Distribution Management Systems

Presented By:
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• What is a DMS?
• Key Applications
• Planning, Procuring, and Implementing a new DMS
• Open discussion
What is a DMS?

- A **Decision Support System** to assist the control room and field operating personnel with the monitoring and control of the electric distribution system in an optimal manner while improving safety and asset protection.
What are the Major DMS Components?
Distribution Management System Components

SCADA provides the foundation

Field Devices
- Switched Cap Banks
- Line regulators
- Line switches
- Faulted circuit Indicators (FCIs)
- DG, Energy storage

Substation Devices
- Substation Switched Cap Banks
- CBs, MODs
- Vreg/LTC
- Subs secondary equip

Distribution SCADA
- Real time data acquisition
- Basic operational alerts (alarms)
- Remote control
- Tagging
- Display real time data
- Data archiving

Real Time

Field Devices

Substation Devices
Distribution Management System Components
DMS Applications Use SCADA Capabilities

Advanced Applications
- Intelligent alarm processing
- On-line power flow
- State estimation
- Distribution model
- Switch order mgmt
- VVO
- FLISR/ONR
- Contingency Analysis
- DER Management

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Distribution Management System Components Interactions with Operational Support Systems

- **Advanced Metering System (AMI)**
  - Mobile Data System (MDS)
  - Switched Cap Banks
  - Line regulators
  - Line switches
  - Faulted circuit Indicators (FCIs)
  - DG, Energy storage

- **Outage Management System (OMS)**
  - Geographic Information System (GIS)
  - Real Time Model updates
  - Predicted outages

- **Advanced Applications**
  - Near Real Time, "day after"
  - Intelligent alarm processing
  - On-line power flow
  - State estimation
  - Distribution model
  - Switch order mgmt
  - VVO
  - FLISR/ONR
  - Contingency Analysis
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The Distribution Management System

Advanced Metering System (AMI)

Outage Management System (OMS)

Geographic Information System (GIS)

Mobile Data System (MDS)

Distribution SCADA

Advanced Applications

• Intelligent alarm processing
• On-line power flow
• State estimation
• Distribution model
• Switch order mgmt
• VVO
• FLISR/ONR
• Contingency Analysis
• DER Management

Switch orders, R-T data

Switch orders, "day after"

Temp Model updates

"As engineered" state of the system

Real Time

Real Time

Real Time

Switched Cap Banks
Line regulators
Line switches
Faulted circuit Indicators (FCIs)
DG, Energy storage
Substation Switched Cap Banks
CBs, MODs
Vreg/LTC
Subs secondary equip
Field Devices

Substation Devices

Near Real Time

"As engineered" state of the system

Real Time

Field Devices
Combined DMS/OMS System

Advanced Metering System (AMI)

Outage Management System (OMS)

Geographic Information System (GIS)

Mobile Data System (MDS)

Distribution Management System

Advanced Applications

Distribution SCADA

Field Devices
- Switched Cap Banks
- Line regulators
- Line switches
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Substation Switched Cap Banks
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Substation Devices

Near Real Time, "day after"

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Model updates

Predicted outages

Real Time

Intelligent alarm processing
- On-line power flow
- State estimation
- Distribution model
- Switch order mgmt
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- DER Management

Real time data acquisition
- Basic operational alerts (alarms)
- Remote control
- Tagging
- Display real time data
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Real Time

Real Time
Typical Distribution Control Center a Few Years Ago

- Distribution System was operated manually with wall-mounted switching diagrams
- Mostly paper driven processes
Electronic Map Visualization

- Static mapboards replaced by large screen, video displays

- Operator workstations include large number of computer monitors (side-by-side)
Current Trend in Control Center Design

- Increasing emphasis on “outside the fence” visualization
- Large mapboards disappearing from distribution control centers
- Use of stackable monitors for operator workstations – allows view of specific “area of responsibility”
• DMS Applications
  – Basic Applications
  – Advanced Applications
Advanced Display Capabilities

- Standard display capabilities

Substation One-Line Schematic

Tabular

Trend line
Advanced Display Capabilities

- Advanced display capabilities
Advanced Display Capabilities

- Topology Processing Feeder Color
Highlighting abnormal sections of the distribution feeders
Intelligent Alarm Processing

- (Standard) Compare measurements against operating limits and alert operator to abnormal conditions
- Conditional alarms
- Prioritization
- Filtering
- Routing
Data Archiving

- Store and retrieve data, alarms, event logs, feeder configuration changes, etc.
- Allow access to data inside and outside the control center for studies etc.
- Most DMS vendors support interface to commercial data management systems (e.g., OSI Soft PI)
Tagging Permits Clearance Management

- Enables users to request, manage and plan outage requests.
- Support the creation and monitoring of safety protection guarantees
- Information exchanged with mobile workforce management system
- All DMS vendors support tagging – most are weak in overall permit/tag request and management
Advanced DMS Applications
Distribution System Model

- Accurate distribution system model is essential element of DMS (the “heart and soul”)
- Provides basis for graphical displays and advanced applications
  - Network model
  - member (Load) Model
Distribution System Model: One Model – Two Parts

Physical Model
- Energized equipment
  - wires, transformers, switches, capacitor banks, voltage regulators, distributed energy resources
- Connections between equipment

Load Model
- member Load Profiles
- Load-Voltage Sensitivities

Source: CEC. June 2010
Distribution System Physical Model

- Extent of **physical** model
  - Most cases – substation transformer high voltage side down to distribution transformer
  - Some applications (e.g. VVO) may need modeling down to member meter
Distribution System Physical Model

- Three main variations for the physical model:
  - As operated – reflects the current energized state of the distribution system
  - As planned – includes work-in-progress, but not yet energized
  - As it was – for “post mortem” analysis
Distribution System Physical Model

- Building and updating the physical model
  - “Permanent” changes from GIS
  - “Temporary” changes from SCADA and by operator entry
  - Need to determine source of substation model (often this information is not maintained via GIS)
- Planned alterations and additions
  - Allows utility to enter information for work that is planned or work in progress, but not yet energized – reduced latency when work is energized
  - Allows utility to consider work in progress when planning future outage
member Load Model – Load Profile

Applications like on-line power flow (OLPF) require a means of estimating the load at distribution service transformer.

Two main alternatives for member load estimation:

- Measure it directly with AMI meters
  - Not practical to send all AMI meter data for all meter locations to DMS in real-time each

- Estimate load using load profile information
  - Load profile based on historical load surveys
  - Provides percent of peak load estimate at each time of day
  - Different load profile for each member class
  - Different load profile for season and different type of day
    - Weekday
    - Weekend
    - Special day (holiday)

Estimate reactive power consumption at each transformer via reactive power profile or fixed power factor.
member Load Model – Load Voltage Sensitivity

- Load profile information provides load estimate at nominal voltage (120 V)
- Need model of member load (real and reactive) variation with voltage – varies with time of day, day of week, weather conditions, mix of appliances, and other factors
- EPRI working with IEEE PES Volt-VAR task Force to create standard library of member load-voltage sensitivity models

Effect of voltage reduction

Plasma TV

Compact Fluorescent Light
Distribution System Model – DMS Perspective

Issues
- Data quality: bad data, incorrect phasing
- Lack of data in GIS for substations and secondary circuits
- Standard models (e.g., Common Information Model)?
- Lack of accurate member load models (Load and load-voltage sensitivity)
- Modeling of distributed energy resources (“negative load” versus “fully dynamic” model)

TYPICAL BAD DATA
- Conductor electrical data
- Switchgear electrical data
- Transformer data missing (voltage, windings, etc.)
- Equipment voltage/phase not matching topology
- Connectivity errors
  - Duplicate lines
  - Loops without switches
  - Segments not connected
  - Multiple sources
  - Devices not connected
- Wrong coordinates
On Line Power Flow (OLPF)

• Similar to engineering analysis tool
  – Engineering tool – peak load analysis
  – OLPF – what’s happening in “near real time
• Calculates electrical conditions right now (near real-time) at all points on the distribution feeder
• Provides “visibility” in places where no measurements exist …. alerts dispatcher to trouble spots
• OLPF used by many DMS applications that require up-to-date electrical information
• Characteristics:
  – 3 phase unbalanced
  – Handles radial and “weakly-meshed” distribution feeders
• “Study mode” - uses past or planned feeder model in off line mode
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OLPF Study Mode

• “Off line” version of DMS power flow useful for analyzing:
  – Past events
  – Upcoming (future) events
• Runs in background – does not impact real-time (live) applications
• Specify time and date for which study is required
• Study mode estimates the load for past or future events
• Potential use for all engineering analysis
Load Estimation for OLPF

- OLPF uses real-time or near-real-time feeder measurements
- At many utilities, measurements available only at “head-end” of feeder
- Need more information to determine feeder powerflow
On Line Power Flow

- If you knew all the electrical impedances, could do a conventional power flow fairly easily
  - Usually have a reasonably good idea of what the line impedance is
  - Generally don’t know the impedance of every house – depends on which appliances are on – changes all the time
On Line Power Flow

Can use kW rating of distribution service transformers to **estimate** the load:

- Split measurement from head-end of feeder in proportion to kW rating of the transformer

**Diagram:**

- Bus Voltage
- CB (Circuit Breaker) kW 4 kW
- 25 kW → 1 kW
- R
- 25 kW → 1 kW 25 kW → 1 kW 25 kW → 1 kW
- Estimated load at each house = kW rating of distribution service transformer / total connected kW = 25 / (4 * 25) = 1/4
On Line Power Flow

This approach works well as long as all members have the same “load profile” (Fraction of peak load at given \textit{time} and given \textit{day}).

Estimated load at each house = kW rating of distribution service transformer / total connected kW = 25 / (4 * 25) = 1/4
Using load profiles to estimate the load

Splitting load in proportion to rating of distribution service transformer works ok if all members have the same load profile

Load Profile - Customer 1

Load Profile - Customer 2

member #1

member #N
Load Estimation with Different Load Profiles

- But if load profile is different for each member, method doesn’t work
- Load estimate = kW of distribution transformer x (fraction of peak load from load profile) / total of all members
  - member 2 gets a little more of the load estimate at hours 11 and 22
  - member 1 gets a higher percentage of the load during hour 18

![Comparison of Load Profiles](image)
Summary of Load Estimation Approach

• Obtain load profile for each member for given day (weekday, weekend, special day) and season
• Determine percent of peak load for each member at given time of day
• Load Estimate For member “i” = (SCADA measurement from head end of feeder) x (transformer rating for member “i”) x (Percent of peak load from load profile for member “i”) / sum of Σ (ratings of all transformers)
Use of Meter Readings from AMI

- Can use meter readings from Advanced Metering Infrastructure (AMI) to:
  - Create a load profile for each member/transformer based on yesterday’s AMI data
  - Determine transformer load for selected members using nearly-real-time data for selected members
Switching Order Management

- One of the most important operating tools – addresses fundamental “person in charge” duties
- Provides software tools to assist in creating switching orders
Switching Order Management

- **Simplest form** – click on schematic display to populate Switch order
Switching Order Management

- **Simplest form** – click on schematic display to populate switch order

Electronic (DMS) Switch Order
Switching Orders
Geographic versus Schematic Views

• When creating Switch Order off DMS geographical display, it's often difficult to get entire, properly scaled diagram on the screen at once
• Operators have to navigate around the geographic display to access the switching components (inconvenient, time consuming)
• Some DMS Vendors offer **automatic schematic diagram** generator
Switching Orders
Geographic versus Schematic Views

- **Schematic** view removes details not needed for switching
  - Not to scale
  - Allows operator to view relevant portion of the feeder on one screen
- “State-of-the-art” DMS includes automatic generation of schematic diagrams from geographic display built using GIS data
- Beware of “build in advance” schematics
Off-Line Validation of Switch Orders

- Allows operator to single step through switching order in Study Mode

- Verifies (in advance) that switching steps do not create unacceptable electrical conditions on the feeder

- Verify loading on adjacent feeders for entire duration of the planned outage work (uses short-term load forecast)
Automatic Generation of Switching Orders

- Some DMS include facility for automatic generation of switching orders based on established work rules and practices

- Operator selects equipment that needs to be worked on

- DMS supplies draft version of switch order
Volt-VAR Control and Optimization

- Develops and executes a coordinated “optimal” switching plan for all voltage and VAR control devices
- DMS uses OLPF program to determine what actions to take
- Two Variations of the Model Driven Approach
  - Voltage Reduction – DMS version of Conservation Voltage Reduction
  - Volt VAR Optimization (VVO) – accomplishes one or more utility specified “objective functions
DMS Conservation Voltage Reduction (CVR)

• Voltage Reduction perform the following activities:
  – “Flatten” the voltage profile
    • This allows levelized voltage drop across the feeder
  – Determine the critical voltage points
    • Allows monitoring of lowest voltage point to ensure voltage is above minimum acceptable voltage
  – Determine the necessary control actions to accomplish CVR
SCADA (Rule Based) Volt-VAR Control
Part 1: VAR Control (Power Factor Correction)

P = 3846 kW
Q = 1318 kVAR
PF = .946
Losses = 96 kW
51

VVO/CVR Processor

RTU

LTC Controller

LTC

Sample Rules:

1. Identify “candidate” cap banks for switching
   - Cap bank “i” is currently “off”
   - Rating of cap bank “i” is less than measured reactive power flow at head end of the feeder

2. Choose the “candidate” cap bank that has the lowest measured local voltage

3. Switch the chosen cap bank to the “ON” position

P = 3846 kW
Q = 1318 kVAR
PF = .946
Losses = 96 kW
SCADA (Rule Based) Volt-VAR Control
Part 1: VAR Control (Power Factor Correction)

Voltage Profile

P = 3846 kW
Q = 1318 kVAR
PF = .946
Losses = 96 kW

Chosen cap bank
SCADA (Rule Based) Volt-VAR Control
Part 1: VAR Control (Power Factor Correction)

Voltage Profile

P = 3880 kW
Q = 920 kVAR
PF = .973
Losses = 91 kW

Chosen cap bank
SCADA (Rule Based) Volt-VAR Control
Part 1: VAR Control (Power Factor Correction)

Voltage Profile

VVO/CVR Processor

P = 3920 kW
Q = 687 kVAR
PF = .985
Losses = 89 kW
SCADA (Rule Based) Volt-VAR Control
Part 1: VAR Control (Power Factor Correction)

Voltage Profile

P = 3940 kW
Q = 532 kVAR
PF = .991
Losses = 88 kW
SCADA (Rule Based) Volt-VAR Control Part 1: VAR Control (Power Factor Correction)

Voltage Profile

Before and After

P = 3940 kW
Q = 532 kVAR
PF = .991
Losses = 88 kW
Sample rule for voltage reduction:

1. If voltage at head end of the feeder exceeds LTC setpoint, then lower the voltage.
SCADA (Rule Based) Volt-VAR Control Part 2: Voltage Control (CVR)
SCADA (Rule Based) Volt-VAR Control
Part 2: Voltage Control (CVR)

Voltage Profile

P = 3898 kW
Q = 508 kVAR
PF = .992
Losses = 88 kW
SCADA (Rule Based) Volt-VAR Control Part 2: Voltage Control (CVR)

Voltage Profile

P = 3805 kW
Q = 508 kVAR
PF = .991
Losses = 88 kW
SCADA (Rule Based) Volt-VAR Control Part 2: Voltage Control (CVR)

**Voltage Profile**

- End of Line Voltage
- Feedback

P = 3778 kW  
Q = 492 kVAR  
PF = .992  
Losses = 88 kW
SCADA (Rule Based) Volt-VAR Control
Part 2: Voltage Control (CVR)

Voltage Profile

Changes:

P = -41 kW (1.05%)
Q = -809 kVAR (61%)
PF = +.045
Losses = -8%

Before and After
Volt-VAR Optimization

• Develops and executes a coordinated “optimal” switching plan for all voltage control devices to achieve utility-specified objective functions:
  – Minimize energy consumption
  – Minimize losses
  – Minimize power demand
  – Combination of the above
• Can bias the results to minimize tap changer movement and other equipment control actions that put additional “wear and tear” on the physical equipment
Volt VAR Optimization (VVO) System Operation

IVVC requires real-time monitoring & control of sub & feeder devices

Monitor & control tap position, measure load voltage and load

Switch Status

Bank voltage & status, switch control

Bank voltage & status, switch control

Monitor & control tap position, measure load voltage and load

IVVC Optimizing Engine

On-Line Power Flow (OLPF)

Distribution SCADA

Substation RTU

Line Voltage Regulator

Switched Cap Bank

Distribution System Model

Perm Changes

Temp Changes

Geographic Information System (GIS)

AMI
Volt VAR Optimization (VVO) System Operation

- Cuts, jumpers, manual switching
- Permanent asset changes (line extension, reconductor)

IVVC requires an accurate, up-to date electrical model
Volt VAR Optimization (VVO) System Operation

OLPF calculates losses, voltage profile, etc

Powerflow Results

Distribution System Model

On-Line Power Flow (OLPF)

IVVC Optimizing Engine

Substation RTU

Substation Capacitor Bank

Substation Transformer with TCUL

Line Voltage Regulator

Switched Cap Bank

Line
Switch

MDMS

AMI

Temp Changes

Perm Changes

Dynamic Changes
Volt VAR Optimization (VVO) System Operation

Determines optimal set of control actions to achieve a desired objective

Powerflow Results

Alternative Switching Plan

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Volt VAR Optimization (VVO) System Operation

Determines optimal set of control actions to achieve a desired objective.
Predictive Fault Location

- **Objective:** Assist field crews in pinpointing fault location
- **Fault distance provided by protective relay IEDs not accurate:**
  - Assumes homogeneous wire size/arrangement
  - Fault impedance unknown
- **DMS Approach:**
  - “Reverse short circuit” analysis
    - Obtain fault magnitude and type (A, B, C, A-B, etc) from relay IED
    - Determine possible fault locations using DMS short circuit analysis tool and associated feeder model
Fault Location Isolation & Service Restoration (FLISR)

- **Fault Location, Isolation, and Service Restoration**

- **Use of automated feeder switching to:**
  - Detect feeder faults
  - Determine the fault location (between 2 switches)
  - Isolate the faulted section of the feeder (between 2 feeder switches)
  - Restore service to “healthy” portions of the feeder
Nature of the Problem

- When a permanent fault occurs, members on “healthy” sections of the feeder may experience a lengthy outage

- FLISR provides the means to restore service to some members before field crews arrive on the scene

<table>
<thead>
<tr>
<th>Step</th>
<th>Time Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fault Occurs</td>
<td>5 – 10 minutes</td>
</tr>
<tr>
<td>member Reports Outage</td>
<td>15 – 30 minutes</td>
</tr>
<tr>
<td>Field Crews On-Scene</td>
<td>15 – 20 minutes</td>
</tr>
<tr>
<td>Fault Located</td>
<td>10 – 15 minutes</td>
</tr>
<tr>
<td>Time to Perform Manual Switching</td>
<td>45 – 75 minutes</td>
</tr>
<tr>
<td>Repair Time</td>
<td></td>
</tr>
<tr>
<td>Feeder Back to Normal</td>
<td></td>
</tr>
</tbody>
</table>

Power restored to members on healthy sections of feeder
System in its normal state (no fault exists)
FLISR keeping track of net load on each section of feeder (15 minute average measured at each DA switch)

Net Load = 1 MW
Net Load = 2.5 MW
Net Load = 2 MW
FLISR Operation – A Fault Occurs

**Permanent** fault occurs in section surrounded by switches 2, 3 and 6

FDs at switches 1 and 2 detect the fault

FLISR stores net load on each feeder section

FLISR logic does not yet open/close any switches
CB Trips – Feeder De-energized

Circuit breaker trips
Entire circuit de-energized (dotted line)
FDs at switches 1 and 2 remain picked up
Still no FLISR control actions
CB Recloses – Fault Still There

FDs at switches 1 and 2 remain picked up
Still no FLISR control actions
CB Trips Again – Feeder Deenergized

Circuit breaker trips and locks out
Entire circuit de-energized (dotted line)
FDs at switches 1 and 2 remain picked up
FLISR open/close logic triggered
FLISR Step 1 – Identify Faulted Section

FDs 1 & 2 saw a fault
FDs 3 and 6 did not see the fault
Fault must be in section between switches 2, 3, & 6
FLISR Step 2 – Isolate Faulted Section

Substation #2

Automatically open switches 2, 3, & 6

Substation #1

Faulted Feeder Section

Fault

Substation #3
FLISR Step 3 – Restore “Upstream” Section

“Upstream” = between substation and faulted section

No need to check load for “Upstream” restoration – we know CB can carry the first section!

FLISR closes CB
FD at switch # 1 resets
FLISR Step 4 – Restore “Downstream” Section (if possible)

“Downstream” = between faulted section and end of feeder

Prior to fault, FLISR was tracking load in each section (15 min average)
FLISR now determines currently available capacity on Substation #2
FLISR Step 4 – Restore “Downstream” Section (if possible)

Compare available capacity with pre-fault load

Available capacity on substation #2 > pre-fault load in section 3-4

Okay to transfer this portion of the downstream load

Available Capacity = 2 MW

Net Load = 1 MW
FLISR Step 4 – Restore “Downstream” Load (If Possible)

Substation #2 currently has capacity – it can carry additional load

Close switch 4 to pick up part of faulted feeder
FLISR Step 5 – Restore “Downstream” Load (continued)

Now check available capacity on Substation #3
Compare with pre-fault net load on section 6-7
Net load exceeds available capacity!
Section 6 - 7 remains de-energized
End of FLISR operation
Time Line Without and With FLISR

**Without FLISR**
- **Fault Occurs**
  - Travel Time: 5 – 10 minutes
  - Field Crews On-Scene: 15 – 30 minutes
  - Fault Located: 15 – 20 minutes
  - Time to Perform Manual Switching: 10 - 15 minutes
  - Repair Time: 1 - 4 Hours
  - POWER RESTORED TO members ON HEALTHY SECTIONS OF FEEDER: 45 – 75 minutes

**With FLISR**
- **Fault Occurs**
  - Travel Time: 5 – 10 minutes
  - Patrol Time: 5 - 10 minutes
  - Repair Time: 1 - 4 Hours
  - Feeder Back to Normal: 1 to 5 minutes
  - POWER RESTORED TO members ON HEALTHY SECTIONS OF FEEDER: 15 – 30 minutes
FLISR with and without Large DG on Distribution Networks

Substation #2

Earlier slide (no DG)

Substation #1

Substation #3

Fault Current

Fault

Fault

No Fault

Fault

No Fault
FLISR with Large DG on Distribution Networks

Include large DG that is capable of producing significant fault current

FD at Switch 6 picks up

FLISR fault detectors might predict fault beyond switch number 6, and....
FLISR with Large DG or Distribution Networks

Trip switch 6, ultimately resulting in…
FLISR with Large DG or Distribution Networks

Substation #1

Substation #2

Entire feeder outage

Substation #3

Fault

No Fault

Fault

Fault

Fault

Fault

Fault
FLISR with Large DG or Distribution Networks

With **directional fault indicators** or more advanced DMS version of FLISR, would locate the fault properly, resulting in
FLISR with Large DG or Distribution Networks

Power restored to as many members as possible!
Assumes a 5 MW DG unit is available
Also assume measured prefault load is 3 MW

3 MW prefault load
Since DG rating exceeds pre-fault load, can establish an island fed by the DG unit.
Optimal Network Reconfiguration

- **Goal:** Identify changes in feeder configuration that would improve overall distribution feeder performance and reliability
  - optimize topology for steady state operations...

- **Selectable Operating Objective**
  - Minimal power and energy losses
  - Maximum reliability
  - Best load balance
  - Best voltage profiles
  - Other?
  - Weighted combination of the above
Optimal Network Reconfiguration

- Goal: Identify changes in feeder configuration that would improve overall distribution feeder performance and reliability
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- Selectable Operating Objective
  - Minimal power and energy losses
  - Maximum reliability
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  - Best voltage profiles
  - Other?
  - Weighted combination of the above
Optimal Network Reconfiguration

- Analyze best state of the network for the selected objective function
  - Minimal power and energy losses
  - Maximum reliability
  - Best load balance
  - Best voltage profiles
- Output = optimal network configuration
  - Ordered switching list
  - Improvement results for each switching operation
  - Cumulative affect of switching steps
- Execute those steps that bring the most benefit

<table>
<thead>
<tr>
<th>No.</th>
<th>Operation</th>
<th>Switchgear ID</th>
<th>Object Name</th>
<th>Abs</th>
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<tbody>
<tr>
<td>1</td>
<td>Open</td>
<td>94476</td>
<td>7 Joint</td>
<td>254.86</td>
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<tr>
<td></td>
<td>Close</td>
<td>97143</td>
<td>TSH 18 HV/MV Sub.</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>94474</td>
<td>RS 112 Joint</td>
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<tr>
<td></td>
<td></td>
<td>97143</td>
<td>TSH 18 HV/MV Sub.</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Close</td>
<td>95542839</td>
<td>TSM 75 MV/LV Sub.</td>
<td>220.19</td>
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<tr>
<td></td>
<td>Open</td>
<td>94364</td>
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Optimal Network Reconfiguration (Load Balancing) – Sample Case

<table>
<thead>
<tr>
<th></th>
<th>Before Load Transfer</th>
<th>After Load Transfer</th>
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<tbody>
<tr>
<td></td>
<td>Real Power</td>
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<td>Feeder 1</td>
<td>8345.9</td>
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<tr>
<td>Feeder 2</td>
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<table>
<thead>
<tr>
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<th>Totals Before Load Transfer</th>
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<td>Peak demand (kW)</td>
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<td>Demand consumption</td>
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<td>Total losses at peak</td>
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<tr>
<td>Primary line losses</td>
<td>291</td>
<td>93</td>
<td>(198.00)</td>
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<td>Sec line losses</td>
<td>75</td>
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<td>Xfrmr load loses</td>
<td>37</td>
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<tr>
<td>Xfrmr no load losses</td>
<td>88</td>
<td>90</td>
<td>2.00</td>
</tr>
</tbody>
</table>

≈40% loss reduction
Distribution Contingency Analysis (DCA)

- Tool to assess whether the network could “survive” a contingency and operate inside technical limits
- “Survive” means the parts of distribution networks that are affected by faults could be re-supplied in reasonable time (without waiting to repair the faulted elements).
- DCA Functions:
  - analyze faults in specified network’s elements
  - Test the possibilities of re-supplying the de-energized consumers
  - Output list of critical outages, after which power cannot be restored to all consumers
Management of Distributed Energy Resources

- DER output and status monitoring
- Transfer tripping
- Dynamic model of all DERs
  - Impact of DER on distribution power flow
  - Fault current contribution of DG units
- Management of intentional islands
  - Monitoring and Control of energy storage facilities
- Future economic dispatch (virtual power plants)
Dispatch Training Simulator

• Difference between “simulator” and “playback”
• Full blown power system model, not just a playback tool for scripted scenarios
  – Open switch, load through switch goes to zero
  – Place fault – model calculates fault current and relays operate with proper coordination
• Simulator uses same displays as on line system
• Maintain model through GIS or live DMS
Planning for a New DMS
Contents of the Plan

• Business case
• Needs analysis (functional requirements)
• Conceptual architecture
• Implementation strategy (Procurement, design/build, Install, commission)
Overview of the Implementation Plan

Business Case Results

Task 1.5: Define DMS Functional Requirements

Task 1e: Develop Conceptual Design

Task 1.6: Develop Interface specifications

Task 1.5f: Develop implementation/Procurement Strategy

Phase 1 Report (Draft)

DMS/OMS Functional Requirements

DMS/OMS Conceptual Design

Implementation/Procurement Strategy

External System Interface Definitions
What is a “Business Case”?

• A set of reasons or arguments to convince persons who hold “purse strings” (company executives, regulators) to spend a lot of money on a proposed project

• Business case usually addresses:
  – Technical issues – “What business problem is solved by the investment?”
  – Financial issues – “Do the benefits outweigh the costs?”
Keys to Business Case Success

• Proposed DMS project must:
  – Address significant business problem(s)
  – Support important business driver(s)
  – Provide monetary payback within an acceptable period to offset the expenditure

• “Technology for technology’s sake” not an acceptable reason to proceed with a significant automation project
  – At best, will result in demonstration ("pilot") project with little support that goes nowhere
Business Case Methodology

Begin Process

1. Understand Business Drivers & Operational Needs
2. Relate Automation to Needs
3. Develop Opportunity Matrix

Gather Operating & Financial Data

Analyze Scenarios

Perform Sensitivity Analysis

Results of Benefit/Cost Analysis

Update Business Case & Cost/Benefit Expectations

Management Approval

Requirement Specs & Technology Selection

Final Report

Conclusions and Recommendations
Identifying Business Drivers

• No “one size fits all”
  – company organization - degree of vertical integration
  – Regional concerns
  – member expectations

• Relevant drivers should be defined by persons who “own” the problems: Senior Level Managers
Identifying Business Drivers

Typical Business Driver categories

- Workforce safety
- Reduce O&M costs
- member satisfaction
- Quality of service (reliability & power quality)
- Worker safety and productivity
- Proactive/direct response to regulatory compliance
- Energy efficiency
- Increased capacity utilization
- Support Demand Response activities
- Accommodate Distributed Energy Resources (e.g. PHEV, DER)
- Manage Electric vehicle charging

DMS projects can contribute to each of these business driver categories
DMS Value Drivers

- Safety
- Reliability
- Efficiency
- Asset Utilization
- Maximize Use of Distributed Energy Resources
- Manage Electric Vehicle Charging Scenarios
Safety

- Create and validate complex switching orders accurately and efficiently
- Maximize awareness of current tags, clearances, etc
- Convey information electronically to field crews
Reliability

- Pinpoint fault location
- Automatically isolate fault and restore service to as many members as possible

Close switch 4 to pick up part of faulted feeder. FLISR logic stops here.
Efficiency

- Reduce losses through Volt-VAR optimization and Load balancing
- Conservation voltage reduction to reduce energy consumption and/or electrical demand
Asset Utilization

- Dynamic rating of cables, transformers
  - Squeeze more capacity out of existing assets
  - Defer capital expenditures for capacity addition

Base rating on current “Real-time” conditions and recent history
Maximize Use of DER

- Balance DER output with load and storage capabilities
- Leverage electronic inverters for VAR support as part of Volt-VAR Control strategy
- Manage power fluctuations using energy storage
Manage Electric Vehicle Charging Scenarios

- Enable/disable fast charging based on feeder conditions
- Manage Vehicle to Grid (V2G) strategy
Needs Analysis –
Identifying Major Functional Requirements for the DMS
DMS “Opportunity Matrix”

- Relates business needs to DMS application functions

<table>
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<tr>
<th></th>
<th>Corporate profitability, e.g. O&amp;M costs</th>
<th>Customer satisfaction</th>
<th>Quality of service (reliability &amp; power quality)</th>
<th>Energy efficiency</th>
<th>Increased capacity utilization</th>
<th>Support Demand Response activities</th>
<th>Accommodate Distributed Energy Resources (e.g. PHEV, DER)</th>
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Discovery Meetings with DMS Stakeholders

- Defined DMS needs for meeting the business drivers via *series of interviews and workshops with key project stakeholders*:
  - Field and control center operations
  - Engineering planning and design
  - Protective relaying
  - Restoration center (outage management)
  - Communication engineering
  - Information technology
    - IT Standards, GIS, OMS, work management, mobile data
  - SCADA engineering
  - Engineering standards
  - Smart metering
  - Member care
  - DG connections
  - Substation engineering
  - Many others
Stakeholder Interviews – Items to Discuss

• **Required DMS functions** (must relate to the business case) – need to get to the next level of detail

• **Operational Needs** – what level of DMS functionality is needed to address operational needs and issues?

• **Existing systems**
  – Will existing systems remain as separate standalone system, be interfaced to the DMS, or be wholly incorporated in the DMS
  – What are the available sources of information? Real time data (SCADA, DA, AMI, external systems) and static data (GIS)
  – Do existing independent systems require DMS data? (e.g. OMS requires feeder outage data)
Request for Information (RFI)

- **Objectives**
  - Obtain information (obviously)
    - General info (financial and people resources, past similar projects, etc)
    - Standard offerings in areas of interest to the utility
    - Handling of specific “tough spots” (GIS data quality, cyber security, interfaces in general, etc.)
  - Create “short list” for DMS procurement (10 vendors -> 3 bidders)
  - Did not request budgetary pricing – in general this is meaningless at RFI stage
Request for Information (RFI)

- **RFI contents**
  - Overview of functional technical requirements
  - Questions, Questions, more questions

- **RFI process**
  - Send RFI to vendors
  - Read vendor responses ("Tell Me" phase)
  - Vendor demonstrations ("Show Me" phase)
  - "Show Me" phase changed opinions developed during “Tell Me’ phase
• Develop “Conceptual” Architecture
  – Goal is to identify high level “technical” features of the DMS (e.g. requirement for primary and independent backup control center)
  – **Should not unnecessarily restrict the vendor** in this area – let them be creative within reason
    • e.g. allow use or “virtualization” for the training/development environment where performance and reliability are not mission critical
Centralized vs. Decentralized

• Refers to the location where the main logic resides under normal circumstances
  – Does not refer to the input/output location
  – Does not refer to the human machine interface location
Alternatives

Centralized  Substation Centered  Distributed (Peer-peer)
Centralized Architecture

Centralized
Substation Centered
Distributed (Peer-peer)

Main Logic Resides here
Substation Centered Architecture

Centralized  Substation Centered  Distributed (Peer-peer)

Main Logic Resides here
Fully Distributed Architecture

Centralized          Substation Centered          Distributed (Peer-peer)

Control Center

Main Logic Resides here

Substation Master

Feeder Locations
Hybrid DMS Architecture

Most DMS systems are a combination of at least 2 of the 3 main alternatives.
Main Architectural Tradeoffs

- Complexity versus Speed (Response Time)

- Centralized
  - Fixed set of rules
  - Static System
  - Milliseconds

- Distributed
  - Model based solution
  - Dynamic System (Frequent changes)
  - Minutes

- Substation Centered
  - Static System
  - Milliseconds

- Centralized
  - Dynamic System (Frequent changes)
  - Minutes
<table>
<thead>
<tr>
<th>Criteria</th>
<th>Centralized</th>
<th>Substation-Centered</th>
<th>Distributed</th>
</tr>
</thead>
<tbody>
<tr>
<td># of DA Feeders</td>
<td>High % of feeders automated</td>
<td>All feeders at selected substations automated</td>
<td>Small # of geographically dispersed feeders automated</td>
</tr>
<tr>
<td>Operator Visibility</td>
<td>Nothing happens without operator being informed</td>
<td>Can tolerate some control actions without operator notification</td>
<td>Can tolerate some control actions without operator notification</td>
</tr>
<tr>
<td>Availability of suitable communication facilities</td>
<td>Requires high-speed wide area communications</td>
<td>Requires local area communications (sub-pole, sub-sub)</td>
<td>Requires local area communications (pole-pole, sub-pole)</td>
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<tr>
<td>Availability of commercial products</td>
<td>VVO, FLISR, ONR</td>
<td>VVC, FLISR, DFA</td>
<td>FLISR</td>
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<tr>
<td>Process large quantity of data</td>
<td>Limited by data transfer capability</td>
<td>Well-suited for waveform analysis, ECM</td>
<td>Little or no capabilities</td>
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</tbody>
</table>

VVO – Volt VAR Optimization  
FLISR – Fault Location, Isolation, and Service Restoration  
ONR – Optimal Network Reconfiguration  
DFA – Distribution Fault Anticipator  
ECM – Equipment Condition Monitoring
# Architecture by Application

<table>
<thead>
<tr>
<th>Application</th>
<th>Centralized</th>
<th>Substation-Centered</th>
<th>Distributed</th>
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<td>FLISR</td>
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<td>✅</td>
<td>✅</td>
</tr>
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<td>Volt VAR Control (rule based)</td>
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<tr>
<td>Volt VAR Opt (model based)</td>
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<tr>
<td>Adaptable VVO</td>
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<td>Fault Anticipator</td>
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<td>Equipment Condition Monitoring</td>
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<td>✅</td>
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</table>
Centralized DMS Architecture

- Distribution Field Devices
- AMI Network and Interface
- EMS/SCADA Network
- Substation RTUs
- Peer-Peer Field Devices
- Distribution Control Center consoles
- GIS
- OMS
- Data Warehouse
- DMS

Network
“Bolt-On” Configuration

- Substation inputs and outputs handled via EMS/SCADA
- Field (feeder) inputs handled directly by DMS (DNP/IP)
Redundant, Location Agnostic Design

- Dual redundant architecture – Fully redundant DMS installed at primary and backup control centers
- “Location Agnostic” Design: Operator consoles and DMS servers installed at different locations (remote data center concept)
DMS Interfaces – Essential for effective deployment

Illustrates the importance of external interfaces to the DMS implementation project
# Interface functional requirements

**Sample Interface spec: DMS - AMI**

<table>
<thead>
<tr>
<th>Interface Requests From DMS</th>
<th>On demand meter read requests, on demand energized state requests, queries of historical data from AMI/MDMS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interface Data Elements Returned to DMS</td>
<td>On demand results, interval transformer demand, energized status</td>
</tr>
<tr>
<td>Interface Function Description</td>
<td>The DMS interface to AMI/MDMS must be capable of requesting and receiving on demand reads, obtaining outage event information, provide an ability to query historical data from AMI/MDMS,</td>
</tr>
<tr>
<td>Frequency of Requests</td>
<td>On demand, 15 minute intervals, occasional, depending on type of request</td>
</tr>
<tr>
<td>Preferred Integration Implementation</td>
<td>ESB</td>
</tr>
<tr>
<td>Preferred Integration Method</td>
<td>Publish-subscribe: web services or XML using Java Message Service (JMS)</td>
</tr>
<tr>
<td>Latency Requirements</td>
<td>30 seconds or less for on demand pinging of up to 100 meters, 15 minute and hourly for transformer readings and interval load profile reads, 30 seconds for on demand energized state requests.</td>
</tr>
</tbody>
</table>
Interface Standards

e.g. MultiSpeak
The implementation strategy should be divided into the following key activities:

- Procurement
- Design and Test
- Installation
- Implementation and Commissioning
- Sustainment
Main objectives for the DMS implementation strategy

• Ensure that the DMS is designed, implemented, tested, installed and commissioned in accordance with utility’s requirements.

• Ensure that the Vendor completes all contractual obligations to utility’s satisfaction.

• Ensure that electric utility personnel are fully trained in design, maintenance, and operation of all aspects of the system so that utility company can be as self-sufficient as possible in the future.
  • Should not have to depend on the vendor and outside consultants for day-to-day DMS “sustenance”.
Contents of the Implementation Strategy

• Identifies strategies for implementing the DMS facilities that satisfy the functional and architectural requirements
• “Multi-Stage” approach versus “Single-Stage” approach
• Provides a roadmap for implementing and maintaining the system.
• Relationships with other projects
• Identifies a strategy for implementing the new system without disrupting ongoing operations
• Summarize the role of Electric Utility personnel and its Subject Matter Experts (consultants) during each activity
• Provide a rough estimate of the level of effort required during each activity.
• Change management and training strategy
• Scheduling and budgeting
Procuring a new DMS
Approaches to System Procurement

- **Sole source** (e.g., incumbent vendor (EMS, OMS, GIS))
- **Competitive Bid Process**
  - Pick vendor based on evaluation of fixed price bid
  - Pick vendor based on evaluation of general capabilities, then work together of specifications and negotiate scope of work and price
  - Other Variation?
Approaches to System Procurement

- **Sole source** (e.g., incumbent vendor (EMS, OMS, GIS))
- **Competitive Bid Process**
  - Pick vendor based on evaluation of fixed price bid
  - Pick vendor based on evaluation of general capabilities, then work together of specifications and negotiate scope of work and price
  - Other Variation?
Prepare RFP & Bid Evaluation Method
An Overview of the Process
Request for Proposal (RFP)

- **Overall objectives**
  - Obtain firm fixed pricing
  - Obtain information to compare proposals from the proponents and pick a winner
  - Lay foundation for DMS Contract
Request for Proposal (RFP)

• Terms of Reference
  – Commercial terms and conditions
  – Instructions to bidders
  – Functional/technical requirements
  – Questionnaire (lots of questions)
Request for Proposal (RFP)

Commercial terms and conditions

– Utilities often start with the same Ts and Cs that are used for other procurements

– There are numerous Ts and Cs pertaining to DMS procurement to be added:
Additions to standard Commercial terms and conditions

- Right to use system and make changes without voiding warranty
- Disclosure of interfaces
- Availability of source code
- Right to move software to replacement hardware
- Right to make copies of documentation
- Complicated definition of “Acceptance”
- Milestone payments
- Many others
Request for Proposal (RFP)

- **Terms of Reference**
  - Instructions to bidders
    - Format of proposal
    - Pricing forms
    - Table of compliance
  - Allows Vendor to concisely indicate where they comply or take exception

Requirement to have consistent format and content simplifies review process
## Sample Table of Compliance (Blank form)

<table>
<thead>
<tr>
<th>TOR Section</th>
<th>Req’#</th>
<th>Requirement Title</th>
<th>Compliance Code</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3.3.1(3)</td>
<td>Control archive</td>
<td>C - Comply, A - Alternative, X - Exception</td>
<td></td>
</tr>
<tr>
<td>3.3.2</td>
<td>3.3.2(1)</td>
<td>Ctrl inhibit/enable</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.2(2)</td>
<td>Off normal</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3.3.3</td>
<td>3.3.3(1)</td>
<td>Tags general</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.3(2)</td>
<td>Multiple tags</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.3(3)</td>
<td>Display # of tags</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.3(4)</td>
<td># of tag types</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.3(5)</td>
<td>Tag properties</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.3(6)</td>
<td>Assigning tags</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.3(7)</td>
<td>Removing tags</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.3(8)</td>
<td>Detailed tag info</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Sample Table of Compliance (With vendor entries)

<table>
<thead>
<tr>
<th>TOR Section</th>
<th>Req’t #</th>
<th>Requirement Title</th>
<th>Compliance Code</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3.3.1(3)</td>
<td>Control archive</td>
<td>C</td>
<td></td>
</tr>
<tr>
<td>3.3.2</td>
<td>3.3.2(1)</td>
<td>Ctrl inhibit/enable</td>
<td>C</td>
<td></td>
</tr>
<tr>
<td>3.3.2</td>
<td>3.3.2(2)</td>
<td>Off normal</td>
<td>C</td>
<td></td>
</tr>
<tr>
<td>3.3.3</td>
<td>3.3.3(1)</td>
<td>Tags general</td>
<td>C</td>
<td></td>
</tr>
<tr>
<td>3.3.3</td>
<td>3.3.3(2)</td>
<td>Multiple tags</td>
<td>C</td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.3(3)</td>
<td>Display # of tags</td>
<td>A</td>
<td>User will be able to open a point with a tag “flag” and open summary which shows all associated tags.</td>
</tr>
<tr>
<td></td>
<td>3.3.3(4)</td>
<td># of tag types</td>
<td>X</td>
<td>Currently has 7 tag types. More are planned to be added in the next release.</td>
</tr>
<tr>
<td></td>
<td>3.3.3(5)</td>
<td>Tag properties</td>
<td>A</td>
<td>Does not provide a direct override, the operator may choose to change the state of the tag to “override” the state and execute the action then replace the tag. All these steps would be logged.</td>
</tr>
<tr>
<td></td>
<td>3.3.3(6)</td>
<td>Assigning tags</td>
<td>C</td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.3(7)</td>
<td>Removing tags</td>
<td>C</td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.3.3(8)</td>
<td>Detailed tag info</td>
<td>C</td>
<td></td>
</tr>
</tbody>
</table>
Request for Proposal (RFP)

• Terms of Reference
  – Questionnaire
    • Prepare questions seeking clarification on specific issues pertaining to the proposal
    • Guideline: At least one question per specification section
    • Questionnaire responses become part of statement of work/contract for winning vendor

14.82 Support for Incremental model changes: Please describe the extent to which the proposed system will support incremental model changes (the capability to update only those portions of the distribution system model that are affected by the change without rebuilding the entire model for each change). Does your proposed system support incremental builds on a per-feeder basis?

's data-entry system is based on Incremental model changes. The system has object model whose instances and/or their attributes can be changed in the increments of various sizes from single attribute change up to the whole network.
Request for Proposal (RFP)

• Terms of Reference
  – Functional/technical requirements
    • Technical description of requirements for equipment, software, services
    • Focus on “what” is needed, not solution
    • Provide enough detail to avoid confusion. But don’t over-specify
Contents of Technical Specification

• Section 1: Project Overview
  – Brief project summary, including identifying major project objectives
  – Responsibility of each party to complete the required work
    • Vendor responsibilities
    • Utility responsibilities
    • Responsibilities of 3rd parties (consultants, installers, system integrators, etc)
Contents of Technical Specification

• Section 2: Functional Requirements
  – Functional description of each major application function
    • Basic functions:
      – data acquisition
      – Displays
      – historian
    • Advanced functions:
      – Intelligent alarming
      – distribution system model
      – On line power flow
      – Volt VAR Optimization
      – Automatic line sectionalizing
      – Switch order management
      – Others…..
Contents of Technical Specification

• Section 3: Technical (Architectural) Requirements
  – Description of architectural requirements for the system
    • General architecture (centralized, decentralized)
    • Primary and back up control centers
    • “Location agnostic” requirements
    • Relevant IT standards
    • Interfacing requirements to external systems
Contents of Technical Specification

• Section 4: Sizing and Performance
  – Define initial and ultimate sizing requirements for the system
    • Number of concurrent users
    • Quantities of operator workstations
    • Initial and ultimate quantities of inputs and outputs
    • Requirement for spare capacity and expansion capability
  – Performance requirements
    • Maximum allowable response time (latency) under normal and peak load (emergency) conditions
    • Maximum time to complete powerflow run for “N” feeders
  – Reliability requirements
    • Overall system reliability requirements (e.g. 99,999% availability)
      − Need to explain what being available means – is the overall system considered unavailable if one console fails
    • Availability of individual system components
Contents of Technical Specification

• Section 5: Hardware and software
  – Relevant standards that apply to hardware and software
  – Acceptable use of virtualization
  – Software to build and edit database, models, displays
  – Required diagnostic capabilities and maintenance tools
Contents of Technical Specification

• Section 6: Documentation and Training

**Documentation**
- Summary of required documentation needed to enable utility to achieve desired level of system support capability
- Required drawings and drawing format
- Quantities of paper copies
- Procedure for review and approval of documentation

**Training**
- Summary of required training needed to enable utility to achieve desired level of system support capability
- General approach to training (train the trainer, versus vendor handles all training)
- Training location
**Training**

- **Categories:**
  
  Programmers, database & display builders, dispatchers, maintenance technicians, installation teams

- Train the trainer?
- Informal hands-on dispatcher training
- Delay formal dispatcher training
- On-the-job training of programmers
  
  (6 mo - 12 mo)
Contents of Technical Specification

• Section 7: Testing and Quality Assurance

  – Factory acceptance testing
  – Site testing
    • Installation tests
    • Site acceptance test
    • System availability test
Contents of Technical Specification

• Section 8: Implementation Services
  – Project management
  – Project meetings
  – Maintenance prior to and following acceptance
  – System installation
  – Expert assistance during installation and checkout of advanced applications
Bid Evaluation Process
Bid Evaluation

- Cross functional evaluation team
- Develop scoring methodology in advance of bids arriving (avoid bias in weighting factors used for scoring)
- Scoring categories
  - Functional & Technical
  - Commercial
  - Bid demonstration
  - Risk
  - Pricing
Bid demonstrations

• All bidders should make bid presentations at your offices

• Presentation included functional demonstration of key application functions (GIS data conversion, model building, OLPF, VVO, FLISR)

• Conversion of company-specific “raw” GIS data

• Bidders convert the data as needed, built company specific models and displays, demonstrated DMS application functions using these models

• Demonstration quality can be a key differentiator among bidders
## Sample score-sheet

<table>
<thead>
<tr>
<th>TOR Section</th>
<th>Req't #</th>
<th>Requirement Title</th>
<th>Vendor 1 Score</th>
<th>Vendor 1 Comment</th>
<th>Vendor 2 Score</th>
<th>Vendor 2 Comment</th>
<th>Vendor 3 Score</th>
<th>Vendor 3 Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>A3.1.3</td>
<td>3. W1(2)</td>
<td>Volt-VAR Optimization</td>
<td>3</td>
<td>Align Vendor proposal further discussion about the voltage limits for load reduction, and operating reserve limits – operation about voltage limits is pretty fundamental Per 62-9, “Vendor complies with this requirement and no additional information is needed”</td>
<td>2</td>
<td>Standard objectives are demand and loss reduction, not even whether they are doing energy consumption reduction function.</td>
<td>3</td>
<td>Vendor requests 20 ma max. development of voltage reduction function. Seems to do a little better work from VSC - voltage reduction implemented through proper usage and cap banks that can be allowed at a brown out function</td>
</tr>
<tr>
<td>341</td>
<td>3. W1(2)</td>
<td>Constraint voltage limits</td>
<td>3</td>
<td>supports all of the objectives except for Reduce Energy Consumption (have some issue with some element not vs. another)</td>
<td>3</td>
<td></td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>342</td>
<td>3. W1(2)</td>
<td>Recalling</td>
<td>3</td>
<td>can use software tool to give preference to solutions that involve the use of inverter operations.</td>
<td>3</td>
<td></td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>344</td>
<td>3. W1(2)</td>
<td>User selected options</td>
<td>3</td>
<td>Substations can be assigned to VSC Groups. The operating objective for each VSC Group can be associated with a predefined task that different objectives can be selected for a set of substations at different times of the day or week. Seems to be similar to what we asked for.</td>
<td>3</td>
<td>Vendor proposed recommendations that achieve the best results based on the user-defined weights on the set of objectives. We asked for specific cases in the recommended solutions that based on operational and maintenance objectives. (Good solution) I think not clear that they understand the requirement. Had a lot of trouble explained how this would be accomplished.</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>346</td>
<td>3. W1(2)</td>
<td>Closed loop &amp; Advisory mode</td>
<td>3</td>
<td>Per 16-19: The user can execute a manual request to solve any individual applications with the procedures just like in real-time mode. Each application that is to be solved must be selected and executed for a given station or set of stations. The OLPF function automatically solves the load allocation algorithm.</td>
<td>3</td>
<td></td>
<td>3</td>
<td></td>
</tr>
</tbody>
</table>

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Bid Evaluation Stages

• Read proposals ("Tell Me")
  • Produce one set of results

• Bid demonstrations ("Show Me")
  • Alters the ranking significantly

• Site visits ("Prove It")
  • Seals the deal
Evaluation Methodology – Weighting Factors

- **Bid Demo & Risk, 15%**
  - General Proponent Responsibilities
  - QA and Testing
  - Documentation and Training
  - Sustainment

- **Total Cost of Ownership, 35%**
  - System Architecture
  - End-End Integration
  - Hardware Characteristics
  - Software Characteristics
  - Performance, expansion, reliability
  - IT Standards

- **Terms of Reference, 50%**
  - Volt Var Optimization
  - Fault Location
  - Data Acquisition & Control
  - User Interface
  - Alarming
  - Decision Support Tools

- **Implementation, 65%**
  - Functional
  - Technical

- **Risk Assessment, 67%**

- **Sustainment, 35%**

- **Bid Demo 32%**
# Scoring Summaries

<table>
<thead>
<tr>
<th>TERMS OF REFERENCE</th>
<th>SCORES (Max score =5)</th>
<th>RANK</th>
<th>Percent below Top Rank</th>
</tr>
</thead>
<tbody>
<tr>
<td>Functional Areas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Control Room Functions</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Data Acquisition and Control</td>
<td>3.361  2.758  2.573</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Tagging</td>
<td>2.981  2.443  1.914</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>User Interface</td>
<td>2.570  2.776  2.791</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>Alarm Processing</td>
<td>2.854  2.794  2.341</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Historical Information System</td>
<td>2.825  2.750  2.900</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Reports</td>
<td>2.875  2.858  3.047</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>Control Room Operating Tools</td>
<td>1.038  2.542  1.075</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>DTS</td>
<td>2.957  2.663  3.000</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>Interfaces (Functional)</td>
<td>1.781  2.103  2.643</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>DMS Security</td>
<td>2.380  2.930  2.630</td>
<td>3</td>
<td>1</td>
</tr>
</tbody>
</table>

## Scoring Summaries

<table>
<thead>
<tr>
<th>TERMS OF REFERENCE</th>
<th>SCORES (Max score =5)</th>
<th>RANK</th>
<th>Percent below Top Rank</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BID DEMONSTRATION</td>
<td></td>
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<tr>
<td>RISK</td>
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</tr>
<tr>
<td>OVERALL SCORING</td>
<td></td>
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<tr>
<td></td>
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<td></td>
</tr>
</tbody>
</table>
Contract Negotiation

- Create statement of work based on winning proposal and clarifications received during bid evaluation

- Developed a “conformed specification” that became part of the contract
  - Started with your terms of reference (TOR)
  - Updated TOR wording only where the bidder proposed alternatives or took exception during bid evaluation process
  - Allows you to essentially maintain control of the contract wording
Designing Building and Implementing the System
Design, Configuration and Testing

- General organization and Project Management
  - Single point of contact
  - Core team with representatives of affected parties
- Design input and review
- Testing
  - Type testing
  - Functional and performance testing
  - Integrated system testing
- Training and Documentation
  - Prepare you for self sufficient O&M

Diagram:
- Work Statement
  - Vendor Design System
    - Preliminary Design Documents
      - Review Preliminary Design
        - Core Team Training
          - Review Test Procedures
            - Approved Test Procedures
              - Conduct Factory Testing
                - Ship System
              - Factory Test Procedures
            - Order Components/Build System
              - Approved Design Documents
                - Provide Input Data

Barriers to Successful Implementation
Barriers to Successful deployment

• Lack of accurate data for modeling
  – No record of construction details for overhead conductors
    • Conductor arrangement needed to compute line reactance, for example
    • Can assume default conductor arrangement
  – Incorrect records of phasing
    • EPRI researching techniques to identify phase
  – Lack of standard models for members and loads
    • EPRI Load/Voltage Modeling Initiative
  – Lack of information on substations in GIS
  – Lack of information about secondary circuits in GIS

• Vendors can do some consistency checks
Barriers to Successful deployment

- Changes to time-proven control room procedures - Lack of trained resources
  - No such thing as “plug and play” when it comes to DMS
  - “System optimization” a new concept for system operators – may require power system engineering support group
  - process design to deal with the degree of DMS business processes both before and after the DMS is implemented
Barriers to Successful deployment

• Lack of reliable, near real-time, two way communication facilities
  – Is AMI communications network the answer?
  – Need failsafe design for local controllers (revert to standalone local control if communications fail)
More Barriers to Successful Deployment

• Lack of support for advanced distribution applications
  – Lack of field proven advanced applications
  – Vendor offerings not fully developed
• Lack of industry standard interfaces (CIM, MultiSpeak)
• Management of distributed energy resources
• Others???
Questions and Discussion

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