Substation modernization – coordination between Transmission and Distribution lines

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I. INTRODUCTION

There are many factors to be considered during the planning stage of an outdoor substation station along with the consideration of existing infrastructure of transmission and distribution networks. Regardless of the use of different distributed generation or demand-side management, the transmission and distribution (T&D) system is the ultimate distributed resource. It consists of numerous equipment scattered throughout the service territory, interconnected and operating in concert to achieve uninterrupted delivery of power to the electric consumers [1]. Coordination between the transmission and distribution systems has previously been investigated for economic dispatch and optimal power flow frameworks [2-5]. Electrical peak demand approach has been reported based on substations' loading condition, load classification, customer type, and their importance [6]. However, connecting critical loads to the electrical grid and expanding the power systems infrastructure requires significant planning and engineering to ensure a constant, reliable power supply. Optimization of substation creates room to integrate different generation sources to meet demand of growing cities, industries, airport, hospitals, businesses etc. Every project becomes unique because of multiple sets of requirements and goals. Substation design must consider all functional requirements and preferences, while exploring possible alternative solutions to deliver the most optimal substation configuration. In a city center area, spaces are limited. To design a substation in the city center area, huge focus is required for the physical arrangement of substation, equipment selection and sizing, bus configuration. This will ensure high reliable electricity delivery system. The arrangement of substation/switching station buses to coordinate transmission and distribution systems affects the maintainability, availability, and reliability. Above all, compliance with the different regulatory boards is obviously required to consider in the planning and designing phases.

Different models using Surrogate Lagrangian Relaxation (SLR) approach was presented [2] to coordinate transmission and distribution systems. At transmission level voltage levels, ring bus configuration described having significant system reliability while remaining an economical and cost-effective design [7]. 3-phase integrated transmission and distribution system model was presented [8-15]. We envisioned a green-field substation design which will be connected to high voltage network, which is fed from coal, gas fired, solar array sources and distributed generations. We present the design and construction of a coordinated substation in a city center area. This substation coordinates 138 kV transmission and 13.2 kV distribution networks. After construction and energization of the substation, feeder data from the distribution network was collected and compared with our simulation results.

Initially we proposed a breaker and a half bus configuration based on our available three (3) incoming 138 kV transmission lines and three (3) main distribution feeders. 13.2 kV feeders connected to 6 buses of 3 switchgears form a ring configuration. The substation has the capacity of handling maximum 84 MVA (=30MVA×140%×2) load with the provision of future growth. Feeder circuits are connected to customers like the international airport, hospitals, government offices along with other businesses, industries, homes, schools and colleges. As this project is implemented in the city center area, gas (SF_6) circuit breakers are used to minimize the space constraint.

After completion of the design and construction of the substation, test trips were performed for circuit breakers, switchers, disconnect switches. Pre commissioning and commissioning were done to ensure proper operation for the whole substation along with other lines and remote control house. This part of the network was integrated into our grid. Peak load data was collected and analyzed and reported in this paper. The detail specification of long-lead equipment like transformers, buses, 145kV circuit breakers, switchers, disconnect switches, 15kV switchgears are not included in this paper.

II. SYSTEM PLANNING AND DESCRIPTION

Design and construction of a modern substation is a part of our grid modernization project. We envisioned to connect three incoming transmission lines for 24 distribution circuits. Our consideration was space allocated for the substation, location of newly constructed overhead 138kV transmission lines, existing underground (U/G) 13.2kV distribution circuits.

The choice of bus configuration between ring and breaker and a half required huge planning, calculation with the understanding of load growth trend and requirement to constantly supply power to the existing customers. Above all, operational view point and maintenance ability were given thoughts. It was found that ring configuration would require 6 high voltage circuit breakers (HVCB), 12 disconnect switches (DS) and cost accordingly. For breaker and a half configuration, it would require 9 HVCBs, 18 DSs and higher cost. For day-to-day operational flexibility, any of the two configurations would be fine. Figure 1 and 2 show the ring and breaker and half bus configuration arrangement for the substation where there are three 138 kV incoming lines (Lines LA, LB, LC) and three main distribution circuits arising from each secondary of three transformers (T1, T2, T3). With increasing interconnection complexity, modern grids are more vulnerable to system-wide disturbances. Our grids are connected to the sources from coal, gas, solar and distributed generations from auto industries. If any two lines (say LA, LB) are short for any reason, we have two transformers to meet the load demand in ring bus configuration. Load balancing and redistribute loads to other circuits need to think to maintain power balance on each transformer. If we take option for breaker and half configuration, we can use three transformers for the loss of two lines. Thus redistributing loads to different circuits and power balancing do not appear to be an issue. We concluded breaker and half configuration is the choice we have to take even though it is more expensive and will be more expensive to maintain properly. By doing so, we ensure the reliability of power to the customers like international airport, hospitals.

Each transformer is rated 138kV//13.8kV, 18/24/30 MVA, OLTC. Each 138kV line is terminated to nearby 138kV primary side of the transformer by a gas circuit breaker (A1, A2, A3, B1, B2, B3 and A11, A12, A13, B11, B12, B13, C11, C12, C13). This SF_6 breaker has 0.05s interrupting time at the operating pressure of 93 psig. On both sides of the high voltage gas circuit breaker, there are two high voltage double end break

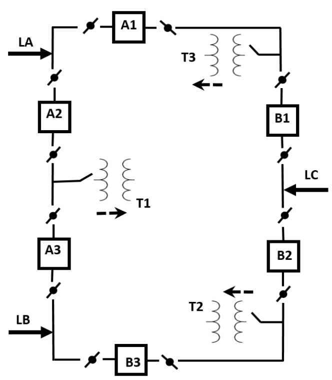

Figure 1. Ring configuration for three incoming lines and three main distribution circuits in the substation.

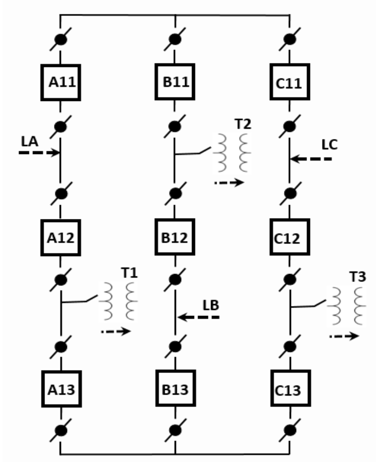

Figure 2. Breaker and a half configuration for 138 kV three incoming lines.

disconnect switches. On the primary side of each HV transformer, there is a circuit switcher. Circuit switchers have sulphur hexafluoride (SF_6) gas interrupters. They were chosen to provide three-phase interruption if any unbalanced phase-to-phase voltage occurs. Overall, they will provide protection for transient over voltages and over loads at a competitive cost between the costs of power fuses and circuit breakers. From each secondary of the transformer, two parallel lines are terminated. One line is terminated to a bus of a double-ended switchgear. The other line is connected to a bus of other switchgear. The three switchgear lineups are positioned inside the substation's control building. To maintain the operational flexibility and hence, system integrity the switchgears chosen are double-ended. Each 15kV switchgear bus, made of aluminum, is rated 3000A. Four distribution feeders are connected from each bus of a double-ended switchgear. The frame size of each main vacuum circuit breaker (VCB) of the distribution feeder is rated at 15 kV, 1200A, 40kA. Higher current rated frame size gives the operational flexibility to replace a lower current rated circuit breaker by a higher current rated circuit breaker up to 1200A to cope with the load growth. This subsequently requires to change the relay settings accordingly.

From the secondary sides of the transformers to the switchgear buses, the configuration chosen is ring. The idea behind is that the system should provide constant power with minimum requirement of one incoming transmission line and two transformers. Our consideration is that six groups of feeders should be kept energized by this substation to provide power to the customers. We explored the options available to us as per our project scope.

Secondary wires are pulled from the substation yard to the inside of the substation control room through above ground (A/G) cable tray. The power cable and control wires for the switchgears are fed from top. Underground distribution circuits are fed from bottom of the switchgears. Each bus of the switchgear has four distribution feeder lines connected through circuit breakers and necessary protection and control circuits.

III. SYSTEM MODELLING

In the grid modernization aspect, the substation bus topology plays a vital role in determining both the reliability and the economy of the distribution system. We had to consider our locations of the nearby power plants, distributed generation sources, available generation capacity, existing transmission line infrastructure and location of the substation. For the distribution network topology selection, we considered the importance of the customers. All the available options were considered. For our design of the 138kV by 13.8kV substation and its control room, the breaker and a half bus configuration for 138kV incoming transmission lines and the ring configuration for 13.2kV distribution network within the substation was found to be the best option.

The transformers are T1, T2, T3, buses of medium voltage (13.2 kV) switchgears are B1, B2, B3, B4, B5 and B6. The tie breaker between bus #1 and #6 of the switchgear #1 (SWGR 1) is T1-6, bus #2 and #3 of switchgear #2 (SWGR 2) is T2-3, bus #4 and #5 of switchgear #3 (SWGR 3) is T4-5. One of secondary sides of T1 is connected to bus B1 of SWGR 1 by circuit breaker S1, the other is terminated to bus B2 of SWGR 2 by breaker S2. Similarly, T2 is connected to bus B3 of SWGR 2 by S3, bus B4 of SWGR 3 by S4 and T3 is connected to B5 of SWGR 3 by S5, B6 of SWGR 1 by S6. Fig. 3 shows

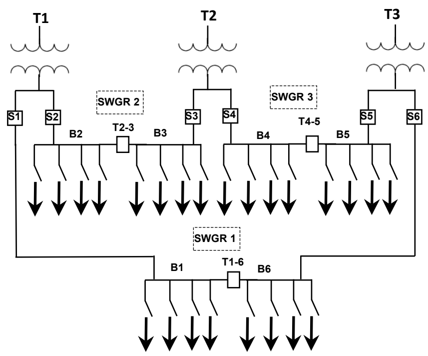

Figure 3. Ring configuration for 13.2 kV three distribution switchgear of total 24 feeders.

the connection diagram of the distribution network within the substation yard and control room.

Maximum load can be connected to each feeder line is 3.6 MVA. While this cannot be in ideal scenario, loads connected to each distribution feeder are varying. Main distribution cable sizing and protection scheme were done to provide maximum of total 28.8 MVA through each switchgear. The maximum load each distribution feeder can provide. To understand the worst-case scenario, we considered total load connected through each line would have 80% inductive and 20% static loads and the loads are running continuously. To model the system, this transient behavior of inductive loads was considered with the consideration of 85% lagging power factor. Based on our observation about the customers connected to these lines are not solely industrial. There are residential and commercial customers who do not absorb that amount of inductive load. As per our system data, short circuit current ratings of 138 kV lines are 3336.8, 3200 and 3269.3 MVA for Line A (LA), Line B (LB), Line C (LC) respectively (Fig. 1).

A key concept realized is that the13.2kV distribution system must be optimized with the 138kV incoming transmission lines and the substation, not subsystem by subsystem. Optimizing the substation and the transmission system separately does not assure an optimal system. In fact, independent design of the transmission and distribution systems is likely to produce a non-optimal system laden with operational and maintenance problems. An integrated approach is essential to assure optimum performance, and the integration process requires an iterative approach to find out the best suitable design. This substation, a part of our whole network, is shown here using ETAP version 18.1.1 for load flow and short circuit studies. Before modelling of the substation, the existing transmission and distribution systems were carefully studied. Summer peak load data of last five years was reviewed. The largest peak was around maximum 50MVA during the peak time of year through this substation. Future growth was considered and expected to serve customers through this substation up to 80MVA. Load flow studies were performed under different situations. Budget and risk factors like loss of a transformer, transmission line, emergency were considered to size the transformers. Thus, the required number of transformers and size of each transformer were selected from the load flow studies. Possible short circuit can occur on any bus. We showed our results on the buses of incoming lines and switchgears for 3-phase bolted faults. This fault produces the maximum short circuit current.

The results obtained from modelling is presented first. The design was implemented, and the substation and control room were constructed. 138kV transmission and 13.2kV distribution lines were connected to this substation. Data were taken from the 13.2kV distribution circuits from this substation. Finally, results were discussed.

IV. SYSTEM REQUIREMENTS

Optimization of transmission and distribution systems were done with the planning of three incoming transmission lines and three transformers and three switchgears, and a total of 24 feeder circuits. Proposed one-line diagram was run in the ETAP to check possible options available to maximize our available resources and infrastructure. We find that the at any point of time to maintain power flow through the six distribution buses, the minimum requirement to meet the demand of our existing customers is one transmission line and two transformers to be in service. Table.1 shows all the possible options along with the maximum load the substation can handle. We set our project scope, duration and hence, budget as per our study report for the long-lead equipment. Considering the best safety practice, operational and maintenance flexibilities, the bus configuration we chose is breaker and a half for the substation comprising of 138kV incoming lines and the 138kV by 13.2kV transformers. From the secondary sides of distribution network to the medium voltage switchgear buses, the ring configuration was selected. The basis was to ensure the continuous power available for customers like the international airport, hospitals, government offices, schools, colleges, businesses, and residents. To determine the size of each bus, cables, switchgear, equipment, circuit breakers, circuit switchers load flow and short circuit studies were done. 60 MVA peak demand can be met by two transformers. Each feeder should be able to supply maximum 3.6MVA if equally distribute load among all 24 feeders. 86.4 MVA load demand can be met by three transformers.

TABLE I. OPERATIONAL SEQUENCE OF LINES, TRANSFORMERS AND BUSES.

Transformers in Service (#)	138 kV Incoming lines in service (#)	Tie Breaker between Buses of Switchgear			Transformer (each) Output Loading		Transformer (total) Output Loading	Short Circuit (3-phase) (kA)	
		SWGR 1 Tie Beaker	SWGR 2 Tie Breaker	SWGR 3 Tie Breaker	MVA	%	MVA	138 kV yard Bus	13.8 kV SWGR Bus
3	3	Open	Open	Open	27.58	91.90	82.75	41.92	16.43
3	2	Open	Open	Open	27.58	91.90		27.96	16.30
3	1	Open	Open	Open	27.58	91.90		14.57	15.97
2	2	Close	Close	Open	29.59	98.60	59.86	14.27	16.38
2	1	Close	Close	Open	29.59	98.60		14.31	16.40
2	3	Close	Close	Open	29.59	98.60		41.15	16.86

V. PROTECTION SCHEME

The relay design brief incorporates the protection associated with the 138kV switchyard and the 13.2kV switchgear. Primary and backup protection schemes were considered for this substation and three 138kV incoming lines. 138 kV lines are connected to the different generating sources- coal, gas fired, solar. In the coming days, more generation from solar and distributed sources will be connected to the grid. To be supportive of the distributed generations, system protection was designed.

Apart from these, to overcome the limitations of the electromechanical relays, digital relays were replaced.

Line, Bus and Transformer Differential Relay

Line Protection

In each transmission line, a current differential (87L) protection scheme was implemented to ensure high-speed protection for phase-to-ground fault between the line terminating end at substation and source end of the 138kV line.

We have current differential as our primary protection as this transmission line length is less than 10 miles. The reason to choose a shorter line length was to ensure the differential protection works almost instantly and transmission system is well protected. Each terminal senses current and sends to the other terminal over dedicated fiber communication channel and compares at both ends. If the current difference is greater than our given preset value, both ends will trip simultaneously. The negative-sequence element detects internal unbalanced faults and is restrained when all three of the phase currents from any terminal exceed three times of nominal current. Back up protection is provided for loss of communications with step directional phase distance impedance elements - zone 1 phase distance instantaneous (M1P), zone 2 time delayed phase distance (M2PT), and zone 4 time delayed phase distance (M4PT) and residual ground directional time overcurrent relaying (51GT). In addition, a permissive overreach transfer trip (POTT) scheme was implemented to provide permissive tripping for overreaching directional phase distance element- forward zone 4 phase distance instantaneous (M4P) or, residual directional ground overcurrent (67G2).

Direct transfer trip (DTT) signal will also be sent over the fiber optic communication channels for breaker failure.

Bus Protection

Primary protection for 138kV bus phase and ground fault is provided by bus differential protection (87B). The node, where three 138kV busses are connected, is protected by high impedance differential relay. The phase-to-phase fault current is higher than that of phase-to-ground fault. This could result in CT saturation for through faults on the bus having short circuit. Using the sufficiently high value of stabilizing resistance and metal oxide varistor in the relay, the CT saturation from short circuit on any bus was resolved. Lockout (86) feature of breaker was used for increased safety. Fig. 5 illustrates a circuit connection for high voltage bus protection.

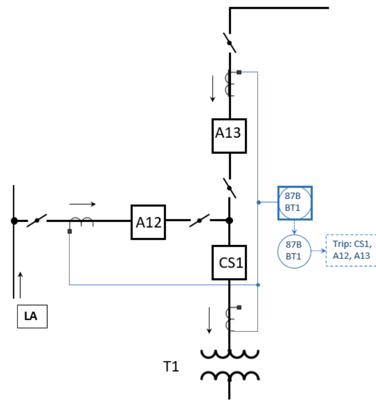

Figure 4. 138kV differential protection scheme, where CS1 is circuit switcher, A12, A13 are gas circuit breakers.

Transformer protection

The primary protection for transformer internal faults consist of high speed phase and ground-fault protection provided by dual transformer differential relays and the sudden fault pressure relay (63).

The protection for internal phase faults on the primary windings consists of the instantaneous overcurrent (50/50N) and the non-directional inverse time phase-overcurrent (51) functions of relays. Protection for ground faults on the primary winding (delta side) is provided by the very inverse residual ground time overcurrent (51G) function of primary and secondary relays. The primary and secondary relays initiate circuit switcher failure to the associated 138kV source breaker relays.

The inverse time ground overcurrent (51G) function of the primary and secondary provide protection against ground faults on the secondary side of the transformer and distribution feeder ground backup protection.

Protection against transformer overload, 15kV bus, and backup protection for feeders is provided by the moderately inverse time phase overcurrent (51) function and the inverse time residual ground overcurrent (51N) of the relays. The Winding 2 and 3 on the primary and secondary relays will also be set with these same values.

If a **feeder** breaker relay fails, an alarm is generated to supervisory control and data acquisition (SCADA) (Control house) and a 50/51 element in the transformer and bus differential relay is armed (torque control on) so that the entire bus does not trip for a failed feeder relay.

Note that this does not provide reclosing capability but solves the problem of unnecessarily tripping the bus for simultaneous feeder faults, as experienced with the three-winding relay used previously. The communications between relays are accomplished via high-speed serial communication. A failed feeder relay can report its own self-test failure to arm the backup overcurrent elements, or if the feeder relay simply stops communicating, the backup relay can also arm the backup overcurrent elements.

VI. RESULTS AND DISCUSSION

We performed load flow and short circuit studies during the design phase of the substation. These studies are conducted using a "what-if" approach that tests the loading of each piece of equipment under a range of reasonably stressed system conditions.

The capability of the system under these conditions is studied using computer simulations which model the electrical parameters of the system. The substation system is analyzed under "normal" conditions, and also under contingencies involving the loss of one or more transmission system facilities.

A. Load Flow

Load flow (LF) studies were performed in different combinations of 138kV incoming lines and the number of transformers in service.

For this study, each of the 13.2kV distribution circuit breakers of the 24 feeders as considered to be 1200A. In actual, relaying is limiting the maximum current flow can be 350A to not allow the cable to overload. These distribution cables will be replaced gradually as part of our grid modernization project. Maximum load that each circuit can reach up to 8MVA. If the demand increases, by changing the breaker setting, we can supply around 26MVA through one feeder circuit.

In the LF study, all 3 transformers were put in service and 2 incoming lines were considered connected to the substation buses as per the one-line diagram (Fig.1). Each transformer output was found to be 17MVA and running at 58% (highlighted in the Table 1). Total distribution load 52 MVA remains the same. Because three transformers are equally sharing this total amount of load, each transformer did not require to run with any stage of cooling. The load flow study for the substation was performed with consideration of one transformer out for service while two others are in service. Each transformer is connected to total three buses. To meet the minimum condition of running with two transformers and one incoming line, each transformer was loaded to provide output of 26 MVA. Each transformer was running at 87% loading capacity. The buses of switchgear were loaded at 99% of which 1% was combined loss in the distribution feeders.

To handle the presently connected peak loads of 52MVA, two 138kV transmission lines and three transformers (without tap changing) need to put in service. Therefore, the third 138kV line connected to the substation is not essential for time being. When load growth demands more MVA, then the third line will be essential to meet the requirements up to 80 MVA.

B. Short Circuit

Short circuit study was done considering any bus can have bolted short circuit or Line-Line-Line fault. This 3-phase short circuit current is the maximum during the first half cycle. Simulation shows that this current is 42kA, 14kA (Table 1) on the incoming transmission (138kV) buses and distribution switchgear (15kV) respectively when all three lines and transformers are in service. When two incoming 138kV lines and two transformers are in service, the values are 28 and 16kA for 138kV and 13.2kV buses respectively. In different scenarios, the values are shown in the Table1. Hence, for our grid modernization project the design of the substation buses was done accordingly.

Based on this calculation, in our design we modernized the relay scheme for the breaker control/failure, line and transformer, bus protection. The ANSI device numbers covered are 25, 27, 50, 51, 59, 81, 86, 87. These relays are for synchronization, voltage, instantaneous over current, time over current, frequency, lock-out and differential protection respectively. The issues resolved are time synchronization of the event records of the relays. Communication between the relays and back to the office due to different communication protocols and relay management software is smoothly going on.

The system minimum requirements can go as low as one transmission line and two transformers needed to keep in service to meet the demand of our all customers connected through the 24 feeders of six buses through this substation. Based on this understanding, a balanced distribution network is maintained by distributing feeder circuits to each transformer. If for any reason, two out of three incoming transmission lines are out of service, we can reliably provide power to the customers through one incoming line. Each transformer needs to feed three buses of the total of six buses of three switchgears. Transformer sizing was done accordingly. Protection, control and logic settings were established as per the operational sequence given in Table 1.

C. Protection and Control

CT saturation is the most critical design consideration when an asymmetric fault within the first half cycle and through fault situation occur.

For line protection, CT selection was to avoid CT saturation completely [16], such that

$$20 \geq \left(\frac{X}{R} + 1\right) \times I_F \times Z_B$$

I_F is secondary fault current (p.u. of nominal secondary current)

Z_B is CT burden (p.u of rated secondary burden)

X/R= 6.06022 (our case, it is the maximum for LA)

For our chosen 2000:5 CT ratio, the maximum (bolted) short circuit current found in the lines LA, LB or LC was found to be 41.92kA (Table I). The CT burden was around 1/8 p.u.

Thus
$\left(\frac{X}{R}+1\right) \times I_F \times Z_B$ becomes 18.34.

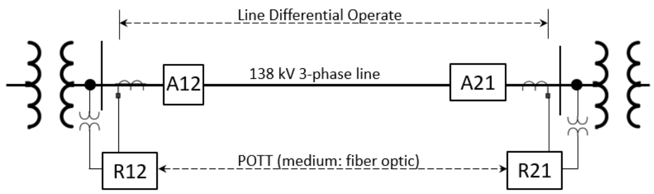

Fig 6: Differential protection scheme between two connected substations to avoid CT saturation. R12, R21 are the relays connected at the two ends of a 138kV line.

Line was designed with consideration of material and distance between phases in a way which would generate very low negative-sequence component of line charging current. Very low amount of negative sequence current differential protection allows for high sensitivity without compromising security. The phase elements provide high-speed protection for severe or balanced faults. This allows high-speed operation even under heavy load flow conditions when system stability may be critical.

For buses and transformer protection, high-impedance differential protection scheme was taken to immune against relay misoperation resulting from CT saturation, provided the stabilizing resistor connected in parallel in the circuit has a sufficiently high value. We chose relays with 2000-ohm resistors. This amount is large enough to provide security against CT saturation for through faults.

For example, maximum short current found at the primary of the transformer T1 is 41.92 kA (fig.5), while the maximum current for 80% inductive load case would be 125.8 A through each breaker of A12, A13. During the fault on the bus located T1, the sum of the fault currents through transformer primary will be

$$=41.92\text{kA}+125.8\times2\text{A}=42.17\text{ kA}.$$

The amount contributed by the adjacent two buses is 0.6% of total fault current seen by the CT located at the primary of T1. To avoid CT saturation, from this 0.6% of total fault current, selected 2000:5 CT secondary current increases by 0.63A, whereas is 104.79A for the fault current. Hence the excitation voltage level increment by 0.6% would not bring the CT at saturation level, only would slightly up in the knee voltage level, at best.

D. Communication

The issues considered are time synchronization of the event record of relays to analyze it. The other issue is to have communication between the remotely located control house and the relays irrespective of the different interfacing softwares and protocols. Major new technology used in this new greenfield substation comprises the GPS-based synchronized sampling, optical sensors, diverse communication media and multifunctional IEDs. Thus in IEDs, we get the time synchronized at the input of data acquisition systems and time-stamped.
The main purpose for using fiber optic communication between local substation control room and remotely located control house is optical sensors from the equipment have the wide frequency bandwidth, wide dynamic range and high accuracy. Furthermore, the new sensors allow online asset condition monitoring. This provides stable operation and reduces the repair time.

VII. SUMMER PEAK LOAD

In the first phase of our grid modernization project, transmission lines were designed and constructed. Based on the detail study reports, investigations, substation was designed. In the second phase of the construction project, the substation was built in a city center area.

Generally, July and August are the hottest months of the year and load demand is the highest. On the 13.2kV feeder line allowing 350A per breaker from the switchgear (SWGR 2), on the hottest day, the average, minimum, instantaneous currents were 122, 77.5 and 176A respectively. At the substation entrance point, currents in the transmission line (LC) connected to the same switchgear through transformer 3 (T3) was showing 839.3, 67.5 and 1287.9A respectively through 2000A breaker. The transmission line A (LA) connected to the other switchgear (SWGR 1) through T1 was showing 839.3, 67.5 and 1287.9A respectively though 2000A breaker. All these values are within the range of the circuit breakers chosen and installed into the substation. This justify the planning, design and construction of this substation.

VIII. CONCLUSION

To accommodate all the rapid technological changes happening in the generation, transmission and distribution of electric power, grid modernization is very crucial. This paper proposes that proper planning is very crucial for the design of the transmission lines, substation to cope with the varying distribution loads. There is no candid way to say that any specific type of bus configuration for the transmission and /or distribution system would be the choice. Indeed, it depends on the existing and/or, planned infrastructure of the transmission and distribution networks, load growth rate, area constraint specially in a city center area and others. In our project, we considered all these factors and modelled the substation. Based on the different possibilities, we concluded that for 138kV network in the substation breaker and a half configuration while for the 13.2kV distribution network ring configuration would be the choice. This was applicable for the substation where there were three incoming 138 kV transmission lines and three power transformers. Proper equipment selection and coordination between transmission and distribution networks were done accordingly.

IX. ACKNOWLEDGEMENT

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