Power System Automation Lab

Distribution system planning and operation

Analysis of short circuit, voltage and load flow conditions w/ new distributed resources

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Black Start Restoration for Electric Distribution Systems and Microgrids

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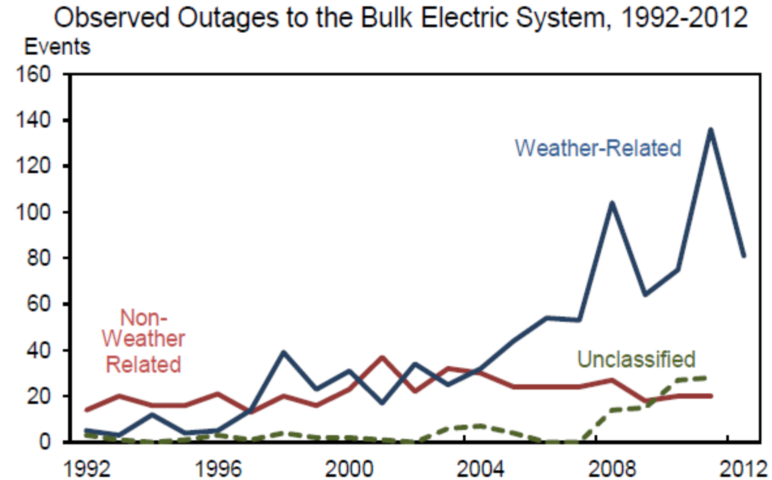
Power Outages and Black Start

- **Severe Weather: Leading cause of power outages in the United States [1]**
- **Extreme weather events can cause complete or partial wide-area blackouts**
  - Take hours or even days to fully restore the system
- **Black start restoration (BSR) is initiated after a blackout happens.**



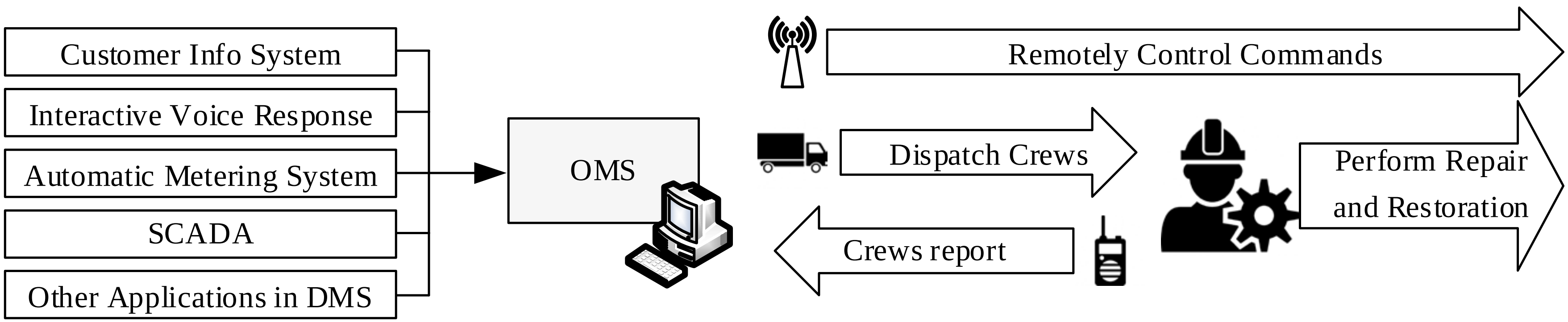
Observed Outages to the Bulk Electric System (Source: Energy Information Administration)

Black Start Resources	Black Start Capability	Dispatchable?	Examples
Black Start DG	Yes	Yes	Microgrid, Diesel Generator
Non-Black Start DG	No	Yes (Dispatchable DG)	Microturbine
		No (Non-dispatchable DG)	Photovoltaic (PV), wind turbine
Energy storage system (ESS)	No	Yes	Battery
Controllable loads	No	Can be switchable for load balancing	Direct Load Control

[1] Executive Office of the President, "ECONOMIC BENEFITS OF INCREASING ELECTRIC GRID RESILIENCE TO WEATHER OUTAGES," 2013.
[2] Adibi, Power System Restoration: Methodologies & Implementation Strategies: Wiley, 2000.

Outage Management System

- Service restoration normally refers to a process of restoring the electricity service after a disruption. The process involves many factors for both transmission systems and distribution systems.
- Outage Management System (OMS) is the core application for BSR.



Damage Assessment
based on various data sources

Fault Detection & Isolation
Performed automatically or by field crews

Restoration
Performed automatically or by field crews

[1] Sun Wei, Liu Chen-Ching, and Liu Shanshan, "Black start capability assessment in power system restoration," in Power and Energy Society General Meeting, 2011 IEEE, 2011, pp. 1-7.
[2] Adibi, Power System Restoration: Methodologies & Implementation Strategies: Wiley, 2000.

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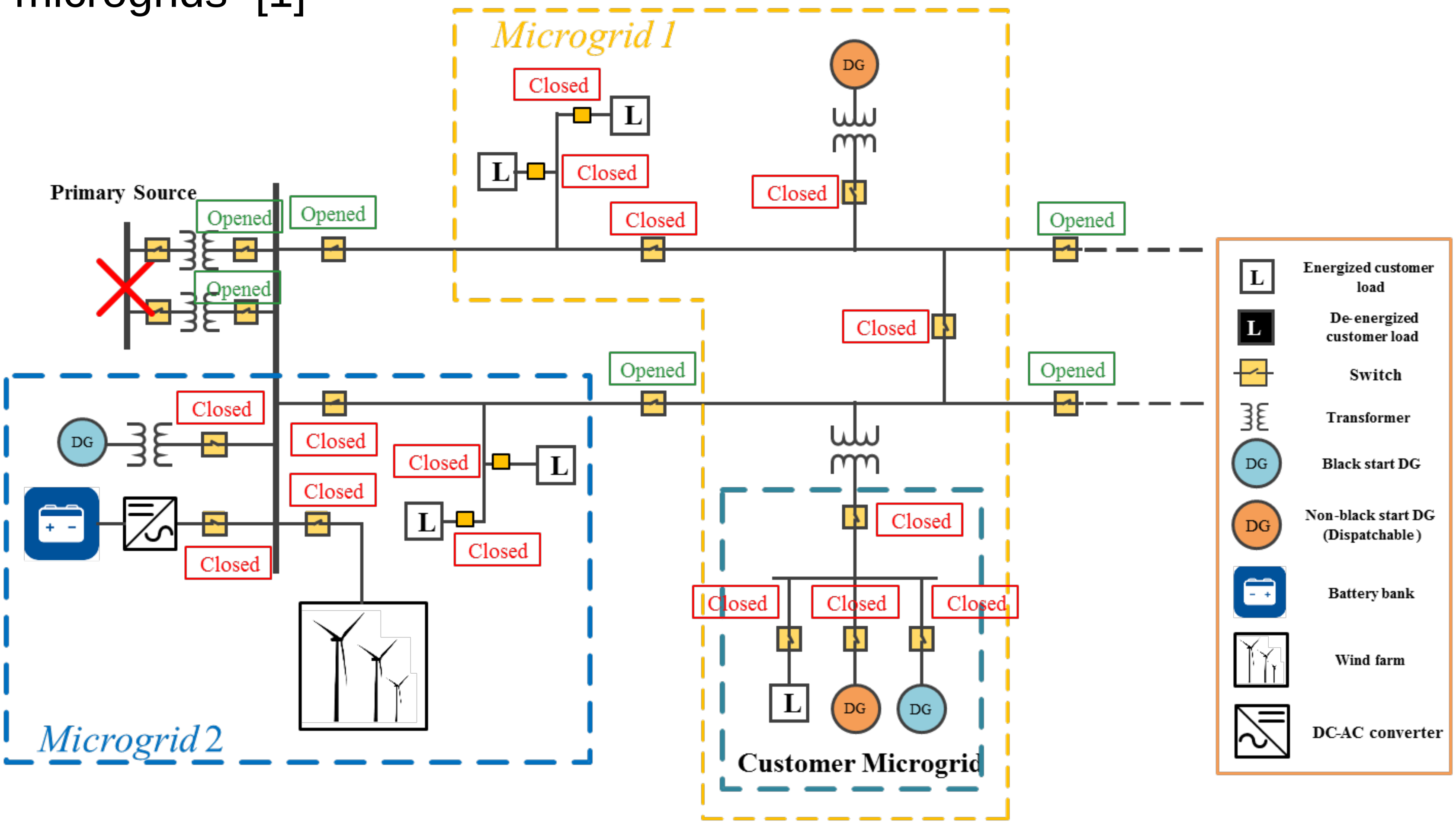
Opportunities and Challenges

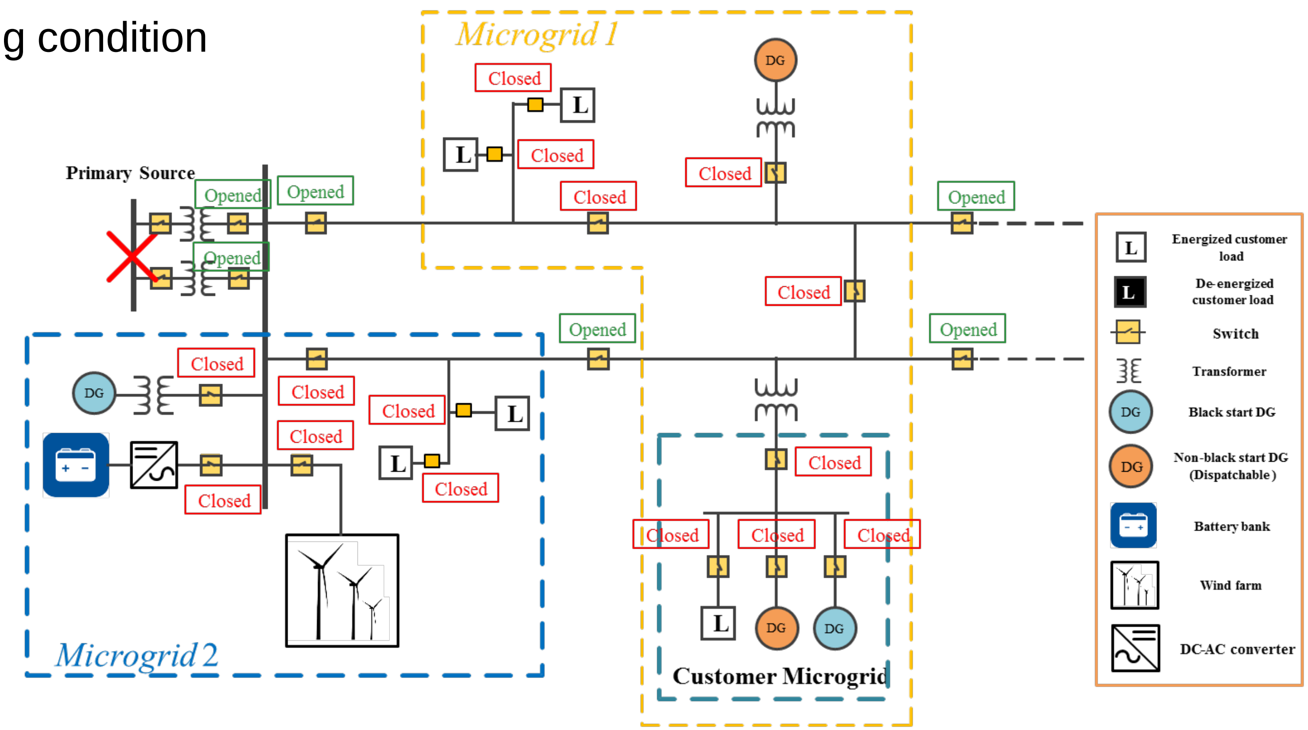
- To perform black start, DERs and loads can be grouped into “dynamic microgrids” [1]



[1] M. Vadari and G. StokeS, "Utility 2.0 and the Dynamic Microgrid," Public Utilities Fortnightly, 2013.

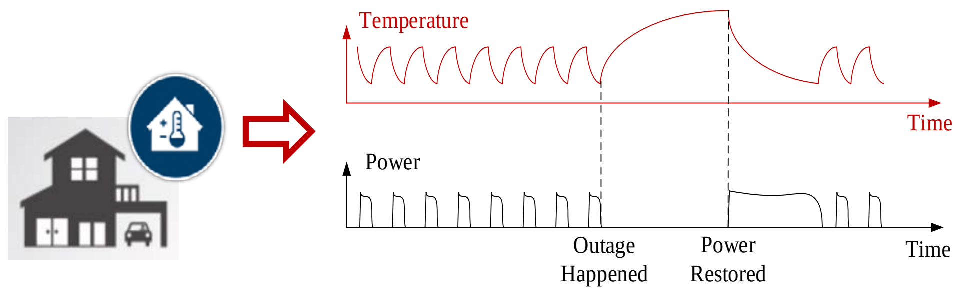
Opportunities and Challenges

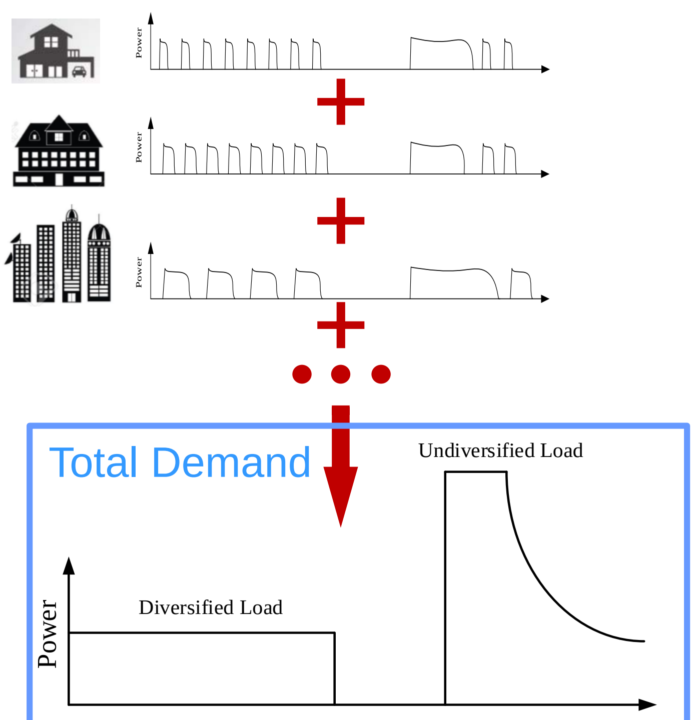
- **Challenges for performing BSR after a general blackout**
  - How to optimally group DGs and loads to minimize affected customers?
  - How to generate a sequence of restoration actions to energize the loads step by step?
  - How to coordinate multiple DGs in a microgrid
- **Several practical issues needing to be considered**
  - Unbalanced system condition
  - Cold load pickup issues
  - Phase balancing condition

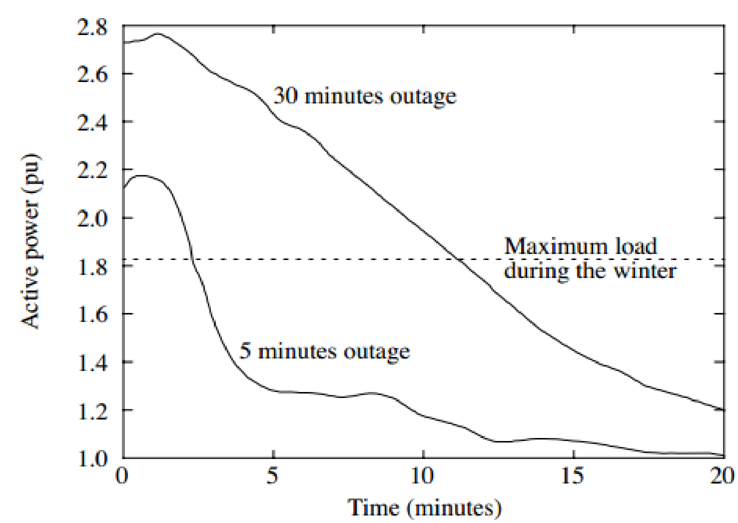


Cold Load Pickup Issues

- CLPU issues should be considered under heavy loading conditions and the customers with many thermostatically controlled devices (e.g., AC units, electric heaters)
- May cause overloading of lines and transformers, frequency drop in some cases







Field measurement of the cold load pick-up for 625 houses [1]

[1] E. Agneholm, Cold Load Pick-up: Chalmers University of Technology, 1999.

BSR Methodology

- Objective function: Maximize the total restored energy over the horizon T

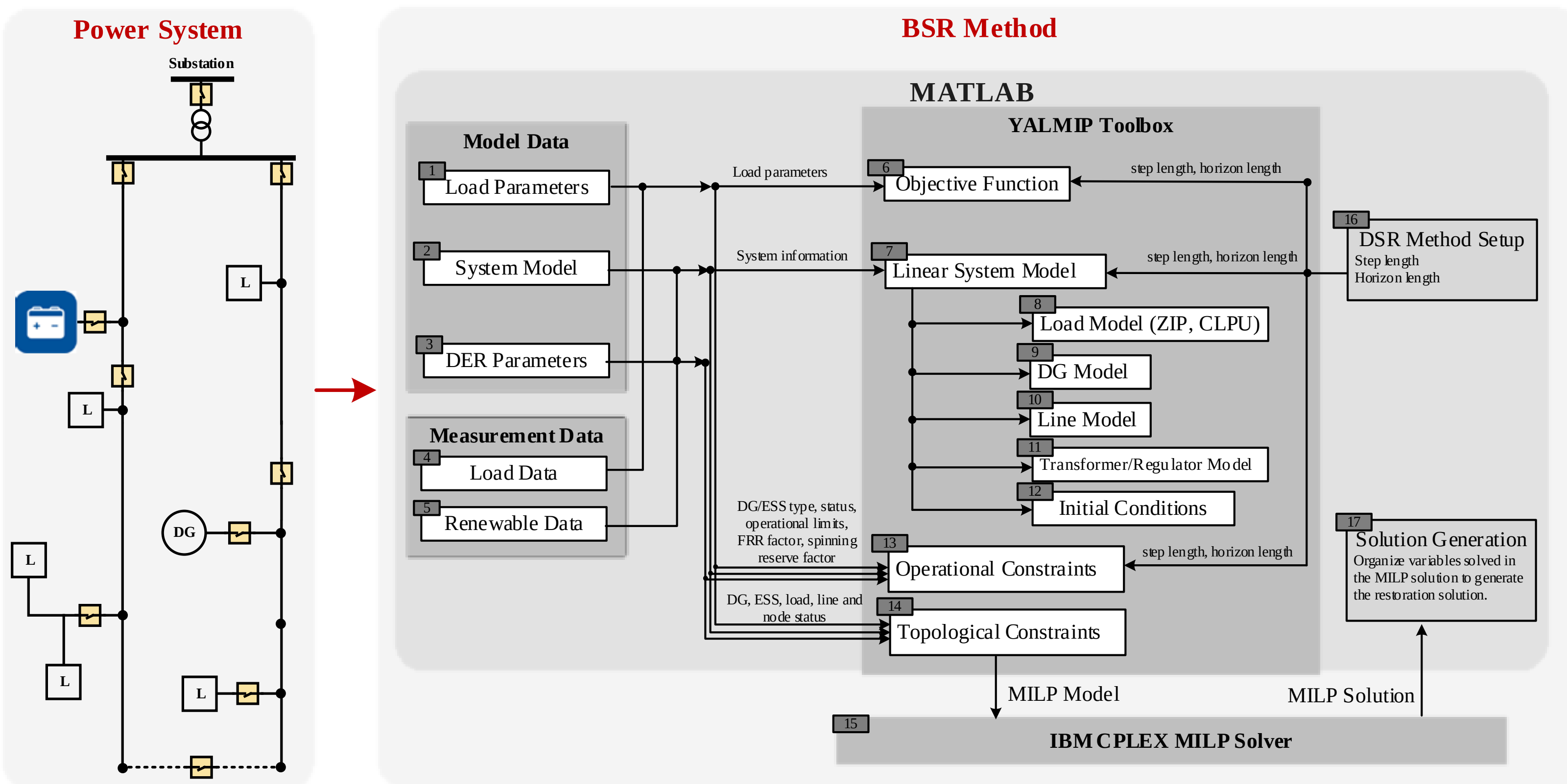
$$\max_{u(t)} \sum_{t\in\mathcal{T}} \sum_{l\in\mathcal{L}} \sum_{\phi\in\{a,b,c\}} P_{l,t}^{\phi} \cdot \Delta t$$

$$\begin{aligned} s.t. \quad & f\big(x(t),u(t)\big) = 0, && \rightarrow \text{System model constraints} \\ & g\big(x(t),u(t)\big) = 0, && \rightarrow \text{Equality constraints} \\ & h\big(x(t),u(t)\big) \le 0, && \rightarrow \text{Inequality constraints} \\ & t \in \mathcal{T} && \rightarrow \text{Considered horizon} \end{aligned}$$

- $g\big(x(t),u(t)\big)$ and $h\big(x(t),u(t)\big)$ represent operational constraints and topological constraints.

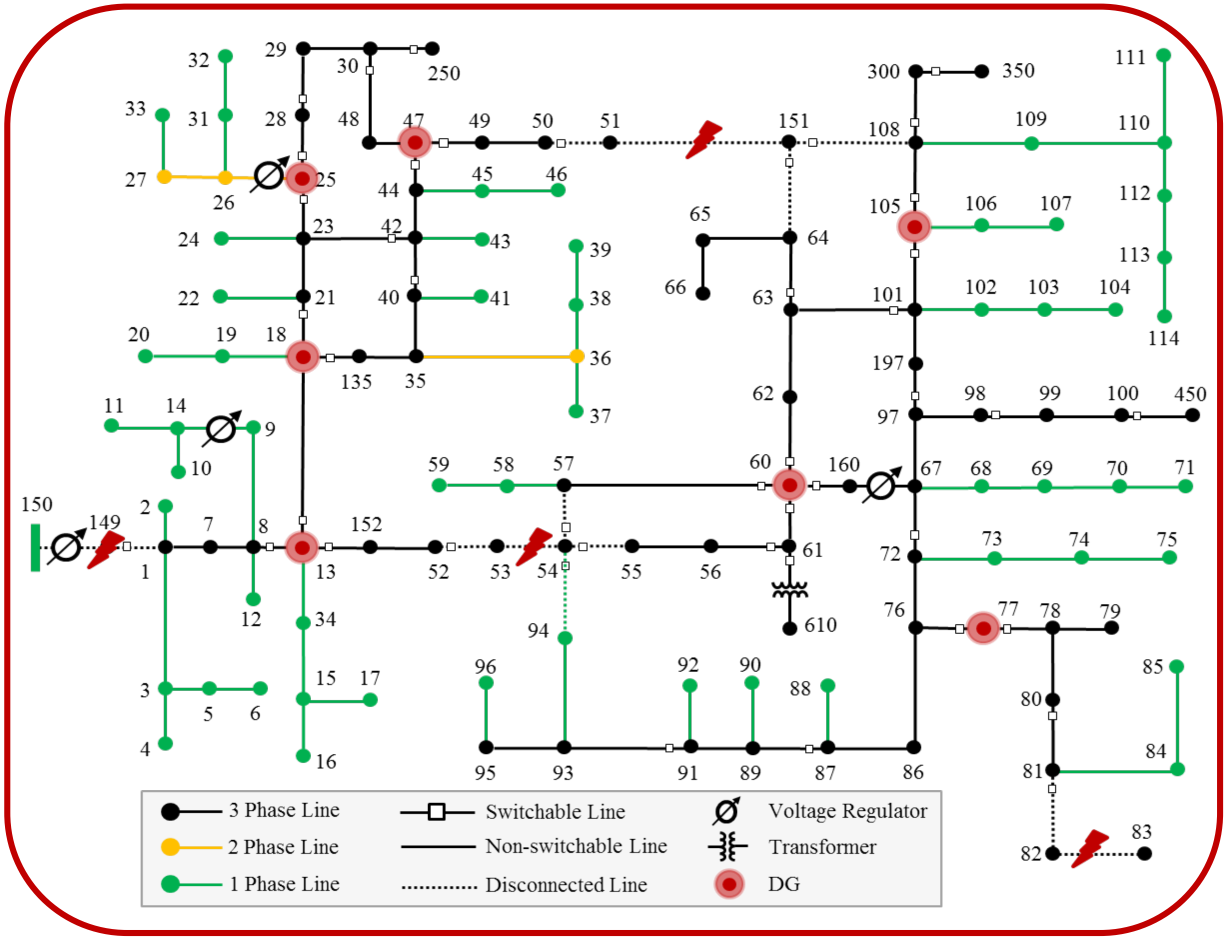
- The BSR problem is formulated as a mixed-integer linear programming (MILP) model
  - Can be solved by commercial solvers such as CPLEX, GUROBI

BSR Methodology ► Implementation Framework



Case Studies ►with ZIP Load
Unbalanced Modified IEEE 123 Node Test System

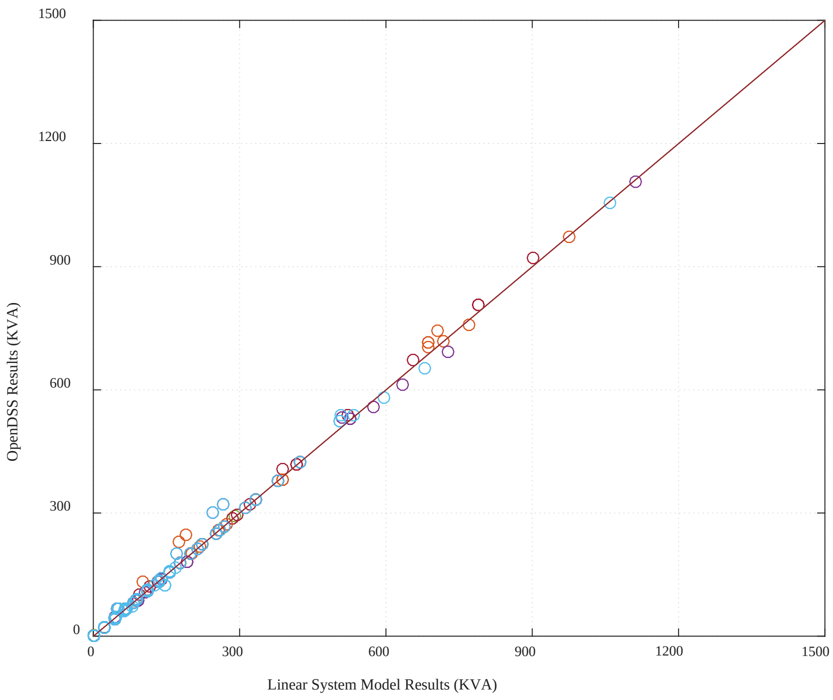
- 7 DGs (4 black start DGs, 3 dispatchable DGs) and several switchable lines were added. All loads were ZIP loads. 4 faults were applied. The system was fully de-energized.



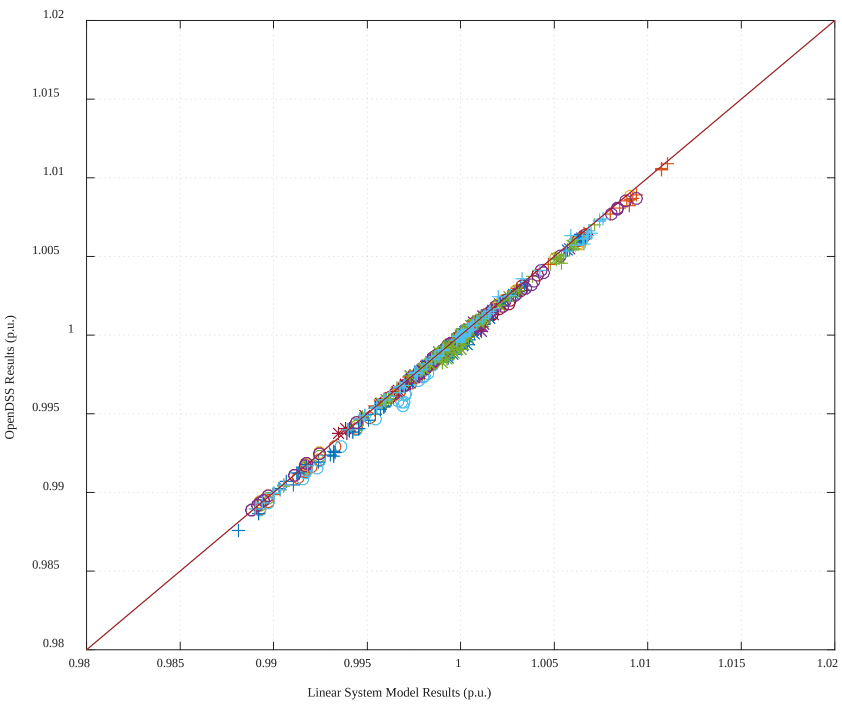
Case Studies ►with ZIP Load

Validate Voltage and Line Power in OpenDSS

- Validate line power in OpenDSS
  - Each line at each step
  - Max error was around 40 kVA

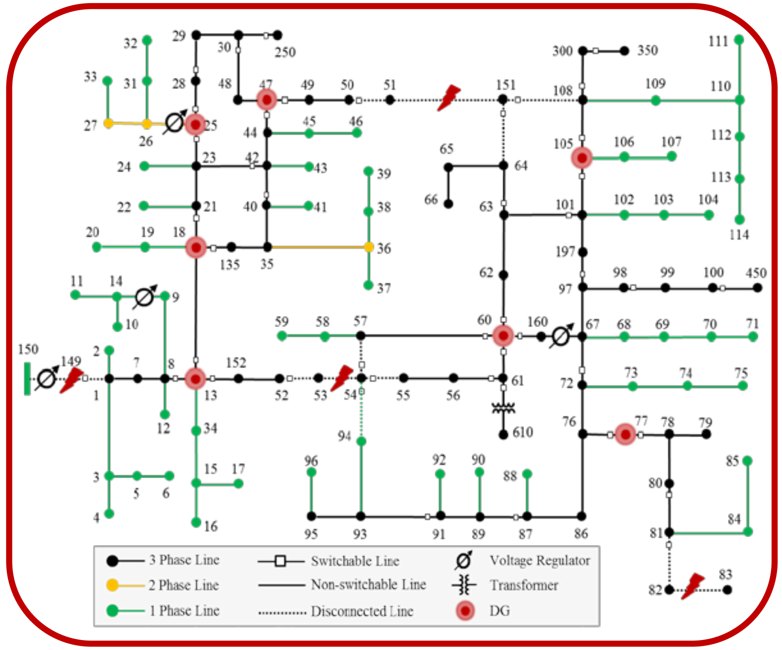


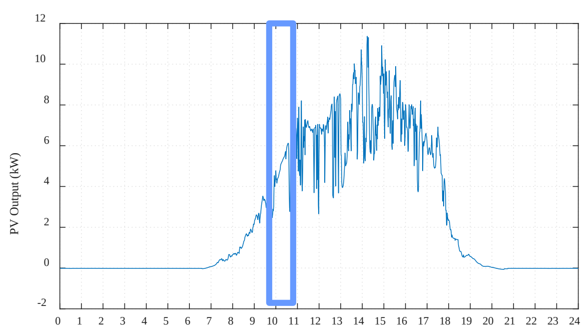
- Validate voltage in OpenDSS
  - Each node at each step
  - Max error was around 0.001 p.u.

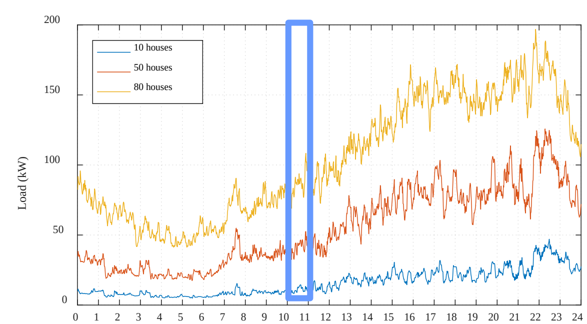


Case Studies ► with CLPU Load ► Unbalanced Modified IEEE 123 Node Test System

- Same system setup with Scenario 1
  - Unbalanced modified 123 node test system.
  - Four faults. The system was fully de-energized.
- **All the loads were under CLPU conditions.**
- Each load node contains 10% penetration of photovoltaic (PV), and 10% penetration of ESS:
  - 85 loads (5 three-phase loads, 80 single-phase loads)
  - PV Penetration: $\gamma^{PV} = \frac{\int_{t=1}^{24hr} P^{PV}(t)dt}{\int_{t=1}^{24hr} P^{LOAD}(t)dt} \times 100\%$
  - ESS Penetration: $\gamma^{PV} = \frac{ESS\ Rated\ Capacity}{\int_{t=1}^{24hr} P^{LOAD}(t)dt} \times 100\%$
- PV data and load data were retrieved from the Pecan Street project database(10:00am on June 1st 2016) [1,2]
- **Total scheduled horizon=60 min. Interval=2min. Single-horizon.**







[1] "The pecan street project." Austin, TX: Working Group Report (2010). www.pecanstreet.org/wordpress
[2] Database available at https://dataport.pecanstreet.org/

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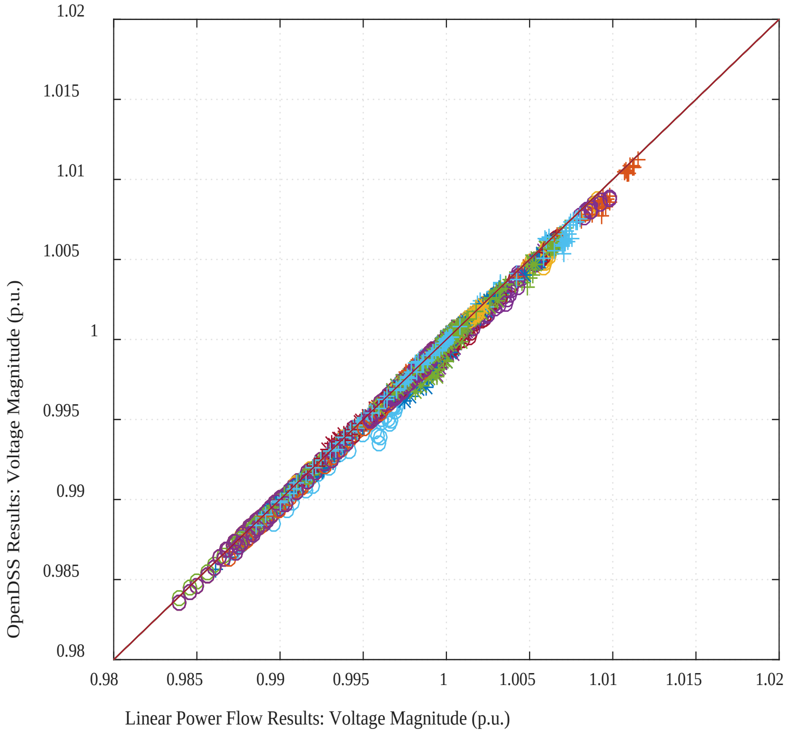
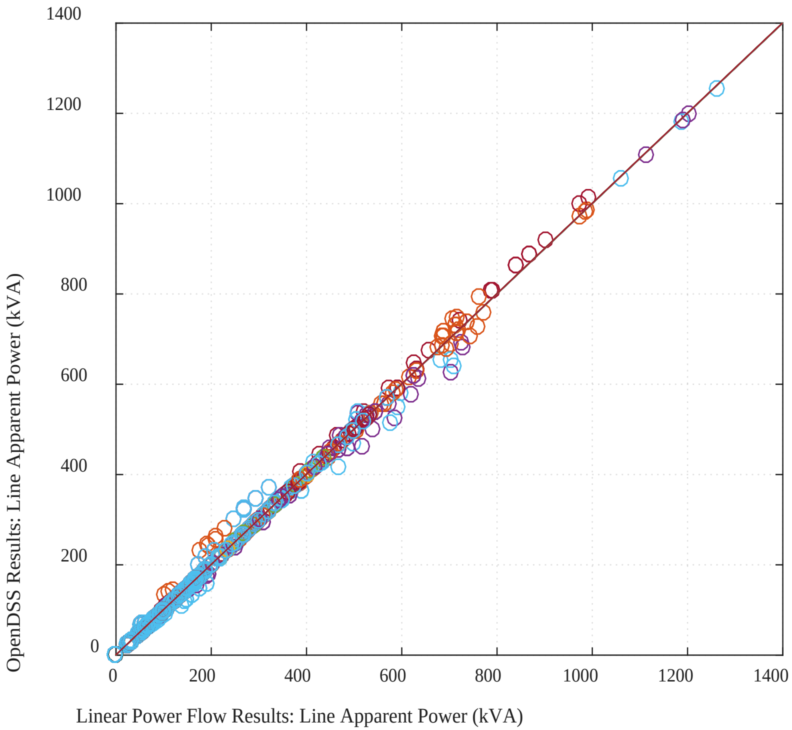
Case Studies: Validation of Linear System Model for Unbalanced Systems against OpenDSS

- **Test System: Unbalanced 123 Node System**
- **20 Scenarios generated using different levels of load demand**





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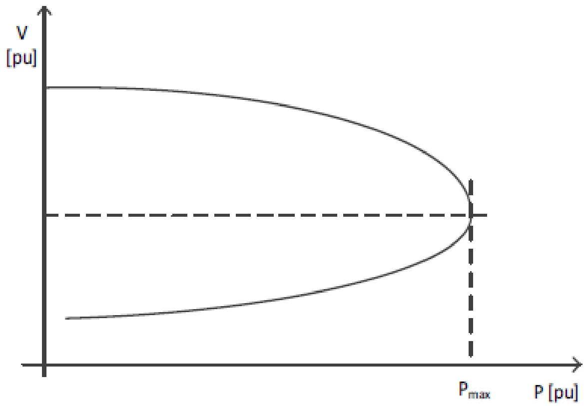
Investigation of Voltage Stability in Three-phase Unbalanced Distribution Systems with DGs

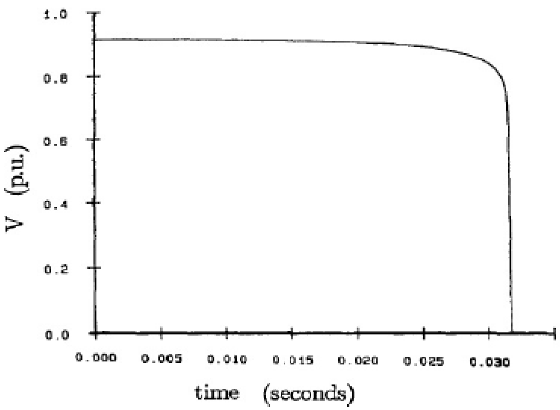
Hung-Ming Chou

Karen Butler-Purry

Voltage stability

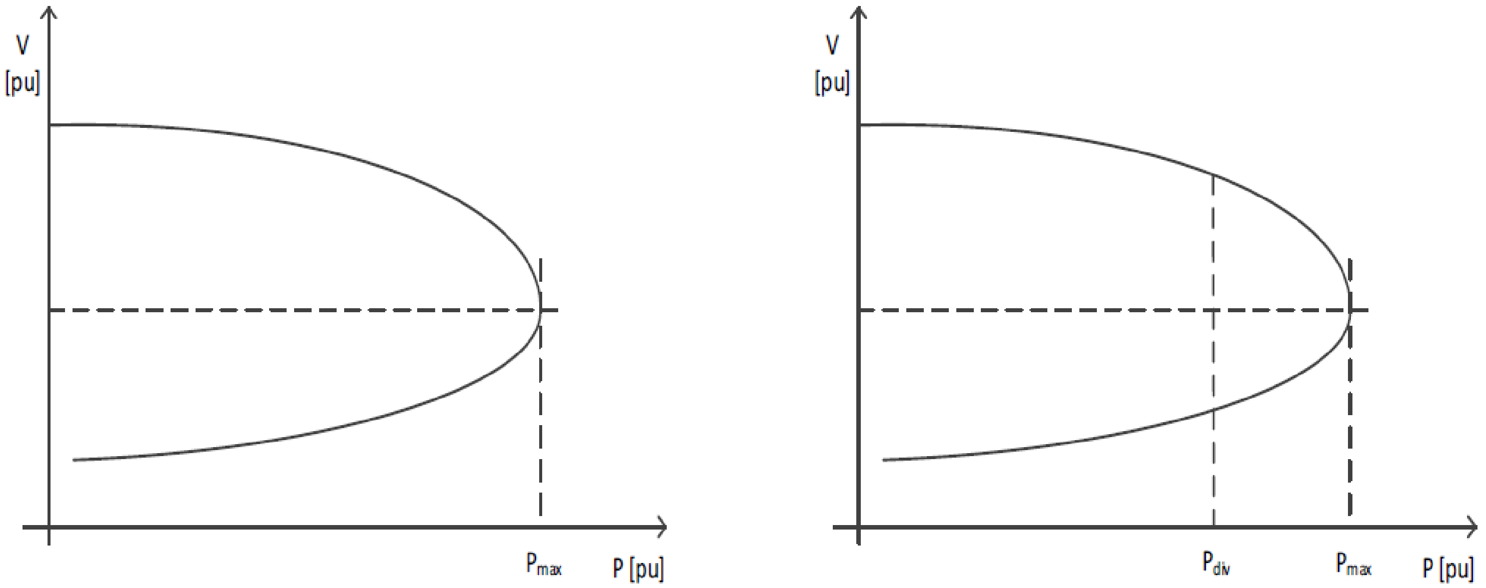
- Ability to maintain acceptable voltages
- Reactive power demand cannot be met
- Voltage collapse: voltage will decrease abruptly





Kundur, P. (1994). Power System Stability and Control, McGraw-Hill Professional

PV curve: Motivation of continuation power flow



- Power flow equations at the loading factor λ

$$\mathbf{f}(\mathbf{x}) = \mathbf{0}$$

$$(\mathbf{x} = [V_1, V_2, \ldots, V_{N-1}, \theta_1, \theta_2, \ldots, \theta_{N-1}])$$

- Singularity issue of Jacobian matrix at P_{div}

Continuation power flow

- Add one continuation parameter in the Jacobian matrix

  Power flow equation

  $$\mathbf{f}(\mathbf{x}) = \mathbf{0}$$

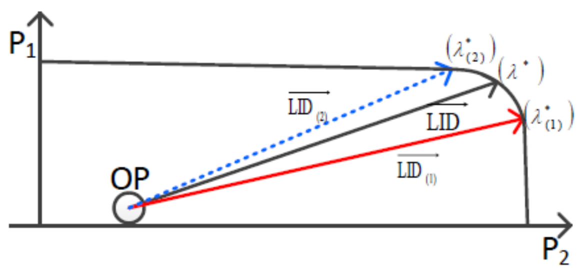
  CPF with arc length parameterization [1]

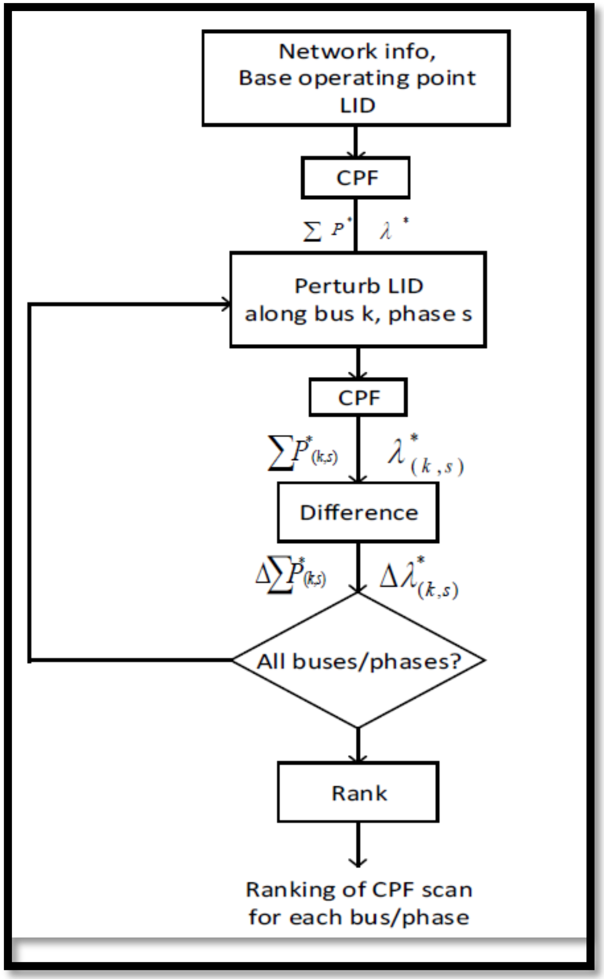
  $$\begin{cases} \mathbf{f}(\mathbf{x}^{\mathbf{i}}, \lambda^{i}) = \mathbf{0} \\ \sum_{k=1}^{N} (x_k^i - x_k^{i-1})^2 + (\lambda^i - \lambda^{i-1})^2 = (\Delta s_{\mathrm{spec}})^2 \end{cases}$$

  N: number of state variables in power flow
  i: CPF iteration number
  Δs_{spec}: specified arc length

New Voltage Stability Analysis Approach: CPF Scan

- Avoids singularity issue
- Considers LID (How the load is increased)
- Considers different factors that influence the weak buses
  - Network characteristics
  - Base operating point
  - Load increase direction (LID)





Two bus example (Single phase) - ranking

Calculate the difference

$$\Delta\lambda^*_{(1)} = \lambda^*_{(1)} - \lambda^*$$

$$\Delta\lambda^*_{(2)} = \lambda^*_{(2)} - \lambda^*$$

$$\Delta\sum P^*_{(1)} = \sum P^*_{(1)} - \sum P^*$$

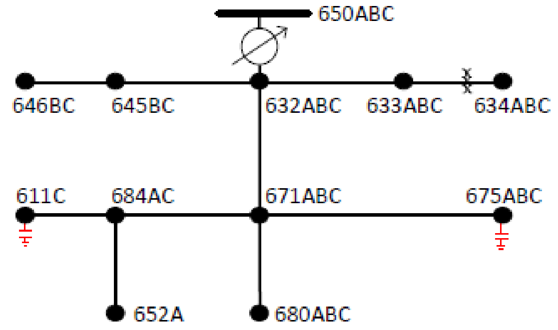
$$\Delta\sum P^*_{(2)} = \sum P^*_{(2)} - \sum P^*$$

Bus 1 weaker if

- $|\Delta\lambda^*_{(1)}| \geq |\Delta\lambda^*_{(2)}|$, or
- $|\Delta\sum P^*_{(1)}| \geq |\Delta\sum P^*_{(2)}|$

13-node - CPF scan

CPF scan		V		P		Q	
632A	0.247	632A	0.837	650-632A	3.228	650-632A	3.103
633A	0.339	633A	0.828	632-671A	2.493	632-671A	2.132
634A	3.595	634A	0.759	671-675A	1.093	671-675A	0.444
684A	4.060	671A	0.712	632-633A	0.374	632-633A	0.283
675A	7.336	684A	0.706	633-634A	0.371	633-634A	0.278
671A	7.666	680A	0.704	671-684A	0.290	671-680A	0.223
652A	8.847	652A	0.688	684-652A	0.289	671-684A	0.194
680A	11.040	675A	0.688	671-680A	0.220	684-652A	0.191
632B	-0.774	675B	0.870	650-632B	3.571	650-632B	3.388
633B	-0.794	671B	0.866	632-645B	1.963	632-645B	1.327
671B	-1.610	680B	0.862	632-671B	1.160	632-671B	0.835
646B	-1.646	632B	0.843	645-646B	1.041	645-646B	0.610
645B	-1.845	633B	0.838	632-633B	0.275	671-680B	0.221
634B	-1.893	634B	0.785	633-634B	0.274	632-633B	0.220
675B	-2.468	645B	0.757	671-680B	0.219	633-634B	0.218
680B	-2.491	646B	0.728	671-675B	0.147	671-675B	0.131
645C	-2.535	646C	0.842	650-632C	3.338	650-632C	3.278
632C	-2.566	645C	0.840	632-671C	2.575	632-671C	2.054
633C	-2.606	632C	0.828	671-675C	0.651	671-675C	0.468
646C	-2.764	633C	0.820	671-684C	0.385	671-680C	0.224
634C	-3.401	634C	0.766	684-611C	0.378	632-633C	0.221
684C	-4.405	671C	0.629	632-633C	0.277	633-634C	0.219
611C	-5.139	680C	0.618	633-634C	0.275	671-684C	0.186
671C	-5.156	684C	0.617	671-680C	0.221	684-611C	0.181
675C	-5.383	675C	0.616	645-646C	0.218	632-645C	0.091
680C	-5.854	611C	0.605	632-645C	0.213	645-646C	0.089



- Does not follow up/down stream
  - 632C is weaker than 645C

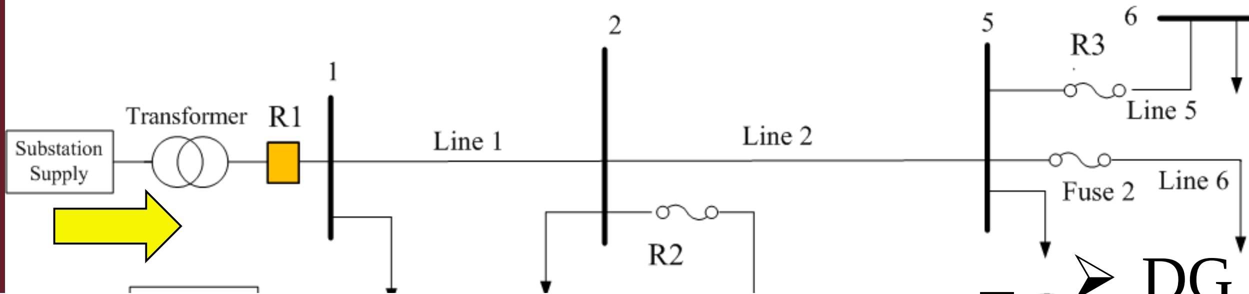
Smart Meter Data Utilization in Protection

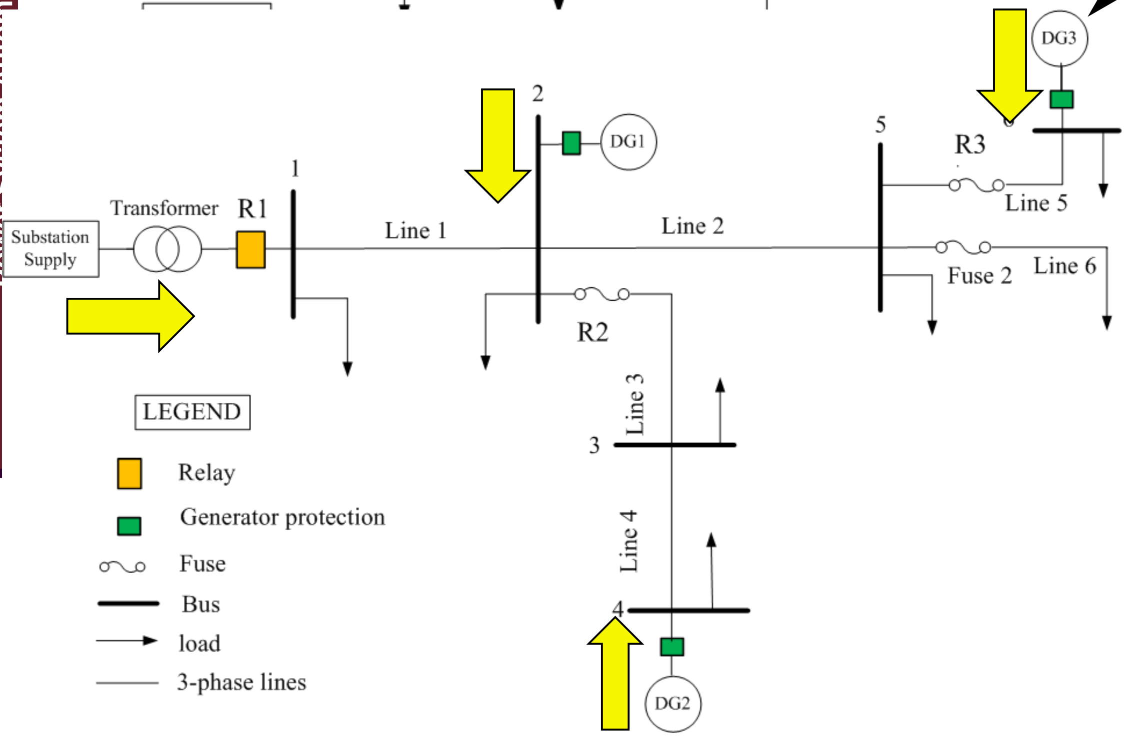
Fred A. Ituzaro and Richard Douglin

Dr. Karen Butler-Purry

Distributed Generation Issues

Conventional Radial distribution feeder





- DG changes radiality of distribution systems (DS) causing a host of protection issues.
  - Bidirectional power flow.
  - Mis-coordination between fuses and reclosers.
  - Reduced reach of relays.
  - Safety.

Smart Meter Data Utilization in Protection

- 2 methods in which smart meter data is utilized to develop adaptive protection schemes for radial distribution systems with DGs.

  - Method 1 (Planning) [1]: An Investigation of The Utilization of Smart Meter Data to Adapt Overcurrent Protection for Radial Distribution Systems with a High Penetration of Distributed Generation

  - Method 2 (Operation) [2]: A Technique to Utilize Smart Meter Load Information for Adapting Overcurrent Protection for Radial Distribution Systems with Distributed Generations

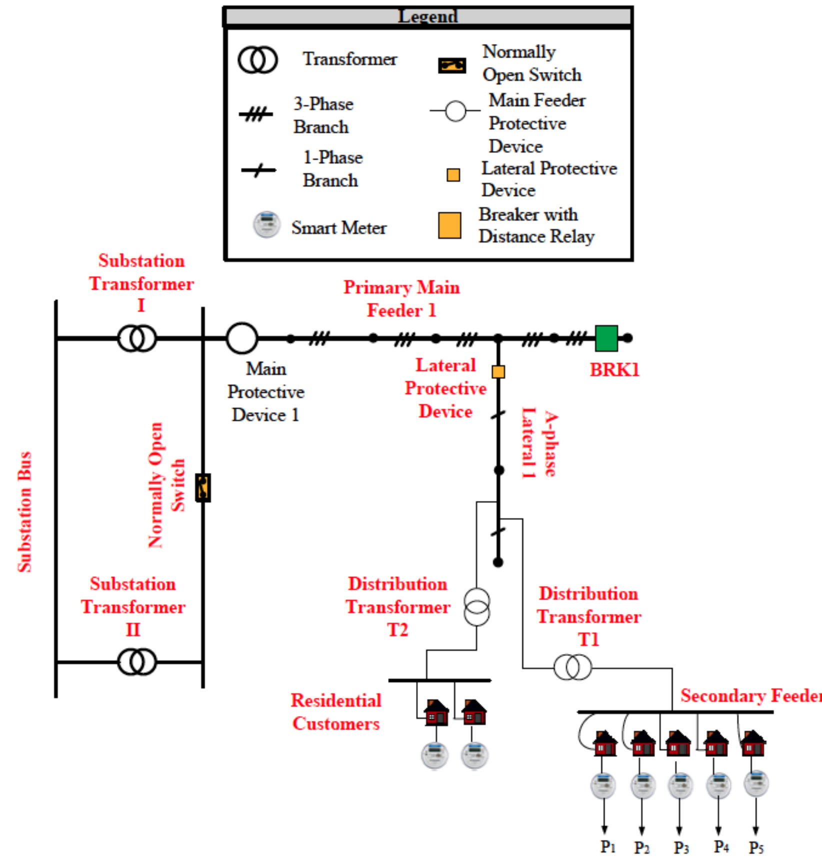
1) R. H. Douglin, "An Investigation of The Utilization of Smart Meter Data to Adapt Overcurrent Protection for Radial Distribution Systems with a High Penetration of Distributed Generation " Master of Science, Dept. Electrical and Computer Eng., Texas A&M University, College Station, TX, US, 2012.
2) F. Ituzaro, "A Technique to Utilize Smart Meter Load Information for Adapting Overcurrent Protection for Radial Distribution Systems with Distributed Generations " Master of Science, Dept. Electrical and Computer Eng., Texas A&M University, College Station, TX, US, 2012.

Method 1 – Summary

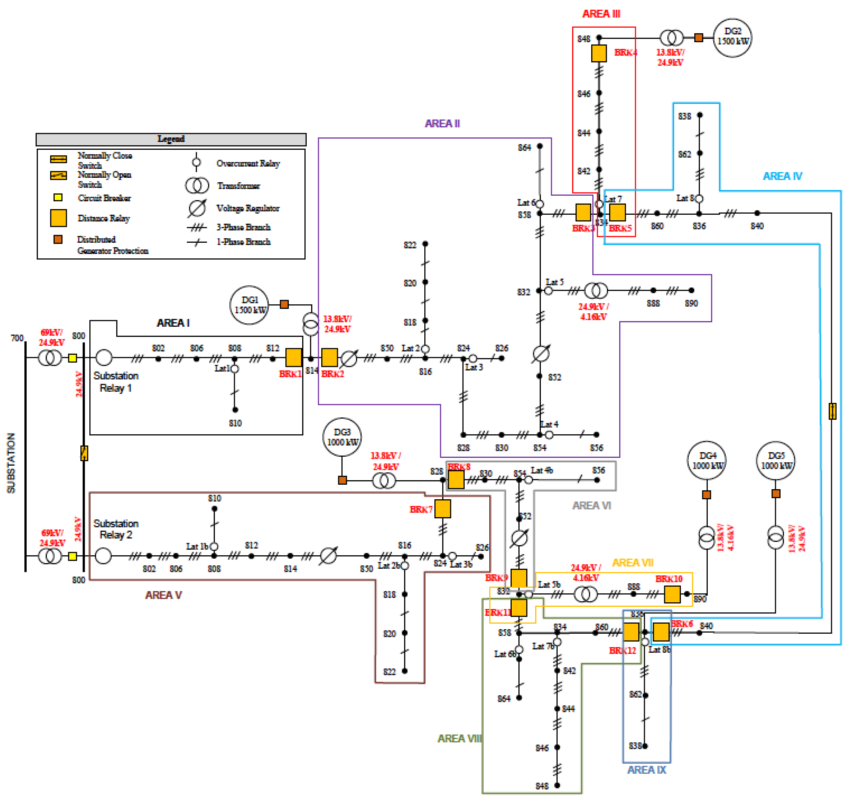
- The smart meter load information was used to generate seasonal maximum 15-minute diversified demands for each radial segment of the multi-feeder test system.
- The values were then used to obtain the seasonal pickup settings for every radial segment for the corresponding substation overcurrent relay.
- Modified an existing non-adaptive protection method to include adaptive settings of substation overcurrent relays
  - **Existing method – uses distance relays to make the faulted area radial**
  - **Overcurrent protection used to clear fault in radial segment**
  - **Settings for overcurrent relay adapted to attempt to provide better sensitivity (faster tripping times)**
- Studies showed that having an adaptive setting based on seasonal maximum diversified demand and known radial segments can improve tripping times

Method 1 – Smart Meters

- Smart meters installed at all customer locations on secondary distribution system
- Smart meters can monitor customer demand in specified intervals (15, 30, 60…)min



Method 1 – Case Study



- Multi-Feeder test system
  - Preserves the structure of IEEE 34 Node Radial Test Feeder
  - Dual Bus substation configuration
  - Closed switch added to end of feeders
- 5 DGs, 2 on Feeder 1; 3 on Feeder 2
- 9 Protection Coordination Areas
  - 9 Possible Radial Segments

Method 1 – Case Study

- Substation Relay 1 sources four (4) different radial segments
- Substation Relay 2 sources five (5) different radial segments

SUBSTATION OVERCURRENT RELAYS

Signal from Open Distance Relay	Radial Segment	Pickup Current (Amps)		
		FALL/ SPRING	WINTER	SUMMER
Substation Relay 1 (Main Protective Device 1)				
BRK1	I	11.463	14.873	12.737
BRK3	II	73.391	86.949	81.118
BRK4, BRK5	III	85.528	101.964	95.877
BRK6	IV	106.925	127.641	119.982
Substation Relay 2 (Main Protective Device 2)				
BRK7	V	52.85	64.686	60.809
BRK9	VI	53.831	66.362	62.126
BRK10, BRK11	VII	67.662	82.526	77.367
BRK12	VIII	95.874	116.261	109.628
BRK6	IV	93.564	115.023	107.723

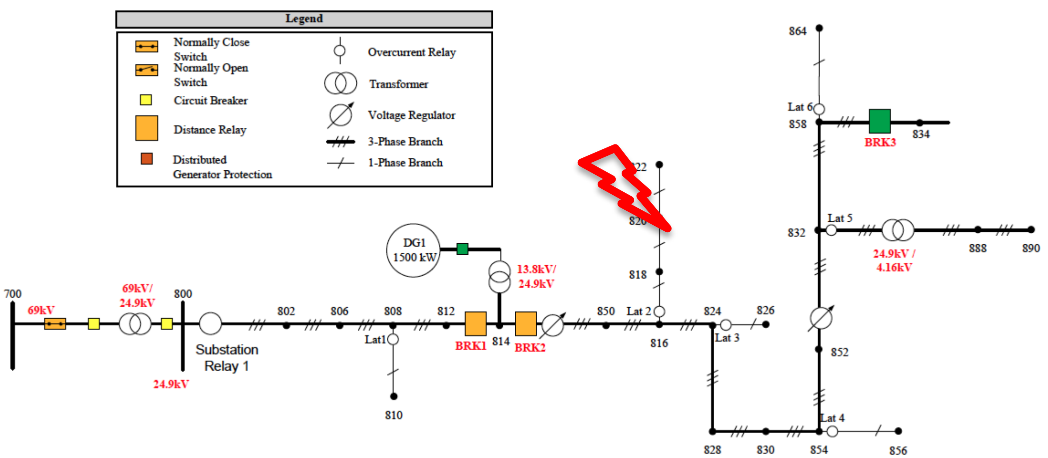
Distance Relay Open Signal

Current Season

Pickup Settings for Substation Relay

Method 1 – Case Study

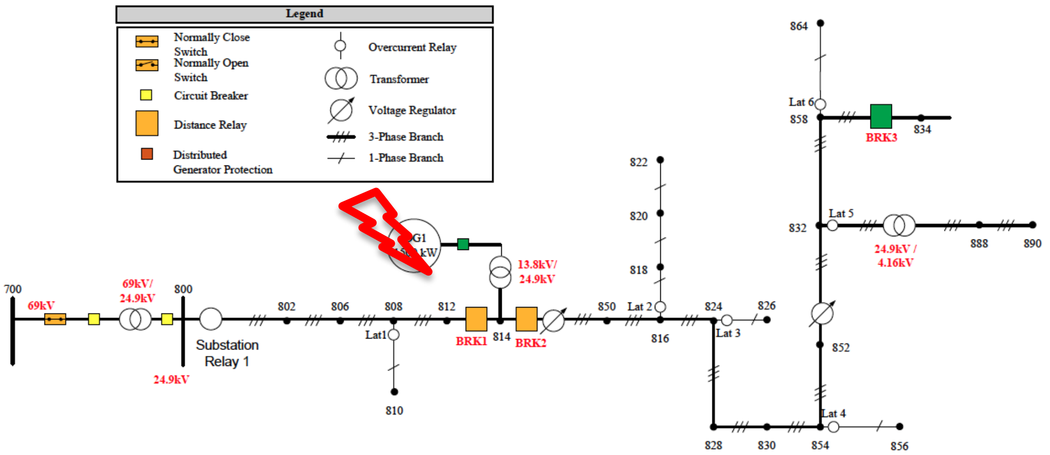
- For fault in Protection Coordination Area II (820-822),
  - BRK3 opens
  - DG1 is disconnected
- Radial Segment II is created
  - Sourced by Substation Relay 1
  - From node 800 to terminals of BRK3
  - Distribution Transformers
    - 44 on Phase A
    - 36 on Phase B
    - 28 on Phase C
  - Seasonal Pickup Settings
    - Fall/Spring – 73.391 A
    - Winter – 86.949 A
    - Summer – 81.118 A



- Original Setting for Substation Relay based on Maximum load of FEEDER 1 – 168.74 A

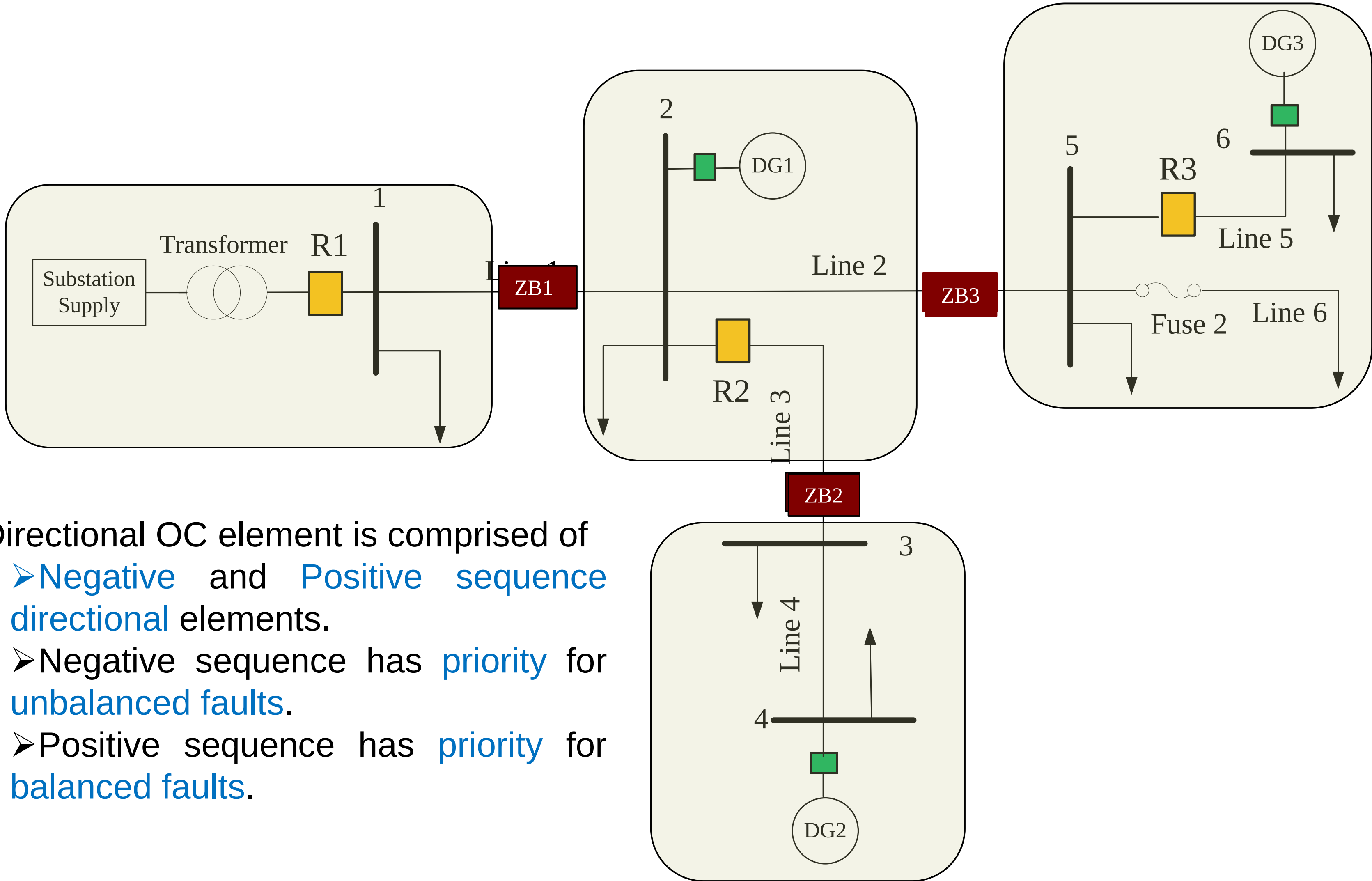
Method 1 – Case Study

- Fault Current measured by Substation Relay 1
  - 356.630 A
- Tripping Time of Substation Relay 1
  - Fall/Spring - 1.717 seconds
  - Winter – 1.913 seconds
  - Summer – 1.827 seconds
  - Original Setting (Maximum Load) – 2.113 seconds



Method 2

- Uses a directional OC relay and a circuit breaker (zonal boundary element)



- Directional OC element is comprised of
  - Negative and Positive sequence directional elements.
  - Negative sequence has priority for unbalanced faults.
  - Positive sequence has priority for balanced faults.

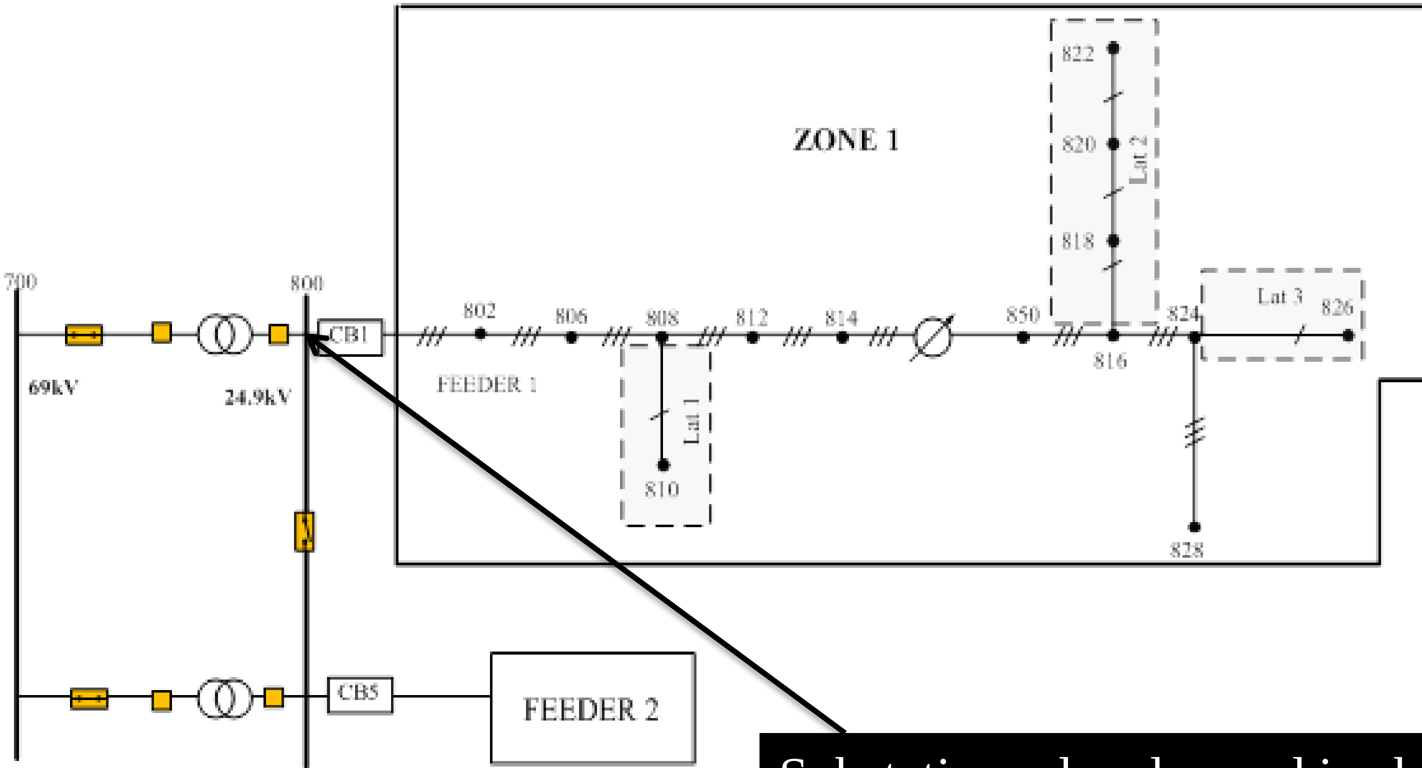
Method 2 – Summary

- The smart meter demand measurements from a load variation pattern randomly developed for the loads in zone 1 of the multi-feeder test system were used to determine a 24-hour time duration demand that the substation OC relay monitors.
- The trip times of the substation relay for bolted and high impedance faults in the zone were monitored using a pickup setting obtained based on the maximum loading of zone 1 (following the conventional approach for determining pickup setting), and a pickup setting that uses the proposed methodology of the maximum diversified demands of the two 12-hour intervals.
- Case studies for bolted and high impedance fault types showed that the sensitivity of the substation OC relay was improved by at least 24% using the demands from the smart meters.

Method 2 – Smart Meters

- The proposed methodology for smart meter data usage for OC protection is applied to the substation relay after the zonal boundary protective elements has operated to isolate a faulted zone downstream the zone of the multi-feeder test system whose main supply is from the substation.
- The approach seeks to aggregate the individual customer load demand from the smart meter measurements at the secondary level for each transformer supplied by substation in the unfaulted zone connected to the substation.
- This technique is to help determine the demand pattern for the substation OC protective relay over a given time duration.

Method 2 – Case Study
Laterals Demand Contribution



Substation relay demand is obtained by adding the corresponding phases of the main feeder individual transformer diversified demands to the contribution of the lateral transformers.

Method 2 - Case Study
Adaptive Pickup Study for First 12-hr Interval

- Substation relay pickup setting
  - Old pickup is based on maximum zone 1 loading = 94.3 A.
  - New pickup setting is based on maximum diversified demand for the first 12-hour interval = 32.84 A.
- Substation relay
  - tripped faster when the new pickup setting was used than when the old pickup setting was used.
  - shows at least a 26% improvement in its sensitivity for the bolted faults.
  - shows a minimum sensitivity improvement of 33% for high impedance faults.

Pickup Variation Study for Substation Relay Using Maximum Zone Loading and Maximum Diversified Demand in 1st 12-hour Interval

Fault Location	Fault Type	Fault Current (A)		Old Pickup Trip Times (s)		New Pickup Trip Times (s)		Sensitivity Improvement	
		Bolted Fault	High Imped. Fault	Bolted Fault	High Imped. Fault	Bolted Fault	High Imped. Fault	Bolted Fault	High Imped. Fault
820-822	A-N	333.75	266.95	1.072	1.293	0.604	0.664	44%	49%
808-810	B-N	782.85	512.14	0.658	0.812	0.454	0.517	31%	36%
824-826	B-N	406.34	328.56	0.944	1.085	0.564	0.608	40%	44%
806-808	C-N	1273.53	641.06	0.543	0.722	0.399	0.481	27%	33%
816-824	AB	561.9	482.67	0.748	0.819	0.492	0.519	34%	37%
814-850	AC	560.17	487.44	0.770	0.719	0.501	0.480	35%	33%
802-806	ABC	1301.12	652.47	0.538	0.715	0.396	0.478	26%	33%
814-850	ABC	665.25	467.94	0.704	0.855	0.474	0.533	33%	38%
824-828	ABC	599.52	441.75	0.739	0.885	0.488	0.544	34%	39%

Method 2 - Case Study
Adaptive Pickup Study for Second 12-hr Int.

Power System Automation Lab

- Substation relay pickup setting
  - Old pickup is again based on maximum zone 1 loading = 94.3 A
  - New pickup based on maximum diversified demand for the second 12-hour interval = 31.59 A.
- Tripping times of the substation relay shows that new pickup trip times are smaller compared to the old pickup trip times.
- There is higher percentage sensitivity improvement of the substation relay in responding to almost all the high impedance faults than the bolted faults.
- New pickup trip times of the 2nd 12-hour interval shows only a slight improvement (less than 0.1s) over that of the 1st 12-hour interval.

Pickup Variation Study for Substation Relay Using Maximum Zone Loading and Maximum Diversified Demand in 2nd 12-hour Interval

Fault Location	Fault Type	Fault Current (A)		Old Pickup Trip Times (s)		New Pickup Trip Times (s)		Sensitivity Improvement	
		Bolted Fault	High Imped. Fault	Bolted Fault	High Imped. Fault	Bolted Fault	High Imped. Fault	Bolted Fault	High Imped. Fault
820-822	A-N	333.7	267.0	1.072	1.292	0.595	0.653	44%	49%
808-810	B-N	783.1	511.2	0.658	0.813	0.449	0.511	32%	37%
824-826	B-N	408.8	328.3	0.945	1.094	0.556	0.601	41%	45%
806-808	C-N	1274.6	642.2	0.543	0.721	0.395	0.475	27%	34%
816-824	AB	559.8	480.0	0.747	0.818	0.486	0.513	35%	37%
814-850	AC	560.5	487.6	0.770	0.719	0.495	0.474	36%	34%
802-806	ABC	1301.5	652.3	0.538	0.715	0.393	0.473	27%	34%
814-850	ABC	664.4	466.8	0.705	0.856	0.468	0.526	34%	39%
824-828	ABC	599.3	438.8	0.739	0.889	0.482	0.538	35%	40%

Pickup Variation Study for Substation Relay Using Maximum Zone Loading and Maximum Diversified Demand in 1st 12-hour Interval

Fault Location	Fault Type	Fault Current (A)		Old Pickup Trip Times (s)		New Pickup Trip Times (s)		Sensitivity Improvement	
		Bolted Fault	High Imped. Fault	Bolted Fault	High Imped. Fault	Bolted Fault	High Imped. Fault	Bolted Fault	High Imped. Fault
820-822	A-N	333.75	266.95	1.072	1.293	0.604	0.664	44%	49%
808-810	B-N	782.85	512.14	0.658	0.812	0.454	0.517	31%	36%
824-826	B-N	406.34	328.56	0.944	1.085	0.564	0.608	40%	44%
806-808	C-N	1273.53	641.06	0.543	0.722	0.399	0.481	27%	33%
816-824	AB	561.9	482.67	0.748	0.819	0.492	0.519	34%	37%
814-850	AC	560.17	487.44	0.770	0.719	0.501	0.480	35%	33%
802-806	ABC	1301.12	652.47	0.538	0.715	0.396	0.478	26%	33%
814-850	ABC	665.25	467.94	0.704	0.855	0.474	0.533	33%	38%
824-828	ABC	599.52	441.75	0.739	0.885	0.488	0.544	34%	39%