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2004 Capital Budget Application
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Information Systems

Project Title: **Hydro Plant Facility Rehabilitation**

Location: **Various**

Classification: **Energy Supply**

Project Cost: **$1,122,000**

This project consists of a number of items as noted.

(a) Pierre's Brook – Replace Forebay Head Gate

Cost: $91,000

Description: Replace the existing head gate, gate guides and lift at the forebay intake structure including rehabilitation of the upstream stop log guides.

Operating Experience: Misaligned gate guides and water leakage around the head gate seals have rendered this structure ineffective in providing the positive water shut off required to perform maintenance and inspections of downstream facilities. An attempt to dewater the penstock in September 2002 proved unsuccessful and the subsequent binding of the gate in the misaligned guides prevented the operation of the plant for three days. The services of a diving contractor were required to open the gate. This structure is the original head gate installed when the project was commissioned in 1931.

Justification: The head gate is a critical link in the continued safe and effective operation and maintenance of the Pierre's Brook Hydro Generator. Normal production at the Pierre's Brook hydro facility is 25.3 GWh per year.

(b) Topsail – Replace Protection and Controls

Cost: $200,000

Description: Replace the existing governor controls and protection with Newfoundland Power's standard design Unit Control Panel, including a Programmable Logic Controller, generator protection, digital voltage regulation, synchronizer and metering.

Operating Experience: Newfoundland Power has an approved 2003 capital project to replace the electronic control portion of the Voest-Alpine governor system at Topsail Plant. The governor was installed by Barber Hydraulic Turbine in 1983 as part of a major plant refurbishment replacing turbine, generator, switchgear, protection and control systems. Originally the unit had difficulty synchronizing to the power system and in 1995 a modification was designed that involved filtering the output of the electronic controller with a programmable logic controller. Original equipment manufacturer ("OEM") support for the system is no longer available and the supply of spare parts has been exhausted. Newfoundland Power has undertaken to repair electronic boards in house for the equipment, however, repairing the electronics has become increasingly difficult as the discrete components and integrated circuits are no longer being manufactured.

The project for 2003 involves the replacement of the function provided by the electronic governor with a similar function relocated to the programmable logic controller (PLC) system. Detailed engineering design began early in 2003 for this project during which it became evident that the existing PLC equipment cannot support the complete governor function, and as a result, additional PLC hardware is required.

During the design phase, a review of the plant operators log identified that most of the 115 unscheduled plant outages were related to protection and control system failures. The inability to filter out transient losses of the speed signal and the instantaneous spiking of the bearing oil and temperature readings accounted for 42% of unit trips over the previous five years. The control of the pressure relief valve accounted for another 17% of unit trips and created another significant design issue to be addressed.

In order to address the problems noted above the scope of the necessary work has significantly expanded, making it impossible to complete the project within the original $230,000 budget. Therefore a decision has been made to carry over the original project to 2004 as a part of a larger project to complete the overall work. The combined budget for the larger project is $430,000.

Justification: Normal production at the Topsail plant is 14.2 GWh of energy annually. The governor is a critical system and the generator cannot be operated without it. Therefore, to ensure the reliable production of energy from this facility the equipment must be replaced. See Attachment A, Engineering Review – Topsail Plant Governor, Protection and Control System.

(c) Morris – Replace Turbine Runner Seals

Cost: $107,000

Description: Replace the mild carbon steel turbine runner stationary seals with either Type 410 stainless steel or ASTM B271 centrifugally cast nickel-aluminum-bronze alloy stationary seals.

Operating Experience: The Morris turbine was installed as a new plant in 1983 by Barber Hydraulic Turbines. The turbine is a horizontal Francis Turbine. In April 2000, operators started to experience problems with the wicket gate operating ring jamming and acting sluggishly. The turbine was inspected and it was found that the carbon steel stationary seals had corroded, rust had accumulated, the two ends of the wicket gates were getting jammed in between the two stationary seals and the seals were in need of replacement.

Justification: Normal production at the Morris plant is 7.2 GWh of energy annually. The turbine runner stationary seals are critical to the operation of the plant. Therefore, to ensure the reliable production of energy from this facility, the equipment must be replaced. See Attachment B, *Morris Plant Turbine & Stationary Seal Inspection*.

(d) Rattling Brook – Rewind Generator G1

Cost: $407,000

Description: Rewind the stator coils in generating unit G1. This involves the disassembly of the generator, the removal of the stator winding, transport to a facility equipped for the work, transport back to site, installation and realignment.

Operating Experience: In 2002 the generator winding in unit G2 failed during a full load rejection. Testing revealed that a turn-to-turn fault had developed in the windings and a complete rewind of the stator was required. Unit G1 is identical in construction to unit G2, and over its forty-five year life has been exposed to a similar operating environment. Concern exists for the condition of generator windings on generators such as G1 that have exceeded their estimated life expectancy as established by the Institute of Electrical and Electronic Engineers (IEEE).

Justification: Rattling Brook generating station is an important source of energy to the Province, with normal hydro production of 69.4 GWh annually. This is Newfoundland Power's largest producing plant. There are times during the year when water flows are such that both generating units are required. An unplanned outage due to the loss of the generator winding on G1 would result in the loss of energy over the period necessary to effect the repair.

(e) Various Plants – Replace Cooling Coils

Cost: $69,000

Description: Replace bearing cooling coils and install bearing oil level controls and bearing cooling water flowmeters and controls. In 2004 cooling coils will be replaced in Rocky Pond, Rattling Brook, Cape Broyle and Pierre's Brook.

Operating Experience: Since 1997 we have experienced seven cooling coil failures which resulted in oil spills and lost production. The latest was in 2002 at Horse Chops plant.

Justification: This project will reduce the risk of bearing failures due to lubricant contamination and will also reduce the risk of hydrocarbon spills to the environment from these hydroelectric plants.

(f) Various Plants – Upgrade Protection and Controls

Cost: $200,000

Description: Replace protection and control systems in Newfoundland Power's hydro plants in order to improve the efficiency, reliability, safety and environmental aspects of the plants. This will be achieved by addressing issues pertaining to equipment that requires maintenance and is no longer supported by the manufacturers which makes replacement parts expensive or unavailable. As well, this project will improve the control and protection of the equipment by using more versatile electronic devices. Additional monitoring, control and protective devices will be installed to meet present day standards. These upgrades will also facilitate increased automation and remote control capabilities. In 2004 upgrades will take place at the following Hydro Plants: Rocky Pond, Rattling Brook, Fall Pond, Pittman Pond, Victoria and Morris.

Operating Experience: The power plants belonging to Newfoundland Power range in age from 5 to 103 years. Much of the original protection and control equipment is still in service, in particular the hydraulic gateshaft governors, switchgear and protective relays. The switchgear in some plants is over fifty years old and the majority of plants have protection schemes utilizing electromechanical relays that do not provide the present IEEE minimum protection requirements. Failure of these components is one of the main reasons for the outages at these hydro plants in 2002.

Justification: The continued efficient, reliable, safe and environmentally responsible operation of Newfoundland Power's generating stations requires the replacement of equipment which has gone beyond its serviceable life as well as the application of new technology to better monitor and control the units to minimize the possibility of costly, major failures.

(g) Projects < $50,000

Cost: $48,000

Description: Listed are projects estimated at less than $50,000.

1. Hearts Content – Replace damaged concrete headwall at intake structure
2. Victoria – Replace corroded trashrack at intake structure

Topsail Plant
Governor, Protection and Control Systems
Engineering Review

Newfoundland Power Inc.

May 16, 2003

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Introduction

Newfoundland Power has an approved 2003 capital project to replace the electronic control portion of the Voest-Alpine governor system at Topsail Plant. The governor was installed by Barber Hydraulic Turbine in 1983 as part of a major plant refurbishment project replacing turbine, generator, switchgear, protection and control systems.

The project for 2003 involves the replacement of the function currently provided by the electronic governor with a similar function located in the programmable logic controller (PLC) system. Detailed engineering design began early in 2003 for this project during which it became evident that the existing PLC equipment could not support the complete governor function. As a result, additional PLC hardware is required.

A review of the plant operators' log identified that most of the unscheduled plant outages were related to protection and control system failures (See Appendix A). The inability to filter out transient losses of the speed signal and instantaneous spiking of the bearing oil and temperature readings accounted for 42% of unit trips over the previous five years. The control of the pressure relief valve accounted for another 17% of unit trips and introduced another significant design issue to be addressed.

As a result, the scope of work has significantly expanded, thereby making it impossible to complete the project within the original $230,000 budget. Therefore a decision must be made as to whether the project will proceed in 2003 or an expanded project be submitted for the 2004 capital budget.

Normal production at the Topsail plant is 14.2 GWh of energy annually. The governor, protection and control systems are critical systems in the operation of the plant. Therefore, to ensure the reliable production of energy from this facility it is recommended that this project proceed as described in the Recommendation in 2004.

Technical Analysis

The following technical analysis has been completed on the governor, protection and control systems at Topsail plant.

<u>Electronic Governor</u>

The existing governor and control system at Topsail Plant was installed in 1983. Newfoundland Power has modified the equipment in order that satisfactory performance can be achieved from the plant. The synchronizing system requires frequent adjustment to maintain operational status as demonstrated in the operators' log provided in Appendix A. As a result, the synchronizing and governor systems are two of the most frequent causes of unscheduled outages for the plant. Originally, the unit had difficulty synchronizing to the power system and in 1995 Newfoundland Power designed a modification that involved filtering the output of the electronic governor controller with a PLC.

Original equipment manufacturer (OEM) support for the system is no longer available and the supply of spare parts has been exhausted. Newfoundland Power has undertaken to repair electronic boards in house for the Voest-Alpine equipment. However, repairing the electronics has become increasingly more difficult as the discrete components and integrated circuits are no longer being manufactured. Therefore, a solution is sought that involves replacing the proprietary hardware with standard PLC based technology consistent with installations in Newfoundland Power's other plants.

Protection

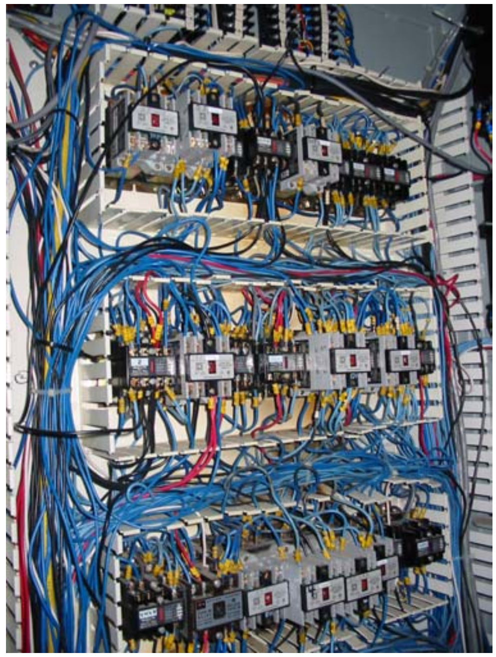
Although the installation is only 20 years old the protective relaying does not include the minimum protection requirements as established by IEEE C37.102-1987. The addition of generator ground fault protection (59GN), rotor field protection (64F) and reverse power protection (32) are required to meet the minimum requirements of the IEEE standard.

Vibration Monitoring

There is no vibration monitoring on the turbine or generator systems. Vibration monitoring should be provided to detect mechanical failures before they can cause permanent damage to the turbine or generator. Trending can be achieved through a PLC to provide insights into the development of problems and allow proactive scheduling of maintenance before failures occur.

Generator Sequencing and Control

The interposing relays associated with the sequencing logic were under designed by the OEM and as a result are the cause of many unit trips. Over the years, numerous relays have been replaced and the number of trips has been reduced. However, relay failures still account for a significant number of unit trips.



Interposing Relays

Over the past five years 26% of all unit trips can been attributed to intermittent loss of the speed reference signal. This is not an unusual situation with electronic controllers employing analog circuitry. When control is provided through a PLC the logic will delay unit trips on loss of speed reference to allow the signal sufficient time to return to normal.

Another common problem with the control system is failure of the voltage regulator's under frequency and over voltage module. In the past these boards have been repaired in house, however integrated circuits and discrete electronic components have become difficult to source. Replacement of the analog voltage regulator with a digital unit will ensure continued support for the system.

Pressure Relief Valve

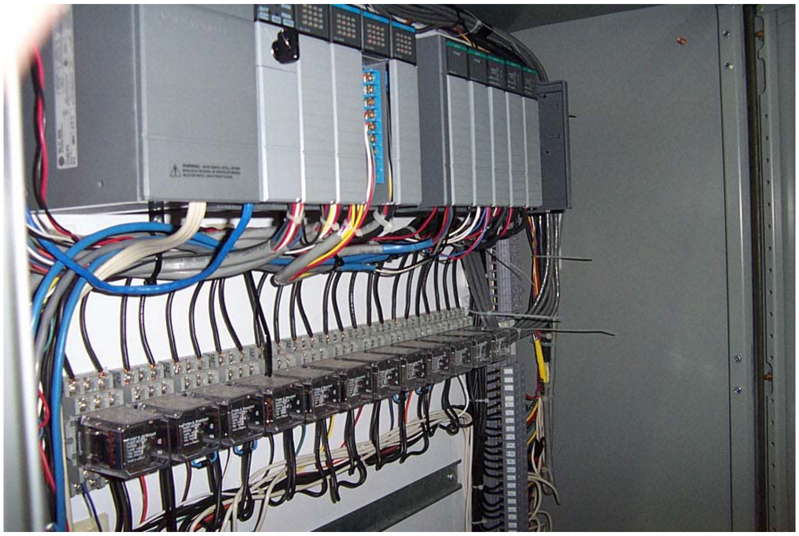
As there is no surge tank associated with the penstock, a pressure relief valve (PRV) is required to relieve pressure under full load rejection. A tracking system was designed to preset the pressure relief valve appropriately in the event of a full load rejection on the unit. The tracking system was the result of infield modifications necessary because of a penstock rupture that occurred during acceptance testing of the 1983 turbine generator system supplied by Barber Hydraulic Turbine.

Interfacing with the PRV tracking system has increased the PLC hardware requirements of both the programming effort and the necessary processing power of the PLC. To ensure the long term reliability of the system it is felt that integrating the control of the PRV into the PLC ladder logic improves control and protection for both the PRV and the penstock.

Pressure Relief Valve

Existing PLC

The existing PLC is an Allen-Bradley SLC model 5/03 acting as a buffer between the electronic governor controller and the hydraulic pressure unit. This modification was completed to increase the reliability of unit synchronization, as the electronic controller was unable to maintain synchronous speed at speed no load conditions. The 5/03 processor has insufficient computing to provide a governing function. In addition, the number of input/output points is limited due to the size of the equipment enclosure.



Allan-Bradley PLC System

The existing equipment cabinets have utilized all available floor space in the plant. The existing PLC cabinet is positioned on a rear wall behind the existing switchgear. Access to the cabinet is limited and there is no room to expand.

Location of existing PLC

To provide the necessary space for a governor PLC, it will be necessary to replace an existing equipment enclosure with an enclosure that also includes the governor function.

Unit Control Panel and Generator Breaker

The replacement of the sequencing logic and associated controls presents an opportunity to combine both the governing function and the protection and control function into a single enclosure.

Recommendations

This report recommends the following:

- The project to replace the governor system with a PLC solution be carried over to 2004.
- A new project to upgrade the protection and control systems at Topsail plant be included in the 2004 Capital Budget.
- The system be designed similar to the unit control panels at Seal Cove and Tors Cove, including the governor function in the unit control PLC.
- The existing Voest-Alpine electronic governor controller be decommissioned and salvaged for spare parts for other in service units at Lawn and Lookout Brook plants.
- The existing protection and control systems be decommissioned.
- Engineering design be completed in 2003 to ensure project completion early in 2004.

Appendix A

Topsail Plant Operators' Log

Morris Plant
Turbine & Stationary Seal Inspection

April 12 2000

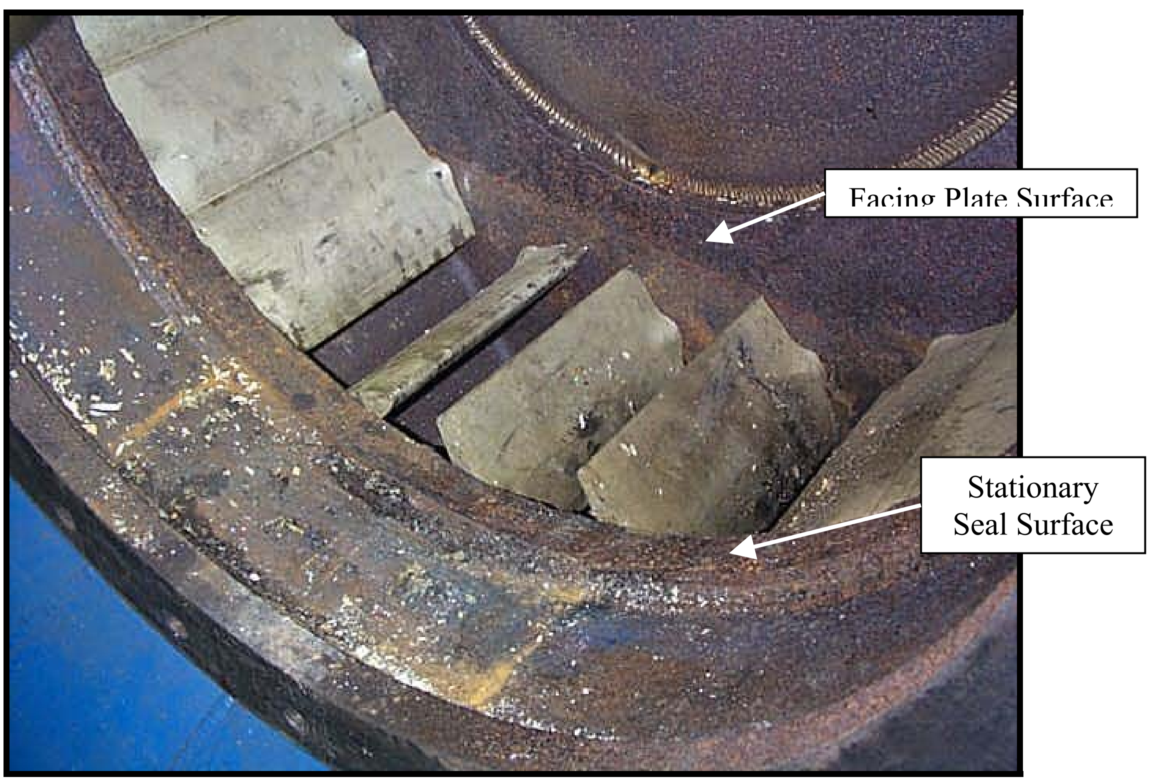
Turbine Inspection

Technical Specifications

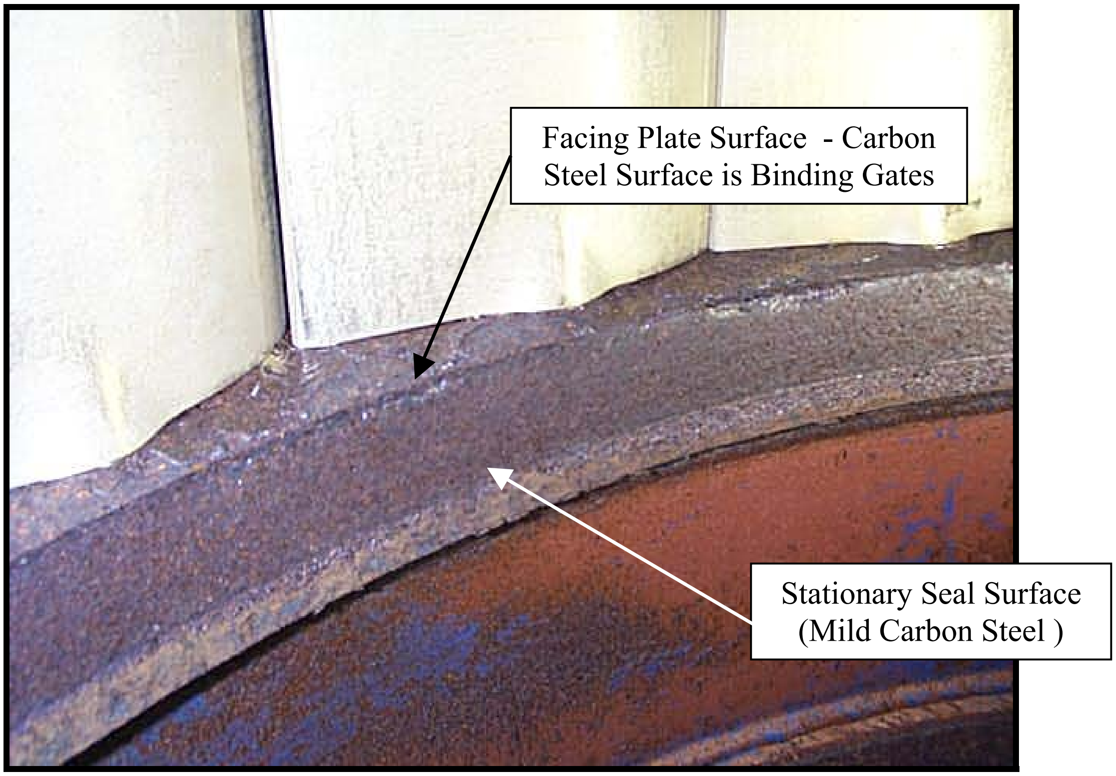
Size:	1100 kW
Manufacturer:	Barber Hydraulic Turbines
Date of manufacture:	1983
Serial Number:	1050
Type:	Francis

Assessment

This unit was installed as a new plant in 1983 by Barber Hydraulic Turbines. The turbine is a horizontal Francis Turbine. In April 2000 operators were experiencing problems with the wicket gate operating ring jamming and acting sluggishly. The turbine was opened up and inspected and it was found that the stationary seals in this turbine were mild carbon steel, and not Type 410 stainless steel or ASTM B271 centrifugally cast nickel-aluminum-bronze alloy typically found in our other hydro plants. The carbon steel stationary seals had corroded and rust had accumulated to the point that the two ends of the wicket gates were getting jammed in between the two stationary seals. The photo attached below shows the mild carbon steel stationary seals on the Morris Hydro Plant Turbine.



The next photo shows the area where the stainless steel wicket gates were getting jammed due to the rust accumulation on the carbon steel stationary seals.



Recommendations

The carbon steel stationary seals should be replaced with either Type 410 stainless steel or ASTM B271 centrifugally cast nickel-aluminium-bronze alloy typically found in our other hydro plants.

Project Title: **New Chelsea Hydro Plant Refurbishment**

Location: **New Chelsea, Trinity Bay**

Classification: **Energy Supply**

Project Cost: **$3,973,000**

See Attachment A, *"New Chelsea Plant Planned Refurbishment – 2004"*, outlining the rationale and justification for this project.

NEW CHELSEA PLANT
PLANNED REFURBISHMENT 2004

NEWFOUNDLAND POWER
Engineering & Energy Supply Department

NEWFOUNDLAND POWER

Engineering & Energy Supply Department

NEW CHELSEA PLANT PLANNED REFURBISHMENT 2004

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Introduction

On September 24, 1954 the Public Utilities Board required that Newfoundland Power's predecessor United Towns Electric provide electrical service to the communities of Hant's Harbour and Old Perlican. As a result, construction began on the New Chelsea Hydroelectric Development. The generating station, with an installed capacity of 3.7 MW, went into service in January 1957 at a construction cost of just over $2.5 million. Two years later the development was expanded when a 0.6 MW generating station was constructed at Pitman's Pond upstream from New Chelsea. The design of the Pitman's Pond generating station allowed for remote control from New Chelsea. In 1960, the generating station at Hearts Content was redeveloped, and was also remotely controlled from New Chelsea. Since that time there has been very little in the way of major refurbishment work at New Chelsea, except in 1986, when the three generating stations were automated to provide remote control from the System Control Centre in St. John's. The control panels, switchgear and protection systems at New Chelsea all date back to the original 1956 installation.

In 2004 the major systems in service at New Chelsea will be 48 years old. The expected life of this type of equipment as established by the Institute of Electrical and Electronic Engineers (IEEE) ranges from 25 to 40 years. The existing woodstave and steel penstock has also deteriorated to the extent that replacement is necessary to ensure continued safe and reliable operation. This presents an opportune time to complete refurbishment of other systems at this facility, since replacement of the penstock will result in a five-month period when the plant will be unavailable for operation. Refurbishment of the other plant systems can be completed in this time period, hence avoiding the need for another prolonged plant outage and associated water spillage in future years.

The justification for the project is based on a combination of dealing with obsolescence, maintaining public safety, supporting environmental stewardship and ensuring reliable electricity supply from this facility.

Role in Power System

New Chelsea provides approximately 15.4 GWh of energy on an annual basis, or 4% of total hydroelectric production for Newfoundland Power. In addition, it provides 3.7 MW of power to the Hants Harbour, New Chelsea and Old Perlican areas in the event of a loss of in-feed through transmission line 43L from Hearts Content. The generator also plays a role in maintaining acceptable voltage levels on this long radial transmission system.

Scope of Work

The scope of this project includes modifications to the electrical, mechanical and civil works of the plant and the 66 kV substation. The site assessments included in the appendices of this document form the basis of the Scope of Work and the associated budget estimate. The following is a summary of the scope of work:

Electrical Work

AC Station Service

The existing 69,000-volt to 600-volt delta station transformers will be replaced. This secondary voltage is non-standard voltage and there are no spares available for the three single-phase transformers. The potential failure of one or more of these transformers places the operation of the plant at risk. They will be replaced with a 6,900-volt to 120/208 volt, wye, three-phase dry-type transformer located inside the plant in a new switchgear cabinet. In addition, a backup station service will be provided from the substation yard using three standard pole mounted transformers and connected to the switchgear with a manual transfer switch. This will provide a contingency in the event of the failure of the dry-type transformer.


Station Service Transformers

The existing 600-volt delta, 3 phase AC service is non-standard and antiquated with numerous auxiliary panels associated with the distribution system. The system will be modernized and consolidated into a single 120/208 volt three phase panel to provide a standard station service supply.

DC Distribution and Battery Charger

The DC distribution panel and battery charger will be replaced. The DC distribution is original to the 1956 installation and the battery charger was installed in 1975. Replacement breakers are not available for the DC distribution panel and spare parts are no longer available for the battery charger. The battery bank was replaced in 1996 and is in good condition.

Switchgear and Power Cables

The existing breaker used to connect and disconnect the generator is located on the high side of the unit transformer resulting in inadequate protection of the generator. The refurbishment will include a new generator breaker installed in conjunction with a digital multifunction protection relay to provide the required generator electrical protection. The switchgear will include new current and potential transformers to replace the units supplied in the 1956 installation. The switchgear will also include a new field breaker, generator neutral grounding reactor, station service transformer and a grounding system for isolating the generator bus for maintenance. The existing breaker and disconnect switch will eventually be replaced with power fuses and an airbreak switch.

The existing power cables went into service in March 2000 and remain in good condition. These power cables will be re-terminated in the new switchgear. Modifications to the bus connection between the generator output terminals and the power cables will be required to interface with a new generator breaker.

Generator

The generator windings are original and have never been rewound. After 48 years in service they have significantly exceeded the average life expectancy of 30 years, which places the reliability of the plant at significant risk, with the potential of six to eight months of downtime and associated spillage of water.

The unit will be rewound as part of this project. The excitation system is in good condition, requiring only a general cleaning and replacement of those parts demonstrating excessive wear. The slip rings and commutator will be inspected prior to shutdown, machined and undercut if required.

Generator Protection and Control

The unit sequencing and control will be implemented using a Programmable Logic Controller (PLC), replacing the numerous discrete relays currently in service. The PLC will be part of our standard Unit Control Panel (UCP) design supplied locally. The UCP will also include a synchronizer, voltage regulator and production metering.

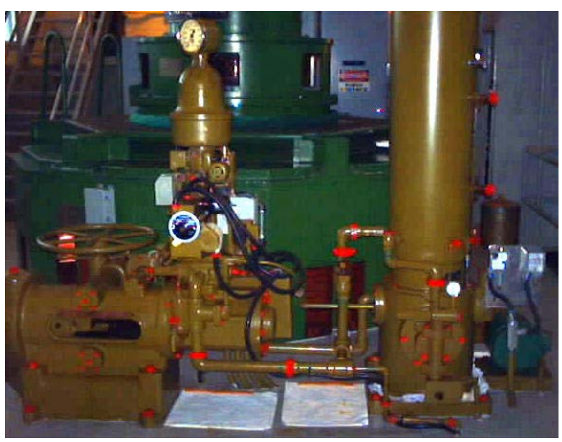
The existing generator protection provided through electromechanical relays does not meet the IEEE recommended minimum set of protection for a generator of this size and duty cycle. To meet the standard the following protection will be added using a multifunction digital generator protection relay:

- Loss of excitation
- Over-voltage protection
- Over-frequency protection
- Stator thermal protection

Governor

Recent experience indicates that the existing governor speed droop is inaccurate and it is no longer able to properly regulate frequency when operating isolated from the provincial power grid. Frequent adjustments are required and, as a result, there are concerns with the quality of power provided to customers when supplying local load. The Woodward governor is original to the plant and is difficult to maintain. The manufacturer is no longer able to provide replacement parts and has limited their support to system upgrades and retrofits. As a result, replacement parts are machined locally and do not meet the tolerances of the original specifications. In addition, the pressurized oil system employed by this governor exposes the plant to the risk of oil release into the tailrace.

There are two options for replacing the original governor. The mechanical governing head can be replaced with an electronic upgrade from the original manufacturer. The hydraulic system would undergo replacement of some parts no longer available and refurbishment of the power piston. The second option is to replace the Woodward system entirely with an all-electric solution, thereby reducing the use of oil at the facility. One significant technical issue to overcome is related to the fact that the existing Woodward governor is mechanically linked to a pressure relief valve. Both solutions have a similar cost, and the final decision as to which option should be implemented will be determined during the detailed engineering design stage. An additional benefit resulting from the implementation of either of these solutions is the provision of spare parts that will be used to maintain similar units still in service.



Woodward Governor

Instrumentation

The unit does not have stator temperature, vibration or bearing oil level monitoring and protection while the bearing temperature protection is of 1956 vintage and requires upgrading. This protection is recommended for a plant of this size. The instrumentation and protection systems on the generator and turbine will be upgraded to include the following:

- Bearing thermocouples or RTD's (two per bearing)
- Vibration monitoring (one per bearing)
- Oil level switches (one per bearing oil pot)
- Stator RTD's (6 10-ohm copper elements)
- Incorporate speed switch into UCP

Bearing Cooling Water Control

Automating the valves and flow meter in the bearing cooling water system through the UCP will enhance mechanical protection for the turbine and generator. Cooling will be provided only when required to maintain constant bearing temperature.

Heating and Ventilation

The existing manual louver system will be motorized and automated to provide improved temperature regulation. Heating of the plant and generator will be controlled through the UCP. These enhancements will provide heat to the stator when the unit is shut down and cooling air to the plant by opening the building louver and operating the exhaust fan when the building ambient temperature increases. The ability to close the louvers when the unit is not operating will reduce energy loss from the plant. Maintaining a controlled environment within the plant will ensure that problems related to condensation will not lead to electrical failures of the generator and associated equipment.

Forebay Water Level Monitoring and Control

The existing water level probe and transducer are obsolete, cannot be accurately calibrated and are no longer supported by the manufacturer. The new system (PLC and water level probe) will be interfaced with the UCP as required to provide efficient water management.

A detailed assessment of the protection and control is provided in Appendix A.

Mechanical Upgrading

Turbine

The scroll case vent and 4-way control valve will be replaced with an automatic float type vent, eliminating the need for separate control valves and electrical interface.

The wicket gates will be replaced or refurbished to reduce the potential of sticking and causing undue wear and tear on governor arms and linkages. It will also reduce the run down time on shutdown.

The turbine shaft gland seal and shaft sleeve will be inspected and replaced or refurbished as required to prevent water leakage.

Bearing Cooling

All bearings will be refurbished as required during the turbine upgrade.

The cooling water system is now fed from two 1 ½" Y type strainers. These will be replaced with a more conventional duplex filter element system.

The cooling water system will be replaced or refurbished as required.

Heating and Ventilation

The stationary intake louvers and shutters will be replaced with a motorized louver system. The control for the plant heating and ventilation will be upgraded by incorporating it into the PLC logic control. Concrete repairs to the louver opening & sill plates will also be completed.

A detailed assessment of the turbine is found in Appendix B.

Civil Work

Powerhouse

Concrete rehabilitation is required in the tailrace area in the vicinity of the water line. The damage is caused by salt-water spray and the freeze thaw cycles experienced in the ocean environment.

Penstock

The project involves the replacement of the 867 metres of 1,829 mm diameter woodstave penstock and 240 meters of steel pipeline. The new penstock is to be constructed with steel and dimensioned similar to the existing woodstave penstock. Drainage will be improved near the steel pipeline by installing culverts and porous gravel where required to reduce the risk of corrosion of the pipe.

A detailed assessment of the condition of the penstock is included in Appendix C, and the internal inspection completed by FGA-CANSPEC consulting engineers in Appendix D.

Substation Work

Transmission Line Protection

At present the transmission line protection is spread across the various generator control panels in the plant control room. This is the result of piecemeal protection and control upgrades throughout the life of the plant. The existing generator protection and control panels will be decommissioned to make room for the new Unit Control Panel (UCP). As a result new transmission line protection panels will be required, which will consolidate the various protection elements and greatly simplify the operation, maintenance, testing and troubleshooting of the system.

Substation Modifications

The existing transformer breaker (NCH-T2-B) is used to synchronize the generator to the power grid. With the addition of a generator breaker this function will no longer be required. The condition of the breaker is questionable and it will eventually be decommissioned. To accommodate the synchronization of the new generator breaker a potential transformer will be installed on the 66 KV bus.

Station service for the substation is provided from the plant station service. This design does not address the situation where station service in the plant is shut down for maintenance. A dedicated substation station service is required to ensure a reliable supply of AC power to the equipment in the substation.

The existing transformer T2 protection provided through electromechanical relays consists of a transformer differential (87T), time delayed overcurrent (51N), and instantaneous overcurrent (50). These protection functions, along with others deemed necessary through a general protection review, will be included in a digital transformer and bus protection relay.

Justification

The project is justified on obsolescence, public safety, environmental stewardship, customer and plant reliability and financial considerations. Examples of each type of justification are provided in this section.

Public Safety

The existing woodstave penstock has progressively deteriorated over the 48-year life of the facility. Considerable effort has been made in recent years to contain leaks from the pipeline, and in the past year two major blowouts have had to be repaired.

Environmental Stewardship

The replacement penstock will be steel and permit the removal of the existing creosote-treated woodstave penstock from the environment.

The amount of oil at the facility would be dramatically reduced by the replacement of the hydraulic governor with an all-electric solution, should this alternative be selected.

The addition of a water management algorithm in the Unit Control PLC (UCP) will support the efficient use of water resources and reduce the risk of spill.

Maintaining hydro production at this plant will reduce the need for burning fossil fuel at Newfoundland Hydro's Holyrood Generating Station.

Reliability

Replacing the manufacturer-discontinued and obsolete equipment at the plant with commercially available equipment will reduce the number of equipment failures, and reduce the duration of unscheduled downtime. This will improve customer reliability when the plant is required to supply local generation and plant reliability by increasing availability and maximizing output.

Financial

The cost of energy for this plant, including the capital expenses associated with this and other planned projects, at 3.19 cents per kilowatt hour is substantially less than the cost of energy for new developments such as Rose Blanche, or thermal sources such as Holyrood. A detailed financial analysis is provided in Appendix E.

Recommendation

Old, deteriorated, high-maintenance equipment places the reliability of the plant at risk and raises concerns regarding potential penstock failure and associated environmental impacts. Newfoundland Power should proceed with this project in 2004. The project will benefit the Company and its customers through improvements in safety, environmental stewardship and reliability. It will reduce the operating and maintenance costs of the plant. Investing in the life extension of facilities such as New Chelsea guarantees the availability of low cost energy to the Province. Otherwise the annual production of 15.4 GWhs would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood thermal generating station.

Appendix A

Protection and Control Site Assessment

NEW CHELSEA REFURBISHMENT PROJECT

SITE ASSESSMENT

Protection and Control

General

The New Chelsea hydro development went into service in January 1957 with a construction cost just over $2.5 million. Since that time there has been very little in the way of major refurbishment work. The plant was automated in 1986, at which time remote control was provided. The control panels, switchgear and protection systems date back to the original 1956 installation.

AC Distribution

The existing 600 volt 3 phase AC service is antiquated and there are numerous auxiliary panels associated with the distribution system. The system needs to be modernized and consolidated into a 600 volt three phase panel and a 120/240 single-phase panel. Another option would be to provide a 120/208 three-phase panel if the existing 600 volt equipment is to be replaced.

Station Service

The existing 69,000-volt to 600-volt station service transformers are unique and we carry no spare units in our system. These units are larger than necessary and can easily be replaced with either standard distribution transformers or a three-phase dry type transformer located in a new switchgear line-up. This will allow for easy replacement if a single transformer were to fail in service. Also there is no emergency station service. Consideration should be given for an emergency station service and a manual transfer switch.

DC Distribution

The DC distribution panel needs to be replaced. The panel was installed in 1956 and replacement breakers are no longer available.

Battery Plant and Charger

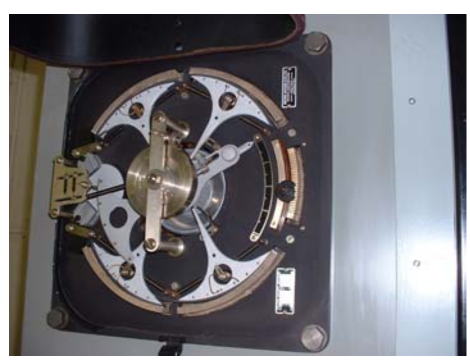
The batteries are in good condition. Records show that the battery bank was replaced in 1996. The charger was installed in 1975 and should be replaced due to unavailability of spare parts.

Generator

The generator windings are original and have never been rewound. At 48 years in service, this generator exceeds the average life expectancy of 30 years. Therefore, a rewind of this unit is warranted.

Excitation System

The excitation system is in good condition, with the exception of the antiquated voltage regulator. The unit control panel will be supplied with a digital voltage regulator to interface with the exciter. Consideration should be given for a brushless exciter if savings in maintenance costs can be demonstrated.



Switchgear

There is no generator breaker with this generator. As a result there is inadequate protection on the generator. The refurbishment will require a new generator breaker be installed to work in conjunction with the digital protection relay to provide adequate generator electrical protection. As a result the protection and control system for the step up transformer will need to be redesigned.

Power Cables

The power cables were replaced in March 2000. The power cables will remain in service and be connected to a new generator breaker. The bus connection between the generator output terminals and the power cables will need to be modified to accept a new generator breaker. The existing PTs and CTs will be replaced with the new switchgear.

Grounding

The generator has a high impedance ground for protection provided in the CT compartment. This compartment will be removed and replaced with a switchgear cabinet. Therefore the original 1956 grounding transformer will either have to be replaced or relocated if it is found to be in good condition.

Protective Relays

The existing generator protection provided through electromechanical relays consists of:

- Generator differential
- Rotor ground fault
- Stator unbalanced current
- Ground fault
- Generator ground fault
- Split phase differential protection

- Voltage restrained overcurrent

The recommended minimum set of protection was provided on this generator, with the exception of the following:

- Loss of excitation
- Over-voltage protection
- Over-frequency protection
- Stator thermal protection

The existing transformer protection provided through electromechanical relays consists of:

- Transformer differential
- Time delayed overcurrent
- Instantaneous overcurrent

Alarm Annunciation

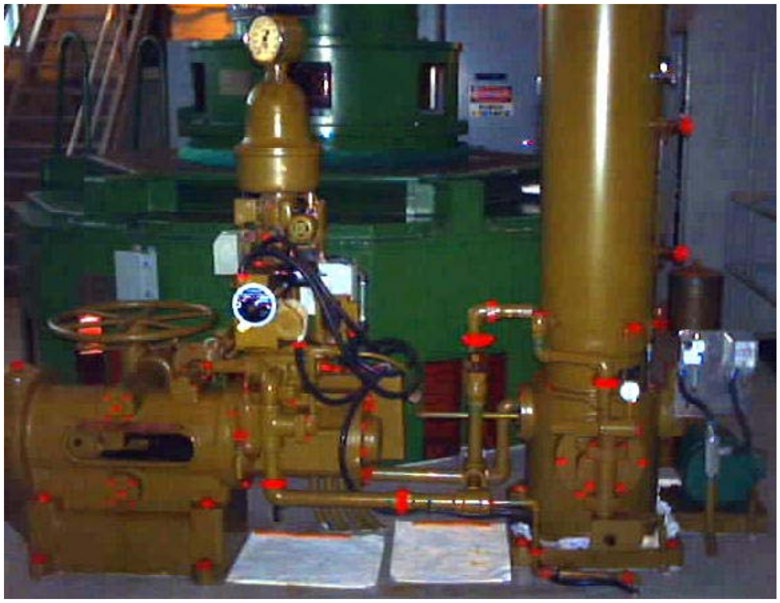
There is little or no annunciation of local plant alarms through the existing control panels.

Governor

Reports from the local staff indicate that the governor performs acceptably when the generator is parallel with the power system. However, when operating isolated from the grid and supplying local load the governor does a poor job maintaining frequency. The quality of power provided by the generator when supplying isolated local load is below acceptable power quality standards.

The existing Woodward governor is mechanically linked to a pressure relief valve. This will impact design solutions for a governor replacement.

Options for governor replacement include a Woodward 505H upgrade (including power piston overhaul) or a new hydraulic replacement, along with the all electric solutions employed recently at Newfoundland Power.



Instrumentation

The following protection additions or enhancements to the existing system protection need to be addressed during a system refurbishment:

- Bearing thermocouples or RTDs
- Vibration Monitoring
- Oil level switches in the bearing pots
- Incorporate the six 10-ohm copper RTDs into the unit control PLc
- Incorporate speed switch

Bearing Cooling Water Control

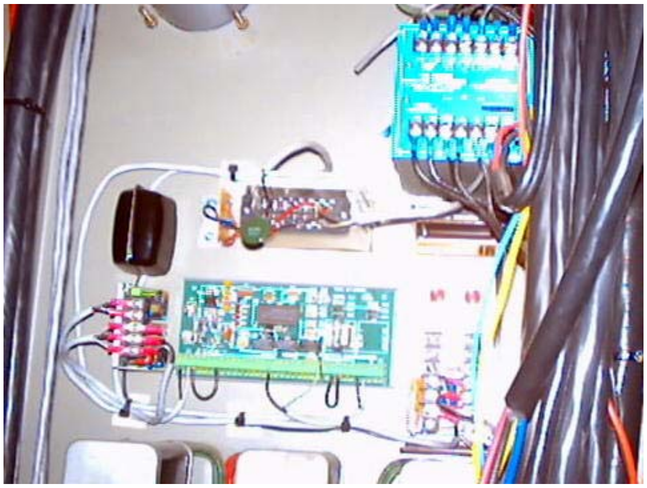
The existing bearings require water-cooling to ensure safe operating temperatures are maintained. There are valves and piping in place, however there is no automated control of these valves at present. Automating the bearing cooling system will ensure that problems are detected before damage is done to the bearings or shaft, thereby eliminating costly future repairs.

Heating and Ventilation

The existing louvers are not controlled. Unit heating and cooling should be incorporated into the unit control PLC.

Forebay Water Level Monitoring and Control

The existing water level probe and transducer are the older vintage Intertechnology equipment. The equipment is manufacturer discontinued and spare parts are no longer available. This equipment should be replaced with a new 4 to 20-milliamp water level transmitter and interfaced with the unit control PLC.



Associated Work

The T2 transformer and transmission line protection for 44L, 43L and 65L is provided by electromechanical relays. The control switches, relays and metering are spread out across the existing plant control panels. To provide sufficient space to install the new protection and control panels, these existing panels will have to be removed. Therefore, the existing transformer and transmission line protection will have to be addressed as part of this project. It is recommended that the substation design group consider replacement panels using the digital protective relays.

Also the existing control panels provide control switches for operating T1-A and T3-A from the plant control room. Control of these switches will have to be included with the T2 transformer protection panel.

Appendix B

Turbine Inspection

New Chelsea Plant
Turbine Inspection

Turbine Inspection

Technical Specifications

Size:	5600 Hp
Manufacturer:	Dominion Engineering Turbine
Date of manufacture:	1956
Serial Number:	816
Type:	Francis

Assessment

The unit was overhauled in 1985 replacing the runner, wicket gates, bushings, and both stationary seals. These components are in good condition with very little wear or evidence of impact damage to the exposed surfaces.

The runner is stainless steel welded construction. The elevation of the runner in the water passage is approximately 3/16” low however this has not caused any erosion to the runner components. See photo 2 - upper seal and runner.

Photo 1 – Wicket Gates

Photo 2 – Upper Seal &Runner

There are small cracks near the root of the weld on several of the runner blades to the inner band. These are most likely surface cracks and do not pose any immediate threat to the integrity of the runner. These will be checked during the next inspection.

The wicket gates are in good condition with very little wear on the sealing surfaces. The heel to toe clearance on the gates is excessive approximately 1/8” in the closed position.   This maybe corrected on the eccentrics. If not the gates will have to be repositioned and the gate arms re-doweled. See photo 1 - wicket gates and stay vanes.

Photo3 – Wicket Gate

The scroll case is in relatively good condition with no signs of major pitting or erosion of the base metal. No cracks in the casing sectional welds that were accessible for viewing. The stay vanes are in good condition with no signs of impact damage or major wear. See photo 3 and 5 - scroll case, wicket gate and stay vane.

Photo 4 – Main Valve

Photo 5 – Scroll Case

A full inspection of the main valve could not be completed due to leakage in the head gate that prohibited the opening of the valve. There is some erosion on the downstream side of the disc, a section approximately 3” in diameter and ¼” deep has delaminated from the base metal. See photo 4 of the Main Valve. The drive sleeve on the valve actuator was weld repaired this year, as replacement parts were unavailable from the manufacturer due to the vintage of the unit.

The pressure relief valve is original equipment and was overhauled in 1990 by Colonial Garage. The actuator cylinder was honed and a new ring installed on the piston to prevent governor oil from bypassing the piston, and migrating into the dashpot cavity causing the dashpot to overflow. The problem persisted and in 1994 a shutoff solenoid was installed in the oil line from the governor oil system to shutoff the supply oil when the valve fully closed.

The governor and control linkages were inspected for worn bushings and lost motion. The cross head on the dump valve connecting arm needs to be re-bushed to reduce the excessive play in the cross head. See photo 6 -Gate operating Arms and Dump valve.

Photo 6 – Gate Operator Arms

Photo 7 - Governor

There is a small amount of play in the governor-operating arm. The needle valve in the dashpot on the governor control head is worn and cannot be properly adjusted. See photo 7 - Governor. The manual gate limit adjustment is seized, and this is left at maximum or 100%.

The pumping unit is in relatively good condition, with no major oil leaks. The unit maintains proper operating pressure and accumulator air volume. The unit was recently fitted with new pressure switches and oil pump motor.

The air intake louver and exhaust fan are in a poor state of disrepair and will need to be replaced within the next couple of years. See photos below:

Photo 8 – Exhaust Fan

Photo 9 – Intake Louver

Recommendations

The scroll case vent and 4-way control valve needs to be replaced with an automatic float type vent, eliminating the need for separate control valves and electrics.

The wicket gates need to be closed up and re-doweled to reduce run down time on shutdown.

The stationary intake louvers and shutters need to be replaced with a motorized louver system. The control for the plant heating and ventilation should be incorporated into the PLC logic control for the plant. There are some concrete repairs required to the louver opening & sill plates.

The pressure release valve cross head needs to be re-bushed. The remaining linkages and bushings should be inspected when the unit is taken out of service next year.

The pressure release valve should be removed and a full internal inspection and any necessary repairs completed when the unit is taken out of service.

All the bearings should be removed and inspected during the overhaul.

The cooling water system is now fed from two 1 ½” Y type strainers, these should be changed to a more conventional duplex filter element system to permit replacement or cleaning of one filter without removing the unit from service.

All cooling water piping and cooling coils to be inspected tested and replaced if required during the overhaul. The upper and lower guide bearing cooling coils were replaced in 1998. The turbine bearing is water-jacketed and should be flushed and tested during the overhaul.

The slip rings and commutator should be inspected prior to shutdown machined and undercut if required.

The turbine shaft gland seal and shaft sleeve should be inspected during the overhaul.

Appendix C

Civil Works Site Assessment

NEW CHELSEA REFURBISHMENT PROJECT

SITE ASSESSMENT

Civil Works

Powerhouse

The powerhouse is in good condition. The exterior of the building and roof appear to be satisfactory. Some concrete repairs are required in the tailrace area at the water line. This area is susceptible to salt water spray and numerous freeze thaw cycles.


View of Back of Powerhouse


Piers in Tailrace Requiring Repairs

Dams

The dams are in fairly good shape. The forebay dam requires additional riprap in some areas and the spillway retaining wall at the end of the dam requires some concrete replacement.

Penstock

The New Chelsea penstock is comprised of 867 m of 1829 mm diameter woodstave and 240 m of 1524 mm diameter welded steel, with the lower 180 m being buried below ground.

The New Chelsea penstock has been in service for about 48 years. Based on previous penstock replacements the life of a woodstave penstock is in range the 45 - 50 years. The woodstave section of the New Chelsea penstock is in a similar condition of deterioration as the other woodstave penstocks that have been replaced by Newfoundland Power in the last five years. The life of a buried steel penstock should be greater than 50 years, however, recent inspections of the steel penstock have shown that this is not the case with the New Chelsea pipe. Both the woodstave and steel sections of the penstock are in poor condition and need to be replaced.

Woodstave Section

Section of Steel Penstock Half Buried

A recent inspection of the woodstave penstock indicates that the woodstaves continue to deteriorate. The majority of the woodstaves along the spring line are crushed and some are starting to bulge and feather around the steel rings. Numerous holes have been plugged in the penstock with wooden wedges (approximately 20,000) over the last few years and in the last year two major blowouts had to be repaired. Overall, the frequency of repairs has increased in recent years. There are three or four areas where large sections of woodstave have blown out and were repaired by bridging the missing woodstave with steel plate and gasket material.

Steel Plate Bridging Missing Woodstave

Crushed Woodstaves

Due to the excessive amount of leakage the bedding material below the penstock is saturated and drainage is poor. In some areas the timber cradles have settled into the bedding material and notable sags can be seen in the penstock alignment. In some areas the penstock is in contact with the ground. Several cradles are cracked and showing signs of failure. The operator reports that in recent years over 100 plates have been installed to repair cracked cradles.

Failed Cradle

Penstock in Contact with Ground

The exterior section of steel penstock that is above ground is in good condition for the age of the pipe. As the penstock enters the ground it was noted that the soil around the pipe has poor drainage with standing water around the pipe.

To assess the condition of the steel penstock an internal and external inspection of the buried pipe was conducted in June 2003 (for inspection results see Memorandum from Gary Murray to Gary Humby dated June 16, 2003). The internal inspection was conducted by FGA-CANSPEC and consisted of visual and ultrasonic testing to determine the wall thickness of the steel penstock. The inspection showed that the inside of the pipe was severely corroded and that the wall thickness is below the design requirement. The external inspection revealed that the pipe is also corroded on the outside, but to a much lesser extent than the inside of the pipe. The external inspection also showed that the backfill material is not free draining and in places the penstock is sitting in saturated backfill. The backfill material is not considered suitable for this type of installation.

In conclusion, the woodstave penstock has passed its reliable service life and needs to be replaced. It would have been expected that the steel penstock would be good for another 20-25 years, however, investigations reveal that the steel section has also deteriorated to a condition, where it must be replaced before reliability or failure become an issue. Based on the above the entire penstock should be replaced in the next year.

Appendix D

Steel Penstock Assessment

NEWFOUNDLAND POWER
A FORTIS COMPANY

June 16, 2003

Memorandum From: Gary L. Murray

To: Gary Humby

Subject: New Chelsea Rehabilitation Projects – Inspection of Steel Penstock

File: 401.01.03.23.00

As part of the study on the replacement of the New Chelsea Penstock we carried out an inspection of the existing steel penstock section. The purpose of the inspection was to determine the condition of the pipe and the amount of the steel wall (thickness) remaining.

The section of steel penstock at New Chelsea is approximately 240 m in length with about 60 m above ground and 180 m buried below ground. According to the original design drawings the wall thickness is 10 mm, except for the lower elbow at the powerhouse, which is 12mm.

On June 3, 2003 FGA-CANSPEC did an internal visual inspection of the penstock and ultrasonic testing to determine the wall thickness. A copy of their report is attached. In summary they inspected 60 m (200 ft) of pipe (30 m upstream of the access manhole and 30 m downstream of the manhole).

The inspection revealed that there is a 25 – 50 mm sludge adhered to the internal surface of the pipe. The sludge was removed at the locations where inspections were performed. Removal of the sludge revealed heavy pitting of the penstock wall in the range of 3 - 5 mm. Ultrasonic test measurements showed that the wall thickness ranged from 3 to 10 mm with the majority of the readings being well below the original design of 10 mm. The average thickness reading in the section below the manhole was 5.74 mm, and 4.43 mm above the manhole. The average reading of all measurements was 5.09 mm. Since the measurements were taken in the pitted areas the numbers have to be interpreted properly. The numbers should not be interpreted as saying that only half of the wall thickness is remaining. However, it would be fair to conclude that the penstock is severely corroded and that the integrity of the penstock is questionable.

The sludge growth and pitting was most evident on the internal surface of the pipe from the 2 –10 o'clock position (top of pipe being 12 o'clock). This would seem to indicate a link between the sludge and amount of corrosion. Based on current design requirements the design thickness of the penstock should be around 8 mm with a 2 mm allowance for corrosion. Based on these requirements it could be said that the penstock has deteriorated beyond its service life.

Based on the findings from the internal inspection we decided to perform an external inspection of the penstock by excavating test pits next to the penstock to observe the external condition of the pipe. This inspection was carried out on June 12, 2003. Three test pits were excavated along the penstock: 1) at the manhole; 2) 25 m downstream of the manhole; and 3) adjacent to the substation (about 40 m from the powerhouse).

At the first location the top of the pipe was at grade and the water table was 300 mm below grade. The fill around the penstock was a till material with a high clay content and some gravel and cobbles. The top half of the pipe showed signs of external corrosion with severe pitting. The bottom half of the pipe was in much better condition with some corrosion. Rusty water could be seen flowing below the penstock and quickly started to fill the excavation.

At the second location the top of the penstock was about 1.5 m below grade. The backfill material was similar with a little less clay content and more gravel. Similarly the top half of the pipe was corroded with less corrosion on the lower half. The water table was about 300 mm above the bottom of the pipe and water flowed freely from along the bottom of the pipe into the excavation.

At the third test pit the top of the pipe was at ground level. Corrosion was evident at the top half of the pipe, however the depth of the pitting was negligible. The backfill material around the pipe could be classified as a dirty gravel with a till material below the pipe. The water table was at the bottom of the pipe. As with the other locations, but to a lesser extent water was flowing along the bottom of the pipe.

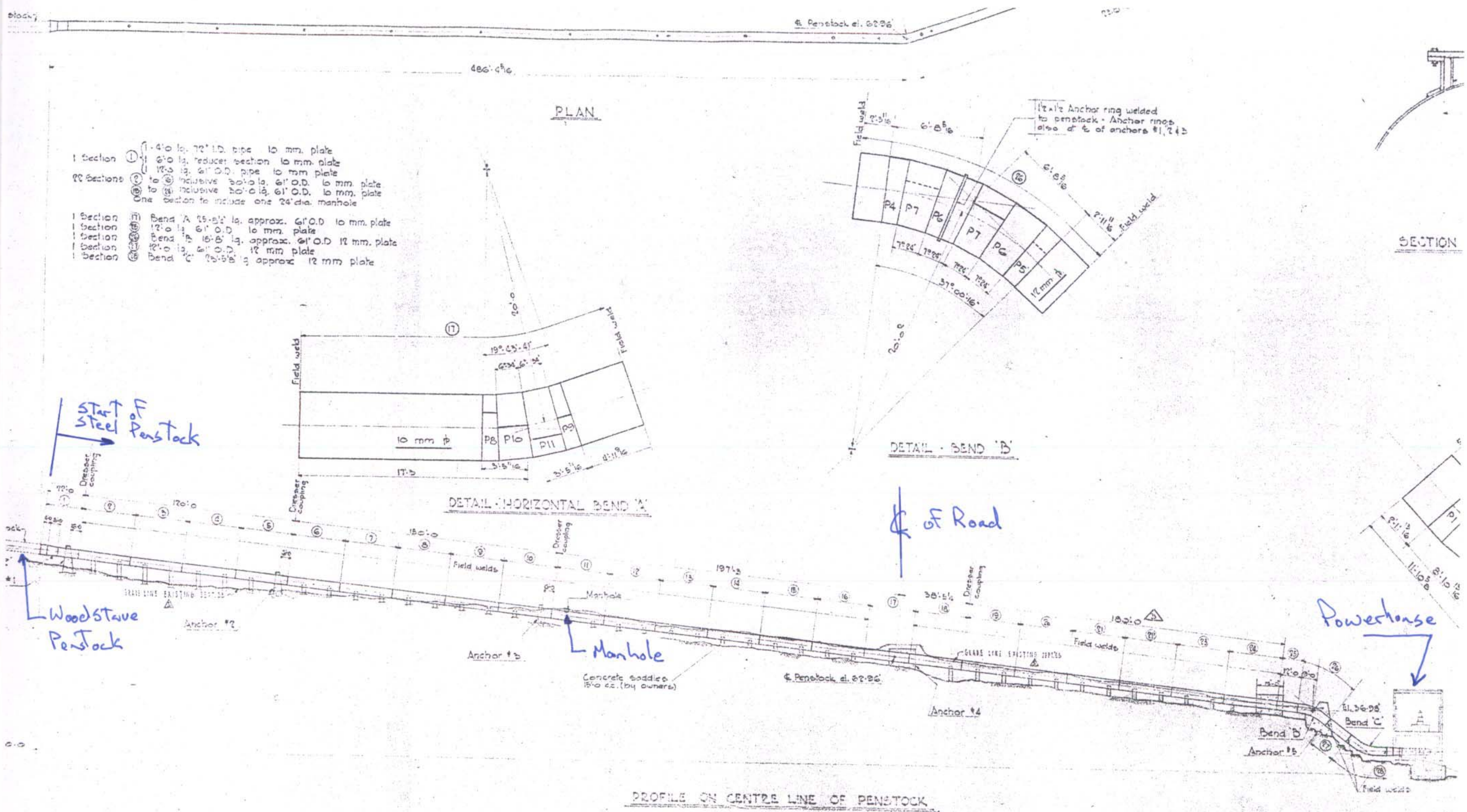
In conclusion, the internal and external inspection of the penstock revealed that the penstock is severely corroded and the thickness is below the design requirement. The deterioration of the pipe seems to be more from the internal corrosion rather than the external corrosion.

The penstock may very well be pitted completely through and leaking in some areas. With pressure rises in the pipe from normal and emergency shutdowns at the plant, penstock leakage and resulting erosion of the bedding material could become problems into the future. While a failure of the pipe is not a concern at this particular time the penstock has passed its reliable service life and should be replaced in the near future.

Based on the extent of internal bacterial growth and corrosion seen in the existing pipe consideration should be given to an internal coating on the new penstock pipe.

Regards,

Gary L. Murray, P. Eng.
Project Engineer



SPECIFICATIONS

The following codes for welding shall be adhered to.

C.S.A. W47. Welding qualifications.

C.S.A. W48 Electrodes.

A.S.M.E. Boiler construction code section VIII & IX Class 2 pressure vessels.

2-602-2

fga-CANSPEC
MATERIALS ENGINEERING AND TESTING

NEW CHELSEA PENSTOCK CORROSION INVESTIGATION

Prepared For:

Mr. Gary Murray
Newfoundland Power
St. John's, NL

fga-CANSPEC Project No. 330 24

June 11th, 2003

fga-CANSPEC
2 HUNTS LANE, ST. JOHN'S, NEWFOUNDLAND, CANADA • TELEPHONE (709) 753-2100 • FAX (709) 753-7011

fga - CANSPEC

June 3, 2003

NF Power

New Chelsea, NL

Internal/External Penstock Inspection

Approximately 200' of penstock at the New Chelsea NF Power site was inspected using ultrasonic and visual techniques. This yielded the following results:

Ultrasonic Thickness Readings in Millimeters

Location	1)	7.6	26)	6.9
	2)	10.7	27)	4.6
	3)	4.6	28)	4.0
	4)	4.5	29)	5.2
	5)	4.0	30)	3.8
	6)	6.8	31)	2.6
	7)	6.1	32)	5.6
	8)	8.7	33)	3.5
	9)	4.0	34)	4.7
	10)	6.8	35)	3.3
	11)	5.9	36)	3.3
	12)	4.8	37)	3.7
	13)	5.9	38)	2.7
	14)	5.0	39)	5.9
	15)	5.9	40)	3.5
	16)	4.1	41)	5.5
	17)	6.0	42)	7.6
	18)	6.0	43)	4.5
	19)	8.2	44)	3.1
	20)	5.8	45)	3.4
	21)	4.7	46)	6.4
	22)	6.1	47)	2.5
	23)	3.7	48)	5.5
	24)	3.0	49)	4.8
	25)	4.6	50)	4.2

fga - CANSPEC

General Site Findings:

Internal

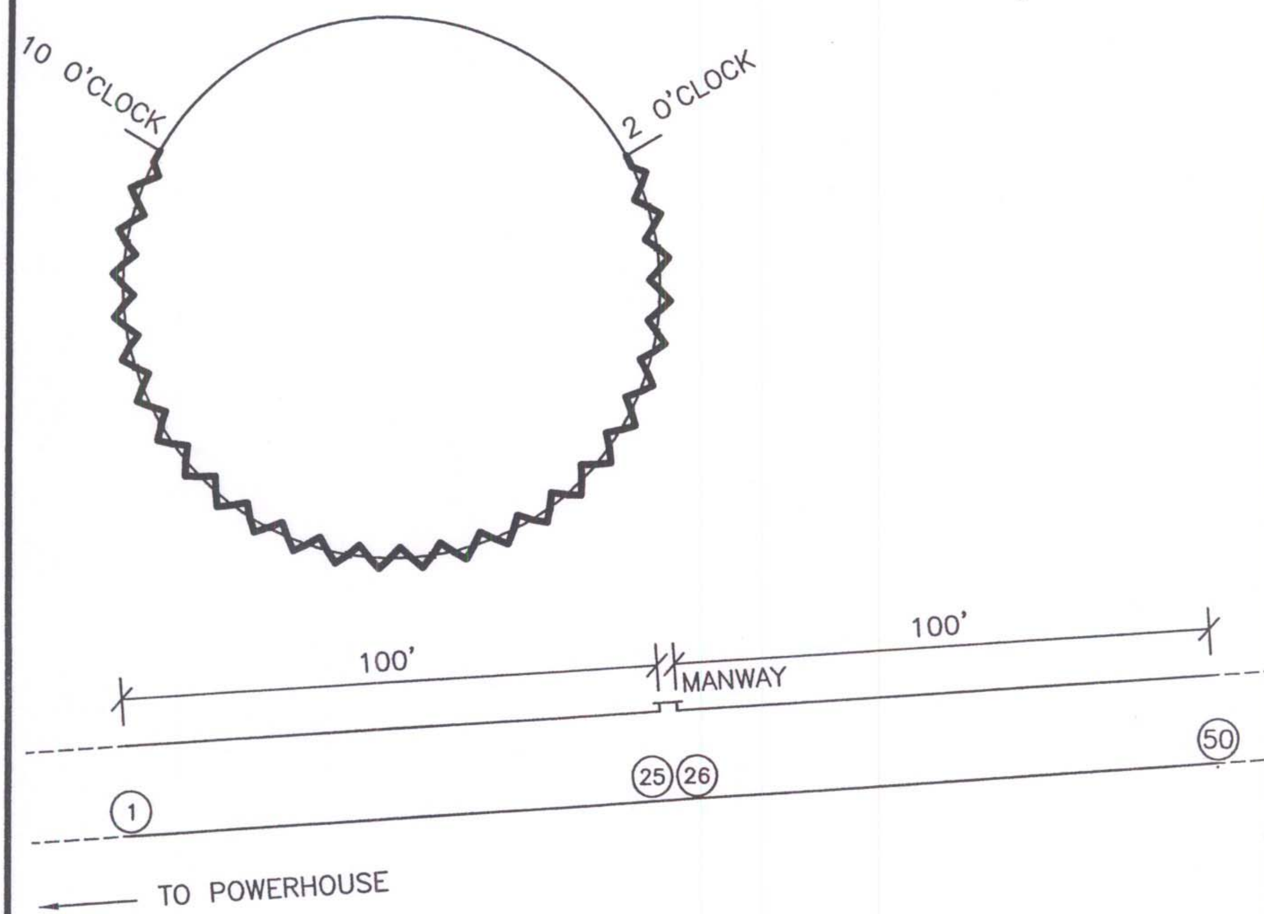
Severe corrosion/pitting was found internally. A 1.5' to 2" layer of sludge had to be removed to facilitate inspection at the fifty (50) UT points listed on Page 1. Beneath all cleaned areas severe pitting was found. Pit depths ranged from 1/8" to 3/16". These values would not be reflected within the UT readings of Page 1.

All inspected welds exhibited preferential weld attack. This form of corrosion appears to have originated in original weld flaw (porosity holes) and has now expanded to affect the weld integrity.

External

The New Chelsea site has seen tremendous vegetation growth over the buried section of penstock. This type of growth is evidence of a moist/oxidized soil which will accelerate corrosion of the external surface. There were also two streams identified as running over and under the penstock. External surfaces were not made available for inspection but the variation in UT thickness values on Page 1 are indicative of a corroded external profile.

AREAS AT 2 O'CLOCK TO 10 O'CLOCK
POSITION VERY HEAVILY CORRODED/PITTED.



NOTE:
ULTRASONIC/VISUALS WERE APPROXIMATELY 4' APART.

TITLE				
NEWFOUNDLAND POWER NEW CHELSEA PENSTOCK				
JOB No.	DWG. No.	REV. No.	SCALE	DATE
330–24	SK1	A	N.T.S.	03.06.11 YY.MM.DD

jga - CANSPEC
MATERIALS ENGINEERING & TESTING
2 Hunt's Lane, St. John's, Nfld. A1B 2L3
Tel: (709) 753–2100 / Fax: (709) 753–7011

Pitting on Inside Surface of Manhole Cover

Growth on Internal Surface of Penstock

Penstock at Test Pit #1

Penstock at Test Pit #2

Penstock at Test Pit #3

Appendix E

Feasibility Analysis

NEWFOUNDLAND POWER
A FORTIS COMPANY

June 25, 2003

Memorandum From: Gary L. Murray

To: Gary Humby

Subject: New Chelsea Rehabilitation Projects – Feasibility Analysis

File: 401.01.03.23.00

We have completed a feasibility analysis on the continued operation of the New Chelsea hydroelectric development. Several major components of the development are in need of replacement or refurbishment, including the penstock, governor, protection & controls, main inlet valve, and generator. With substantial investment required in the near-term to permit the continued reliable operation of this plant, an economic analysis of this development over a 25-year horizon was warranted. A summary of the costs and benefits associated with this analysis follows.

Capital Costs

All significant capital expenditures foreseen for the hydroelectric development over the next 25 years have been identified. The majority of these expenditures are currently planned for 2004. The expenditures required to maintain the safe and reliable operation of the facilities are summarized below. A complete breakdown of capital costs and operating costs are provided in Schedule "A".

Description	Cost (2004 $)	Year of Expenditure	Cost (Escalated 1.7% Per Year)
Penstock Replacement - Woodstave	$1,735,000	2004	$1,735,600
Penstock Replacement - Steel	$500,000	2004	$500,000
Forebay Dam Rehab	$30,000	2004	$30,000
Electrical, Protection & Controls	$972,000	2004	$972,000
Main Inlet Valve Repalcement	$150,000	2004	$150,00
Refurbish Runner & Wicket Gates	$23,000	2004	$23,000
Generator Rewind	$400,000	2004	$400,000
Substation Modifications	$163,000	2004	$163,000
Intake Concrete Rehab	$50,000	2010	$55,300
Powerhouse Roof Replacement	$50,000	2010	$55,300
Spillway Concrete Rehab	$30,000	2010	$33,200
Transformer Replacement	$250,000	2024	$350,200
TOTAL	**$4,353,000**		**$4,467,600**

The total capital expenditure of all of the projects listed above is $4,353,000 (in 2004 dollar values). All estimates are also shown as escalated values using an assumed escalation rate of 1.7%.

Operating Costs

Operating costs for this hydroelectric system were based primarily upon recent years' operating experience. These costs represent both direct charges for operations and maintenance at this plant as well as indirect costs related to activities associated with managing the environment, safety, dam safety inspections, staff training, etc.

In addition to inflationary adjustments, operating costs are also increased by $0.50 per horsepower year water usage charges. This fee is paid annually to the Provincial Department of Environment (Water Resources Division) based on yearly hydroplant generation/output. Such a charge is not reflected in the historical annual operating costs for the New Chelsea development. Therefore, an adjustment is applied to account for this operating expense.

Penstock maintenance has accounted for a significant portion of the operating costs of this plant in recent years. Future operating cost has been estimated to include an assumed reduction of $5,000 per year to reflect the penstock replacement.

Benefits

The estimated long-term normal production at this plant under present operating conditions is 15.6 GWh/yr. This estimate is based on the results of the Water Management Study completed by Acres International Limited in December 2000. With an assumed station service adjustment of 0.1 GWh/yr, the normal plant output is estimated at 15.5 GWh/yr.

Some of the capital improvement projects will result in decreased energy losses (such as leakage from the woodstave penstock and less head losses in the new steel pipe) and subsequent increases in capacity and generation. The magnitude of these increases is difficult to estimate, but are not significant, so no allowance has been made for any increase in the forecasted generation at New Chelsea.

The downtime associated with the 2004 capital works at this plant will result in a higher amount of spill at the forebay compared to a normal operating year. It is anticipated that the potential lost generation may be in the order of 0.5 GWh. Therefore, the analysis assumed production at New Chelsea of 15.0 GWh in 2004, and 15.5 GWh/yr thereafter.

Financial Analysis

An overall financial analysis of combined costs and benefits has been completed using the levelized cost of energy approach. The levelized cost of energy is representative of the revenue requirement required to support the combined capital and operating costs associated with the development.

The estimated levelized cost of energy from the New Chelsea plant over the next 25 years is 3.19 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. For comparative purposes the levelized cost was also calculated over 40 years and found to be 3.17 cents per kWh. The levelized cost of energy from New Chelsea can be produced at a lower price than the cost of replacement energy, assumed to come from Hydro's Holyrood Generating Station. Using Hydro's short term price forecast and an assumed fuel price escalation rate of 2% in the longer term, incremental energy from the Holyrood Generating Station is estimated to cost 5.53 cents per kWh, levelized over the same 25 year period. Energy from New Chelsea plant also compares favourably with 5.86 cents per kWh (2002 dollars) for the Rose Blanche Brook development and with marginal energy values implied by recent contracts entered into by Hydro with non-utility generators.

The future capacity benefits of the continued availability of New Chelsea hydro plant have not been considered in this analysis. In addition, decommissioning costs would be associated with any decision to shut down this facility and the financial benefit associated with the deferral of these costs has not been factored into this analysis.

Conclusions

It is concluded that operation of the New Chelsea hydroelectric development is economically viable over the long term. Based on the results of this feasibility analysis, it is recommended that the rehabilitation work proposed at New Chelsea for 2004 proceed as planned.

Schedule A
Summary of Capital Costs and Operating Costs

CAPITAL COSTS

Description	Cost (2004 $)	Year of Expenditure	Cost (Escalated 1.7% Per Year)
Civil			
Penstock Replacement - Woodstave	$1,735,000	2004	$1,735,600
Penstock Replacement - Steel	$500,000	2004	$500,000
Forebay Dam Rehab	$30,000	2004	$30,000
Intake Concrete Rehab	$50,000	2010	$55,300
Powerhouse Roof Replacement	$50,000	2010	$55,300
Spillway Concrete Rehab	$30,000	2010	$33,200
Subtotal Civil	**$2,395,000**		**$2,409,400**
Mech/Elec			
Governor/Protection & Controls	$972,000	2004	$972,000
Main Inlet Valve Repalcement	$150,000	2004	$150,000
Refurbish Runner & Wicket Gates	$23,000	2004	$23,000
Generator Rewind	$400,000	2004	$400,000
Substation Modifications	$163,000	2004	$163,000
Transformer Replacement	$250,000	2024	$350,200
Subtotal Mech/Elec	**$1,958,000**		**$2,058,200**
TOTAL	**$4,353,000**		**$4,467,600**

		Hydro 4% CCA	Hydro 30% CCA	Hydro TOTAL
0	2004	$2,238,000	$1,735,000	$3,973,000
1	2005			
2	2006			
3	2007			
4	2008			
5	2009			
6	2010	$143,800		$143,800
7	2011			
8	2012			
9	2013			
10	2014			
11	2015			
12	2016			
13	2017			
14	2018			
15	2019			
16	2020			
17	2021			
18	2022			
19	2023			
20	2024	$350,200		$350,200
21	2025			
22	2026			
23	2027			
24	2028			
25	2029			
	TOTAL	**$2,755,900**	**$1,735,000**	**$4,467,600**

OPERATING COSTS

Year	Amount
1989	$93,887
1990	$135,654
1991	$92,686
1992	$81,721
1993	$89,374
1994	$92,907
1995	$92,057
1996	$87,252
1997	$85,037
1998	$70,794
1999	$56,762
2000	$86,593
2001	$61,128
Average	$86,604

1989 to 2001 Average Operating Cost =	**$86,600**
Water Use Charges =	**$1,700**
Reduced Future Penstock Maintenance =	**$5,000** (-ve)
Total Annual Operating Cost =	**$83,300**

Appendix F

Budget Estimate

2004 Capital Budget Estimates

Description	Cost Estimate ($1,000s)
Penstock	$ 2,235,000.00
Forebay Dam Rehabilitation	$ 30,000.00
Electrical, Protection & Control	$ 972,000.00
Main Inlet Valve	$ 150,000.00
Refurbish Runner & Wicket Gates	$ 23,000.00
Rewind Generator	$ 400,000.00
Substation Modifications	$ 163,000.00
Total	**$ 3,973,000.00**

Project Title: **Rebuild Substations**

Location: **Grand Bay, Trepassey, Indian Cove, Port Blandford, Wheelers, Laurentian, Bay Roberts and Stamps Lane**

Classification: **Substations**

Project Cost: **$1,023,000**

This project consists of a number of items as noted.

(a) Grand Bay Site Modifications

Cost: $145,000

Description: This project involves enlarging the substation to provide the proper clearances for the new 2.5 MW portable diesel generator being acquired in 2003.

Operating Experience: There are presently 2 mobile diesel generators at Grand Bay substation, which are being retired in 2003. A new 2.5 MW unit being acquired in 2003 will be installed in their place and will provide additional backup generation for the area.

Justification: The overall project is justified based on improvement in the reliability of the electrical system.

(b) Trepassey Site Modifications

Cost: $145,000

Description: This project involves enlarging the substation to provide the proper clearances. This is required to accommodate the existing portable gas turbine (during emergencies) as well as for the new portable diesel generator unit to be acquired in 2004. See Volume I, Energy Supply, Schedule B, page 14, for more information on the new portable diesel generator unit.

Operating Experience: Trepassey has a peak load of approximately 3.3 MW and is supplied over a long radial transmission (95L). The new portable diesel generator unit has a capacity of 2.5 MW and can carry approximately 75 % of peak load. With 95L out of service power could be restored to Trepassey with little or no power rationing.

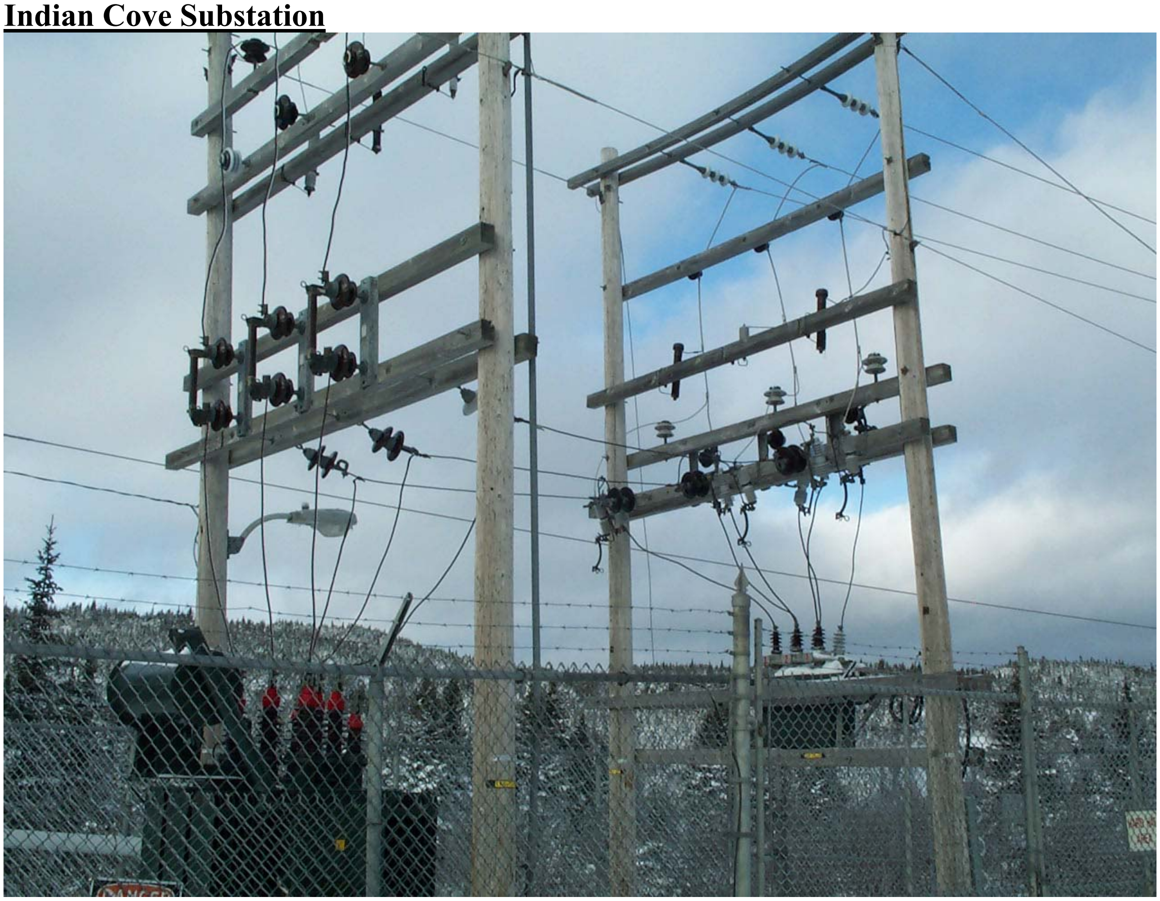
Justification: The overall project is justified based on improvement in the reliability of the electrical system.

(c) Indian Cove - Upgrade Structure / Transformer

Cost: $138,000

Description: This project involves replacing the 45 year old deteriorated 1.8 MVA, 25 kV to 12.5 kV stepdown transformer and structure at Indian Cove substation and to make improvements to the substation.

Indian Cove Substation



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Operating Experience: Inspections have indicated that the power transformer and structure have deteriorated to the point of requiring replacement.

Justification: Due to equipment deterioration, there is a risk of power outages and oil spills.

(d) Port Blandford - Replace 138 kV Switches

Cost: $217,000

Description: Replace PBD-124-A6 and PBD-124L-A7 switches and structures with new switches and low profile steel structure. A 138kv dead-end structure will be placed in front of each switch location, and new switches will be installed on low profile steel structure.

Operating Experience: The two existing switches are under-built on wood pole structures and were placed in service in 1990. The switches are in constant need of adjustment due to the movement of the wood pole structures each time the switches are opened or closed. There have been occasions when the switches failed to properly break the electrical arc that occurs during switching, which has the potential to cause a fault on the transmission line. This in turn results in unplanned outages to customers and creates a safety hazard for the employees who operate the switches.

The switches are now tagged as “Out of Service” and will only be operated by first removing the power from 124L.

Port Blandford Switch

Justification: Improve reliability to customers when switching sections of 124L out of service for maintenance.

(e) Wheelers – Re-terminate Line

Cost: $85,000

Description: Install a new dead-end structure for 404L inside Wheelers substation, reterminate 404L to the existing airbreak switch 404L-A and install protective relaying at Gallants and Stephenville substations.

Operating Experience: Wheelers (WHE) is a deteriorated and obsolete substation that is past its useful life. The retermination of 404L along with changes to system protection at Gallants and Stephenville substations will allow the decommissioning of this station without compromising reliability or system performance.

Justification: Replacement of deteriorated substation and associated obsolete equipment. This will reduce maintenance costs and provide a more straightforward operating arrangement.

(f) Stamps' Lane - Power Cable Replacement

Cost: $95,000

Description: This project involves the replacement of power cables supplying T1 and T2 transformers.

Operating Experience: The cables at Stamps Lane substation were installed in 1958. These oil-insulated cables supply the 4 kV transformers.

In 2002, while maintaining the transformers, staff found that the cable terminations were leaking insulating compound and the metal bodies of the terminations were cracked. Maintenance staff determined that these cables are too deteriorated to allow the installation of new terminations. While neither cable has failed to date, this is most likely due to the low system voltage. Deterioration will continue and the cables will ultimately fail.

Justification: Replacement of deteriorated equipment to prevent outages to customers.

(g) Stamps Lane, Bay Roberts and Laurentian – Site and Foundation Upgrades

Cost: $120,000

Description: This work involves rectifying deteriorated concrete foundations, inadequate drainage and security/safety issues.

Operating Experience: The major item for this project in 2004 is the replacement and refurbishment work required at Stamps Lane and Bay Roberts in response to SGE Acres 2002 report on the condition of all substation concrete installations. In addition to these locations, work will be undertaken at the Laurentian substation yard to address drainage issues.

Justification: Structural and equipment concrete foundations/pads in many substations have deteriorated over time. There is varying degrees of deterioration evident within many substations. SGE Acres inspected all concrete installations in every substation and produced a prioritized list of installations which require replacement or refurbishment. The underlying causes of the deterioration are:

- Natural actions, such as freeze-thaw, thermal movement and shrinkage cracking.
- Mechanical damage such as impact or abrasion
- Chemical damage such as carbonation, sulphate attack and alkai-aggregate reactions.

The SGE Acres report details the deterioration and the type of remediation work required in each substation. The SGE Acres report was previously filed in response to Request for Information CA-20 (b), Attachment F in the Newfoundland Power 2003 Capital Budget Application.

(h) Projects < $50,000

The following is a list of projects estimated at less than $50,000.

1. Wesleyville – replace feeder disconnect switches
2. Glendale – replace underground cable with overhead conductor
3. Old Perlican – rectify safety clearance related to regulators
4. Trepassey – rectify safety clearance related to regulators
5. Long Lake – rectify safety clearance related to regulators

Project Title: **Replacement & Standby Substation Equipment**

Location: **Pepperell, Summerford, Milton, Bonavista, Glenwood, Boyd's Cove, Glovertown, Gambo, Laurentian, Gillams, Dunville, Cape Broyle, Greenhill and Mobile Substation P-435**

Classification: **Substations**

Project Cost: **$1,314,000**

This project consists of a number of items as noted.

(a) Deteriorated Breaker/Recloser Replacement

Cost: $300,000

Description: This project is part of an ongoing program to replace circuit breakers and reclosers that are deteriorated beyond economical repair.

In 2004 the 66 kV breaker at Pepperell and the 66 kV breaker at Summerford will be replaced.

Operating Experience: The Pepperell unit is 51 years old and its mechanism doesn't operate fast enough for the criteria required in the "Critical Clearing Time Study". It cannot be repaired due to the unavailability of parts. The Summerford unit is approximately 37 years old and its control circuitry does not operate consistently to ensure safe operation of the electrical system. The manufacturer's estimated cost to correct this problem is approximately equal to the cost of a new breaker.

Justification: This project is justified based on the need to replace equipment to maintain reliable and safe operation of the electrical system.

(b) Corporate Spares & Replacements

Cost: $600,000

Description: Purchase equipment to be used for corporate spares.

For 2004, the budgeted figure includes:

1 – 66 kV Circuit Breaker
1 – 15/25 kV Circuit Breaker
1 – 25 kV Electronic Recloser
3 – 138 kV Potential Transformers
3 – 66 kV Potential Transformers
3 – 15/25 kV Potential Transformers
3 – 15/25 kV 100 amp Voltage Regulators
9 – 15/25 kV 200 amp Voltage Regulators
10 – Universal Regulator Controls and Enclosures
1 – Model 210C Remote Telemetry Unit
2 – Transducers
4 – 48 Volt Battery Banks
1 – 120 Volt Battery Bank
3 – 48 Volt Battery Chargers
2 – 120 Volt Battery Chargers

This equipment is required to either replace equipment that fails in the field or to return corporate spares to appropriate levels.

Operating Experience: Every year the Company retires equipment due to vandalism, storm damage, lightning strikes, electrical or mechanical failure, corrosion damage, technical obsolescence, failure during maintenance testing, excessive maintenance costs, etc. This equipment is essential to the integrity and reliability of the electrical supply to our customers and as such, the Company has to be able to replace "failed" equipment in a timely manner. Based on past operating experience, the above list is representative of what will need to be replaced in a typical year.

Justification: This project is justified on the basis of reliability in that this equipment is necessary to maintain service in a reliable, safe, environmentally sound manner. The following provides details on the major components to be acquired in 2004.

Circuit Breakers:

Newfoundland Power has approximately 400 circuit breakers in service. Breakers are used to switch transmission lines, transformers, feeders, generators and other equipment on and off the electrical system. In conjunction with protective relaying, they are used to isolate electrical faults. The majority of breakers are either transmission breakers (138 or 66 kV) or distribution breakers (typically 15 or 25 kV). The remainder are required in generation stations. The older breakers are often oil-filled and represent an environmental risk. By the nature of their operation, breakers will deteriorate and even though they are maintained, unexpected failures can occur.

Based on past experience, the Company maintains a pool of spare breakers to respond to these failures. This pool normally contains one 138 kV, two 66 kV and two 25 kV breakers. The 25 kV units can be installed in either 15 or 25 kV installations, thereby reducing the number of spares required. Based upon past experience and existing quantities in the pool, the budget includes purchases to allow for response to operational situations.

Electronic Reclosers:

The Company has approximately 200 reclosers in service. Reclosers allow switching of rural feeders, which carry lighter loads and have smaller electrical fault levels than urban feeders. They have built-in control units that sense electrical faults and operate the recloser to de-energize the feeder in the event of a fault.

The Company's older reclosers can be divided into four basic types – hydraulic, relay, resistor, and electronic, depending upon controller. The ability to isolate an electrical fault and their operational functionality increases in the order they are listed above. Therefore, as the electrical system has evolved, the units with lower functionality have fewer places where they can be installed.

Reclosers are replaced due to electrical/mechanical failure; severe physical deterioration; inability to provide adequate protection to a growing electrical system; and, parts obsolescence. In order to respond to these situations, the Company maintains a pool of spare reclosers. Based upon past experience and existing quantities in the pool, the budget includes purchases to allow for effective response to operational situations. The purchased unit will be an oil free, low maintenance and digitally controlled so that it is capable of replacing any other recloser and being integrated in to the SCADA system if the opportunity exists.

Potential Transformers (PTs):

The Company has approximately 220 PTs in-service. They measure voltage levels for input to protective relays, the SCADA system and metering circuitry. Failure of this equipment compromises the reliable operation of the electrical system. A failure can endanger staff and require clean up of a large area as oil can be sprayed over a 25 to 35 meter area. Each year unexpected PT replacements are required due to in-service failures. Based upon past experience and existing quantities in the pool, the budget includes purchases to allow for response to operational situations. Normally new units will be a *dry-type* design, eliminating the environmental risk associated with the older oil-filled units.

Voltage Regulators:

The Company has approximately 340 voltage regulators in service. These regulators are normally used to control voltages on long rural feeders.

The control units on voltage regulators have a service life of approximately 20 years. If they fail in service, the regulator becomes non-functional. These control units utilize obsolete electronic components and cannot be repaired. A universal replacement control unit enables the extension of the life of an older regulator for about 15% of the cost of a new regulator. These new control units are in stainless steel enclosures, thereby reducing corrosion. As well, they add increased functionality to the existing equipment, such as reverse power flow capability, more accurate voltage control and optional remote control capability. Based upon past experience and existing quantities, the budget number of 10 control units allows for the expected failure rate in the coming year.

The budget also includes replacement voltage regulators. These units are to replace units recently scrapped. The replacements will maintain the pool of spare voltage regulators at a level sufficient to respond to operational situations and maintenance programs. The new units can operate at 15 or 25 kV, allowing a reduction in the size of the pool. They also have stainless steel cases to reduce future corrosion related failures.

Direct Current Electrical Supply Systems (Batteries and Battery Chargers):

The substation DC power supplies provide electricity for equipment like protective relays, circuit breakers and reclosers, as well as provide emergency substation lighting.

The use of advanced battery testing methods has allowed the Company to adopt an approach whereby battery banks are replaced only when problems to a majority of batteries in the bank occur. Based upon past experience, the budget includes an allocation to replace battery banks as required.

Battery chargers are low maintenance, long life devices. The Company maintains a small pool of units to allow prompt replacement of failed units so as to ensure the security of its direct current electrical supplies. The units in the budget will allow for unexpected failures of battery chargers.

(c) Non-PCB Environmental Initiative

Cost: $175,000

Description: This is a long term program to replace equipment in substations which contain more than 50 PPM of PCB. This project will replace equipment such as substation service transformers, metering tanks and potential transformers. Often to accomplish the replacements, a portable substation will have to be installed.

In 2004, work will occur in Milton, Bonavista, Glenwood, Boyd's Cove and Glovertown substations.

Operating Experience: The Company has a large quantity of oil filled electrical equipment. Due to cross contamination, mineral oil in distribution transformers and other electrical equipment was inadvertently contaminated with PCB's at the manufacturing plant. Years ago transformer manufacturers used the same hoses and pumps to fill electrical equipment with PCB's and mineral oil. This resulted in some pieces of oil filled electrical equipment having 50 ppm PCB's or more. In other cases some equipment such as capacitors and ballasts were manufactured with pure PCB's.

The Company may experience spills from oil filled electrical equipment due to a number of reasons including rust, lightning, mechanical damage, storms, and human error. In the event of a spill, PCB's may be involved.

PCB spills can result in significant clean up costs. The general public and the environmental regulators also view PCB spills very negatively.

Justification: PCB's are synthetic chemical compounds consisting of chlorine, carbon and hydrogen. First synthesized in 1881, PCB's are relatively fire-resistant, very stable, do not conduct electricity and have low volatility at normal temperatures. PCB's were used for insulating fluid for electrical equipment, surface coatings for carbonless copy paper, as plasticizers in sealants, caulking, paints, waxes, asphalts, etc.

Unfortunately, one of the properties of PCB's which most contribute to their widespread use – their chemical stability – is also one of the properties which causes the greatest amount of environmental concern. This unusual persistence coupled with its tendency to accumulate in living organisms, means that PCB's are stored and concentrated in the environment. This bioaccumulation raises concern because of the wide dispersal of PCB's in the environment and the potential adverse effects they can have on various organisms. When PCB's are involved in fires the combustion of these materials can result in the production of highly toxic substances.

As a result of these concerns Government placed a ban on the manufacturing of PCB's in the late 1970's with further regulations established in the early 1980's. Under the regulations PCB's removed from equipment must be properly stored and disposed of in accordance with the regulations. There is also a requirement to report PCB spills, if one or more of the following conditions apply:

- The PCB concentration is 50 parts per million (ppm) or more by weight
- The quantity of PCB's released is 1 gram or more per day.

In the late 1980's the Company started to remove PCB's from its system and in the early 1990's a PCB phase out plan was implemented to ensure that the PCB level in equipment was below the permitted level of 50 ppm.

(d) Deteriorated Potential Transformer (PT) Replacement

Cost: $140,000

Description: This project involves the replacement of deteriorated high voltage potential transformers (PT) that are attached to substation high voltage buses. These units provide voltage level inputs into protective relaying, SCADA system and metering circuitry.

In 2004, three 66 kV PTs will be replaced in both Laurentian and Greenhill substations. The original PTs were installed in these substations in 1975.

Operating Experience: The amount of oil in a PT is small. Therefore any oil loss may compromise the insulation integrity of the PT and result in its failure. In the marine environment, to which substation equipment is exposed, rusting of metal components and subsequent loss of oil is an on-going issue. Since the beginning of 2001, twelve PTs, at five locations, were replaced due to rusting and oil leakage.

Greenhill and Laurentian substations have PTs from the same manufacturer. Several years ago, a PT failed in Laurentian due to the rusting of its top cover and water entering the PT. Also a PT in Greenhill had to be replaced due to rusting. The top covers of the other PTs in Greenhill and Laurentian were patched. Maintenance personnel are now concerned with the integrity of the patches and the likelihood of failure of those PTs.

Justification: PTs provide voltage level inputs for protective relaying, SCADA system and metering circuitry. Failure of these critical pieces of equipment compromises the safe operation of the electrical system.

(e) Recording Voltmeter Replacement

Cost: $59,000

Description: This project involves the replacement of recording broken voltmeters at Gillams, Dunville and Cape Broyle.

Operating Experience: The existing recording voltmeter has deteriorated beyond repair.

Justification: To properly manage the power system and to address voltage quality concerns monitoring of the low voltage bus is required. The recording voltmeter will provide this information to Newfoundland Power.

(f) Project < $50,000

The following project is estimated at less than $50,000.

1. Purchase a tandem axle dolley for use in transporting portable substation number P-435.

Project Title: **Feeder Additions Due To Load Growth and Reliability**

Location: **Chamberlains and Pulpit Rock Substations**

Classification: **Substations**

Project Cost: **$200,000**

This project consists of a number of items as noted.

(a) Chamberlains – Terminate New Feeder

Cost: $106,000

Description: This project involves the substation work associated with the construction of a distribution feeder from Chamberlains substation on Fowlers Road. The new feeder will run south along Fowler's Road to the Conception Bay South bypass road (CBS) then west along the CBS to the intersection of Dunn's Hill Road and along Dunn's Hill Road for approximately 1 km. The project also includes the transfer of approximately 4.5 MVA of load from the Kelligrews substation to the Chamberlains substation.

Operating Experience: Load and customer growth in the Conception Bay South area is causing certain electrical system parameters to exceed recommended guidelines.

Justification: An engineering study, *"Conception Bay South – Planning Study"* indicates that this proposal is the low cost alternative to maintain electrical system parameters within recommended guidelines in this area. (See Volume III, Distribution, Appendix 4, Attachment A)

(b) Pulpit Rock – Terminate New Feeder

Cost: $94,000

Description: This project involves the substation work associated with the construction of a distribution feeder from Pulpit Rock substation in Torbay, along Country Drive and Manning's Hill to Torbay Road.

Operating Experience: Load growth in the Torbay area as well, the extended length of the feeder is a contributing factor to the inferior service reliability in the Torbay, Flatrock and Pouch Cove area.

Justification: An engineering review, *"Pulpit Rock Substation, Loading and Reliability Review"* indicates that this project is the low cost alternative to address growth and reliability issues in this area. (See Volume III, Distribution, Appendix 3, Attachment C)

Project Title: **Increase Corner Brook Transformer Capacity**

Location: **Walbournes and Bayview**

Classification: **Substations**

Project Cost: **$1,184,000**

(a) Walbournes – Replace T2

Description: Replace WAL-T2 transformer in Walbournes substation with a 25 MVA transformer. The existing 15 MVA unit will be removed and installed at Bayview substation.

Operating Experience: There are presently two power transformers at Walbournes substation and one power transformer at Bayview. WAL-T1 (20 MVA) is presently loaded to 95% of its capacity and WAL-T2 (15 MVA) is loaded to 111% of its capacity. The Bayview transformer is loaded to 110% of its capacity. The life expectancy of these units can be significantly reduced by continuous overloads.

The most cost effective solution is to replace the 15 MVA Walbournes unit (WAL-T2) with a 25 MVA transformer. The 15 MVA unit from Walbournes transformer will then be moved to the Bayview substation, where it will be installed as a second transformer. This transformer will reduce the loading on the existing unit, and allow sufficient capacity for load growth.

Justification: Two of the three transformers in these substations are presently overloaded. The life expectancy of these units can be significantly reduced by continuous overloads. A failure of one of these units would have a serious impact on reliability in the area.

Loss of the transformer at Bayview would mean an extended outage to all customers served from this substation. A portable transformer would have to be placed at Bayview until a suitable replacement unit can be obtained.

Loss of the overloaded unit at Walbournes would mean extended power outages in the form of power rationing for most customers served from this substation. The remaining unit would not have enough spare capacity to supply power to all customers. Power rationing would continue until a portable transformer could be installed to replace the failed unit. The portable would have to remain there until a suitable replacement unit can be obtained.
A copy of a planning study outlining the various alternatives and corrective action is contained in Volume II, Substations, Appendix 4, Attachment A.

Power Transformer Study

City of Corner Brook

Newfoundland Power Inc.

Power Transformer Study – Corner Brook

Introduction

The purpose of this report is to provide a plan to meet the increasing electrical demand in the City of Corner Brook through increasing the City's limited substation transformer capacity. The 2003 Substation Load Forecast indicates that the total 12.5 kV load in the city will exceed the total 12.5 kV substation transformer capacity in 2004.

This study projects the electrical demands for the City of Corner Brook, develops alternatives to meet these demands, ensuring they meet minimum technical criteria. Further, an economic analysis for each alternative establishes the relative ranking of the alternatives with respect to customer revenue requirement. In conclusion the study recommends a preferred alternative.

Description of Existing System

Within the City of Corner Brook there are 3 substations: Bayview, Humber and Walbournes. These substations are supplied through 66 kV transmission lines from the Hydro in-feed substation at Massey Drive. Each substation has power transformers with a total of 5 among them. With the exception of replacements due to failure, the last new transformer was installed in 1977.

The power transformers are as follows:

Bayview Substation (BVS Sub)

- BVS-T1, 20 MVA, 12.5 kV, Installed in 1977

Walbournes Substation (WAL Sub)

- WAL-T1, 20 MVA, 12.5 kV, Installed in 1976
- WAL-T2, 15 MVA, 12.5 kV Installed in 1969

Humber Substation (HUM Sub)

- HUM-T2, 7.5 MVA, 4.16 kV, Installed in 1982
- HUM-T3, 13.3 MVA, 12.5 kV, Installed in 1974

HUM-T2 is a 4.16 kV unit and services 3 – 4.16 kV feeders within the city. Since there is no capacity constraint with respect to these 4.16

kV feeders, there is no plan to add 4.16 kV transformer capacity or to convert these feeders to 12.5 kV. These loads and the associated 4.16 kV transformer capacity are not included in the study.

The distribution system inside the city limits makes it possible to interconnect substations to avoid power outages by transferring loads between substations. In the past this has been used to limit outages to customers for planned work and major problems with the system. The distribution system also permits a second point of supply for critical customers like Western Memorial Regional Hospital. Since some power transformers will reach full capacity before others, these interconnecting feeders are used to manage the load until it rises to the total substation transformer capacity within the city.

A schematic diagram of the transmission and distribution systems supplying the area is shown in Figure 1.

Load Forecast and Growth Projections

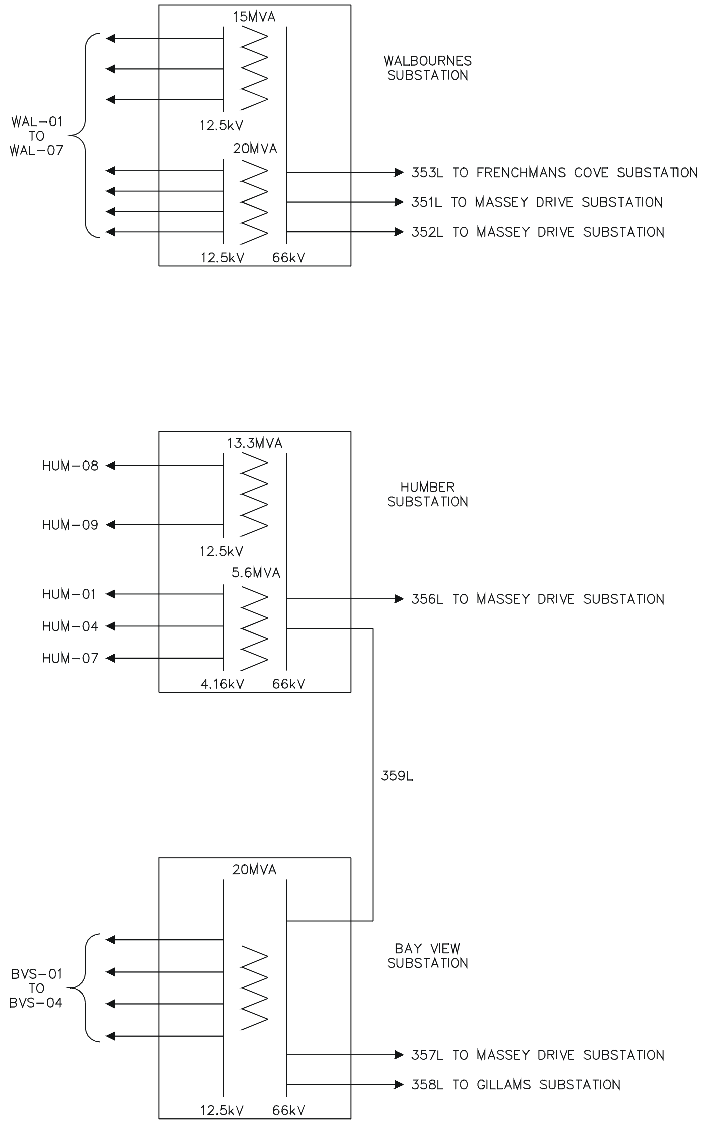
This study uses a 20-year Load Forecast for the power transformers within the city. The percent growth used is a combination of the "2003 Substation 5 Year Forecast" and guidance from the Director, Forecast within the Finance department. Appendix A, Page 1, contains a copy of the 5 Year Substation Forecast for the Corner Brook Area. Appendix A, Page 2, contains the 20-year load growth used in this study. Detailed load forecasts for each substation are also noted in Appendix B as part of the description of each alternative.

Development of Alternatives

Technical Criteria

The following technical criteria were considered pertinent to this study and to ensure acceptable operating conditions for the Corner Brook system:

1. The minimum steady state feeder voltage should not fall below 116 volts on a 120-volt base.



NEWFOUNDLAND POWER A FORTIS COMPANY	CORNER BROOK 2003 POWER SYSTEM			
	FIGURE 1			
	Scale: N.T.S.	Drawn: 03.06.09	DWG. NO.	
	Date: 03.07.03	App:		

2. The steady state power transformer loading should not exceed the nameplate rating.
3. The recloser normal peak loading should be sufficient to permit adequate cold load pickup.
4. the conductor loading should not exceed the ampacity rating established in the distribution planning guidelines.

Planning methodology and the Development of Alternatives

The planning methodology is the process whereby the forecasted electrical demands are serviced through developing alternatives that meet the technical criteria. These alternatives are then evaluated using economic analysis and other judgment factors. Based on this analysis a preferred alternative is recommended. As the load forecast extended to 2022, capital additions are projected over the same period.

In reviewing the substation load forecasts and comparing them to the associated substation transformer capacities, it is apparent that 12.5 kV substation transformer capacity will be exceeded in Corner Brook in 2004. Prior to considering alternatives to add transformer capacity, every effort was made to transfer load between substations and utilize whatever remaining capacity there might be at any substation. However, once the total load for the city's 12.5 kV feeders exceeds the capacity of the 12.5 KV transformer, there are no further options other than to add capacity. From the "2003 5 Year Substation Load Forecast", the total load within the city in 2004 will be 68.4 MVA while the total capacity is 68.3 MVA.

Three alternatives were developed that initially add 12.5 kV transformer capacity among the three Corner Brook substations. Each of the three alternatives uses a different location to add 2004 transformer capacity to the system. Using the load forecast, the load at each substation is established for a 20-year period. Effort is made to delay any additional transformers by using a combination of load transfers, additional feeders and down line equipment such as regulators. With increasing loads, as technical constraints are encountered in each alternative, projects are established to continue customer service and permit operation within the technical criteria.

Each alternative contains estimates for all costs involved including transformers, new feeders and load transfers. A present value calculation is provided for each alternative.

Alternative #1 - Install a new unit at Bayview Substation in 2004

Alternative #1 is the addition of a second, 25 MVA transformer at Bayview Substation in 2004 and an additional 25 MVA transformer at Walbournes in 2009. Feeder upgrades, transfers and additions are made when necessary.

Alternative # 1	**Cost**	**Year**
Add 25 MVA transformer at Baview / Load Transfers to Bayview from Walbournes & Humber / Feeder Upgrades	1,028,000	2004
Replace Walbournes T2 with 25 MVA Transformer	835,000	2009
Transfer Load from Walbounes to Humber & Upgrade Feeder	90,000	2010
Install New Feeder at Bayview	295,000	2012
Install New Feeder at Bayview with load transfers from Walbournes to Humber and Humber to Bayview	395,000	2019
Total Capital Cost	**2,643,000**	

Alternative #2 - Replace one of the existing units at Walbournes Substation and move it to Bayview in 2004

Alternative #2 is the replacement of one of the existing power transformers at Walbournes Substation in 2004 with a new 25 MVA unit. However, due to limits on the amount of load that can be transferred between Walbournes and Bayview, it is necessary to install additional capacity at Bayview. Accordingly, the unit removed from Walbournes will be installed in Bayview as BVS-T2 in 2004 to meet this requirement. The next transformer addition occurs in 2018 with an additional 25 MVA installed at Humber. Feeder upgrades, transfers and additions are made when necessary.

Alternative # 2	Cost	Year
Replace Walbournes T2 with a 25 MVA Transformer / Install transformer removed from Walbournes at Bayview	1,025,000	2004
Transfer Load from Humber to Bayview	15,000	2009
Transfer Load from Walbournes T1 to T2 and Feeder Upgrading	90,000	2010
Install New Feeder Bayview and feeder upgrading	295,000	2013
Replace Humber T3 with 25 MVA Transformer / Install New Feeder Humber / Transfer Load Walbournes to Humber	1,130,000	2018
Total Capital Cost	**2,555,000**	

Alternative #3 - Replace the existing transformer at Humber Substation in 2004

Alternative #3 is the replacement in 2004 of the existing 12.5 kV 13.3 MVA power transformer at Humber Substation with a new 25 MVA unit. In 2008 the 12.5 kV 15 MVA transformer at Humber is replaced with a 25 MVA transformer and in 2010 an additional 25 MVA transformer is added at Bayview . Feeder upgrades, transfers and additions are made when necessary. This option has the greatest overall substation transformer capacity at the end of the 20-year study.

Alternative # 3	Cost	Year
Replace Humber T3 with a 25 MVA transformer / Install New Feeder from Humber towards Bayview / Transfer load from Walbournes and Bayview to Humber	1,130,000	2004
Replace Walbournes T2 with 25 MVA Transformer	835,000	2008
Transfer Load from Walbournes T1 to T2 and upgrade feeders	90,000	2010
Install Additional 25 MVA Transformer at Bayview	780,000	2012
Install New feeder at Bayview / transfer load from Humber to Bayview / Upgrade feeders	295,000	2018
Total Capital Cost	**3,130,000**	

Economic Analysis

In order to compare the customer economic impact of the alternatives, a net present value calculation of customer revenue requirement was completed for each alternative. Capital costs from 2004 to 2022 were converted to revenue requirement and the resulting customer revenue requirement from 2004 to 2042 was reduced to a net present value using the corporate weighted average incremental cost of capital. The result for each alternative is indicated in the following table. The detail of the projects associated with each alternative and the net present value calculations for each alternatives are shown in Appendix B.

In comparing the alternatives, all of which meet the technical criteria, alternative #2 is the lowest cost.

Alternative	Net Present Value Revenue Requirement ($)
1	2,312,236
2	2,034,380
3	2,465,195

Economic Analysis – Adjusting For Unequal Transformer Capacity at Study End

Alternative #3 results in the largest overall transformer capacity existing in the study's last year. An analysis was completed to force all alternatives to have the same capacity in year 20. To complete this analysis, the cost of a power transformer was added in year 20 of the study to the other alternatives. This analysis is summarized in the following table, which indicates that alternative #2 again has the least present worth cost. The details of this analysis are contained in Appendix C, Economic Analysis – Adjusting For Unequal Transformer Capacity at Study End.

Alternative	Net Present Value Revenue Requirement ($)
1	2,550,948
2	2,273,092
3	2,465,195

Conclusions and Recommendations

A 20-year load forecast has projected the electrical demands for the City of Corner Brook. The development and analysis of alternatives has established a preferred expansion plan to meet these needs. A further analysis has confirmed the validity of this alternative in adjusting the analysis for the unequal transformer capacity in the study's last year.

The lowest cost alternative that meets all of the technical criteria is alternative #2. It includes the 2004 replacement of the existing unit, Walbournes WAL-T2 transformer, with a new 25 MVA unit and moving the existing WAL-T2 unit to Bayview Substation in 2004. This scenario increases the transformer capacity of both substations. This alternative has the least present value costs, adds capacity in the known load growth areas and meets the technical criteria. It is therefore the preferred and recommended alternative.

Appendix A

Load Forecast

Western Region - Corner Brook Area
2003 Five Year Forecast

Substation (Notes)	Operating Des.	Transformer Voltage (kV)	Capacity (MVA) Rating	Capacity (MVA) Existing	2002 Peak (MVA)	Forecasted Undiversified Peak (MVA) 2003	2004	2005	2006	2007	2008	Max. Xfmr. Util.
Howley	T2	4.16	2.5/3.3/4	4.0	0.4	0.5	0.5	0.5	0.5	0.5	0.5	13%
Deer Lake	T1	12.47	10/13.3/16.7	16.7	15.0	15.6	15.3	15.4	15.5	15.5	15.6	94%
Marble Mountain	T1	12.47	3/4	4.0	3.0	3.3	3.2	3.1	3.2	3.2	3.2	83%
Pasadena	T1	12.47	10/13.3	13.3	7.3	8.7	8.6	8.8	8.9	9.0	9.1	69%
Bayview (3, 4 & 5)	T1	12.47	15/20	45.0	19.9	22.0	25.9	25.6	25.8	27.4	27.9	62%
Frenchmans Cove	T1	12.47	5/6.67	6.7	4.4	4.7	4.9	4.8	4.8	4.9	5.0	75%
Gillams	T1	12.47	5/6.67	6.7	4.6	5.0	5.1	5.1	5.1	5.2	5.3	79%
Humber	T2	4.16	5.6/7.46	7.5	5.0	5.4	5.5	5.5	5.5	5.6	5.7	76%
Humber	T3	12.47	10/13.3	13.3	10.9	11.8	12.1	12.0	12.1	12.3	12.5	94%
Walbournes	T1	12.47	15/20	20.0	16.1	17.9	18.4	18.1	18.3	18.6	19.0	95%
Walbournes (4 & 5)	T2	12.47	11.25/15	15.0	**15.0**	**16.6**	14.0	14.2	14.6	14.1	14.7	**111%**
TOTAL					**101.6**	**111.6**	**113.6**	**113.1**	**114.3**	**116.5**	**118.7**	

Notes:

(1) Substation forecast based on 2002 to 2007 energy forecast released Feb 4, 2003.
(2) 2008 data is based on the same load growth experienced in 2007.
(3) 2004 Additional 25MVA Transformer installed at Bayview.
(4) 2004 - 3MVA of load transferred from WAL-06 to BAY-04.
(5) 2007 - 1MVA of load transferred from WAL-06 to BAY-04.

Load Growth per Year
Forecasted Undiversified Peak

Year	Growth
2003	1.106
2004	1.030
2005	0.993
2006	1.012
2007	1.024
2008	1.024
2009	1.023
2010	1.022
2011	1.021
2012	1.020
2013	1.019
2014	1.018
2015	1.017
2016	1.016
2017	1.015
2018	1.015
2019	1.014
2020	1.013
2021	1.012
2022	1.011
2023	1.010

2003 to 2008 - 2003 5 year Substation Load Forecast
2009 to 2023 - Load growth in 2023 to be 1%. All other years prorated to this

Appendix B

Economic Analysis

APPENDIX B - ECONOMIC ALTERNATIVES – INTRODUCTION

For each of the three alternatives there follows a detailed listing of capital and operating expenditures. The reasons for each of these expenditures are noted and related to technical criteria or other requirements for expenditures to be made.

Following the detailed listing of capital and operating expenditures is a one page present worth economic analysis using the revenue requirement or customer cash flow methodology. Each capital cost is converted to a multi year stream of capital related revenue requirements extending over the life of the asset. Operating costs are also added to achieve the overall revenue requirement for each alternative in every year. This multi year revenue requirement is then discounted to the present using the average incremental cost of capital. It is this present worth amount for each alternative that is brought forward to the economic analysis section of the report's body.

One item of note in the present worth analysis sheets is the Deferment Benefits column. When an alterative indicates that a substation transformer is to be removed from the Corner Brook system, it is still of value to the Newfoundland Power electrical system. Its remaining life will be utilized in another substation. It is therefore important that when the transformer is shown as removed from an alternative, that the alternative be credited with the value of the remaining life of that transformer. The Deferment Benefit reflects the value of this remaining life.

Alternative #1 - Install New Unit at Bayview Substation in 2004

Transformer	BVS-T1		BVS-T2		HUM-T3		WAL-T1		WAL-T2		Capital Cost per Year in 2003 dollars	Extra Maint Cost per Year 2003 dollars (6)	Notes
Size (MVA)	20.0		25.0		13.3		20.0		15.0	25.0			
	Load	Util	Load	Util	Load	Util	Load	Util	Load	Util			
2002 Peak	19.9	99.5%	0.0	0.0%	10.9	82.0%	16.1	80.5%	15.0	100.0%			
2003	22.0	110.0%	0.0	0.0%	12.1	90.6%	17.8	89.0%	16.6	110.6%			
2004	13.1	65.4%	13.1	52.3%	11.9	89.6%	18.3	91.7%	14.1	93.9%	1,028,000.00	600.00	(1)
2005	13.0	64.9%	13.0	52.0%	11.8	88.9%	18.2	91.0%	14.0	93.2%		600.00	
2006	13.1	65.7%	13.1	52.6%	12.0	90.0%	18.4	92.1%	14.2	94.3%		1796.00	
2007	13.5	67.3%	13.5	53.8%	12.3	92.1%	18.9	94.3%	14.5	96.6%		600.00	
2008	13.8	68.9%	13.8	55.1%	12.5	94.3%	19.3	96.5%	14.8	98.8%		600.00	
2009	14.1	70.4%	14.1	56.3%	12.8	96.4%	19.7	98.7%	15.2	60.6%	835,000.00	1796.00	(2)
2010	14.4	71.9%	14.4	57.6%	10.1	76.0%	17.2	85.8%	21.5	86.0%	90,000.00	600.00	(3)
2011	14.7	73.4%	14.7	58.8%	10.3	77.6%	17.5	87.6%	21.9	87.8%		600.00	
2012	15.0	74.9%	15.0	59.9%	10.5	79.1%	17.9	89.4%	22.4	89.5%	295,000.00	1796.00	(4)
2013	15.3	76.3%	15.3	61.1%	10.7	80.6%	18.2	91.1%	22.8	91.2%		600.00	
2014	15.5	77.7%	15.5	62.2%	10.9	82.1%	18.5	92.7%	23.2	92.9%		600.00	
2015	15.8	79.1%	15.8	63.2%	11.1	83.5%	18.9	94.3%	23.6	94.5%		8036.00	
2016	16.1	80.3%	16.1	64.3%	11.3	84.8%	19.2	95.9%	24.0	96.0%		600.00	
2017	16.3	81.6%	16.3	65.3%	11.5	86.1%	19.5	97.3%	24.4	97.5%		600.00	
2018	16.6	82.8%	16.6	66.2%	11.6	87.4%	19.8	98.8%	24.7	98.9%		1796.00	
2019	18.8	93.9%	18.8	75.1%	11.8	88.6%	18.0	90.1%	23.1	92.2%	395,000.00	600.00	(5)
2020	19.0	95.1%	19.0	76.1%	11.9	89.7%	18.2	91.2%	23.4	93.4%		600.00	
2021	19.2	96.2%	19.2	77.0%	12.1	90.8%	18.5	92.3%	23.6	94.5%		1796.00	
2022	19.5	97.3%	19.5	77.8%	12.2	91.8%	18.7	93.3%	23.9	95.5%		600.00	
2023	19.6	98.2%	19.6	78.6%	12.3	92.7%	18.9	94.3%	24.1	96.5%		600.00	

Notes:

(1) 2004 Load Changes

Additional 25 MVA Transformer installed at Bayview. (impedance match)		780,000.00
3 Mva transferred from WAL-T2 to BVS-T1		
0.5 MVA transferred from HUM-T3 to BVS-T1		
Upgrade the BVS-04 U/G Crossing at Confederation Drive.		65,000.00
Reconductor 6 spans along Golf Course,		5,000.00
Reframe pole O'Connell and West Valley,		8,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
Install 1 – 1 Phase Regulator for Gallants line BVS-04		40,000.00
Install 1 – 3 Phase Regulator in Park		115,000.00
	Total for 2004	1,028,000.00

(2) 2009 Load Changes

Replace WAL-T2 with 25 MVA transformer, Replace Cables	835,000.00

	Total for 2009	835,000.00
(3) 2010 Load Changes		
Replace WAL-03 Cables		75,000.00
3 Mva Transferred from WAL-T1 to WAL-T2		
3 Mva Transferred From HUM-T3 to WAL-T2		
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
	Total for 2010	90,000.00
(4) 2012 Load Changes		
Install New Feeder BVS and Extend Bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
	Total for 2012	295,000.00
(5) 2019 Load changes:		
Build new feeder from BVS 12.5 bus - extend 12.5 kv bus		380,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering $15,000		15,000.00
4 MVA transferred from HUM-T3 to BVS		
2 MVA transferred from WAL-T2 to HUM-T3		
2 MVA transferred from WAL-T1 to HUM-T3		
	Total for 2019	395,000.00

(6) Additional Maintenance Cost per extra Transformer
$600 per year - Oil Testing
One Maint III every two years - 2 man crew - 2 Days - $1196
One Maint IV every ten years - 3 man crew - 5 Days plus material - $7436

Reasoning

(1) Transfer WAL-06 up to and including Canada Games Centre
This transfer would offload the upper section of HUM-09. BVS-02 would feed through the cable at CNIB to the McPherson Hgts area. BVS-04 would need an aerial route to the golf course, along with the other items indicated to allow it to feed this load. This will load BVS-04 to 7 MVA and put the University and Canada Games Centre at risk of outages caused on the long Rural section of BVS-04.

(2) Without Transformer Changeout WAL-T2 would be at 101.1% in this year

(3) Necessary to Transfer Load to WAL-T2
Without Transfer, WAL-T1 would be at 100.8% in 2010
Without Transfer, HUM-T3 would be at 100.6% in 2011

(4) Necessary for loading at BVS. Without the new feeder, we would have 30 MVA on 4 feeders.

(5) Without Transformer Changeout / Transfer WAL-T2 would be at 101.1% in this year, WAL-T2 would be at 100.2%
This feeder would have to be Double Circuit through the town. It would pick up some load
from HUM-09 and HUM-09 would pick up load from WAL-T2 and WAL-T1.

(6) Based on current practices and pricing

Based on matched impedance Transformer at BVS in 2004

Spare Capacity			
Year	**Available**	**Used**	**Spare**
2002 Peak	68.3	61.9	6.4
2003	68.3	68.4	-0.1
2004	93.3	70.5	22.8
2005	93.3	70.0	23.3
2006	93.3	70.8	22.5
2007	93.3	72.5	20.8
2008	93.3	74.2	19.1
2009	93.3	75.9	17.4
2010	103.3	77.5	25.8
2011	103.3	79.2	24.1
2012	103.3	80.7	22.6
2013	103.3	82.3	21.0
2014	103.3	83.8	19.5
2015	103.3	85.2	18.1
2016	103.3	86.6	16.7
2017	103.3	87.9	15.4
2018	103.3	89.2	14.1
2019	103.3	90.4	12.9
2020	103.3	91.6	11.7
2021	103.3	92.6	10.7
2022	103.3	93.7	9.6
2023	103.3	94.6	8.7

Present Worth Analysis Alternative #1 (Install New BVS-T2)

Weighted Average Incremental Cost of Capital 8.52%
Escalation Rate 1.70%
PW Year 2003

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Generation Thermal 25.58 yrs 4% CCA	Generation Hydro 49.26 yrs 4% CCA	Generation Thermal 25.51 yrs 30% CCA	Generation Hydro 49.26 yrs 30% CCA	Transmission 30.6 yrs 4% CCA	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Telecommunication 15.0 yrs 20% CCA	Capital Revenue Requirement	Present Operating Costs	Escalated Operating Costs	Operating Benefits	Deferment Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2004						1,045,476			144,849	600	610	0		-145,460	-134,039	-134,039
2005									131,029	600	621	0		-131,650	-111,790	-245,829
2006									128,901	1,796	1,889	0		-130,790	-102,340	-348,169
2007									126,737	600	642	0		-127,379	-91,845	-440,014
2008									124,539	600	653	0		-125,192	-83,181	-523,196
2009						923,873			250,310	1,796	1,987	0	203,991	-48,306	-29,576	-552,772
2010						101,272			249,867	600	675	0		-250,542	-141,355	-694,127
2011									244,355	600	687	0		-245,042	-127,398	-821,525
2012						343,329			287,484	1,796	2,090	0		-289,575	-138,731	-960,256
2013									278,446	600	710	0		-279,156	-123,239	-1,083,495
2014									273,189	600	722	0		-273,911	-111,430	-1,194,925
2015									267,863	8,036	9,838	0		-277,701	-104,102	-1,299,027
2016									262,473	600	747	0		-263,220	-90,927	-1,389,954
2017									257,020	600	760	0		-257,780	-82,056	-1,472,010
2018									251,507	1,796	2,313	0		-253,820	-74,452	-1,546,463
2019						517,288			317,606	600	786	0		-318,392	-86,061	-1,632,523
2020									305,142	600	799	0		-305,942	-76,203	-1,708,726
2021									298,410	1,796	2,433	0		-300,843	-69,050	-1,777,776
2022									291,610	600	827	0		-292,436	-61,851	-1,839,627
2023									284,743	600	841	0		-285,584	-55,659	-1,895,286
2024									277,814	1,796	2,559	0		-280,373	-50,354	-1,945,640
2025									270,824	600	869	0		-271,694	-44,964	-1,990,604
2026									263,776	600	884	0		-264,660	-40,361	-2,030,965
2027									256,672	8,036	12,043	0		-268,716	-37,762	-2,068,727
2028									249,515	600	914	0		-250,429	-32,430	-2,101,157
2029									242,306	600	930	0		-243,236	-29,025	-2,130,182
2030									235,048	1,796	2,831	0		-237,879	-26,157	-2,156,339
2031									227,742	600	962	0		-228,704	-23,174	-2,179,513
2032									220,391	600	978	0		-221,370	-20,670	-2,200,183
2033									212,997	1,796	2,978	0		-215,975	-18,583	-2,218,766
2034									205,560	600	1,012	0		-206,572	-16,378	-2,235,144
2035									198,083	600	1,029	0		-199,112	-14,547	-2,249,691
2036									190,567	1,796	3,133	0		-193,700	-13,041	-2,262,732
2037									183,015	600	1,064	0		-184,079	-11,420	-2,274,152
2038									175,426	600	1,082	0		-176,509	-10,091	-2,284,243
2039									167,804	8,036	14,743	0		-182,547	-9,617	-2,293,860
2040									160,149	600	1,120	0		-161,268	-7,829	-2,301,688
2041									152,462	600	1,139	0		-153,600	-6,871	-2,308,559
2042									85,722	1,796	3,466	0		-89,188	-3,676	-2,312,236

Alternative #2 - Replace Walbournes T2 with 25 MVA Transformer

Transformer	BVS-T1		BVS-T2		HUM-T3		WAL-T1		WAL-T2		Capitial Cost per Year in 2003 dollars	Extra Maint Cost per Year 2003 dollars (6)	Notes
Size (MVA)	20.0		15.0		13.3	25.0	20.0		15.0	25.0			
	Load	Util	Load	Util	Load	Util	Load	Util	Load	Util			
2002 Peak	19.9	99.5%	0.0	0.0%	10.9	82.0%	16.1	80.5%	15.0	100.0%			
2003	13.2	66.0%	8.8	58.7%	12.1	90.6%	17.8	89.0%	16.6	110.6%			
2004	13.6	68.0%	9.1	60.4%	12.4	93.3%	18.3	91.7%	17.1	68.3%	1,025,000.00	600.00	(1)
2005	13.5	67.5%	9.0	60.0%	12.3	92.7%	18.2	91.0%	17.0	67.8%		600.00	
2006	13.7	68.3%	9.1	60.7%	12.5	93.8%	18.4	92.1%	17.2	68.7%		1796.00	
2007	14.0	69.9%	9.3	62.2%	12.8	96.0%	18.9	94.3%	17.6	70.3%		600.00	
2008	14.3	71.6%	9.5	63.6%	13.1	98.3%	19.3	96.5%	18.0	71.9%		600.00	
2009	15.8	79.2%	10.6	70.4%	11.4	85.4%	19.7	98.7%	18.4	73.6%	15,000.00	1796.00	(2)
2010	16.2	80.9%	10.8	71.9%	11.6	87.3%	17.2	85.8%	21.8	87.2%	90,000.00	600.00	(3)
2011	16.5	82.6%	11.0	73.4%	11.9	89.1%	17.5	87.6%	22.2	89.0%		600.00	
2012	16.8	84.2%	11.2	74.9%	12.1	90.9%	17.9	89.4%	22.7	90.7%		1796.00	
2013	17.2	85.8%	11.4	76.3%	12.3	92.6%	18.2	91.1%	23.1	92.5%	295,000.00	600.00	(4)
2014	17.5	87.4%	11.7	77.7%	12.5	94.3%	18.5	92.7%	23.5	94.2%		600.00	
2015	17.8	88.9%	11.9	79.0%	12.8	95.9%	18.9	94.3%	23.9	95.8%		8036.00	
2016	18.1	90.4%	12.0	80.3%	13.0	97.5%	19.2	95.9%	24.3	97.3%		600.00	
2017	18.4	91.8%	12.2	81.6%	13.2	99.0%	19.5	97.3%	24.7	98.8%		600.00	
2018	18.6	93.1%	12.4	82.7%	18.4	73.4%	17.3	86.3%	22.6	90.3%	1,130,000.00	1796.00	(5)
2019	18.9	94.4%	12.6	83.9%	18.6	74.4%	17.5	87.4%	22.9	91.5%		600.00	
2020	19.1	95.6%	12.7	84.9%	18.8	75.4%	17.7	88.5%	23.2	92.7%		600.00	
2021	19.3	96.7%	12.9	85.9%	19.1	76.3%	17.9	89.6%	23.4	93.8%		1796.00	
2022	19.5	97.7%	13.0	86.9%	19.3	77.1%	18.1	90.6%	23.7	94.8%		600.00	
2023	19.7	98.7%	13.2	87.7%	19.5	77.9%	18.3	91.5%	23.9	95.7%		600.00	

Notes:

(1) 2004 Load Changes

Replace WAL-T2 with 25 MVA unit, Replace WAL-T2 Cables		835,000.00
Install WAL-T2 (Existing) at BVS		190,000.00
	Total for 2004	1,025,000.00

(2) 2009 Load Changes:

Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
2 MVA from HUM-T3 to BVS		
	Total for 2009	15,000.00

(3) 2010 Load Changes:

Replacement of Cable WAL-03 - $75,000		75,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
4 MVA from WAL-T1 to WAL-T2		
	Total for 2010	90,000.00

(4) 2013 Load Changes

Install New Feeder BVS and Extend Bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
	Total for 2013	295,000.00

(5) 2018 Load changes:

Replace HUM-T3 with 25 MVA unit, replace cables		835,000.00
Build new feeder from HUM 12.5 bus - extend 12.5 kv bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering $15,000		15,000.00
2.5 MVA transferred from WAL-T2 to HUM-T3		
2.5 MVA transferred from WAL-T1 to HUM-T3		
	Total for 2018	1,130,000.00

(6) Additional Maintanance Cost per extra Transformer

$600 per year - Oil Testing
One Maint III every two years - 2 man crew - 2 Days - $1196
One Maint IV every ten years - 3 man crew - 5 Days plus material - $7436

Reasoning

(1) Without transfer, both BVS-T1 and WAL-T2 would be over 100%

(2) Without Load transfer HUM-T3 will be at 100.5%

(3) Without Load transfer WAL-T1 will be at 100.8%

(4) Necessary for loading at BVS. Without the new feeder, we would have 28.6 MVA on 4 feeders.

(5) Because of the load sharing on the BVS XFMRs, there is no extra capacity at BVS. HUM-T3 will be replaced. If transfers are not complete - HUM-T3, 100.4% in 2018, WAL-T1 100.1% in 2019, WAL-T2 100.3% in 2018. New feeder required to handle load.

(6) Based on current practices and pricing

Based on Transformer to replace WAL-T2 in 2004
Installing WAL-T2 as BVS-T2 in 2004

Year	Spare Capacity Available	Used	Spare
2002 Peak	68.3	61.9	6.4
2003	68.3	68.4	-0.1
2004	93.3	70.5	22.8
2005	93.3	70.0	23.3
2006	93.3	70.8	22.5
2007	93.3	72.5	20.8
2008	93.3	74.2	19.1
2009	93.3	75.9	17.4
2010	93.3	77.5	15.8
2011	93.3	79.2	14.1
2012	93.3	80.7	12.6
2013	93.3	82.3	11.0
2014	93.3	83.8	9.5
2015	93.3	85.2	8.1
2016	93.3	86.6	6.7
2017	93.3	87.9	5.4
2018	105.0	89.2	15.8
2019	105.0	90.4	14.6
2020	105.0	91.6	13.4
2021	105.0	92.6	12.4
2022	105.0	93.7	11.3
2023	105.0	94.6	10.4

Present Worth Analysis - Alternative #2 (Replace WAL-T2 with 25MVA)

Weighted Average Incremental Cost of Capital 8.52%
Escalation Rate 1.70%
PW Year 2003

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Generation Thermal 25.58 yrs 4% CCA	Generation Hydro 49.26 yrs 4% CCA	Generation Thermal 25.51 yrs 30% CCA	Generation Hydro 49.26 yrs 30% CCA	Transmission 30.6 yrs 4% CCA	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Telecommunication 15.0 yrs 20% CCA	Capital Revenue Requirement	Present Operating Costs	Escalated Operating Costs	Operating Benefits	Deferment Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2004						1,042,425			144,427	600	610	0		-145,037	-133,650	-133,650
2005									130,647	600	621	0		-131,268	-111,465	-245,115
2006									128,525	1,796	1,889	0		-130,414	-102,045	-347,160
2007									126,367	600	642	0		-127,009	-91,579	-438,739
2008									124,175	600	653	0		-124,828	-82,940	-521,679
2009						16,597			124,251	1,796	1,987	0		-126,238	-77,292	-598,970
2010						101,272			135,808	600	675	0		-136,483	-77,003	-675,974
2011									132,150	600	687	0		-132,837	-69,062	-745,036
2012									129,596	1,796	2,090	0		-131,686	-63,089	-808,125
2013						349,166			175,387	600	710	0		-176,097	-77,742	-885,866
2014									168,155	600	722	0		-168,878	-68,701	-954,568
2015									164,799	8,036	9,838	0		-174,637	-65,466	-1,020,034
2016									161,404	600	747	0		-162,151	-56,013	-1,076,048
2017									157,970	600	760	0		-158,730	-50,527	-1,126,574
2018						1,455,100			356,102	1,796	2,313	0	94,879	-263,536	-77,302	-1,203,877
2019									333,362	600	786	0		-334,148	-90,320	-1,294,196
2020									326,860	600	799	0		-327,659	-81,612	-1,375,809
2021									320,277	1,796	2,433	0		-322,710	-74,069	-1,449,878
2022									313,616	600	827	0		-314,442	-66,505	-1,516,383
2023									306,879	600	841	0		-307,720	-59,974	-1,576,356
2024									300,071	1,796	2,559	0		-302,629	-54,351	-1,630,707
2025									293,193	600	869	0		-294,062	-48,666	-1,679,373
2026									286,248	600	884	0		-287,133	-43,788	-1,723,161
2027									279,240	8,036	12,043	0		-291,284	-40,934	-1,764,095
2028									272,171	600	914	0		-273,085	-35,363	-1,799,458
2029									265,043	600	930	0		-265,973	-31,738	-1,831,196
2030									257,858	1,796	2,831	0		-260,690	-28,665	-1,859,862
2031									250,620	600	962	0		-251,582	-25,492	-1,885,354
2032									243,329	600	978	0		-244,307	-22,811	-1,908,165
2033									235,988	1,796	2,978	0		-238,966	-20,561	-1,928,726
2034									228,600	600	1,012	0		-229,612	-18,205	-1,946,931
2035									221,165	600	1,029	0		-222,194	-16,234	-1,963,165
2036									213,686	1,796	3,133	0		-216,819	-14,597	-1,977,762
2037									206,165	600	1,064	0		-207,229	-12,856	-1,990,619
2038									198,603	600	1,082	0		-199,686	-11,416	-2,002,035
2039									191,002	8,036	14,743	0		-205,746	-10,839	-2,012,873
2040									183,364	600	1,120	0		-184,483	-8,956	-2,021,829
2041									175,689	600	1,139	0		-176,828	-7,910	-2,029,739
2042									109,129	1,796	3,466	0		-112,595	-4,641	-2,034,380

Alternative #3 - Replace Humber T3 with 25 MVA Transformer

Transforme Size (MVA)	BVS-T1		BVS-T2		HUM-T3		WAL-T1		WAL-T2		Capitial Cost per Year in 2003 dollars	Extra Maint Cost per Year 2003 dollars (6)	Notes
	20.0		25.0		13.3	25.0	20.0		15.0	25.0			
	Load	Util	Load	Util	Load	Util	Load	Util	Load	Util			
2002 Peak	19.9	99.5%	0.0	0.0%	10.9	82.0%	16.1	80.5%	15.0	100.0%			
2003	22.0	110.0%	0.0	0.0%	12.1	90.6%	17.8	89.0%	16.6	110.6%			
2004	17.7	88.3%	0.0	0.0%	19.9	79.7%	18.3	91.7%	14.6	97.2%	1,130,000.00		(1)
2005	17.5	87.7%	0.0	0.0%	19.8	79.1%	18.2	91.0%	14.5	96.5%			
2006	17.7	88.7%	0.0	0.0%	20.0	80.0%	18.4	92.1%	14.7	97.7%			
2007	18.2	90.8%	0.0	0.0%	20.5	81.9%	18.9	94.3%	15.0	100.0%			
2008	18.6	93.0%	0.0	0.0%	21.0	83.8%	19.3	96.5%	15.4	61.4%	835,000.00		(2)
2009	19.0	95.1%	0.0	0.0%	21.4	85.7%	19.7	98.7%	15.7	62.8%			
2010	19.4	97.1%	0.0	0.0%	21.9	87.6%	16.2	80.8%	20.0	80.2%	90,000.00		(3)
2011	19.8	99.2%	0.0	0.0%	22.4	89.4%	16.5	82.5%	20.5	81.8%			
2012	10.1	50.6%	10.1	40.5%	22.8	91.2%	16.8	84.2%	20.9	83.5%	780,000.00	600.00	(4)
2013	10.3	51.5%	10.3	41.2%	23.2	93.0%	17.2	85.8%	21.3	85.0%		600.00	
2014	10.5	52.5%	10.5	42.0%	23.7	94.6%	17.5	87.3%	21.6	86.6%		1796.00	
2015	10.7	53.4%	10.7	42.7%	24.1	96.3%	17.8	88.8%	22.0	88.1%		600.00	
2016	10.8	54.2%	10.8	43.4%	24.5	97.8%	18.1	90.3%	22.4	89.5%		600.00	
2017	11.0	55.1%	11.0	44.1%	24.8	99.3%	18.3	91.7%	22.7	90.9%		1796.00	
2018	13.7	68.4%	13.7	54.7%	20.2	80.8%	18.6	93.0%	23.1	92.2%	295,000.00	600.00	(5)
2019	13.9	69.3%	13.9	55.4%	20.5	81.9%	18.9	94.3%	23.4	93.5%		600.00	
2020	14.0	70.2%	14.0	56.2%	20.7	82.9%	19.1	95.5%	23.7	94.7%		1796.00	
2021	14.2	71.0%	14.2	56.8%	21.0	83.9%	19.3	96.6%	23.9	95.8%		600.00	
2022	14.4	71.8%	14.4	57.4%	21.2	84.8%	19.5	97.6%	24.2	96.8%		600.00	
2023	14.5	72.5%	14.5	58.0%	21.4	85.7%	19.7	98.6%	24.4	97.8%		8036.00	

Notes:

Replace HUM-T3 with 25 MVA unit, replace cables		835,000.00
Build new feeder from HUM 12.5 bus to BVS-03 North Street - extend 12.5 kv bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering $15,000		15,000.00
2.5 MVA transferred from WAL-T2 to HUM-T3		
5 MVA transferred from BVS-T1 to HUM-T3		
	Total for 2004	1,130,000.00

(2) 2008 Load changes:

Replace WAL-T2 25 MVA unit, Replace WAL-T2 Cables		835,000.00
	Total for 2008	835,000.00

(3) 2010 Load Changes:

Replacement of Cable WAL-03 - $75,000		75,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
4 MVA from WAL-T1 to WAL-T2		

	Total for 2010	90,000.00

(4) 2012 Load Changes:

Additional 25MVA Transformer installed at Bayview. (Impedance Match)		780,000.00
	Total for 2012	780,000.00

(5) 2018 Load changes:

Install New Feeder at BVS		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering 5 MVA from HUM-T3 to BVS		15,000.00
	Total for 2018	295,000.00

(6) Additional Maintenance Cost per extra Transformer

$600 per year - Oil Testing
One Maint III every two years - 2 man crew - 2 Days - $1196
One Maint IV every ten years - 3 man crew - 5 Days plus material - $7436

Reasoning

(1) Without transfer, both BVS-T1 and WAL-T2 would be over 100%. New feeder needed to handle additional load.

(2) If not completed load on WAL-T2 102.3% in 2008

(3) Necessary to Transfer Load to WAL-T2
Without Transfer, WAL-T1 would be at 100.8% in 2010

(4) Without Transfer, BVS-T1 would be at 101.1% in 2012

(5) Without Transfer, HUM-T3 would be at 100.8% in 2018

(6) Based on current practices and pricing

Based on Transformer to replace HUM-T3 2004

Spare Capacity			
Year	Available	Used	Spare
2002 Peak	68.3	61.9	6.4
2003	68.3	68.4	-0.1
2004	80.0	70.5	9.5
2005	80.0	70.0	10.0
2006	80.0	70.8	9.2
2007	80.0	72.5	7.5
2008	90.0	74.2	15.8

2009	90.0	75.9	14.1
2010	90.0	77.5	12.5
2011	90.0	79.2	10.8
2012	115.0	80.7	34.3
2013	115.0	82.3	32.7
2014	115.0	83.8	31.2
2015	115.0	85.2	29.8
2016	115.0	86.6	28.4
2017	115.0	87.9	27.1
2018	115.0	89.2	25.8
2019	115.0	90.4	24.6
2020	115.0	91.6	23.4
2021	115.0	92.6	22.4
2022	115.0	93.7	21.3
2023	115.0	94.6	20.4

Present Worth Analysis Alternative #3 (Replace HUM-T1)

Weighted Average Incremental Cost of Capital 8.52%
Escalation Rate 1.70%
PW Year 2003

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Generation Thermal 25.58 yrs 4% CCA	Generation Hydro 49.26 yrs 4% CCA	Generation Thermal 25.51 yrs 30% CCA	Generation Hydro 49.26 yrs 30% CCA	Transmission 30.6 yrs 4% CCA	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Telecommunication 15.0 yrs 20% CCA	Capital Revenue Requirement	Present Operating Costs	Escalated Operating Costs	Operating Benefits	Deferment Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2004						1,149,210			159,222	600	610	0	315,061	155,229	143,042	143,042
2005									144,030	600	621	0		-144,651	-122,829	20,213
2006									141,690	1,796	1,889	0		-143,580	-112,348	-92,135
2007									139,312	600	642	0	228,884	88,930	64,123	-28,012
2008						908,430			262,758	600	653	0		-263,410	-175,018	-203,030
2009									248,298	1,796	1,987	0		-250,285	-153,241	-356,272
2010						101,272			257,993	600	675	0		-258,668	-145,940	-502,212
2011									252,255	600	687	0		-252,942	-131,505	-633,717
2012						907,785			373,361	1,796	2,090	0		-375,451	-179,873	-813,589
2013									356,632	600	710	0		-357,343	-157,756	-971,346
2014									349,996	600	722	0		-350,718	-142,676	-1,114,022
2015									343,271	8,036	9,838	0		-353,109	-132,371	-1,246,392
2016									336,463	600	747	0		-337,210	-116,486	-1,362,878
2017									329,573	600	760	0		-330,333	-105,151	-1,468,029
2018						379,871			375,236	1,796	2,313	0		-377,549	-110,746	-1,578,775
2019									363,173	600	786	0		-363,958	-98,377	-1,677,152
2020									355,285	600	799	0		-356,084	-88,692	-1,765,844
2021									347,317	1,796	2,433	0		-349,749	-80,275	-1,846,120
2022									339,269	600	827	0		-340,096	-71,931	-1,918,050
2023									331,147	600	841	0		-331,988	-64,703	-1,982,754
2024									322,953	1,796	2,559	0		-325,511	-58,460	-2,041,214
2025									314,689	600	869	0		-315,558	-52,223	-2,093,437
2026									306,358	600	884	0		-307,242	-46,855	-2,140,292
2027									297,964	8,036	12,043	0		-310,007	-43,565	-2,183,857
2028									289,508	600	914	0		-290,423	-37,609	-2,221,466
2029									280,994	600	930	0		-281,924	-33,642	-2,255,107
2030									272,423	1,796	2,831	0		-275,254	-30,267	-2,285,374
2031									263,798	600	962	0		-264,760	-26,827	-2,312,202
2032									255,120	600	978	0		-256,099	-23,912	-2,336,114
2033									246,393	1,796	2,978	0		-249,371	-21,456	-2,357,570
2034									237,618	600	1,012	0		-238,630	-18,920	-2,376,490
2035									228,796	600	1,029	0		-229,825	-16,791	-2,393,282
2036									219,931	1,796	3,133	0		-223,063	-15,018	-2,408,299
2037									211,023	600	1,064	0		-212,087	-13,158	-2,421,457
2038									202,074	600	1,082	0		-203,156	-11,614	-2,433,071
2039									193,086	8,036	14,743	0		-207,829	-10,948	-2,444,020
2040									184,060	600	1,120	0		-185,180	-8,989	-2,453,009
2041									174,998	600	1,139	0		-176,137	-7,879	-2,460,888
2042									101,023	1,796	3,466	0		-104,489	-4,307	-2,465,195

Appendix C

Economic Analysis - Adjusting For Unequal Transformer Capacity at Study End

APPENDIX C - Economic Analysis – Adjusting For Unequal Transformer Capacity at Study End – Introduction

It is important that all alternatives have comparable transformer at the end point of the study. It is not appropriate that one alternative has much more transformer capacity at the end time of the study, and therefore accrues disproportionate cost. In order that all alternatives end with the same transformer capacity, an adjustment is made in the alternatives to ensure this is the case.

In this study, alternative #3 has much more transformer capacity at the end of the study than do the other two alternatives. In order to make the alternatives comparable, Appendix C adds transformer capacity added with associated costs incurred to bring the alternatives to the same capacity / cost base.

Similar to Appendix B, details of expenditures and present worth analysis follow for each of the alternatives with the exception of alternative #3. The present worth of these alternatives is brought forward to the table in the body of the report. Adjusting for Unequal transformer Capacity at Study End, as is the present worth for alternative #3 noted in Appendix B.

Alternative #1 - Add Transformer at BVS - Adjust for Unequal Transformer Capacity

Transforme	BVS-T1		BVS-T2		HUM-T3		WAL-T1		WAL-T2		Capital Cost per Year in 2003 dollars	Extra Maint Cost per Year 2003 dollars (6)	Notes
Size (MVA)	20.0		25.0		13.3		20.0		15.0	25.0			
	Load	Util	Load	Util	Load	Util	Load	Util	Load	Util			
2002 Peak	19.9	99.5%	0.0	0.0%	10.9	82.0%	16.1	80.5%	15.0	100.0%			
2003	22.0	110.0%	0.0	0.0%	12.1	90.6%	17.8	89.0%	16.6	110.6%			
2004	13.1	65.4%	13.1	52.3%	11.9	89.6%	18.3	91.7%	14.1	93.9%	1,028,000.00	600.00	(1)
2005	13.0	64.9%	13.0	52.0%	11.8	88.9%	18.2	91.0%	14.0	93.2%		600.00	
2006	13.1	65.7%	13.1	52.6%	12.0	90.0%	18.4	92.1%	14.2	94.3%		1796.00	
2007	13.5	67.3%	13.5	53.8%	12.3	92.1%	18.9	94.3%	14.5	96.6%		600.00	
2008	13.8	68.9%	13.8	55.1%	12.5	94.3%	19.3	96.5%	14.8	98.8%		600.00	
2009	14.1	70.4%	14.1	56.3%	12.8	96.4%	19.7	98.7%	15.2	60.6%	835,000.00	1796.00	(2)
2010	14.4	71.9%	14.4	57.6%	10.1	76.0%	17.2	85.8%	21.5	86.0%	90,000.00	600.00	(3)
2011	14.7	73.4%	14.7	58.8%	10.3	77.6%	17.5	87.6%	21.9	87.8%		600.00	
2012	15.0	74.9%	15.0	59.9%	10.5	79.1%	17.9	89.4%	22.4	89.5%	295,000.00	1796.00	(4)
2013	15.3	76.3%	15.3	61.1%	10.7	80.6%	18.2	91.1%	22.8	91.2%		600.00	
2014	15.5	77.7%	15.5	62.2%	10.9	82.1%	18.5	92.7%	23.2	92.9%		600.00	
2015	15.8	79.1%	15.8	63.2%	11.1	83.5%	18.9	94.3%	23.6	94.5%		8036.00	
2016	16.1	80.3%	16.1	64.3%	11.3	84.8%	19.2	95.9%	24.0	96.0%		600.00	
2017	16.3	81.6%	16.3	65.3%	11.5	86.1%	19.5	97.3%	24.4	97.5%		600.00	
2018	16.6	82.8%	16.6	66.2%	11.6	87.4%	19.8	98.8%	24.7	98.9%		1796.00	
2019	18.8	93.9%	18.8	75.1%	11.8	88.6%	18.0	90.1%	23.1	92.2%	395,000.00	600.00	(5)
2020	19.0	95.1%	19.0	76.1%	11.9	89.7%	18.2	91.2%	23.4	93.4%		600.00	
2021	19.2	96.2%	19.2	77.0%	12.1	90.8%	18.5	92.3%	23.6	94.5%		1796.00	
2022	19.5	97.3%	19.5	77.8%	12.2	91.8%	18.7	93.3%	23.9	95.5%		600.00	
2023	19.6	98.2%	19.6	78.6%	12.3	92.7%	18.9	94.3%	24.1	96.5%	780,000.00	600.00	(7)

(1) 2004 Load changes:

Additional 25 MVA Transformer installed at Bayview. (impedance match)	780,000.00
3 Mva transferred from WAL-T2 to BVS-T1	
0.5 MVA transferred from HUM-T3 to BVS-T1	
Upgrade the BVS-04 U/G Crossing at Confederation Drive.	65,000.00
Reconductor 6 spans along Golf Course,	5,000.00
Reframe pole O'Connell and West Valley,	8,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00
Install 1 – 1 Phase Regulator for Gallants line BVS-04	40,000.00
Install 1 – 3 Phase Regulator in Park	115,000.00
Total for 2004	1,028,000.00

(2) 2009 Load Changes

Replace WAL-T2 with 25 MVA transformer, Replace Cables	835,000.00

Total for 2009	835,000.00

(3) 2010 Load Changes

Replace WAL-03 Cables	75,000.00
3 Mva Transferred from WAL-T1 to WAL-T2	
3 Mva Transferred From HUM-T3 to WAL-T2	
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00
Total for 2010	90,000.00

(4) 2012 Load Changes

Install New Feeder BVS and Extend Bus	280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00
Total for 2012	295,000.00

(5) 2019 Load changes:

Build new feeder from BVS 12.5 bus - extend 12.5 kv bus	380,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering $15,000	15,000.00
4 MVA transferred from HUM-T3 to BVS	
2 MVA transferred from WAL-T2 to HUM-T3	
2 MVA transferred from WAL-T1 to HUM-T3	
Total for 2019	395,000.00

(6) Additional Maintenance Cost per extra Transformer

$600 per year - Oil Testing
One Maint III every two years - 2 man crew - 2 Days - $1196
One Maint IV every ten years - 3 man crew - 5 Days plus material - $7436

(7) Additional Transformer added for Sensitivity Analysis	780,000.00
	780,000.00

Reasoning

(1) Transfer WAL-06 up to and including Canada Games Centre
This transfer would offload the upper section of HUM-09. BVS-02 would feed through the cable at CNIB to the McPherson Hgts area. BVS-04 would need an aerial route to the golf course, along with the other items indicated to allow it to feed this load. This

(2) Without Transformer Changeout WAL-T2 would be at 101.1% in this year

(3) Necessary to Transfer Load to WAL-T2
Without Transfer, WAL-T1 would be at 100.8% in 2010
Without Transfer, HUM-T3 would be at 100.6% in 2011

(4) Necessary for loading at BVS. Without the new feeder, we would have 30 MVA on 4 feeders.

(5) Without Transformer Changeout / Transfer WAL-T2 would be at 101.1% in this year, WAL-T2 would be at 100.2%
This feeder would have to be Double Circuit through the town. It
would pick up some load from HUM-09 and HUM-09 would pick up
load from WAL-T2 and WAL-T1.

(6) Based on current practices and pricing

Based on matched impedance Transformer at BVS in 2004

	Spare Capacity		
Year	Available	Used	Spare
2002 Peak	68.3	61.9	6.4
2003	68.3	68.4	-0.1
2004	93.3	70.5	22.8
2005	93.3	70.0	23.3
2006	93.3	70.8	22.5
2007	93.3	72.5	20.8
2008	93.3	74.2	19.1
2009	93.3	75.9	17.4
2010	103.3	77.5	25.8
2011	103.3	79.2	24.1
2012	103.3	80.7	22.6
2013	103.3	82.3	21.0
2014	103.3	83.8	19.5
2015	103.3	85.2	18.1
2016	103.3	86.6	16.7
2017	103.3	87.9	15.4
2018	103.3	89.2	14.1
2019	103.3	90.4	12.9
2020	103.3	91.6	11.7
2021	103.3	92.6	10.7
2022	103.3	93.7	9.6
2023	115.0	94.6	20.4

Present Worth Analysis (Install New BVS-T2 Sensitivity Analysis)

Weighted Average Incremental Cost of Capital 8.52%
Escalation Rate 1.70%
PW Year 2003

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Generation Thermal	Generation Hydro	Generation Thermal	Generation Hydro	Transmission	Substation	Distribution	Telecommunication	Capital Revenue Requirement	Present Operating Costs	Escalated Operating Costs	Operating Benefits	Deferment Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
	25.58 yrs	49.26 yrs	25.51 yrs	49.26 yrs	30.6 yrs	38.5 yrs	30.4 yrs	15.0 yrs								
	4% CCA	4% CCA	30% CCA	30% CCA	4% CCA	4% CCA	4% CCA	20% CCA								
2004						1,045,476			144,849	600	610	0		-145,460	-134,039	-134,039
2005									131,029	600	621	0		-131,650	-111,790	-245,829
2006									128,901	1,796	1,889	0		-130,790	-102,340	-348,169
2007									126,737	600	642	0		-127,379	-91,845	-440,014
2008									124,539	600	653	0		-125,192	-83,181	-523,196
2009						923,873			250,310	1,796	1,987	0	203,991	-48,306	-29,576	-552,772
2010						101,272			249,867	600	675	0		-250,542	-141,355	-694,127
2011									244,355	600	687	0		-245,042	-127,398	-821,525
2012						343,329			287,484	1,796	2,090	0		-289,575	-138,731	-960,256
2013									278,446	600	710	0		-279,156	-123,239	-1,083,495
2014									273,189	600	722	0		-273,911	-111,430	-1,194,925
2015									267,863	8,036	9,838	0		-277,701	-104,102	-1,299,027
2016									262,473	600	747	0		-263,220	-90,927	-1,389,954
2017									257,020	600	760	0		-257,780	-82,056	-1,472,010
2018									251,507	1,796	2,313	0		-253,820	-74,452	-1,546,463
2019						517,288			317,606	600	786	0		-318,392	-86,061	-1,632,523
2020									305,142	600	799	0		-305,942	-76,203	-1,708,726
2021									298,410	1,796	2,433	0		-300,843	-69,050	-1,777,776
2022									291,610	600	827	0		-292,436	-61,851	-1,839,627
2023						1,092,732			436,140	600	841	0	47,770	-389,211	-75,856	-1,915,483
2024									414,766	1,796	2,559	0		-417,325	-74,950	-1,990,432
2025									405,551	600	869	0		-406,421	-67,261	-2,057,693
2026									396,241	600	884	0		-397,126	-60,562	-2,118,255
2027									386,840	8,036	12,043	0		-398,884	-56,055	-2,174,310
2028									377,352	600	914	0		-378,266	-48,984	-2,223,294
2029									367,779	600	930	0		-368,709	-43,998	-2,267,292
2030									358,126	1,796	2,831	0		-360,957	-39,691	-2,306,982
2031									348,395	600	962	0		-349,357	-35,399	-2,342,382
2032									338,590	600	978	0		-339,568	-31,706	-2,374,088
2033									328,713	1,796	2,978	0		-331,691	-28,539	-2,402,627
2034									318,768	600	1,012	0		-319,780	-25,354	-2,427,981
2035									308,757	600	1,029	0		-309,786	-22,633	-2,450,614
2036									298,683	1,796	3,133	0		-301,815	-20,320	-2,470,934
2037									288,548	600	1,064	0		-289,612	-17,967	-2,488,902
2038									278,355	600	1,082	0		-279,437	-15,975	-2,504,877
2039									268,106	8,036	14,743	0		-282,849	-14,901	-2,519,777
2040									257,803	600	1,120	0		-258,923	-12,569	-2,532,346
2041									247,449	600	1,139	0		-248,588	-11,120	-2,543,466
2042									178,022	1,796	3,466	0		-181,488	-7,481	-2,550,948

Alternative #2 - Add Transformer at WAL - Adjust for Unequal Transformer Capacity

Transforme	BVS-T1		BVS-T2		HUM-T3		WAL-T1		WAL-T2		Capitial Cost per Year in 2003 dollars	Extra Maint Cost per Year 2003 dollars (6)	Notes
Size (MVA)	20.0		15.0		13.3	25.0	20.0		15.0	25.0			
	Load	Util	Load	Util	Load	Util	Load	Util	Load	Util			
2002 Peak	19.9	99.5%	0.0	0.0%	10.9	82.0%	16.1	80.5%	15.0	100.0%			
2003	13.2	66.0%	8.8	58.7%	12.1	90.6%	17.8	89.0%	16.6	110.6%			
2004	13.6	68.0%	9.1	60.4%	12.4	93.3%	18.3	91.7%	17.1	68.3%	1,025,000.00	600.00	(1)
2005	13.5	67.5%	9.0	60.0%	12.3	92.7%	18.2	91.0%	17.0	67.8%		600.00	
2006	13.7	68.3%	9.1	60.7%	12.5	93.8%	18.4	92.1%	17.2	68.7%		1796.00	
2007	14.0	69.9%	9.3	62.2%	12.8	96.0%	18.9	94.3%	17.6	70.3%		600.00	
2008	14.3	71.6%	9.5	63.6%	13.1	98.3%	19.3	96.5%	18.0	71.9%		600.00	
2009	15.8	79.2%	10.6	70.4%	11.4	85.4%	19.7	98.7%	18.4	73.6%	15,000.00	1796.00	(2)
2010	16.2	80.9%	10.8	71.9%	11.6	87.3%	17.2	85.8%	21.8	87.2%	90,000.00	600.00	(3)
2011	16.5	82.6%	11.0	73.4%	11.9	89.1%	17.5	87.6%	22.2	89.0%		600.00	
2012	16.8	84.2%	11.2	74.9%	12.1	90.9%	17.9	89.4%	22.7	90.7%		1796.00	
2013	17.2	85.8%	11.4	76.3%	12.3	92.6%	18.2	91.1%	23.1	92.5%	295,000.00	600.00	(4)
2014	17.5	87.4%	11.7	77.7%	12.5	94.3%	18.5	92.7%	23.5	94.2%		600.00	
2015	17.8	88.9%	11.9	79.0%	12.8	95.9%	18.9	94.3%	23.9	95.8%		8036.00	
2016	18.1	90.4%	12.0	80.3%	13.0	97.5%	19.2	95.9%	24.3	97.3%		600.00	
2017	18.4	91.8%	12.2	81.6%	13.2	99.0%	19.5	97.3%	24.7	98.8%		600.00	
2018	18.6	93.1%	12.4	82.7%	18.4	73.4%	17.3	86.3%	22.6	90.3%	1,130,000.00	1796.00	(5)
2019	18.9	94.4%	12.6	83.9%	18.6	74.4%	17.5	87.4%	22.9	91.5%		600.00	
2020	19.1	95.6%	12.7	84.9%	18.8	75.4%	17.7	88.5%	23.2	92.7%		600.00	
2021	19.3	96.7%	12.9	85.9%	19.1	76.3%	17.9	89.6%	23.4	93.8%		1796.00	
2022	19.5	97.7%	13.0	86.9%	19.3	77.1%	18.1	90.6%	23.7	94.8%		600.00	
2023	19.7	98.7%	13.2	87.7%	19.5	77.9%	18.3	91.5%	23.9	95.7%	780,000.00	600.00	(7)

Notes

(1) 2004 Load changes:

Replace WAL-T2 with 25 MVA unit, Replace WAL-T2 Cables		835,000.00
Install WAL-T2 (Existing) at BVS		190,000.00
	Total for 2004	1,025,000.00

(2) 2009 Load Changes:

Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering 2 MVA from HUM-T3 to BVS		15,000.00
	Total for 2009	15,000.00

(3) 2010 Load Changes:

Replacement of Cable WAL-03 - $75,000		75,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering 4 MVA from WAL-T1 to WAL-T2		15,000.00

	Total for 2010	90,000.00
(4) 2013 Load Changes		
Install New Feeder BVS and Extend Bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering		15,000.00
	Total for 2013	295,000.00
(5) 2018 Load changes:		
Replace HUM-T3 with 25 MVA unit, replace cables		835,000.00
Build new feeder from HUM 12.5 bus - extend 12.5 kv bus		280,000.00
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering $15,000		15,000.00
2.5 MVA transferred from WAL-T2 to HUM-T3		
2.5 MVA transferred from WAL-T1 to HUM-T3		
	Total for 2018	1,130,000.00
(6) Additional Maintanance Cost per extra Transformer		
$600 per year - Oil Testing		
One Maint III every two years - 2 man crew - 2 Days - $1196		
One Maint IV every ten years - 3 man crew - 5 Days plus material - $7436		
(7) Additional Transformer added for Sensitivity Analysis		780,000.00
		780,000.00

Reasoning

(1) Without transfer, both BVS-T1 and WAL-T2 would be over 100%

(2) Without Load transfer HUM-T3 will be at 100.5%

(3) Without Load transfer WAL-T1 will be at 100.8%

(4) Necessary for loading at BVS. Without the new feeder, we would have 28.6 MVA on 4 feeders.

(5) Because of the load sharing on the BVS XFMRs, there is no extra capacity at BVS. HUM-T3 will be replaced. If transfers are not complete - HUM-T3, 100.4% in 2018, WAL-T1 100.1% in 2019, WAL-T2 100.3% in 2018. New feeder required to handle load.

(6) Based on current practices and pricing

Based on Transformer to replace WAL-T2 in 2004
Installing WAL-T2 as BVS-T2 in 2004

	Spare Capacity		
Year	Available	Used	Spare
2002 Peak	68.3	61.9	6.4
2003	68.3	68.4	-0.1
2004	93.3	70.5	22.8
2005	93.3	70.0	23.3
2006	93.3	70.8	22.5
2007	93.3	72.5	20.8
2008	93.3	74.2	19.1
2009	93.3	75.9	17.4
2010	93.3	77.5	15.8
2011	93.3	79.2	14.1
2012	93.3	80.7	12.6
2013	93.3	82.3	11.0
2014	93.3	83.8	9.5
2015	93.3	85.2	8.1
2016	93.3	86.6	6.7
2017	93.3	87.9	5.4
2018	105.0	89.2	15.8
2019	105.0	90.4	14.6
2020	105.0	91.6	13.4
2021	105.0	92.6	12.4
2022	105.0	93.7	11.3
2023	115.0	94.6	20.4

Present Worth Analysis (Replace WAL-T2 with 25MVA - Sensitivity Analysis)

Weighted Average Incremental Cost of Capital 8.52%
Escalation Rate 1.70%
PW Year 2003

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Generation Thermal 25.58 yrs 4% CCA	Generation Hydro 49.26 yrs 4% CCA	Generation Thermal 25.51 yrs 30% CCA	Generation Hydro 49.26 yrs 30% CCA	Transmission 30.6 yrs 4% CCA	Substation 38.5 yrs 4% CCA	Distribution 30.4 yrs 4% CCA	Telecommunication 15.0 yrs 20% CCA	Capital Revenue Requirement	Present Operating Costs	Future Operating Costs	Operating Benefits	Deferment Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit
2004						1,042,425			144,427	600	610	0		-145,037	-133,650	-133,650
2005									130,647	600	621	0		-131,268	-111,465	-245,115
2006									128,525	1,796	1,889	0		-130,414	-102,045	-347,160
2007									126,367	600	642	0		-127,009	-91,579	-438,739
2008									124,175	600	653	0		-124,828	-82,940	-521,679
2009						16,597			124,251	1,796	1,987	0		-126,238	-77,292	-598,970
2010						101,272			135,808	600	675	0		-136,483	-77,003	-675,974
2011									132,150	600	687	0		-132,837	-69,062	-745,036
2012									129,596	1,796	2,090	0		-131,686	-63,089	-808,125
2013						349,166			175,387	600	710	0		-176,097	-77,742	-885,866
2014									168,155	600	722	0		-168,878	-68,701	-954,568
2015									164,799	8,036	9,838	0		-174,637	-65,466	-1,020,034
2016									161,404	600	747	0		-162,151	-56,013	-1,076,048
2017									157,970	600	760	0		-158,730	-50,527	-1,126,574
2018						1,455,100			356,102	1,796	2,313	0	94,879	-263,536	-77,302	-1,203,877
2019									333,362	600	786	0		-334,148	-90,320	-1,294,196
2020									326,860	600	799	0		-327,659	-81,612	-1,375,809
2021									320,277	1,796	2,433	0		-322,710	-74,069	-1,449,878
2022									313,616	600	827	0		-314,442	-66,505	-1,516,383
2023						1,092,732			458,276	600	841	0	47,770	-411,346	-80,170	-1,596,553
2024									437,022	1,796	2,559	0		-439,581	-78,947	-1,675,499
2025									427,920	600	869	0		-428,789	-70,962	-1,746,462
2026									418,714	600	884	0		-419,598	-63,989	-1,810,451
2027									409,408	8,036	12,043	0		-421,452	-59,226	-1,869,677
2028									400,008	600	914	0		-400,922	-51,918	-1,921,595
2029									390,516	600	930	0		-391,446	-46,711	-1,968,306
2030									380,936	1,796	2,831	0		-383,767	-42,199	-2,010,505
2031									371,272	600	962	0		-372,234	-37,717	-2,048,222
2032									361,527	600	978	0		-362,506	-33,848	-2,082,070
2033									351,705	1,796	2,978	0		-354,683	-30,517	-2,112,588
2034									341,808	600	1,012	0		-342,819	-27,181	-2,139,768
2035									331,839	600	1,029	0		-332,868	-24,320	-2,164,088
2036									321,802	1,796	3,133	0		-324,934	-21,876	-2,185,964
2037									311,698	600	1,064	0		-312,762	-19,404	-2,205,368
2038									301,532	600	1,082	0		-302,614	-17,300	-2,222,668
2039									291,304	8,036	14,743	0		-306,047	-16,123	-2,238,791
2040									281,018	600	1,120	0		-282,138	-13,696	-2,252,487
2041									270,676	600	1,139	0		-271,815	-12,159	-2,264,646
2042									201,430	1,796	3,466	0		-204,896	-8,446	-2,273,092

Project Title: **Rebuild Transmission Lines**

Location: **Various**

Classification: **Transmission**

Project Cost: **$2,315,000**

This project consists of a number of items as noted.

(a) Rebuild 3L (Petty Harbour – Goulds)

Cost: $364,000

Description: This project consists of the replacement of deteriorated poles, hardware and conductor on a 4.7km section of 3L.

Operating Experience: 3L was built in 1930. It is a radial line servicing 400 customers in the Petty Harbour area. It also provides a tie between the Petty Harbour hydro plant and the main electrical grid. There have been several unplanned outages on this line during the past 4 or 5 years resulting from deteriorated line components. In 2000, $10,000 was spent correcting deficiencies identified during that year's inspection. In 2003, one kilometre of line was rebuilt due to deterioration and substandard ground clearances at a cost of $139,000.

Justification: Inspections have determined that there is significant deterioration of the poles, crossarms and other hardware on a 4.7 km section of 3L. Upgrading of this section of line is necessary to ensure continuity of service to customers in the Petty Harbour area as well as provide the hydro plant with a secure connection to the main grid.

(b) Rebuild 16L (Pepperell – King's Bridge)

Cost: $197,000

Description: This project consists of increasing the conductor size and the replacement of deteriorated poles and hardware on 2.0 km of transmission line 16L.

Operating Experience: 16L was built in 1950. The conductor on this line is a small size relative to that in use today which creates a restriction in the power flow and an outage to Virginia Waters Substation when 58L and 34L are out of service. See Volume III, Transmission, Appendix 1, Attachment A. From a structural perspective the most recent work was in December 1994, and involved the replacement of several poles which collapsed during a sleet storm.

Justification: The small conductor used on this transmission line limits its ability to carry current. Upgrading this line will strengthen the east end transmission loop which will increase reliability of the transmission grid.

(c) Rebuild 38L (Seal Cove – Duffs)

Cost: $231,000

Description: This project consists of increasing the conductor size and the replacement of deteriorated poles and hardware on a 2.8 km section of transmission line 38L.

Operating Experience: This line was built in 1961. Poles, crossarms, insulators and hardware are showing deterioration on a 2.8 km section of this transmission line. The small size conductor on this section of the line has on several occasions limited the line's ability to carry available power between Duffs and Hardwood Substations. See Volume III, Transmission, Appendix 1, Attachment A. In 2001, $8,000 was spent correcting miscellaneous deficiencies.

Justification: This line is a tie between Hydro's Holyrood Generating Plant and the substations in the CBS area (SCV, KEL and CHA). By upgrading this 2.8 km section of line and increasing the conductor size this project will increase reliability not just to the CBS area but also to St. John's in the event of a loss of infeed to Hardwoods Substation.

(d) Replace deteriorated poles and hardware 116L (Hare Bay – Wesleyville)

Cost: $130,000

Description: This project consists of the replacement of approximately 25 deteriorated poles and hardware on transmission line 116L.

Operating Experience: 116L was built in 1973. It is a radial line servicing the Bonavista Bay North area. Based on inspections, replacement of deteriorated material is completed as necessary. In 2000, $151,000 was spent on replacement of deteriorated poles, crossarms, insulators and hardware. In 2002, a further $19,000 was spent.

Justification: Inspections have identified deteriorated poles and hardware that require replacement in order to maintain the integrity of the line and reliability of service to customers in the Bonavista North area.

(e) Replace defective insulators and associated hardware on transmission line 123L (Clarenville to Catalina)

Cost: $112,000

Description: This project consists of the replacement of approximately 1,200 defective insulators and associated hardware on transmission line 123L.

Operating Experience: 123L was built in 1976. It is a radial line servicing the Bonavista Peninsula. Inspections have identified defective insulators and deteriorated hardware on this line. Based on inspections, $3,000, $229,000 and $61,000 were spent in 2000, 2002 and 2003 respectively on the replacement of deteriorated hardware.

Justification: The type of insulator being replaced has a manufacturing defect that leads to mechanical failure. Replacement is necessary in order to maintain integrity of the line and reliability of service to customers on the Bonavista Peninsula.

(f) Replace deteriorated poles and hardware on transmission line 124L (Clarenville to Gambo)

Cost: $96,000

Description: This project consists of the replacement of approximately 16 deteriorated poles, structures and hardware on transmission line 124L.

Operating Experience: 124L was built in 1964. Based on inspections, $16,000, $40,000 and $26,000 were spent in 2000, 2001 and 2002 respectively on the replacement of deteriorated line hardware.

Justification: Inspections have identified deteriorated poles, structures and hardware that require replacement in order to maintain the integrity of this line.

(g) Replace defective insulators and associated hardware on transmission line 132L (Grand Falls to Bishop's Falls)

Cost: $66,000

Description: This project consists of the replacement of approximately 1,100 insulators and associated hardware on 52 structures of transmission line 132L.

Operating Experience: 132L was built in 1976. Based on inspections, replacement of excessively worn or broken parts is completed as necessary. In 2000, $2,000 was spent and in 2002, $1,000 was spent. There have been several outages over the past few years caused by failed insulators.

Justification: The type of insulator being replaced has a manufacturing defect that leads to mechanical failure. Replacement is necessary in order to maintain the integrity of the line, and reliability of service to customers in the Bishop's Falls area.

(h) Rebuild 5.1 km of 403L (St. Georges – Lookout Brook)

Cost: $380,000

Description: This project consists of the replacement of deteriorated poles, hardware and conductor on a 5.1 km section as well as selective pole and hardware replacement on a 4 km section of transmission line 403L.

Operating Experience: 403L was built in 1958. It is a radial line servicing customers in the Robinson's/Flat Bay area. It also provides a tie between the Lookout Brook hydro plant and the main electrical grid. In 2001, 11.6 km of this line was replaced because of significant deterioration of its poles and hardware. Another 5.1 km of this line is in a similar deteriorated condition.

Justification: Inspections have determined that there is significant deterioration of the poles, crossarms and other hardware. Extensive upgrading is necessary to ensure continuity of service to customers in the area as well as to provide the hydro plant with a secure connection to the main grid.

(i) Projects < $50,000

Cost: $739,000

Description: There are approximately 50 other lines that require replacement of deteriorated items.

Operating Experience: Annual inspections have identified deteriorated items that need to be replaced.

Justification: This project is necessary to replace poles, crossarms, conductors, insulators and miscellaneous hardware due to deficiencies identified during annual inspections in order to ensure that such lines provide reliable service to customers and are safe for both the public and line workers.

Newfoundland Power Inc.
St. John's Transmission
Ampacity Review

Prepared On:
July 17, 2003

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Introduction

This review was initiated as a result of recent events associated with the loss of the Oxen Pond (OXP) - Hydro infeed to the St. John's electrical system. While the widespread customer outages were caused by equipment failure in the Hydro portion of the OXP substation, there were difficulties encountered in switching the loads to the Hardwoods (HWD) substation. Among the limitations that were recognized in the process was the inability of some of the local 66 kV transmission lines to carry these loads without overloading due to exceeding the ampacity ratings of those transmission line conductors.

Many lines in the St. John's area 66 kV transmission system are limited in the load that can be carried due to conductor thermal ampacity ratings. This is not typical of the majority of the Newfoundland Power transmission system where low voltage conditions tend to be the limiting factor. The lines in the St. John's transmission system that are ampacity limited tend to be relatively short lines carrying relatively large loads compared to the transmission lines elsewhere in the Newfoundland Power electrical system.

Comparing forecasted substation loads and existing St. John's transmission line ampacities indicates that existing St. John's transmission lines will not be overloaded under normal peak loading conditions for the foreseeable future. This review focuses on contingency situations, where one or more transmission lines, or Hydro infeed transformers, are out of service. In such circumstances some St. John's transmission lines will overload by exceeding ampacity ratings.

While this review was initiated by the recent events at OXP, the review analyses other contingencies. Contingencies can be both unplanned and planned. For example the OXP equipment failure was unplanned. An example of a planned situation would be Hydro requiring portions of the OXP or HWD infeed substations in St. John's to be removed from service for preventative maintenance purposes.

The result of this review is a recommendation to upgrade the ampacity of certain 66 kV transmission lines in the St. John's area. Table 1 (Page 10) identifies the proposed transmission lines, the proposed year for upgrade and the estimated upgrade cost.

Existing System

The St. John's 66 kV transmission system is composed of the transmission lines identified in Figure 1 (Page 14). A unique line number identifies the lines and each line connects two or more substations. (e.g. transmission line 51L connects KEL [Kelligrews] substation to CHA [Chamberlains] substation) The ampacity limitation of each line in MVA is indicated below the line number. This ampacity limitation is based on the smallest conductor on the transmission line. A transmission line is usually constructed entirely of one conductor type when it is initially built. However, as portions of a transmission line are rebuilt over time, the construction standards at the time dictate conductors that may not be the same as the rest of that transmission line. Table 2 (Page 11) shows the various conductors on each transmission line in the St. John's area.

The ampacity limitations (MVA) in Figure 1 on page 14 show two numbers for each transmission line. The smaller number is reflective of summer conditions, and the larger number of winter or peak load conditions. The summer condition is based on an ambient temperature of 25 °C, wind of 0.61 m/sec (2 feet per sec) and a maximum conductor temperature of 75 °C. The winter condition is based on an ambient temperature of 0°C, wind of 0.61 m/sec (2 feet per sec) and a maximum conductor temperature of 75°C. Protective relaying and company practices would ensure that conductors are not operated in such a way as to exceed these limitations.

Contingency Situations

Under normal peak load conditions, with all facilities in service, ampacity limitations of the St. John's 66 kV transmission system are not exceeded for the near future (minimum of 5 years). This review therefore focuses on contingency situations. These are situations under which one or more components of the transmission or substation system are out of service. Under some of these contingencies the system can continue to supply service through alternate routes with loadings that may exceed peak load conditions for that route. However, the issue addressed in this review, is that contingency loading may exceed the ampacity limitations of certain transmission lines.

The contingencies considered as part of this review are in two categories. The first is 'single contingency outages'. This means that substations that normally have two sources of supply would continue to be supplied when one of those sources of supply is removed. Typical of this is a substation that is supplied via two transmission lines. The removal of one transmission line could be either an unscheduled outage or scheduled outage to perform maintenance. In the St. John's area there are a number of substations that are supplied via two or more transmission lines. These provide single contingency outage backup. A major portion of this analysis reviews such contingencies and proposes upgrading transmission lines when overloads occur under such single contingency circumstances. When one transmission line is removed, the substation can still be supplied via the other line within acceptable voltage limits and without other components of the electrical system becoming overloaded under peak load conditions.

The second general category is loss of 230 kV infeed supply to either of Hydro's substations. While the loss of one infeed transformer at either substation is considered a single contingency event, the loss of all transformers or a bus fault is considered a multiple contingency event. Power system planning criteria does not provide for no loss of load under multiple contingency events. It would not be reasonable to provide the amount of capacity that would be required at one Hydro infeed substation such that the loss of the other substation could be accommodated under peak load conditions. However, it is prudent that such a situation be accommodated at some load level. It was such a condition that initiated this review of transmission line loadings.

This review examines the transmission loadings that occur on loss of infeed supply to one Hydro substation under reduced loading conditions. The review examines the conditions where the infeed transformers at the remaining infeed substation are loaded to capacity and establishes which 66 kV transmission lines are overloaded in such circumstances. Where such lines are overloaded it proposes upgrading the lines for increased capacity. As part of this analysis, load flow simulations were undertaken using the 2004 forecasted peaks indicated in Table 3 (Page 13). The results of these load flows are contained in Appendix A. The flows indicated on the charts are in MW and MVAR, and should be converted to MVA for comparison with ampacity expressed in MVA.

Appendix A contains the 2004 load flows used to identify current problem areas within the St. John's area transmission system. Appendix B contains the 2008 load flows used to confirm the validity of upgrading transmission lines for ampacity purposes within the 2004 – 2008 time period. The base case system and associated load flow for this analysis is indicated in load flow 1 of Appendix A.

The following examine various contingency situations and establish which transmission lines should be upgraded for ampacity purposes.

<u>OXP-RRD-KBR-PEP-VIR-OXP Loop</u>

This is composed of a simple loop with dual supplies from the OXP substation to each of the Ridge Road (RRD) and Virginia Waters (VIR) substations. These dual lines are on separate structures with the exception of a section of the OXP-VIR double circuit where the lines are on the same structure. This loop is highlighted in Figure 2.

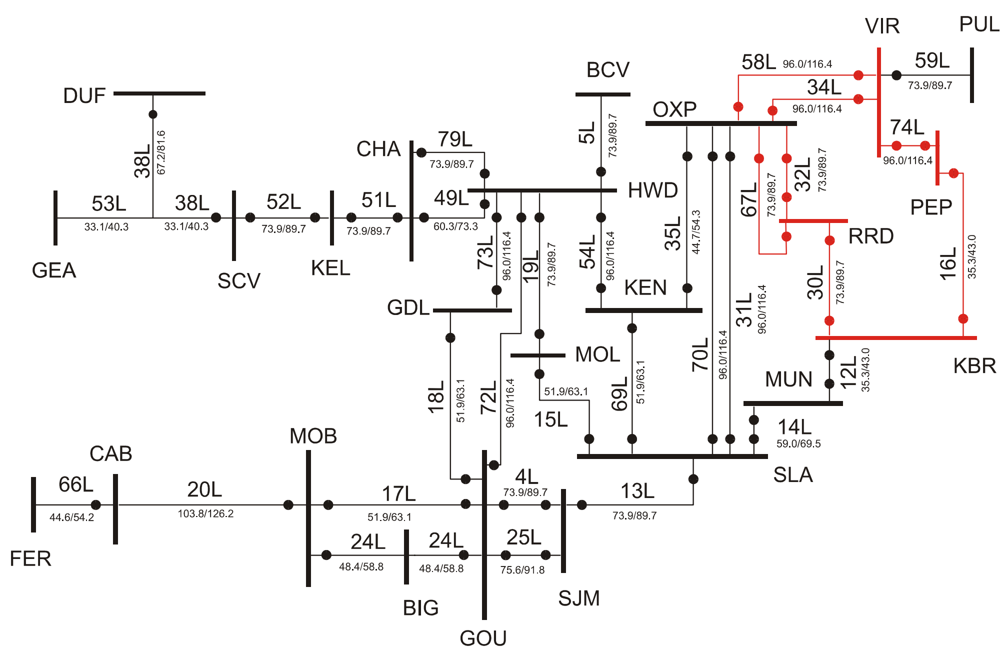


Figure 2: OXP-RRD-KBR-PEP-VIR-OXP Loop.

The 2004 peak substation loads supplied via this loop, including the Newfoundland Power substations noted above and Pulpit Rock (PUL) substation, total 171.7 MVA. Contingency analysis does not normally evaluate the loss of two lines at the same time. However in this case where a portion of the dual supply lines is on the same structures, there is concern regarding the ability to perform preventative maintenance on the double circuit OXP-VIR line without removing customers from service. For example, the ability to perform maintenance on OXP-VIR (58L and 34L) even under a typical summer daily conditions (50% of peak) without removing some customers from service would not be possible without overloading 16L transmission line from PEP-VIR. The summer load typical daily peak is considered to be 50% of annual peak. For the substations serviced from 16L, the summer peak load totals 45.7 MVA {(PEP+VIR+PUL)*50%} compared to summer ampacity of 16L at 35.3 MVA. Such maintenance would not be possible in winter months without removing customers from service. It is recommended that 16L transmission line ampacity be increased to 116.4 MVA in 2004. This involves changing the conductor from 1/0 copper to 715.5 aluminium. In order to further improve the capacity of this loop system, it is recommended that 30L be upgraded to 116.4 MVA when the line is rebuilt in 2007 due to deteriorated poles and hardware. This has been identified as part of the Company's annual transmission inspection process.

Two further transmission lines that are on the same structures for part of their length are 30L (KBR-RRD) and 16L (KBR-PEP). On contingency loss of these lines during peak conditions, the King's Bridge load can be accommodated through 12L (KBR-MUN).

The overloads of 16L under 2004 peak load conditions are indicated in load flows 2, 3 and 6 of Appendix A. An overload of 30L is indicated in load flow 3.

<u>OXP-SLA Dual Supply</u>

The dual transmission supply from OXP-SLA (31L and 70L) has both lines on the same structure for a significant portion of its length. This dual supply is highlighted in Figure 3.

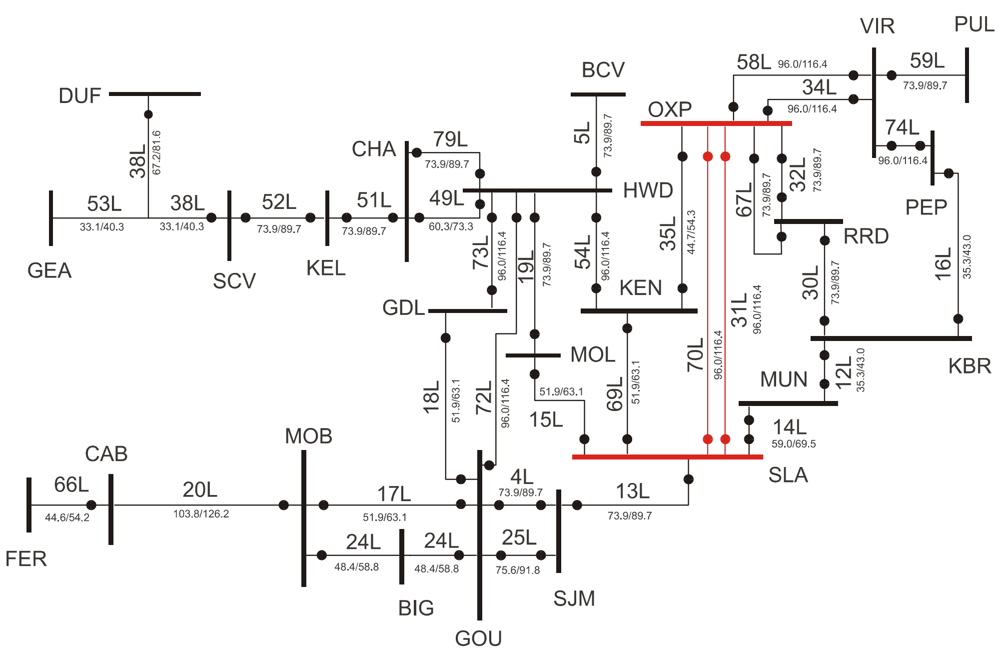


Figure 3: OXP-SLA Dual Supply.

Simultaneous loss of both lines, as indicated in load flow 7, results in 12L becoming overloaded. As shown in load flow 8, opening 35L will eliminate this overload. In addition, SLA-MUN (14L) is also on the same structures for part of its length. An outage of this line at the same time causes no transmission ampacity problems.

SLA- MUN-KBR Alternate Supply to MUN

This is a dual supply to Memorial University (MUN) from two adjacent loop systems. The dual supply to MUN is highlighted in Figure 4.

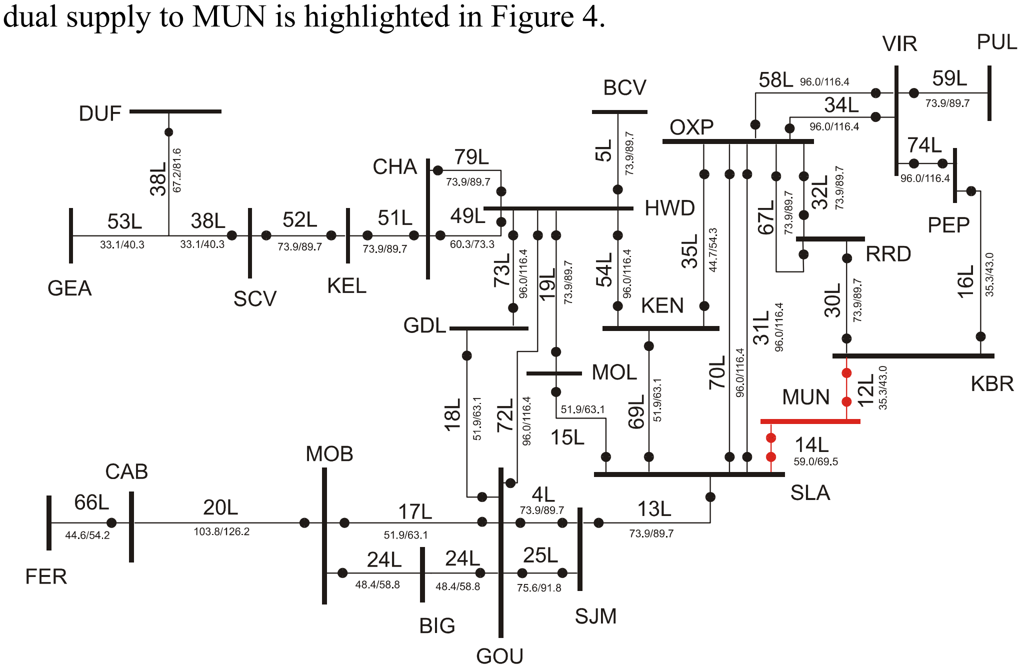


Figure 4: SLA-MUN-KBR Alternate Supply to MUN.

Both 12L and 14L have sections that are composed of underground cable rated 59/69.5 MVA. While the SLA-MUN-KBR supply can provide support to other substations under some outage circumstances; its ampacity limitation would not be exceeded in supplying only the MUN peak load (16 MVA).

Load flows 5 and 7 indicate cases where 12L is overloaded under contingency conditions. It is recommended that 12L be upgraded such that the cable section is the limiting ampacity. The Company's annual transmission inspection process has identified that 12L should be rebuilt in 2008, at which time the conductor should also be upgraded.

DUF-SCV-KEL-CHA-HWD Dual Infeed System

Within this system a portion of 38L has an ampacity of 33.1/40.3 MVA. The 50 MVA of transformer capacity at Holyrood 230/66 kV also limits this dual infeed system from the Holyrood supply point. This dual infeed system is highlighted in Figure 5.

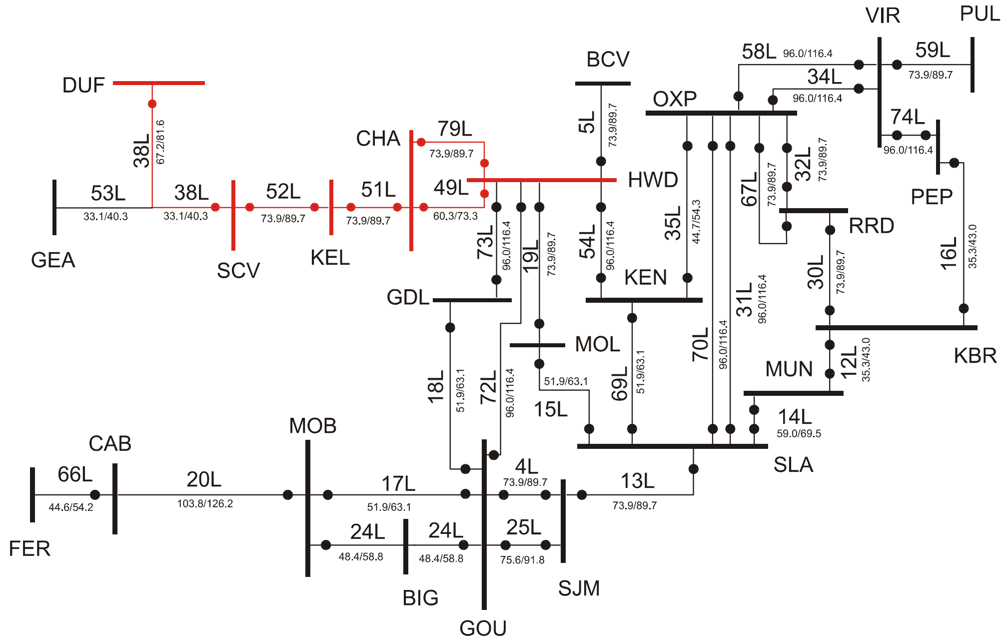


Figure 5: DUF-SCV-KEL-CHA-HWD Dual Infeed System.

Concerns with this system are the contingencies that involve the loss of 230/66 kV transformer infeed capacity at HWD and OXP. Under such circumstances it is necessary to reduce the load on the HWD and OXP transformers to within their rated capacities. Opening the lines between CHA and HWD would enable this entire Conception Bay South load to be supplied via the DUF infeed transformers. The 2004 peak loads at SCV, KEL and CHA total 53.8 MVA. This exceeds the 40.3 MVA of 38L but approximates the transformer capacity at the DUF infeed. Under low load conditions, this system can supply load into the HWD area as well. It is recommended that the ampacity of 38L be increased to 116.4 MVA through the installation of 715.5 MCM conductor.

Of special concern is the circumstance immediately following loss of infeed supply at HWD or OXP. If, as a result of loss of infeed supply to one of HWD or OXP, the protective relaying for 38L trips the line due to overload, then the result would further exacerbate infeed overloads at HWD or OXP. These overloads might then contribute to further overloads or St. John’s system collapse. Improving the ampacity of 38L would mitigate the potential for this problem occurring.

Load flow 9 indicates that 38L is overloaded under winter peak conditions with both HWD-CHA lines (49L and 79L) out of service. Also load flows 24, 27 and 28 show examples where an upgraded 38L is important when there are transformer infeed outages at OXP and HWD.

It is recommended that 38L be upgraded in 2004 such that this system is not limited by the ampacity rating of the transmission line.

HWD-GDL-GOU-SJM-SLA-OXP Dual Infeed System

This is a valuable dual infeed system on loss of HWD or OXP infeed supply. This dual infeed system is highlighted in Figure 6.

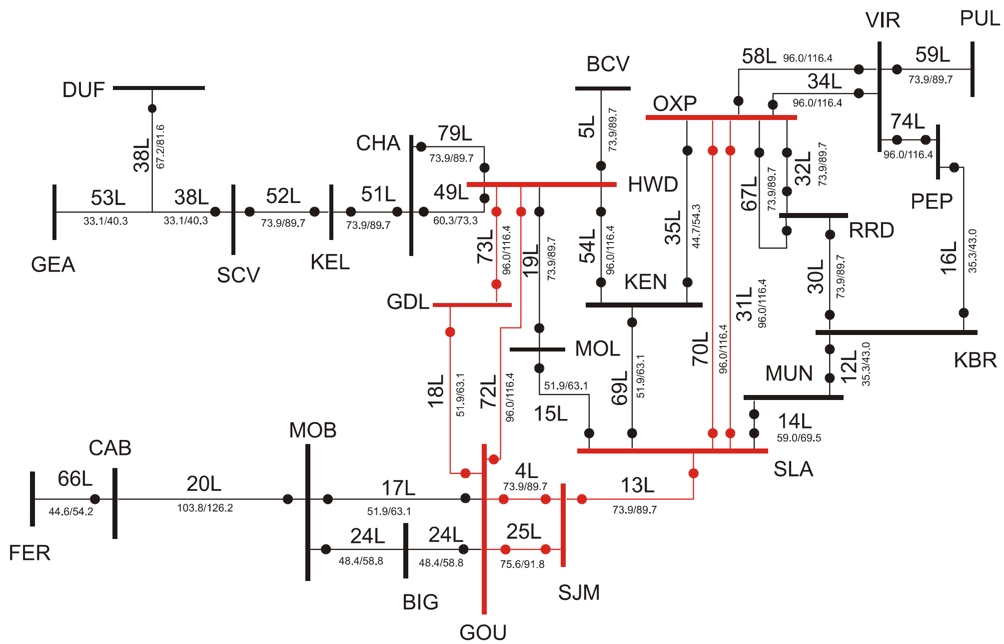


Figure 6: HWD-GDL-GOU-SJM-SLA-OXP Dual Infeed System.

Given the loads and the ampacity limitations, it is not considered necessary to upgrade the lines within this loop for ampacity purposes.

There are two transmission lines on the same structures for a portion of their length after they exit St. John's Main SJM substation, SJM-SLA (13L) and SJM-GOU (4L). Loss of these two lines is adequately carried on peak by the remaining SJM-GOU line (25L) as indicated in load flow 29.

HWD-MOL-SLA-KEN-OXP Dual Infeed System

This is a valuable dual infeed system on loss of HWD or OXP infeed supply. This dual infeed system is highlighted in Figure 7.

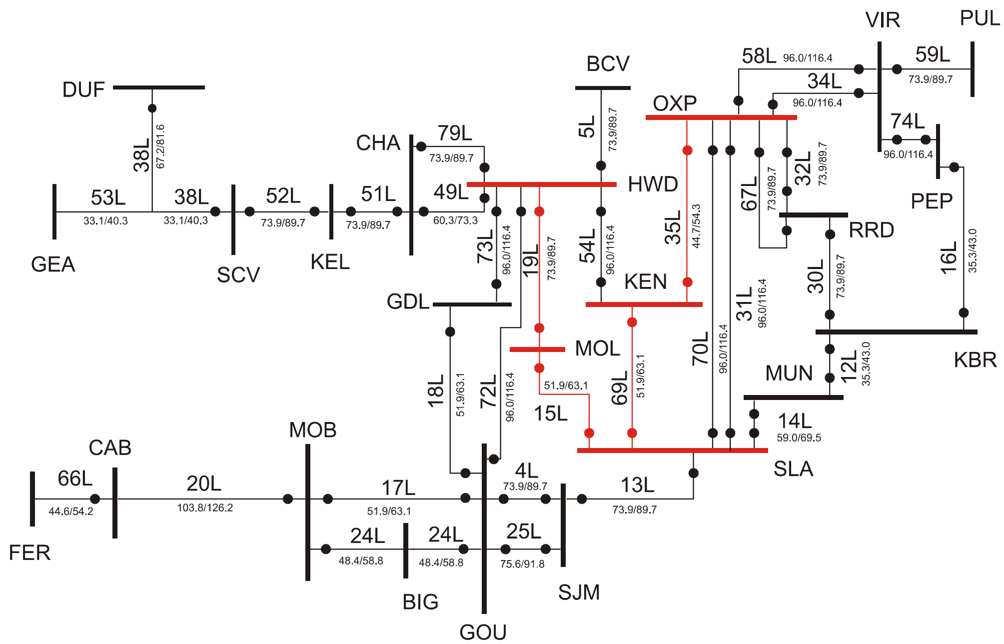


Figure 7: HWD-MOL-SLA-KEN-OXP Dual Infeed System.

The ampacity of 69L and 19L are of concern under these conditions, especially under conditions where summer ampacity conditions may apply. Load flows 14, 15, 16, 17 and 24 are examples where an upgrade to 69L and19L would be of value.

As part of the Company's transmission inspection process, 69L has been scheduled for rebuilding in 2007. It is recommended that 69L be upgraded for ampacity purposes during that time.

Loss of one of Hydro's largest transformers at the infeed point has been an accepted contingency to be met under peak load conditions. Load flow 10 indicates the power flows under peak loads for loss of a 125 MVA 230/66 kV transformer at OXP. There are no transmission overloads as a result, but the remaining infeed transformers at OXP become overloaded. By using the 50 MW gas turbine at HWD and opening selected lines in the 66 kV system, the overload on the OXP transformers can be removed with no overloads on the 66 kV transmission system, as indicated in load flow 13.

<u>All OXP 230/66 kV Transformers Out Of Service</u>

While the loss of all OXP 230/66 kV transformers constitutes an extreme contingency, it has happened a number of times because the transformer protection clears the 230 kV incoming circuits and the 66 kV bus. One would not expect the system to be able to supply all customers on peak under such circumstances. However, there is an expectation that, at some load level, service would be maintained to all customers in such a contingency.

There is also the circumstance where Hydro requires an outage to its portion of the OXP substation for preventative maintenance purposes. This is normally done during lighter load conditions. This condition has the same system configuration as loss of all infeed transformers at the substation.

At 65% of peak loads, all customers can be supplied by HWD with the HWD 50 MW GT in service and no infeed transformers or transmission lines overload at HWD.

At 80% of peak loads with the HWD 50 MW GT in service, there are transformer overloads at HWD that cannot be reduced below overload, as indicated in load flow 17b.

Care must be taken when the system is not under winter peak conditions and when ambient temperatures are higher, that appropriate transmission line ratings be used. This may be the case when the complete 230/66 kV supply is lost at either the OXP or HWD substations or especially under summer preventative maintenance conditions.

One HWD 125 MVA Transformer Out Of Service

Load flow 18 shows the power flows under peak loads for loss of a 125 MVA 230/66 kV transformer at HWD. While there are no transmission overloads as a result, remaining infeed transformers at HWD become overloaded. The transformer overloads are removed by using the 50 MW gas turbine at HWD as seen in load flow 20.

All HWD 230/66 kV Transformers Out Of Service

As in the OXP case, the loss of all HWD 230/66 kV transformers constitutes an extreme contingency. One would not expect the system to be able to supply all customers on peak under such circumstances. However, there is an expectation that, at some load level, service would be maintained to all customers in such unplanned contingencies and for scheduled maintenance outages of the Hydro infeed system at HWD.

At 60% of peak loads, all customers can be supplied via the existing system, but 38L overloads as indicated in load flow 23.

At 80% of peak loads with the HWD 50 MW GT in service, there are no transformer overloads. However 38L overloads as indicated in load flow 26.

Summary of Recommendations

Table 1 indicates a proposed upgrading of transmission lines within the St. John's area transmission system for ampacity purposes.

Table 1
Proposed St. John's Area Transmission Upgrades For Ampacity Purposes

Transmission Line	Existing Ampacity (MVA)	Upgrade Length (Km)	Proposed Ampacity	Proposed Year	Estimated Cost
16L - Pepperell to King's Bridge	35.3 / 43.0	1.98	96 / 116.4	2004	$197,000
38L - Golden Eagle Tap to Seal Cove	33.0 / 40.3	2.74	96 / 116.4	2004	$231,000
30L – Ridge Road to King's Bridge	73.9 / 89.7	2.91	96 / 116.4	2007	$340,000
69L – Kenmount to Stamp's Lane	51.9 / 63.1	3.41	96 / 116.4	2007	$269,000
12L – Memorial to King's Bridge	35.3 / 43.0	2.17	59/69.5	2008	$240,000

Table 2
Transmission Line Conductors

LINE ID	FROM	TO	LENGTH (km)	VOLT (kV)	EQUIV. SPC. (m)	CONDUCTOR SIZE	CONDUCTOR TYPE	AMPACITY RATING MVA @ 25C	AMPACITY RATING MVA @ 0C
3 L	GOULDS	PETTY HARBOUR	5.63	33	1.219	1/0	CU	17.6	21.5
4 L	GOULDS	POINT A	8.85	66	1.402	477	ASC	73.9	89.7
4 L	POINT A	MAIN SUB	0.40	66	0	1000	CBLE	86.3	98.9
5 L	HARDWOODS	BROAD COVE	12.87	66	1.951	477	ASC	73.9	89.7
7 L	BROAD COVE	BELL ISLAND	5.40	12.5	0	250	CBLE	0	9.5
11 L	MOBILE	TORS COVE	4.96	66	1.219	3/0	CU	48.4	58.8
12 L	KING'S BRIDGE	POINT A	2.17	66	1.402	1/0	CU	35.3	43
12 L	POINT A	MEMORIAL	0.97	66	0	350	CBLE	59	69.5
13 L	MAIN SUB	POINT A	0.42	66	0	1000	CBLE	86.3	98.9
13 L	POINT A	STAMP'S LANE	2.64	66	1.402	477	ASC	73.9	89.7
14 L	MEMORIAL	POINT A	1.13	66	0	350	CBLE	59	69.5
14 L	POINT A	STAMP'S LANE	1.13	66	1.402	477	ASC	73.9	89.7
15 L	STAMP'S LANE	POINT A	2.35	66	1.707	477	ASC	73.9	89.7
15 L	POINT A	POINT B	0.37	66	1.707	266.8	ASCR	51.9	63.1
15 L	POINT B	POINT C	0.54	66	1.707	477	ASC	73.9	89.7
15 L	POINT C	MOLLOY'S LANE	0.90	66	2.682	477	ASC	73.9	89.7
16 L	KING'S BRIDGE	PEPPERRELL	1.98	66	1.707	1/0	CU	35.3	43
17 L	GOULDS	MOBILE	28.65	66	3.993	266.8	ASCR	51.9	63.1
18 L	GOULDS	POINT A	4.62	66	1.707	266.8	ASCR	51.9	63.1
18 L	POINT A	GLENDALE	1.13	66	1.615	715.5	ASC	96	116.4
19 L	HARDWOODS	POINT A	8.00	66	1.951	715.5	ASC	96	116.4
19 L	POINT A	POINT B	0.61	66	1.951	477	ASC	73.9	89.7
19 L	POINT B	POINT C	0.47	66	1.951	715.5	ASC	96	116.4
19 L	POINT C	MOLLOY'S LANE	0.92	66	2.682	477	ASC	73.9	89.7
20 L	MOBILE	ROCKY PD PLANT	5.81	66	3.993	266.8	ASCR	51.9	63.1
20 L	ROCKY PD PLANT	HORSE CHOPS TAP	12.25	66	3.993	266.8	ASCR	51.9	63.1
20 L	HORSE CHOPS TAP	CAPE BROYLE	2.06	66	3.993	266.8	ASCR	51.9	63.1
21 L	HORSE CHOPS TAP	HORSE CHOPS	5.73	66	3.993	266.8	ASCR	51.9	63.1
22 L	ROCKY POND PLAN	MORRIS PLANT	5.45	66	2	4/0	AASC	44.6	54.2
23 L	MOBILE	PIERRE'S BROOK	5.47	33	1.219	3/0	CU	24.2	29.4
24 L	GOULDS	BIG POND SUBST.	7.76	66	1.951	3/0	CU	48.4	58.8
24 L	BIG POND SUB.	POINT A	12.87	66	1.951	3/0	CU	48.4	58.8
24 L	POINT A	MOBILE	7.76	66	3.993	266.8	ASCR	51.9	63.1
25 L	GOULDS	MAIN SUB	9.25	66	3.444	477	ASCR	75.6	91.8

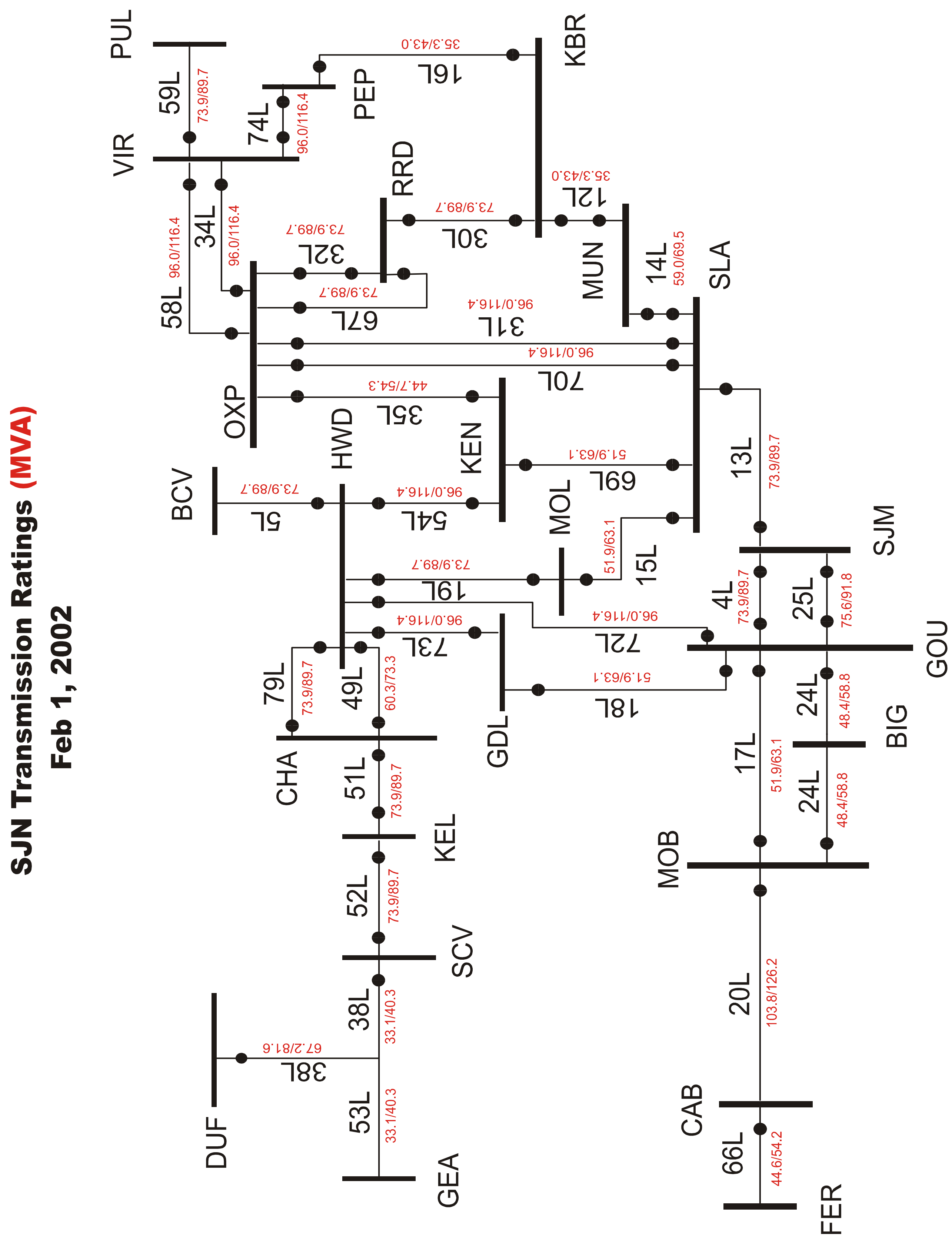
Table 2b
Transmission Line Conductors

LINE ID	FROM	TO	LENGTH (km)	VOLT (kV)	EQUIV. SPC. (m)	CONDUCTOR SIZE	CONDUCTOR TYPE	AMPACITY RATING MVA @ 25C	AMPACITY RATING MVA @ 0C
28 L	BROAD COVE	POINT A	0.58	12.5	1.219	3/0	CU	9.2	11.1
28 L	POINT A	BELL ISLAND	6.11	12.5	0	4/0	CBLE	0	7.7
30 L	RIDGE ROAD	KING'S BRIDGE	2.91	66	1.402	477	ASC	73.9	89.7
31 L	OXEN POND	STAMP'S LANE	2.54	66	2.304	715.5	ASC	96	116.4
32 L	OXEN POND	RIDGE ROAD	3.07	66	1.402	477	ASC	73.9	89.7
34 L	OXEN POND	POINT A	2.09	66	2.286	715.5	ASC	96	116.4
34 L	POINT A	POINT B	2.83	66	1.947	715.5	ASC	96	116.4
34 L	POINT B	POINT C	1.53	66	1.951	715.5	ASC	96	116.4
34 L	POINT C	VIRGINIA WATERS	2.83	66	2.286	715.5	ASC	96	116.4
35 L	OXEN POND	POINT A	2.04	66	1.951	477	ASC	73.9	89.7
35 L	POINT A	POINT B	3.39	66	1.707	4/0	ASCR	44.7	54.3
35 L	POINT B	KENMOUNT	1.51	66	1.951	715.5	ASC	96	116.4
38 L	HOLYROOD	GLDEN EAGLE TAP	0.80	66	1.951	397.5	ASCR	67.2	81.6
38 L	GLDEN EAGLE TAP	SEAL COVE	2.74	66	1.951	2/0	ASCR	33.1	40.3
49 L	HARDWOODS	POINT A	2.72	66	1.402	336.4	ASCR	60.3	73.3
49 L	POINT A	CHAMBERLAINS	5.50	66	1.951	477	ASC	73.9	89.7
51 L	CHAMBERLAINS	POINT A	1.54	66	1.92	477	ASC	73.9	89.7
51 L	POINT A	KELLIGREWS	8.61	66	1.951	477	ASC	73.9	89.7
52 L	KELLIGREWS	SEAL COVE	8.22	66	1.951	477	ASC	73.9	89.7
53 L	GLDEN EAGLE TAP	GOLDEN EAGLE	5.95	66	1.951	2/0	ASCR	33.1	40.3
54 L	HARDWOODS	KENMOUNT	8.00	66	1.951	715.5	ASC	96	116.4
58 L	OXEN POND	POINT A	3.84	66	1.951	715.5	ASC	96	116.4
58 L	POINT A	VIRGINIA WATERS	2.85	66	2.682	715.5	ASC	96	116.4
59 L	VIRGINA WATERS	PULPIT ROCK	7.72	66	1.951	477	ASC	73.9	89.7
66 L	CAPE BROYLE	POINT A	7.24	66	4.039	266.8	ASCR	51.9	63.1
66 L	POINT A	FERMEUSE	14.32	66	1.951	4/0	AASC	44.6	54.2
67 L	OXEN POND	POINT A	4.30	66	1.951	715.5	ASC	96	116.4
67 L	POINT A	RIDGE ROAD	0.16	66	1.951	477	ASC	73.9	89.7
69 L	KENMOUNT	POINT A	1.32	66	1.707	715.5	ASC	96	116.4
69 L	POINT A	POINT B	1.98	66	1.707	266.8	ASCR	51.9	63.1
69 L	POINT B	POINT C	0.37	66	1.951	715.5	ASC	96	116.4
69 L	POINT C	STAMPS LANE	0.76	66	1.707	266.8	ASCR	51.9	63.1
70 L	OXEN POND	STAMPS LANE	2.54	66	2.304	715.5	ASC	96	116.4
72 L	HARDWOODS	GOULDS	11.36	66	1.951	715.5	ASC	96	116.4
73 L	HARDWOODS	POINT A	5.58	66	1.951	715.5	ASC	96	116.4
73 L	POINT A	GLENDALE	1.21	66	1.615	715.5	ASC	96	116.4
74 L	VIRGINIA WATERS	POINT A	1.11	66	3.594	715.5	ASC	96	116.4
74 L	POINT A	PEPPERRELL	4.50	66	2.043	715.5	ASC	96	116.4
79 L	HARDWOODS	POINT A	1.50	66	1.951	715.5	ASC	96	116.4
79 L	POINT A	POINT B	5.42	66	1.947	477	ASC	73.9	89.7
79 L	POINT B	CHAMBERLAINS	1.54	66	1.92	477	ASC	73.9	89.7

Table 3
St. John's Area Substation 5-Year Load Forecast
(2003/05/14)

	Substation (Notes)	Des.	Operating Voltage (kV)	Transformer Capacity - MVA Rating	Existing	2002 Peak MVA	2003	2004	2005	2006	2007	2008	Max. XFMR. Util.
BIG	Big Pond (13)	T1	12.47	8.4/11.2	11.2	7.5	8.0	8.0	8.0	8.0	9.2	9.3	83%
BCV	Broad Cove (8 & 10)	T1	12.47	15/20/25	25.0	22.9	24.7	25.0	24.3	24.7	24.4	24.9	100%
CAB	Cape Broyle	T1	12.47	5.0/6.7	5.0	2.3	2.5	2.5	2.5	2.5	2.6	2.6	52%
CHA	Chamberlains (6 & 11)	T1	24.94	15/20/25	25.0	24.2	13.2	15.7	16.0	16.5	19.0	19.7	79%
CHA	Chamberlains	T2	24.94	15/20/25	25.0		13.2	15.7	16.0	16.5	19.0	19.7	79%
FER	Fermeuse	T1	12.47	3.0/4.0	4.0	2.6	2.8	2.8	2.9	2.9	3.0	3.0	75%
GDL	Glendale (3, 5 & 9)	T1	12.47	15/20/25	25.0	22.2	24.7	23.8	23.8	16.6	16.8	17.0	99%
GDL	Glendale	T2	12.47	15/20/25	25.0	22.2	24.9	24.0	23.9	16.7	16.9	17.1	99%
GDL	Glendale	T3	12.47	15/20/25	25.0					16.7	16.9	17.1	68%
GOU	Goulds (5 & 14)	T2	12.47	15/20	20.0	8.1	8.9	11.0	11.4	11.8	12.3	15.1	75%
GOU	Goulds	T3	12.47	10/13.3	13.3	8.4	9.0	9.2	9.2	9.4	9.5	9.7	73%
HWD	Hardwoods (3, 4 & 9)	T1	12.47	15/20	20.0	19.6	19.5	19.8	19.8	19.0	19.3	19.6	99%
HWD	Hardwoods	T2	12.47	15/20	20.0	19.6	19.4	19.7	19.7	18.9	19.2	19.5	99%
HWD	Hardwoods (8, 10 & 11)	T3	24.94	15/20/25	25.0	17.3	19.4	20.5	22.6	23.9	22.0	23.3	96%
HOL	Holyrood 02					1.7	1.8	1.8	1.9	1.9	1.9	1.9	
KEL	Kelligrews (6, 7 & 12)	T1	12.47	11.25/14.95	15.0	13.4	14.6	11.8	12.0	12.3	13.6	14.0	97%
KEN	Kenmount (4)	T1	24.94	15/20/25	25.0	16.9	18.4	18.7	18.7	18.9	19.1	19.4	78%
KEN	Kenmount	T2	24.94	15/20/25	25.0	17.3	19.2	19.4	19.5	19.7	19.9	20.2	81%
KBR	King's Bridge	T1	4.16	7.5/10	10.0	7.2	7.7	7.8	7.8	7.8	7.9	8.0	80%
KBR	King's Bridge	T2	4.16	7.5/10	10.0	7.2	7.7	7.7	7.7	7.8	7.9	8.0	80%
KBR	King's Bridge	T3	12.47	15/20/25	25.0	18.7	20.1	20.3	20.4	20.6	20.9	21.2	85%
MOB	Mobile (13)	T2	12.47	5.0/6.7	6.7	5.9	6.4	6.5	6.6	6.6	6.3	6.5	99%
MOL	Molloy's Lane (14)	T1	12.47	15/20/25	25.0	22.0	24.2	24.4	24.4	24.6	24.9	24.0	100%
MOL	Molloy's Lane	T2	12.47	15/20/25	25.0	22.0	22.9	23.1	23.1	23.3	23.5	22.7	94%
OXP	Oxen Pond	T1	12.47	10/13.3	13.3	8.5	9.1	9.3	9.3	9.4	9.5	9.7	73%
PEP	Pepperrell	T1	12.47	15/20/25	25.0	20.9	22.4	22.6	22.6	22.8	23.1	23.4	94%
PHR	Petty Harbour	T1	4.16	3.0/4.0	3.0	2.4	2.6	2.6	2.7	2.7	2.7	2.8	94%
PUL	Pulpit Rock	T1	12.47	15/20/25	25.0	17.5	18.9	19.4	19.6	20.0	20.4	20.9	84%
RRD	Ridge Road	T1	4.16	1.7/2.2	2.2	0.8	0.9	0.9	0.9	0.9	0.9	0.9	40%
RRD	Ridge Road	T2	12.47	15/20	20.0	13.6	15.9	16.3	16.6	17.0	17.5	18.1	91%
RRD	Ridge Road	T3	12.47	15/20	20.0	17.2	17.6	18.1	18.4	18.8	19.4	20.0	100%
SCV	Seal Cove (7 & 12)	T2	12.47	11.2	11.2	10.6	**11.5**	10.7	10.8	11.1	10.3	10.5	**103%**
SJM	St. John's Main	T4	4.16	7.5/10	7.5	2.1	2.2	2.3	2.3	2.3	2.3	2.3	31%
SJM	St. John's Main	T2	12.47	15/20/25	25.0	20.7	20.4	20.7	20.7	20.9	21.1	21.4	86%
SJM	St. John's Main	T1	12.47	15/20/25	25.0	19.4	22.5	22.8	22.8	23.0	23.3	23.6	94%
SLA	Stamps Lane	T1	4.16	10/13.3	13.3	10.0	10.7	10.8	10.8	10.8	11.0	11.1	83%
SLA	Stamps Lane	T3	12.47	15/20/25	25.0	19.8	22.8	23.0	23.0	23.2	23.5	23.8	95%
SLA	Stamps Lane	T4	12.47	15/20/25	25.0	18.4	19.8	20.2	20.3	20.6	21.0	21.4	86%
VIR	Virginia Waters	T1	12.47	15/20/25	25.0	22.1	16.4	16.9	17.3	17.8	18.5	19.2	77%
VIR	Virginia Waters	T2	12.47	15/20/25	25.0	21.6	15.0	15.5	15.9	16.3	16.9	17.6	70%
VIR	Virginia Waters	T3	12.47	15/20/25	25.0		16.4	16.9	17.3	17.8	18.5	19.2	77%

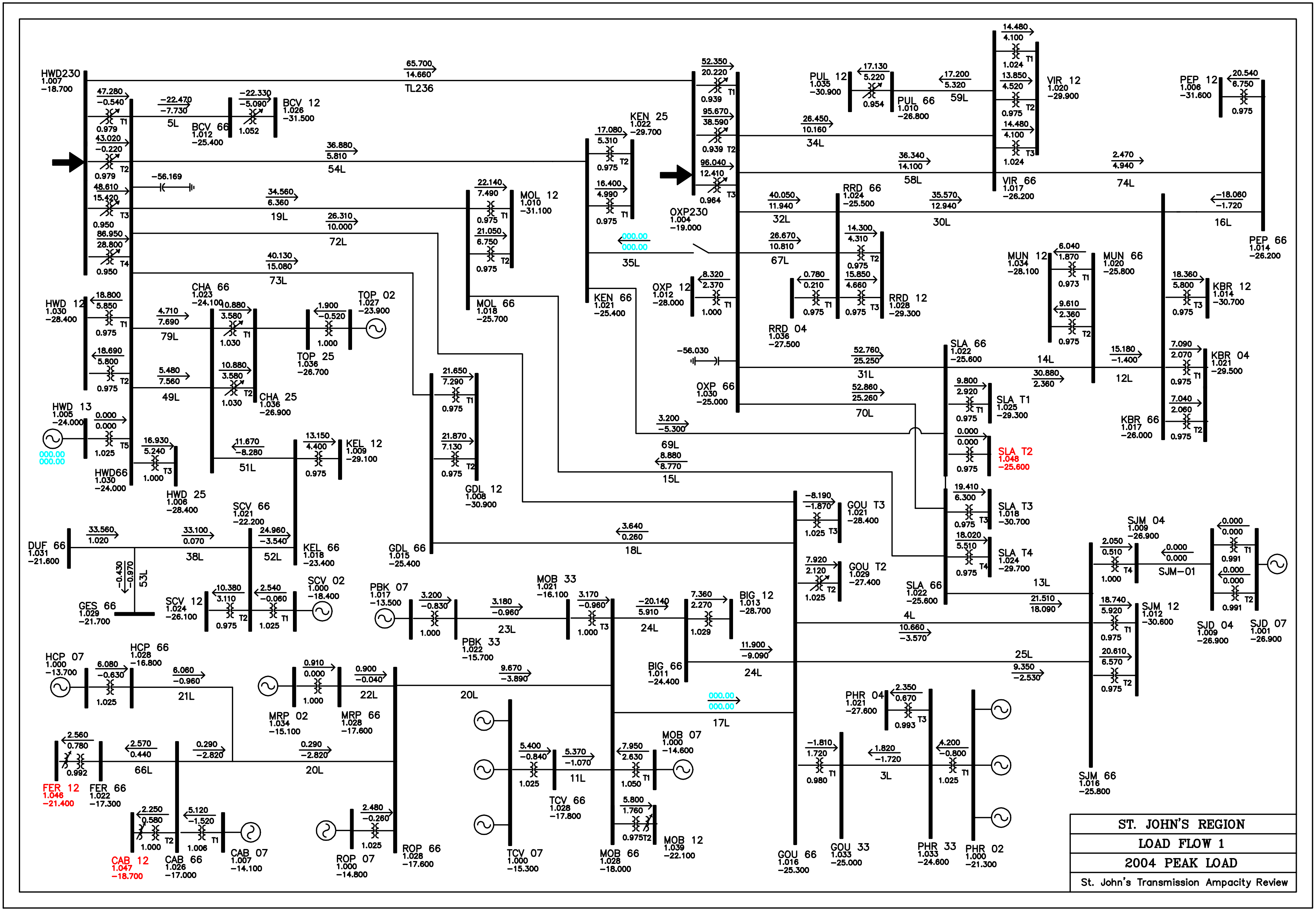
Figure 1
St. John's Area Transmission Line Ampacity

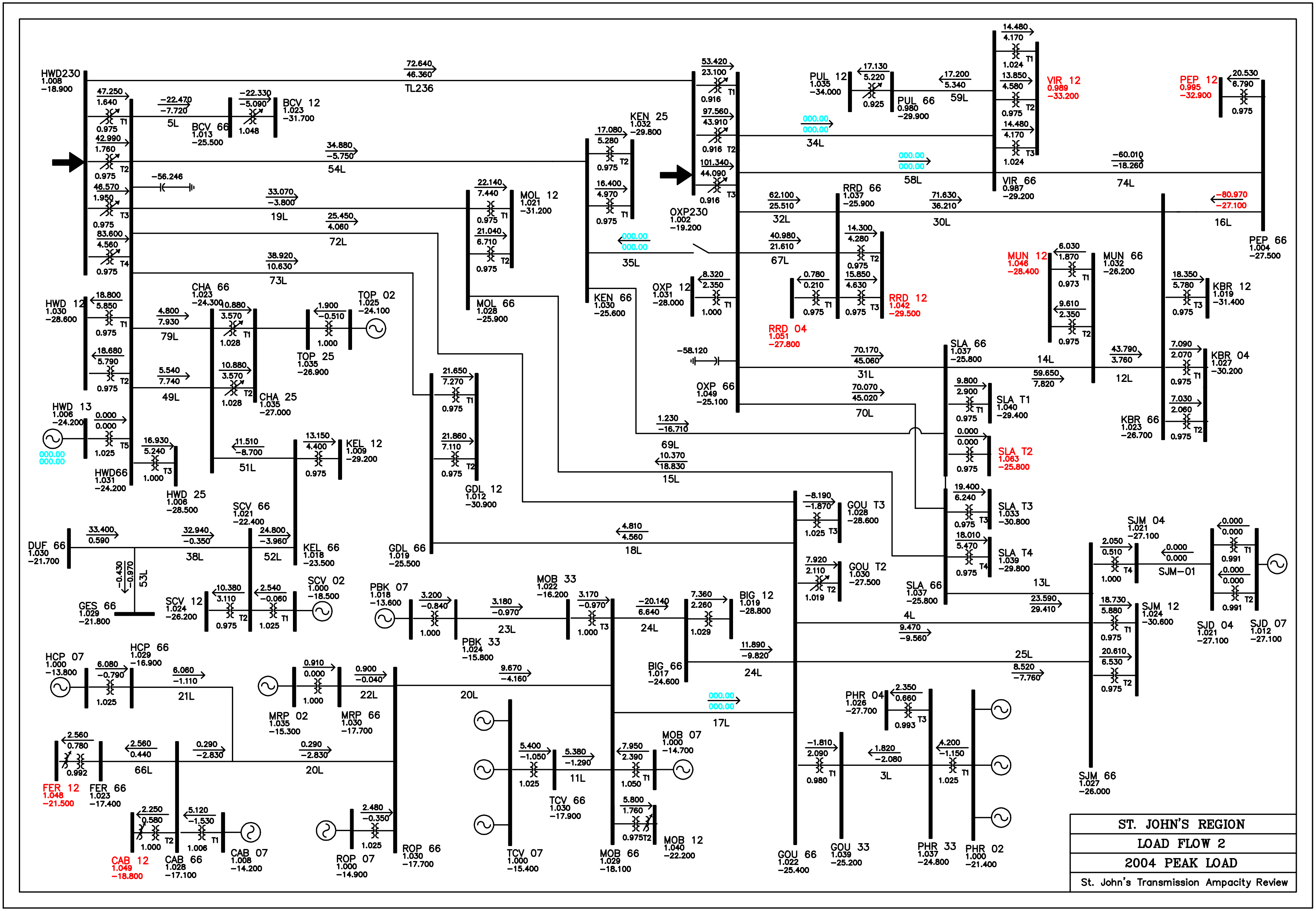


APPENDIX A
2004 LOAD FLOW DRAWINGS

Index

1. Base case 2004 peak loads
2. Base case, open two lines OXP-VIR (34L and 58L), raise OXP voltage to 1.05 pu
3. As in #2, and open MUN-KBR (12L)
4. Base case, Open one line OXP-VIR (58L), raise OXP voltage to 1.05 pu, and open MUN-KBR (12L)
5. Base case, open two lines OXP-RRD (32L and 67L), raise OXP voltage to 1.05 pu
6. Base case, open two lines OXP-RRD (32L and 67L), raise OXP voltage to 1.05 pu and open MUN-KBR (12L)
7. Base case, open two lines OXP-SLA (31L and 70L)
8. As in #7, close OXP-KEN (35L)
9. Base case, open two lines HWD-CHA (79L and 49L)
10. Base case, open 125 MVA transformer at OXP 230/66
11. As in #10, close OXP-KEN (35L)
12. As in #10, open OXP-SLA (70L)
13. As in #10, open two lines OXP-SLA (31L and 70L)
14. 50% of 2004 peak loads, open OXP 230/66 kV transformers (T1, T2 &T3), HWD GT on
15. 65% of 2004 peak loads, open OXP 230/66 kV transformers (T1, T2 &T3), HWD GT on
16. As in #15, close OXP-KEN (35L)
17. 80% of 2004 peak loads, open OXP 230/66 kV transformers (T1, T2 &T3), HWD GT on, HWD voltage to 1.05 pu, close OXP-KEN (35L)
18. Base case, open 125 MVA transformer at HWD 230/66
19. As in #18, open two lines OXP-CHA (79L and 49L)
20. As in #18, HWD GT on
21. 50% of 2004 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4)
22. As in #21, HWD GT on
23. 60% of 2004 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4)
24. 75% of 2004 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4)
25. As in #24, HWD GT on
26. 80% of 2004 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4), HWD GT on
27. As in #24, HWD GT on, no Southern Shore generation
28. As in #24, HWD GT on, no Southern Shore generation, close OXP-KEN (35L)
29. Base case, open SJM-SLA (13L) and SJM – GOU (4L)


ST. JOHN'S REGION
LOAD FLOW 1
2004 PEAK LOAD
St. John's Transmission Ampacity Review

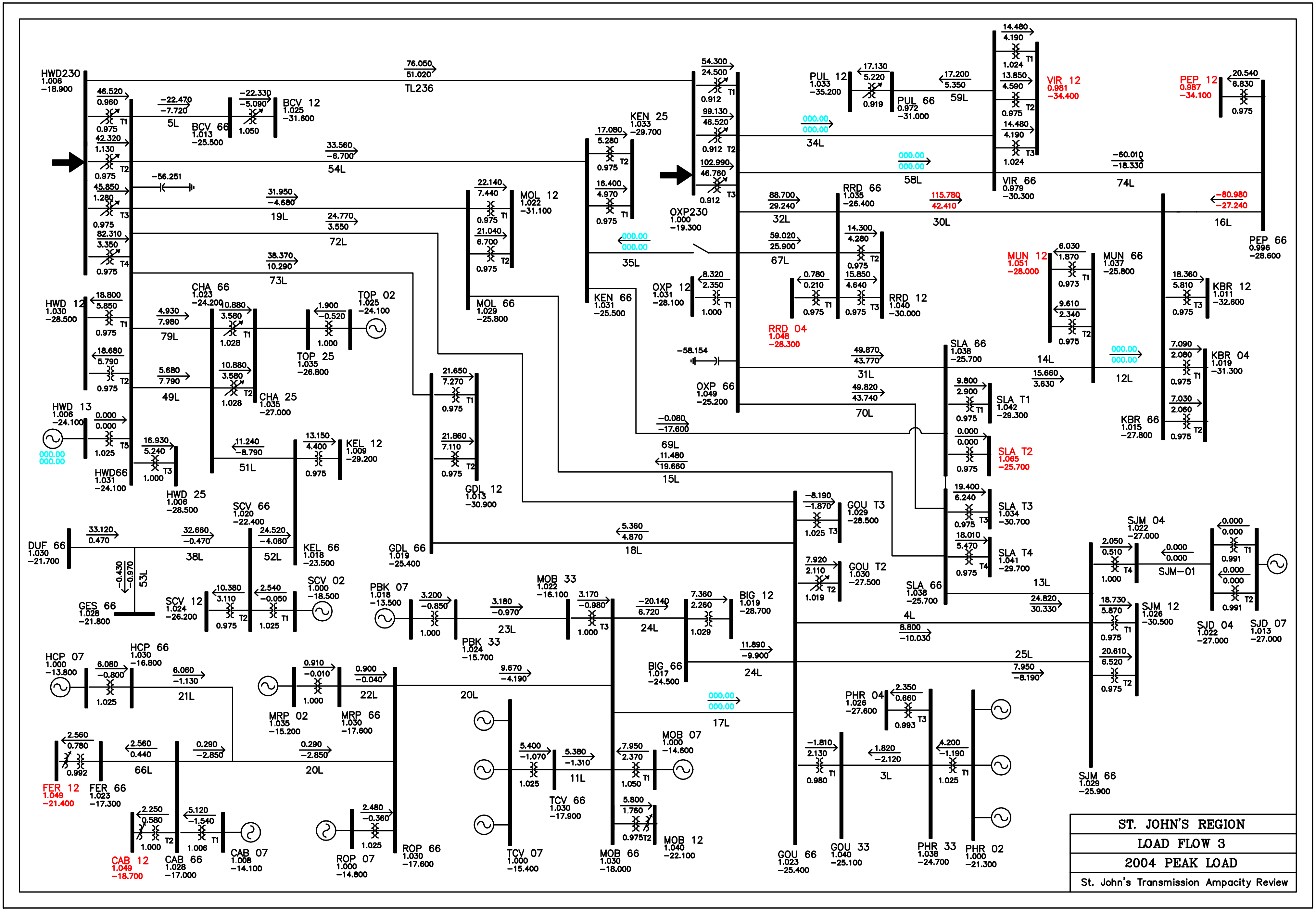


ST. JOHN'S REGION

LOAD FLOW 2

2004 PEAK LOAD

St. John's Transmission Ampacity Review

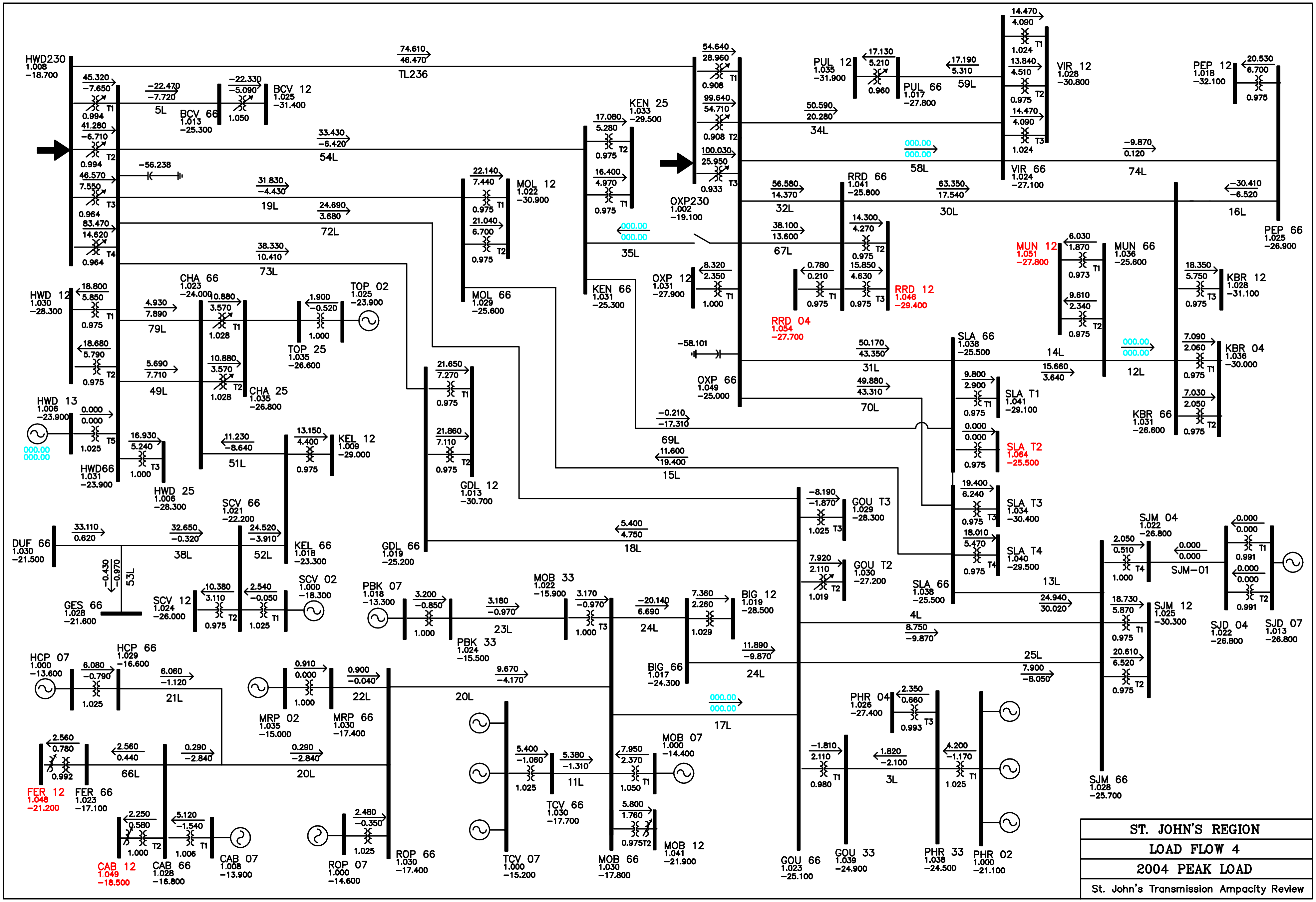


ST. JOHN'S REGION

LOAD FLOW 3

2004 PEAK LOAD

St. John's Transmission Ampacity Review

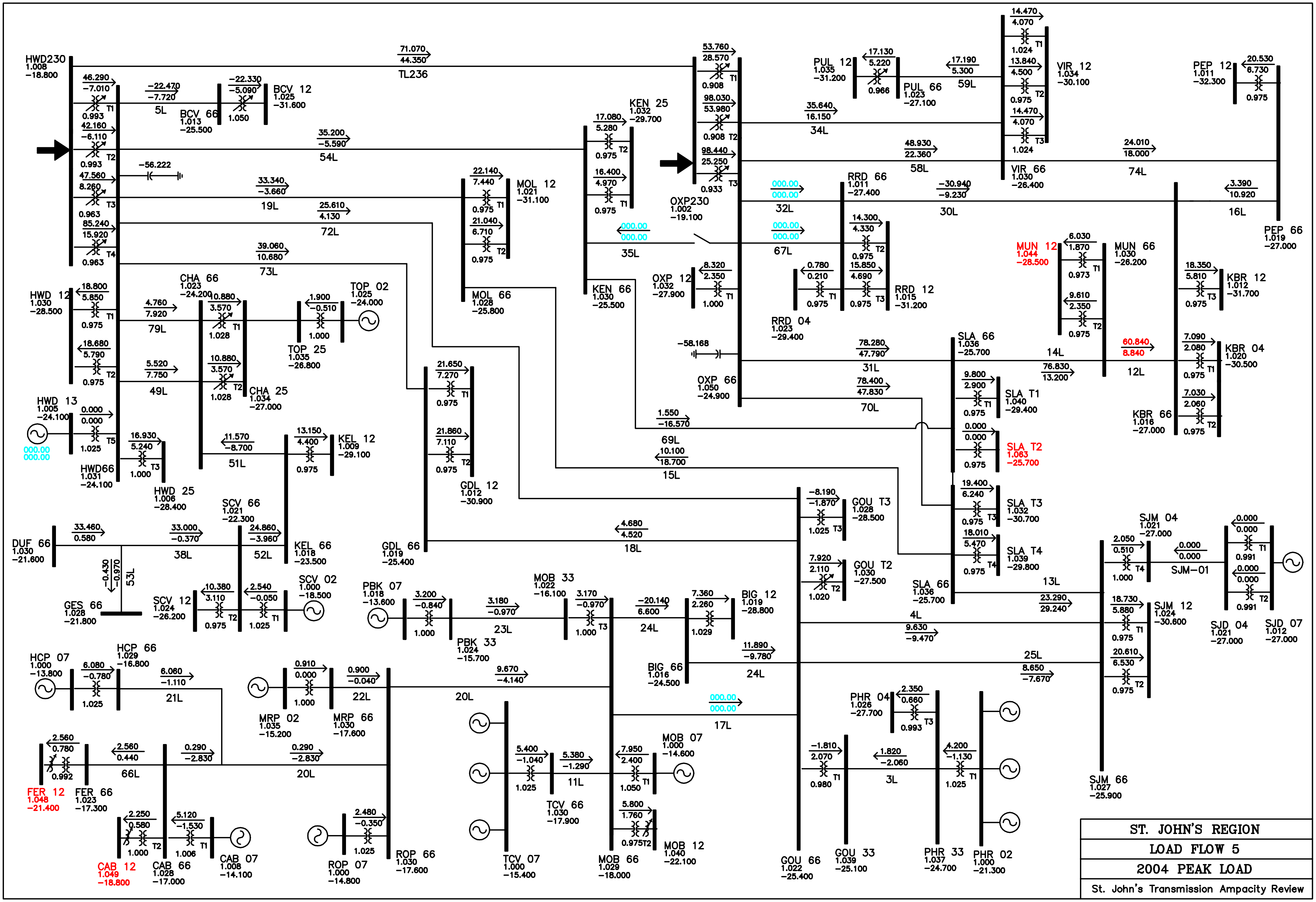


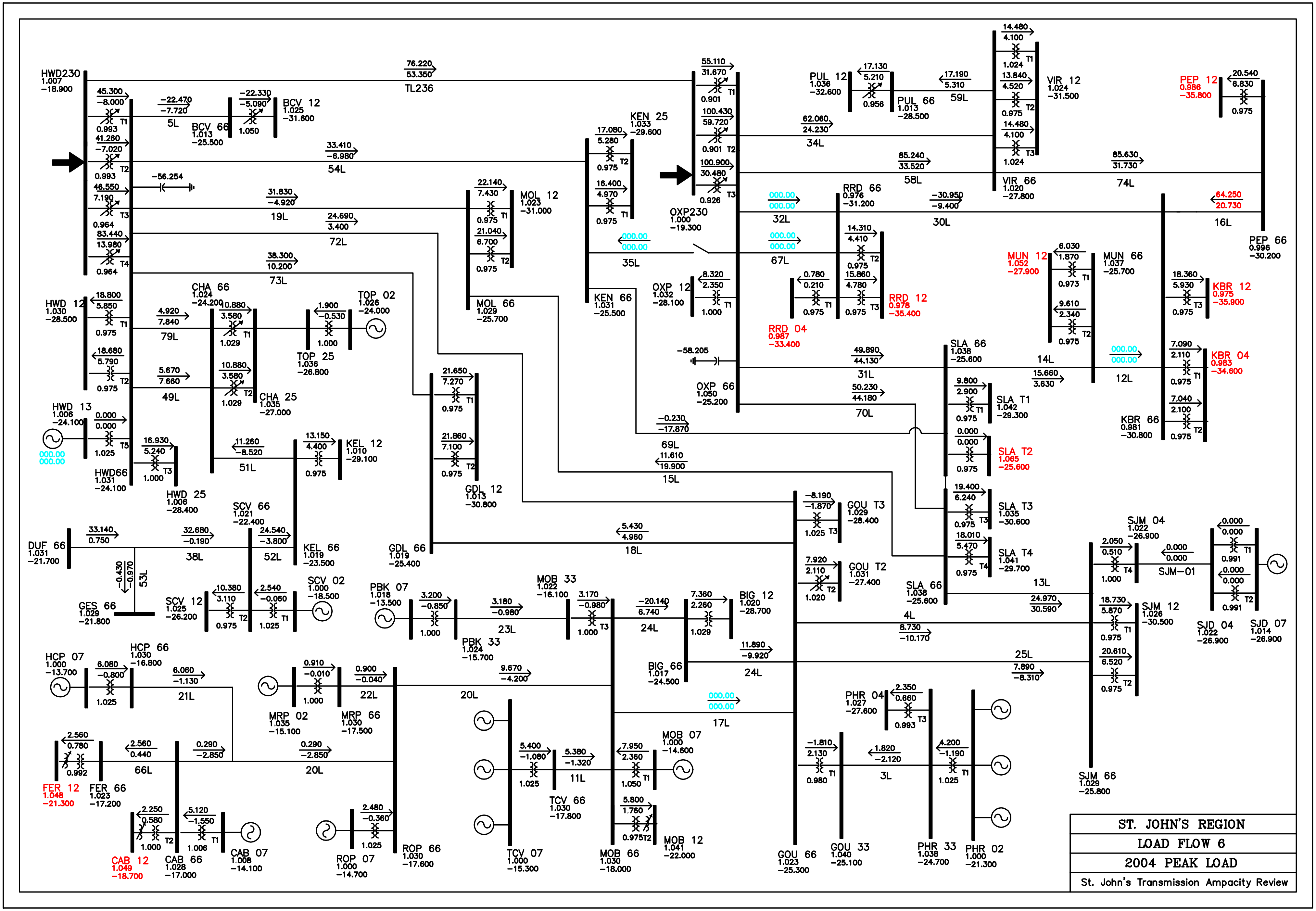
ST. JOHN'S REGION

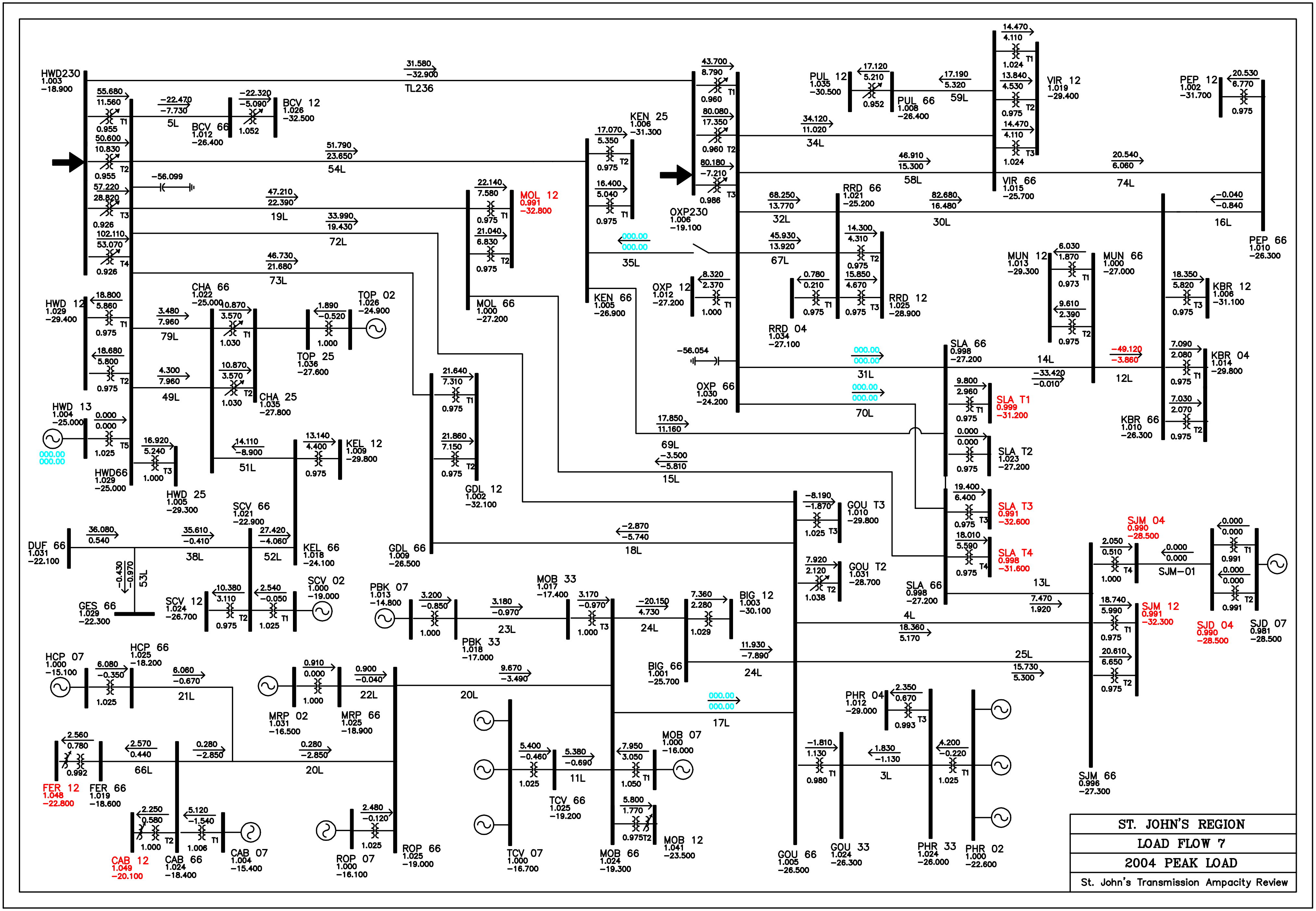
LOAD FLOW 4

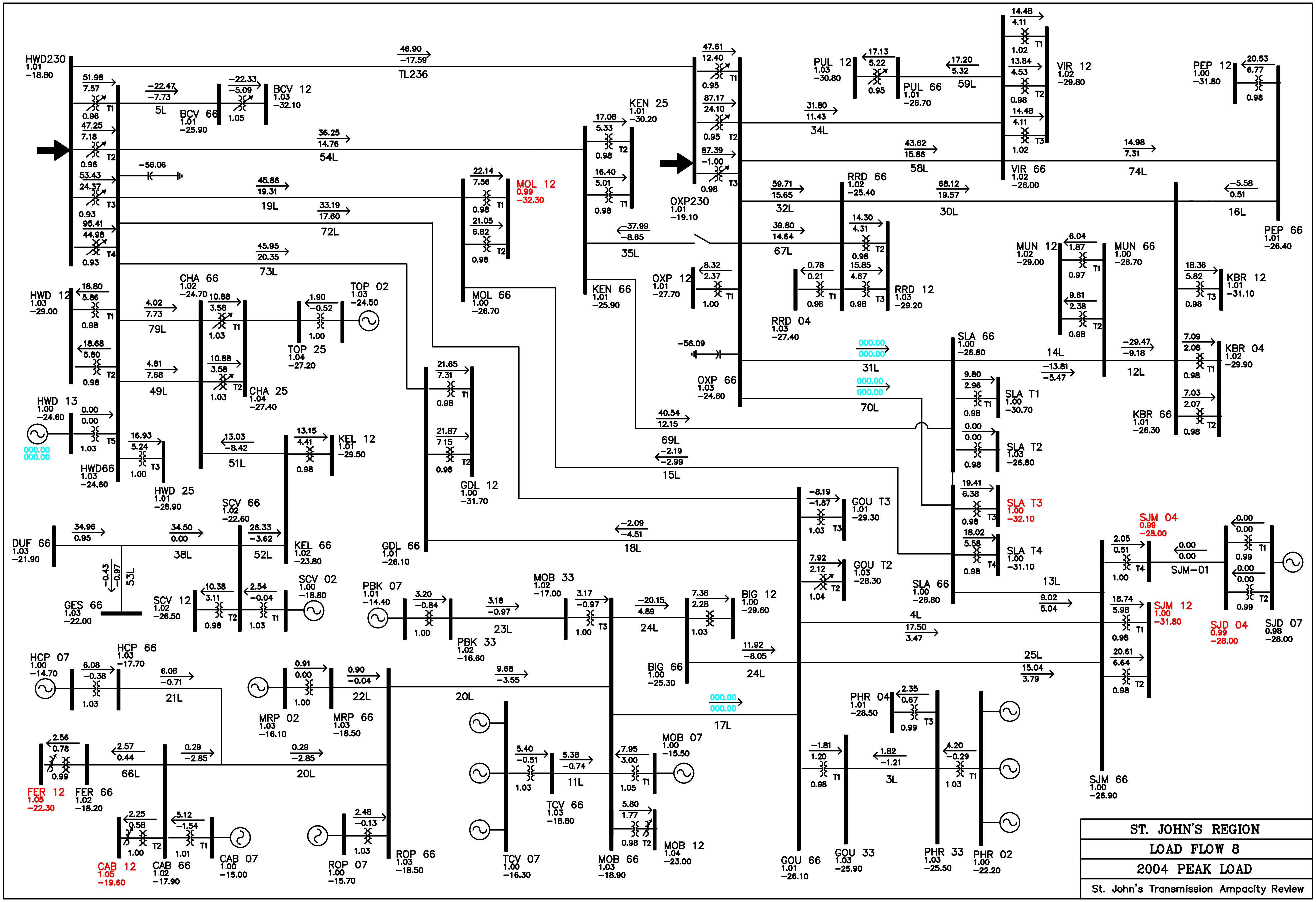
2004 PEAK LOAD

St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 5
2004 PEAK LOAD
St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 6
2004 PEAK LOAD
St. John's Transmission Ampacity Review


HWD230 1.003 −18.900
TL236
BCV 12 1.026 −32.500
BCV 66 1.012 −26.400
5L
54L
19L
72L
73L
79L
49L
51L
KEN 25 1.006 −31.300
KEN 66 1.005 −26.900
35L
MOL 12 0.991 −32.800
MOL 66 1.000 −27.200
OXP230 1.006 −19.100
OXP 12 1.012 −27.200
OXP 66 1.030 −24.200
PUL 12 1.035 −30.500
PUL 66 1.008 −26.400
59L
34L
58L
32L
67L
30L
VIR 12 1.019 −29.400
VIR 66 1.015 −25.700
PEP 12 1.002 −31.700
PEP 66 1.010 −26.300
74L
16L
RRD 66 1.021 −25.200
RRD 12 1.025 −28.900
RRD 04 1.034 −27.100
MUN 12 1.013 −29.300
MUN 66 1.000 −27.000
KBR 12 1.006 −31.100
KBR 04 1.014 −29.800
KBR 66 1.010 −26.300
SLA 66 0.998 −27.200
SLA T1 0.999 −31.200
SLA T2 1.023 −27.200
SLA T3 0.991 −32.600
SLA T4 0.998 −31.600
14L
12L
31L
70L
69L
15L
HWD 12 1.029 −29.400
HWD 13 1.004 −25.000
HWD66 1.029 −25.000
HWD 25 1.005 −29.300
CHA 66 1.022 −25.000
CHA 25 1.035 −27.800
TOP 02 1.026 −24.900
TOP 25 1.036 −27.600
KEL 12 1.009 −29.800
KEL 66 1.018 −24.100
GDL 12 1.002 −32.100
GDL 66 1.009 −26.500
GOU T3 1.010 −29.800
GOU T2 1.031 −28.700
GOU 66 1.005 −26.500
GOU 33 1.024 −26.300
18L
13L
4L
25L
24L
17L
3L
SJM 04 0.990 −28.500
SJM−01
SJM 12 0.991 −32.300
SJM 66 0.996 −27.300
SJD 04 0.990 −28.500
SJD 07 0.981 −28.500
DUF 66 1.031 −22.100
38L
52L
53L
GES 66 1.029 −22.300
SCV 66 1.021 −22.900
SCV 12 1.024 −26.700
SCV 02 1.000 −19.000
PBK 07 1.013 −14.800
PBK 33 1.018 −17.000
23L
MOB 33 1.017 −17.400
BIG 12 1.003 −30.100
BIG 66 1.001 −25.700
HCP 07 1.000 −15.100
HCP 66 1.025 −18.200
21L
MRP 02 1.031 −16.500
MRP 66 1.025 −18.900
22L
20L
FER 12 1.048 −22.800
FER 66 1.019 −18.600
66L
CAB 12 1.049 −20.100
CAB 66 1.024 −18.400
CAB 07 1.004 −15.400
ROP 07 1.000 −16.100
ROP 66 1.025 −19.000
TCV 07 1.000 −16.700
TCV 66 1.025 −19.200
11L
MOB 07 1.000 −16.000
MOB 66 1.024 −19.300
MOB 12 1.041 −23.500
PHR 04 1.012 −29.000
PHR 33 1.024 −26.000
PHR 02 1.000 −22.600
ST. JOHN'S REGION
LOAD FLOW 7
2004 PEAK LOAD
St. John's Transmission Ampacity Review

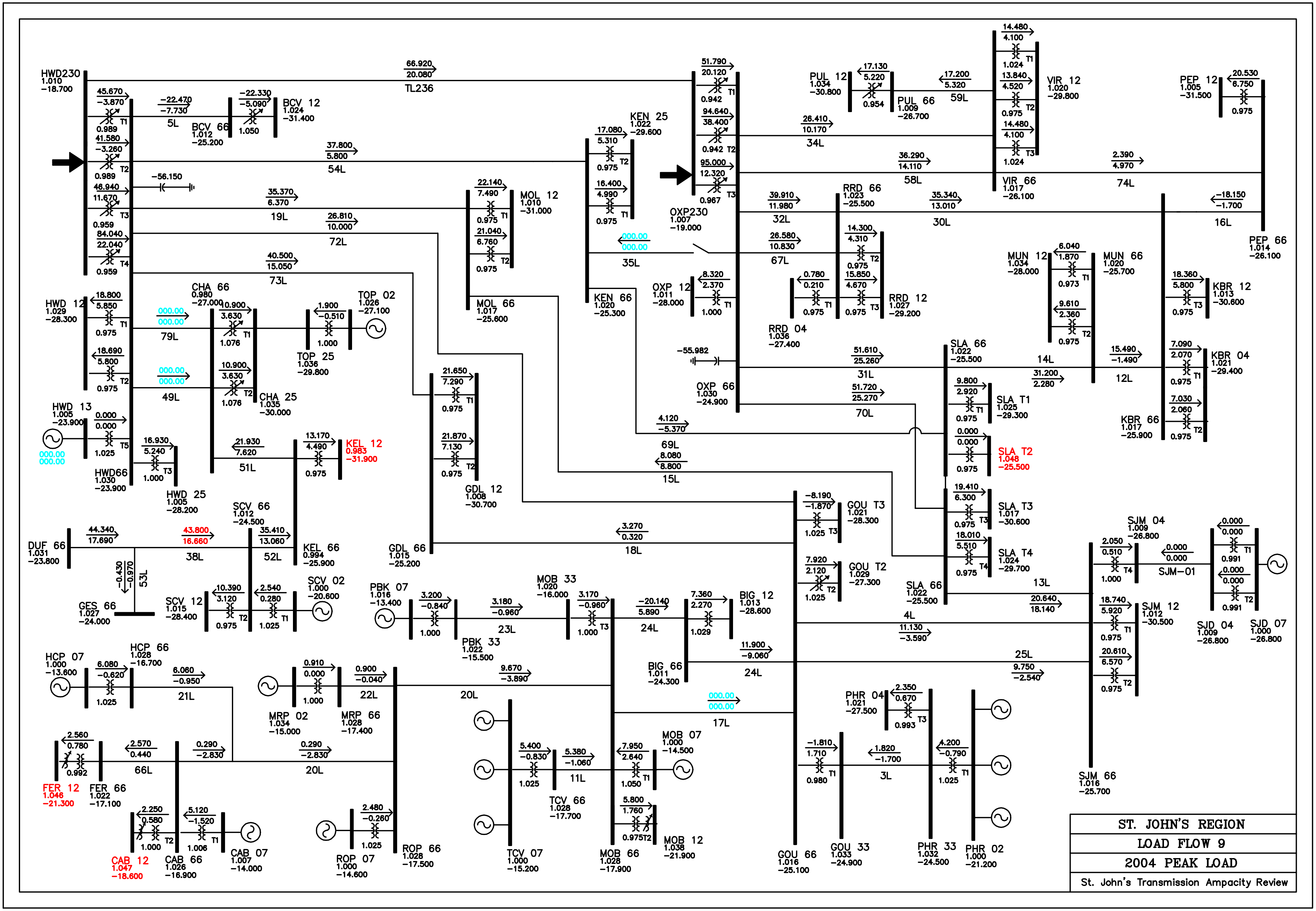


ST. JOHN'S REGION

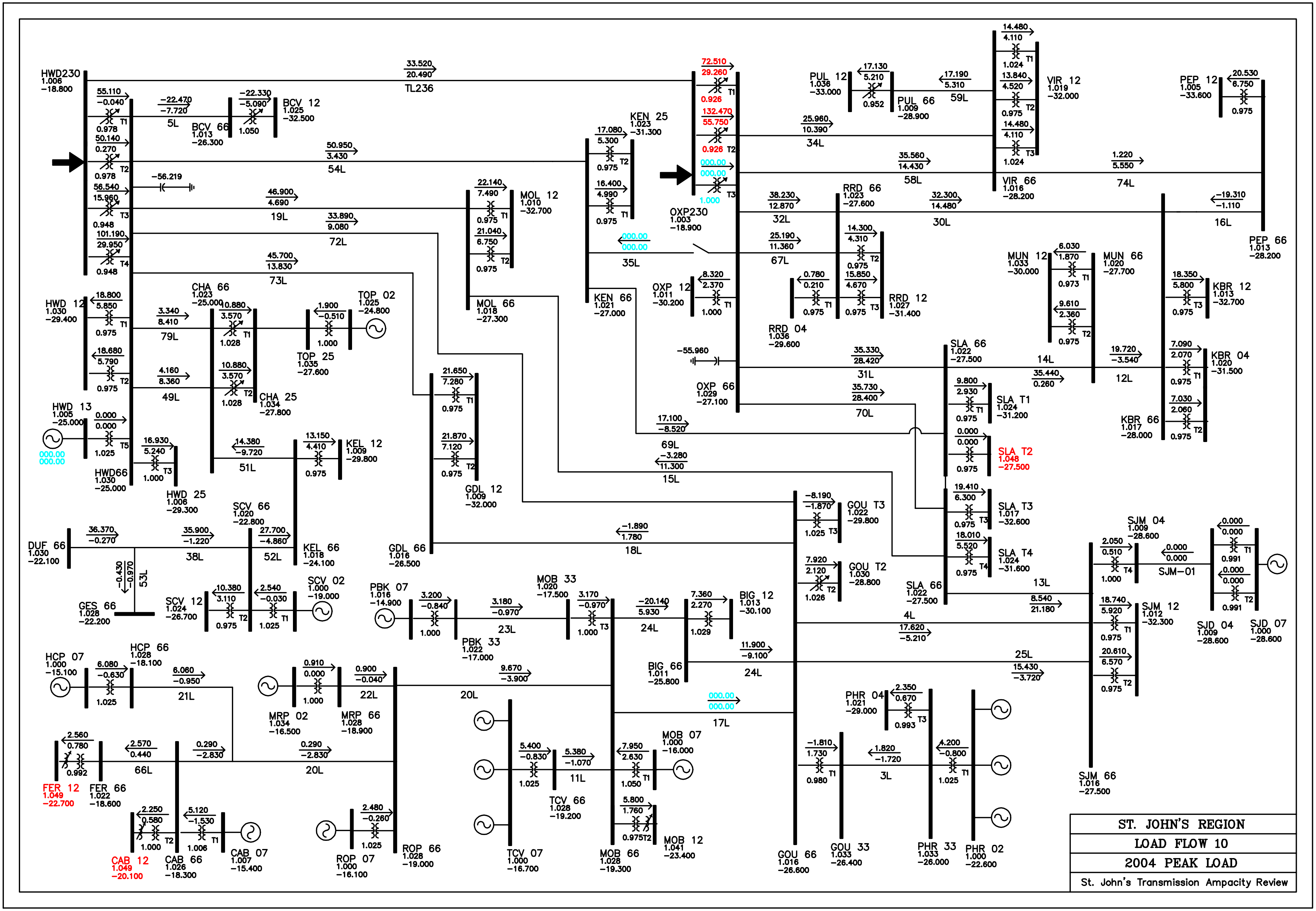
LOAD FLOW 8

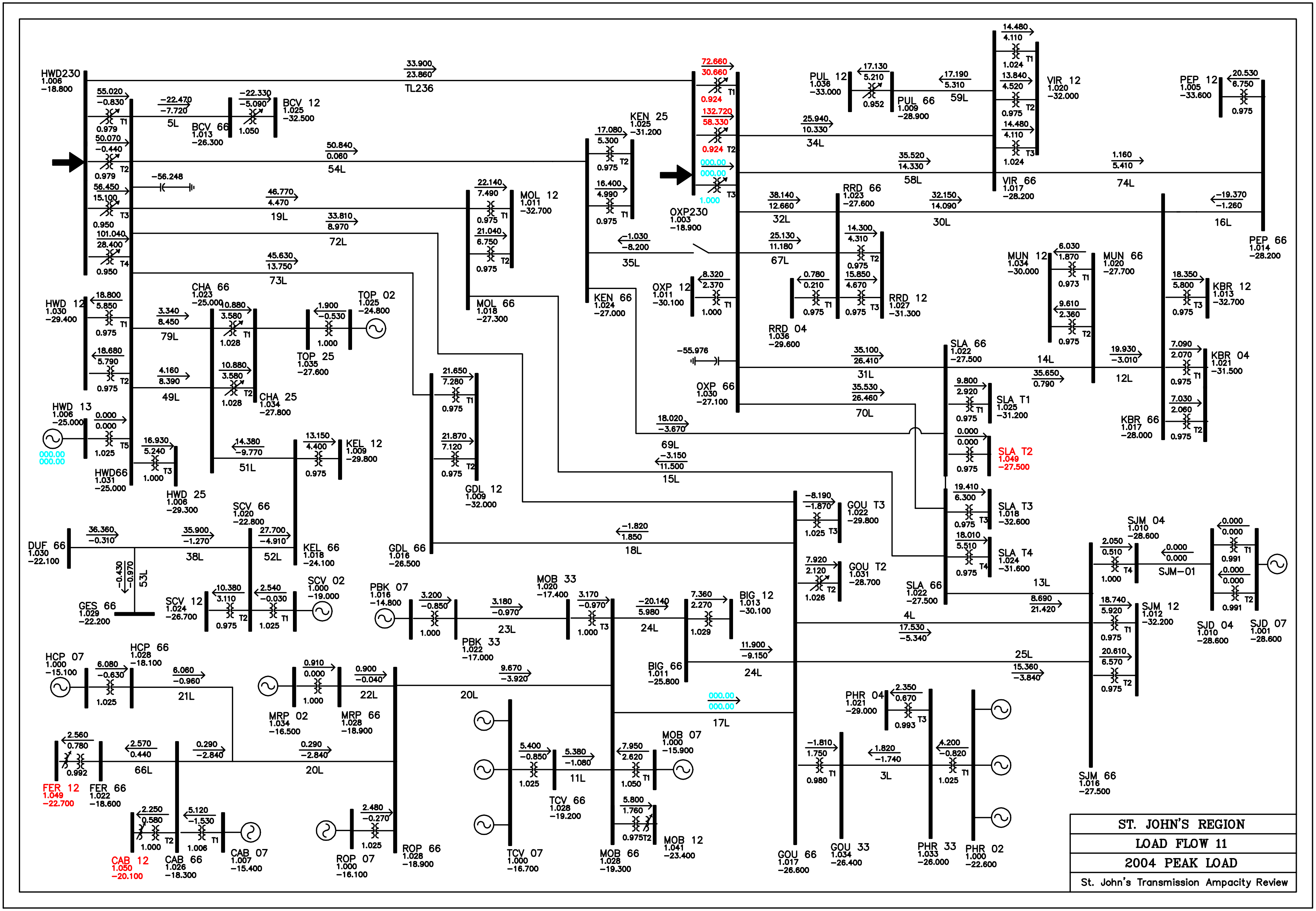
2004 PEAK LOAD

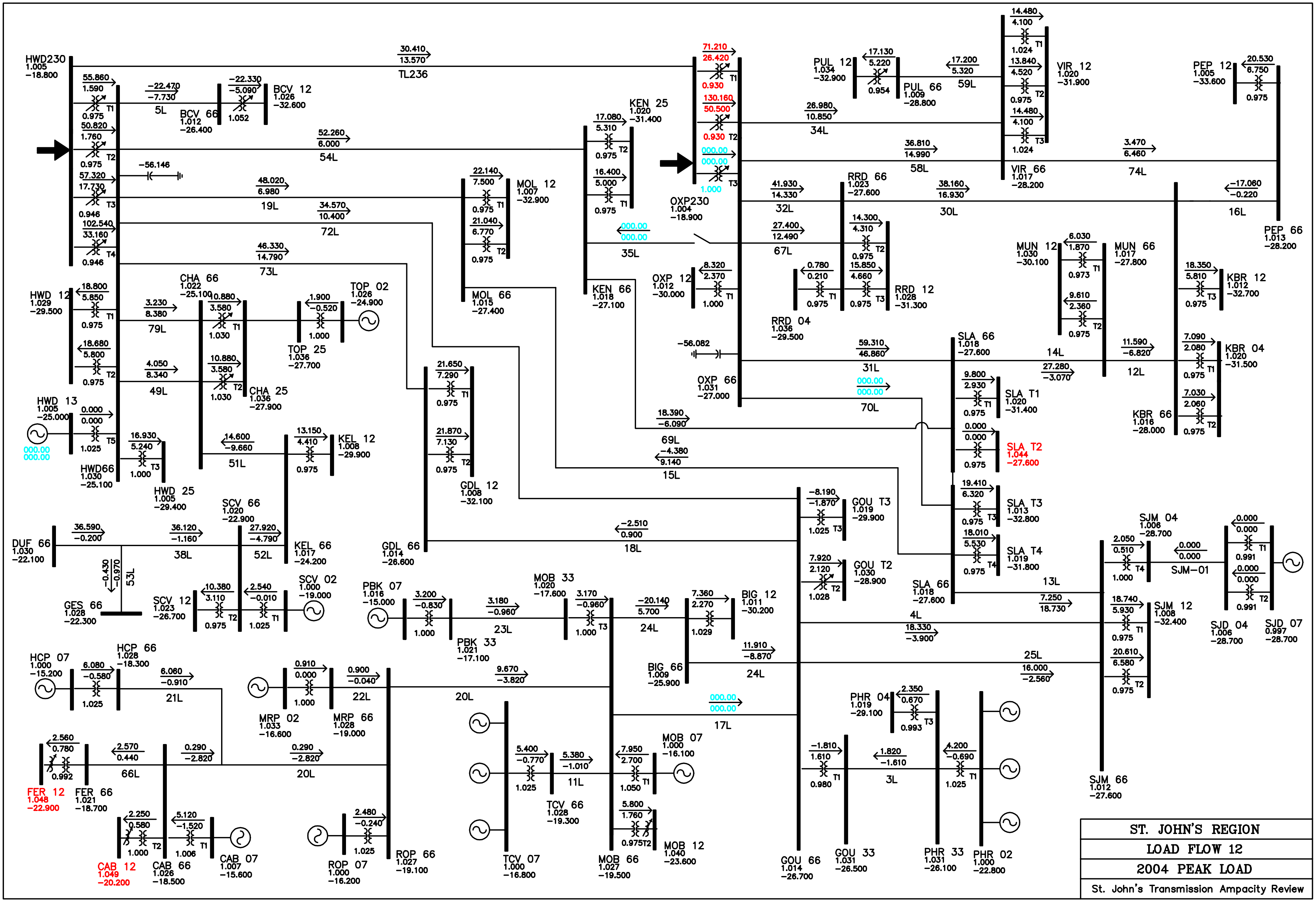
St. John's Transmission Ampacity Review



ST. JOHN'S REGION
LOAD FLOW 9
2004 PEAK LOAD
St. John's Transmission Ampacity Review


HWD230
TL236
5L
54L
19L
72L
73L
79L
49L
51L
BCV 12
BCV 66
MOL 12
MOL 66
KEN 25
KEN 66
35L
OXP230
OXP 12
OXP 66
PUL 12
PUL 66
59L
VIR 12
VIR 66
34L
58L
74L
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
32L
30L
16L
67L
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
14L
12L
31L
70L
69L
15L
HWD 12
HWD 13
HWD66
HWD 25
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
GDL 12
GDL 66
DUF 66
38L
52L
53L
SCV 66
SCV 12
SCV 02
GES 66
18L
GOU T3
GOU T2
GOU 66
GOU 33
PBK 07
PBK 33
23L
MOB 33
MOB 07
MOB 66
MOB 12
24L
BIG 12
BIG 66
13L
4L
25L
SJM 04
SJM–01
SJM 12
SJM 66
SJD 04
SJD 07
HCP 07
HCP 66
21L
MRP 02
MRP 66
22L
20L
17L
FER 12
FER 66
66L
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 66
TCV 07
11L
PHR 04
PHR 33
PHR 02
3L
ST. JOHN'S REGION
LOAD FLOW 10
2004 PEAK LOAD
St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 11
2004 PEAK LOAD
St. John's Transmission Ampacity Review

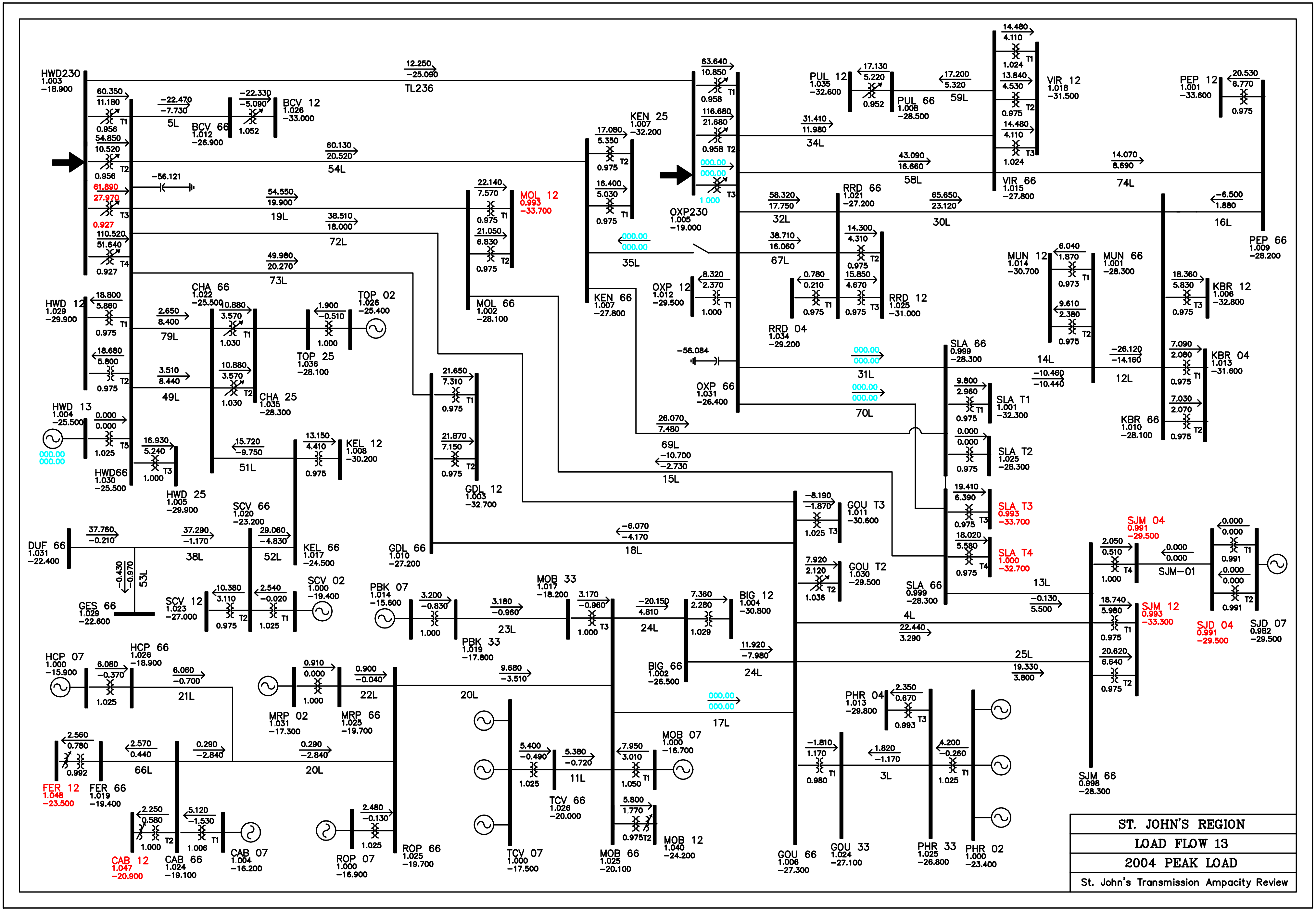


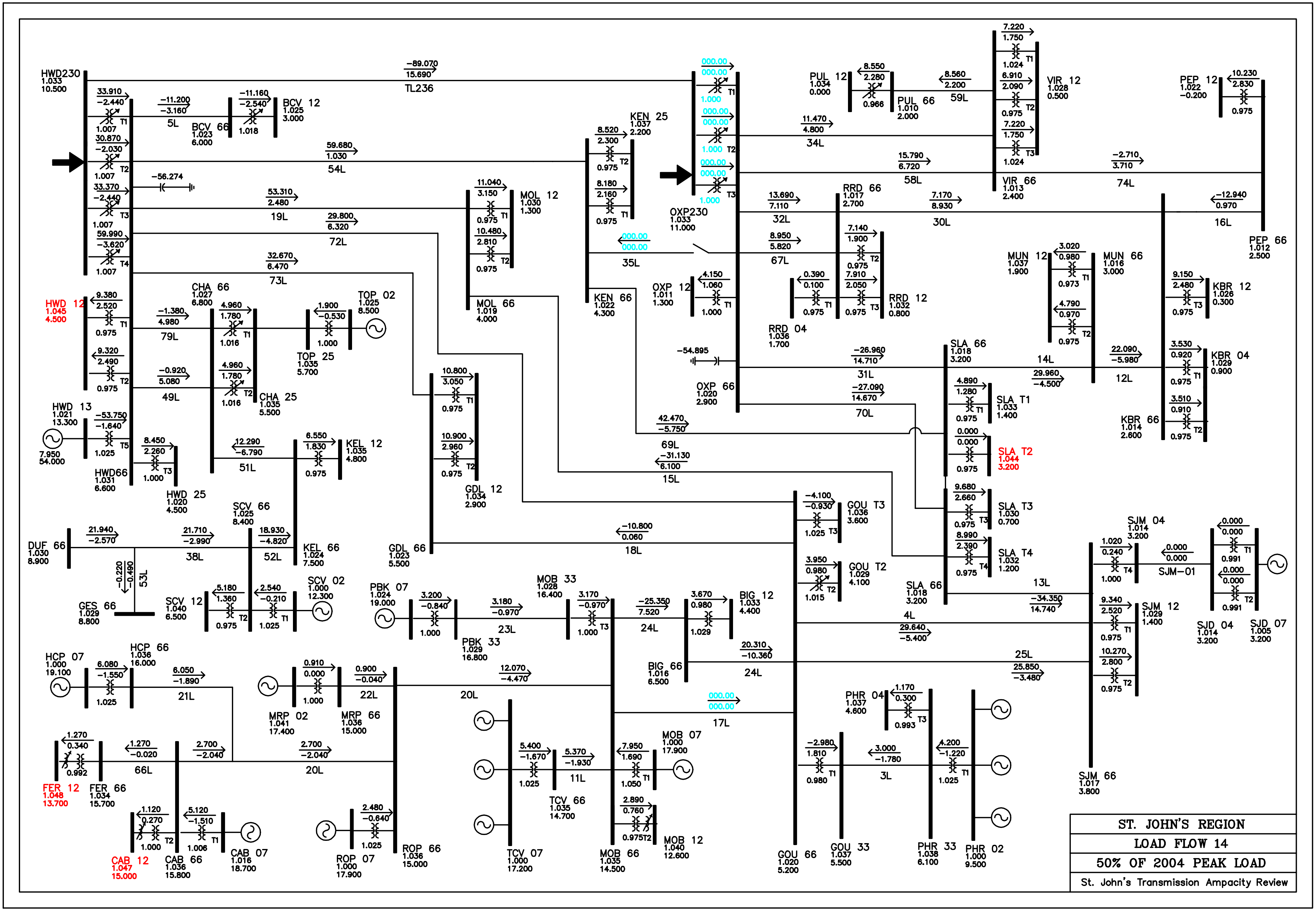
ST. JOHN'S REGION

LOAD FLOW 12

2004 PEAK LOAD

St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 13
2004 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230 1.003 −18.900
HWD 12 1.029 −29.900
HWD 13 1.004 −25.500
HWD66 1.030 −25.500
HWD 25 1.005 −29.900
BCV 12 1.026 −33.000
BCV 66 1.012 −26.900
CHA 66 1.022 −25.500
CHA 25 1.035 −28.300
TOP 02 1.026 −25.400
TOP 25 1.036 −28.100
KEL 12 1.008 −30.200
KEL 66 1.017 −24.500
SCV 66 1.020 −23.200
SCV 12 1.023 −27.000
SCV 02 1.000 −19.400
DUF 66 1.031 −22.400
GES 66 1.029 −22.600
HCP 07 1.000 −15.900
HCP 66 1.026 −18.900
FER 12 1.048 −23.500
FER 66 1.019 −19.400
CAB 12 1.047 −20.900
CAB 66 1.024 −19.100
CAB 07 1.004 −16.200
MRP 02 1.031 −17.300
MRP 66 1.025 −19.700
ROP 07 1.000 −16.900
ROP 66 1.025 −19.700
PBK 07 1.014 −15.600
PBK 33 1.019 −17.800
MOB 33 1.017 −18.200
MOB 07 1.000 −16.700
MOB 66 1.025 −20.100
MOB 12 1.040 −24.200
TCV 66 1.026 −20.000
TCV 07 1.000 −17.500
BIG 12 1.004 −30.800
BIG 66 1.002 −26.500
GDL 12 1.003 −32.700
GDL 66 1.010 −27.200
MOL 12 0.993 −33.700
MOL 66 1.002 −28.100
KEN 25 1.007 −32.200
KEN 66 1.007 −27.800
OXP230 1.005 −19.000
OXP 12 1.012 −29.500
OXP 66 1.031 −26.400
PUL 12 1.035 −32.600
PUL 66 1.008 −28.500
VIR 12 1.018 −31.500
VIR 66 1.015 −27.800
PEP 12 1.001 −33.600
PEP 66 1.009 −28.200
RRD 66 1.021 −27.200
RRD 12 1.025 −31.000
RRD 04 1.034 −29.200
MUN 12 1.014 −30.700
MUN 66 1.001 −28.300
KBR 12 1.006 −32.800
KBR 04 1.013 −31.600
KBR 66 1.010 −28.100
SLA 66 0.999 −28.300
SLA T1 1.001 −32.300
SLA T2 1.025 −28.300
SLA T3 0.993 −33.700
SLA T4 1.000 −32.700
SLA 66 0.999 −28.300
GOU T3 1.011 −30.600
GOU T2 1.030 −29.500
GOU 66 1.006 −27.300
GOU 33 1.024 −27.100
PHR 04 1.013 −29.800
PHR 33 1.025 −26.800
PHR 02 1.000 −23.400
SJM 04 0.991 −29.500
SJM−01
SJM 12 0.993 −33.300
SJM 66 0.998 −28.300
SJD 04 0.991 −29.500
SJD 07 0.982 −29.500
TL236 5L 54L 19L 72L 73L 79L 49L 51L 38L 52L 53L 35L 34L 58L 74L 59L 32L 30L 16L 67L 31L 70L 14L 12L 69L 15L 18L 13L 4L 25L 24L 23L 21L 22L 20L 66L 11L 17L 3L

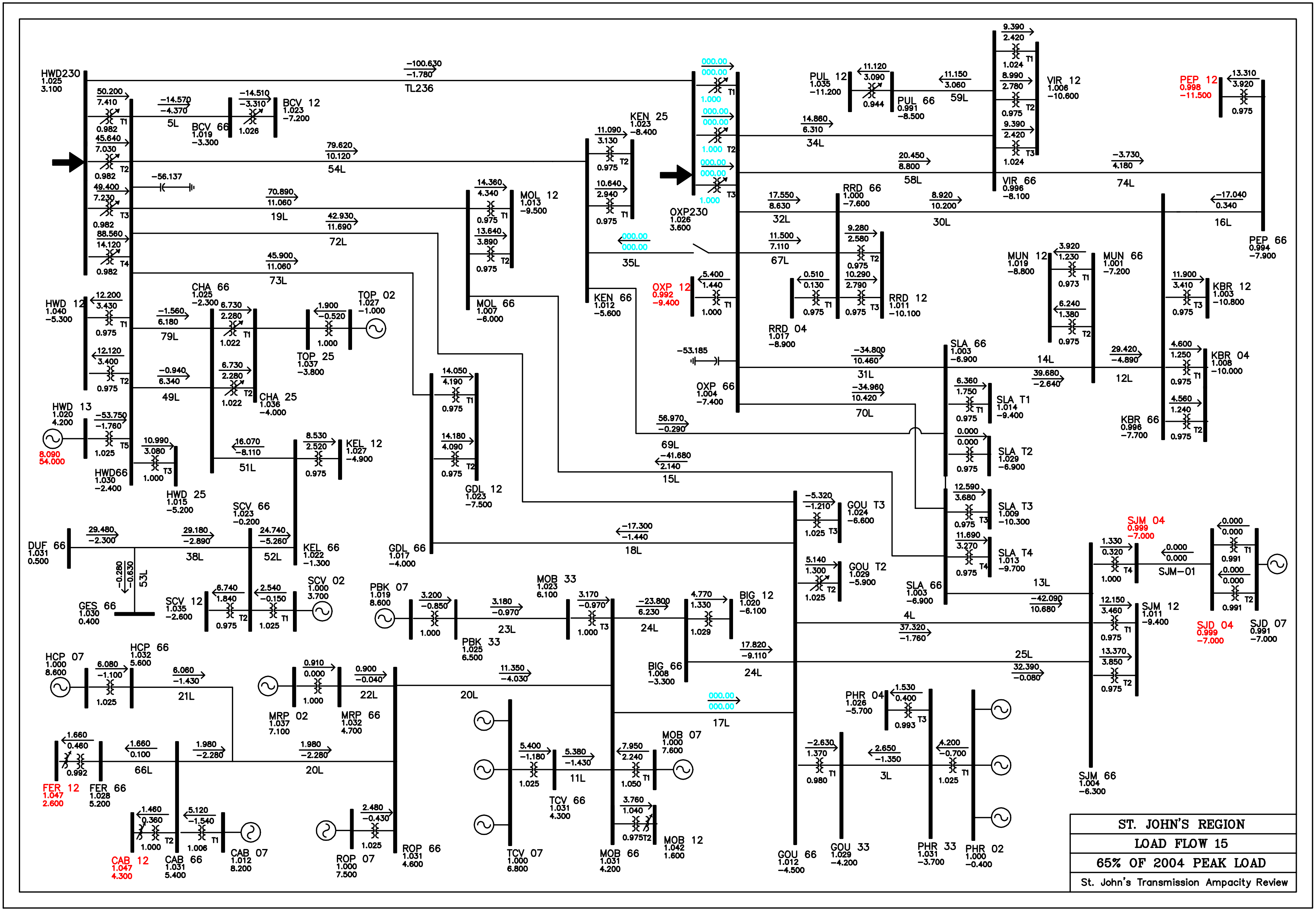


ST. JOHN'S REGION

LOAD FLOW 14

50% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review



ST. JOHN'S REGION
LOAD FLOW 15
65% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
HWD 12
HWD 13
HWD66
HWD 25
BCV 66
BCV 12
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
SCV 66
SCV 12
SCV 02
DUF 66
GES 66
HCP 07
HCP 66
MRP 02
MRP 66
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
PBK 07
PBK 33
MOB 33
MOB 07
MOB 12
MOB 66
TCV 66
TCV 07
BIG 12
BIG 66
GDL 12
GDL 66
MOL 12
MOL 66
KEN 25
KEN 66
OXP230
OXP 12
OXP 66
PUL 12
PUL 66
VIR 12
VIR 66
RRD 66
RRD 12
RRD 04
MUN 12
MUN 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
GOU T3
GOU T2
GOU 66
GOU 33
PHR 04
PHR 33
PHR 02
SJM 04
SJM-01
SJM 12
SJM 66
SJD 04
SJD 07
PEP 12
PEP 66
KBR 12
KBR 04
KBR 66
TL236
5L
54L
19L
72L
73L
79L
49L
51L
38L
52L
53L
21L
22L
20L
66L
23L
24L
11L
17L
18L
15L
69L
35L
34L
58L
59L
32L
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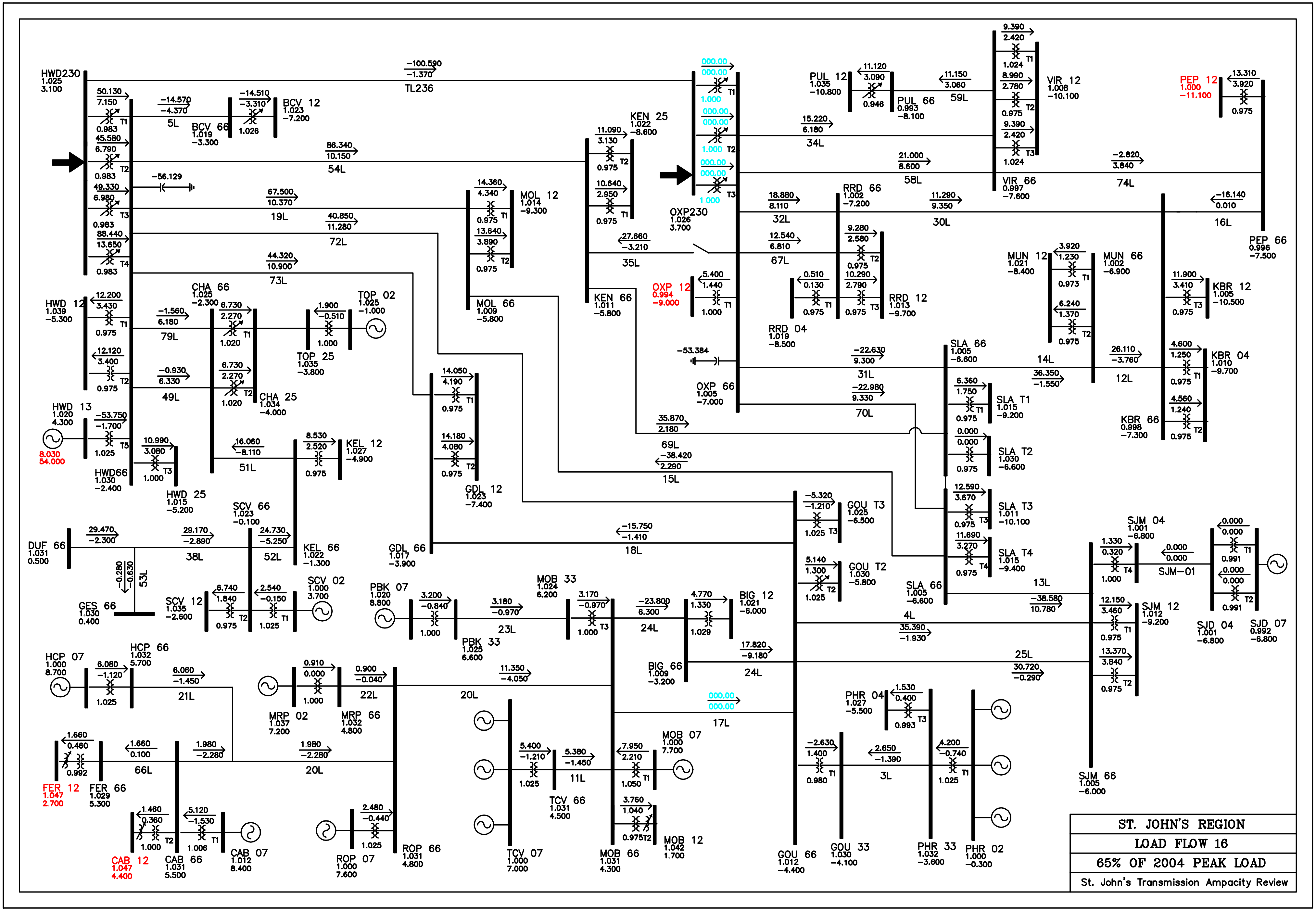
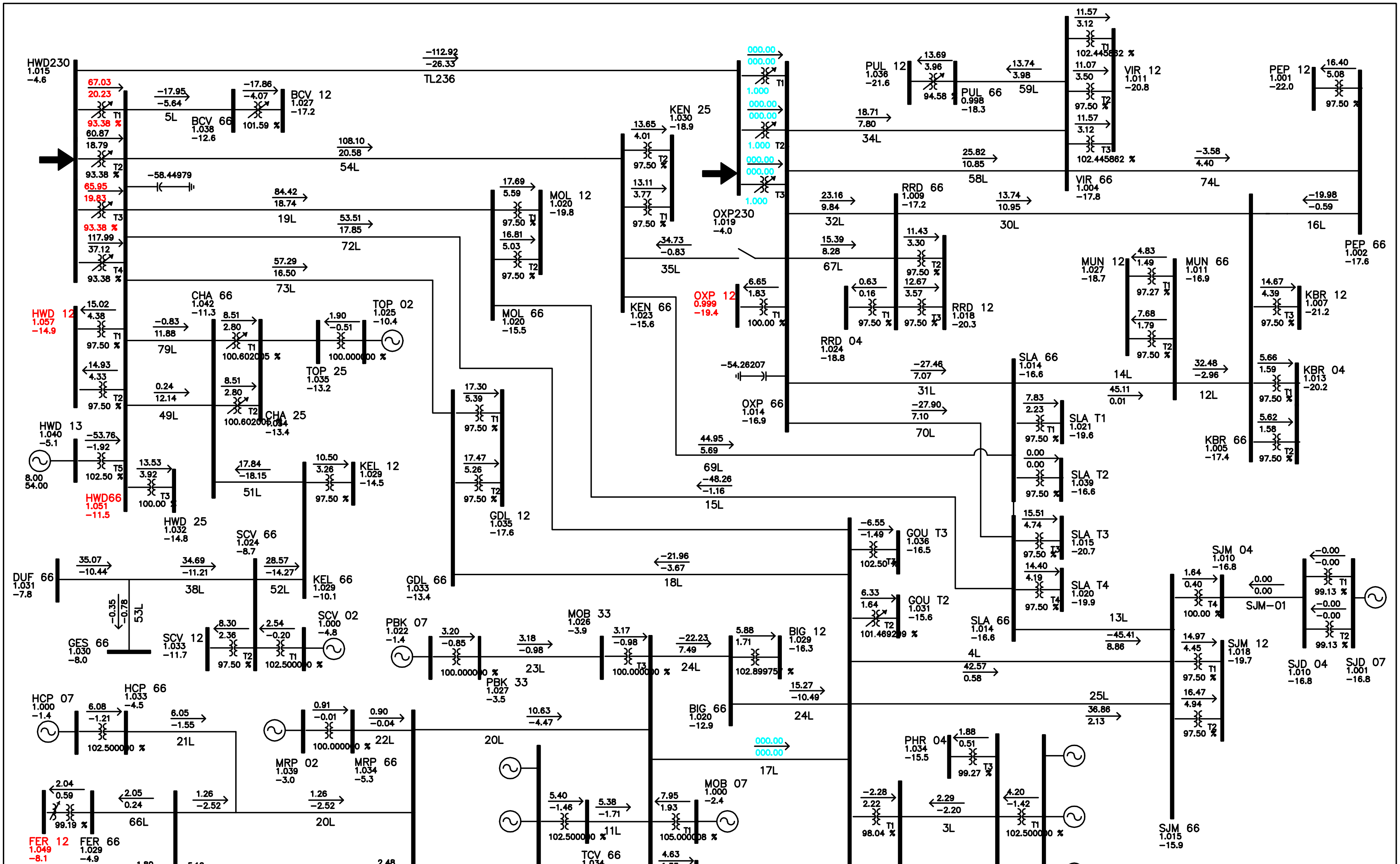
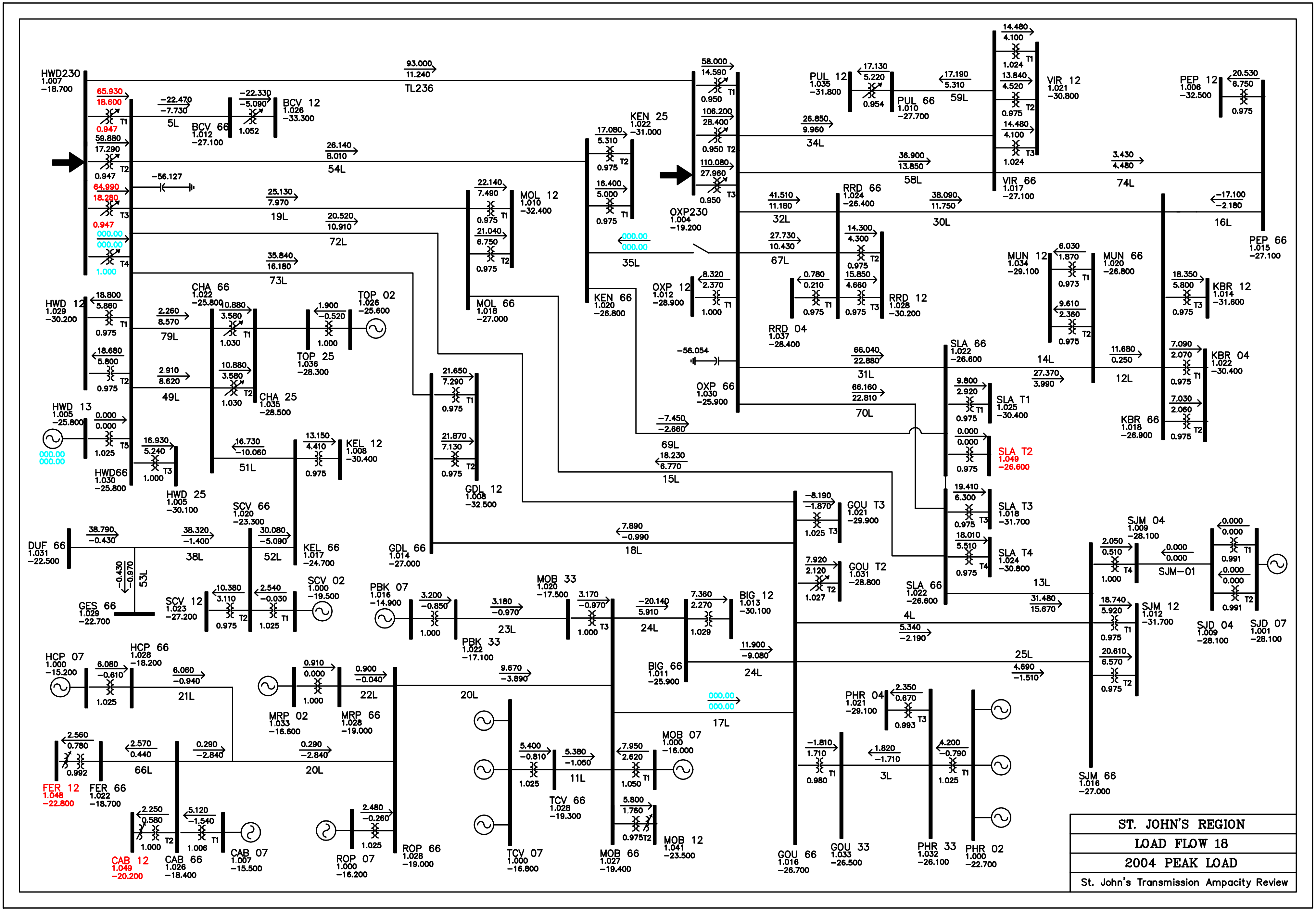
67L
31L
70L
14L
12L
13L
4L
25L
3L
74L
16L



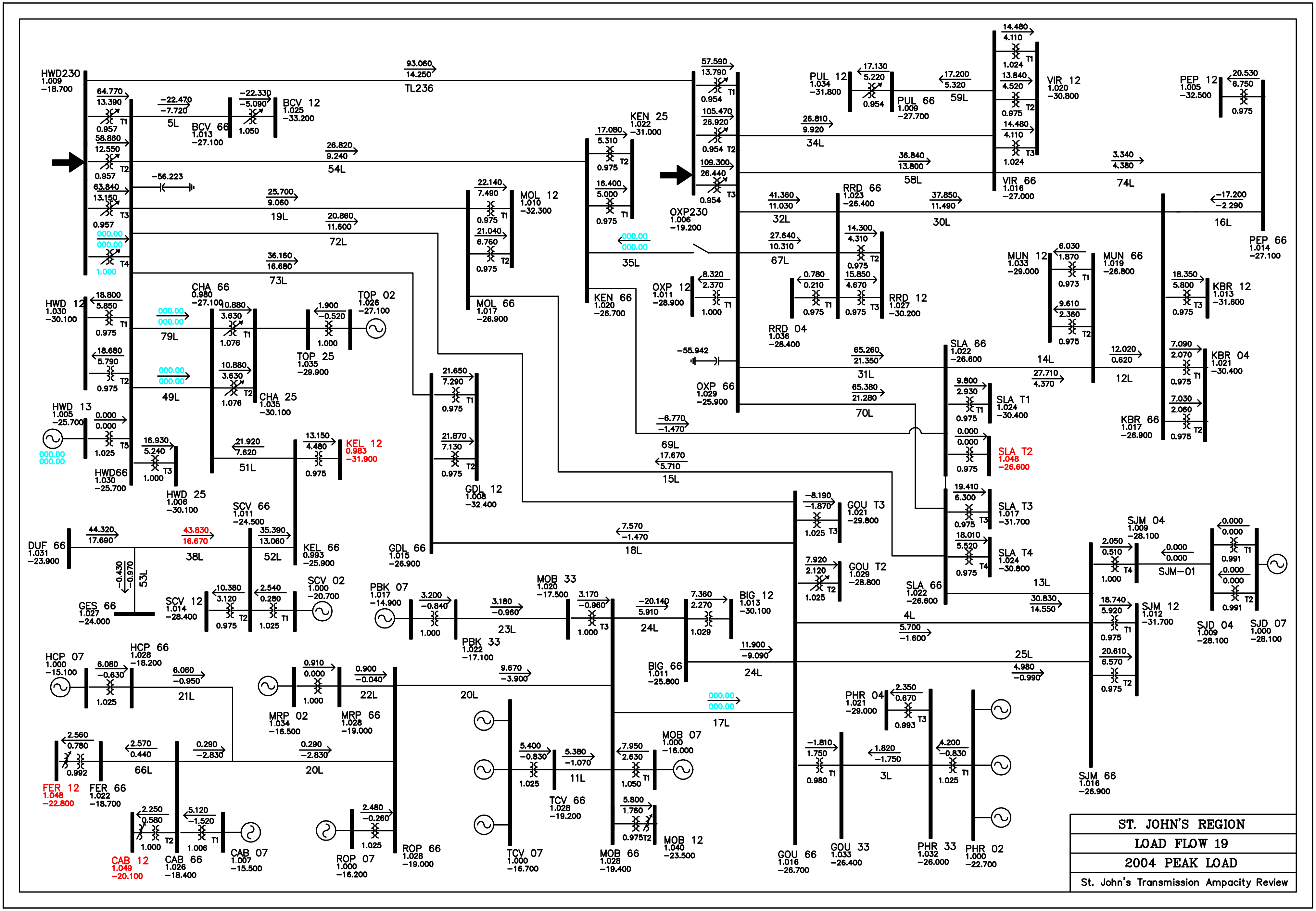
HWD230 1.025 3.100
TL236
5L
BCV 12 1.023 −7.200
BCV 66 1.019 −3.300
54L
19L
72L
73L
HWD 12 1.039 −5.300
79L
49L
CHA 66 1.025 −2.300
CHA 25 1.034 −4.000
TOP 02 1.025 −1.000
TOP 25 1.035 −3.800
HWD 13 1.020 4.300
8.030 54.000
HWD66 1.030 −2.400
HWD 25 1.015 −5.200
51L
KEL 12 1.027 −4.900
KEL 66 1.022 −1.300
SCV 66 1.023 −0.100
52L
DUF 66 1.031 0.500
38L
53L
GES 66 1.030 0.400
SCV 12 1.035 −2.600
SCV 02 1.000 3.700
MOL 12 1.014 −9.300
MOL 66 1.009 −5.800
GDL 12 1.023 −7.400
GDL 66 1.017 −3.900
KEN 25 1.022 −8.600
KEN 66 1.011 −5.800
35L
OXP230 1.026 3.700
OXP 12 0.994 −9.000
OXP 66 1.005 −7.000
69L
15L
18L
PUL 12 1.035 −10.800
PUL 66 0.993 −8.100
59L
34L
58L
VIR 12 1.008 −10.100
VIR 66 0.997 −7.600
PEP 12 1.000 −11.100
PEP 66 0.996 −7.500
74L
16L
32L
30L
RRD 66 1.002 −7.200
RRD 12 1.013 −9.700
RRD 04 1.019 −8.500
67L
MUN 12 1.021 −8.400
MUN 66 1.002 −6.900
14L
12L
31L
70L
KBR 12 1.005 −10.500
KBR 04 1.010 −9.700
KBR 66 0.998 −7.300
SLA 66 1.005 −6.600
SLA T1 1.015 −9.200
SLA T2 1.030 −6.600
SLA T3 1.011 −10.100
SLA T4 1.015 −9.400
GOU T3 1.025 −6.500
GOU T2 1.030 −5.800
13L
SJM 04 1.001 −6.800
SJM−01
SJM 12 1.012 −9.200
SJD 04 1.001 −6.800
SJD 07 0.992 −6.800
SJM 66 1.005 −6.000
4L
25L
PBK 07 1.020 8.800
PBK 33 1.025 6.600
23L
MOB 33 1.024 6.200
24L
BIG 12 1.021 −6.000
BIG 66 1.009 −3.200
HCP 07 1.000 8.700
HCP 66 1.032 5.700
21L
MRP 02 1.037 7.200
MRP 66 1.032 4.800
22L
20L
17L
FER 12 1.047 2.700
FER 66 1.029 5.300
66L
CAB 12 1.047 4.400
CAB 66 1.031 5.500
CAB 07 1.012 8.400
ROP 07 1.000 7.600
ROP 66 1.031 4.800
TCV 66 1.031 4.500
11L
TCV 07 1.000 7.000
MOB 07 1.000 7.700
MOB 12 1.042 1.700
MOB 66 1.031 4.300
GOU 66 1.012 −4.400
GOU 33 1.030 −4.100
3L
PHR 04 1.027 −5.500
PHR 33 1.032 −3.600
PHR 02 1.000 −0.300
ST. JOHN'S REGION
LOAD FLOW 16
65% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review

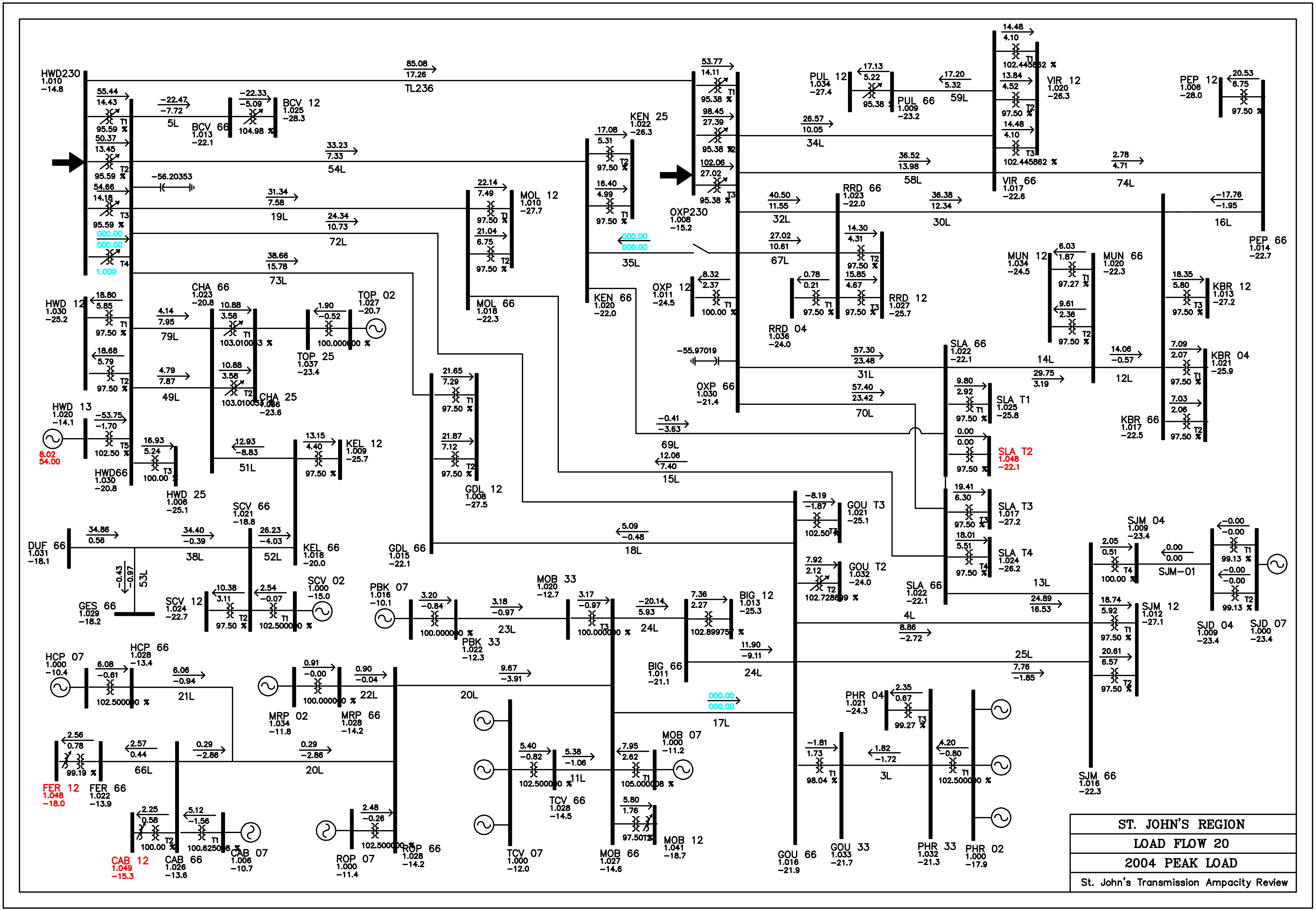


ST. JOHN'S REGION
LOAD FLOW 17
80% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review

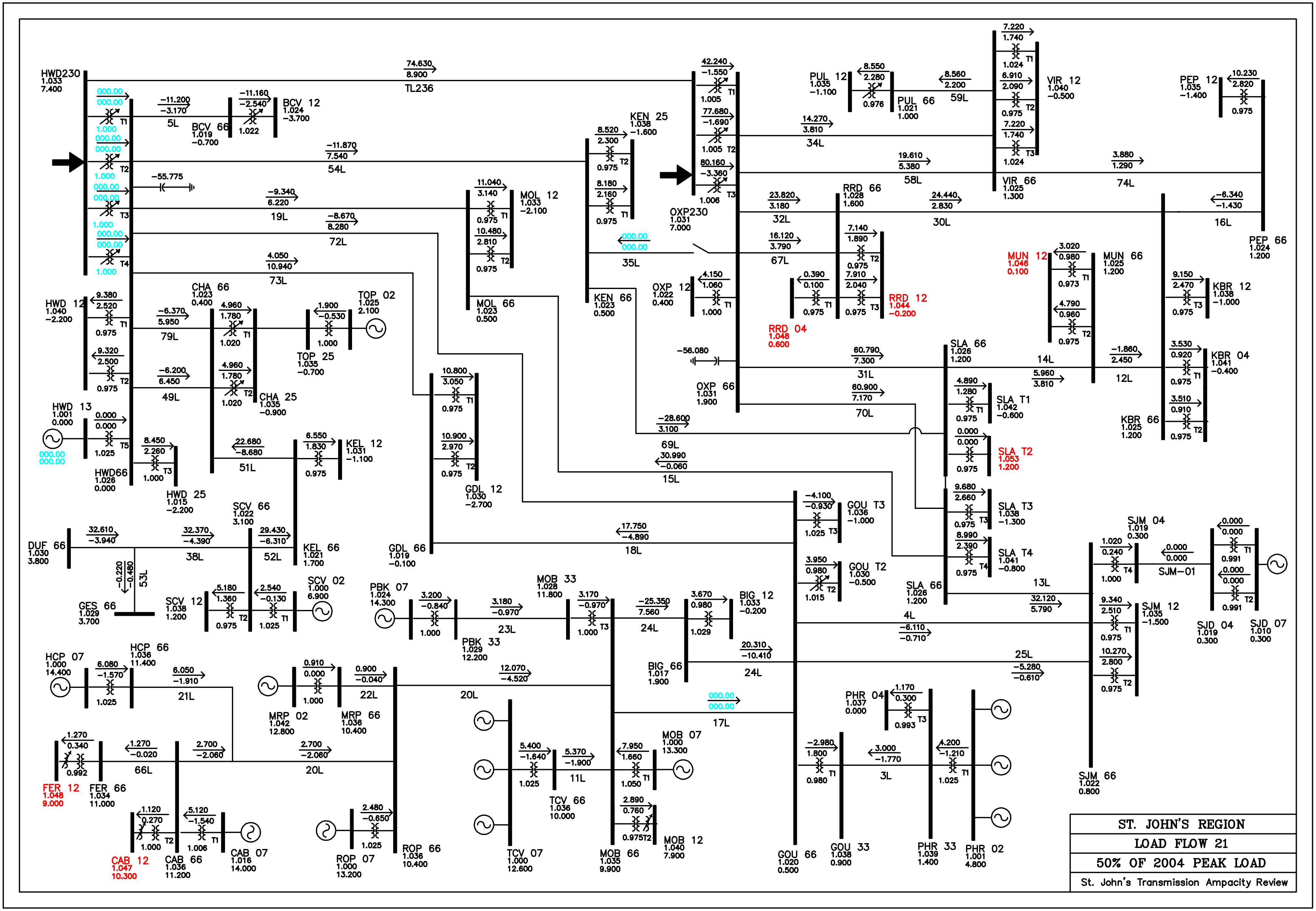


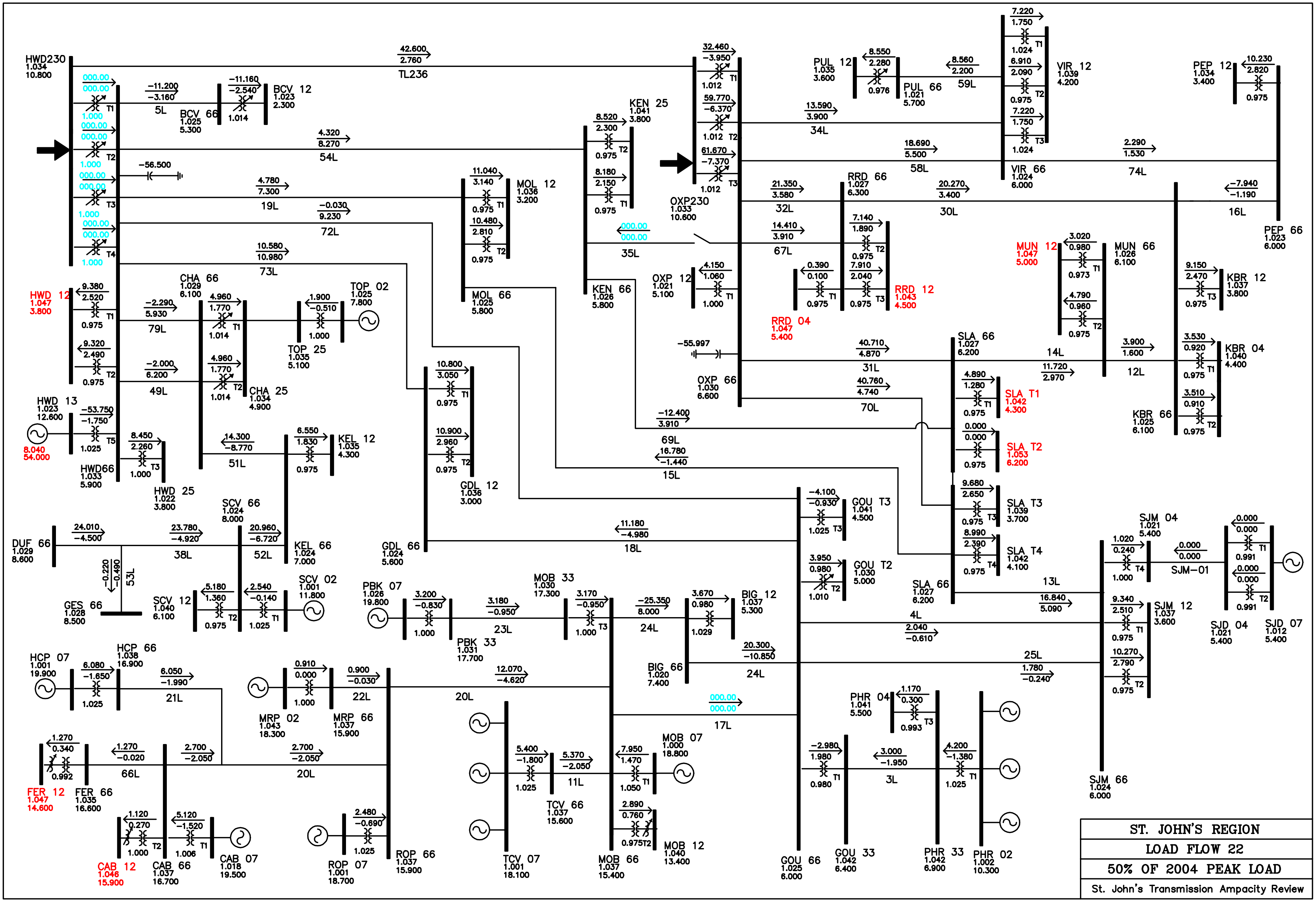
HWD230
TL236
5L
BCV 66
BCV 12
54L
19L
72L
73L
KEN 25
KEN 66
35L
OXP230
OXP 12
OXP 66
MOL 12
MOL 66
PUL 12
PUL 66
59L
VIR 12
VIR 66
34L
58L
74L
PEP 12
PEP 66
32L
30L
16L
67L
RRD 66
RRD 12
RRD 04
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
14L
12L
31L
70L
69L
15L
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
HWD 12
HWD 13
HWD66
HWD 25
79L
49L
CHA 66
CHA 25
TOP 02
TOP 25
51L
KEL 12
KEL 66
GDL 12
GDL 66
18L
GOU T3
GOU T2
GOU 66
GOU 33
SCV 66
SCV 12
SCV 02
DUF 66
38L
52L
53L
GES 66
PBK 07
PBK 33
23L
MOB 33
24L
BIG 12
BIG 66
13L
4L
25L
SJM 04
SJM–01
SJM 12
SJM 66
SJD 04
SJD 07
HCP 07
HCP 66
21L
MRP 02
MRP 66
22L
20L
17L
FER 12
FER 66
66L
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 07
TCV 66
11L
MOB 07
MOB 66
MOB 12
PHR 04
PHR 33
PHR 02
3L
ST. JOHN'S REGION
LOAD FLOW 18
2004 PEAK LOAD
St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 19
2004 PEAK LOAD
St. John's Transmission Ampacity Review

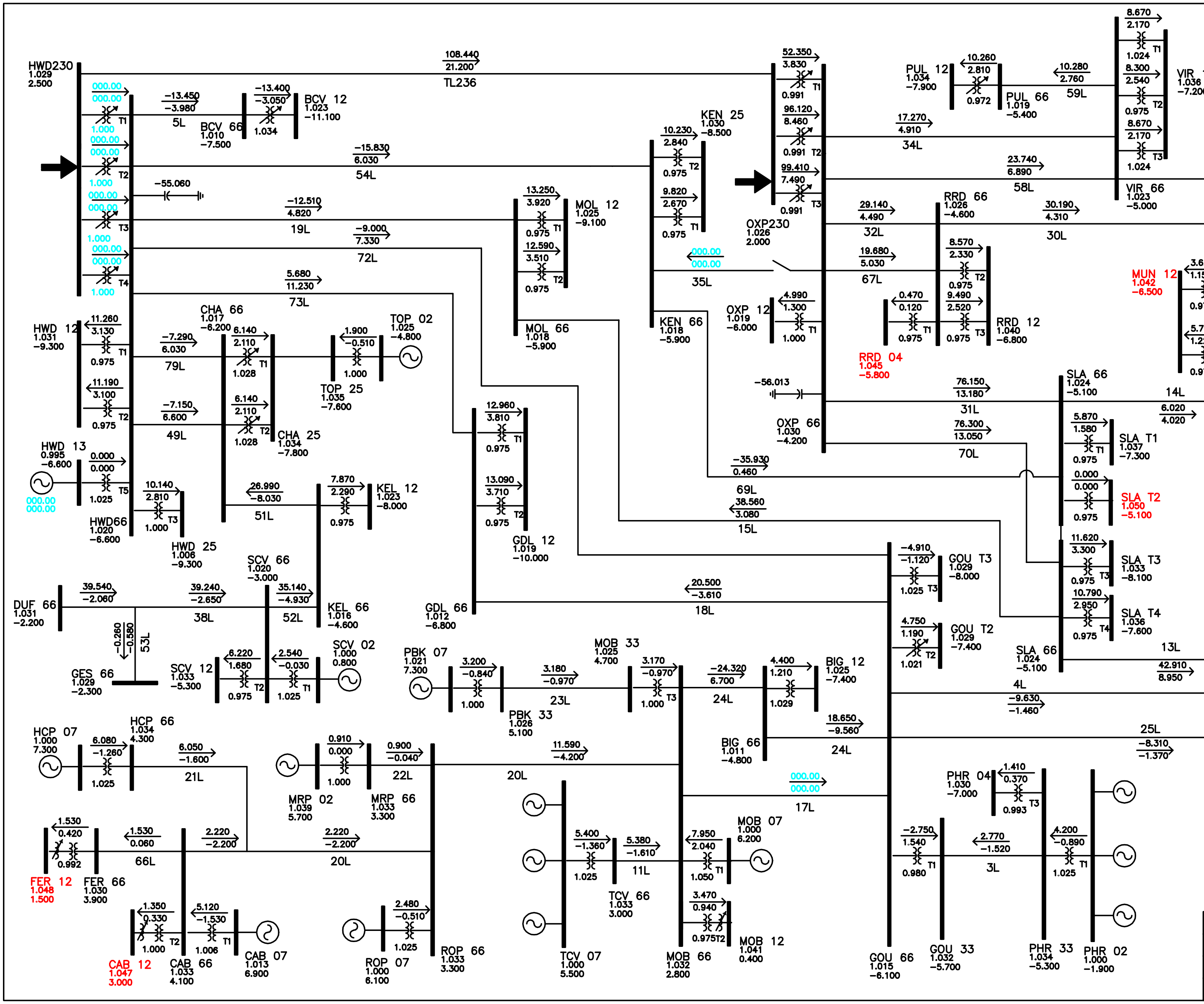


HWD230
HWD 12
HWD 13
HWD66
HWD 25
BCV 66
BCV 12
CHA 66
CHA 25
TOP 02
TOP 25
MOL 12
MOL 66
KEN 25
KEN 66
OXP230
OXP 12
OXP 66
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
GDL 12
GDL 66
KEL 12
KEL 66
SCV 66
SCV 12
SCV 02
DUF 66
GES 66
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM 12
SJM 66
SJM-01
SJD 04
SJD 07
PBK 07
PBK 33
MOB 33
MOB 07
MOB 66
MOB 12
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
TCV 66
TCV 07
PHR 04
PHR 33
PHR 02
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TL236
5L
54L
19L
72L
73L
79L
49L
51L
52L
53L
38L
35L
34L
58L
74L
32L
30L
16L
67L
14L
12L
31L
70L
69L
15L
18L
13L
23L
24L
4L
25L
21L
22L
20L
17L
11L
66L
3L
59L
ST. JOHN'S REGION
LOAD FLOW 20
2004 PEAK LOAD
St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 21
50% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
TL236
5L
BCV 66
BCV 12
54L
19L
72L
73L
HWD 12
79L
49L
HWD 13
HWD66
HWD 25
CHA 66
CHA 25
TOP 02
TOP 25
51L
KEL 12
KEL 66
MOL 12
MOL 66
KEN 25
KEN 66
35L
OXP230
OXP 12
OXP 66
PUL 12
PUL 66
59L
VIR 12
VIR 66
34L
58L
74L
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
32L
30L
16L
67L
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
14L
31L
12L
70L
SLA T1
SLA T2
SLA T3
SLA T4
69L
15L
GDL 12
GDL 66
18L
GOU T3
GOU T2
GOU 66
GOU 33
DUF 66
38L
52L
53L
SCV 66
SCV 12
SCV 02
GES 66
PBK 07
PBK 33
23L
MOB 33
24L
BIG 12
BIG 66
13L
SJM 04
SJM-01
SJM 12
SJM 66
SJD 04
SJD 07
4L
25L
HCP 07
HCP 66
21L
MRP 02
MRP 66
22L
20L
17L
PHR 04
PHR 33
PHR 02
3L
FER 12
FER 66
66L
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 07
TCV 66
11L
MOB 07
MOB 66
MOB 12



ST. JOHN'S REGION
LOAD FLOW 22
50% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review

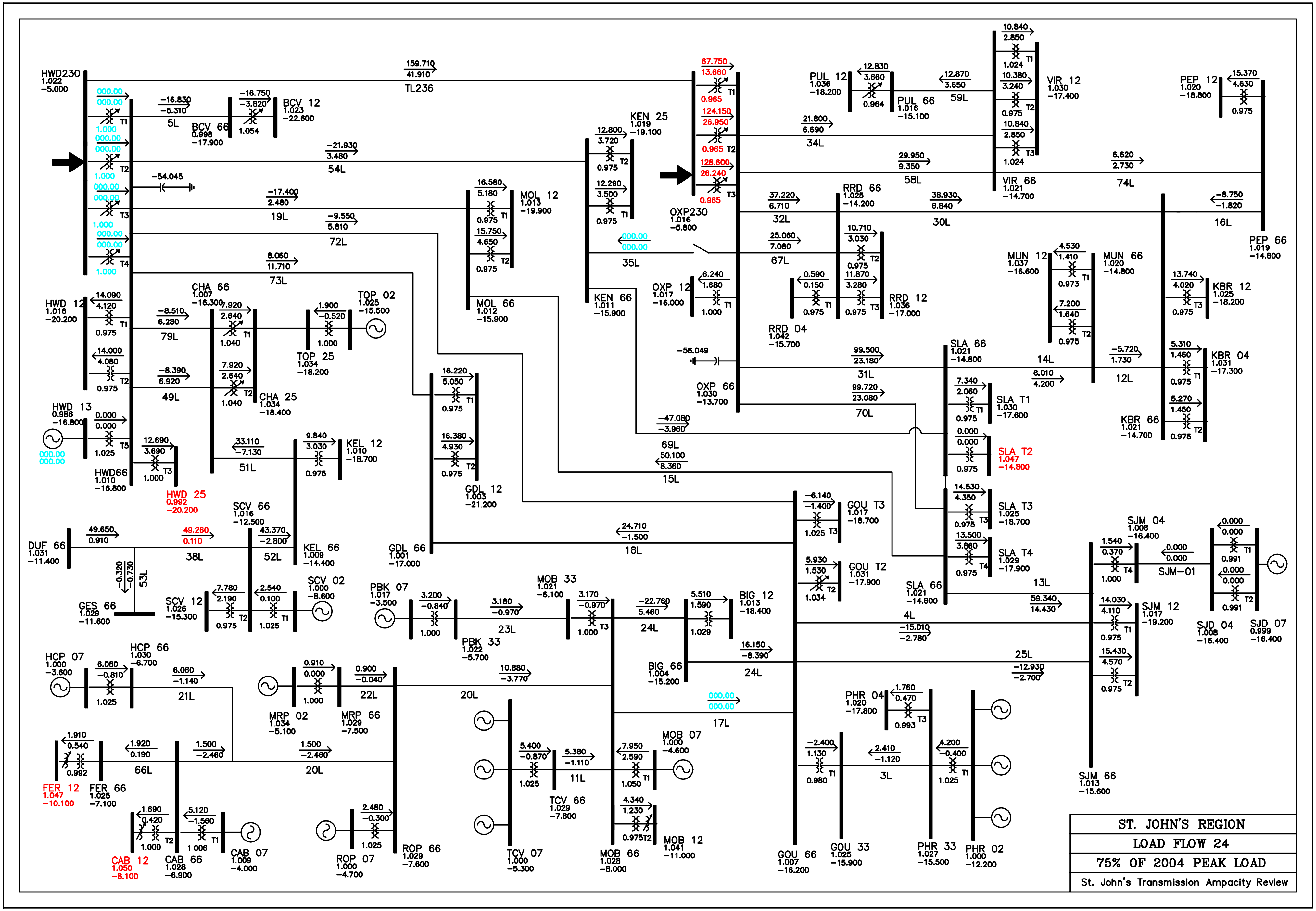


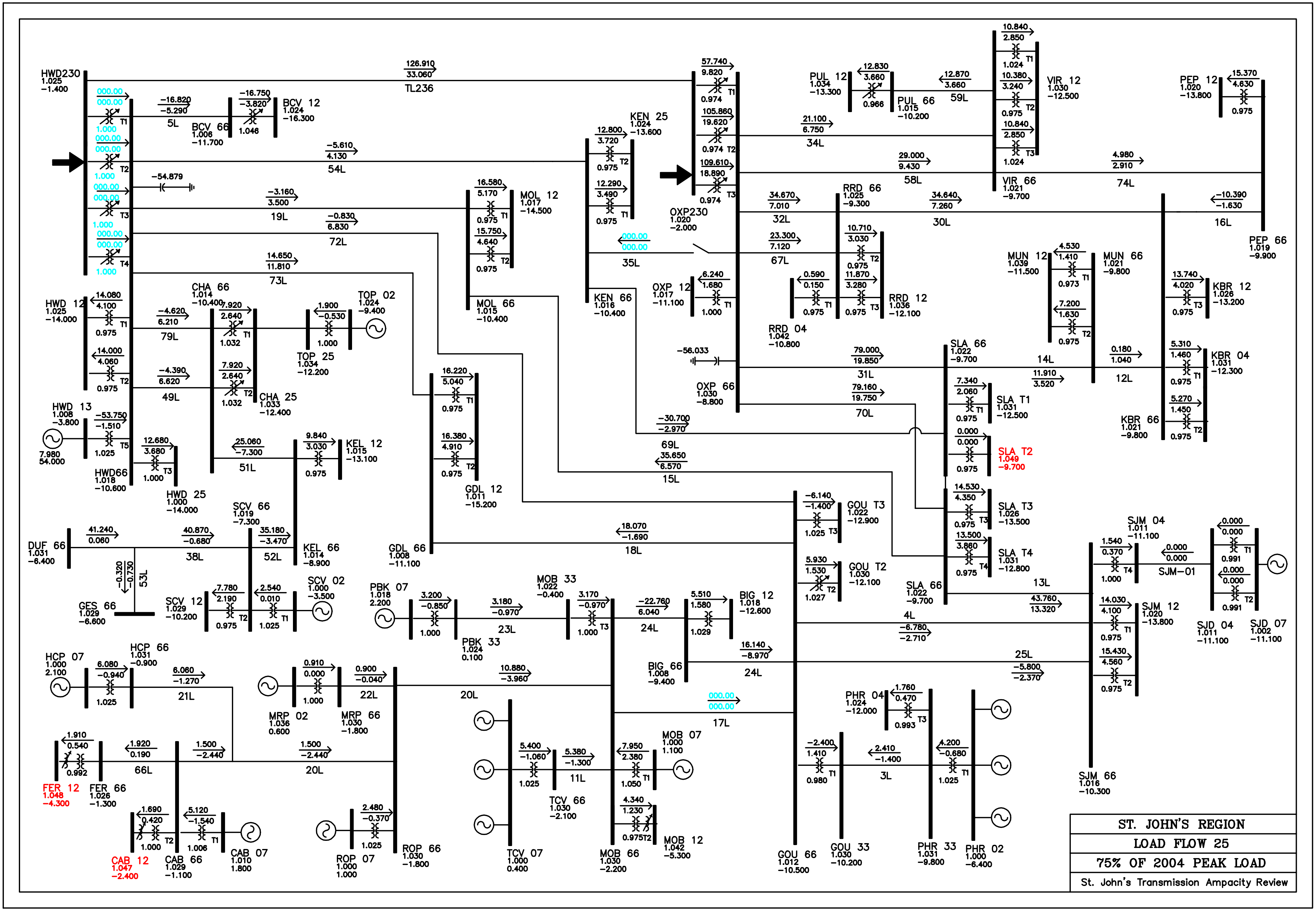
ST. JOHN'S REGION

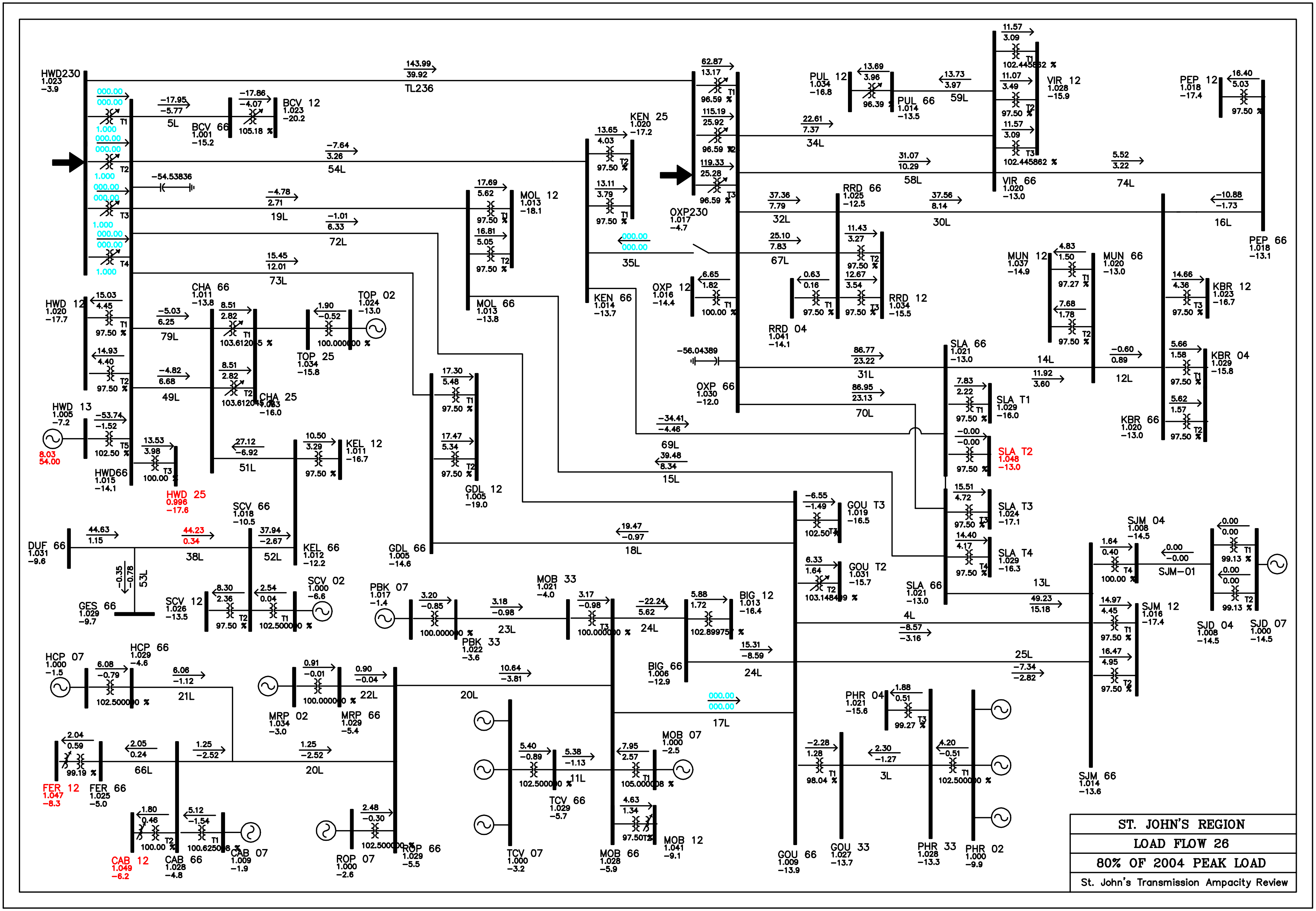
LOAD FLOW 23

60% OF 2004 PEAK LOAD

St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 24
75% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
OXP230
TL236
HWD 12
HWD 13
HWD66
HWD 25
BCV 66
BCV 12
KEN 25
KEN 66
MOL 12
MOL 66
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
SCV 66
SCV 12
SCV 02
GES 66
DUF 66
GDL 12
GDL 66
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
OXP 12
OXP 66
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM 12
SJM 66
SJM-01
SJD 04
SJD 07
PBK 07
PBK 33
MOB 33
MOB 07
MOB 12
MOB 66
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
ROP 07
ROP 66
TCV 66
TCV 07
FER 12
FER 66
CAB 12
CAB 66
CAB 07
PHR 04
PHR 33
PHR 02
5L
54L
19L
72L
73L
79L
49L
51L
38L
52L
53L
15L
18L
69L
35L
34L
32L
67L
58L
59L
30L
74L
16L
14L
12L
31L
70L
13L
4L
25L
24L
23L
21L
20L
22L
17L
11L
66L
3L


ST. JOHN'S REGION
LOAD FLOW 25
75% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 26
80% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
TL236
OXP230
BCV 12
BCV 66
KEN 25
KEN 66
MOL 12
MOL 66
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
OXP 12
OXP 66
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
HWD 12
HWD 13
HWD66
HWD 25
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
GDL 12
GDL 66
SCV 66
SCV 12
SCV 02
DUF 66
GES 66
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM-01
SJM 12
SJM 66
SJD 04
SJD 07
PBK 07
PBK 33
MOB 33
MOB 07
MOB 12
MOB 66
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 66
TCV 07
PHR 04
PHR 33
PHR 02
5L
54L
19L
72L
73L
79L
49L
51L
38L
52L
53L
18L
23L
24L
20L
21L
22L
66L
11L
17L
3L
4L
25L
13L
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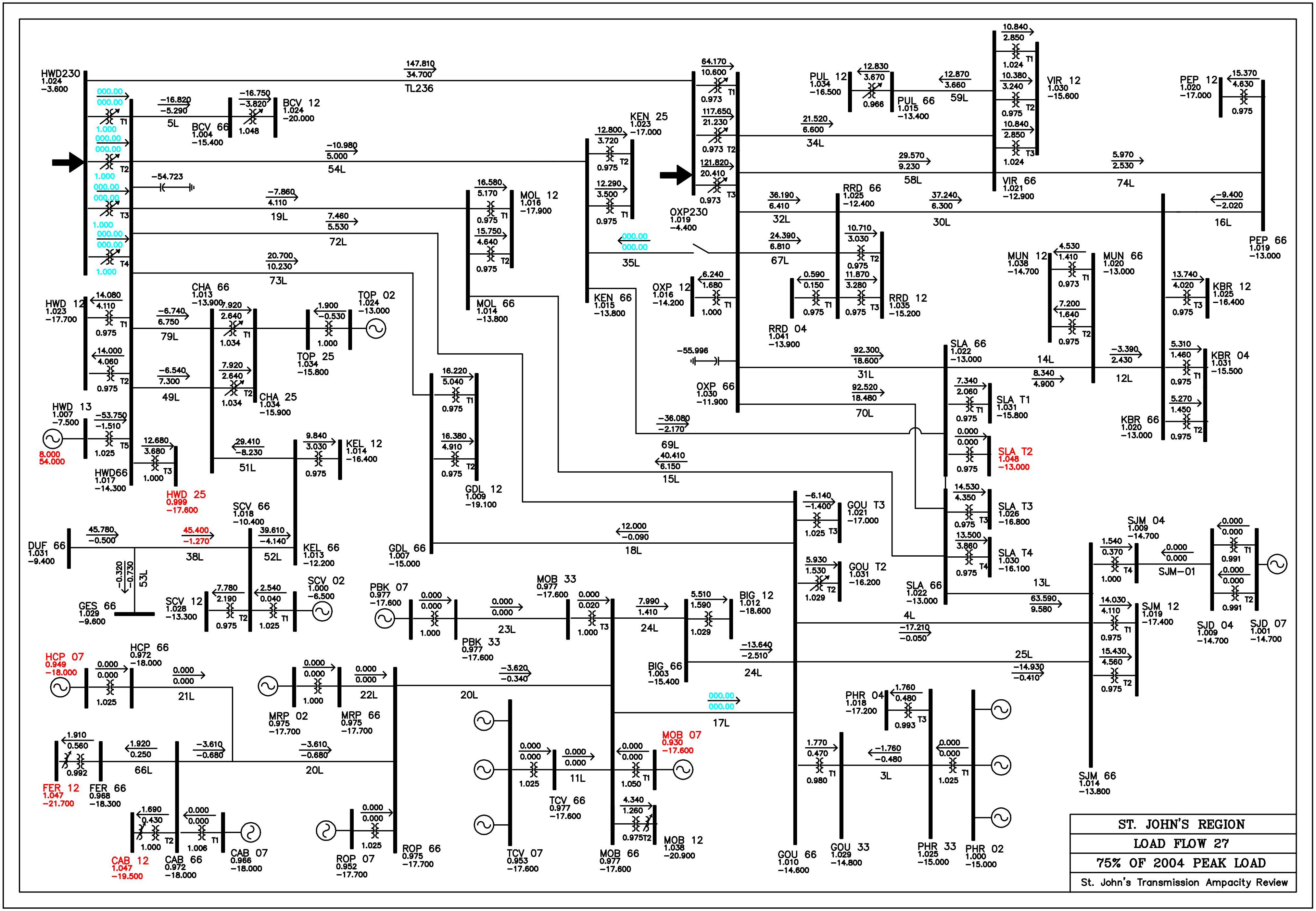
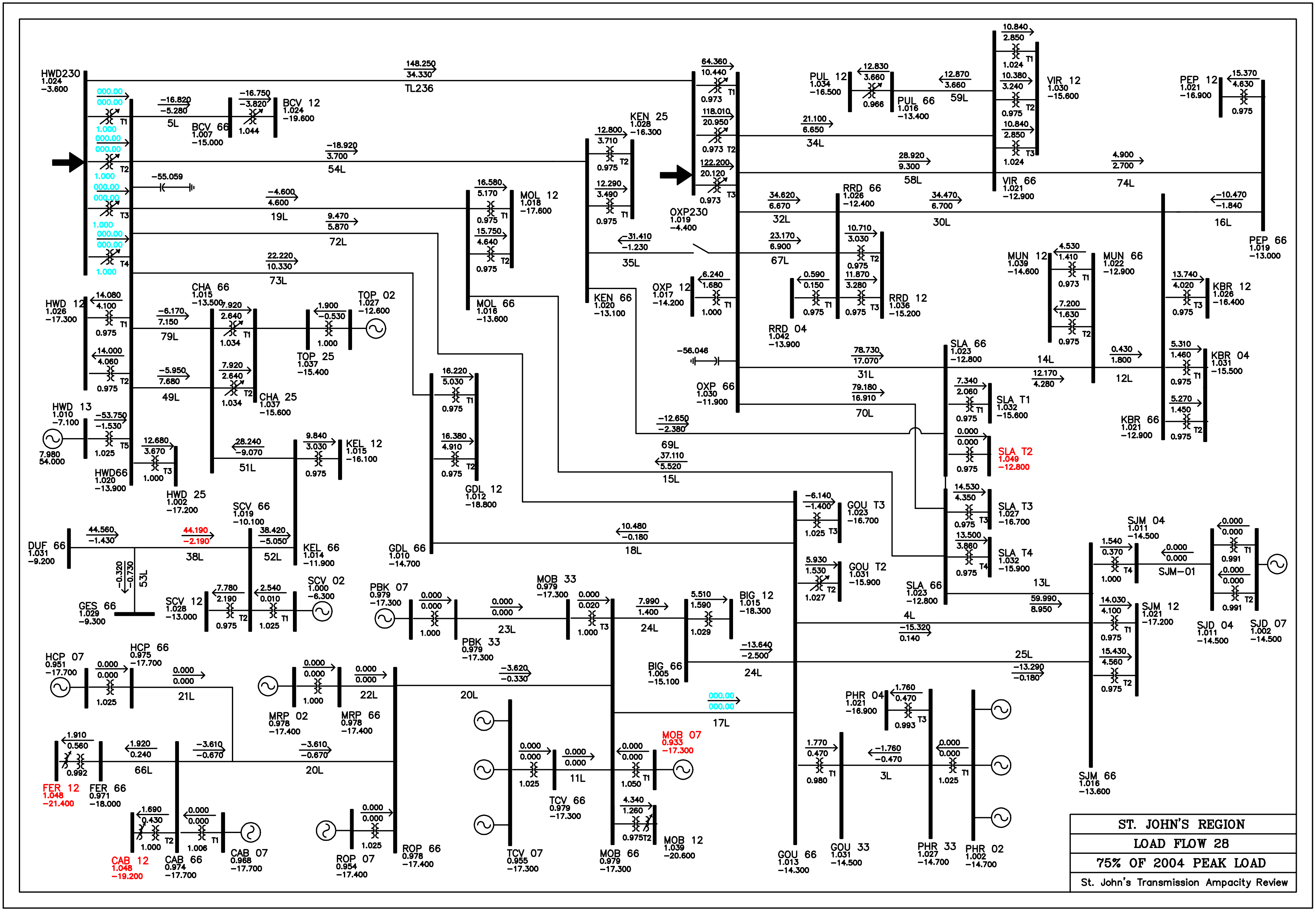
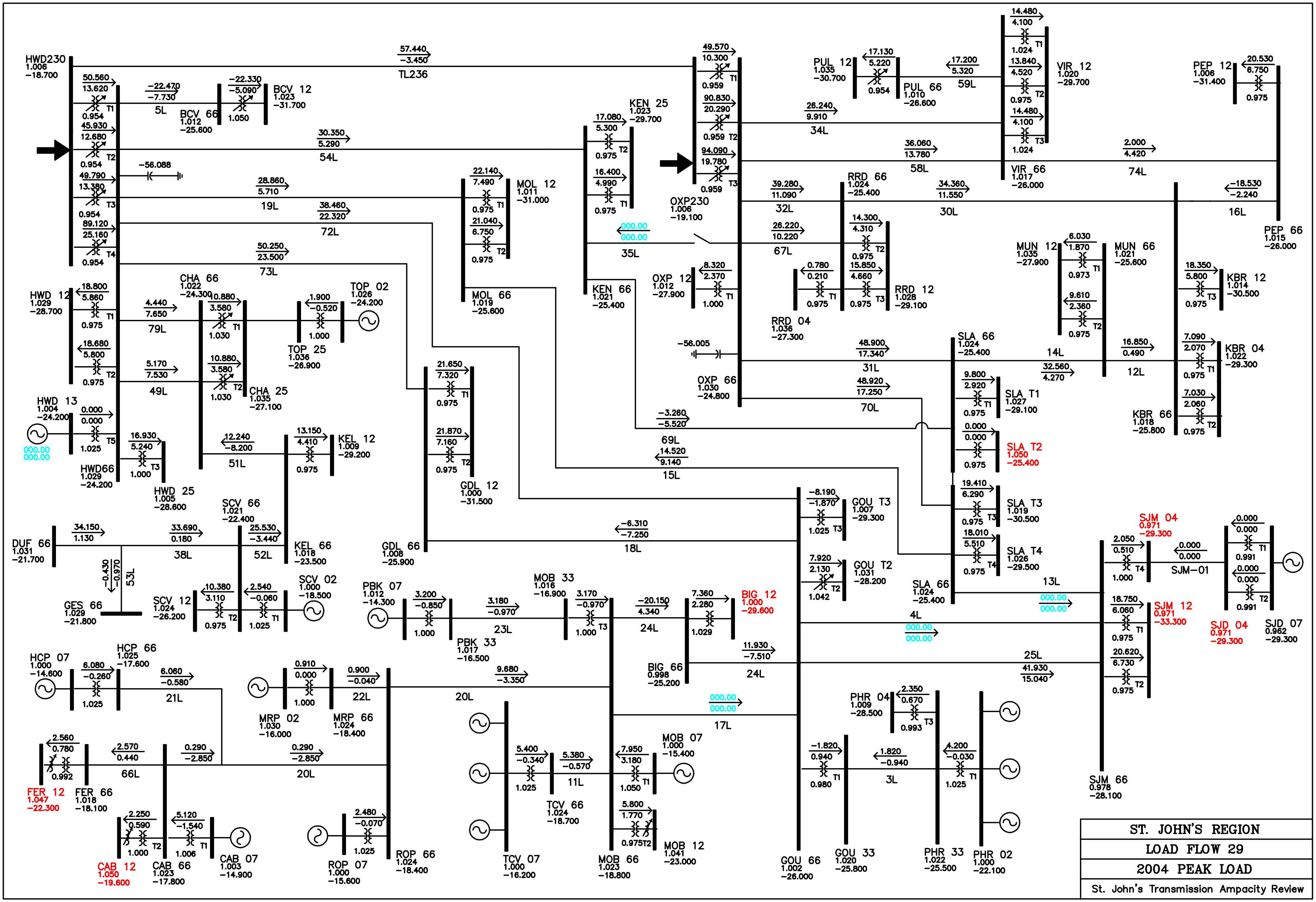
74L
16L
14L
12L


ST. JOHN'S REGION
LOAD FLOW 27
75% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 28
75% OF 2004 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
1.024
-3.600
TL236
OXP230
1.019
-4.400
BCV 12
BCV 66
KEN 25
KEN 66
MOL 12
MOL 66
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
OXP 12
OXP 66
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
HWD 12
HWD 13
HWD66
HWD 25
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
GDL 12
GDL 66
SCV 66
SCV 12
SCV 02
DUF 66
GES 66
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM-01
SJM 12
SJM 66
SJD 04
SJD 07
PBK 07
PBK 33
MOB 33
MOB 07
MOB 66
MOB 12
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 66
TCV 07
PHR 04
PHR 33
PHR 02

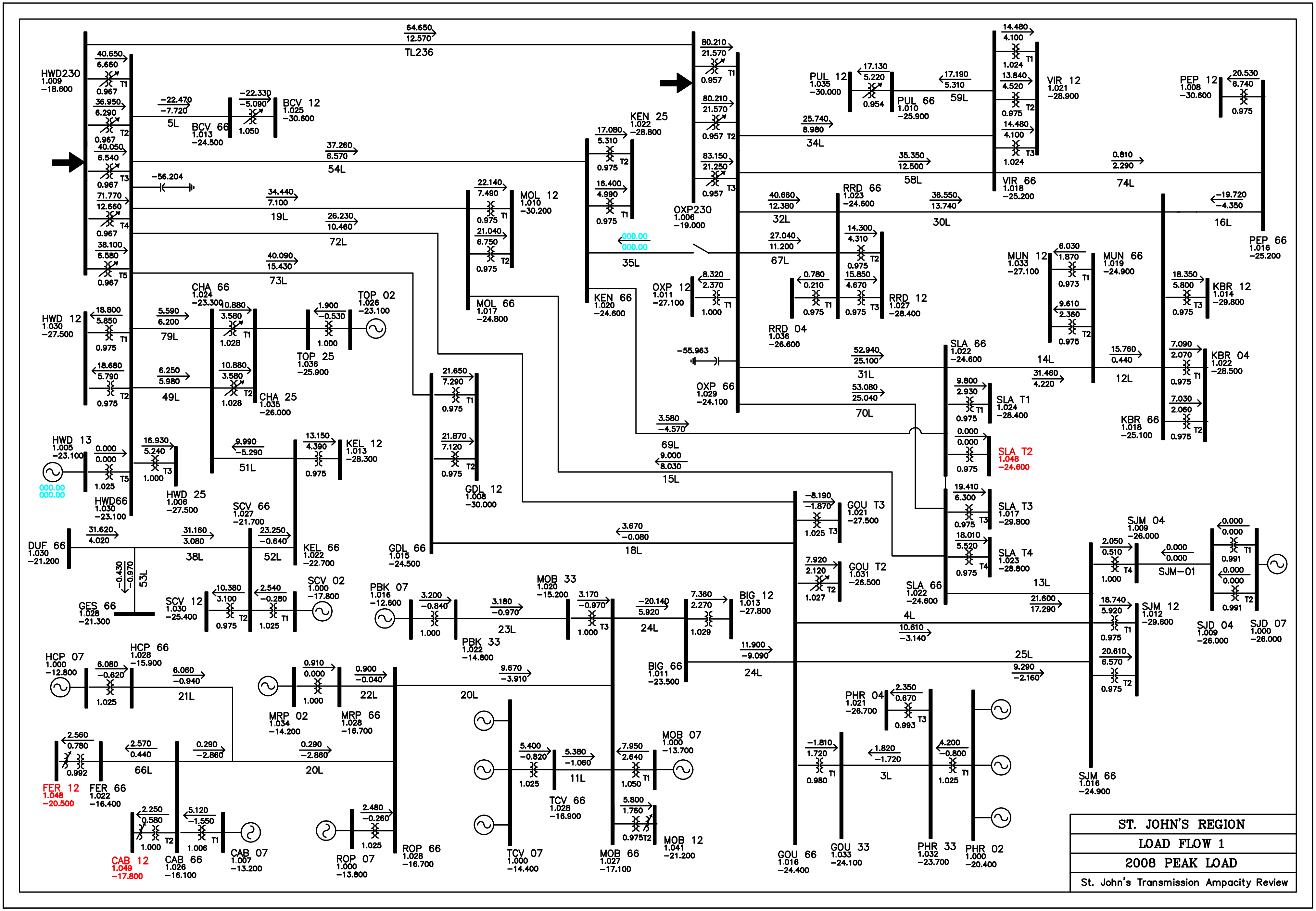


ST. JOHN'S REGION
LOAD FLOW 29
2004 PEAK LOAD
St. John's Transmission Ampacity Review

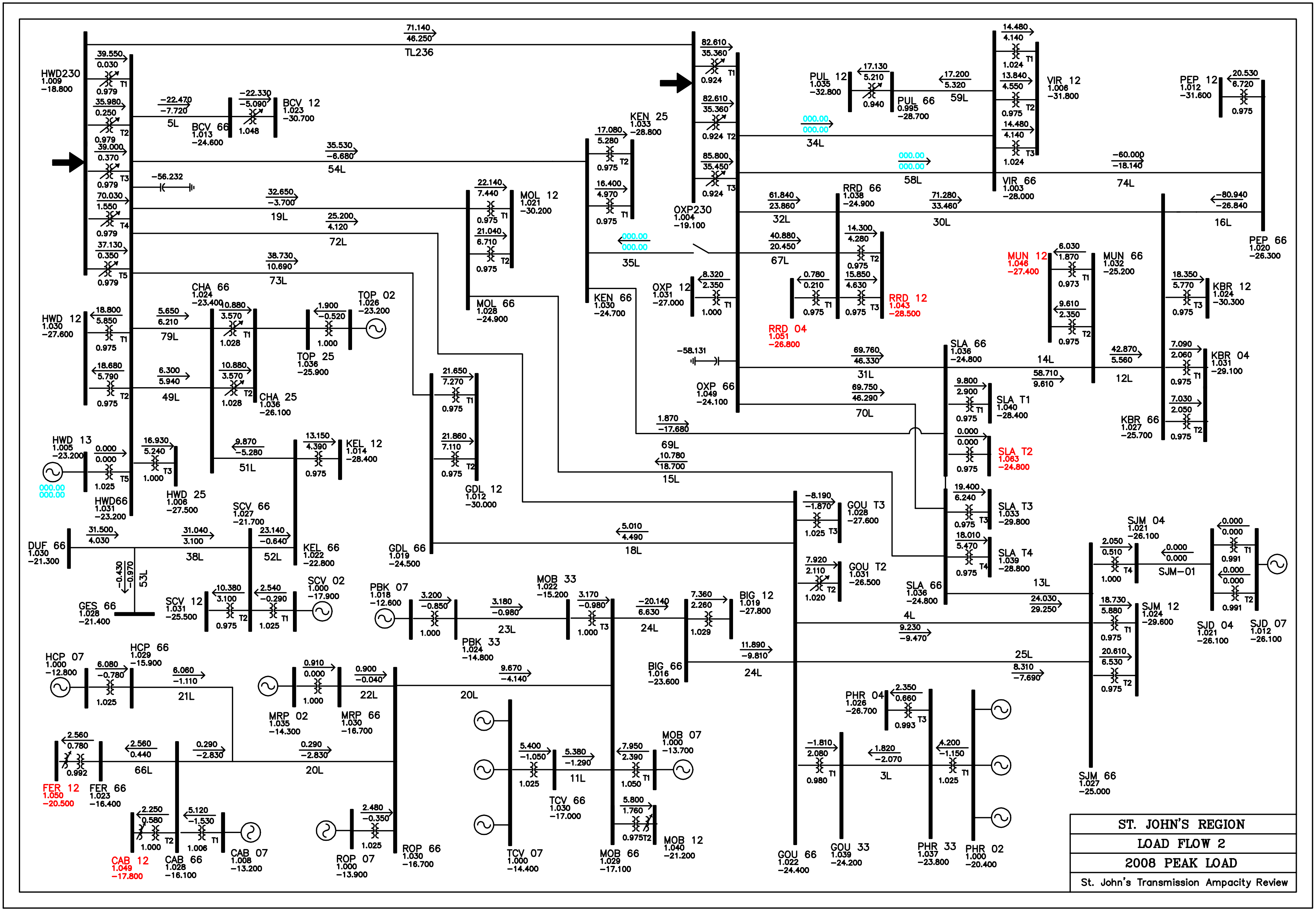
APPENDIX B
2008 LOAD FLOW DRAWINGS

Index

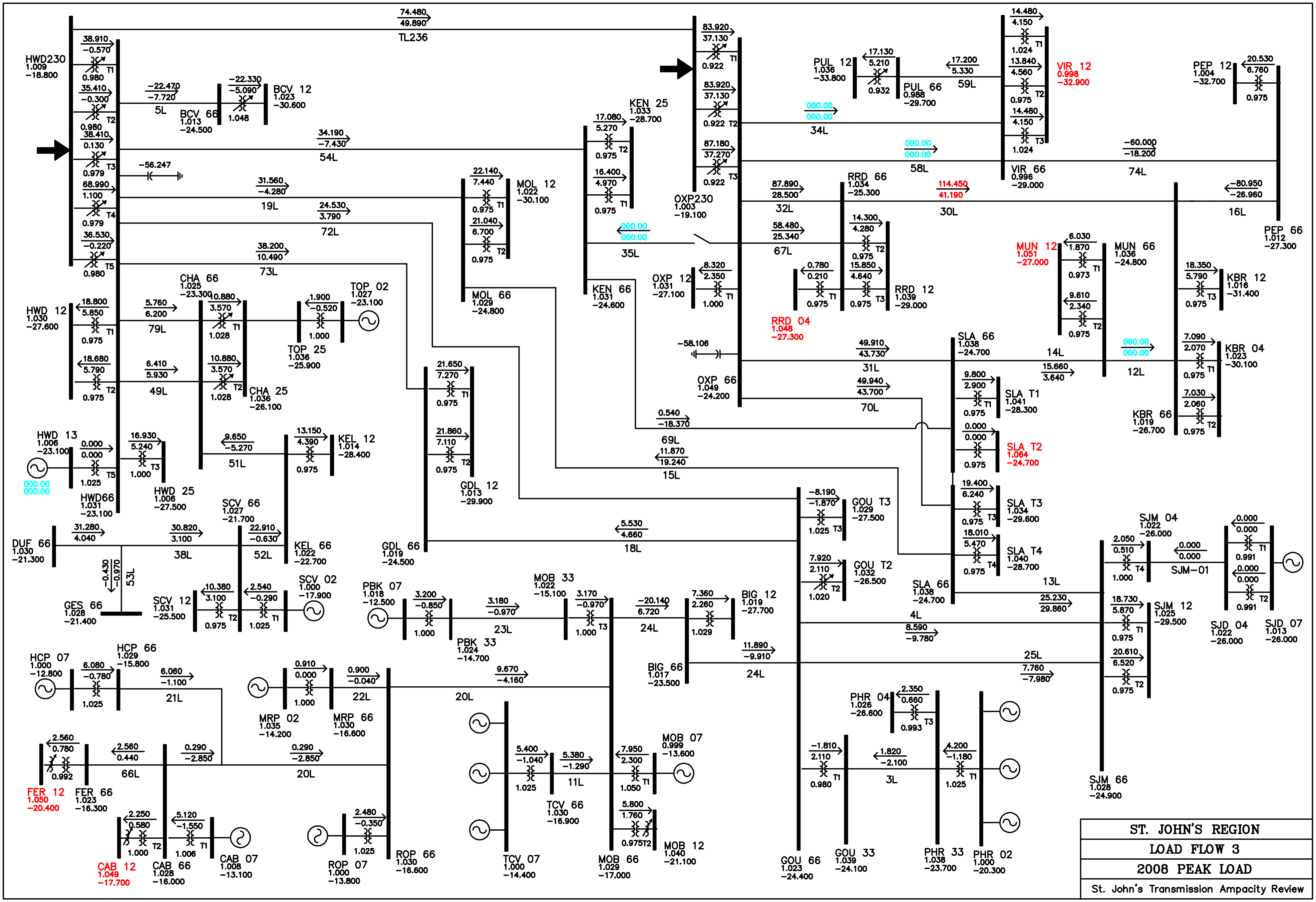
1. Base case 2008 peak loads
2. Base case, open two lines OXP-VIR (34L and 58L), raise OXP voltage to 1.05 pu
3. As in #2, and open MUN-KBR (12L)
4. Base case, Open one line OXP-VIR (58L), raise OXP voltage to 1.05 pu, and open MUN-KBR (12L)
5. Base case, open two lines OXP-RRD (32L and 67L), raise OXP voltage to 1.05 pu
6. Base case, open two lines OXP-RRD (32L and 67L), raise OXP voltage to 1.05 pu and open MUN-KBR (12L)
7. Base case, open two lines OXP-SLA (31L and 70L)
8. As in #7, close OXP-KEN (35L)
9. Base case, open two lines HWD-CHA (79L and 49L)
10. Base case, open 125 MVA transformer at OXP 230/66
11. As in #10, close OXP-KEN (35L)
12. As in #10, open OXP-SLA (70L)
13. As in #10, open two lines OXP-SLA (31L and 70L)
14. 50% of 2008 peak loads, open OXP 230/66 kV transformers (T1, T2 &T3), HWD GT on
15. 65% of 2008 peak loads, open OXP 230/66 kV transformers (T1, T2 &T3), HWD GT on
16. As in #15, close OXP-KEN (35L)
17. 80% of 2008 peak loads, open OXP 230/66 kV transformers (T1, T2 &T3), HWD GT on, HWD voltage to 1.05 pu, close OXP-KEN (35L)
18. Base case, open 125 MVA transformer at HWD 230/66
19. As in #18, open two lines OXP-CHA (79L and 49L)
20. As in #18, HWD GT on
21. 50% of 2008 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4)
22. As in #21, HWD GT on
23. 60% of 2008 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4)
24. 75% of 2008 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4)
25. As in #24, HWD GT on
26. 80% of 2008 peak loads, open HWD 230/66 kV transformers (T1, T2, T3 &T4), HWD GT on
27. As in #26, HWD GT on, no Southern Shore generation, HWD GT off
28. As in #27, HWD GT on, no Southern Shore generation, close OXP-KEN (35L)
29. Base case, open SJM-SLA (13L) and SJM – GOU (4L)

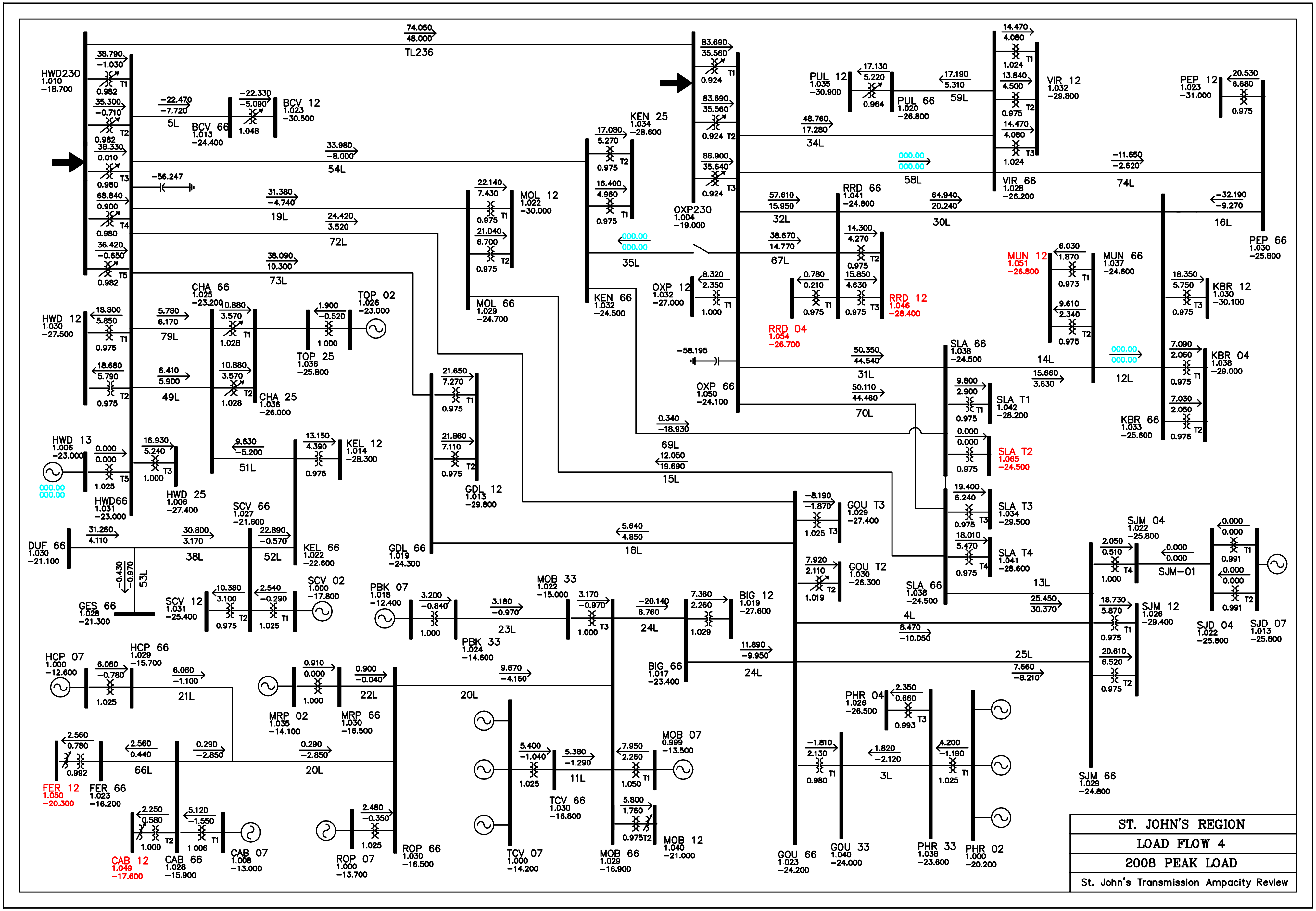


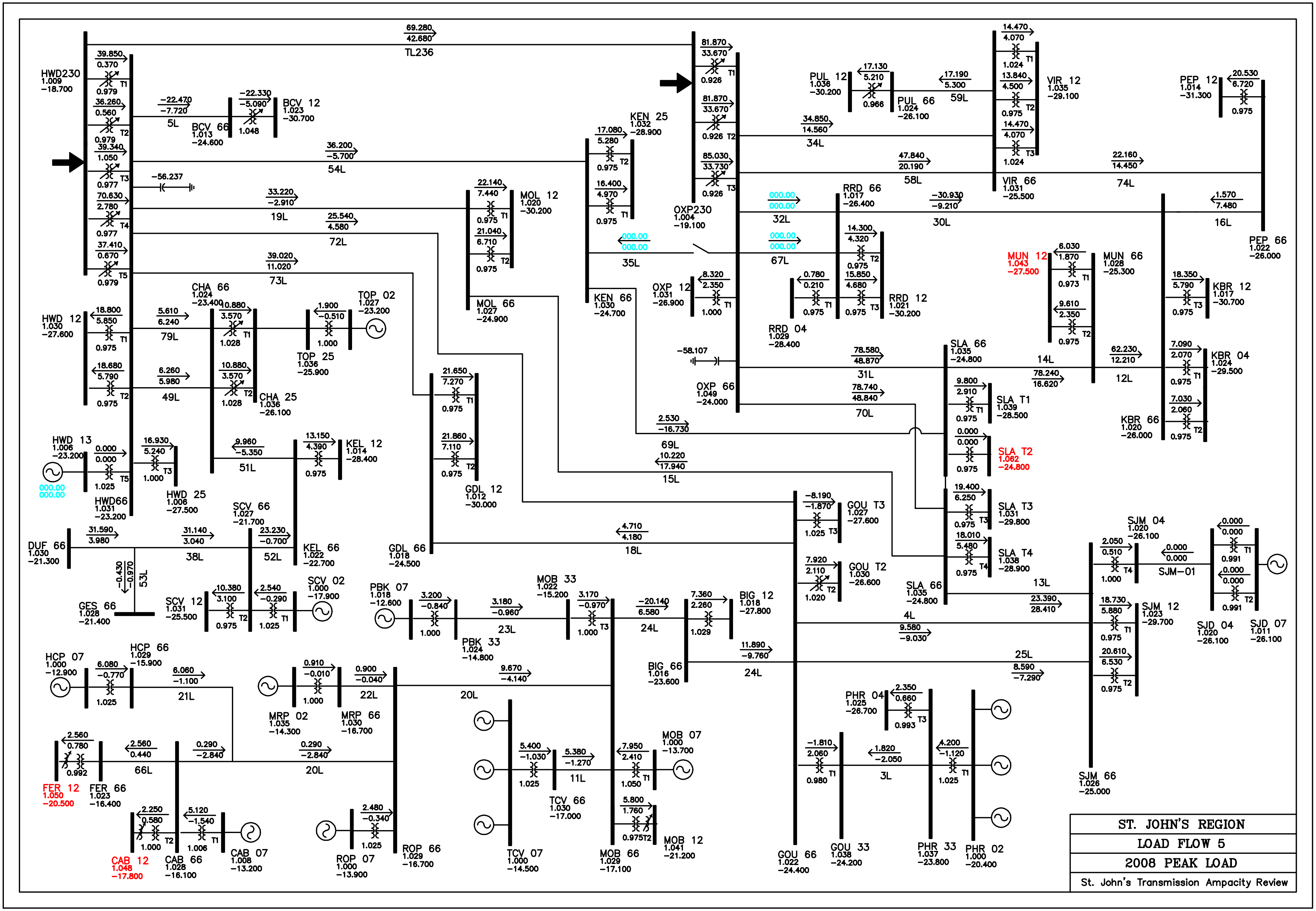
ST. JOHN'S REGION
LOAD FLOW 1
2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230 1.009 −18.600
OXP230 1.006 −19.000
TL236
BCV 12 1.025 −30.600
BCV 66 1.013 −24.500
KEN 25 1.022 −28.800
KEN 66 1.020 −24.600
MOL 12 1.010 −30.200
MOL 66 1.017 −24.800
PUL 12 1.035 −30.000
PUL 66 1.010 −25.900
VIR 12 1.021 −28.900
VIR 66 1.018 −25.200
PEP 12 1.008 −30.600
PEP 66 1.016 −25.200
RRD 66 1.023 −24.600
RRD 12 1.027 −28.400
RRD 04 1.036 −26.600
MUN 12 1.033 −27.100
MUN 66 1.019 −24.900
KBR 12 1.014 −29.800
KBR 04 1.022 −28.500
KBR 66 1.018 −25.100
OXP 12 1.011 −27.100
OXP 66 1.029 −24.100
SLA 66 1.022 −24.600
SLA T1 1.024 −28.400
SLA T2 1.048 −24.600
SLA T3 1.017 −29.800
SLA T4 1.023 −28.800
HWD 12 1.030 −27.500
HWD 13 1.005 −23.100
HWD 25 1.006 −27.500
HWD66 1.030 −23.100
CHA 66 1.024 −23.300
CHA 25 1.035 −26.000
TOP 02 1.026 −23.100
TOP 25 1.036 −25.900
KEL 12 1.013 −28.300
KEL 66 1.022 −22.700
SCV 66 1.027 −21.700
SCV 12 1.030 −25.400
SCV 02 1.000 −17.800
DUF 66 1.030 −21.200
GES 66 1.028 −21.300
GDL 12 1.008 −30.000
GDL 66 1.015 −24.500
GOU T3 1.021 −27.500
GOU T2 1.031 −26.500
GOU 66 1.016 −24.400
GOU 33 1.033 −24.100
SJM 04 1.009 −26.000
SJM−01
SJM 12 1.012 −29.600
SJM 66 1.016 −24.900
SJD 04 1.009 −26.000
SJD 07 1.000 −26.000
PBK 07 1.016 −12.600
PBK 33 1.022 −14.800
MOB 33 1.020 −15.200
MOB 07 1.000 −13.700
MOB 66 1.027 −17.100
MOB 12 1.041 −21.200
BIG 12 1.013 −27.800
BIG 66 1.011 −23.500
HCP 07 1.000 −12.800
HCP 66 1.028 −15.900
MRP 02 1.034 −14.200
MRP 66 1.028 −16.700
FER 12 1.048 −20.500
FER 66 1.022 −16.400
CAB 12 1.049 −17.800
CAB 66 1.026 −16.100
CAB 07 1.007 −13.200
ROP 07 1.000 −13.800
ROP 66 1.028 −16.700
TCV 66 1.028 −16.900
TCV 07 1.000 −14.400
PHR 04 1.021 −26.700
PHR 33 1.032 −23.700
PHR 02 1.000 −20.400
5L 54L 19L 72L 73L 79L 49L 51L 38L 52L 53L 35L 34L 58L 59L 74L 32L 30L 16L 67L 31L 70L 69L 15L 14L 12L 13L 18L 4L 25L 24L 23L 21L 22L 20L 66L 11L 3L



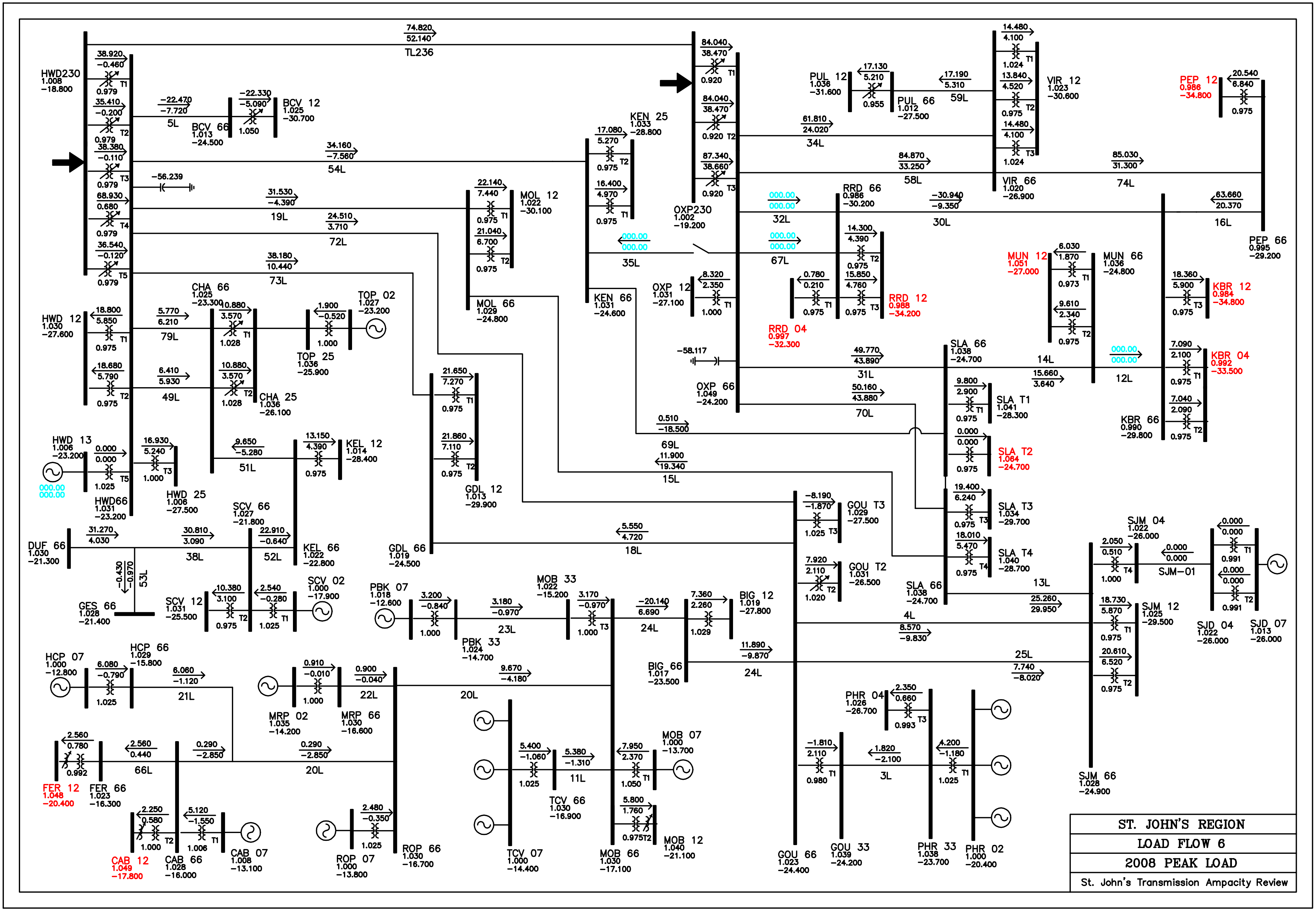
ST. JOHN'S REGION
LOAD FLOW 2
2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
TL236
OXP230
BCV 12
BCV 66
KEN 25
KEN 66
MOL 12
MOL 66
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
OXP 12
OXP 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
HWD 12
HWD 13
HWD 25
HWD66
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
SCV 66
SCV 12
SCV 02
GDL 12
GDL 66
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM 12
SJM 66
SJM-01
SJD 04
SJD 07
DUF 66
GES 66
PBK 07
PBK 33
MOB 33
MOB 07
MOB 12
MOB 66
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 66
TCV 07
PHR 04
PHR 33
PHR 02
5L
54L
19L
72L
73L
79L
49L
51L
38L
52L
53L
35L
34L
58L
74L
59L
32L
30L
16L
67L
31L
70L
69L
15L
18L
14L
12L
13L
4L
25L
23L
24L
21L
22L
20L
66L
11L
3L

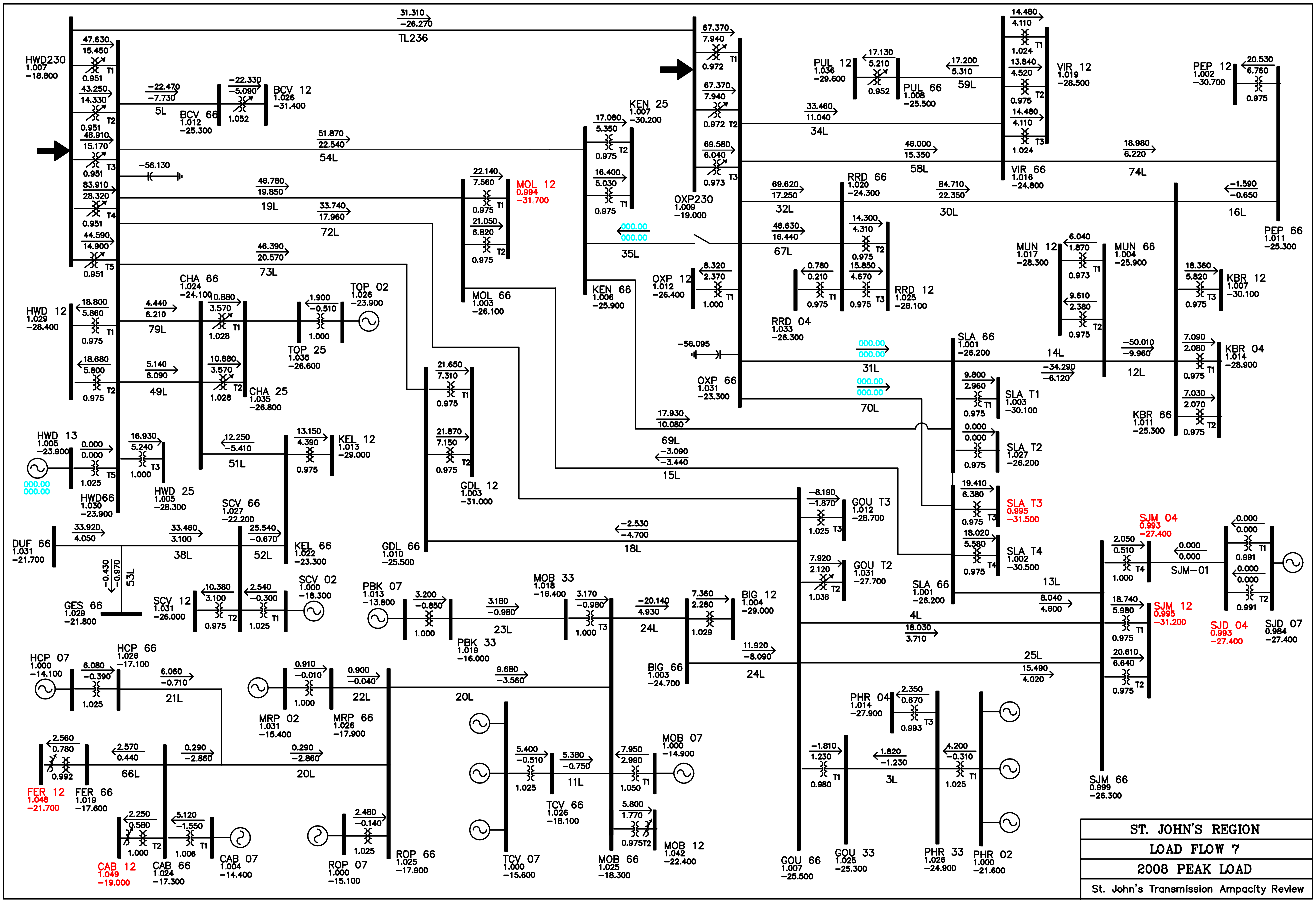

ST. JOHN'S REGION
LOAD FLOW 3
2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
OXP230
TL236
HWD 12
HWD 13
HWD 25
HWD66
BCV 12
BCV 66
KEN 25
KEN 66
MOL 12
MOL 66
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
GDL 12
GDL 66
DUF 66
GES 66
SCV 66
SCV 12
SCV 02
PBK 07
PBK 33
MOB 33
MOB 07
MOB 12
MOB 66
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 66
TCV 07
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
OXP 12
OXP 66
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM 12
SJM 66
SJM-01
SJD 04
SJD 07
PHR 04
PHR 33
PHR 02


ST. JOHN'S REGION
LOAD FLOW 4
2008 PEAK LOAD
St. John's Transmission Ampacity Review



ST. JOHN'S REGION
LOAD FLOW 5
2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230 1.009 −18.700
OXP230 1.004 −19.100
TL236
HWD 12 1.030 −27.600
HWD 13 1.006 −23.200
HWD 25 1.008 −27.500
HWD66 1.031 −23.200
BCV 12 1.023 −30.700
BCV 66 1.013 −24.600
KEN 25 1.032 −28.900
KEN 66 1.030 −24.700
MOL 12 1.020 −30.200
MOL 66 1.027 −24.900
CHA 66 1.024 −23.400
CHA 25 1.036 −26.100
TOP 02 1.027 −23.200
TOP 25 1.036 −25.900
KEL 12 1.014 −28.400
KEL 66 1.022 −22.700
SCV 66 1.027 −21.700
SCV 12 1.031 −25.500
SCV 02 1.000 −17.900
DUF 66 1.030 −21.300
GES 66 1.028 −21.400
GDL 12 1.012 −30.000
GDL 66 1.018 −24.500
PUL 12 1.036 −30.200
PUL 66 1.024 −26.100
VIR 12 1.035 −29.100
VIR 66 1.031 −25.500
PEP 12 1.014 −31.300
PEP 66 1.022 −26.000
RRD 66 1.017 −26.400
RRD 12 1.021 −30.200
RRD 04 1.029 −28.400
OXP 12 1.031 −26.900
OXP 66 1.049 −24.000
MUN 12 1.043 −27.500
MUN 66 1.028 −25.300
KBR 12 1.017 −30.700
KBR 04 1.024 −29.500
KBR 66 1.020 −26.000
SLA 66 1.035 −24.800
SLA T1 1.039 −28.500
SLA T2 1.062 −24.800
SLA T3 1.031 −29.800
SLA T4 1.038 −28.900
GOU T3 1.027 −27.600
GOU T2 1.030 −26.600
GOU 66 1.022 −24.400
GOU 33 1.038 −24.200
SJM 04 1.020 −26.100
SJM−01
SJM 12 1.023 −29.700
SJM 66 1.026 −25.000
SJD 04 1.020 −26.100
SJD 07 1.011 −26.100
PBK 07 1.018 −12.600
PBK 33 1.024 −14.800
MOB 33 1.022 −15.200
MOB 07 1.000 −13.700
MOB 66 1.029 −17.100
MOB 12 1.041 −21.200
BIG 12 1.018 −27.800
BIG 66 1.016 −23.600
HCP 07 1.000 −12.900
HCP 66 1.029 −15.900
MRP 02 1.035 −14.300
MRP 66 1.030 −16.700
TCV 66 1.030 −17.000
TCV 07 1.000 −14.500
FER 12 1.050 −20.500
FER 66 1.023 −16.400
CAB 12 1.048 −17.800
CAB 66 1.028 −16.100
CAB 07 1.008 −13.200
ROP 07 1.000 −13.900
ROP 66 1.029 −16.700
PHR 04 1.025 −26.700
PHR 33 1.037 −23.800
PHR 02 1.000 −20.400
5L 54L 19L 72L 73L 79L 49L 51L 38L 52L 53L 35L 32L 67L 34L 58L 59L 30L 74L 16L 31L 70L 69L 15L 18L 14L 12L 13L 4L 25L 24L 23L 21L 22L 20L 66L 11L 3L


ST. JOHN'S REGION
LOAD FLOW 6
2008 PEAK LOAD
St. John's Transmission Ampacity Review

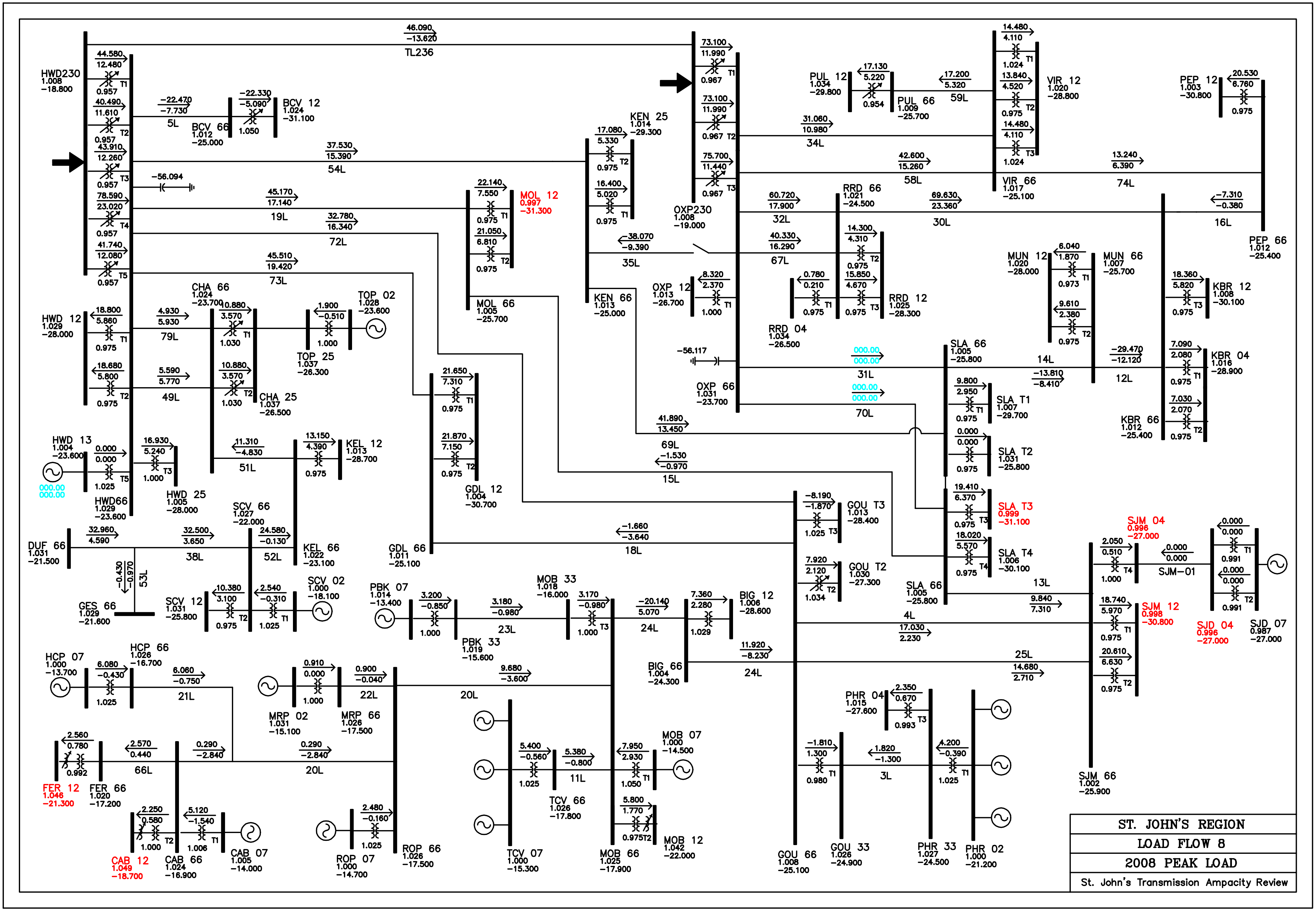


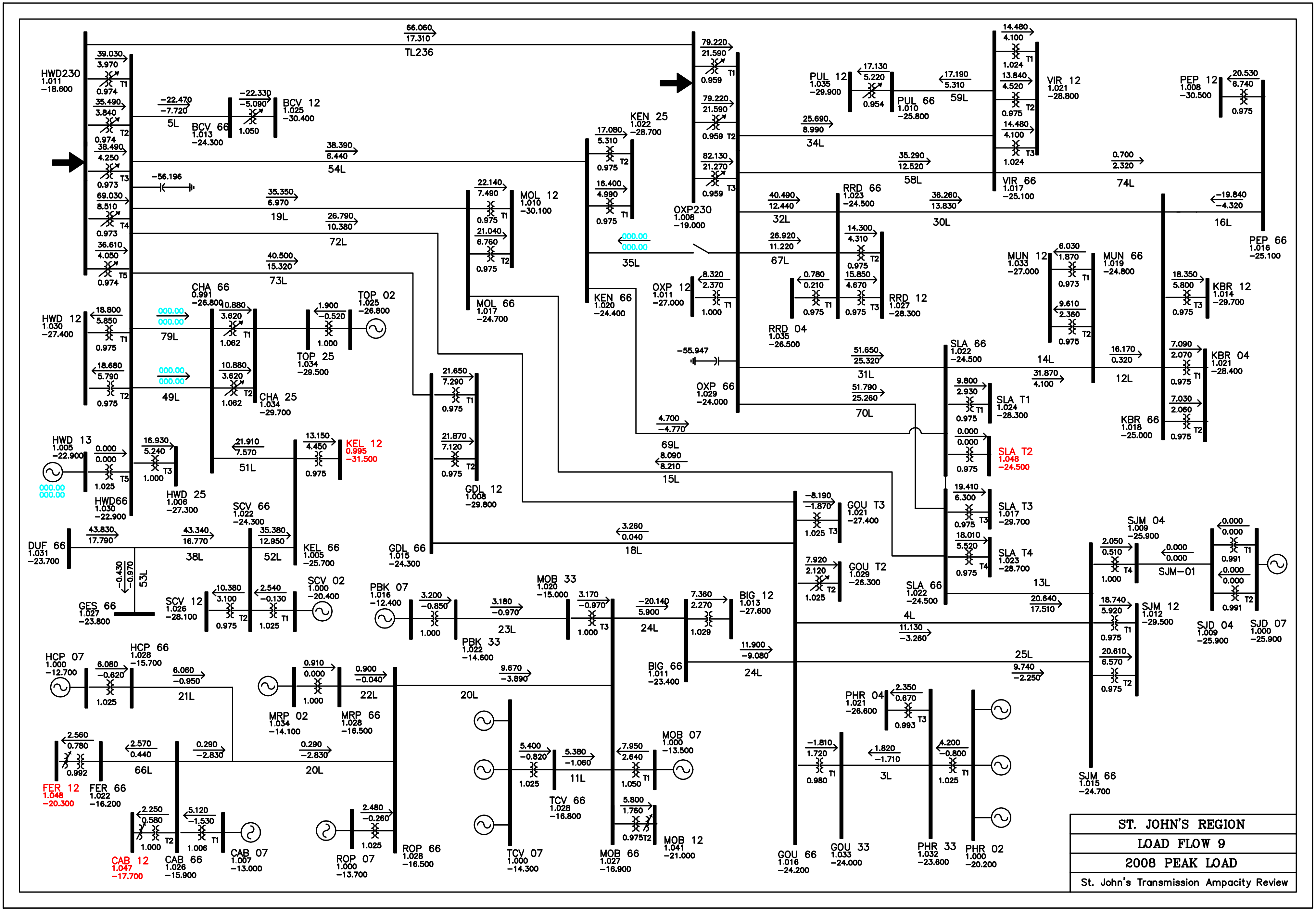
ST. JOHN'S REGION

LOAD FLOW 7

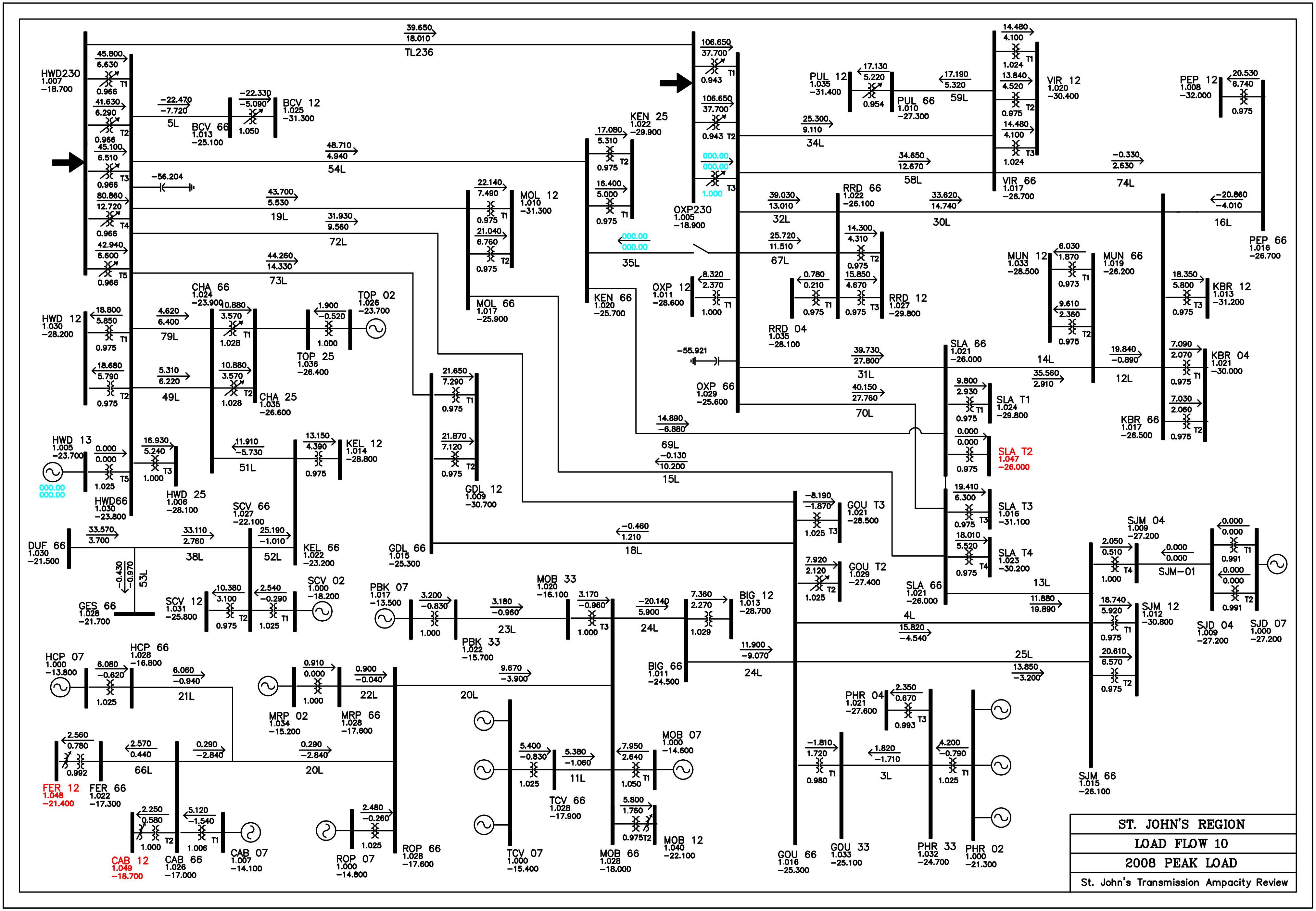
2008 PEAK LOAD

St. John's Transmission Ampacity Review

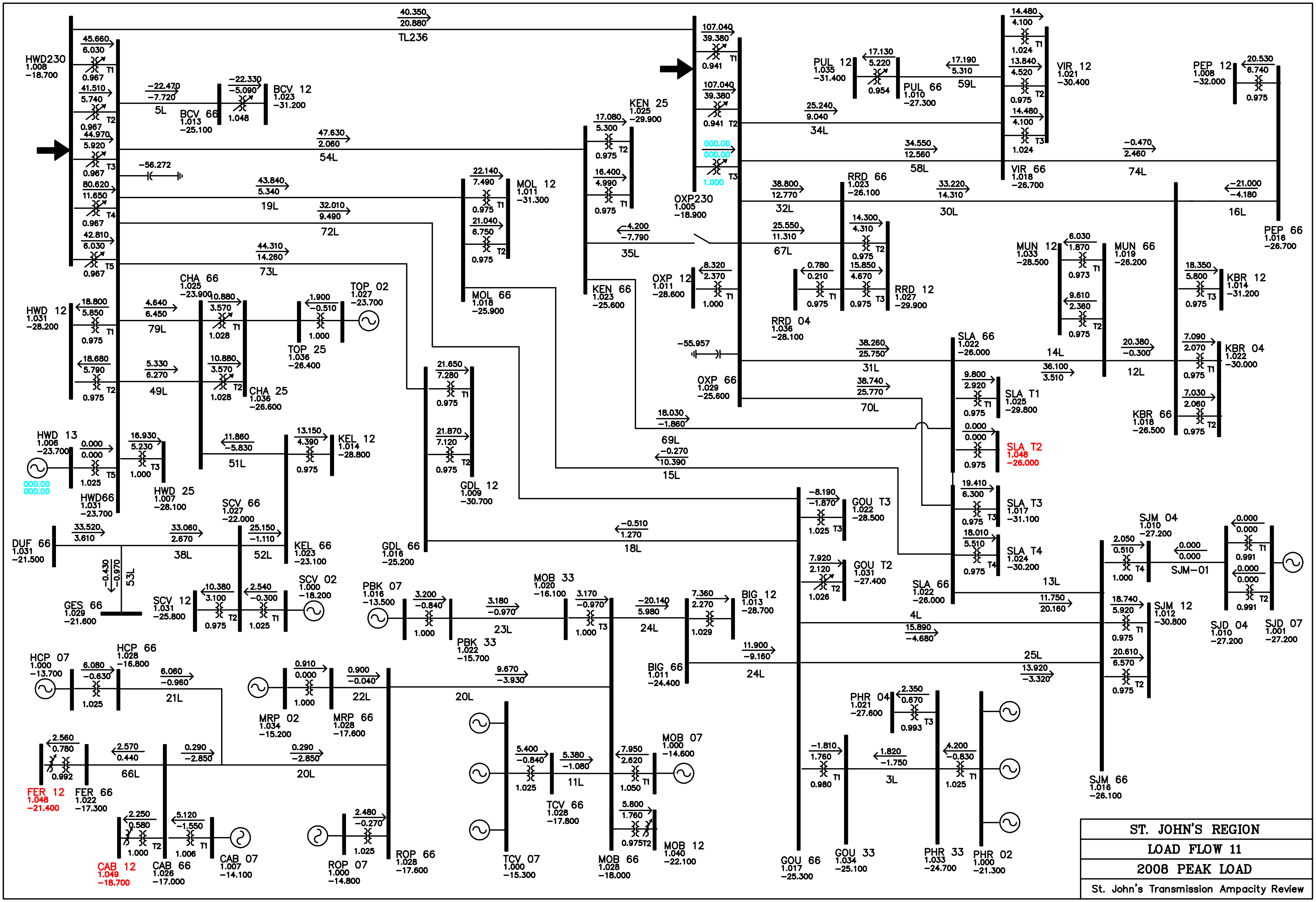

ST. JOHN'S REGION
LOAD FLOW 8
2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
OXP230
TL236
HWD 12
HWD 13
HWD 25
HWD66
BCV 66
BCV 12
KEN 25
KEN 66
MOL 12
MOL 66
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
SCV 66
SCV 12
SCV 02
DUF 66
GES 66
GDL 12
GDL 66
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
OXP 12
OXP 66
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM 12
SJM 66
SJM-01
SJD 04
SJD 07
PBK 07
PBK 33
MOB 33
MOB 07
MOB 12
MOB 66
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
TCV 66
TCV 07
PHR 04
PHR 33
PHR 02
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66



HWD230 1.011 −18.600
TL236
HWD 12 1.030 −27.400
HWD 13 1.005 −22.900
HWD66 1.030 −22.900
HWD 25 1.006 −27.300
BCV 66 1.013 −24.300
BCV 12 1.025 −30.400
5L
54L
19L
72L
73L
79L
49L
CHA 66 0.991 −26.800
CHA 25 1.034 −29.700
TOP 02 1.025 −26.800
TOP 25 1.034 −29.500
KEL 12 0.995 −31.500
51L
SCV 66 1.022 −24.300
KEL 66 1.005 −25.700
DUF 66 1.031 −23.700
38L
52L
53L
GES 66 1.027 −23.800
SCV 12 1.026 −28.100
SCV 02 1.000 −20.400
MOL 12 1.010 −30.100
MOL 66 1.017 −24.700
GDL 12 1.008 −29.800
GDL 66 1.015 −24.300
KEN 25 1.022 −28.700
KEN 66 1.020 −24.400
35L
OXP230 1.008 −19.000
OXP 12 1.011 −27.000
OXP 66 1.029 −24.000
69L
15L
18L
PUL 12 1.035 −29.900
PUL 66 1.010 −25.800
59L
34L
58L
32L
67L
30L
RRD 66 1.023 −24.500
RRD 12 1.027 −28.300
RRD 04 1.035 −26.500
31L
70L
VIR 12 1.021 −28.800
VIR 66 1.017 −25.100
74L
PEP 12 1.008 −30.500
PEP 66 1.016 −25.100
16L
MUN 12 1.033 −27.000
MUN 66 1.019 −24.800
14L
12L
KBR 12 1.014 −29.700
KBR 04 1.021 −28.400
KBR 66 1.018 −25.000
SLA 66 1.022 −24.500
SLA T1 1.024 −28.300
SLA T2 1.048 −24.500
SLA T3 1.017 −29.700
SLA T4 1.023 −28.700
GOU T3 1.021 −27.400
GOU T2 1.029 −26.300
13L
SJM 04 1.009 −25.900
SJM−01
SJM 12 1.012 −29.500
SJD 04 1.009 −25.900
SJD 07 1.000 −25.900
SJM 66 1.015 −24.700
4L
25L
HCP 07 1.000 −12.700
HCP 66 1.028 −15.700
21L
MRP 02 1.034 −14.100
MRP 66 1.028 −16.500
22L
20L
PBK 07 1.016 −12.400
PBK 33 1.022 −14.600
23L
MOB 33 1.020 −15.000
24L
BIG 12 1.013 −27.600
BIG 66 1.011 −23.400
FER 12 1.048 −20.300
FER 66 1.022 −16.200
66L
CAB 12 1.047 −17.700
CAB 66 1.026 −15.900
CAB 07 1.007 −13.000
ROP 07 1.000 −13.700
ROP 66 1.028 −16.500
TCV 66 1.028 −16.800
11L
TCV 07 1.000 −14.300
MOB 07 1.000 −13.500
MOB 66 1.027 −16.900
MOB 12 1.041 −21.000
GOU 66 1.016 −24.200
GOU 33 1.033 −24.000
3L
PHR 04 1.021 −26.600
PHR 33 1.032 −23.600
PHR 02 1.000 −20.200
ST. JOHN'S REGION
LOAD FLOW 9
2008 PEAK LOAD
St. John's Transmission Ampacity Review



ST. JOHN'S REGION
LOAD FLOW 10
2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
TL236
OXP230
HWD 12
HWD 13
HWD 25
HWD66
BCV 66
BCV 12
KEN 25
KEN 66
MOL 12
MOL 66
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
SCV 66
SCV 12
SCV 02
DUF 66
GES 66
GDL 12
GDL 66
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
OXP 12
OXP 66
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM-01
SJM 12
SJM 66
SJD 04
SJD 07
PBK 07
PBK 33
MOB 33
MOB 07
MOB 66
MOB 12
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 66
TCV 07
PHR 04
PHR 33
PHR 02

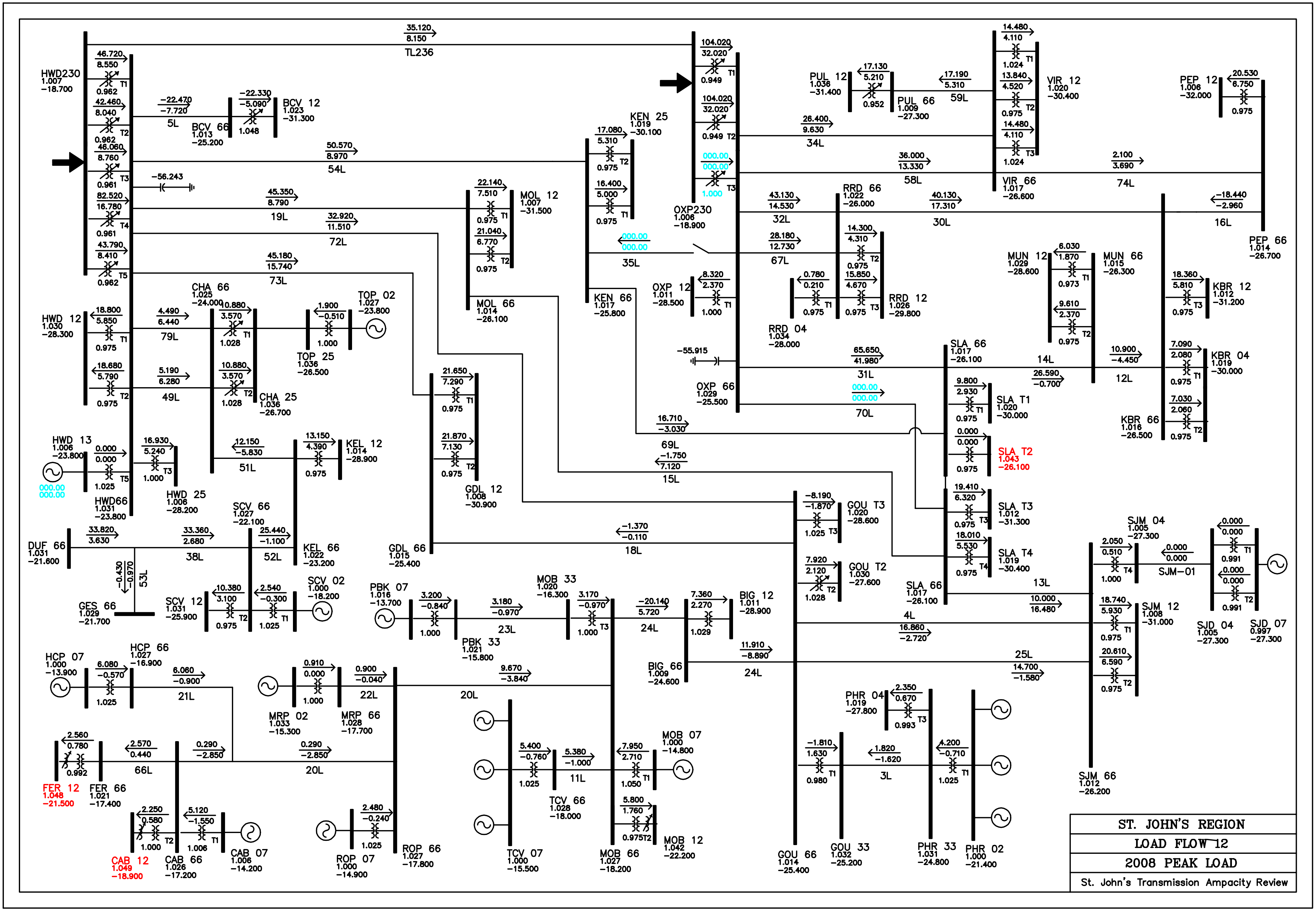


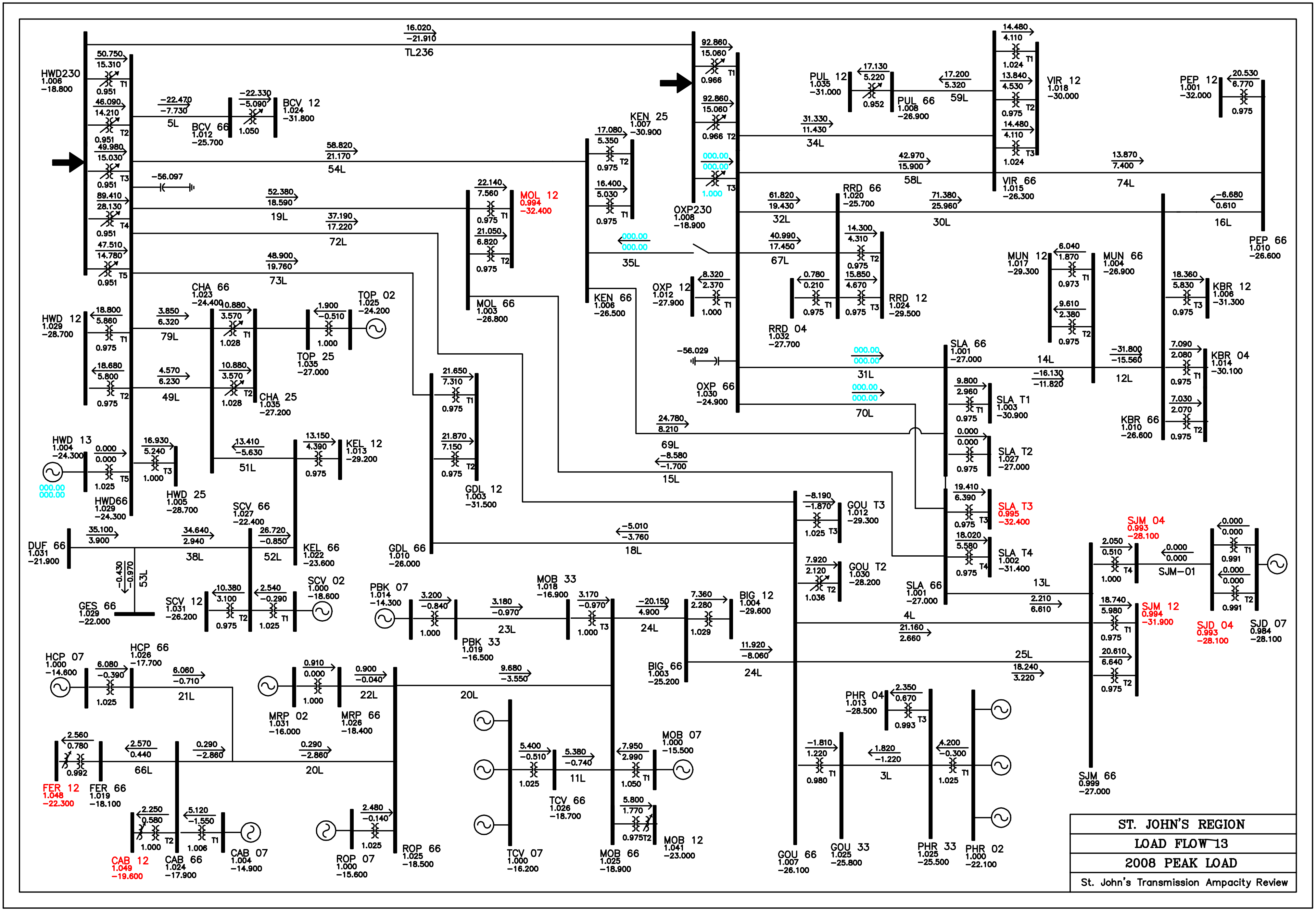
ST. JOHN'S REGION

LOAD FLOW 11

2008 PEAK LOAD

St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 12
2008 PEAK LOAD
St. John's Transmission Ampacity Review

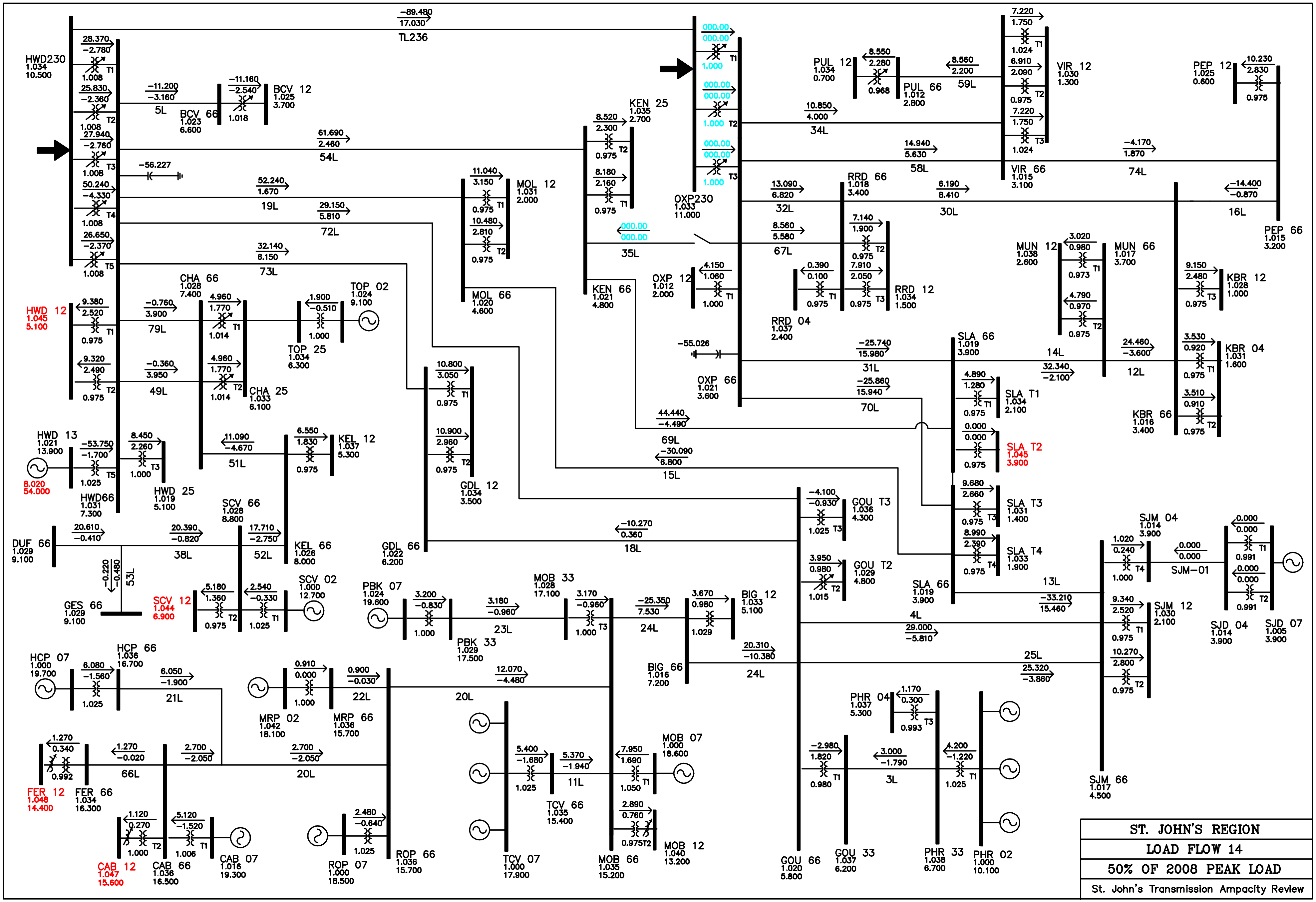


ST. JOHN'S REGION

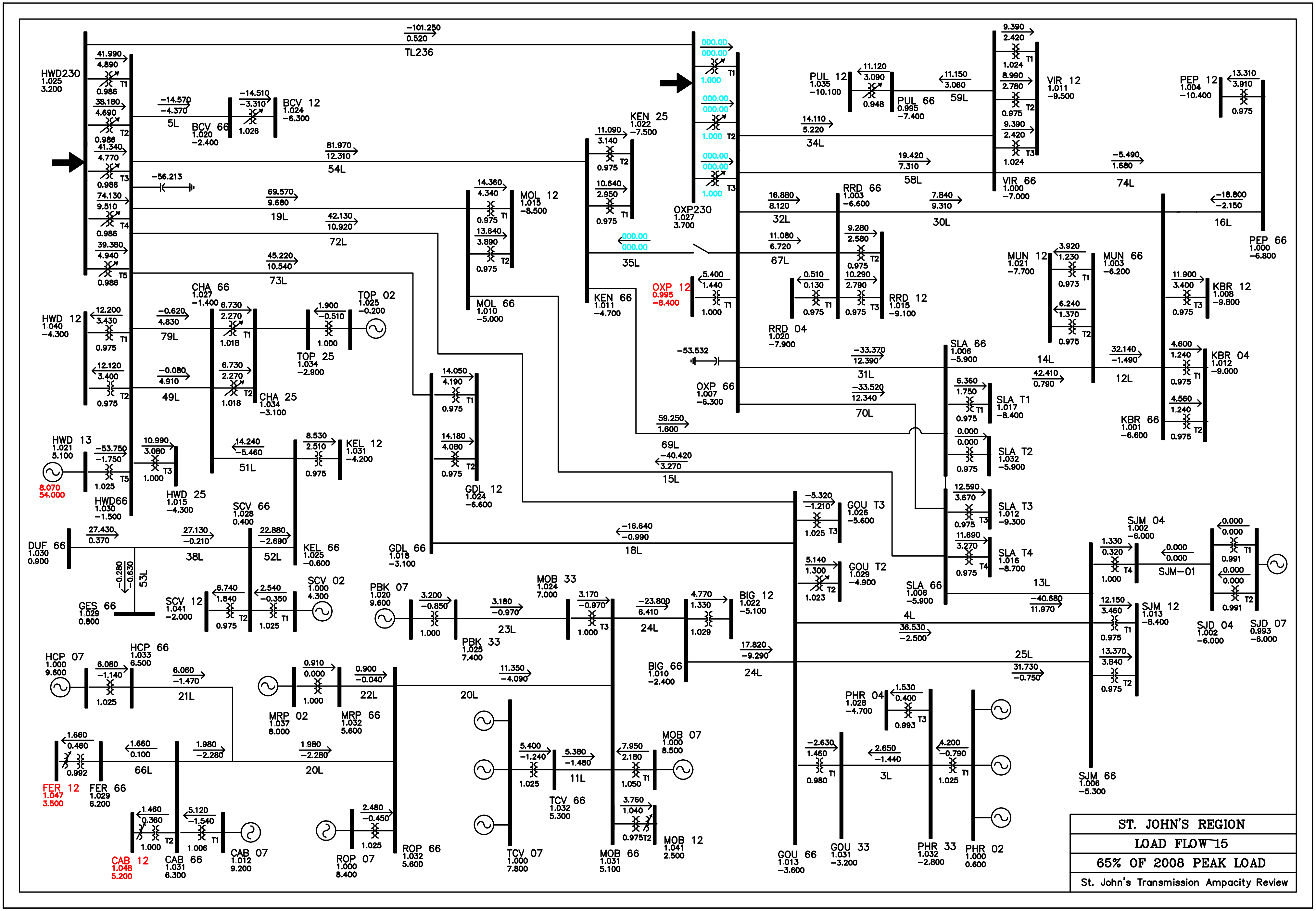
LOAD FLOW 13

2008 PEAK LOAD

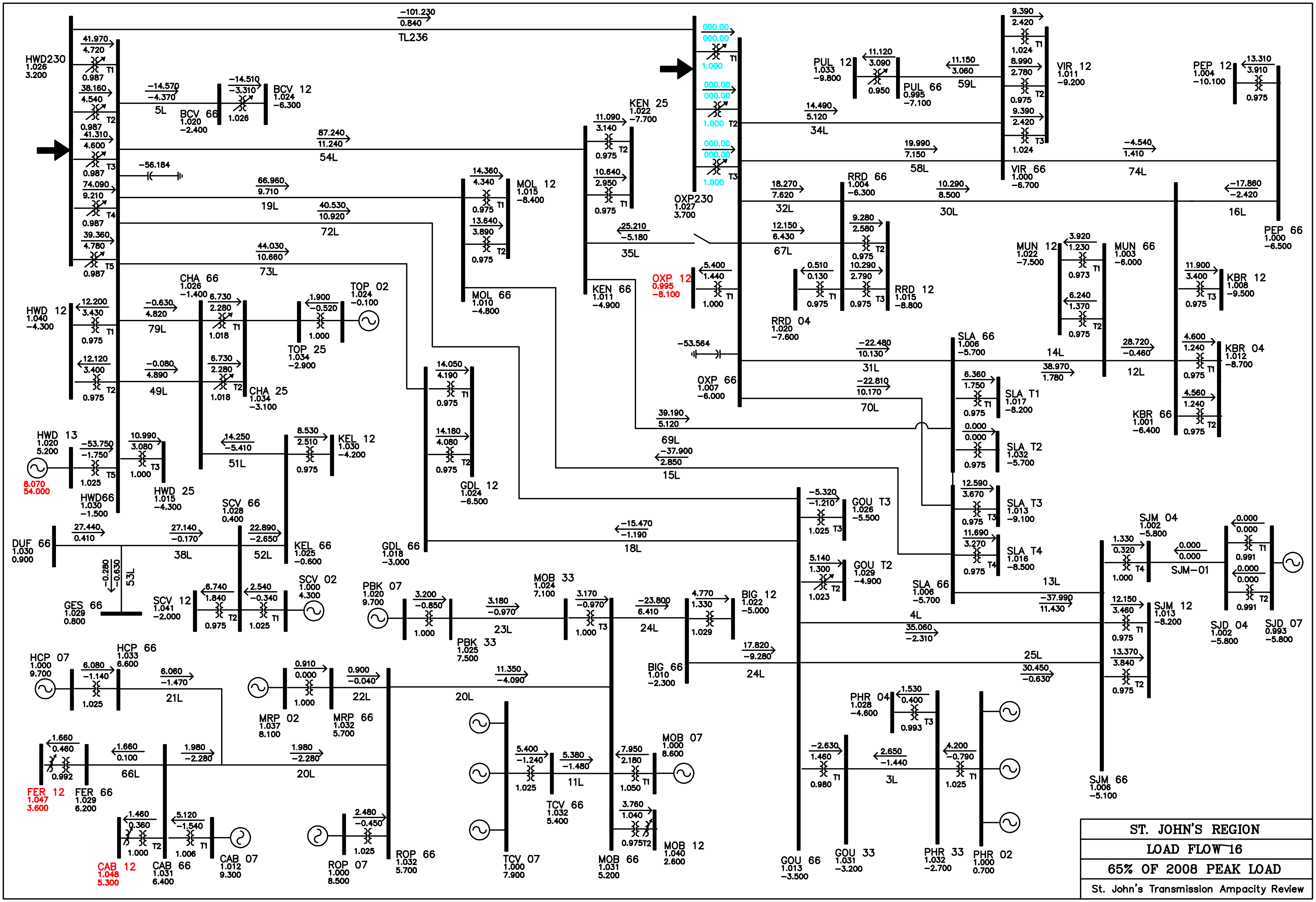
St. John's Transmission Ampacity Review



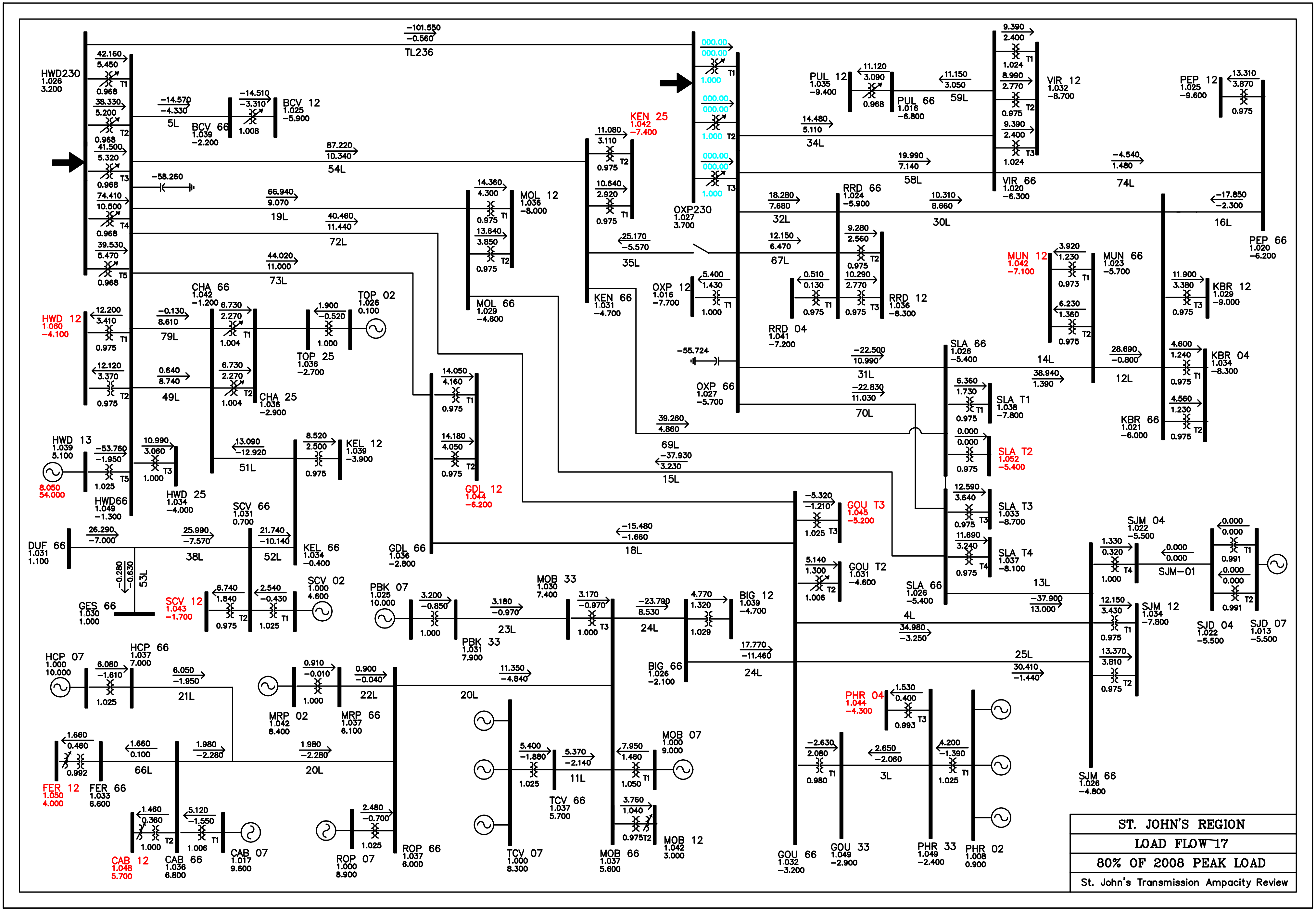
HWD230
HWD 12
HWD 13
HWD66
HWD 25
BCV 66
BCV 12
CHA 66
CHA 25
TOP 02
TOP 25
MOL 12
MOL 66
KEN 25
KEN 66
OXP230
OXP 12
OXP 66
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
KEL 12
KEL 66
GDL 12
GDL 66
SCV 66
SCV 12
SCV 02
DUF 66
GES 66
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM 12
SJM 66
SJM-01
SJD 04
SJD 07
PBK 07
PBK 33
MOB 33
MOB 07
MOB 12
MOB 66
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 07
TCV 66
PHR 04
PHR 33
PHR 02
TL236
5L
54L
19L
72L
73L
79L
49L
51L
38L
52L
53L
35L
34L
58L
59L
74L
32L
30L
16L
67L
31L
70L
69L
15L
14L
12L
18L
13L
4L
25L
24L
23L
20L
21L
22L
66L
11L
3L
ST. JOHN'S REGION
LOAD FLOW 14
50% OF 2008 PEAK LOAD
St. John's Transmission Ampacity Review

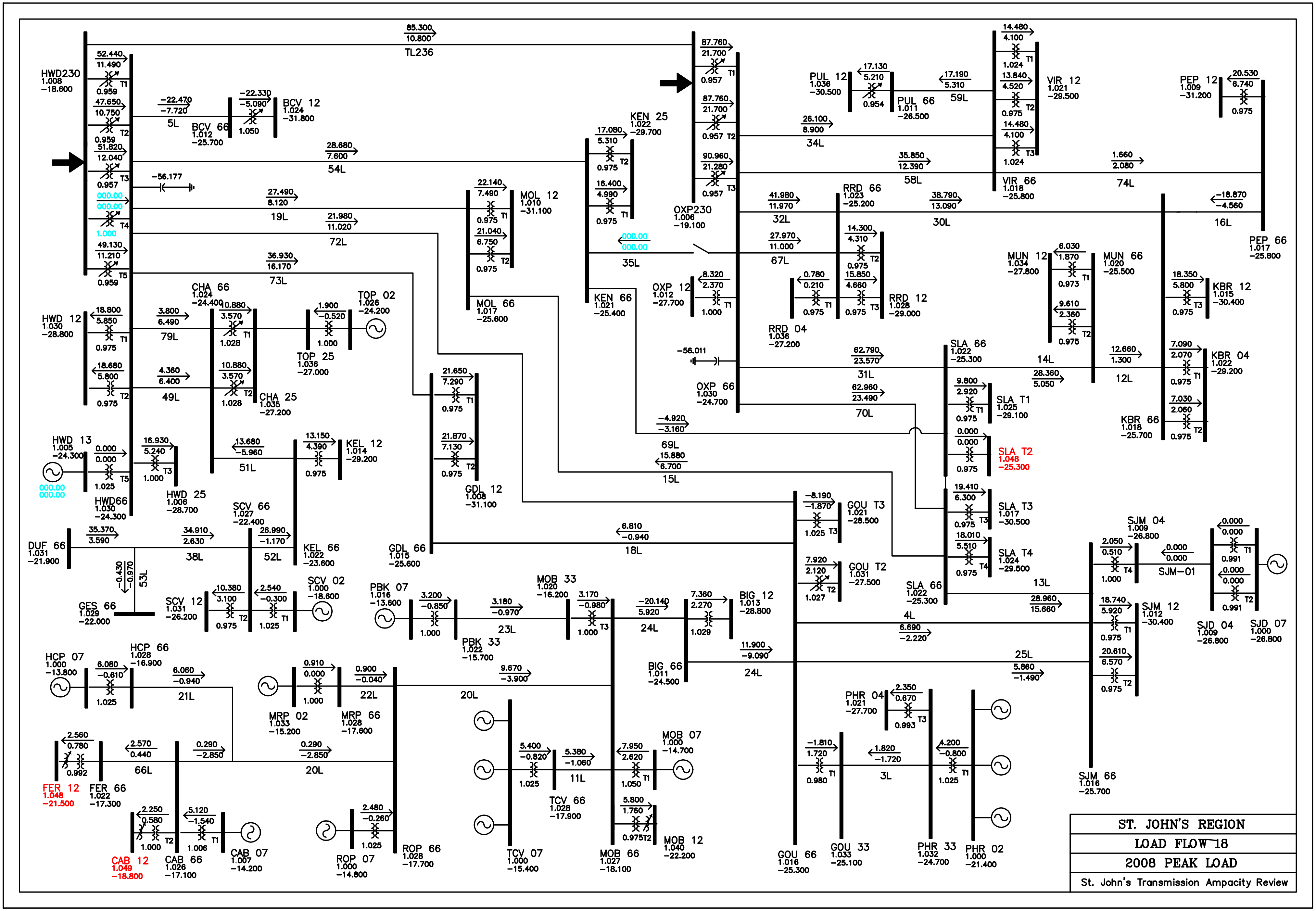


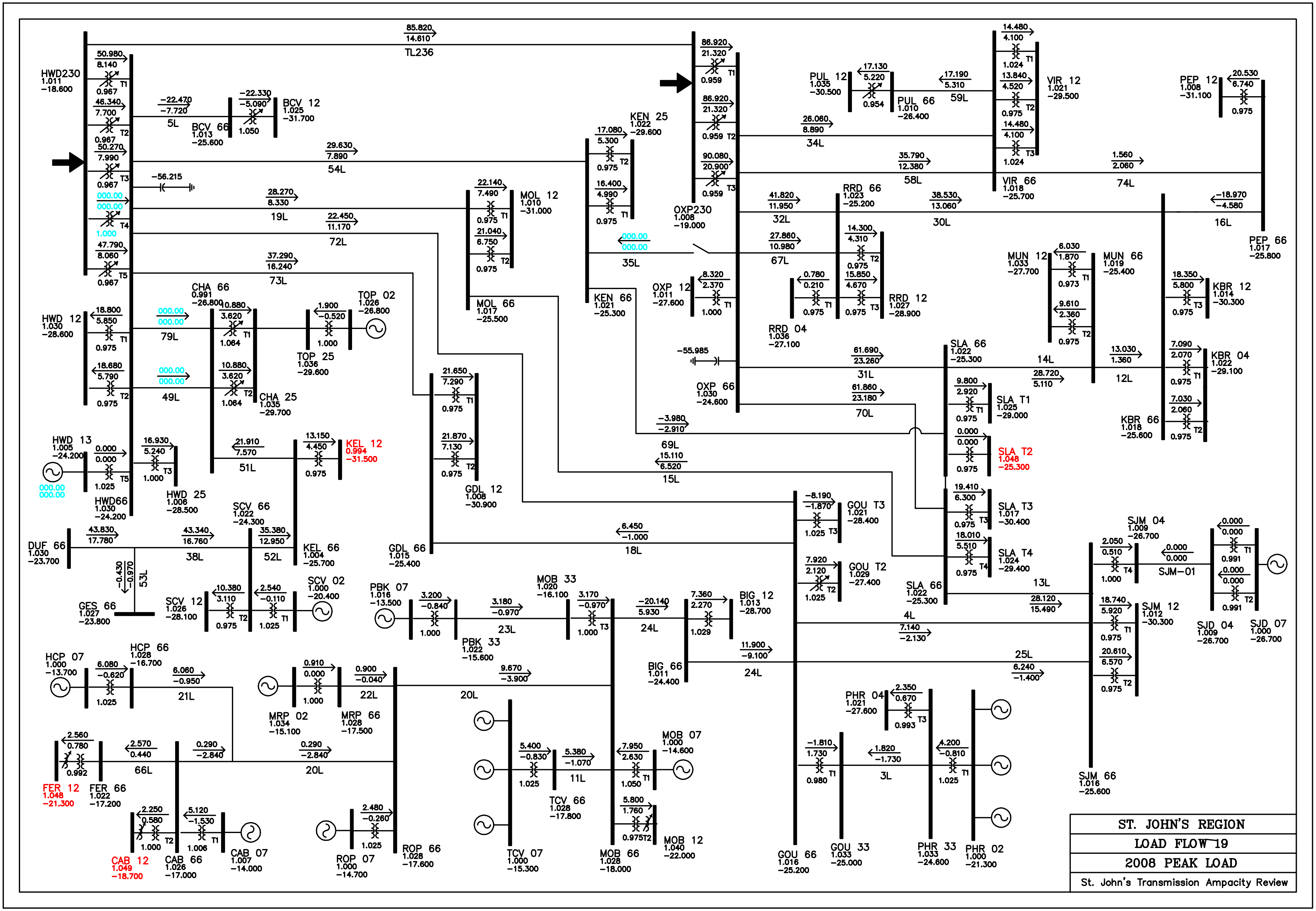
ST. JOHN'S REGION
LOAD FLOW 15
65% OF 2008 PEAK LOAD
St. John's Transmission Ampacity Review

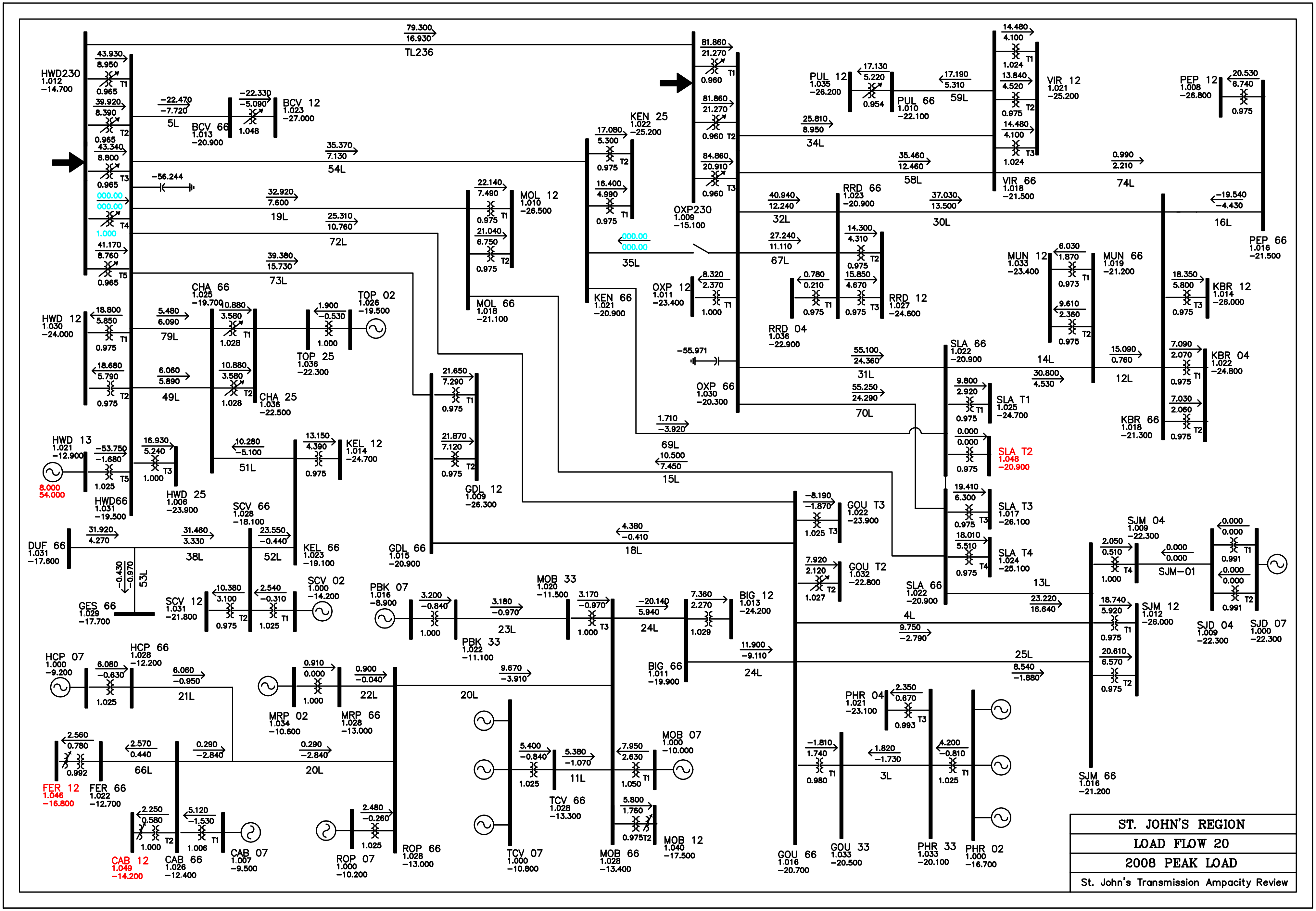


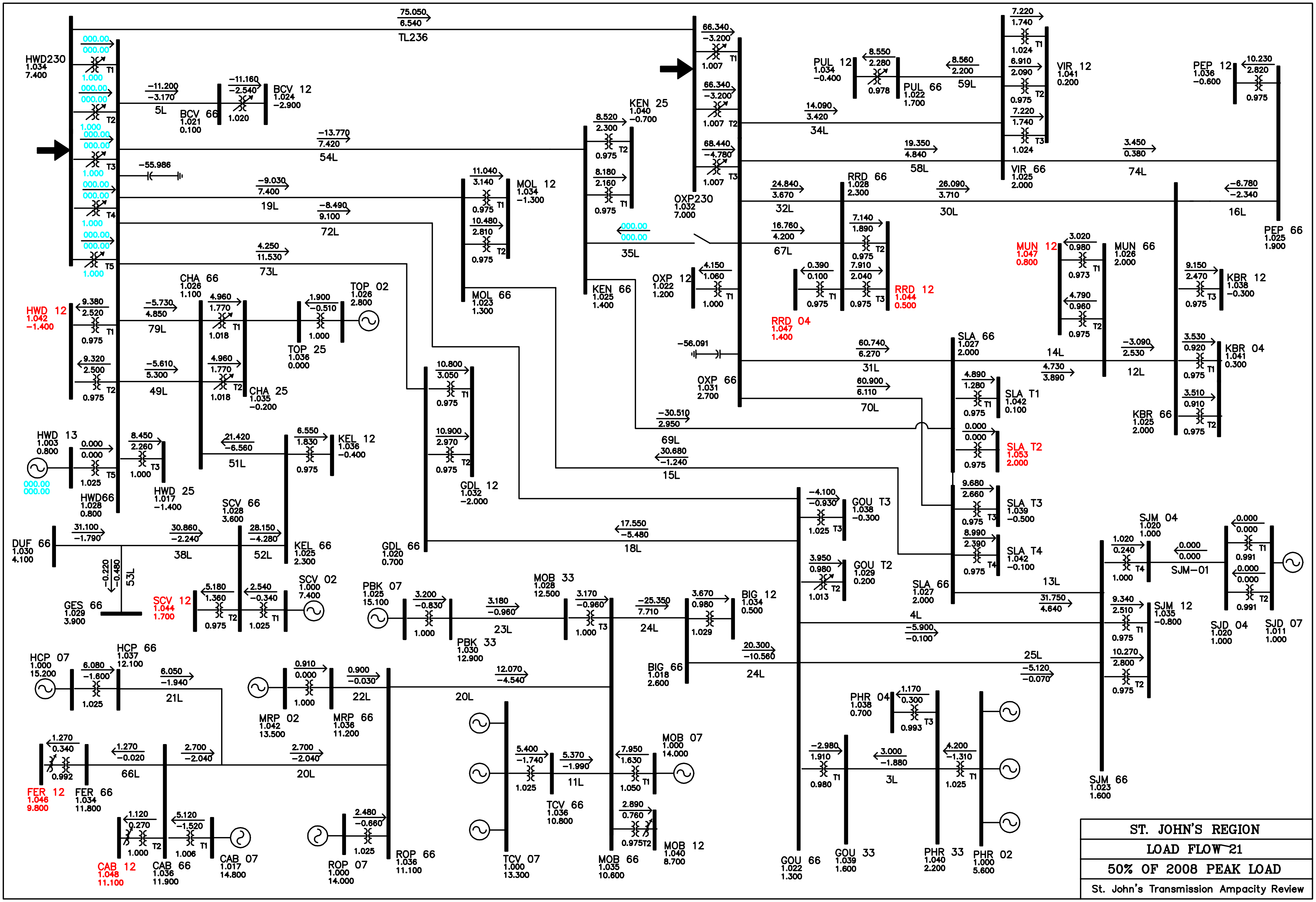
ST. JOHN'S REGION
LOAD FLOW 16
65% OF 2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
OXP230
TL236
HWD 12
HWD 13
HWD 25
HWD66
BCV 12
BCV 66
KEN 25
KEN 66
MOL 12
MOL 66
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
SCV 66
SCV 12
SCV 02
DUF 66
GES 66
GDL 12
GDL 66
PBK 07
PBK 33
MOB 33
MOB 07
MOB 66
MOB 12
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 07
TCV 66
GOU 66
GOU 33
GOU T3
GOU T2
PHR 04
PHR 33
PHR 02
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
OXP 12
OXP 66
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
SJM 04
SJM 12
SJM 66
SJM-01
SJD 04
SJD 07

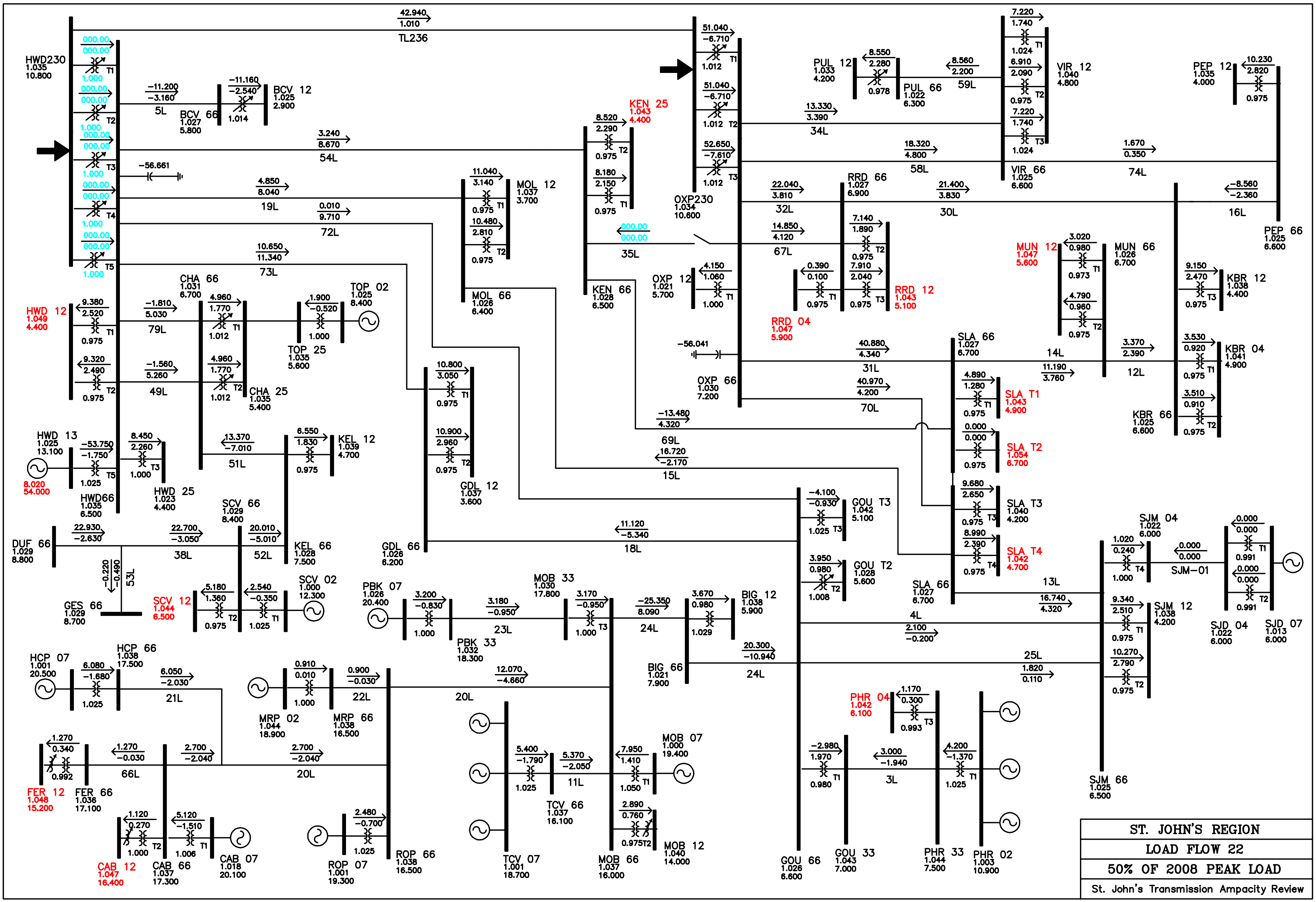

ST. JOHN'S REGION
LOAD FLOW 17
80% OF 2008 PEAK LOAD
St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 18
2008 PEAK LOAD
St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 19
2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
OXP230
TL236
HWD 12
HWD 13
HWD 25
HWD66
BCV 12
BCV 66
KEN 25
KEN 66
MOL 12
MOL 66
CHA 66
CHA 25
TOP 02
TOP 25
KEL 12
KEL 66
SCV 66
SCV 12
SCV 02
DUF 66
GES 66
GDL 12
GDL 66
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
OXP 12
OXP 66
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM-01
SJM 12
SJM 66
SJD 04
SJD 07
PBK 07
PBK 33
MOB 33
MOB 07
MOB 66
MOB 12
BIG 12
BIG 66
HCP 07
HCP 66
MRP 02
MRP 66
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 66
TCV 07
PHR 04
PHR 33
PHR 02


ST. JOHN'S REGION
LOAD FLOW 20
2008 PEAK LOAD
St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 21
50% OF 2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
OXP230
TL236
HWD66
OXP 66
HWD 12
HWD 13
HWD 25
BCV 66
BCV 12
KEN 25
KEN 66
MOL 12
MOL 66
CHA 66
CHA 25
TOP 02
TOP 25
PUL 12
PUL 66
VIR 12
VIR 66
PEP 12
PEP 66
RRD 66
RRD 12
RRD 04
MUN 12
MUN 66
KBR 12
KBR 04
KBR 66
SLA 66
SLA T1
SLA T2
SLA T3
SLA T4
GDL 12
GDL 66
SCV 66
SCV 12
SCV 02
KEL 12
KEL 66
DUF 66
GES 66
PBK 07
PBK 33
MOB 33
MOB 66
MOB 07
MOB 12
BIG 12
BIG 66
GOU T3
GOU T2
GOU 66
GOU 33
SJM 04
SJM 12
SJM 66
SJM-01
SJD 04
SJD 07
HCP 07
HCP 66
MRP 02
MRP 66
FER 12
FER 66
CAB 12
CAB 66
CAB 07
ROP 07
ROP 66
TCV 07
TCV 66
PHR 04
PHR 33
PHR 02
OXP 12

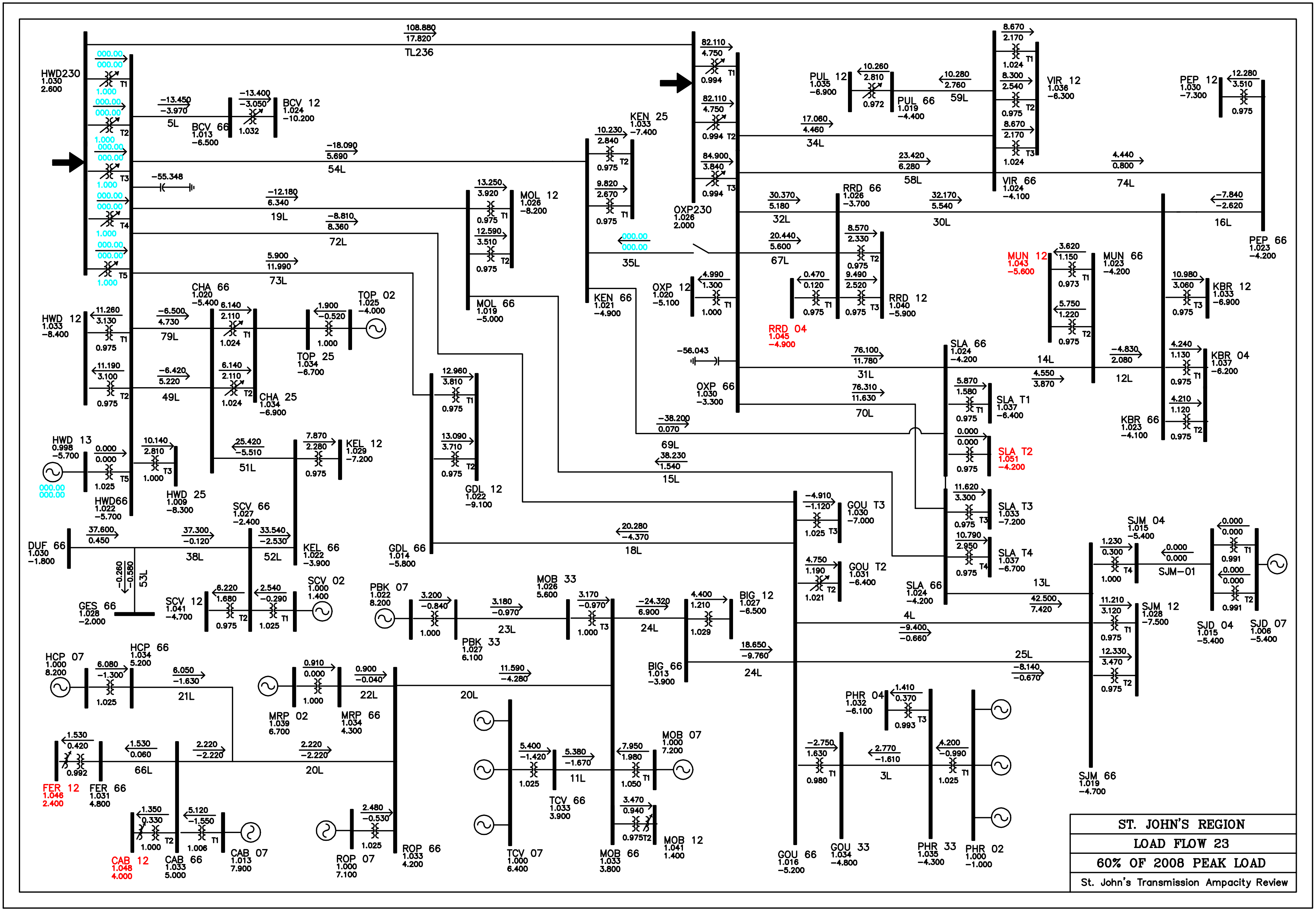


ST. JOHN'S REGION

LOAD FLOW 22

50% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review

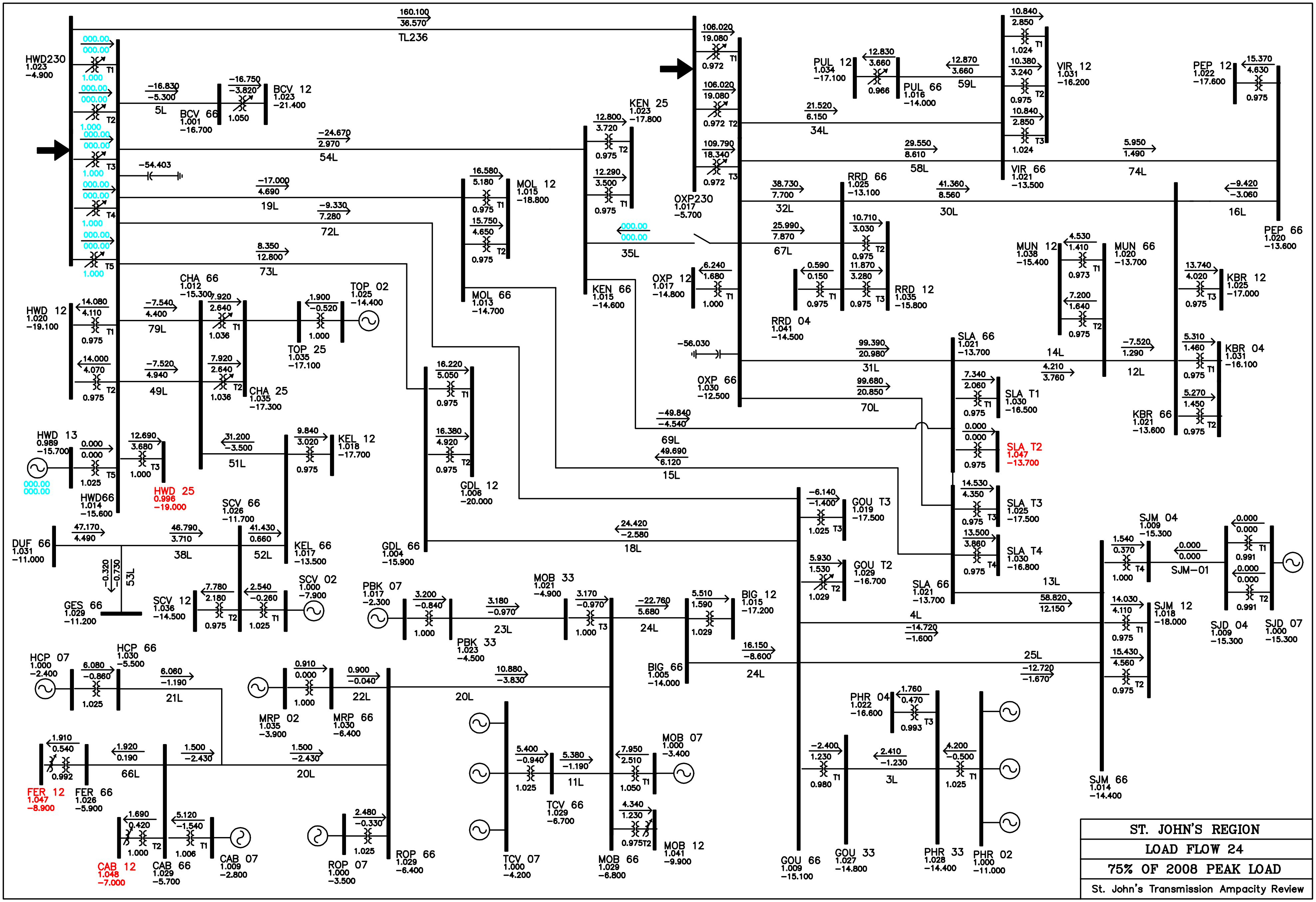


ST. JOHN'S REGION

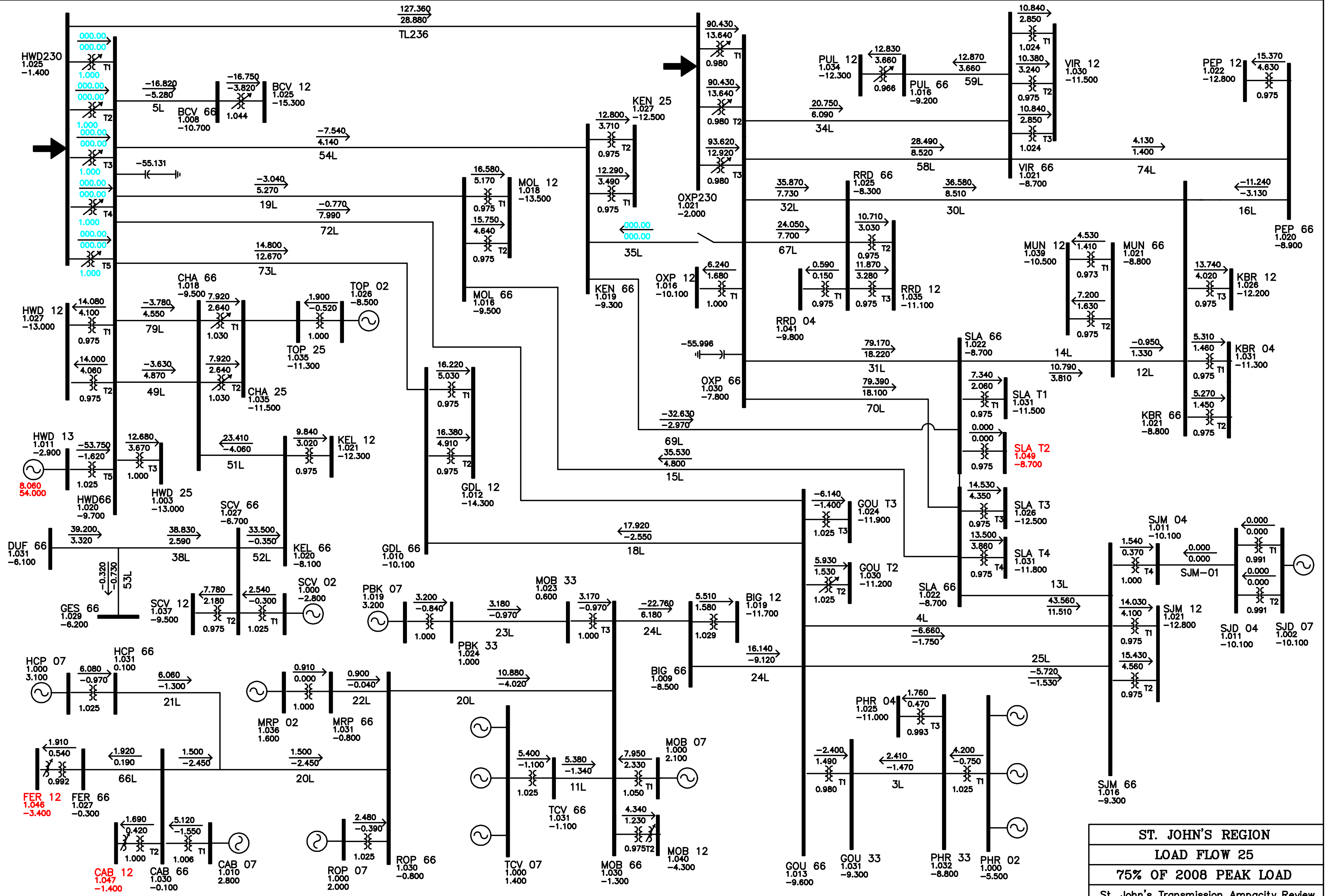
LOAD FLOW 23

60% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review



ST. JOHN'S REGION
LOAD FLOW 24
75% OF 2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230 1.023 −4.900
TL236
OXP230 1.017 −5.700
BCV 66 1.001 −16.700
BCV 12 1.023 −21.400
KEN 25 1.023 −17.800
KEN 66 1.015 −14.600
MOL 12 1.015 −18.800
MOL 66 1.013 −14.700
PUL 12 1.034 −17.100
PUL 66 1.016 −14.000
VIR 12 1.031 −16.200
VIR 66 1.021 −13.500
PEP 12 1.022 −17.600
PEP 66 1.020 −13.600
RRD 66 1.025 −13.100
RRD 12 1.035 −15.800
RRD 04 1.041 −14.500
OXP 12 1.017 −14.800
OXP 66 1.030 −12.500
MUN 12 1.038 −15.400
MUN 66 1.020 −13.700
KBR 12 1.025 −17.000
KBR 04 1.031 −16.100
KBR 66 1.021 −13.600
SLA 66 1.021 −13.700
SLA T1 1.030 −16.500
SLA T2 1.047 −13.700
SLA T3 1.025 −17.500
SLA T4 1.030 −16.800
HWD 12 1.020 −19.100
CHA 66 1.012 −15.300
CHA 25 1.035 −17.300
TOP 02 1.025 −14.400
TOP 25 1.035 −17.100
HWD 13 0.989 −15.700
HWD66 1.014 −15.600
HWD 25 0.996 −19.000
KEL 12 1.018 −17.700
KEL 66 1.017 −13.500
SCV 66 1.026 −11.700
SCV 12 1.036 −14.500
SCV 02 1.000 −7.900
GDL 12 1.006 −20.000
GDL 66 1.004 −15.900
GOU T3 1.019 −17.500
GOU T2 1.029 −16.700
GOU 66 1.009 −15.100
GOU 33 1.027 −14.800
DUF 66 1.031 −11.000
GES 66 1.029 −11.200
PBK 07 1.017 −2.300
PBK 33 1.023 −4.500
MOB 33 1.021 −4.900
MOB 07 1.000 −3.400
MOB 66 1.029 −6.800
MOB 12 1.041 −9.900
BIG 12 1.015 −17.200
BIG 66 1.005 −14.000
SJM 04 1.009 −15.300
SJM−01
SJM 12 1.018 −18.000
SJM 66 1.014 −14.400
SJD 04 1.009 −15.300
SJD 07 1.000 −15.300
HCP 07 1.000 −2.400
HCP 66 1.030 −5.500
MRP 02 1.035 −3.900
MRP 66 1.030 −6.400
FER 12 1.047 −8.900
FER 66 1.026 −5.900
CAB 12 1.048 −7.000
CAB 66 1.029 −5.700
CAB 07 1.009 −2.800
ROP 07 1.000 −3.500
ROP 66 1.029 −6.400
TCV 66 1.029 −6.700
TCV 07 1.000 −4.200
PHR 04 1.022 −16.600
PHR 33 1.028 −14.400
PHR 02 1.000 −11.000
5L 54L 19L 72L 73L 79L 49L 51L 38L 52L 53L 35L 34L 58L 74L 32L 30L 16L 67L 59L 14L 12L 31L 70L 69L 15L 18L 13L 23L 24L 4L 25L 21L 22L 20L 66L 11L 3L

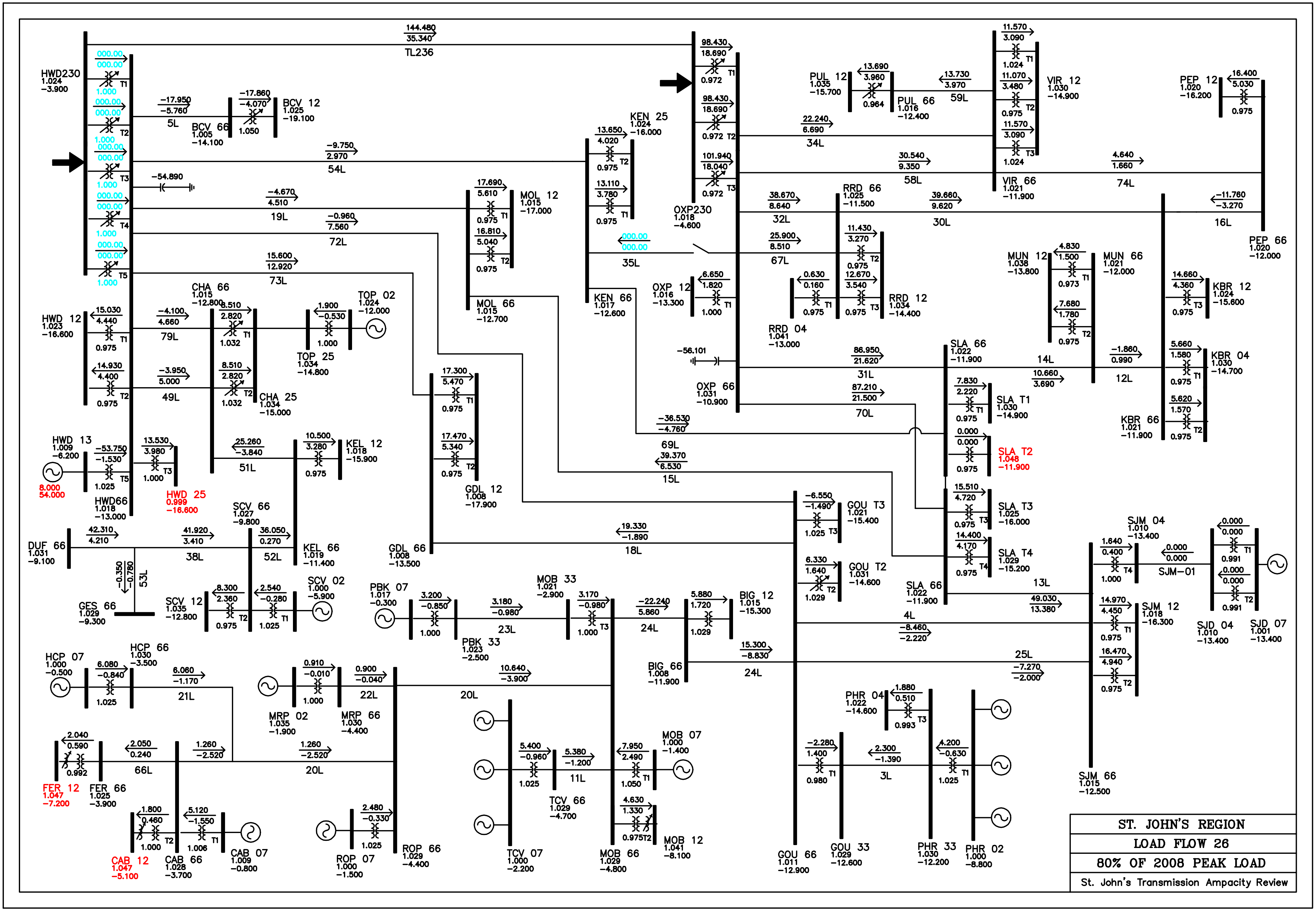


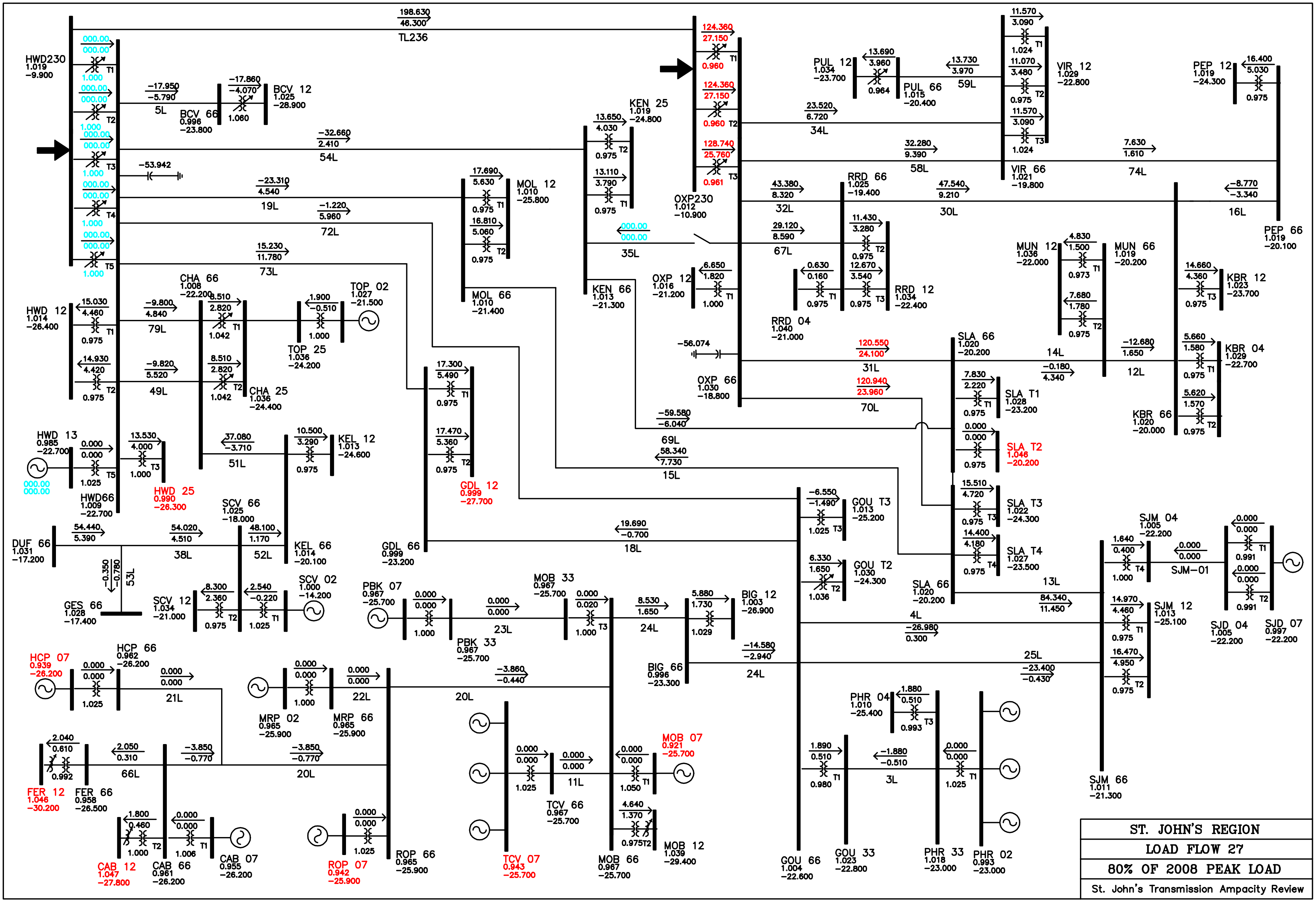
ST. JOHN'S REGION

LOAD FLOW 25

75% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review


ST. JOHN'S REGION
LOAD FLOW 26
80% OF 2008 PEAK LOAD
St. John's Transmission Ampacity Review
HWD230
OXP230
TL236

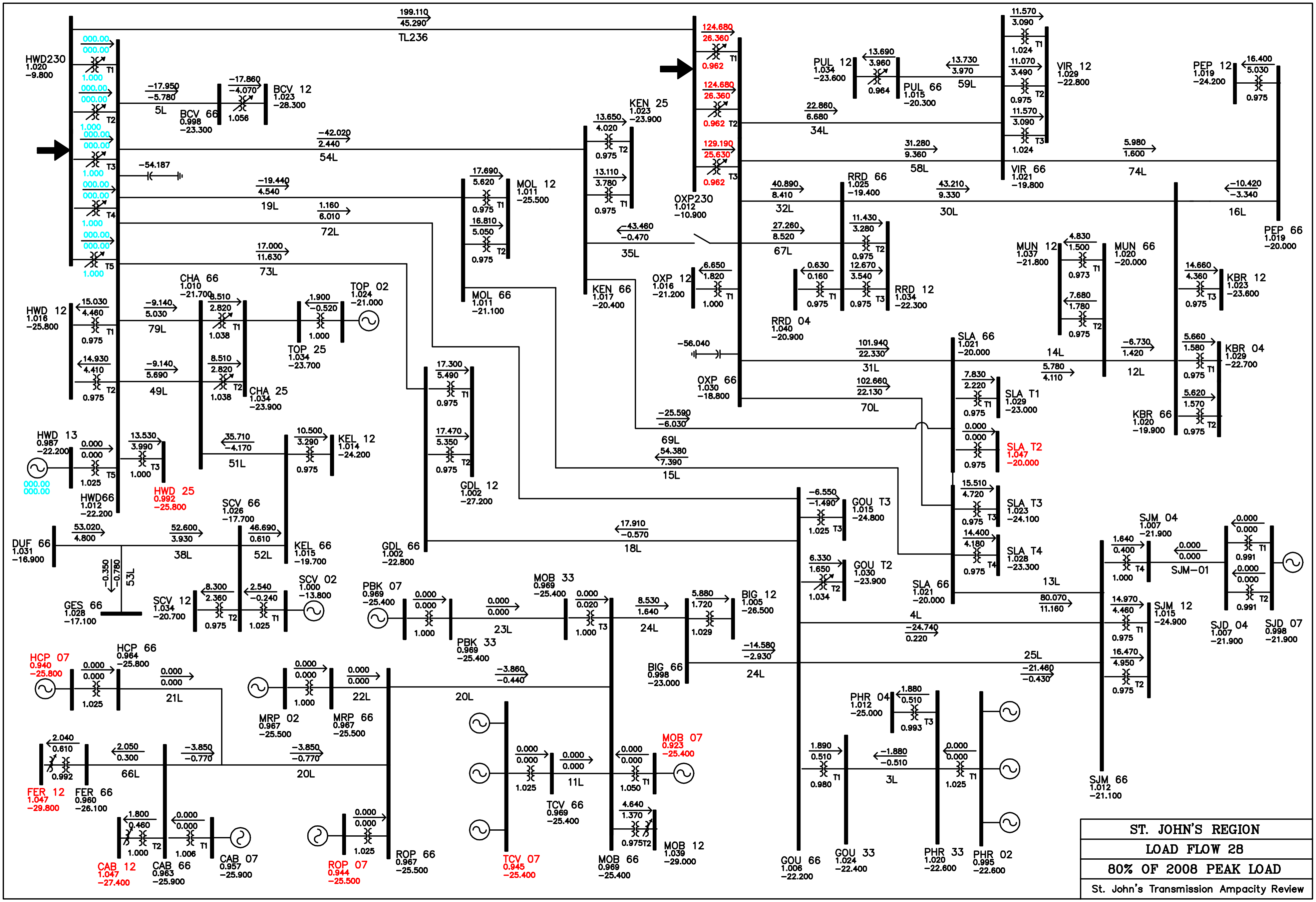


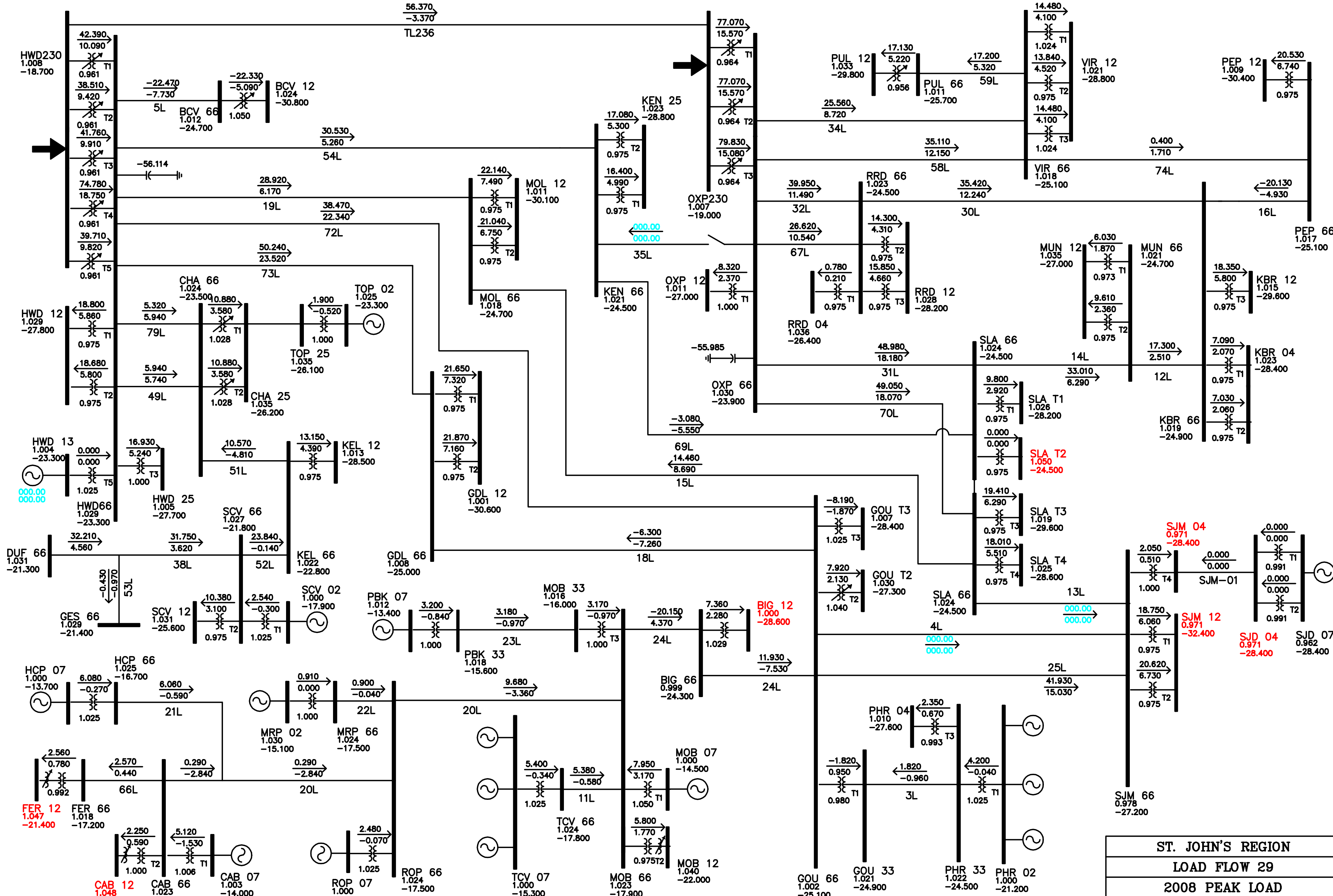
ST. JOHN'S REGION

LOAD FLOW 27

80% OF 2008 PEAK LOAD

St. John's Transmission Ampacity Review


TL236
HWD230 1.020 −9.800
BCV 12 1.023 −28.300
BCV 66 0.998 −23.300
5L
54L
19L
72L
73L
KEN 25 1.023 −23.900
KEN 66 1.017 −20.400
35L
MOL 12 1.011 −25.500
MOL 66 1.011 −21.100
OXP230 1.012 −10.900
OXP 12 1.016 −21.200
OXP 66 1.030 −18.800
PUL 12 1.034 −23.600
PUL 66 1.015 −20.300
59L
34L
58L
VIR 12 1.029 −22.800
VIR 66 1.021 −19.800
74L
PEP 12 1.019 −24.200
PEP 66 1.019 −20.000
16L
RRD 66 1.025 −19.400
RRD 12 1.034 −22.300
RRD 04 1.040 −20.900
32L
30L
67L
MUN 12 1.037 −21.800
MUN 66 1.020 −20.000
KBR 12 1.023 −23.600
KBR 04 1.029 −22.700
KBR 66 1.020 −19.900
14L
12L
31L
70L
SLA 66 1.021 −20.000
SLA T1 1.029 −23.000
SLA T2 1.047 −20.000
SLA T3 1.023 −24.100
SLA T4 1.028 −23.300
HWD 12 1.016 −25.800
79L
49L
CHA 66 1.010 −21.700
CHA 25 1.034 −23.900
TOP 02 1.024 −21.000
TOP 25 1.034 −23.700
HWD 13 0.987 −22.200
HWD66 1.012 −22.200
HWD 25 0.992 −25.800
51L
KEL 12 1.014 −24.200
KEL 66 1.015 −19.700
SCV 66 1.026 −17.700
SCV 12 1.034 −20.700
SCV 02 1.000 −13.800
GDL 12 1.002 −27.200
GDL 66 1.002 −22.800
69L
15L
18L
DUF 66 1.031 −16.900
38L
52L
53L
GES 66 1.028 −17.100
GOU T3 1.015 −24.800
GOU T2 1.030 −23.900
GOU 66 1.006 −22.200
GOU 33 1.024 −22.400
PBK 07 0.969 −25.400
PBK 33 0.969 −25.400
23L
MOB 33 0.969 −25.400
24L
BIG 12 1.005 −26.500
BIG 66 0.998 −23.000
4L
13L
25L
SJM 04 1.007 −21.900
SJM−01
SJM 12 1.015 −24.900
SJM 66 1.012 −21.100
SJD 04 1.007 −21.900
SJD 07 0.998 −21.900
HCP 07 0.940 −25.800
HCP 66 0.964 −25.800
21L
MRP 02 0.967 −25.500
MRP 66 0.967 −25.500
22L
20L
FER 12 1.047 −29.800
FER 66 0.960 −26.100
66L
CAB 12 1.047 −27.400
CAB 66 0.963 −25.900
CAB 07 0.957 −25.900
ROP 07 0.944 −25.500
ROP 66 0.967 −25.500
TCV 07 0.945 −25.400
TCV 66 0.969 −25.400
11L
MOB 07 0.923 −25.400
MOB 66 0.969 −25.400
MOB 12 1.039 −29.000
PHR 04 1.012 −25.000
PHR 33 1.020 −22.600
PHR 02 0.995 −22.600
3L
ST. JOHN'S REGION
LOAD FLOW 28
80% OF 2008 PEAK LOAD
St. John's Transmission Ampacity Review



ST. JOHN'S REGION
LOAD FLOW 29
2008 PEAK LOAD
St. John's Transmission Ampacity Review