PUB 7.0
(RE: p. 25 & 26 of 82) Distribution System Feeder Remote Control ($1,200,000)

PUB 7.1

Q. Compare, using the number of replacements and the expenditures, the planned replacement of relays and reclosers for 2002 with the actual replacements.

A. The 2002 Capital Budget, Distribution Feeder Remote Control project contemplated the replacement of 17 reclosers and 62 relays with modern electronic reclosers and relays at a cost of $1.0 million.

Reclosers are self-contained units used to interrupt the current flow in case of a fault on rural distribution lines. Relays are used in conjunction with breakers to perform the same function in urban settings where current flows and fault levels are greater.

Reclosers

The estimate for the installation of the reclosers was developed for the 2002 Capital Budget early in 2001 based upon the best information available at that time. Based on experience with a similar project completed in the Stephenville area in late 2001 (after the hearing of the 2002 Capital Budget), it was recognized that the cost of the recloser replacement project had been significantly underestimated.

The principal component of the recloser project, involving 11 of the 17 units, was intended to facilitate the automatic monitoring and control of feeders serviced from the Gambo, Hare Bay, Trinity, Greenspond and Wesleyville substations in Bonavista North. In conjunction with the relocation of the gas turbine from Salt Pond to Wesleyville, this project would enable System Control Centre staff, in many instances, to remotely control the reclosers to minimize the number of customers that would be affected by outages on those feeders. In light of the increase in the unit cost of replacing the reclosers, it was decided to complete only the Bonavista North segment of the recloser project.

Relays

The replacement of relays was primarily focused on urban feeders in the St. John's area. As detailed engineering was completed, it was determined that the relays being supplied were capable of providing substantial amounts of information that would allow for better power quality and system operation analysis. However, utilizing this additional data would have degraded the response time of the SCADA System, and also limited the ability of operating staff to remotely change relay settings and obtain relay data. The available choices were to (1) install the relays as originally planned and forego the benefits of the additional available data, or (2) maximize the benefits of the additional data and avoid the impacts on the SCADA System by installing additional communication equipment at each substation in which the relays were to be installed.

The Company chose the second option because of the operational improvements that could be achieved using the additional relay data. Further, if the first option had been chosen, when the system was subsequently modified to take advantage of the additional relay data, additional costs would have been incurred to reconfigure the SCADA system. The second option was therefore the least cost option for achieving the broader scope of benefits available from the new relays.

To remain within the approved budget, it was necessary to reduce the number of relays to be installed. The 14 relays are to be installed at the Glendale, Kenmount and Hardwoods substations in the St. John's area.