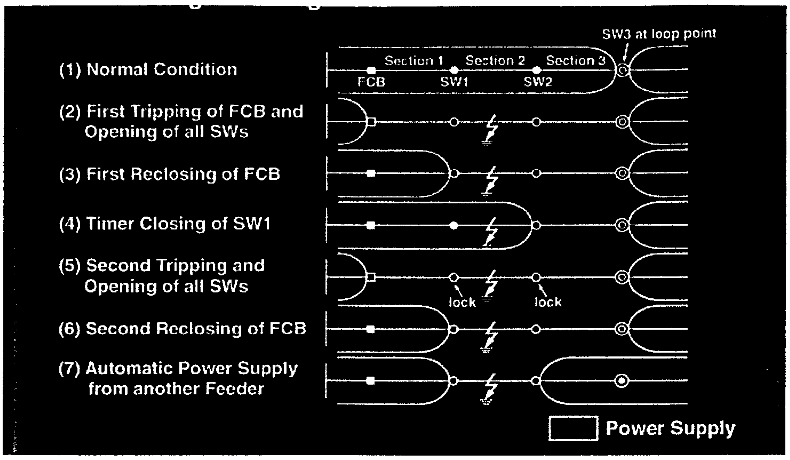

圖 3.4 電壓偵測故障方式 FDIR

FDIR 停電管理功能：可估算工作停電或事故停電受影響戶數之統計及分析，協助停電工作之排程。

TOSMELS/D3000 軟體即為提供上述功能之 DAS 軟體，而 TM T&D 公司應用軟體已由一般應用程式所提供之 GUI 界面，發展至以瀏覽器為作業平台的操作界面及圖資編輯畫面，此方式可縮短操作及圖資建置人員之系統操作教育時間。

2. 控制中心硬體：

（1）伺服器及工作站：Sun Server(UX7000)及 Workstation（AS7000）

（2）網路設備：集線器(Hubs),交換器(Switches),區域網路程(LAN)

（3）列表機—彩色印表機(Color Printer) ,複印機(Copier)

（4）遠端控制主機 Tele-Control Master Unit (TCM)：收集變電所資訊末端設備（TCR）所蒐集現場設備資料，與本公司規劃控制中心之通

訊伺服器功能相近，圖 3.5 為控制中心 TCM 與其他現場設備之通訊架構。

（5）配電線路模擬盤（Distribution Board）、視訊投影器

3. 現場通訊設備：

（1）變電所資訊末端設備採用 Tele-Control Receiver（TCR）；蒐集變電所內所有饋線資訊末端設備回應之相關數位狀態及類比資料，與本公司規劃之變電所 FRTU 功能相近。

（2）饋線資訊末端設備 Remote Terminal Unit （RTU）：蒐集現場開關、電容器相關數位狀態及類比資料，即本公司規劃之 FTU。

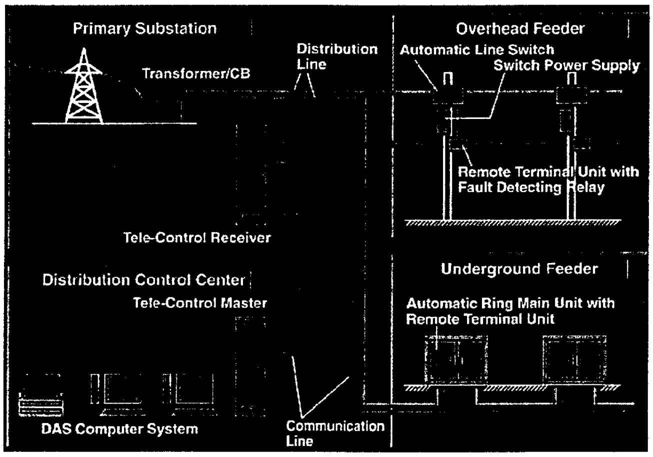

圖 3.5 控制中心 TCM 與其他現場設備之通訊架構

三、 GE 公司配電饋線自動化系統控制中心軟體研討

GE 公司之配電自動化研發部門源自 Harris Control 及 HP 公司之 SCADA 技術，西元 2000 年併購所有 GE Harris 剩餘之股權後，成為獨

立之 GE Network Solution 部門，該部門隸屬於 GE　Power　Systems。其配電饋線自動化系統控制中心軟體稱為「ENMAC 系統」。GE 公司強調其 ENMAC 系統為運用現代資訊工具做為配電管理之解決方案(Solution)，讓配電線路運轉維護人員透過該系統管理散佈各地之配電資產並且有效地即時操作線路，目前在電業自由化之英國地區，其產品含蓋率(Coverage)超過 90 百分比。其功能主要強調以下三點：

a. 減少配電設備維護及運轉成本(Costs)

b. 改善配電設備之運轉效率(Efficiency)

c. 改善配電資產之使用率(Utilization)

1.控制中心應用軟體（一）：ENMAC/DMS 解決方案(Solution)

將 DAS 功能切割為不同的系統模組，由系統需求者依功能要求選用其系統模組，如圖 3.6 所示，其系統模組特性有：

（1）ENMAC SCADA 軟體系統：

a. 即時(Real Time)資料庫最大容量可達 650 具 FRTU 及 3500 具 FTU，共 4 百萬即時資料點。

b. 通訊協定庫 : INC IEC-870, DNP 3.0 及 ICCP 等

c. 視窗介面之前端處理軟體(Windows-based Front End Processor FEPs)

（2）ENMAC NMS（Network Management System）線路管理系統：

a. 連結性模組

b. 即時性配電線路簡略圖

c. 電子文件管理 (安全格式及開關切換文件)ENMAC TCS – Trouble Call System 事故來電處理系統

a. 整合性事故電話處理

b. 自動事故預測

c. 提供網頁功能之事故來電處理

（4）ENMAC DPA – 配電電力潮流分析

a. 即時產生負載潮流計算結果

b. 電力潮流分析

（5）ENMAC WEB – 網頁式應用程式

a. 網頁式報表(Report)伺服器

b. 網頁式低壓線路管理系統

c. 網頁式高壓線路瀏覽功能及自動開關切換排程

（6）Advanced Graphical User Interface– 進階圖形化使用者介面

a. 提供強力及直覺式之 ENMAC 應用程式介面

b. 表現描繪圖形與地理圖資(Schematic and Geographic)兩種形式之資訊

c. 讓使用者有效率地瀏覽大型網路

（7）ENMAC Call Taker– 網頁式電話受理紀錄程式(類似本公司 OMS 中

電話受理及颱風搶修處理功能)

a. 提供大型配電系統之 Call Center(電話服務中心)故障電話之管理

b. 經由搜尋引擎快速顯示來電用戶資料，並提供精靈程式歸類事故問題

c. 追蹤既有事故之顯示更新及處理過程

（8）Corporate Data Exchange－交互運作之資料交換介面

a. 提供 DMS 與其他合作系統(諸如 GIS、CIS、Call Center 等軟體)無隙縫(Seamless)資料交換之介面

b. 每一獨立之系統管理自己的資料

c. 經由電子交換方式與 DMS 共享相關之資料

d. 消除因人為轉換資料之成本耗費及錯誤傾向，確保 DMS 永遠有最新之配電線路及用戶連結等相關資料

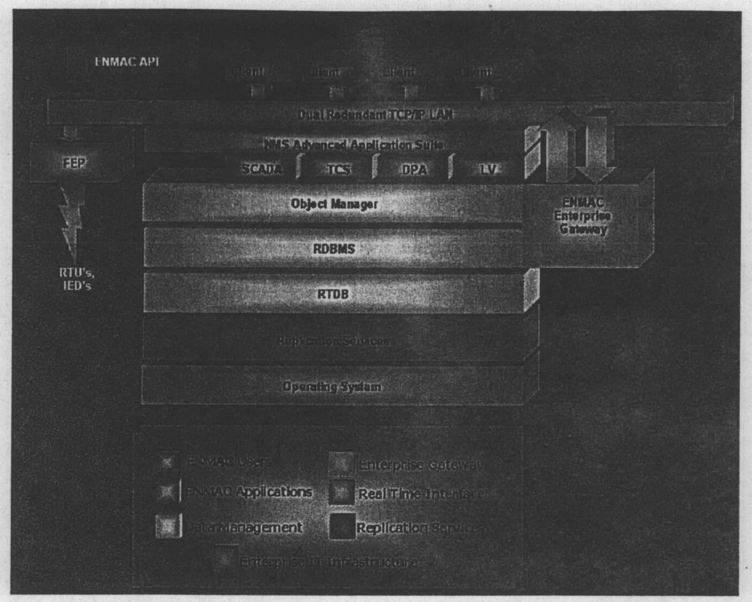

圖 3.6 GE ENMAC 系統模組架構

2.控制中心應用軟體（二）－Smallworld PowerOn

可依據 ENMAC DMS 系統傳遞之現場停電資料及 Smallworld PowerOn 之軟體特性，有效降低操作程序及成本，提昇電力系統穩定要求，進而提高顧客滿意度，該軟體特性有：

（1）停電影響用戶預測

（2）事故工作班派遣及管理

（3）開關切換排程管控

（4）事故統計報表

3.控制中心硬體架構

（1）伺服器及工作站：Compag Server(Unix)及 Intel Workstation

（WindowNT）

（2）前端通訊處理器（Front End Processor FEP）：Intel（WindowNT）

四、SNC 公司配電饋線自動化系統控制中心軟體研討

1. 中間界面軟體

為達成不同的電腦間、不同應用程式間(如 SCADA、FDIR、Web Server 等）之資料流通及傳送，使用中間界面軟體 (DAE Middleware)技術，如圖 3.7 所示，此界面軟體符合分散式架構下的運轉要求，可滿足 SCADA/EMS/DMS 高穩定性及高效率的作業要求，亦支援即時資料庫之複製。

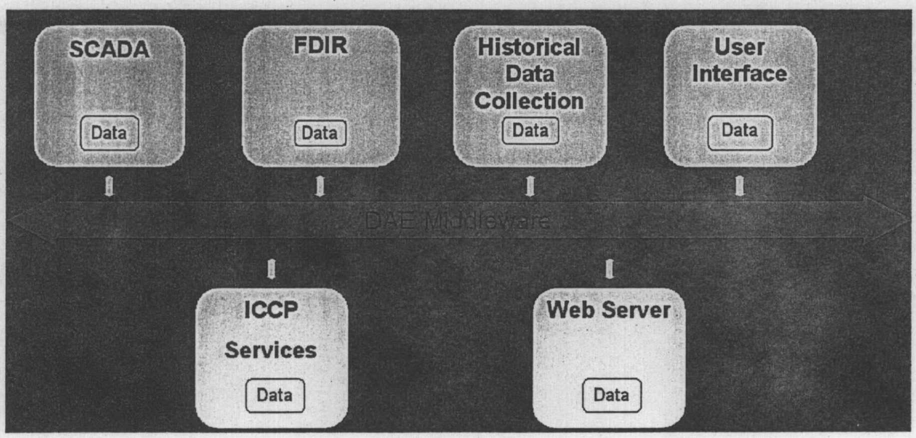

圖 3.7 SNC DAE Middleware 軟體架構

2. GIS gateway 圖資轉換程式

可快速應用即有 GIS/AMS 系統(Graphic Information System/Automatic Mapping System)所提供的地形及線路圖資匯入 DMS，做為 DMS 系統之資料庫及圖資，其軟體架構如圖 3.8 所示。其程式元件有：

(1) FME（Feature Manipulation Engine (FME)）軟體元件為結合協力廠商之軟體技術所研發的軟體如圖 3.9 FME 功能視窗：

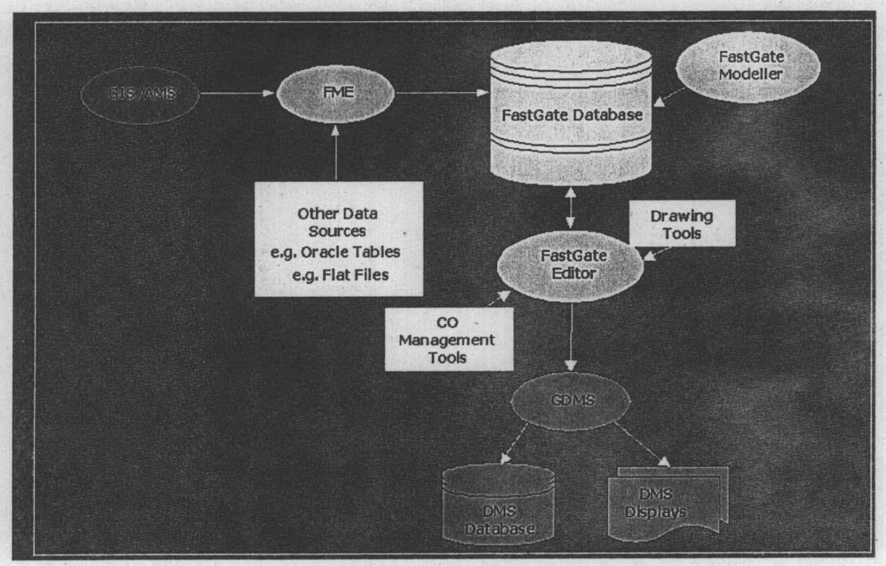

圖 3.8GIS Gateway 軟體架構

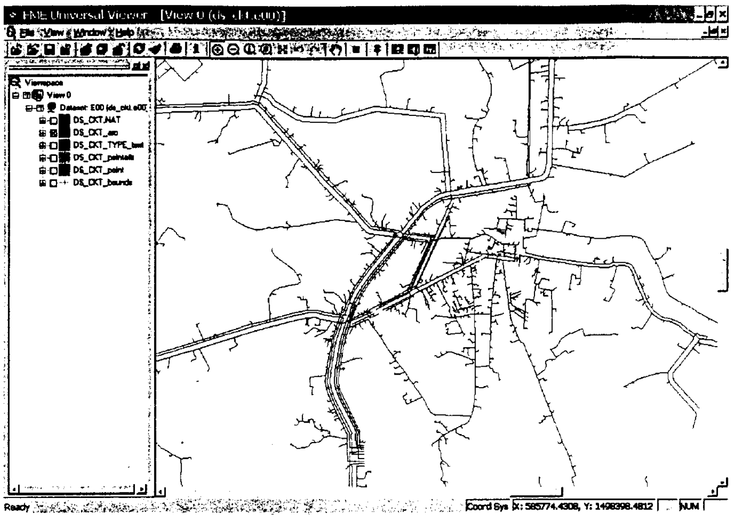

圖 3.9 FME 功能視窗

其功能特性：

a.可匯入及匯出的 GIS 格式有：AutoCAD, ESRI, Smallworld and Intergraph 的檔案格式。

b. 可定義圖資規則（mapping rules）將 GIS 的資料轉為 SLECS 的資料模式。

c.可產生圖資不一致報表，供圖資維護者核對圖資。

（2）FastGate 軟體元件特性：

a. 提供 GIS 圖資版本管理

b. 圖資編輯及模組化工具

c. 預覽及修正匯入之 GIS 資料

（3）GDMS 軟體元件特性：

a. DMS 系統與 FASTGATE 軟體元件之介面程式

b. 分配更新之屬性資料至編輯服務資料伺服器（Database Edit Server（DES））

c. 分配更新之圖形資料至圖形資料庫檔案伺服器（Graphical Database File Server（GDFS））

d. 將 DES 及 GDFS 伺服器所擷得之有效圖資資料傳送至 FastGate

e. 由 FastGate 所接收的異動之資料經 DES 及 GDFS 伺服器判定更新無誤之圖資，GDMS 才接受此筆資料，否則異動之資料系統不予接受。

（4）以本公司各區處所建置之 OMS（Outage Manager System）為例，其所建立的地形圖資（街道、建物、輪廓線等）及配電電力系統圖（11.4 及 22.8KV 電壓之架空及地下主幹及分歧線路，開關、變壓器等圖資），若使用此程式轉換程式可大幅縮短圖資數化時間。

3. 控制中心系統軟體：GEN-3 DMS/SCADA

其 DAS 控制中心軟體模組計有：

（1）動態線路模組：提供系統開關狀態異動時（事故停電之開關跳脫、工作停電之開關切換）線路架構組態，可提供系統做配電線路分析、事故停電管理。

（2）配電線路分析：依據動態線路模組所提供的線路架構組態，做電

力潮流分析，做為系統轉供的參考。

（3）事故停電管理：依據動態線路模組所提供的線路架構組態，做為事故用戶停電資料之分析及統計，提供電力公司及用戶之停電相關資訊。

（4）開關切換排程管理：工作停電時，提供系統調度人員之開關切換行程；事故停電時，FDIR之復電開關切換順序。

（5）SCADA核心軟體：如圖3.10所示，核心軟體功能為藉由控制中心通訊伺服器所蒐集之現場設備狀態及數據資料，計算及判斷系統所監控的設備工作情形，異常時，系統之警示及設備之回應情形。其特性有：

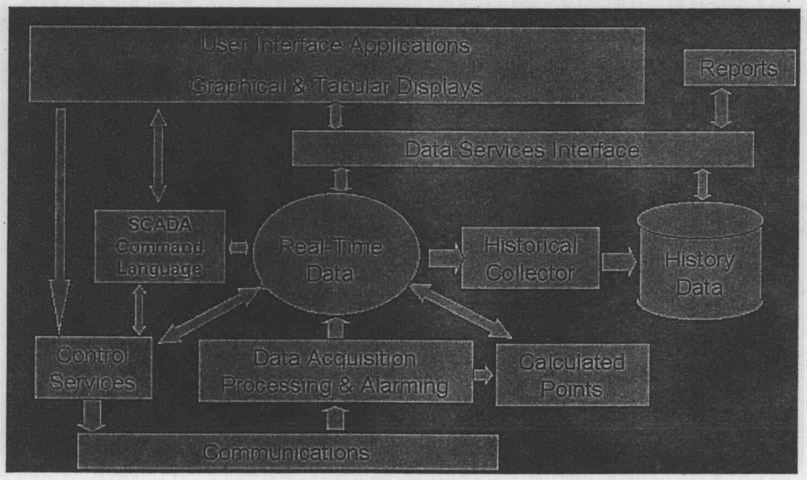

圖3.10　SCADA核心軟體架構

a. 提供可適用於 Unix 及 MS_Windows 作業系統全圖形中英文操作介面工作站，此圖形介面(GUI)提供圖資位移、放大、縮小及無間隙的地理及電力系統圖資顯示。

b. 支援標準工業通訊協定；現場 RTU 及 FRTU 採用 DNP3.0 及 IEC870-5 通訊方式，而控制中心則使用 IEC-870-6 TASE.通訊模式。

c. 支援使用者導向之 scripting 程式語法；例可依現場傳回之電壓、電流及相關饋線開關狀態數據資料，系統自動研判後，執行單一指令既可自動執行多組自動開關之操作。

d. 有強大的數學及邏輯運算處理能力，可同時做現場蒐集資料之處理、拓樸架構（電氣連結關係）合理性判定、突發性事故處理及開關之操作等。

（6）SCADA 圖資編輯軟體：提供監控圖符之編輯、現場監控點取樣資料及屬性相關資料之建置。

肆、心得與建議

一、控制中心軟體方面

1. 模組化、彈性化的程式設計：日本 TM T&D、美國 GE、加拿大 SNC 等三廠家在配電饋線自動化控制中心之應用軟體方面均秉其過去承攬 EMS/SCADA 工程豐富之經驗，採模組化、彈性化之程式架構，此架構

除可針對不同的系統需求，採用不同的功能模組組合，可減少客製化的時間，亦可避免系統軟體昇級時，與原系統資料庫架構及軟體相容性不符之情形。

2. EMS 與 DMS 之主要差異如下表：

系統 / 項目	EMS	DMS
處理電力系統	100KV 以上	100KV 以下
節點數/線路型態	100 至 1000/環路結構	1000 以上/常開環路放射狀
事故影響層面	大	局部
SCADA 技術實務	較多	較少
RTU 數量/種類	約 100 具/大型	達 1000 具/小型

3. 日本「中國電力公司」廣島服務所其 DMS 系統是藉由現場 FTU（Feeder Terminal Unit）取樣現場開關啟閉狀態、電壓、電流訊息供控制中心饋線 SCADA 來監控，系統運轉一段時日後，大幅提昇供電可靠度(2002 年事故停電實績為 2.0 分/戶)，未來計畫導入完整的 FDCS (Feeder Dispatch Control System)功能，包含 GIS、FDIR（Fault Detection Isolation and Restoration）、OMS（Outage Management System））等相關程式功能。

而本公司建置之饋線 SCADA 系統（資訊末端設備建置工程），也類似「中國電力公司」DMS 系統建置的方式，未來將導入完整之 FDCS 系統，唯：

（1）本公司為國營單位，SCADA 系統建置及未來 FDCS 功能之導入，因採公開招標方式，將面臨的不同廠商產品整合問題，未來相關軟、硬體整合界面應儘早釐清，於系統建置時與廠商充分討論提出較佳的解決方案。

（2）為減少日後系統維護人力及營運成本，本公司所有區處運轉的 DMS 系統應求統一，故通訊模式、界面應訂定標準化，此標準化的建立，除可確保爾後購置之現場設備可順利與系統整合運作外，更有利於日後與上游 DDCS(Distribution Dispatch Control System)配電調度控制系統整合，形成一完整 DMS 系統。

4. 先進的 DAS 系統軟體功能，除傳統 SCADA 系統功能外，亦納入 GIS 及 OMS 功能，調度人員可藉由 GIS 提供之設備現場圖資，協助工作班人員迅速掌握事故地點，減少事故時間，而 OMS 功能可輔助本公司及用戶停電訊息的掌握，而本公司北南、高雄區處建置中的「配電饋線自動化系統」除加入 GIS 輔助功能外，而與既有 OMS 系統整合部份是以 OMS 資料庫為溝通界面，DAS 現場開關狀態之改變透過此界面告知 OMS，由 OMS 過濾及處理停電資料，圖 4.1 說明，本公司 DAS（FDCS）與 OMS 間之運作界面。

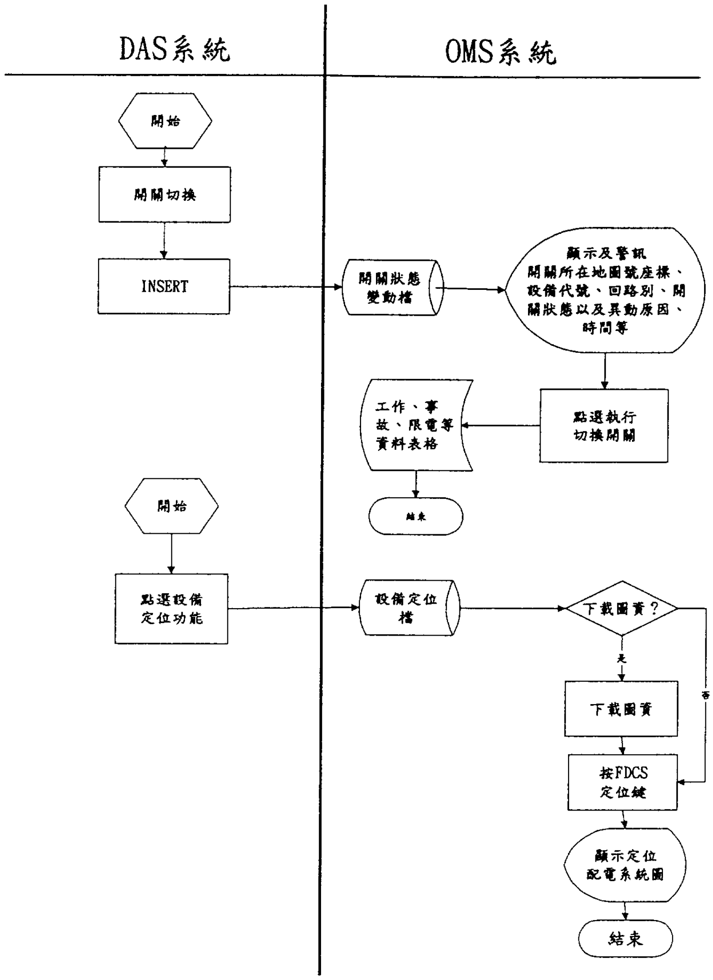

圖 4.1 DAS 系統與 OMS 系統介面圖

二、控制中心硬體方面：

1. 各控制中心相關之伺服器如資料伺服器、應用程式伺服器及通訊伺服器等除有相對備援伺服器外，對備援控制中心的設置亦不可或缺，而備援控制中心的運作除備援的角色外，平日也擔任區域性控制中心的功能，可避免備援系統設備的閒置，可提昇系統整體的利用率及效率。

2. 由於資訊設備製造廠商已採國際間標準化，控制中心硬體設備間相容性

極高，因此未來硬體之擴充可由本公司依需要單獨發包辦理，以節省初期建置成本。

三、其他

1. 本公司預計民國九十六年完成百分率 50%之饋線自動化，所需維護的現場設備(自動開關、FTU、FRTU 及通訊設備、線路等)大幅增加，控制中心資料庫及應用程式的更新維護，需大量的人力，應儘早規劃因應的方法及機制。

2. 未來執行饋線自動化系統建置之區處，其廠內接收測試人員宜儘早選定，對於廠商之技術研習與背景可事先瞭解，預做準備以達到事半功倍之效果。

3. 日本中國電力公司成立饋線自動化系統設備研發及生產製造、維護之子公司「中國計器工業」，值得做為本公司未來民營化後之借鏡。

4. 本公司配電饋線自動化系統建置，建議自動化開關的導入方式為：

（2）既有饋線系統納入自動化監控，可考量饋線上將汰換之手動開關逐一取代為自動開關並加入 RTU (即本公司規劃之 FTU)，納入控制中心之監控。

為兼顧自動化的靈活性及完整性，應將饋線上所有手動開關替換為自動化開關納入監控為目標。

（3）用戶供電可靠度要求並不很高的饋線，可新增一組自動化開關於饋線上，納入監控範圍。

（4）新增饋線可依饋線用戶用電可靠度需求，部分或全部開關納入自動化監控。

圖 4.2 為於原有之饋線使用自動開關取代手動開關或於原有饋線新增一組自動開關來達成自動化監控的目的。

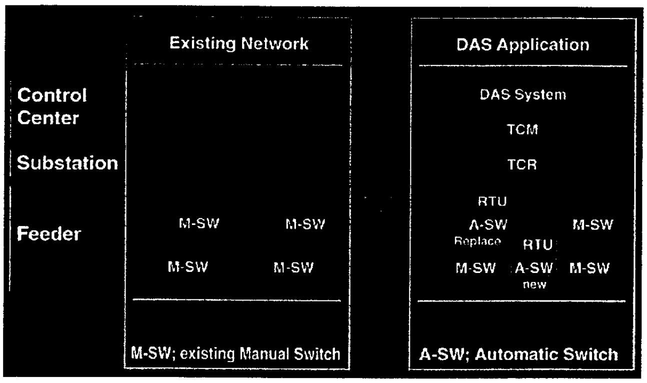

圖 4.2 饋線自動開關取代手動開關及新增饋線自動開關

5. 配電饋線自動化系統架構分為：

（1）配電自動化系統依監控型式可分為「地方（Local）」及「中央集中（Centralized）」兩種監控方式（如圖 4.3 及圖 4.4）：

a.地方（Local）監控方式：饋線上的事故隔離、復電機制由現場饋線上 RTU 來研判事故及啟閉開關來完成，本公司配電常閉環路自動化系統就屬地方監控方式。

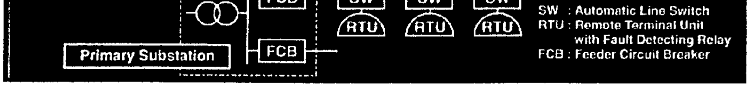

圖 4.3 地方監控方式自動化系統架構

b. 中央集中(Centralized)監控方式：饋線上的事故隔離由現場 IED 電驛動作 CB 來完成，復電機制由控制中心蒐集現場資料研判及 FDIR 功能來完成，本公司常閉環路饋線自動化系統就屬中央集中監控方式。

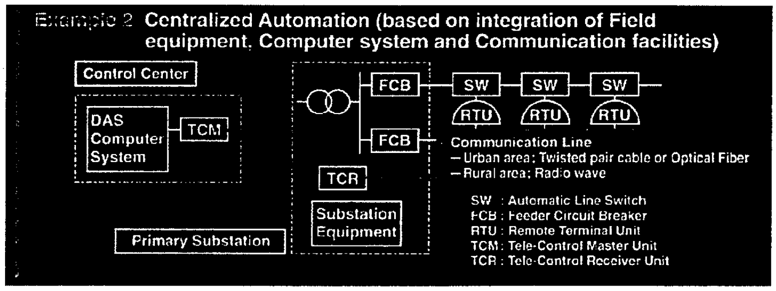

圖 4.4 中央集中監控式自動化系統架構

（2）附表 4-1 「配電常閉環路自動化系統」與「配電常開環路自動化系統」特性比較表，由表列之分析，建議如下：

a. 就供電可靠度及電力品質之比較，其優劣順序依序為「配電常閉環路自動化系統」、「配電常開環路自動化系統」。但「配電常閉環路自動化系統」之建置費用及其配合工程均較「配電常開環路自動化系統」為多，且「配電常閉環路自動化系統」之饋線利用率較「配電常開環路自動化系統」低。惟事故時，不論「配電常閉環路自動化系統」或「配電常開環路自動化系統」靠近事故點處 所產生之電壓驟降，均無法滿足半導體製造廠 SEMI F47-0200 壓降建議之曲線要求。

b、依照建置費用、配合工程、供電可靠度及饋線利用率等之考量，建議「配電常開環路自動化系統」建置於供電可靠度要求較高的地區，如科學工業園區及都會金融商業中心;「配電常開環路自動化系統」建置於工業區、加工出口區、一般市鎮地區及重要偏遠山區。

附表 4-1 「配電常閉環路自動化系統」與「配電常開環路自動化系統」特性比較表

比較項目	配電常開環路自動化系統	配電常閉環路自動化系統（同一主變）
1. 建置費用	約為 300 萬/每饋線	約為 700 萬/每饋線
2. 配合工程(相同部份不列出)	1. 將饋線上之手動開關更換為自動開關	1. 將饋線上之手動四路開關更換為常閉環路自動開關。 2. 重新調整供電負載，增加配置空間以安裝斷路器，規劃環路保護協調(Ring Protection Coordination)。
3.供電可靠度 3.1 饋線故障時停電範圍	1. 幹線故障時，饋線 CB 跳脫，饋線所有用戶供電中斷。 2. 分歧線故障時，分歧線路斷路器跳脫。故障分歧線路所有用戶供電中斷。 3. 用戶端故障時，該用戶供電中斷。	1. 幹線故障時，故障區段兩端電驛跳脫，不影響用戶用電。 2. 分歧線故障時，分歧線路斷路器跳脫。故障分歧線路所有用戶供電中斷。 3. 用戶端故障時，該用戶供電中斷。 停電用戶數較「常開自動化系統」為少。
3.2 饋線故障時停電時間	幹線或分歧故障時，饋線 CB 或分歧線 CB 跳脫時，故障端上游供電區間復電為 30 秒，下游恢復供電需為 2~5 分鐘（技術規範 FDIR 要求，視停電主變壓器及饋線數量多寡而定）。	同一環路饋線故障時，雖不會造成本身饋線用戶斷電，但會造成同一主變其他饋線用戶約 8-16 週波（視系統設定）的電壓驟降。 停電時間較「常開自動化系統」少。

4. 電壓驟降 其電壓驟程度視距離故障點大小而定	1. 以實際理論推算 $S_{0.5標么}$ =1.62 Km(維持 0.5 標么時，距離事故點 1.62km 以上) $S_{0.7標么}$ =3.78 Km(維持 0.7 標么時，距離事故點 3.78km 以上) $S_{0.8標么}$ =6.48 Km(維持 0.8 標么時，距離事故點 6.48km 以上)	電壓值約為常開環路型之二分之一以上。
5. 饋線利用率	配電常開環路系統一主變壓器可供應 6 至 8 條常開饋線	配電常閉環路系統以二條常開饋線組成一條常閉饋線

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二、 “FEATURES AND BENEFITS OF MODERN DISTRIBUTION MANAGEMENT SYSTEMS”, R. Hoffman SNC-Lavalin Energy Control Systems

三、 “THE DISTRIBUTION DISPATCHING CENTER PROJECT ATTHE PROVINCIAL ELECTRICITY AUTHORITY OF THAILAND”, R. Hoffman, M. Duboisl, W. Koykul, S. Chiochanchai, R. Wasley

四、 “ENMAC NETWORK SOLUTIONS”, GE Network Solution

五、 “SMALLWORLD PowerON Network SOLUTIONS” (GE Network Solution)

SMALLWORLD POWERON®

Network Solutions

OVERVIEW

General Functions

Smallworld PowerOn® DMS offers a number of other important features. These include:

- The seamless integration with Smallworld Core Spatial Technology™, providing spatial representation of distribution networks, outages and crews
- Network management functions that support both the daily updating of device statuses and the emergency updating of device statuses due to restoration switching
- Seamless integration to other operational products to support Web-based dispatching
- Mobile data terminal interfaces for wireless use
- Thin client access to both textual and graphical data.

Developed using Oracle®, Microsoft® and GE Network Solutiuons standard technologies, Smallworld PowerOn™ software is fully supported – 24 hours a day, 7 days a week, 365 days a year – customer service.

Moving into the Future with GE Network Solutions

GE Network Solutions is committed to continuously enhancing its products and its technology backs up this commitment. It is highly scalable and incorporates all of the features required to enable data integration and interoperability between different business systems. It is the right technology to take you comfortably into the future.

GE Network Solutions

Americas: + 1 303 779 6980
+ 1 888 779 6980 (toll free)

Asia Pacific: + 65 536 0501

United Kingdom: + 44 (0) 1223 301144 (England)
+44 (0) 1506 591 200 (Scotland)

Germany: + 49 2102 1080

gepower com/networksolutions

GEA-13058 b 0502

SMALLWORLD POWERON®

Network Solutions

OVERVIEW

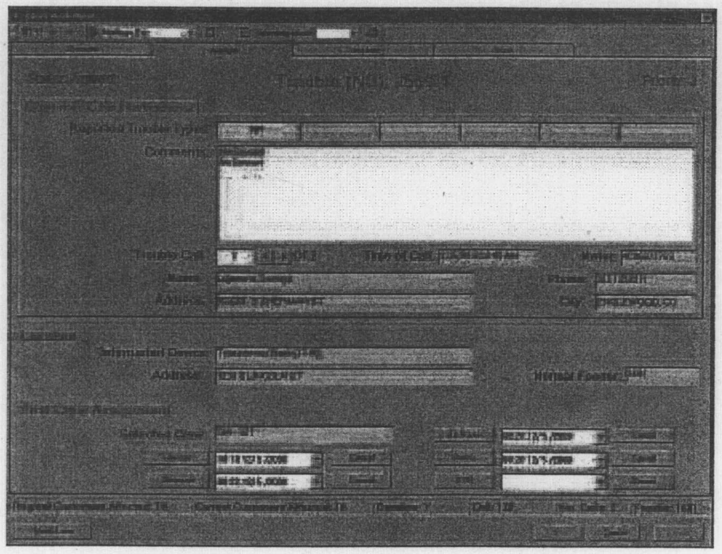
The Smallworld PowerOn™ distribution management system delivers integrated tools that seamlessly manage operational and customer data across an enterprise. Going far beyond other systems on the market, Smallworld PowerOn® software provides a comprehensive solution that would typically be possible only through the integration of multiple products from multiple vendors.

With GE Network Solution's comprehensive outage and distribution management solution, you have a technology alternative that can be used by your enterprise today, as well as your enterprise of tomorrow. Smallworld PowerOn® software's proven scalability provides the ability to grow with your business.

What's Available Now

Smallworld PowerOn® 2.0 is a comprehensive distribution management system (DMS). It addresses distribution management functions and opens up operational capabilities and data to your entire utility organization. Smallworld PowerOn® DMS empowers utilities to achieve exceptional levels of service by:

- Quickly responding to customer queries – even in storm conditions.
- Decreasing outage restoration time through intelligent prediction and integration of operating centers and crews.
- Distributing information throughout the utility over both the company Intranet and the Internet, and allowing dispatch terminals anywhere.
- Giving users an easy-to-use, logical workflow process to follow.



Assigning switching tasks for selected devices

GE Network Solutions

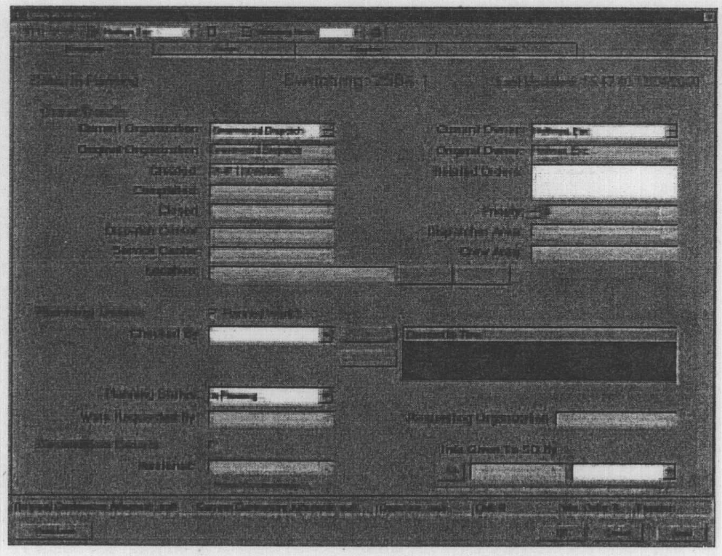
SMALLWORLD POWERON®
Network Solutions

Smallworld PowerOn® 2.0 Includes These Powerful Features

Network Management
Smallworld PowerOn® DMS gives you the ability to originate and track requests for planned switching. Features and functionality include:

- The ability to generate switching order tasks via a graphical user interface or to simulate the execution in a "what-if" mode and store the tasks for future execution.
- The ability to issue, maintain and track all crew safety clearances, assurances and safety tags.
- A complete workflow model that includes dispatching functions and user interfaces to streamline the workflow of planned and unplanned switching.
- A network navigation and search tool that provides the ability to navigate electrical networks with search-and-find functions, including a graphical display showing all feeder ties/reclosers for a selected circuit and giving users the ability to navigate upstream or downstream from a selected device and to assign switching tasks for selected devices.

Reduce costs by maximizing your utility network efficiency and staff productivity



ENMAC™

Network Solutions

OVERVIEW

ENMAC™ Architecture

Technology

ENMAC™ is a completely open and highly configurable distribution management solution incorporating the following technologies:

- Client/Server
- Relational Database
- Object Oriented Database
- Object Oriented Design
- Expert Systems
- Web
- Hypertext.

Standards

Standards benefit the vendor as well as the customer. ENMAC™ is built on a foundation of industry and de-facto standards:

- UNIX® and Windows NT®
- ANSI® C, C++, Visual Basic®
- X Windows Systems
- OSF/MOTIF®
- ORACLE® relational database
- DNP 3.0
- IEC 870-5
- ICCP
- ELCOM 90
- TCP/IP-based networking
- Postscript 2
- DXF and NTF 2 graphics exchange formats.

Characteristics

As a result of its adherence to standards and innovative use of technology, the ENMAC™ Distribution Management System exhibits the following characteristics:

- Inherent flexibility to adapt to changing business needs
- Cost effective scalability
- High availability/fault tolerance
- Deterministic responsiveness
- Data-driven, Object Oriented design
- Ease of integration with other systems
- Secure, reliable operation
- Integrity of data
- Paperless work environment.

ENMAC™ Hardware Environment

ENMAC™ is supported on the following major hardware platforms:

Hardware/OS Environment	Client	Server	Front End Processor
Compaq®/UNIX®		•	
Intel®/Windows NT®	•		•

GE Network Solutions

Americas: + 1 303 779 6980
+ 1 888 779 6980 (toll free)

United Kingdom: + 44 (0) 1223 301144 (England)
+44 (0) 1506 591 200 (Scotland)

gepower.com/networksolutions

Asia Pacific: + 65 536 0501

Germany: + 49 2102 1080

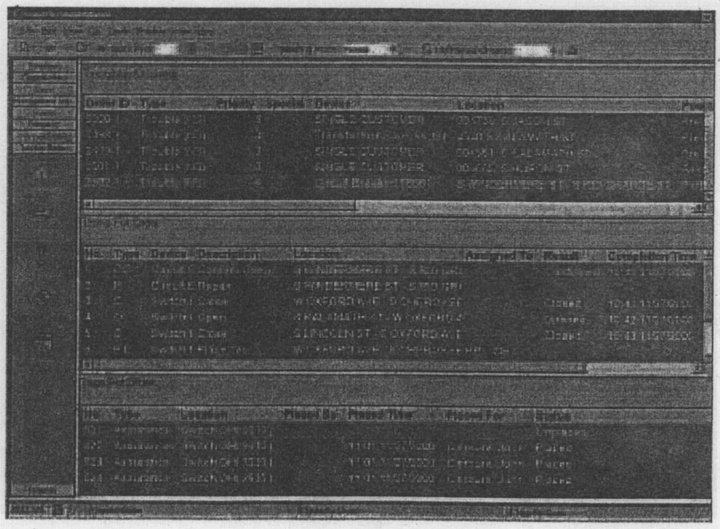
GEA-13351

OVERVIEW

Outage Management

Smallworld PowerOn® DMS supports a streamlined workflow for each outage. Features include:

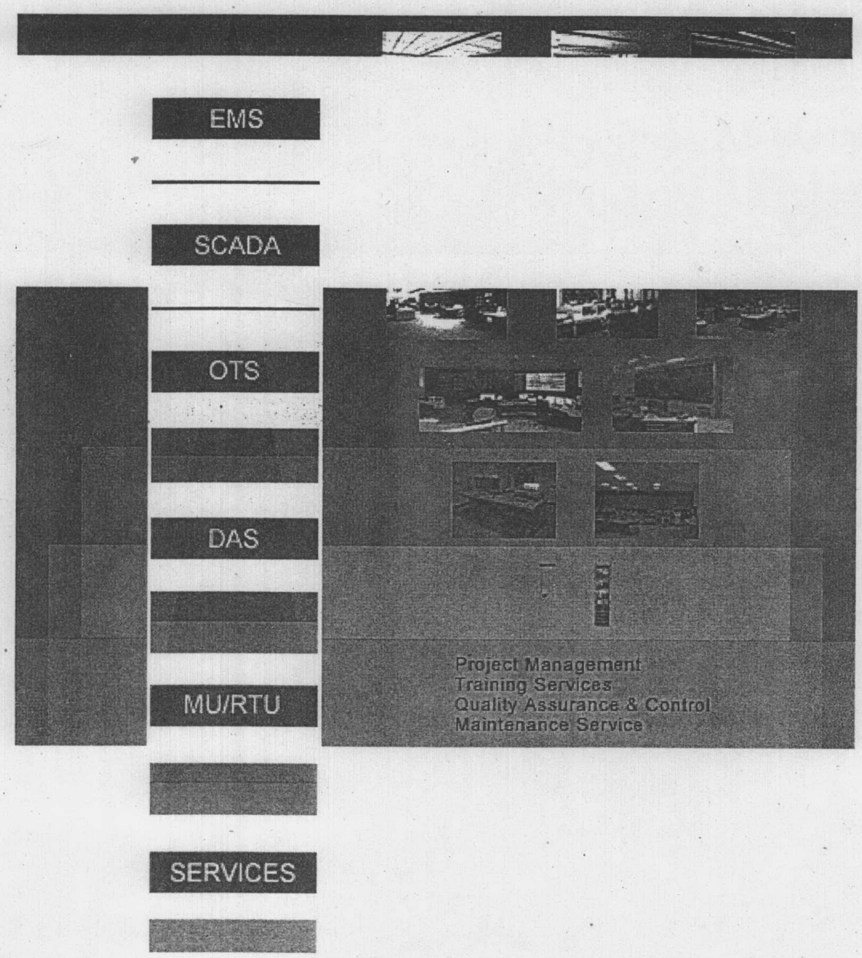
- A SCADA interface for automatic outage generation and use of load data for network management
- Network schematics for creating a working schematic view for network management operations
- Integration with customer information systems and interactive voice response units to accept trouble calls and provide the status of restoration efforts
- Automated analysis and prediction of trouble calls to determine probable device based on customer-configurable prediction rules
- Crew management functions that support the tracking and use of restoration crews
- Capabilities to build dynamic organizations to support decentralized dispatching during large volume events
- Automatic calculation of minutes of interruption for full and partial restoration efforts
- Reports to support operational decisions during outage events
- Dynamic outage management functions to build organizations to support decentralized dispatching during large volume events
- Calculation of customer minutes interrupted for full and partial restoration efforts
- Additional workflow capabilities, such as maintenance and service order dispatching.



Make better decisions throughout your organization by delivering information and applications using Internet technology

TMT&D

Network Control Systems (NCS)



Network Control Systems for Electrical Power Systems

Computer based Network Control Systems (NCS) utilizing high-performance workstations with server/client technologies are used widely for stable and efficient power system operation. TMT&D provides broad range of systems, such as Supervisory Control And Data Acquisition (SCADA) systems which covers the High Voltage (HV) transmission lines, Distribution Automation Systems (DAS) to manage and control Medium Voltage (MV) distribution lines, Energy Management Systems (EMS) for generation control and network analysis, as well as

Energy Management Systems (EMS) for generation control and network analysis, as well as Operator Training Simulators (OTS) to support Utilities operator training programs. These systems are based on a distributed, open architecture that provides a flexible platform to expand its functions.

Our Long History with Network Control Systems (NCS)

TMT&D has supplied over 700 EMS/SCADA/DAS systems to domestic and overseas customers including Toshiba's and Mitsubishi Electric's peviod. TMT&D also has more than 35 years of experiences in this field since we delivered our first computer-based system to a utility back in 1962. TMT&D has supplied 25 systems overseas to countries such as Australia, Bulgaria, China, Egypt, Indonesia, Kuwait, South Africa, South Korea, and Taiwan.

*) EMS : Energy Management System

SCADA : Supervisory Control And Data Acquisition system

OTS : Operator Training Simulator

DAS : Distribution Automation System (Distribution SCADA)

MU : Master Unit

RTU : Remote Terminal Unit

Concept

TOSMELS™/D (DAS computer system) will provide supervision and remote control of switches and sectionalizes such as Pole-mounted Vacuum Switches (PVS) and Ring Main Switchgears (RMS) on a high-voltage distribution line for switching the load current of the distribution line. This can be remote controlled either automatically or manually, so that it can provide automatic isolation of faulty line section, which enables quick and accurate recovery of a stable power supply, and also minimizes the out-of-service areas by units of distribution sections.

Reduction of Outage Time
• TOSMELS™/D(DAS computer system) will automatically isolate faulty section using its intelligent network switching procedure calculation function, and can quickly restore and provide power to the healthy section, which leads to earnings from electricity charges.
• The DAS equipment can also recover certain areas automatically by itself without a computer system, just by implementing Fault Detecting Relay (FDR) to switches.

Reduction of Personal Expense

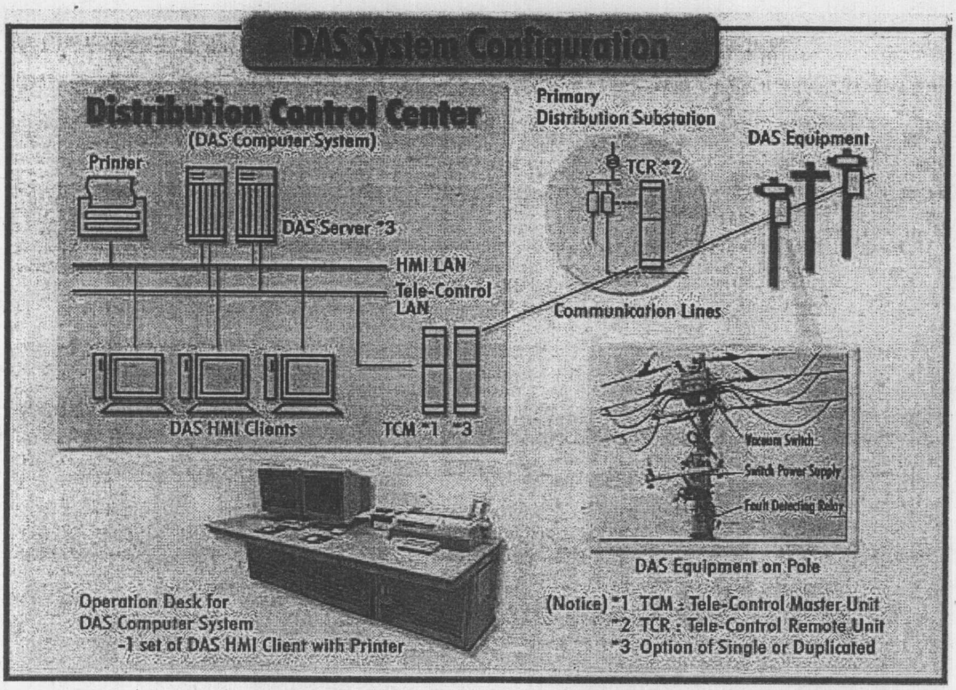
- TOSMELS™/D(DAS computer system) will find the faulty section using the fault section detecting function, and highlight the corresponding section on real-time Geographical Information System displays. There is no need for your maintenance crews to be running around the field trying to find the location of a failure.

- The DAS equipment also has a simplified sequence to detect the faulty section with combination of switches.

Reduction of Capital Investment

- TOSMELS™/D(DAS computer system) can minimize the invested amount of spare capacity to each feeder line, for instance down 33%, which may reduce 67% capacity of not only the distribution lines but also the capacity of substation transformers.

System Configuration



Fault Detection Isolation and Recovery (FDIR)

- This not only simply monitors and controls the real-time network status like other ordinary SCADA's but also can automatically 'detect' the occurrence of a fault, automatically 'isolate' the fault section, and automatically create and execute the 'recovery' sequence of the healthy section while giving alarms to the operators and getting the final decision from the operators.

Distribution Management System (DMS)

- This supports the full suite of functions to manage the distribution network and to support your real-time operations. With a variety of applications employing the operator definable Sequential Switching Operations (SSO) and maintenance and trainings functions are also packaged, including regular distribution facility data management.

Real-time Geographical Information System (GIS)

- Overloading street maps and geographical data to real-time information of your distribution lines and equipment will support your operators with quick access and immediate execution of action.

Functions

One of the major advantages of the TOSMELS™/D (DAS Computer System) is the integration and harmonization of 3 major functions to operate the distribution network.

Fault Detection Isolation and Recovery(FDIR) and Remote Monitoring and Control

- Intelligent Fault Section Detection on failures, automatic Fault Section Isolation, and automatic creation of intelligent non-fault Section Recovery Sequence.
- Monitoring of status data, relay operation, current and voltages on distribution network, and primary distribution substation.
- Remote control of PVS,RMS, and Feeder Circuit Breaker.(FCB)
- Remote setting and resetting for Over Current Relay(OCR) and Fault Detection Relay(FDR)
- Data Recording Reporting by printer or color hard copy
- Alarm Processing and Event Messages

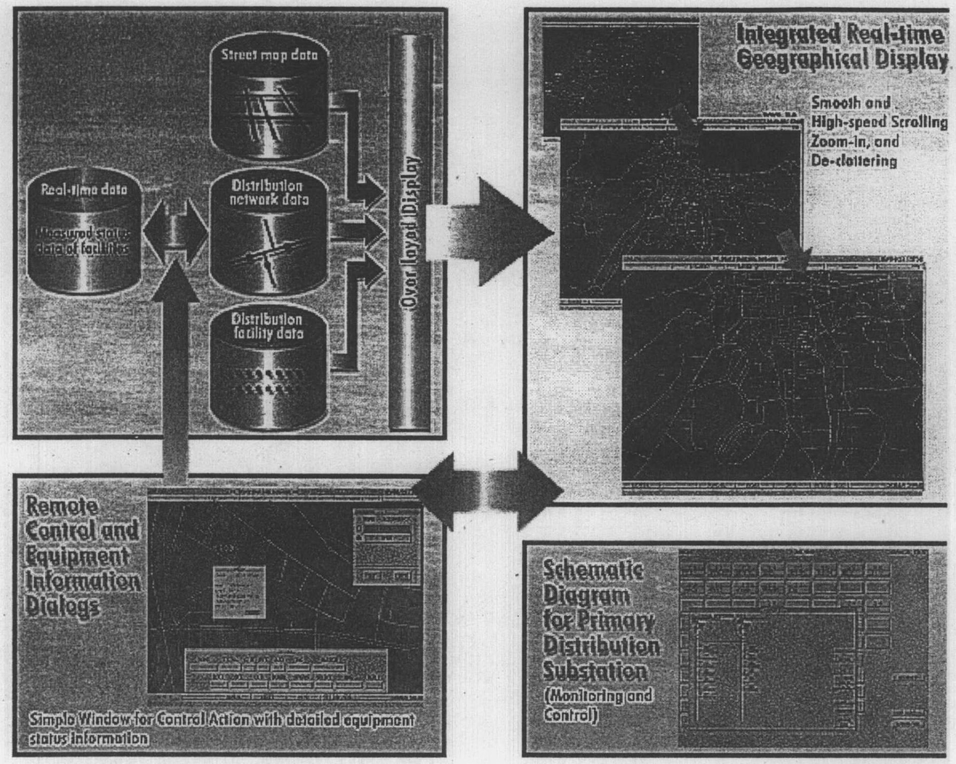
Distribution Management System(DMS)

- Database Maintenance mode for substation and distribution network equipment

- Database Maintenance mode for substation and distribution network equipment
- Dispatcher Training Simulation (DTS) mode for operator training
- Trouble call and Crew management function

Graphical User Interface(GUI) with GIS

- Integrated Geographical Displays for distribution networks, and Schematic Diagram Displays for primary distribution Substation.
- Smooth Scrolling and Zoom-in with De-clattering of distribution facility information.
- Distinguish and Clarifying the distribution network status by color, such as normal condition of in-service, out-of-service conditions on failures and maintenance, or inter-connected by another feeder.
- Network highlighting responding to pointing device.


Street map data
Real-time data
Measured status data of facilities
Distribution network data
Distribution facility data
Over layed Display
Integrated Real-time Geographical Display
Smooth and High-speed Scrolling Zoom-in, and De-cluttering
Remote Control and Equipment Information Dialogs
Simple Window for Control Action with detailed equipment status information
Schematic Diagram for Primary Distribution Substation
(Monitoring and Control)

FEATURES AND BENEFITS OF MODERN DISTRIBUTION MANAGEMENT SYSTEMS

R. Hoffman
SNC-Lavalin Energy Control Systems

(Presented at the CIRED Regional Symposium on Electricity Distribution Aug 5-8, 2002 Kuala Lumpur)

INTRODUCTION

Distribution networks have traditionally been the poor cousins of the high voltage (HV) transmission networks as far as centralized SCADA control is concerned.

For many years it has been accepted that as a minimum SCADA monitoring and supervisory control is an absolute necessity for operation of a transmission network. Furthermore today most dispatching centers for HV transmission networks have an Energy Management System (EMS) which, in addition to basic SCADA capability, also have advanced application software for modelling the HV network and performing State Estimation, On-line Dispatcher Power Flow, Contingency Analysis and even optimisation applications.

Meanwhile, at the distribution level there still are many distribution utilities around the world which do not have any form of SCADA or computer-based distribution management systems. The reason for this disparity between transmission and distribution system control is easy to understand and explain.

First of all, in a distribution network generally the impact of a network outage or other operating problem is relatively limited in terms of the number of customers affected by an outage. Thus the "benefit" of computerized investment generally is less. Secondly, generally the size of the distribution network in terms of the number of power system devices such as circuit breakers, sectionalising switches, fuses, etc. is very large. Therefore the total number of automation devices, e.g. Remote Terminal Units (RTUs), required on a distribution network is generally much larger than on a transmission network. For example, the PEA distribution network in Thailand will have over 2000 feeder RTUs in Phase 1 which covers only 5 of their 12 areas.

However, for several reasons, the situation is beginning to change, Most importantly, it is becoming increasingly important to customers to get reliable supply of power with fewer interruptions of supply and more rapid restoration of power when outages do occur. With the move toward de-regulation regulatory agencies are forcing utilities to provide higher quality of service, often with financial penalties for poor performance.

At the same time, with the improved price-performance of modern electronics, micro-processors, computers and communication technology, the cost of automation has decreased significantly over the last decade.

The end result is that large scale distribution automation and management technology is becoming both increasingly important and economically viable.

There are three main components in an automated distribution system:

- Field devices, including remotely controlled switches, digital relays, and other intelligent electronic devices.
- Communication systems, including radios, fibre optics, WAN/LAN technology and remote terminal units (RTUs)
- Control and Dispatching Centers, including SCADA systems, Outage Management Systems (OMS) and Distribution Management Systems.

This paper is concerned primarily with the various types of Control Center systems and especially Distribution Management Systems.

COMPUTER-BASED SYSTEMS USED IN DISTRIBUTION OPERATIONS

There are various types of computer-based systems which are commonly used by distribution operations. These systems have some common characteristics which, superficially, make them look very similar to each other. Three of these systems, all of which are used to some extent in real-time operations - are briefly described in the following.

Geographic Information Systems

Because of the large size of most distribution networks, the distribution utility must maintain a large volume of data or records about their network, including many drawings. Indeed the common characteristic of most distribution dispatching centers is the large number of cabinets of drawings, and not infrequently most of the walls of the dispatching rooms are covered with drawings of the network.

Prior to the use of computers, these records were maintained manually in paper form. When computers were first introduced in this area of electric power utilities they were primarily known as Automated Mapping / Facilities Management (AM/FM) systems. Today the term Geographic Information Systems (GIS) is more common. GIS is a generic computer industry term for database management systems primarily concerned with data that has a significant spatial or geographic component.

Over recent years many distribution utilities have made significant investments, with varying degrees of success, in acquiring GIS systems and converting their paper based records and network drawings into GIS form. Once these GIS systems exist it seems natural to want to use them directly in real-time operation of the network.

However, in my opinion, unfortunately most GIS systems are not suitable as the primary platform for real-time distribution operations. GIS systems are designed primarily for their off-line records management role. In particular their user interface tends to be optimised for the data entry and editing task, not for rapid display call-up and navigation. Also, most GIS systems are not intended for 24-hours-per-day, 7-days-per-week operation, which is what is needed in the real-time operations environment.

Another commonly occurring problem with GIS systems, in our experience, is that the GIS data is captured primarily for asset management purposes, with only a graphical representation of the electrical connectivity. To be useful for subsequent analysis of the electric network, it is essential that the electrical connectivity of all the devices in the network be explicitly modelled in the GIS databases.

Outage Management Systems

Outage Management Systems (OMS) appear to have arisen first in the North American context, where with some significant exceptions, most distribution networks traditionally have had relatively little automation. In the typical distribution utility where SCADA telemetry exists at all, it generally exists only at the distribution substation. Quite frequently, the substation SCADA monitoring is done by the transmission operations and distribution operations may have some limited access, for example, via remote consoles.

In the past, and to a considerable extent today, it is not uncommon for there to be no real-time telemetry outside the substation, in which case the primary source of real-time information regarding problems on the distribution network is telephone calls from customers reporting, or asking about, power outages affecting them. Typically such calls from customers are received by the customer service department which, in the past, would write a paper "trouble ticket" and pass them on to the operations department for resolution.

In a large utility, management of trouble tickets, particularly under storm conditions becomes a monumental task. In general a number of customer calls may pertain to a common network problem. For most efficient dispatching of trouble crews, the trouble tickets must be sorted and grouped into suspected common outages to minimize the likelihood of dispatching multiple crews for a common network problem. Furthermore, the dispatcher must try to prioritise the suspected outages so that crews can be dispatched to the most critical or the largest outages first.

It is in this environment and to address this particular task, that Outage Management Systems (OMS) were initially developed. OMS are designed specifically for the real-time operational environment. Furthermore, to perform their work of grouping customer trouble calls, and determining the size and impact of distribution outages they need a connectivity model of the network, including the switches and protective devices as well as a mapping of individual customers to their network attachment point, usually the MV/LV distribution transformer. An OMS system usually will include a full graphical representation of the network.

However, most OMS do not purport to manage real-time telemetry or remotely-controlled switching operations on the distribution network. While they may accept switch status information from SCADA systems to perform outage tracking and management they do not address the full range of real-time distribution network operations.

Distribution Management Systems

A distribution management system (DMS) is defined as a complete computer-based system used by a distribution dispatcher to manage all aspects of real-time network operations. It provides to the dispatcher a continually updated view of the distribution network based on all available information, including real-time SCADA telemetry, as well as information such as customer reported outages, manual switching operations effected by field crews.

The following paragraphs summarize some of the most important characteristics and capabilities of a modern DMS.

Performance. A DMS is based on a SCADA platform with all of the real-time performance expected by dispatchers of electric power networks.

Full graphic displays of the network should be accessible to the dispatcher in the order of one second.

Availability. A DMS must provide reliable operation 24 hours per day, 365 days per year. This can only be guaranteed with dual-redundant architectures with the capability for automatic fail over.

SCADA. A DMS should have a full range of traditional and advanced SCADA functionality with the ability to monitor and issue supervisory controls via substation and feeder RTUs. It should support the industry standard RTU protocols such as DNP and IEC870-5. It must be able to interface to a variety of communication media, in particular radio, as well as IP-based wide area networks.

Network Model. A 3-phase model of the electrical distribution network is essential. This model must include electrical connectivity as well as network impedance and customer loads. All conducting equipment such as switches, breakers, fuses, overhead lines and underground cables, transformers, capacitors must be modelled.

Full Graphics. The user interface is perhaps the most important feature of a DMS since it is essentially the sole mechanism for the dispatcher to perceive the state of the network as determined by the DMS. Full graphics capability, including pan, zoom and de-clutter, is essential for representation of geographical displays of the distribution network overlaid, for example, over maps showing streets and roads. At the same time, schematic views of the network should also be supported in parallel with the geographic views

The GUI must be expressive by having a variety of ways, such as coloring, to convey the current state of the network. It must provide intuitive and efficient ways to navigate through the large number of displays available. Above all it must have high performance response to user requests.

Connectivity Analysis. The model must have Connectivity Analysis capability which can rapidly and efficiently in real-time determine the live-dead-grounded status of each network element whenever any switching action is performed. In addition to recognizing connections via switching actions, it should also recognize temporary network connectivity changes via cuts and jumpers and grounding achieved via portable grounds. A variety of network tracing functions must be supported, including upward tracing from multiple customer reported outages to determine common suspected outages.

Load Flow. This application automatically computes the estimated 3-phase unbalanced voltages and currents throughout the network based on customer load profiles and the results of the connectivity analysis application. Where real-time SCADA telemetry is available, load estimates must automatically be scaled such that the current flows calculated by the load flow match the telemetry.

Switching Advice. The DMS should have tools which can be used by the dispatcher to quickly and efficiently determine the optimum switching actions to restore power to outaged areas when the normal supply path is unavailable or to transfer load to neighbouring feeders to relieve overloads.

Fault Management. Whenever there are uncommanded breaker trips due to faults on feeders, the DMS must have the ability to automatically and quickly analyse fault current passage data from RTUs on the feeder to determine the location of the fault. It must then be able to determine optimum switching actions to isolate the faulted section and to restore power to unfaulted sections of the feeder both upstream and downstream of the faulted section.

Switching Orders. A great deal of the distribution dispatcher's workload consists in the creation and supervision of switching orders, usually in support of maintenance and construction activities by field crews. Therefore a modern DMS should include a computer-based switching order management facility which will support creation, validation and execution of switching orders. This facility should be linked to the switching advice and fault management subsystems. The user interface must be at least as efficient as the paper-based systems used in the past.

Trouble Call and Outage Management. The DMS must have capabilities to perform the trouble call and outage management functions of an Outage Management system, as described above.

Dispatcher Training Simulator. A modern DMS should include a dispatcher training system (DTS) which can be used to train new dispatchers and provide refresher training for experienced dispatchers on how to best operate and manage the distribution network via the advanced facilities of the DMS. The DTS trainee environment should be as near as possible to an exact replica of the hardware and software of the real-time DMS. In addition it should have special tools to allow an instructor to define realistic training scenarios including equipment malfunctions.

DMS BENEFITS

A modern DMS provides benefits in many respects to the distribution utility. The following are some of the principal benefits which should result from a good DMS installation.

- A DMS should improve the quality of service and customer relations by responding to customer service interruptions more rapidly.
- A DMS should improve the dispatcher's ability to monitor and control the power system during normal, abnormal, and emergency conditions by providing reliable and appropriate real-time data from the network.
- It should improve power system efficiency by helping to maintain acceptable power factors and reducing technical losses
- A DMS should assist power system maintenance and safety practices by providing more reliable, meaningful, and timely records of the operating history of the power system and its field devices.
- A DMS should improve the ability of the engineering staff to perform power systems analysis and planning by providing increased access to past and current operations data and associated software tools.

CHALLENGING ISSUES

In spite of the variety of modern computer-based tools and technologies there are a number of challenges to the implementation and effective operation of DMS systems. The following sections briefly discuss some of these main issues.

Data Capture

The initial capture of the necessary data to fully populate a computer-based DMS is a daunting task. Usually the data exists in a variety of formats, often in different departments, and often data must be combined and merged from different sources, including paper records. This complexity along with the sheer volume of data required for a large distribution utility is a major undertaking.

In many utilities, the data capture process has already been undertaken in the context of the acquisition and implementation of a GIS system. Where a GIS exists, it is obviously desirable to import the data from the GIS. As obvious as this is, nonetheless in the real-world it is not uncommon that the GIS data does not fully satisfy the operational needs. As has already been mentioned, many GIS systems do not have adequate modelling of the electrical connectivity of the network.

DMS Data Change Management

Unfortunately the challenge does not end with a successful one-time capture and population of DMS data. A distribution network is constantly changing, virtually every day as new customers are added, feeders are re-configured, new substations are constructed, older feeders are upgraded to higher voltages, etc. Furthermore, each change has a life-cycle of its own as it goes through planning, design, construction, placing into service and decommissioning of old plant.

It is important to note that generally one network change can affect multiple databases in the DMS. For example, the installation of one new remotely controllable switch on a feeder requires as a minimum, changes to the SCADA points lists. RTU and communications database, the distribution network model and the full graphics displays of the feeder.

It is essential that a modern DMS has full support for management of such network changes. It must have facilities to allow a set of related changes to be defined as a "batch" in an off-line environment and then installed into the on-line environment as a single operation initiated by the dispatcher. The changes must be able to be installed and made effective without interrupting real-time operations, with the possibility of an automatic roll-back if the update is not completely successful in all the databases.

Human Resources. In planning the implementation of a modern DMS a utility must make sure it takes into account the need for dedicated personnel to manage the data and generally maintain the DMS system.

Interfaces between different systems

While some vendors offer a full range of integrated subsystems to make up a complete DMS system, in reality most distribution utilities end up with a variety of different subsystems from different vendors.

Not too long ago many systems were sold as stand-alone packages with not too much thought being given to interfaces with other systems. Integrating such systems was generally very painful and expensive if not totally impossible. However, over the last 10 or so years the need for so called "open" systems has become increasingly evident and important.

Great progress has been made in computer and communication technology to allow computers to communicate with each other. This includes the definition and acceptance of standard SCADA protocols such as DNP and ICCP. Furthermore, the internet has introduced a variety of very common protocols such as HTML, FTP and many others. Thus all modern computers have a basic ability to communicate electronic data with other computers.

However, within specialized areas such as distribution network management there still remains a challenge to determine and define precisely which data in one sub-system is of interest to another sub-system and exactly when, how and under what circumstances data should be exchanged with another system.

Fortunately, this problem is being addressed by the International Electrotechnical Commission, Technical Committee 57, Working Group 13 which has defined an architecture and a data model for distribution networks and operations. It is currently working on defining standard sets of messages and data to be exchanged between subsystems of a distribution management system. Further information on this activity is available on the internet at **http://standards.ces.com/wg14/**. These standards are still in progress, but if and when they get widely accepted they will greatly facilitate such data exchange.

CONCLUSION

There is an increasing need for better and more efficient management of distribution networks. Fortunately, the modern computer industry has come a long way toward providing cost effective technology which can be used to address this need.

While GIS and OMS systems have a role to play, they do not have the full functionality needed on an automated distribution network.

Modern SCADA-based DMS systems have the capability to significantly improve the quality of service to customers as well as making the overall operations more effective and efficient. However, there is still a lot of work which needs to be done to collect, implement and keep up to date all of the data needed for effective distribution management.

THE DISTRIBUTION DISPATCHING CENTER PROJECT AT THE PROVINCIAL ELECTRICITY AUTHORITY OF THAILAND

R. Hoffman[1], M. Dubois[1], W. Koykul[2], S. Chiochanchai[2], R. Wasley[3]

[1]SNC-Lavalin Energy Control Systems, [2]Provincial Electricity Authority of Thailand, [3]KEMA Consulting

INTRODUCTION

The Provincial Electricity Authority of Thailand (PEA) is modernizing its power system distribution network by installing distribution automation (DA) facilities in its HV/MV substations and on its MV feeders. A large-scope Distribution Management System (DMS) is also being installed to allow remote operation of the distribution network. This hierarchical system will provide PEA with its first ever computer-based distribution dispatching centers.

The DA and DMS procurement is part of PEA's Distribution Dispatching Center (DDC) Project 1st Stage, which is partially funded by a loan from the World Bank. The project includes a new System Management Center (SMC) and five new Area Distribution Dispatching Centers (ADDCs).

The SMC will manage ADDC power system operations from PEA headquarters in Bangkok, whereas the ADDCs will perform their power system operations from sites within their own service territories. This distribution system automation and management project is believed to be the largest of its kind ever undertaken in the world.

The purpose of this paper is to give a brief over view of PEA's operations and distribution network and then to describe the main DA and DMS facilities that are being installed.

BACKGROUND

PEA Operating Responsibilities

PEA collaborates and shares responsibility for electricity supply in Thailand with two other state enterprises, namely the Electricity Generating Authority of Thailand (EGAT) and the Metropolitan Electricity Authority (MEA). EGAT is responsible for generation and bulk power transmission. On the other hand, MEA distributes power to Bangkok and two adjoining provinces, while PEA distributes power to all other parts of Thailand.

PEA is organized into four administrative regions. Each of these Northern, North-eastern, Central, and Southern regions consists of three service areas, each with its own Administrative Office and ADDC.

Before completion of the DDC Project 1st Stage, power system operations continue to depend not on computer-based facilities, but on manual dispatch procedures aided by hand-dressed mimic boards, paper maps, and voice communications based on telephone and UHF and VHF radio systems. Dispatchers plan and direct daily operations that are performed by personnel located at the substations and electric offices.

The electric offices are responsible for providing local customer services that include meter reading, bill collecting, connecting and disconnecting power, responding to customer telephone calls, and executing power system construction, maintenance, and repair activities.

PEA Power System

The PEA power system serves more than 11.7 million customers. The maximum demand from these customers is more than 10,500 MW and, with annual energy sales in excess of 56,500 GWh, demand continues to grow rapidly at more than 5.9% per year.

The system covers 510,000 square kilometers (approximately 99% of Thailand's total area). It includes more than 298 substations with circuits operating at 115, 69, 33 and 22 kV. The 115 and 69 kV circuits constitute the high-voltage (HV) subtransmission system with a total length of 4,624 km. The 33 and 22 kV circuits constitute the medium-voltage (MV) primary distribution system. Their total length is more than 244,617 km (approximately 19% at 33 kV and 81% at 22 kV).

PEA's low-voltage (LV) secondary distribution system is operated at a voltage of 380/220V.

With few exceptions, the power system is overhead and radial in nature. It is anticipated, however, that the HV circuits will become more meshed in the future. The substations include switchable shunt capacitor banks and transformers with on-load tap changers. More and more substations are being automated through the application of Computer-Based Substation Control Systems (CSCSs). The MV circuits include circuit breakers at substations, reclosers on main lines, and fuse cut-outs on branch lines. Line regulators are used as well as fixed and time-switched capacitor banks. For efficiency and reliability, a system of open loops has been adopted. Feeders can be reconfigured by closing the normally open tie-switches at substation load transfer buses and at various pole-mounted locations outside the substations.

A small number of generators are connected to PEA's power system. They are owned and operated by Small Power Producers (SPPs) under contract with EGAT.

PROJECT OBJECTIVE AND GOALS

The objective of the DDC Project 1st Stage is to apply distribution automation and management facilities to improve service reliability, reduce operating costs, increase profitability, and enhance customer service in five of PEA's most industrialized and heavily loaded service areas. It is anticipated that PEA's other seven service areas will be automated at some future time in a separate second stage project. To meet the objective, the DMS has been designed to achieve the following goals:

- Improve dispatcher ability to monitor and control the power system during normal, abnormal, and emergency conditions by providing more reliable and appropriate real-time data.
- Improve ability of PEA engineering staff to perform power systems analysis and planning by providing increased access to past and current operations data and associated software tools.
- Improve quality of service and customer relations by responding to customer service interruptions more rapidly.
- Improve quality of customer power supplies in regard to voltage sags and swells as well as harmonics.
- Improve power system efficiency by maintaining acceptable power factors and reducing losses.
- Improve power system effectiveness by controlling and limiting peak power demands.
- Improve power system maintenance and safety practices by providing more reliable, meaningful, and timely information on the status of the power system and its field devices.
- Improve PEA's ability to manage its power system assets and system operations by providing increased access to better performance data and other historical records and statistics.
- Improve dispatcher training facilities and hence dispatcher abilities and skills as they relate to modern operating practices.
- Improve efficiency of operations by providing increased automation and the potential for reducing PEA manpower requirements.

The rest of this paper describes the facilities, equipment and software systems that are being procured and installed as part of the DDC 1st Stage Project.

FIELD EQUIPMENT

Remote Terminal Units

A large number of Remote Terminal Units (RTUs) are being installed to enable automation of the distribution network. They are being installed in substations (SRTUs) and on various types of feeder devices outside the substation (FRTUs). In addition, RTUs are being installed as digital communication interfaces to existing CSCSs.

The RTUs are modular in design and can be configured in various sizes ranging, from a single node configuration for pole-top applications, to large multi-node configurations for use in HV/MV substations.

A distributed architecture is used that allows small input/output nodes to be distributed throughout the substation near the equipment being monitored and controlled, thus greatly minimizing the amount of wiring needed. The distributed nodes communicate with a central node via fiber optic communication links. The central node in turn communicates with the DMS master using the DNP3.0 protocol. The ability to use other protocols such as IEC 870-5 is also provided. Unsolicited report-by-exception will be used for status changes while analog values will be reported by exception with polling.

I/O nodes include a Digital Signal Processor (DSP) that permits direct AC input from potential and current transformers. In addition to basic RMS amplitude determination, the DSP enables computation of MW and Mvar power, calculation of harmonic content and other power quality data such as voltage sags and swells, detection and collection of disturbance data including sequence of events, and detection of fault passage, etc.

The RTU also supports definition and execution of programmable logic functions, such as closed loop voltage control of transformer taps.

The following is a summary of the locations and quantities of RTUs being installed under the current phase of the program:

- 50 large substation RTUs
- 100 communication interfaces to CSCSs
- 1600 remotely controlled pole-top SF_6 load break switches
- 422 line reclosers
- 40 line voltage regulators with reclosers.

Multiple Address Radio System

Most of the SRTUs will communicate with the DMS master over existing digital microwave links and/or a time division multiple access radio system. However, all FRTUs as well as a few SRTUs, will communicate via an extensive Multiple Address Radio System (MARS) that will extend digital communications from the microwave facilities to the FRTU locations.

The MARS includes 56 sets of redundant master radios, 42 sets of redundant repeater radios (at 21 sites), and 2,062 individual remote radios. The number of remote radios corresponds to the number of FRTUs. A communication path analysis was performed automatically using digitized topography data from PEA's Geographical Information System (GIS). In some remote or mountainous areas, up to 3 hops are required to get adequate signal strength.

Feeder Capacitor Control

PEA uses both fixed and time-of-day switched capacitors on its distribution feeders. However, to make better and more efficient use of switched capacitors, a total of 139 capacitors are being equipped with interfaces to allow remote control from the DMS via a commercial paging communication facility. The DMS will determine when the capacitor should be switched based on estimated voltages and Var flows at the capacitor locations

DMS MASTER STATIONS

Control Center Buildings

Six new control center buildings have been constructed under the DDC 1st Stage Project to house the five ADDCs and the SMC.

System Hardware and Software

The SMC and each ADDC will be equipped with a modern DMS. The DMS hardware consists of multiple Compaq Alpha processor nodes in an open distributed architecture with dual 100Base-T LANs to connect the various computer nodes.

The Tru64 UNIX operating system is used on each node along with the SNC-Lavalin Distributed Application Environment (DAE) middleware to enable high-performance and high-availability operation of the distributed system. Among its numerous features, the DAE supports replicated real-time databases, which allow virtually instantaneous fail-over of dual-redundant software processes.

Each ADDC control room is furnished with a supervisor console, an HV console, two MV consoles, and two LV consoles, whereas the SMC control room is furnished with a supervisor console and two HV consoles. Except for the LV consoles, which have two dispatcher monitors, the other control room consoles have three. All control rooms include a BARCO large screen (2.25 m x 5 m) rear projection system. Each system also supports a visitor's console, approximately 10 PCs used for a variety of data maintenance and other support functions, and up to 15 PC-based consoles in remote electric offices.

SCADA Software

Each DMS has full, high-performance SCADA functionality. This provides all typical data acquisition, alarming, supervisory control, historical data collection, and other functions expected in a modern day system. The following is a brief summary of some of the features included:

- It has a high-performance full graphics user interface (GUI) that can operate both on UNIX workstations and on MSWindows PCs for displaying electrical networks. The GUI supports panning, zooming and decluttering and has a rich set of rendering and network colouring functions. The system's user interface supports both Thai and English.

- It has a powerful calculated points package that in addition to usual arithmetic operations supports advanced features such as low-pass filtering, best source selection from multiple points, counting of breaker operations, maintaining last non-zero value of current through a breaker before it tripped, and many more.

- It has a user-programmable scripting language that can, for example, with a single command automatically perform multiple switching operations including programmable logic including conditional branching based on values of current telemetered data.

- There is full support of modern industry standard communication protocols such as DNP3.0 and IEC870-5 for RTUs and IEC-870-6 TASE.2 (ICCP) for control centers.

DMS APPLICATION FUNCTIONS

At the heart of the DMS are the application functions that provide network modelling and analysis capability. The main DMS applications are described in the following sections.

Network Model

The DMS includes a full 3-phase unbalanced model of the entire MV distribution network. This model begins with an injection device representing the bulk supply point from the EGAT or PEA HV network.

All conducting devices including HV/MV transformers, overhead lines, underground cables and all circuit breakers, sectionalising switches and fuses down to the MV/LV distribution transformers are modelled. If desired, it is also possible to model the LV network, but generally modelling to this level of detail is not considered cost-effective. The wired connectivity between all of the conducting devices must be modelled explicitly.

The total customer load supplied by each distribution transformer is modelled as a single aggregate load. For the trouble call and outage analysis subsystem, it is also necessary to model which distribution transformer supplies each customer.

The network model will be extracted from whatever adequate data is available from PEA's GIS. In addition, data must be obtained from PEA's customer information system (CIS) and other sources of engineering data not currently included in the GIS. A considerable amount of work is required to capture the initial data needed for the model.

Temporary Changes

The model is capable of correctly representing temporary network changes including allowing dispatchers in the real-time on-line environment to define conductor cuts, jumpers, and temporary grounds such as may be applied during maintenance operations and temporary restoration of power following storms.

Connectivity Analysis

The Connectivity Analysis (CA) application uses the open-closed status of every telemetered and manually up-dated switch device in the network to determine the live/dead and grounded status of every device in the network. In real-time operation, CA automatically updates the network state whenever any switch device changes state or whenever a temporary change is applied or removed.

Power Flow

After CA has determined a new network state the Power Flow (PF) application automatically computes the estimated 3-phase unbalanced voltage and current flow at every point in the distribution network. The results of the power flow are automatically checked against limits and alarms raised. At regular intervals the loads used by PF are scaled by the Demand Estimation application so that the results of the PF application match any available telemetered measurements from the real network.

Var Control

PEA has contractual obligations on power factors at bulk supply points from EGAT. Also keeping power factors on feeders close to 1.0 will minimize losses in the PEA network.

The Var control application uses telemetered measurements of Var flows in substations as well as estimated values of Var flows as determined by the PF application to determine when to automatically switch capacitors. The objective is to keep power factors throughout the distribution network as well as voltages seen by customers within pre-defined limits.

Voltage Control

It is generally recognized that the total MW load in a distribution network can be slightly reduced during times of peak demand by reducing the system voltage slightly. The objective of the Voltage Control application is to achieve temporary small reductions in system load by reducing the voltage at the secondary side of HV/MV transformers. The voltage Control application uses the PF application to ensure that voltage levels received by customers remain within obligatory levels

Load Shedding and Restoration

The objective of the load shedding and restoration (LSR) application is to enable dispatchers to quickly and efficiently shed load under emergency conditions when EGAT is unable to supply the total PEA demand. The load shedding application will automatically trip breakers on feeders according to predefined lists until the amount of load requested by the dispatcher is shed.

LSR also includes a rotating mode under which loads that have been shed for longer than a defined period of time are automatically restored and replaced by other loads.

Fault Location, Isolation and System Restoration

The objective of the FISR application is to minimize the duration of outages to customers caused by network faults. FISR automatically assists the dispatcher in locating network faults that cause feeder breakers to trip and in quickly determining the switching actions that will isolate faulted sections and restore power to unfaulted feeder sections both upstream and downstream of the faulted sections.

FISR execution is triggered automatically whenever a feeder breaker trips on its own and where reclosing attempts are unsuccessful. It automatically checks which of the FRTUs downstream of the tripped breaker did and did not detect a passage of fault current. The fault is deemed to have occurred in the section downstream of the last FRTU which saw the fault passage and upstream of the first FRTU that did not see the fault.

The most difficult task for the FISR application is to determine switching actions that will restore power to the unfaulted downstream island by finding normally-open tie switches to close without causing system overloads or low voltages to customers. The restoration task is especially difficult when there is a problem in the substation and restoration strategies must be found for multiple feeders.

Trouble Call and Outage Management

The TCOM application is used to assist the dispatcher in identifying and responding to network outages undetected by SCADA telemetry. Generally, customers report these outages via trouble calls to the utility.

TCOM provides computer-based facilities for keeping track of each customer trouble call and automatically grouping multiple calls in the same part of the network into a single suspected outage. This is achieved by mapping customer calls to the electrical network model and tracing them to a common suspected open fuse or other protective device.

TCOM automatically determines the number of customers affected by each outage and assists the dispatcher in prioritising outages according to their size and in dispatching trouble crews to deal with the outage.

TCOM also automatically collects statistics on the number of customers affected and the duration of each outage. These statistics are used to determine industry standard quality-of-service indices.

Switching Order Management

The purpose of the Switching Order Management (SOM) application is to provide computer-aided creation, verification and execution of switching orders. The objective is to reduce dispatcher workload and to ensure higher quality switching plans.

SOM includes facilities to automate to a large extent the creation and verification of switching orders by making use of the network tracing services of the distribution network model. SOM has support for the PEA safety rules that must be followed during switching procedures.

Switching sheets may be automatically executed in study mode to verify the validity of the proposed switching actions prior to actually implementing them.

During actual execution, SOM automatically tracks progress from the field crews, and records the time of completion of each step in the order. As switching actions are completed the real-time network model is automatically updated accordingly. Where switching involves remotely controllable devices, SOM is able to automatically execute such steps when enabled by the dispatcher.

High Voltage Applications

Under the DDC 1st Stage Project, a complete set of EMS-type applications is also being provided for the PEA HV distribution network. This includes Load Forecast, State Estimation, Power Flow and Contingency Analysis as well as Fault Level Calculation. Some of the HV applications will have limited usefulness initially, but will become more important in the future as the HV network becomes more meshed.

Dispatcher Training Simulator

A DTS facility is being provided at one of the ADDCs. It will be used to train new dispatchers how to operate the power system via the actual DMS, and to provide refresher training to more experienced dispatchers.

The objective of the DTS is to make the training environment match the real-time operational environment as closely as possible. Thus, it includes an exact copy of the displays and applications used on the real-time DMS, but in such a way that the DTS supports these facilities by also executing a simulation of the PEA distribution network, RTUs and associated communications system.

The DTS includes instructor facilities to define realistic training scenarios that may include both simulated network faults as well as RTU or communication malfunctions.

PROJECT STATUS AND SCHEDULE

In July 2000, PEA signed a contract with SNC-Lavalin of Montreal, Canada, for the supply of the DMS. This includes the computer systems, the SRTUs, the FRTUs, the MARS radio system, the six new distribution dispatching center buildings, and all necessary field installation and adaptation services.

The 1600 line switches were procured under two separate contracts for 800 switches each and most are already installed by PEA. The installation of the RTUs and the MARS radio system commenced in the first quarter of 2002.

The SCADA component of the DMS systems were delivered during the second quarter of 2002 and are being used along with the communication facilities to perform end-to-end testing of the RTUs as they are being installed.

The systems, including the control centers and all field equipment, will be fully operational and commissioned in 2003.

ENMAC™

Network Solutions

OVERVIEW

State-of-the-art information tools to optimize distribution.

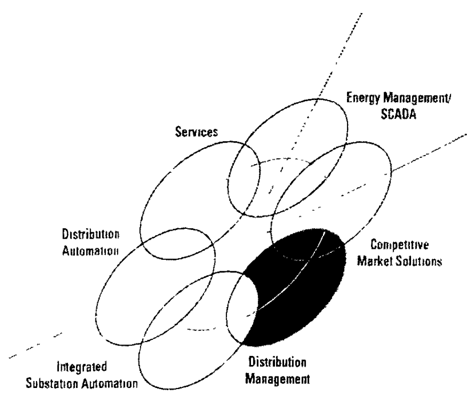
The Business Case

Privatization, deregulation, and reregulation initiatives have had sweeping effects on the worldwide electric utility business. Deregulation is allowing more and more competitors into the market, and as a distribution utility, you must now compete aggressively for each and every customer. In order to do so, you're facing pressures to substantially improve productivity, reduce operating and maintenance costs, and increase the reliability and breadth of your customer service offerings. Effective use of Information Technology is key to your success under the new regulatory regime.

The GE Network Solutions ENMAC™ System is the distribution management solution delivering state-of-the-art information tools that enable control room staff and management of the next generation utility to efficiently and effectively manage the real time operation of dispersed distribution assets. ENMAC™ covers more than 90% of the UK landmass, a leading edge area for deregulation.

- Reduced Operating & Maintenance Costs
- Improved Operational Efficiency
- Improving Asset Utilization

ENMAC™ is designed to reduce total operating and maintenance costs, including costs of ownership. ENMAC™ gives you the ability to substantially improve operational efficiency, providing the potential to consolidate existing control centers. Alternatively, existing control center locations and communication facilities can be integrated, allowing for the sharing of data and leveraging a common support infrastructure.



Unlike the all too common 'islands of automation' so prevalent in today's marketplace, ENMAC™'s seamless interoperability with other corporate systems such as Customer Information Systems, Geographic Information Systems, and Call Centers can lead to significant reductions in support cost, while maximizing access to current system information. ENMAC™ also can help to reduce power losses and improve asset utilization, allowing costly capital expenditures to be deferred.

GE Network Solutions

ENMAC™

Network Solutions

How the ENMAC™ System Will Improve Your Performance

By Improving Decision Support – Information Versus Data

ENMAC™ presents a consistent, real-time view of the entire electrical network to operators and management. Operators are provided with valuable information regarding the most likely cause of a disturbance rather than a simple summary of raw data. The capability to analyze alternate operating strategies based on current or postulated system conditions provides valuable insight into possible courses of action. ENMAC™ is designed to ensure that timely, accurate information is available when you need it most.

By Focusing on the Bottom Line

Reduced outage rates, improved power quality, and a competitive price are the keys to customer satisfaction, retention, and attraction in today's competitive energy market.

In addition, the emergence of performance-based rates has fundamentally changed the way utilities view service performance.

ENMAC™'s field proven distribution applications enable the next generation utility to significantly improve service performance where it counts most and thereby recognize its true revenue and earnings potential.

Base features

The ENMAC™ distribution management system is a modular and flexible client-server architecture comprising a number of collaborative software applications At the foundation of this architecture are the following modules which provide the basic framework for the day-to-day operation and maintenance of the distribution grid:

Advanced Graphical User Interface (AGUI)

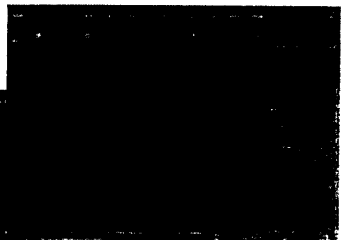
- Provides a powerful, intuitive interface to ENMAC™ applications
- Renders information in both schematic and geographic form
- Allows the user to effectively navigate large networks.

Supervisory Control and Data Acquisition (SCADA)

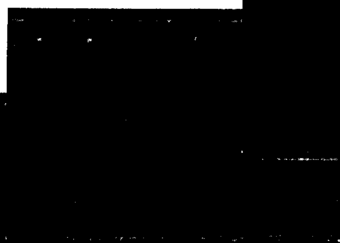
- Acquires measurement data via remote terminal units or data links
- Validates data for reasonability
- Performs checks on process variable limits and executes user-defined calculations
- Provides remote supervisory control capability

Network Management System (NMS)

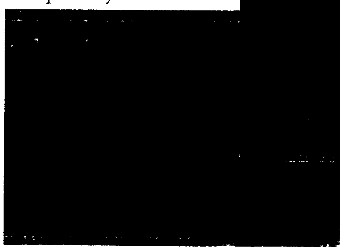
- Provides an up-to-date connectivity model of the entire electrical network for other applications using
  - As-built configuration
  - Available-telemetry
  - Operator entries
- Provides extensive circuit tracing capability
- Manages day-to-day maintenance of the electrical network
- Commissioning of new equipment
- De-commissioning of existing equipment
- Temporary re-configuration of the network (jumpers, cuts, and grounds)
- Development of switching plans
- Electronic creation of associated work permits and safety documentation
- Validation of planned switching with respect to safety and operational rules
- Real-time validation, execution, and recording (audit trail) of all switching procedures



33 KV - 11 KV Primary Substation



11 KV Feeders



6.6 KV Feeders

OVERVIEW

Advanced Features

Trouble Call System

- Interfaces to call center to gather customer trouble calls
- Uses network connectivity in conjunction with customer call locations to predict source of trouble and event scope
- Identifies and groups related calls into a single trouble ticket
- Manages assignment of trouble tickets to field crews
- Considers crew location, workload, equipment, and experience level
- Interfaces to telephony system (IVR) or call center to update status of event
- Provides complete electronic history of event

Distribution Power Analysis

ENMAC™'s Distribution Power Analysis provides the operator with the capability to analyze and optimize the operation of the electrical network under current and postulated system conditions. Whether directed at the current real-time network or a future planned network or supporting the development of switching plans, ENMAC™'s Distribution Power Analysis provides the operator with clear and concise information with respect to system vulnerabilities and opportunities.

The ENMAC™ Distribution Power Analysis Suite is comprised of the following applications:

- Feeder Load Estimation
- Powerflow
- Short Circuit Analysis
- Volt/VAr Optimization
- Topology Optimization

Web Applications

ENMAC LV WebView™

ENMAC LV WebView™ integrates LV network diagrams and GIS data with network management and customer connection features. It can be linked to ENMAC™ to enable operators to have a fast and easy method of viewing both schematic and geographic diagrams. In addition the location of customer trouble calls and transformers off supply are shown. It provides high availability and presents geospatial networks at speeds normally achieved by operational schematic diagrams, these factors combine to make it a highly desirable tool for operational, real-time environments. Its web-based interface is ideal for use on mobile devices and for remote viewing.

ENMAC Call Taker™

The ENMAC Call Taker™ is a web-based call logging system designed for large-scale distribution in a call center. The logged calls are then managed within ENMAC TCS™. It allows call takers to find customer' data quickly by means of a search engine and a wizard can help to categorise the problem. Previous calls and faults along with up-to-date status on existing faults are displayed to ensure all parties are kept informed.

Reports

The ENMAC™ System was conceived to provide cost-effective yet secure dissemination of near real-time and historical operations information throughout the utility enterprise and beyond, without compromising the responsiveness or security of the mission critical system. Separated from the core ENMAC™ Distribution Management System via a firewall, the ENMAC™ Business Information Gateway leverages the power of web-based technology in order to provide secure information access to utility executives, planners, and engineers as well as key commercial customers.

Corporate Data Exchange

Corporate Data Exchange provides a seamless interface between the Distribution Management System and other corporate business systems such as Geographic Information Systems, Customer Information Systems, and Call Center that allows each system to administrate its own data and the relevant data items to be shared electronically with the Distribution Management System as it changes. Corporate Data Exchange eliminates costly and error prone manual transfer of data and ensures that the Distribution Management System always has the latest up to date information regarding network and customer connectivity.