STEAM GENERATOR MANAGEMENT AT ONTARIO HYDRO NUCLEAR STATIONS

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ABSTRACT

Managing ageing steam generators involves costly decisions for the utility, both in terms of the cost of the maintenance activities and in terms of having the unit shutdown and consequent power loss while performing these activities. The benefits of these activities are seldom guaranteed and are sometimes very intangible. For nuclear utilities the most pertinent questions that arise are have we identified all the problem(s), can we predict the risk due to these problems? Can we implement corrective and preventive activities to manage the problem and what is the optimum timing of implementation? Is the money spent worthwhile, i.e. has it given us a return in production and safety? Can we avoid surprises? How can we tangibly measure success? This paper touches briefly on all the questions mentioned above but it mainly addresses the last question: "*how can we tangibly measure success*?" by using several ***success indicators*** proposed by EPRI and by applying them to actual Ontario Hydro experience. The appropriateness of these success indicators as the means to assess the success of these programs, to feed back the results, and to enhance or revise the programs will be discussed.

INTRODUCTION

Steam Generators are large heat exchangers that transfer the heat from the reactor coolant to make the steam that drives the turbine generator. The steam generators at Ontario Hydro (OH) are shell and tube heat exchangers with several thousand tubes each. There are 4, 8 or 12 steam generators in each OH reactor unit for a total of 176 steam generators with approximately half a million tubes in-service for the utility. A critical sub-component of the steam generator is the tubing. At Ontario Hydro three different types of tubing alloy have been used: Inconel 600 at the Bruce A and B units, Incoloy 800 at the Darlington units and Monel 400 at the Pickering A and B units.

The steam generator has two main functions: *integrity*, as an important barrier between the radioactive primary fluid to the non-radioactive secondary fluid, and *thermal performance*, i.e. the production of steam for the turbine generator. To act as a barrier, the tubing must be essentially free of cracks, perforations, and general deterioration. Widespread tubing degradation has been occurring world wide at a large number of plants and also at Ontario Hydro, (EPRI Progress Report, 1997). This deterioration has resulted in very large scale mitigative action programs which include: tube inspection and plugging, chemical cleaning and high pressure water lancing, internal and external modifications and repairs. Ultimately, at Ontario Hydro, tubing degradation has also been one of the main reasons for premature shutdown of two units.

The role of steam generator Life Cycle Management (LCM), as defined by EPRI (Welty, 1990), is to optimize steam generator operation relative to safety, reliability and cost-effective maintenance. The purpose of such a program is to identify age-related degradation mechanisms, assess cumulative damage to date and predict future risk due to this damage. With this information, one can identify possible counter-measures. A formal LCM program assesses the cost-benefit of each and defines an integrated set of such counter-measures in a program document that takes into account the objectives of the station and the utility.

The general approach used at Ontario Hydro to prepare and implement steam generator LCM programs was developed over the past 6 to 7 years, see for example the LCM program development for BNGS-B (Maruska, 1994). The process at OH has not been altogether uniform from station to station and has evolved with time as lessons are learned. The suddenness of the onset of major degradation modes in some OH plants has resulted in largely reactive steam generator programs being implemented.

For OH plants not yet experiencing major steam generator degradation there is a drive towards more proactive programs as both internal and external experience have strongly indicated the need to be vigilant well into the future due to the possibility of new or unexpected degradation. Table 1 gives a brief summary of the various problems experienced at Ontario Hydro, the possible contributing factors, and a summary of counter-measures implemented to date to address them. For up to date descriptions of these programs, see references quoted (Tapping, Nickerson et al, 1996 and Tapping, Maruska et al, 1998).

In a very simplified form, LCM programs are based on the Shewhart-Deming Cycle, the ***Plan Do Check Adjust*** cycle (PDCA), (Deming, 1986). The bulk of this paper discusses the ***Check*** part of the cycle. In order to maintain or improve steam generator performance one needs to *check* or to measure the effect or success of the programs that may be in place.

There are two very important criteria for these success measures. Good performance measures should be forward looking, and their interpretation should effectively determine the action(s) that need to be taken, either to continue or to change the present program of activities. This requires performance measures which are clear, valid and relevant and which somehow can be projected into the future in order to be able to ***adjust*** programs and direct attention and effort to achieve the objectives set out by the utility or station.

HOW CAN WE TANGIBLY MEASURE SUCCESS?

This paper builds on some of the success measures suggested by EPRI (Welty, 1990) and includes: forced and planned station incapability due to steam generators, number and rate of forced outages due to steam generator problems (usually due to tube leaks), tube plugging and inspection trends which can be used to trend degradation and in turn allow end-of-cycle condition and end-of-life predictions, the ALARA principle on dose consumed for steam generator activities, and the predicted gain/loss in terms of production achieved through these activities. All of these measures mentioned above will be discussed in this paper. The appropriateness of these indicators as the means to assess the success of LCM programs and to feedback the results to enhance or revise the programs will also be discussed.

These are just a sample of indicators that may be used. There are other measures which may not be so readily quantifiable but which are also critically important including: safety measures, such as meeting regulatory end-of-cycle requirements, increasing regulator confidence or lowering overall probability of tube ruptures.

There are also a number of measures which are more readily quantified and are shorter term but can not be so readily related to the objectives of the unit/utility. These include measures on: factors which may impact on degradation: amount of deposits removed due to cleaning, chemistry improvements, lowering impurity levels in the steam generator, amount of condenser leakage, etc.

Station Incapability due to Steam Generators.

Forced and planned station incapability due to steam generators as a function of time is shown in Figure 1 for all Ontario Hydro units since the first unit went in-service in 1971 (PNGS-A, Unit 1). Although the total amount of incapability is important, it is the ratio between the forced and planned incapability that is the more interesting and telling aspect of this graph. Forced incapability means that an unexpected development took place leading to immediate shutdown and consequently lack of time for proper analysis and preparation. Unplanned actions invariably incur high cost. Planned incapability, as the term indicates means a pre-scheduled shutdown; consequently reasonable time was available to plan actions and resources thus lowering overall cost.

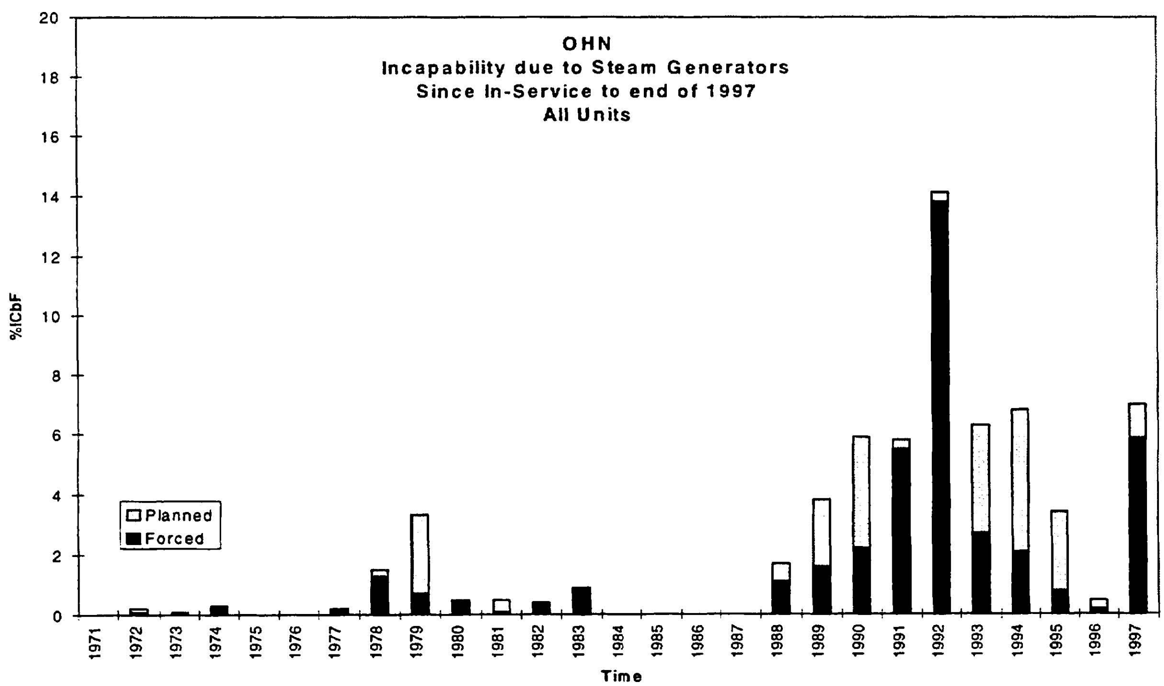

Figure 1 **Forced and Planned Incapability due to Steam Generators - OHN All Units**

The ratio of forced to planned incapability, as well as the total incapability, improved in OH following the truly disastrous year of 1992 (where capacity factor losses reached 14.1%, mostly forced) up until 1996. This was an indication that steam generator programs were achieving the objective, i.e. degradation management, but overall, capacity losses were still below standard and in 1997 a new degradation mode at BNGS-A once again increased significantly the station incapability due to steam generators.

The average OH capacity loss in the last ten years has been about 5%. By comparison, during the last 10 years the capacity factor loss due to steam generator problems in the U.S. has averaged 2.5%. In 1996 the U.S. capacity factor loss was 2.3% of which 0.7% was due to steam generator replacement and 1.6% was due to steam generator tube problems (EPRI Progress Report, 1997).

Based on U.S. and world experience capacity losses due to steam generators should stay between 2 to 3%, all of it planned.

Station incapability is a good indicator of steam generator performance but can not be used in isolation of information from other station information. For example, incapability due to steam generators seemed to have decreased dramatically in 1996. On a first assessment this seemed to indicate that the steam generator problems were finally resolved perhaps due to the large amount of work carried out post 1992. However, this was not the total picture, several units were shutdown for other reasons in that year which meant that many steam generators were simply not operating. Also of concern is the trend appearing in 1997 reflecting the most recent degradation mechanism found at BNGS-A (ODSCC and PWSCC at the tubesheet) indicating a new set of problems and actions which also reinforces the need to be ever vigilant of new developments.

Forced Outage Rate

Another good indicator of the ability to manage steam generator performance is the rate of forced outages. Figure 2 shows the number of forced outages due to steam generator problems, mainly due to tube leaks, with time for all OH units since the first unit went in-service. By dividing the number of forced outages by the number of operating units a forced outage rate can be obtained.

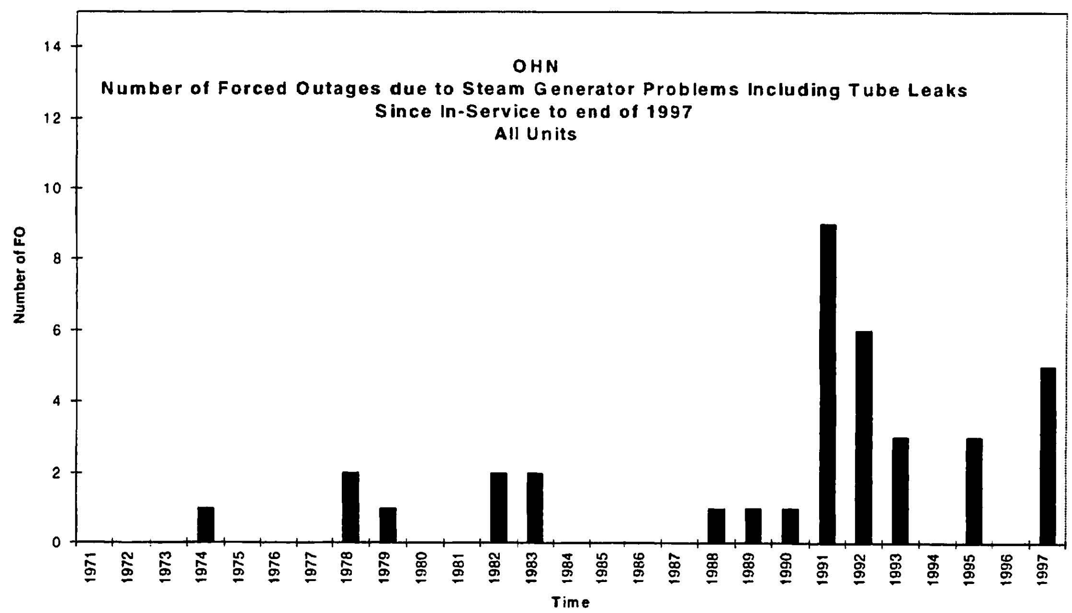

Figure 2 Number of Forced Outages due to SG Problems, mainly Tube Leaks OHN - All Units

The average forced outage rate for OH from 1971 to 1996 was 0.09 but there have been some years in OH experience where the forced outage rate reached 0.5. The average rate compares favourably with the average forced outage rate in the U.S. for 1975 to 1996 which was 0.19 (EPRI Progress Report, 1997). However, in the U.S. there has been a steady trend of improvement. The 1996 forced outage rate in the U.S was 0.03.

Ideally, the long-range goal should be to have no forced outages due to steam generator tube leaks. The best way to achieve this is to know and predict the actual condition of the tubes. See next indicator on inspection and plugging trends.

Tube Inspection and Plugging Trends

The number of tubes plugged (left *y*-axis) and the number of tubes inspected (right *y-axis* in plot) for all OH units since the first unit went in-service are plotted in Figure 3. Plugging and inspection trending on a per unit and per mechanism basis trends the progression of degradation with time and leads to predictions of end-of-cycle condition and also, when all degradation mechanisms are combined, to end-of-life projections for the particular unit's steam generators.

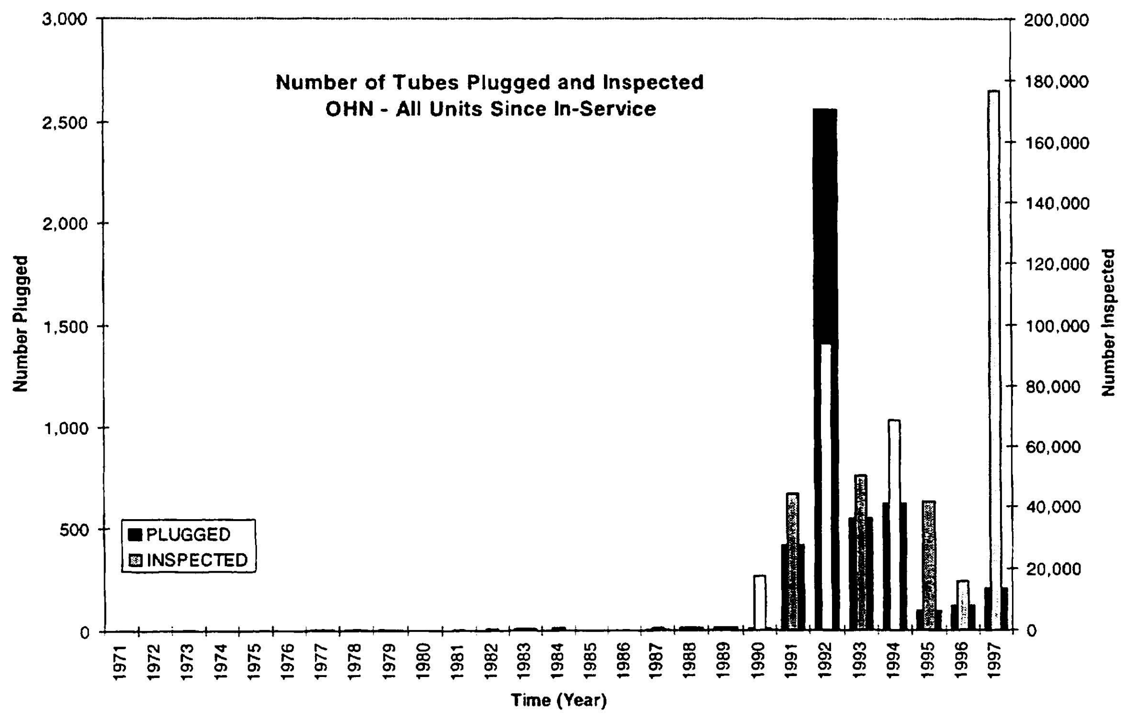

Figure 3 Number of Tubes Plugged and Inspected -OHN All Units

Large scale inspection campaigns, i.e. in the order of thousands of tubes, using a variety of Non Destructive Examination techniques did not start until after 1989 (at this time OH acquired much of the technology required for these campaigns). There was very little inspection performed prior to this time that resulted in no real knowledge of the actual condition of the tubes. The large number of steam generators per OH unit, smaller tubes, reactor heat sink requirements and deep ID magnetite layer require specialized inspection technology and makes it difficult to inspect all the tubes in a single outage without greatly extending the outage. Hence, there is an ever-increasing demand to improve speed and quality of inspection methods and techniques.

To project into the future and make valid end-of-cycle or end-of-life predictions, good, reliable in-service information is essential. In OH experience this information has been generally poor, especially for early operation, which sometimes has forced projections to be made on the basis of one point in time. In addition, in OH experience, the steam generators have demonstrated variations in behaviour, within the same plant, within the same unit and sometimes within the same steam generator. Inspection sample sizes have seldom been sufficient to account for this variation which has led to some very unpleasant surprises occurring at the worst possible time.

Inspection and plugging trends are good indicators of the health of the steam generator and of the reliance one can place on end-of-cycle condition and end-of-life predictions. However, inspection and plugging data remain merely information until some judgment is applied and must be supplemented with other forms of information such as root cause investigations, inspection capability verification, and other monitoring activities and analysis in order to truly understand the behaviour of the degradation mechanism. Ideally, there should be a steady amount of inspection being carried out continuously according to a program of inspection suited to the component and a steady decrease in the amount and rate of tube plugging if LCM activities are implemented effectively.

ALARA

Worldwide advances in tube inspection tube plugging and tube removal methods and technologies have led to a very dramatic decrease in the amount of dose consumed for these activities. Ontario Hydro adopted much of this improved technology over time, with the resultant decrease in total dose consumed in steam generator activities.

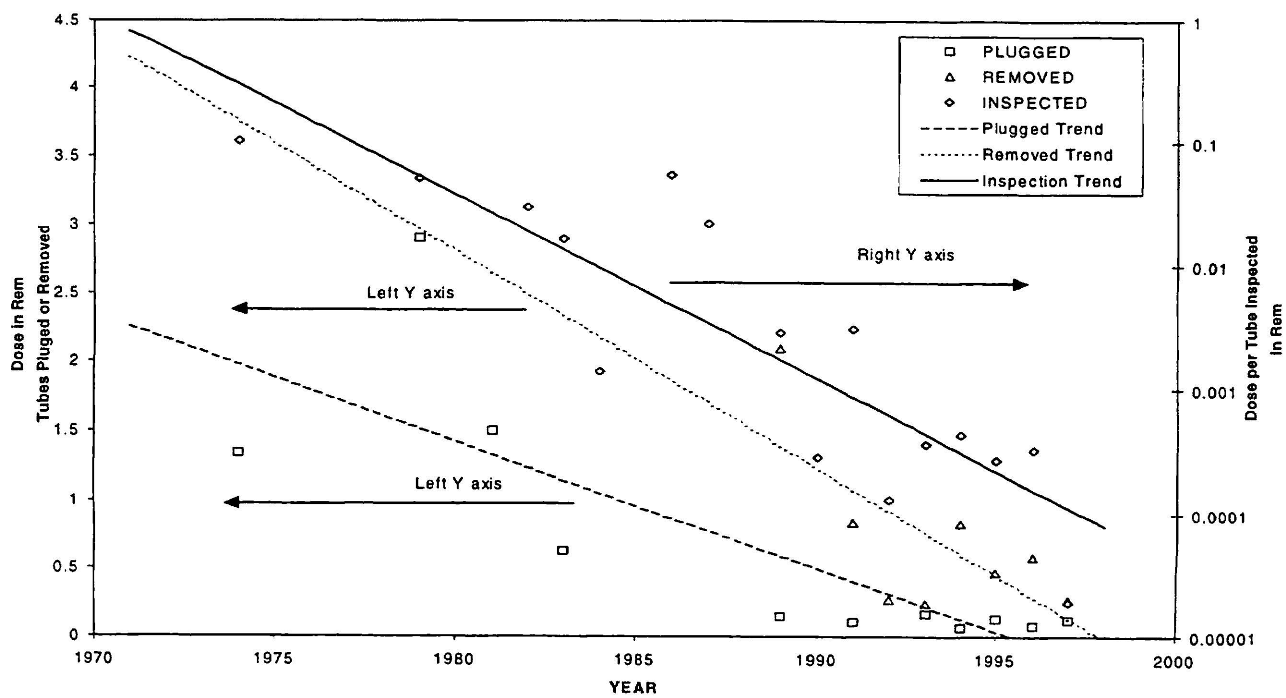

Figure 4 Dose Spent per Tube - Inspection, Plugging and Removal - OHN All Units since In-Service

This is very evident in Figure 4 which plots the amount of dose consumed per tube inspected (logarithmic *y* axis on the right), and also plots the amount of dose consumed per tube plugged or removed from the steam generator (normal *y* axis on the left) with time for all units at OH since in-service. This information was extracted from in-service reports from all units.

The amount of dose consumed per tube inspected has decreased by several orders of magnitude since 1971, while the amount of dose consumed per tube plugged or removed from service has decreased by at least an order of magnitude. This has led to a significant savings in dose consumed, in the order of hundreds of rem [100 rem = 1 Sievert]. It is worthwhile to point out that the large inspection and plugging campaigns of today would not really be possible had not these advances taken place. Dose consumed through steam generator activities should continuously decrease with time through improvements in methods and techniques.

Predicted and Actual Production Gain/Loss due to Steam Generator Activities and Problems

PNGS B is a four unit station which has been in-service since 1984 (PNGS-B Unit 5 or P5 was first in-service). These units have 12 steam generators per unit, tubing is made with Monel 400 alloy. In this type of analysis PNGS-B will be used as a specific example although it could be applied to any other station.

In late 1991 following a boiler tube leak that resulted in a forced outage, P5 was found to have extensive pitting of the boiler tubing caused by under-deposit corrosion, see Table 1 for more details. The pitting degradation rate was extremely high before any mitigative action took place. Major rehabilitative work was started in 1992, which included inspection and tube plugging, major water lancing and cleaning campaigns, upgraded chemistry control, and major modifications to the secondary side system to replace all copper bearing components including the condenser.

These actions appear to have been successful since, to date, the degradation rate decreased to almost non-detectable by NDE techniques. The other 3 units have a similar tube alloy and were also at high risk (P6 also had a forced outage due to a tube leak in 1992, pitting degradation was also found recently in P8) therefore the rehabilitative actions were carried out on all 4 units.

These actions were carried out in a pre-determined schedule since 1992 and are almost complete (completion expected in 1999). Further preventive actions are planned for the life of the plant but the cost/benefit of these actions is not included in this particular analysis. The total actual cost of the rehabilitative programs amounted to about $185 Million (Can.), not including downtime.

A simple analysis was carried out to determine if the actions carried out gave a return on the investment in terms of power production. Figure 5 plots the actual station incapability from 1990 to 1996 plus a hypothetical case which assumes no rehabilitative actions were undertaken on any unit and only code minimal inspection/plugging took place (as shown by the dotted line). The difference between the two cases shows an initial gain in capacity (in 1992 and 1993), the predicted situation changes as the degradation in P5 reaches the point were the steam generators are no longer operable causing the unit to shutdown for major repairs or waiting for steam generator replacement. This causes the large predicted increase in capacity loss in and after 1994.

Degradation due to pitting would also have affected the other three units in time increasing the predicted capacity loss post 1995.

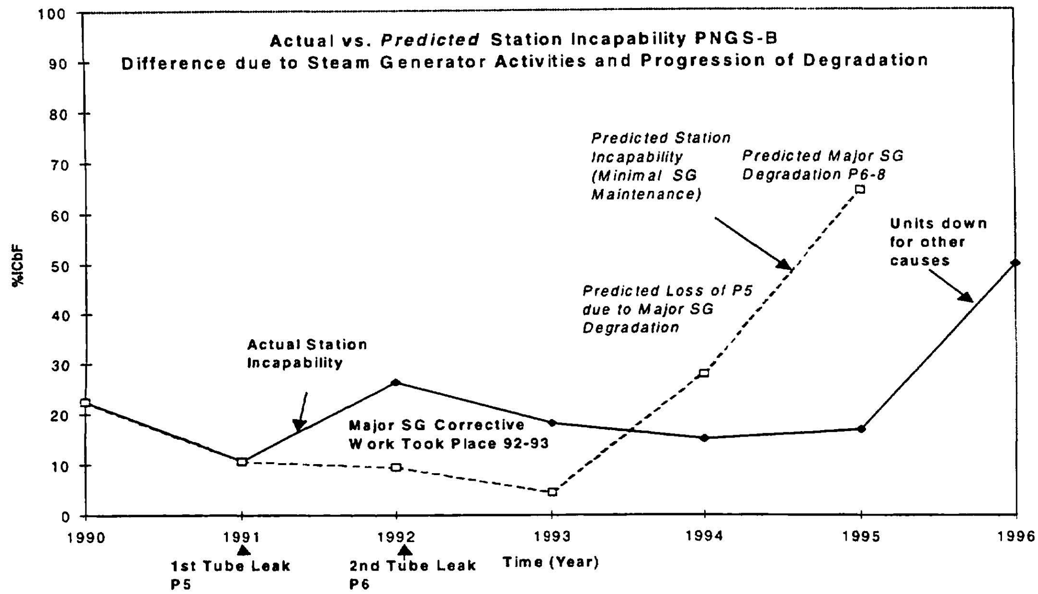

Figure 5 PNGS-B - Predicted and Actual Station Incapability

Unfortunately, actual station incapability reached 49 %ICbF in 1996 due to other causes unrelated to steam generators. The costs associated with large steam generator programs can not be recovered if the units are not operating, therefore the analysis was stopped at this point.

Figure 6 depicts the predicted gain/loss in terms of power production (MW-h) and cost ($) for the predicted scenario discussed above in Figure 5. The predicted initial gain would have amounted to about 95.3M$ (all cost is computed using the value of power at the time in $/MW-h) in recovered outage time (i.e. time not spent performing corrective measures). Add this cost to the 185M$ of the cost of the corrective maintenance activities themselves and the total cost of all steam generator corrective actions for PNGS-B was about 280.3M$.

However, increasing steam generator degradation and the subsequent loss of the units for long term major corrective measures (which may have included steam generator replacement) would have cost the station 209.6M$ in lost production to the end of 1995. By the end of 1995 all but 70.7M$ was recovered.

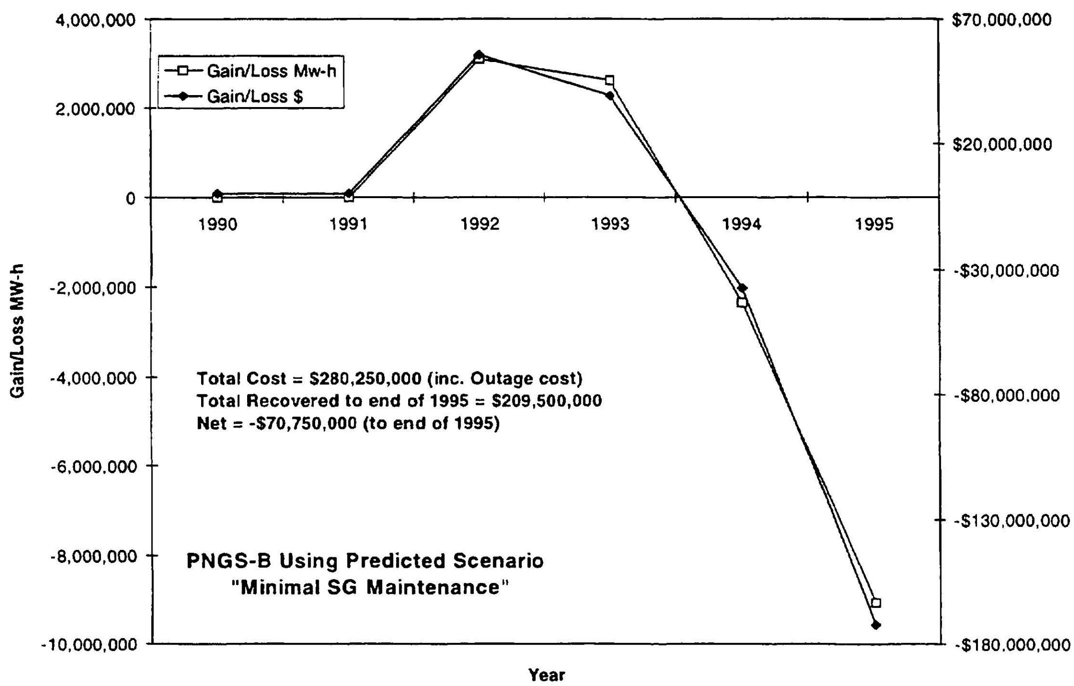

Figure 6 PNGS-B Predicted Gain/Loss in MW-h and $

This indicator is also a good one to calculate to assess the success of past performance and to determine if the counter-measures should be continued or strengthened in the future, but it does exemplify the fact that the steam generators are not isolated components in the unit. The performances of other components have direct and indirect impact on the operation and cost effectiveness of the steam generators.

SUMMARY AND CONCLUSIONS

The performance measures discussed in this paper all are good measures of the overall success of steam generator LCM programs. However, In order to be able to project into the future and determine future changes to the LCM programs no single measure is enough. A combination of all the above supplemented by indicators related to other aspects such as safety or some shorter term measures related to the success of individual LCM program activities is needed. These steam generator specific measures can not be used in isolation and must also be supplemented with information from other components or other sources that complete the total picture for the unit or station.

The success of the LCM programs implemented has been mixed for OH units, which demonstrates that the benefits of the LCM program are not guaranteed. Predictions made through the program that do not match the actual outcomes need to be reviewed and revised accordingly in an ever-continuous circle of improvement. It is important also to realize that not only is the steam generator ageing, so are all the other components in the unit and the extent of ageing in other reactor unit components may not be fully accounted for.

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Table 1

Summary of Steam Generator Problems and Countermeasures - OHN All Units

UNIT	PROBLEM	CONTRIBUTING FACTORS	COUNTERMEASURES
Pickering-A	Pitting/wastage in top of tubesheet area mainly in Unit 1	Deep sludge piles. Poor chemistry control (for all Pickering units) for some time. Impurity ingress due to condenser in-leakage	Waterlancing and crevice chemical cleaning carried out in Units 1 and 2. Inspection and plugging of tubes.
	RIHT rise (loss of thermal performance)	Primary side fouling? Divider plate leakage.	Primary side cleaning of straight legs in Unit 1 (produced no improvement in RIHT)
Pickering-B	Pitting/wastage in top of tubesheet area and at support-plate broaches RIHT rise (as in PGA)	Sludge piles; heavy deposits; impurity ingress due to chronic condenser in-leakage. Secondary/primary side fouling. Poor chemistry control (for all Pickering units) for some time. Mixed Cu/Fe secondary side system.	Manage pitting degradation. Massive inspection and plugging in Unit 5. Tube removals. Chemistry upgrading in all units. Chemical cleaning and water lancing of deposits in all units. Removal of all Cu components in secondary system, including condenser (all units to be finished end of 1997). Sleeving developments
	Tube fretting due to debris	Debris left maintenance activities, pre or in-service	Minimal inspection only to code
	Shallow erosion of tubes at supports (unit s 8, 7)	Unknown at this time	Inspection trending
Bruce-A	IGSCC/IGA in U-bend at scallop bars.	High-induced stresses due to locked tube supports, denting of tubes at scallop bar intersections and "jacking" of scallop bars due to carbon steel corrosion. Lead (Pb) contamination in Unit 2 accelerated cracking. Some fatigue/corrosion fatigue involvement.	Large inspection and plugging campaigns. Tube removals Release of stresses by unlocking supports. Feedwater chemistry upgrading. Secondary side chemical cleaning and waterlancing carried out in Units 1, 3 and 4. Removal of Cu components including condenser in Units 3 and 4. Lead control and monitoring measures. Boric acid addition. WTP improvements
	IGSCC/IGA @ tubesheet on secondary side (discovered in 1997)	Unknown at this time. Tube stresses, susceptible material, hard sludge piles and acid excursion may have contributed to mechanism	Inspection and plugging campaign. Tube removals for metallography
	PWSCC at tubesheet in Unit 4 (discovered in 1997)	Unknown at this time	Inspection and plugging
	Shallow pitting in top of tubesheet area	Presence of sludge pile and possibly acidic sulphate conditions due to WTP excursion	Inspection trending
	Boiler level oscillations. Fatigue	Fouling of upper support plate. Excessive vibration	Lancing effective in stopping oscillations. Additional supports installed to reduce vibration in all units
	Tube fretting due to debris	Debris from maintenance activities	Minimal
	Scallop bar corrosion	Unknown. Possibly crevice corrosion under deposits/acidic conditions. May be some flow assisted corrosion also	Inspection and additional supports installed in Units 1, 3 and 4
Bruce-B	Fretting of tubes at U-bend and top support plate.	Excessive clearances of U-bend supports	Inspection and plugging. Additional supports installed as prototypes in some steam generators
	Possible tube SCC at TS similar to BNGS-A	Susceptible material, stress, environment	Extensive inspection with special probes. Root cause analysis. Possible development of sleeving techniques.
	Tube fretting due to debris	Debris left from maintenance activities pre or in-service	Minimal
	Shallow pitting.	Possible acid and caustic excursion (WTP in 1989) or may be due to start-up oxygen transients	Inspection trending. Chemical environment monitoring. Deposit monitoring. Evaluation of cleaning options. Tube removals for metallographic assessments
Darlington	Shallow U-bend tube fretting No other major problems to date	Under investigation at this time	Inspection trending and root cause analysis on fretting degradation Proactive/preventive program of maintenance (preventive water lancing), inspection and chemistry control. Evaluation of chemical cleaning methods.

DISCUSSION

Authors: J. Nickerson, C. Maruska, AECL and Ontario Hydro

Paper: Steam Generator Management at Ontario Hydro Nuclear Stations

Questioner: J. Gorman

Question/Comment:

What level of inspection will be used for thus far unaffected SGs, e.g., 800 tubed SGs at Darlington? What amount of special inspection techniques, e.g. plus point, will be used? Any planned investigatory tube removals are planned?

Response:

A definitive inspection program has not been approved yet for any OHN unit, although a comprehensive plan is currently under preparation. The proposed inspection scope for Darlington is: baseline inspection with bobbin probe of all tubes by the year 2002. Post this date the proposal for inspection call for inspection of approximately 50% of the tubes in 2 to 4 boilers with bobbin probe plus about 20% of the tubes with special crack detection probes such as Plus Point or Cecco every 4 years. The proposal also includes one tube to be removed from service from a representative SG every 4 years. However, all this information is very preliminary and needs to be approved.