PRIMARY SEPARATOR REPLACEMENT FOR BRUCE UNIT 8 STEAM GENERATORS

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ABSTRACT

During a scheduled maintenance outage of Bruce Unit 8 in 1998, it was discovered that the majority of the original primary steam separators were damaged in two steam generators. The Bruce B steam generators are equipped with GXP type primary cyclone separators of B&W supply. There were localized perforations in the upper part of the separators and large areas of generalized wall thinning. The degradation was indicative of a flow related erosion corrosion mechanism. Although the unit restart was justified, it was obvious that corrective actions would be necessary because of the number of separators affected and the extent of the degradation. Repair was not considered to be a practical option and it was decided to replace the separators, as required, in Unit 8 steam generators during an advanced scheduled outage. GXP separators were selected for replacement to minimize the impact on steam generator operating characteristics and analysis. The material of construction was upgraded from the original carbon steel to stainless steel to maximize the assurance of full life. The replacement of the separators was a first of a kind operation not only for Ontario Power Generation and B&W but also for all CANDU plants. The paper describes the degradations observed and the assessments, the operating experience, manufacture and installation of the replacement separators.

1. Introduction

During routine inspection in 1998, many of the primary steam separators in two of steam generators at Bruce Nuclear Division B Unit 8 were observed to have through wall perforations. This paper describes assessment of this condition. It also discusses the manufacture and testing of replacement primary steam separators and the development and execution of the replacement separator installation program.

2. Background

The steam generators at Bruce B are of the vertical U-tube type with integral steam drums (Figure 1). Each steam generator incorporates 4,200 U-tubes of Alloy 600 (1/2"). Fifty-six sets of steam separators are located in the steam drum. The separator sets incorporate GXP type centrifical primary steam separators and the corresponding number of secondary cyclone separators (Figure 2). These relatively small steam separators are designed to allow full scale performance testing of each primary/ secondary separator set at full prototypic conditions of steam flow, water flow, pressure etc.

The functions of the steam separators are as follows:

1. The primary separators receive the two-phase mixture rising from the tube bundle at a mass quality in the 15 to 20% range. They separate the water which returns to the steam drum and downcomer and thus to the heat transfer surfaces. The separated steam along with several percent of moisture is delivered to the secondary separators.
2. The function of the secondary separators is to remove the remaining moisture from the steam so that steam is delivered to the turbine with acceptably low total moisture content (<0.25%).
3. The primary and secondary separator sets must perform their function for a range of power conditions, separator to separator quality variation, water level variation, etc.

Performance of the steam separators is stated in terms of moisture carryover and vapour carryunder. Carryover is the weight percent of moisture in the steam delivered to the turbine. Carryunder is the weight percent of vapour in the flow returned by the separators to the downcomer. Moisture carryover (MCO) can result in loss of turbine efficiency. Excessive carryunder can reduce secondary side flow re-circulation due to a decrease in the downcomer density.

The steam separators for the Bruce B units performed well both in the laboratory and on start up. Tests performed by the utility on the startup of Unit 6 in 1984 (Ref. 6) indicated an excellent MCO result of .08% at 92% power. This is considerably better than the required performance of 0.25% (max) at 100% power and acceptably close to the single separator laboratory test result.

Construction of the steam separators is almost entirely of 12 gauge (0.105") A569 sheet material. This material typically has a very low content of chrome, molybdenum and other alloying elements.

The flow configuration of the GXP primary steam separators is quite complex. Two phase flow from the tube bundle arrives at the primary separator deck to which the primary separators are fixed and enters the axial riser tube at the bottom of the separator. The flow than enters an annular passage and has a flow rotation induced by spin vanes. After passing over a skimmer slot for removal of some of the water loading, the mixture continues upwards through an annulus to the upper region where the flow is pulled from the outer annular passage inwards to the main separation chamber. The mixture velocity in this region is relatively high at about 39 feet/sec.

Similar GXP primary steam separators are in operation in several of the earlier CANDU 6 units. These separators have performed well and inspections to date have not revealed any degradation. All later BWC steam generators employ curved arm primary (CAP) separators in combination with the same type of secondary cyclones. CAP separators are simpler, have lower velocities and better performance.

3. Degradation

The degradation was first noticed in the removable primary separators on BO 3 and BO 8 of Unit 8. Erosion damage was observed to be primarily in the outershell and the internal flow baffles in the region where these internal flow baffles or scoops (Figure 3) direct the flow from the annulus into the inner separation chamber. Through wall perforations were found in the outer cans of four of the eight separators (Figures 4 and 6). In situ inspection of the fixed separators confirmed the damage extent to be about 90% and 100% perforation in BO 3 and BO 8 respectively. The secondary separators were not damaged. One separator was disassembled and the outer and inner cans were removed for detailed examination (Figure 4). Metallographic examination, thickness survey and visual inspection were carried out on the removed sections.

The outer cans had narrow circumferential perforations just below the plug welds and close to the lower edge of the horizontal vane drawing fluid into the inner chamber of the separator (Figure 6). This coincides with a major flow obstruction within the separator. There are two such flow paths in each separator, located 180° apart, and perforations are present along both flow paths in some separators. The surface above the perforation was dimpled and the surface below was smooth and highly polished (Ref. 1). Erosion damage was also seen just above the row of the plug welds.

Perforations were also seen in the inner can, generally at points across the flow passage from the holes in the outer can (Figure 5). In general, the inner can also showed dimpled surface and polished areas. The outline of the circumferential weld joining the two halves of the inner could be seen in the sectioned inner can.

In the outer can there was a wall loss up to 40% in the area above the perforation and less than 20% in the area below. At the vertical weld seam, about 60% wall loss was seen.

The inner can showed an average wall loss of 60%. The lower section was made from different plate. It was found to have slightly higher chromium and manganese and showed a lower rate of erosion.

The damage to the separators appears to have been caused by an erosion corrosion process but two different mechanisms (Ref. 1) were seen to be active.

(i) A local effect associated with the ends of the horizontal vane that produced the perforations.

(ii) A general mechanism affecting larger areas of the inner surfaces of both the inner and outer cans.

The first mechanism produced smooth surfaces and local areas of high wall loss characteristic of a two phase flow of steam and water. This is a mechanical erosion process.

The second mechanism characterized by a more general loss of wall is indicative of a combination of flow assisted corrosion (FAC) and erosion process. The small difference in material alloy content and microstructure in the lower part of the inner may account for variation in the wall loss.

4. Fitness-for-Service Assessment

There are two possible ways the degraded separators could affect steam generator operation. The leakage through the perforated areas could reduce the separating capability leading to more water reaching the secondary separators. Moisture carry over in the outlet steam would increase if the secondary separators were overloaded. Increased carry over can result in erosion damage of the turbine blades and loss of thermal performance.

The other consequence is increased carry under of steam into the drum water and eventually into the downcomer flow. The uncondensed steam can:

- Flood the separators by raising the drum level and increase carry over.
- Result in loss in the pumping head and reduced circulation.

The unit was returned to service following an assessment by B & W (Ref. 2). The assessment concluded that the leakage flow would not significantly increase carry over and carry under. Bruce B operating experience supports this conclusion because there have been no reports of turbine blading damage, loss of power or level control problems. It also concluded that the size of the perforations or the area affected by the general loss of wall did not affect the structural integrity of the separators because of low mechanical loading during normal operating or postulated accident conditions. Potential for damage from loose parts was also assessed to be low.

5. Post Restart Separator Performance

Following the return to service, Bruce Site initiated a monitoring program as an on-going check on the Unit 8 separator conditions. The monitoring program included on-line measurement of the downcomer flow in BO8 that had the most extensive separator damage and a moisture carry over test on the unit.

On-line ultrasonic flow measurement of the downcomer flow was started in BO8 after the restart. Both transit and transflection type UT devices were used. The transit device is used for liquid flow and the transflection device is suitable for two phase flow. The results from the transit type device indicated that the average downcomer remained unchanged at about the 2.05 metres/sec level before and after the separator replacement. The test data from the transflection device before and after the change was erratic indicating that there was no significant steam carry under.

An MCO test was carried out in September 1999, approximately 9 months after the return to

service (before replacement) and the results showed very low level of MCO. In fact, the MCO level had remained unchanged from the test results of 1987. The measured level was 0.022% with an upper bound of 0.037%, well below the guarantee level of 0.25% (max).
The results of the MCO and the Downcomer Flow measurements indicated that although there was an active degradation it could be managed.

6. Inspection of Other Units

Following the discovery in Unit 8, inspection of primary separators was included in the steam generator In-Service Inspection scope. The table below shows the inspection results in terms of number of separators with holes/number of separators inspected out of a total of 56 per boiler.

Separator Inspection Results

	Unit 7 (1998)	Unit 5 (1999)	Unit 8 (1999)	Unit 6 (2000)
BO1	0/49	0/30	0/26	0/31
BO2	0/30	24/56	8/56	O
BO3	0/27	0/30	49/56 ®	O
BO4	0/54	18/56	51/56 ®	0/30
BO5	O	O	0/29	O
BO6	O	O	0/26	O
BO7	O	O	2/56	0/31
BO8	O	O	56/56 ®	0/30

® - Replaced in 1999
O - Not Inspected yet

Unit 7 steam generators were inspected in the fall outage of 1998, soon after the restart of Unit 8. The separators had no perforations in the outer cans or in the inner chambers. The removable separators did not show any significant loss of wall either. This was unexpected because the separators in Unit 7 operate under very similar conditions as in Unit 8. Steam output, pressure and velocities are the same. They had also seen a similar length of operating time.

Minor differences in trace elements were found between the separators in Units 7 and 8. However in the absence of a root cause analysis the different conditions of the Units 7 and 8 cannot be clearly explained. Factors relevant to flow assisted erosion corrosion are; material constituents principally chromium, process conditions like temperature, velocity and operating environment i.e., process chemistry particularly pH, oxygen and hydrazine levels. Similar results were seen later, Unit 6 boilers (or at least those inspected) did not have any damaged separators while some boilers in Unit 5 did. The Unit 7 inspection results although unexpected did not influence the replacement decision.

7. Replacement Decision

It was recognized that corrective action would be necessary because continued operation of Unit 8 with degraded separators posed an unknown risk of a long and unplanned outage. This is because a large number of separators were affected and the degradation rate was not known. Following the Unit 8 Restart OPG made the following decision:

- The damaged Separators will be replaced in Unit 8 and the replacement will be carried out at the first opportunity
- The Spring 2000 Unit 8 outage was brought forward to Fall 1999
- B&W, the steam generator OEM will supply the replacement separators

The first step was to select the replacement separator from a number of alternatives including other designs (e.g., B&W type CAP). The criteria applied for the selection process were (i) the separators would last for the remaining life of the steam generators and (ii) the steam generator operating characteristics would remain unaltered. Additionally, the manufacture and supply would have to support the advanced outage schedule.

The first criterion meant that a material change was needed to enhance the erosion corrosion resistance. The second criterion required that the replacement separators duplicate the hydraulic performance (resistance) of the original separators, otherwise there would be some significant impacts. Impacts of a change of separator type would include:

- Unique steam generator level control program and hence operating procedure would be needed for Unit 8

- Change out would have to cover all eight boilers irrespective of the damage extent
- The steam generator design analysis would have to be reassessed and probably revised

The following replacement options were evaluated using the above criteria:

1. Replace with GXP separators made from 0.2% Chromium steel
2. Replace with Stainless steel GXP separators
3. Replace with CAP separators made from 0.2% Chromium steel
4. Replace with Stainless steel CAP separators

Early in the selection process the option of repair and of no replacement but monitoring with operational changes was addressed. This option was rejected because the risk of a long and unplanned outage too high.

Option 1 above would maintain the steam generator operating characteristics and no new design analysis would be required. The chromium content of 0.2% was based on industry practice to enhance the erosion corrosion resistance of carbon steel seeing two phase flow. This chromium level was considered to be a minimum and not providing sufficient margin for full operating life under the service conditions. Hence it did not meet the first criterion. Although a higher chromium level would increase the erosion corrosion resistance, this would increase manufacturing complexities. Pre and post weld heating would be required to assure weld integrity. This meant new manufacturing procedures would have to be developed and this would not support the outage schedule.

Options 3 and 4 involve CAP type separators and a different design. This is a proven design and is installed in Darlington and subsequent steam generators. These separators have higher capacity but lower internal flow velocities. However, there would be a mismatch in the hydraulic characteristics. This meant that although there would have been assurance of longer life, the operation would be impacted and steam generator analysis would have had to be revised. Hence it did not satisfy the second criterion.

Option 2 was selected. This was the replacement in kind with GXP separators but constructed from type 304 L stainless steel. The use of stainless steel significantly increased the resistance to erosion and corrosion and provided highest assurance of full life in view of the service condition uncertainties (velocity, quality and chemistry). This option also satisfied the second criterion completely and meant zero impact on operation and steam generator analysis. Also these could be delivered in time to support the September 1999 outage recognizing that some manufacturing changes would be required due to the choice of stainless steel.

Two project teams were set up within OPG. An engineering team in Mechanical Systems & Equipment Department (MSED) was responsible for all pre-tender engineering work including the Technical Requirements for the replacement separators. The team interfaced with B&W for all OPG matters and oversaw the technical aspects of separator design, manufacture and testing carried out by B&W. The Bruce site team was responsible for managing the modification project and oversaw the actual replacement of the separators in the selected steam generators. Additionally, B&W developed the Installation Procedure and supplied a full scale Bruce B Steam Drum mock-up and selected tooling. The mock up was used for validating the installation procedure including the tooling as well as crew training.

8. Manufacturing and Testing

Replacement primary separators of the GXP type in 304L stainless material were manufactured so as to provide one complete set of separators for the eight Unit 8 steam generators. Manufacture of these separators required retrieval of the numerous separator detail drawings, upgrading some drawings to electronic format, and total reconstruction of tooling. Because of material change, the tooling needed to be redesigned to take into account the different forming characteristics of the stainless material. Stainless is inherently springier, has more weld shrinkage and is more difficult to machine than carbon steel. In addition to cutting, forming and fitting operations, new welding procedures had to be developed in order to join this material. This was a substantial change from the prior production. Stainless steel also requires unique precautions in manufacture to avoid material contamination, which has in other situations resulted in rapid corrosion due to embedment to carbon steel particles into the stainless surface.

The GXP type of separator is quite complex in design and has a number of small internal passages. The complexity, together with the change of material fabrication characteristics, put a lot of pressure on tolerance control issues in order to avoid loss of performance in operation. Because of the passage of time since these separators were last built (approx. 1976) and the fact that construction involved a new material with new tooling by new craftsmen, it was decided that it was essential to perform a full scale performance test on a prototype steam separator. This performance test essentially duplicates the original qualification testing of the GXP separator which was most recently completed in 1980. While no problem was expected, the test was essential to ensure that the performance of these intricate steam separators with their narrow flow passages was not degraded by any detail of manufacture.

Deliverables in the replacement separator manufacturing scope include 56 GXP primary steam separators for each of the 8 steam generators of one reactor unit, four replacement secondary separator drain tubes per separator, plus various fasteners, fittings and brackets. These 56 sets per steam generators include four separators that are removable for upper steam generator access. In addition the scope included the tooling necessary for installation, installation procedures, design qualification reports and a full scale steam drum mockup.

9. Installation

After gaining access to the steam generators of Unit 8, the previously uninspected boilers were examined and it was decided that the separators would be replaced in BO 3, BO 8 and in BO4. The order of separator replacement was finalized in coordination of other boiler maintenance work.

The Site Project Team managed the installation project. The actual work was carried out by trades under the supervision of site construction staff. A B&W team was present at the site to provide technical support during the separator replacement.

The Crew was trained over three weeks in the following areas:

- Installation Procedure including practical training on the set up and operation of all tools and equipment. This part of the training was carried out in the steam drum mock up.
- Pertinent OPG training for work environment and tasks
- Radiological and conventional safety aspects
- Foreign Material Exclusion (FME) practice in accordance with OPG procedures as well as FME precautions included in the installation procedure.

One of the challenges of the replacement was the supporting of the back drain pipes which were installed ahead the separator. This was resolved by a timely innovative design. A horseshoe shaped strap was designed to support the two drain pipes at one elevation. Hence each separator ended up with two straps welded at two elevations supporting the back drain pipes and conventional clips supporting the near side pipes.

The critical operation of the separator replacement was the welding of the replacement stainless drain pipes to the stubs remaining from the removal process. The local vertical clearance was no more than 2.5". The challenge was greatest for carrying out the welding for the two pipes at the far side of each separator. The welds had to be leak tight for effective operation of the secondary separator. The following decisions were made to ensure the field weld integrity.

1. A carbon steel coupling would be used so that the field weld is between like materials.
2. An orbital welding machine would be used to ensure weld quality and repeatability.

The orbital welding heads (ARC Machines) with modifications designed by B&W worked well on this critical welding operation.

The separator replacement was a first of a kind operation for OPG, B&W and indeed for all CANDU units in general. Although the procedure and the replacement were aided by other in-boiler maintenance work, there were challenges typical of a first exercise. These were resolved and the installation met all requirements. While special FME (Foreign Materials Exclusion) barriers and procedures were implemented, FME was a major issue. Foreign objects (tooling and small parts) had to be retrieved from each of the steam generators worked on. The weld insert in the coupling also caused some delay because it produced fumes affecting the working environment in the drum.

The pace of the in-boiler work was slow to start with but picked up as the work continued. Increased resources in areas such as accesssupport would have accelerated the program.

Steam separator replacement was completed for three of the eight steam generators of Unit 8 during the period of September 13, 1999 through November 15, 1999.

10. Replacement Separator Performance

The down comer flow measurement on BO8 was continued after replacement. The results show no change indicating that the replacement separators are operating satisfactorily. No further moisture carry-over test has been carried out.

During the next Unit 8 outage, BO2 & BO7 which were returned to service with some damaged separators will be inspected. It is also planned to inspect one of the replacement separators from BO4.

11. Conclusion

The damaged separators were removed and the replacement separators were installed successfully in selected Unit 8 steam generators. There is a high degree of confidence that the selection of stainless steel as the material of construction addressed the uncertainties of process conditions and chemistry and that the replacement separators will achieve full operating life.

Although the experience showed that the degradation could be managed, the discovery of the separator degradation reinforced the need for periodic secondary side inspection of steam generators as part of a well managed life cycle management program.

This was a first of a kind operation but other in-boiler maintenance practices aided the exercise. Nevertheless, challenges did present themselves and were resolved. The lessons learned during this exercise will benefit any future separator replacement at Bruce B. Optimization of support resources and increased training in the FME procedures appear to be the ones that would bring the most benefit.

12. Acknowledgements

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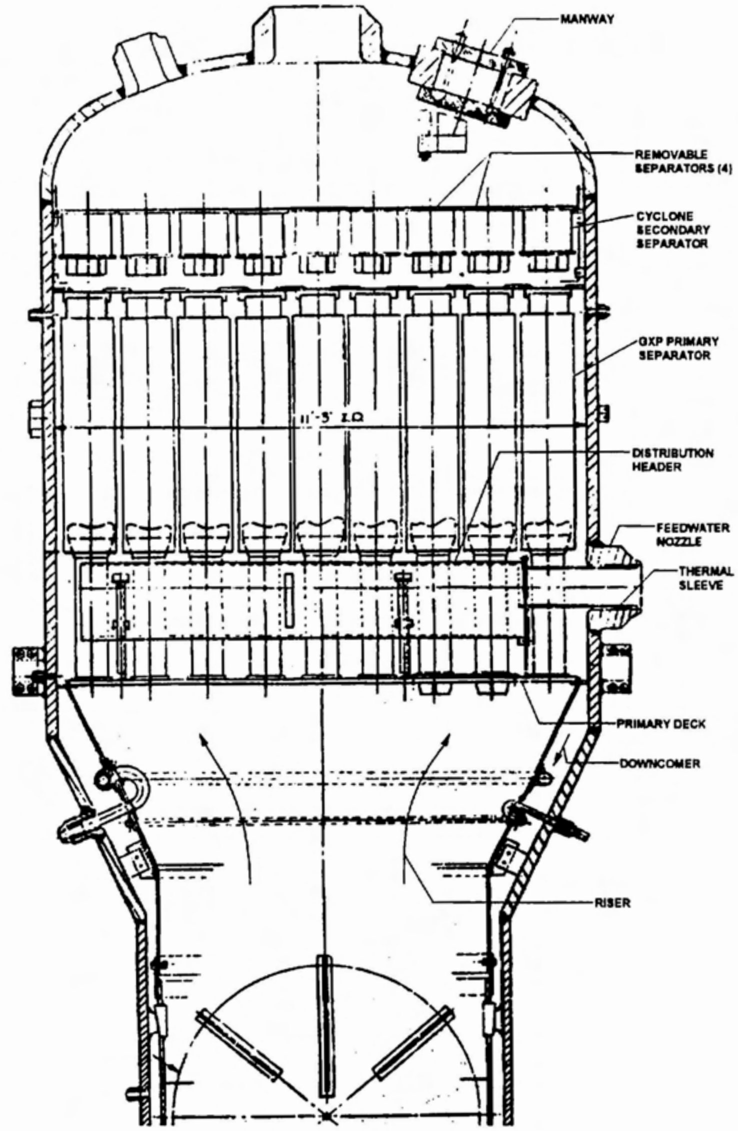

FIGURE 1:
Bruce 'B' Steam Drum Arrangement

FIGURE 2:
GXP Primary Separator and Cyclone Secondary Separator

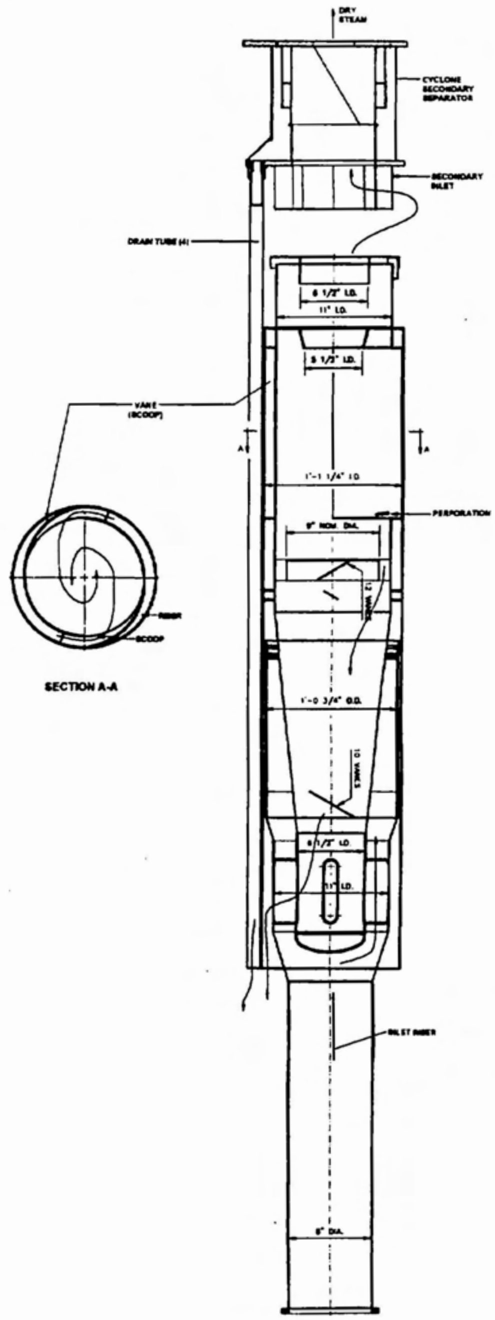

Figure 3
GXP Separator– Outer Can Removed to Show Inner Flow Scoop.

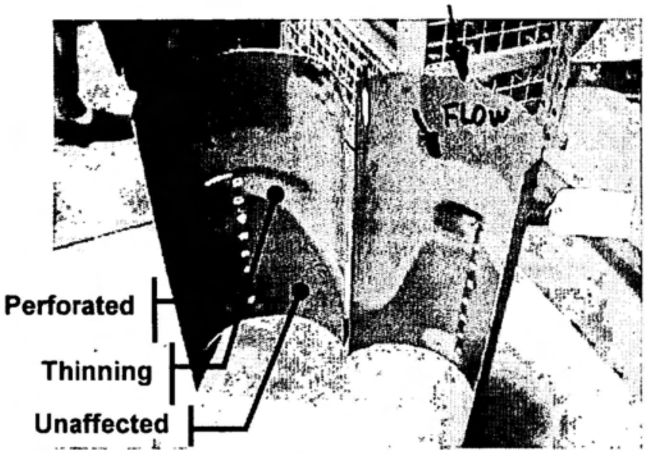

Figure 4
GXP Outer Can – Removed to Show Thinning and Perforations (Can is Inverted).

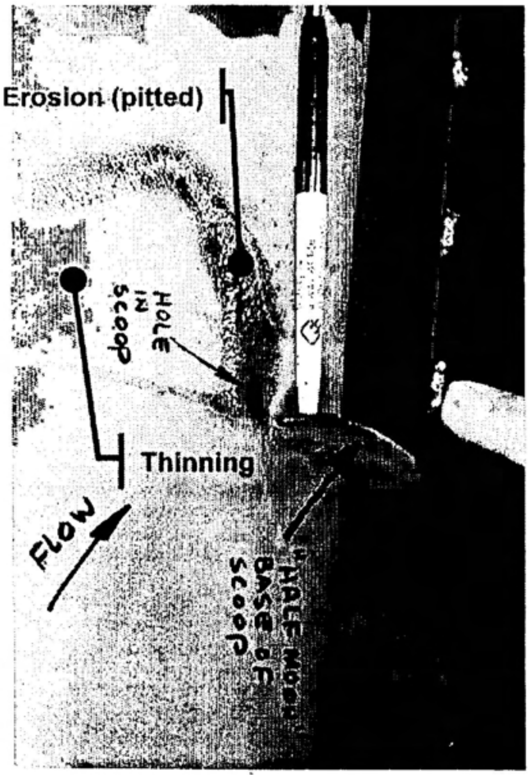

Figure 5
GXP Separator– Inner Can and Scoop Showing Thinning and Perforation.

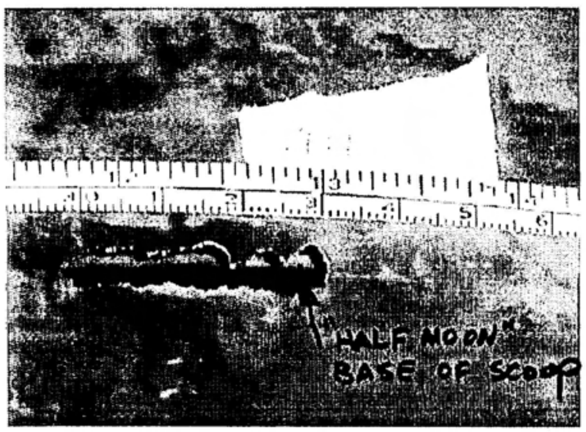

Figure 6
GXP Separator Outer Can – From Exterior Showing Perforation.