| Electric T&D Reliability | Year Total | | | | | | Year Total | Year Total | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Previous 5 Year Actual | | | | | | Forecast | Current 5 Year Budget | | | | | |
| | | | | | | | 2012 Forecast | Working | | | | | |
| | Total Dollars ($000) | | | | | | Total Dollars ($000) | Total Dollars ($000) | | | | | |
| | FY07 | FY08 | FY09 | FY10 | FY11 | 5 Yr. Total | FY12 | FY13 | FY14 | FY15 | FY16 | FY17 | 5 Yr. Total |
| **Electric Transmission** | | | | | | | | | | | | | |
| **Reliability** | | | | | | | | | | | | | |
| ECC Ups Battery Replacement | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 250.0 | 200.0 | 0.0 | 0.0 | 250.0 | 0.0 | 450.0 |
| ECC/AECC Facility Security | 0.0 | 0.0 | 268.0 | 80.0 | 85.0 | 433.0 | 0.0 | 0.0 | 250.1 | 600.1 | 200.0 | 0.0 | 1,050.2 |
| Emergent Transmission Reliability | 0.0 | 1,790.0 | 3,973.0 | 8,358.0 | 5,072.0 | 19,193.0 | 4,993.0 | 10,000.0 | 9,500.0 | 9,500.0 | 9,500.0 | 9,500.0 | 48,000.0 |
| L-Line Splice andDead End Assembly | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,900.0 | 0.0 | 0.0 | 0.0 | 2,900.0 |
| Upgrade Overhead 345kv Transmission Structures | 0.0 | 0.0 | 568.0 | 1,759.0 | 1,291.0 | 3,618.0 | 2,000.0 | 1,500.0 | 2,000.0 | 2,000.0 | 2,000.0 | 2,000.0 | 9,500.0 |
| Re-Conductor Dunwoodie - Sprain Brook Co | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,400.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,400.0 |
| Transmission Fdr. Pipe Support at Queensboro Bridge | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,600.0 | 3,600.0 | 3,500.1 | 0.0 | 0.0 | 10,700.1 |
| 38M72 Upgrade Vernon-West 49th Street | 0.0 | 1,318.0 | 11,781.0 | 17,323.0 | 4,410.0 | 34,832.0 | 5,000.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Establish New Alternate Energy Control Center | 1,238.0 | 10.0 | 10.0 | 0.0 | 0.0 | 1,258.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Feeder M51 | 0.0 | 1,973.0 | (2.0) | 0.0 | 0.0 | 1,971.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Install Phasor Devices | 52.0 | 7.0 | 96.0 | 189.0 | 16.0 | 360.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| M29 | 16,888.0 | 109,593.0 | 173,063.0 | 97,746.0 | 34,279.0 | 431,569.0 | 1,800.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Pothead Alarms | 268.0 | 483.0 | 308.0 | 17.0 | 0.0 | 1,076.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Promenade - Relocate Feeder 46/48 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 600.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Rainey - 75th Street Cooling Plant | 21.0 | 0.0 | 0.0 | 0.0 | 0.0 | 21.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Re-conductor 38B01 - 38B04 | 3,670.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,670.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Re-conductor 69M65 | 0.0 | (2.0) | 0.0 | 0.0 | 0.0 | (2.0) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Reinforce Crossing Tower Hudson River | 0.0 | 0.0 | 2,536.0 | 1,829.0 | 1,644.0 | 6,009.0 | 1,300.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Replace 138kV Feeder 95891 L&M | 0.0 | (25.0) | 0.0 | 0.0 | 0.0 | (25.0) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Replace 183kV Feeders 18001 and 18002 | 0.0 | 0.0 | 3,701.0 | 1,879.0 | 131.0 | 5,711.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Replace 38W02, 38W13 and 38W14 | 135.0 | 0.0 | 0.0 | 0.0 | 0.0 | 135.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Replace 69M43/44 with 38M53/54 | 10,679.0 | 2,806.0 | 1,659.0 | (36.0) | 4.0 | 15,112.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Replace 99032 | (17.0) | 0.0 | 0.0 | 0.0 | 0.0 | (17.0) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Replace Wood Poles with Steel Poles | 5,663.0 | 3,429.0 | 120.0 | 17.0 | 0.0 | 9,229.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Sub-Total | **38,597.0** | **121,382.0** | **198,081.0** | **129,161.0** | **46,932.0** | **534,153.0** | **15,943.0** | **17,700.0** | **18,250.1** | **15,600.2** | **11,950.0** | **11,500.0** | **75,000.3** |
| **Electric Substations** | | | | | | | | | | | | | |
| **Reliability** | | | | | | | | | | | | | |
| Area Substation Reliability And Auto Ground Circuit Switchers | 7,959.0 | 5,321.0 | 6,346.0 | 8,514.0 | 6,665.0 | 34,805.0 | 12,000.0 | 11,222.0 | 11,366.4 | 11,345.5 | 11,427.0 | 11,500.0 | 56,860.9 |
| Breaker - Capital Upgrade Program | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5,178.0 | 9,500.0 | 9,500.0 | 9,500.0 | 9,500.0 | 43,178.0 |
| Buchanan: Make Y94 Wood Pole Bypass Permanent | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 390.0 | 0.0 | 3,500.0 | 0.0 | 0.0 | 0.0 | 3,500.0 |
| Category Alarms | 0.0 | 479.0 | 904.0 | 1,256.0 | 1,360.0 | 3,999.0 | 1,300.0 | 1,500.0 | 1,499.9 | 1,500.0 | 1,500.0 | 1,500.0 | 7,499.9 |
| CIP - Security Upgrades | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,000.0 | 1,000.0 | 1,000.1 | 0.0 | 0.0 | 3,000.1 |
| Circuit Switcher Replacement Program | 0.0 | 367.0 | 470.0 | 0.0 | 0.0 | 837.0 | 0.0 | 0.0 | 1,000.0 | 1,000.0 | 1,099.9 | 0.0 | 3,099.9 |
| Condition Based Monitoring Equipment | 137.0 | 516.0 | 493.0 | 1,605.0 | 968.0 | 3,719.0 | 200.0 | 250.0 | 250.1 | 250.0 | 300.1 | 300.0 | 1,350.2 |
| Control Cable Upgrade Program | 0.0 | 1,074.0 | (236.0) | 0.0 | 230.0 | 1,068.0 | 1,085.0 | 0.0 | 1,000.0 | 1,000.0 | 1,100.0 | 1,100.0 | 4,200.0 |
| Stabilization of Pothead Stand Supports | 0.0 | 46.0 | 2.0 | 684.0 | 2.0 | 734.0 | 1,000.0 | 1,000.0 | 1,000.0 | 1,000.0 | 1,100.0 | 1,100.0 | 5,200.0 |
| Dc System Upgrade Program | 1,557.0 | 2,336.0 | 1,790.0 | 1,911.0 | 1,181.0 | 8,775.0 | 1,000.0 | 3,206.3 | 3,788.6 | 3,782.1 | 3,265.0 | 3,300.0 | 17,342.0 |
| Disconnect Swtich Program | 3,680.0 | 6,378.0 | 3,700.0 | 2,194.0 | 1,945.0 | 17,897.0 | 2,500.0 | 3,000.0 | 3,000.0 | 2,999.9 | 3,300.0 | 3,300.0 | 15,599.9 |
| Disturbance Monitoring Equipment - 138kv | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4,999.5 | 5,000.0 | 6,000.1 | 7,000.1 | 22,999.7 |
| Disturbance Monitoring Equipment - 345kv | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,500.0 | 8,599.9 | 8,800.0 | 8,799.9 | 0.0 | 0.0 | 26,199.8 |
| East River: Station Upgrade | 5,275.0 | 3,394.0 | 3,854.0 | 6,183.0 | 4,038.0 | 22,744.0 | 4,863.0 | 6,000.0 | 5,000.0 | 6,000.0 | 0.0 | 0.0 | 17,000.0 |
| Elmsford: Install New Substation | 8,112.0 | (5,973.0) | 12,756.0 | 26,250.0 | 27,797.0 | 68,942.0 | 3,000.0 | 1,000.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,000.0 |
| Fire Suppression (Also See Fire Protection Under Other Esu 17) | | | 2,299.0 | 4,228.0 | 8,781.0 | 15,308.0 | 8,000.0 | 8,016.0 | 7,036.0 | 5,401.9 | 6,529.9 | 7,000.0 | 33,983.8 |
| High Voltage Test Sets | 0.0 | 1,541.0 | 6,345.0 | 1,945.0 | 3,273.0 | 13,104.0 | 2,000.0 | 4,999.9 | 5,000.0 | 5,000.0 | 5,000.0 | 4,999.9 | 24,999.8 |
| Reinforced Ground Grid | 310.0 | 719.0 | 487.0 | 1,614.0 | 901.0 | 4,031.0 | 600.0 | 800.0 | 1,600.0 | 1,600.0 | 1,749.9 | 1,749.9 | 7,499.8 |
| Relay House Enclosures | 0.0 | 31.0 | 1,466.0 | 0.0 | 0.0 | 1,497.0 | 342.0 | 0.0 | 1,095.9 | 1,097.1 | 1,088.0 | 1,100.0 | 4,381.0 |
| Relay Modifications Program | 3,724.0 | 4,432.0 | 4,377.0 | 5,859.0 | 9,735.0 | 28,127.0 | 6,500.0 | 8,549.9 | 8,659.9 | 8,644.0 | 8,706.0 | 8,800.0 | 43,359.8 |
| Relay Protection Sytem Redundancy - Single Point Of Failure | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5,000.0 | 5,000.0 | 5,000.0 | 4,999.9 | 19,999.9 |
| Replace/Retrofit Overdutied 13/27kv Circuit Breakers | 0.0 | 11,076.0 | 15,803.0 | 10,488.0 | 9,866.0 | 47,233.0 | 5,000.0 | 10,278.0 | 11,300.7 | 10,500.5 | 10,000.0 | 10,000.0 | 52,079.2 |

| *Electric T&D Reliability* | Year Total | | | | | | Year Total | Year Total | | | | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| | Previous 5 Year Actual | | | | | | Forecast | Current 5 Year Budget | | | | | |
| | | | | | | | 2012 Forecast | Working | | | | | |
| | Total Dollars ($000) | | | | | | Total Dollars ($000) | Total Dollars ($000) | | | | | |
| | FY07 | FY08 | FY09 | FY10 | FY11 | 5 Yr. Total | FY12 | FY13 | FY14 | FY15 | FY16 | FY17 | 5 Yr. Total |
| Roof Replacement Program | 759.0 | 1,172.0 | 641.0 | 2,701.0 | 1,229.0 | 6,502.0 | 2,000.0 | 3,000.0 | 3,000.0 | 2,999.9 | 3,300.0 | 3,300.0 | 15,599.9 |
| Security Enhancements (Includes Other) | 11.0 | 3,557.0 | 1,297.0 | 3,199.0 | 3,620.0 | 11,684.0 | 7,000.0 | 9,084.6 | 6,495.1 | 6,699.3 | 4,353.0 | 4,999.9 | 31,631.9 |
| Small Capital Equipment Program | 3,260.0 | 2,486.0 | 5,177.0 | 2,796.0 | 3,127.0 | 16,846.0 | 5,000.0 | 3,000.2 | 3,000.1 | 3,000.1 | 4,000.0 | 3,999.9 | 17,000.3 |
| Switchgear Enclosure Upgrade | 0.0 | 19.0 | 86.0 | 123.0 | 794.0 | 1,022.0 | 600.0 | 0.0 | 1,000.0 | 1,000.0 | 1,100.0 | 1,100.0 | 4,200.0 |
| Transformer Replacement Program | 0.0 | 24,932.0 | 10,953.0 | 13,293.0 | 21,117.0 | 70,295.0 | 12,500.0 | 20,650.5 | 25,862.9 | 25,417.1 | 25,336.2 | 25,118.2 | 122,384.9 |
| 138kv Circuit Breaker Upgrade Program | 5,279.0 | 8,936.0 | 14,275.0 | 7,551.0 | 6,747.0 | 42,788.0 | 3,500.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 345kv Circuit Breaker Capital Upgrade Program | 10,309.0 | 8,878.0 | 6,837.0 | 2,007.0 | 1,743.0 | 29,774.0 | 1,500.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Additional G&T Devices | 408.0 | | | | | 408.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Analog To Digital Upgrade | 0.0 | 1,615.0 | 2,776.0 | 1,137.0 | 684.0 | 6,212.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Audiotone Replacement Program | 195.0 | | | | | 195.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Cancelled Projects - Reliability | | | (10.0) | (44.0) | (19.0) | (73.0) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Capacitor Cable Upgrade Program | 1,246.0 | 1,295.0 | 1,886.0 | 717.0 | | 5,144.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Carryover - Reliability | 5,191.0 | 3,130.0 | 631.0 | 1,904.0 | 785.0 | 11,641.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Completed Projects - Reliability | 5.0 | 632.0 | (4,492.0) | 132.0 | 723.0 | (3,000.0) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Corona: New 138kv Breakers (6s And 8x) | | | 4,350.0 | 1,298.0 | | 5,648.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Diesel Upgrade | 0.0 | 202.0 | 472.0 | | | 674.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| East 179th Street: Bus Section Upgrade | | | | 600.0 | 155.0 | 755.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| East 36th St: Install Feeder Position | 375.0 | | | | | 375.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| East 63rd Street: Station Upgrade | 0.0 | 0.0 | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Enhanced Reliability (Installation Of Test Systems) | 40.0 | | | | | 40.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Fire Protection Program | 4,481.0 | 131.0 | 192.0 | | | 4,804.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Fresh Kills - Upgrade 13kv L&P Transformer | (1.0) | 0.0 | | | | (1.0) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| GIC Monitoring | | | | | | | 750.0 | | | | | | |
| G&T Devices | 0.0 | 190.0 | 159.0 | | 0.0 | 349.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hudson Avenue: L&P Transformers | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,000.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Install Underfrequency Relays | 2,682.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,682.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Jamaica - Install 138kv Breakers 7 & 8 And Third Cap Bank | 5,549.0 | 2,971.0 | 0.0 | 0.0 | 0.0 | 8,520.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Rapid Restore Enhancements (Also See Under Other In Later Years) | 316.0 | | | | | 316.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Reduce Fault Clearing Time Program | 5,201.0 | 2,041.0 | | | | 7,242.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Retrofit Overdutied 13kv Circuit Breakers | 3,849.0 | | | | | 3,849.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Retrofit Overdutied 27kv Circuit Breakers | 5,634.0 | | | | | 5,634.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Revenue Metering Upgrade | 77.0 | 35.0 | 96.0 | 48.0 | | 256.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Storm Hardening | | | | | | | | 30,000.0 | 60,000.0 | 70,000.0 | 80,000.0 | | |
| Sikap Equipment | | | | 2,940.0 | | 2,940.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Substation Automation (Target Information System) | 0.0 | 1,224.0 | 2,786.0 | | | 4,010.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Substation Control Room Betterment Program | 628.0 | | | | | 628.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Substation Loss Contingency | 0.0 | 182.0 | 323.0 | 457.0 | 153.0 | 1,115.0 | | | | | | | 0.0 |
| Transformer Replacement Program - Cherry Street | 4,703.0 | | | | | 4,703.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Transformer Replacement Program - West 19th Street | 8,036.0 | | | | | 8,036.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Underfrequency Load Shedding Relays | 0.0 | 242.0 | | | | 242.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Upgrade Analog Circuits To Digital Fiber | 1,837.0 | | | | | 1,837.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| White Plains - Substation Continuance | | | 580.0 | | | 580.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Sub-Total | 100,824.0 | 95,607.0 | 109,871.0 | 113,590.0 | 117,600.0 | 537,492.0 | 87,130.0 | 140,335.3 | 194,755.1 | 199,537.4 | 194,755.1 | 115,767.8 | 605,150.7 |
| **Electric Distribution** | | | | | | | | | | | | | |
| **Reliability** | | | | | | | | | | | | | |
| #4,#6 Self Supporting Wire | 1,206.5 | 1,921.2 | 2,336.6 | 594.1 | 660.8 | 6,719.3 | 1,539.0 | 2,655.0 | 1,400.0 | 1,297.0 | 1,256.0 | 1,252.0 | 7,860.0 |
| 4 kV UG Reliability | 59.0 | 745.0 | 1,226.8 | 23.5 | 1,491.5 | 3,545.8 | 1,008.0 | 2,278.0 | 2,000.0 | 1,853.0 | 1,795.0 | 1,788.0 | 9,714.0 |
| Aerial Cable Replacement | 43.9 | 538.9 | 1,411.9 | 1,401.1 | 282.8 | 3,678.6 | 100.0 | 1,243.0 | 1,100.0 | 1,019.0 | 987.0 | 983.0 | 5,332.0 |
| ATS Installation USS Reliability XW | | 150.0 | 1,106.0 | 484.0 | 891.3 | 2,631.3 | 183.0 | 208.0 | 200.0 | 185.0 | 180.0 | 179.0 | 952.0 |
| Autoloop Reliability (27kV Inc'l.) | 880.3 | 4,446.5 | 4,230.0 | 4,068.6 | 3,781.3 | 17,406.7 | 700.0 | 3,738.0 | 3,500.0 | 3,242.0 | 3,141.0 | 3,129.0 | 16,750.0 |
| Automated Emergency Ties | | | 0.0 | 0.0 | | 0.0 | 0.0 | 728.0 | 700.0 | 648.0 | 0.0 | 0.0 | 2,076.0 |

| Electric T&D Reliability | Year Total<br>Previous 5 Year Actual<br><br>Total Dollars ($000) | | | | | | Year Total<br>Forecast<br>2012 Forecast<br>Total Dollars ($000) | Year Total<br>Current 5 Year Budget<br>Working<br>Total Dollars ($000) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | FY07 | FY08 | FY09 | FY10 | FY11 | 5 Yr. Total | FY12 | FY13 | FY14 | FY15 | FY16 | FY17 | 5 Yr. Total |
| Grounding transformers | 241.1 | 60.4 | 521.4 | 1,090.7 | 195.5 | 2,109.1 | 464.0 | 624.0 | 600.0 | 556.0 | 539.0 | 536.0 | 2,855.0 |
| HiPot | 4,220.9 | 3,549.3 | 2,593.9 | 3,142.5 | 3,297.7 | 16,804.3 | 4,442.0 | 2,078.0 | 2,000.0 | 1,852.0 | 1,796.0 | 1,788.0 | 9,514.0 |
| Modernization and Other | 669.0 | 3,564.0 | 5,518.1 | 2,907.2 | 1,835.1 | 14,493.4 | 3,742.0 | 3,300.0 | 3,500.0 | 3,500.0 | 3,500.0 | 3,500.0 | 17,300.0 |
| Network Reliability | | 4,963.5 | 14,230.2 | 12,388.5 | 25,388.8 | 56,971.0 | 16,000.0 | 14,320.0 | 20,513.0 | 15,043.0 | 14,575.0 | 14,518.6 | 78,969.6 |
| Osmose (C Truss) | 971.6 | 1,443.1 | 1,325.5 | 1,057.9 | 1,401.6 | 6,199.7 | 865.0 | 1,779.0 | 1,700.0 | 1,552.0 | 1,495.0 | 1,488.0 | 8,014.0 |
| Overhead Conductor Clearance | | | 0.0 | 399.0 | 151.0 | 550.0 | 60.0 | 620.0 | 500.0 | 463.0 | 0.0 | 0.0 | 1,583.0 |
| Overhead Feeder Reliability/VRS Replacement | | 19.0 | 3.0 | 1.0 | 3,463.1 | 3,486.1 | 2,000.0 | 2,759.0 | 1,500.0 | 463.0 | 449.0 | 447.0 | 5,618.0 |
| Overhead Feeder Sectionalizing Program | | | | | 117.3 | 117.3 | 41.0 | 1,679.0 | 1,600.0 | 1,453.0 | 1,395.0 | 1,388.0 | 7,515.0 |
| Overhead Secondary Reliability Program | 0.0 | | 0.0 | 19.0 | 244.5 | 263.4 | 119.0 | 208.0 | 199.0 | 186.0 | 179.0 | 179.0 | 951.0 |
| PILC | 19,742.6 | 32,376.3 | 21,961.4 | 17,168.4 | 18,032.9 | 109,281.5 | 14,000.0 | 20,786.0 | 17,000.0 | 16,674.0 | 16,156.0 | 16,092.0 | 86,708.0 |
| Pressure, Temperature and Oil Sensors | | | | | 704.2 | 704.2 | 624.0 | 3,118.0 | 3,000.0 | 2,780.0 | 2,693.0 | 2,682.0 | 14,273.0 |
| Remote Monitoring System 3rd Generation | 15,099.3 | 15,274.7 | 13,302.2 | 7,905.4 | 2,656.9 | 54,238.6 | 2,500.0 | 3,118.0 | 1,500.0 | 1,390.0 | 1,346.0 | 1,341.0 | 8,695.0 |
| Shunt reactors | 404.2 | 140.6 | 917.1 | 1,760.3 | 1,080.2 | 4,302.5 | 1,540.0 | 1,767.0 | 1,700.0 | 1,575.0 | 1,526.0 | 1,520.0 | 8,088.0 |
| Street Lights Service Reliability Program | | 2,515.8 | 5,310.8 | 5,224.1 | 2,478.0 | 15,528.7 | 500.0 | 500.0 | 500.0 | 500.0 | 500.0 | 500.0 | 2,500.0 |
| Storm Hardening | | | | | | | | 30,000.0 | 80,000.0 | 170,000.0 | 171,000.0 | 130,000.0 | 581,000.0 |
| Targeted Primary DBC Replacement | 2,468.0 | 2,409.0 | 310.0 | 991.9 | 1,280.1 | 7,459.0 | 632.0 | 520.0 | 500.0 | 463.0 | 449.0 | 447.0 | 2,379.0 |
| Transformer Vault Modernization | | | | | | 0.0 | 4,500.0 | 6,500.0 | 5,000.0 | 5,000.0 | 5,000.0 | 5,000.0 | 26,500.0 |
| UG Sectionalizing Switches | 2,056.9 | 1,662.2 | 2,501.7 | 991.4 | 852.5 | 8,064.8 | 695.0 | 2,111.0 | 2,993.0 | 2,773.0 | 2,687.0 | 2,676.0 | 13,240.0 |
| Underground Secondary Reliability Program | 42,534.4 | 33,614.0 | 27,593.5 | 40,047.6 | 42,480.8 | 186,270.4 | 38,000.0 | 32,538.0 | 36,200.0 | 32,679.0 | 31,498.0 | 31,266.0 | 164,181.0 |
| Vented Service Box Covers | 757.0 | 6,306.9 | 11,033.0 | 7,280.4 | 8,409.1 | 33,786.4 | 6,000.0 | 6,700.0 | 11,700.0 | 11,700.0 | 11,700.0 | 11,000.0 | 52,800.0 |
| 4 kV Feeder Sectionalizing/ Add'l Kyle | | 102.0 | 596.0 | 374.0 | | 1,072.0 | | | | | | | 0.0 |
| 4 kV Substations - Reliability | 276.7 | 121.9 | 238.1 | 0.0 | 161.7 | 798.4 | | | | | | | 0.0 |
| Additional 13 kV Feeder Sectionalizing | | 125.0 | 1,224.0 | 465.0 | | 1,814.0 | 100.0 | | | | | | 0.0 |
| Coastal Storm Risk Mitigation | 21.0 | 73.5 | 112.0 | 39.0 | 1.2 | 246.6 | | | | | | | 0.0 |
| ESCO Switch Replacement | 497.3 | 3,089.9 | 2,230.6 | 63.4 | 1.0 | 5,882.3 | | | | | | | 0.0 |
| Known Point Splice | 907.0 | 0.0 | 89.0 | 0.0 | | 996.0 | | | | | | | 0.0 |
| Network Transformer Replacements >100% <115% | (19.0) | 1,022.0 | | | | 1,003.0 | | | | | | | 0.0 |
| Network transformer replacements >115% <125% | 21,818.8 | 18,626.8 | | | | 40,445.6 | | | | | | | 0.0 |
| Other reliability | 548.0 | | (34.2) | 1,606.0 | 1,517.2 | 3,636.9 | 1,900.0 | | | | | | 0.0 |
| Rear-Lot Pole Elimination | | 632.9 | 524.6 | 585.1 | 835.7 | 2,578.4 | | | | | | | 0.0 |
| Vented Manhole Cover | 3,080.5 | 6,604.8 | 4,210.4 | 303.8 | (0.6) | 14,198.9 | | | | | | | 0.0 |
| Sub-Total | 118,485.1 | 146,099.1 | 126,623.8 | 112,382.9 | 123,693.0 | 627,284.1 | 102,254.0 | 145,875.0 | 201,105.0 | 278,846.0 | 275,842.0 | 233,699.6 | 1,135,367.6 |
| TOTAL ELECTRIC<br>Total Reliability | 257,906.1 | 363,088.1 | 434,575.8 | 355,133.9 | 288,225.0 | 1,698,929.1 | 205,327.0 | 303,910.3 | 414,110.2 | 493,983.6 | 482,547.1 | 360,967.4 | 1,815,518.6 |

**Infrastructure Investment Panel**
**O&M Program Changes**
**Reliability**
**($000)**

| | RY1 Program Change | RY2 Program Change | RY3 Program Change |
|---|---|---|---|
| **Substation Operations** | | | |
| Relay Trip Checks and Calibrations | $1,151 | $1,151 | $1,151 |
| CIP V5 | $0 | $685 | $685 |
| **Total Substation Operations** | **$1,151** | **$1,836** | **$1,836** |
| | | | |
| **Central Engineering** | | | |
| CIP V5 | $610 | $560 | $560 |
| **Total Central Engineering** | **$610** | **$560** | **$560** |
| | | | |
| **System and Transmission Operations** | | | |
| Telecommunications | $469 | $505 | $537 |
| District Operations Position | $120 | $120 | $120 |
| System Analyst (Watch Engineer) | $100 | $100 | $100 |
| Human Performance Coordinator | $100 | $100 | $100 |
| Transmission Operator (TOP) Position | $100 | $100 | $100 |
| CIP Position - Engineer (NEW) | $100 | $100 | $100 |
| NERC Standards and Compliance Staffing | $100 | $100 | $100 |
| **Total System and Transmission Operations** | **$1,089** | **$1,125** | **$1,157** |
| | | | |
| **Electric Operations** | | | |
| Transformer (Inspections & Repairs) | -$12,755 | $4,756 | $1,949 |
| Engineering & Other Services | $1,343 | $1,493 | $952 |
| Structure (Inspections & Repairs) | $26,665 | -$27,649 | $906 |
| Tree Trimming | -$1,456 | $2,300 | $0 |
| Field Ops/Unit SS/Other O&M | -$925 | $1,289 | $192 |
| **Total Electric Operations** | **$12,872** | **-$17,811** | **$3,999** |
| | | | |
| **Grand Total** | **$15,722** | **-$14,290** | **$7,552** |

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | ECC UPS Unit 2 and 3 Battery Replacement |
| **Project Number** | |
| **Work Plan Category** | Oper - Emergency Response |
| **Priority** | |
| **Project Manager** | Anderson, Michael |
| **Project Engineer** | Rawczak, Eugene |
| **Budget Reference** | |
| **Project Status** | Not Started |
| **End Date** | Apr 1 2013 |
| **ERM Addressed** | Oper Risk 20 West End Ave. ECC Loss,Admin Risk 34 Unsupported Computer Systems |

**Work Description:**

The batteries that are used at the Energy Control Center to provide protection and uninterrupted transfer of load to the diesel generators by the three 100kva UPS systems will be replaced. This project will replace the battery systems associated with UPS #2 and UPS #3

**Justification:**

The critical systems at the Energy Control Center are protected by three 100kva UPS systems. The critical systems require large battery support to provide protection and to allow uninterrupted transfer of load to the back-up diesel generators. The batteries for UPS1, UPS2 and UPS3 were delivered in 1998, and placed into service in 2001 for UPS1 and 1998 for UPS2 and 3. The batteries are isolated in three different rooms for protection and separation. This project will replace the battery systems for UPS #2 and UPS #3 based on test results and age. The batteries will be replaced one room at a time with critical load transferred to another UPS during replacement to ensure continued operation of the critical computer systems. The batteries for UPS #1 will be scheduled for replacement in 2016 under a separate project.

* Alternatives:
* Risk of No Action: The UPS system will not provide support during power outages or emergency diesel tests. Without battery support computer equipment would shutdown during any type of loss of power, interrupting operability and potentially corrupting data files.
* Non Financial Benefit Explanation:
* Technical Evaluation and Analysis:
* Project Relationships:

**Current Status:** Project scope submitted to Engineering via ESR2013, 3/18/2011

**Current Working Estimate:**

**Funding: ($000s)**

| Funding Cost | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | $500 | $200 | $0 | $0 | $0 | $0 | $0 | $0 | $700 |

**Benefit: ($000s)**

* **2008 to 2012 Budget in Thousands-** $500
* **2013 to 2017 Budget in Thousands-** $200
* **Authorization-**
* **Appropriation-**

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | ECC UPS Unit 1 Battery Replacement |
| **Project Number** | |
| **Work Plan Category** | Oper - Emergency Response |
| **Priority** | |
| **Project Manager** | Anderson, Michael |
| **Project Engineer** | Rawczak, Eugene |
| **Budget Reference** | |
| **Project Status** | Not Started |
| **End Date** | Dec 30 2016 |
| **ERM Addressed** | Oper Risk 20 West End Ave. ECC Loss,Admin Risk 34 Unsupported Computer Systems |

**Work Description:**

The batteries that are used at the Energy Control Center to provide protection and uninterrupted transfer of load to the diesel generators by the three 100kva UPS systems will be replaced. This project will replace the battery system associated with UPS #1. The batteries associated with UPS #2 and UPS #3 are scheduled to be replaced in 2013.

**Justification:**

The critical systems at the Energy Control Center are protected by three 100kva UPS systems. The critical systems require large battery support to provide protection and to allow uninterrupted transfer of load to the back-up diesel generators. This project will replace the battery system for UPS #1. The batteries will be replaced with critical load transferred to another UPS during replacement to ensure continued operation of the critical computer systems. The batteries for UPS #1 were placed into service in 2001, and were not replaced in 2013 along with UPS #2 and #3 because of their age at that time.

* Alternatives:
* Risk of No Action: The UPS system will not provide support during power outages or emergency diesel tests. Without battery support computer equipment would shutdown during any type of loss of power, interrupting operability and potentially corrupting data files.
* Non Financial Benefit Explanation:
* Technical Evaluation and Analysis:
* Project Relationships:

**Current Status:**

**Current Working Estimate:**

**Funding: ($000s)**

| **Funding Cost** | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | $250 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $250 |

**Benefit: ($000s)**

* **2008 to 2012 Budget in Thousands-** $0
* **2013 to 2017 Budget in Thousands-** $250
* **Authorization-**
* **Appropriation-**

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | ECC and AECC Facility Security Enhancements |
| **Project Number** | |
| **Work Plan Category** | Reg - Agency Mandated |
| **Priority** | |
| **Project Manager** | Gross, Scott |
| **Project Engineer** | |
| **Budget Reference** | 7ET9704 |
| **Project Status** | Ongoing Program |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 20 West End Ave. ECC Loss |

**Work Description:**

This project will add, as required, new and improved physical security systems to the Energy Control Center and Alternate Energy Control Center. This will include items such as card access, security cameras, biometrics or automated applications to monitor security.

**Justification:**

The control centers provide an essential service, each having full remote control capability of the electric and steam systems. Physical security systems must be maintained and levels that provide proper access control and allow for both local and remote monitoring. In addition, NERC (The North American Reliability Council) policies require specific levels of physical security for critical cyber locations, which this project will address as necessary.

* Alternatives:
* Risk of No Action:
* Non Financial Benefit Explanation:
* Technical Evaluation and Analysis:
* Project Relationships:

**Current Status:**

**Current Working Estimate:**

**Funding: ($000s)**

| Funding Cost | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $0 | $0 | $0 | $268 | $16 | $100 | $0 | $0 | $250 | $600 | $200 | $0 | $200 | $1,634 |

**Benefit: ($000s)**

| | | |
|---|---|---|
| * | **2008 to 2012 Budget in Thousands-** | $384 |
| * | **2013 to 2017 Budget in Thousands-** | $1,050 |
| * | **Authorization-** | $600,000 |
| * | **Appropriation-** | $600,000 |

## 2012 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Emergent Transmission Reliability |
| **Project Number** | Various |
| **Work Plan Category** | Oper - System Capacity |
| **Priority** | |
| **Project Manager** | Bauer, Mark |
| **Project Engineer** | |
| **Budget Reference** | 8ET0500 |
| **Project Status** | Ongoing Program |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 16 Southern Milwood Transmission Loss |

**Work Description:**

The Emergent Transmission Reliability program provides funding for non-forecasted projects that emerge and must be performed expeditiously in order to maintain system reliability or reduce environmental risks through project work of relatively limited scope and duration.

To exemplify the importance and flexibility of this program, in the second quarter of 2011, 345 kV pipe-type transmission Feeder M51 failed at manhole M61736 on Broadway & 144th St in Manhattan. The failed semistop joint was subsequently opened, inspected, and replaced. The cause of failure was determined to be cable movement in a downhill direction toward the semistop feature causing the outer jacket insulation of the splice joint to contact the semistop plate and disturb the shielding and insulating tapes. As a result of this failure, another semistop joint on Feeder M51 located in manhole M10349 at Palmer Road & Gramercy Ave in Yonkers was selected for X-ray inspection based on a similar elevation condition as the failed joint. In March 2012, the joint in M10349 was proactively opened and inspected due to irregularities noted in the digital x-rays taken on the joint. Visual inspection of the joint revealed significant cable movement toward the semistop feature and similar cable damage to the joint that previously failed in Manhattan. The damaged joint was removed and replaced with an insert of cable and two new splice joints. The feeder was returned to service in April 2012, well ahead of the critical summer load period with repairs funded through the Emergent Transmission Reliability Program. Going forward, Engineering will continue to utilize various methods (including x-rays) to proactively inspect and address semistop joints and other reliability issues as they emerge on the transmission system.

Previously identified emergent projects associated under this program are currently funded and scheduled to be completed during the 2013 through 2014. However, more urgent, previously unidentified projects requiring immediate attention may emerge and temporally displace identified projects. Details of these previously identified projects are provided below.

• Feeder 38B11T is a short pipe-type high pressure feeder between Bensonhurst Substation Transformers No.1 and No.9. The feeder pipes containing the cable are partly copper and partly stainless steel. The transition couplings joining the copper to the stainless steel pipes have been the source of historical leaks. Mechanical clamps installed over the couplings to stop the leaks are now leaking as well, despite attempts to re-tighten them. The transition couplings will be replaced (requiring removal and replacement of the cable and cable terminations) to eliminate the environmental and reliability risks associated with the ongoing leak issues. The work associated with feeder 38B11T is outage dependant; materials are on hand and the work is currently scheduled for 2013. This work was originally planned for 2012, but had to be deferred due to outage scheduling conflicts that developed in the fall of that year.

• Install new support clamps for porcelain insulators on pressure switch assemblies at pothead stands. High-pressure fluid filled feeders are equipped with Barksdale switches which monitor pothead pressures. Most of the switches are connected using unsupported ceramic insulators that are susceptible to breaking due to excessive mechanical forces caused by either fault currents or by being accidentally hit during maintenance work. The investigation of the fire and subsequent failure of B phase pothead on feeder B47 concluded that mechanical forces were exerted on the Barksdale alarm manifold connecting piping and accessories by magnetic field induced by the fault currents associated with the failure of feeder G13 at Astoria. The underlying cause of the start of the fire was a break in the insulator with coincident ignition of the release of dielectric fluid due to arcing. The solution that is recommended to resolve this problem for a select group of feeders is to install a clamp across the insulator that would support the insulator when and if mechanical or magnetic forces are exerted against it. This work is expected to be completed in 2014.

• Buried sections of pipe type cables are cathodically protected to prevent corrosion that can result is dielectric fluid leaks. Cathodic protection systems are comprised of a rectifier that applies DC current to the pipe surface, a protective coating to minimize the required current and Isolating Surge Protectors (ISP) to afford DC isolation between the pipe and substation ground mats. As the coating deteriorates over time and its resistance decreases, the amount of current required for effective cathodic protection needs to increase often by the replacement of existing rectifiers or the installation of new ones. The Gas Corrosion Group performs an annual survey on the underground high-pressure pipe-type cable system to determine if system deterioration of the pipe coating has occurred and will evaluate and make recommendations if additional cathodic protection is required. Based upon recent survey data, additional rectifiers are proposed to be installed on Feeders M51/M52 cooling loop.

• Pressurized fluid (“BICC-type”) reservoirs used to supply emergency dielectric fluid to HPFF terminations have been installed on various critical feeders. The BICC systems operate in the event of failure of the pressurizing plants to supply sufficient operating pressure and provide additional time for emergency switching to de-energize the feeder and prevent the catastrophic failure of the terminations. Presently BICC systems are installed on select 345 kV feeders with major elevation differences between terminals. A program has been developed to install BICC systems on the terminations of additional critical or sensitive feeders. The installation of the BICC reservoirs is currently ongoing; long lead time materials have been ordered and outages windows are being evaluated as system conditions allow to facilitate installation of the systems.

• Upgrade of obsolete fluid reservoirs with new pre-pressurized reservoirs and associated equipment for select low pressure fluid filled feeders is now planned for various substations, including East River, Eastview, and Bruckner Substations. The current reservoir systems have deteriorated, are prone to leaks, and are obsolete, so they can no longer be replaced in kind. The upgrade of the fluid reservoirs is currently ongoing; long lead time materials have been ordered and outages windows are being evaluated as system conditions allow to facilitate installation of the systems.

**Justification:**

This project is initiated to address emerging issues that affect the reliability of the transmission system.

* Alternatives:
* Risk of No Action:
* Non Financial Benefit Explanation:
* Technical Evaluation and Analysis:
* Project Relationships:

**Current Status:** Planning and Engineering.

**Current Working Estimate:**

**Funding: ($000s)**

| **Funding Cost** | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $54 | $0 | $1,790 | $3,973 | $8,357 | $8,321 | $11,000 | $10,000 | $9,500 | $9,500 | $9,500 | $9,500 | $81,495 |

**Benefit: ($000s)**

* **2008 to 2012 Budget in Thousands-** $33,441
* **2013 to 2017 Budget in Thousands-** $48,000
* **Authorization-**
* **Appropriation-**

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | L-Line Towers Between Pleasant Valley SS and Connecticut Border |
| **Project Number** | |
| **Work Plan Category** | |
| **Priority** | |
| **Project Manager** | Mark Davis |
| **Project Engineer** | Peter Chan |
| **Budget Reference** | |
| **Project Status** | Ongoing Program |
| **End Date** | Dec 31 2014 |
| **ERM Addressed** | |

**Work Description:**

This program involves the reinforcement of the in-line and dead end assemblies on the overhead 138kV feeder 398 on the L-Line between Pleasant Valley Substation and the Connecticut Border.
Units per Year: Various
Mandatory: No. This discretionary program proactively addresses aging infrastructure, reduces risk of additional connector failures, and increases system reliability.
High-level schedule: 2013 Material Ordering; 2013 and 2014 - complete construction on Feeder 398 based upon outage availability. All work is feeder outage dependent.

**Justification:**

Feeder 398 consists of single-wire bundle 2156 MCM ACSR (aluminum conductor steel reinforced). 345kV feeder 398 which is are approximately 17.8 miles in length, was originally built in 1964. Significant problems with compression fittings have surfaced on feeder 398. Thermographic inspection has detected dead end fittings operating at high temperatures. Subsequent testing at The National Electric Energy Testing, Research and Applications Center (NEETRAC) indicated that the fittings were either at end-of-life or could reasonably be expected to be at or near end-of-life in the near future. The NEETRAC report also indicated that the conductor does not meet minimum ASTM requirements, possibly as a result of a manufacturer defect. The conductor's aluminum strands show that annealing has occurred which is an indication of a history of thermal overloads on the line. Studies conducted in 1994 on line 398 also suggest that the splices should be reinforced / replaced.

* Alternatives: One alternative was to replace only the splices on the line. Financial analysis determined that it was cost effective to replace the splices, conductor and hardware between the two substations. This would significantly increase reliability.

* Risk of No Action: Additional hot spots, outages and reduced system reliability.

* Non Financial Benefit Explanation: There are two non-financial benefits associated with this program:

  1. This work increases employee safety since the reinforced tower components have less risk of failure when line constructors conduct routine and emergency tower maintenance work.
  2. This work increases system reliability since aging components are being replaced with new ones and this reduced feeder failures.

* Technical Evaluation and Analysis: Since the replacement of the defective components in 2006, annual thermographic and visual inspections of the transmission lines have not identified any additional deficiencies or abnormalities. Therefore, this project will be deferred with material procurement scheduled for 2010 and construction in years 2013 and 2014. As a proactive measure, to ensure the continued reliability of the feeders, additional thermographic and visual inspections will be performed during the year.

  Procurement and storage of materials in 2010 will ensure that we could rapidly implement a repair or replacement effort should the need arise.

* Project Relationships:

**Current Status:**

**Current Working Estimate:**

**Funding: ($000s)**

| **Funding Cost** | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | $2,900 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,900 |

**Benefit: ($000s)**

* **2008 to 2012 Budget in Thousands-** $0
* **2013 to 2017 Budget in Thousands-** $2,900
* **Authorization-**
* **Appropriation-**

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Upgrade Overhead 345kv Transmission Structures |
| **Project Number** | 21598-05 |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | |
| **Project Manager** | Davis, Mark |
| **Project Engineer** | Shuman, Robert |
| **Budget Reference** | 7ET0800 |
| **Project Status** | Ongoing Program |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 16 Southern Milwood Transmission Loss |

**Work Description:**

This project provides for upgrades on specific 345 kV steel lattice towers selected based on engineering analysis that was concluded in 2010 and 2011 input from Transmission Planning and System Operations. Analysis was performed on a corridor-by-corridor basis with priority given to critical corridors as specified by System Operations. Reinforcement of these overhead towers shall increase structural capacity and system reliability. The first priority has been given to the approximately two mile corridor south of Millwood Substation consisting of six 345kV circuits. Reinforcement of this Six Circuit Corridor will complete in the last quarter of 2012. The next highest priority line to be upgraded is 138kV feeders 99941 and 99942 on the E-Line between Dunwoodie SS and Sprainbrook SS. This will involve the reinforcement of 11 towers.

This program will continue to identify potential failure scenarios that will be used to prioritize other work to be done in future years. Based on this evaluation, selective reinforcement of tower elements will be identified which can mitigate the possibility of tower failures or severe cascading events.

Units per Year: 10 - 40 structures
Mandatory: No. This discretionary program addresses the higher risk areas of the overhead transmission system.
High-level schedule: Complete six circuits south of Millwood in 2012; Upgrade next highest risk line in 2013 and continue upgrading towers on lines with higher risk assessments.

**Justification:**

This program is necessary since upgrading existing structures will reduce potential tower failures, thus reducing operating constraints and improving reliability. While Con Edison currently has eight single circuit guyed aluminum lattice structures available for emergency use following the loss of a tower or multiple towers, these may not be sufficient in a postulated extreme event where many double circuit structures could be damaged. Through selective reinforcement of towers, this project shall decrease the likelihood and impact of multiple failures resulting from cascading. Work on the six circuits south of Millwood is approaching completion. Engineering analysis for additional tower upgrades on other overhead lines is being scheduled and will commence before the end of 2013 with additional reinforcement work proceeding in ensuing years.

* Alternatives: The alternative is to not upgrade structures and accept the risk of potential cascading in the event of a tower failure.
* Risk of No Action:
* Non Financial Benefit Explanation: Non-financial benefits include employee safety, increased reliability, and increased security in the more vulnerable areas of the overhead transmission system.
* Technical Evaluation and Analysis: Structural analysis of the existing towers is currently on-going with consultants and company engineers.
* Project Relationships:

**Current Status:** The Six Circuit corridor portion of this Project is approaching completion. Additional reinforcement work on other overhead lines is being developed and will be implemented in 2012 and beyond based on System priorities.

**Current Working Estimate:**

**Funding: ($000s)**

| **Funding Cost** | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $0 | $0 | $0 | $568 | $1,759 | $2,500 | $2,700 | $1,500 | $2,000 | $2,000 | $2,000 | $2,000 | $17,027 |

**Benefit: ($000s)**

* **2008 to 2012 Budget in Thousands-** $7,527
* **2013 to 2017 Budget in Thousands-** $9,500
* **Authorization-**
* **Appropriation-** $9,380,000.

# 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Re-Conductor Dunwoodie - Sprain Brook Transmission Corridor |
| **Project Number** | 22592-07 |
| **Work Plan Category** | |
| **Priority** | |
| **Project Manager** | Davis, Mark |
| **Project Engineer** | Cocking, Orville |
| **Budget Reference** | 8ET9805 |
| **Project Status** | Not Started |
| **End Date** | Dec 31 2013 |
| **ERM Addressed** | Oper Risk 16 Southern Milwood Transmission Loss |

**Work Description:**

This program involves the replacement of the compression fittings on overhead 138kV feeders 99941 and 99942 on the E-Line between Dunwoodie and Sprain Brook substations.
Units per Year: Various
Mandatory: No. This discretionary program proactively addresses aging infrastructure, reduces risk of additional connector failures, and increases system reliability.
High-level schedule: 2012 Material Ordering; 2013 - complete construction on Feeder 99941 and 99942 based upon outage availability. All work is feeder outage dependent.

**Justification:**

Feeders 99941 and 99942 consist of single-wire bundle 2156 MCM ACSR (aluminum conductor steel reinforced). Each of the 138 kV feeders, which are approximately 1.5 miles in length, was originally built in 1956 with single-wire bundle 1033 kcmil 54/7 ACSR conductor and later rebuilt and reinforced in 1965 when the portion of the line between Sprain Brook and Dunwoodie (approximately 1.5 circuit miles) was upgraded to larger single-wire bundle 2156 kcmil 84/19 ACSR conductors. Significant problems with compression fittings have surfaced on feeders 99941 and 99942. Thermographic inspection detected three dead end fittings operating at high temperatures. The dead end fittings were replaced in 2006. Subsequent testing at The National Electric Energy Testing, Research and Applications Center (NEETRAC) indicated that the fittings were either at end-of-life or could reasonably be expected to be at or near end-of-life in the near future. The NEETRAC report also indicated that the conductor does not meet minimum ASTM requirements, possibly as a result of a manufacturer defect. The conductor’s aluminum strands show that annealing has occurred which is an indication of a history of thermal overloads on the line. Separate studies conducted in 1994 on line 398 also suggest that the splices should be reinforced / replaced. The splices on feeders

99941 and 99942 are similar to those on feeder 398.

* Alternatives: One alternative was to replace only the splices on the line. Financial analysis determined that it was cost effective to replace the splices, conductor and hardware between the two substations. This would significantly increase reliability.

* Risk of No Action: Additional hot spots, outages and reduced system reliability.

* Non Financial Benefit Explanation: There are two non-financial benefits associated with this program:

  1. This work increases employee safety since the reinforced tower components have less risk of failure when line constructors conduct routine and emergency tower maintenance work.
  2. This work increases system reliability since aging components are being replaced with new ones and this reduced feeder failures.

* Technical Evaluation and Analysis: Since the replacement of the defective components in 2006, annual thermographic and visual inspections of the transmission lines have not identified any additional deficiencies or abnormalities. Therefore, this project will be deferred with material procurement and construction scheduled for 2013. As a proactive measure, to ensure the continued reliability of the feeders, additional thermographic and visual inspections will be performed during the year.

* Project Relationships:

**Current Status:** This project was included in the 2008 Rate Case submittal and completion dates are feeder outage dependent.

**Current Working Estimate:**

**Funding: ($000s)**

| **Funding Cost** | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | $0 | $0 | $0 | $2,400 | $0 | $0 | $0 | $0 | $2,400 |

**Benefit: ($000s)**

* **2008 to 2012 Budget in Thousands-** $0
* **2013 to 2017 Budget in Thousands-** $2,400
* **Authorization-** $12,300,000
* **Appropriation-**

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Queensboro Bridge - Transmission Fdr Pipe Support |
| **Project Number** | 24042-10 |
| **Work Plan Category** | Oper - Critical Repair |
| **Priority** | |
| **Project Manager** | Mark Bauer |
| **Project Engineer** | Peter Chan |
| **Budget Reference** | 3ET0100 |
| **Project Status** | Not Started |
| **End Date** | Dec 31 2015 |
| **ERM Addressed** | |

**Work Description:**

Currently Consolidated Edison has six (6) 138kV solid dielectric feeders and six (6) 69kV nitrogen-filled feeders traversing the Queensboro Bridge. Based on visual inspections, several supports along all feeders are in need of replacement or re-alignment. To remediate this problem, an analysis of the existing system and installation of new supports are needed to ensure proper functionality of the system and to prevent the feeders from laterally moving off of the supports. The existing feeders were analyzed for the full range of anticipated thermal and operational temperature movements, and under bridge live load conditions. The forces and displacement resulting from the feeder analyses was used to design the new supports at the piers and to re-design the malfunctioning feeder supports. A temporary structural support system to provide access to complete the repairs is also required due to the fact that the leaks are located beneath the bridge deck and above the river.

The Queensboro Bridge is under the jurisdiction of the New York City Department of Transportation - Division of Bridges (NYC DOT). The DOT requires that any major work or modification to the bridge be checked by a third-party engineering company. Due to the unique location of the work, work area access and egress, equipment access, rescue boats and emergency egress, allowable bridge member support loads, and various other requirements must be considered at each support location.

**Justification:**

This project is initiated to address existing issues that can potentially impact the reliability of the transmission system. The damaged or missing supports cause the feeders to be improperly supported and abrasion to the coatings. In many places the pipes are improperly resting directly on the concrete piers and steel beams. By mitigating these problems by installing new supports before a failure occurs, it will prevent the spending of the associated costs for leak emergency response and remediation. The solution to this problem is to support a system of hanger supports at the ends of the feeders by the piers and additionally to install new rollers in places that are damaged, as well as, rollers on all sides of the feeders in targeted locations in order to prevent the lateral movement of the feeders off of the rollers. By implementing these changes, the system of the feeders and the bridge structure will function as originally designed for and intended.

* Alternatives:
* Risk of No Action: Not addressing the failed supports will result in continued feeder deterioration and leaks and emergency failures. Additionally, if the pipes are damaged beyond repair, it may cause costly replacements or re-location of the feeder pipes.
* Non Financial Benefit Explanation: The abrasion to the pipes due to improper support causes the coating to become damaged and for leaks to occur. If the support system is repaired, the system will have increased reliability and extend the useful life of the feeder system.
* Technical Evaluation and Analysis: As discussed, the damaged and missing supports are causing deterioration to existing feeders on the Queensboro Bridge. Even if a specific leak incident does not result in immediate failure of the feeder, the long-term effective life of the feeder may have been reduced.
* Project Relationships:

**Current Status:**

**Current Working Estimate:**

**Funding: ($000s)**

| **Funding Cost** | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | $0 | $3,600 | $3,600 | $3,500 | $0 | $0 | $0 | $0 | $10,700 |

**Benefit: ($000s)**

* **2008 to 2012 Budget in Thousands-** $0
* **2013 to 2017 Budget in Thousands-** $10,700
* **Authorization-**
* **Appropriation-**

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Area Substation Reliability And Auto Ground Circuit Switchers |
| **Project Number** | |
| **Work Plan Category** | Reg - Agency Mandated |
| **Priority** | 14 |
| **Project Manager** | J. Palma |
| **Project Engineer** | S.Stroumbakis |
| **Budget Reference** | 2ES8500 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 06 Prolonged Electric Outtage Impact Customers,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This program provides for the installation of high side switching circuits in the substation transformer vaults to provide for redundant clearing. The high side switching circuits shall consist of a circuit switcher and / or an interrupter. Digital Transfer Trip (DTT) could be substituted for one or both of the switching devices where it is impossible to install the switching devices because of space limitations.

Of the remaining 134 transformers that need to be addressed, fifty-four (54) vaults can accommodate a local high side clearing device (original scope) but due to space limitations and bus-work design, the remaining eighty (80) vaults will be designed with two lines of DTT and a motor operated disconnect or removable flexible link (modified scope).

Also, the previous Auto Ground Switch (AGS) retirement program has been combined with this reliability program and where feasible the work will be done simultaneously since the AGS can only be retired when either a circuit switcher or transfer trip relay scheme is installed. Typically 5 to 7 circuit switchers are installed per year depending on system outage constraints. Cost can vary anywhere from $1M to $2M per transformer vault depending on station arrangement and spatial constraints.

**Justification:**

A single-mode failure philosophy was developed to prevent extensive damage and station shutdown from a sustained 13kV fault. The philosophy includes the addition of an independent line of protracted fault protection, installation of a 138 kV transformer circuit switcher and interrupter, the provision for control cable system route separation, separate DC supply systems, switchgear compartmentalization, and improved fire rated design. The design philosophy has changed since some substations were designed and constructed. Upgrading existing area substations to meet present design philosophy will reduce the possibility of loss of the area substation during a protracted fault incident. Also, as part of this program we will look to retire the AGS where feasible.

**Current Status:**

2012 Planned work
Leonard Street – continue installation of DTT – Completed 2 banks – 4/22/12.
2 banks scheduled for 10/13/12 – 11/19/12.
Washington Street– complete installation of DTT on Tr. #2. – Completed 3/127/12.
Greenwood and Bensonhurst – install DTT equipment for 38B13 and 38B14. – 38B13 scheduled for 12/10/12 – 1/4/13.
Harrison – complete installation of new circuit switchers & circuit interrupters. Civil work completed. 38W14 – Tr. 1 scheduled for 10/31/12 – 1/6/13.
East 40th St. – complete installation of new circuit switchers & circuit interrupters. Completed Tr.5 - 4/3/12. Tr. 1- scheduled for 9/30/12 – 11/11/12.
Washington Street – complete installation of DTT on Tr. #4.- Equipment installed, Outage changed to Tr. 3, scheduled for 4/2/13 – 5/15/13.
Greenwood / Bensonhurst – complete installation for 38B11. – Outage scheduled for 1/6/13 – 1/25/13.
West 65th Street – begin installation of DTT. – Equipment installation in progress by ECB work forces.
Willowbrook – Begin installation of circuit switchers.- No window available for 2012. Civil work to progress in late fall 2012 . Outage window provided for April 2013.
Ossining / Millwood – complete installation of DTT- Completed 38W41- Tr.1.- 4/21/12.

Stations planned for 2013 – 2015
Leonard Street – continue installation of DTT.
Washington Street – continue installation of DTT
Harrison – Complete installation of new circuit switchers and interrupters.
East 40th Street – Complete installation of new circuit switchers, interrupters and relay upgrades.
West 65th Street – continue installation of DTT.

Greenwood / Bensonhurst – complete installation of DTT.
WIlowbrook – Complete installation of circuit switchers.

Currently under design or funding requests are the following stations: Brownsville, Willowbrook, W 65th St.

**Funding: ($000s)**

| **Funding Cost** | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 7759 | 5321 | 6346 | 8514 | 6665 | 8000 | 11222 | 11366 | 11345 | 11427 | 11500 | 99465 |

* **2008 to 2012 Budget in Thousands-** $34,846
* **2013 to 2017 Budget in Thousands-** $56,860

# 2013 Capital - Central Operations/Transmission & Substation Operations

| **Project Name** | High Voltage Circuit Breaker Capital Upgrade Program |
|---|---|
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 8 |
| **Project Manager** | C. Davoren |
| **Project Engineer** | S. Stroumbakis |
| **Budget Reference** | 2ES8100 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 06 Prolonged Electric Outage Impact Customers, per Risk 07 Prolonged Transmission Substation Loss, per Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This program combines and replaces the 138kV and 345kV capital upgrade programs that had existed until 2012. The program scope has also been expanded to include 13, 27, 33, and 69kV breaker replacement or upgrades—with the exception of work that would be covered under the 13/27 Breaker Retrofit program. The work scope includes the replacement or capital upgrade of breakers based on their performance in accordance with guidelines established in CE-ES-1000. These breakers will be targeted for replacement when major maintenance is required in accordance with the EPRI maintenance ranking program and subsequent Peer team review as directed by CE-ES-1000. Replacement is performed when a breaker or breaker type is deemed to be in poor performing condition due to progressive deterioration, lack of spare parts, high maintenance costs, oil and/or gas leakage and poor performance history.

Replacement is also performed when determined to be more economical than overhaul, a decision that also results in enhanced reliability. The Westinghouse 1380SF6 138kV breakers have been targeted for replacement due to performance, including SF6 leakage, in-service failures, and maintainability issues. Oil-filled breakers are also targeted for replacement based on performance, environmental concerns, risk of major substation events, inability to obtain parts and the high cost to maintain these 50 -60 year old vintage breakers. 345kV SFA breakers have also been targeted for replacement due to SF6 leakage concerns.

Each breaker replacement will be reviewed individually to state the business case for its replacement. If the replacement costs are too high or if other factors determine that the replacement is not justified than other maintenance plans (overhauls) may be enacted.

• Units per year: The funding for this program will support approximately 8-12 breaker replacements/year at an average cost of $800,000/breaker.

**Justification:**

This program is a significant driver in the reduction of operation and maintenance costs, SF6 emissions, and forced outages. In the last few years, we have seen a dramatic decrease of over 50% in the labor hours for corrective maintenance on high voltage breakers. Similar reductions in SF6 emissions have been realized during this same time frame. The reliable operation of circuit breakers is required during any system disturbance to effectively isolate that disturbance from the system. Failure to do so can have serious system consequences and affect customer service reliability. The proper isolation of system disturbances is also critical in maintaining a safe working environment for station personnel as well as safety for the public. The replacement of deteriorated or problematic circuit breakers provide system enhancement through better reliability and is cost effective versus the alternative of frequent repairs. In addition, this program will reduce future maintenance costs such as special custom fabrication of unavailable replacement parts and expensive SF6 gas replenishment.

***** Alternatives:

One alternative is to overhaul or replace circuit breakers based on time. This method was employed up to the end of 2008. While it did maintain the circuit breakers in a reliable manner it was not the most effective or efficient method to maintaining the circuit breaker fleet. Advances in database record keeping, on-line monitoring systems, as well as maintenance ranking programs have allowed the circuit breaker maintenance program to be moved from time-based to performance-based. The time-based maintenance method is therefore not recommended.

Another alternative is to perform no overhauls or replacements of circuit breakers. This is not recommended because of reliability, system performance, environmental, and safety concerns. The 1380SF6 circuit breakers have known operational issues. Failure to continue to replace these breakers would significantly affect the operation of the electric system as well as continuing to provide environmental and safety concerns. The failure to address deteriorating oil circuit breaker population would also have similar effects.

**Current Status:** The circuit breaker candidates for replacement are listed in the 5 year budget plan. Additional circuit breakers, not shown on this list may be chosen replacement based on their performance.

**2012 Planned Work:**
Dunwoodie 1N
Dunwoodie 2N
Dunwoodie 3N
Millwood 8W
E13th St F6
E13th St BT6-5
Farragut 11E
Pleasant Valley RS3

**2013 Planned Work**
Pleasant Valley RNS4
Pleasant Valley RN4
Fresh Kills 6
Fresh Kills 2
Dunwoodie 2S
Buchanan F3
Buchanan BT 2-3
Millwood 1W
E13th BT8-7
E13th BT4-3
33kV breakers – positions to be determined

**Funding: ($000s)**

| **Funding Cost** | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 15588 | 17814 | 21112 | 7558 | 8490 | 6500 | 5178 | 9500 | 9500 | 9500 | 9500 | 120240 |

* **2008 to 2012 Actuals in Thousands-** $61,474

* **2013 to 2017 Budget in Thousands-** $43,178

## 2012 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Conversion of the Y-94 From Temporary to Permanent |
| **Project Number** | 24617-12 |
| **Work Plan Category** | |
| **Priority** | |
| **Project Manager** | J. Dorn |
| **Project Engineer** | E. Hereira |
| **Budget Reference** | |
| **Project Status** | Ongoing |
| **End Date** | April 01 2014 |
| **ERM Addressed** | |

**Work Description:**

Buchanan Substation – Replacement of SF6 Bus associated with Feeder Y-94

Remove the existing bypass: conductor, hardware, and insulators and replace with new conductor, hardware, and insulators that meet current standards. Test and reinforce/replace existing wooden poles as needed.

The current bypass does not meet minimum clearances for ground levels maintenance, testing and vegetation management. Therefore, the area under the current bypass is to be re-graded to meet minimum clearance to perform preventative maintenance and vegetation management with the feeder energized.

The retired SF6 bus was equipped with a disconnect switch. The current bypass is not. Therefore a new 345 kV motor operated disconnect switch is to be installed at the interconnection point of the line to the Buchanan 345 kV bus.

**Justification:**

This project is initiated to address emerging issues that affect the reliability of the transmission system. Feeder Y94 is one of the tie feeder's connecting the Buchanan substation in Westchester County with the Ramapo substation in Orange County. It is one of the major outlet feeders for the Indian Point Nuclear Station. Feeder Y94 previously exited the Buchanan Substation as a gas insulated bus before transitioning to an overhead steel pole line. The SF6 bus has had a history of gas leaks and failures in the past and as a result it was permanently retired in the Spring of 2012. The feeder is currently in service via a bypass that was put in place several years ago for the sole purpose of keeping the feeder in-service during times of failures and/or leaks on the SF6 insulated bus. The bypass does not meet current standards and needs to be upgraded or replaced.

Finally, the overhead bypass line also crosses a paper road, First Street, which belongs to the municipality of Buchanan and should the municipality requires the property we would need to move the line.

**Alternatives:**

Alternative 1:
Install a new overhead line on steel H-frame structures in route of the retired SF6 gas insulated feeder trench and connect to existing disconnect switch F11-12. This new overhead will require a large amount of excavation of rock to provide vertical clearances as well as to mitigate the drainage issue, which makes this alternative more expensive and therefore it is not being pursed at this time.

Alternative 2:
Install new solid dielectric cable in the area of the retired GIS and connect it to existing disconnect switch F11-12. To obtain the needed rating, multiple solid dielectric cables will need to be installed. This option while feasible is the most expensive of all other options and therefore it is not being pursed at this time.

**Risk of No Action:** The current installation of feeder Y-94 does not include a disconnect switch and does not meet the minimum clearance and therefore the feeder would be required out of service should personnel needed to enter the area for routine/vegetation maintenance.

**Current Status:** Scoping document.

**Funding: ($000s)**

| **Funding Cost** | | 2014 | Total |
|---|---|---|---|
| | | 3500 | 3500 |

# 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Category Alarms Program |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 30 |
| **Project Manager** | A. Bykov |
| **Project Engineer** | D. Drakulich |
| **Budget Reference** | 8ES3000 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

The program consists of replacing the present substation failing electro-mechanical and solid-state-based alarm systems with a standardized programmable PLC/PC type alarm annunciator, comprising of a PLC - logic processing unit (LPU), Remote I/O units (where needed), and redundant set of HMIs. It provides local alarm functionality to the station operators and sends category alarms to EMS at ECC/AECC.

The new alarm annunciator has been developed solely by company forces. Its logic and HMI applications are both standardized to a level where the system does not require engineering/programming effort for individual installations. A localization text file is all that is needed; it can be edited either off-line, using any text editing program, or via pop-up windows while the system is running. It carries all the parameters needed for a particular system, from total I/O count to the individual settings for each input point. Debugging of logic and HMI applications is not needed, as exactly the same application gets applied to all installations. Furthermore, the system processes a same single point logic block and a same single point alarm tile object for all input points, and for all alarm tile screens. Thus, the system acceptance testing is limited to verifying that each individual input triggers a single expected action (i.e. that it is wired properly), and to visual inspection of point configurations at alarm tile screen(s) (verifying that the displayed information, coming directly from the logic controller, matches the intended operation for each point). The universal Coned alarm annunciator system is configurable to provide additional information for each point (drawing references, directions to operators, etc) and to serve alarm event logs and system configuration data to authorized users or systems, residing elsewhere at the corporate network.

**Justification:**

Most station alarm equipment were placed in service as part of station commissioning and on average have been in service for 40 years. Many units require high levels of maintenance and are beyond their useful life so there are no spare parts or vendor support. Deficiencies associated with station alarm panels present a risk to system operations and station personnel. It is of utmost importance that station operations personnel can rely upon the indication and alarms presented to them through the station Annunciator displays. Where deficiencies exist to alarm panels, operating personnel would need to rely on jumpers and station logs to understand the alarm condition, thus increase the possibility for human errors. In situations like this, Operators typically must verify field conditions and consider alarms jumped out to eliminate masked alarms. Replacement of degraded alarm panels will improve operation by allowing quick acknowledgement of and response to abnormal station conditions.

Panel repairs for the units slated for replacement are not possible in many cases, as the panel manufacturers no longer support spare parts or field service for the panels. The panels have been repaired and/or serviced to the extent possible, but continue to provide unreliable operation. Spare parts have also been obtained from units removed from service to the extent possible. However, in many cases, all previously obtained spares have been used in making repairs.

* Alternatives: The alternative is to take no action. This is not recommended as each failure of alarm panels increases operational costs and reduces reliability.
* Risk of No Action: This is not recommended as the failure of alarm panels increases operational costs and reduces reliability.

**Current Status:**

The following work is being done in 2012:
W42nd St. Station 1 and Station 2
W110th street, North Queens, Rainey, Sherman Creek, Cherry street, E65th St., Avenue A.,

The following work is going to be done in 2013: four systems (Granite Hill, S138kV, N138kv and Minibus 345kV) at Dunwoodie, Gowanus, Hudson Ave East, Farragut, Willowbrook, Parkchester

**Funding: ($000s)**

| Funding Cost | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 736 | 46 | 904 | 1256 | 1360 | 1300 | 1500 | 1500 | 1500 | 1500 | 1500 | 13102 |

- **2008 to 2012 Actuals in Thousands-** $4,866
- **2013 to 2017 Budget in Thousands-** $7,500

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | CIP V5 Required Security Upgrades |
| **Project Number** | |
| **Work Plan Category** | Reg – Agency Mandated |
| **Priority** | 49 |
| **Project Manager** | A. Cardoza |
| **Project Engineer** | N/A |
| **Budget Reference** | |
| **Project Status** | Not Started |
| **End Date** | Dec 31 2015 |
| **ERM Addressed** | |

**Work Description:**

This program funds security enhancements that will be required at various Substation Operations facilities as a result of the new CIP version 5 requirements. Substations that fall into certain CIP facility classifications will require physical and electronic perimeters for their critical cyber assets. These perimeters will be established through the use of security features such as card access control to equipment, same day access revocation, and SCADANET expansion.

**Justification:**

CIP version 5 has significantly changed the requirements for determining which cyber assets are in scope of the standards. In general CIP version 5 places just about all the computers in the substation in scope, regardless of how accessible these computers are to the outside world. A quick explanation/summary of the rules/guidelines to determine if a cyber asset is in scope is as follows: Any computer system or group of computer systems that can if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact one or more BES Reliability Operating Services. The BES Reliability Operating Services are defined as follows:

1. Dynamic Response to BES conditions
2. Balancing Load and Generation
3. Controlling Frequency (Real Power)
4. Controlling Voltage (Reactive Power)
5. Managing Constraints
6. Monitoring & Control
7. Restoration of BES
8. Situational Awareness
9. Inter-Entity Real-Time Coordination and

Communication

CIP Version 5 also sets up distinct requirements for different categories of facilities. There are three categories, defined as High, Medium, & Low. In simple terms the High category is for the control centers (the ECC and Alt ECC), the Medium and Low category is for the 345 kV & 138 kV system, with some slight deviations. In general, there is very little difference between the requirements for the High and Medium locations. Presently our review of the High, Medium, and Low guidelines places the two control centers in the High category and thirteen 345kV & two 138kV stations in the Medium category, and seven 345 kV & sixteen 138 kV substation in the Low category.

To meet the various requirements of the CIPs on the microprocessor devices at these stations, the devices require significant physical access protection/controls, electronic access protection/controls, and controls on the design information (access control to the drawings designs).

The location within the substations where the microprocessor/computer equipment is located will be the physical boundaries for the assets. This would limit the areas that need to be protected for example: the control rooms, relay houses, and pump houses, etc. This would allow more unescorted access to areas of the substation to do work. However, it would require a large capital investment to implement the necessary physical (Doors with swipe cards) and electronic security controls (firewalls) at all these locations around the substation to meet the new standards.

- ***** <u>Alternatives:</u> The alternative to take no action is not recommended. Failure to install the equipment required by the standard could result in critical cyber assets being unprotected, leaving them vulnerable to cyber attack.

- ***** <u>Risk of No Action:</u> The risk of no action would be leaving our electric system vulnerable to cyber attack. It would also leave us subject to substantial fines for failure to comply with an agency mandated program.

**Current Status:**

Work scopes and priorities are still being developed, and are expected to be completed by the end of the year. Construction activities will commence in 2013 and continue until all required equipment has been installed, currently projected as 2015.

**Funding: ($000s)**

| **Funding Cost** | 2013 | 2014 | 2015 | Total |
|---|---|---|---|---|
| | 1000 | 1000 | 1000 | 3000 |

* **2008 to 2012 Actuals in Thousands-** $0
* **2013 to 2017 Budget in Thousands-** $3,000

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Circuit Switcher Replacement Program |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 51 |
| **Project Manager** | H. Nguyen |
| **Project Engineer** | P. Dilillo |
| **Budget Reference** | 9ES3200 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2016 |
| **ERM Addressed** | |

**Work Description:**

We have identified 4 circuit switchers on our system where maintenance activities have become increasingly more challenging. The S&C Mark 2 and the S&C type G are no longer supported by the manufacturer with parts or service. This program will replace one (1) circuit switcher per year with a reliable upgraded model at a unit cost of $600K per circuit switcher. As this program proceeds, additional circuit switcher makes/models may be identified as challenges to maintenance effectiveness. As these are identified they will be scoped into this program for future years of the program.

In 2008, a circuit switcher was purchased for the replacement of one associated with Gowanus Substation Reactor 18. Due to system constraints, an outage to perform the replacement could not be obtained in 2008 and unit was subsequently replaced April, 2009. In addition to this replacement, the circuit switcher associated with Gowanus Reactor R6 was planned for replacement in the fall of 2009 but an outage could not be obtained. Due to a failure of Rainey CSW 5W, the kit for R6 was used to rebuild this failed switch. It was also decided to purchase a spare circuit switcher under the program in case another failure occurs.

A new kit has been received and R6 will be scheduled for replacement as soon as an outage window becomes available, likely in 2013. Following the R6 work, the plan is to continue to replace one circuit switcher per year from the following list of circuit switchers presently scoped into the program:

- Millwood TA1
- Sprain Brook CS-49

As the program progresses, other circuit switchers will be considered for replacement based on concerns such as performance, reliability, and difficulty in procuring replacement parts.

**Justification:**

A failure of these circuit switchers would compromise the reliability of the equipment that it is associated with and, consequently the system as a whole. Since the equipment is no longer manufactured, part procurement is increasingly difficult. Delays in procuring replacement parts could translate into extension of outage times and consequently a decrease in system reliability. Replacing these circuit switchers will ensure the ability to properly maintain the equipment and their continued reliability.

* Alternatives: The alternative is to take no action. This is not recommended as the unavailability of spare parts increases the risk of extended outages and increased maintenance costs in the event of equipment failure.

* Risk of No Action: This is not recommended as the unavailability of spare parts increases the risk of extended outages and increased maintenance costs in the event of equipment failure.

**Funding: ($000s)**

| **Funding Cost** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | 367 | 470 | 0 | 0 | 0 | 0 | 1000 | 1000 | 1100 | 3937 |

* **2008 to 2012 Actuals in Thousands-** $837
* **2013 to 2017 Budget in Thousands-** $3,100

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Condition Based Monitoring Equipment |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 18 |
| **Project Manager** | P. Panico |
| **Project Engineer** | A. O'Malley |
| **Budget Reference** | 2ES7900 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 22 Significant Oil Spill Water Damages,Oper Risk 14 Transmission or Area Substation Transformer Catastrophic Failure |

**Work Description:**

The purpose of this program is to install condition based monitoring equipment on power transformers to provide increased capability to identify and respond to equipment problems prior to failure thereby improving transformer reliability. The main drivers of this program are maintenance optimization through the integration of condition monitoring and reliability improvements realized by the reduction of unanticipated transformer failures. The equipment presently included in the program are Load Tap Changer (LTC) monitoring equipment and on-line dissolved gas-in-oil analyzers (DGOA) units. As technologies evolve, other monitoring devices will be evaluated for inclusion in the program as deemed effective. The installations are prioritized based on lessons learned through past experience as to where monitoring has been found to be most effective.

The current scope of work includes installing on-line DGOA units on all new transformers, Allis Chalmers autotransformers, 345/138 kV phase shifters and transformers where performance and condition indicators suggest continuous monitoring is recommended. All new transformers are equipped with TM100 or Tapguard LTC monitoring equipment.

**Justification:**

Dissolved Gas-in-Oil Analysis is the most effective means of monitoring the health of transformers. Continuous monitoring of dissolved gasses can detect insipient faults and allow equipment to be removed from service and repaired prior to failure. Monitoring the load tap changer is also an effective means to monitor a vital component of the transformer. The load tap changer is used to dynamically maintain the secondary voltage of the transformer due to load variation and changing system voltage conditions. By monitoring key parameters of the load tap changer, problems can be identified prior to equipment malfunction, thus avoiding system impacts. It also allows for optimization of our maintenance program, thereby reducing costs.

Our first generation of LTC monitoring (Datawatch/SAGE) was installed in the 1990s on approximately 300 transformers. This technology relied mostly on temperature monitoring to detect failures and successfully detected 26 insipient transformer failures resulting in savings in costly maintenance and equipment outages. The specific failure modes that these monitors could detect were in UZD and 996 Load Tap Changers. These tap changers have since been retrofitted with new contacts which have eliminated this failure mode, making the monitoring system obsolete. Other utilities are also no longer pursuing this type of monitoring and the manufacturer is discontinuing manufacturing of the system. Therefore, this type of monitoring is being retired. Gas-in-oil monitoring has been found to be a much more effective means of monitoring the health of transformers.

Continuous monitoring can identify abnormal conditions and predict deterioration of components prior to failure. We have been able to remove the equipment from service to perform maintenance and parts replacement prior to performance deterioration or failure. Installation of the monitoring equipment on additional transformers is required to further enhance the reliability for all transformer installations. All new transformers will be equipped with on-line gas-in-oil monitors installed by the manufacturer. Existing transformers have been prioritized based upon system importance, equipment costs and specific equipment cases. Transformers at two-bank area stations have continuous monitoring to ensure reliable service to customers when one of the units is removed from service. Allis Chalmers have continuous monitoring due to gassing trends that have arisen in these types of transformers. Phase shifting transformers will have continuous monitoring due to the cost of the equipment and their criticality to our system. Monitors are also planned for specific units that have indicated abnormal operating parameters. The cost for each monitor is between $45,000-$65,000 plus installation costs.

This system enhancement program improves our ability to closely monitor the condition of our critical power transformers and hence better schedule our maintenance activities. Condition monitoring is also used to circumvent time-based maintenance thereby improving transformer availability and reducing overall maintenance costs.

The program is driven by criticality of units (phase angle regulators) and recent repair/gassing history. In addition, 2-bank area substations and System Operations defined “sensitive stations” were identified to include monitoring. The decision to install monitoring is determined by our Transformer Technical Specialist with input from the Transformer Peer Group.

* Alternatives: The only alternative is to take no action. This alternative is not recommended as the installation of condition monitoring improves our ability to detect emerging equipment problems prior to failure thereby improving reliability and lowering overall maintenance costs.

* Risk of No Action: This alternative is not recommended as the installation of condition monitoring improves our ability to detect emerging equipment problems prior to failure thereby improving reliability and lowering overall maintenance costs.

**Current Status:**

12 new monitors were purchased in 2011 and are planned for 2012-2013 at Dunwoodie Substation.
The installation of 6 monitors is also planned in 2012 at Academy Substation.
Installations are also planned for 2012 at Astoria East F34051A and Farragut R11.

**Funding: ($000s)**

| **Funding Cost** | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 137 | 516 | 493 | 1605 | 968 | 300 | 250 | 250 | 250 | 300 | 300 | 5369 |

* **2008 to 2012 Actuals in Thousands-** $3,882
* **2013 to 2017 Budget in Thousands-** $1,350

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Control Cable Upgrade Program |
| **Project Number** | Various |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 39 |
| **Project Manager** | J. McCoy |
| **Project Engineer** | V. Patel |
| **Budget Reference** | 8ES0500 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This program provides funding to replace degraded control and instrumentation cables that have experienced a higher failure rate. New conduits and junction boxes will also be installed to expedite the cable replacements and to minimize scheduled outages. The cables are typically run in covered troughs, ducts, and conduits.

• Units per year: The approximate cost of a control cable upgrade is $1.5M per station. The requested funding will complete upgrades at less than 1 station per year.

**Justification:**

Control cables are essential for the safe and reliable operation. These cables are used to send high-speed fault clearing trip signals to protective relays and equipment status to SCADA systems. Due to exposure to the elements, some of these cables have deteriorated as demonstrated by very low insulation resistance measurements obtained during testing and by operational issues caused by grounds and cable failures such as trip outs, failures to operate on demand, and loss of indication. Depending on the type of installation and amount of environmental exposure, associated cable conduits and troughs also experience similar degradation. In addition to reliability concerns, cable degradation can also result in potential lead and asbestos exposure presenting a safety concern to employees. Inadvertent trips of equipment impact system performance and can result in outages and damage to equipment. Replacement of the old instrumentation and control cables will improve substation reliability, availability, and performance.

* Alternatives: An alternative is to take no action. There is some level of deterioration at many of our stations. Typically, grounds that come up are limited in scope and are corrected simply via routine corrective maintenance. This program is aimed at addressing more pervasive problems, where frequent O&M repairs have not resolved long-standing operational issues due to cable degradation and station reliability is being challenged. The risk of no action would be to accept reduced reliability and potential equipment damage caused by cable degradation where it has already been demonstrated that corrective maintenance is not effective. To ensure continued reliability, this alternative is not recommended.

* Risk of No Action: The risk of no action would be to accept reduced reliability and potential equipment damage caused by cable degradation where it has already been demonstrated that corrective maintenance is not effective.

**Current Status:** Work planned for 2012 includes Fresh Kills, designed and appropriated and will start in April, Hell Gate, scheduled to start in June, and E13th St. which must be scoped out and designed, and will likely commence in 2013.

**Funding: ($000s)**

| **Funding Cost** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1074 | -236 | 0 | 230 | 1085 | 0 | 1000 | 1000 | 1100 | 1100 | 6353 |

* **2008 to 2012 Actuals in Thousands-** $2,153
* **2013 to 2017 Budget in Thousands-** $4,200

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Stabilization of Pothead Stand Supports/Settlement |
| **Project Number** | 23334-09 and 24581-11 |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 36 |
| **Project Manager** | N. Roberts |
| **Project Engineer** | M. Rendon |
| **Budget Reference** | 2ES4300 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This is a multi-year project to correct equipment settlement problems, primarily at the Corona Substation. The project is being completed in stages with construction being performed when Engineering develops and issues a package for each segment of work. The scope of work in these packages typically include stabilizing disconnect switch stands, prefabricated concrete control cable trenches, junction boxes and direct buried conduits. While this program originally addressed issues only at the Corona Substation, we are expanding the scope to include other stations. We have also found that similar settlement issues are present in Astoria East and Queensbridge, and will use this program funding to address issues at these stations as well.

**Justification:**

The Corona substation was constructed on reclaimed land. Many of the structures and buried facilities are settling, resulting in damage to foundations, troughs, conduit, splice boxes, and cable. In the past six years, we have experienced damage to substation equipment.

A settlement study was performed by Muser Rutledge Corporation to determine if settlement will continue or if we have reached the end of the settlement issue. Their report states that the ground surface settlement will continue to occur as the result of secondary compression of organic, marsh soils immediately underlying site fills, but at a decreasing rate. Due to expected continued settling, installation of trenches is the first required action to allow for the replacement of existing control cables impacted by the current settlement. This trench system is required to mitigate the problem created by equipment foundation settlement. To ensure that the new trench will not settle, helical screw piles and continuous concrete-grade beams will be used to support it.

In 2012, we have identified several similar settlement issues at the Astoria East and Corona substations. We have begun to study the extent of the settlement issues at these stations, but believe we will have to perform similar mitigation at these stations as well. Corona has already experienced issues with disconnect switch alignment due to settlement, as well as experiencing leakage at several points on their bus enclosures.

* Alternatives: Increase the size of the existing footings to further spread out the structural loads in the surrounding soil. This alternative will only decrease the rate of settlement, but not prevent it, therefore this alternative was rejected.

* Risk of No Action: The stabilization of the disconnect switch stands, junction boxes and conduits is required to prevent further bending and damage to the existing electrical conduit risers that connect to the equipment. If the disconnect switch stands, junction boxes and conduits, will continue to bend and will eventually:

- disconnect stands sink, creating the bus conductor to be misaligned, cables and conduits will break away from the control cabinet junction boxes; this could force unscheduled outages at the station, jeopardize the integrity of the equipment and the station, and create safety issues for the employees working at the station.

**Current Status:**

2013 Planned Work:
DS 5N5, 5N4, 6N5, 6N6 and 6S6 (PN 24581-11)

2012 Scheduled Work:
Stabilization of Disconnect Switches 9N8, 9N9, 10N9, and HF8 (PN 23334-09)

Potential projects for Astoria East and Corona are currently under study, and may be added to the project queue for 2014 or beyond.

**Funding: ($000s)**

| **Funding Cost** | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | 684 | 2 | 1000 | 1000 | 1000 | 1000 | 1100 | 1100 | 6886 |

* **2008 to 2012 Actuals in Thousands-** $1,686
* **2013 to 2017 Budget in Thousands-** $5,200
* **Authorization-** $9,900,000

* **Appropriation-** $4,191,000

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | DC System Upgrade Program |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 21 |
| **Project Manager** | S. Steck |
| **Project Engineer** | L. Blackwood |
| **Budget Reference** | 2ES8300 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 06 Prolonged Electric Outtage Impact Customers,Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This program replaces the DC system batteries in substations that need to be replaced with new batteries, and upgrade DC system equipment such as load boards, rectifiers, and the associated cables and conduits.

• Units/Year: About 14 batteries will be replaced per year at approximately $70,000 each, 10 load boards at approximately $120,000 and 10 rectifiers at approximately $20,000 each.

Battery Replacement Basis:
The purpose of the DC system is to supply power to the control system during a loss of AC power. To ensure the reliability of DC systems in existing substations, the first priority is to maintain the integrity of the batteries. When battery capacity starts to decrease, Company engineering guidelines are used to determine the required capacity of new batteries.

Before battery size can be increased, the following supporting constraints are considered:
1. The size of the existing battery room.
2. The capacity of the existing HVAC system for heat and H2 removal.
3. Capacity of existing rectifier.
4. Potential impact on load board.

Because of the significant increase in time needed and cost associated with changing the support systems or structures listed above, if battery size must be increased and its replacement cannot be delayed, the size is increased up to the limit of the most restrictive constraint.

Rectifier Replacement Basis:
To ensure the battery is charged and available for a loss of AC power, the DC system needs a healthy rectifier. A healthy rectifier has stable voltage regulation, as defined in CE-ES-4068, and is able to maintain battery terminal voltage without excessive drift. To limit thermal deterioration of batteries, the AC ripple of a rectifier output should be less than 5amps RMS for every 100AH of capacity (i.e. for a 500AH battery, ripple should be less than 25amps RMS). Rectifiers should be repaired or replaced if it cannot regulate DC voltage or if the AC ripple current is too high.

Load Board Replacement Basis:
Load boards serve as the main distribution point for the DC system. Conditions that could force load board replacement are:

1. Instrument failure that cannot be replaced due to unavailability of parts.
2. Insufficient spare slots for branch circuit breakers, or room on the bus bar to add links, to support station expansion.
3. Branch circuit breakers are degraded and cannot be replaced due to unavailability for purchase.

Replacement rates and upgrade requirements between the core components of the DC System will not always coincide. The replacement of any one of these components is not delayed for the sake of an entire system upgrade. Initially, 90 load boards were identified for replacement as part of an overall review of Substation Operations (SSO) DC system upgrades. To date, 44 load boards have been replaced. The remaining load boards continue to be addressed via the DC upgrade program. Additional load boards may be considered for replacement. Battery and rectifier replacement will continue to be scheduled as batteries reach the end of their useful life.

**Justification:**

The DC system provides a reliable source of power to operate, protect and control transmission and distribution supply systems during normal operation and contingencies that affect offsite AC power. Each DC system consists of a battery, battery charger and load board with instrumentation. The nominal control voltage of the DC system is 125 or 250 volts. Some existing substations utilize 125 or 250 volts DC for controls and relaying and 48 volts for monitoring and indication. All substations have two DC power systems to provide power for the control and operation of the circuit breakers, circuit switchers, alarms, power transformers, protective relaying systems, supervisory controls, fire protection controls, etc. This program will ensure the continued reliability of substation DC systems.

When batteries are to be replaced, an Engineering load study is performed to properly size the replacement battery. The DC systems are sized to operate for 8 hours with 1 battery or 24 hours with 2 batteries in the event of a loss of AC power. Over time, the addition of new substation equipment such as new feeder positions, computers and intelligent electronic devices (IED), can result in increased DC load necessitating the need to increase battery size. This load study also determines if upgrades to the remaining DC components and support systems are required when a battery size is increased. The replacement of the battery chargers will assure proper charger sizing for the new batteries and will include modern control circuitry. The new instrumentation systems will provide accurate and reliable measurement and monitoring of the DC system conditions and will provide out-of-limit alarms.

Replacement of batteries and rectifiers are driven by the following:
Batteries - CE-ES-1034
Rectifiers- CE-ES-1000, CEES-1034 and CE-ES-2002 Part 4 DC Systems

* <u>Alternatives:</u> An alternative is to take no action. This is not recommended as much of the equipment being replaced such as batteries have a life cycle after which the equipment no longer can perform its intended function. Failure of the DC system could result in a failure to automatically clear faults, which could result in a safety hazard for personnel, equipment and the public. Failure of the DC system would also inhibit the monitoring and operation of substation breakers, switches and other essential equipment needed to control the transmission and distribution systems; this could lead to power outages or equipment damage.

* <u>Risk of No Action:</u> This is not recommended as much of the equipment being replaced such as batteries have a life cycle after which the equipment no longer can perform its intended function. Failure of the DC system could result in a failure to automatically clear faults, which could result in a safety hazard for personnel, equipment and the public. Failure of the DC system would also inhibit the monitoring and operation of substation breakers, switches and other essential equipment needed to control the transmission and distribution systems; this could lead to power outages or equipment damage.

**<u>Current Status:</u>** The following work is being done in 2012:

| Station | Description |
|---|---|
| 1.Sherman Creek | Replace ATS |
| 2.Harrison | Replace Rectifiers |
| 3.Greenwood | Full DC upgrade |
| 4. E 179th street | Full DC upgrade |
| 5. Rainey | Replace Batteries |
| 6.Gowanus | Replace Batteries and Rectifiers |
| 7. Willowbrook | Replace charger and batteries |

The following work is planned for 2013:
1. East 13th street
2 .Dunwoodie South
3. Queensbridge
4. The Learning center
5. ECC
6. Goethals

**Funding: ($000s)**

| **Funding Cost** | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1560 | 2336 | 1790 | 1911 | 1181 | 1800 | 3206 | 3789 | 3782 | 3265 | 3300 | 25397 |

* **2008 to 2012 Actuals in Thousands-** $9,018

* **2013 to 2017 Budget in Thousands-** $17,342

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Program Name** | Upgrade Disconnect Switches |
| **Project Number** | Various |
| **Work Plan Category** | Oper - System Capacity |
| **Priority** | 33 |
| **Project Manager** | B. Kennedy |
| **Project Engineer** | S. Stroumbakis |
| **Budget Reference** | 0ES0700 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This is an on-going program to retrofit, overhaul, or replace transmission voltage class disconnect switches found to be unreliable based on performance.

Disconnect switches are not replaced or retrofit/overhauled on a time-based frequency. The entire population is reviewed on a periodic basis by Substation Operations and Engineering and candidate disconnect switches are chosen based on such factors as criticality of application, prior maintenance history, safety concerns, outage availability, and end of useful life issues.

Substation Operations and Engineering determine whether a retrofit, overhaul, or replacement is needed. Some of the factors used to determine if a replacement is necessary include structural and /or foundation issues, the condition of the grounding blade, motor operator, operating linkage, and the porcelain insulator. A disconnect switch retrofit consists of the replacement of all current carrying components including the jaws and blade.

• Units/year: About seventeen (17) disconnect switches will be replaced each year as part of the program at an approximate unit cost of $280,000 for replacements, $150,000 for retrofits, and $30,000 for overhauls.

**Justification:**

This program maintains the current reliability of the system by proactively addressing disconnect switch performance issues on an annual basis. As disconnect switches deteriorate the probability of malfunction increases. Replacing the units on an emergency basis increases the replacement cost and impacts reliability. For disconnect switches, where replacement parts are no longer available or require special custom order with long lead times, the potential for extended repair outages exists.

This program has been effective and costs efficient at ensuring disconnect switch reliability as opposed to time-based periodic maintenance/replacement. Funding has been allocated to address the needs of underperforming disconnect switches identified as part of our periodic reviews.

The worst performing disconnect switches are identified by the Disconnect Switch Peer Team through a qualitative and quantitative performance evaluation. The quantitative factors consist of hot spots, O&M labor hours, category emergencies, and operating issues. The qualitative factors considered include parts availability originating from models discontinued or manufactures no longer in business, model, type, year, damaged insulators, and special consideration such as lessons learned from a specific event. The scope of work determined can be unique to each asset however best management and engineering practices are employed during the scoping, design, planning, and construction process to produce a cost effective and viable solution.

The three most typical refurbishment options defined below go from least expensive to most expensive.

OVERHAUL
* Intended to be used where Spare Parts are readily available from the OEM. (note if blade tips are welded then a LIVE PARTS KIT should be considered)
* The work includes:
  -Replacement of all Current Carrying Contact Parts with Like-In-Kind OEM parts:
    -Stationary Fingers
    -Blade Tip Inserts
  -Other Maintenance Activities include:
    -Lubrication of Linkages/Bearings
    -Adjust mechanical and electrical stops
    -Ground SW Operator - - Clean and lubricate
    -Disconnect SW Operator - - Clean and lubricate
    -Document As-found and As-Left data (data-sheet to be developed/standardized)

LIVE PARTS KIT
* Intended to be used when extensive maintenance issues exist with existing switch OR if OEM parts are not available or cost effective.
*The work includes replacement of:
  -All Current Carrying Parts:

- Blade and Jaw Assembly
- Linkage Rods and Clevises
- Center and Vertical Bearings (with housings)
- Disconnect SW Operator (Hojo) with mounting plate
- Motor Operator OR Manual-Hugo crank

* Other Maintenance Activities include:
  - Refurbish Ground SW Operator
  - Adaptor Plates may be required fit-up.
  - Document As-found and As-Left data

FULL REPLACEMENT
* Intended to be used where work required to restore design function of the Disconnect Switch is beyond simply replacing the Current Carrying Parts of the switch.
*The work includes:
  - Replacement of entire Disconnect, Ground Switch Assembly, and upgrade stand and foundation

* Alternatives: Disconnect switches could be maintained according to a time-based maintenance program, however this approach does not focus maintenance dollars to the most unreliable disconnect switches.

* Risk of No Action: Another alternative is to take no action and allow the disconnect switches to run to failure. The failure of a disconnect switch to operate properly impacts the ability to operate the system reliably and efficiently. Failure to maintain disconnect switches can also result in catastrophic failures which can have severe system consequences resulting in decreased reliability and safety of operating personnel.

Current Status: Seventeen (17) disconnect switches are planned for 2011.
Seventeen (17) disconnect switches are planned for 2012.
Seventeen (17) disconnect switches are planned for 2013.

Funding: ($000s)

| Funding Cost | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1320 | 3680 | 5800 | 3700 | 2194 | 1945 | 2500 | 3000 | 3000 | 3000 | 3300 | 3300 | 37317 |

* 2008 to 2012 Budget in Thousands- $16,717
* 2013 to 2017 Budget in Thousands- $15,600

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Disturbance Monitoring Equipment Program (138kV) |
| **Project Number** | various |
| **Work Plan Category** | Reg - Agency Mandated |
| **Priority** | 46 |
| **Project Manager** | A. Bykov |
| **Project Engineer** | Peter Chan |
| **Budget Reference** | 1ES6400 |
| **Project Status** | Planning |
| **End Date** | TBD |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This program will increase the amount of Disturbance Monitoring Equipment (DME) deployed throughout the Con Edison 138kV transmission system. DME includes digital fault, sequence of event, and dynamic disturbance recording capabilities. The scope of the program includes installation of new DME and expansion and upgrades of existing DME capability at the following 20 transmission substations:

| **Substation** | **OOM Cost** (1,000$) |
|---|---|
| Astoria East | $1,272 |
| Astoria West | $1,396 |
| Bruckner | $724 |
| Buchanan 138 | $785 |
| Corona | $1,871 |
| Dunwoodie North | $967 |
| Dunwoodie South | $1,081 |
| East 13 St 138 | $1,920 |
| East 179 St | $1,094 |
| Fox Hills | $747 |
| Fresh Kills East | $1,304 |
| Greenwood | $1,175 |
| Hell Gate | $870 |
| Hudson Ave. East | $1,091 |
| Jamaica | $1,008 |
| Millwood West 138 | $854 |
| Parkchester | $812 |
| Queensbridge | $1,350 |
| Sherman Creek | $1,264 |
| Vernon | $1,265 |

**Justification:**

This program is required to comply with the new regional NERC Reliability Standard PRC-002-NPCC-1 Disturbance Monitoring, as applied to the newly defined Bulk Electric System. In Con Edison, this would include at least, all 138 kV transmission switching substations. This standard was approved by NPCC Membership (January 2010), NPCC Board of Directors (February 2010) and by NERC Board of Trustees (November 2010).

* Alternatives: There is no alternative, as compliance with approved NERC Reliability Standards is legally mandatory. However, the allowable time for Implementation is still indeterminate.

* Risk of No Action: Fines for each day of non-compliance.

* Non Financial Benefit Explanation: Increased ability to analyze system disturbances and determine root causes of incorrect relay operations. Increased ability to validate dynamic models of power system equipment.

* Current Status:

- Order of magnitude estimates were prepared for installation/expansion at 29-138kV substations
- Due to the change in the NERC definition of the Bulk Electric System, several NPCC members have requested NPCC to extend the DME Standard's original Implemenetation Plan. NPCC leadership has agreed to explore an Interpretation of the Standard requirements such that the Implementation Plan can be extended by several years. In November 2012, NPCC will meet again to review this issue.
- The program is being planned to be engineered in 2013-2014 based on the existing outages on the system.
- Construction is planned to start in 2014 and to finish in 2017.

**Funding: ($000s)**

| **Funding Cost** | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | 0 | 0 | 0 | 5000 | 5000 | 6000 | 7000 | 0 | 23000 |

* **2008 to 2012 Actuals in Thousands-** $0

* **2013 to 2017 Budget in Thousands-** $23,000

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Disturbance Monitoring Equipment Program |
| **Project Number** | various |
| **Work Plan Category** | Reg - Agency Mandated |
| **Priority** | 46 |
| **Project Manager** | A. Bykov |
| **Project Engineer** | Peter Chan |
| **Budget Reference** | 1ES6400 |
| **Project Status** | On Going |
| **End Date** | Dec 31 2015 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This program will increase the amount of Disturbance Monitoring Equipment (DME) deployed throughout the Con Edison transmission system. DME includes digital fault, sequence of event, and dynamic disturbance recording capabilities. The scope of the program includes[1]:
– Installation of new DME at 3 transmission substations.
– Installation of new DME at 1 generating station (East River Unit #1).
– Expansion and upgrades of the existing DME capability at 17 transmission substations.

The NERC Regional Reliability Standard PRC-002-NPCC-1 Disturbance Monitoring was approved on 10/20/2011 and associated Implementation Plan became effective.
• Units Per Year: The current plan is to start the expansion/ upgrade this year at Rainey, Ladentown and East 13th substations, and work to incorporate work with any 345kV equipment that is coming out for other purposes.
• Mandatory:
• Completion Milestones:

- 50% 10/20/213
- 75% 10/20/2014
- 100% 10/20/2015

**Justification:**

This program is required to comply with the new regional NERC Reliability Standard PRC-002-NPCC-1 Disturbance Monitoring. This standard was approved by NPCC

[1] The details of the final scope are contingent upon the final definition of the "Bulk Electric System" as it applies to NPCC and to Con Edison.

Membership (January 2010), NPCC Board of Directors (February 2010) and by NERC Board of Trustees (November 2010).

* <u>Alternatives:</u> There is no alternative, as compliance with approved NERC Reliability Standards is legally mandatory.

* <u>Risk of No Action:</u> Fines for each day of non-compliance.

* <u>Non Financial Benefit Explanation:</u> Increased ability to analyze system disturbances and determine root causes of incorrect relay operations. Increased ability to validate dynamic models of power system equipment.

* Current Status:
  - Engineering prepared generic scoping documents
  - Partial appropriation for long lead equipment approved, final appropriation in progress..
  - Equipment procurement is in progress
  - Preliminary work to extend lockout relay contacts to facilitate tie-in to DME with no or minimal scheduling outages.
  - Priority substations (Rainey, Ladentown and East 13th Street) as these substations have no fault and sequence of event recoding capabilities.

**Funding: ($000s)**

| **Funding Cost** | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | 0 | 8000 | 8600 | 8800 | 8800 | 0 | 0 | 0 | 34200 |

* **2008 to 2012 Actuals in Thousands-** $8,000
* **2013 to 2017 Budget in Thousands-** $26,200

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | East River - Protection System Upgrade (Substation Automation) |
| **Project Number** | 21216-04 |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 24 |
| **Project Manager** | P. Murphy |
| **Project Engineer** | Z. Wolff |
| **Budget Reference** | 9ES4000 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2015 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 17 Major East River Complex Component Loss |

**Work Description:**

This project will purchase and install a new state-of-the-art microprocessor based automation system to perform operating, protective, and monitoring functions for the 69 kV circuit breakers, transformers, phase angle regulators, feeders, and buses at the East River Substation, as well as several 138 kV circuit breakers at East 13th Street. This system will include approximately 100 new protective relay panels, a new operating console with monitors, control and supervisory equipment, and all associated peripheral and support systems including 125Vdc and 208/120Vac control/auxiliary power distribution. The new components will be installed in the recently completed control room in the 69 kV yard at East River thereby completing relocation of all operating, protective, and monitoring functions from the 8th floor of the East River generating station. The project will also retire in place the existing operating, control, and protective systems and devices, currently located in the generating station control room, terminal board room, and various relay rooms.

• Units per year: We completed one outage last year and are presently in the middle of our second outage to finish April 2012. We have another outage in the fall of 2012, and plan to complete the cutover of approximately 3 Bus Sections per year until 2015.

Previous projects appropriated against this parent budget reference number are 20092-99, 20138-99, and 20156-99 for other ER substation improvements and upgrades. Expenditures for these projects are included in the cash flow shown below.

**Justification:**

This project will enhance system performance, improve operator response time and productivity, and upgrade the protection and control systems, thereby increasing reliability. The project is required to support the retirement of the existing operating, control, and protective systems and devices, currently located in the generating station control room, terminal board room, and various relay rooms.

* Alternatives: Continue to use existing equipment, and repair grounded wiring and defective components as needed.
* Risk of No Action: Lower reliability of the power supply to the Leonard Street substation, and lower reliability for the outlet for East River Gen. #1.
* Non Financial Benefit Explanation: Increased reliability for the Greenwich, Sheridan, Canal, and Park Place networks.
* Project Relationships: Implementation will require an outage of each of the East River 69 kV Bus Sections. These outages are contingent on other scheduled and emergency outages at East River and East 13th Street substations.

**Funding: ($000s)**

| Funding Cost | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 17249 | 5275 | 5614 | 3854 | 6183 | 4038 | 4863 | 6000 | 5000 | 6000 | 64076 |

* **2008 to 2012 Actuals in Thousands-** $24,552
* **2013 to 2017 Budget in Thousands-** $17,000

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Upgrade Of Elmsford 2 Substation |
| **Project Number** | 20762-03 |
| **Work Plan Category** | |
| **Priority** | 11 |
| **Project Manager** | J. McCoy |
| **Project Engineer** | J. Barlok |
| **Budget Reference** | 0ES0300 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2013 |
| **ERM Addressed** | Oper Risk 06 Prolonged Electric Outtage Impact Customers,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This project will enhance the reliability of the Elmsford Substation. Modern switchgear controlled by state-of-the art relay protection will be installed in a new building that will also provide space for a new control room, new battery rooms, new communications room, and new relay rooms. Multiple outages are required on the existing equipment to transfer the supply of power from the existing distribution bus sections to the new bus sections. Additionally, individual distribution feeder outages are required to transfer the supply of each feeder from the previous bus sections to the new bus sections. All of these outages will occur in a pre-approved sequence and none can be completed during our summer period. Each of the outages creates the first contingency in a single contingency area.

**Justification:**

The Elmsford Substation, located in Westchester County, is in service for over 50 years. It is one of the few area stations with outdoor switchgear and underground protection and control wiring. Being an outdoor substation, the weather has taken its toll on the equipment, its supporting structures, and protection/control wiring.

The existing substation consists of 4 transformers, 8 sections of switchgear, and 3-20 MVAR capacitor banks. The switchgear utilizes circuit breakers that have reached the end of their useful life due to lack of spare parts and manufacturer support. The equipment enclosures have deteriorated resulting in leaks and equipment outages due to water damage and misalignment. The equipment supporting structures are corroding and switchgear components have also been susceptible to water damage. As the structural components deteriorate, manual operation of the existing heavy circuit breakers has become increasingly difficult and requires more time and resources. .

Finally, by first rebuilding the substation on the existing property the number of system outages and the time duration for outages will be minimized, as well as facilitating the transfer of the station load from the existing station to the new station.

* Alternatives:

The only means of improving existing conditions is to either replace the switchgear and its protection/control wiring or transfer load to nearby substations and retire the Elmsford substation. The station currently supplies approximately 180 MW of load, and transferring this load to nearby substations will result in those stations exceeding their capability, therefore the only option is to replace the switchgear and its protection/control wiring.

Another alternative is to rebuild switchgear sections to 63kA and replace breakers with vacuum type circuit breakers. This alternative is not recommended because:
• The estimated cost for procurement and installation of new switchgear would be approximately $15,000,000. This investment would not be cost effective for the following reasons:
• This alternative would not mitigate the overall problems caused by poor drainage in a low-lying area, and would not address the deteriorated wiring and control systems.
• Equipment would still be located in deteriorated enclosures. The substructure is rusting, floors are deforming under load and the building leaks.
• 13 kV outages will be very restrictive and lengthy to allow for environmental mitigation and will impact customer service.
• The substation would not contain the latest automation technologies.

* Risk of No Action:

Continued risk of outages, including extended outages, to our customers due to failures of the existing equipment. This project will vastly improve the feeder processing durations of the Elmsford electric distribution system. The substation would still be an outdoor facility, subject to weather conditions, and less conducive to efficient operation and maintenance.

**Current Status:**

The following work has been completed:
- Completed physical construction of the new switchgear building in October 2010.
- Commenced the installation of the BMS, HVAC and Fire Protection systems.
- Completed a substantial portion of the new distribution feeder conduit banks and the control and indication troughs/conduits.
- Commenced the installation of the exterior bus support foundations.
- Completed the installation and testing of the building BMS, HVAC and Fire protections systems.
- Received and installed all sections of new switchgear and bus duct
- Completed preliminary testing of the new switchgear

- Completed installation of equipment in the new Control Room, Battery Rooms and Communications Rooms
- Completed the installation of all remaining troughs and conduits.
- Completed the migration of all distribution feeders to the new station.
- Completed the physical and electrical isolation of the retired switchgear from the new facility.
- Completed lead and asbestos abatement of all retired equipment.
- Completed the demolition of the old switchgear and other retired electrical facilities and above grade conduits around the station, including all retired equipment in the old control room.
- Completed the modifications to the façade of the old control room and fire walls visible from the street.

Work Planned for 2013:
- Complete final grading work.

**Funding: ($000s)**

| **Funding Cost** | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | Total |
|---|---|---|---|---|---|---|---|---|---|
| | 3050 | 1258 | 881 | 12757 | 26251 | 27797 | 3500 | 1000 | 76494 |

* **2008 to 2012 Actuals in Thousands-** $71,186
* **2013 to 2017 Budget in Thousands-** $1,000
* **Authorization-** $92,500,000
* **Appropriation-** $92,170,000

# 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Fire Suppression System Upgrades |
| **Project Number** | Various |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 3 |
| **Project Manager** | J. Palma |
| **Project Engineer** | P. Chan |
| **Budget Reference** | 2ES8800 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 03 Fatality Due to Safety Negligence, Oper Risk 06 Prolonged Electric Outage Impact Customers, Oper Risk 07 Prolonged Transmission Substation Loss, Oper Risk 08 Prolonged Area Substation Loss, Oper Risk 22 Significant Oil Spill Water Damages |

**Work Description:**

This program is to perform upgrades, replacements, and/or new installations of fire protection, suppression, deluges, and detection systems at various substations. The fire detection upgrades include the replacement of fire/heat/smoke detection equipment, wiring, control systems, alarm devices, etc. used to detect a fire and initiate an alarm and, in many cases, activates a deluge system. The deluge system upgrades include the replacement of piping, pumps, spray nozzles, wiring, control systems, and enclosures associated with delivering water to a fire once it is detected.

This program will fund modification of the existing substation fire protection fire pump piping by adding a fire pump discharge valve and a fire pump test header including valve, piping, and test header manifold. This will be performed at forty-five (45) substations. This is a multi-year project starting in 2008 and project to be completing at least six (6) substations per year.

This program will also fund the installation of clean agent fire suppression systems in various dielectric fluid enclosures (pumping/cooling/PURS plants). 57 locations have been identified. This project is a multi-year effort.

**Justification:**

The fire detection and deluge systems represent a critical component in our ability to quickly and safely respond to a fire event in our substations. These systems protect not only our equipment, but our personnel, emergency responders, and the public. The systems installed at our substations are required to comply with NFPA and NYC Codes and Regulations, and it is critical they are maintained in proper working order. Our deluge systems, in certain cases, are approaching their expected end of life and are beginning to show signs of deterioration or decreased reliability. We have instances where systems have begun to show excessive leaking, failure to provide adequate flow rates, or maintain adequate pressure. At several stations, we have determined that the entire deluge system—including pumps, piping, and controls—should be replaced. A number of our fire detection systems show similar end of life issues. In many cases, replacement detection heads can no longer be obtained, control panel parts are unavailable, and system reliability is compromised.

These modifications, including the addition of valves and a fire pump test header, are required to comply with NFPA and NYC Codes and regulations. The fire pump test header installation will also provide a means to test and evaluate the condition of the fire pumps to ensure proper performance for adequate protection of transformers. The addition of the fire pump discharge valve will improve equipment availability by eliminating the need to shutdown all transformer deluge system valves and all fire department siamese connections while performing the monthly required ten (10) minute operating fire pump test.

In the past two years Con Edison has suffered three incidents that resulted in damage to pumping plants or cooling plants. These events have demonstrated the vulnerability of these enclosures and systems. There are several potential consequences to pumping plant fires. One is the sudden loss of pressurization at the plant, which could affect multiple feeders and electric service to a myriad of customers. The other consequence is the potential impact to the public or surrounding structures.

Substation Operations and Electrical Engineering performed a review of existing plants and provided recommendations (report dated 12/21/10) stating that certain facilities (pumping plants, cooling plants, PURS) should be upgraded with fire suppression systems based on their proximity to public property or critical system infrastructure. System Operations and Electrical Engineering also conducted a study of the importance of each pumping plant on the system during the peak summer load period (refer to white paper “Pumping Plant Improvements – Based on Lessons Learned from Recent Fire Events”, by Electrical Engineering Rev 0 dated 5/31/11) and provided recommendations. Efficient Frontier Curves were developed which illustrated the relative efficacy of options to reduce the risk of load drop. The most efficient capital solution to this risk was the deployment of FM-200 fire suppression systems. The pumping, cooling, and PURS Plants listed above were identified by one or both of these studies as candidates to be retrofitted with a fire suppression system.

In reference to the new fire detection systems, the existing systems have been repaired and/or serviced to the extent possible, but continue to provide unreliable operation or are out of service. When replaced, the systems are upgraded to meet current local and national fire codes.

* Alternatives:

* Risk of No Action:

* Non Financial Benefit Explanation:

* Technical Evaluation and Analysis:

* Project Relationships:

**Funding: ($000s)**

| **Funding Cost** | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 4481 | 1319 | 192 | 4228 | 8781 | 8000 | 8016 | 7036 | 5401 | 6530 | 7000 | 60984 |

* **2008 to 2012 Actuals in Thousands-** $22,520

* **2013 to 2017 Budget in Thousands-** $33,983

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | High Voltage Test Sets |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 35 |
| **Project Manager** | J. Dorn |
| **Project Engineer** | A. Hazarika / H Malaj |
| **Budget Reference** | 2ES8400 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 06 Prolonged Electric Outage Impact Customers |

**Work Description:**

DC High Pot Test Sets
There are 113 high voltage DC test sets in Substation Operations that are used for distribution feeder processing. This program will purchase and replace on average 3 DC test sets per year.

AC Very Low Frequency (VLF) Test Sets Mobile & Fixed Location. We intend to purchase and install 3-5 fixed AC VLF test sets per year to expand the number of AC hi-pots performed on distribution feeders.

We are also working to develop a dual function test set that will give us the capability to perform AC hi-pots and fault conditioning in one unit. These units would allow us to perform all feeder processing activities with a single test set. Currently, we need to use DC test sets to condition feeder faults in order to locate them expeditiously, since existing AC test sets cannot perform this function. Maintaining both AC and DC test sets in the stations will be difficult in many facilities, as there is insufficient space to house these units. Our long term goal is to be able to move to a dual function test set and have these sets in place once we remove greater than 80% of the paper cable from any given network on our system. We are expecting the development process to take several years, and will need to maintain both AC and DC test sets in the stations until the development process is complete. Once we have a viable dual purpose test set available to us, we would move to purchase only these sets, and begin replacing all of our DC test sets with the dual purpose set. At that time, we expect to transition away from future purchases of DC test sets.

AC Test Sets, 345 kV
This program will also fund the purchase of 1new 345 kV transmission voltage AC test sets. This unit will be utilized at W49th St. substation.

• Units per Year: As stated, this program will fund the purchase of on average 3 DC test sets and 4 AC VLF test sets per year. The estimated unit purchase cost of the equipment (excluding installation materials, costs, and commissioning tests) is:
- DC test set: $109k
- AC VLF test set: $265k
- AC 345kV test set: $1.75M

Installation costs can range from approximately $300-600k, depending on the exact scope that is required. Typically, a test bus must be installed and its length and complexity greatly affect the cost of the job. In some cases, additional facility upgrades are required in order to provide adequate space for the test set within the station. This is a primary reason we are looking to develop a combination type set, to reduce these additional costs.

**Justification:**

DC High Pot Test Sets
A minimum of 2 feeder processing DC test sets per distribution station are required to process feeders. These test sets will be used to perform on-site testing and diagnostics of medium voltage feeder cables primarily for 4, 13, 27, and 33 kV feeders and for locating network ground faults (outside of the station). Various test sets are over 20 years old and require constant repair. The replacement program will systematically replace existing test sets based on age, corrective maintenance, and availability of parts. The worst performing test sets will be slated for replacement first. Since these sets currently perform conditioning of feeder faults on all cable types for the purpose of fault locating, and provide hi-pot capability on paper insulated cable, it is important that poorly performing sets are removed and replaced.

The DC Test sets to be replaced will be determined based on age, hours of operation, and maintenance issues, and operational need. A scoring matrix has been developed and is being utilized to determine the AC test sets for replacement. Sets are ranked on a scoring scale that looks at set age, hours of operation, maintenance history, manufacturer, etc. The current fleet scores from a 0 (best) to a 23 (worst).
AC VLF Test Sets Mobile & Fixed Location
These test sets are used to perform on-site testing and diagnostics of medium voltage feeder cables primarily for 4, 13, 27, and 33 kV feeders. This program is to support conducting AC hi-pot testing on EPR and Poly cable. The test sets are required to meet our feeder processing objectives and recommendations to conduct more VLF AC

hi-pot tests.

AC Test Sets, 345 kV
The W49th St. Substation test set, which has been in service for over 30 years, is no longer supported by the manufacturer. The Dunwoodie Substation no longer has an AC test set. Its test set is no longer functioning and cannot be repaired. These sets are used to perform conditioning and proof tests of equipment after overhauls and repairs, and are no longer reliable. Replacement of these units will eliminate the need to rent units when required which is not preferred due to cost and vendor availability constraints. The transmission test sets are required to maintain the reliability of station equipment and to ensure equipment is tested prior to restoring to service.

The 345 kV AC test set at W49th Street Substation for GIS testing is obsolete and undependable. The original OEM is out of business and there is no company to support repair and spare parts. The option of leasing a set as required to perform testing at this station was explored. However, due to clearance issues at this station, we could not find a suitable source of supply for leasing.

* <u>Alternatives:</u>

AC Test Sets - As noted above, we are working to see if a combination AC/DC test set can be developed. This would reduce our overall funding needs for this program, as it would halve the number of test sets that we would be required to purchase and maintain in our stations. However, at this time, there is no such unit on the market. We will continue to work with equipment manufacturers in this area to see if such a set can be developed. We could also move back to DC hi-pots on our distribution feeders, negating the need to purchase AC hi-pot sets. This alternative is not recommended, as AC hipots have proven to be better at detecting incipient faults on solid dielectric feeders.

DC Test Sets - Our primary alternative is to stop replacing DC test sets and continue to repair our problematic sets. This alternative is not recommended. Test set availability is critical to our ability to process feeders expeditiously. Leaving units in place that are likely to break down when called upon to perform will result in an increase in feeder processing times.

345kV AC Test Sets - Rather than purchase a new test set, we could look to lease a set on an as needed basis. This alternative is not recommended. Our experience has been that there are a very limited number of AC test sets in this voltage class available in the United States. We have had to bring units from as far away as California in the past, and this process has taken several weeks. Obtaining these sets under emergency conditions would be difficult and expensive.

* Risk of No Action: Performing routine DC High Voltage testing will create insipient faults in the cable causing a higher failure rate among the feeders tested.

**Current Status:** There are currently 20 permanently installed sets at various area substations. Under this program, we have also increased the number of mobile sets to 6 with the purchase of an additional 3 mobile AC VLF test sets for distribution feeder processing on the Con Edison system (two per operating region in Manhattan, Brooklyn/Queens, Westchester/Bronx). We will continue to install additional AC VLF test sets, giving priority to stations that have sufficient space to house the additional sets, or stations that have been highlighted by Electric Operations. To expedite the deployment of sets in the stations, we will split installation into 2 phases—first simply installing the test set and providing it a power feed, allowing testing to be done via the test lead provided with the set. Phase 2 would then install test boxes and conduit, replacing the coiled test lead that is provided with the set, and enhancing the efficiency with which the test set can be used to process feeders.

We are also continuing our activities to develop a combo AC/DC test set and plan to enter the procurement and construction phase of a prototype set in 2013.

We have currently awarded the engineering and fabrication of a new 345KV Test Set to be installed at West 49th St. Substation. The project has begun as of April 1, 2012 and we fully expect delivery of the test set by the end of 2012, with the set fully commissioned by April of 2013.

**Funding: ($000s)**

| **Funding Cost** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1541 | 6345 | 1945 | 3273 | 4000 | 5000 | 5000 | 5000 | 5000 | 5000 | 42104 |

* **2008 to 2012 Actuals in Thousands-** $17,104
* **2013 to 2017 Budget in Thousands-** $25,000

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Reinforced Ground Grid |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 17 |
| **Project Manager** | C. Davoren |
| **Project Engineer** | A. Mukhopadhyay |
| **Budget Reference** | 1ES7400 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 03 Fatality Due to Safety Negligence, per Risk 07 Prolonged Transmission Substation Loss, per Risk 08 Prolonged Area Substation Loss |

**Work Description:**

The intent of this program is to ensure the effectiveness of the grounding system at each station. As a result of a 2005 lightning incident at Astoria East Substation, a program has been implemented, as specified in CE-ES-1001, to test the ground mats of all substations periodically. This program reinforces the ground grid of those stations with degraded grounding systems that are identified by this periodic testing.

The following stations have been added to the ground grid reinforcement program based on the findings from the testing program and will be completed in future years.

Hudson Ave. East (originally planned for 2012, now deferred until 2013)
Corona (Currently planned for 2014)
Elmsford (Year TBD based on priority)
Hellgate(Year TBD based on priority)
E179th Street (Year TBD based on priority)

• Units per year: One (1) substation ground grid will be reinforced each year as part of this program at an approximate cost of $800,000 per station.

**Justification:**

In August 2005, lightning struck a transmission tower at the Astoria East Substation and caused extensive damage to a revenue metering current transformer and its associated wiring. An investigation revealed that the A-frame Tower was not properly grounded and various substation structures and equipment within the Astoria East yard had high grounding impedance. Inspections to determine the cause of the high impedance revealed several instances of damaged ground connection cables and one of the two main 1000 MCM cables that made up the existing main ground grid was badly corroded.

The excessive corrosion and deterioration of ground cables and underground connectors due to age related degradation require the ground grid be reinforced to minimize damage in the event of lightning strikes, switching surges, equipment, and/or feeder faults. Ground grid deficiencies are identified through the Company's periodic ground impedance test program. Ground Grid continuity measurements were taken at Stations that were built around the same time as the Astoria East Substation.

This program is driven by specifications CE-ES-2002-10 and CE-ES-1001. Key criteria driving action are ground grid impedance and ground grid continuity. The stations targeted do not meet acceptable levels in one or both of these categories. In this case, repair versus replacement is not truly applicable—the work covered under the program represents the required repairs to bring the station ground grid back to spec. The work is capitalized, as per Property Records Ruling.

* Alternatives: The alternative is to take no action. This is not recommended as ground grid deficiencies are identified through a periodic testing program and the failure to correct these deficiencies could result in serious equipment damage, personnel safety hazards, and reduced reliability.

* Risk of No Action: This is not recommended as ground grid deficiencies are identified through a periodic testing program and the failure to correct these deficiencies could result in serious equipment damage, personnel safety hazards, and reduced reliability.

**Current Status:**

2013 Planned Work: Hudson Ave East Substation
2014 Planned work: Corona Substation, plus one other from the work queue.

**Funding: ($000s)**

| **Funding Cost** | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 310 | 719 | 27 | 1614 | 901 | 1200 | 800 | 1600 | 1600 | 1750 | 1750 | 12271 |

* **2008 to 2012 Actuals in Thousands-** $4,461

| | | |
|---|---|---|
| * | **2013 to 2017 Budget in Thousands-** | $7,500 |

# 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Construct Relay Protection Canopies |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 39 |
| **Project Manager** | R. DeNezzo |
| **Project Engineer** | K. Davis |
| **Budget Reference** | 8ES4900 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 06 Prolonged Electric Outage Impact Customers |

**Work Description:**

This program is to install canopies to preclude deterioration of the relay cabinets while providing for safe inspection, maintenance, and repairs under most weather conditions. The installation of the canopies is a long-term solution to protect relay cabinets from inclement weather and enhance the reliability of the electric system. The canopies will consist of a structural frame with a roof and partial siding attached to the frame and panels protecting the roof and sides of the enclosure. Due to the slenderness of these panels, in some cases this housing can be mounted onto the existing relay cabinet foundations. Presently, the following facilities have relay canopies that are targeted for construction:

- Fresh Kills (4 canopies)
- Vernon Substation (2 canopies)
- Corona Substation (4 canopies)
- Greenwood Substation (4 canopies)

- Units per year: This program is funded to complete 4 canopies in 2012 and 8 canopies in 2013 at a unit cost of approximately $125,000 each.

**Justification:**

Relays are usually housed in heavy gauge steel cabinets designed to be water tight. When these steel cabinets are exposed to weather, they will deteriorate with time. In various substations, several of these outdoor relay cabinet installations are deteriorated and jeopardize the reliability of the electric system.

Relays are used to detect electrical problems or faults in transmission and area substations. When these relays detect a fault, they send a signal that operates protective equipment, such as a circuit breaker, which will isolate the fault and limit the damage. Relays will also send a signal to the control room and notify the station operator of the electrical hazard. It is important to ensure that these relays will always function because the detection of electrical problems in the substation will protect the operators in the area, limit the potential damage on substation equipment, and will minimize the number of customer outages. For these reasons, relays must be maintained in a dry and safe environment.

The metal relay cabinets are exposed to the elements and they have deteriorated over time. This has allowed water to enter the cabinets, and we run the risk of compromising the equipment and jeopardizing the reliability of the station. Installation of canopies will preclude deterioration of the relay cabinets while providing for safe inspection, maintenance, and repairs under all weather conditions. The installation of the canopies is a long-term solution to protect relay cabinets from inclement weather and enhance the reliability of the electric system. The canopies will consist of a structural frame with a roof and partial siding panels attached to the frame. These frames and panels will enclose and protect the existing relay cabinets.

* Alternatives: An alternative to the current solution is to build masonry structures to provide protection for the relay cabinets. This is a higher cost option and therefore not recommended.

* Risk of No Action: The risk of no action would be increased frequency of repairs and inspections and reduced reliability.

Current Status: Currently in progress on construction package to complete 4 relay canopies at Fresh Kills substation. Anticipate construction completion by end of 2012.

**Funding: ($000s)**

| **Funding Cost** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 31 | 1466 | 0 | 0 | 342 | 0 | 1096 | 1097 | 1088 | 1100 | 6298 |

* **2008 to 2012 Actuals in Thousands-** $1,839
* **2013 to 2017 Budget in Thousands-** $4,459

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Relay Modifications |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 1 |
| **Project Manager** | N. Roberts |
| **Project Engineer** | J. Vasco |
| **Budget Reference** | 2ES7800 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 03 Fatality Due to Safety Negligence,Oper Risk 06 Prolonged Electric Outtage Impact Customers,Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This program provides for technology upgrades to the relay protection systems at various substations.

Magnetic Inrush relay installations are complete for the feeders that have been identified by Engineering.

1. MCO Relays: The MCO relay is sensitive to certain transients and as a result, the relays have been removed from service system wide. The 87N MCO relays are being replaced with a Basler BE1-851 microprocessor relay which was tested and found to be not affected by transients.
2. Modification of D.C.T.T. for 138kV Feeders: A temporary modification was implemented to install a timer to delay the lockout relay operation from a direct current transfer trip (DCTT) signal. This allowed the circuit to override a communication disturbance without actuation of the lockout relay. In addition, the breaker failure scheme is being enhanced by opening the pilot wire on breaker failure lockout relay operation.
3. HCB Replacement: The HCB Westinghouse Pilot Wire electromechanical relay schemes utilize fault detector relays as a security element to prevent false trips and a PM relay to monitor the pilot wire. Misoperation data shows these systems have been historically poor performers. The HCB systems that have misoperated the most have been targeted to be replaced. HCB based systems have shown to be prone to false trips due to problems with the communication systems and/or defective relays. There are currently microprocessor based alternatives available that can be easily be used to replace the existing HCB systems. These new microprocessor relays eliminate the need for the PM relay and they have logic built into the software to differentiate between fault currents, load currents,

and communication problems.

4. GE AES300 Type Audiotone Systems: The GE AES300 is a first generation solid state audiotone transfer trip system that has become obsolete and is highly prone to communication line noise/interference generated trips. The equipment is being maintained using spare parts and new or reconditioned components are no longer available. Various microprocessor alternatives are available that utilize digital communications that alarms and alerts the station operator when a communication problem exists.

5. ABB LCBII and GE DLS: Recent data on the ABB LCBII and GE DLS relay systems have indicated component failures on these solid state relays. The failures have resulted in unnecessary trips especially during hot, humid and thunderstorm activity periods. Numerous attempts by the manufacturers to find and fix the root cause of the problems have not been very successful. There are currently microprocessor based alternatives available that can be easily be used to replace the existing systems.

6. Blocking Carrier Relay Systems: The blocking carrier relay systems rely on a trip blocking signal transmitted and received at a remote terminal to prevent unfaulted/unaffected circuit breakers from opening. Misoperation data indicate that these systems are prone to misoperate causing unnecessary trips. A modified system utilizing an un-blocking carrier system was installed on Feeders 5018, RFK 305 and Y94. This modified system includes microprocessor based relaying and PLC communication chassis.

7. Distance Relay Systems: There are 345 KV feeders that have a standard distance relay protection package, that includes CEY or SLY phase and ground relays for distance protection. The distance relays are being maintained using spare parts and new or reconditioned components are no longer available. There are currently microprocessor based alternatives available that can be easily used to replace the existing systems.

8. Digital Migration: Many of the relay system on the transmission system require communication circuits between the different ends of the transmission line for the relays to operate properly. Many of these systems used older technology analog circuits. These circuits have become less reliable over the years and the telephone companies no longer support this technology. To improve the overall reliability of the communication lines and the relay systems these analog communication circuits have been migrated over to digital communication circuits.

9. East 63rd Street Relay Upgrade: The intent is to upgrade the electro-mechanical relays in reference to the distribution feeders, transformers and syn bus to the new microprocessor type of relays. The scope of work is still in development phase.

10. Transformer Differential Upgrades - Modern transformers generally operate at higher flux density values due to the use of higher grain oriented steels during manufacturing. Due to this reason the transformers have a lower second harmonic over peak inrush current ratio and can

cause misoperations.

**Justification:**

Con Edison relay protection systems employs over 60,000 relays, 90% of these are electromechanical relays. Only in the past decade we have either replaced some of the electromechanical relays with microprocessor relays or have added new microprocessor relays whenever we have added new equipment and/or substations to our system. In general the electromechanical relays are quite robust in design, however, spare parts and/or new replacement relays are difficult to obtain as the original suppliers stopped manufacturing them over two decades ago. Furthermore, electromechanical relays are often single function relays that rely on precision mechanical parts like jewel bearings and watch springs that are prone to age related wear and tear. In addition they do not possess the ability to electronically store event information and transmit the data to a remote location. Implementation of this program will upgrade protection equipment to modern standards, improve reliability, prevent incorrect automatic relay operations, and provide better analysis capabilities.

1. Replace MCO Relays: The 87N MCO relays associated with all 5 transformers at Plymouth Street Substation, mis-operated and resulted in the loss of the Plymouth Street Substation. Due to this mis-operation at Plymouth Street, in depth testing was conducted and has been determined that the MCO relay is sensitive to certain transients and as a result, the relays have been removed from service system wide.
2. Modification of D.C.T.T. for 138kV Feeders: A modification is being implemented to install a timer to delay the lockout relay operation from a direct current transfer trip (DCTT) signal. This will allow the circuit to override a communication disturbance without actuation of the lockout relay. In addition, the breaker failure scheme is being enhanced by opening the pilot wire route 1 on breaker failure lockout relay operation.

3. Replace HCB Relays: The 1st and 2nd Line protection of various feeders are provided by electromechanical type HCB relays which are susceptible to communication line disturbances. The associated feeders have mis-operated and the existing relays' lack the design features that modern relays have, which are needed for analytical evaluation.

4. Replace LCB Relays: The existing relays are aged and have misoperated causing loss of feeders. Additionally, the existing relays lack the design features of modern relays for analytical evaluation (Fdrs 38R55 & 38R56).

**Current**

**Status:** 2012 Planned Work:

| | |
|---|---|
| Woodrow/Freshkills | Feeder 38R55 - Replace 1st & 2nd Line LCB Relays. |
| Woodrow/Freshkills | Feeder 38R56 - Replace 1st & 2nd Line LCB Relays. |
| Vernon/Queensbridge | Feeder 31281 - Replace 1st and 2nd Line HCB Systems. |
| Astoria W /Hell Gate | Feeder 24053 - Replace 1st and 2nd line relays. |
| Astoria W /Hell Gate | Feeder 24054 - Replace 1st and 2nd line relays. |
| Dunwoodie | Feeder W75 - Replace reclosing relays |
| Ramapo/Laden Town | Feeder W72 - Upgrade entire Relay System |
| Ramapo | Feeder 5018 - Replace First Line Blocking Carrier Relay |
| Sherman Creek /Dunwoodie North/E179th | Feeder 99031 Replace LCB System |

2013 Planned work

| | |
|---|---|
| Sherman Creek /Dunwoodie North/E179th | Feeder 99032 & 15031/15032 - Replace LCB System |
| Hell Gate /Astoria East /179th St | Feeders 34051 /15053 & 34052/15054 - Replace both 1st Line HCB /FCB and 2nd Line HCB /DCTT Systems |
| Buchanan | Feeder Y88 - Replace second line relay groups |
| Sprainbrook/Dunwoodie | 138 kV Feeder 99941 Audio tone upgrade |
| W49th st/E13th st | Feeder M54 Audiotone replacement |
| Ramapo | Feeder 69 - Replace First Line Blocking Carrier Relay |

**Funding: ($000s)**

| Funding Cost | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 3353 | 3724 | 4432 | 4377 | 5859 | 9735 | 8500 | 8550 | 8660 | 8644 | 8706 | 8800 | 83340 |

* **2008 to 2012 Actuals in Thousands-** $32,903
* **2013 to 2017 Budget in Thousands-** $43,360

| | |
|---|---|
| **Project/Program Title** | Relay Protection System Redundancy(Single Point of Failure) |
| **Priority Number** | Regulatory Requirement – NERC / NPCC |
| **Project Manager** | |
| **Project Engineer** | |
| **Budget Reference** | |
| **Project Number** | |
| **Status** | Planning/Concept |
| **Estimated Service Date** | 2014 -2024 |
| **Work Plan Category** | System and Component Performance |
| **ERM Addressed** | 3-Prolonged loss of transmission substation |

**Work Description**:

The project will provide addition of components on 138 kV switching stations, such that a failure or removal of any one of the following components of Protection Systems will not prevent achieving the Bulk Electric System (BES) performance requirements identified in the NERC TPL Reliability Standards:

- Any single AC current source and/or related input to the relay protection groups associated with a single element.
- Any single secondary AC voltage source and/or related input to the relay protection groups associated with a single element, when such voltage inputs are needed excluding the complete loss of an entire CCVT, VT, or similar device with multiple secondary windings.
- Any single protective relay that is used to measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal condition.
- Any single communication channel and/or any single piece of related communications equipment, used for the relay protection groups associated with a single element, when such communication between protective relays is needed to satisfy the BES performance requirements.
- Communications functions for communications-aided protection functions (i.e., pilot relaying systems)
- Communications functions for communications-directed protection functions (i.e., direct transfer trip)
- The failure or removal of any single element of the DC control circuitry that is used relay protection groups associated with a single element.
- The failure or removal of any single auxiliary relay that is used for any of the above functions.
- The failure or removal of any single breaker trip coil for any breaker operated by the Protection System (If a single trip coil is used, the breaker failure scheme DC must be independent of the breaker trip coil DC).
- The failure or removal of any single station battery, or single charger, or other single DC source. In some cases, this may require re-connecting existing DC branch circuits.

Note the above scope does not include expansion of existing control rooms, or outdoor relay panel line-ups, because we anticipate this will not be required to meet the requirements of the future NERC Reliability Standard..

**Justification:**
This project is intended to meet the expected requirements of the future NERC Reliability Standard, being developed by NERC Project 2009-07. Furthermore, we anticipate that the NERC definition of the Bulk Electric System (BES) will be adopted within the NPCC Region. For Con Edison, we anticipate that the BES will include, at least, all 138 kV transmission substations and

portions of the East River Generating Station. At this time, the implementation schedule and implementation plan requirements for complying with the future Reliability Standard are unknown.

**Estimated Completion Date:**
This is a multi-year project that is planned to be implemented over a minimum 10-year interval.

**Status:**
This project is in the planning/concept stage. Project scope will determine when the first draft standard is posted by NERC Project 2009-07 Standard Drafting Team.

**Funding ($000):**
A review of our facilities indicates that approximately $350M will be needed to implement all the changes that may be required by this project. This would likely be a multi (10-20 year) program if all of the components noted above have to up installed/upgraded, resulting in an annual spending requirement of $17.5-$35 mill. There is some belief that the final standard will not be as intensive as noted above, so we have planned a lower up front spending requirement. This will be finalized as more the Standard is finalized and implemented.

| Forecast 2013 | Forecast 2014 | Forecast 2015 | Forecast 2016 | Forecast 2017 | 5-year Forecast 2013 -2017 |
|---|---|---|---|---|---|
| - | 5,000 | 5,000 | 5,000 | 5,000 | 20,000 |

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Retrofit Overdutied 13kV and 27kV Circuit Breaker Programs |
| **Project Number** | |
| **Work Plan Category** | Reg - Agency Mandated |
| **Priority** | 32 |
| **Project Manager** | N. Roberts / N. Febrizio |
| **Project Engineer** | R. Gosine, John Urdea |
| **Budget Reference** | 0ES1300 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 06 Prolonged Electric Outage Impact Customers |

**Work Description:**

This program provides funding to replace a number of existing 13 & 27 kV circuit breakers installed in our substations that currently are not rated to interrupt maximum fault currents under worst-case scenario fault conditions. Circuit breakers will be replaced where the maximum fault current could, under a worst-case fault scenario, exceed their rating.
• Units per year: Currently, it is a PSC requirement to perform a minimum of 60 13/27 breaker retrofits per calendar year. With the funding budgeted, a combined total of 60 breaker replacements per year is targeted. This allows for the maximum number of replacements per year within the delivery and resource constraints associated with this equipment. In 2012, The Elmsford S/S breakers will be included in the count of 60.

The unit cost for a 13 kV circuit breaker retrofit is approximately $125,000 and the unit cost for a 27 kV circuit breaker is $250,000. In 2011, 65 - 13kV and 14 - 27kV breakers were retrofitted for a total of 79.

**Justification:**

Based on a 2005 study analysis, performed by the Company and verified by an independent consultant (ABB), fault currents exceed breaker interrupting capability at 35 area substations. The analysis assumes a worst-case scenario based on all the equipment in the station being on line, a failure occurring across all three phases at or near the station switchgear, and perfect conductivity between the phases at the failure point. Despite the unlikelihood of all these factors occurring simultaneously, we take the extra precaution of physically isolating the three phases within the station to further reduce the probability of such an event.
A long-term system enhancement program was established to replace and/or upgrade all of these 13 and 27 kV circuit breakers. Under this program, the first priority is given to the

stations where the potential over-duty is 10 percent or greater. The second priority is given to the substations where the potential over-duty is between 3 and 10 percent. Finally, the substations with less than 3% potential over-duty are being addressed as the third priority.

* Alternatives: Complete switchgear replacement – not considered because it is cost prohibitive. Average cost of $125K/position for retrofit vs. $500K/position cost for replacement. Replacement is also time consuming and compromises reliability for the duration of replacement.
* Risk of No Action: Do Nothing – not recommended, can lead to extensive equipment failure in case of breaker inability to open under fault conditions. Inability to accommodate IPP's to hook up to our networks.

**Current Status:** 2011 13kV: Completed work at the following stations: E75th St, W42nd St, , W110-1, West 65th St
2012 13kV completed and planned work at the following stations: W110th St. #1 and #2. , Corona, W65th St, East 63rd St.

2013 13kV: Planned work at the following stations: W110th St #2, , East 63rd St., West 65th St

2011 27kV: Completed work at the following stations: Jamaica, Corona, Glendale

2012 27kv: Planned work at the following stations: Bensonhurst, Corona, Glendale, Jamaica.

2013 27kv: Planned work at the following stations: Bensonhurst, Glendale, Jamaica.

**Funding: ($000s)**

| **Funding Cost** | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 10955 | 9483 | 11076 | 15803 | 10488 | 9866 | 8000 | 10278 | 11300 | 10500 | 10000 | 10000 | 127749 |

* **2008 to 2012 Actuals in Thousands-** $55,233
* **2013 to 2017 Budget in Thousands-** $52,078

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Roof Replacement T&S |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 28 |
| **Project Manager** | J. McCoy |
| **Project Engineer** | K. Davis |
| **Budget Reference** | 2ES8200 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | |

**Work Description:**

This program provides replacement of roofing on buildings at our substations and other facilities where the roofing has deteriorated or when leaks are found. The Company has an on-going program to inspect each of the 500 roofs approximately once every five years (more frequently for older roofs, less frequently for newer roofs), averaging 100 roofs per year. A large number of our facility roofs have deteriorated and have been repaired numerous times. The roof inspection program reveals which of our roofs have deteriorated beyond repair. Roofs are replaced when needed. The current unit cost for roof replacement is $26 per square foot for EPDM roofs and $65 per square foot for Kemper roofs.

This work is required to avoid permanent damage to equipment, accelerated structural deterioration and personal safety hazards. Delay in roof replacements when needed increases the likelihood of these events.

**Justification:**

Water intrusion due to roof leaks can result in equipment damage and affect substation reliability. Standing water on floors and roofs causes slippery conditions and electrical hazards that are personnel safety concerns. Prolonged exposure to water intrusion causes concrete spalling, corrosion of rebar, and degradation of the structural integrity of the building. The installation of new roofing will eliminate leaks and the operational and safety hazards associated with water intrusion and accumulation. Removal of existing roofing materials will also assure any asbestos issues, if present, are alleviated. This is a system enhancement program.

There is no specification driving this program however in order to provide reliable service, we must maintain our facilities in good working condition and toward that end have initiated the roofing program. This program is committed to inspecting each of the approx. 500 roofs every five years (more frequently for older roofs, less frequently for newer roofs), averaging 100 roofs per year, and to repair or replace roofs as needed. The results from the roof inspections determine if a particular roof can be repaired or needs to be replaced. The roofs are rated on a standardized 1-9 scale, with 1 being a roof in excellent condition and 9 being a roof requiring immediate attention. Roofs scoring 7 or above are scheduled for replacement, all others are repaired as required. Generally, roofs scoring below a 7 can be effectively repaired to address issues found. Repairs are short term fixes that will extend the life of the roof by a few years. Replacement roofs are typically good for 20years. Typically roofs requiring replacement are not candidates for repair, except on an emergency basis.

RATINGS DESCRIPTION
1. New Roof 1 to 2 years old, no work needed.
2. Roof more than 2 years old, no work needed.
3. Roof has no leaks, less than 5% of the roof area to be repaired. This also includes repairs to gutters, drains, leaders, and painting of metal roof and debris removals.
4. Roof has no leaks, 5-10% of the roof area needs repairs.
5. Roof has no leaks, 10-20% of the roof area needs repairs.
6. Roof has leaks; up to 20% of the roof area needs repairs.
7. Roof has leaks; up to 40% of the roof area needs repairs.
8. Roof leaks and requires replacement. No structural damage to deck or framing.
9. Roof leaks are very bad and require replacement. Structural damage to deck and/or framing. Hazard to occupants and equipment.

* Alternatives: The only viable alternative for this program is to take no action or cover with tarps. This approach is not recommended as prolonged exposure to the elements will result in water intrusion that will consequently result in further degradation of the roofing system. Since equipment housed within the substation buildings is not designed to be exposed to the elements, water intrusion will adversely affect the equipment housed under the roofing system, thereby impacting system reliability.

**Current Status:**

Work planned for 2012 includes the following roof replacements:

Hudson Ave E. Pump House #1 – Rated 8
West 132nd St. M52S PURS R2 – Rated 6
West 132nd St. M52N PURS R4 – Rated 7
Jamaica Switchgear House – Rated 8
Jamaica Pump House 6A – Rated 8
Jamaica Pump House 6B – Rated 8
Jamaica Pump House 3 – Rated 8
Vernon Pump House 6 – Rated 7
Fresh Kills Oil Pump House 1 – Rated 8
Fresh Kills 34KV Relay House 2 – Rated 7
Goethals Oil Pump House 1 – Rated 7
Fox Hills 138KV Relay House – Rated 7
Fox Hills 34KV Relay House A and B – Rated 7
Fox Hills Fire Pump House – Rated 7
Parkchester 1&2 Control Building – Rated 7

Work planned for 2013 includes the following roof replacements:

Greenwood Pump House #1 – Rated 8
E179th Street Control Building & Penthouse – Rated 8
Hellgate Reporting Center Stair Tower – Rated 8
Glendale Bathroom & Battery Room Addition – Rated 8
Astoria East Oil Pump House 3 – Rated 8
North Queens Pump House 1 – Rated 8
West 49th St. Pump House 6 – Rated 7
Ramapo Fire Pump House – Rated 7
Sprain Brook M52 PURS R2 – Rated 7
McLean Avenue M52N PURS R2 – Rated 5
McLean Avenue M52S PURS R4 – Rated 7

**Funding: ($000s)**

| **Funding Cost** | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1236 | 861 | 1172 | 641 | 2701 | 1229 | 3000 | 3000 | 3000 | 3000 | 3300 | 3300 | 26440 |

* **2008 to 2012 Actuals in Thousands-** $8,743
* **2013 to 2017 Budget in Thousands-** $15,600

# 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Security Enhancements T&S |
| **Project Number** | |
| **Work Plan Category** | Strat - Public & Employee Safety |
| **Priority** | 12 |
| **Project Manager** | F Lupo |
| **Project Engineer** | S Eagleton |
| **Budget Reference** | 2ES7100 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This program continues to upgrade security systems at Bulk Power System (BPS) stations. BPS stations became the focus of security enhancements beginning in 2010. Security upgrades include new CCTV systems, card access and perimeter protection.

The following have been BPS selected for upgrade in 2012-2013
Eastview
Fresh Kills
Pleasant Valley
Farragut
East Fishkill
Pleasantville
Tremont
Rainey

This program will also upgrade the 450 MHz walkie-talkie radio system at 10 substations per year. The radio system has two primary functions. One function, the man-down system, is a safety feature installed in the radio that sends an alert when the radio remains in the horizontal position for more than 15 seconds. This feature is used by Station Operators when working in a station. The alert is sent to the Substation Operations Shift Manager. The second function of the radio system is to provide a back-up means of communications to the Energy Control Center and Alternate Energy Control Center in the event of the loss of the telephone lines.

**Justification:**

The security upgrades at the listed stations are necessary to meet the requirements of Con Edison Security Specification CE-ES-2002-24. This program will bring substation facilities into compliance with the existing specification. In addition it will comply with the recommendations of the Public Service Commission with regards to in place security measures for Bulk Power System substations. The man-down radio feature facilitates the ability to conduct one person switching operations thereby helping to reduce labor costs and improve operational response time. The upgrade will also improve the reliability of back-up communications.

* Alternatives: The only alternative is to take no action. This is not recommended as these security enhancements are necessary to meet the minimum requirements of CE-ES-2002-24. These requirements are necessary to ensure Substation facilities are adequately protected against vandalism, theft, and security breaches that can result in compromised service to our customers as well as an increased risk to the safety of the public and company personnel.

**Funding: ($000s)**

| **Funding Cost** | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 11 | 2678 | 1262 | 2833 | 3620 | 8000 | 9085 | 6495 | 6699 | 4353 | 5000 | 50036 |

* **2008 to 2012 Actuals in Thousands-** $18,393
* **2013 to 2017 Budget in Thousands-** $31,632

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Small Capital Equipment Program |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 22 |
| **Project Manager** | N. Graham |
| **Project Engineer** | K. Davis |
| **Budget Reference** | 0ES3200 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 08 Prolonged Area Substation Loss |

**Work Description:**

This program funds various smaller scoped project modifications and upgrades at individual substations for equipment related upgrades, as required. Minor equipment improvements, such as the following, are covered under this program:
• Cable Trough Replacement
• Replacement of Potential Transformers
• Barksdale Switch Installations
• Bird Netting in Transformer Vaults
• Purchase of Spare or Replacement Distribution Voltage Breakers
• Installation of HVTS test boxes and test bus

**Justification:**

This program is required to fund small scoped projects that are not covered by other capital programs. These projects are necessary to maintain and improve the infrastructure of substation facilities and the electrical system.

* Alternatives: The alternative is to take no action. This is not recommended as the improvements described are necessary to maintain facilities and equipment in working order. The risk of no action is that the continued degradation of equipment and facilities could lead to potentially hazardous conditions that could impact equipment reliability and the safety of company personnel and the public.

* Risk of No Action: This is not recommended as the improvements

described are necessary to maintain facilities and equipment in working order. The risk of no action is that the continued degradation of equipment and facilities could lead to potentially hazardous conditions that could impact equipment reliability and the safety of company personnel and the public.

**Current Status:**

Projects Completed in 2011 – The following projects were completed in 2011: 1) Parkchester Test Probe Cabinets Installation Feeder Processing, 2) Astoria West Relocate Diesel Generator Tank to Comply with FDNY Regulations, 3) Queensbridge Installation New Fire Detection System, 4) W. 49th St. Replace GIS Section N-S CCPD's with PT's, 5) Various Replace Capacitor Bank Breakers Granite Hill, Washington St., and Harrison, 6) Jamaica Upgrade Diesel Fuel Tank Monitoring System, 7) Plymouth St. Overhaul (2) 27 KV Capacitor Bank Breakers, 8) Rainey Upgrade Kenitron Plug Enclosures, 9) Brownsville and Glendale Installation New Capacitor Bank Grounding Systems.

Current Status 2012: The following projects are a sampling of Small Capital Projects identified as candidates to be funded via this program in 2012.

1) Replace Various 13 KV Cap Bank Breakers
2) Various Bronx S/S Installation of Barksdale Switch Assemblies
3) E. 63rd St. – Replace Bird Netting System
4) Greenwood – Install Gaurdail System Roof Area
5) Parkchester – Extend HVTS Room and Run Cable & Install Test Boxes HVTS System
6) Various – Piping Modifications Emergency Diesel Generators
7) E. 13th St. – Install New Support Insulators on Transformers 10 & 11
8) Vernon – Replace PTs Bus Section 2E & 5W
   Other projects similar to these listed make up the entire candidate listing. We expect other projects similar to those listed above to emerge and be added to future candidate listings.

Projected 2013 Projects: The following projects are a sampling of Small Capital Projects identified as candidates to be funded via this program in 2013.

1) E. 13 th St – Barksdale Switch Installations
2) Sherman Creek/Sedgwick Ave – Bird Netting Installations
3) Eastview/Buchanan/Astoria East – Trough Cover Replacements
4) Rainey – Replace Bus Section6E CCPD's
5) E. 13th St – Replace 3 138KV PTs w/CCVTs in Bus Section 9

Other projects similar to these listed make up the entire candidate listing. We expect other projects similar to those listed above to emerge and be added to future candidate listings

**Funding: ($000s)**

| **Funding Cost** | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 5061 | 3263 | 2486 | 5177 | 2796 | 3127 | 4942 | 3000 | 3000 | 3000 | 4000 | 4000 | 43852 |

* **2008 to 2012 Actuals in Thousands-** $18,528
* **2013 to 2017 Budget in Thousands-** $17,000

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Storm Hardening |
| **Project Number** | Various |
| **Work Plan Category** | Strat. - System and Component Upgrades |
| **Priority** | |
| **Project Manager** | TBD |
| **Project Engineer** | TBD |
| **Budget Reference** | TBD |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss, Oper Risk 08 Prolonged Area Substation Loss, Oper Risk 22 Significant Oil Spill Water Damages |

**Work Description:**

This program consists of improvements to a number of area and transmission substations that have been recommended following assessments of the damages and system impacts that were experienced during Hurricane Sandy. The work to be done on this program focuses on near term improvements that we intend to make to the stations that were most impacted by Sandy, as well as stations that shut down as a result of the storm which had the greatest impact on our customers. We anticipate additional work to fall under this program in future years, as we further evaluate our entire system and potential hardening options.

The program developed to protect these stations has been broken into phases. The first phase is for 'Immediate Hardening Measures.' We are working to install the bulk of these measures prior to the start of the hurricane season of 2013 (June 1) where practicable, to ensure that a repeat storm this year would not cause a loss of load at critical stations and would result in significantly less customer outages. Any measures that cannot be completed prior to the start of the hurricane season will be completed as soon as possible after that. The measures that are planned for this first phase include:

- Installation of moats and walls around critical station equipment
- Sealing of troughs, conduits, panels and cabinets, as well as any other critical station penetrations
- Installation of removable flood doors and barriers

The second phase of the project is for full 'Storm Hardening' at our highest priority locations—those that saw the most impact from Hurricane Sandy. This effort will include protecting these stations and all critical equipment and assets against future storms. This phase is expected to span several years, with the majority of the work done at these facilities completed in 2014, and any remaining work completed by 2015. This work is intended to ensure the permanent protection of the stations against flooding, wind and tidal surge. The permanent measures that will be undertaken in this phase include:

- Migration of the substation control room at select stations
- Elevation of critical relays and control panels
- Installation of nitrogen powered pumps for pressurization plants
- Installation of fiber optic communication lines
- Raising and sealing of moat walls, curbs, louvers and flood barriers

In addition to these permanent measures, the scopes for the stations in Brooklyn (Gowanus) and Staten Island (Goethals and Fresh Kills) will also include perimeter surge walls to better protect the stations and all station equipment.

Much of our work in the near term (2013 and 2014) will be focused on nine facilities:

- E13th Street Substation
- East River Substation
- East 16th Street PURS Plant
- Gowanus Substation
- Goethals Substation
- Fresh Kills Substation
- East 36th Street Substation
- Trade Center Substation
- Seaport Substation

At some of these locations, such as East River Substation, East 36th Street, Seaport, and Trade Center, we are looking to make relatively smaller scale upgrades to the stations. These modifications include items such as flood barriers in the transformer vault walls, flood gates, water tight roll up doors, backflow preventers, and moat walls.

At other locations we are focusing on installing perimeter surge barrier walls to protect the entire facility from flood waters and storm surges. We are currently planning to do this at Gowanus, Goethals, and Fresh Kills.

At the East 13th Substation and East 16th Street PURS, our focus is on elevating critical equipment. At this station, we intend to relocate the control room to a 2nd story elevation. This will involve substantial wiring upgrades and replacements to migrate all of the control wiring from one site to another. We also intend to raise the control panels in our pumphouses and cooling plants, install flood barriers and doors, and raise some key pieces of equipments such as light and power transformers, diesel generators, and critical load boards and switchgear.

A more detailed list of all the work planned in these initial phases can be found in **Attachment 1.**

Our third phase of work is at an earlier stage of development. We are anticipating the need to harden other stations based on different hurricane/flooding scenarios. These have yet to be fully studied and work scopes developed, but we anticipate the likelihood that we will be undertaking some level of hardening initiatives similar to the ones mentioned above at the following stations:

- Sherman Creek
- Bruckner/Hellgate
- West 49th Street
- Academy
- Astoria East/Astoria West/North Queens
- Farragut
- Rainey
- Vernon

We may also determine that hardening efforts related to wind events are required at additional facilities. We would anticipate that the hardening efforts at these facilities would commence in 2015 and would be completed in 2016.

**Justification:**

Hurricane Sandy caused an unprecedented amount of damage to our system and outages to our customers. The loss of our East 13th Street/East River complex caused outages to all of lower Manhattan. We also experienced significant damages to a number of other stations and could have lost these stations as well under slightly different circumstances—increasing the overall cost for damage repairs and the hardships endured by our customers.

Following the Sandy recovery effort, Con Edison evaluated the necessary changes to the system that would have to be made to protect and harden substations against similar design basis storms. The stations that were affected include:

- East 13th Street Substation
- East River Substation
- East 15th Street Public Utility Regulating Station
- East 36th Street Substation
- Seaport Substation
- World Trade Center Substation
- West 49th Street Substation
- Goethals Substation*
- Fresh Kills Substation*

- Gowanus Substation*
- Academy Substation
- Sherman Creek Substation
- Hellgate/Bruckner Substation

This program will address many of the issues that were experienced during Hurricane Sandy, and prevent their recurrence. This initial set of work focuses on the stations that are most vulnerable to shutdowns and/or service interruptions.

The work recommended here is aimed to either prevent future station shutdowns altogether, or allow for equipment to be returned to service quickly after a shutdown occurs (in certain cases, we would preemptively shut facilities down to prevent extensive damages, until flood waters recede).

**Current Status:**

We have prepared preliminary scopes and order of magnitude estimated for the majority of our 2013 and 2014 planned work. We are continuing to review these scopes and developing work plans to most effectively and efficiently implement these projects. We anticipate having the majority of our final scoping and appropriation documents in place by the second quarter of 2013, which should allow equipment purchases and construction activities to commence in the summer of 2013. Work would continue on these initial projects through 2014, with some work on the largest projects (East 13$^{th}$ Street Control Room Relocation, Gowanus/Goethals/Fresh Kills Surge Walls) carrying over into 2015 . Interim measures work is expected to be in place by June of 2013

As noted above, while this work is in progress, we expect to develop additional, longer term projects to provide hardening to more of our stations. The specific work scopes and funding required for these projects will be provided as they become available.

**Funding: ($000s)**

| **Funding Cost** | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|
| | 30000 | 60000 | 70000 | 80000 | TBD | 240000 |

* **2008 to 2012 Actuals in Thousands-** $0

| | | |
|---|---|---|
| * | **2013 to 2017 Budget in Thousands-** | $240,000 |

## *East 13th Street S/S: IMMEDIATE HARDENING MEASURE- SCOPE OF WORK*

| ***Equipment Type*** | ***Scope of Work*** |
|---|---|
| Control Room | Seal all penetrations into the Control Room whether conduits, doors, blanked panel on E13th Street. Install flood doors/barriers at egresses. |
| Relay Houses | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Millhouse Transformers | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| E13th Street Transformers | Install higher walls at Louvers, Seal all doors and station egresses |
| Pumphouses | Elevate all control cabinets in the houses. Install nitrogen driven pumps as backup. |
| Cooling Plants | Elevate all control cabinets in the plants and replace pumps |
| Diesel Generator | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Disc. & Ground Switches | Seal all penetrations at conduits and cabinets. Seal cable troughs. |

## *East 13th Street S/S: FINAL MEASURE- SCOPE OF WORK*

| ***Equipment Type*** | ***Scope of Work*** |
|---|---|
| Control Room | Relocate Control Room to the existing SSO work space on the second floor. Relocate work space to temporary location until existing control room can be remodeled. |
| Relay Houses | Relocate Relay Cabinets to localized areas near the transformers at a higher elevation utilizing micro-processor relays and fiber optic connections. |
| Millhouse Transformers | Isolate critical operational controls/circuits within the existing transformer control cabinets, installing jumpers to new cabinets at higher elevations. Create Operational Procedure for the isolation of critical and non-essential circuits during an inclement event. Convert relay protection circuits to fiber optic through installation of fiber bricks. |
| E13th Street Transformers | |
| Pumphouses | Elevate all control cabinets in the houses. Install nitrogen driven pumps as backup. |
| Cooling Plants | Elevate all control cabinets in the plants and replace pumps |
| Diesel Generator | Elevate the Diesel Generators above the flood line. Install on a trailer or easily removeable pallet for quick removal/installation. Install quick-type emergency connection points accessible at the station. |

## *East River S/S: IMMEDIATE HARDENING MEASURE & FINAL MEASURE SCOPE OF WORK*

| ***Equipment Type*** | ***Scope of Work*** |
|---|---|
| East River Substation | Remove existing perimeter fencing, raise concrete threshold level around perimeter of station, install new louvers, install flood barriers and water-proof doors |
| Relay Houses | Proceed with East River Automation Project which is elevating and relocating compromised relays and controls. |
| Pumphouses | Elevate all control cabinets in the houses. Install nitrogen driven pumps as backup. |
| Cooling Plants | Elevate all control cabinets in the plants and replace pumps |
| Diesel Generator | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Disc. And Ground Switches | Seal all penetrations at conduits and cabinets. Seal cable troughs. |

## East 15th Street Cooling Plants: IMMEDIATE HARDENING MEASURE- SCOPE OF WORK

| Equipment Type | Scope of Work |
|---|---|
| Control Room | Seal all penetrations into the Control Room whether conduits, doors, blanked panel on E13th Street. Install flood doors/barriers at egresses. |
| Relay Houses | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Light and Power Transformers, Switchgear Cubicles, and Load Boards | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| E13th Street Transformers | Install higher walls at Louvers, Seal all doors and station egresses |
| Pumphouses | Elevate all control cabinets in the houses. |
| Cooling Plants | Elevate all control cabinets in the plants and replace pumps |
| Diesel Generator | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| | |

## East 15th Street Cooling Plants: FINAL MEASURE- SCOPE OF WORK

| Equipment Type | Scope of Work |
|---|---|
| Control Room | Seal all penetrations into the Control Room whether conduits, doors, blanked panel on E13th Street. Install flood doors/barriers at egresses. |
| Relay Houses | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Light and Power Transformers, Switchgear Cubicles, and Load Boards | Replace Transformers and switchgear. Relocate to a higher elevation on a steel platform with handrails and access. |
| E13th Street Transformers | Install higher walls at Louvers, Seal all doors and station egresses |
| Pumphouses | Elevate all control cabinets in the houses. |
| Cooling Plants | Elevate all control cabinets in the plants and replace pumps |
| Diesel Generator | Elevate the Diesel Generators above the flood line. Install on a trailer or easily removeable pallet for quick removal/installation. Install quick-type emergency connection points accessible at the station. |

## East 36th Street S/S: IMMEDIATE HARDENING MEASURE & FINAL MEASURE - SCOPE OF WORK

| Equipment Type | Scope of Work |
|---|---|
| Perimeter of the Station | Remove existing baffle plates on Louvers and install reinforced plates to withstand water from entering through the louvers, reseal all joints at the pre-cast panels, replace the doors |
| Relays and Switchgear | Protected via above methods. As a final measure, elevate lowest level of terminal blocks, connections, etc in the cabinets, cubicles, and switchgear. |
| Cooling Plants | Elevate all control cabinets in the plants and replace pumps |
| Diesel Generator | Install a quick connect system at the station so that a Portable Emergency Diesel can be installed during an Emergency situation. |
| Reactors | Install new Air-Core Reactors similar to ER R14 which are higher |
| Disc. And Ground Switches | Seal all penetrations at conduits and cabinets. Seal cable troughs leading from transformer vaults into the switchgear area. |
| Deluge Pump Room | Install a removeable flood barrier at the top of the staircase to limit water from entering the subterranean room. |

| TRADE CENTER S/S: IMMEDIATE HARDENING MEASURE-SCOPE OF WORK | |
|---|---|
| ***Equipment Type*** | ***Scope of Work*** |
| Pressurization Plant | **Cellar Level**<br>•Install flood gates/barriers at doors separating Con Edison section of cellar from office building section of cellar.<br>•Seal all foundation wall penetrations.<br><br>**Ground Floor Level** |
| Fire Protection Equipment | |
| Oil Water Separator | |
| AC Panels for Lights, Receptacles & Telecom Room | |
| Transformer Vaults | **Ground Floor Level**<br>Raise existing moat curbs along vault louvers and install flood gates/barriers at vault exterior doors. |
| **TRADE CENTER S/S: FINAL MEASURE-SCOPE OF WORK** | |
| ***Equipment Type*** | ***Scope of Work*** |
| Pressurization Plant | **Cellar Level**<br>Same as interim measures. Flood waters reached the cellar ceiling so raising equipment is not an option. |
| Fire Protection Equipment | |
| Oil Water Separator | |
| AC Panels for Lights, Receptacles & Telecom Room | |
| Transformer Vaults | **Ground Floor Level**<br>Raise vulnerable cabinets above storm water levels. Provide access platforms to raised equipment. |

| SEAPORT S/S: IMMEDIATE HARDENING MEASURE-SCOPE OF WORK | |
|---|---|
| ***Equipment Type*** | ***Scope of Work*** |
| **Transformer Vaults**<br>•Circuit Switcher & Circuit Interrupter Control Cabinets<br>•Transformer Control Cabinets & Tap Changer Cabinets<br>•Back-up Relay Panels<br>•Audio Tone Panels<br>•Barksdale Switches | Replace the existing metal flood panels behind the vault louvers with taller concrete moat curbs. |
| **L&P Transformer Room**<br>•Exhaust Fan Switch Boxes | Install flood doors/barriers at exterior doors. |
| **Loading Dock Area**<br>•Pumping Plant Crossover Valve | Install removable flood gate/barrier at the roll up door. Install flood door/barrier at exterior door in the stairwell adjacent to the loading dock area. |

| ***SEAPORT S/S: FINAL MEASURE-SCOPE OF WORK*** | |
|---|---|
| ***Equipment Type*** | ***Scope of Work*** |
| **Transformer Vaults**<br>•Circuit Switcher & Circuit Interrupter Control Cabinets<br>•Transformer Control Cabinets & Tap Changer Cabinets<br>•Back-up Relay Panels<br>•Audio Tone Panels<br>•Barksdale Switches | Raise affected control cabinets and panels above the storm water level. Provide movable platforms for access to raised cabinets/panels. Move wiring terminal blocks above the flood level inside the transformer control cabinets. |
| **L&P Transformer Room**<br>•Exhaust Fan Switch Boxes | |
| **Loading Dock Area**<br>•Pumping Plant Crossover Valve | |

| ***Goethals S/S: IIMMEDIATE HARDENING MEASURE - SCOPE OF WORK*** | |
|---|---|
| ***Equipment Type*** | ***Scope of Work*** |
| Control Room | Seal all penetrations into the Control Room whether conduits, doors, etc. Install flood doors/barriers at egresses. |
| Relay Houses | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Transformers | Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Pumphouses | Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Diesel Generator | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Reactors | Install new Air-Core Reactors similar to ER R14 which are higher |
| Disc. & Ground Switches | Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| ***Goethals S/S: FINAL MEASURE- SCOPE OF WORK*** | |
| ***Equipment Type*** | ***Scope of Work*** |
| All | Install perimeter flood wall and flood gates to provide surge protection and station security. |

| ***Fresh Kills S/S: IMMEDIATE HARDENING MEASURE - SCOPE OF WORK*** | |
|---|---|
| ***Equipment Type*** | ***Scope of Work*** |
| 345kV Control Houses | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Reactors | Install new Air-Core Reactors similar to ER R14 which are higher |
| Motor Operated Disconnects | Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| ***Fresh Kills S/S: FINAL MEASURE- SCOPE OF WORK*** | |
| ***Equipment Type*** | ***Scope of Work*** |
| All | Install perimeter flood wall and flood gates to provide surge protection and station security. |

| ***Gowanus S/S: IMMEDIATE HARDENING MEASURE - SCOPE OF WORK*** | |
|---|---|
| ***Equipment Type*** | ***Scope of Work*** |
| Control Room | Seal all penetrations into the control room. Install removable flood barriers at egress. |
| Relay Houses | Install removable flood barriers to protect equipment. Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| Pumphouses | Seal all penetrations at conduits and cabinets. Seal cable troughs. |
| ***Gowanus S/S: FINAL MEASURE- SCOPE OF WORK*** | |
| ***Equipment Type*** | ***Scope of Work*** |
| All | Install perimeter flood wall and flood gates to provide surge protection and station security. |

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Switchgear Enclosure Upgrade Program |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 48 |
| **Project Manager** | J Dorn |
| **Project Engineer** | W. Ziminski |
| **Budget Reference** | 8ES1200 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 06 Prolonged Electric Outtage Impact Customers |

**Work Description:**

This program will modify and upgrade selected outdoor switchgear enclosures throughout the system ensuring the switchgear cubicles are weatherproof.

**Justification:**

The switchgear cubicles in a number of substations require upgrading. These outdoor switchgear housings are typically about 40 years old. They have been weathered by the years of exposure to the elements. Their construction is typically a sheet metal enclosure resting on a concrete slab. Many steel components are corroded. The exterior doors no longer close and seal correctly. Many slabs are deteriorated and do not allow proper drainage accelerating corrosion of the housings. The roofs leak. The upgraded enclosures will reduce weather intrusion related trip outs, unscheduled outages, and alarms.

* Alternatives: An alternative is to replace the switchgear. This is not a reasonable consideration because the high cost and significant outage requirements of replacement

* Risk of No Action: The locations scoped into this program have been included due to the fact that the enclosure conditions present a risk to the reliable operation of the equipment housed within the switchgear. The risk of no action is a higher probability of unanticipated equipment failures and outages.

**Current Status:**

Planned work for 2012:
East 63rd St, East River will be completed and an upgrade to the enclosure doors at W42nd St that will prevent weather

intrusion St will begin and complete in 2012.
Planned work for 2013:
Parkchester No.1 and Jamaica Substations will have their switchgear enclosures upgraded to prevent weather intrusion.

**Funding: ($000s)**

| **Funding Cost** | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 19 | 86 | 123 | 794 | 1000 | 0 | 1000 | 1000 | 1100 | 1100 | 6222 |

* **2008 to 2012 Actuals in Thousands-** $2,022
* **2013 to 2017 Budget in Thousands-** $4200

## 2013 Capital - Central Operations/Transmission & Substation Operations

| | |
|---|---|
| **Project Name** | Transformer Replacement Program |
| **Project Number** | |
| **Work Plan Category** | Strat - System and Component Upgrades |
| **Priority** | 7 |
| **Project Manager** | J. Palma |
| **Project Engineer** | J. Liberatori |
| **Budget Reference** | 2ES8000 |
| **Project Status** | Ongoing |
| **End Date** | Dec 31 2017 |
| **ERM Addressed** | Oper Risk 07 Prolonged Transmission Substation Loss,Oper Risk 08 Prolonged Area Substation Loss,Oper Risk 22 Significant Oil Spill Water Damages |

**Work Description:**

The purpose of this program is to replace transformers that have reached the end of their life expectancy and cannot be maintained in a reliable operating condition. Included in the scope of the transformer replacement is the installation of a moat system for the vault, a new fire protection system, and a transformer condition monitoring system. Funding will also be used to secure future transformer orders with long lead times for future replacements identified by our asset management program.

• Units per year: The program is being funded to replace the following units:

- Washington St TR2.
- Dunwoodie PAR N1.
- Dunwoodie S1/S2- Purchase 300 MVA, 138 kV PAR.
- East 179th Street TR 6 and TR5.
- Cherry Street TR5 (Feeder 69M45) and TR1 (Feeder 69M41).
- Avenue A TR3 and TR1.
- East 13th Street TR11.

These units have been targeted for replacement due to their operating conditions and higher risk of failure. The program needs to remain flexible to be able to replace transformers as conditions dictate. The cost to replace a typical area substation transformer is $14,000,000. The cost to replace a typical transmission substation transformer is $20,000,000.

**Justification:**

There are approximately 400 transformers on the system of which approximately 150 have been in service for over 40 years. As these units deteriorate there is an increase in the amount of corrective maintenance and the probability of malfunction. Replacement parts are special custom order and require long lead times to receive. Proactively replacing problematic transformers prior to failure is cost effective when compared to emergency replacement, improves the reliability of the system, and provides a process for life renewal of the transformer fleet.

* <u>Alternatives:</u> An alternative strategy of running transformers to failure could be employed. This strategy was rejected because failures can occur at inopportune times, leading to customer outages. Failures also have the potential to be catastrophic resulting in large costs for damages and severe environmental impact. The lack of a replacement strategy would lead to a deteriorated transformer fleet that could not be maintained in a reliable condition.

* <u>Risk of No Action:</u> Failures can occur at inopportune times, leading to customer outages. Failures also have the potential to be catastrophic resulting in large costs for damages and severe environmental impact. The lack of a replacement strategy would lead to a deteriorated transformer fleet that could not be maintained in a reliable condition.

* <u>Technical Evaluation and Analysis:</u> A research project is on-going with EPRI (Electric Power Research Institute) for the Intelligent Fleet Management of our transformers. EPRI has developed a program for evaluating transformers using available data to make intelligent repair/replace decisions. A similar one-time study was also completed with ABB, who has worldwide experience with transformer manufacturing, to evaluate our fleet. As part of these research programs, all retired transformers are being inspected and tested to determine the condition of the insulating system. A new program was initiated in 2010 to test every transformer for Furans, which may be used to determine the condition of the insulation.

**<u>Current Status:</u>**

<u>2012 Planned Work</u>
Washington Street Tr. # 2 – Complete Replacement
Dunwoodie Replace PAR N1 – Begin Replacement

<u>2013 Planned Work</u>
Dunwoodie PAR N1 – Complete Replacement.
Dunwoodie – PAR S1 and S2 - Begin Replacement.
Avenue A Tr. # 3 – Begin replacement

<u>2014 Planned Work</u>

Complete Dunwoodie PAR S1/S2 Replacement
Avenue A Tr. #3 – Complete Installation
Avenue A Tr. #1 – Begin Installation
Cherry Street Tr. #1- Begin Replacement

2015 Planned Work
E179th Street – Replace TR #6 –Begin Installation
Avenue A –Tr. #1 Complete Installation
Cherry Street Tr. # Complete Replacement.
East 13th Street Tr. #11- Begin Installation

2016 Planned Work
East 179th Street Tr. #6 – Complete Installation
East 13th Street Tr. #11 – Complete Installation
East 179th Street Tr. #5 – Begin Installation

**Funding: ($000s)**

| **Funding Cost** | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 14044 | 24932 | 10953 | 13293 | 21117 | 15000 | 20651 | 25863 | 25417 | 25336 | 25118 | 221724 |

* **2008 to 2012 Actuals in Thousands-** $85,295
* **2013 to 2017 Budget in Thousands-** $122,385

## 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **#4 and #6 and Self Supporting Cable** |
| **Project Manager** | Troy Devries |
| **Project Engineer** | Troy Devries |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per year and a high level schedule):**
Continue a #4 and #6 Copper Wire and Self-supporting Cable (SSC) Replacement Program on the 4 kV and 13kV Non-Network distribution systems to increase overall system performance and reliability. In many cases, the outer tree-jacketed (protective) layers on the open wire and the insulation of SSC are aged and severely degraded. The program is to replace the existing deteriorated #4 and #6 copper open wire and SSC with new primary wires in order to reduce the frequency of customer interruptions (SAIFI). The #4 and #6 wire, which is located predominantly on spurs (radial branches of feeders), will be replaced with 1/0 or 4/0 Aluminum conductors as deemed appropriate. The SSC, which is usually located on the main run of the feeders, will generally be replaced with 477 kcmil Aluminum conductors. Aluminum conductors are the current industry standard used in overhead open wire construction. In all cases, the pole lines will be reconstructed to current specifications with new poles and new secondary wire where needed. Replacement of the #4 and #6 wire and SSC will be prioritized based on customer outages on those feeders. The feeders with the worst performance and highest degradation of cable will be given a higher priority for replacement.

**UPDATE 2012**
The #4 & #6 wire and Self-Supporting Cable removal program on the 4kV system represents another of the programs (along with the Osmose program) that specifically tackle the aging infrastructure on the Overhead system.

It should also be noted that new methodologies are being implemented which add value to the #4 & #6 wire replacement, specifically the use of the historic STAR data to highlight spurs that have repeated outages. The replacement of #4 & #6 wires on spurs with a history of repeated outages has the added benefit of immediate customer satisfaction, and an improvement in SAIFI/CAIDI indices.

**Justification (Technical Evaluation/Analysis):**
In order to improve system performance, it is important that a #4 and #6 wire and Self Supporting Cable replacement program be completed for the following reasons:

- Electric wires tend to sag when subjected to heavy load current conditions. Since the majority of this #4 and #6 wire has been in service for well over 40 years, much of this antiquated wire has been subjected to a great deal of these sagging effects. As a result, they are more vulnerable to breaking especially during winter weather conditions such as ice storms.
- Electric service to our customers is interrupted when these older open wire facilities, exposed to the environment without outer jackets, strike one another or make contact with tree branches during windy and adverse weather conditions. This situation can cause a fault on the open wire and can lead to component failure and / or the activation of protective equipment that de-energizes a portion of the circuit.
- When working on SSC, by the nature of its design, that portion of the circuit must be de-energized, thereby compromising reliability to any customers on the feeder.

- These outages which include both repairs and replacements are for the most part preventable through a proactive replacement program. By avoiding these outages in the first place, we wish to avoid the repair costs and tying up valuable resources during storms and other contingencies.
- With a proactive replacement program we would also reduce customer outage duration (CAIDI).

**Alternatives:**
Addition of automated sectionalizing switches, fuses and tie points. These measures may limit the customer interruption and expedite restoration but, they don't completely solve the reliability issues. Undergrounding would be another possibility but, it would be cost prohibitive. Advancing tree trimming efforts would help but only on a limited basis. Funding for this program is used to target areas with recurring issues and customer complaints.

**Risk of No Action:**

**Summary of Benefits (financial and non-financial):**
The primary benefits of the Replacement Program on the 4 kV and 13kV Non-Network distribution systems to increase overall system performance and reliability. In many cases, the outer tree-jacketed (protective) layers on the open wire and the insulation of SSC are aged and severely degraded. The program is to replace the existing deteriorated #4 and #6 copper open wire and SSC with new primary wires in order to reduce the frequency of customer interruptions (SAIFI). The #4 and #6 wire, which is located predominantly on spurs (radial branches of feeders), will be replaced with 1/0 or 4/0 Aluminum conductors as deemed appropriate. The SSC, which is usually located on the main run of the feeders, will generally be replaced with 477 kcmil Aluminum conductors. Aluminum conductors are the current industry standard used in overhead open wire construction. In all cases, the pole lines will be reconstructed to current specifications with new poles and new secondary wire where needed. Replacement of the #4 and #6 wire and SSC will be prioritized based on customer outages on those feeders. The feeders with the worst performance and highest degradation of cable will be given a higher priority for replacement.

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

**Specifications & Procedures pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

## Funding Forecast (Capital or O&M)

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 2,337 | 594 | 661 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 1,469 | 2,655 | 1,400 | 1,297 | 1,256 | 1,252 | 7,860 |

**2013 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | **4 kV UG Reliability** |
| **Project Manager** | Winnie Yueh |
| **Project Engineer** | Winnie Yueh |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**

Each year, approximately 33,000 overhead customers experience a sustained outage due to failures of cables, joints, and terminations. This type of underground cable failure typically occurs on either the sections from the station breaker to the first primary riser or on underground portions between overhead portions of the feeder (dips).These customer interruptions equate to almost 10% of the total reported PSC overhead related outages. We can better serve these customers by preemptively replacing poor performing 4kV underground cable.

Units per Year: 37 Sections, 5 Risers, and 810 ft of Conduit

**Justification (Technical Evaluation/Analysis):**

This program will reduce the frequency of customer interruptions due to underground cable failures on 4kV systems.

One of the major drivers of these outages is the failure of 3-350 underground rubber 4kV cable (spec. # 427/450). The 3-350 rubber 4kV cable was originally installed on the 4kV system between 1950 and 1970. Over the years, the integrity of the rubber insulation has deteriorated, leading to frequent failures. Presently, there are approximately 186 sections of this and other types of poor performing rubber cable which should be replaced. On average, each failure interrupts 499 customers for 3 hours and 24 minutes. The cable will be upgraded with new Ethylene Propylene Rubber (EPR) cable which is made with much higher quality rubber insulation.

In addition, other feeders that have failed frequently due to underground faults will be targeted for cable replacement. For these feeders, we will replace cable from the station breaker to the first riser or from riser to riser creating a solid underground run of cable which will be a more reliable installation. Presently, approximately 27 risers are targeted for replacement. This program will also include approximately 4,050 trench feet of associated conduit including risers.

**Alternatives:**
The alternative to proactive replacement of this cable is replacement on an emergency basis.

**Risk of No Action:**
No action would result in continued customer interruptions as well as extended customer outage durations during underground faults.

**Summary of Benefits (financial and non-financial):**

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of Prior Year Funding Request Versus Actual:**

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 1,227 | 23 | 1,491 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| Funding ($000s) | 2,098 | 2,278 | 2,000 | 1,853 | 1,795 | 1,788 | 9,714 |

Total replacement plan:

| | Units | Cost / Unit | Total Cost | Years of Program | Cost / Year | Avg repl. / year |
|---|---|---|---|---|---|---|
| **Rubber Cable (section)** | **186** | **$35,000** | **$6,510,000** | **5** | **$1,302,000** | **37** |
| **Riser (cable section)** | **27** | **$35,000** | **$945,000** | **5** | **$189,000** | **5** |
| **Conduit (ft)** | **4,050** | **$346** | **$1,401,300** | **5** | **$280,260** | **810** |
| | | | | | **$1,771,260** | |

Based on a five year program, the plan is to replace approximately 37 sections of primary cable, 5 primary risers and 810 trench feet of associated conduit in each year of the program. The average annual budget is estimated to be approximately $1.8 million plus an additional 10% contingency to address potential interference and unanticipated issues.

## 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **Aerial Cable Replacement** |
| **Project Manager** | Troy Devries |
| **Project Engineer** | Troy Devries |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per year and a high level schedule):**
Continue the program to replace high failure rate aerial cable on the non-network distribution systems to increase overall system performance and reliability. Replacing existing cable such as Okonite with new primary cable will reduce the frequency of customer interruptions (SAIFI) due to aerial cable failures.

**Justification (Technical Evaluation/Analysis):**
Replacing aerial cable with high failure rates will improve system reliability. The aerial cable in this program supplies first contingency non-network loads including 13kV loops and 4kV unit substations. These feeders also serve sensitive loads such as hospitals, nursing homes and corporate headquarters. Failures of this cable place loops and unit substation customers in frequent contingency operations resulting in unacceptable customer interruptions. A review of our feeder performance over the last five years indicates that we experienced on average 18 failures per year on aerial cable. While the average number of failures remains relatively constant since 2004, we have expanded our aerial cable maintenance budget by an average of $950,000 per year as the replacement of sections of aerial cable for these failures has become more extensive. The outer jacket on this older aerial cable has in many cases become porous over the years, causing the cable to absorb water. When a failure does occur, it is sometimes necessary to replace as much as 3,000 to 5,000 feet of cable in order to find dry cable to splice, thereby resulting in lengthy feeder outages. Proactive replacement of this troublesome cable with our standard Aerial Cable (3-1c500 kcmil copper with EPR insulation, Con Edison specification 7558E) will increase reliability and decrease the frequency of customer outages caused by aerial cable failures, and the duration of feeder outages following a cable failure. Replacement priority will be determined by the failure history of the various sections of cable.

**Alternatives:**
Replacing existing aerial cable with 3-1c500 kcmil copper with EPR insulation whenever there is a failure would be an option. However, that practice would cause thousands of customers to be out of service for an unspecified period of time. Another option would be to increase sectionalizing capability on these feeders and add tie points. The addition of underground switches and overhead switches is a possibility but may be as expensive and not offer the same improvement to reliability.

**Risk of No Action:**
The additional cost of emergency response to feeder failure in comparison to targeted work performed on a scheduled basis.

**Summary of Benefits (financial and non-financial):**

**Project Relationships (if applicable):**

**EH&S Overview:**

We follow the standards set in Corporate Environmental Procedure (CEP) 11.04. CEP 11.04 requires organizations to make an overall assessment of their routine daily work (recurring) and then create categories for this work activity. The purpose of this process is to identify EH&S hazards/issues. This process will also help to ensure EH&S compliance, resource conservation, risk reduction and alternate design considerations are incorporated in the early planning and design stages of project work.

**Analysis of Prior Year Funding Request Versus Actual:**

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**
The Aerial Cable Replacement program targets vintage cable on poor performing feeders supplying network and non-network load. The program is to replace all sections of this cable due to the high failure rate of this cable.

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 1,412 | 1,401 | 283 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 1,154 | 1,243 | 1,100 | 1,019 | 987 | 983 | 5,332 |

# 2013 Capital – Electric Operations

| **Project/Program Title** | **ATS Installation USS Reliability XW** |
|---|---|
| **Project Manager** | Troy Devries |
| **Project Engineer** | Jonathan Daniels |
| **Status** | Ongoing program |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per year and a high level schedule):**
This program will install new Automatic Transfer Switches (ATS) on a priority basis at Unit Stations at an estimated cost of $200k per ATS location.

Units per Year: We plan to install 1 to 2 ATS units each year.

The list below highlights a number of areas in the Bronx/Westchester 4kV primary grid system that require an additional level of support. These are areas where loss of two adjoining stations at or near peak load times could result in an extended outage to a large group of customers. An ATS is one of the solutions being considered for each of these areas. (Other considerations to be evaluated in each case are re-enforcing the 4kV system or converting sections to 13kV Auto-loops)

1. Valley Pl or Flint Park (1031)
2. Shawnee or Lawrence Park (1032)
3. Woodlawn-55 or Woodlawn-75 (1032)
4. Underhill or Barnes Lane (1034)
5. Milton Point or Manursing (1035)
6. Van Wart/Manhattan Park-62 (1036)
7. Brookville or Briarcliff (1037)

**Justification (Technical Evaluation/Analysis):**
Automatic Transfer Switches (ATS) switch a unit substation to an alternate 13kV supply automatically when the primary supply is lost. An ATS is a 'smart' automation element that enables our system to automatically reconfigure itself upon the loss of a preferred source. Of the 113 unit substations in the Bronx / Westchester region, 39 are currently equipped with ATS units. This program will add ATS switches on a prioritized basis to those unit stations that could significantly benefit from them. The Priority for installation is based on the need *(risk of dropping large numbers of customers for extended periods during high load periods*) and also the cost of installation *(primarily the cost of extending the alternate feeder, which can vary considerably from project to project).*

**Alternatives:**
Each ATS installation is a unique project. The available space to install the switch is taken into consideration, but the largest cost factor that needs to be considered is the cost to extend the alternate feeder and whether any re-enforcement is required for the alternate feeder. This cost to extend and re-enforce the feeder can vary greatly.
Alternatives considered on every project are:

1. Re-enforcing the 4kV feeders in the grid. *(Generally only viable when the 4kV feeders are of a low initial rating and the cost to upgrade is comparable to the ATS installation. However, it is noted that upgrading the 4kV feeder has the added benefit of replacing old infrastructure (poles etc..) that may need upgrading in time anyway)*

2. De-loading the 4kV system by converting sections (e.g. large spurs) to 13kV Auto-Loops. *(Converting 4kV to 13kV has the added advantage of reducing line losses, but again the main factor that needs to be considered is the cost of the conversion)*

It is also understood that adding an ATS does nothing should the failure be in the Unit Transformer, 4kV Bank Breaker or Bus itself. This is another factor taken into account when choosing between the various options.

**Risk of No Action:**

The areas identified for the installation of an ATS switch are those areas where, after we have one feeder open auto, the next worse condition under heavy loading conditions will result in a large number of customers out for an extended period of time. The risk to the corporation's non-network CAIDI goal is the primary impact of no action.

**Summary of Benefits (financial and non-financial):**

This program provides enhanced reliability to the customers and better enables the Company to meet its mandate to provide safe and reliable service to its customers by allowing for additional supply feeders to 4kV grids. It also limits the cost of mobile generation deployment in summer and the added strain on company resources this requires.

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of Prior Year Funding Request Versus Actual:**

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M)**

| **Actual 2009** | **Actual 2010** | **Actual 2011** |
|---|---|---|
| 1,106 | 484 | 891 |

| | **2012 Budget** | **2013 Request** | **2014 Request** | **2015 Request** | **2016 Request** | **2017 Request** | **5 yr (13-17)** |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 210 | 208 | 200 | 185 | 180 | 179 | 952 |

**2013 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | **Autoloop Reliability (27 kV Inc'l.)** |
| **Project Manager** | Joseph Lenge |
| **Project Engineer** | Joseph Lenge |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | Reliability |

**Work Description (Includes units per Year and a high level schedule):**

This project makes modifications to three Brooklyn autoloops to bring them into compliance with Con Edison design standards, adds tie points to 13 URD loops on Staten Island to reduce restoration times and adds a third feeder to five 13kV autoloops in Westchester in order to improve reliability.

Perform the following work on the listed auto-loops:

Brooklyn – Loop Split

1. Gravesend Loop is currently a system III loop with 21,062 kVA of load which exceeds the current specification. A new autoloop will be created via the following work:
   - Extend 2 new 27 kV primary feeders by installing approximately 12,000' of 2-5" concrete conduit, 13 M11-6 slotted manholes, and 96 sections of 3-500epr 27 kV cable.
   - Install 2 feeder reclosers, 2 midpoint reclosers, 1 tie recloser, and 6 sensing transformers.
   - Install 67 new 45' poles and 210 spans of 477 AL open wire cable.
   - Transfer approximately half of the Gravensend Loop load to the new loop.

2. Dyker Loop is currently a system III loop with 24,157 kVA of load which exceeds the current specification. A new autoloop will be created via the following work:
   - Extend 2 new 27 kV primary feeders by installing approximately 8100' of 2-5" concrete conduit, 10 M11-6 slotted manholes, and 56 sections of 3-500epr 27 kV cable.
   - Install 2 feeder reclosers, 2 midpoint reclosers, 1 tie recloser, and 6 sensing transformers.
   - Install 18 new 45' poles and 20 spans of 477 AL open wire cable.
   - Transfer approximately half of the Dyker Loop load to new loop.

3. Marine Park Loop is currently a system III loop with 22,343 kVA of load which exceeds the current specification. A new autoloop will be created via the following work:
   - Extend 2 new 27 kV primary feeders by installing approximately 5200' of 2-5" concrete conduit, 8 M11-6 slotted manholes, and 45 sections of 3-500epr 27 kV cable.
   - Install 2 feeder reclosers, 2 midpoint reclosers, 1 tie recloser, and 6 sensing transformers.
   - Install 15 new 45' poles and 18 spans of 477 AL open wire cable
   - Transfer approximately half of the Marine Park Loop load to the new loop.

Staten Island - URD Tie Points

Install Underground Radial Distribution (URD) primary cable and risers to provide tie points on 13 URD loops with 5 or more transformers.

Bronx/Westchester

Provide a third feeder on each side of a two feeder 13kv auto loop. There are currently 45 auto loops that require a third feeder as a backup, either on one side or both sides. We have currently identified 9 locations in 5 auto loops where a third feeder is available as a backup. These 5 autoloops are: Warburton loop, Southside loop, Woodlawn loop, Tarrytown loop, and King St loop.

**<u>Justification (Technical Evaluation/Analysis):</u>**

<u>27kV Autoloops</u>

According to spec *EO-2066 "OVERHEAD AUTOLOOP DESIGN FOR 27Kv RADIAL SYSTEM"*, *section 5, "Type of Systems"*, a type III auto-loop should be installed if the loads are between 6.0 MVA and 12.0 MVA. The above-mentioned auto-loops have loads greater than the current specification allows and should be relieved with the establishment of new loops. In addition, the auto-loops should not exceed a total load of 25 MVA (560 Amps) which is the limitation of the feeder reclosers and are approaching this level of loading; in fact, three of the Brooklyn auto-loops have loads greater than 21,000 kVA.

Due to the current autoloop loading, the emergency ties to these auto-loops do not have sufficient capacity to supply customer load during contingencies or when the 27kV feeders are out of service. In order to reduce customer outages, normalization of the loop with an emergency tie feeder is the preferred method of operation.

On a peak day, should both normal supply feeders be out of service, there is insufficient capacity to fully supply all customers. The proposed solution resolves this issue by splitting the load and establishing new autoloops. This will improve reliability and reduce SAIFI and CAIDI.

<u>Staten Island URD Tie Points</u>

A review of URD installations in Staten Island has found 13 autoloops serving a total of 35 transformers that do not have any alternate tie. Faults involving primary cable or a transformer on any one of these spurs, it takes a very long time to restore power because there is no alternate feed. Overland primary shunts are usually required. Typically, these are the longest duration outages on Staten Island. URD outages average 2.52 hours vs. 1.76 for all SI outages. The top 10 worst feeders for URD outages averaged 5-10 hours. By adding tie points to those spurs with 5 or more transformers Staten Island CAIDI can be reduced. It is estimated that each of these 13 locations will cost approximately $150,000 to correct.

<u>Bronx / Westchester Third Feeders</u>

The third feeder will provide additional reliability whenever the main feeder supply is scheduled to be out of service for work or opens auto. This situation is applicable for most part of the year except during the summer period where a closer look at the loads is required. In cases where the third feeder is equipped with an emergency vacuum recloser switch (VRS), the switch is remotely operated from the control center, restoring customers within 5 minutes. Over the years, 16 autoloops have been converted from a 2 supply feeder loops to three supply feeder loops to provide load relief. The conversions also increased the reliability of the autoloops.

**<u>Alternatives</u>:**

The alternatives to address the overload condition for each loop consist of extending existing network boundaries into non-network areas currently serviced by the auto loop system and establishing a mini-grid secondary network.

Gravesend Loop

-Extend five network feeders and establish two mini-grids by installing six 1000kVA network transformers supplying a total of 5,500.5 kva of load. Estimated cost $8,500,000

Dyker Loop

-Extend four network feeders and establish one mini-grid by installing thirteen 1000kVA network transformers supplying 7,000 kva of load. Estimated cost $9,100,000

Marine Park Loop
-Extend six network feeders and establish two mini-grids by installing nine 1000kVA network transformers supplying a total of 8,000 kva of load. Estimated cost $7,100,000

**Risk of No Action:**

If no action is taken load will continue to grow exceeding the maximum continuous current rating of the reclosers. This will reduce reliability of the affected auto loops should a contingency occur. Any fault that occurs on the auto-loop would then be cleared only by the substation breaker operating taking out of service all other load supplied by that feeder.

**Summary of Benefits (financial and non-financial):**
Splitting existing autoloops reduces the possibility of communication and operational issues due to excess load demand between reclosers.

**Project Relationships (if applicable):**

**EH&S Overview:**

We follow the standards set in Corporate Environmental Procedure (CEP) 11.04. CEP 11.04 requires organizations to make an overall assessment of their routine daily work (recurring) and then create categories for this work activity. The purpose of this process is to identify EH&S hazards or issues. This process will also help to ensure EH&S compliance, resource conservation, risk reduction and alternate design considerations are incorporated in the early planning and design stages of project work.

**Analysis of Prior Year Funding Request Versus Actual:**

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**
According to spec *EO-2066 section 5, "Type of Systems"*, a type III auto-loop should be installed if the loads are between 6.0 MVA and 12.0 MVA. In order to maintain reliability, no more than 3.0 MVA of load shall be permitted between automatic sectionalizing devices. The above-mentioned auto-loops have loads greater than the current specification allows and should be relieved with the establishment of new loops.

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 4,230 | 4,069 | 3,781 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 3,671 | 3,738 | 3,500 | 3,242 | 3,141 | 3,129 | 16,750 |

**2013 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | **Automated Emergency Ties** |
| **Project Manager** | Steve Daquila |
| **Project Engineer** | Steve Daquila |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
This project will convert approximately 40 manually controlled emergency feeder tie switches on 13 kV auto-loops to electronically controlled, automatic circuit reclosers equipped with wireless communication, remote monitoring and control capability.

**Justification (Technical Evaluation/Analysis):**
According to Distribution Engineering Department specification EO-4119 Rev-3, EO-2067 Rev-5 and EO-6075 Rev-5 emergency manual ties switches should be installed on auto-loops so that the auto-loop can be normalized as an emergency measure should the circuit become de-energized due to a loss of normal supply.

Operations personnel will be able to monitor and control these SCADA operated emergency tie recloser switches from the Control Center, allowing for more rapid response to distribution feeder events and avoiding the need to dispatch crews to operate this equipment. On average, this remote operation capability will save approximately 45 minutes in restoration time for these types of outages.

Also, engineering personnel can access load data from the line reclosers for system long range planning.

The average installation is estimated to cost $70,000 per switch for equipment and installation varying slightly based on field conditions. It is planned to install approximately 8-11 switches per year.

**Alternatives:**
Continue to dispatch emergency crews to manually operate these switches and adversely impact SAIFI and CAIDI performance.

**Risk of No Action:**
The Company may not be able to meet its non-network SAIFI and CAIDI reliability performance targets and could incur penalties imposed by the PSC.

**Summary of Benefits (financial and non-financial)**:
Faster response to feeder related loop outages and the potential avoidance of outages exceeding five minutes.

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

**Specifications & procedures pertaining to Program/Project:**
Distribution Engineering Department specification EO-4119 Rev-3, EO-2067 Rev-5 and EO-6075 Rev-5

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M)**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 0 | 0 | 3,463 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 735 | 728 | 700 | 648 | 0 | 0 | 2,076 |

**2013 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | **Grounding Transformers** |
| **Project Manager** | Elie Chebli |
| **Project Engineer** | Robert Szabados |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**

The grounding transformers will be installed on three-phase, 13kV and 27kV distribution network feeders in Bronx/Westchester and Brooklyn/Queens Regions that supply single-phase loads on open-wire distribution circuits. Their use is intended to limit over voltages on the unfaulted phases of open-wire circuits during line-to-ground faults during back feeding conditions.

The installation/upgrade of grounding transformers are on the supply feeder and/or the alternate supply feeder to 13kV and 27 kV auto loops with back feed devices such as unit substations or network transformers. The upgrade of 2.6 ohms to 5.63 ohm grounding transformers is necessary to allow for the placement of needed ground transformer per Area Substation so that the line to ground fault current does not exceed the 3 phase fault current. The first phase of this program will address feeders with back feed devices that supply loops but do not contain a grounding transformer. The second phase of this program is for the installation of grounding transformers on alternate supply feeders to loops. In addition to adding grounding banks to existing feeders it required to conform to specifications EO-2042 and EO-2053, and EO-2066.

The remaining installation of grounding transformers for Bronx/Westchester will be on the following feeders/Loops:

| **Feeder** | **Loop** | | **Year** |
|---|---|---|---|
| 2W12 | Tuckahoe Loop | Install new GTV | 2012 |
| 17W50 | Don Bosco Loop | Upgrade GTV to 5.3 Ohms | 2012 |
| 6W64 | Ossining Loop | Upgrade GTV to 5.3 Ohms | 2012 |
| 6W67 | Ossining Loop | Upgrade GTV to 5.3 Ohms | 2012 |
| 6W69 | Croton Loop | Upgrade GTV to 5.3 Ohms | 2012 |
| 10W85 | Ludlow Loop | Install additional GTV | 2013 |
| 15W03 | Yonkers Loop | Install additional GTV | 2013 |
| 15W16 | Hastings Loop | Install additional GTV | 2013 |
| 8W94 | White Plains Loop | Install additional GTV | 2013 |

The remaining installation of 12 grounding transformers for Brooklyn/Queens will require 4 grounding banks per year for the next 3 years (2013 – 2015) for the following loops:

Marine Park Loop
Dyker Loop
Graves End Loop

In addition to the required installation of the grounding transformers it is estimated to have 2 replacement grounding transformers per year for each Region.

**Justification (Technical Evaluation/Analysis):**

**Alternatives:**
The alternative is to utilize a dedicated feeder that does not have any back feed sources. The cost of a dedicated feeder as compared to using an existing network feeder is not cost effective.

The elimination/reduction of the grounding transformer program will result in the inability to put backup feeders into use without serious risk to customer equipment from single phase faults and load imbalances. Without the ability to use the backup feeders, restorations will take longer and the SAIFI will increase Grounding transformers are required on all 13 kV and 27 kV feeders that supply both line-to-neutral loads and three-phase delta-wye transformers which could backfeed under certain operating conditions as per EO-2042 and EO-2053.

**Risk of No Action:**
Without the grounding transformers, the back-up feeders cannot be used to normalize the auto-loops if the supply feeders come out of service for any reason. The purpose of a grounding transformer is to limit over-voltages on single-phase open-wire circuits during faults, as well as load imbalance conditions under backfeed. Customer equipment will be damaged if we use a network feeder with no grounding bank to supply non network load under backfeed conditions.

**Summary of Benefits (financial and non-financial:**
This will reduce cost associated with dropping customers that are single sided (fed from one side of the loop). A whole loop can be dropped if the second feeder fails and no back up feeder can be used due to lack of grounding banks. SAIFI is unnecessarily increased for lack of the grounding banks.
Grounding transformers enable the use of network feeders to supply open-wire auto-loops and increase the reliability of the auto-loop by reducing the possible of dropping load or customers upon the loss of the supply feeder when the loop becomes single sided. We estimate that the average yearly SAIFI contribution due to lack of grounding banks is 10% or 5,000 customers a year or 14% towards its SAIFI for 2007.

**Project Relationships (if applicable):** In Brooklyn/Queens 16 out of the 23 grounding banks are related to the splitting of existing loops to comply with EO-2066 (for reference see the Auto-loop Reliability White Paper).

**EH&S Overview:**

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

**Specifications & procedures pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M)**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 521 | 1,091 | 196 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 629 | 624 | 600 | 556 | 539 | 536 | 2,855 |

## 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **Hi-Pot** |
| **Project Manager** | Neil Brown/George Murray |
| **Project Engineer** | Neil Brown/George Murray |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule)**:

The Hi-Pot program relies on a high-voltage withstand test to ferret out defects in electric distribution feeder components (primarily cable and splices), through a controlled high-voltage test failure, before they cause an in-service feeder failure. The program is intended to improve the long term reliability of the company's distribution feeders by removing compromised components before they result in an in-service failure.

The Hi-Pot program is implemented through the application of a high-voltage (either DC or Very-Low-Frequency AC) withstand test following almost all feeder emergency or maintenance outages. These feeder outages include: Open-Autos (OA), Fail-On-Test (FOT), Out-On-Emergency (OOE), and any scheduled maintenance outage

The program has a short-term reliability benefit by reducing the number of in-service feeder failure that would occur when the feeder is returned to service following an emergency or scheduled maintenance outage (Cut-In-Open-Auto, CIOA).

In 2011 the primary distribution feeder experienced approximately 250 test failures (FOT) through the current application of the Hi-Pot program.

**High-level schedule:** A Maintenance Withstand (Hipot) test is performed following any emergency feeder outages including: OA (Open Auto), FOT (Failed On Test), and OOE (Out On Emergency). Additionally, Hipot tests are also routinely performed on distribution feeders following any scheduled maintenance outage.

**Justification (Technical Evaluation/Analysis):**

The Hi-Pot program relies on a high-voltage withstand test to ferret out defects in electric distribution feeder components (primarily cable and splices), through a controlled high-voltage test failure, before they cause an in-service feeder failure. The program is intended to improve the long term reliability of the company's distribution feeders.

The program is intended to improve the long term reliability of the company's distribution feeders by removing compromised components before they result in an in-service failure.

An engineering evaluation of the Hi-Pot program was recently conducted through an independent industry group (National Electric Energy Testing, Research and Application Center, NEETRAC). They concluded that the program, in its current configuration, enhance the long term reliability of the Con Edison distribution system.

**Alternatives:**
One alternative to the Hipot program is the creation of backbone feeders (removing all PILC cable and associated splices from a feeder) to eliminate the failure prone stop-joints, which the program would have removed through a test failure. Another would be alternative cable diagnostic tool that include Partial Discharge and Tan-Delta measurements. The feasibility and effectiveness of these alternative diagnostic techniques are currently being investigated.

**Risk of No Action:**
System reliability will decrease as the failure prone stop-joints age and their failure rate increases. This will result in more summer feeder failures and CIOAs.

**Summary of Benefits (financial and non-financial):**

- Feeder Hipot program will increase network reliability and reduce the risk of network shut down. Costs associated with network shutdowns such as restoration costs and regulator penalties are minimized.

- Feeder Hipot program will benefit Electric Operations in meeting annual key performance indicators, such as SAIFI and CAIDI interruption rates for the non-network system thereby avoiding potential regulator penalties.

**Project Relationships (if applicable):**

**EH&S Overview:**
Hipots capture incipient faults in components that have high failure rates. A large percentage of these are related to Paper Insulated Lead Covered (PILC) cable, which is constructed with a lead sheath. By accelerating the removal of PILC cable, we are helping to the environment and improving the safety of the replaced components.

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

An engineering evaluation of the Hi-Pot program was recently conducted through an independent industry group (NEETRAC). They concluded that the program, in its current configuration, enhance the long term reliability of the Con Edison distribution system.

**Specifications & procedures pertaining to Program/Project:**
The HiPot test procedure is described in detail in specification EO – 4019 “Testing of AC Feeders Operating at 4kV to 33kV.

**Is this a mandated program?  If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M)**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 2,594 | 3,143 | 3,298 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 20176 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 3,147 | 2,078 | 2,000 | 1,852 | 1,796 | 1,788 | 9,514 |

# 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **4 kV USS Switchgear Replacement** |
| **Project Manager** | Benjamin Lee |
| **Project Engineer** | Maxim Tsarenkov |
| **Status** | Engineering |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
This program in intended to address problems related to the aging of this equipment. It will improve system reliability and reduce maintenance costs. There are approximately 170 unit substations switchgear line-ups that have been in service for more than 40 years. The plan is to purchase and install one switchgear house in each year. One switchgear house was replaced at St. Albans in 2011 and we are scheduled to replace another at Whitestone West in 2012.

**Justification (Technical Evaluation/Analysis):**
Serious water leaks have developed in roofs and walls of some of the existing switchgear. The water leaking into the switchgear has caused rust and corrosion conditions within the switchgear. This condition creates a serious possibility of short circuits in the switchgear cubicles. The new switchgear houses will include modern vacuum circuit breakers, microprocessor-based protective “smart relays” that better protect our switchgear and feeders, and an indoor climate controlled environment for the equipment to operate.

**Alternatives**:
Continue to repair the old equipment that have air magnetic circuit breakers and are high maintenance due to rusting and corrosion. These conditions cause misalignment of circuit breaker and switchgear cubicles. The misalignment also requires additional mechanics on site to rack a breaker into and out of operating positions.

**Risk of No Action:**

**Summary of Benefits (financial and non-financial):**
The new switchgear houses will require fewer maintenance personnel on site to properly align the breakers. The new breakers will create a safer more reliable distribution system. The purchase price of each new switchgear house is in the range of $500K, with the total cost including overhead to purchase and install a new switchgear line-up at $1,200K.

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

**Specifications & procedures pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M)**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 0 | 1,114 | 690 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 1,256 | 1,256 | 1,256 | 1,256 | 1,256 | 1,256 | 6,280 |

**2013 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | **USS Life Extension Program** |
| **Project Manager** | Benjamin Lee |
| **Project Engineer** | Benjamin Lee |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
This program involves two components for the life extension of unit substations, namely replacement of air circuit breakers with new vacuum circuit breakers and replacement of electro-mechanical protective relays with microprocessor based relays. The program plans to replace approximately 28 feeder breakers ($25K each) and perform 7 feeder cubicle relay upgrades ($50K each) per year.

**Justification (Technical Evaluation/Analysis):**
Many existing feeder breakers are at the end of their useful life with replacement parts difficult to procure and require frequent maintenance cycles. The Allis Chalmers type breakers are especially problematic exhibiting difficulties in their charging and breaker closing mechanisms. The feeder cubicles protective relays are antiquated electro-mechanical types that require upgrade to microprocessor based protection relays to more accurately and reliably perform the protection function. We estimate that with the installation of modern vacuum feeder breakers and micro-processor based protective relaying we could lengthen our maintenance cycle from a 3 year program to a 5 year program. This reduction would reduce out total maintenance labor expenditures by an estimated 15 to 20 percent.

**Alternatives**:
The continued reliance on the existing feeder breakers and protective relays to perform their designed function is problematic and decreases 4 kV system reliability.

**Risk of No Action**:
The 4 kV distribution system would be subject to a reduced level of protection from system faults and contingencies. Customer outages could be more extensive and of longer duration.

**Summary of Benefits (financial and non-financial):**
The 4 kV distribution system would be more reliable, isolating system disturbances accurately and dependably. Customer outage severity and length would be reduced and distribution equipment better protected.

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of Prior Year Funding Request Versus Actual:**

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 0 | 585 | 615 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 1,446 | 869 | 1,069 | 1,069 | 1,069 | 1,069 | 5,145 |

# 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **Failed Transformer Replacement** |
| **Project Manager** | Benjamin Lee |
| **Project Engineer** | Benjamin Lee |
| **Status** | Planning |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
This program is to provide funding to replace failed unit substation transformers. Historically, there has been one transformer failure every year. In the event of a unit substation transformer failure, the spare units maintained in the company's Astoria facility are immediately dispatched and utilized to replace the failed transformer. A new replacement must be procured to maintain spare transformer capabilities.

**Justification (Technical Evaluation/Analysis):**
Due to age, insulation breakdown and other factors, transformers periodically fail beyond repair and need to be replaced with a new unit. Each unit substation is required to maintain the reliability of the 4 kV distribution systems.

**Alternatives:**
If a replacement spare is not ordered immediately, the 4 kV distribution system reliability would be reduced. There would be no spare replacement available for a subsequent transformer failure.

**Risk of No Action:**
4 kV system reliability would be greatly jeopardized.

**Summary of Benefits (financial and non-financial):**

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of Prior Year Funding Request Versus Actual:**

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 596 | 925 | 328 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 500 | 1,000 | 1,000 | 1,000 | 1,000 | 1,000 | 5,000 |

## 2013 Capital – Electrical Operations

| **Project/Program Title** | **Tap Changer Position Indicator System Frame Relay** |
|---|---|
| **Project Manager** | Paul Stergiou |
| **Project Engineer** | Joseph Rak/Francisco Chen |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**

It is necessary to install a new tap changer position indicator in the 4kV Unit Substation transformer compartment and connect it to the Unit Substation Automation (USA) System. In order to use the USA system to facilitate functions such as voltage reduction and to provide the capability of remotely de-loading transformers during a contingency, the use of remote tap changer control with accurate tracking is necessary. There are 160 stations that have been completed with 50 left to do.

**Justification (Technical Evaluation/Analysis):**

In order to ensure obtaining the desired system response to voltage reduction, the 4kV substations must have their tap changers placed in the "remote manual position" prior to initiating system voltage reduction in order to prevent automatic operation of the tap changers which would counter the desired voltage-reduction. It is essential for control center operators to be able to monitor these conditions accurately. Similarly, the ability to operate taps accurately, with remote indication on 4kV unit substation transformers, is needed so that taps can be lowered while simultaneously monitoring the reduction in loading. There is no alternative to the addition of the tap changer position indicator system.

Units per Year: 10

**Alternatives:** **There are no other alternatives, continue to operate the system in a similar fashion.**

**Risk of No Action:**

If nothing is done with this program, for those 50 stations left to complete, the CC operators would not have the correct tap position setting of the 4kV Unit substation transformers, which would cause confusion and possibly expending manpower to find it out. Runaway tap changers would not be detected immediately.

**Summary of Benefits (financial and non-financial):**

There are no direct financial benefits from this program. A non-financial benefit is that it improves system reliability.

**Project Relationships (if applicable):**

**EH&S Overview:**

There is no EH&S impact for this program.

**Analysis of Prior Year Funding Request Versus Actual:**

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**

**Is this a mandated program?  If yes, include verbiage associated with mandate:**
This is not a mandated program.

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 20 | 20 | 64 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 75 | 75 | 75 | 75 | 75 | 75 | 375 |

**2013 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | **Temperature Gauges** |
| **Project Manager** | Benjamin Lee |
| **Project Engineer** | Maxim Tsarenkov |
| **Status** | Ongoing |
| **Estimated Service Date** | 2017 |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
This program entails the replacement/upgrade of existing temperature gauges with new electronic temperature monitoring units at all Unit Substations. The work scope includes material purchase, equipment installation (cabinets, conduits, cables) as well as programming and testing.

**Justification (Technical Evaluation/Analysis):**
The existing gauges are inaccurate and unreliable. Incorrect temperature readings could result in unit substation transformers operating beyond their temperature limits resulting in increased loss of life and increased risk of failure. Inaccurate temperature readings may result in unnecessarily removing a transformer from service due to erroneous high temperature readings, reducing the reliability of the associated 4kV grid. Real-time archived temperature data will also allow implementation of dynamic ratings which could help optimize the use of transformer capacity.

**Alternatives:**
The alternative to installing new electronic temperature gauges is to continue utilizing the PT-Load software application which predicts peak transformer temperatures based on transformer data, ideal ambient conditions, and historical load cycle and is used to determine transformer ratings. The weakness of this approach is that it results in less accurate and less reliable ratings than could be achieved with direct temperature measurements and provides no real-time operational information.

**Risk of No Action:**
The inaccurate readings could result in incorrect operator action, increased loss of life on transformers, increased risk of failure and sub-optimal use of transformer capacity and consequently, unnecessary transformer replacement.

**Summary of Benefits (financial and non-financial):**
The electronic temperature monitoring units provide a number of beneficial features such as SCADA connectivity which provides remote temperature data for real time operations and planning, local indication and storage of maximum temperature reached which allows field crews to utilize temperature data for operations. The implementation of this program will result in more accurate operation of the 4 kV distribution system, fewer customer outages and will provide dynamic rating capability which will allow optimal use of transformer capacity and may defer capital expenditures. The purchase and installation cost of each electronic temperature monitoring system is $12,000.

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

**Specifications & procedures pertaining to Program/Project:**

**Is this a mandated program?  If yes, include verbiage associated with mandate:**
No, this is not a mandated program.

## Funding Forecast (Capital or O&M)

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 93 | 115 | 116 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 100 | 100 | 100 | 100 | 100 | 100 | 500 |

## 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **Network Reliability** |
| **Project Manager** | Elie Chebli |
| **Project Engineer** | Adetunji Adeniyi |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Performance Improvement |

**Work Description (Includes units per Year and a high level schedule):**
Establish new distribution feeders by de-bifurcating existing feeders. To accomplish this, bifurcated feeders supplying a given network or load area via two main runs of cables (legs) will be de-bifurcated, creating two separate feeders with one leg each. The Company will utilize existing spare feeder position in area substations, or construct new area substation cubicles where necessary, to accommodate the new distribution feeders.

Units per Year: 5 to 6 new feeders per year
High-level schedule: Approximately four to five feeders per year will be established between 2012-2017.

**AREA SUBSTATION FEEDER POSITIONS SCHEDULED TO BE ESTABLISHED BY SUMMER 2012**

## 2012

| Area Substation | Project Description | Network/ Load Area |
|---|---|---|
| Trade Center No. 1 | Utilize Feeder Positions 32A to accommodate growing WTC load. | Freedom |
| | Establish new Feeder 41M84 | |
| | | |
| | Utilize Feeder Positions 43A to accommodate growing WTC load. | |
| | Establish new Feeder 41M86 | |
| | | |
| | Utilize Feeder Positions 32B to accommodate growing WTC load. | |
| | Establish new Feeder 41M85 | |
| | | |
| | Utilize Feeder Positions 42B to accommodate growing WTC load. | |
| | Establish new Feeder 41M87 | |
| | | |
| Corona # 1 | Establish Feeder Position 33S to supply Feeder 7Q91. | Flushing |
| | Establish Feeder 7Q91, required for network reliability. | |
| | | |
| | Establish Feeder Position 22S to supply Feeder 7Q90. | |
| | Establish Feeder 7Q90, required for network reliability. | |
| | | |
| | Establish Feeder Position 12S to supply Feeder 7Q89. | |
| | Establish Feeder 7Q89, required for network reliability. | |
| | | |
| | Establish Feeder Position 43S to supply Feeder 7Q92. | |
| | Establish Feeder 7Q92, required for network reliability. | |
| | | |
| **Corona # 2** | Establish Feeder Position 61E to supply Feeder 9Q51. | Jackson Heights |
| | Establish Feeder 9Q51, required for network reliability. | |
| | | |
| | Establish Feeder Position 71E to supply Feeder 9Q52 | |
| | | |
| | Establish Feeder 9Q52, required for distribution feeder reliability | |
| | | Rego Park |
| Corona # 2 | Establish Feeder Position 81W to supply Feeder 3Q98 | |
| | Establish Feeder 3Q98 required for distribution feeder reliability | |

| | | |
|---|---|---|
| | | |
| | Establish Feeder Position 91W to supply Feeder 3Q97. | |
| | Establish Feeder 3Q97, required for network reliability. | |
| | | |
| Glendale | Utilize Feeder Position 14W to supply new Feeder 6Q45. | Maspeth |
| | Establish Feeder 6Q45, required for network reliability. | |
| | | |
| | Utilize Feeder Position 34E to supply new Feeder 6Q43. | |
| | Establish Feeder 6Q43, required for network reliability. | |
| | | |
| | Establish Feeder 6Q44, required for network reliability. | |
| | | |
| | Establish Feeder Position 14E to supply Feeder 6Q46. | |
| | Establish Feeder 6Q46, required for network reliability. | |
| | | |
| Brownsville No. 2 | Establish Feeder 9B23 (supplied from Feeder Position 73W), | Richmond Hill |
| | required for network reliability. | |
| | | |
| | Establish Feeder 9B24 (supplied from Feeder Position 93W), | |
| | required for network reliability. | |
| | | |
| | Establish Feeder Position 74W to supply existing Feeder 9B91 | |
| | Reconnect Feeder 9B91 from Position 93E to Position 74W. | |
| | | |
| | Establish Feeder Position 94W to supply existing Feeder 9B92 | |
| | Reconnect Feeder 9B92 from Position 73E to Position 94W. | |
| | | |
| | Utilize Feeder Position 73E to supply new Feeder 9B26. | |
| | Establish Feeder 9B26, required for network reliability. | |
| | | |
| | Utilize Feeder Position 93E to supply new Feeder 9B25. | |
| | Establish Feeder 9B25, required for network reliability. | |
| | | |
| Greenwood | Establish Feeder Position No. 35N to supply Feeder 8B94 | Bay Ridge |
| | Establish Feeder 8B94, required for network reliability. | |
| | | |
| Grasslands | Utilize Feeder Position 11A to supply Feeder 19W20 | Grasslands |
| | Establish Feeder 19W20 to supply UV Water Treatment Plant. | |
| | | |
| | Utilize Feeder Position 21B to supply Feeder 19W21. | |
| | Establish Feeder 19W21 to supply UV Water Treatment Plant. | |

## AREA SUBSTATION FEEDER POSITIONS SCHEDULED TO BE ESTABLISHED BY SUMMER 2013

# 2013

| Area Substation | Project Description | Network/ Load Area |
|---|---|---|
| Plymouth Street | Utilize Feeder Position 41N to supply new Feeder 1B73. | Borough Hall |
| | Establish new Feeder 1B73. | |
| | | |
| Water Street | Utilize Feeder Position 42A to supply new Feeder 6B60. | Williamsburg |
| | Establish new Feeder 6B60. | |
| | | |
| | | |
| Jamaica | Establish Feeder Position 13E required to supply Feeder 5Q58 | Jamaica |
| | Establish Feeder 5Q58 required for distribution feeder reliability | |
| | | |
| | Establish Feeder Position 52E required to supply Feeder 5Q59 | |
| | Establish Feeder 5Q59 required for distribution feeder reliability | |
| | | |
| | Establish Feeder Position 23W required to supply Feeder 5Q60 | |
| | Establish Feeder 5Q60 required for distribution feeder reliability | |
| | | |
| | Establish Feeder Position 62W required to supply Feeder 5Q61 | |
| | Establish Feeder 5Q61 required for distribution feeder reliability | |

## AREA SUBSTATION FEEDER POSITIONS SCHEDULED TO BE ESTABLISHED BY SUMMER 2014

## 2014

| Area Substation | Project Description | Network/ Load Area |
|---|---|---|
| Brownsville No. 1 | Establish Feeder Position 33E to supply Feeder 5B35 | Ridgewood |
| | Establish Feeder 5B35, required for network reliability | |
| | | |
| W. 65th St. No. 2 | Establish Feeder Position 81S to supply Feeder 23M64 | Lincoln Square |
| | Establish Feeder 23M64, required for network reliability | |
| | | |
| | Establish Feeder Position 84S to supply Feeder 23M67 | |
| | Establish Feeder 23M67, required for network reliability | |
| | | |
| Brownsville No. 2 (Bk) | Establish Feeder 9B27, required for network reliability | Richmond Hill |

Distribution Engineering is conducting a pilot project to improve selected network's reliability through installing two compact circuit breakers in the space of one air insulated breaker, two legs of an existing feeder will be electrically separated. The first network selected is the Ridgewood network. If the pilot program is successful, it will be installed on more 2 leg feeders. The focus will be to create at least two new feeders on every network that is above 1 Per Unit (Network Reliability Index).

**Justification (Technical Evaluation/Analysis):**
The reliability of the networks and load areas where these new feeders will be established is expected to improve. Since 1999, Con Edison has worked to identify the factors that affect the reliability of network feeders and the likelihood of multiple network contingencies. For heat waves, feeder and component load and the occurrence of feeder open-autos (OAs) within a short time of a previous OA are found to be particularly important.

These additional feeders will provide a more distributed and balanced supply to the network and more balanced feeder loading during normal conditions (all feeders in service). The increased number of feeders available during contingencies will also mitigate the potential for cascading feeder failures associated with high feeder loading due to shifting load following a feeder open-auto.

Additionally, this program will reduce the number of components (i.e. cable, splices, and transformers) per feeder, thereby reducing exposure to failures and improving reliability.

**Alternatives:**
Alternatives for increasing network reliability are installing sectionalizing switches, known point splices, and replacing PILC cable. None of these alternatives are as effective (measured by the NRI model) for increasing reliability as establishing a new feeder.

**Risk of No Action:**
Network outages due to cascading feeder failures associated with high feeder loading due to shifting load following a feeder open-auto.

**Summary of Benefits (financial and non-financial)**
Establishing new feeders increase network reliability and reduce the risk of network shut down. Costs associated with network shutdowns such as restoration costs, and regulator penalties are minimized.

**Project Relationships (if applicable):**

**EH&S Overview:**
We follow the standards set in Corporate Environmental Procedure(CEP) 11.04. CEP 11.04 requires organizations to make an overall assessment of their routine daily work (recurring) and then create categories for this work activity. The purpose of this process is to identify EH&S hazards/issues. This process will also help to ensure EH&S compliance, resource conservation, risk reduction and alternate design considerations are incorporated in the early planning and design stages of project work.

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**
The reliability of the networks and load areas where these new feeders will be established is expected to improve. Since 1999, Con Edison has worked to identify the factors that affect the reliability of network feeders and the likelihood of multiple network contingencies. For heat waves, feeder and component load and the occurrence of feeder open-autos (OAs) within a short time of a previous OA are found to be particularly important.

These additional feeders will provide a more distributed and balanced supply to the network and more balanced feeder loading during normal conditions (all feeders in service). The increased number of feeders available during contingencies will also mitigate the potential for cascading feeder failures associated with high feeder loading due to shifting load following a feeder open-auto.

Additionally, this program will reduce the number of components (i.e. cable, splices, and transformers) per feeder, thereby reducing exposure to failures and improving the overall feeder performance.

**Specifications & procedures pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 14,230 | 12,389 | 25,389 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 30,419 | 14,320 | 20,513 | 15,043 | 14,575 | 14,519 | 78,970 |

# 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **Osmose (C Truss)** |
| **Project Manager** | Steve Daquila |
| **Project Engineer** | Steve Daquila |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
Accelerate capital installation of C-Trusses and pole replacements to address significant backlogs.

**Justification (Technical Evaluation/Analysis):**
Pole inspections are performed to ensure the reliability of installed poles and safety of the public as referenced in the U.S. Department of Agriculture Bulletin 1730B-121, *Pole Inspection & Maintenance*, Utilities in Decay Severity Zone 2 (New York Area). A majority of the poles are inspected and treated as part of a maintenance program. Inspected poles requiring attention are either replaced or restored to full strength and functionality by way of C-Trussing thus deferring the need to replace the poles and at a reduced cost when compared to replacement. Accelerating the program, which has been under-funded in the past, will allow for a substantial reduction to the backlog of defective poles.

**Alternatives:**

**Risk of No Action:**
Pole failures that could adversely impact public safety and system reliability. Additionally, the increased cost of emergency response activity versus planned pre-emptive work.

**Summary of Benefits (financial and non-financial):**
Public Safety

**Project Relationships (if applicable):**

**EH&S Overview:**
The inspection program is meant to reveal and replace priority poles and to identify the poles that are in the early stages of decay so that corrective action can be taken. The primary objective of the inspection program is to establish and sustain a continuing program of effective, ongoing pole maintenance, thereby extending the average service life of all poles on the system, maintaining system reliability and removing potential threats to public and employee safety. The inspection and treatment objectives are meant to ensure that the structural strength of the wood poles meets National Electrical Safety Code requirements (NESC).

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

**Specifications & procedures pertaining to Program/Project:**

**Benefits/Outcome of Program/Project:**

**Is this a mandated program?  If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 1,326 | 1,058 | 1,402 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 2,098 | 1,779 | 1,700 | 1,552 | 1,495 | 1,488 | 8,014 |

# 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **Overhead Conductor Clearance** |
| **Project Manager** | Steve Daquila |
| **Project Engineer** | Steve Daquila |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | Reliability |

**<u>Work Description (Includes units per Year and a high level schedule):</u>**
EO-4647-C Rev 13 provides compliance with the latest electrical code of the City of New York and the 2008 edition of the National Electrical Safety Code, and defines the required minimum clearances between any building and other structure from the energized wire / equipment on the Overhead System. Over the years, these specifications have changed and builders have begun building to the property line, encroaching on the required clearances. As a result, Con Edison has identified locations where the energized Overhead wire and equipment do not meet the current specification. This program was initiated to begin to rectify these situations.

There are a number of specifications that provide detailed instructions for overhead installations. Company specification EO-4647-C Rev 13 Overhead Distribution Clearances, stipulates the minimum clearances that must be maintained from buildings and structures for electric equipment.

EO-4647-C Rev 13 describes minimum clearances from overhead electric facilities as described in the National Electric Safety Code. These clearances are required for the safety of the public and the protection of our distribution system. A number of locations exist along congested areas where live conductors are too close to buildings or residences (primary, secondary, service, and aerial cable).

Some locations have multiple feeders, double cross arms for two open wire feeders, or two feeders on one set of cross arms, one on each side. Correcting these problems require the relocation of the circuit. This could be to the other side of the street, into an aerial cable position, or underground to completely rectify the situations. Based on past history, the typical clearance job will involve the installation of three poles, 200’ primary wire, 200’ secondary wire, and possible additional aerial cable. Other standard jobs could include a riser, splice box and transformer if field conditions warrant an underground solution. The average job is projected to cost $80,000. At this estimate, it is planned to complete 5-7 jobs per year.

**<u>Justification (Technical Evaluation/Analysis):</u>**
There is currently a public safety issue if these clearance issues are not rectified. Con Edison must relocate various pieces of the Overhead Electric Distribution System to meet the current clearance requirements.

**<u>Alternatives:</u>**
Conductors not meeting current specifications are currently protected by protective line hose. Inspection of these protective line hose is required every 3 months and inspections take approximately two labor hours per location. Relocation of conductors onto alley arms or extension brackets is not an option. The pole lines are in franchised areas and were constructed before the buildings or the renovations of the buildings took place.

**<u>Risk of No Action:</u>**

The safety concerns have been temporarily addressed by applying protective guards to the conductors, allowing for closer proximity to structures. These protective guards must be inspected every 3 months to ensure that they have not moved or deteriorated.

**Summary of Benefits (financial and non-financial):**

Many of the locations with clearance concerns have other specification related deficiencies such as distances from communication zones, double gain poles, and proper guying. Relocating facilities provides the opportunity to rebuild the pole line and bring them up to current specifications and standards.

**Project Relationships (if applicable):**

**EH&S Overview:**
This program supports the mitigation of public safety concerns associated with inadequate clearance to our electric facilities. As outlined in EO-4647-C, there are specific guidelines for the clearance of energized lines to a structure. As these specifications have changed throughout the years, there are a large amount of areas where the Overhead wire is not meeting the current specification.

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**
The Independent Monitor and Ombudsman have cited these overhead clearance issues in their reports.

**Specifications & procedures pertaining to Program/Project:**
EO-4647-C Rev 13

**Benefits/Outcome of Program/Project:**
The outcome of this project is to correct clearance issues on the overhead system that do not conform to current specifications. The benefit is to support the safety of the public.

**Is this a mandated program? If yes, include verbiage associated with mandate:**
Required by EO-4647-C Rev 13, and The National Electric Safety Code.

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 0 | 399 | 151 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 524 | 620 | 500 | 463 | 0 | 0 | 1,583 |

# 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **Overhead Feeder Reliability/VRS Replacement** |
| **Project Manager** | Troy Devries |
| **Project Engineer** | Troy Devries |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
Replace remaining aged Vacuum Recloser Switch (VRS) upper units. The replacement prioritization of these units is as follows:

Priority 1: The 12kA units which are estimated to be between 20 and 30 years old.
Priority 2: The 16kA units that are estimated to be over 20 years old.
Priority 3: The remaining 16kA units that are less than 20 years old.

Bronx/Westchester Engineering plans give higher priority to the FVRS's as part of this program in 2012 due to the higher impact of failure, versus the impact of failure of a mid-point or Tie FVRS.

Units per Year: Fifteen (15) in 2012, 2013 & 2014

Mandatory: *EO-10320 - Maintenance of Three Phase Overhead Vacuum Reclosers (4kV, 13kV, & 27kV Bulletin -52 active)*

**Justification (Technical Evaluation/Analysis):**
Vacuum Recloser Switches are essential for the automatic operation of the 13kV and 4kV auto-loops. All units over 20 years old are required to be evaluated for replacement as mandated by engineering specification *EO-10320.Maintenance of three phase overhead vacuum reclosers (4kV, 13kV, & 27kV bulletin -52 active).* Many of these switches are in poor physical condition and are rusting in place. They are well past the manufacturers duty cycle limits.

In addition the older style units cannot properly coordinate with the most up to date control box in use which may cause reclosers to misoperate interrupting additional customers. This limits the ability to control them remotely which has significant benefits during outage restoration. Failure to have this remote controllability will increase non-network CAIDI. Consequently, we plan replace all aged units that are over 20 years old. Fault current evaluation will be done to determine the appropriate replacement units.

**Alternatives:**
Increase inspection frequency and/or operate to failure. Failure of a switch during operation has a significant impact on customer reliability. Replacement on emergency involves more significant expense than planned replacement. Another alternative would be to develop a program to rebuild units as they are replaced, costs uncertain at this time.

**Summary of Financial Benefits and Costs**:

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

**Specifications & procedures pertaining to Program/Project:**
All units over 20 years old are required to be evaluated for replacement as mandated by engineering specification *EO-10320 Maintenance of three phase overhead vacuum reclosers (4kV, 13kV, & 27kV bulletin -52 active).*

**Benefits/Outcome of Program/Project:**
Vacuum Recloser Switches are essential for the automatic operation of the 13kV and 4kV auto-loops. Many of these switches are in poor physical condition and are rusting in place. They are well past the manufacturers duty cycle limits.

In addition the older style units cannot properly marry with the most up to date control box in use. This limits the ability to control them remotely which has significant benefits during outage restoration. Failure to have this remote controllability will increase non-network CAIDI. Consequently, we plan replace all aged units that are over 20 years old. Fault current evaluation will be done to determine the appropriate replacement units.

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M)**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 3 | 1 | 0 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 1,573 | 2,759 | 1,500 | 463 | 449 | 447 | 5,618 |

# 2013 Capital – Business Unit/ Division

| | |
|---|---|
| **Project/Program Title** | **Overhead Feeder Sectionalizing Program** |
| **Priority Number** | |
| **Project Manager** | Steve Daquila |
| **Project Engineer** | Steve Daquila |
| **Budget Reference** | |
| **Project Number** | |
| **Status** | New |
| **Estimated Start Date** | Continuous |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |
| ***ERM Addressed*** | |

**Work Description (Includes units per Year and a high level schedule):**

This program consolidates four (4) automatic and manual feeder sectionalizing programs deployed for the non-network open wire systems in the Bronx, Brooklyn, Queens, Staten Island and Westchester County. These programs are initiated on various devices to enhance system performance, and in particular SAIFI and CAIDI. Obsolete switches are replaced, damaged and inoperable ones repaired or replaced, new automation and technologies deployed and additional switches installed on a prioritized basis to enhance overall system performance as well as emergency response requirements. The automatic switch designs have been consolidated with O&R to provide standardization between companies and a resultant unit cost reduction.

The program is made up of four components:

i) 4kV Feeder Automatic Sectionalizing Switches (with SCADA)
ii) 13kV Auto-Loop Mid-Point Automatic Sectionalizing switches (with SCADA)
iii) 4, 13, 27, & 33kV Manual Isolation Switches
iv) 33kV Isolation Switches with SCADA functionality (Staten Island Only)

The program covering the installation of 4kV Feeder Automatic Sectionalizing switches is described below:

- Proactive installation of automatic Cooper Kyle® switches (or functional equivalent), where there are presently no automatic switches. At the beginning of 2013 there will be approximately 135 4kV Station-to-Station Feeders with no sectionalizing switch, all of which are potential locations for the installation of a Kyle® switch (or functional equivalent). The switches will be fitted with Supervisory Control and Data Acquisition (SCADA) equipment to allow remote monitoring and control
- Each year we plan to install an average of 32 4kV Kyle® switches company-wide at a cost of $50k per switch installation. After this four year period 52 potential locations for installation of a 4kV Kyle® switch would remain.
- Addition of communication and automation functionality to 36 single phase, 4kV sectionalizing switches. We currently plan to retrofit 21 of these over the next 4 years at an estimated cost of $2.5K/switch.

The program covering the installation of mid-point reclosing (automatic sectionalizing) switches on various 13kV Auto-loops is described below:

- Proactive installation of Mid-Point Vacuum Recloser Switches (VRS) switches.
- The switches will be fitted with Supervisory Control and Data Acquisition (SCADA) equipment to remotely monitor and control these devices.
- At the beginning of 2013 there will be a total of 120 locations within 13kV auto-loops where a mid-point recloser is presently not installed.

The program covering the installation of manual isolation switches which can enable the reconfiguration of open wire circuits is described below:

- Replacement of an average of 10 inoperable switches per year and the installation of an average of 40 new switches per year.
- The average cost of replacing an existing three-phase gang Switch is $13k and the average cost of installing a new switch is $9k (note that half of the new switches to be installed are three-phase gang switches with the other half being single-phase air switches).

The program covering the installation of 33 kV Isolation switches with SCADA functionality is described below:

- Installation of 34 SCADA switches is planned for Staten Island’s 33KV feeders at a total cost of $330k/year.
- 30 of these installations would require extensive work because the SCADA installation requires an up feed primary riser on the first pole, a section of open wire between the first and second poles, the SCADA controlled gang switch on the third pole, another section of open wire from the second to the third poles, and a down feed riser on the third pole. All three poles have to be 50’ poles.
- The 18 dead move switches that are being proposed for replacement only involve one pole with an up feed and down feed riser on the same pole as the single phase underarm switches. With the additional infrastructure requirements involved, average cost would be about $110K per installation.
- Replacement of three disconnect manholes with SCADA switches at an average of $110K per installation.
- Of the 13 SCADA switches proposed for the transfer of load between Fresh Kills substation and Fox Hills substation, 8 would be new installations require all the same infrastructure at an average of $110K per installation. The other 5 locations would be replacement of existing interrupter switches where this infrastructure already exists, at an average cost of about $20K per installation.

Units per Year: Outlined in work description.
Mandatory: Required
High-level schedule: Annual program – Majority after load relief season (late second quarter through 4th quarter each year)

**Justification (Technical Evaluation/Analysis):**

With regards to the addition of the 4kV Automatic Sectionalizing "Kyle" Switches. The addition of these switches can be justified for the following:

i) They significantly reduce the number of customers that experience outages for permanent faults on the main run or non-fused spurs of the feeder. For the most common single phase fault, they reduce the customers affected from all customers (100%) to on average 17%. They easily provide for the most cost effective benefit to customer reliability (SAIFI) that is available.

ii) They provide for more sensitive detection and isolation of downed 4kV conductors, improving public and employee safety.

iii) When fitted with SCADA capability, they allow for the 4kV grid to be reconfigured more easily during emergencies, improving operating flexibility.

The addition of 13kV Mid-point Reclosers (automatic sectionalizers), can be justified for the following reasons:

i) They significantly reduce the number of customers that experience outages for permanent faults on the main run or non-fused spurs of the feeder. For any type of fault they reduce the customers affected from all customers (100%) to on average 50%. They easily provide for the most cost effective benefit to customer reliability (SAIFI) that is available.

ii) They provide for more sensitive detection and isolation of downed 13kV conductors, providing for public safety and utility personnel benefits.

iii) When fitted with SCADA capability they allow for the 13kV auto-loop to be reconfigured more easily during emergencies.

With regard to manual isolation switches, during an outage to a 4kV circuit or a 13, 27 & 33kV auto-loop circuit, manual isolation switches allow the defective portion of the circuit to be isolated by a first responder between two switches and all other customers to be restored. The customers on the affected phases between the two switches experience the longest outage, in general they need to wait until physical repairs or other isolation moves are made, however all other affected customers can be restored more rapidly. Reducing the spacing between the switches reduces the number of customers that experience this longer outage and increases the number of customers that can be restored quickly by switching alone.

The installation of manual isolation switches can also enable the reconfiguration of open wire circuits. This is useful during emergency situations and also during scheduled outages as a risk management tool.

Both of these uses have a significant impact on the corporate CAIDI goal.

With regard to the addition of additional SCADA switches in Staten Island, there are 18 dead move disconnect switches on the 33KV feeders in Staten Island. They were installed to enable the feeders to be sectionalized for either a fault condition or to allow work without interrupting service to the entire run of the feeder. This capability is critically important to ensuring reliable service because of our first contingency design on Staten Island. It gives us the ability to limit the contingency to a very small area. The 33KV feeders on Staten Island feed the 4KV unit substation grids, so being able to keep portions of feeders alive (while working on other portions) means we can keep more unit substations feeding our grids. Because of our work rules and the close proximity of equipment at these installations, they cannot be operated unless both sides of the switch are de-energized. This means the whole feeder must be removed from service to isolate the portion being serviced. This is a lengthy process that exposes customers to risk of outage for several hours. The process has to be repeated in reverse in order to restore the feeder to normal, creating additional risk. SCADA switches, on the other hand, can be operated remotely, can be operated live (to drop or pick up load), and provide real time loading and voltage information. Therefore, SCADA switches eliminate a considerable amount of switching and exposure to contingency operation. Replacing a dead move switch with a SCADA switch usually requires the replacement of three poles, the installation of two risers, two sets of terminators, two underground splices, and the installation of two sections of open wire, at an average cost of about $110K for each location.

There are three disconnect manholes on the 33KV feeder in Staten Island. They present the same operating limitations listed above and replacing them with SCADA switches would involve similar work.

There are 5 tie switches on the 33KV feeders in Staten Island that link feeders out of Fresh Kills substation to feeders out of Fox Hill substation. Therefore, 10 feeders are involved in total. The ability to shift load between the two station means that station load relief projects can be postponed or even eliminated. The speed at which that transfer can be accomplished is critical. Right now, two of the tie switches have been changed to SCADA, so all other switches have to be visited by field forces and manually operated. Manual operation means that the transfer cannot be accomplished in less than an hour so the load transfer cannot help us to stay below the 1 hour rating on the transformers, but, it does help us stay below the 3 hour ratings. To optimally leverage the contingency capacity of the transformers in both stations, we would need to have SCADA switches at all the tie points and SCADA switches along each of the 10 feeders involved (so that we don't have to switch the entire load of the feeder from one station to another but, rather pick load pockets that make sense to transfer). All in all, this would include approximately 8 switches with similar work and cost as described in the first paragraph above and 5 switches that would simply require the replacement of an interrupter switch (poles already bigger size, risers already existing, open wire already existing, cost only about $15K per location).

Finally, the advantage to having remote monitoring and operational capability lies in understanding the extent of an outage and restoring it quickly. When a portion of a 4KV grid collapses we get information from the Unit Substation Automation application, which tells us the status of the 4KV breakers. However, since each 4KV feeder is fed from two substations, we don't know if the feeder is out of service unless both breakers are open. The single phase sectionalizers are typically at the electrical midpoint of the feeder. If we know that they have opened and one of the station breakers has opened, then we would know immediately that an outage exists between the two. When a portion of a grid collapses, a lot of time is spent trying to figure out exactly who is out of service and what caused the outage, which delays the restoration efforts. These are large outages (often 1,000-4,000 customers), which means that they have a significant impact on our CAIDI goals.

**Alternatives:**

The alternative to adding new 4kV Automatic sectionalizing switches or to adding additional 13kV mid-point reclosers is to miss out on the significant and cost effective gains to be made in customer reliability, particularly SAIFI. Design alternatives to provide similar benefits, which would involve breaking up the loops and running new supply feeders may cost 20 to 40 times on a unit cost basis.

The alternative to adding additional manual isolation switches on 4, 13, 27 & 33kV open wire circuits is to accept longer customer outage durations.

The alternative to adding SCADA switches on Staten Island involves work procedures which require the full de-energization of a feeder so line personnel may lift taps and isolate or cut in breaks to separate feeders. All this is extremely manual intensive and would have adverse impacts on SAIFI and CAIDI.

**Risk of No Action:**

Degradation of reliability and adverse effects on public and employee safety.

**Summary of Benefits (financial and non-financial):**

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

**Specifications & procedures pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

The Company has recently been directed to improve its non-network CAIDI performance. Portions of this program address that mandate.

# Funding Forecast Capital

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 4,051 | 0 | 0 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 0 | 1,679 | 1,600 | 1,453 | 1,395 | 1,388 | 7,515 |

**2013 Capital – Electric Operations**

| **Project/Program Title** | **Overhead Secondary Reliability Program** |
|---|---|
| **Project Manager** | Troy Devries |
| **Project Engineer** | Bob Symons |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
Replace overhead secondary wires that are aged, un-insulated, and undersized to improve service reliability and reduce customer complaints. Replace aged open wire services which have inadequate insulation qualities and poor connections.

Units per Year: 50 Spans per year

**Justification (Technical Evaluation/Analysis):**
Defective and undersized overhead secondary wires are the primary cause of complaints regarding low voltage and flickering lights. Also, much of this wire is bare and has excessive slack which can cause the wires to "slap together" in windy conditions. Replacement of this wire will improve customer satisfaction by improving the quality of power delivered to our customers. Approximately 2,500 spans (500,000 feet) of secondary wire will be replaced under this program. The new service wire is more robust and resilient and capable of withstanding greater tree and element exposure.

We will utilize reliability indices based on storms, customer complaints, low voltage and other records to identify, and prioritize targeted cable for replacement.

**Alternatives:**
Expedite OSI repairs or increase tree trimming. These options provide short term solutions. This program is used to respond to repeated outages and customer complaints, where short term solutions are not an adequate response.

**Risk of No Action:**
Decreased customer satisfaction, increased voltage complaints, and public safety issues from live wires.

**Summary of Benefits (financial and non-financial):**
This program will enhance our storm hardening strategy of risk prevention and mitigation. Public safety is improved since a failure of one leg of triplex cable generally does not drop the conductor to the ground as it would with open wire, thereby reducing public exposure to live wires.

This program will enhance power quality experienced by customers who are served by old overhead secondary.

**Project Relationships (if applicable):**

**EH&S Overview:**
Public safety is improved since a failure of one leg of triplex cable generally does not drop the conductor to the ground as it would with open wire, thereby reducing public exposure to live wires.

**Analysis of Prior Year Funding Request Versus Actual:**

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**

**Benefits/Outcome of Program/Project:**

**Is this a mandated program?  If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 0 | 19 | 244 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 210 | 208 | 199 | 186 | 179 | 179 | 951 |

## 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **PILC** |
| **Project Manager** | George Murray |
| **Project Engineer** | Robert Skabowski |
| **Status** | Ongoing |
| **Estimated Service Date** | Year-end 2020 |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
This program is designed to facilitate the removal of PILC cable from the primary distribution network feeders. This program, working with other PILC cable removal methods, will reduce the amount PILC cable to less than 10% of the total population of primary distribution network cable by year-end 2020. The other methods of PILC cable removal include: burn-outs, load relief and other reliability work.

Units per Year: About 1,000 sections per year through 2020
Mandatory: The PILC cable removals are a commitment made to the PSC
High-level schedule: On average, about 900 sections must be removed each year to achieve the year-end 2020 goal.

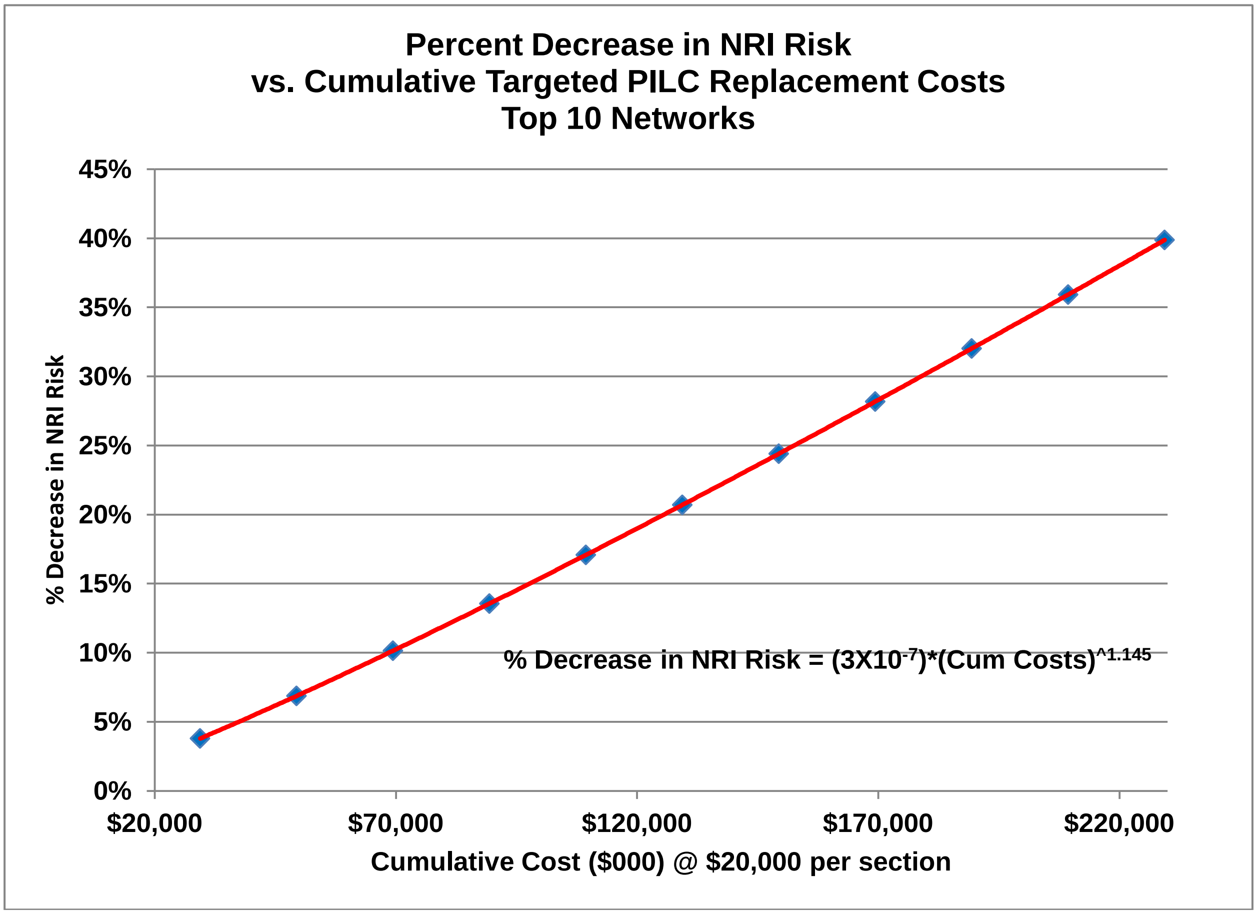
**Justification (Technical Evaluation/Analysis):**
The program began in the mid 1980's due to concerns over the reliability and potential environmental impact of PLIC cable. Paper Insulated Lead Covered cable contains a dielectric fluid (usually a mineral oil) and a lead sheath that are potential environmental contaminants. Failure data collected during the 1980's also showed that older PILC cable was responsible for many feeder failures, especially during the summer months.

Reliability studies have determined that several distribution components, among them PILC cable and transition splices (stop-joint connecting PILC cable to the newer solid dielectric cable), had significantly elevated failure rates during summer heat waves. These studies also showed that the removal of these high failure rate components would result in major improvements in network reliability. Currently, transition splices remain the single biggest contributor to primary feeder failures during summer heat-wave periods. The PILC cable, while less of a reliability issue than the transition splices, still has a failure rate, on the Con Edison system, that is an order of magnitude higher than the newer solid dielectric cable (principally Ethylene Propylene Rubber, EPR, cable). The only practical method to remove these heat sensitive transition splices is through the removal of the attached PILC cable.

The primary network system is currently comprised of approximately 13 percent PILC cable while the associated transition splices make up around 6 percent of the splice population. These relatively low populations, however, are responsible for over 38 percent of the primary feeder failures during high-load summer heat events. Transition splices, especially, have been responsible for cascading feeder failures where multiple outages have put the network at an increased risk of shutdown. The replacement of the PILC cable and associated transition splices reduces that risk.

Recent reliability studies have shown that the removal of PILC cable, and the associated transition splices, results in significant improvements to the Network Reliability Index (NRI).

The plot below (Efficiency Frontier Curve) demonstrates the efficiency of increased spending on PILC cable replacement (including associated transition splices) in terms of improvement in the NRI risk.




**Alternatives:**
An alternative to the PILC Cable Replacement program would be to leave the PILC cable and replace the high failure rate of transition splices with a newer, more reliable, splice design. This would reduce the cost of the program by one-third but would not have the same impact on reliability as removing both the cable and the transition splice. We have developed a better transition splice but replacing the nearly 10,000 in-service transition splices would take the same amount of time and still result in a less reliable system.

**Risk of No Action:**
Reliability studies have shown that level of the NRI risk would significantly increase, indicating network degradation over time, if the PILC cable and transition splices were left in operation.

**Summary of Benefits (financial and non-financial):**
Recent reliability studies have shown that the removal of PILC cable, and the associated transition splices, results in significant reduction to the Network Reliability (NRI) risk.

**Project Relationships (if applicable):**

**EH&S Overview:**

This program has a significant EH&S benefit by removing potentially hazardous material, lead and oil,l from the environment

**Analysis of Prior Year Funding Request Versus Actual:**
The 2011 funding request for PILC removal was $20 million. The actual spend was $18 million.

**Data Reports Issued that Support Program:**
See the Efficiency Frontier Curve included above.

**Is this a mandated program? If yes, include verbiage associated with mandate:**
This is not a mandated program.

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 21,961 | 17,168 | 18,033 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 20,979 | 20,786 | 17,000 | 16,674 | 16,156 | 16,092 | 86,708 |

# 2012 Capital – Electrical Operations

| | |
|---|---|
| **Project/Program Title** | **Pressure, Temperature and Oil Sensors** |
| **Project Manager** | Kevin Oehlmann |
| **Project Engineer** | Ogbonna Chilaka |
| **Status** | Working |
| **Estimated Service Date** | 2017 |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**

The installation of pressure, temperature, and oil level sensors on Con Edison network distribution transformers is funded via this program. As of January 1, 2012, approximately 13,500 network transformers had PTO sensors installed and were in service. Con Edison expects to install 2,738 PTO sensors this year with stimulus and rate-case funding. Under this program 1,738 will be installed by regional construction crews with stimulus funding. The other 1,000 will be installed on new transformers in the Astoria Transformer Shop and funded under a different program (ED2). Con Edison expects to install approximately 2,000 new PTO sensors per year on average. All network transformers are expected to have sensors installed by December 2017.

**Justification (Technical Evaluation/Analysis):**

This is one of the transformer failure mitigation programs that have contributed to an 81% reduction in transformer failures since 2005. In 2011, twenty-two (22) transformers were preemptively removed from service due to problems detected via PTO sensors.

**Alternatives:**

Decrease time interval between maintenance inspections in order to attempt to detect units at risk of failure. Since PTO sensors report information real time, this would require a very drastic increase in maintenance costs.

**Risk of No Action:**

In service transformer failures are a public safety concern and these devices help mitigate such occurrences by giving us the ability to identify a suspect transformer prior to failure. Network transformers used by Con Edison are installed underground vaults and manholes in public areas. When a network transformer fails, there is a chance that it may rupture and oil may escape from the vault. This can result in public injury, property damage and/or environmental contamination.

**Summary of Benefits (financial and non-financial):**

**Project Relationships (if applicable):**

PTO sensors require 3$^{rd}$ generation transmitters to communicate with Con Edison's network. In 2008 the installation of PTO sensors and 3$^{rd}$ generation transmitters was funded under one combined program. PTO sensor installations have been funded separately from the installation of 3$^{rd}$ generation RMS transmitters since 2010.

**EH&S Overview:**

The Company has recently developed sensors to capture critical transformer data. These sensors work in conjunction only with a 3$^{rd}$ generation transmitter. Current 3$^{rd}$ gen transmitters add tank pressure, oil temperature, oil level status (RMSPTO) and Alive on Backfeed detection. The RMSPTO program has helped mitigate catastrophic transformer failure with corresponding public safety benefits. The Alive on

Backfeed (ABF) detection will improve feeder processing time with corresponding cost reductions, personnel safety and system reliability benefits.

**Analysis of Prior Year Funding Request Versus Actual:**
The funding request in 2011 was $2.308M. The actual capital money spent was $.704M. The difference was due to a reprioritization of work.

**Data Reports Issued that Support Program:**
Monthly PSC Report Cards – generated every 1st of month.

**Specifications & Procedures Pertaining to Program/Project:**
B-47 “Setting Used to Program RMS Transmitters”, EO-6612 “Remote Monitoring System for Network Transformers & Protectors”, EO-10110 “Inspection and Maintenance of Network Type Distribution Equipment”.

**Is this a mandated program? If yes, include verbiage associated with mandate:**
Not mandated.

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 0 | 1,611 | 704 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 3,147 | 3,118 | 3,000 | 2,780 | 2,693 | 2,682 | 14,273 |

## 2012 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **Remote Monitoring System 3rd Generation** |
| **Project Manager** | Kevin Oehlmann |
| **Project Engineer** | Kevin Oehlmann |
| **Status** | Working |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
Install new Remote Monitoring System (RMS) 3rd generation (gen) transmitters at various network transformer vault locations throughout all service territories. This includes all ED-2 work, repairs, and RMSPTO field conversions. An average of 1,200 units/year will be installed by Company Regional I&A/Equipment personnel through stimulus and rate case funding. This will enable the Company to meet required levels reported to the Public Service Commission.

**Justification (Technical Evaluation/Analysis):**
The transmitter is the individual transformer data collector of the Remote Monitoring System. Each Company network transformer has a transmitter with a unique network ID number. This enables the Company to receive transformer information remotely for each unique ID/vault. The Company has recently developed additional sensors to capture critical transformer data. These sensors work in conjunction only with a 3rd generation transmitter. Earlier gen transmitters provided network protector status, phase current loading, phase voltages, high water and oil minder alarms. Current 3rd gen transmitters add tank pressure, oil temperature and oil level status (RMSPTO) with Alive on Backfeed detection and asset management features. The RMSPTO program has helped mitigate catastrophic transformer failure with corresponding public safety benefits. The Alive on Backfeed (ABF) detection will improve feeder processing time with corresponding cost reductions and system reliability benefits. Better asset management will enable the company to plan more effectively. This should lower associative costs and provide auditors and budgetary personnel with formally unattainable data for Company budgets and reports. The 3rd gen transmitter also has a lower failure rate. Replacing older gen units with 3rd gen also provides more reliable data that is used by operations and engineering for short and long term decisions. Hence, better use of man power and equipment.

There are no alternatives to not installing the 3rd gen transmitter. The Company now has qualified a 2nd source vendor through which competition has enabled an approximate $2M cost savings on the two year contract. There is a $10M penalty if any 2nd contingency network reports below 90% during four PSC audits conducted per year. The higher failure rate of the earlier gen transmitters insures that 3rd gen replacements are needed for required reporting rates to be achieved.

Consequently, RMSPTO sensors work in conjunction with the 3rd gen transmitter. The valuable information received by these sensors has contributed to better public/worker safety and proactive environmental control of the distribution system. Therefore, it is virtually impossible to put a monetary value to the installation of the 3rd gen transmitter as a replacement for previous models. It is imperative to continue with the deployment in an efficient timely manner.

**Alternatives:**
There are alternative technologies available for remotely monitoring distribution equipment. Since Con Edison already has the existing remote monitoring system in place, it would be much more costly to replace the existing system with an alternative design.

**Risk of No Action:**

In service transformer failures are a public safety concern and these devices help mitigate such occurrences by giving us the ability to identify a suspect transformer prior to failure. Network transformers used by Con Edison are installed underground vaults and manholes in public areas. When a network transformer fails, there is a chance that it may rupture and oil may escape from the vault. This can result in public injury, property damage and/or environmental contamination.

**Summary of Benefits (financial and non-financial):**

**Project Relationships (if applicable):**

PTO sensors require 3rd generation transmitters to communicate with Con Edison's network. In 2008 the installation of PTO sensors and 3rd generation transmitters was funded under one combined program. PTO sensor installations have been funded separately from the installation of 3rd generation RMS transmitters since 2010.

**EH&S Overview:**

The Company has recently developed sensors to capture critical transformer data. These sensors work in conjunction only with a 3rd generation transmitter. Current 3rd gen transmitters add tank pressure, oil temperature, oil level status (RMSPTO) and Alive on Backfeed detection. The RMSPTO program has helped mitigate catastrophic transformer failure with corresponding public safety benefits. The Alive on Backfeed (ABF) detection will improve feeder processing time with corresponding cost reductions, personnel safety and system reliability benefits.

**Analysis of Prior Year Funding Request Versus Actual:**

Last year's funding request was $5.2429M. The actual capital money spent was $2.657M. The difference was due to a reprioritization of work.

**Data Reports Issued That Support Program:**

Monthly PSC Report Cards – generated every 1st of month.

**Specifications & Procedures Pertaining to Program/Project:**

B-47 "Setting Used to Program RMS Transmitters", EO-6612 "Remote Monitoring System for Network Transformers & Protectors", EO-10110 "Inspection and Maintenance of Network Type Distribution Equipment".

**Is this a mandated program? If yes, include verbiage associated with mandate:**

Not mandated.

**Funding Forecast (Capital or O&M) ($000s):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 0 | 356 | 2,657 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 4,196 | 3,118 | 1,500 | 1,390 | 1,346 | 1,341 | 8,695 |

## 2013 Capital – Electric Operations

| **Project/Program Title** | **Shunt Reactors** |
|---|---|
| **Project Manager** | Elie Chebli |
| **Project Engineer** | Robert Szabados |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
This program is for the installation of Shunt Reactors to provide compensation within the Brooklyn/Queens and Staten Island load areas.

Units per Year:
The plan in Brooklyn/Queens will be to install approximately 20 reactors per year over the next five years. Currently there are 122 feeders from the original study that are pending a shunt reactor. The projected schedule is as follows:

2012 – 20
2013 – 21
2014 – 21
2015 – 20
2016 – 20
2017 – 20

High-level schedule:
The goal is to have the proper compensation for each 27 KV network feeder in the Brooklyn/Queens region by 2017.

**Justification (Technical Evaluation/Analysis):**
Shunt Reactors are required to reduce over voltage on the secondary system that may occur during back fed conditions.

**Alternatives:**
The alternative to installing shunt reactors is to deploy crews during abnormal backfeed conditions to block open network protectors in order to eliminate the overvoltages. However, this does not fully protect customer equipment from damage since overvoltages will persist until crews find and correct the backfeed condition.

Installing shunt reactors limits overvoltages and reduces the potential for damage to customer equipment. In addition, shunt reactor installation improves feeder processing productivity and reduces O&M costs on scheduled feeder outages.

**Risk of No Action:**
A 27 kV and 33 kV network feeder that is not properly compensated with a shunt reactor has the potential to cause over voltages on the secondary system and primary feeders during a back feed condition. The magnitude of the over voltage condition could result in more than 140 Volts line to neutral on the secondary side of the back feeding transformer and 20 to 40% overvoltages on the primary back fed

feeder. These over voltages have the potential to do damage to the company's equipment as well as the customer's equipment.

**Summary of Benefits (financial and non-financial):** The cost of the program includes the installation of new vaults, installation of ducts and the installation and splicing of new primary cable. When feasible the cost of the reactor job will be minimized by utilizing existing vacant vaults. When there are no vacant vaults then the new vault will be placed as close as possible to existing manholes in order to minimize the length of the duct run and the associated cost. Compensating for overvoltage on the primary feeders will prolong the life of primary cables and transformers since they will not see excess overvoltage during their life cycle.

**Project Relationships (if applicable):**

**EH&S Overview:** CEP 11.04 Environmental, Health and Safety Considerations in Recurring Work

We follow the standards set in Corporate Environmental Procedure (CEP) 11.04. CEP 11.04 requires organizations to make an overall assessment of their routine daily work (recurring) and then create categories for this work activity. The purpose of this process is to identify EH&S hazards/issues. This process will also help to ensure EH&S compliance, resource conservation, risk reduction and alternate design considerations are incorporated in the early planning and design stages of project work.

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

**Specifications & procedures pertaining to Program/Project:**
EO-2069 Application of 27 KV and 33 KV Shunt Reactors

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 917 | 1,760 | 1,080 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 1,573 | 1,767 | 1,700 | 1,575 | 1,526 | 1,520 | 8,088 |

**2013 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | **Street Lights Service Reliability Program** |
| **Project Manager** | Don Lucia |
| **Project Engineer** | Rafael Dominguez |
| **Status** | On-going |
| **Estimated Service Date** | On-going |
| **Work Plan Category** | |

**Work Description:**
This is a multi-year Program that started in 2008 to protect the public from stray voltage associated with street lights. Over the next several years the Company will continue to purchase and install isolation transformers and associated connectors in underground structures supplying streetlamps and traffic lights in New York City and Westchester. To optimize our expenditures and best reduce risk to the public, transformers will be installed in targeted locations.

From the beginning of the program, through 2011, we have installed a total of 12,734 units. Our installation goal for 2012 is 1,300 units and 300 units per year thereafter totaling approximately 15,200 units through 2017.

The company has periodically evaluated the effectiveness of the program and has found that installing isolation transformers in locations with repeat instances of stray voltage and high population density areas provides the greatest benefit for the resources expended. The requested funding will allow the Company to address all issues pertaining to the installation of isolation transformers. The request also includes funding for spare units to account for manufacturing problems or the need to install transformers in new streetlights. The Company will continue to periodically evaluate the effectiveness of the program.

Units per Year: 1,300 in 2012 and 300 per year thereafter until 2017

**Justification:**
Isolation transformers create an isolated, ungrounded circuit for each streetlight; which protects workers and the public against electrical hazards caused by cable failure, poor neutral connections or ineffective grounding. Also, as part of the isolation transformer installation process, unsafe connectors discovered in lamp bases are removed and replaced with waterproof fuse holders and crimp connectors, further reducing risk.

**Alternatives**:
We have investigated the use of ground fault circuit interrupters as well as re-cabling every streetlight and neither alternative was cost effective as compared to installing Isolation Transformers.

**Risk of No Action**:
Energized streetlights or traffic lights and risk of electric shock to the public or employees.

**Summary of Benefits (financial and non-financial)**:

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**
Yes this program is mandated. In Case 07-E-0523, the Public Service Commission approved the Company's proposal to install isolation transformers on its underground secondary distribution system in order to eliminate stray voltage conditions associated with streetlights and traffic signals. The Commission's order directed the Company to "perform as many installations as can reasonably and cost effectively be accomplished." Since that time, a multi-year, multi-faceted effort by Con Edison and the NYCDOT had significantly reduced the number of shock events attributed to street lights and traffic signals (from 87 in 2004 to six in 2011). Those efforts included

- Con Edison's ongoing mobile scanning program;
- Con Edison's multi-year streetlight cable replacement program;
- NYCDOT's application of non-conductive paint to street light and traffic signal poles;
- Improved electrical connections in the lamps;
- Removal of the bond to Con Edison's neutral in the street light base to eliminate stray voltage caused by neutral failures and the potential for a failed phase conductor within the duct to energize the street light pole; and
- Pre and post-work stray voltage testing by Con Edison and NYCDOT workers.

Due to the effectiveness of these efforts, the Company has concluded that the full scale installation of isolation transformers was no longer cost effective or reasonable. The Company optimized the program by installing isolation transformers in locations with repeat instances of stray voltage and high population density areas. As a result, the Company forecasts the ability to achieve the program objectives at lower funding levels than previously anticipated. On April 19, 2012 the Commission issued an order in Case 07-E-0523 authorizing the modified Isolation Transformer Installation discussed above.

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 5,311 | 5,217 | 2,478 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 3,600 | 500 | 500 | 500 | 500 | 500 | 2,500 |

**2012 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | Storm Hardening of Overhead System |
| **Project Manager** | Jonathan Russell |
| **Project Engineer** | Thomas Langlois |
| **Status** | Planning |
| **Estimated Service Date** | Year 2013 and then ongoing as needed |
| **Work Plan Category** | Reliability |

**Work Description:**

Emergency Management data predict that the Northeast Region will experience an increase in severe storms in the future. Currently, Category 1 and 2 hurricanes affect the region once every 19 years and major hurricanes, Category 3 or greater, affect the region once every 74 years.

In the past 2 years our overhead system has experienced severe damage from Hurricane Irene and Hurricane Sandy. In addition to these larger named storms we experienced a number of large unnamed storms that were also devastating, including the February 2010 snowstorm, March 2010 Nor'easter and October 29 2011 snowstorm. Recent experience indicates that the number of these events is increasing. Prior to 2010 the last year with more than one devastating storm year was 2006. `

The damage caused by the January 2006 ice storm and the remnants of Tropical Storm Ernesto in 2006 also resulted in significant customer interruptions and long restoration times. Since weather forecasts indicate storms of this nature are expected to increase, Con Edison is faced with the challenge of operating a vulnerable overhead electric system in an area with an overgrown urban forest. In addition the challenge faced by the Company is the expectations of the customers to have their power on at all times.

Con Edison's mission is to provide energy services to our customers safely, reliably, efficiently and in an environmentally sound manner. The time for complete restoration for each of these storms was a week or more. This is an extreme burden on our customers resulting in spoiled food, lack of heat and inability to use technology which is so heavily relied upon. In order to satisfy our customer's expectations for shorter duration outages and less regional impact we must look at ways to harden the existing overhead system to prevent damage.

To this end the Company is evaluating a number of strategies to make the system more resilient to these wide scale storms.

**Overhead Distribution Equipment Upgrade & Retrofitting**

Distribution circuit hardening would reduce damage to distribution circuits and expedite restoration efforts after storm events. This program involves strategic use of aerial cable which is more resilient to tree impact, reduction of the size of circuit segments and increased use of automation (sectionalizing devices, fuses and reclosers)

Aerial (URD) cable mounted on poles to supply customer load via a shielded cable on a messenger would be less susceptible to tree branch faults, animal contacts and more resistant to damage from downed trees than open wire. The work to implement this design would involve changing existing primary open wire to URD cable on a messenger with new transformers serving existing open wire secondary and services.

Reduction in the size of circuit segments results in fewer customers being interrupted due to storm damage. Our current standard designs typically involve 4kV feeders with one midpoint sectionalizing device (recloser), minimal fusing. Our typical design for automatic loops (13 and 27kv) uses a maximum of five reclosers. These designs may be improved by the addition of sectionalizing switches and fuses which will reduce the segment size and the impact of a single point of failure. The newer technology of microprocessor relays allows us to add fusing and sectionalizing where we previously could not have, thus enhancing reliability, safety and customer satisfaction.

In addition, in place of fused cutouts, the Company would look to employ new "trip saver" devices on selected spurs where open wire will remain and incidental tree branch contact is likely. This will reduce the number of loop operations during a storm event and help keep the loop in service.

**Selective Undergrounding of Overhead Infrastructure**

Selective undergrounding of portions of overhead infrastructure would provide immunity from overhead storm damage. Undergrounding would be employed to gain the maximum reliability benefit and would be applied to areas where tree trimming alone isn't sufficient protection due to overgrown canopies and areas with prior history of significant damage. This would involve taking the existing radial style system and burying the same type of design in underground ducts.

**Justification:**

The purpose of the storm hardening program is to establish a strategic and cost effective method to minimize damage to the electrical system. Implementing this project will ensure the timely transition back to normal operations of the New York City and Westchester area, its residents and businesses as the storm recedes. In addition with less damage there will be less future restoration costs.

As was detailed in the work description these major storm events cause large amounts of system damage and restoration takes a long period of time costing a large amount of money.

We anticipate the actual costs and scope of work for these projects to be better defined as we conduct further analysis, revise equipment and system designs and refine our storm hardening strategy.

For the aerial cable design, once finalized, would be employed on the worst 50 miles of main run overhead circuits. This would also be pending a detailed analysis of outage data and tree density. We expect this system to fail 50% as much as open wire under the same tree conditions. The incremental cost per mile is approximately $250,000 capital and $75,000 maintenance when compared to re-conductoring with tree wire. This URD system in the air would result in reduced customer impact and restoration cost. To change out the open wire, transformers, add transitions to fuse cutouts and bring this system live we expect a cost of around $600,000 per mile including pole change outs. We expect an additional cost of $100,000 maintenance per mile to make transitions to existing open wire and open wire equipment as well as associated with the pole change outs. The current analysis indicates a requirement of **$17 million** in funding for the aerial cable program but this funding level may change upon further analysis. The maintenance associated with capital (MAC) funding is estimated at $2.5 million.

Regarding the increased use of automation, the Company is currently performing a more detailed engineering study to determine the locations where fuses, fuse bypass switches and automatic sectionalizing switches should be added. The criteria we used is to fuse all spurs and sub-spurs with open wire that are more than 2 spans in length, break down main run segments to 500 customers or less by installing Kyle/VRS sectionalizing switches and put fuse bypasses where un-fused emergency ties. The addition of fuses and fuse bypass switches removes vulnerable open wire areas and their associated customers from affecting the main run, thus each outage event affects fewer customers. Based on a preliminary study of typical feeders we find the total cost for increased use of automation is approximately **$14 million** as outlined in the table below. This funding may change upon further analysis. The maintenance associated with capital (MAC) funding is estimated at $**660,000**.

| | Single phase fuses | Three phase fuses | Three phase fuse bypass |
|---|---|---|---|
| Total Units | 1045 | 520 | 630 |
| Total Cost | $2,613,399 | $2,865,286 | $8,521,315 |
| Overall Cost | $14,000,000 (rounded) | | |

This cost is based on $1,500 per location for a single phase fuse, $4,500 per location for a three phase fuse and $12,500 per location for a fused bypass switch. In addition to these base unit costs we assume poles must be replaced at a rate of 20% with a cost of $5,000 per location. In addition to the $5,000 capital cost we require approximately $1,500 in MAC (maintenance associated with capital) per pole location.

| Poles for 1 phase fuse | Poles for 3 phase fuses | Poles for fused bypass |
|---|---|---|
| 209 | 124 | 126 |
| $313,640 | $156,200 | $190,000 |

Regarding reduction in segment size, an evaluation of the segment size on the main runs of 4kV feeders and 13 & 27 kV autoloops reveals an opportunity to add additional Kyle switches/VRS switches to bring segment sizes to 500 customers per segment. To accomplish this in total we would require 300 additional Kyle switches or VRS switches depending on fault current levels at the particular location. Engineering analysis is underway to identify locations for the switches to perform this task. For the purposes of this paper our preliminary estimate is 10% of locations will require VRS switches and 90% will require Kyle switches. A Kyle has a unit cost of $50,000 per location and a VRS switch a cost of $90,000 per location, including pole installation. The current analysis indicates a requirement of **$29 million** in funding for reducing segment size but this funding level may change upon further analysis. The associated MAC funding is estimated at $1,200,000 as every location would need a new pole.

Regarding undergrounding of selective overhead infrastructure, we would anticipate selectively undergrounding the 10 worst performing linear miles of main run overhead system. The selection of these 10 miles would be done based on outage data analysis and field surveys for density of vegetation. The cost is estimated to be $8,500,000 per mile and is pending a reevaluation of our 2007 study which identified the cost at approximately $6,340,000 per mile. The Company is in the process of retaining the same consultant update the report. The current analysis indicates a requirement of **$200,000,000** in funding for this program but this funding level may change upon further analysis.

**Alternative:**

The alternative is to continue with our current practices. While these result in industry leading SAIFI performance on a blue sky day, the system remains vulnerable for a large storm event and our customers can expect multi day outage events on a more frequent basis.

**<u>Risk of No Action</u>:**

The possibility exist that no major hurricane or storm will hit our service area, but in the event that a major hurricane does hit the Con Edison service area we will experience severe electric infrastructure damage. This damage is extremely costly to the local community, Company and our ratepayers. The blocked streets, lost power and expensive repairs take its toll on the NYC area.

**<u>Summary of Financial Benefits and Costs</u>:**

Current estimated cost of this project is $260,000 million (this estimate will change as the engineering scope is refined.) The benefits of the project are ensuring enhanced reliability during a major storm. In addition to saving the Company and rate payers money it would increase economic activity in the region as life would resume to normal faster and towns will spend less waiting for our assistance in clearing blocked roadways. It would also require approximately $12 million in MAC.

**<u>Non-financial Benefits (if applicable)</u>:**

Safety will be increased by less downed wires and less areas without lights.
Customer satisfaction will increase since the power will be on more than it was in the past.

**<u>Technical Evaluation/Analysis</u>:**

Regional Engineering has developed appropriate prevention strategies as outlined above by changing system design and adding/upgrading infrastructure. The refinement of these high level strategies and engineering details associated with each project will be performed if funding is granted.

**<u>Sensitivity Analysis (if applicable)</u>:**

**<u>Project Relationships (if applicable)</u>:**

**<u>Status:</u>**

Planning

**EH&S Overview:**

We will follow the standards set in Corporate Instruction CI-260-4 Corporate Response to Incidents and Emergencies which establishes guidelines for determining the appropriate level of response and mobilizing the appropriate Company and external resources in a timely manner in response to any incident. It also describes the Company's Electric Emergency Response Plan (ERP) – The Company's Electric Emergency Response Plan details the organization for the response to storms and manmade events affecting the overhead and underground electric system in accordance with the requirements of Part 105 of the Rules of the New York State Department of Public Service.

The Corporate Coastal Storm Plan (CCSP) of Consolidated Edison Company of New York, Inc. provides a comprehensive overview that attempts to identify the potential effects of a severe tropical storm and/or hurricane, prepare strategies to mitigate these identified risks, and guides the subsequent corporate response to such an event. This guide focuses on ensuring public and employee safety while maintaining and restoring the integrity of our energy delivery services.

Adhering to these processes will also help to ensure that EH&S compliance, resource conservation, risk reduction and alternate design considerations are incorporated in the early planning and design stages of project work.

Spill reporting is a primary concern during major storms and this project would limit the amount of transformer spills by preventing damage to the overhead system.

**Analysis of prior year funding request versus actual:**

N/A

**Data Reports issued that support program:**

N/A

**Specifications & procedures pertaining to Program/Project:**

These will be identified as the engineering work commences.

**Benefits/Outcome of Program/Project:**

See Justification section.

**Is this a mandated program? If yes, include verbiage associated with mandate:**

No

**Current Working Estimate (if applicable):**
N/A

**Funding Forecast (Capital or O&M)**

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 0 | 18,000 | 15,000 | 115,000 | 112,000 | | 260,000 |

**O&M – MAC for capital construction pieces**

| Forecast RYE 2015 | Forecast RYE 2016 | Forecast RYE 2017 | Forecast Total 2015-2017 |
|---|---|---|---|
| 4,005 | 4,005 | 4,005 | 12,015 |

**2013 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | Coastal Storm Hardening |
| **Project Manager** | Robert Pettenato |
| **Project Engineer** | Juan Adon |
| **Status** | Planning |
| **Estimated Service Date** | Year 2013 |
| **Work Plan Category** | Reliability |

**Work Description:**

Emergency Management data predict that the Northeast Region will experience an increase in severe storms in the future. Currently, Category 1 and 2 hurricanes affect the region once every 19 years and major hurricanes, Category 3 or greater, affect the region once every 74 years. During August 24, 2011 to August 31, 2011, Hurricane Irene produced 3-4 foot storm surge. More recently, on October 29, 2012 to October 31, 2012, Hurricane Sandy produced a record 14 foot storm surge. The storm tide (combination of surge and high tide) reached 13.88 feet above normal. The surge topped the seawall at The Battery in lower Manhattan and flooded parts of the city's subway system. On the whole, Hurricane Sandy caused five times as many outages as the next largest storm in Con Edison history, Hurricane Irene. Overall, this demonstrates the need for and benefits of storm hardening of our electric infrastructure. An analysis of equipment during the development of the Company's Coastal Storm Plan ("CCSP") identified electric underground apparatus in the various storm surge zones that would be affected. We therefore need to expand Con Edison's storm hardening efforts, particularly in low-lying and other vulnerable areas.

Con Edison's mission is to provide energy services to our customers safely, reliably, efficiently and in an environmentally sound manner. Presently, if New York City were to be impacted by a Category 1 or 2 storm, the effects would be devastating to electric infrastructure. Southerly networks in Brooklyn and Queens as well as those in Manhattan such as Bowling Green, Fulton, and Cortlandt would be completely submerged by at least several feet of flood water. Right now, the course of action is limited to completely shutting down these networks because individual, non-submersible equipment that will be subjected to flood water cannot be individually isolated. Even so, it would take days or even weeks to restore our systems to normal operating conditions.

Con Edison's highest priority during such an event is to safely de-energize all non-essential 265/460V units that fall within Category 1 and Category 2 storm surge zones. 265/460V transformers feed as much as four times the amount of power as a typical 120/208V unit. These units also feed some of the largest customers in the Brooklyn, Manhattan, Queens, and Westchester Region. For these reasons, it is imperative for the safety of personnel and the public to prevent the 265/460V installations from feeding directly into brackish flood waters, creating a hazardous situation.

Once the 265/460V units are addressed, the Company will pursue the lower energy 120/208V installations that may nonetheless pose a threat to public safety. Similar to the 265/460V transformers, 120/208V transformers are equipped with non-submersible network protectors that will be vulnerable in a flood condition. The exposure of non-submersible equipment, when energized, may cause internal failure, thereby risking the integrity of distribution feeders and their associated networks. In addition, the exposure of non-submersible equipment to corrosive salt water would also result in significant damage to exposed parts, such as relays and motors. The repair or replacement of these damaged parts will prolong restoration of networks to normal operating conditions.

Regional Engineering has developed appropriate prevention strategies, such as identifying feeders that can be taken out of service during a Category 1 or 2 storm surges with low customer impact. During such an event, a significant load reduction is expected throughout the region, allowing multiple feeders to be taken out of service in different flood-prone networks while staying within our network design criteria; identifying new switch locations to disconnect transformers; and identifying 265/460V and 120/208V units that would be impacted. All of this with the goal of minimizing the extent of damage to regional networks, maintain public safety, and allow for an expeditious recovery from such events.

Units per Year: Not Applicable
Mandatory: No.
High-level schedule: Using data gathered from Hurricane Sandy, Regional Engineering Design will establish a list and schedule of location be completed on 2013 and beyond. The goal is to complete all required work by 2016.

**Justification:**

The purpose is to establish a strategic and cost effective method to minimize damage to the electrical system. Implementing this project will ensure the timely transition back to normal operations of the New York City area, its residents and businesses as the flood water recedes. In an effort to reduce costs and expedite the replacement of the non-submersible equipment, we will continue to proactively replace any defective non submersible transformers and network protectors in Category 1 and Category 2 storm surge with submersible transformers and network protectors that fit into existing vaults. The replacement of non-submersible equipment in flood prone areas, as described above, would prove beneficial to public safety, network restoration, network integrity, and mitigate the cost of extensive damages that can potentially be caused by flood water. It will mitigate the extent of damages caused by fresh and salt water infiltrating our electrical facilities. Overall, this program will reduce the number of components failures, thereby reducing our exposure to failures and improve reliability.

Related to installing additional equipment, this proposal involves:

1. Storm hardening 265/460V units to minimize damage to these units for which there are currently no submersible options. All of these units will be receiving new, water resistant network protectors and will be de-energized through a combination of targeted feeder outages and the installation of flood switches.
2. Replacing 120/208V units with submersible units in affected areas. This will involve changing all network protectors with ventilated housings and transformers with new units that can be submerged.
3. Reconfiguring network boundaries to allow the isolation of vulnerable zones and minimize the impact to customers in non flood zones during storms.

Below are the estimated costs and number of units for installation, replacement or storm hardening. We anticipate the actual costs and scope of work for these projects to be better defined as we conduct further analysis, revise equipment and system designs and refine our storm hardening strategy.

Storm Hardening Summary:

To storm harden against a Category 1 or 2 storm on our electric system, approximately 400 non-submersible 265/460V and 1,000 non-submersible 120/208V units would require replacement.

On all 265/460V equipment in flood zone 1&2, we shall be implementing our newly developed submersible alternatives. By implementing this new initiative we will reduce the number of primary feeders affected and therefore will reduce the risk of a network shutdown. The replacement of our 120/208V equipment would consist of retrofitting all non-submersible network protectors and associated equipment with the equivalent submersible type network protector and submersible housing equipment. This will allow us to mitigate and minimize area outages and restoration time. For both 120/208 and 265/460V locations, we estimate at total of $100,000 per location.

To minimize the impact to on our most vulnerable networks, we are establishing flood zone isolation plans. The plans would consist of reconfiguring the network boundaries to isolate known flood zone areas from non-flood area. In addition, we are also considering introducing isolation switches to minimize outage areas on feeders. These flood switches will provide a means of remotely de-energizing 265/460V transformers before a hurricane, rendering them inert in the event of a flood condition.

During Hurricane Sandy, some of the most impacted networks were Brighton Beach, Bowling Green, and the Fulton network. For the Bowling Green and Fulton networks, Regional Engineering is evaluating a number of different options to best support our system. For instance, in addition to combining networks and reconfiguring the boundaries, engineering is also evaluating the option of establishing a number of smaller more sustainable micro-grids. This will provide additional operations flexibility to mitigate storm surge damage. Another approach is to introduce isolation switches along with the rearrangement of the networks. The cost to storm-harden two of our most vulnerable networks, Bowling Green and Fulton, is estimated at $40 million.

The current estimated expenditure for the storm hardening initiatives is $180 million. This estimate will change as the engineering scope is refined. The break out by costs and work associated for Category 1 and 2 storms is shown below:

Storm Hardening 265/460V Units

| Storm Category | # of NWP to be replaced with GPXE NWP | Total |
|---|---|---|
| 1 | 160 | $16,000,000 |
| 2 | 240 | $24,000,000 |
| **Total** | **400** | **$40,000,000** |

*Cost of replacing 265/460V units with the newly developed submersible network protectors & submersible housings*

Storm Hardening 120/208V Units

| Storm Category | Transformers in Flood Zone | New Transformer, Submersible Network Protector and Housing |
|---|---|---|
| 1 | 400 | $40,000,000 |
| 2 | 600 | $60,000,000 |
| **Total** | **1,000** | **$100,000,000** |

*Cost of replacing 120/208V units with new transformers, submersible network protectors, and submersible housings*

Bowling Green/Fulton Network Boundary Reconfiguration

| Storm Category | Boundary Reconfiguration, Flood Switch Installation |
|---|---|
| 1 | $20,000,000 |
| 2 | $20,000,000 |
| **Total** | **$40,000,000** |

Storm Hardening Summary

| Storm Category | 265/460V | 120/208V | Flood Zone Isolation | Total |
|---|---|---|---|---|
| 1 | $16,000,000 | $40,000,000 | $20,000,000 | $76,000,000 |
| 2 | $24,000,000 | $60,000,000 | $20,000,000 | $104,000,000 |
| **Total** | **$40,000,000** | **$100,000,000** | **$40,000,000** | **$180,000,000** |

**Alternative:**

The other option is to replace 265/460V and 120/208V non-submersible equipment with submersible equipment as they fail. This will address the problem over time, but will not mitigate the risk to our electric infrastructure.

**Risk of No Action:**

The possibility exists that no major hurricane or storm will hit our service area, but in the event that a major hurricane does hit the Con Edison service area we will experience severe electric infrastructure damage. Some of our underground equipment within the anticipated storm surge area is not designed to be exposed to salt water. The exposure of 265/460V and 120/208V with non-submersible equipment when energized may cause it to fail, thereby risking the integrity and reliability of the distribution feeder and the associated network. The repair or replacement of these exposed de-energized units would increase the restoration time and countless number of customers will be out of service for days and even for weeks. This will cause undue stress to the remaining energized equipment, and could potentially lead to cascading feeder outages which would increase the likelihood of a network shutdown. In addition, the cost and the environmental impact of restoring the electric infrastructure back to normal conditions will be significant.

**Summary of Financial Benefits and Costs:**

Current estimated cost of this project is $180 million; (this estimate may change as the engineering scope is refined.) The benefits of the project are ensuring continued reliable service to our system. A secondary benefit to doing this work now, is improved cost and logistics of proactively installing new equipment versus reactively repairing the existing after failure.

**Non-financial Benefits (if applicable):**

**Technical Evaluation/Analysis:**

Hurricane Sandy has provided Regional Engineering with the required data to help us develop appropriate prevention strategies, such as addressing all 265/460V and 120/208V impacted by storm surge damage and identifying feeders that can be taken out of service during a Category 1 or 2 storm surges with low customer impact.

**Sensitivity Analysis (if applicable):**

**Project Relationships (if applicable):**

**Status:**

Planning

**<u>EH&S Overview:</u>**

We will follow the standards set in Corporate Instruction CI-260-4 *Corporate Response to Incidents and Emergencies* which establishes guidelines for determining the appropriate level of response and mobilizing the appropriate Company and external resources in a timely manner in response to any incident. It also describes the Company's Electric Emergency Response Plan (ERP) – The Company's Electric Emergency Response Plan details the organization for the response to storms and manmade events affecting the overhead and underground electric system in accordance with the requirements of Part 105 of the Rules of the New York State Department of Public Service.

The Corporate Coastal Storm Plan (CCSP) of Consolidated Edison Company of New York, Inc. provides a comprehensive overview that attempts to identify the potential effects of a severe tropical storm and/or hurricane, prepare strategies to mitigate these identified risks, and guides the subsequent corporate response to such an event. This guide focuses on ensuring public and employee safety while maintaining and restoring the integrity of our energy delivery services.

Adhering to these processes will also help to ensure that EH&S compliance, resource conservation, risk reduction and alternate design considerations are incorporated in the early planning and design stages of project work.

**<u>Analysis of prior year funding request versus actual:</u>**
N/A

**<u>Data Reports issued that support program:</u>**
The Corporate Coastal Storm Plan (CCSP)

**<u>Specifications & procedures pertaining to Program/Project:</u>**
These will be identified as the engineering work commences.

**<u>Benefits/Outcome of Program/Project:</u>**
See Justification section.

**<u>Is this a mandated program? If yes, include verbiage associated with mandate:</u>**
No

**<u>Current Working Estimate (if applicable):</u>**
N/A

**Funding Forecast (Capital or O&M)**

| | **2012 Budget** | **2013 Request** | **2014 Request** | **2015 Request** | **2016 Request** | **2017 Request** | **5 yr (13-17)** |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 0 | 11,000 | 60,000 | 55,000 | 54,000 | | 180,000 |

# 2013 Capital – Electrical Operations

| | |
|---|---|
| **Project/Program Title** | **Targeted Primary DBC Replacement** |
| **Project Manager** | Troy Devries |
| **Project Engineer** | Troy Devries |
| **Status** | Ongoing |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
This program targets primary and secondary Direct Buried Cable (DBC) cables to be replaced with cable-in-conduit (CIC) to improve the reliability of Underground Residential Distribution (URD) customers and to reduce burnout expenditures incurred to repair DBC cables. Candidate cables for replacement usually experienced two or more failures at different spots along the cable section where often the insulation is found to be cracked or split. These candidate cables for replacement will be prioritized appropriately to address the highest urgency replacements.

**Justification (Technical Evaluation/Analysis):**
Based on historical records, approximately 60% of all URD customer interruptions were due to insulation breakdown of DBC primary and secondary cables. These interruptions result in an increase in SAIFI by an average of 22 outages/year and 46 outages/year for Westchester and Staten Island, respectively. On average, it takes 20% longer to locate and repair a fault when it occurs on DBC than it does to repair a fault that occurs on the same cable installed in a conduit. From 2002 to 2007, an average of 1,250 URD customers each year in Westchester and Staten Island (98% of all URD customers) experienced a service interruption due to problems with DBC. Targeted installation of URD cable-in-conduit for both primary/secondary sections and services will reduce the amount of DBC on the system thereby reducing URD customer outage frequency (SAIFI) by approximately 60% and reducing annual repair expenses.

**Alternatives:**
URD Cable Rejuvenation Rehabilitation and Fault Indicator Program. These programs do not help much for cable that has faulted repeatedly because of the buried splices. Targeted DBC replacement is primarily used to address neighborhoods where we receive complaints for repeated outages and repairs.

**Risk of No Action:**
Continued customer interruptions due to URD cable failure

**Summary of Benefits (financial and non-financial):**

**Project Relationships (if applicable):**

**EH&S Overview:**

**Analysis of Prior Year Funding Request Versus Actual:**

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 310 | 992 | 1,280 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 524 | 520 | 500 | 463 | 449 | 447 | 2,379 |

# 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | Transformer Vault Modernization |
| **Priority Number** | |
| **Project Manager** | Neil Weisenfeld |
| **Project Engineer** | Liliana Kandic |
| **Budget Reference** | |
| **Project Number** | |
| **Status** | On-going |
| **Estimated Service Date** | On-going |
| **Work Plan Category** | Reliability/Performance Enhancement, Life Extension, Safety |
| **ERM Addressed** | Potential Structural Collapse – Prevention of harm to personnel, general public, and equipment |

**Work Description:**

The Modernization Program for CECONY's Electric Distribution Transformer Vault Structures is a proactive program to mitigate public and system safety concerns regarding structures that have been identified as requiring significant upgrades. These upgrades involve significant rebuilds of walls, floors, and roofs of subsurface vaults , involving steel, concrete and masonry components, along with the associated excavation, waterproofing, inspection, and backfill/restoration tasks. This program will address potential safety concerns, provide increased reliability and extend the useful life of our existing structures.

Transformer Vault locations requiring major upgrades are normally identified by field forces and recorded in our Electric Distribution Information System (EDIS). Occasionally, customers and municipalities also notify Con Edison of structures with structural concerns. Structural deficiencies include findings such as settlement, cracked concrete, spalled concrete, collapsed walls, collapsed ceilings, corroded steel beams and columns, and corroded rebar.

**Justification (Technical Evaluation/Analysis):**

Resolving structural deficiencies deemed severe by Con Edison specifications are mandatory as part of the EDIS inspection program, in accordance with a mandate set by the PSC.

Unattended deficiencies may lead to:

- Employee injuries and trip/fall incidents
- System impacts including damaged transformers from falling debris, damaged cable from falling debris, work stoppages, and delays in restoring system outages
- Fines from the City of New York due to settled structures and cracked concrete.
- Impact to customer premises due to water intrusion at customer service take-offs.

The company has developed several protocols and procedures to provide direction for implementing a major structural reconstruction program, from structural deficiency reporting to final rebuild. Latest engineering materials including epoxy-coated rebar, concrete roof waterproof membranes, embedded steel beams, anti-corrosive galvanizing paint over beams and welds, and fiber-reinforced concrete have been incorporated into protocols for complete structural modernization. On-the-Job Training (OJT) has been developed to guide proper construction techniques for concrete, asphalt, and soil. Special inspections and laboratory testing are specified in accordance with national standards.

**Alternatives:**

The Company devotes significant effort to evaluating and prioritizing structural deficiencies in order to reduce costs. Deficiencies initially identified during inspections by field crews are further evaluated by engineering personnel to insure that they are properly categorized and prioritized. The structural deficiencies deemed significant after evaluation must eventually be addressed as they pose safety risks to the public and Company personnel as well as to the equipment. The repairs outlined in this program description could be deferred in lieu of installing temporary shoring within the structures. Shoring would provide a temporary solution but since structural degradation is progressive and shoring is constructed from non-permanent materials, repairs must eventually be completed.

**Risk of No Action:**

Failure to address deteriorated structures will, over time, result in increased structural damage, increased water damage to customer premises, increased spending at times of feeder-restoration emergencies due to the inability of employees to access structures, increased damage to transformers and equipment, , and potential for injury. At locations where temporary measures such as steel plates and barricades are installed, trip/fall hazards and potential fines by the city exist. Steel plates prevent air-flow to structures reducing the capability of transformers.

**Summary of Benefits (financial and non-financial):**

The cost of altering a vault roof post-incident can be up to ten times the cost of altering a vault pre-incident. Two estimated case studies are shown below:

**Case Study 1 – Roof Replacement:**

In this case, proactive roof replacement could be completed for $50,000 while the total cost of repairs should the roof collapse and damage the transformer and associated cable could be as much as $527,695.

**Cost to Upgrade Vault Roof and to Replace Transformer:**

| Description | Unit Cost | Units | Cost |
|---|---|---|---|
| Roof Replacement | $50,000 | 1 | $50,000 |
| Install Primary Cable | $37,912 | 1 | $37,912 |
| Install Secondary Cable | $27,984 | 8 | $223,872 |
| Remove Primary Cable | $24,890 | 1 | $24,890 |
| Remove Secondary Cable | $15,530 | 8 | $124,240 |
| Install Transformer | $14,712 | 1 | $14,712 |
| Remove Transformer | $5,069 | 1 | $5,069 |
| Transformer Replacement | $47,000 | 1 | $47,000 |
| | | Total Cost: | $527,695 |

**Case Study 2 – Wall Replacement:**

In this case, proactive wall replacement could be completed for $30,000 while the total cost of repairs should the roof collapse and damage the transformer and associated cable could be as much as $527,695.

| Description | Unit Cost | Units | Cost |
|---|---|---|---|
| Wall Replacement | $30,000 | 1 | $30,000 |
| Install Primary Cable | $37,912 | 1 | $37,912 |
| Install Secondary Cable | $27,984 | 8 | $223,872 |
| Remove Primary Cable | $24,890 | 1 | $24,890 |
| Remove Secondary Cable | $15,530 | 8 | $124,240 |
| Install Transformer | $14,712 | 1 | $14,712 |
| Remove Transformer | $5,069 | 1 | $5,069 |
| Transformer Replacement | $47,000 | 1 | $47,000 |
| | | Total Cost: | $557,695 |

**Case Study 3 – Floor Replacement:**

In this case, where a transformer vault is installed over vaulted space, proactive floor replacement could be completed for $50,000 while the total cost of repairs should the floor collapse, destroying the transformer and associated cable, could be as much as $527,695.

| Description | Unit Cost | Units | Cost |
|---|---|---|---|
| Floor Replacement | $50,000-$150,000 | 1 | $50,000–$150,000 |
| Install Primary Cable | $37,912 | 1 | $37,912 |
| Install Secondary Cable | $27,984 | 8 | $223,872 |
| Remove Primary Cable | $24,890 | 1 | $24,890 |
| Remove Secondary Cable | $15,530 | 8 | $124,240 |
| Install Transformer | $14,712 | 1 | $14,712 |
| Remove Transformer | $5,069 | 1 | $5,069 |
| Transformer Replacement | $47,000 | 1 | $47,000 |
| | | Total Cost: | $577,695 - $677,695 |

Additional benefits are improved public and employee safety, increased reliability, extension of useful life, and mitigation of customer-related water damage complaints.
Additionally, this program would assist in building better relationships with key external stakeholder organizations such as the NYC DOB, NYC DOT, Mayor’s Office, and the PSC.

**Project Relationships (if applicable):**

**EH&S Overview:**
We follow the standards set in Corporate Environmental Procedure (CEP) 11.04. CEP 11.04 requires organizations to make an overall assessment of their routine daily work (recurring) and then create categories for this work activity. The purpose of this process is to identify EH&S hazards/issues. This process will also help to ensure EH&S compliance, resource conservation, risk reduction and alternate design considerations are incorporated in the early planning and design stages of project work.

**Analysis of prior year funding request versus actual:**

**Data Reports issued that support program:**

**Specifications & procedures pertaining to Program/Project:**
EO-10222, "Guidelines for Underground Distribution Structural Inspections". This specification provides guidance for performing inspections of structures installed on Con Edison's underground distribution system.

EO-10359, "Periodic Underground Distribution Structure Inspections". This specification describes periodic inspections, reporting requirement and repair priority of the Underground distribution system to insure its safe and continuous operation as described by the New York State Public Service Commission Electric Safety Standards (ESS) issued in Case 04-M-0159 on January 5, 2005 and revised on December 15, 2008.

EO-5227, "Repair Procedure for Underground Distribution Structures". This specification describes the methods to be used for repairs of underground structures on the electric distribution system.

**Estimated Completion Date:**
On-going

**Status:**
On-going annual program

**Current Working Estimate** (if applicable):

**Funding ($000):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 0 | 0 | 0 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 5,000 | 6,500 | 5,000 | 5,000 | 5,000 | 5,000 | 26,500 |

**2013 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | **UG Sectionalizing Switches** |
| **Project Manager** | Joe Lenge |
| **Project Engineer** | Regional Engineering Managers |
| **Status** | Planning |
| **Estimated Service Date** | |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
Install primary underground sectionalizing switches on targeted network feeders. The Company has recently initiated the installation of the new Elastimold Three Phase Molded Vacuum 40kA switch that replaces the old motor operated three phase SF6(sulfur hexafluoride) gas insulated switch. The new switch does not require a manual operation and is SCADA ready for remote operation. All new sectionalizing switches will be integrated into the Company's Distribution Automation System (DAS) application for remote operation and control. The work involves installing a new structure or identifying an existing structure to accommodate the equipment, installing the switch with cam disconnects, fault indicators, and associated cabling.

In order to maintain NRI for all networks below the target of 1.0PU, the program has been extended to add additional switches in networks that may see their NRI worsen due to changes in component failure rate as well as load growth and higher component loading characteristics.

In addition, this program will address replacing the first generation of underground sectionalizing switches the old motor operated three phase SF6(sulfur hexafluoride) gas insulated switch. These switches due to age and field conditions in many cases has resulted in operational difficulties when called upon to be used. These switches will be replaced with Elastimold Three Phase Molded Vacuum 40kA switch and have remote control operability.

Units per Year: 9 to 10

High-level schedule:

| Year | Manhattan | Brooklyn/Queens | Total |
|---|---|---|---|
| 2012 | 0 | 7 | 7 |
| 2013 | 0 | 10 | 10 |
| 2014 | 2 | 8 | 10 |
| 2015 | 2 | 8 | 10 |
| 2016 | 2 | 8 | 10 |
| 2017 | 2 | 8 | 10 |

**Justification (Technical Evaluation/Analysis):**
Installation of primary sectionalizing switches to isolate feeder failures increases network reliability. The sectionalizing switches permit rapid isolation of faulted segments of primary feeders, allowing the portion that is not faulted to be re-energized, and thereby reducing the amount of load shifted to other distribution feeders. This will in turn reduce the failure rates for adjacent feeders that pick up the load of the faulted feeder section, as the loading of the components has an impact on their failure rates.

The benefits of installing sectionalizing switches have been documented through the “Contingency” network reliability model. The analysis concluded that the reduction in time between manual switch operations of four hours compared to the remote switch operation in 5 minutes significantly reduces the increase in temperature of feeder components, and thereby reduces the probability of subsequent component failure. Feeder restoration time plays an important role in network reliability and with the more feeders are out of service, the higher is the probability of a network going into cascading events. The feeders in a network are targeted for sectionalizing switch installation based on their individual contribution to network reliability and with existing bifurcated feeder legs.

The new switches are fitted with SCADA equipment for remote monitoring and operation. The new switches will be integrated into the Distribution Automation System (DAS/RealFlex) system that uses the 900MHz licensed frequency “company owned,” and eliminate any communication expense.

The new cam disconnects are easy to operate, provide more security and safety and are more reliable than the existing H-type disconnects.

**Alternatives:**

Network Reliability Program is the alternate to the UG Sectionalizing program but is only applicable if there are spare feeder positions available at the Area Substation. This program includes de-bifurcating an existing feeder to create two new feeders utilizing existing spare feeder positions at Area Substations. To accomplish this, bifurcated feeders supplying a given network or load area via two main runs of cables (legs) will be de-bifurcated, creating two separate feeders with one leg each. These additional feeders will provide a more distributed and balanced supply to the network and more balanced feeder loading during normal conditions (all feeders in service). The increased number of feeders available during contingencies will also mitigate the potential for cascading feeder failures associated with high feeder loading due to shifting load following a feeder open-auto.

The cost to modify existing substation cubicles and to replace a single feeder position with the dual ABB breakers is approximately $2,000,000 per feeder de-bifurcation and this includes the cost of the breakers, installation and distribution feeder reconfiguration.

**Risk of No Action:**

Feeder loading has an effect on feeder reliability and installation of sectionalizing switches mitigates increased feeder loadings on existing feeders through partial restoration of the section that is not faulted. Feeder load increases with temperature rise and very high loads, as compared to the normal rating, have an adverse effect on feeder components.

Based on the projections for the Network Reliability Index (NRI) of Brooklyn and Queens networks, there are indications that as load continues to grow there will be a need to install additional sectionalizing switches to improve the NRI. The following networks are susceptible to an increase to over 1.0 PU: Park Slope, Williamsburg, Borough Hall, Richmond Hill, and Brighton Beach. There are also operational uses for these switches which have been used in the past to prevent cascading outages.

The risk of no action increases the chance of a cascading outage in a network, which could be especially significant during contingency events.

**Summary of Benefits (financial and non-financial**:

The new remotely operated switches significantly reduce the annual O&M switch maintenance costs associated with the mandatory operation of the switch once every 6 months. The SCADA equipment installed on the switch has remote diagnostics capability and only requires a field visit for repairs if it fails, thereby resulting in additional O&M savings. There is no recurring communication expense associated with the remote operation of the switches. Non-financial Benefits (if applicable): Elastimold 40 kA Molded Vacuum Switch is more environmentally friendly as compared to SF6 Switch as there is no risk of gas leaks. In addition, the Vacuum switch has the same rating as SF6 switch and is more compact with cam-op disconnects to provide visible breaks that meet the Con Edison work rules for worker safety and protection. The new switch requires minimal maintenance and operates faster (in approximately 2.5 cycles) compared to the old SF6 switch that can take a few seconds to operate due to the motor operation.

**Project Relationships (if applicable):**

**EH&S Overview:**

We follow the standards set in Corporate Environmental Procedure (CEP) 11.04. CEP 11.04 requires organizations to make an overall assessment of their routine daily work (recurring) and then create categories for this work activity. The purpose of this process is to identify EH&S hazards/issues. This process will also help to ensure EH&S compliance, resource conservation, risk reduction and alternate design considerations are incorporated in the early planning and design stages of project work.

**Analysis of Prior Year Funding Request Versus Actual:**

2011 Funding: $2,621,000
2011 Actual: $ 853,000

**Data Reports Issued that Support Program:**

Installing primary sectionalizing switches to isolate feeder failures will increase network reliability. These switches will permit rapid isolation of faulted segments of primary feeders, allowing the unfaulted portion to be re-energized, and thereby will reduce the amount of load shifted to other distribution feeders.

These benefits of installing sectionalizing switches were documented through the “Contingency” network reliability model. Analyses were performed on a number of networks to ascertain the costs and benefits of installing sectionalizing switches and other alternative means with which to improve network reliability. From these analyses, we can conclude that, while there is no one single best way to increase network reliability, the reduction in time between local manual switch operation (4 hours) to remote operation (5 minutes) significantly reduces the increase in temperature of feeder components, and thereby reduces the probability of subsequent component failure. The switches currently on the system were designed for manual operation and, under a separate program, are being retrofit with SCADA equipment. The new switches will be fitted with SCADA equipment for remote monitoring and operation.

**Specifications & procedures pertaining to Program/Project:**

E0-2127 Design Criteria for the Application of SF6 switches
E0-4086 Operation of Three Phase Submersible Sectionalizing Switch With/Without Disconnects
E0-2152 Distributed Network Reliability Improvements.

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 2,502 | 991 | 853 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 2,832 | 2,111 | 2,993 | 2,773 | 2,687 | 2,676 | 13,240 |

**2013 Capital – Electric Operations**

| | |
|---|---|
| **Project/Program Title** | **Underground Secondary Reliability Program** |
| **Project Manager** | Joe Lenge |
| **Project Engineer** | Regional Engineering Managers |
| **Status** | Ongoing |
| **Estimated Service Date** | Ongoing |
| **Work Plan Category** | System and Component Performance |

**Work Description (Includes units per Year and a high level schedule):**
Initiate a system wide Underground Secondary Cable Replacement Program to increase overall system performance reliability and mitigate public safety events such as electric shock, manhole fire and manhole explosion incidents. The program targets the reinforcement of the secondary grid infrastructure by targeting secondary cable based on past performance, age, conductor size, conductor type, cable loading and underground structures to eliminate congestion.

Units per Year: Varies by Year

Mandatory: No

High-level schedule:

| Estimated Type (Units) | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| UG Conduit (Trench Feet) | 26,712 | 26,205 | 31,858 | 29,660 | 29,048 | 28,500 |
| UG Service Conduit (Trench Feet) | 1,665 | 1,630 | 1,978 | 1,844 | 1,807 | 1,750 |
| UG Primary Cable (Sections) | 107 | 105 | 128 | 119 | 117 | 115 |
| UG Secondary Cable (Sections) | 622 | 610 | 741 | 690 | 677 | 660 |
| UG Service Cable (Sections) | 82 | 80 | 98 | 91 | 89 | 90 |
| UG Service Boxes (Number) | 66 | 65 | 79 | 74 | 72 | 75 |
| UG Manholes (Number) | 86 | 84 | 102 | 95 | 93 | 90 |
| Transformers (Number) | 179 | 176 | 214 | 199 | 195 | 180 |

**Justification (Technical Evaluation/Analysis):**
Damage to the secondary system is generally harder to identify than on the primary system due to the redundancy of the secondary grid and the lack of remote monitoring equipment beyond the network transformer. As a result, adverse condition(s) typically are not found until they result in a customer outage, manhole event or stray voltage condition. Since these conditions can lead to potential hazards to the public or prolonged outages, maintaining the reliability of the secondary grid is a priority. Damaged secondary cables on the networks reduce the reliability of the secondary network system, stress remaining transformers and secondary mains, and expose customers to a higher risk of outages. We have identified areas in the targeted networks based on the M&S Plate Targeting Model and the Vulnerability Structure Ranking to improve the reliability and performance of the secondary grid. We will also employ extensions of secondary burnouts where practical when the underground has determined the existing secondary layout can result in potential problems. In addition, as the secondary visualization modeling program is implemented and the secondary load flow results become available, the load flows on the

secondary system will be used to prioritize the existing repairs as identified from the M&S Plate Targeting Model.

**Alternatives:**
Allow backlog of repairs found from underground structure safety inspections to grow. This is the only program that prioritizes the reinforcement of the secondary grid.

**Risk of No Action**:
The five year underground inspection program had completed a full cycle in 2009. The Company faces a large backlog of repairs that have been identified through these inspections. The PSC has a penalty mechanism in place to track the number of underground and overhead inspections done on a yearly basis and the fine if missed is $95,000,000. There is a risk that aged repairs left unaddressed for a significant period of time will trigger the PSC to impose additional penalties upon the amount of time repairs can remain open and unaddressed.

**Summary of Benefits (financial and non-financial):**
The program is crucial to enhancing the reliability of the secondary grid and enhancing the safety of the grid by reinforcing the weakest areas of the grid and preventing secondary cable failures. This program is instrumental to the Company's long term strategy to mitigate the risk to public safety posed by secondary cable failures that may result in stray voltage or manhole events.

**Project Relationships (if applicable):**

**EH&S Overview:**
Follow all applicable Corporate Environmental Procedures in the operation and maintenance of the distribution systems.

**Analysis of Prior Year Funding Request Versus Actual:**
2011 Funding: $33,021,000
2011 Actual: $42,481,000

**Data Reports Issued that Support Program:**

**Specifications & Procedures Pertaining to Program/Project:**

**Is this a mandated program? If yes, include verbiage associated with mandate:**

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 27,594 | 40,048 | 42,481 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| **Funding ($000s)** | 30,140 | 32,538 | 36,200 | 32,679 | 31,498 | 31,266 | 164,181 |

## 2013 Capital – Electric Operations

| | |
|---|---|
| **Project/Program Title** | **Vented Service Box Covers** |
| **Project Manager** | Anthony Cedrone |
| **Project Engineer** | Kenneth Neuner |
| **Status** | Ongoing |
| **Estimated Service Date** | 2025 |
| **Work Plan Category** | Public and Employee Safety |

**Work Description (Includes units per Year and a high level schedule):**

The Scope of Work includes the installation of vented *metal* service box covers on the street and vented *composite* service box covers on the sidewalks. The program shall entail replacing all solid covers with vented composite covers on the sidewalk and a minimum of one cover panel at all service box locations on the street. There are ~181,000 service box locations pending replacement from 2008 to 2025. Many service box locations contain more than one vented cover resulting in a total of 200,500 covers. Based on 2008 history (Vented Manhole Program), the company found that some of the structures required re-grades. The material and labor cost associated with re-grade is significantly higher than regular installations.

**Units per Year:**

The original plan for the Service Box Program was to install 12,000 vented covers in 2009. However, due to the Company's austerity budget there were 7, 919 vented service box covers installed between metallic and composites. The Company continued with the plan to install 10,663 vented service box covers in 2010 and 11,187 in 2011. The Company will install approximately 10,800 vented service box covers in 2012. For 2013, the company will be installing approximately 5850 vented service box covers and approximately 10,800 from 2014 until 2025. The original plan was to complete the program at the end of 2017 with the current allowable funding; we will need to extend the program to 2025 in order to complete approximately 181,000 vented service box locations.

**Mandatory:**

This program is not mandated by the Public Service Commission, however, the installation of vented service box covers will help to reduce the buildup of combustible gases associated with secondary events thereby reducing the severity of underground events, enhancing public safety, and mitigating stray voltage with the installation of vented composite service box covers on the sidewalks.

**High-level schedule:**

| 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|
| 9,563 | 10,663 | 11,187 | 10,800* | 5850* | 10800* | 10800* | 10800* | 10800* |

*Projected

**Justification (Technical Evaluation/Analysis):**

The installation of vented service box covers helps to reduce the buildup of combustible gases associated with secondary events thereby reducing the severity of underground events and enhancing public safety. Electrical Power Research Institute (EPRI) testing results indicate the success of vented covers in terms of reducing cover dislodgement. The installation of vented manhole covers has successfully validated the effect of ventilation in mitigating secondary events. In addition, smoke emitted through the ventilated cover creates a visible indicator and raises awareness for the public thereby increasing public safety.

The ongoing installation of vented composite (i.e. electrically insulating) service box covers on the sidewalks enhances public safety by mitigating stray voltage in addition to facilitating the escape of combustible gases. Since the inception of the program, in 2004, underground structure events have been reduced by 17% (2011). Company related electric shock reports went from 210 cases in 2004 to 27 cases in 2011, a reduction of 87%. Also, when compared to 2004, property damage, caused by manhole fires and explosions, has fallen by 47% (2011).

**Alternatives**:
This ongoing program was initiated to increase public safety and reduce property damage due to buildup of combustible gases associated with secondary events and mitigation of stray voltage. We are considering the possibility of using different technology and/or materials which is currently under research and development stage. Current research shows that as of now the existing composite technology and materials used are the most effective choice.

**Risk of No Action**:
There is a potential increase on the severity and volume of underground events and possible increase in stray voltage/energized metal covers on sidewalks if the Service Box Vented Cover and Composite Program is reduced or terminated.

**Summary of Benefits (financial and non-financial)**:
This is an ongoing program. The reliability of energy distribution has been increased by reducing associated secondary events. Through competitive bids the company has been able to reduce the expenditure for the Service Box Vented Cover Program. The average cost per installation in 2011 was $750.

The Service Box Vented Cover Program is helping to reduce the buildup of combustible gases associated with secondary events thereby reducing the severity of underground events and enhancing public safety. By mitigating stray voltage, with the installation of vented composite service box covers on the sidewalks, we limit the number of electric shock incidents each year.

**Funding Forecast (Capital or O&M):**

| Actual 2009 | Actual 2010 | Actual 2011 |
|---|---|---|
| 11,033 | 7,280 | 8,409 |

| | 2012 Budget | 2013 Request | 2014 Request | 2015 Request | 2016 Request | 2017 Request | 5 yr (13-17) |
|---|---|---|---|---|---|---|---|
| Funding ($000s) | 11,700 | 6,700 | 11,700 | 11,700 | 11,700 | 11,000 | 52,800 |