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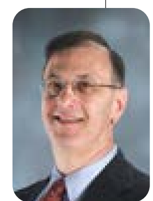
Chemical Processing (ISSN 0009-2630) is published monthly by Putman Media Inc.,1501 E. Woodfield Road, Suite 400N, Schaumburg, IL 60173. Phone (630) 467-1300. Fax (630) 467-1120. Periodicals postage paid at Schaumburg, IL, and additional mailing offices. Postmaster: Please send change of address to Putman Media, PO Box 1888, Cedar Rapids IA 52406-1888; 1-800-553-8878 ext. 5020. SUBSCRIPTIONS: Qualified reader subscriptions are accepted from operating management in the chemical processing industries at no charge. To apply for a free subscription, email putman@stamats.com. To nonqualified subscribers in the United States, subscriptions are $68 per year. Single copies are $15. Canadian and other international annual subscriptions are accepted at $200 Airmail. Single copies are $16. Canada Post International Publications Mail Product Sales Agreement No. 40028661. Canadian Mail Distributor information: Frontier/BWI, PO Box 1051, Fort Erie, Ontario, Canada, L2A 5N8. REPRINTS: Reprints are available on a custom basis. For price quotation, contact Foster Reprints, (866) 879-9144, www.fostereprints.com. Putman Media Inc. also publishes Control, Control Design, Food Processing, The Journal, Pharma Manufacturing™, Plant Services and Smart Industry. Chemical Processing assumes no responsibility for validity of claims in items reported.

Report Dives into Water Security

Several key points emerge from the record number of responses



Water security efforts can provide substantial benefits to companies.

THE LATEST water report from CDP, London, details progress but also stresses the need for ambitious action. "A Wave of Change — The role of companies in building a water-secure world," released in early March, summarizes information gathered from 2,934 companies worldwide that filled out the organization's water security questionnaire in 2020 — about a 20% uptick in responses compared to 2019.

The organization, which acts on behalf of 515 investors worth over $106 trillion, emphasizes that the private sector must play a crucial role in building worldwide water security.

CDP draws several key conclusions from the companies' questionnaires:

• The cost of inaction is five times greater than that of action. The firms risk more than $300 billion in business value against an estimated $55 billion cost to improve and innovate around water use.

• Business models must fully integrate water into strategies and ensure accountability for water targets at the highest level. The report cites a number of companies, such as BASF, transforming their approaches. The Ludwigshafen, Germany, chemicals maker notes: "Using CDP's water questionnaire as a framework has helped us improve our comprehensive water-management strategy to mitigate water-related risks and capitalize on opportunities." This has spurred development of sustainable "Accelerator" products. The report devotes a full page to the company's efforts. (For details on the diverse financial approaches for sustainability efforts taken by some chemical companies, including BASF, with CDP's top ranking for water security, see "Water Accounting Remains Fluid," https://bit.ly/3duY9QE.)

• Nearly two in three companies are reducing or maintaining water withdrawals. The 64% of firms reporting such results is up from 58% in 2019. Another, related key performance indicator (KPI) also rose: 64% of companies said they factor in water availability at a basin/catchment level into water risk assessments versus 48% last time. Likewise, 38% of companies reported using climate-related scenario analysis to inform their business strategy, up from 33% in 2019. Six other KPIs for water security didn't budge much if at all.

• Only 4.4% of the firms are making progress on their water-pollution-reduction targets.

Cate Lamb, global director of water security at CDP, notes: "With a clear business case for taking action on water risks, we hope this report inspires companies across all sectors to be part of this vision and place water at the heart of your business strategy — enabling you to not only build resilience but also unlock strategic opportunities..."

She adds: "...CDP is calling for all companies to develop ambitious targets to reduce water withdrawals and eliminate water pollution, including net-zero water targets. Companies must take bold action now to transform their business models."

The benefits are substantial, Lamb underscores. "Companies that transform their businesses and work to safeguard valuable water resources have the potential to achieve both short- and long-term cost savings, sustainable revenue generation, and a more resilient future."

You can download the 2020 report at http://bit.ly/3bhWjl1.

By the way, in the latest *CP* poll, p. 10, almost half of respondents report their sites have increased attention to water resources in the past three years. ●

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Don't Fall for Flowability Myths

Some widely accepted ideas aren't supported by real-world performance

Simpler often is better when looking at flowability of solids.

FLOWABILITY TESTING is expensive, as I mentioned in my November 2017 column ("Conduct Flowability Tests," https://bit.ly/3sVSVD4), but usually pays off in the long run. That being said, in certain situations some simple tests or observations could give results almost as good as an expensive series of evaluations. In that earlier column, I hinted at one case where you could avoid tests when the particle size distribution (PSD) shifted to a larger size. You might wonder how I knew the larger PSD would behave that way. It's because I understood how flowability testing is conducted: large particles are screened from the samples prior to testing.

A little education goes a long way. It's important to fully understand not only how to apply the results of a test but also how they were obtained. Here, for instance, the testing firm may not want to speculate on how the large particles will change flowability. It is possible they may bring moisture into the mix and make the mixture sticky. Fortunately, that's easy to determine without the flowability tests.

A lot of myths about flowability have predominated in solids processing. My favorite is that you can find out how flowable a material is by looking at the angle of repose. First, we must understand what angle of repose is and how it's determined. If you pour beach sand through a funnel, the slope angle of the pile will be about 35–45°, depending on which beach the sand came from and how you run the test. Keeping the tip of the funnel at the top of the pile as the sand is poured will give a higher angle than if you have a large drop distance. Other common methods of getting angle of repose are to use a tilting box or a rolling cylinder (see Wikipedia: https://bit.ly/3dB9q0L); these can give a different angle than that found with a funnel. However, simply using a funnel can provide a handy way to compare an existing material and a new one destined for the same equipment. A significant difference in angle would suggest performing shear testing; its modest cost may prevent expensive production problems in the future.

Another common myth in solids processing is that fluidized solids flow like water. This is correct as long as the solids stay in motion. De-aeration can kill this flow and result in pluggage and segregation. A corollary to this myth is that vibration increases flowability. In fact, vibration often compacts the solids.

Fluidized beds frequently are blamed for attrition — but this is another myth. While particle/particle contact is the main source of attrition and fluidization has a lot of this contact, finer particles take more energy than large particles to break. Also, the fines can act as cushions to breakage. A particulate distribution that follows a Fibonacci sequence is a classic example of this cushioning.

From the early days of pneumatic conveying, the use of long-radius elbows was considered the best way to reduce attrition and pressure drop. This seems logical because the particles would make the turn at a lesser angle and a lower velocity. However, detailed testing of various configurations has shown that particles bounce rather than slide and that dense flow reduces the attrition. One of my plants handled a very abrasive solid and was wearing out long-radius elbows every three months. It switched to short-radius elbows; these lasted only a few more months but were easier to replace and incurred a lower pressure drop. Attrition was insignificant on the product. Another plant welded a plate over a hole generated by abrasion; eventually the abrasion stopped — probably because of cushioning from the dense pocket of solids. Today, a lot of plants use T-elbows or a variation of short-radius elbows to avoid either particle attrition or elbow wear.

Fluidization can be a friend or foe when it comes to blending. In my November 2016 column ("Beware of Blending Myths," http://bit.ly/34mdQTi), I described the effect of blending time on uniformity. In the example, friction on the particles induced a charge that made the blend less uniform as blend time increased. The style of blender makes a big difference in the amount of aerated and dense material, which can influence the extent of fluidization or flowability. Remember that simpler often is better when looking at flowability of solids. ●

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EXPLORE ISSUES POSED BY SOLIDS

Check out previous Solid Advice columns online at www.ChemicalProcessing.com/voices/solid-advice/. Find out the questions others have had about solids processing — and the answers to them — and pose your own questions by visiting www.ChemicalProcessing.com/experts/solids-processing/.

Intelligently Edit P&IDs

Getting mechanical details right requires some knowledge of pipe construction

THE CONSTRUCTION foreman probably thought the engineer who worked up the piping and instrumentation diagram (P&ID) was an idiot. It showed a ¾-in. pipe connected to a 24-in. cooling water line with a reducer. Just imagine how that would work: the smallest reducer in a 24-in. pipe is 6-in. Then, you probably go to 3-in., followed by a reducer to 1-in., and, finally, you get to ¾-in.! I actually have seen such a monstrosity. Going with the reducers will take eight welds and require two welders the better part of a week for construction and installation. How would an old salt like me do it? Drill a hole in the 24-in. pipe and install a coupling; you can either thread it or make a socket-weld out of it.

In editing P&IDs, you should know when not to use reducers. I keep a table handy that lists the minimum-size reducers for each pipe size. This is just one shortcut in editing.

Another is identifying where flanges are missing. Far too often I have seen a pipe directly connecting to a tank or heat exchanger. For instance, I recently was editing a drawing with a molten-product storage tank. Even the general arrangement (GA) drawing for the tank showed the vessel was delivered without a flange; the nozzle schedule said "pipe." I knew better and insisted on adding a socket-welded valve with a flange when the tank was installed. Generally, though, anything smaller than 1½-in. doesn't require a flange. I have seen ½-in. flanges but they're so rare that I usually review the equipment drawings and want to see the connections for myself.

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Also, it's worth noting that thermocouples and resistance temperature detectors generally go into ½-in. thermowells. Often, these thermowells are socket-welded into vessels like distillation towers or evaporators. In rare cases, you'll see a flanged thermowell or a thermowell that's socket-welded or threaded into a flange. In pipe, the connection nearly always is a female national pipe thread (NPT) using polytetrafluoroethylene tape as filler for the threads. It's important to know the plant standards: companies like to solve a problem once and then repeat using that solution.

As for pressure connections, gauge or instrument, ½-in. is most common; the connection generally is a coupling for pipe or equipment.

Sometimes, you'll come across a larger NPT connection but you know it's threaded into a smaller pipe. Generally, a "hex bushing" is the piper's choice. So, you'll see a 1-in. coupling connected with a 1×½-in. hex bushing to a nipple and then to the bottom or back of a pressure gauge. Once you get some experience "stringing" pipe together, it's fairly easy to know how pipe should look on P&IDs. For one thing, anything beyond what I described would include a union to allow easier pipe orientation.

Missing mechanical drawings also are a common problem. If you can't find the GA drawing for one tank or vessel look for a "sister" drawing for equipment bought at the same time.

Then, there are steam systems. First of all, nearly all control valves are a variant on a globe valve; sometimes, you'll see V-port or even ordinary ball valves but, for steam and most process operations, globe valves rule. Second, if a 1-in. steam control valve regulates flow, a ½-in. steam trap probably is on the other side.

Gate valves may appear as the default symbol on P&IDs to represent valves but ball valves largely have replaced them, even in steam systems below 2-in. Some gate valves are used for smaller lines in steam but they are bulkier than ball valves and, so, have fallen out of favor.

And, then there's missing equipment. Did you ever stare at a P&ID and know it couldn't be right — like when there's no flange or expansion joint or boot between a screw conveyor and a weigh tank above. First, nobody who builds equipment forgets that it's hooked up to something else; there will be a flange. Second, how's a scale supposed to work if it's welded to the equipment around it. Expansion joints and boots are crafted elastomers that are difficult to replace; you want them on your P&ID, if only for inventory purposes.

Mechanical details are crucial on a P&ID. They are every bit as important as the instruments.

DIRK WILLARD, Contributing Editor
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Did you ever stare at a P&ID and know it couldn't be right?

Catalyst Promises Greener Styrene Production

Less-energy-intensive process also boasts higher yields

A TEAM of researchers at North Carolina State University (NCSU), Raleigh, N.C., has developed a catalyst that efficiently converts ethylbenzene to styrene with significantly higher yield and lower energy consumption. "Because it [styrene] is in such widespread use, we are pleased that we could develop a technology that is cost effective and will reduce the environmental impact of styrene manufacturing," says Fanxing Li, a chemical engineering professor at NCSU. Current styrene production reportedly emits over 27 million tons of carbon dioxide.

The multifunctional core-shell redox oxidative dehydrogenation (redox-ODH) catalyst acts as a heterogeneous catalyst, an oxygen separation agent, and a selective hydrogen combustion material. This converts ethylbenzene to styrene with up to 97% single-pass conversion and 94% selectivity, report the researchers. Conventional styrene production technologies have a single-pass yield of about 54%.

"We were able to prepare redox catalysts with a core-shell architecture using earth-abundant materials and a relatively simple preparation method," notes Li. The team also determined the underlying catalytic mechanism. "This finding allowed us to fine-tune the catalyst performance by optimizing the core and shell structures and compositions to yield even better results," he adds.

"The oxygen storage phase of the redox catalyst can be further tuned, along with improving the surface compositions, to achieve even better styrene yields by minimizing the initial less selective region under the full oxidation mode. In fact, we have developed better performing catalysts," says Li.

The conversion process temperature is similar to traditional methods at 500–600°C, however, the redox-ODH process requires no steam for a reaction to take place.

"In practical terms, this drastically reduces the amount of energy needed to perform the conversion," says Yunfei Gao, a postdoctoral scholar at NCSU and co-lead author of a paper in *Nature Communications* on the work. The new process uses 82% less energy — and reduces carbon dioxide emissions by 79%, report the researchers.

The catalyst boasts stability and robustness, exhibiting excellent long-term performance under industrially compatible conditions, they note.

In the article, the researchers write, "These findings… provide important mechanistic insights for designing effective redox catalysts for alkylbenzene conversions."

So far, we have tested 100 repeated redox-oxidative dehydrogenation (ODH) cycles. Longer-term validation is certainly desirable from an industrial application standpoint but it can be done through future studies," states Li.

"Most of our experiments used high purity ethylbenzene as the feed, but we did look at a few other alkylbenzenes. The data do not suggest that the catalyst will be deactivated by common contaminants but this certainly needs to be further investigated. It would be relatively easy to test them out, elaborates Li.

The team is interested in finding an industrial partner for scaling up the technology — for which it has received a patent.

"Scale up and long-term catalyst testing are the key challenges ...," says Li. "It may take 3–5 years for a pilot study."

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More than a quarter of respondents report a significant increase in interest.

REDOX CATALYST

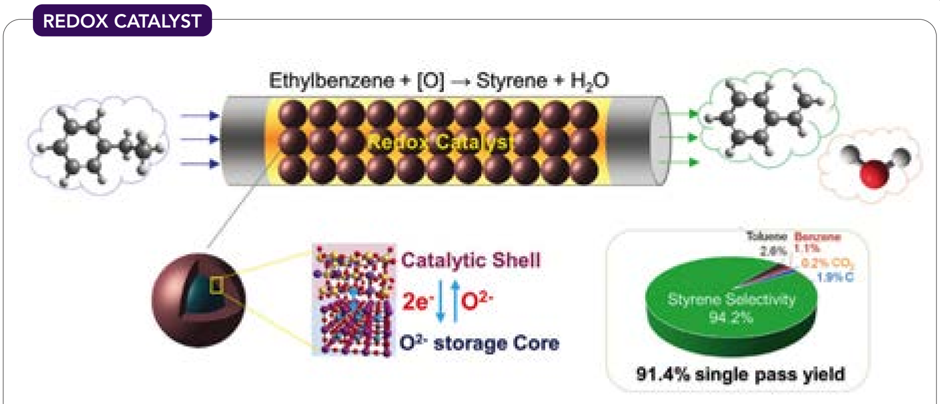


Figure 1. Researchers develop a redox-oxidative dehydrogenation scheme that converts ethylbenzene to styrene using a tailored multi-functional redox catalyst. *Source: Nature Communication.*

Waste Polyolefins Become Feedstocks

A NOVEL catalyst enables producing liquid fuels and waxes from recycled polyolefinic plastics at yields of up to 92% of useful materials, say its developers at Osaka City University (OCU), Osaka, Japan. Moreover, the heterogenous catalyst, a combination of ruthenium and cerium dioxide (Ru/CeO_2), works at 473°K rather than the 573–1,173°K required by other waste-plastic-recycling processes.

Masazumi Tamura, associate professor in the Research Center for Artificial Photosynthesis in the Advanced Research Institute for Natural Science and Technology at OCU, and Keiichi Tomishige, professor in the Graduate School of Engineering in Tohoku University, Sendai, Japan, already had found that Ru-based catalysts showed high activity and selectivity in the hydrogenolysis of single short (≤30 carbons) alkanes.

They wondered if the same catalyst would work with polyolefinic plastics.

The longer chains, different molecular weights and structures, high viscosity and poor hydrogen diffusion in such plastics hamper contact between themselves and catalysts, thus reducing reactivity.

The researchers carried out the hydrogenolysis reaction in a 190-mL stainless steel autoclave pressurized to 6 MPa with hydrogen (Figure 2). They ran trials with various polyolefins, including low-density polyethylene, high-density polyethylene and polypropylene. Yields of valuable chemicals ranged from 83–92%.

A commercial polyethylene (PE) food bag was converted to 87% C_5–C_{21} liquid fuels and 4.3% C_{22}–C_{45} waxes. Waste PEs gave the same conversion to liquid fuels but 1.6% waxes.

Describing the work in a recent issue of *Applied Catalysis B: Environmental*, the OCU team reported that the Ru/CeO_2 catalyst selectively dissociated the inner C–C bonds in polyolefins without isomerization or aromatization, which enabled the high yield of the target valuable chemicals.

Catalyst stability poses the biggest problem for reaction scale-up, states Tamura. "Waste plastics have many impurities, which can poison the catalyst."

Other potential issues he highlights are catalyst durability and cost.

"Catalysts composed of cheap metals would be ideal for the system. Therefore, developing a new catalyst system substituting for Ru-based catalysts is desirable. As for the process, a fixed-bed reactor would be ideal for the industrial process. However, feeding the waste plastics and regeneration of the catalyst will be problems."

The team already is working to improve its existing process and also is seeking the funds and extra resources needed to carry out in-depth process simulation investigations.

HIGH-PRESSURE BATCH REACTOR

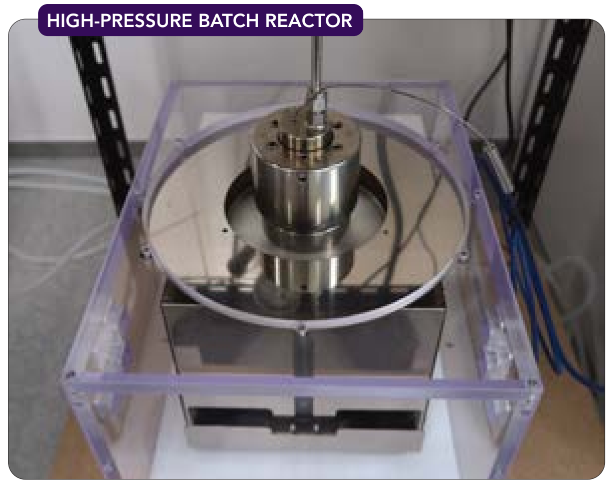
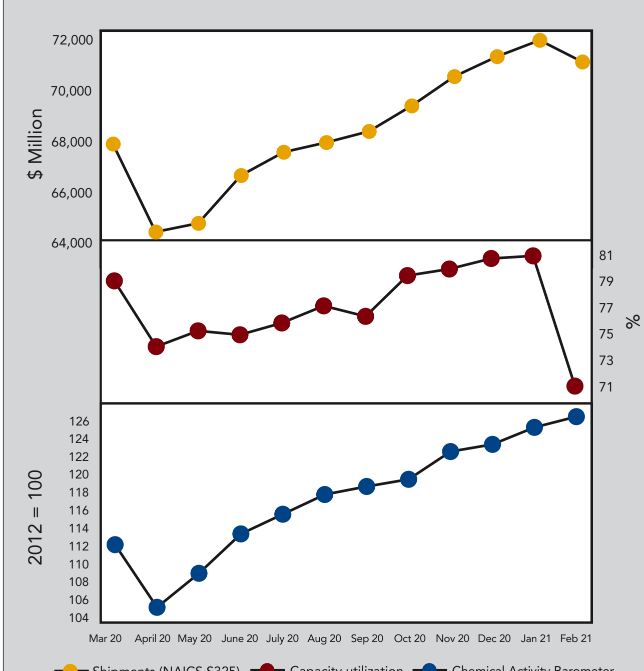


Figure 2. Reaction takes place at a lower temperature than needed by other plastics conversion processes. *Source: Osaka City University.*

"Many companies, including chemical and petroleum companies, show interest in the catalyst system, although I cannot go into details. Currently, however, the study is not supported by enough national and corporate funding," notes Tamura.

ECONOMIC SNAPSHOT



Deep freeze and electricity problems in Texas contributed to February's drop in shipments and capacity utilization. *Source: American Chemistry Council.*

Stay on Top with EnPIs

Energy performance indicators can help improve understanding of plant operations

Simple EnPIs are calculated based on a single pair of variables.

LAST MONTH we discussed one way in which the digital transformation has impacted energy management — steam/power system optimization ("Get Less Steamed Up," https://bit.ly/31UuVUN). This month we turn to another way — energy performance indicators, or EnPIs.

Key performance indicators (KPIs) have been around a long time, and typically are used for financial-based measurements and comparisons. EnPIs extend the KPI concept to energy management and serve two distinct purposes: 1) high-level business management metrics based on monthly, weekly and daily production volume; and 2) actionable indicators to improve and maintain the operation and energy efficiency of plants, processes and equipment.

A high-level EnPI typically is a statistical model or regression analysis that examines the impact of various factors on the energy intensity (energy consumption/production) of a complete plant. Simple EnPIs are calculated based on a single pair of variables — most often, energy use and production rate. However, other variables also may be important. For example, ambient temperature, multiple heat flows into and out of a process area, differing energy densities of different products, or the quality or condition of raw materials, all can influence energy intensity. Multivariable regression analysis (MVR) can flush out the relationships among these factors.

EnPIs can help compare the performance of peer plants and track improvements over time, typically on a monthly basis. This can serve a variety of purposes. One example is "measurement and verification" for projects or programs. In this application, process conditions are measured and modeled both before and after the project or program is completed. This provides a view of energy savings on a normalized basis, taking into account changes in production volume, runtime, or any other variable included in the model to see how well the project has performed. Other applications are based on performance forecasts, which can serve to support budgets or set performance targets for plant operations.

Relatively simple systems with manual data entry can be used for high-level EnPIs. For example, you can download the U.S. Department of Energy's Energy Performance Indicator Tool (EnPI) V5.1.5 at https://bit.ly/3fSpb6e; a Microsoft Excel add-in provides MVR capabilities.

However, high-level EnPIs do not provide enough insight on what's happening in the plant to enable operators to drive performance in real time. To create actionable information, you need an energy management platform that can handle more-complex requirements. Some oil refining and chemical companies have developed their own in-house platforms, and several "Energy Management Systems" are available commercially. (Note: The term "Energy Management System" also applies to the ISO 50001 energy management standard, and other programs intended to standardize practices. This terminology can cause some confusion.) Capabilities vary significantly between the various platforms, but key requirements include:

• More granular measurements within the plant. EnPIs generally are created for specific process units, systems or equipment items. These typically are the significant energy users within a plant or site.

• Shorter reporting intervals. Many plants choose a 15-min. data capture interval, which aligns with the 15-min. demand interval period most electric utilities use to calculate demand charges. At this frequency, manual data entry isn't practical. Instead, plant measurements (e.g., flows, temperatures, pressures) are obtained from transmitters at the measuring devices, or via programmable logic controllers, distributed control systems, or plant historian systems.

• Performance targets. These are commonly based on "best performance" values derived from historical data. However, in some cases, they stem from plant simulations, or are determined by other methods.

• User interface or "dashboard." This should be customized for the needs of specific users. For example, plant operators need to know in real time how the equipment under their care is performing against target. Some systems also provide online recommendations if performance doesn't meet the target. Site energy leaders and engineers may need to see strategic information that helps them drive energy efficiency across the plant. Finance and plant management personnel typically have different needs focused on longer-term trends.

The potential energy benefits are similar to those of steam/power optimizers — i.e., around 3% of total site energy cost; often added benefits accrue from improved understanding of the plant and how it performs. ●

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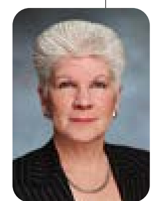
EPA Eyes Stricter Phosphogypsum Rule

Petition seeks regulatory action regarding the chemical's toxicity



IN EARLY April, a Florida pond that sits atop phosphogypsum tailings sprung a leak. State authorities scrambled to keep the pond from collapsing and flooding the surrounding area with millions of gallons of contaminated water. This situation likely wasn't top of mind on February 8, 2021, when a group of environmental protection advocates prepared and submitted to the U.S. Environmental Protection Agency (EPA) a petition under Section 21 of the Toxic Substances Control Act (TSCA). The petition seeks to reverse the EPA's 1991 "Bevill" regulatory determination excluding phosphogypsum and process wastewater from phosphoric acid production (process wastewater) from hazardous waste regulation under Subtitle C of the Resource Conservation and Recovery Act (RCRA). The timing of the Florida near-catastrophe could not be more ironic.

Section 21 allows any person to petition the EPA for the issuance, amendment, or repeal of a rule under TSCA Section 4, 6, or 8 or an order under TSCA Section 4 or 5(e) or (f). In this case, petitioners requested the EPA initiate TSCA Section 6(b) existing chemical prioritization process to designate phosphogypsum and process wastewater as "high-priority" substances for risk evaluation under TSCA Section 6. Petitioners also requested that EPA issue a TSCA Section 4 test rule for disposed phosphogypsum as well as a significant new use rule (SNUR) under TSCA Section 5 for phosphogypsum used in road construction, effectively prohibiting that use. The EPA has 90 days from the filing date to grant or deny the petition.

According to petitioners, studies have found widespread groundwater contamination at "phosphogypsum stack sites including contaminated off-site wells, the potential for drinking water source exposures, several documented damage cases that impacted both ground and surface waters and threatened and harmed aquatic life, increased air pathway cancer risk for those living near stacks, and varied and inadequate state regulation." The EPA issued a regulatory determination in 1991 exempting phosphogypsum and process wastewater from Subtitle C hazardous waste regulation. Multiple large-volume releases of phosphoric acid production waste have occurred over the years, causing contamination.

Phosphogypsum wastewater contains heavy metals and naturally occurring radioactive materials. This is one reason the petitioners asked the EPA to ban use of phosphogypsum in road construction. The petition notes the agency's decision to allow this use "reversed course on its 30+ years of finding that radon from phosphogypsum poses an unacceptable risk to public health if used in road construction."

Apart from the ongoing risks posed by the Florida incident, the Section 21 petition raises interesting questions regarding whether TSCA Section 21 is the most appropriate or efficient means to address risks. Neither phosphogypsum nor process wastewater is listed on the TSCA Inventory. It's likely that any commercial use of phosphogypsum is included under the identity of calcium sulfate, in which other components (notably the toxic metals discussed in the petition) are considered impurities. The EPA would thus prioritize calcium sulfate under Section 6, but not all calcium sulfate is from phosphogypsum, and not all calcium sulfate has the impurities of note here. In short, the requested relief sought by the petitioners doesn't appear to be an easy fix.

Other options exist if the EPA were to go this route. If the agency determined that disposal of phosphoric acid production waste poses an unreasonable risk, it could take action under TSCA to mitigate risks from disposal. In addition, the EPA could employ one or more EPA-administered authorities (e.g., RCRA) if the risk could be eliminated or reduced to a sufficient extent under that authority. The petitioners also seek a TSCA SNUR to prohibit use of phosphogypsum. Given the agency's prior decision to allow use of phosphogypsum in roadbeds, that use would likely be considered ongoing, in which case the EPA couldn't issue an SNUR as those apply to "new" uses. In short, RCRA is perhaps a more-effective mechanism for addressing the risks identified in the petition.

The petition is yet another example of the increasing perceived utility of TSCA as a potent tool to address chemical risks. It may not be the best tool for all situations, but we can expect to see more Section 21 petitions in our future, and some interesting legal theories supporting their application. ●

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The timing of the Florida near-catastrophe could not be more ironic.

SPOTLIGHT REMAINS ON ENERGY EFFICIENCY

Companies realize that ample opportunities for improvements still exist | By Seán Ottewell, Editor at Large

CHEMICAL MAKERS are pursuing a variety of routes to improve energy efficiency, ranging from corporate programs and cooperative efforts with specific vendors to a global initiative. Many of these endeavors focus on taking greater advantage of digitalization and big data.

Aitor Bru, Barcelona, Spain-based global head of digital operations, group operational excellence, for Clariant, Muttenz, Switzerland, spends his time scouring for promising digital innovations and evaluating how they might improve the company's operations and supply chains.

"We start from the business end. We don't want to digitalize for the sake of it; we want to close gaps and meet a need. Energy is an important topic. Our vision is to reduce the energy intensity of our products contributing towards Clariant's greenhouse gas (GHG) emission reduction targets," he says.

"For example, once digitalized, systems can provide remote access to virtually every aspect of a plant with a multitude of tools collecting, reporting and allowing management of detailed features, such as consumption, utilities, raw materials, reactor temperatures, equipment performance and quality data — all within seconds," Bru explains.

The company's aim is a 40% absolute reduction in scope 1 and 2 GHG emissions, i.e., those from sources it owns or controls, and a 14% decrease in scope 3 emissions, e.g., ones generated in procurement, waste and water management, and business travel.

Clariant prides itself on being among the first specialty chemical companies to set such ambitious targets — ones in line with the Science Based Targets Initiative, a partnership of CDP, the United Nations Global Compact, World Resources Institute and the World Wide Fund for Nature (see: https://sciencebasedtargets.org).

A key tool to achieving this is Clariant's dedicated diagnostic program Energy Watch (eWATCH).

Launched three years ago, eWATCH identifies opportunities to reduce the energy intensity of operations at every one of the company's sites. The program has three pillars: collating information, analyzing it, and then acting based on the evaluations.

"The big advantage today is that we have the Internet of Things (IoT)," notes Bru. "That helps a lot with the granularity of our data. Plus, we get a lot more information than was possible in the past, at about a tenth the cost of installing an old-fashioned sensor and its associated wiring. Now, we just install the sensor, use wireless technology to send data to the cloud and then analyze it. The IoT has hugely improved the visibility of energy use in our operations."

Clariant uses the IoT, on WiFi and other tools such as radio frequency identification and the LoRaWAN point-to-multipoint networking protocol, to analyze the resulting data repository. Here, it applies advanced data techniques on top of existing monitoring so individual sites can preset algorithms to help manage energy consumption and detect leaks, which also impact energy use.

The eWATCH team develops specific algorithms tailored for each site. These can be embedded into routine operations with results presented to plant staff as monitoring dashboards. The aim is continuous improvement, so review of the validity of key performance indicators occurs at least monthly.

Bru cites a Clariant site in Germany as an example of how eWATCH can identify energy-related issues. One plant there uses steam, generated by natural gas, to heat multiple individual reactors.

"The granularity of the measuring system wasn't the best," he notes. "We had the measurement of steam volume after the boiler but not for each reactor. So, we measured what were thought to be the highest consuming reactors."

It turned out they actually weren't the largest steam consumers. Clariant implemented a strategy of real-time steam consumption monitoring for each reactor and, in less than six months, reduced the amount of steam produced and, thus, natural gas needed. This allowed the site to pare its spending for natural gas by almost a quarter.

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"One surprise is that the improvement in data granularity allows us to better understand individual contributors to consumption. Here, we get strong hints for the design of reactors and operational changes such as less heating time to reduce batch cycle times and increase reactor throughput," Bru adds.

eWATCH also enables the company to compare similar processes operating at different plants.

"There is always some variability, even if processes and conditions are similar, but we can create a benchmark for the same product. Then, we can use this to create energy improvements in terms of electricity and natural gas consumption," he concludes.

BETTER CONTROL LOOPS

Drilling down to individual operations can enable significant energy savings, other companies have found. For instance, Emerson Automation Solutions, Round Rock, Texas, stresses that monitoring of control loops can lead to improvements that reduce process variability and the associated and often substantial energy losses.

"In a typical process plant, almost two-thirds of control loops are underperforming, which can be due to many reasons, including poor valve performance, incorrect loop tuning and inappropriate control strategy. As a result, huge amounts of energy are wasted because of suboptimal control, particularly in high-energy-use units, such as distillation columns, boilers, reactors, dryers and evaporators," notes James Beall, a principal process control consultant for Emerson.

Poor tuning leads to greater process variability, he emphasizes. In turn, this spurs operators to run the plant away from the most-efficient regions, which typically are close to operating constraints, such as quality limits, to allow for a greater margin of error.

"For example, in a feed heater, this could mean a higher temperature setpoint and higher energy consumption. Despite process variability caused by poor control loop tuning being a regular feature of process plants, many facilities do not have a formal, consistent approach to troubleshooting, and the root causes of issues can, therefore, go undetected for weeks, months or even years," Beall adds.

Unfortunately, many operating companies lack the tools, resources and skilled personnel needed to make the necessary improvements, he believes.

Here, automation providers can help, for example by using loop performance dashboards to measure the performance of every control loop, indicating when these have limited control, high variability, uncertain inputs or are not in the normal operating mode.

"Where performance issues are identified, control performance experts can support the customer to make improvements, with a remote service providing monthly reviews of control performance, identifying issues and making recommendations for corrective actions and prioritizing areas for the next month," says Beall.

Due to the relatively low cost of enhancing the performance of regulatory control loops, they provide the highest return on investment of all process improvement efforts, he notes. In addition, when the regulatory control loops are performing well, existing advanced process control applications on the process can provide a higher level of economic benefits. Typical results of improvements in control loop performance include: 4–8% increase in throughput; 5–10% reduction in energy costs; 2–8% drop in product inventories; 40–80% decrease in quality variation; and 1–5% gain in equipment availability.

Beall cites a chemical company that worked with Emerson on its control loop tuning and improved the energy performance of a distillation column by 16%.

Process tests showed that the distillation column could produce on-specification product using less energy. However, lowering the setpoints on the control loops to the desired energy usage made the loops unstable.

"Through automated monitoring of the control loops and their components, we detected some poorly performing control valves and issues with the loops' tuning. The team used this data to repair underperforming valves and install high-performance digital positioners that provided better performance and detailed status directly to the control system for faster resolution in the future," Beall explains.

Armed with the new data and improved equipment, Emerson's advanced control team tuned the loops

DOING MORE WITH DIGITALIZATION

Figure 1. New Open AI Energy Initiative eventually aims to cover all aspects of plant operations. *Source: Baker Hughes.*

as a system to provide a coordinated response and mitigate the normal loop interaction on a distillation column. The team also taught personnel at the chemical company their advanced loop-tuning techniques. The 16% reduction in energy use per unit of product paid for the improvements in two months.

Distillation columns in general offer opportunities for substantial energy savings. Beall notes that flexible advanced control technologies are ideally suited to supporting the complex tradeoffs between energy usage and product recovery in running a column. "They reduce key process variabilities, allowing operation closer to process constraints and limits, and further increasing energy efficiency."

Another approach he highlights is state-based control (SBC), which uses a combination of operator-initiated state transitions and automated control logic to drive a process to a desired state.

"SBC automates workflows and provides decision support and simplified change management, three of the core competencies of digital transformation," he points out.

NEW GLOBAL INTIATIVE

Meanwhile in February, Shell, The Hague, The Netherlands; and Baker Hughes, Houston, announced they had teamed up with enterprise artificial intelligence (AI) software supplier C3 AI, Redwood City, Calif.; and Microsoft, Redmond, Wash., to launch the Open AI Energy Initiative (OAI). It aims to develop an open ecosystem of AI-based technologies for the energy and process industries. (A similar initiative already is well underway for open process automation; see: "Process Automation Opens Up," https://bit.ly/3fUAFGa and the *CP* on-demand webinar "Unlock Value from Open Process Automation," https://bit.ly/2Q5BCAA.)

"The concept of an open ecosystem is an acknowledgement that no single vendor alone has the capabilities to solve industries' most pressing challenges. While AI brings significant promise and potential, the ability to scale it operationally requires a new approach which includes a modern set of technology standards and participation across the landscape of technology and supply chain participants," explains Dan Brennan, vice president of Baker-HughesC3.ai at Baker Hughes.

"Non-productive time remains a challenge across the energy value chain. The BakerHughesC3.ai alliance developed an application called BHC3

EXTENSIVE MONITORING

Figure 2. Shell is monitoring more than 5,200 pieces of equipment using machine learning. *Source: Shell/Ernst Bode.*

Reliability, which takes a novel systems approach to improve reliability by predicting asset failures and reducing unplanned downtime. The OAI builds on this premise," he adds.

Together with Shell and Microsoft, Baker Hughes is extending the power of BHC3 Reliability by offering domain-specific modules to augment the application and by creating an open ecosystem that enables existing reliability software to interoperate with these AI applications (Figure 1).

"The OAI modules offered by Shell are a great example. Shell is taking proven capabilities that they have developed on the BHC3 AI Suite for predicting failure on control valves and making it available for other consumers of BHC3 Reliability," Brennan notes.

Shell has been working with C3 AI since 2018 to scale its AI-based predictive maintenance technologies to reduce costs and improve the productivity, reliability and performance of its assets.

"We are monitoring more than 5,200 pieces of equipment using machine learning across upstream and downstream manufacturing as well as integrated gas assets [Figure 2]. We are now taking this capability to market and want to develop an open ecosystem where others can offer AI solutions to help improve reliability across the industry," says Freddie Darbyshire, Shell's digital product manager.

This follows the successful implementation of the Shell Predictive Maintenance for Control Valves application at a major refinery and, more recently, at a deep-water platform in the Gulf of Mexico. Within weeks of installing the C3 system, the application enhanced process stability; avoided pressure- or temperature-related trips on the main gas compressor; and halted unplanned downtime from valve failures, boosting production.

Darbyshire notes that Shell has quantified these benefits but isn't sharing the information publicly.

The reliability technologies currently offered help address energy efficiency issues but sustainability options available shortly will aim directly at improving energy efficiency, he adds.

OAI welcomes input from process engineers about the technologies and features they would like the ecosystem to offer. Process optimization ideas would be particularly valuable, Darbyshire believes.

Brennan agrees, adding that while the OAI's current focus on reliability should solve the persistent challenge of costly unexpected downtime and unplanned maintenance and their inherent risks and inefficiencies, process optimization, supply chain efficiency and scheduling optimization, as well as sustainability and energy management all will become part of the ecosystem.

The OAI also provides a springboard for energy operators, independent energy software vendors, equipment manufacturers, and service providers to offer additional interoperable technologies including AI and physics-based models, libraries, and data connectors to third parties, Brennan notes.

"We expect this will mean expanding in the future to other areas that help with business efficiency and decarbonization," he concludes.

Improve Your Plant's Resilience

Become more proactive in dealing with acute and chronic natural disasters

By Dale Sands, MD Sands Consulting Solutions

CHEMICAL MAKERS must boost their resiliency — that is, their ability to withstand, recover from and continue to prosper in the face of an increasing number of natural and man-made disasters. Natural disasters, including those due to climate change, come in both acute and chronic forms. Acute shocks are storms, hurricanes, tornados, earthquakes and floods, while chronic stresses are longer-term impacts such as droughts or rising sea levels.

The increasing trend of natural disasters since 1980 is irrefutable. Figure 1, developed by Munich Reinsurance America, New York City, clearly shows this. That company noted 2020 was a record hurricane season, with more storms in the North Atlantic than ever previously recorded. Worldwide disasters accounted for losses of $210 billion, with only 39% covered by insurance. The United States incurred 45% of these losses.

The United Nations Office for Disaster Risk Reduction (UNDRR), Geneva, reported that 7,348 disasters took place from 2000 to 2019, a 74% increase over the previous 20 years. Financial losses during 2000–2019 approached $3 trillion! Moreover, the global trend of population migration to major metropolitan areas puts more people at risk to the impact of disasters.

To counter this trend, chemical manufacturers must consider adaptive actions to reduce risks today and prepare for further changes in the future as well as mitigative moves to address the root causes of climate change (e.g., atmospheric greenhouse gases and current industrial emissions) to secure long-term solutions. This article highlights steps a company may take to reduce its risks from climate change and resulting disasters — with an emphasis on adaptation.

A TROUBLING TREND

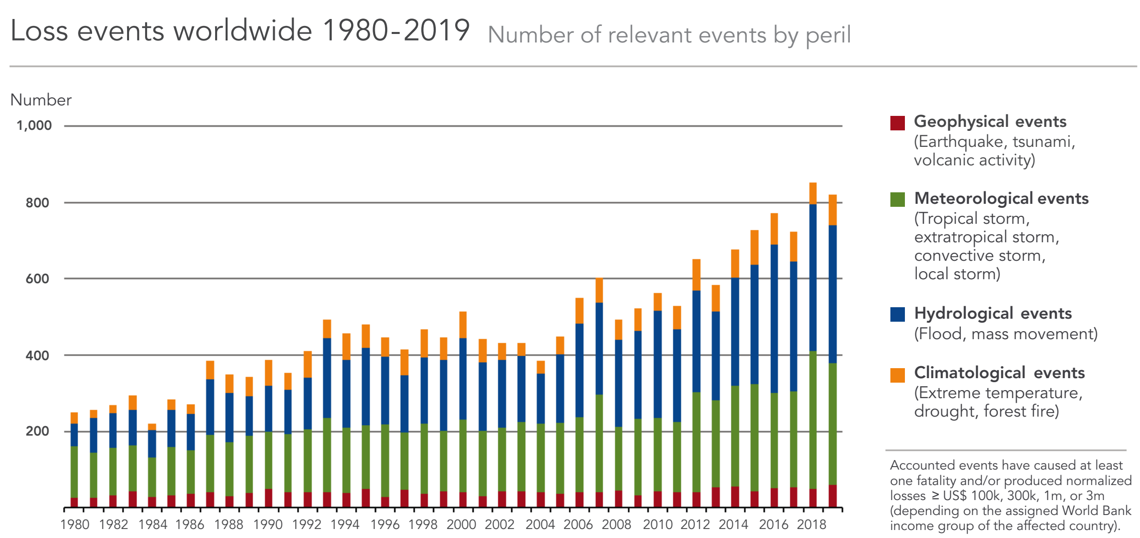

Figure 1. The number of natural disasters has been growing over recent decades. *Source: Munich Re.*

Improving resilience by implementing adaptive actions to climate change should be a strategic priority. Facilities operating in high-risk locations may become undisclosed liabilities to shareholders, with significant potential impact on financial performance. This also is true of members of the supply chain that provide essential supplies and services.

The Financial Stability Board, Basel, Switzerland, an international body that looks at global financial vulnerabilities, set up a taskforce in 2015 to develop voluntary, consistent climate-related-risk disclosures for use by corporations. That taskforce in 2017 outlined a framework for reporting climate-related financial information. In 2010, the U.S. Securities and Exchange Commission (SEC), Washington, D.C, published guidance for public companies to disclose the impact of climate change on their business and the costs of complying with climate-related laws. There is speculation the Biden Administration will do more to have companies disclose potential liabilities from climate-related events.

DEVELOPING A STRATEGY

When assessing how to prepare for, respond to and recover from disaster events, a company should factor in ten general considerations:

1. Risk evaluation is a natural part of capital investment decisions. However, assessments often don't consider climate-related risks from acute shocks or chronic stresses. Threats are unique to each location and plant configuration. To manage risk effectively and build sustained resilience requires an understanding of risk/reward trade-offs. Unless investment decisions become more "risk informed," we will continue to experience increasing loss of life and capital assets.

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2. The intensity and frequency of climate-related disaster events is growing globally, as Figure 1 highlights. There's no shortage of evidence of North America suffering from more fires due to drought conditions and increasing damage from more-intense severe weather incidents such as tornados, hurricanes, floods and extreme temperatures (most recently experienced in Texas).

3. A company should consider the risk of such disasters not just in its investment decisions but also in the planning, development, design, siting and building of plant infrastructure — for instance, by avoiding construction in high-risk areas where adaptation is extremely expensive or not even possible.

4. An investment in disaster risk reduction through structural and non-structural measures is essential to enhance the economic, social, health and cultural resilience of a company as well as to protect the environment. If targeted correctly, risk-informed investments will reward an organization with continuity of business operations, leading to better financial performance over the long term — pleasing shareholders and attracting investors.

5. With so much competition for investment dollars, creating a compelling case to invest capital today for an event that "may" happen tomorrow will remain challenging. A company should recognize this funding dilemma.

6. There are pockets of innovative breakthrough investments but much more must be done. The public sector can increase private sector incentives for resilient investments for both retrofitting as well as for siting and design of new plants.

Programs such as no-interest loans or tax incentives are needed. "Resilience" or "green" bonds to finance risk-reducing interventions should become important funding sources.

7. Work remains to create the right enabling environment for risk-informed, risk-reducing investments. For good reason much disaster-risk-reduction work focuses on vulnerable environments (e.g., coastlines) but extreme weather events aren't limited to those areas. Flash floods, chronic droughts, extreme temperatures and wildfires occur across continents. Here, visionary private sector companies are leading the way.

8. A systematic application of technology will deliver faster improvements. There's a need for early warning systems and resilience analytics. In addition, regulators must update and enforce building codes. Lessons learned must be effectively shared locally, regionally, nationally and globally. Many tools and resources available today, like the UNDRR "Disaster Resilience Scorecard for the Owners and Operators of Industrial and Commercial Buildings," deserve wider use to identify priority needs to improve resilience.

9. A broad range of technical resources are needed to holistically evaluate climate-related risks and ensure siting and design are resilient to local threats.

10. The UNDRR's Sendai Framework 2015–2030 for Disaster Risk Reduction (https://bit.ly/2PYt2DS) does embrace participation by the private sector but now we must operationalize this intent. We must strengthen risk governance to sharpen the measurement and articulation of resilience, track improvements over time, accelerate public/private collaboration, and share lessons learned. These efforts will help reduce losses and the impact of disasters on people, governments and economies to achieve the goals of the Sendai Framework.

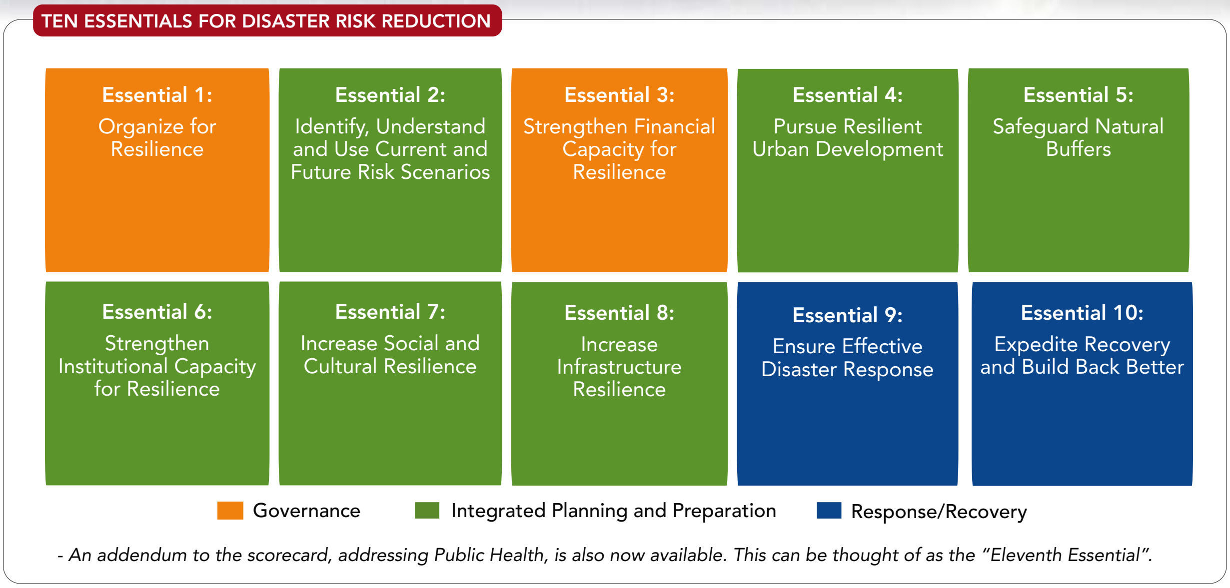

Figure 2. The United Nations Office for Disaster Risk Reduction bases its resilience scorecard on these elements. *Source: UNDRR.*

PLANNING AND ADAPTING IN ADVANCE

In 2020, the UNDRR's private-sector advisory group known as ARISE released the "Disaster Resilience Scorecard for the Owners and Operators of Industrial and Commercial Buildings." This tool suits both single- and multi-building facilities. It provides a way for owners and managers to baseline the resilience of their buildings to climate-related disasters and, thus, to prioritize resilience improvements. This scorecard is based upon what UNDRR considers the ten essentials for disaster risk reduction (Figure 2). The scorecard comes in two versions: a screening assessment tool and a more-granular assessment tool with more than 100 indicators to score in a self-assessment process. You can access the scorecard at https://bit.ly/3fLW3NT.

The scorecard enables you to better understand your climate-related-disaster risk-reduction position by looking at a variety of factors and issues (Table 1). It involves ten steps:

1. Review the existing organizational structure: Is a plan in place? Are staff trained?

2. Check available data to define the risks your location faces: hurricanes, tornados, catastrophic floods, droughts, storms of major proportions, etc. What about the potential for earthquakes or extreme temperature events as occurred recently in Texas? To become resilient, you must define the type and magnitude of threats that might impact your plant.

3. Evaluate access to capital to prepare for and facilitate recovery from a disaster event. Are contractors and equipment available to provide needed services and products?

4. Integrate resilience planning with capital investment. Will this capital expenditure improve resilience? Will the investment face climate-related risks?

5. Consider the existing inventory of green infrastructure (rain gardens, green roofs, high-moisture-absorbing trees, etc.); these can play an important part in tempering extreme rainfall events.

6. Strengthen the overall institutional capacity for resilience. These resources need not necessarily be local if they are available within the company or through contractors. For example, many plants require access to water for their operations. Too little water due to drought conditions or too much water from floods can have significant adverse impact. One example of a way to mitigate such events is, if land near the plant is available, to construct a reservoir. It then could provide water during droughts and collect water to mitigate floods.

7. Strive to better connect the plant with the community to work together to improve resilience. Evacuation centers, transportation corridors and emergency response actions must interact and connect with the community at large to be successful. Plans for plant growth and expansion must consider the effect on evacuation corridors.

8. Establish routine evaluations of the vulnerability of critical infrastructure. How secure is chemical storage? What about energy production units? Will they continue to operate in extreme conditions? What if power lines go down or cell tower failures interrupt communications?

9. Take actions necessary to ensure the availability of effective disaster response capabilities, including the operation of communication systems and access to healthcare facilities. Are the emergency plans updated and reviewed at least quarterly? Are emergency drills performed to prepare for disaster events?

10. Develop and implement plans to expedite recovery and build back better. Part of this step is to make certain that early warning systems are in place and plant personnel are trained to respond.

RESILIENCY CHECKLIST

Resilience planning and organization:	• Do plans exist to define current resilience condition and improve resilience? • Is there clear organizational authority and responsibility for resilience? • Are resilience issues routinely covered in location decision-making?
Appreciation of disaster risks:	• Is there a good understanding of the risks facing the facility today? Tomorrow? In five years? • Are risks defined and detailed? Have cascading impacts across infrastructure been considered? • What are financial/legal/social consequences if the plant is out of service for a month? Six months?
Do budgets allow for access to capital:	• Is there a plan to access capital should disaster strike the facility? • Are contractors identified and contracts established? • Is maintenance performed routinely on critical infrastructure? • Are emergency systems regularly inspected and performance tested? • Are financial resources readily available to meet cashflow needs post-disaster?
Resilient development:	• Does the building(s) comply with federal/state/local codes with respect to resilience? • Is the facility current with applicable industry resilience building codes?
Natural buffers:	• Have low impact development principles been applied? • Is the plant located in or near a flood plain? • Has green infrastructure been used to mitigate disaster events to the extent allowed by local rules? • Are ecosystem and green infrastructure condition and use evaluated regularly?
Institutional capacity:	• Is there a trained resilience expert available who has authority and responsibility for improvement? • Are local measurements regularly taken to develop a baseline of environmental conditions? • Is there a decision process if environmental conditions indicate a pending disaster event? • Are employees aware of the hazards and how to prepare, respond and recover from an event?
Social and cultural resilience:	• Does the plant have a critical role in the local community (i.e., as a site for evacuation, etc.)? • Are drills conducted routinely to simulate disaster events? • Are special-needs employees identified for specific help during a disaster? • Has the plant interacted with community leaders regularly to discuss emergency actions?
Infrastructure resilience condition:	• Has a vulnerability and risk assessment been conducted of plant assets and operations? • Do building/plant managers understand natural and man-made threats the facility faces? • Are there materials on site that may pose threats to employees or the community during a disaster? • Has an adaptation plan been prepared to mitigate or reduce these risks? • Has this plan been peer reviewed? Shared with local government officials?
Disaster response:	• Are communication systems and emergency response equipment and systems routinely tested? • Are communication systems functional without power? • Are emergency response plans and employee evacuation plans prepared, communicated and practiced?
Recovery:	• Is there a process to conduct a "lessons learned" process post-disaster? Is it shared with applicable facilities? • Are post-disaster recovery plans practiced? • Are "build back better" plans in place following a disaster? • Are financial resources readily available to accelerate recovery?

Table 1. A resiliency assessment should probe into a wide variety of issues.

MAKE RESILIENCE IMPERATIVE

The journey to improve plant resilience is a multi-step process that requires commitment, careful analysis and corporate support. Resources always are limited, so getting funds to prepare and protect against what "could" happen can pose challenges. However, it's essential to establish a proper balance that enables taking adaptive actions consistently and in a measured way to improve survivability of assets and protect personnel and the community at large.

The chemical industry must address climate-related risks. Indeed, resilience improvement should factor into all capital expenditures. Adaptation is the first but not the only priority. While we certainly must deal with current risks, we also must take steps to mitigate the emissions of greenhouse gases and other factors that contribute to climate change. These are inter-related priorities. ●

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Get a Flair for Flares

This important safety system is more complicated than often assumed

By Amin Almasi, mechanical consultant

A FLARE plays a crucial safety role at many process plants. Indeed, it often provides the last line of defense against a serious incident by burning off flammable gases released. No practical alternatives to a flare (or flare stack as it's often called) exist.

A flare primarily serves to handle gases released by pressure relief valves and other devices during emergency or equipment over-pressurization events. For instance, interruption of the usual operation of a plant, such as by failure of key equipment or a power outage, may lead to potentially dangerous accumulation of gases; sending these to a flare and igniting them via a pilot light ensures their safe combustion, thus preventing their escape into the atmosphere.

A flare also often combusts gases for relatively short periods during startups and shutdowns, e.g., to allow proper sequencing of events (such as reintroducing fluids during startups and emptying process equipment and lines during shutdowns). Many plants resort to flaring to deal with gases generated during transients in regular operations; such avoidable gas flaring should be kept to the absolute minimum possible.

Flares are a major source of air pollution such as carbon dioxide emissions. An improperly operated flare may emit hydrocarbons (methane, etc.) and other harmful gases or volatile organic compounds.

A typical flare package is simply a set of equipment that safely combusts waste gases at a pressure drop that doesn't compromise plant relief systems or can't be utilized. However, it is far more complicated than it seems. So, here, we'll look at flares.

THE FLARE SYSTEM

Typical components of a flare system include:

- a flare stack;
- a liquid seal drum or similar arrangement, e.g., a section in the upper portion of the stack, to prevent any flashback of the flame from the top of the flare stack;
- a liquid/vapor separator, usually called a knockout drum, to remove liquid from the gases;
- a pilot flame (with ignition system) that's on continuously so it can burn relieved gases whenever needed; and
- an alternative gas-recovery system for use during partial plant startups and shutdowns as well as other times when required/possible. The recovered gas goes into a fuel gas or similar system.

Let's now briefly turn to three aspects of a flare system.

FLARE

Figure 1. By burning released gases, unit provides an essential safety function.

Smoking and steam injection. Inadequate air flow will cause a smokey flare. Some smoking may occur when the flare initially lights until the flame gets enough air. In some modern flare control systems, operators use cameras to monitor the flame and adjust the operation to prevent smoking. For significant plant shutdowns such as those caused by power failures, the flare may smoke for several minutes.

Steam sometimes is injected into the flame to reduce the formation of black smoke. Using the optimum amount of steam is important because too much steam added to the flame can result in a condition known as "over steaming" that leads to reduced combustion efficiency and higher emissions.

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The mixing of gases, air and water mist causes the rumbling noise frequently associated with flares. This noise increases with the rate of flaring. Loud noises might stem from extra steam to the flare and combustion of a larger amount of gas.

The gas needs air to burn correctly; this comes either via the gas flow to the flare or steam aspirators.

Flare usage and flare gas recovery. A plant can keep flaring to an absolute minimum by using waste gases instead of burning them. Flare gas recovery systems and flare gas recovery compression units, which are suitable under certain situations, have seen good progress and improvements. However, the amount, conditions and compositions of the gases delivered to a typical flare system vary considerably, creating a great challenge for any flare recovery system. Thus, unfortunately, recovering large amounts of released gases under all emergency conditions currently isn't feasible.

Flare knockout drum. This prevents liquids from reaching the flare stack. Burning liquid droplets can spread over a large area in the plant and are a potential hazard. So, a knockout drum usually is designed to collect liquid droplets greater than a certain size, which generally is defined with respect to the details of the flare tip, particularly those related to safely burning small droplets. As a very rough indication, this size could be 200 microns.

A flare knockout drum typically is a large horizontal or vertical vessel. It generally should provide at least 30 minutes of liquid holdup from all safety/relief valves and other emergency releases. The drum also should be able to handle liquid slugs that usually occur at the start of a significant flaring event.

KEY CONSIDERATIONS

The sizing and design of a flare requires consideration of the full range of flaring duties in different operating and emergency scenarios, as listed in a contingency table or the like. This is a major exercise for a chemical processing plant. The selected configuration also must work within the smokeless flaring operating range.

The first set of scenarios is flaring during a whole plant emergency shutdown. This may involve a very large flow of gases that should be destroyed, with safety the primary consideration. That flow determines the necessary hydraulic capacity — i.e., the maximum waste-gas flow the flare system can handle. The second set of scenarios is for treatment of waste gases generated during normal operation, including planned decommissioning of machines and equipment in different units. While safety still is imperative for such scenarios, emissions also are important. The actual waste-gas flow rate and composition may vary significantly during normal operation but the flare still should be capable of safely destroying the waste gases while minimizing emissions.

Four performance parameters are important for most flares.

The first is the so-called smokeless capacity. This is the maximum flow of waste gases that can be sent to the flare without producing significant levels of smoke. Smokeless capacity typically at least should equal the maximum waste-gas flow rate expected during normal operation.

The second performance parameter is the thermal radiation generated by the flare as a function of the waste-gas flow rates and compositions. Radiation levels at ground level usually are limited to avoid disturbing personnel and damaging equipment. After choosing the most-remote practical flare location, stack height is set so acceptable radiation levels aren't exceeded at ground level.

The third parameter is noise. Excessive noise can create problems for plant personnel, the environment and the local community.

The fourth key parameter is emissions produced. Flaring gases creates emissions such as nitrogen oxides (NO_x), sulfur oxides, greenhouse gases and volatile organic compounds. These emissions, in combination with any unburned gases, contribute to total facility emissions. Decades ago, flare emissions weren't specifically parameters of interest. One reason was because they were difficult to measure. However, this isn't the case anymore. Today, flare emission reduction garners great interest. Indeed, it's a serious requirement for modern flaring systems.

COMMON CONCERNS

A flare must contend with environmental and plant conditions such as strong winds, storms, extremely high gas flows, etc. So, a variety of issues can arise.

Traditional flares have suffered many problems, including environmental pollution, operational difficulties, safety issues and integrity concerns. Two significant potential issues are "flaming rain" (consisting of unburned droplets of fluids) and smoke. In addition, strong crosswinds sometimes have extinguished flare flames; this can produce a high level of environmental pollution as well as operational and safety concerns.

Aerodynamics plays a major role in the chemical reactions and, therefore, pollutant formation in the flame. In general, high temperatures in the central zones of the flame lead to more pollution, particularly increased NO_x production. So, avoiding very high temperatures in the center zone of the flame is important.

High winds can cause issues and disturbances to flares. For instance, in some old-fashioned flares as the crosswinds increase from below 10 km/h to above 20 km/h, the flame becomes unstable. Swirl technology can provide a solution. For example, in a modern flare design, as wind speed rises, the swirl produced by the flare also goes up and the area of recirculation gets stronger. This can stabilize the flame more and act as a pilot light to the flame. One possible arrangement uses the wind itself to cause swirling; when the wind speeds up, the inlet air speed increases, leading to higher swirl and a stronger recirculation zone. The strong recirculation area stabilizes the flame and better combustion takes place. Proper atomization of liquid droplets that passed through the knockout drum is another important factor in flare performance.

The flare tip — whose job is to produce a vertical flame standing above the flare stack at high gas flow rates — should work under harsh thermal and corrosive conditions. So, its service life is important. However, operational conditions may vary considerably; at low gas flow rates, especially with a strong prevailing wind, external burning with flame impingement on the outer surface of the flare tip often occurs. A flare tip needs very careful design. The tip nearly always is fabricated from a corrosion- and heat-resistant alloy steel. Today, alloys with higher nickel and chromium content such as 800 series, alloy 625, etc., have supplanted traditional type-300 and other stainless steels. These changes have provided some improvements but unpredictable flare tip failures still happen. Failure may be catastrophic and can occur at apparently random operating times, requiring not just tip replacement but also an unscheduled shutdown. While the cost of tip replacement itself may be relatively small, an unscheduled shutdown could result in a substantial economic penalty. For instance, a large chemical processing plant incurred an estimated $11-million hit from two weeks of unscheduled shutdown caused by a flare tip failure.

Thermal fatigue, corrosion, stress-assisted oxidation and creep typically are responsible for such failures — with thermal fatigue, the repeated stresses exerted on the flare tip during heating and cooling, thought to be the main culprit. In the presence of wind and at low gas flow rates, flame impingement on one side of the flare tip can create large temperature gradients, causing considerable thermal stresses. Sophisticated thermal studies and modern thermal imaging can quantify the levels of temperatures and stresses formed as a result of different operating and malfunctioning modes.

A CASE OF COLD GAS

Let's briefly examine why a process plant ran into the serious issue of cold gas in the flare system. As part of a renovation/expansion program, the facility added processing units; it also put in a new flare stack because the old flare was small in size and capacity. At the final review before the commissioning, it was found that the minimum operating temperature of the flare system (flare piping, flare stack, etc.) was only -15°C. (Apparently, details were copied and pasted from the old flare.) However, this wasn't suitable because the gas pressure in new units, particularly the high pressure compressors, exceeded 100 Barg. In case of blowdown, the gas could reach low temperatures, below -15°C. The travel between the high pressure discharge of the compressors and flare stack would raise the gas temperature somewhat. However, the volume of low temperature gas in a full blowdown could affect the flare system. Based on accurate simulations performed after this finding, at the highest possible pressure (relief pressure of the high pressure compressor unit) and ambient temperature of about 2°C (winter), the lowest gas temperature at blowdown could be around -47°C. Yet, the provided piping and flare only could stand a temperature of about -29°C.

This led to ordering a new flare stack and flare piping with proper materials and low temperature capability (below

-47°C) to replace with existing flare system. However, delivery time was four months.

Since it was summer, rather than wait, it was decided to commission the plant but impose some restrictions. Operating procedures were developed for the four-month interim period to maintain gas temperature at 25°C or more at all times, to keep the minimum operating temperature in the flare system above -29°C. Also, a site standing instruction mandated avoiding blowdown or depressurizing after prolonged trip or non-vented shutdown where gas temperature (static inventory) might cool down below 25°C.

Then, when the new flare stack, piping, header, etc., were delivered (within four months), the flare system and piping were replaced in a short one-week plant shutdown.

AN EMISSIONS EXAMPLE

Let's now look at another case study to compare the performance and emissions of a traditional flare with a modern one. In the old-fashioned flare, the flame was long, yellow and highly luminous, indicating poor mixing. Within a distance of around two-to-three times the flare stack diameter, the flame was a simple diffusion one. Considering a zone of six times the flare stack diameter, the flame temperature went from 1,400°C at the center to 1,000°C in the middle and 800°C at the boundary. The central high-temperature zone created considerable pollution, particularly a high rate of NO_x production. Lower temperatures at the boundary were due to more entrainment of air there. Combustion efficiency was estimated at less than 90%.

After replacement with a modern flare, the temperature of the central part dropped to about 1,250°C and zones of temperatures above 1,000°C were substantially reduced. Large portions of the central section previously in the 1,400°C zone were converted to areas of 1,000°C or lower. The modern design and improved aerodynamics provided combustion efficiency estimated at more than 94%. Moreover, due to better temperature distribution, NO_x production fell to less than 30% of that of the old flare. ●

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Right-Size Your Safety Instrumented Systems

Consider the cost versus value of adopting a higher safety integrity level

By Tetsu Ishidu, Yokogawa Electric Corp.

WHEN SOLVING a design challenge, most engineers like to build in a safety factor. For example, if structural calculations suggest ⅜-in. bolts will suffice for an application, designers often will specify ½-in. bolts to be "on the safe side." Here, the change incurs only slight added expense. However, in many cases, providing an extra margin can create significant costs. For instance, increasing the horsepower rating of a motor driving a pump by 20% means a more expensive motor but, worse, the cost of the extra electricity to run it over its lifetime.

Let's extend this thought progression into another area: process safety. Is it possible to overdesign a safety instrumented system (SIS) or individual safety instrumented function (SIF)? Is it desirable to do so to build in the extra cushion of protection? Overdesign certainly is possible. However, engineers should carefully consider the cost, while ensuring provision of the required degree of safety.

This article will not get into evaluating potential safety hazards or designing safety systems, which are extensively covered elsewhere. Instead, we will discuss ways of interpreting and implementing the findings of these evaluations.

Before that, though, let's go over some basics of the design methodology, as detailed in IEC standard 61511. A process hazards analysis (PHA) leads to assignment of a particular SIF to a specific hazard, such as an overpressure incident in a given vessel. The criticality of an SIF, which depends on the likelihood or frequency of the incident occurring, is then multiplied by its degree of severity, e.g., a small chemical spill versus a fire or explosion, to determine the safety integrity level (SIL) or risk reduction factor needed for the SIF.

Because no two chemical processing plants are identical, specific analyses invariably differ from site to site. However, we can draw some insights by looking at types of installations that are fairly common — the fire-and-gas (F&G) detection systems and burner management systems (BMSs) associated with boilers and fired heaters. These systems require evaluation in the same way as any other equipment in a facility, with SIL values assigned. Due to their widespread application, they have been evaluated countless times under many different circumstances. So, the questions become: what is the appropriate SIL value and how should a facility respond?

BURNER MANAGEMENT SIL

A BMS must ensure the fire is burning in a controlled and efficient manner (Figure 1). Of first concern is that combustion actually is taking place so the fuel gas is not simply accumulating in a large explosive cloud. If the flame is lost, the BMS must cut off fuel flow immediately. It also must analyze the combustion to ensure the fuel-to-air mixture is correct. There are more subtle functions as well but these two are the most important. In many plant environments, analysis of BMS SIFs calls for SIL-2 protection.

The question some plants struggle with relates to the SIL value. Is SIL-2 sufficient or should the value be higher? In rare cases, the PHA of the BMS does indeed call for SIL-3 based on the severity of a potential incident. Often though, the decision to build to SIL-3 rather than SIL-2 stems from a motivation to err on the safe side or a desire to have everything in a plant at the same SIL. However, this can quickly result in excess cost and complexity.

To understand how all this works, it is useful to consider the elements of a SIF and how equipment and systems get their SIL rating.

An SIF consists of three parts: a sensor, logic solver and final control element (FCE) (Figure 2). For a BMS, the sensor might be a flame scanner to verify that combustion actually is occurring. The sensor sends its measurement to a logic solver, which compares the value against its internal programming. If the value falls below the setpoint, the logic solver triggers the FCE, in this case, closing a valve to shut off the fuel supply.

A safety-certified instrument, such as a flame scanner, must pass an in-depth analysis of its design and construction to determine all the ways it could malfunction or fail. By providing sufficient controls or redundancies, the device receives a low probability of failure on demand (PFD) value that is translated into the SIL classification — the lower the PFD, the higher the SIL. (Strictly speaking, a device receives a PFD value that places it into one of the SIL ranges, not a SIL rating. However, a transmitter with a PFD of 1 in 500 commonly is characterized as "SIL-2 rated.") The same treatment applies to logic solvers and FCEs.

The cost of certification combined with the specialized manufacturing and testing requirements of safety instruments make for premium pricing for anything with an SIL rating; higher levels increase the price, often more than proportionally.

Few systems depend on a discrete three-piece SIF. The logic solver for a BMS or F&G system typically is its own safety-rated programmable-logic-controller-based system (Figure 3) — with inputs and outputs for multiple

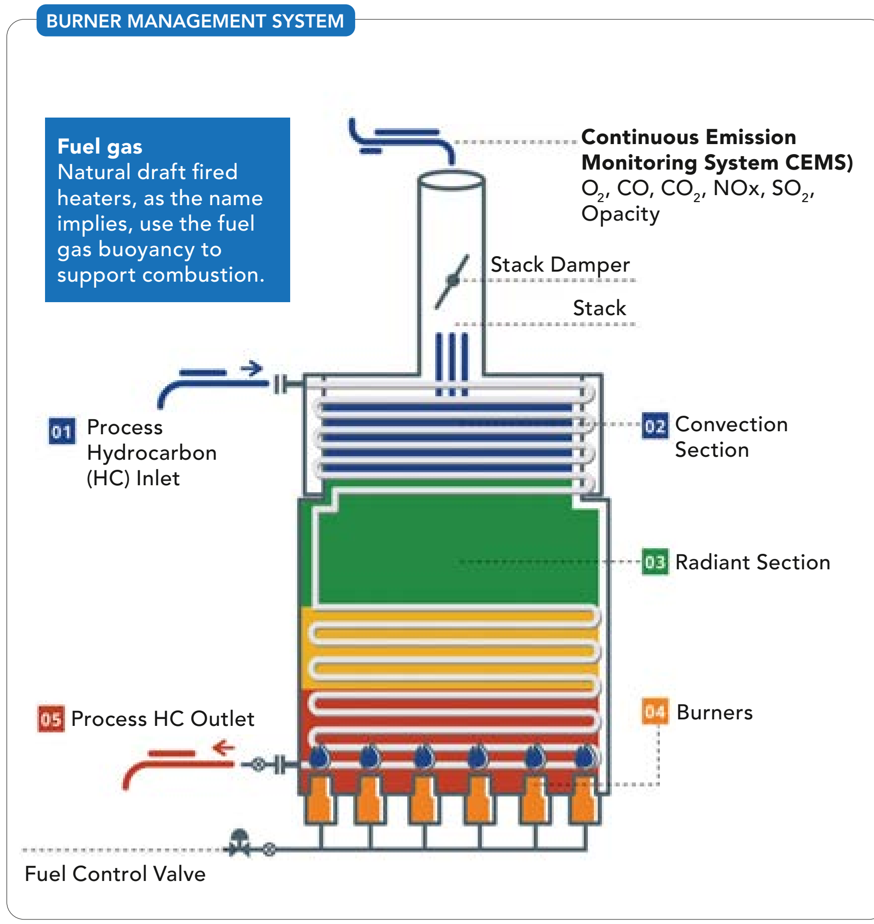

Figure 1. This requires evaluation just like any other safety system in a plant.

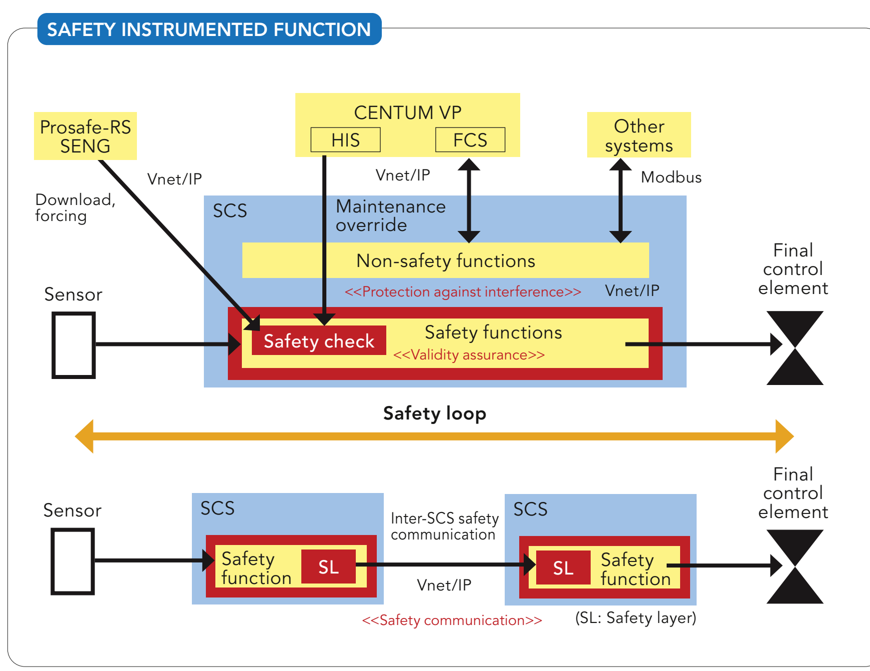

Figure 2. A safety loop always must include a sensor, logic solver and final control element to bring the process to a safe state.

SAFETY-RATED CONTROL SYSTEM

Figure 3. Controllers such as Yokogawa's ProSafe RS can support complex safety functions with multiple sensors and final control elements.

sensors and FCEs, all connected to a central processor running certified software. It, like the other elements, has its own SIL rating, which, when evaluated with all the supporting elements, yields an SIL rating for the complete installation.

GENERAL SIL SELECTIONS

While there hasn't been a hard statistical study, Yokogawa's engineers who have consulted at production sites shared the following observations on general SIL selections:

- process emergency shutdown (ESD) system, SIL-3;
- process F&G system, SIL-2/SIL-3;
- plant utilities ESD system, SIL-2; and
- plant utilities BMS, SIL-2.

Naturally, exceptions exist based on the processes and products involved. However, these observations apply widely throughout the chemical industry. This raises questions such as: How many facilities need an SIL rating higher than SIL-2 for anything outside of the main process ESD? Without a clear hazard evaluation legitimately calling for the extra level of protection, does a BMS or F&G system ever need more than SIL-2?

When answering such questions, safety specialists point to two important truths:

1. Any hazard could occur at any time. There is no hazard that cannot happen.

2. Any component of a safety system could fail at any time. Nothing is 100% reliable in every situation.

These points underscore that you should take nothing for granted — that's why we have safety systems in the first place. We cannot eliminate risk, we can only reduce it to an acceptable level. However, there's no need to reduce it more than necessary.

HIGHEST COMMON DENOMINATOR

Real-world plants like to avoid complications wherever possible. So, some managers and engineers ask if working to multiple SIL ratings is required or desirable. They wonder if having some part of the plant at SIL-4 with its PFD of 1 in 10,000 is necessary, and whether scaling back to SIL-2 really provides that much in savings? Adopting SIL-3 for everything seems a simpler solution.

Using SIL-3 or SIL-4 instead of SIL-2 certainly increases the amount of protection — but to what end? SIL-2 offers a risk-reduction factor of between 100 and 1,000. Even at the lowest value, a SIL-2 system will perform its task correctly 99 times out of 100, statistically speaking. Moving to SIL-3 decreases the PFD by a factor of ten but likely at least doubles the cost for the hardware and commissioning alone compared to SIL-2.

Moreover, maintaining a higher rating requires more rigorous proof-testing and verification routines. Increasing the SIL to be on the safe side always imposes extra cost and other demands. So, you never should select a higher SIL without careful analysis of the total lifecycle cost. Of course, you should use a higher rating where a risk analysis indicates that it truly is needed.

One more consideration is the availability of the best system selection from the plant's chosen safety partner. Implementing a higher-rated system than necessary simply because of lack of better choices in the particular vendor's product line is not optimal. The probability that fewer transmitters and final control elements are available to meet this higher requirement compounds the difficulty. Companies that choose to standardize on a higher rating for some degree of convenience frequently find it costlier than first envisioned.

The desire for standardization presupposes that the systems for the respective SIL ratings differ and, therefore, create training problems because technicians must learn multiple approaches. However, that is not always the case. Some safety controller platforms are indistinguishable from each other in spite of supporting different SIL ratings. Operator graphics, programming code, etc., do not need to change — negating a key driver for standardizing on one SIL rating for an entire process plant or facility.

Most facilities pose a mix of safety requirements and, thus, need safety systems in different SIL-ratings.

CASE STUDY 1: CONSOLIDATED F&G SYSTEM

The tank farm of a mid-sized refinery relied for F&G protection on a hodgepodge of individual F&G detection safety loops, with little coordination among them. Most functioned entirely autonomously and provided limited response, such as local alarms. Some of the fire detectors were tied to fire suppression systems able to dump foam on strategic pump and valve clusters; however, these also had little or no coordination. While determining n SIL rating for some of the loops was possible, formulating a comprehensive value for the overall system was difficult.

The plant was particularly worried about the potential for a false alarm triggering a suppression system, given the operational disruption and environmental cleanup that would result. Consequently, many of the loops had very high setpoints, causing concerns about their ability to respond promptly to an actual incident.

The plant launched a full evaluation of the system in effort to create a more unified F&G strategy and implementation. A centralized safety controller brought the fragmented parts together to allow more strategic responses based on signals from multiple sensors and FCEs. The site replaced some sensors and added others; it recalibrated all, many with revised setpoints. In especially strategic areas, the new controller allowed voting schemes to increase protection against false alarms. The system now has a consistent capability to meet SIL-2 requirements and it can coordinate alarm and suppression efforts.

CASE STUDY 2: SITE-WIDE RE-EVALUATION

An agricultural chemical producer was considering a site-wide safety system upgrade at one of its decades-old locations. The first step was a re-evaluation of the existing PHAs for each of the seven production units to determine if the working assumptions still were valid. This analysis yielded a variety of results, with most of the plant's units and utilities calling for SIL-2 protection but several organic-solvent-based production lines needing SIL-3.

The intention was to standardize on one SIL for the entire site. This meant SIL-3, even though it was far too high a standard to apply everywhere. So, the company checked

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whether applying SIL-3 across the rest of the plant was practical.

The answer was yes, at least theoretically. However, studying the practical implications convinced the company otherwise. The costs connected with implementing SIL-3 rather than SIL-2 for more than half the systems on the site proved to be more than the budget could handle. Not only was the cost of the controller hardware alone more than double, but far more of the existing safety transmitters and FCEs would need upgrading, including many that were allowable under proven-in-use evaluation sufficient for SIL-2.

One suggestion to upgrade just the controllers proved pointless because it simply would add cost without achieving any improvement in SIL rating. Based on the equipment provided by its selected vendor, no operational differences effectively existed between the SIL-2 and SIL-3 controllers, which negated much of the motivation for standardizing in the first place. Both platforms used the same setup and programming methods, so accommodating the different SILs was easy. The plant decided to use the appropriate SIL for each safety system.

PROTECTION WITHOUT EXCESS

Chemical plants and refineries must have appropriate safety systems in place, following the standards and practices outlined in IEC 61511. This is not an area where a company should cut corners to reduce cost — but neither is it one where excess is necessary. Safety is costly to install and manage, so overbuilding offers no advantage.

At one time, the systems designed for SIL-2 and SIL-3 may have differed enough to drive a desire to standardize on just one, even if it meant increased costs. Now, though, the differences between some vendors' controllers for SIL- 2 and SIL-3 are indistinguishable to technicians and operators, which provides companies with substantial savings for SISs applied to BMS and F&G systems as well as to ESD systems for plant utilities and nonhazardous processes. SIL-3, where necessary, should be deployed but far more opportunities exist for SIL-2 than many plants may realize. ●

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Direct Heating Technology Simplifies Styrene Plant Revamp

Novel approach provides both operational and capital-cost advantages

By Vincent Welch, Technip Energies

INNOVA IS the leading producer of styrene-based polymers in Brazil. Production at its integrated facility in Triunfo, Rio Grande do Sul, includes ethylbenzene, styrene monomer, toluene, general-purpose and high-impact polystyrenes as well as expandable polystyrene.

Originally commissioned in 2000, the styrene monomer unit had a design nameplate capacity of 180 kt/yr. As a result of catalyst improvements and equipment design margins, the unit generally could operate at capacities as high as 260 kt/yr. Given the significant demand growth for styrene-based polymers in South America, Innova in 2018 awarded a contract for the basic engineering, equipment supply and technology license to Badger Licensing (a wholly owned subsidiary of Technip Energies) to expand the plant to 390 kt/yr (more than double its original nameplate rating). Goals of the Innova expansion were to not only markedly increase throughput but also simultaneously significantly reduce energy consumption.

Here, we'll focus on one element crucial to achieving these goals — the implementation of Badger's "Direct Heating" technology that employs flameless combustion for adding heat to high temperature processes.

MONOMER PRODUCTION PROCESS

The most widely used technology for making styrene monomer is the adiabatic dehydrogenation of ethylbenzene to styrene. Dehydrogenation occurs in the presence of excess steam over a potassium-promoted iron oxide catalyst. The dehydrogenation reaction is highly endothermic and equilibrium limited. Low pressure or high steam concentrations (or both) favor the main reaction. Steam serves to supply heat for the endothermic reaction, remove coke generated by thermal reactions, and dilute the reaction components, thus shifting equilibrium towards the desired styrene reaction. For these reasons, nearly all grassroots styrene units have two reactors in series with a steam reheat exchanger between them. The reactors operate under vacuum with inlet temperatures in the range of 600°C–650°C.

For the dehydrogenation process, given typical tradeoffs between raw material/energy consumption and capital investment, operating at the lowest possible pressure always is more economic. For revamps, minimizing the pressure drop of existing and new equipment in the reactor section is crucial. Furthermore, maximizing the throughput increase is best achieved by using the lowest practical steam-to-ethylbenzene-feed ratio, which also is best accomplished by operating at low pressure.

PROJECT ISSUES

Accomplishing the goals of the Innova project required resolving three fundamental issues: 1) providing additional catalyst to achieve an economic run life; 2) minimizing the reactor operating pressure; and 3) supplying the necessary extra source of high temperature heat to drive the endothermic reaction.

The original grassroots design of the Innova reactor section consisted of two reactors in series with a steam reheat exchanger between them; two steam superheaters (one that superheats steam to the reheat exchanger and the other that heats the main steam to the first reactor); a horizontal effluent heat recovery exchanger; a cooling water condenser; and a single vent-gas compressor.

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Based on historical operating data, solely using the existing two reactors to boost production would not have been economically possible. The reactors already were operating well above their design capacity; any further increase in ethylbenzene feed would result in high pressure drop, reduced conversion, catalyst instability and shortened run times. To circumvent this issue, it was decided to install a new, larger third reactor downstream of the existing ones and maintain the same ethylbenzene feed rate to the existing reactors pre- and post-revamp. The additional ethylbenzene feed would go into the effluent stream just upstream of the new third reactor. From a thermodynamic equilibrium standpoint, by converting to a three-reactor system and keeping the same overall ethylbenzene conversion to styrene, the existing reactors would operate at milder conditions (i.e., lower temperature/conversion) post-revamp.

However, hydraulically debottlenecking the effluent heat exchange train required overcoming the high pressure drop of the existing horizontal effluent heat recovery exchanger located downstream of the reactors. Because of fouling and tube plugging, the pressure drop across this horizonal exchanger would increase substantially over the course of a run, degrading performance. To alleviate this problem, a new ultra-low-pressure-drop vertical feed/effluent exchanger sized for the new higher flows was adopted. Likewise, a new condenser of greater capacity replaced the original and a second vent gas compressor was installed in parallel with the first one. In general, implementing these equipment modifications facilitated operating at the low pressure. Ultimately, even with the significantly higher flows of the revamp, the critically important reactor outlet pressure would remain about the same pre- and post-revamp.

THE DIRECT HEATING UNIT

Having identified solutions for the catalyst and hydraulic limitations of the system, the engineering team then turned to finding the best way to supply high temperature heat to the system. In the three-reactor configuration, the combined ethylbenzene feed/reactor effluent stream to the new third reactor required heating to 630°C from roughly 550°C.

During the study phase of the project, the team considered conventional methods for supplying this high temperature heat; these included adding a third superheater, extending the fire box of existing heaters, and increasing the amount of feed preheating. However, in due course, the team determined that the Direct Heating option was most economical.

The Direct Heating technology resulted from years of cooperative research and development by Badger, TOTAL Petrochemical and Refining, and Shell Oil. In general, the technology takes advantage of a concept initially proposed by Shell Oil for crude oil recovery from subterranean rock formations. The Direct Heating Unit (DHU) employs the novel concept of flameless combustion — achieved by separately preheating air and fuel gas such that the mixture temperature exceeds the fuel's autoignition temperature. Unlike conventional furnace burners that combine large amounts of fuel and air at a single point, the DHU works by adding fuel in small increments into a high velocity air stream via injections over an extended heating zone. By combining air and fuel in this way, the fuel reacts more slowly in a controlled manner and at significantly lower temperatures than in classic combustion, which gives off concentrated visible light (i.e., a flame). One advantage of using this technique in the styrene process is that the dehydrogenation reaction generates hydrogen; its relatively low autoignition temperature makes hydrogen an ideal fuel for flameless combustion.

As with most revamp projects, the team carefully considered the location of new equipment. The proposed fired superheater had to comply with both industry risk mitigation practices and insurance obligations that require fired devices to maintain minimum spacing requirements from nearby equipment containing flammable materials. At the Triunfo site, the available plot space for a new fired heater was relatively remote from the reaction section. All practical locations would call for more than 100 m of large-bore high-alloy steam piping that typically operates at over 800°C as well as numerous expensive expansion joints. From an operational standpoint, a distantly located fired heater would result in high piping heat losses and an undesirably high steam-system pressure drop.

COMPELLING ADVANTAGES

Conceptually, the DHU shares many characteristics of a conventional heat exchanger. However, the unit boasts a significantly smaller footprint than a fired heater (about 25% less), and doesn't incur the above-mentioned placement constraints. So, it could be located conveniently near the existing structure. Moreover, the all-important process-side pressure drop is far lower than that of the standard reheat exchanger approach. From a safety and design simplicity standpoint, Innova particularly appreciated that the DHU design eliminated the complicated burner management system, large fire box, pilots and complex safety interlocks associated with a fired heater. In addition, because the DHU combines two unit operations (fired heater/exchanger) into a single vessel, it offers a lower total capital cost.

Based on these advantages, Innova chose to apply the novel DHU technology for its plant expansion. Following basic design, detailed engineering and commissioning, the revamped unit successfully went onstream in May 2019.

"The DHU is easy to start-up and responds well to changes in operation. The success of DHU is due to close cooperation between Innova and Badger throughout the entire project execution, start-up and day-to-day operation of the unit," comments Wagner Debom, Innova's plant manager.

With the change to the three-reactor system and by operating at deep vacuum conditions, Innova has decreased the weight ratio of reactor steam to ethylbenzene feed to as low as 1.02:1 from a pre-revamp average of approximately 1.5:1. Intrinsically, this translates into significant savings in fuel and steam. When combined with the distillation section upgrades, the project achieved an overall energy savings of approximately 25%.

Badger Licensing offers DHU technology for both revamp and grassroots designs. By eliminating certain temperature and metallurgical constraints of the conventional technology, it allows efficient recovery of low-level process heat and, thus, significantly reduces energy input and carbon dioxide emissions. ●

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Make Mill Improvements Materialize

Use a planned expansion to address important issues

THIS MONTH'S PUZZLER

I run a mill (figure online at https://bit.ly/3mp1x2w) that processes different types of oil seeds, e.g., soybeans, into oils that our clients then sell. After five years of operation, we want to expand capacity and improve quality. This also will provide an opportunity to deal with some lingering problems in the process; the grinding part of the plant and the cleaning system is designed well but the owners seemingly ran out of money when it came to the solvent extraction set-up. The word has gotten out that we are looking for improvements to consider — and everyone has an idea. I need help sorting through these suggestions.

One of the owners says we should consider an enzyme addition to the hexane we use; during construction, he had pushed for going with an exotic solvent instead of tried-and-true hexane; at his behest, the salesperson continues to badger me.

Our young maintenance engineer has a fairly lengthy list: 1) cartridge filters to take care of fouling in the solvent recycle system (I reckon socks would work better); 2) a weir instead of spray nozzles that clog (but a weir can plug); 3) stronger vacuum on the percolator screen and in the meal dryer (which seems sensible until you consider flammability with hexane); 4) fouling in the steam deaerator tank (he blames the chemical treatment — but that needs more study); 5) decanter fouling in the solvent recovery prior to steam stripping; and 6) tearing of the percolator screen every month — he found a screen maker that invented an easier unzipping of the screen, which is a really good idea!

Our quality control manager's agenda is to improve the clarity in the oil. I'm still waiting for his shopping list.

What do you think is the best approach for us to improve the plant performance?

DON'T DISMISS ENZYMES

From a project management viewpoint, one notable point is that you have a very enthusiastic and supportive team. Consider:

1. Several research papers claim that enzyme addition or pretreatment has better yield than that with solvents consisting primarily of n-hexane and isomers. You need data from industrial-scale operations. An abrupt change of solvent system could cause unforeseen and, perhaps, major operational problems. To minimize operational risk, conduct a survey to determine plant-scale experience with enzyme systems. You might contact percolator manufacturers to see if they would conduct pilot runs to quantify the benefits of enzyme addition or pretreatment.

2. As environmental concerns escalate, you should consider a switch to "green solvents" as a long-range strategy.

3. Review current operating data and bottlenecks to see if changes in operation — such as solvent temperature, (soybean) flake size, crushing of the soybeans prior to their entry to percolator, flow rate from hopper and solvent recycle — could improve oil extraction yield and hexane consumption.

4. The suggestion about deeper vacuum on the percolator requires you to examine associated issues:

- Deeper vacuum on the percolator will reduce potential solvent leaks to atmosphere. Because leaks could form a flammable vapor cloud, deeper vacuum helps minimize flammability risk.
- Deeper vacuum lowers the boiling point of hexane, which, in turn, will lower the oil extraction rate from soybeans (and other seeds). Of course, you should keep solvent temperature as high as practical (considering hexane/water azeotrope) to enhance oil extraction rate from seeds.
- It's a balancing act between vacuum and flammability risk. Effective ventilation in the percolator building helps with lowering the flammability risk.

5. Filters in the solvent recycle system should help reduce fouling as well as clogging of spray nozzles.

6. Frequent tears in the percolator screen obviously are a bottleneck. Check past records to determine possible causes of tearing. In addition, investigate improvements in screen attachment and maintenance.

As is common in any project work, prioritize key action items and assign projected completion times for these items. Keep all stakeholders in the loop.

GC Shah, consultant
Houston

FOCUS ON THE LEACHING

The very heart of your process is the leaching operation. Anything you do to improve it will have multipliers that will save you money. Let's consider what leaching is: close contact of a solvent with a solid. Contact is a factor. Time is a factor. Driving force is a factor. Everything else is a distraction from what makes you money.

Improved contact comes from mixing providing increased surface area between the solid and solvent. This means making the grind as fine as possible but avoiding clumping. It means removing spent solvent from the contact area between fresh solvent and fresh solid.

Time is a factor because this extractive process is between a solid and a liquid, not a liquid and a gas.

Driving force is the concentration differential between the oil and the solvent; it's promoted by temperature.

Maintenance is a factor but only where leaching is involved. Filtering recycled solvent is a quick fix for fouling spray nozzles — and, perhaps, the steam deaerator tank. Cartridge filters, also called "depth filters," are a landfill nightmare; sock filters, also known as "surface filters," are limited to 1 micron, though. The typical range of cartridge filters is 0.1–500 microns; for sock filters, it's 1–1,000 microns. Also, you can backwash and reuse sock filters; cartridge filters aren't reusable and are limited to light loads, i.e., 0.01% solids by weight in a liquid. Perhaps a combination — the sock upstream of the cartridge filter — will work. For more information, see: https://bit.ly/39RiDRx

I'm not big fan of weirs, which also foul. Fix the fouling.

Increasing the vacuum on the percolator seems like a good idea but, with higher vacuum, you also get more tramp air. Unless you've designed your vacuum system for this problem, this is an expensive option with questionable payback.

Improve the mixing over the percolator surface to expose more of the solid to the solvent.

Using the new screen is an excellent idea. But don't lose sight of the main goal of improving leaching. Choose a screen that's easily removed or adjusted with the right sieve resistance not just a screen that's easy to replace.

Perhaps the enzyme is the way to go — but first run some tests in the laboratory. While you're there, try optimizing your grind to improve the efficiency of the heart of the problem: the leaching.

Dirk Willard, consultant
Wooster, Ohio

JULY'S PUZZLER

We just replaced a high-density polypropylene (HDPP) mesh pad and glass-filled polypropylene packing at the top of our distillation tower with a metal mesh pad and metal packing. We had installed the packing and mesh pad because we needed greater efficiency than we were getting with the simple tray design below in the tower. Unfortunately, we now can't seem to make purity in the condenser.

Operations was concerned about spikes in temperature beyond 200°F during start-up and maintenance's desire to steam the packing and pad to speed up cleaning. Our condenser set point is 162°F. The project engineer fought long and hard against the metal replacement because he says it's less efficient than the HDPP and can crust over, making removal difficult.

Maintenance also worries about carryover of broken mesh into the condenser and product. Quality control has seen no sign of mesh in the three years we have used HDPP packing.

Even with that concern, maintenance said a bed limiter wasn't needed for metal packing like it was for plastic. So, one wasn't installed with the metal packing.

Currently, cleaning the distillation tower involves washing with a detergent and then muriatic acid, followed by hot water. Maintenance insists that a high-pressure gun easily can steam clean the metal packing and metal mesh.

Did we make the right choice? Is there any other way to get higher efficiency in the upper section of the distillation tower? What kind of trouble might we encounter by using the metal packing and metal mesh pad?

Send us your comments, suggestions or solutions for this question by June 11, 2021. We'll include as many of them as possible in the July 2021 issue and all on ChemicalProcessing.com. Send visuals — a sketch is fine. E-mail us at ProcessPuzzler@putman.net or mail to Process Puzzler, *Chemical Processing*, 1501 E. Woodfield Rd., Suite 400N, Schaumburg, IL 60173. Fax: (630) 467-1120. Please include your name, title, location and company affiliation in the response.

And, of course, if you have a process problem you'd like to pose to our readers, send it along and we'll be pleased to consider it for publication.

Select the Optimum Materials

Consider a variety of factors beyond inherent corrosion resistance

You must take into account material availability.

MATERIALS SELECTION should strike an appropriate balance among capital, operating and maintenance costs. It should consider control of process conditions (temperature, pressure and velocity) and stream composition, use of protective coatings and additives, as well as preventative maintenance and inspection programs. The exact mix depends upon the constraints of the process. It's a given, though, that some corrosion is inevitable at nearly every plant. After all, few materials are completely invulnerable to the conditions they'll face in a process.

Here, we'll look at a new plant to illustrate how numerous elements may affect materials selection. This plant is for a first-of-a-kind process that involves using a couple of organic acids to produce a high-value intermediate. While the corrosion behavior of one of the organic acids is well understood, that's far from the case for the second. In addition, one of the streams contains a rarely encountered but potentially corrosive chemical that essentially has unknown behavior.

Initial materials selection focused on a well-known proprietary alloy — but getting it in all the forms needed for the equipment is extremely difficult. This problem has re-opened the question of what are the right materials to choose.

First, you must determine which materials are suitable. This involves understanding the corrosion rate, the failure type and the consequences of failure — and then picking a material that gives the plant a reasonable life. In one case, a client specified a plant life of only eight years but, more typically, the stipulated life is 20–25 years. The right choice for eight years may differ markedly from the one for 25 years. Failures from corrosion can result from gradual deterioration of an entire surface; steady but localized pitting; or sudden attack. Process temperature or pressure can induce failures. You also must consider the consequences of failure. Leaking a little cooling water may pose a minor issue but a sudden loss of containment of a flammable or toxic chemical may lead to catastrophic consequences. For the new plant, many alloys would be suitable, with an alloy's molybdenum content likely a key issue for the organic acids.

Second, you must evaluate the cost balance between the available choices. In this case, a material that's almost sure to work cost over eight times more than the least expensive one that might work. The economics of the project could tolerate a material only ≈2.5–3 times costlier than the least expensive option. This restricted the choices to six alloys.

Third, you must take into account material availability — looking at two factors: the forms in which a material is manufactured; and whether these are readily purchasable or require a special order. So, you must assess your process requirements. Do you need tubes, plate, forged fittings, thin or thick sheets? Also, how will the equipment be assembled? In this case, we could get the forms necessary but only three of the alloys had off-the-shelf availability; these were the less expensive (good) but probably lower-performing (bad) choices. We could purchase equipment in these three without excessive lead-times. In addition, these choices would simplify future spare-parts procurements and maintenance. The other three materials had regional variations in availability; one was easier to get in the United States and the other two more readily available in Europe. While this isn't a major problem, it is a factor to consider.

Because this is a new process, the three candidate materials — the cheapest that might work; an off-the-shelf material that likely will offer much higher corrosion resistance; and an uncommon (and expensive) material expected to give excellent corrosion resistance — will undergo testing. The program will use mixtures of the organic acids to check corrosion rates and look for unexpected problems. The results should provide a prudent basis for economic and safe materials selection. (For some caveats about the use of stainless steels, see "Don't Put Peddle to the Metal," https://bit.ly/3fMW9ov.)

Ultimately, we'll probably opt for a mix of materials, with the choice depending upon the equipment type and the part of the process. For example, structured packing in distillation towers is thin and corrodes on both sides; a loss of just 1–2 mils may destroy the packing. In contrast, adding a corrosion allowance to a vessel wall usually is straightforward.

ANDREW SLOLEY, Contributing Editor
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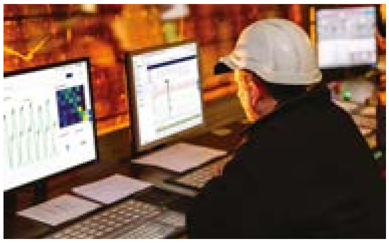

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Put the Bull and Bear in Clean Energy

A stock-market-style price index could help better calculate and forecast U.S. energy prices

EPIC takes a three-pronged approach.

RESEARCHERS FROM Texas A&M University, Collage Station, Texas, have devised a predictive framework known as the energy price index (EPIC) that reflects changes in energy prices resulting from the energy sources available and their supply chains.

Such a tool is needed, the researchers say, for several reasons. For example, energy markets are sensitive and volatile to technological innovations, changes in monetary and fiscal policies, major global events and consumer trends.

At the same time, important strategic, political and commercial decisions and their associated policies are assessed in economic terms, so accurately evaluating the price of energy is crucial.

Similar to how the Dow index reflects trends in the stock market, the new metric can calculate and forecast the average price of energy in the United States.

"Energy is affected by all kinds of events, including political developments, technological breakthroughs and other happenings going on at a global scale," says Stefanos Baratsas, a graduate student in chemical engineering at Texas A&M and the lead author on the study. "It's crucial to understand the price of energy across the energy landscape along with its supply and demand. We came up with one number that reflects exactly that. In other words, our metric monitors the price of energy as a whole on a monthly basis," he adds.

Writing in a recent issue of *Nature Communications*, the researchers point out that while targets are being set for the use of renewables in the overall energy mix, up to now there hasn't been a way to quantitatively and accurately measure the price of energy as a whole.

EPIC takes a three-pronged approach to overcome this. Firstly, it represents the average price of energy in the United States over the entire energy landscape, covering all the different energy sources and feedstocks (non-renewables and renewables), as well as the end-use sectors.

Second, the proposed formulation collectively captures the two key attributes of energy: the supply and demand mechanisms along with the prices of the energy feedstocks and products across the entire energy landscape. The authors note here that other methodologies in the literature generally focus on specific energy sectors.

Lastly, the forecasting ability — called excellent by the authors — of the proposed mathematical framework allows estimating the current value of EPIC and, thus, the current price of energy, overcoming the issue of the non-availability of actual data. It also can be used to forecast future values of energy demand accurately.

They put EPIC into practice on two real-life policy case studies.

The first looked at crude oil. Here, the researchers parametrically examined the effects of a crude oil tax ranging from $2.50/bbl up to $25/bbl, while noting that in 2016 President Barack Obama proposed a $10.25/bbl tax to support new transportation systems designed to reduce carbon emissions and congestion.

EPIC calculated the amount of potential revenue such a policy could generate from January 2003 until June 2020 — finding it could produce around $148 billion in four years for every $5/bbl increase in crude oil tax. Also, this tax wouldn't significantly increase the monthly cost of energy for U.S. households.

President Obama's proposed increase in crude oil tax would have raised $284 billion over four years while boosting monthly energy-related expenses per household by $76.90, or 5.54%.

The second case study explored the effect of subsidies in the production of electricity from renewable energy sources including hydroelectric, biomass, geothermal, solar and wind. It found that such policies can cause a dip in energy prices even with no tax credit.

Baratsas says their approach offers a way to optimize policies at the state, regional and national level for a smooth and efficient transition to clean energy. Further, he notes their metric could adapt or self-correct its forecasting of energy demands and prices in the event of sudden, unforeseen situations, such as the COVID-19 pandemic, that may trigger a drastic decrease in demand for certain energy products.

"This metric can help guide lawmakers, government or non-government organizations and policymakers on whether, say, a particular tax policy or the impact of a technological advance is good or bad, and by how much," says Stratos Pistikopoulos, director of the Texas A&M Energy Institute and senior author on the study. "We now have a quantitative and accurate, predictive metric to navigate the evolving energy landscape, and that's the real value of the index," he concludes.

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