New tools for tube repair, analysis of risks posed by safety/relief valve clinic

Over the past 13 years, the annual conference and exhibition of the HRSG User’s Group (HRSG UG) developed a reputation for great venues, exceptional food, and—most importantly—a solid technical program that provided participants the practical information needed to reduce outage time and O&M costs, increase plant efficiency and availability, and lower emissions. The 2006 event, held last March at the Broadmoor Hotel in Colorado Springs, certainly enhanced that reputation, exceeding expectations both in creature comforts and in program and exhibition content.

Delegates were treated to the organization’s most impressive venue and culinary service yet: The Broadmoor is one of only three resorts in the country to have earned the AAA Five-Diamond rating every year since the awards were established in 1976. This year’s information exchange comprised two jam-packed days of insightful presentations by industry experts, plus the traditional user-driven discussions. The latter were skillfully moderated by Chairman Bob Anderson, principal, Competitive Power Resources Corp, Palmetto, Fla (anderson@competitivepower.us), and summarized in a special report for attendees by Rob Swaneckamp, executive director of the HRSG User’s Group (swaneckamp@hrsgusers.org).

A relaxed, but productive, exhibition enhanced collaboration among users, manufacturers, architect/engineers, consulting engineers, and service providers in attendance (see montage above).

Another bonus. All attendees received a copy of the HRSG Users Handbook, a new 500-page reference work that contains a wealth of practical knowledge on the procurement, design, operation, and maintenance of heat-recovery steam generators. The editors of the COMBINED CYCLE Journal consider this handbook a “must-read” for the combined-cycle/cogen community (to order online, access www.hrsgusers.org).

From the users’ vantage point in the Broadmoor Hall, it was clear that the group’s Steering Committee—Anderson, Swaneckamp, Yogesh Patel of Tampa Electric Co, and Paul
Fernandez of GE Contractual Services—worked hard to produce an enjoyable event, while compiling a program that delivered high-caliber technical information on HRSGs and their associated steam systems.

Constant format, fresh info

Through the years, the meeting’s format has remained relatively constant: A series of Open Forum Discussions—self-help clinics, if you will—dominate the agenda, with only a handful of prepared presentations sprinkled in to cover particularly challenging issues.

While this year’s presentations were interesting and on-point as usual, the things that really separate welding best practices, prolonged low-load operation, highlight annual meeting

1. Steam-plant issues raised by owner/operators at the 2006 HRSG User’s Group conference included methods to monitor HRSG performance, the pros and cons of all-volatile water-chemistry treatment, and the challenges associated with controlling superheater and reheater outlet temperatures while at low loads
this event from the rest of the conference pack are the number of attendees—upwards of 350—and the type of people actively contributing to the discussion topics—mostly end users (plant managers, O&M supervisors, operators, maintenance techs, chemists, and so on), with a significant and vocal contingent of plant-support authorities (HRSG OEM engineers, water-chemistry specialists, plant service contractors, engineering consultants, etc.). This technically skilled assembly, unleashed to raise whatever steam-plant issues they currently face, ensures that the discussions are fresh and timely year after year.

Note that the delegate assembly was particularly robust this year, thanks in part to the active participation of the “dog that wags the tail” of this industry: Several leaders from GE Energy’s team that specifies and delivers complete combined-cycle plants participated in the 2006 event. Their technical contributions, and the customer feedback they received, were of significant value to the industry.

The formal presentations delivered at this year’s conference are summarized in the large sidebars included with this report. What follows are some highlights of the Open Forum Discussions, the centerpiece of the HRSG UG’s annual conference (Fig 1).

Heat transfer opens the meeting

The conference opened with a question from a refinery operator concerning the tools and methods available to predict HRSG thermal performance, given gas-turbine (GT) and duct-burner theoretical heat input data. This design-related discussion then evolved toward practical methods that operators can apply to monitor HRSG performance, given the limited instrumentation installed at the typical plant. For instance, operators can trend the pinch, approach, and
stack temperatures, one consulting engineer explained to the crowd. Discussion of this topic might have gone on longer if one of the attendees hadn’t noted that Chapter 5.2 of the HRSG Users Handbook—dubbed “the Blue Book” by that individual—covered this topic in great detail.

Next came a good example of a user bringing a vexing question to the meeting and getting a definitive answer on the spot. A steam specialist from a southeastern utility displayed a photo of salt deposits that had formed in the cold end of one of his HRSGs, and asked of the audience why these deposits seem to be forming only along the sides of the unit, rather than uniformly across the HRSG (Fig 2).

After studying the photo for a minute, one experienced consultant suggested that the pattern was typical of cross-flow tube coils where cold inlet water starts at the side of the coil, and moves across the tube bank progressively picking up heat. The end result is some tubes being warmer than others. The salt deposition selectively builds up on the colder tubes, the consultant explained.

The user thought he had his answer, until an engineer from that HRSG’s OEM interjected that this particular design did not use any cross-flow coils. The OEM engineer proposed that, instead, these deposits might be forming during shutdown when a slipstream of colder air along the sidewalls is created because of natural draft. Often the corrosion and deposition phenomena are worse when a unit is not operating, than when online and up to temperature, he explained.

The proverbial “light bulb” went off in the user’s head, as he realized that other evidence he had observed supported the OEM’s suggestion. The user had found a very similar, localized pattern of ammonium salts collected around the HRSG’s manway door gaskets—gaskets that were known to be experiencing air in-leakage.

Unfortunately, not all questions during the Open Forum Discussions can be as definitively answered as this one, even by the large group of experts and operators gathered in the room. For example, a user from the Midwest with experience in fossil-fired boilers asked how many years of service the typical HRSG can be expected to deliver before it requires chemical cleaning. The response: It depends.

As other attendees explained, there are many variables affecting this interval—various design factors, the operator’s execution of the water chemistry program, and base-load versus cyclic operation, to name a few. The answer also is not definitive because of the lack of data within the industry on tube-deposit formation.

The fleet of high-pressure HRSGs in power-generation service, compared to the fleet of fossil boilers, is still quite young, and little, if any, empirical data on tube deposition have been collected and analyzed. As a result, discussion of this question centered around when, where, and how to take evaporator tube samples to analyze the rate of deposit formation in your HRSG.

While a definitive answer for the HRSG community awaits such data, a consensus seemed to emerge among the veterans in attendance that a well-designed and well-run HRSG can be expected to go without chemical cleaning for 10 to 15 years. Of course, it only takes a few hours of operation outside accepted water chemistry limits to create a situation that could necessitate immediate chemical cleaning, Chairman Anderson pointed out.

Continues on page 39
Welding techniques for a successful plant outage

Ever since riveted pressure vessels went the way of the horse 'n buggy, welding has been an essential and common activity in the construction and maintenance of boilers and piping systems. Most users see it going on during plant outages and some may even get involved in its planning and execution. Most also can list some of the well-known problems associated with welding—such as the frustrating length of time required (often on the critical path) for fit up, welding, and post-weld heat treating (PWHT) of large pipe; rework of rejected welds; and finding sufficient numbers of skilled welders when needed (Fig A).

While these are significant issues worthy of the maintenance manager's attention, there are many other less obvious considerations associated with planning and executing a welding job that can mean the difference between an on-budget, on-schedule project and the proverbial train wreck. At the 2006 HRSG User’s Group meeting, William F Newell, Jr, PE, IWE, a vice president of Euroweld Ltd, Mooresville, NC (wfnwell@pobox.com) shared with the audience several of these less obvious—but still important—welding pitfalls, covering both technical troubles and financial flops.

**Measure twice, cut once**

Newell opened by emphasizing the importance of planning your outage well in advance. Key planning steps include collecting the applicable specifications and drawings, identifying predictable trouble spots based on previous problems and fleet history, deciding how to work with dissimilar metal joints, obtaining sufficient materials inventory, and so on. He pointed out that these fundamental planning activities—though perhaps a bit tedious and unexciting—can prove highly valuable to a successful outage.

Following the review of outage-planning fundamentals, Newell discussed some of the planning tasks that are specific to welding projects. These include becoming familiar with codes, NDE techniques, and acceptance criteria; selecting the optimum weld processes and consumables for each job; procuring the right materials; creating and implementing qualified procedures, engaging qualified and productive welders, and—last but not least—satisfying the authorized inspector and/or regulatory bodies so all repairs are acceptable for a plant restart.

In Newell’s experience, observing ASME Boiler & Pressure Vessel Code (Code), specification, and jurisdiction criteria—coupled with hiring the right personnel—can lead directly to enhanced equipment reliability and higher plant availability.

But someone “at the top” must appreciate and understand the job, he said. That’s not always easy given the complexity of welding with advanced alloys. “Older materials were very forgiving, compared with the alloys in today’s combined-cycle plant,” Newell pointed out. And just as welding has gotten more complicated, fewer and fewer people are taking the time to truly understand the discipline.

**Material shortages**

Another very timely aspect of his presentation dealt with today’s challenge of procuring sufficient materials for welding projects. Such items as welding rods, wires, fluxes, and special-alloy piping are in short supply. To a large extent, Newell said, these shortages are attributed to the significant amount of industrial construction going on today. That may seem surprising to power generation professionals in North America and Europe, because new construction in this industry and in these locales is quite sluggish. But there is so much work going on in other parts of the world, particularly in China, Newell said, that it “is literally sucking up the
raw materials” we need for our power projects.

Compounding that problem is the fact that most of the weld metal for chrome-moly piping—used extensively in combined-cycle/cogen plants—is being made overseas these days. This adds perhaps four to six weeks to the delivery time—for shipment across the ocean—and often keeps much of that piping in its country of origin. Why should steel producers ship it to far-flung reaches of the world, when they can sell it at handsome profit to a nearby construction project?

It’s a similar situation even for the base metals, Newell said. Reportedly there is only one US vendor that can make seamless pipe, and that supplier is very busy. “We put in an inquiry for strip cladding in 250-ton increments, and we were laughed at,” Newell reported. “They said, ‘Don’t bother us. We’re making money selling the cheap stuff. We don’t want to make anything sophisticated.’ And this was a premier melter!”

Newell cautioned HRSG users that this situation could become very critical if they have an emergency need for a particular fitting or special piping. “Trying to get that special fitting, or forging, or valve you need [in an emergency] could be very problematic,” he said. Moral of the story, as Aesop’s ant understood but his grasshopper did not: Better lay in some stores while you can!

Cost and schedule

Estimating and controlling costs and schedule challenge plant managers during most welding projects. That’s because there are many variables that can enter into the equation. Newell offered a few rules of thumb that he’s found handy:

- Regardless of the job, assume preheat and PWHT will be required, and budget your money and time accordingly.
- Regardless of the job, skilled craft and welders are necessary. Don’t think you can save money by hiring on the cheap.
- Regardless of the job, certified material test reports for weld metal should be required because they’ll reduce your project headaches.
- Regardless of the job, demand good fit-up and you’ll save time in the long run (Fig B).

For every welding dollar spent, figure labor and overhead will cost 86 cents, equipment (manual) six cents, and filler metal and shielding gasses eight cents.

To minimize time, Newell suggested that users:

- Coordinate weld-groove geometries with welding process selection.
- Use gas tungsten arc welding (GTAW, TIG, heliarc) when possible. Although considered slow, it is faster in the long run than other processes on small-bore or stan-

tard-wall piping.

- Implement processes to be used based on “who shows up.” In other words, coordinate the selection of welding processes with the available skilled labor pool.
- Pre-select or pre-qualify your heat-treatment contractor.

Plan how the heat treatment on each job will be conducted. Is it best to preheat and weld, then to perform PWHT on a number of joints? Will you heat-treat single versus multiple components? Should you cluster the heat treating activities in one area, or heat-treat individual components in remote locations? Maybe it’s best to use a combination—perform individual preheat, then batch PWHT (Fig C).

Also plan the heat sources to be used: flame (not on the latest alloys), electrical resistance, electrical induction, or portable furnaces (gas or electric). Today it is not uncommon for the alloys and configurations to dictate the methods available.

To increase productivity without sacrificing quality, Newell said you should cull the welders in the weld test shop—rather than on the job. High reject rate in the test shop always equals lower reject rate on the job, and vice versa. Newell recommended requalifying each welder on important projects rather than accepting CommonArc or UA certifications unless you have prior positive experience with these group qualification efforts.

As evidence, he discussed a case study where all of the above steps were considered during the planning stage. The project competed ahead of schedule with a reject rate of less than 1%. Of course, there were other details during execution of the work that also had a great impact on this success. For example, the best planned welding job won’t be successful if you don’t keep the arc “on and hot,” he said.

No welding process permits deposition of weld metal 100% of the time. Some things that require interruption of welding include changing electrodes, the welder repositioning, chipping slag, grinding, preheat/PWHT, joint preparation and personal time.

Selection of the welding process also can have an impact on welding productivity. For example, typical operating factors for some common welding processes when used in the shop are 30% for manual GTAW and shielded metal arc welding (SMAW or “stick”), 40% for semi-automatic gas metal arc welding (GMAW, Mig) and flux cored arc welding (FCAW), and 50% for fully automatic submerged arc welding (SAW).

All of the above values are at least 10 percentage points lower for field application. This 10 percentage point reduction correlates with only six additional minutes each hour when weld metal is not being deposited, but it can drive a 21% to 50% increase (dependent upon electrode size and process) in the cost per pound to deposit the weld metal.

One of the things you can do to increase welder productivity is to select welding processes and consumables that appeal to the operator. This means those that produce a smooth arc, good control of the puddle and bead, reduce weld clean-
ing and grinding by producing slag that is easy to remove, produce no spatter and produce good bead shape. It's also important, Newell said, to take steps that reduce the welder's personal time requirements (distance to water cooler and rest room) and eliminate non-welding tasks and diversions.

As for keeping the arc hot, Newell explained that reducing the current 10% below optimum when using the FCAW process will result in a decrease in weld metal deposition rate of 13% and an increase of deposition cost of 15%.

Another factor that can have a significant effect on the cost of the welding project and its schedule is the choice of welding wire when using the FCAW process. For example, a low-alloy wire with an efficiency of 60% may cost $10/lb, while a wire with an efficiency of 90% may cost $14/lb. Therefore, to get one pound of metal deposited requires 1.7 lb of the less expensive wire, but only 1.1 lb of the premium material. If that's not already bad enough, most of the lost metal ends up as spatter that requires grinding.

You can see where this is going. If you do the math, the cheap wire actually costs $17/lb of deposited metal while the more expensive wire can be deposited for $15.40/lb. Which one would you choose?

Using Code as king

One of Newell's concluding messages dealt with the Code, and the propensity of today's users to rely on it as some sort of infallible construction handbook. Many purchasers of combined-cycle and cogeneration plants are under the impression that their specifications will be sufficient as long as they require compliance with the Code. But the sole purpose of the Code, Newell reminded the audience, is to ensure safety—to prevent catastrophic failures and the resultant loss of life, injury, and property. "It's a set of minimum requirements—only the bare-bones minimum. If you think you need more, then it's up to you to do more."

The comment, triggered by a question from a user in the audience, prompted Newell to regale the crowd with a short anecdote based on his many years of experience in welding and on Code committees. "We were sitting in an ASME Strength of Weldments Subgroup meeting," Newell recalled, "and three Fellows present reasoned that the problem with the Code and the allowables and everything else is that no rule-of-thumb is provided as a guide and young designers sitting in front of their computer screens today actually believe what they're seeing."

In the past, Newell continued, designers would determine what the Code required, and would then add a margin of safety. "If I need an inch, I'll use an inch and a quarter. If I need an inch and a half, I'll use an inch and three quarters. If I need five inches, I'll use seven." But those designers—and their conservative design philosophy—are no longer in charge.

Newell also pointed out that the advanced materials being used in HRSGs—and in the next generation of fossil boilers—are simply not as forgiving as the older, traditional steels. Plus we're running these components at higher stress levels. Net result, Newell said, is that users do need to be more diligent in their specification, than to simply say "comply with ASME Code."

Meanwhile, Newell, along with many other materials and design experts, are working within ASME committees to set more prescriptive standards when appropriate.
At early HRSG UG conferences, leakage around drum-door gaskets and their catastrophic failure were revealed to be relatively common problems in the industry. Hence, the reasons causing the leaks and the methods to avoid them usually garnered considerable discussion. At the 2006 event, drum-door leakage was raised yet again as a serious issue, suggesting that even after more than a decade of US experience, this problem remains. As usual, some excellent tips were bantered about, but this year’s discussion of drum-door gaskets didn’t consume a lengthy time period because this is another topic now covered in detail in the HRSG Users Handbook.

Water chemistry, as always

Discussions surrounding water chemistry are always popular at HRSG UG meetings, and the 2006 event was no exception. This year the topic that seemed to garner the most interest is the desire, if not an outright trend, for operators to move toward all-volatile treatment (AVT) and away from their conventional phosphate treatment programs (Fig 3). Discussion on this topic was so lively, that an excerpt is presented below. It was extracted directly from the meeting notes with permission of the HRSG User’s Group.

User: One of our consultants has recommended going to AVT. We’re having issues with phosphate hide-out; result is that every time we start up, pH drops down in the 8-range for probably the first one or two hours that we’re operating. If people are not switching to an AVT program, I’d be curious as to why they’re not. What are the concerns?

Chemical vendor: To answer the first question, about experience in changing to AVT-O: It is happening right now in many plants. They’ve had, generally, a good degree of success. But there are a number of qualifiers that you have to meet at the plant level, and at the chemistry level, in order to make that change successfully. Issues associated with dissolved oxygen in the hotwell; with air in-leakage; with what happens when you’re cycling, etc, all can be addressed mechanically and chemically.

When people have done that, they’ve had good results, in terms of iron transport, and generally they’re very satisfied with the switch to AVT-O, and also with the change to no phosphate in the drums. So it’s an effective, and from my point of view it’s an industry trend that we’ll see more of. To make the transition it requires taking care of the mechanical, as well as the chemical, things.

Chairman Anderson: I want to ask a couple of follow-up questions. When you say AVT-O, are you talking about true all-volatile treatment, or are you just talking about very low phosphate levels to avoid the hideout. And if you’re talking all-volatile treatment, are you using a condensate polisher?

Chemical vendor: The terminology can be a bit confusing. Of course,
we always use all-volatile treatment in the condensate/feedwater system, so even if you use phosphate in the boiler, you are on an AVT program in the condensate/feedwater. The AVT-O specifically refers to no use of passivators—so no hydrazine, no carbohydrazide, no other chemical passivator for an all-steel system. And that has been a very successful change, whether you’re still using phosphate in the drums or not.

Now, going completely to a non-phosphate treatment in the drum is something we also see people doing, without condensate polishing, as long as they have tight condensers. Many plants recently commissioned that don’t have condenser tube leaks have gone to all-volatile treatment with no polisher—successfully.

Some go to a backup of phosphate in case they do have a condensate conductivity issue. Others have...
EPRI says you can have 90/10 copper/nickel-tubed condensers and still get away with it. But for us, that was not the case.

So I would be interested in speaking with people who are making these AVT-O swaps, getting rid of the reducing agent. Gosh, we’re carrying 9.4, 9.5, 9.6 pH levels, which is 10 times the ammonia we used to have when we were on an AVT-R program with a copper condenser. I’m curious if anybody is having any success doing that, because it really addresses the question: Why would you not go to AVT-O? That’s two parts of ammonia and 25 or 50 ppb of dissolved oxygen, and that’s deadly.

**Chemical vendor:** I think the devil is in the details. Reading the EPRI guidelines carefully, they say that if there is a copper condenser then let’s move the pH up very slowly. The new pH range for copper, for mixed-metal systems, is 9.0 to 9.3. They suggest that if you’re adopting AVT-O, try going to 9.4 to 9.6, but monitor the copper levels in the condensate both before and after the change, and see what your system will tolerate. Copper pickup from the condenser is also going to be tied to the air or oxygen level, so it’s not necessarily a blind man’s step to a high pH. It’s a careful evaluation of what your system can tolerate.

**Independent consultant:** I disagree completely. There is a large trend, and it’s a continuing trend over the last decade, of getting cleaner and cleaner in the evaporator sections until you can’t get any cleaner because something stops you—whether that’s air in-leakage or condenser contamination from the circulating water. If you’re on a cooling tower and chlorides and sulfates start butting up against your controls, then you have to start putting some sort of buffering chemistry in there. In the entire loop, both high and intermediate pressure (HP, IP), AVT is becoming a very viable process.

I’m concerned about the recommendation to summarily removing oxygen scavenger from non-ferrous systems. Just like some others here, I came back from a conference all ‘hot-to-trot’ about knocking out the scavenger/reducing agent, in a unit with a copper condenser, and it ate our lunch in a heartbeat. EPRI says that’s not supposed to happen.

EPRI says that’s not supposed to happen.
New technologies to facilitate HRSG tube repair

The most common location for leaks to occur in HRSGs is at tube-to-header welds. Sometimes, the leak will be in the front or rear tube row of a module, along a lower header, and quite accessible for repair. More often, however, the leak is located in a tube row in the interior of a module, and is therefore extremely difficult to access. To reach the leak, many undamaged tubes must be removed and replaced—a process often described as “cutting your way in and welding your way out.” Not only is this time-consuming and expensive, but it often leads to future failures of the tubes that had to be disturbed for access.

Another repair method sometimes used on inaccessible tube-to-header welds is to cut a window in the back side of the header, on each end of the failed tube, and then weld a plug into the tube opening—a process of abandoning the tube in place. Most HRSG coils can handle a few abandoned tubes without serious thermal performance impact, but there is a limit to how many times this method can be applied.

**Tube-to-header leaks**

In his presentation at the 2006 HRSG User’s Group meeting, David Gandy, senior project manager for materials and repair, EPRI, Palo Alto, Calif, described new, specialized tooling that can improve on these traditional methods. The new tooling allows removal and replacement of the leaking weld using field machining tools and a remote welding device. The new tools gain access to the damaged area via a precisely machined window cut into the back side of the header.

The proprietary process and specialized tooling was developed for EPRI by Encompass Machines Inc, Rock Hill, SC. Like tube plugging, discussed above, this technique avoids the need to cut and replace many otherwise good tubes. It offers the added advantages that it leaves the repaired tube in-service—hence no reduction in HRSG thermal performance—and it requires only a window weld in the header adjacent to the leak—not in the headers on both ends.

According to Gandy, the new equipment provides precise control of tube and tooling alignment via a precision base-plate strapped to the header, and mandrels to provide close tolerance weld fit-up and high quality full-penetration welds. The result, Gandy reported, is considered a permanent repair.

Here’s the process: The header window and the internal header weld prep are precisely and rapidly cut using specially shaped carbon electrodes, and electrical discharge machining (EDM) technology (Fig A). Next, a precisely measured length of the original tubing (containing the crack) along with the original tube-to-header weld is removed by remote machining through the header window. A custom-machined replacement “oversize” tapered stub is then pressed into the header, and remotely welded on each end, to the tube and header respectively (Fig B). All tube and stub welding is automated, and performed from the inside. Finally, the header window is manually welded back into place, and any

failure mechanisms in HRSGs has been over-feed of phosphate, because of hideout, that causes acid-phosphate attack. This is a critical issue to consider if you want to move into AVT-O. If you have an all-steel system, there’s no problem. If you have a system with a copper-alloy condenser, then you must consider the earlier comments by my colleague.

Chairman Anderson: Are there any users here who are using AVT in their evaporators? If so, can you share with us why you are, and how that program is working out for you?

User: Yes, we’ve switched to AVT and only using ammonia. One of the big reasons we could make the switch is because we’re air-cooled. We don’t have a cooling tower, so we avoid the issues that come with it. It’s been three years since we made the switch. We find it easier and more cost-effective to control pH. We no longer use any other chemicals regularly; however, occasionally we’ll use caustic for additional pH support on the drums—if we start getting high on the condensate. Copper transport is not an issue for us. And we have been seeing steadily decreasing iron.

We’re now six years old, and originally we had a lot of iron transport when the air-cooled condenser was breaking in. I don’t know how much of our decrease in iron can be attributed to the switch to AVT, and how much is attributed to the air-cooled condenser finally getting passivated. Regarding dissolved oxygen in the feedwater: We’re real close to 10. We’ve got the deaerator working quite well. I’ve heard a lot of people talking about demin makeup. Sometimes
Leaks along the tube length

When water chemistry is not managed well, under-deposit corrosion can cause tube leaks along a tube’s length—rather than at the more common tube-to-header weld. If located some distance from a header, the leaks cannot be repaired using the tooling described above, Gandy pointed out. In these cases, traditional tube plugging or “cutting in/welding out” probably are the only options.

But Gandy described to the group another recent innovation that might be useful for some of these leaks along the tube length. Like the technology described in the first half of his presentation, this technique also was developed for EPRI, this time by Carolina Energy Solutions, Rock Hill, SC. It requires removing a precisely measured length of original tubing via conventional non-flame cutting methods. The tube ends are then prepped and a prefabricated replacement section is installed.

Why is that innovative? Because the welding is performed remotely from the inside of the tube, typically in only one pass per end. This is accomplished using new remote welding tooling through a precisely machined oval window in the replacement tube’s wall. Once the tube ends are welded and inspected (both inside and out), a precision-machined section of tube material is manually welded into the window opening.

This is considered a permanent repair, Gandy reported, since the carefully controlled geometry of the window produces no large stress concentrations—as are often found in field-fabricated window welds. According to the supplier, use of this technique is faster than conventional external tube welding, and it provides welds of superior quality. It has the minor disadvantage, Gandy conceded, that tube sections of appropriate dimensions and materials must be prefabricated with the oval window and window closure plug.

Although the technique was developed for use in fossil boilers, Gandy expects it to find use in HRSGs where access for conventional welding to the back and sides of tubing is limited by the close spacing of adjacent tubes. It also may be put to good use in quickly and reliably removing tube samples for determination of when to chemically clean an HRSG. Premachined tube sections, the remote welding equipment, or turnkey field service using this technique is available from Aggressive Tooling described above, Gandy pointed out. In these cases, traditional tube plugging or “cutting in/welding out” probably are the only options.

The supplier provides tooling and trained technicians as a contract service for EPRI members and non-members alike.

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We have some tube leaks and the condensate dissolved oxygen will be high. We’ve got a pretty tight HRSG, I think right now we’re down to the 20s or so. Ammonia level at condenser discharge: I don’t have any idea right now. Chemistry savings: Obviously we’ve had some, because the chemicals are a lot cheaper. And it’s easier for the operators to test the chemistry. I don’t know if we’ve had more tube leaks, or fewer, directly related to the AVT switch. Regarding the oxide layer: It’s kind of red in the drums, and it’s black in the air-cooled condenser and LP turbine exhaust.

Chairman Anderson: Thanks. It’s very helpful to hear directly from users with their experience on this, particularly since you’re out there at the leading edge of the technology.

Those interested in learning more about transitioning away from phosphate treatment to other chemistry programs, as well as what the latest guidelines are for phosphate programs, should consider attending the HRSG UG’s upcoming Steam Plant Workshop, where a full day will be dedicated to presentations and discussion of water chemistry (see sidebar, p 40).

Confounding controls questions

Control systems was the third of 10 Open Forum Discussions in Colorado Springs. Several users reported difficulty in controlling superheater and reheater outlet temperatures while at low loads—particularly with HRSGs operating behind a 7FA gas turbine (GE Energy, Atlanta).

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Risks to HRSGs in low-load operation

Many of today’s combined-cycle plants are compelled by market demands to shut down and restart frequently—whether the plant was designed to do so or not. These repeated start/stop cycles, as readers of the COMBINED CYCLE Journal and attendees of HRSG User’s Group conferences have come to understand, imposes substantial wear-and-tear on heat-recovery steam generators.

But market demands also are forcing many plants to spend long periods operating at low loads. At the 2006 conference, Scott Wambeke, systems engineer for HRST Inc, Eden Prairie, Minn, (swambeke@hrstinc.com) discussed the less well-known risks of this low-load operating mode. For purposes of his presentation, Wambeke defined low-load as being below 80% of base load, although some gas turbines (GTs) permit operation as low as 30% of the nameplate rating. There is a long list of potential steam-plant problems caused by low-load operations, not all of which are intuitive. While Wambeke focused on the first four of these, he listed the many potential low-load problems as:

- **Economizer and preheater fatigue.**
- **Desuperheater overspray.**
- **Failure of non-pressure parts—such as perforated plates, turning vanes, liners, and baffles.**
- **Operation below the design base-pressure** (also called floor pressure).
- **Insufficient catalyst temperatures.**
- **Elevated cold reheat temperatures.**
- **Control valve throttling.**
- **Economizer steaming.**
- **Off-design duct firing.**
- **Vibration.**
- **Water chemistry.**

**Economizer and preheater fatigue** can occur during low-load operation if feedwater flow instability exists. Flow instability causes some tubes to fluctuate in temperature relative to their neighboring tubes. The resulting differential thermal expansion between these tubes—which in many horizontal HRSGs are restrained between rigid top and bottom headers—produces the stress necessary for fatigue (Fig A).

All types of economizer/preheater panels (multiple row, single row, and return bend) are susceptible to this condition. Wambeke’s case in point: A feedwater preheater that was suffering repeated tube leaks at specific tube-to-header welds. A study performed by HRST indicated that low water velocities were occurring when the unit was operating at low load, resulting in flow instability (Fig B), hence differential thermal expansion. The solution? HRST worked with the client to modify the internal header flow baffles in such a way as to increase flow in the affected tubes.

Desuperheater overspray occurs when more cooling water is sprayed into the steam flow than can be completely vaporized. When the resulting steam/water mixture enters the superheater panel, the heavier water droplets take a straight path into those tubes directly opposite the panel’s inlet nozzle, while dry steam makes the turn and enters the other tubes. The tubes receiving the “wet steam” are quenched significantly and therefore experience significant tensile stresses, compared to the other tubes. The tensile stresses can be so significant that these tubes often are found elongated and warped out of position during visual inspections of HRSG internals. In severe cases, these tubes can be cracked and/or pulled away from the header.

What does low-load operation have to do with desuperheater overspray? As GT load is decreased, Wambeke explained, steam flow through the superheaters and reheaters also decreases. Depending on the exhaust profile from the GT, this may shift heat absorption in the HRSG to favor the superheaters and reheaters. At the same time, reduced steam velocities around the desuperheater may result in a less-than-optimal mixing environment for the steam and water.

Making matters worse, some GTs—notably the 7FA (GE Energy, Atlanta)—actually produce higher exhaust-gas temperatures at low load than at base load. The result is that very high desuperheater spray-water flow is needed (to prevent exceeding design steam temperatures) at a time when spray-nozzle performance is probably degraded.

How can you tell if your HRSG is experiencing desuperheater overspray? Wambeke pointed out that one obvious indication is superheater or reheater tube failures near the header inlet nozzles. Warped tubes can be another indication, but thorough investigation may be necessary to eliminate other possible sources of tube warping. If the steam temperature downstream of your desuperheater has less than 35 deg F residual superheat, you probably have high risk of an overspray condition. Likewise, if the desuperheater is installed near upstream or downstream pipe bends, you probably have poorly mixed and poorly vaporized spray and overspray-like symptoms (Fig C).

What to do? Depending on the situation, here are a few possible options that Wambeke presented:

- **Modify steam piping around the desuperheater.**
- **Install a different style desuperheater less prone to performance loss during low steam flow periods.**
Modify superheaters to reduce heat pickup.

Install a steam bypass around the superheater.

Investigate if higher superheater outlet steam temperature is permissible without causing other problems to piping, steam turbine, etc.

Reduce GT exhaust temperature.

**Look at non-pressure parts, too**

Pressure parts are not the only components that can take a beating during low-load operation, as Wambeke’s presentation made clear. Reduction in exhaust-gas flow and changes in exhaust-gas temperature patterns occur, when moving from base- to low-load operation. This can cause non-pressure parts in the exhaust-gas stream—such as perforated plates, turning vanes, liner systems, and tube supports—to overheat or experience unanticipated vibrations (Fig D). It also can degrade duct-burner and catalyst performance.

Sometimes simple fixes such as stiffening components and adding supports can solve these problems. In other cases, it may be necessary to replace components with improved designs or better materials. Problems with duct- burner and catalyst performance may require physical or CFD (computational fluid dynamics) modeling of gas-flow profiles before effective modifications can be made.

**How low can you go?**

Many of today’s combined-cycle plants operate in “sliding pressure” mode. This means that as GT load is reduced, the steam turbine’s inlet...
valves are left wide open (for maximum thermal efficiency), resulting in lower HRSG steam pressures. As steam pressure falls, water and steam densities decrease and their velocities increase. Eventually, as Wambeke explained, a point is reached where further increase in steam/water velocities will cause carryover of water into the superheater or water-side erosion of evaporator tubes and risers.

Realize too that when evaporator pressure drops, so does evaporator temperature—as the Mollier Diagram illustrates for saturated steam conditions. Because the evaporator temperature sets the exhaust-gas temperature entering the catalyst, and because the catalyst has a minimum operating temperature, there is a minimum evaporator pressure below which the catalyst will not function properly (Fig E).

When the first of these lower pressure limits is reached, the boiler is said to be at its “basement” or “floor” pressure. Unfortunately, significant operating time at low load often was not anticipated by the OEM, Wambeke said, and many HRSGs were designed with relatively high floor-pressure limits.

Some possible solutions if too high a floor pressure limits your ability to operate at low load? Increase...

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The issue stems from thermodynamic fundamentals. While at high loads, steam pressure and mass flow are high, and GT exhaust temperature is conducive to desired steam conditions. At low loads, steam pressure is lower (at least for units operating on sliding-pressure control) as is steam mass flow. However, GT exhaust temperature actually is much higher. This apparent paradox is a design characteristic of advanced gas turbines—particularly evident on the 7FA—that is required to maintain turbine—particularly evident on the 7FA—that is required to maintain flame stability in the combustor.

Unfortunately, many users report that at low loads they are not able to cool the steam sufficiently using their interstage attemperators without creating an “overspray” condition where some spray water fails to vaporize. Overspray conditions create very severe thermal stresses and fatigue damage in piping, headers, and tubing.

A lengthy discussion ensued about turndown ratios, valve trim, soft...
ing the catalyst temperature without increasing the evaporator pressure is difficult. Throttling the steam-turbine inlet valves can raise HRSG evaporator pressures at the cost of some ST efficiency. Consider checking with the HRSG OEM or a qualified consultant for evaluation of your unit’s evaporator circulation and possible modifications to mitigate the problem.

Wambeke also pointed out that operating in sliding-pressure mode and at low load can exacerbate flow-accelerated corrosion (FAC), because FAC tends to increase at temperatures around 300°F. If this pertains to your plant, you should have a program in place to monitor the highest risk areas. (Note that all HRSG users should have an FAC monitoring program covering their entire steam plant, even if they never operate at low load.)

Another component that takes a beating at low operating pressure is the feedwater control valves when used with fixed-speed boiler feedwater pumps. In this situation, the control valves experience enormous pressure drop across their control surfaces for extended periods of time. Wambeke suggested that a second “low-flow” feedwater control valve may need to be installed, to mitigate this problem.

- Use electric heating pads to warm the HP drum before GT startup.
- Full automation of total plant startup.
- Careful integration of all plant equipment and systems.
- Better access for pressure-part inspection and maintenance.
- Keep the difference in size between tubes and headers as small as possible.
- Allow sufficient time in the project schedule for the HRSG designer to do a proper job.
- Specify a once-through, Benson-type boiler rather than a drum-type unit.

**Taking it home**

During the two days of Open Forum Discussions, many more in-depth and valuable deliberations transpired, covering the seven remaining categories: piping systems; ductwork; dampers, and stacks; valves; supplementary firing; environmental systems; and balance of plant (BOP). Many questions were asked, and many solutions identified. Still other questions were raised that require either more time than a conference allows, or more study and analysis by both the user and the supplier communities.

One thing seemed clear: The hundreds of users and suppliers who come together each year at the HRSG UG conference to share their knowledge, experience, problems, and solutions will continue to drive the industry forward. As Chairman Anderson (Fig 4) reminded the crowd at the event’s conclusion, “This format works because of the people that attend and openly contribute to the discussions. No matter what your level of experience, we hope you leave each conference with more than you brought.”

**Pre-conf seminar debut**

This year the HRSG UG added something new to its annual conference: a one-day technical seminar held the day prior to the event’s official start. “Damage Mechanisms in Combined-Cycle Plants” was attended by 80 power professionals and conducted by European Technology Development (ETD). The Surrey, UK-based firm is an engineering advisory, consulting, and R&D company specializing in plant life extension, maintenance, materials, and engineering issues in all types of power generating and process plants.

In addition to conducting the pre-conference seminar in Colorado, ETD has organized numerous workshops, training courses, and conferences in Europe and Asia. The seminar was led by Tony Lant, ETD’s plant services manager, who covered such damage mechanisms as:
- Creep.
- Fatigue.
- Thermal fatigue.
- Acid dewpoint corrosion (Fig 5).
- Flow-accelerated corrosion.
- Stress corrosion cracking.
- Corrosion fatigue.

Lant also discussed drivers in HRSG design, thermodynamic considerations in design, HRSG tubing and panels, welding in HRSG fabrication, and issues for cycling operation. Following are a few excerpts from the seminar:

1. **Ever wonder why** HRSGs are so much larger than fossil-fired boilers of similar capacity? Seminar attendees now know. As Lant explained:

   *Temperature differences—between furnace and flue gas, and between water and steam—are much lower in HRSGs. This makes heat-transfer rates in HRSGs low, relative to conventional boilers. Low temperature differences in HRSGs—between the exhaust gas and the steam/water mixtures—require the use of finned tubes, and lots of them. Not all HRSGs use all of the features for maximum heat-transfer efficiency. Tradeoffs are often necessary. For example, tight tube pitch with a staggered arrangement may not be appropriate for the cold end of HRSGs that burn oil or are equipped with an SCR.*

   *Gas-turbine exhaust contains 100 to 200% excess air. This is because of the need to air-cool hot parts in the combustion system and hot gas path, to avoid overheating of GT components. This high excess-air content of the exhaust gas results in stack losses that are two to three times higher than in a conventional boiler. In addition, flue-gas flow through an*
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Safety/relief valves: Installation, maintenance, testing

Like all high-pressure boilers, HRSGs are required by the ASME Boiler & Pressure Vessel Code (Code) to employ a variety of safety valves (covered in Section I) and relief valves (Section VIII) to prevent overpressure operation and eliminate the risk of explosion. In fact, because of their multiple pressure levels and greater complexity, HRSGs typically will have many more safety/relief valves than conventional fossil boilers.

Note: While the terms often are thought of as interchangeable, a “safety valve” is a pressure-relief device characterized by rapid and full opening (or “pop action”) at its setpoint. By contrast, a “relief valve” is a device that opens in proportion to the increase in pressure that exceeds its setpoint.

Both types of valves have a long track record of reliable performance and often are considered “simple devices.” But they still require careful attention to installation details, as well as recurring maintenance and testing, if safe, reliable performance is to be attained (Fig A). In his presentation to the 2006 HRSG User’s Group conference, Robert Pabst, a valve design/maintenance consultant for Movaco Inc, Bradenton, Fla (bobmovaco@aol.com), provided a useful summary of those details and reminded users of the ongoing valve work they need to accomplish in their maintenance programs.

Start with drains, vents

Pabst began with a review of the vent and drain subsystems so important to pressure-relief valve operation. For example, rainwater and condensation routinely collect in the valve body, discharge elbow, drip pan, vent piping/stack, and silencer. If the small-bore, carbon-steel drain piping that removes this water is not installed correctly or is allowed to plug with rust and debris, you can count on expensive, and possibly dangerous, system damage (Fig B).

Water left standing in vent piping or silencers also will, if the valve lifts, immediately flash to steam. This, in turn, can cause backpressure fluctuations conducive to shortened blowdown cycles, irregular valve behavior, water hammer, and internal damage to the valve, piping, and silencers. Pabst said, “Incidents of shrapnel being ejected from the silencers are not uncommon.” Even if the valve is never forced to lift, standing water in the valve body is certain to cause corrosion damage to valve internals, altering the valve’s operation—if not entirely preventing it.

Another potential problem arises if the drains from the pressure-relief system are routed to locations that restrict flow or otherwise cause the drains to pressurize—such as improper tie-ins to other piping systems. Improper tie-ins to pressurized systems have prevented safety valves from lifting at their setpoint, Pabst reported, resulting in catastrophic plant damage.

Here’s another all-too-common installation mistake that Pabst has seen: Many safety valves have a small-bore vent connection on the body cap. This vent is supposed to be piped to a safe location where escaping steam during valve operation will not restrict flow or otherwise create backpressure. Pabst has sometimes seen this vent incorrectly piped into the valve’s drain system. When this occurs, undesirable backpressure and improper valve operation is sure to follow.

Pabst recommended that plant personnel include drain-line inspections as part of each of their regulatory-mandated valve tests and repair tasks. Check to ensure that no alternative source of pressure can be introduced into the drain system, and that vent cap ports are vented to atmosphere using very short runs of pipe—just enough, he said, for personnel protection as the short burst of steam vents during a lift.

The manufacturer’s manual is an excellent reference for both drain-line installation and inspection. Where drain pipe is hard-plumbed into the valve, Pabst urged users to install a pipe union at the first avail-

A. Maintenance and testing of safety/relief valves should be essential elements of any combined-cycle or cogeneration plant’s O&M program. These pressure-relief devices protect the vital investment of the facility.
Valve installation

Pabst also had a lot to say about the selection and installation of the valves themselves. For example, when pilot-operated safety valves are used in high-temperature applications, a heat exchanger on the pilot sensing line should be incorporated to protect vital O-rings and seals inside the valve. Such heat exchangers, Pabst reported, often are omitted from the initial design of combined-cycle/cogen plants.

When backpressures are known to exist that could shorten the blowdown, Pabst advised that a bellows-type safety valve should be used (Fig C). A typical application in a combined-cycle plant is on the cold reheat steam system, if the valves discharge into a single or combined silencer.

He also said that if any of your pressure-relief valves require frequent, repetitive maintenance, then your existing valve probably is not suitable for the given application. A user in the audience brought up just such an example. Only a month after initial commissioning, both of his hot reheat safety valves started leaking. One was chattering noticeably, before the spring and stem broke.

Pabst suspected that these valves were incorrectly specified because they’re operating too close to their set pressure. “Go back and look at your system pressures at the time the chattering happened,” he responded, “and see if your safety valve setpoint is within 20% of that margin. If it is, you need to think about going to a different type of valve, or raising the setpoint. You can do that within the Code, but you have to check with the boiler manufacturer and go through some hoops.”

A final installation tip that Pabst covered deals with initial quality control. This year the National Board of Boiler & Pressure Vessel Inspectors, Columbus, Ohio, will publish some new rules concerning QC, he reported. At issue is that some Section I safety valves are designed with capacities greater than that of the manufacturers’ boiler capabilities for flow testing and cannot be tested for capacity blowdown. Set pressures are checked at the manufacturer.

Manufacturers normally cannot ship a new valve without flow testing and still comply with the Code, but the National Board has given suppliers allowance for this constraint. A typical allowance is a sign-off check sheet from the manufacturer notifying the end user that capacity blowdown cannot be tested and that an alternative means of setting the blowdown will be done. Pabst made HRSG users aware that if they want to test for full blowdown, they must do so after installation at the plant site.

Valve maintenance, testing

Developing and executing a safety/relief valve maintenance program compliant with all codes and regulations is important for all powerplants. Pabst offered the following suggestions for such a program:

Determine the code that applies to each of your valves. A “V” stamp on the ASME nameplate indicates Section I applies. A “UV” stamp on the plate indicates Section VIII applies. A “V” stamp on the ASME nameplate indicates Section I applies. A “UV” stamp on the plate indicates Section VIII applies.

Define maintenance intervals for each valve based on the most restrictive requirements among the National Board, local jurisdictions, and your insurance carrier.

Typically, an annual pressure set test is required for all Section I safety valves.
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valves. This should be done just prior to your annual outage, Pabst said, so that if any valve fails to reseat during the test can be repaired during the upcoming outage.

Typically, pressure set testing for Section VIII relief valves is required on a three-year interval. This requires that some valves be removed from the system and tested at a qualified test and repair facility. Smaller relief valves should simply be replaced. Pabst noted, because the cost of testing them might exceed their replacement cost.

Typically, Section I safety valves must undergo teardown and internal inspection every six years. This must be performed by a technician from a VR stamp-holding repair facility. During such teardown and inspection, certain components must have critical dimensions checked and recorded, and any found to be out-of-tolerance must be either replaced or machined. Which components require this scrutiny is determined by the manufacturer for each model of safety valve. After completing inspection and reassembly, the safety valve also must be set-pressure tested either at the qualified shop or on the owner’s equipment.

If set pressure testing is performed using plant steam pressure, plant load must be held steady between 80 and 90% of the full-load rating. Sometimes this is difficult to accomplish on intermediate- and low-pressure (IP and LP) systems in multi-pressure HRSGs.

Therefore, Pabst suggested that electronic valve testing equipment—such as that supplied by AVK Industries Inc., Jacksonville—be used for on-boiler valve set-point testing. A certified test report is required for each valve. A warning from Pabst: When performing on-boiler setpoint testing, an accurate reading of the steam pressure at the valve is required. Normal DCS pressure readouts, even when recently calibrated, may not give sufficiently accurate pressure at the safety valve’s location. “Best practice” involves installing a pressure tap near the safety valve for temporary use during testing.

New designs on the horizon

As an excellent supplement to Pabst’s presentation, Jorgen Gertz, now marketing manager for North American Power Products at Valvtechnologies Inc. (jgerz@valv.com), presented information on very recent developments that could change the type of safety valves allowed for use on Section I boilers.

The basic design of the direct spring-operated safety valve, Gertz pointed out, has been around almost as long as boilers themselves. Currently, Section I of the Code permits only this type of safety valve. While this has been the case for many years and has worked well for conventional boilers, the wider range of operating pressures of today’s more complex HRSGs can tax the simple action of the direct spring-operated safety valve.

Section VIII of the Code, which addresses relief valves, allows the use of pilot-operated valves and direct spring-operated with power actuator safety relief valves, in addition to the traditional direct spring-operated valve.

Gertz and other valve professionals are working within the ASME to modify the Code to allow the use of alternative safety valve designs on Section I applications. This has already been accomplished to some extent, Gertz reported, via Code Case 2446 which permits the use of pilot-operated safety relief valves on Section I economizers. Benefits of this change, according to Gertz, include:

- Improved seat tightness.
- System can operate closer to set pressure.
- Stable operation in multi-phase flow.
- Ability to modulate.
- Can handle higher backpressure.
- In-situ setpoint verification without lifting main valve.

Gertz anticipates that the next change will be expansion of the scope of Code Case 2446 to permit the use of pilot-operated safety valves for all Section I boilers.

‘Support group’ for HRSG users

The 14th annual conference was supported by representatives of 74 suppliers of combined-cycle equipment and/or suppliers who participated in more than just the event’s trade show. In contrast to many user events, which restrict suppliers to the expo hall only, all HRSG UG conference sessions are open to all industry participants—including manufacturers, EPC contractors, water-treatment suppliers, engineering consultants, insurance carriers, and so on. CCJ
"There is no better single source of information on the topic of HRSGs! Typically a book of this nature is full of theory, with a few practical experiences interjected as examples. However, the HRSG Users Handbook is a compendium of experience-based knowledge, supported by theory. It has become an essential tool in our control room, and is a great reference during outage planning discussions at our site."

Terry Toland, Facility Manager
GE Contractual Services - River Road Generating Plant

"We found the HRSG Users Handbook to be very useful for our plant engineers. The book covers all aspects of O&M issues, and provides excellent guidance to the operating engineers. It's compact, easy to read, and easy to understand."

Lenin Vadlamudi, Planning Engineer
TransAlta Energy Corp

"This book is written with practical application in mind. The topics are definitive to daily operations and maintenance issues. There was sufficient interest from operators, maintenance, and management personnel, after reviewing the book, that we purchased multiple copies for each of our sites."

Charles Dameron, Resource Manager
Duke Energy - Combined Cycle Non-Regulated Fleet

"HRSG Users Handbook should be required reading for all who manage or operate a GT-based combined-cycle or cogeneration plant. It's a foundation upon which all users can build more reliable and efficient generating facilities."

Bob Schwieger, Editor and Publisher
Combined Cycle Journal

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